# Attachment 1.1 Non-Technical Summary

2019/2020

# Integrated Resource Plan

VECTREN

A CenterPoint Energy Company

## Non-Technical Summary

## I. Introduction

Southern Indiana Gas and Electric Company d/b/a Vectren a CenterPoint Energy Company's ("Vectren") 2019/2020 Integrated Resource Plan is submitted in accordance with the requirements of the Indiana Utility Regulatory Commission (IURC or Commission) and the guidance provided in the Commission's recent orders related to the preferred portfolio described in Vectren's previous 2016 Integrated Resource Plan ("IRP"). The preferred portfolio in Vectren's previous 2016 IRP contemplated replacement of some of Vectren's coal fleet by the end of 2023 with a mix of renewable, energy efficiency and gas resources while retaining other coal resources. To implement this plan, Vectren filed two cases seeking Certificates of Public Convenience and Necessity ("CPCN") to (1) own and operate a 50 MW solar project located on its system (the "Troy Solar Project"), (2) install equipment designed to achieve compliance with environmental regulations in order to continue operation of its 270 MW Culley Unit 3 beyond 2023 and construct a 700-850 MW Combined Cycle Gas Turbine ("CCGT"). The Commission approved issuance of CPCNs authorizing the construction of the Troy Solar Project and Culley Unit 3 compliance projects. The Commission order denying a CPCN for the 700-850 MW CCGT urged Vectren to:

- Focus on outcomes that reasonably minimize the potential risk of an asset becoming uneconomic in an environment of rapid technological innovation;
- Fully consider options that provide a bridge to the future;
- Utilize a request for proposals ("RFP") to determine the price and availability of renewables; and
- Consider resource diversity and alternatives that provide off ramps that would allow Vectren to react to changing circumstances.

Vectren began its 2019/2020 IRP process in April 2019 with the objective of engaging in a generation planning process responsive to the Commission's guidance and seeking input from a variety of stakeholders. As part of its 2019/2020 IRP process, Vectren's evaluation has focused on exploring all new and existing supply-side and demand side resource options to reliably serve Vectren customers over the next 20 years. While the fundamentals of integrated resource planning were adhered to in developing the 2016 IRP, Vectren has enhanced its process and analysis in several ways. These enhancements include, but are not limited to the following:

- Issuance of an All-Source RFP to provide current market project pricing to be utilized in IRP modeling and potential projects to pursue, particularly for renewable resources such as wind and solar;
- An exhaustive review of reasonable options that leverage existing coal resources;
- increased participation and collaboration from stakeholders on all aspects of the analysis, inputs and resource evaluation criteria, with specific considerations and responses from Vectren;
- An encompassing analysis of wholesale market dynamics that accounts for MISO developments and market trends;
- The use of a more sophisticated IRP modeling tool, Aurora, which provided several benefits (simultaneous evaluation of many resources, evaluation of portfolios on an hourly basis and consistency in modeling, including least cost long-term capacity expansion planning optimization, simulated dispatch of resources and probabilistic modeling); and
- A more robust risk analysis, which encompasses a broad consideration of risks and an exploration of resource performance over a wide range of potential futures.

Based on this planning process and detailed analysis, Vectren has selected a preferred portfolio plan that significantly yet prudently diversifies the resource mix for its generation portfolio with the addition of significant solar and wind energy resources, the retirement or exit of four coal units, and continued investment in energy efficiency. These resources are complemented with dispatchable resources including continued operation of Culley Unit 3 and the addition of two flexible natural gas Combustion Turbines (CTs). The gas units represent a much smaller portion of Vectren's generation portfolio as compared to the 2016 IRP preferred portfolio while still providing reliable capacity and energy. The highly dispatchable and fast-ramping gas units are an important match with the significant renewable investment, enabling Vectren to maintain constant electric supply during potentially extended periods of low output from renewable energy sources. The units ramp quickly and provide load following capability, complimenting renewable energy production, which is expected to grow throughout the MISO footprint. Vectren's preferred portfolio reduces its cost of providing service to customers over the next 20 years by more than $320 million as compared to continuing with its existing generation fleet. Additionally, the preferred portfolio reduces carbon dioxide output by approximately 67% by 2025 and 75% by 2035 when compared to 2005 levels, which helps Vectren's parent company, CenterPoint Energy, achieve its commitments to environmental stewardship and sustainability, while meeting customer expectations for clean energy that is reliable and affordable.

Vectren's preferred resource plan reduces risk through diversification, reduces the cost to serve load over the next 20 years and provides the flexibility to continue to evaluate and respond to future needs through subsequent IRPs. The preferred portfolio has several advantages: including: 1) Energy supplied by this portfolio is generated primarily through a significant amount of near-term renewable solar and wind projects that take advantage of the Investment Tax Credit and the Production Tax Credit. This lowers portfolio costs and takes advantage of current tax-advantaged assets. 2) Two new, low-cost gas combustion turbines, continued use of Vectren's most efficient coal unit (Culley 3) and new battery storage resources, provide resilient, dispatchable power to Vectren's system that is complementary to significant investment in new intermittent renewable resources. This is very important, as coal plants, which have provided these attributes in the past, continue to retire in MISO Zone 6. 3) The portfolio provides flexibility to adapt to and perform well under a wide range of potential future legislative, regulatory, and market conditions. The preferred portfolio performed well under $CO_2$, methane constraints, and other related regulations such as a fracking ban. The cost position of this portfolio that is backed up by the two combustion turbine capacity resources does not change because the gas turbines predominantly run during peak load conditions. This provides a financial hedge against periodic instances of high market energy and capacity prices, while also providing reactive reserves and system reliability in times of extended renewable generation droughts, i.e., cloud cover and low wind. 4) It reasonably balances energy sales against purchases to remain poised to adapt to market shifts. 5) It includes new solar capacity when it is most economic to the portfolio. 6) Finally, it is timely. New combustion turbines can come online quickly to replace coal generation that retires by the end of 2023, minimizing in-service lag and reducing exposure to the market.

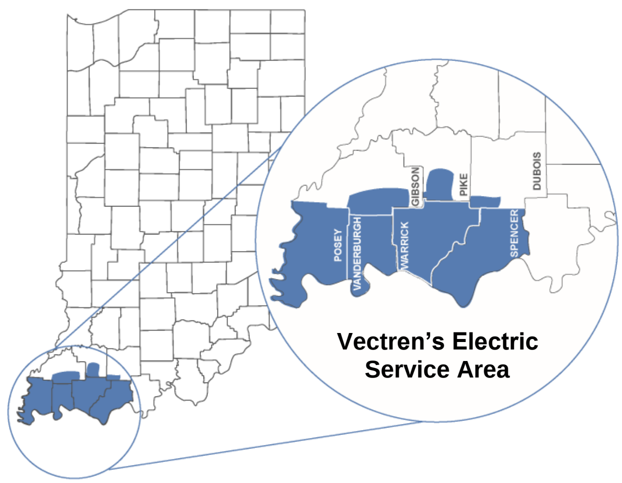
The resource options selected in this plan provide a bridge to the future. For example, CT's allow time for battery storage technology to continue to become more competitive in price and further develop longer duration storage capabilities. Further, should there be a need for new baseload generation in the future to accommodate a large load addition or to replace Warrick 4 and Culley 3, one or both CT's could be converted to a CCGT, a highly efficient gas energy resource. Even with the large commitment in the near term to renewable resources, additional renewable resources can be added over time.

The preferred portfolio also provides several off-ramps (future transitional inflection points) should they be needed. 1) Vectren continues to speak with Alcoa about a possible extension of Warrick 4 (W4) joint operations through 2026. This option could provide additional time and shield Vectren customers from capacity purchases at a time where the market is expected to be tight, causing much higher projected prices than today. Additionally, time may be needed to allow Vectren to secure the level of renewable resources identified in the preferred portfolio and to allow for contingency for permitting and construction of new combustion turbines. 2) While Culley 3 is not scheduled to be retired within the timeframe of this analysis, including thermal dispatchable generation in this portfolio will allow Vectren flexibility to evaluate this option in future IRPs. 3) Vectren will work to secure attractive renewables projects from the recent All-Source RFP but will likely require a second RFP to fully secure 700-1,000 MWs of solar on multiple sites and 300 MWs of wind constructed over a span of several years. Issuing a second RFP provides two main benefits. It allows more local renewable options to select from, as some offered proposals are no longer available. Second, it provides additional time to better understand how MISO intends to move forward with market adjustments, such as capacity accreditation and energy price formation. MISO's wholesale market is adapting to fleet transition that is moving toward intermittent renewable resources.

What follows is a summary of Vectren's process to identify this portfolio, focusing on Vectren's operations, an explanation of the planning process and a summary of the preferred portfolio.

## II. Vectren Overview

Vectren provides energy delivery services to more than 146,000 electric customers located near Evansville in Southwestern Indiana. In 2018, approximately 44% of electric sales were made to large (primarily industrial) customers, 30% were made to residential customers and 26% were made to small commercial customers.




The table below shows Vectren generating units. Since the last IRP, Vectren has formally retired four, older small natural gas units[1] rather than investing significant capital dollars to ensure safety and reliability. Note that Vectren also offers customers energy efficiency programs to help lower customer energy usage and bills.

| Unit | Installed Capacity ICAP (MW) | Primary Fuel | Year in Service | Unit Age | Coal Unit Environmental Controls[2] |
|---|---|---|---|---|---|
| A.B. Brown 1 | 245 | Coal | 1979 | 41 | Yes |
| A.B. Brown 2 | 245 | Coal | 1986 | 34 | Yes |
| F.B. Culley 2 | 90 | Coal | 1966 | 54 | Yes |
| F.B. Culley 3 | 270 | Coal | 1973 | 47 | Yes |

[1] In 2018, Vectren retired BAGS 1 (50 MW). In 2019, Vectren retired Northeast 1&2 (20 MW) and BAGS2 (65 MW)

[2] All coal units are controlled for Sulfur Dioxide ($SO_2$), Nitrogen Oxide ($NO_X$), Particulate Matter (dust), and Mercury. All coal units are controlled for Sulfur Trioxide ($SO_3$) and Sulfuric Acid ($H2S0_4$) except F.B. Culley 2.

| Unit | Installed Capacity ICAP (MW) | Primary Fuel | Year in Service | Unit Age | Coal Unit Environmental Controls[2] |
|---|---|---|---|---|---|
| Warrick 4 | 150 | Coal | 1970 | 50 | Yes |
| A.B. Brown 3 | 80 | Gas | 1991 | 29 | |
| A.B. Brown 4 | 80 | Gas | 2002 | 18 | |
| Blackfoot[3] | 3 | Landfill Gas | 2009 | 11 | |
| Fowler Ridge | 50 | Wind PPA | 2010 | 10 | |
| Benton County | 30 | Wind PPA | 2007 | 13 | |
| Oak Hill[4] | 2 | Solar | 2018 | <2 | |
| Volkman Rd[5] | 2 | Solar | 2018 | <2 | |
| Troy | 50 | Solar | 2021 | | |

## III. Integrated Resource Plan

Every three years Vectren submits an IRP to the IURC as required by IURC rules. The IRP describes the analysis process used to evaluate the best mix of generation and energy efficiency resources (resource portfolio) to meet customers' needs for reliable, low cost, environmentally sustainable power over the next 20 years. The IRP can be thought of as a compass setting the direction for future generation and energy efficiency options. Future analysis, filings and subsequent approvals from the IURC are needed to implement selection of new resources.

Vectren utilized direct feedback on analysis methodology, analysis inputs, and evaluation criteria from stakeholders, including but not limited to Vectren residential, commercial and industrial customers, regulators, elected officials, customer advocacy groups and environmental advocacy groups. Vectren continues to place an emphasis on reliability, customer cost, risk, resource diversity, and sustainability. The IRP process has become increasingly complex in nature as renewable resources have become more cost competitive, battery energy storage has become more viable, and existing coal resources are dispatched less and less.

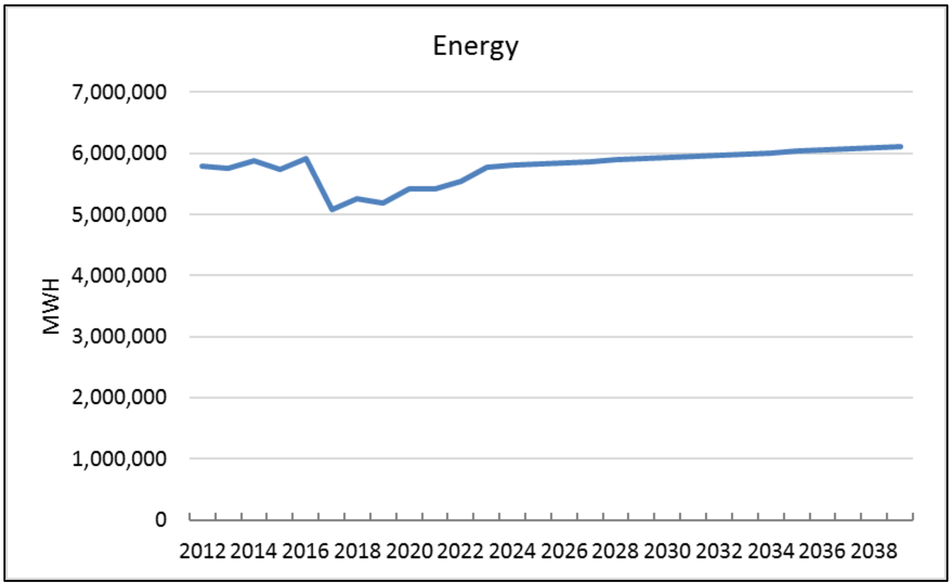
[3] The Blackfoot landfill gas generators are connected at the distribution level.
[4] Oak Hill Solar is connected at the distribution level.
[5] Volkman Rd. Solar is connected at the distribution level.

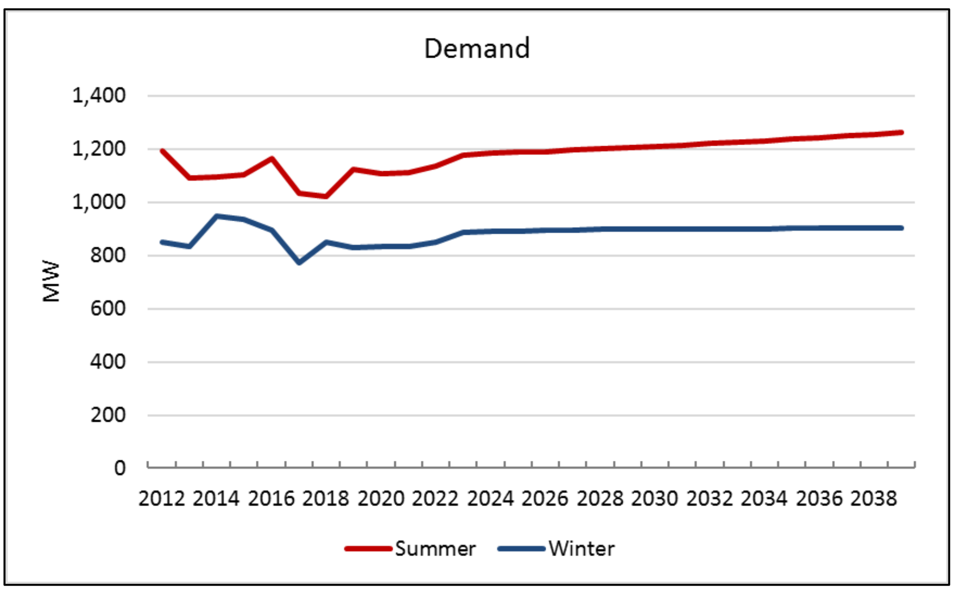
## A. Customer Energy Needs

The IRP begins by evaluating customers' need for electricity over the 20-year planning horizon. Vectren worked with Itron, Inc., a leader in the energy forecasting industry, to develop a forecast of customer energy and demand requirements. Demand is the amount of power being consumed by customers at a given point in time, while energy is the amount of power being consumed over time. Energy is typically measured in Megawatt hours (MWh) and demand is typically measured in Megawatts (MW). Both are important considerations in the IRP. While Vectren purchases some power from the market, Vectren is required to have enough generation and energy efficiency resources available to meet expected customers' annual peak demand plus additional reserve resources to meet MISO's Planning Reserve Margin Requirement (PRMR) for reliability. Reserve resources are necessary to minimize the chance of rolling black outs; moreover, as a MISO (Midcontinent Independent System Operator) member, Vectren must comply with MISO's evolving rules to maintain reliability.

Historically, IRPs have focused on meeting customer demand in the summer, which is typically when reserve margins are at a minimum. As the regional resource mix changes towards intermittent (variable) renewable generation, it is important to ensure that resources are available to meet this demand in all hours of the year, particularly in the times of greatest need (summer and winter). MISO functions as the regional transmission operator for 15 Midwestern and Southern states, including Indiana (also parts of Canada). In recognition of MISO's ongoing evaluation of how changes in the future resource mix impact seasonal reliability, Vectren ensured that its preferred portfolio would have adequate reserve margins for meeting both the winter and summer peak demand. Later in this document it is further explained how MISO is evaluating measures to help ensure year-round reliability.

Vectren utilizes sophisticated models to help determine energy needs for residential, commercial and large customers. These models include projections for the major drivers of energy consumption, including but not limited to, the economy, appliance efficiency trends, population growth, price of electricity, weather, specific changes in existing large customer demand and customer adoption of solar and electric vehicles. Overall, customer energy and summer demand are expected to grow by 0.6% per year. Winter demand grows at a slightly slower pace of 0.5%.



## B. Resource Options

- **Energy Efficiency/Demand Response**
- **Natural Gas**
- **Coal**
- **Renewables, Wind & Solar**
- **Battery Storage**

The next step in an IRP is identifying resource options to satisfy customers' anticipated need. Many resources were evaluated to meet customer energy needs over the next 20 years. Vectren considered both new and existing resource options. Burns and McDonnell, a well-respected engineering firm, conducted an All-Source RFP which generated 110 unique proposals to provide energy and capacity from a wide range of technologies, including: solar, solar + short duration battery storage, standalone short duration battery storage, demand response, wind, gas and coal. These project bids provided up-to-date market-based information to inform the analysis and provide actionable projects to pursue to meet customer needs in the near to midterm. Additionally, Vectren utilized other information sources for long term costs and operating characteristics for these resources and others over the entire 20-year period. Other options include continuation of existing coal units, conversion of coal units to natural gas, various natural gas resources, hydro, landfill gas, and long-duration batteries, as well as partnering with other load-serving entities. Every IRP is a snapshot in time producing a direction based on the best information known at the time. It is helpful to provide some background into significant issues that help shape the IRP analysis, including but not limited to: projected low stable gas prices, low cost and projected high penetration of intermittent renewable resources, future of coal resources, new technology and projected changes in the MISO market to adapt and help ensure reliability.

### i. Industry Transition

The cost of fuel used by generation facilities to produce electricity is also accounted for in evaluating the cost of various electric supply alternatives. Gas prices are near record low levels and are projected to remain stable over the long term. Shale gas has revolutionized the industry, driving these low gas prices and has fueled a surge in low-cost gas generation around the country. Vectren's IRP reflects the benefit low gas prices provide to the market, as gas units are on the margin and typically set market prices for energy.

Within the MISO footprint, energy from gas generation has increased from less than 10% of total electric generation, used primarily to meet the needs during peak demand conditions in 2005, to approximately 26% of total generation in 2018[6]. Meanwhile, the cost of renewable energy has declined dramatically over this time period due to improvements in technology and helped by government incentives in the forms of the Production Tax Credit for wind and the Investment Tax Credit (ITC) for solar, both of which are set to expire or ratchet down significantly over the next few years.

MISO Energy Mix Transition (GWH) from 2005 to 2018 to 2030
(Based on Utility Announcements and State Integrated Resource Plans)*

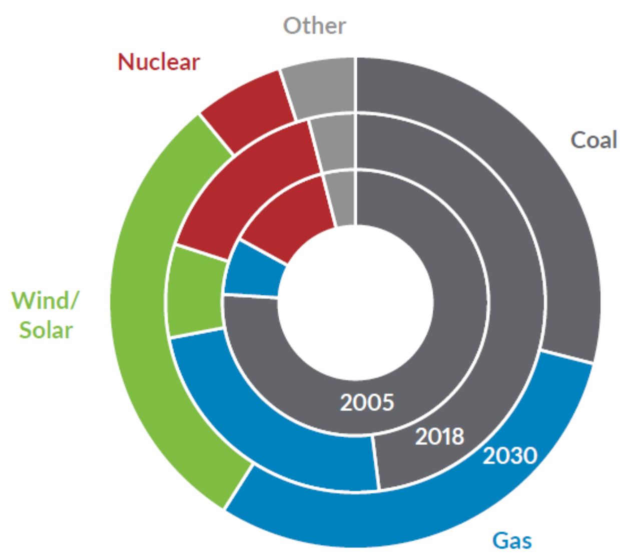



*Chart reflects ratios of generation.

The move toward low cost renewable and gas energy has come at the expense of coal generation, which has been rapidly retiring for several reasons. Coal plants have not been able to compete on price with low cost renewable and gas energy. Operationally, the move toward intermittent renewable energy requires coal plants to more frequently cycle on and off. These plants were not

[6] MISO Forward Report, March 2019, page 10. https://cdn.misoenergy.org/MISO%20FORWARD324749.pdf

designed to operate in this manner. The result is increased maintenance costs and more frequent outages. Additionally, older, inefficient coal plants are being retired to avoid spending significant dollars on necessary upgrades to achieve compliance with Environmental Protection Agency (EPA) regulations. Finally, public and investor pressure, coupled with future cost risk associated with the objective of decreasing carbon emissions, has driven unit retirements. Based on these and other major factors, MISO expects the generation mix in 2030 to be much more balanced than in the past with roughly one third renewables, one third gas and one third coal. Some large nuclear plants remain but have also found it challenging to compete on cost.

**ii. Changing Market Rules to Help Ensure Reliability**

MISO recognizes these major changes in the way energy is being produced. Traditionally, baseload coal plants produced energy at a constant level, while peaking gas plants were available to come online as needed to meet peak demand. Gradual increases and decreases in energy demand throughout the day and seasonally were easily managed with these traditional resources. As described above, the energy landscape is continuing its rapid change with increased adoption of more intermittent renewable generation which is available when the sun is shining, or the wind is blowing. This creates much more variability by hour in energy production. Some periods will have over production (more energy produced than is needed at the time) and other periods will have low to no renewable energy production, requiring dispatchable resources to meet real time demand for power. MISO is in the process of studying how this transition will affect the electrical grid and what is needed to maintain reliable service, as renewables penetrations reach 30-50%. Possible ramifications include challenges to the ability to maintain acceptable voltage and thermal limits on the grid.

To deal with these challenges, MISO has been working through a series of studies and has put forth guidance for how they intend to evaluate resources moving forward. One significant development is the recognition that all hours matter. In the past, MISO resource adequacy requirements focused on only the peak hour each year. Recent MISO emergencies in all seasons have demonstrated that the system can experience potential energy shortfalls in any hour due to changing resource conditions. As such, MISO is planning for new requirements to ensure resources are available for reliability in each of the 8,760 hours of the year. Each resource has different operating characteristics and different output levels, depending on the season. Vectren has accounted for these changes by validating that portfolios in this analysis provide sufficient resources to meets its MISO obligations[7] in the two heaviest demand periods (summer/winter). MISO has initiatives underway that include new testing requirements to ensure that Demand Response (DR) resources are available when needed. MISO's annual Market Road Map process has prioritized the development of mechanisms to more accurately account for resource availability. This includes an evaluation of how to best incent resources with the right kinds of critical attributes needed to keep the system operating reliably. Incentives are contemplated for resources that are available (dispatchable), flexible (ability to start quickly and meet changing load conditions when needed) and visible (have a better understanding of customer owned generation in addition to larger utility assets). MISO expects that traditional dispatchable coal and gas resources will continue to provide resilience to the grid.

**iii. Battery Storage and Transmission Resources**

Increasingly, utilities are considering the opportunity to add battery storage to resource portfolios to help provide the availability, flexibility and visibility needed to move to more reliance on intermittent renewable resources. Lithium-ion batteries have seen significant cost declines over the last several years as the technology begins to mature and as the auto industry creates economies of scale by increasing production to meet the anticipated demand for electric vehicles. Large scale batteries for utility applications have begun to emerge around the country, particularly where incentives

[7] Some portfolios have a heavy reliance on the market for both energy and capacity.

are available to lower the cost of this emerging technology or for special applications that improve the economics.

There are many applications for this resource, from shifting the use of renewable generation from time of generation to the time of need, to grid support for maintaining the reliability of the transmission system. Vectren has installed a 1 MW battery designed to capture energy from an adjacent solar project. This test project is providing information regarding the ability to store energy for use during the evening hours to meet customer energy demand. Along with the benefits provided by this technology, there are some limitations to keep in mind as utility scale battery storage is still evolving. Currently, commercially feasible batteries are short duration, typically four hours. There are some commercially available longer-duration batteries that show promise, but these are still very expensive. Additionally, safety standards are being developed and fire departments are being trained for the fire risk posed by L-ion batteries. Other chemistries are being developed to account for this issue but are not commercially imminent. Moreover, batteries today are a net energy draw on the system. They can produce about 90-95 percent of the energy that is stored in them. Part of this loss is due to the need to be well ventilated, cool and dry, which takes energy. Batteries are promising and have their place in current energy infrastructure, but they do not yet replace the need for other forms of dispatchable generation during extended periods without sun and wind. Vectren's All-Source RFP included bids for stand-alone batteries and batteries connected to solar resources.

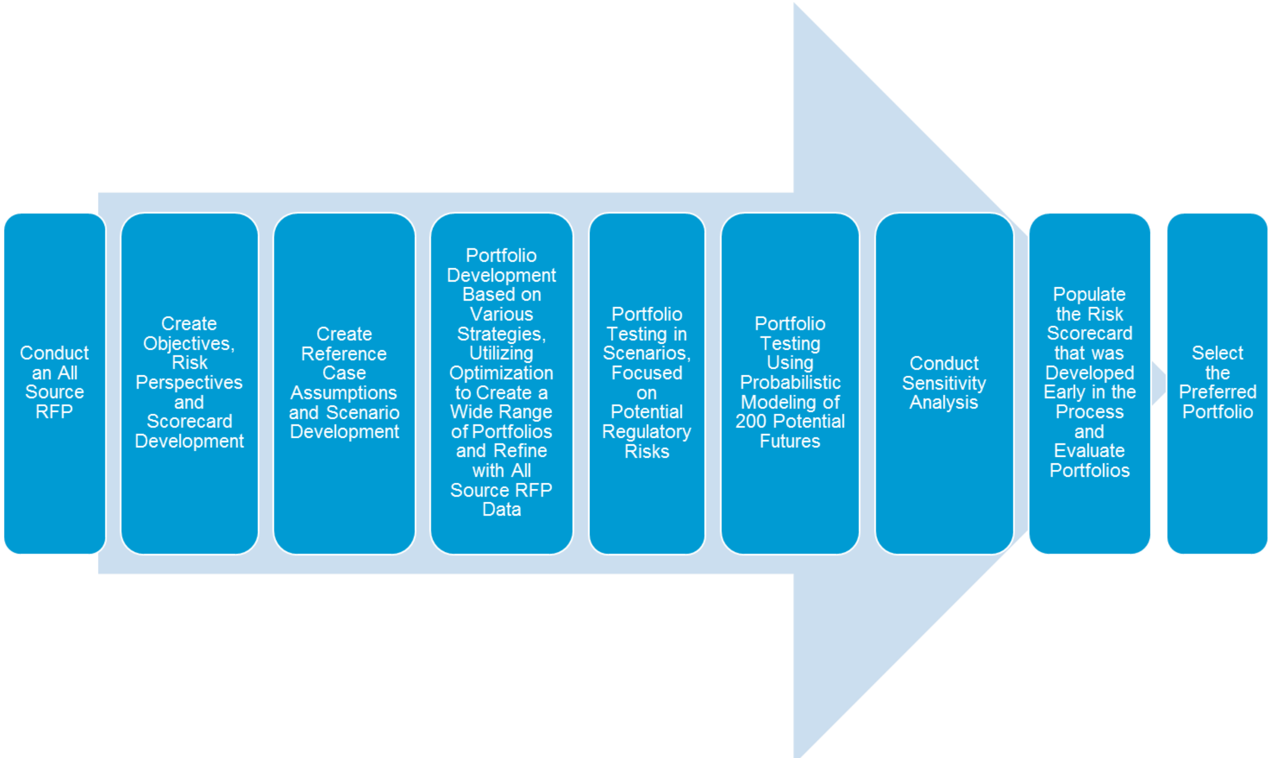
## C. Uncertainty/Risk

The future is far from certain. Uncertainty creates a risk that a generation portfolio that is reasonable under an anticipated future fails to perform as expected if the future turns out differently. Vectren's IRP analysis was developed to identify the best resource mix of generation and energy efficiency to serve customer energy needs over a wide range of possible future states. Vectren performed two sets of risk analyses, one exposing a defined set of portfolios to a limited number of scenarios and another that exposed the same portfolios to 200 scenarios (stochastic or probabilistic risk assessment). To help better understand the wide range of possibilities for wholesale market dynamics, regulations, technological breakthroughs and shifts in the economy, complex models were utilized with varying assumptions for major inputs (commodity price forecasts, energy/demand forecasts, market power prices, etc.) to develop and test portfolios with diverse resource mixes.

## IV. Analysis

Vectren's analysis included a step-by-step process to identify the preferred portfolio. The graphic below summarizes the major steps which included the following:

1. Conduct an All-Source RFP to better understand resource cost and availability.
2. Work with stakeholders to develop a scorecard as a tool in the full risk analysis to help highlight several tradeoffs among various portfolios of resources.
3. Work with stakeholders to develop a wide range of future states, called scenarios, to be used for testing of portfolios (mixes of various resource combinations to serve customer power and energy need).
4. Work with stakeholders to develop a wide range of portfolios for testing and evaluation within scenarios, sensitivity analysis and probabilistic analysis. Each of these analyses involves complex modeling.
5. Utilize the quantitative scorecard measures and judgement to select the preferred portfolio (the best mix of resources to reliably and affordably serve customer energy needs while minimizing known risks and maintaining flexibility).




## V. Stakeholder Process

Vectren reevaluated how to conduct the stakeholder process based on comments in the Director's report, stakeholder feedback and the Commission order in Cause number 45052. Careful consideration was taken to ensure that the time spent was mutually beneficial.

Each of the first three stakeholder meetings began with stakeholder feedback. Vectren would review requests since the last stakeholder meeting and provide feedback. Suggestions were taken and in instances where suggestions were not acted upon, Vectren made a point to further discuss and explain why not. Per stakeholder feedback, notes for each meeting were included in question and answer format, summarizing the conversations. Additionally, feedback was received, and questions were answered via e-mail (irp@centerpointenergy.com) and with phone calls/meetings in between each session per request.

Three of four public stakeholder meetings were held at Vectren in Evansville, IN. The final stakeholder meeting on June 15, 2020 was held via webinar due to the COVID-19 situation. Dates and topics covered are listed below:

| August 15, 2019 | October 10, 2019 | December 13, 2019 | June 15, 2020* |
|---|---|---|---|
| • 2019/2020 IRP Process<br>• Objectives and Measures<br>• All-Source RFP<br>• Environmental Update<br>• Draft Reference Case Market Inputs & Scenarios | • RFP Update<br>• Draft Resource Costs<br>• Sales and Demand Forecast<br>• DSM MPS/ Modeling Inputs<br>• Scenario Modeling Inputs<br>• Portfolio Development | • Draft Portfolios<br>• Draft Reference Case Modeling Results<br>• All-Source RFP Results and Final Modeling Inputs<br>• Scenario Testing and Probabilistic Modeling Approach and Assumptions | • Final Reference Case and Scenario Modeling Results<br>• Probabilistic Modeling Results<br>• Risk Analysis Results<br>• Preview the Preferred Portfolio |

- Moved final stakeholder meeting date per stakeholder request and the COVID-19 situation

Based on this stakeholder engagement, Vectren made fundamental changes to the analysis in real time to address concerns and strengthen the plan. IRP inputs and several of the evaluation measures used to help determine the preferred portfolio were updated through this process. Vectren utilized stakeholder information to create boundary conditions that were wide enough to produce plausible future conditions that would favor opposing resource portfolios (i.e. Indiana Coal Council (ICC) request to continue coal through 2029 or 2039 and environmental stakeholders' request to utilize all renewable resources by 2030). For example, the low regulatory future includes declining coal prices and higher gas prices, which was a request from the ICC. The High Regulatory scenario, which was heavily influenced by environmental stakeholders, is the other plausible future bookend with a natural gas fracking ban (sustained high price), a social cost of carbon fee starting at $50 per ton in 2022 and lower renewables cost trajectory than what is expected. Additionally, an evaluation measure was adjusted based on direct stakeholder input. Vectren included the life cycle of carbon emissions for all resources in response to the ICC and environmental stakeholders. The table below shows key stakeholder requests made during the process and Vectren's response.

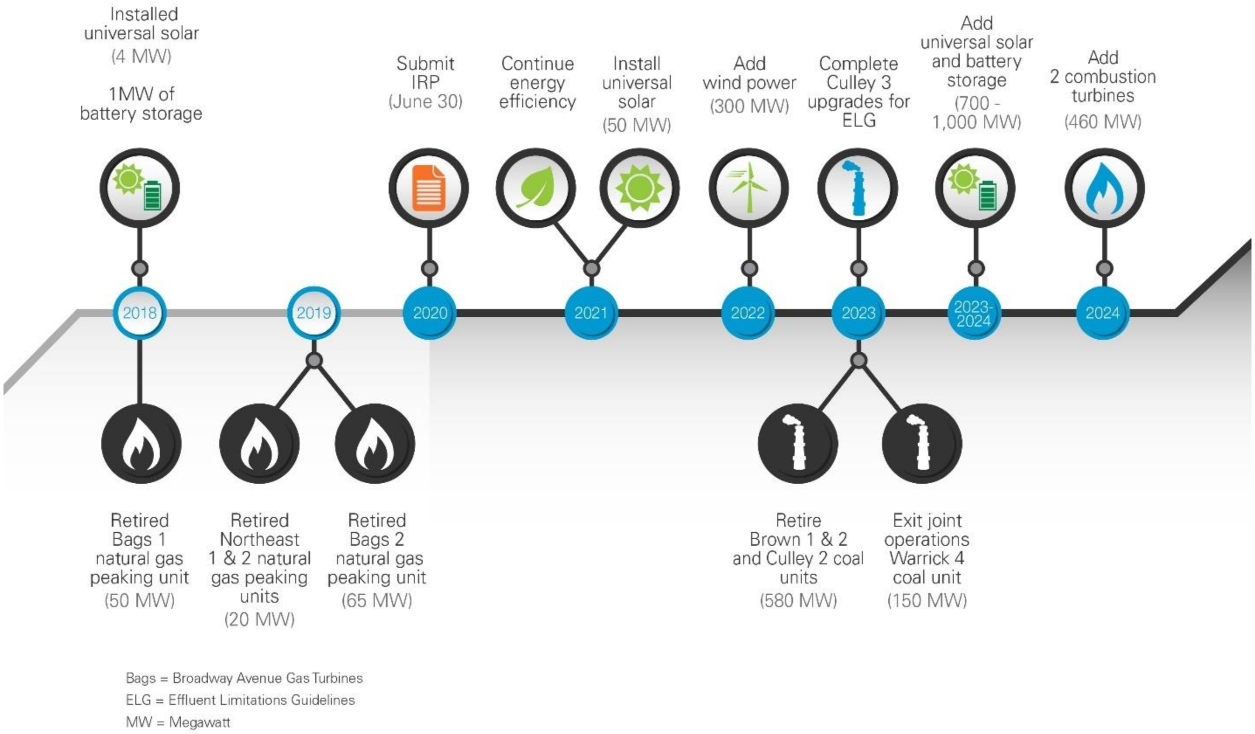
| Request | Response |
|---|---|
| Update the High Regulatory scenario to include a carbon fee and dividend | Included a fee and dividend construct which assumed a balanced impact on the load (the economic drag from a carbon fee is neutralized by the economic stimulus of a dividend) |
| Lower renewables costs in the High Regulatory and 80% $CO_2$ Reduction scenarios | Updated scenario to include lower costs for renewables and storage than the Reference scenario |
| Consider life cycle emissions using $CO_2$ equivalent | Included a quantitative measure on the risk scorecard based on National Renewable Energy Lab (NREL) Life Cycle Greenhouse Gas Emissions ($CO_2e$) from Electricity Generation by Resource |
| Include a measure within the risk score card that considers the risk that assets become uneconomic | Included an uneconomic asset risk as a consideration in the overall evaluation. Not included in the scorecard. |
| Include a scenario with a carbon dividend modeled after HB 763 with a $CO_2$ price that was approximately $200 by the end of the forecast | Utilized a scenario with these prices to create an additional portfolio. Ultimately, this portfolio was not selected for the risk analysis, as the amount of generation built |

| Request | Response |
|---|---|
| | within modeling vastly exceeded Vectren's need and resulted in large energy sales |
| Reconsider the use of a seasonal construct for MISO resource accreditation | Reviewed calculation for solar accreditation in winter and utilized an alternate methodology, increasing accreditation in the winter |
| Include a $CO_2$ price in the reference case | Included mid-range $CO_2$ prices 8 years into the forecast. The Low Regulatory scenario did not include a $CO_2$ price, thus becoming a boundary condition |

Meeting materials of each meeting can be found on www.vectren.com/irp and in Technical Appendix Attachment 3.1 Stakeholder Materials.

## VI. The Preferred Portfolio

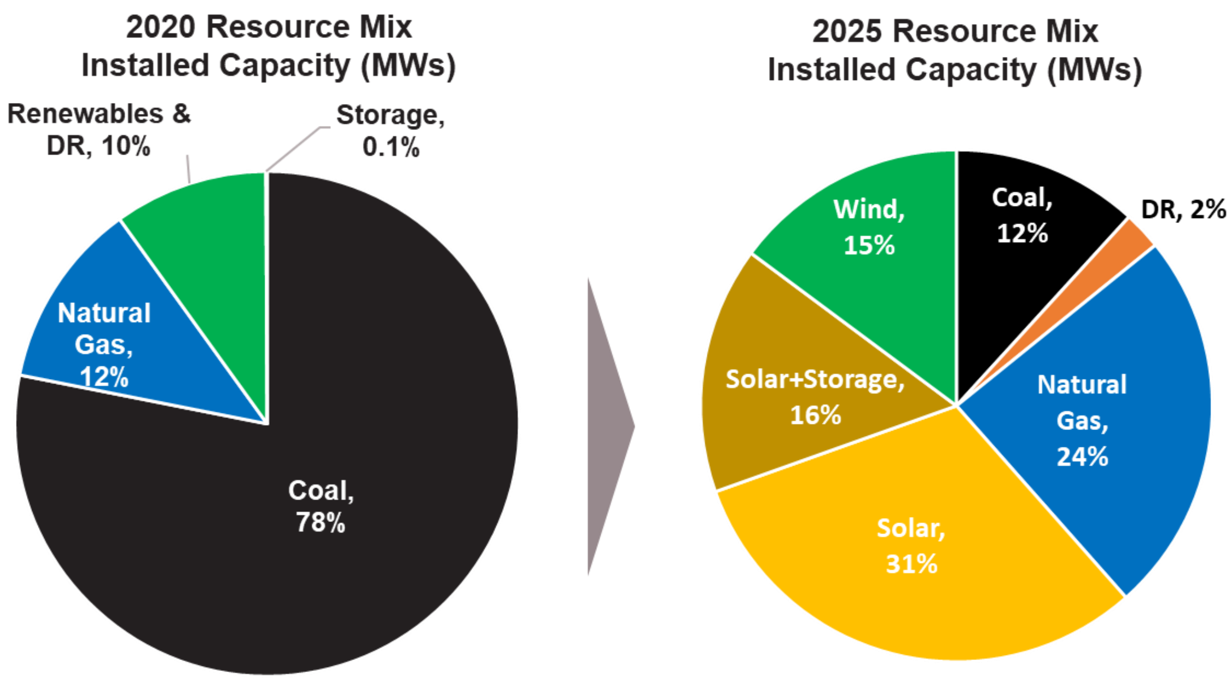
The Preferred Portfolio recommendation is to retire or exit 730 MWs of coal generation and replace with 700-1,000 MWs of solar generation (some connected to battery storage), add 300 MWs of wind backed by dispatchable generation that consists of 2 new Combustion Turbine (CT) gas units and maintaining Culley 3 (coal unit).




This preferred portfolio:

- Allows customers to enjoy the benefits of low-cost renewable energy, while ensuring continued reliable service as Vectren moves toward higher levels of intermittent renewable energy in the future.
- Saves customers over $320 million over the next 20 years when compared to continued operation of Vectren's coal fleet. The preferred portfolio is a low-cost portfolio in the near, mid and long term.
- Reduces lifecycle greenhouse gas emissions, which includes methane, by nearly 60% over the next 20 years. Direct carbon emissions are reduced 75% from 2005 levels by 2035.

- Includes a diverse mix of resources (renewables, gas and coal), mitigates the impacts of extended periods of limited renewable generation and protects against overreliance on the market for energy and capacity.
- Maintains future flexibility with several off ramps to accommodate a rapidly evolving industry, includes a multi-year build out of resources on several sites and maintains the option to extend the contract with Alcoa for Warrick 4 for a few years and maintains the option to consider the replacement of Culley 3 in the future when appropriate based on continual evaluation of changing conditions. These options will be revaluated in future IRPs.
- Provides the flexibility to adapt to future environmental regulations or upward shifts in fuel prices relative to Reference Case assumptions. The preferred portfolio performed consistently well across a wide range of potential future environmental regulations, including $CO_2$, methane and fracking.
- Adds some battery energy storage in the near term, paired with solar resources to provide clean renewable energy when solar is not available. Provides time for technological advances that will allow for high penetration of renewables across the system, further cost declines and further Vectren operational experience to meet Vectren’s customers’ energy needs.
- Continues Vectren’s energy efficiency programs with near term energy savings of 1.25% of eligible sales and further long-term energy savings opportunities identified over the next 20 years. Vectren is committed to Energy Efficiency to help customers save money on their energy bills and will continue to evaluate this option in future IRPs.




## VII. Next Steps

The preferred portfolio calls for Vectren to make changes to its generation fleet. Some of these changes require action in the near term. First, Vectren will finalize the selection process to secure renewable projects from the All-Source RFP and seek approval from the IURC for attractive projects. Second, the IRP calls for continuation of energy efficiency. Vectren filed a 2021-2023 plan with the IURC in June of 2020, consistent with the IRP. Third, Vectren intends to pursue two natural gas combustion turbines to provide dispatchable support to the large renewables based preferred portfolio. These filings will be consistent with the preferred portfolio. However, the assumptions included in any IRP can change over time, causing possible changes to resource planning. Changes in commodities, regulations, political policies, customer need and other assumptions could warrant deviations from the preferred plan.

Vectren's plan must be flexible; as several items are not certain at this time.

- The timing of exiting joint operations of the Warrick 4 coal plant could change. The plant is jointly owned with Alcoa. Without incremental investment, the plant does not comply with the ELG and other water discharge control requirements. Vectren therefore continues to talk to Alcoa about its plans.

- The availability of attractive renewable projects is currently being evaluated. Negotiations for resources must take place to finalize availability and cost of projects. The Coronavirus has put pressure on supply chains and put in jeopardy the ability of full utilization of the Production Tax Credit and Investment Tax Credit for some projects. Competition for these projects is steep, with multiple, on-going RFP processes in the state of Indiana.
- Finally, MISO continues to evaluate the accreditation of resources. Vectren will continue to follow developments to determine the right amount of renewable resources to pursue in the near term.

**Attachment 1.2 Vectren Technology Assessment Summary Table**

**VECTREN 2019 IRP TECHNOLOGY ASSESSMENT**
**SIMPLE CYCLE TECHNOLOGY ASSESSMENT PROJECT OPTIONS**
**PRELIMINARY - NOT FOR CONSTRUCTION**
**December 2019**

| **PROJECT TYPE** | **1x Aeroderivative SCGT - Natural Gas** | | **1x Aeroderivative SCGT - Natural Gas** | | **1x E Class Frame SCGT - Natural Gas** | | **1x F Class Frame SCGT - Natural Gas** | | **1x G/H Class Frame SCGT - Natural Gas** | |
|---|---|---|---|---|---|---|---|---|---|---|
| **BASE PLANT DESCRIPTION** | First Unit | Next Unit | First Unit | Next Unit | First Unit | Next Unit | First Unit | Next Unit | First Unit | Next Unit |
| Number of Gas Turbines/Engines/Units | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 |
| Representative Class Gas Turbine | GE LM6000 PF | | LMS100 PB | | GE 7E.03 | | GE 7F.05 | | GE HA.01 | |
| Capacity Factor, % | Peaking (10%) | | Peaking (10%) | | Peaking (10%) | | Peaking (10%) | | Peaking (10%) | |
| Startup Time to Base Load, min (Notes 1, 2) | 5 | | 10 | | 10 fast start / 30 conventional | | 10 fast start / 30 conventional | | 10 fast start / 30 conventional | |
| Startup Time to MECL, min (Note 3) | 4 | | 8 | | 8 fast start / 24 conventional | | 8 fast start / 24 conventional | | 8 fast start / 24 conventional | |
| Cold Startup Time to SCR Compliance, min (Note 3) | N/A | | N/A | | N/A | | N/A | | 45 | |
| Maximum Ramp Rate, MW/min (Online) | 10 | | 32 | | 10 | | 40 | | 30 | |
| Book Life, Years | 30 | | 30 | | 30 | | 30 | | 30 | |
| Equivalent Planned Outage Rate, % (Note 4, 15) | 22.3% | | 22.3% | | 26.8% | | 26.8% | | 26.8% | |
| Equivalent Forced Outage Rate, % (Notes 4, 15) | 25.9% | | 25.9% | | 5.8% | | 5.8% | | 5.8% | |
| Equivalent Availability Factor, % (Notes 4, 15) | 90.6% | | 90.6% | | 93.8% | | 93.8% | | 93.8% | |
| Assumed Land Use, Acres | 30 | 15 | 30 | 15 | 30 | 15 | 30 | 15 | 30 | 15 |
| Fuel Design | Natural Gas Only | | Natural Gas Only | | Natural Gas Only | | Natural Gas Only | | Natural Gas Only | |
| Heat Rejection | Fin Fan Heat Exchanger | | Fin Fan Heat Exchanger | | Fin Fan Heat Exchanger | | Fin Fan Heat Exchanger | | Fin Fan Heat Exchanger | |
| $NO_x$ Control | Dry Low NOx | | Dry Low NOx | | Dry Low NOx | | Dry Low NOx | | Dry Low NOx / SCR | |
| CO Control | Good Combustion Practice | | Good Combustion Practice | | Good Combustion Practice | | Good Combustion Practice | | CO Catalyst | |
| Particulate Control | Good Combustion Practice | | Good Combustion Practice | | Good Combustion Practice | | Good Combustion Practice | | Good Combustion Practice | |
| Technology Rating | Mature | | Mature | | Mature | | Mature | | Mature | |
| Permitting & Construction Schedule (Years from FNTP) | 3 | | 3 | | 3 | | 3 | | 3 | |
| **ESTIMATED PERFORMANCE (All BASED ON NATURAL GAS OPERATION)** | | | | | | | | | | |
| Nominal Base Load Performance @59° F (ISO Conditions) | | | | | | | | | | |
| Net Plant Output, kW | 41,580 | 41,580 | 97,222 | 97,222 | 84,721 | 84,721 | 236,635 | 236,635 | 279,319 | 279,319 |
| Net Plant Heat Rate, Btu/kWh (HHV) | 9,280 | 9,280 | 8,895 | 8,895 | 11,527 | 11,527 | 9,928 | 9,928 | 9,311 | 9,311 |
| Heat Input, MMBtu/h (HHV) | 386 | 386 | 865 | 865 | 977 | 977 | 2,349 | 2,349 | 2,601 | 2,601 |
| Nominal Min Load @ 59° F (ISO Conditions) | | | | | | | | | | |
| Net Plant Output, kW | 20,790 | 20,790 | 48,611 | 48,611 | 42,361 | 42,361 | 96,448 | 96,448 | 83,197 | 83,197 |
| Net Plant Heat Rate, Btu/kWh (HHV) | 12,170 | 12,170 | 10,431 | 10,431 | 15,158 | 15,158 | 13,240 | 13,240 | 13,527 | 13,527 |
| Heat Input, MMBtu/h (HHV) | 253 | 253 | 507 | 507 | 642 | 642 | 1,277 | 1,277 | 1,125 | 1,125 |
| Base Load Performance @ 20° F (Winter Design) | | | | | | | | | | |
| Net Plant Output, kW | 48,100 | 48,100 | 98,709 | 98,709 | 95,908 | 95,908 | 234,585 | 234,585 | 287,269 | 287,269 |
| Net Plant Heat Rate, Btu/kWh (HHV) | 9,050 | 9,050 | 8,840 | 8,840 | 11,254 | 11,254 | 9,813 | 9,813 | 9,226 | 9,226 |
| Heat Input, MMBtu/h (HHV) | 435 | 435 | 873 | 873 | 1,079 | 1,079 | 2,302 | 2,302 | 2,650 | 2,650 |
| Min Load Operational Status @ 20° F (Winter Design) | | | | | | | | | | |
| Net Plant Output, kW | 24,050 | 24,050 | 49,354 | 49,354 | 47,954 | 47,954 | 100,440 | 100,440 | 85,521 | 85,521 |
| Net Plant Heat Rate, Btu/kWh (HHV) | 11,650 | 11,650 | 10,407 | 10,407 | 14,608 | 14,608 | 13,240 | 13,240 | 13,653 | 13,653 |
| Heat Input, MMBtu/h (HHV) | 280 | 280 | 514 | 514 | 701 | 701 | 1,330 | 1,330 | 1,168 | 1,168 |
| Base Load Performance @ 90° F (Summer Design) | | | | | | | | | | |
| Net Plant Output, kW | 32,610 | 32,610 | 86,225 | 86,225 | 75,072 | 75,072 | 216,502 | 216,502 | 256,829 | 256,829 |
| Net Plant Heat Rate, Btu/kWh (HHV) | 9,790 | 9,790 | 9,198 | 9,198 | 11,906 | 11,906 | 10,086 | 10,086 | 9,476 | 9,476 |
| Heat Input, MMBtu/h (HHV) | 319 | 319 | 793 | 793 | 894 | 894 | 2,184 | 2,184 | 2,434 | 2,434 |
| Min Load Operational Status @ 90° F (Summer Design) | | | | | | | | | | |
| Net Plant Output, kW | 16,300 | 16,300 | 43,113 | 43,113 | 37,536 | 37,536 | 90,576 | 90,576 | 84,246 | 84,246 |
| Net Plant Heat Rate, Btu/kWh (HHV) | 13,830 | 13,830 | 11,040 | 11,040 | 15,866 | 15,866 | 13,645 | 13,645 | 13,327 | 13,327 |
| Heat Input, MMBtu/h (HHV) | 226 | 226 | 476 | 476 | 596 | 596 | 1,236 | 1,236 | 1,123 | 1,123 |

**VECTREN 2019 IRP TECHNOLOGY ASSESSMENT**
**SIMPLE CYCLE TECHNOLOGY ASSESSMENT PROJECT OPTIONS**
**PRELIMINARY - NOT FOR CONSTRUCTION**
**December 2019**

| PROJECT TYPE | 1x Aeroderivative SCGT - Natural Gas | | 1x Aeroderivative SCGT - Natural Gas | | 1x E Class Frame SCGT - Natural Gas | | 1x F Class Frame SCGT - Natural Gas | | 1x G/H Class Frame SCGT - Natural Gas | |
|---|---|---|---|---|---|---|---|---|---|---|
| **BASE PLANT DESCRIPTION** | First Unit | Next Unit | First Unit | Next Unit | First Unit | Next Unit | First Unit | Next Unit | First Unit | Next Unit |
| **ESTIMATED CAPITAL AND O&M COSTS** | | | | | | | | | | |
| **EPC Project Capital Costs, 2019 MM$ (w/o Owner's Costs)** | **$65** | **$46** | **$123** | **$86** | **$85** | **$60** | **$125** | **$93** | **$168** | **$134** |
| **Owner's Costs, 2019 MM$** | **$27** | **$13** | **$38** | **$20** | **$40** | **$21** | **$48** | **$27** | **$57** | **$36** |
| Owner's Project Development | $0.3 | $0.0 | $0.3 | $0.0 | $0.3 | $0.0 | $0.3 | $0.0 | $0.3 | $0.0 |
| Owner's Operational Personnel Prior to COD | $0.3 | $0.0 | $0.3 | $0.0 | $0.3 | $0.0 | $0.3 | $0.0 | $0.3 | $0.0 |
| Owner's Engineer | $0.8 | $0.0 | $0.8 | $0.0 | $0.8 | $0.0 | $0.8 | $0.0 | $0.8 | $0.1 |
| Owner's Project Management | $1.0 | $0.0 | $1.0 | $0.0 | $1.0 | $0.0 | $1.0 | $0.0 | $1.0 | $0.2 |
| Owner's Legal Costs | $0.5 | $0.0 | $0.5 | $0.0 | $0.5 | $0.0 | $0.5 | $0.0 | $0.5 | $0.0 |
| Owner's Start-up Engineering and Commissioning | $1.2 | $0.6 | $1.2 | $0.6 | $1.5 | $0.8 | $1.5 | $0.8 | $1.6 | $0.8 |
| Land | $0.2 | $0.1 | $0.2 | $0.1 | $0.2 | $0.1 | $0.2 | $0.1 | $0.2 | $0.1 |
| Construction Power and Water | $0.5 | $0.1 | $0.5 | $0.1 | $0.5 | $0.1 | $0.5 | $0.1 | $0.5 | $0.1 |
| Permitting and Licensing Fees | $0.5 | $0.0 | $0.5 | $0.0 | $0.5 | $0.0 | $0.5 | $0.0 | $0.5 | $0.1 |
| Switchyard | $5.3 | $1.8 | $5.3 | $1.8 | $5.3 | $1.8 | $5.3 | $1.8 | $5.2 | $1.7 |
| Political Concessions & Area Development Fees | $0.5 | $0.0 | $0.5 | $0.0 | $0.5 | $0.0 | $0.5 | $0.0 | $0.5 | $0.0 |
| Startup/Testing (Fuel & Consumables) | $0.5 | $0.4 | $0.5 | $0.4 | $2.0 | $1.8 | $2.0 | $1.8 | $2.3 | $2.0 |
| Initial Fuel Inventory | $0.6 | $0.6 | $0.6 | $0.6 | $3.1 | $3.1 | $3.1 | $3.1 | $3.6 | $3.6 |
| Site Security | $0.4 | $0.0 | $0.4 | $0.0 | $0.4 | $0.0 | $0.4 | $0.0 | $0.4 | $0.0 |
| Operating Spare Parts | $1.8 | $0.5 | $1.8 | $0.5 | $5.5 | $1.4 | $5.5 | $1.4 | $6.0 | $1.5 |
| Water Supply Infrastructure | Excluded | Excluded | Excluded | Excluded | Excluded | Excluded | Excluded | Excluded | Excluded | Excluded |
| Natural Gas Supply Infrastructure | Excluded | Excluded | Excluded | Excluded | Excluded | Excluded | Excluded | Excluded | Excluded | Excluded |
| Transmission Interconnect | $0.2 | $0.2 | $0.4 | $0.4 | $0.3 | $0.3 | $0.9 | $0.9 | $1.1 | $1.1 |
| Transmission Upgrade Costs | Excluded | Excluded | Excluded | Excluded | Excluded | Excluded | Excluded | Excluded | Excluded | Excluded |
| Firm Gas Supply Reservation Charge | Provided by Owner | Provided by Owner | Provided by Owner | Provided by Owner | Provided by Owner | Provided by Owner | Provided by Owner | Provided by Owner | Provided by Owner | Provided by Owner |
| Permanent Plant Equipment and Furnishings | $0.3 | $0.0 | $0.3 | $0.0 | $0.3 | $0.0 | $0.3 | $0.0 | $0.3 | $0.0 |
| AFUDC (12.2% of EPC Project Capital Costs) | $7.9 | $5.6 | $15.0 | $10.5 | $10.3 | $7.3 | $15.3 | $11.4 | $20.5 | $16.3 |
| Builders Risk Insurance (0.45% of Construction Costs) | $0.3 | $0.2 | $0.6 | $0.4 | $0.4 | $0.3 | $0.6 | $0.4 | $0.8 | $0.6 |
| Owner's Contingency (5% for Screening Purposes) | $4.4 | $2.8 | $7.7 | $5.1 | $5.9 | $3.8 | $8.2 | $5.7 | $10.7 | $8.1 |
| **Total Project Costs, 2019 MM$** | **$93** | **$59** | **$161** | **$106** | **$124** | **$81** | **$173** | **$121** | **$225** | **$170** |
| **EPC Cost Per kW, 2019 $/kW (Note 7)** | **$1,570** | **$1,110** | **$1,270** | **$890** | **$1,000** | **$710** | **$530** | **$390** | **$600** | **$480** |
| **Total Cost Per kW, 2019 $/kW (Note 7)** | **$2,230** | **$1,420** | **$1,660** | **$1,090** | **$1,470** | **$950** | **$730** | **$510** | **$810** | **$610** |
| **FIXED O&M COSTS (Note 8)** | | | | | | | | | | |
| Fixed O&M Cost - LABOR, 2019$MM/Yr | $0.8 | $0.0 | $0.9 | $0.0 | $0.9 | $0.0 | $0.9 | $0.0 | $0.8 | $0.0 |
| Fixed O&M Cost - OTHER, 2019$MM/Yr | $0.7 | $0.3 | $0.7 | $0.3 | $0.9 | $0.5 | $1.1 | $0.4 | $1.4 | $0.4 |
| **LEVELIZED CAPITAL MAINTENANCE COSTS** | | | | | | | | | | |
| Major Maintenance Cost, 2019$/GT-hr or $/engine-hr (Notes 9, 10) | $190 | $190 | $190 | $190 | $370 | $370 | $350 | $350 | $600 | $600 |
| Major Maintenance Cost, 2019$/GT-start | N/A | N/A | N/A | N/A | $10,000 | $10,000 | $9,500 | $9,500 | $16,200 | $16,200 |
| Major Maintenance Cost, 2019$/MWh | $4.60 | $4.60 | $2.00 | $2.00 | $4.40 | $4.40 | $1.50 | $1.50 | $2.20 | $2.20 |
| Catalyst Replacement Cost, 2019$/MWh | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | $0.30 | $0.30 |
| **NON-FUEL VARIABLE O&M COSTS (EXCLUDES MAJOR MAINTENANCE, Note 11)** | | | | | | | | | | |
| Total Variable O&M Cost, 2019$/MWh | $0.90 | $0.90 | $1.24 | $1.24 | $0.90 | $0.90 | $0.90 | $0.90 | $1.10 | $1.10 |
| Water Related O&M, $/MWh | $0.00 | $0.00 | $0.34 | $0.34 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 |
| SCR Reagent, $/MWh | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | $0.20 | $0.20 |
| Other Consumables and Variable O&M, $/MWh | $0.90 | $0.90 | $0.90 | $0.90 | $0.90 | $0.90 | $0.90 | $0.90 | $0.90 | $0.90 |
| **ESTIMATED BASE LOAD OPERATING EMISSIONS: NATURAL GAS (See Note 13)** | | | | | | | | | | |
| Turbine Only (lb/MMBtu, HHV) | | | | | | | | | | |
| $NO_x$ | 0.12 | 0.12 | 0.09 | 0.09 | 0.03 | 0.03 | 0.03 | 0.03 | 0.01 | 0.01 |
| $SO_2$ | < 0.002 | < 0.002 | < 0.002 | < 0.002 | < 0.002 | < 0.002 | < 0.002 | < 0.002 | < 0.002 | < 0.002 |
| CO | 0.048 | 0.048 | 0.026 | 0.026 | 0.056 | 0.056 | 0.014 | 0.014 | 0.004 | 0.004 |
| $CO_2$ | 120 | 120 | 120 | 120 | 120 | 120.00 | 120 | 120 | 120 | 120 |

**VECTREN 2019 IRP TECHNOLOGY ASSESSMENT**
**SIMPLE CYCLE TECHNOLOGY ASSESSMENT PROJECT OPTIONS**
**PRELIMINARY - NOT FOR CONSTRUCTION**
**December 2019**

| PROJECT TYPE | 1x Aeroderivative SCGT - Natural Gas | | 1x Aeroderivative SCGT - Natural Gas | | 1x E Class Frame SCGT - Natural Gas | | 1x F Class Frame SCGT - Natural Gas | | 1x G/H Class Frame SCGT - Natural Gas | |
|---|---|---|---|---|---|---|---|---|---|---|
| **BASE PLANT DESCRIPTION** | First Unit | Next Unit | First Unit | Next Unit | First Unit | Next Unit | First Unit | Next Unit | First Unit | Next Unit |

**Notes**

Note 1: Simple cycle GT starts are not affected by hot, warm or cold conditions. Simple cycle starts assume purge credits are available. Recip engine start times assume the engines are kept warm when not operational.
Note 2: Fast start package options allow 10 minute GT start.
Note 3: MECL start time assumes the min load at which the GT achieves the steady state NOx emissions ppm rate. The SCR compliance start time assumes a cold start, ending at the time when the catalysts are heated and the NOx levels meet the desired SCR emissions.
Note 4: Outage and availability statistics are collected using the NERC Generating Availability Data System. Simple cycle data is based on North American units that came online in 2006 or later. Reporting period is 2011-2016. Note that a unique gas reciprocating engine category does not exist in GADS. Diesel Engine data is used as a proxy.
Note 5: New and clean performance assumed for all scenarios. All performance ratings based on NATURAL GAS operation. Minimum loads are based on OEM information at requested ambient conditions.
Note 6: For the reciprocating engine option, it is assumed that six engines tie to one GSU.
Note 7: Capital and fixed O&M costs are presented in 2019 USD $MM.
Note 8: All Gas Turbine FOM costs assume 7 full time personnel for first unit. No additional personnel are included for the next unit(s). FOM costs do not include engine lease fees that may be available with LTSA, depending on OEM.
Note 9: Major maintenance $/hr holds for all aero gas turbines. Major maintenance $/hr holds for frame gas turbines where hours per start is >27.

Note 10: Recip engine FOM assumes 8 FTE for the first 200 MW plant. The NEXT plant adds 3 FTE. Major maintenance $/hr is per engine. LTSA costs are split in two categories: major overhauls and catalyst replacements are shown as capitalized maintenance, while scheduled minor maintenance supervision is shown in VOM.

Note 11: VOM assumes the use of temporarily trailers for demineralized water treatment, where applicable.
Note 12: This reflects startup when OEM fast start package is included. Fast start options are NOT reflected in base capital costs. Market trends suggest that O&M impacts from fast starts are negligible.
Note 13: Emissions estimates are shown for steady state operation at annual average conditions. Estimates account for the impacts of SCR and CO catalysts, as applicable.
Note 14: Performance ratings are based on elevation of 750 ft above msl.

Note 15: EFOR data from GADS may not accurately represent the benefits of a reciprocating plant, depending on how events are recorded. Typically, a maintenance event will not impact all engines simultaneously, so the plant would not be completely offline as it may be during an event at 1x gas turbine plant.

Note 16: Fuel Oil emissions based on ultra low sulfur diesel. Per the US EPA, this fuel must meet 15 ppm sulfur.
Note 17: Fuel oil performance conversion factors are included in a separate Fuel Oil Conversion tab in this workbook.
Note 18: Estimated Costs exclude decommissioning costs and salvage values.

**VECTREN 2019 IRP TECHNOLOGY ASSESSMENT**
**RECIPROCATING ENGINE TECHNOLOGY ASSESSMENT PROJECT OPTIONS**
**PRELIMINARY - NOT FOR CONSTRUCTION**
**December 2019**

| PROJECT TYPE | Reciprocating Engine (9 MW Engines) Natural Gas | | Reciprocating Engine (18 MW Engines) Natural Gas | |
|---|---|---|---|---|
| **BASE PLANT DESCRIPTION** | First Unit | Next Unit | First Unit | Next Unit |
| Number of Gas Turbines/Engines/Units | 6 | 6 | 6 | 6 |
| Representative Class Gas Turbine | Wartsila 20V34SG | | Wartsila 18V50SG | |
| Capacity Factor, % | Peaking (10%) | | Peaking (10%) | |
| Startup Time to Base Load, min (Notes 1) | 5 | | 5 | |
| Startup Time to MECL, min | 4 | | 4 | |
| Cold Startup Time to SCR Compliance, min | 45 | | 45 | |
| Maximum Ramp Rate, MW/min (Online) | 10 | | 100 | |
| Book Life, Years | 35 | | 35 | |
| Equivalent Planned Outage Rate, % (Note 2, 10) | 4.0% | | 4.0% | |
| Equivalent Forced Outage Rate, % (Notes 2, 10) | 7.3% | | 7.3% | |
| Equivalent Availability Factor, % (Notes 2, 10) | 94.3% | | 94.3% | |
| Assumed Land Use, Acres | 30 | 10 | 30 | 10 |
| Fuel Design | Natural Gas Only | | Natural Gas Only | |
| Heat Rejection | Fin Fan Heat Exchanger | | Fin Fan Heat Exchanger | |
| $NO_x$ Control | SCR | | SCR | |
| CO Control | Oxidation Catalyst | | Oxidation Catalyst | |
| Particulate Control | Good Combustion Practice | | Good Combustion Practice | |
| Technology Rating | Mature | | Mature | |
| Permitting & Construction Schedule (Years from FNTP) | 3 | | 3 | |
| **ESTIMATED PERFORMANCE (All BASED ON NATURAL GAS OPERATION) (Note 9)** | | | | |
| Nominal Base Load Performance @59° F (ISO Conditions) | | | | |
| Net Plant Output, kW | 54,600 | 54,600 | 109,900 | 109,900 |
| Net Plant Heat Rate, Btu/kWh (HHV) | 8,480 | 8,480 | 8,290 | 8,290 |
| Heat Input, MMBtu/h (HHV) | 450 | 450 | 910 | 910 |
| Nominal Min Load @ 59° F (ISO Conditions) - Single Engine | | | | |
| Net Plant Output, kW | 2,300 | 2,300 | 4,600 | 4,600 |
| Net Plant Heat Rate, Btu/kWh (HHV) | 12,150 | 12,150 | 11,040 | 11,040 |
| Heat Input, MMBtu/h (HHV) | 30 | 30 | 40 | 40 |
| Base Load Performance @ 20° F (Winter Design) | | | | |
| Net Plant Output, kW | 54,600 | 54,600 | 109,900 | 109,900 |
| Net Plant Heat Rate, Btu/kWh (HHV) | 8,480 | 8,480 | 8,290 | 8,290 |
| Heat Input, MMBtu/h (HHV) | 450 | 450 | 910 | 910 |

**VECTREN 2019 IRP TECHNOLOGY ASSESSMENT**
**RECIPROCATING ENGINE TECHNOLOGY ASSESSMENT PROJECT OPTIONS**
**PRELIMINARY - NOT FOR CONSTRUCTION**
**December 2019**

| PROJECT TYPE | Reciprocating Engine (9 MW Engines) Natural Gas | | Reciprocating Engine (18 MW Engines) Natural Gas | |
|---|---|---|---|---|
| **BASE PLANT DESCRIPTION** | First Unit | Next Unit | First Unit | Next Unit |
| Min Load Operational Status @ 20° F (Winter Design) - Single Engine | | | | |
| Net Plant Output, kW | 2,300 | 2,300 | 4,600 | 4,600 |
| Net Plant Heat Rate, Btu/kWh (HHV) | 12,150 | 12,150 | 11,040 | 11,040 |
| Heat Input, MMBtu/h (HHV) | 30 | 30 | 40 | 40 |
| Base Load Performance @ 90° F (Summer Design) | | | | |
| Net Plant Output, kW | 54,600 | 54,600 | 109,900 | 109,900 |
| Net Plant Heat Rate, Btu/kWh (HHV) | 8,480 | 8,480 | 8,310 | 8,310 |
| Heat Input, MMBtu/h (HHV) | 450 | 450 | 910 | 910 |
| Min Load Operational Status @ 90° F (Summer Design) - Single Engine | | | | |
| Net Plant Output, kW | 2,300 | 2,300 | 4,600 | 4,600 |
| Net Plant Heat Rate, Btu/kWh (HHV) | 12,150 | 12,150 | 11,040 | 11,040 |
| Heat Input, MMBtu/h (HHV) | 30 | 30 | 40 | 40 |
| **ESTIMATED CAPITAL AND O&M COSTS** | | | | |
| **EPC Project Capital Costs, 2019 MM$ (w/o Owner's Costs)** | **$81** | **$61** | **$120** | **$100** |
| Engineering | $3.3 | $0.3 | $5 | $1 |
| Gas Turbines/Engines | $10.3 | $8.8 | $112 | $112 |
| GSU (Note 6) | $0.4 | $0.1 | $2 | $2 |
| Environmental Equipment (SCR/CO) | Included with Engines | Included with Engines | Included with Engines | Included with Engines |
| BOP Equipment and Materials | $2.1 | $1.4 | $28 | $21 |
| Construction | $10.7 | $10.4 | $46 | $28 |
| Indirects and Fees | $4.1 | $2.2 | $15 | $10 |
| EPC Contingency | $1.0 | $0.7 | $10 | $8 |

| VECTREN 2019 IRP TECHNOLOGY ASSESSMENT<br>RECIPROCATING ENGINE TECHNOLOGY ASSESSMENT PROJECT OPTIONS<br>PRELIMINARY - NOT FOR CONSTRUCTION<br>December 2019 | | | | |
|---|---|---|---|---|
| **PROJECT TYPE** | **Reciprocating Engine (9 MW Engines) Natural Gas** | | **Reciprocating Engine (18 MW Engines) Natural Gas** | |
| **BASE PLANT DESCRIPTION** | First Unit | Next Unit | First Unit | Next Unit |
| **Owner's Costs, 2019 MM$** | **$27** | **$14** | **$39** | **$24** |
| Owner's Project Development | $0.3 | $0.0 | $0.3 | $0.0 |
| Owner's Operational Personnel Prior to COD | $0.3 | $0.0 | $0.3 | $0.0 |
| Owner's Engineer | $0.8 | $0.0 | $0.5 | $0.0 |
| Owner's Project Management | $1.0 | $0.0 | $1.0 | $0.0 |
| Owner's Legal Costs | $0.5 | $0.0 | $0.5 | $0.0 |
| Owner's Start-up Engineering and Commissioning | $0.4 | $0.2 | $0.9 | $0.5 |
| Land | $0.2 | $0.0 | $0.2 | $0.1 |
| Construction Power and Water | $0.5 | $0.1 | $0.5 | $0.1 |
| Permitting and Licensing Fees | $0.5 | $0.0 | $0.5 | $0.0 |
| Switchyard | $5.3 | $1.8 | $7.1 | $3.6 |
| Political Concessions & Area Development Fees | $0.5 | $0.0 | $0.5 | $0.0 |
| Startup/Testing (Fuel & Consumables) | $0.1 | $0.09 | $0.5 | $0.4 |
| Initial Fuel Inventory | $0.0 | $0.0 | $0.0 | $0.0 |
| Site Security | $0.3 | $0.0 | $0.4 | $0.0 |
| Operating Spare Parts | $0.2 | $0.1 | $2.0 | $0.5 |
| Water Supply Infrastructure | Excluded | Excluded | Excluded | Excluded |
| Natural Gas Supply Infrastructure | Excluded | Excluded | Excluded | Excluded |
| Transmission Interconnect | $0.2 | $0.2 | $0.4 | $0.4 |
| Transmission Upgrade Costs | Excluded | Excluded | Excluded | Excluded |
| Firm Gas Supply Reservation Charge | Provided by Owner | Provided by Owner | Provided by Owner | Provided by Owner |
| Permanent Plant Equipment and Furnishings | $0.3 | $0.0 | $0.3 | $0.0 |
| AFUDC (12.2% of EPC Project Capital Costs) | $9.9 | $7.4 | $14.6 | $12.2 |
| Builders Risk Insurance (0.45% of Construction Costs) | $0.4 | $0.3 | $0.5 | $0.5 |
| Owner's Contingency (5% for Screening Purposes) | $5.1 | $3.5 | $7.6 | $5.9 |
| **Total Project Costs, 2019 MM$** | **$108** | **$74** | **$159** | **$124** |
| **EPC Cost Per kW, 2019 $/kW** | **$1,480** | **$1,110** | **$1,090** | **$910** |
| **Total Cost Per kW, 2019 $/kW** | **$1,970** | **$1,360** | **$1,440** | **$1,130** |
| **FIXED O&M COSTS** | | | | |
| Fixed O&M Cost - LABOR, 2019$MM/Yr | $1.0 | $0.0 | $1.0 | $0.4 |
| Fixed O&M Cost - OTHER, 2019$MM/Yr | $1.5 | $0.20 | $0.98 | $0.35 |

**VECTREN 2019 IRP TECHNOLOGY ASSESSMENT**
**RECIPROCATING ENGINE TECHNOLOGY ASSESSMENT PROJECT OPTIONS**
**PRELIMINARY - NOT FOR CONSTRUCTION**
**December 2019**

| PROJECT TYPE | Reciprocating Engine (9 MW Engines) Natural Gas | | Reciprocating Engine (18 MW Engines) Natural Gas | |
|---|---|---|---|---|
| **BASE PLANT DESCRIPTION** | First Unit | Next Unit | First Unit | Next Unit |
| **LEVELIZED CAPITAL MAINTENANCE COSTS** | | | | |
| Major Maintenance Cost, 2019$/GT-hr or $/engine-hr (Notes 6, 11) | $0.07 | $0.07 | $0.00 | $0.00 |
| Major Maintenance Cost, 2019$/GT-start | N/A | N/A | N/A | N/A |
| Major Maintenance Cost, 2019$/MWh | $1.40 | $1.40 | $0.00 | $0.00 |
| Catalyst Replacement Cost, 2019$/MWh | $0.30 | $0.30 | $0.20 | $0.20 |
| **NON-FUEL VARIABLE O&M COSTS (EXCLUDES MAJOR MAINTENANCE, Note 7)** | | | | |
| Total Variable O&M Cost, 2019$/MWh | $4.50 | $4.50 | $4.50 | $4.50 |
| Water Related O&M, $/MWh | $0.00 | $0.00 | $0.00 | $0.00 |
| SCR Reagent, $/MWh | $0.90 | $0.90 | $0.90 | $0.90 |
| Other Consumables and Variable O&M, $/MWh | $3.60 | $3.60 | $3.60 | $3.60 |
| **ESTIMATED BASE LOAD OPERATING EMISSIONS: NATURAL GAS (See Note 8)** | | | | |
| Engine Only (lb/MMBtu, HHV) | | | | |
| $NO_X$ | 0.33 | 0.33 | 0.32 | 0.32 |
| $SO_2$ | < 0.002 | < 0.002 | < 0.002 | < 0.002 |
| CO | 0.52 | 0.52 | 0.51 | 0.51 |
| $CO_2$ | 120 | 120 | 120 | 120 |
| Engine with SCR and CO Catalyst (lb/MMBtu, HHV) | | | | |
| $NO_X$ | 0.017 | 0.017 | 0.016 | 0.016 |
| $SO_2$ | < 0.002 | < 0.002 | < 0.002 | < 0.002 |
| CO | 0.03 | 0.03 | 0.031 | 0.031 |
| $CO_2$ | 120 | 120 | 120 | 120 |

**Notes**

Note 1: Recip engine start times assume the engines are kept warm when not operational.
Note 2: Outage and availability statistics are collected using the NERC Generating Availability Data System. Note that a unique gas reciprocating engine category does not exist in GADS. Diesel Engine data is used as a proxy.
Note 3: New and clean performance assumed for all scenarios. All performance ratings based on NATURAL GAS operation. Minimum loads are based on OEM information at requested ambient conditions.
Note 4: It is assumed that a maximum of six reciprocating engines tie to one GSU.
Note 5: Capital and fixed O&M costs are presented in 2019 USD $MM.
Note 6: Recip engine FOM assumes 8 FTE for the first 200 MW plant. Major maintenance $/hr is per engine. LTSA costs are split in two categories: major overhauls and catalyst replacements are shown as

Note 7: VOM assumes the use of temporarily trailers for demineralized water treatment, if required.

Note 8: Emissions estimates are shown for steady state operation at annual average conditions. Estimates account for the impacts of SCR and CO catalysts, as applicable.
Note 9: Performance ratings are based on elevation of 750 ft above msl.

Note 10: EFOR data from GADS may not accurately represent the benefits of a reciprocating plant, depending on how events are recorded. Typically, a maintenance event will not impact all engines simultaneously, so the plant would not be completely offline as it may be during an event at 1x gas turbine plant.

| VECTREN 2019 IRP TECHNOLOGY ASSESSMENT<br>RECIPROCATING ENGINE TECHNOLOGY ASSESSMENT PROJECT OPTIONS<br>PRELIMINARY - NOT FOR CONSTRUCTION<br>December 2019 | | | | |
|---|---|---|---|---|
| **PROJECT TYPE** | **Reciprocating Engine (9 MW Engines) Natural Gas** | | **Reciprocating Engine (18 MW Engines) Natural Gas** | |
| **BASE PLANT DESCRIPTION** | First Unit | Next Unit | First Unit | Next Unit |
| Note: 11: If major maintenance is $0.00 - the units have will not reach a major overhaul even per manufacturer's recommendations of hours of operation based on the life of the plant and the capacity factor. | | | | |

**VECTREN 2019 IRP TECHNOLOGY ASSESSMENT**
**COMBINED CYCLE TECHNOLOGY ASSESSMENT PROJECT OPTIONS**
**PRELIMINARY - NOT FOR CONSTRUCTION**
**December 2019**

| **PROJECT TYPE** | **1x1 F Class CCGT - Unfired** | **1x1 F Class CCGT - Fired** | **1x1 G/H Class CCGT - Unfired** | **1x1 G/H Class CCGT - Fired** |
|---|---|---|---|---|
| **BASE PLANT DESCRIPTION** | Unfired | Fired | Unfired | Fired |
| Number of Gas Turbines | 1 | 1 | 1 | 1 |
| Number of Steam Turbines | 1 | 1 | 1 | 1 |
| Representative Class Gas Turbine | GE 7F.05 | | GE 7HA.01 | |
| Steam Conditions (Main Steam / Reheat) | 1,050°F / 1,050°F | | 1,050°F / 1,050°F | |
| Main Steam Pressure | 2,330 | | 2,330 | |
| Steam Cycle Type | Subcritical | | Subcritical | |
| Capacity Factor (%) | 70% | | 70% | |
| Startup Time, Minutes (Cold Start to Unfired Base Load) (Note 7, 8) | 180 | | 180 | |
| Startup Time, Minutes (Warm Start to Unfired Base Load) (Note 7, 8) | 120 | | 120 | |
| Startup Time, Minutes (Hot Start to Unfired Base Load) (Note 7, 8) | 80 | | 80 | |
| Startup Time, Minutes (Cold Start to Stack Emissions Compliance) (See note 4) | 60 | | 60 | |
| Maximum Ramp Rate, MW/min (Online) | 36 | | 41 | |
| Book Life (Years) | 30 | | 30 | |
| Equivalent Planned Outage Rate (%) | 10.1% | | 10.1% | |
| Equivalent Forced Outage Rate (%) | 3.6% | | 3.6% | |
| Equivalent Availability Factor (%) | 86.5% | | 86.5% | |
| Assumed Land Use (Acres) | 70 | 30 | 70 | 30 |
| Fuel Design | Natural Gas | | Natural Gas | |
| Heat Rejection | Wet Cooling Towers | | Wet Cooling Towers | |
| $NO_x$ Control | DLN/SCR | | DLN/SCR | |
| CO Control | Oxidation Catalyst | | Oxidation Catalyst | |
| Particulate Control | Good Combustion Practice | | Good Combustion Practice | |
| Technology Rating | Mature | | Mature | |
| Permitting & Construction Schedule (Years from FNTP) | 4 | | 4 | |
| **ESTIMATED PERFORMANCE (See note 2)** | | | | |
| Base Load Performance @59 °F (Nominal) | | | | |
| Net Plant Output, kW | 357,200 | 359,900 | 410,600 | 412,100 |
| Net Plant Heat Rate, Btu/kWh (HHV) | 6,490 | 6,440 | 6,280 | 6,260 |
| Heat Input, MMBtu/h (HHV) | 2,320 | 2,320 | 2,580 | 2,580 |
| Incremental Duct Fired Performance @ 59 °F (Nominal) | | | | |
| Incremental Duct Fired Output, kW | N/A | 82,600 | N/A | 98,600 |
| Incremental Heat Rate, Btu/kWh (HHV) | N/A | 8,370 | N/A | 8,420 |
| Incremental Heat Input, MMBtu/h (HHV) | N/A | 690 | N/A | 830 |
| Minimum Load (Single Turbine at MECL) @ 59 °F (Nominal) | | | | |
| Net Plant Output, kW | 168,400 | 170,900 | 129,500 | 128,800 |
| Net Plant Heat Rate, Btu/kWh (HHV) | 7,740 | 7,630 | 7,970 | 8,010 |
| Heat Input, MMBtu/h (HHV) | 1,300 | 1,300 | 1,030 | 1,030 |

**VECTREN 2019 IRP TECHNOLOGY ASSESSMENT**
**COMBINED CYCLE TECHNOLOGY ASSESSMENT PROJECT OPTIONS**
**PRELIMINARY - NOT FOR CONSTRUCTION**
**December 2019**

| **PROJECT TYPE** | **1x1 F Class CCGT - Unfired** | **1x1 F Class CCGT - Fired** | **1x1 G/H Class CCGT - Unfired** | **1x1 G/H Class CCGT - Fired** |
|---|---|---|---|---|
| **BASE PLANT DESCRIPTION** | Unfired | Fired | Unfired | Fired |
| Base Load Performance @ 20 °F (Winter) | | | | |
| Net Plant Output, kW | 357,100 | 360,900 | 415,100 | 417,400 |
| Net Plant Heat Rate, Btu/kWh (HHV) | 6,610 | 6,540 | 6,350 | 6,320 |
| Heat Input, MMBtu/h (HHV) | 2,360 | 2,360 | 2,640 | 2,640 |
| Incremental Duct Fired Performance @ 20 °F (Winter) | | | | |
| Incremental Duct Fired Output, kW | N/A | 88,500 | N/A | 102,000 |
| Incremental Heat Rate, Btu/kWh (HHV) | N/A | 8,380 | N/A | 8,540 |
| Incremental Heat Input, MMBtu/h (HHV) | N/A | 740 | N/A | 870 |
| Minimum Load (Single Turbine at MECL) @ 20 °F (Winter) | | | | |
| Net Plant Output, kW | 182,200 | 180,700 | 137,000 | 124,100 |
| Net Plant Heat Rate, Btu/kWh (HHV) | 7,610 | 7,670 | 7,850 | 8,660 |
| Heat Input, MMBtu/h (HHV) | 1,390 | 1,390 | 1,080 | 1,070 |
| Base Load Performance @ 90 °F (Summer) | | | | |
| Net Plant Output, kW | 335,100 | 335,300 | 381,100 | 379,700 |
| Net Plant Heat Rate, Btu/kWh (HHV) | 6,540 | 6,540 | 6,340 | 6,370 |
| Heat Input, MMBtu/h (HHV) | 2,190 | 2,190 | 2,420 | 2,420 |
| Incremental Duct Fired Performance @ 90 °F (Summer) | | | | |
| Incremental Duct Fired Output, kW | N/A | 80,600 | N/A | 95,000 |
| Incremental Heat Rate, Btu/kWh (HHV) | N/A | 8,220 | N/A | 8,200 |
| Incremental Heat Input, MMBtu/h (HHV) | N/A | 660 | N/A | 780 |
| Minimum Load (Single Turbine at MECL) @ 90 °F (Summer) | | | | |
| Net Plant Output, kW | 164,900 | 161,800 | 147,000 | 142,100 |
| Net Plant Heat Rate, Btu/kWh (HHV) | 7,690 | 7,840 | 7,570 | 7,830 |
| Heat Input, MMBtu/h (HHV) | 1,270 | 1,270 | 1,110 | 1,110 |

VECTREN 2019 IRP TECHNOLOGY ASSESSMENT
COMBINED CYCLE TECHNOLOGY ASSESSMENT PROJECT OPTIONS
PRELIMINARY - NOT FOR CONSTRUCTION
December 2019

| **PROJECT TYPE** | **1x1 F Class CCGT - Unfired** | **1x1 F Class CCGT - Fired** | **1x1 G/H Class CCGT - Unfired** | **1x1 G/H Class CCGT - Fired** |
|---|---|---|---|---|
| **BASE PLANT DESCRIPTION** | Unfired | Fired | Unfired | Fired |
| **ESTIMATED CAPITAL AND O&M COSTS** | | | | |
| **EPC Project Capital Costs, 2019 MM$ (w/o Owner's Costs)** | **$351** | **$369** | **$400** | **$420** |
| **Owner's Costs, 2019 MM$** | **$125** | **$129** | **$136** | **$139** |
| Owner's Project Development | $3.5 | $3.5 | $3.5 | $3.5 |
| Owner's Operational Personnel Prior to COD | $1.7 | $1.7 | $1.7 | $1.7 |
| Owner's Engineer | $2.3 | $2.3 | $2.4 | $2.4 |
| Owner's Project Management | $5.9 | $5.9 | $6.1 | $6.1 |
| Owner's Legal Costs | $1.0 | $1.0 | $1.0 | $1.0 |
| Owner's Start-up Engineering and Commissioning | $5.7 | $5.7 | $5.6 | $5.6 |
| Land | $0.4 | $0.4 | $0.4 | $0.4 |
| Temporary Utilities | $1.6 | $1.6 | $1.7 | $1.7 |
| Permitting and Licensing Fees | $0.5 | $0.5 | $0.5 | $0.5 |
| Switchyard | $9.9 | $9.9 | $9.9 | $9.9 |
| Political Concessions & Area Development Fees | $0.5 | $0.5 | $0.5 | $0.5 |
| Startup/Testing (Fuel & Consumables) | $0.9 | $0.9 | $1.0 | $1.0 |
| Initial Fuel Inventory | $0.0 | $0.0 | $0.0 | $0.0 |
| Site Security | $0.8 | $0.8 | $0.8 | $0.8 |
| Operating Spare Parts | $6.0 | $6.0 | $6.5 | $6.5 |
| Water Supply Infrastructure (5 Mile Pipeline) (Note 13) | $15.0 | $15.0 | $15.0 | $15.0 |
| Natural Gas Supply Infrastructure | Excluded | Excluded | Excluded | Excluded |
| Transmission Interconnect | $1.4 | $1.4 | $1.6 | $1.6 |
| Transmission Upgrade Costs | Excluded | Excluded | Excluded | Excluded |
| Firm Gas Supply Reservation Charge | Provided by Owner | Provided by Owner | Provided by Owner | Provided by Owner |
| Permanent Plant Equipment and Furnishings | $1.3 | $1.3 | $1.3 | $1.3 |
| AFUDC (12.2% of EPC Project Capital Costs) | $42.8 | $45.0 | $48.8 | $51.2 |
| Builders Risk Insurance (0.45% of Construction Costs) | $1.6 | $1.7 | $1.8 | $1.9 |
| Owner's Contingency | $22.7 | $23.7 | $25.5 | $26.6 |
| **Total Project Costs, 2019 MM$** | **$476** | **$498** | **$536** | **$559** |
| **EPC Cost Per UNFIRED kW, 2019 $/kW** | **$982** | **$1,026** | **$974** | **$1,019** |
| **Total Cost Per UNFIRED kW, 2019 $/kW** | **$1,333** | **$1,384** | **$1,305** | **$1,357** |
| **EPC Cost Per FIRED kW, 2019 $/kW** | **N/A** | **$834** | **N/A** | **$822** |
| **Total Cost Per FIRED kW, 2019 $/kW** | **N/A** | **$1,125** | **N/A** | **$1,095** |
| **FIXED O&M COSTS (See note 9)** | | | | |
| Fixed O&M Cost - LABOR, 2019 $MM/Yr | $2.8 | $2.8 | $2.8 | $2.8 |
| Fixed O&M Cost - OTHER, 2019 $MM/Yr | $1.8 | $1.8 | $2.1 | $2.1 |

**VECTREN 2019 IRP TECHNOLOGY ASSESSMENT**
**COMBINED CYCLE TECHNOLOGY ASSESSMENT PROJECT OPTIONS**
**PRELIMINARY - NOT FOR CONSTRUCTION**
**December 2019**

| PROJECT TYPE | 1x1 F Class CCGT - Unfired | 1x1 F Class CCGT - Fired | 1x1 G/H Class CCGT - Unfired | 1x1 G/H Class CCGT - Fired |
|---|---|---|---|---|
| **BASE PLANT DESCRIPTION** | Unfired | Fired | Unfired | Fired |
| **LEVELIZED CAPITAL MAINTENANCE COSTS** | | | | |
| Major Maintenance Cost, 2019 $/GT-hr | $350 | $350 | $580 | $580 |
| Major Maintenance Cost, 2019 $/MWh | $0.98 | $0.97 | $1.41 | $1.41 |
| Catalyst Replacement Cost, 2019 $/MWh | $0.19 | $0.19 | $0.17 | $0.17 |
| **NON-FUEL VARIABLE O&M COSTS (EXCLUDES MAJOR MAINTENANCE)** | | | | |
| Total Variable O&M Cost, Unfired 2019 $/MWh | $1.80 | $1.74 | $1.80 | $1.68 |
| Water Related O&M ($/MWh) | $0.39 | $0.40 | $0.36 | $0.36 |
| SCR Reagent, $/MWh | $0.20 | $0.20 | $0.20 | $0.20 |
| Other Consumables and Variable O&M ($/MWh) | $1.20 | $1.10 | $1.20 | $1.10 |
| Incremental Duct Fired Variable O&M, 2019 $/MWh (For Incremental Output Only) | N/A | $1.39 | N/A | $1.40 |
| **ESTIMATED BASE LOAD OPERATING EMISSIONS: NATURAL GAS, lb/MMBtu (HHV)** | | | | |
| $NO_x$ | 0.01 | 0.01 | 0.007 | 0.007 |
| $SO_2$ | < 0.002 | < 0.002 | < 0.002 | < 0.002 |
| CO | 0.00 | 0.00 | 0.004 | 0.004 |
| $CO_2$ | 120.00 | 120.00 | 120 | 120 |

**Notes**

Note 1: New and clean performance assumed. All performance is based on NATURAL GAS operation. Min load ratings are based on OEM performance information at specified ambient conditions. Fuel oil conversion factors are included in the "Fuel Oil Conversion" tab in this workbook.

Note 2: Base O&M costs are based on performance at annual average conditions.

Note 3: Major maintenance $/hr holds for frame gas turbines where hours per start is >27.

Note 4: Startup time to stack emissions compliance is not the same as the start time for gas turbine MECL. Stack emissions compliance is expected to be limited by the temperature of the CO catalyst, which impacts VOC emissions.

Note 5: Capital costs include duct firing to 1,600°F.

Note 6: Outage and availability statistics are collected using the NERC Generating Availability Data System. Combined cycle data is based on North American units that came online in 2006 or later. Reporting period is 2011-2016.

Note 7: Cold start is >72 hours after shutdown. Hot start is <8 hours after shutdown.

Note 8: Startup times reflect unrestricted, conventional starts for all gas turbines. These start times assume the inclusion of terminal point desuperheaters, full bypass, and associated controls. Fast start packages are not included in CCGT plants.

Note 9: Fixed O&M assumes 22 FTE for 1x1 configurations.

Note 10: Variable O&M costs assume onsite demin treatment system.

Note 11: Emissions estimates are shown for steady state operation at annual average conditions. Estimates account for the impacts of SCR and CO catalysts.

Note 12: Estimated costs exclude decommissioning costs and salvage values.

**VECTREN ENERGY 2019 GENERIC UNIT ASSESSMENT SUMMARY TABLE**
**COMBINED HEAT AND POWER TECHNOLOGY ASSESSMENT PROJECT OPTIONS**
**PRELIMINARY - NOT FOR CONSTRUCTION**
**December 2019**

| PROJECT TYPE | Combined Heat and Power | Combined Heat and Power |
|---|---|---|
| **BASE PLANT DESCRIPTION** | 2x 9MW Reciprocating Engine (Wartsila 20V34SG) | 1 x Titan 250 CTG w/ unfired HRSG |
| Number of Gas Turbines / Engines / Reactors | 2 | 1 |
| Number of HRSGs | 1 | 1 |
| Number of Steam Turbines | 0 | 0 |
| Steam Conditions (Main Steam / Reheat) | 150 psig/366F (saturated) | 150 psig/366F (saturated) |
| Main Steam Pressure | 150 psig | 150 psig |
| Steam Cycle Type | Topping Cycle | Topping Cycle |
| Capacity Factor (%) | 85% | 85% |
| Startup Time (Cold Start), hours | 0.5 | < 1.5 Hrs to Full Plant Load |
| Startup Time (Warm Start), hours | 0.5 | < 45 min to Full Plant Load |
| Startup Time (Hot Start), hours | 0.5 | < 45 min to Full Plant Load |
| Startup Time to MECL | 0.5 | < 45 min to Full Plant Load |
| Maximum Ramp Rate (Online), MW/min | 4 | 2 |
| Book Life, years | 35 | 35 |
| Equivalent Planned Outage Rate (%) | 4% | 6% |
| Equivalent Forced Outage Rate (%) | 7% | 8% |
| Equivalent Availability Factor (%) | 94% | 88% |
| Assumed Land Use (Acres) | 1 | 1 |
| Fuel Design | Natural Gas | Natural Gas |
| Heat Rejection | Remote Radiator | Remote Radiator |
| $NO_x$ Control | SCR | Low NOx Combustion / SCR |
| $SO_2$ Control | N/A | N/A |
| $CO_2$ Control | N/A | N/A |
| Particulate Control | Good Combustion Practice | Good Combustion Practice |
| Technology Rating | Mature | Mature |
| Permitting & Construction Schedule (Years from FNTP) | 3 | 3 |
| **ESTIMATED PERFORMANCE** | | |
| Base Load Performance @ (Annual Average) | | |
| Net Plant Output, kW | N/A - See Below | N/A - See Below |
| Net Plant Heat Rate, Btu/kWh (HHV) | N/A - See Below | N/A - See Below |
| Heat Input, MMBtu/h (HHV) | N/A - See Below | N/A - See Below |

| VECTREN ENERGY 2019 GENERIC UNIT ASSESSMENT SUMMARY TABLE<br>COMBINED HEAT AND POWER TECHNOLOGY ASSESSMENT PROJECT OPTIONS<br>PRELIMINARY - NOT FOR CONSTRUCTION<br>December 2019 | | |
|---|---|---|
| **PROJECT TYPE** | **Combined Heat and Power** | **Combined Heat and Power** |
| **BASE PLANT DESCRIPTION** | 2x 9MW Reciprocating Engine (Wartsila 20V34SG) | 1 x Titan 250 CTG w/ unfired HRSG |
| Minimum Load Operational Status @ (Annual Average) | | |
| Net Plant Output, kW | N/A - See Below | N/A - See Below |
| Net Plant Heat Rate, Btu/kWh (HHV) | N/A - See Below | N/A - See Below |
| Heat Input, MMBtu/h (HHV) | N/A - See Below | N/A - See Below |
| CHP Base Load Performance @ (Winter) | | |
| Net Plant Output, kW | 17,940 | 21,670 |
| Simple Cycle Heat Rate, Btu/kWh (HHV) | 8,180 | 10,120 |
| Plant Heat Rate, Btu/kWh (HHV) | 6,830 | 6,420 |
| Heat Input, MMBtu/h (HHV) | 152 | 219 |
| Plant Steam Output, pph | 25,800 | 68,100 |
| Plant Steam Output, MMBtu/h (HHV) | 26 | 68 |
| CHP Minimum Load Operational Status @ (Winter) (Single Unit) | | |
| Net Plant Output, kW | 4,530 | 10,860 |
| Simple Cycle Heat Rate, Btu/kWh (HHV) | 8,990 | 13,920 |
| Plant Heat Rate, Btu/kWh (HHV) | 7,010 | 7,410 |
| Heat Input, MMBtu/h (HHV) | 42 | 151 |
| Plant Steam Output, pph | 9,000 | 60,100 |
| Plant Steam Output, MMBtu/h (HHV) | 9 | 60 |
| CHP Base Load Performance @ (Annual Average) | | |
| Net Plant Output, kW | 17,940 | 19,910 |
| Simple Cycle Heat Rate, Btu/kWh (HHV) | 8,180 | 10,390 |
| Plant Heat Rate, Btu/kWh (HHV) | 6,830 | 6,120 |
| Heat Input, MMBtu/h (HHV) | 152 | 207 |
| Plant Steam Output, pph | 25,800 | 72,300 |
| Plant Steam Output, MMBtu/h (HHV) | 26 | 72 |
| CHP Minimum Load Operational Status @ (Annual Average) (Single Unit) | | |
| Net Plant Output, kW | 4,530 | 9,980 |
| Simple Cycle Heat Rate, Btu/kWh (HHV) | 8,990 | 14,220 |
| Plant Heat Rate, Btu/kWh (HHV) | 7,010 | 7,060 |
| Heat Input, MMBtu/h (HHV) | 42 | 142 |
| Plant Steam Output, pph | 9,000 | 60,700 |
| Plant Steam Output, MMBtu/h (HHV) | 9 | 61 |

| VECTREN ENERGY 2019 GENERIC UNIT ASSESSMENT SUMMARY TABLE<br>COMBINED HEAT AND POWER TECHNOLOGY ASSESSMENT PROJECT OPTIONS<br>PRELIMINARY - NOT FOR CONSTRUCTION<br>December 2019 | | |
|---|---|---|
| **PROJECT TYPE** | **Combined Heat and Power** | **Combined Heat and Power** |
| **BASE PLANT DESCRIPTION** | 2x 9MW Reciprocating Engine (Wartsila 20V34SG) | 1 x Titan 250 CTG w/ unfired HRSG |
| CHP Base Load Performance @ (Summer) | | |
| Net Plant Output, kW | 17,940 | 15,860 |
| Simple Cycle Heat Rate, Btu/kWh (HHV) | 8,180 | 11,260 |
| Plant Heat Rate, Btu/kWh (HHV) | 6,830 | 6,030 |
| Heat Input, MMBtu/h (HHV) | 152 | 179 |
| Plant Steam Output, pph | 25,800 | 70,600 |
| Plant Steam Output, MMBtu/h (HHV) | 26 | 71 |
| CHP Minimum Load Operational Status @ (Summer) (Single Unit) | | |
| Net Plant Output, kW | 4,530 | 7,950 |
| Simple Cycle Heat Rate, Btu/kWh (HHV) | 8,990 | 16,170 |
| Plant Heat Rate, Btu/kWh (HHV) | 7,010 | 6,910 |
| Heat Input, MMBtu/h (HHV) | 42 | 128 |
| Plant Steam Output, pph | 9,000 | 62,500 |
| Plant Steam Output, MMBtu/h (HHV) | 9 | 63 |

| VECTREN ENERGY 2019 GENERIC UNIT ASSESSMENT SUMMARY TABLE<br>COMBINED HEAT AND POWER TECHNOLOGY ASSESSMENT PROJECT OPTIONS<br>PRELIMINARY - NOT FOR CONSTRUCTION<br>December 2019 | | |
|---|---|---|
| **PROJECT TYPE** | **Combined Heat and Power** | **Combined Heat and Power** |
| **BASE PLANT DESCRIPTION** | 2x 9MW Reciprocating Engine (Wartsila 20V34SG) | 1 x Titan 250 CTG w/ unfired HRSG |
| **ESTIMATED CAPITAL AND O&M COSTS** | | |
| **EPC Project Capital Costs, 2019 MM$ (w/o Owner's Costs)** | **$54** | **$48** |
| **Owner's Costs, 2019 MM$** | **$22** | **$22** |
| Owner's Project Development | $0.3 | $0.3 |
| Owner's Operational Personnel Prior to COD | $0.3 | $0.3 |
| Owner's Engineer | $0.4 | $0.4 |
| Owner's Project Management | $0.8 | $0.8 |
| Owner's Legal Costs | $0.5 | $0.5 |
| Owner's Start-up Engineering and Commissioning | $0.2 | $0.2 |
| Land | $0.01 | $0.01 |
| Construction Power and Water | $0.5 | $0.5 |
| Permitting and Licensing Fees | $0.5 | $0.5 |
| Switchyard | N/A | N/A |
| Political Concessions & Area Development Fees | $0.3 | $0.3 |
| Startup/Testing (Fuel & Consumables) | $0.1 | $0.3 |
| Initial Fuel Inventory | $0.0 | $0.0 |
| Site Security | $0.2 | $0.2 |
| Operating Spare Parts | $0.3 | $0.5 |
| Water Supply Infrastructure (5 Mile Pipeline) (Note 6) | $7.5 | $7.5 |
| Natural Gas Supply Infrastructure | Excluded | Excluded |
| Transmission Interconnect | $0.1 | $0.1 |
| Transmission Upgrade Costs | Excluded | Excluded |
| Firm Gas Supply Reservation Charge | Provided by Owner | Provided by Owner |
| Permanent Plant Equipment and Furnishings | $0.0 | $0.0 |
| AFUDC (12.2% of EPC Project Capital Costs) | $6.6 | $5.8 |
| Builders Risk Insurance (0.45% of Construction Costs) | $0.3 | $0.3 |
| Owner's Contingency (5% for Screening Purposes) | $3.7 | $3.3 |

VECTREN ENERGY 2019 GENERIC UNIT ASSESSMENT SUMMARY TABLE
COMBINED HEAT AND POWER TECHNOLOGY ASSESSMENT PROJECT OPTIONS
PRELIMINARY - NOT FOR CONSTRUCTION
December 2019

| | | |
|---|---|---|
| **PROJECT TYPE** | **Combined Heat and Power** | **Combined Heat and Power** |
| **BASE PLANT DESCRIPTION** | 2x 9MW Reciprocating Engine (Wartsila 20V34SG) | 1 x Titan 250 CTG w/ unfired HRSG |
| **Total Project Costs, 2019 MM$** | **$77** | **$69** |
| **EPC Cost Per kW, 2019 $/kW** | **$3,040** | **$3,010** |
| **Total Cost Per kW, 2019 $/kW** | **$4,290** | **$4,370** |
| **FIXED O&M COSTS** | | |
| Fixed O&M Cost - LABOR, 2019$MM/Yr | $0.60 | $0.60 |
| Fixed O&M Cost - Other, 2019$MM/Yr | $0.15 | $0.15 |
| **MAJOR MAINTENANCE COSTS** | | |
| Major Maintenance Cost, 2019$/MWh | $2.40 | $8.70 |
| **NON-FUEL VARIABLE O&M COSTS (EXCLUDES MAJOR MAINTENANCE)** | | |
| Total Variable O&M Cost, 2019$/MWh | $5.93 | $1.22 |
| Water Related O&M ($/MWh) | $0.00 | $0.00 |
| SCR Related O&M ($/MWh) | $0.93 | $0.32 |
| Other Variable O&M ($/MWh) | $5.00 | $0.90 |
| **ESTIMATED BASE LOAD OPERATING EMISSIONS, lb/MMBtu (HHV)** | | |
| $NO_X$ | 0.018 | 0.01 |
| $SO_2$ | < 0.002 | < 0.002 |
| CO | 0.03 | 0.01 |
| $CO_2$ | 120 | 120 |

**Notes**

Note 1: Combined heat and power (CHP) options assume that water treatment costs are the responsibility of the host and are not included in the O&M costs above.
Note 2: CHP start time shown is total system startup time. CTG or engine is capable of full load operation within ~10 minutes. Overall length of startup is primarily dependent upon startup rates recommended by HRSG manufacturer.

Note 3: CHP make-up water costs for the steam system will be dependent on Host condensate return percentage. DI water cost for water wash is negligible.

Note 4: LFG engine start times account for time required to heat engine jacket water appropriately to accommodate startup.
Note 5: Decommissioning costs and salvage values are excluded from analysis.

**VECTREN ENERGY 2019 GENERIC UNIT ASSESSMENT SUMMARY TABLE**
**WASTE-TO-ENERGY TECHNOLOGY ASSESSMENT PROJECT OPTIONS**
**PRELIMINARY - NOT FOR CONSTRUCTION**
**December 2019**

| **PROJECT TYPE** | **Bubbling Fluidized Bed** | **Landfill Gas Engine** |
|---|---|---|
| **BASE PLANT DESCRIPTION** | | 3x Reciprocating Engine |
| Number of Gas Turbines / Engines / Reactors | N/A | 3 |
| Number of HRSGs | N/A | N/A |
| Number of Steam Turbines | 1 | N/A |
| Main Steam Pressure | 1,400 psi-a | N/A |
| Steam Cycle Type | 950°F / 950°F | N/A |
| Capacity Factor (%) | 85% | 10% |
| Startup Time (Cold Start), hours | 12 Hours | 6+ Hours |
| Startup Time (Warm Start), hours | Not Provided | 1-2 Hours |
| Startup Time (Hot Start), hours | Not Provided | 7 Minutes |
| Startup Time to MECL | Not Provided | 5 Minutes |
| Maximum Ramp Rate (Online), MW/min | Not Provided | 1 |
| Book Life, years | 30 | 30 |
| Equivalent Planned Outage Rate (%) | 2% | 2% |
| Equivalent Forced Outage Rate (%) | 10% | 10% |
| Equivalent Availability Factor (%) | 83% | 83% |
| Fuel Design | Chipped Wood Biomass | Landfill Gas |
| Heat Rejection | Wet Cooling Tower | Fin Fan Heat Exchanger |
| $NO_x$ Control | SNCR | Good Combustion Practice |
| $SO_2$ Control | Dry Sorbent Injection | N/A |
| $CO_2$ Control | Good Combustion Practice | N/A |
| Particulate Control | Baghouse | N/A |
| Technology Rating | Mature | Mature |
| Permitting & Construction Schedule (Years from FNTP) | 4 | 2 |
| **ESTIMATED PERFORMANCE** | | |
| Base Load Performance @ (Annual Average) | | |
| Net Plant Output, kW | 50,000 | 4,500 |
| Net Plant Heat Rate, Btu/kWh (HHV) | 13,000 | 10,740 |
| Heat Input, MMBtu/h (HHV) | 650 | 48 |
| Minimum Load Operational Status @ (Annual Average) | | |
| Net Plant Output, kW | 17,500 | 2,200 |
| Net Plant Heat Rate, Btu/kWh (HHV) | 15,500 | 11,910 |
| Heat Input, MMBtu/h (HHV) | 270 | 26 |

**VECTREN ENERGY 2019 GENERIC UNIT ASSESSMENT SUMMARY TABLE**
**WASTE-TO-ENERGY TECHNOLOGY ASSESSMENT PROJECT OPTIONS**
**PRELIMINARY - NOT FOR CONSTRUCTION**
**December 2019**

| PROJECT TYPE | Bubbling Fluidized Bed | Landfill Gas Engine |
|---|---|---|
| **BASE PLANT DESCRIPTION** | | 3x Reciprocating Engine |
| **ESTIMATED CAPITAL AND O&M COSTS** | | |
| **EPC Project Capital Costs, 2019 MM$ (w/o Owner's Costs)** | **$224** | **$14** |
| **Owner's Costs, 2019 MM$** | **$58** | **$5** |
| Owner's Project Development | $3.0 | $0.3 |
| Owner's Operational Personnel Prior to COD | $1.6 | $0.0 |
| Owner's Engineer | $1.0 | $0.1 |
| Owner's Project Management | $2.0 | $0.1 |
| Owner's Legal Costs | $1.0 | $0.1 |
| Owner's Start-up Engineering and Commissioning | $0.2 | $0.1 |
| Land | $1.0 | $0.0 |
| Construction Power and Water | $1.3 | $0.2 |
| Permitting and Licensing Fees | $1.0 | $0.1 |
| Switchyard | $6.0 | $2.0 |
| Political Concessions & Area Development Fees | $0.5 | $0.1 |
| Startup/Testing (Fuel & Consumables) | $1.5 | $0.0 |
| Initial Fuel Inventory | $4.3 | $0.0 |
| Site Security | $0.8 | $0.1 |
| Operating Spare Parts | $0.6 | $0.0 |
| Water Supply Infrastructure | Excluded | Excluded |
| Natural Gas Supply Infrastructure | Excluded (On-site) | Excluded (On-site) |
| Transmission Interconnect | $0.2 | $0.0 |
| Transmission Upgrade Costs | Excluded | Excluded |
| Firm Gas Supply Reservation Charge | Provided by Owner | Provided by Owner |
| Permanent Plant Equipment and Furnishings | $0.6 | $0.0 |
| AFUDC (12.2% of EPC Project Capital Costs) | $27.4 | $1.8 |
| Builders Risk Insurance (0.45% of Construction Costs) | $1.0 | $0.1 |
| Owner's Contingency (5% for Screening Purposes) | $2.8 | $0.2 |
| **Total Project Costs, 2019 MM$** | **$282** | **$20** |
| **EPC Cost Per kW, 2019 $/kW** | **$4,490** | **$3,190** |
| **Total Cost Per kW, 2019 $/kW** | **$5,640** | **$4,110** |

| VECTREN ENERGY 2019 GENERIC UNIT ASSESSMENT SUMMARY TABLE<br>WASTE-TO-ENERGY TECHNOLOGY ASSESSMENT PROJECT OPTIONS<br>PRELIMINARY - NOT FOR CONSTRUCTION<br>December 2019 | | |
|---|---|---|
| **PROJECT TYPE** | **Bubbling Fluidized Bed** | **Landfill Gas Engine** |
| **BASE PLANT DESCRIPTION** | | 3x Reciprocating Engine |
| **FIXED O&M COSTS** | | |
| Fixed O&M Cost - LABOR, 2019$MM/Yr | $3.60 | $0.40 |
| Fixed O&M Cost - Other, 2019$MM/Yr | $2.60 | $0.10 |
| **MAJOR MAINTENANCE COSTS** | | |
| Major Maintenance Cost, 2019$/MWh | $4.28 | $9.50 |
| **NON-FUEL VARIABLE O&M COSTS (EXCLUDES MAJOR MAINTENANCE)** | | |
| Total Variable O&M Cost, 2019$/MWh | $2.85 | $7.62 |
| Water Related O&M ($/MWh) | Included | $0.00 |
| SCR Related O&M ($/MWh) | Included | $0.00 |
| Other Variable O&M ($/MWh) | Included | $7.62 |
| **ESTIMATED BASE LOAD OPERATING EMISSIONS, lb/MMBtu (HHV)** | | |
| $NO_X$ | 0.10 | 0.15 |
| $SO_2$ | 0.01 | 0.01 |
| CO | 0.08 | 1.27 |
| $CO_2$ | 205 | 170 |

**Notes**

Note 1: Combined heat and power (CHP) options assume that water treatment costs are the responsibility of the host and are not included in the O&M costs above.

Note 2: CHP start time shown is total system startup time. CTG or engine is capable of full load operation within ~10 minutes. Overall length of startup is primarily dependent upon startup rates recommended by HRSG manufacturer.

Note 3: CHP make-up water costs for the steam system will be dependent on Host condensate return percentage. DI water cost for water wash is negligible.

Note 4: LFG engine start times account for time required to heat engine jacket water appropriately to accommodate startup.

Note 5: Decommissioning costs and salvage values are excluded from analysis.

**VECTREN 2019 IRP TECHNOLOGY ASSESSMENT**
**RENEWABLE AND STORAGE TECHNOLOGY ASSESSMENT PROJECT OPTIONS**
**PRELIMINARY - NOT FOR CONSTRUCTION**
**December 2019**

| **PROJECT TYPE** | **Hydroelectric** | **Wind Energy** | **Wind Energy** | **Wind Energy** | **Wind Plus Storage** | **Solar Photovoltaic** | **Solar Photovoltaic** | **Solar Photovoltaic** |
|---|---|---|---|---|---|---|---|---|
| **BASE PLANT DESCRIPTION** | Low Head Hydroelectric | Southern IN | Northern IN | North Dakota | Indiana | Single Axis Tracking | Single Axis Tracking | Single Axis Tracking |
| Nominal Output, MW | 50 | 200 | 200 | 200 | 50 MW Wind & 10 MW / 40 MWh Storage | 10 | 50 | 100 |
| Number of Turbines | 1 | 58 x 3.45 MW | 58 x 3.45 MW | 58 x 3.45 MW | 15 x 3.45 MW | N/A | N/A | N/A |
| Capacity Factor (%) (Notes 1,2) | 40% | 28% | 38% | 41% | 38% | 24.3% | 24.2% | 24.2% |
| Startup Time (Cold Start) | | N/A | N/A | N/A | N/A | N/A | N/A | N/A |
| Book Life (Years) | 40 | 30 | 30 | 30 | 30 | 30 | 30 | 30 |
| Equivalent Planned Outage Rate (%) | 11% | < 5% | < 5% | < 5% | < 5% | < 1% | < 1% | < 1% |
| Equivalent Forced Outage Rate (%) | < 5% | < 5% | < 5% | < 5% | < 5% | < 1% | < 1% | < 1% |
| Equivalent Availability Factor (%) (Note 6) | 84% | 95% | 95% | 95% | 95% | 99% | 99% | 99% |
| Assumed Land Use (Acres) | N/A | 44 | 44 | 44 | 44 | 80 | 400 | 800 |
| Fuel Design | Elevated Water | N/A | N/A | N/A | N/A | N/A | N/A | N/A |
| Heat Rejection | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A |
| Total System Cycles | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A |
| Interconnection Voltage Assumption | 230 kV | 230 kV | 230 kV | 230 kV | 230 kV | 34.5kV | 230 kV | 230 kV |
| PV Inverter Loading Ratio (DC/AC) | N/A | N/A | N/A | N/A | N/A | 1.40 | 1.40 | 1.40 |
| PV Degradation (%/yr) (Note 7) | N/A | N/A | N/A | N/A | N/A | First year: 2% After 1st Year: 0.5% per year | First year: 2% After 1st Year: 0.5% per year | First year: 2% After 1st Year: 0.5% per year |
| Storage System Initial Overbuild (%) | N/A | N/A | N/A | N/A | 18% | N/A | N/A | N/A |
| Storage System Augmentation (%/yr) | N/A | N/A | N/A | N/A | 2.5% | N/A | N/A | N/A |
| Storage System AC Roundtrip Efficiency (%) | N/A | N/A | N/A | N/A | 85% | N/A | N/A | N/A |
| Technology Rating | Mature | Mature | Mature | Mature | Mature | Mature | Mature | Mature |
| Permitting & Construction Schedule (Years from FNTP) | 7 | 2.5 | 2.5 | 2.5 | 2.5 | 2 | 2 | 2 |
| **ESTIMATED PERFORMANCE** | | | | | | | | |
| Base Load Performance @ (Annual Average) | | | | | | | | |
| Net Plant Output, kW | 50,000 | 200,000 | 200,000 | 200,000 | 50,000 | 10,000 | 50,000 | 100,000 |
| Net Plant Heat Rate, Btu/kWh (HHV) | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A |
| Heat Input, MMBtu/h (HHV) | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A |
| **ESTIMATED CAPITAL AND O&M COSTS** | | | | | | | | |
| **Project Capital Costs, 2019 MM$ (w/o Owner's Costs)** | **$210** | **$230** | **$230** | **$230** | **$73** | **$16** | **$73** | **$145.9** |
| **Wind Capital Cost Breakdown** | | | | | | | | |
| Engineering | N/A | $1.05 | $1.05 | $1.05 | $0.26 | N/A | N/A | N/A |
| Equipment and Materials | N/A | $160 | $160 | $160 | $40 | N/A | N/A | N/A |
| Turbine Towers | N/A | Incl | Incl | Incl | Incl | N/A | N/A | N/A |
| Turbine Blades | N/A | Incl | Incl | Incl | Incl | N/A | N/A | N/A |
| Turbine Hubs | N/A | Incl | Incl | Incl | Incl | N/A | N/A | N/A |
| Nacelle and nacelle components | N/A | Incl | Incl | Incl | Incl | N/A | N/A | N/A |
| SCADA Equipment | N/A | Incl | Incl | Incl | Incl | N/A | N/A | N/A |
| Construction | N/A | $69 | $69 | $69 | $17 | N/A | N/A | N/A |
| Turbine Foundation and Erection | N/A | Incl | Incl | Incl | Incl | N/A | N/A | N/A |
| BOP Costs | N/A | Incl | Incl | Incl | Incl | N/A | N/A | N/A |
| Collector Bus | N/A | Incl | Incl | Incl | Incl | N/A | N/A | N/A |
| Indirects and Fees | N/A | Incl | Incl | Incl | Incl | N/A | N/A | N/A |
| EPC Contingency | N/A | Incl | Incl | Incl | Incl | N/A | N/A | N/A |
| **PV Capital Cost Breakdown** | | | | | | | | |
| Engineering | N/A | N/A | N/A | N/A | N/A | $1.2 | $1.2 | $1.5 |
| Equipment and Materials | N/A | N/A | N/A | N/A | N/A | | | |
| Modules | N/A | N/A | N/A | N/A | N/A | $5.2 | $25.8 | $51.6 |
| Inverters | N/A | N/A | N/A | N/A | N/A | $0.6 | $3.1 | $6.2 |
| Racking | N/A | N/A | N/A | N/A | N/A | $1.7 | $8.4 | $16.8 |
| Construction (Note 16) | N/A | N/A | N/A | N/A | N/A | $5.1 | $25.7 | $51.4 |
| Indirects and Fees | N/A | N/A | N/A | N/A | N/A | $1.5 | $7.1 | $14.0 |
| EPC Contingency | N/A | N/A | N/A | N/A | N/A | $0.5 | $2.1 | $4.2 |
| | N/A | | | | | | | |
| **Battery Storage Capital Cost Breakdown** | | | | | | | | |
| Batteries | N/A | N/A | N/A | N/A | $8 | N/A | N/A | N/A |
| Inverters | N/A | N/A | N/A | N/A | $1 | N/A | N/A | N/A |
| BOP | N/A | N/A | N/A | N/A | $1 | N/A | N/A | N/A |
| Construction and Indirects | N/A | N/A | N/A | N/A | $6 | N/A | N/A | N/A |
| **Owner's Costs, 2019 MM$** | **$93** | **$66** | **$66** | **$66** | **$18.9** | **$9** | **$17** | **$27** |
| Owner's Project Development | Allowance Included | Allowance Included | Allowance Included | Allowance Included | Allowance Included | Allowance Included | Allowance Included | Allowance Included |
| Owner's Engineer | Allowance Included | Allowance Included | Allowance Included | Allowance Included | Allowance Included | Allowance Included | Allowance Included | Allowance Included |
| Owner's Project Management | Allowance Included | Allowance Included | Allowance Included | Allowance Included | Allowance Included | Allowance Included | Allowance Included | Allowance Included |
| Startup / Testing / Warranties | Allowance Included | Allowance Included | Allowance Included | Allowance Included | Allowance Included | Allowance Included | Included in EPC | Included in EPC |
| Land (Note 11) | Excluded - Assumes Existing Dam | Excluded - Assumes Lease | Excluded - Assumes Lease | Excluded - Assumes Lease | Excluded - Assumes Lease | Excluded - Assumes Lease | Excluded - Assumes Lease | Excluded - Assumes Lease |
| Transmission Upgrade Costs | Excluded | Excluded | Excluded | Excluded | Excluded | Excluded | Excluded | Excluded |
| Permitting and Licensing Fees | Included | Included | Included | Included | Included | Included in EPC | Included in EPC | Included in EPC |
| Switchyard / Substation (Notes 8,9,12) | $2.0 M Allowance Included | $5.3 M Allowance Included | $5.3 M Allowance Included | $5.3 M Allowance Included | $5.3 M Allowance Included | $5.3M Allowance Included | $5.3M Allowance Included | $1.0M Allowance Included |
| AFUDC (Note 17) | $25.6 | $23.2 | $23.2 | $23.2 | $7.4 | $1.3 | $5.9 | $11.7 |
| Builder's Risk Insurance | Allowance Included | Allowance Included | Allowance Included | Allowance Included | Allowance Included | Allowance Included | Allowance Included | Allowance Included |
| Owner's Contingency | Allowance Included | Allowance Included | Allowance Included | Allowance Included | Allowance Included | Allowance Included | Allowance Included | Allowance Included |
| **Total Project Costs, 2019 MM$** | **$303** | **$296** | **$296** | **$296** | **$92** | **$25** | **$90** | **$173** |
| **EPC Cost Per kW, 2019 $/kW (plus $/kWh for Storage)** | **$4,200** | **$1,150** | **$1,150** | **$1,150** | **$1460 / $390** | **$1,580** | **$1,470** | **$1,460** |
| **Total Cost Per kW, 2019 $/kW (plus $/kWh for Storage)** | **$6,050** | **$1,480** | **$1,480** | **$1,480** | **$1840 / $650** | **$2,500** | **$1,810** | **$1,730** |

**VECTREN 2019 IRP TECHNOLOGY ASSESSMENT**
**RENEWABLE AND STORAGE TECHNOLOGY ASSESSMENT PROJECT OPTIONS**
**PRELIMINARY - NOT FOR CONSTRUCTION**
**December 2019**

| PROJECT TYPE | Hydroelectric | Wind Energy | Wind Energy | Wind Energy | Wind Plus Storage | Solar Photovoltaic | Solar Photovoltaic | Solar Photovoltaic |
|---|---|---|---|---|---|---|---|---|
| **BASE PLANT DESCRIPTION** | Low Head Hydroelectric | Southern IN | Northern IN | North Dakota | Indiana | Single Axis Tracking | Single Axis Tracking | Single Axis Tracking |
| Nominal Output, MW | 50 | 200 | 200 | 200 | 50 MW Wind & 10 MW / 40 MWh Storage | 10 | 50 | 100 |
| **Fixed O&M Cost - TOTAL, 2019$MM/Yr (Notes 3-5)** | **$4.6** | **$8.0** | **$8.0** | **$8.0** | **$2.2** | **$0.3** | **$1.3** | **$2.44** |
| Annual Fixed Labor Cost, 2019$MM/Yr | Included in FOM | $0.6 | $0.6 | $0.6 | $0.2 | $0.0 | $0.0 | $0.00 |
| Equipment Maintenance Cost, 2019$MM/Yr | Included in FOM | $4.8 | $4.8 | $4.8 | $1.4 | $0.1 | $0.4 | $0.70 |
| BOP and Other Cost, 2019$MM/Yr | Included in FOM | $1.8 | $1.8 | $1.8 | $0.5 | $0.1 | $0.4 | $0.85 |
| Land Lease Allowance, 2019$MM/Yr (Notes 10,11,14) | Included in FOM | $0.8 | $0.8 | $0.8 | $0.2 | $0.0 | $0.2 | $0.48 |
| Property Tax Allowance, 2019$MM/Yr (Note 14) | Included in FOM | $0.0 | $0.0 | $0.0 | $0.0 | 0 | $0.0 | $0.00 |
| Capital Replacement Allowance, 2019$/MWh (Notes 3-5) | Included in FOM | % of OPEX; See Table | % of OPEX; See Table | % of OPEX; See Table | % of OPEX; See Table | $0.0 | $0.2 | $0.42 |
| Variable O&M Cost, 2019$/MWh (excl. major maint.) (Note 4) | Included in FOM | Included in FOM | Included in FOM | Included in FOM | $14.5 (Storage MWh Only) | Included in FOM | Included in FOM | Included in FOM |
| **ESTIMATED BASE LOAD OPERATING EMISSIONS, lb/MMBtu (HHV)** | | | | | | | | |
| $NO_x$ | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A |
| $SO_2$ | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A |
| CO | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A |
| $CO_2$ | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A |

**Notes**
1. Wind capacity factor represents Net Capacity Factor (NCF), which accounts for typical system losses. Capacity factor is based on Vestas V125-3.45 MW turbines with 87 meter hub height and 7.0 m/s average wind speed. Offshore capacity factor is based on estimates from publicly available studies.
2. Solar capacity factor accounts for typical losses. Fixed tilt systems assumes 20 degree tilt.
3. Capital maintenance allowances for onshore wind options are not included in the annual FOM above. A supplemental table in the report shows capital allowances estimated as percentages of annual operating expenses for a 30 year life. Offshore wind O&M estimates, based on publicly available documents, include levelized capital maintenance.

4. Battery FOM assumes the site is remotely controlled. Capital costs assume the system is oversized to accommodate normal degradation, so no battery replacement fund is included. Variable O&M accounts for the parasitic power draw of the system, including HVAC and efficiency losses.
5. PV O&M estimates assume fixed contracts for all maintenance activities. It is assumed the system is remotely controlled. Capital maintenance assumes an inverter replacement allowance levelized over the first 15 years. Inverter replacement is not included in the Solar + Storage option because of 15 year project life.
6. NERC GADS performance statistics are not available for PV, battery storage, and wind technologies. Availability estimates are based on vendor correspondence and industry publications.
7. PV degradation based on typical warranty information for polycrystalline products. Assuming factory recommended maintenance is performed, PV performance is estimated to degrade ~2% in the first year and 0.5% each remaining year.
8. Battery system assumes interconnection at distribution voltage and therefore excludes GSU and switchyard.
9. EPC costs for wind include 34.5 kV collection system and GSU to 230 kV. Owner's costs include 3 position ring bus switchyard for interconnection at 230kV. EPC cost for offshore wind include HVDC line and onshore converter. Owner's costs include 3 position ring bus switchyard for interconnection at 230kV.
10. Offshore wind project assumes cost for BOEM ocean lease is included in fixed O&M.
11. Onshore wind and PV projects assume that land is leased and therefore land costs are included in O&M, not capital costs. Onshore wind assumes one acre per turbine. PV assumes seven acres per MW for fixed tilt and eight acres per MW for tracking options.
12. PV scope for EPC includes 34.5 kV collector bus and circuit breaker. Owner costs include allowance for interconnection at 34.5 kV. PV costs updated in March 2019 to reflect potential impacts of tariffs on PV panels and steel.
13. Battery storage costs are shown as $/kW and as $/kWh per industry norms.
14: Land lease and property estimates are assumed allowances.
15: Estimated Costs exclude decommissioning costs and salvage values.
16. Construction line item for PV includes Labor, Construction Materials, and miscellaneous BOP Equipment
17. AFUDC of 12.2% used for the hydro option, 10.1% for the wind options, and 8% for the solar and storage options. AFUDC percentage is based on project schedule.

**VECTREN 2019 IRP TECHNOLOGY ASSESSMENT**
**RENEWABLE AND STORAGE TECHNOLOGY ASSESSMENT PROJECT OPTIONS**
**PRELIMINARY - NOT FOR CONSTRUCTION**
**December 2019**

| **PROJECT TYPE** | **Solar Plus Storage** | **Battery Storage** | **Battery Storage** | **Battery Storage** | **Battery Storage** | **Battery Storage** | **Battery Storage** |
|---|---|---|---|---|---|---|---|
| **BASE PLANT DESCRIPTION** | Single Axis Tracking | Lithium Ion | Lithium Ion | Flow Battery | Flow Battery | Flow Battery | Flow Battery |
| Nominal Output, MW | 50 MW PV &<br>10 MW / 40 MWh Storage | 10 MW / 40 MWh | 50 MW / 200 MWh | 10 MW / 60 MWh | 10 MW / 80 MWh | 50 MW / 300 MWh | 50 MW / 400 MWh |
| Number of Turbines | N/A | N/A | N/A | N/A | N/A | N/A | N/A |
| Capacity Factor (%) (Notes 1,2) | 24.2% | 17% | 17% | 25% | 33% | 25% | 33% |
| Startup Time (Cold Start) | N/A | N/A | N/A | N/A | N/A | N/A | N/A |
| Book Life (Years) | 15 | 15 | 15 | 20 | 20 | 20 | 20 |
| Equivalent Planned Outage Rate (%) | < 3% | < 3% | < 3% | < 3% | < 3% | < 3% | < 3% |
| Equivalent Forced Outage Rate (%) | < 3% | < 3% | < 3% | < 3% | < 3% | < 3% | < 3% |
| Equivalent Availability Factor (%) (Note 6) | 97% | 97% | 97% | 97% | 97% | 97% | 97% |
| Assumed Land Use (Acres) | 402 | 5 | 8 | 20 | 20 | 20 | 20 |
| Fuel Design | N/A | N/A | N/A | N/A | N/A | N/A | N/A |
| Heat Rejection | N/A | Air-cooled HVAC | Air-cooled HVAC | Air-cooled chiller | Air-cooled chiller | Air-cooled chiller | Air-cooled chiller |
| Total System Cycles | N/A | 5,500 | 5,500 | 7,200 | 7,200 | 7,200 | 7,200 |
| Interconnection Voltage Assumption | 230 kV | 230 kV | 230 kV | 230 kV | 230 kV | 230 kV | 230 kV |
| PV Inverter Loading Ratio (DC/AC) | 1.40 | N/A | N/A | N/A | N/A | N/A | N/A |
| PV Degradation (%/yr) (Note 7) | First year: 2%<br>After 1st Year: 0.5% per year | N/A | N/A | N/A | N/A | N/A | N/A |
| Storage System Initial Overbuild (%) | 18% | 18% | 18% | 0% | 0% | 0% | 0% |
| Storage System Augmentation (%/yr) | 2.5% | 2.5% | 2.5% | 0% | 0% | 0% | 0% |
| Storage System AC Roundtrip Efficiency (%) | 85% | 85% | 85% | 68% | 68% | 68% | 68% |
| Technology Rating | Mature | Mature | Mature | Developing | Developing | Developing | Developing |
| Permitting & Construction Schedule (Years from FNTP) | 2 | 2 | 2 | 2 | 2 | 2 | 2 |
| **ESTIMATED PERFORMANCE** | | | | | | | |
| Base Load Performance @ (Annual Average) | | | | | | | |
| Net Plant Output, kW | 50,000 | 10,000 kW / 40,000 kWh | 50,000 kW / 200,000 kWh | 10,000 kW / 60,000 kWh | 10,000 kW / 80,000 kWh | 50,000 kW / 300,000 kWh | 50,000 kW / 400,000 kWh |
| Net Plant Heat Rate, Btu/kWh (HHV) | N/A | N/A | N/A | N/A | N/A | N/A | N/A |
| Heat Input, MMBtu/h (HHV) | N/A | N/A | N/A | N/A | N/A | N/A | N/A |
| **ESTIMATED CAPITAL AND O&M COSTS** | | | | | | | |
| **Project Capital Costs, 2019 MM$ (w/o Owner's Costs)** | **$88.8** | **$16.5** | **$63.1** | **$35.8** | **$44.6** | **$162.8** | **$205.5** |
| **Wind Capital Cost Breakdown** | | | | | | | |
| Engineering | N/A | N/A | N/A | N/A | N/A | N/A | N/A |
| Equipment and Materials | N/A | N/A | N/A | N/A | N/A | N/A | N/A |
| Turbine Towers | N/A | N/A | N/A | N/A | N/A | N/A | N/A |
| Turbine Blades | N/A | N/A | N/A | N/A | N/A | N/A | N/A |
| Turbine Hubs | N/A | N/A | N/A | N/A | N/A | N/A | N/A |
| Nacelle and nacelle components | N/A | N/A | N/A | N/A | N/A | N/A | N/A |
| SCADA Equipment | N/A | N/A | N/A | N/A | N/A | N/A | N/A |
| Construction | N/A | N/A | N/A | N/A | N/A | N/A | N/A |
| Turbine Foundation and Erection | N/A | N/A | N/A | N/A | N/A | N/A | N/A |
| BOP Costs | N/A | N/A | N/A | N/A | N/A | N/A | N/A |
| Collector Bus | N/A | N/A | N/A | N/A | N/A | N/A | N/A |
| Indirects and Fees | N/A | N/A | N/A | N/A | N/A | N/A | N/A |
| EPC Contingency | N/A | N/A | N/A | N/A | N/A | N/A | N/A |
| **PV Capital Cost Breakdown** | | | | | | | |
| Engineering | $1.2 | N/A | N/A | N/A | N/A | N/A | N/A |
| Equipment and Materials | | N/A | N/A | N/A | N/A | N/A | N/A |
| Modules | $25.8 | N/A | N/A | N/A | N/A | N/A | N/A |
| Inverters | $3.1 | N/A | N/A | N/A | N/A | N/A | N/A |
| Racking | $8.4 | N/A | N/A | N/A | N/A | N/A | N/A |
| Construction (Note 16) | $25.7 | N/A | N/A | N/A | N/A | N/A | N/A |
| Indirects and Fees | $7.1 | N/A | N/A | N/A | N/A | N/A | N/A |
| EPC Contingency | $2.1 | N/A | N/A | N/A | N/A | N/A | N/A |
| **Battery Storage Capital Cost Breakdown** | | | | | | | |
| Batteries | $8 | $8 | $40 | $26 | $34 | $128 | $170 |
| Inverters | $1 | $1 | $3 | $1 | $1 | $3 | $3 |
| BOP | $1 | $2 | $2 | $1 | $1 | $5 | $5 |
| Construction and Indirects | $6 | $6 | $17 | $9 | $9 | $27 | $27 |
| **Owner's Costs, 2019 MM$** | **$19** | **$9.6** | **$16** | **$16** | **$17** | **$33** | **$36** |
| Owner's Project Development | Allowance Included | Allowance Included | Allowance Included | Allowance Included | Allowance Included | Allowance Included | Allowance Included |
| Owner's Engineer | Allowance Included | Allowance Included | Allowance Included | Allowance Included | Allowance Included | Allowance Included | Allowance Included |
| Owner's Project Management | Allowance Included | Allowance Included | Allowance Included | Allowance Included | Allowance Included | Allowance Included | Allowance Included |
| Startup / Testing / Warranties | Included in EPC | Allowance Included | Allowance Included | Allowance Included | Allowance Included | Allowance Included | Allowance Included |
| Land (Note 11) | Excluded - Assumes Lease | Excluded - Assumes Lease | Excluded - Assumes Lease | Excluded - Assumes Lease | Excluded - Assumes Lease | Excluded - Assumes Lease | Excluded - Assumes Lease |
| Transmission Upgrade Costs | Excluded | Excluded | Excluded | Excluded | Excluded | Excluded | Excluded |
| Permitting and Licensing Fees | Included in EPC | Allowance Included | Allowance Included | Allowance Included | Allowance Included | Allowance Included | Allowance Included |
| Switchyard / Substation (Notes 8,9,12) | $1.0M Allowance Included | $5.3M Allowance Included | $5.3M Allowance Included | $5.3M Allowance Included | $5.3M Allowance Included | $5.3M Allowance Included | $5.3M Allowance Included |

**VECTREN 2019 IRP TECHNOLOGY ASSESSMENT**
**RENEWABLE AND STORAGE TECHNOLOGY ASSESSMENT PROJECT OPTIONS**
**PRELIMINARY - NOT FOR CONSTRUCTION**
**December 2019**

| **PROJECT TYPE** | **Solar Plus Storage** | **Battery Storage** | **Battery Storage** | **Battery Storage** | **Battery Storage** | **Battery Storage** | **Battery Storage** |
|---|---|---|---|---|---|---|---|
| **BASE PLANT DESCRIPTION** | Single Axis Tracking | Lithium Ion | Lithium Ion | Flow Battery | Flow Battery | Flow Battery | Flow Battery |
| Nominal Output, MW | 50 MW PV & 10 MW / 40 MWh Storage | 10 MW / 40 MWh | 50 MW / 200 MWh | 10 MW / 60 MWh | 10 MW / 80 MWh | 50 MW / 300 MWh | 50 MW / 400 MWh |
| AFUDC (Note 17) | $7.1 | $1.3 | $5.0 | $2.9 | $3.6 | $13.0 | $16.4 |
| Builder's Risk Insurance | Allowance Included | Allowance Included | Allowance Included | Allowance Included | Allowance Included | Allowance Included | Allowance Included |
| Owner's Contingency | Allowance Included | Allowance Included | Allowance Included | Allowance Included | Allowance Included | Allowance Included | Allowance Included |
| **Total Project Costs, 2019 MM$** | **$108** | **$26** | **$79** | **$51** | **$61** | **$195** | **$242** |
| **EPC Cost Per kW, 2019 $/kW (plus $/kWh for Storage)** | **$1,780** | **$1650 / $410** | **$1260 / $320** | **$3580 / $600** | **$4460 / $560** | **$3260 / $540** | **$4110 / $510** |
| **Total Cost Per kW, 2019 $/kW (plus $/kWh for Storage)** | **$2,160** | **$2610 / $650** | **$1580 / $390** | **$5150 / $860** | **$6140 / $770** | **$3910 / $650** | **$4830 / $600** |
| **Fixed O&M Cost - TOTAL, 2019$MM/Yr (Notes 3-5)** | **$1.5** | **$0.3** | **$0.7** | **$1.9** | **$1.9** | **$2.1** | **$2.1** |
| Annual Fixed Labor Cost, 2019$MM/Yr | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 |
| Equipment Maintenance Cost, 2019$MM/Yr | $0.6 | $0.2 | $0.5 | $1.9 | $1.9 | $1.9 | $1.9 |
| BOP and Other Cost, 2019$MM/Yr | $0.4 | Included | Included | Included | Included | Included | Included |
| Land Lease Allowance, 2019$MM/Yr (Notes 10,11,14) | $0.2 | $0.003 | $0.005 | $0.01 | $0.01 | $0.01 | $0.01 |
| Property Tax Allowance, 2019$MM/Yr (Note 14) | $0.0 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 |
| Capital Replacement Allowance, 2019$/MWh (Notes 3-5) | $0.3 | $0.04 | $0.20 | $0.1 | $0.1 | $0.2 | $0.2 |
| Variable O&M Cost, 2019$/MWh (excl. major maint.) (Note 4) | $14.5 (Storage MWh Only) | $14.50 | $14.50 | Included in FOM | Included in FOM | Included in FOM | Included in FOM |
| **ESTIMATED BASE LOAD OPERATING EMISSIONS, lb/MMBtu (HHV)** | | | | | | | |
| $NO_X$ | N/A | N/A | N/A | N/A | N/A | N/A | N/A |
| $SO_2$ | N/A | N/A | N/A | N/A | N/A | N/A | N/A |
| CO | N/A | N/A | N/A | N/A | N/A | N/A | N/A |
| $CO_2$ | N/A | N/A | N/A | N/A | N/A | N/A | N/A |

**Notes**

1. Wind capacity factor represents Net Capacity Factor (NCF), which accounts for typical system losses. Capacity factor is based on Vestas V125-3.45 MW turbines with 87 meter hub height and 7.0 m/s average wind speed. Offshore capacity factor is based on estimates from publicly available studies.
2. Solar capacity factor accounts for typical losses. Fixed tilt systems assumes 20 degree tilt.
3. Capital maintenance allowances for onshore wind options are not included in the annual FOM above. A supplemental table in the report shows capital allowances estimated as percentages of annual operating expenses for a 30 year life. Offshore wind O&M estimates, based on publicly available documents, include levelized capital maintenance.
4. Battery FOM assumes the site is remotely controlled. Capital costs assume the system is oversized to accommodate normal degradation, so no battery replacement fund is included. Variable O&M accounts for the parasitic power draw of the system, including HVAC and efficiency losses.
5. PV O&M estimates assume fixed contracts for all maintenance activities. It is assumed the system is remotely controlled. Capital maintenance assumes an inverter replacement allowance levelized over the first 15 years. Inverter replacement is not included in the Solar + Storage option because of 15 year project life.

6. NERC GADS performance statistics are not available for PV, battery storage, and wind technologies. Availability estimates are based on vendor correspondence and industry publications.
7. PV degradation based on typical warranty information for polycrystalline products. Assuming factory recommended maintenance is performed, PV performance is estimated to degrade ~2% in the first year and 0.5% each remaining year.
8. Battery system assumes interconnection at distribution voltage and therefore excludes GSU and switchyard.
9. EPC costs for wind include 34.5 kV collection system and GSU to 230 kV. Owner's costs include 3 position ring bus switchyard for interconnection at 230kV. EPC cost for offshore wind include HVDC line and onshore converter. Owner's costs include 3 position ring bus switchyard for interconnection at 230kV.

10. Offshore wind project assumes cost for BOEM ocean lease is included in fixed O&M.
11. Onshore wind and PV projects assume that land is leased and therefore land costs are included in O&M, not capital costs. Onshore wind assumes one acre per turbine. PV assumes seven acres per MW for fixed tilt and eight acres per MW for tracking options.
12. PV scope for EPC includes 34.5 kV collector bus and circuit breaker. Owner costs include allowance for interconnection at 34.5 kV. PV costs updated in March 2019 to reflect potential impacts of tariffs on PV panels and steel.
13. Battery storage costs are shown as $/kW and as $/kWh per industry norms.
14: Land lease and property estimates are assumed allowances.
15: Estimated Costs exclude decommissioning costs and salvage values.
16. Construction line item for PV includes Labor, Construction Materials, and miscellaneous BOP Equipment
17. AFUDC of 12.2% used for the hydro option, 10.1% for the wind options, and 8% for the solar and storage options. AFUDC percentage is based on project schedule.

| VECTREN 2019 IRP TECHNOLOGY ASSESSMENT<br>COAL TECHNOLOGY ASSESSMENT PROJECT OPTIONS<br>PRELIMINARY - NOT FOR CONSTRUCTION<br>December 2019 | | |
|---|---|---|
| **PROJECT TYPE** | **Supercritical Pulverized Coal with Carbon Capture** | **Ultra-Supercritical Pulverized Coal with Carbon Capture** |
| **BASE PLANT DESCRIPTION** | | |
| Nominal Output | 500 MW Net with CCS | 750 MW Net with CCS |
| Number of Gas Turbines | N/A | N/A |
| Number of Boilers/Reactors | 1 | 1 |
| Number of Steam Turbines | 1 | 1 |
| Steam Conditions (Main Steam / Reheat) | 1050 F/1050F | 1100 F/1100F |
| Main Steam Pressure | 3675 psia | 3694 psia |
| Steam Cycle Type | Supercritical | Ultra-Supercritical |
| Capacity Factor (%) | 70% | 70% |
| Startup Time (Cold Start) | 10 Hours | 10 Hours |
| Startup Time (Warm Start) | 6 Hours | 6 Hours |
| Startup Time (Hot Start) | 4 Hours | 4 Hours |
| Book Life (Years) | 33 | 33 |
| Equivalent Planned Outage Rate (%) | 9.0% | 8.8% |
| Equivalent Forced Outage Rate (%) | 10.9% | 8.8% |
| Equivalent Availability Factor (%) | 79.5% | 80.8% |
| Fuel Design | Bituminous Coal | Bituminous Coal |
| Heat Rejection | Wet Cooling Tower | Wet Cooling Tower |
| $NO_x$ Control | Low NOx burners / SCR | Low NOx burners / SCR |
| $SO_2$ Control | Integrated WFGD and DFGD | Integrated WFGD and DFGD |
| Acid Gas Control | Integrated WFGD and DFGD | Integrated WFGD and DFGD |
| $CO_2$ Control | Advanced Amine | Advanced Amine |
| Particulate Control | Baghouse | Baghouse |
| Ash Disposal | Landfill | Landfill |
| Technology Rating | Mature | Mature |
| Permitting & Construction Schedule (Years from FNTP) | 6.5 Years | 6.5 Years |
| **ESTIMATED PERFORMANCE** | | |
| Base Load Performance @ (Annual Average) w/ Carbon Capture | | |
| Net Plant Output, kW | 505,750 | 747,100 |
| Net Plant Heat Rate, Btu/kWh (HHV) | 11,290 | 10,480 |
| Heat Input, MMBtu/h (HHV) | 5,710 | 7,830 |
| Minimum Load Operational Status @ (Annual Average) | | |
| Net Plant Output, kW | 177,010 | 298,840 |
| Net Plant Heat Rate, Btu/kWh (HHV) | 13,410 | 12,240 |
| Heat Input, MMBtu/h (HHV) | 2,370 | 3,660 |

**VECTREN 2019 IRP TECHNOLOGY ASSESSMENT**
**COAL TECHNOLOGY ASSESSMENT PROJECT OPTIONS**
**PRELIMINARY - NOT FOR CONSTRUCTION**
**December 2019**

| PROJECT TYPE | Supercritical Pulverized Coal with Carbon Capture | Ultra-Supercritical Pulverized Coal with Carbon Capture |
|---|---|---|
| **ESTIMATED CAPITAL AND O&M COSTS** | | |
| **EPC Project Capital Costs, 2019 MM$ (w/o Owner's Costs)** | **$2,609** | **$3,523** |
| **Owner's Costs, 2019 MM$** | **$612** | **$780** |
| Owner's Project Development | $7.5 | $7.5 |
| Owner's Operational Personnel Prior to COD | $7.7 | $7.7 |
| Owner's Engineer | $11.5 | $11.5 |
| Owner's Project Management | $10.0 | $10.0 |
| Owner's Legal Costs | $3.0 | $3.0 |
| Owner's Start-up Engineering | $0.4 | $0.4 |
| Land | $5.0 | $5.0 |
| Operator Training | $0.6 | $0.6 |
| Construction Power and Water | $3.6 | $3.6 |
| Permitting and Licensing Fees | $4.0 | $4.0 |
| Switchyard | $10.1 | $10.1 |
| Political Concessions & Area Development Fees | $2.5 | $2.5 |
| Startup/Testing (Fuel & Consumables) | $30.1 | $30.1 |
| Initial Fuel Inventory | $16.8 | $16.8 |
| Site Security | $0.6 | $0.6 |
| Operating Spare Parts | $8.2 | $8.2 |
| Water Supply Infrastructure | Included in Project Capital | Included in Project Capital |
| Natural Gas Supply Infrastructure | N/A | N/A |
| Transmission Interconnect | $2.0 | $3.0 |
| Transmission Upgrade Costs | Excluded | Excluded |
| Firm Gas Supply Reservation Charge | Provided by Owner | Provided by Owner |
| Permanent Plant Equipment and Furnishings | $4.6 | $4.6 |
| AFUDC (12.2% of EPC Project Capital Costs) | $318.3 | $429.8 |
| Builders Risk Insurance (0.45% of Construction Costs) | $11.7 | $15.9 |
| Owner's Contingency (5% for Screening Purposes) | $153 | $205 |
| **Total Project Costs, 2019 MM$** | **$3,220** | **$4,302** |
| **EPC Cost Per kW, 2019 $/kW** | **$5,158** | **$4,715** |
| **Total Cost Per kW, 2019 $/kW** | **$6,370** | **$5,760** |

| VECTREN 2019 IRP TECHNOLOGY ASSESSMENT<br>COAL TECHNOLOGY ASSESSMENT PROJECT OPTIONS<br>PRELIMINARY - NOT FOR CONSTRUCTION<br>December 2019 | | |
|---|---|---|
| **PROJECT TYPE** | **Supercritical Pulverized Coal with Carbon Capture** | **Ultra-Supercritical Pulverized Coal with Carbon Capture** |
| **$CO_2$ Transportation and Geologic Sequestration (See note 4)** | | |
| 50 Mile Pipeline Cost, 2019 MM$ | $122 | $122 |
| $CO_2$ Pipeline Maintenance ($/MWh) | $3.52 | $3.52 |
| $CO_2$ Storage Cost ($/MWh) | $9.14 | $9.14 |
| Fixed O&M Cost, 2019$/kW-Yr | $29.10 | $29.10 |
| Fixed O&M Cost, 2019 $MM/Yr | $14.70 | $21.70 |
| Major Maintenance Cost, 2019$/MWh | $5.20 | $5.20 |
| Variable O&M Cost, 2019$/MWh (excl. major maint.) | $11.20 | $11.20 |
| **ESTIMATED BASE LOAD OPERATING EMISSIONS (NO CCS), lb/MMBtu (HHV)** | | |
| $NO_X$ | 0.02 | 0.02 |
| $SO_2$ | 0.02 | 0.02 |
| CO | 0.15 | 0.15 |
| $CO_2$ | 100 | 100 |

Notes

Note 1: PC cost and performance are based on net performance inclusive of carbon capture.

Note 2: The PC unit assumes that cooler tower blowdown is recycled in the wet FGD.

Note 3: The PC unit assumes a spray dry absorber will be used to control acid gases. FGD purge will be recycled in the SDA.

Note 4: Carbon transportation and sequestration assumes 50 mile pipeline to a suitable subterranean reservoir.

Note 5: Outage and availability statistics are collected using the NERC Generating Availability Data System. Reporting period is those units that reported evenings between 2013-2017.

**Attachment 3.1 Stakeholder Materials**

# VECTREN PUBLIC STAKEHOLDER MEETING

AUGUST 15, 2019

# WELCOME, INTRODUCTION TO CENTERPOINT, AND SAFETY SHARE

**LYNNAE WILSON**

INDIANA ELECTRIC CHIEF BUSINESS OFFICER

# SAFETY SHARE

**Know your exits**

- Whenever you are entering a public area or a guest in a facility such as this, always know your exits.  Take note of the signs
- There are two emergency exits, immediately behind me,  Additionally, there are exit doors directly behind you – once through the door, to the left is the main entrance into the  building.  Should the main entrance be blocked there is an exit to the right of this room through a set of doors leading to the loading dock area

**Visualize for safety**

- When you enter a new space, visualize that an emergency – like a fire, bad weather, or an earthquake – could happen there and consider how you can respond
- The best way is to prepare to respond to an emergency before it happens. Few people can think clearly and logically in a crisis, so it is important to do so in advance, when you have time to be thorough

**Fire**

- Evacuate the building and move to the back of the Vectren parking lot, near the YWCA

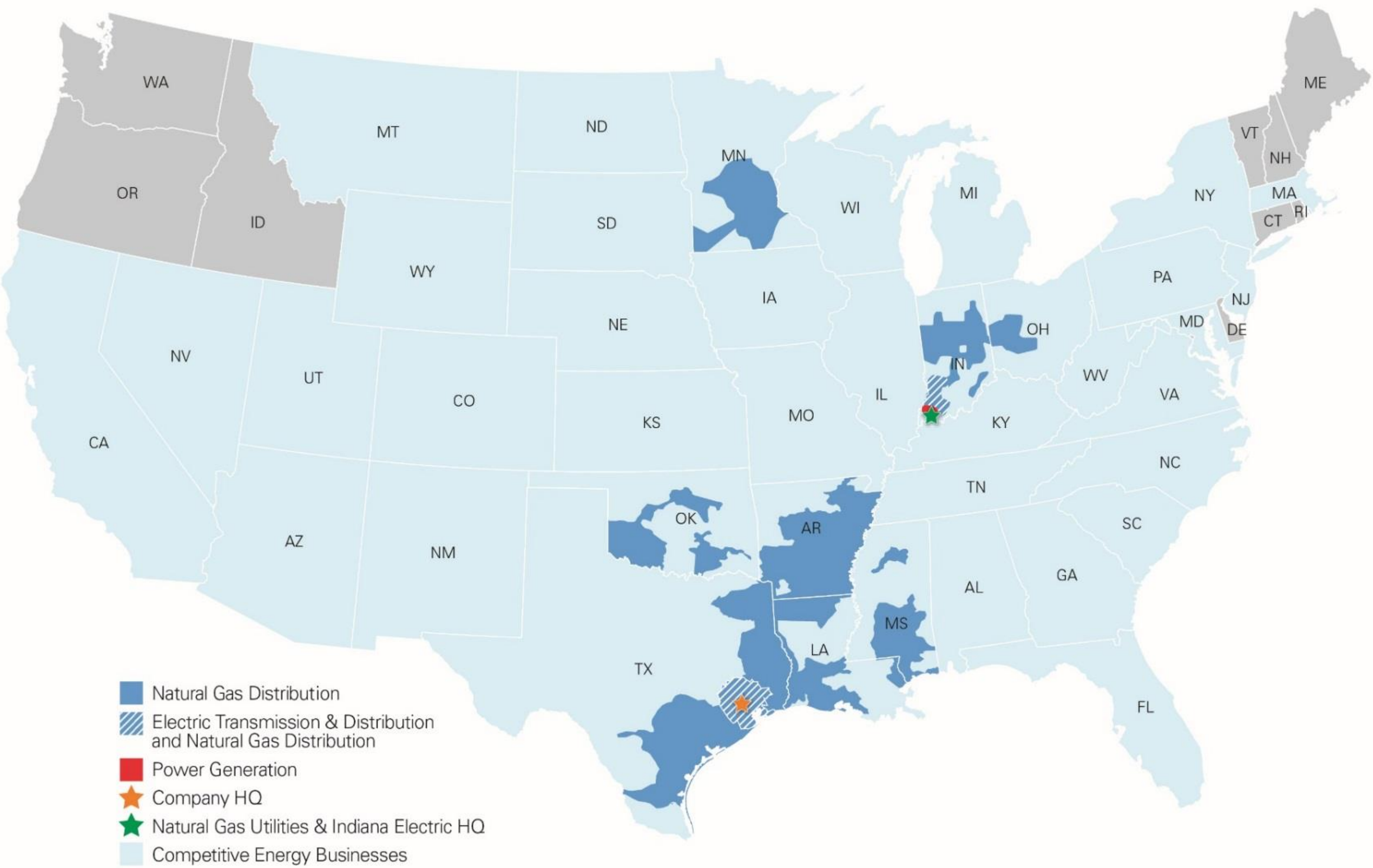
**Bad Weather**

- During a tornado warning, stay away from windows, glass doors, and outside walls
- Move in an orderly fashion to the stairwell, just outside of the lobby in the main entrance way

**Earthquake**

- Move under the desk where you are sitting, facing away from glass, and cover your head and face
- Once shaking has subsided, move in an orderly fashion towards the nearest exit and move to the back of the Vectren parking lot, near the YWCA

# OUR BUSINESSES



# AGENDA

| Time | | |
|---|---|---|
| **9:00 a.m.** | Sign-in/Refreshments | |
| **9:30 a.m.** | Welcome, Safety Message | Lynnae Wilson, CenterPoint Energy Indiana Electric Chief Business Officer |
| **9:45 a.m.** | 2019/2020 IRP Process | Matt Rice, Vectren Manager of Resource Planning and Gary Vicinus, Managing Director for Utilities, Pace Global |
| **10:35 a.m.** | Break | |
| **10:45 a.m.** | Objectives & Measures Workshop | Gary Vicinus, Managing Director for Utilities, Pace Global |
| **11:30 a.m.** | Lunch | |
| **12:15 p.m.** | All-Source RFP | Matt Lind, Resource Planning & Market Assessments Business Lead, Burns and McDonnell |
| **1:00 p.m.** | Environmental Compliance Update | Angila Retherford, CenterPoint Energy, Vice President Environmental Affairs and Corporate Responsibility |
| **1:35 p.m.** | Break | |
| **1:45 p.m.** | Draft Base Case Market Inputs and Scenarios Workshop | Gary Vicinus, Managing Director for Utilities, Pace Global |
| **2:30 p.m.** | Stakeholder Questions and Feedback | Moderated by Gary Vicinus, Managing Director for Utilities, Pace Global |
| **3:00 p.m.** | Adjourn | |

# MEETING GUIDELINES

1. Please hold most questions until the end of each presentation. Time will be allotted for questions following each presentation. (Clarifying questions about the slides are fine throughout)
2. For those on the webinar, we will open the (currently muted) phone lines for questions within the allotted time frame. You may also type in questions via the chat feature. Only questions sent to ‘All-Entire Audience’ will be seen and answered during the session.
3. At the end of the presentation, we will open up the floor for “clarifying questions,” thoughts, ideas, and suggestions.
4. There will be a parking lot for items to be addressed at a later time.
5. Vectren does not authorize the use of cameras or video recording devices of any kind during this meeting.
6. Questions asked at this meeting will be answered here or later.
7. We will do our best to capture notes but request that you provide written feedback (concepts, inputs, methodology, etc.) at IRP@CenterPointEnergy.com following the meeting. Additional questions can also be sent to this e-mail address.

# 2019/2020 IRP PROCESS

**MATT RICE**

VECTREN MANAGER OF RESOURCE PLANNING

# DIRECTOR'S REPORT FEEDBACK

| Improvement Opportunities | Positive Comments |
|---|---|
| Include lower and higher boundary scenarios to create a wider range of portfolios | Significant improvements in all aspects of the IRP |
| Model a wide range of portfolios | Use of state-of-the art models |
| Strategist model did not consider enough options simultaneously | A collegial stakeholder process with a concerted efforts to broaden stakeholder participation |
| Update risk analysis methodology to be less qualitative and more encompassing of known risks | Appropriate use of short, mid, and long term breaks in forecasts |
| Explore other options for modeling EE cost options and make greater use of a Market Potential Study (MPS) | Being credible and well-reasoned, with narratives that were clear |
| More consideration given to Warrick unit 4 in scenario development | Maintaining optionality in the plan |
| Clearly define risk analysis methodology | Commendable use of multiple fuel prices |
| Clearly define Energy Efficiency Methodology | Top management participation |

# ADDITIONAL DIRECTOR'S REPORT GUIDANCE

The director had five specific requests of all utilities that should be incorporated into IRPs

- Greater use of tables
- Easier comparisons for scenario assumptions
- List of technical modeling constraints
- Expanded use of graphics
- Solicit stakeholder inputs and improve the exploratory nature of IRPs

# IURC ORDER 45052

- Vectren selected a Combined Cycle Gas Turbine (CCGT) that was too large for a small utility
  - Did not adequately consider flexibility to change paths, adding stranded asset risks
  - Did not consider fuel or geographic diversity
- Risk analysis did not consider the full range of portfolios
  - Did not fully explore options at the Brown plant (conversion or scrubber alternatives)
  - Need to more fully consider customer-generator opportunities
  - Did not fully consider energy and capacity purchases
  - Did not consider smaller gas plant options in the risk analysis
- Vectren's analysis disadvantaged renewable resources
  - Vectren did not make a serious effort to determine the price and availability of renewables
  - The RFP was too restrictive
- Vectren did not fully respond to the Director's report critiques in updated CPCN analysis
  - Did not update the risk modeling
  - Did not consider the full range of gas prices (including methane regulation)

Other Items to Note

- Acknowledged that Vectren needs to act swiftly to develop our 2019 IRP to meet the 2023 constraints
- DSM was compared on a consistent and comparable basis with supply side alternatives

# VECTREN COMMITMENTS FOR 2019/2020 IRP

- Will strive to make every encounter meaningful for stakeholders and for us
- Will provide a data release schedule and provide modeling data ahead of filing for evaluation
- The IRP process informs the selection of the preferred portfolio
- Utilize an All-Source RFP to gather market pricing & availability data
- Use one model for consistency in optimization, simulated dispatch, and probabilistic functions
- Attempt to model more resources simultaneously
- Will include a balanced, less qualitative risk score card. Draft to be shared at the first public stakeholder meeting
- Work with stakeholders on portfolio development
- Will test a wide range of portfolios in scenario modeling and ultimately in the risk analysis
- Will conduct a sensitivity analysis
- Exhaustive look at existing resource options
- The IRP will include information presented for multiple audiences (technical and non-technical)

# KEY DIFFERENCES FROM 2016 APPROACH

| 2016 | 2019/2020 |
|---|---|
| Utilized technology assessment information | All-Source RFP, supplemented with technology assessment information |
| Discussed objectives, risks, and provided example of potential metrics. Showed scorecard and final metrics in the last stakeholder meeting | Will show objectives, metrics, and gather feedback on scorecard early in the process |
| Built 15 portfolios for the risk analysis, including continuing use of coal plants, least cost portfolios, diversified portfolios, and stakeholder portfolios | Work with stakeholders to build a wide range of portfolios to be tested in the risk analysis. Utilize models to develop least cost portfolios for various portfolio strategies |
| Other than the continue coal portfolio, alternatives such as gas conversion or repower options did not ultimately make it into the risk analysis | More exhaustive look at viability of existing units, and include in the risk analysis |
| Utilized scenario modeling to create computer generated portfolios. Essentially used as a screening tool for the risk analysis | Utilize scenarios to evaluate regulatory risk, with simulated dispatch for a wide range of portfolios |
| No sensitivity analysis | Will include a sensitivity analysis on various risks, utilizing data from probabilistic modeling. EE Sensitivity. |
| Modeled 8 blocks of EE up to 2% of sales. Costs based on EIA penetration model. EE selection was binary (selected for full period or not) | Will model EE bins of varying sizes and timeframes. Ties directly to MPS with costs based in empirical data and historical experience |
| Did not provide modeling data until after IRP was filed | Will provide modeling data throughout the process |
| Utilized two IRP models (Strategist & Aurora) | Moving to Aurora for all IRP modeling |

# PROPOSED 2019/2020 IRP PROCESS

VECTREN
A CenterPoint Energy Company

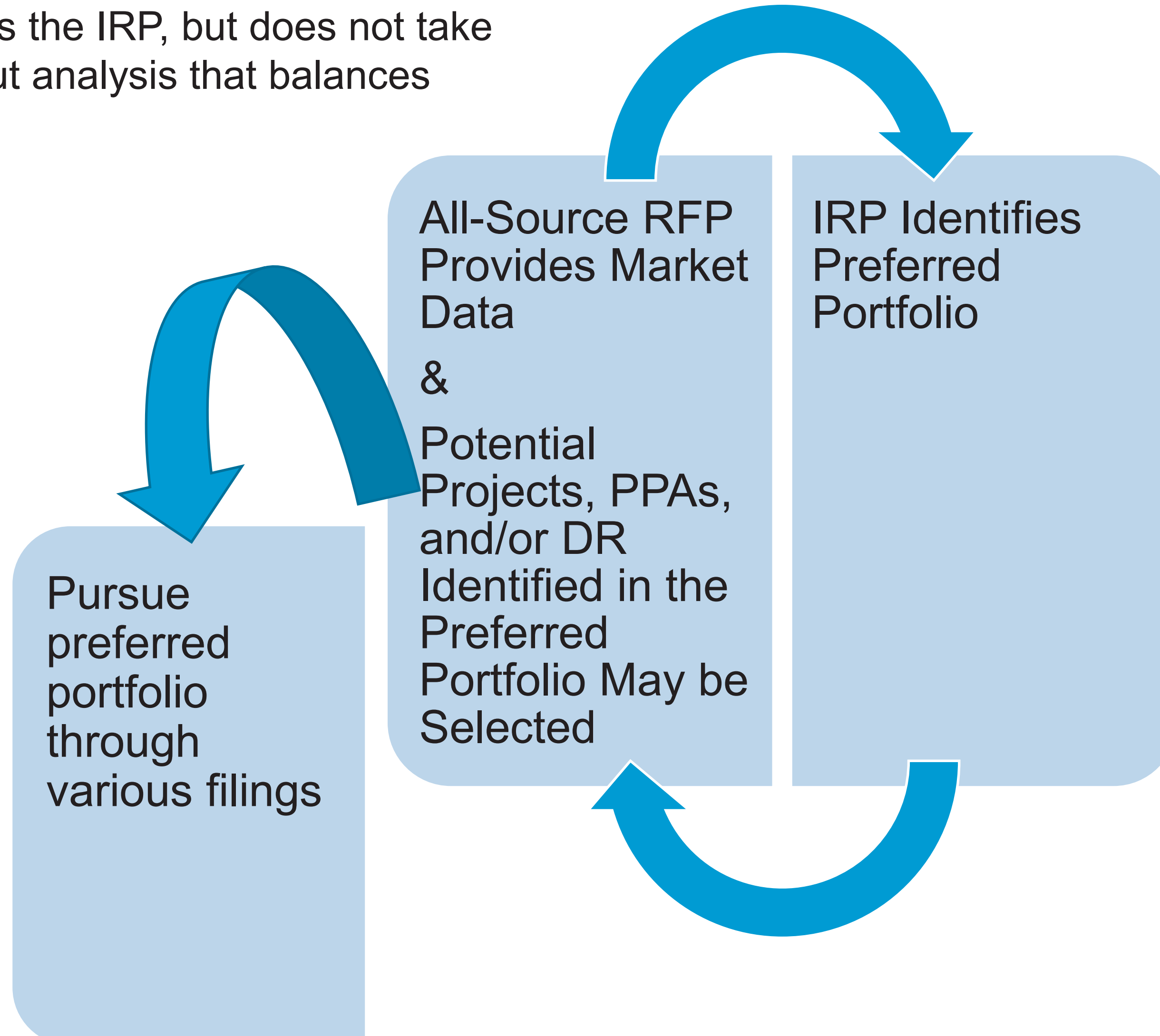
Stakeholder input is provided on a timely basis throughout the process, with meetings held in August, October, December, and March

1. Conduct an All Source RFP
2. Create Objectives, Risk Perspectives and Scorecard Development
3. Create Base Case Assumptions and Scenario Development
4. Portfolio Development Based on Various Strategies, Utilizing Optimization to Create a Wide Range of Portfolios and Refine with All Source RFP Data
5. Portfolio Testing in Scenarios, Focused on Potential Regulatory Risks
6. Portfolio Testing Using Probabilistic Modeling of 200 Potential Futures
7. Utilize the Probabilistic Modeling to Conduct Sensitivity Analysis
8. Populate the Risk Scorecard that was Developed Early in the Process and Evaluate Portfolios
9. Select the Preferred Portfolio

# ROLE OF THE ALL-SOURCE RFP

The All-Source RFP informs the IRP, but does not take the place of well thought out analysis that balances multiple objectives

- Average delivered cost by resource will inform modeling
- Resources to be modeled on a tiered basis
- The full IRP analysis, including risk analysis, will test a diverse set of resource mixes and will ultimately identify a preferred portfolio
- Vectren will pursue resources consistent with those identified in the preferred portfolio



# KEY VENDORS

VECTREN
A CenterPoint Energy Company

RFP

- Burns and McDonnell
  - Draft RFP
  - Post
  - Interpret and align bids
  - Bid risk assessment
  - Convert into modeling inputs
  - Further evaluation on viable projects
  - Transmission analysis where needed

IRP

- Pace
  - Moderation of stakeholder meetings
  - Strategy (assist with stakeholder engagement, scenario, portfolio, objectives, & metrics development)
  - Deterministic modeling (determined scenarios)
  - Probabilistic modeling
  - Sensitivity analysis
  - Risk assessment and scorecard

File May 1, 2020

# 2019/2020 STAKEHOLDER PROCESS

VECTREN
A CenterPoint Energy Company

### August 15, 2019

- 2019/2020 IRP Process
- Objectives and Measures
- All-Source RFP
- Environmental Update
- Draft Base Case Market Inputs & Scenarios

### October 10, 2019

- RFP Update
- Draft Resource costs
- Sales and Demand Forecast
- DSM MPS/ Modeling Inputs
- Scenario Modeling Inputs
- Portfolio Development

### December 12, 2019

- Draft Portfolios
- Draft Base Case Modeling Results
- All-Source RFP Results and Final Modeling Inputs
- Probabilistic Modeling Approach and Assumptions

### March 19, 2020

- Final Base Case Modeling
- Probabilistic Modeling Results
- Risk Analysis Results
- Preview the Preferred Portfolio

# FEEDBACK AND DISCUSSION

# OBJECTIVES & MEASURES

**GARY VICINUS**

MANAGING DIRECTOR FOR UTILITIES, PACE GLOBAL

# IRP OBJECTIVES & MEASURES

The purpose of the IRP is to evaluate Vectren's current energy resource portfolio and a range of alternative future portfolios to meet customers' electrical energy needs in an affordable, system-wide manner

In addition, the IRP process evaluates portfolios in terms of environmental stewardship, market and price risk, and future flexibility, system flexibility to provide backup resources, reliability, and resource diversity

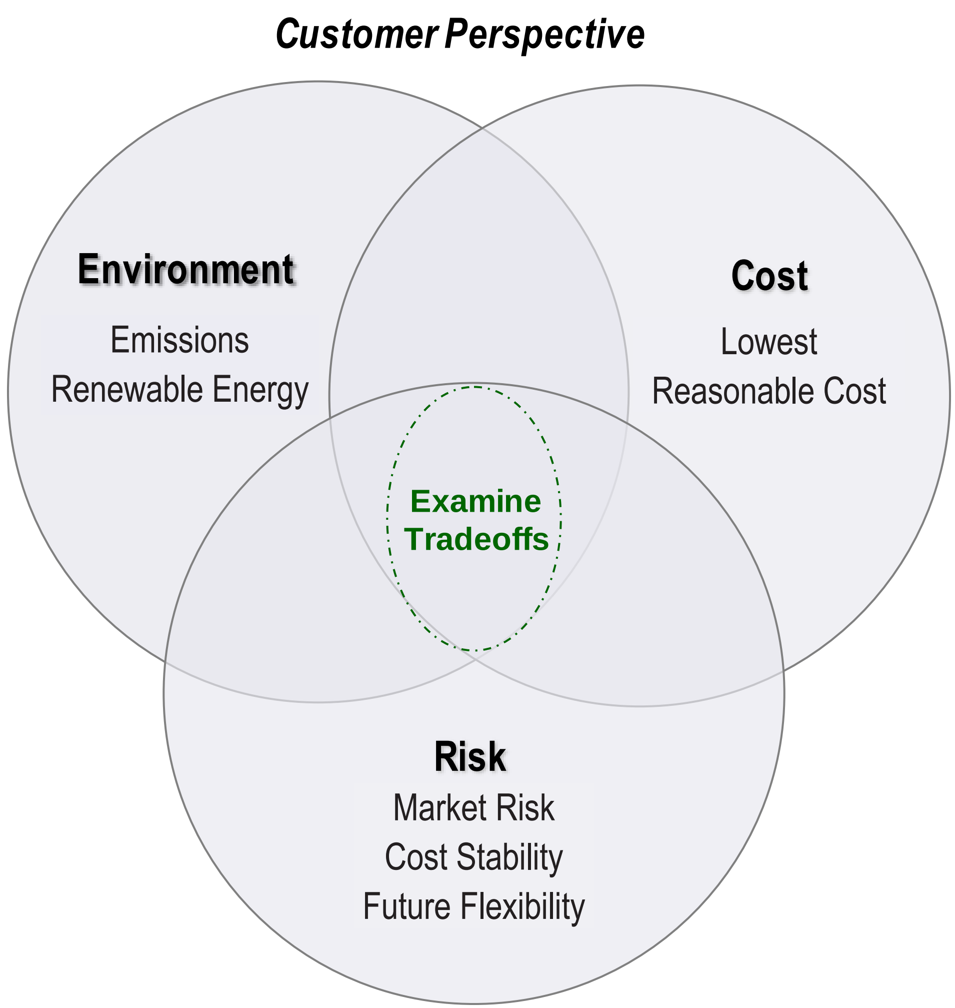
Each objective is important and worthy of balanced consideration in the IRP process, taking into account uncertainty. Some objectives are better captured in portfolio construction than as a portfolio measure

The measures allow the analysis to compare portfolio performance and potential risk on an equal basis

| Quantitative IRP Objectives |
| --- |
| Affordability |
| Environmental Risk Minimization |
| Price Risk Minimization |
| Market Risk Minimization |
| Future Flexibility |

| Qualitative IRP Objectives |
| --- |
| Resource Diversity |
| System Flexibility |

# EACH PORTFOLIO WILL HAVE TRADEOFFS



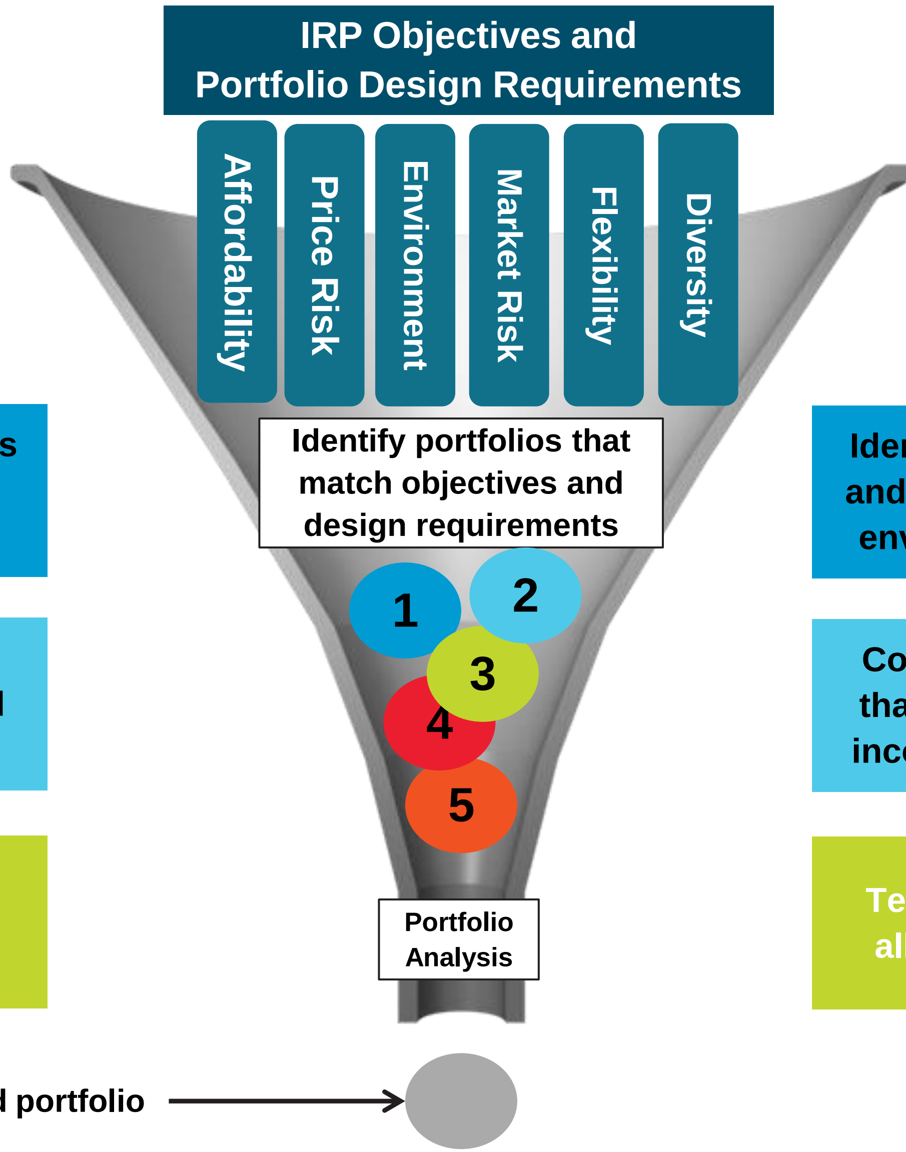
# IRP OBJECTIVES & MEASURES

For each resource portfolio, the objectives are tracked and measured to evaluate portfolio performance in the base case, in four alternative scenarios, and across a wide range of possible future market conditions. All measures of portfolio performance are based on probabilistic modeling of 200 futures

| Objective | Measure | Unit |
|---|---|---|
| Affordability | 20-Year NPVRR | $ |
| Price Risk Minimization | 95th percentile value of NPVRR | $ |
| Environmental Risk Minimization | $CO_2$ Emissions | tons |
| Market Risk Minimization | Energy Market Purchases or Sales outside of a +/- 15% Band | % |
| | Capacity Market Purchases or Sales outside of a +/- 15% Band | % |
| Future Flexibility | MWh of impairment by asset | MWh |

# SCREENING PORTFOLIO PERFORMANCE

VECTREN
A CenterPoint Energy Company




| *Task* | *Approach* |
|---|---|
| **Screen portfolio options for objectives and design requirements** | **Identify design requirements and rank options by cost and environmental performance** |
| **Combine individual options into integrated portfolios** | **Construct portfolio options that meet requirements and incorporate strategy options** |
| **Perform risk analysis** | **Test each portfolio against all objectives & measures** |

**Select preferred portfolio**

# FEEDBACK AND DISCUSSION

# ALL-SOURCE RFP UPDATE

**MATT LIND,**

**RESOURCE PLANNING & MARKET ASSESSMENTS BUSINESS LEAD, BURNS AND MCDONNELL**

# OVERVIEW

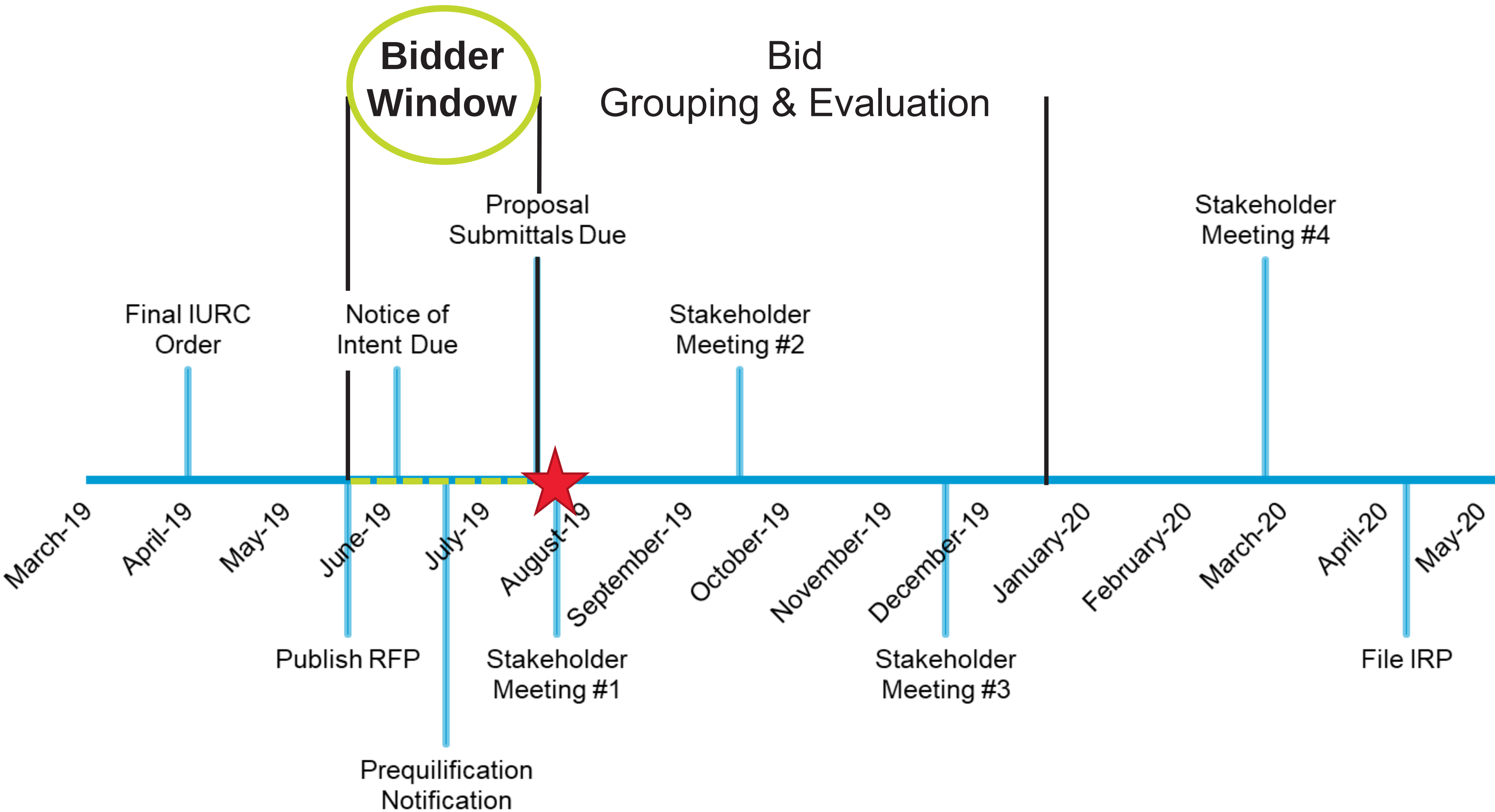
- 2016 IRP:
  - – Identified capacity and energy shortfall beginning in 2023
  - – Potential need of ~700 MW accredited capacity
- 2019/2020 IRP:
  - – Must examine existing resources alongside alternatives
  - – Potentially a similar need
- 2019 All-Source RFP:
  - – Feed IRP inputs
  - – Identify potential cost effective resources

# ALL-SOURCE RFP KEY DATES

| Event | Anticipated Date* |
|---|---|
| All-Source RFP Issued | Wednesday, June 12, 2019 |
| Notice of Intent (NOI), All-Source RFP NDA, and Respondent Pre-Qualification Application Due | 5:00 p.m. CDT<br>Thursday, June 27, 2019 |
| Respondents Notified of Results of Pre-Qualification Application Review | 5:00 p.m. CDT<br>~~Wednesday, July 3, 2019~~<br>Friday, July 12, 2019 |
| **Proposal Submittal Due Date** | **5:00 p.m. CDT**<br>**~~Wednesday, July 31, 2019~~**<br>**Friday, August 9, 2019** |
| Initial Proposal Review and Evaluation Period | August - September 2019 |
| Interconnection Evaluation | August - October 2019 |
| Congestion Evaluation | 4$^{th}$ Quarter, 2019 |
| Inputs to IRP | 4$^{th}$ Quarter, 2019 |

*Negotiation schedule for smaller projects can be expedited at Vectren's discretion

# TIMELINE


Bidder Window
Bid Grouping & Evaluation
Proposal Submittals Due
Stakeholder Meeting #4
Final IURC Order
Notice of Intent Due
Stakeholder Meeting #2
March-19
April-19
May-19
June-19
July-19
August-19
September-19
October-19
November-19
December-19
January-20
February-20
March-20
April-20
May-20
Publish RFP
Stakeholder Meeting #1
Stakeholder Meeting #3
File IRP
Prequilification Notification

# ALL-SOURCE RFP PUBLICATION & DISTRIBUTION

VECTREN
A CenterPoint Energy Company

- Ad published in Megawatt Daily (~20,000 recipients)
- North American Energy Markets Association (NAEMA) distribution (150 members)
- Published in June 2019 Midwest Energy Efficiency Alliance (MEEA) Minute (161 members)
- Included on Vectren.com
- Sent to participants in Vectren's 2017 RFP
- BMcD RFP contact list (>450 industry contacts)
- Vectren stakeholders & industry contacts
- Interviews with Evansville Courier & Press

REQUEST FOR PROPOSALS

Vectren Energy Delivery (Vectren), a subsidiary of CenterPoint Energy, is issuing this

**All-Source**

Request for Proposals (RFP) targeting

**10 to 700 MW**

of capacity and unit-contingent energy to meet the needs of its customers.

**Bids are due by Wednesday, July 31, 2019.** The RFP documents, schedule, and other RFP information can be found at: http://VectrenRFP.rfpmanager.biz/

**Vectren has retained Burns & McDonnell to act as its agent in managing the RFP process.** All RFP inquiries and communications are to be made via e-mail: VectrenRFP@burnsmcd.com

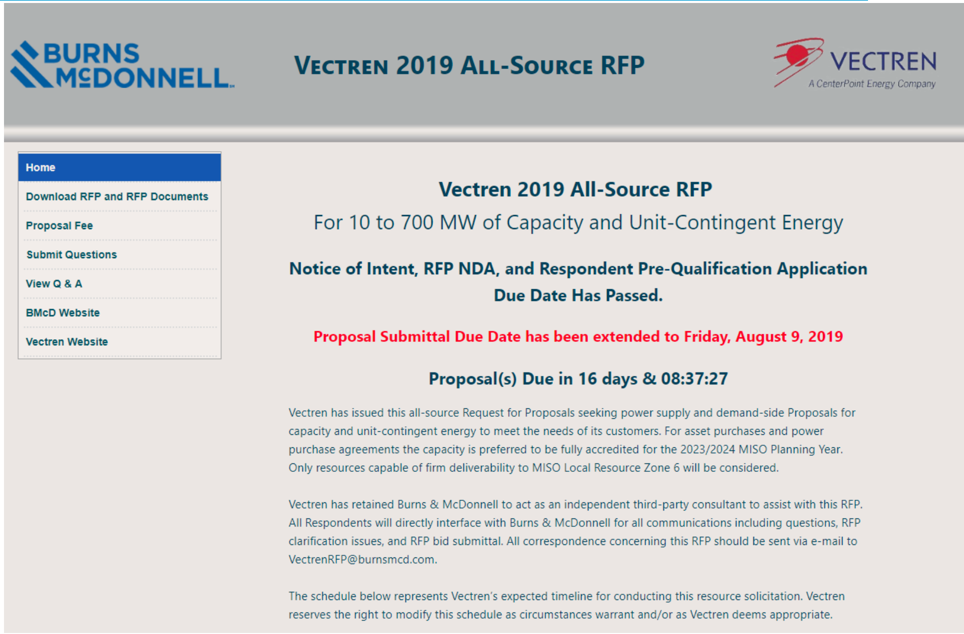
VECTREN
A CenterPoint Energy Company

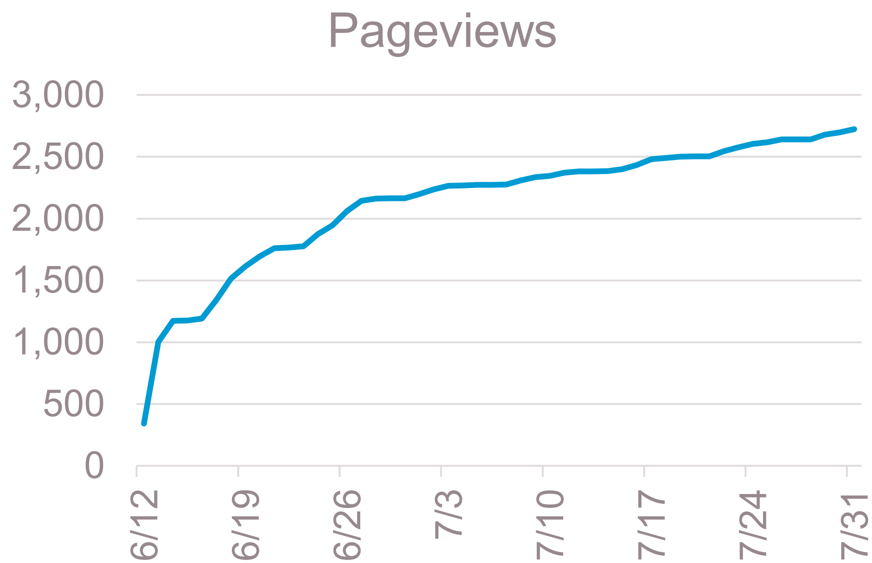
BURNS McDONNELL

# WEBSITE: HTTP://VECTRENRFP.RFPMANAGER.BIZ/

VECTREN
A CenterPoint Energy Company

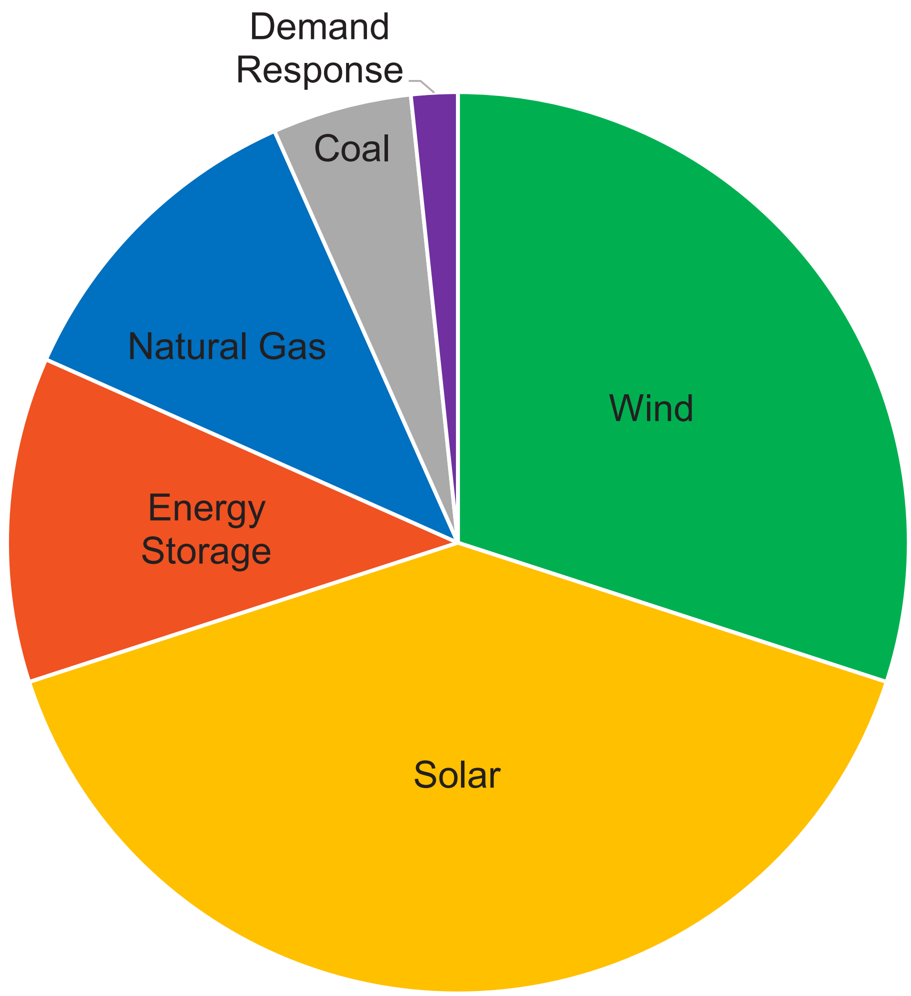
- RFP document downloads
  - 142 unique people
  - 107 companies
- Website visits (June 12th-July 31st)
  - ~800 users
  - ~3,000 pageviews
- Question & Answers posted



# ALL-SOURCE RFP PARTICIPATION

- 32 companies submitted Notice of Intent (NOI)



# TYPES OF RESOURCES CONSIDERED

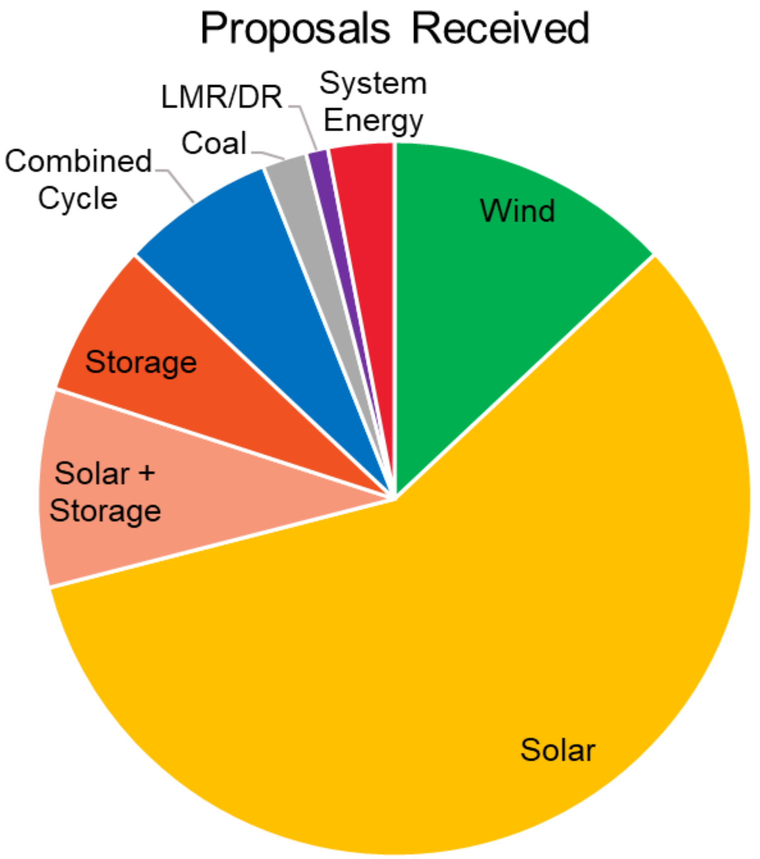
- Open, non-limiting All-Source RFP
  - Asset purchase or power purchase agreement (PPA)
    - Existing or planned dispatchable generation
    - Existing or planned utility scale renewable resources
    - Existing or planned utility scale storage facilities, either stand-alone or paired with renewables
  - Load modifying resource (LMR)/Demand Resource (DR)
    - In Local Resource Zone 6 (LRZ6)
    - Proposals outside of Vectren's service territory are only eligible for capacity

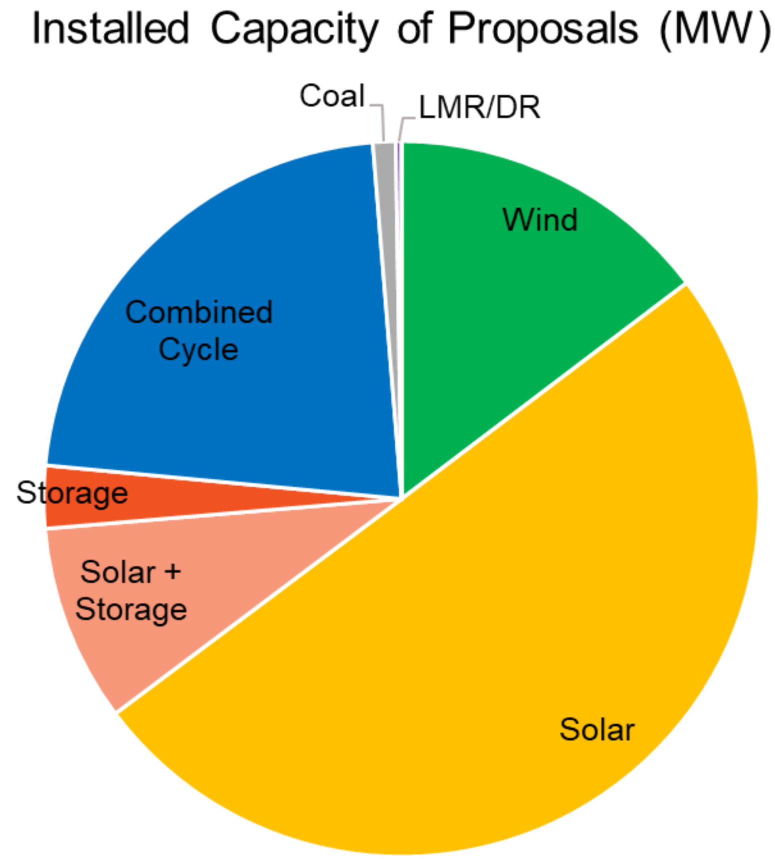
# PROPOSAL REQUIREMENTS

- MISO accredited or accreditable capacity (including Zonal Resource Credits) of no less than 10 MW to MISO LRZ 6
- Submittal forms (NOI, NDA, Pre-Qualification Application)
- 1-year pricing guarantee (from Proposal Submittal Due Date)
- Credit worthy bidders
- Respondent information and experience
- Facility information (Appendix D)
- Remaining life of at least 5 years from acquisition date for asset purchase

# PRELIMINARY* RFP STATISTICS

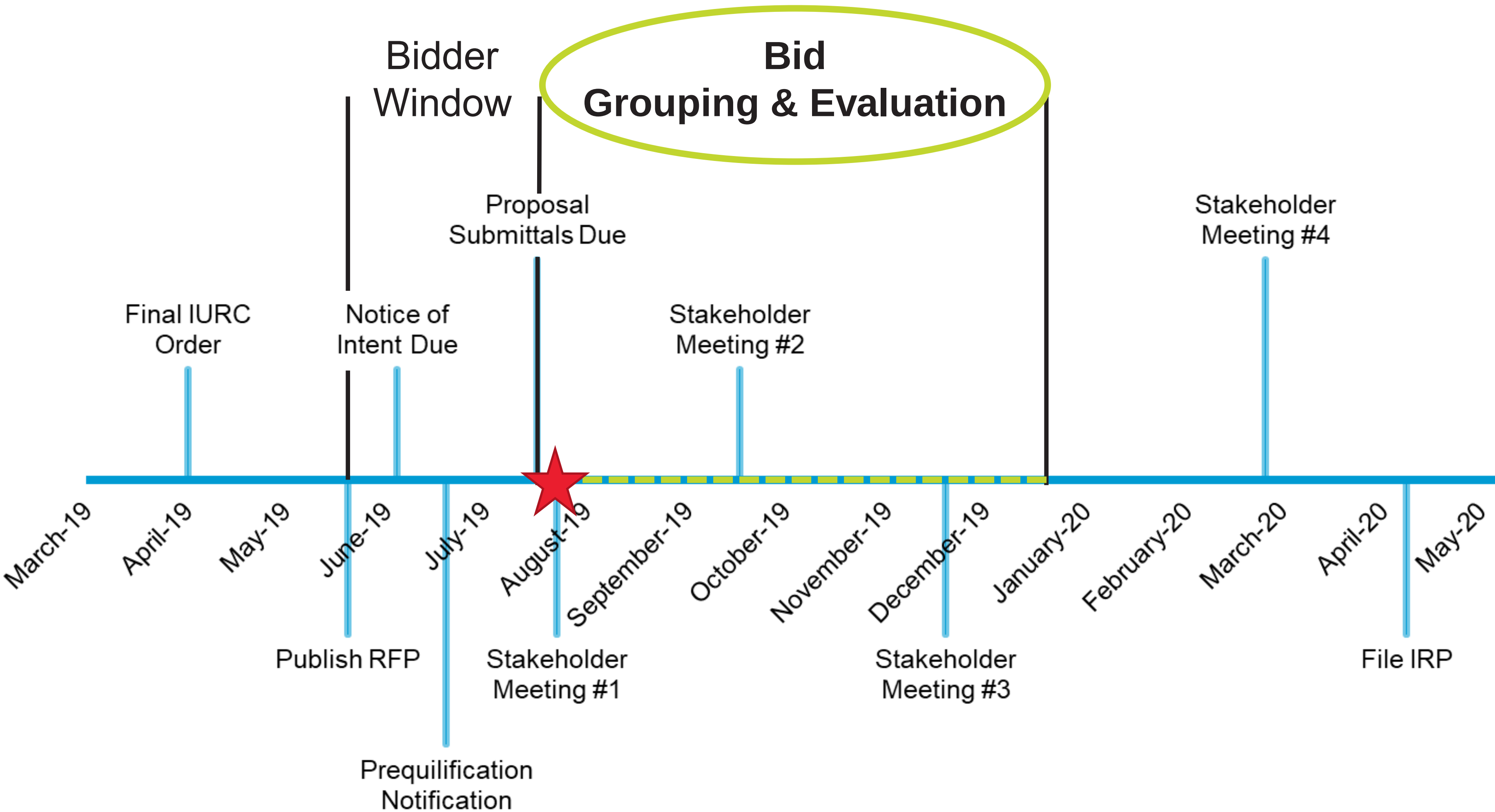
- 100 Proposals from 22 Respondents (4/5 in Indiana, 2/3 are PPA)




*Proposals received 4 business days ago. Follow-up and clarification process with respondents is ongoing.

# TIMELINE

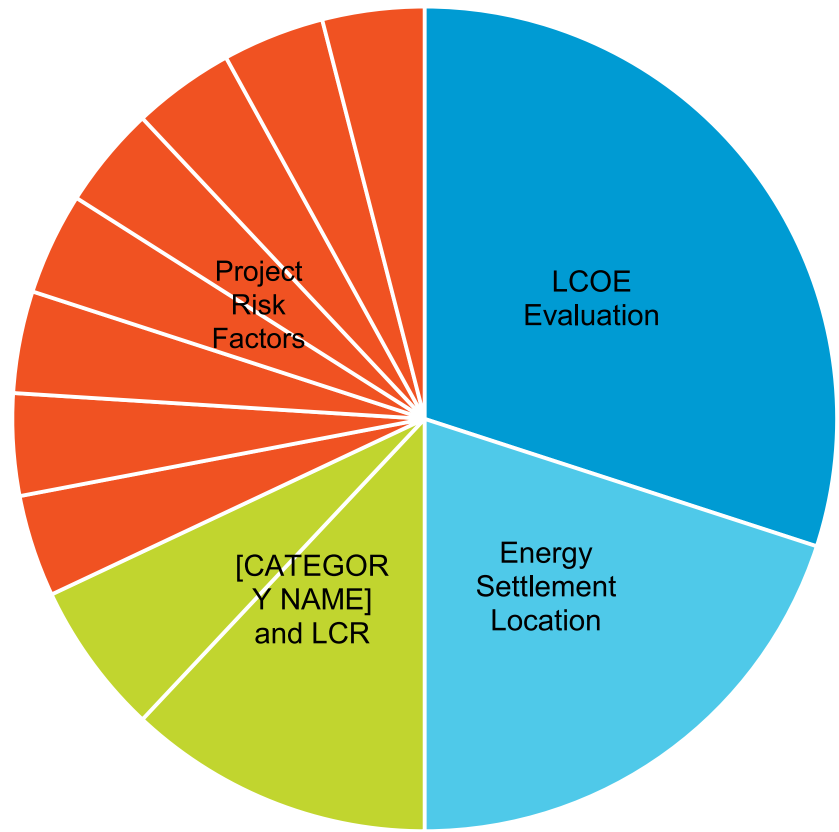

Bidder Window
Bid
Grouping & Evaluation
Proposal Submittals Due
Stakeholder Meeting #4
Final IURC Order
Notice of Intent Due
Stakeholder Meeting #2
March-19
April-19
May-19
June-19
July-19
August-19
September-19
October-19
November-19
December-19
January-20
February-20
March-20
April-20
May-20
Publish RFP
Stakeholder Meeting #1
Stakeholder Meeting #3
File IRP
Prequilification Notification

# PROPOSAL EVALUATION

- Proposals will be grouped with similar proposals and scored relative to other bids within the same grouping
  - The preferred resource mix will be identified by the IRP analysis
  - All-Source RFP evaluation will rank order available resources within each grouping

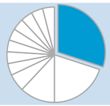
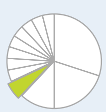
| Rank | Illustrative Resource Groupings | | | | | | |
|---|---|---|---|---|---|---|---|
| 1 | Solar | Wind | Storage | Coal | Gas | Demand Response | etc. |
| 2 | | | | | | | |
| 3 | | | | | | | |
| 4 | | | | | | | |
| 5 | | | | | | | |
| 6 | | | | | | | |
| 7 | | | | | | | |
| 8 | | | | | | | |

500 Total Points*



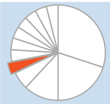
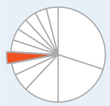
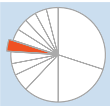
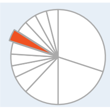
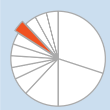
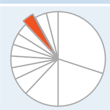
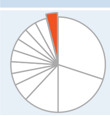

*Vectren reserves the right to add up to 100 points to Proposals located in Southern Indiana (generally defined as the following counties within Vectren's service territory; Dubois, Gibson, Pike, Posey, Spencer, Vanderburgh, and Warrick), as local resources provide multiple benefits: VAR support, economic development, less future congestion risk, etc.

# EVALUATION SUMMARY

| Scoring Criteria Name | Points | | Scoring Method | Definition | Importance |
|---|---|---|---|---|---|
| **LCOE Evaluation** | 150 |  | Curve | $/MWh calculation within asset class | An LCOE evaluation comparing similar resource groups will help to show which Project(s) may provide lower cost energy to Vectren's customers. |
| **Energy Settlement Location** | 100 |  | Binary | Proposals that include all costs to have energy financially settled or directly delivered to Vectren's load node (SIGE.SIGW) | Having financial settlement or direct delivery to Vectren's load node provides Project's true resource cost to Vectren's customers, eliminating risks/costs associated with the delivery of energy. |
| **Interconnection and Development Status** | 60 |  | Binary | Executed a pro-forma MISO Service Agreement and Interconnection Construction Services Agreement (12 points)<br>Completed a MISO Facilities Study (12 points)<br>Completed a MISO System Impact Study (12 points)<br>Achieved site control and completed zoning requirements (12 points)<br>EPC Contract awarded (12 points) | These points are for completion of various critical milestones in the interconnection and development process. Projects which are further through the interconnection and development process will receive more points as cost certainty improves. |
| **Local Clearing Area Requirement** | 30 |  | Binary | Physically and electrically located in LRZ 6 | Being located in LRZ 6 provides greater certainty that asset capacity can be deliverable to Vectren and fall within LCR requirements through entire life or contract term. |

# EVALUATION SUMMARY

VECTREN
A CenterPoint Energy Company

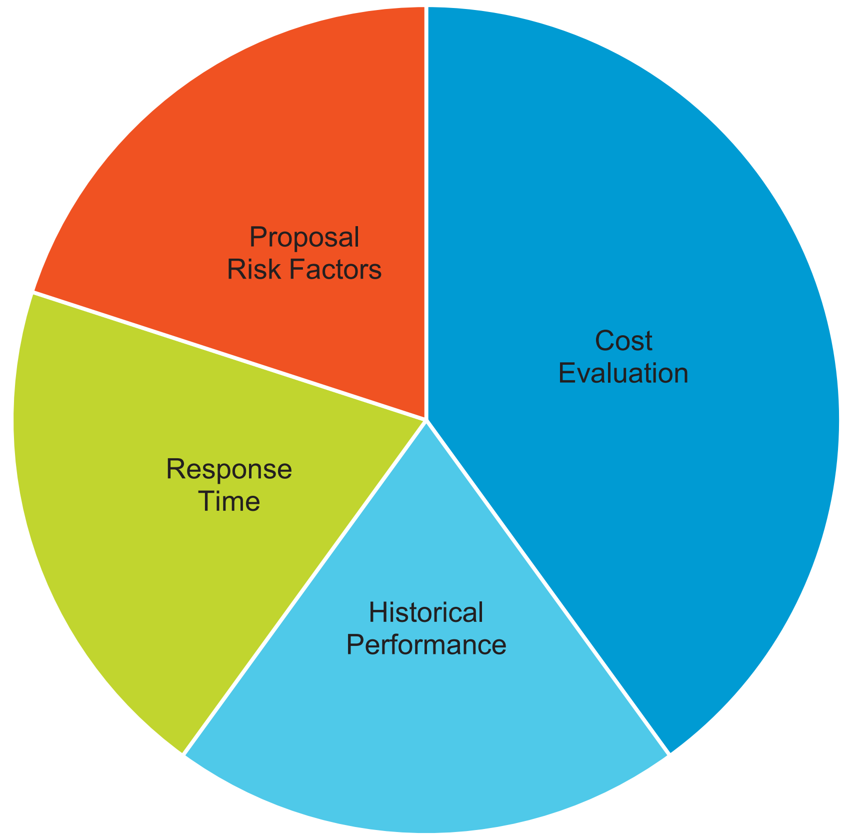
| Scoring Criteria Name | Points | | Scoring Method | Definition | Importance |
|---|---|---|---|---|---|
| **Credit and Financial Plan** | 20 |  | Curve | Vectren will be reviewing the credit rating and financing capabilities in relation to a Bidder's Project | Projects which lack the financial wherewithal to ensure development pose a significant risk to Vectren and their customers. |
| **Development Experience** | 20 |  | Curve | Scored based on 1,500 MW of relevant development experience | Relevant technology experience is important when looking at asset purchases or PPA's for facilities which are not in service. A Bidder's track record of project completion is a benefit to the Project's scoring. |
| **Sole Ownership/ Partial Owner** | 20 |  | Binary | Being a sole owner would allow full site and dispatch rights/preferences | Being able to solely own, operate, and maintain a Project lowers risks for Vectren and their customers. |
| **Ownership Structure (Purchase/PPA)** | 20 |  | Binary | Vectren has a preference for ownership | Owning an asset and having control with regards to dispatch, maintenance, and operation of the facility lowers risks for Vectren and their customers. |
| **Operational Control** | 20 |  | Binary | Dispatch parameters used for the scheduling of energy into MISO and approval for maintenance outage periods | Operational control provides the ability to make prudent operational decisions when it makes economic sense for Vectren's customers. |
| **Fuel Risk** | 20 |  | Binary | Sites having firm and reliable fuel supply | Having fuel restrictions or a lack of reliable fuel could effect the operation of the Project and be a risk to the owner/off taker. |
| **Delivery Date** | 20 |  | Curve | For each year prior or after MISO PY 2023/2024, 25% of the points will be deducted | To the extent resources are brought on-line before potential Vectren unit retirements, Vectren customers could pay for duplicative capacity and/or energy; while there may be reasons to proceed with such projects, in recognition of their incremental costs, it is appropriate for such projects to not score as well in terms of timing. |
| **Site Control** | 20 |  | Binary | Proper rights to the site in which the facility will be located | Without proper permitting and permissions from the owner, there is a risk that the project may not move forward or could experience significant delays. |

# LMR/DR - PROPOSAL EVALUATION

- Proposals will be grouped with similar proposals and scored relative to other bids within the same grouping
  - The preferred resource mix will be identified by the IRP analysis
  - All-Source RFP evaluation will rank order available resources within each grouping

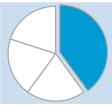
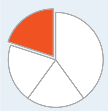
| Rank | Illustrative Resource Groupings | | | | | | |
|---|---|---|---|---|---|---|---|
| 1 | Solar | Wind | Storage | Coal | Gas | Demand Response | etc. |
| 2 | | | | | | | |
| 3 | | | | | | | |
| 4 | | | | | | | |
| 5 | | | | | | | |
| 6 | | | | | | | |
| 7 | | | | | | | |
| 8 | | | | | | | |

500 Total Points*




*Vectren reserves the right to add up to 100 points to Proposals located in Southern Indiana (generally defined as the following counties within Vectren's service territory; Dubois, Gibson, Pike, Posey, Spencer, Vanderburgh, and Warrick), as local resources provide multiple benefits: VAR support, economic development, less future congestion risk, etc.

# LMR/DR - EVALUATION SUMMARY

| Scoring Criteria Name | Points | | Scoring Method | Definition | Importance |
|---|---|---|---|---|---|
| **Cost Evaluation** | 200 |  | Curve | $/MW calculation to determine scoring based on rank order | The cost of the Project will have the most impact on Vectren's ability to provide low cost energy to its customers. |
| **Historical Performance** | 100 |  | Range | Scored based on the length of time the Project has provided demand response services without receiving a non-performance penalty | Historical data can show a track record of performance which can be a benefit to the Project's scoring. |
| **Response Time** | 100 |  | Range | Scored based on the time it takes the LMR/DR to reach load reduction target after receiving notification | Fast response time allows the LMR/DR to take advantage of specific control signals |
| **Proposal Risk Factors** | 100 |  | Binary | Scored based on the amount of material risk identified | Risk factors may cause concern for the reliability or cost of delivery. Risks associated with a specific Proposal will be considered during the evaluation process. |

# FEEDBACK AND DISCUSSION

# ENVIRONMENTAL COMPLIANCE UPDATE

ANGILA RETHERFORD

VICE-PRESIDENT ENVIRONMENTAL AFFAIRS AND CORPORATE RESPONSIBILITY

# REVIEW ENVIRONMENTAL CONTROLS

| Unit | In Service Date | Installed Generating Capacity | $SO_2$ Control | $NO_x$ Control | Soot Control | Hg Control | $H_2SO_4$ Control |
|---|---|---|---|---|---|---|---|
| Culley 2* | 1966 | 90 MW | Scrubber (1995) | Low $NO_x$ (1995) | ESP (1972) | Organosulfide Injection (2015) | |
| Culley 3 | 1973 | 270 MW | Scrubber (1995) | SCR (2003) | Fabric Filter (2006) | Organosulfide Injection (2015) | Sorbent Injection System (2016) |
| Brown 1 | 1979 | 250 MW | Scrubber (1979) | SCR (2005) | Fabric Filter (2004) | Organosulfide Injection (2015) | Sorbent Injection System (2015) |
| Brown 2 | 1986 | 250 MW | Scrubber (1986) | SCR (2004) | ESP (1986) | Organosulfide Injection (2015) | Sorbent Injection System (2016) |
| Warrick 4 | 1970 | 150 MW | Scrubber (2009) | SCR (2004) | ESP (1970) | Organosulfide Injection | Lime Injection |

# COAL COMBUSTION RESIDUALS RULE

VECTREN
A CenterPoint Energy Company

- Final Rule issued April 2015
- Allows continued beneficial reuse of coal combustion residuals
  - Majority of Vectren's fly ash beneficially reused in cement application
  - Scrubber by-product at Culley and Warrick beneficially reused in synthetic gypsum application
- Rule established operating criteria and assessments as well as closure and post-closure care standards
- Groundwater monitoring requirements are underway
- "Phase 1, Part 1" rule was published on July 30, 2018
  - Requires closure of surface impoundments effective October 2020 for impoundments that fail uppermost aquifer location restriction or groundwater protection standard

# COAL COMBUSTION RESIDUALS RULE

VECTREN
A CenterPoint Energy Company

- D.C. Circuit Court decision on August 2018 declared all unlined impoundments an unacceptable risk under CERCLA
  - IDEM interprets D.C. Circuit Court as requiring enhanced focus on mitigating and/or eliminating horizontal infiltration of groundwater through impounded ash
- Evaluating closure-by-removal for Culley East Ash Pond and planning for a closure-by-removal with beneficial reuse for Brown Ash Pond
- Timing for commencement of closure activities based upon results of groundwater monitoring, alternative disposal capacity, and construction of new impoundment or other water storage and treatment system
- Same closure strategy assumed under all scenarios

# EFFLUENT LIMITATION GUIDELINES

- On September 30, 2015, the EPA finalized its new Effluent Limitation Guidelines (ELGs) for power plant wastewaters, including ash handling and scrubber wastewaters
- The ELGs prohibit discharge of water used to handle fly ash and bottom ash, thereby mandating dry handling of fly ash and bottom ash
  - Vectren has previously converted its generating units to dry fly ash handling, however we currently anticipate additional modifications to the existing dry fly ash handling system at Brown to comply with the ELGs
- ELG Postponement Rule published September 2017
  - Delayed initial compliance deadline for Bottom Ash Transport Water by two years, to November 2020
  - Compliance deadline for Fly Ash Transport Water remains November 2018, however the rule provides that utilities can seek an alternative compliance schedule through the water discharge permit renewal process

# EFFLUENT LIMITATION GUIDELINES CONT.

- The ELG rules provide an alternative compliance date of December 2023 for generating units that agree to a more stringent set of discharge limits, which could include retirement
- While we continue to work on engineering solutions to reduce potential compliance costs, the following technologies are in process or being evaluated for ELG compliance for Vectren plants:
  - Culley
    - Includes dry bottom ash conversion, scrubber wastewater treatment and ash landfill construction
    - Converting to dry bottom ash Fall 2020
    - FGD Wastewater conversion to Zero Liquid Discharge (ZLD) estimated late 2022
  - Brown
    - Includes dry fly ash system upgrades, dry bottom ash conversion, an ash landfill and a new lined process pond or tank system
    - The existing Brown scrubbers are closed loop, and are not required to meet ELG wastewater discharge limits for scrubber wastewater discharges; Any new scrubber retrofits would be required to comply with applicable scrubber wastewater discharges

# CLEAN WATER ACT 316B

- In May 2014 EPA finalized its Clean Water Act §316(b) rule which requires that power plants use the best technology available to prevent and/or mitigate adverse environmental impacts to fish and aquatic species
- The final rule did not mandate cooling water tower retrofits
- The Brown plant currently uses closed loop technology
- Vectren submitted the multi-year studies for F.B. Culley as required under the rule and the NPDES permit
- For purposes of IRP modeling, Vectren has assumed intake screen modifications for the Culley plant and assumed a 2024 deadline for compliance

# AFFORDABLE CLEAN ENERGY (ACE) RULE

- Rule finalized in June 2019. Repealed & replaced the Clean Power Plan (CPP)
- Rule establishes standards for states to use when developing plans to limit $CO_2$ at coal-fired power plants
- Establishes heat rate improvement, or efficiency improvement, targets as the best system of emissions reductions for $CO_2$
  - These heat rate targets to be set on a unit by unit basis; Averaging not allowed
  - Vectren currently reviewing technology alternatives available for each unit
- State Implementation Plans are due September 2022 with compliance planned to begin within 24 months of submission
- For purposes of base case assumptions, Vectren assumed that ACE will be upheld upon judicial review

# FEEDBACK AND DISCUSSION

# DRAFT BASE CASE MARKET INPUTS AND SCENARIOS WORKSHOP

**GARY VICINUS**

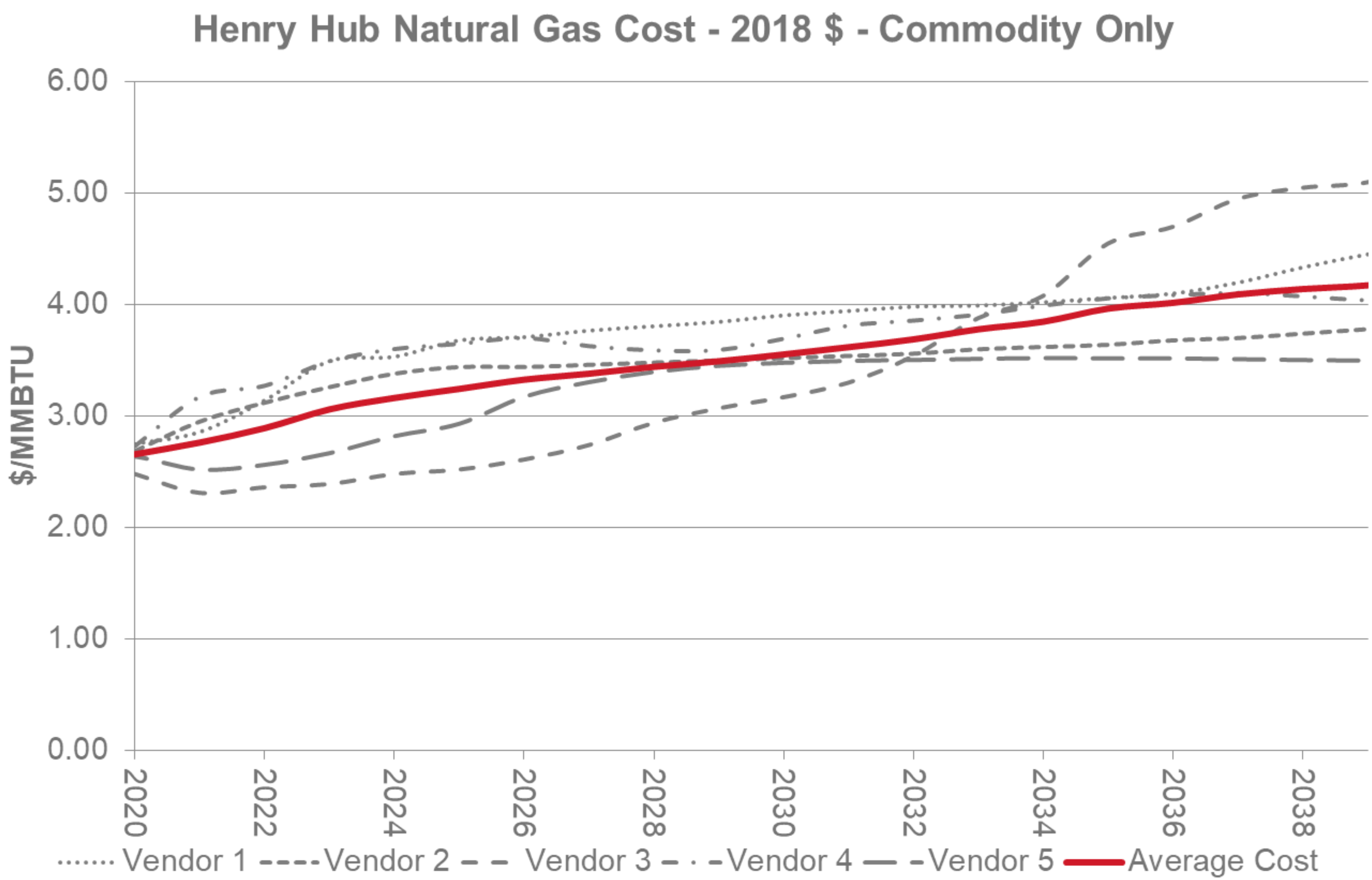
MANAGING DIRECTOR FOR UTILITIES, PACE GLOBAL

# BASE CASE INPUTS

Vectren surveyed and incorporated a wide array of sources in developing its base case assumptions, which reflect a current consensus view of key drivers in power and fuel markets

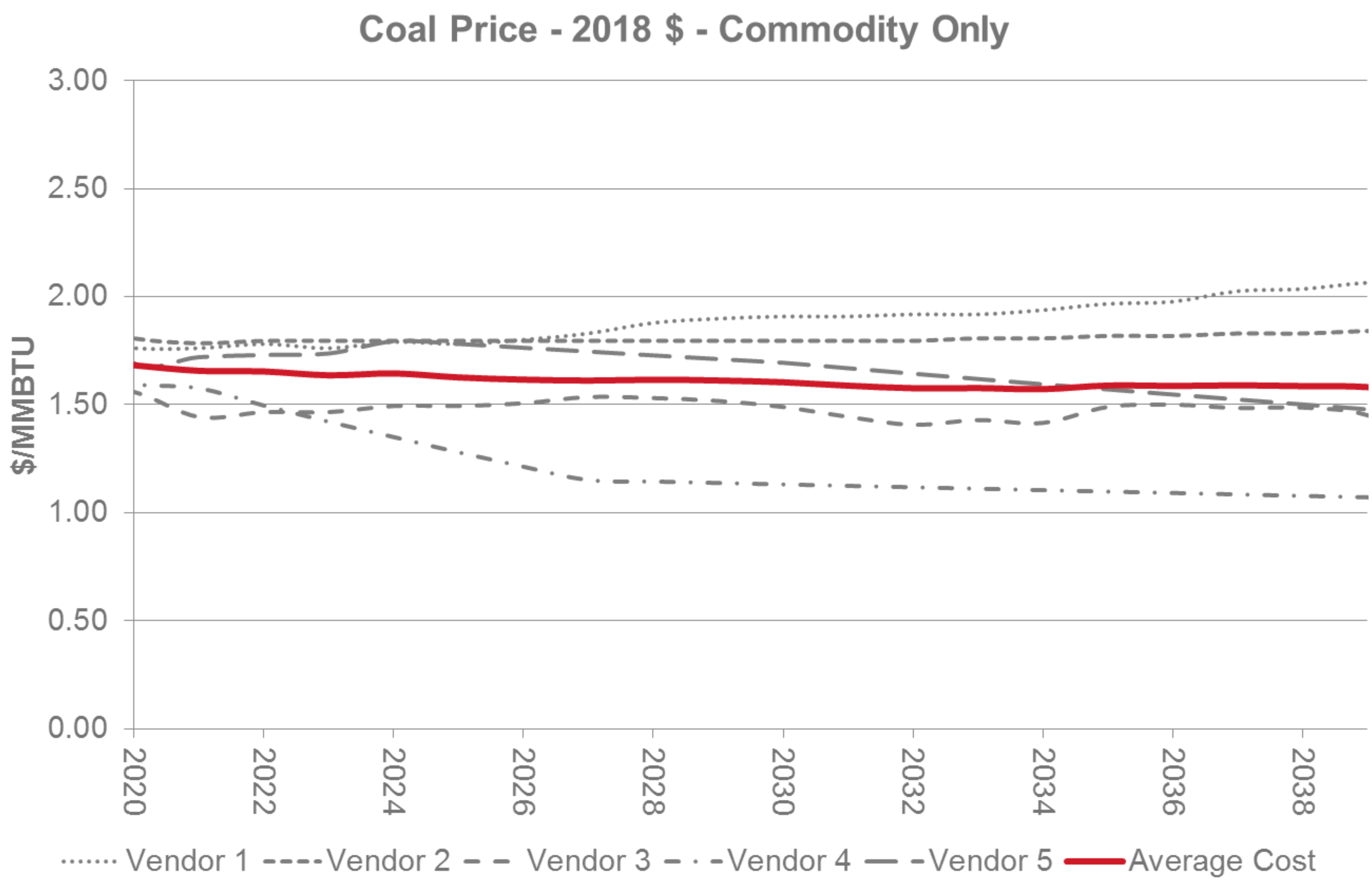
- Base case assumptions include forecasts of the following key drivers:
  - Vectren and MISO energy and demand (load)
  - Henry Hub and delivered natural gas prices
  - Illinois Basin minemouth and delivered coal prices
  - Capital costs for various generation technologies
- On- and off-peak power prices are an output of scenario assumptions
- Vectren uses a consensus base case view, by averaging forecasts from several sources where applicable

# BASE CASE CONSENSUS FUEL FORECASTS



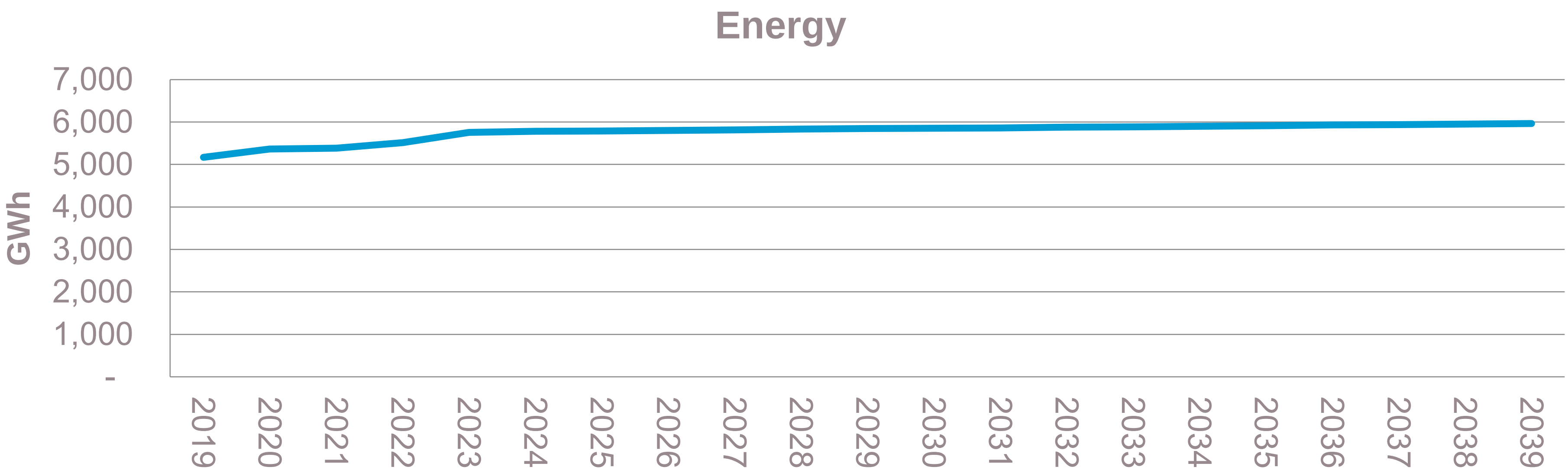

Note: Vendors used were PIRA, Wood Mackenzie, Pace, ABB, & EVA

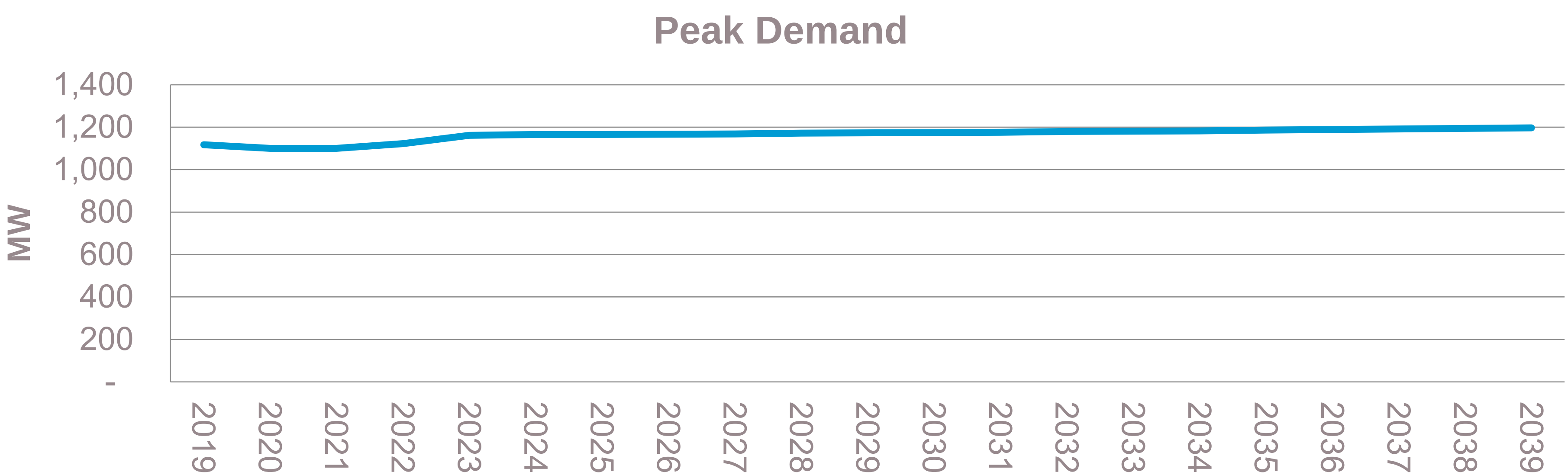
# BASE CASE CONSENSUS FUEL FORECASTS



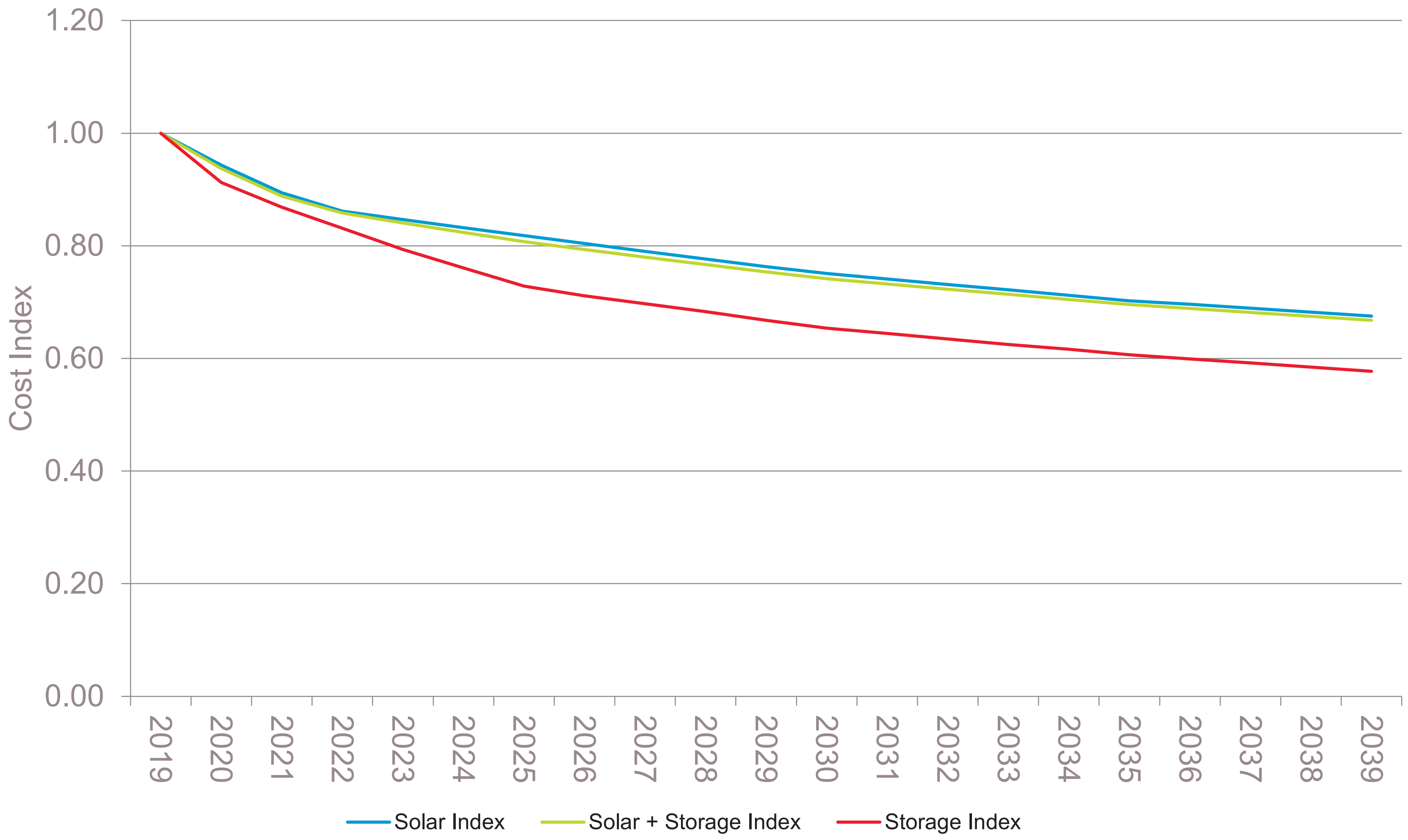

Note: Vendors used were PIRA, Wood Mackenzie, Pace, ABB, & EVA

# BASE CASE LOAD (PRELIMINARY – FORECAST IS CURRENTLY BEING UPDATED)



# BASE CASE RENEWABLES AND STORAGE LONG TERM COST CURVES

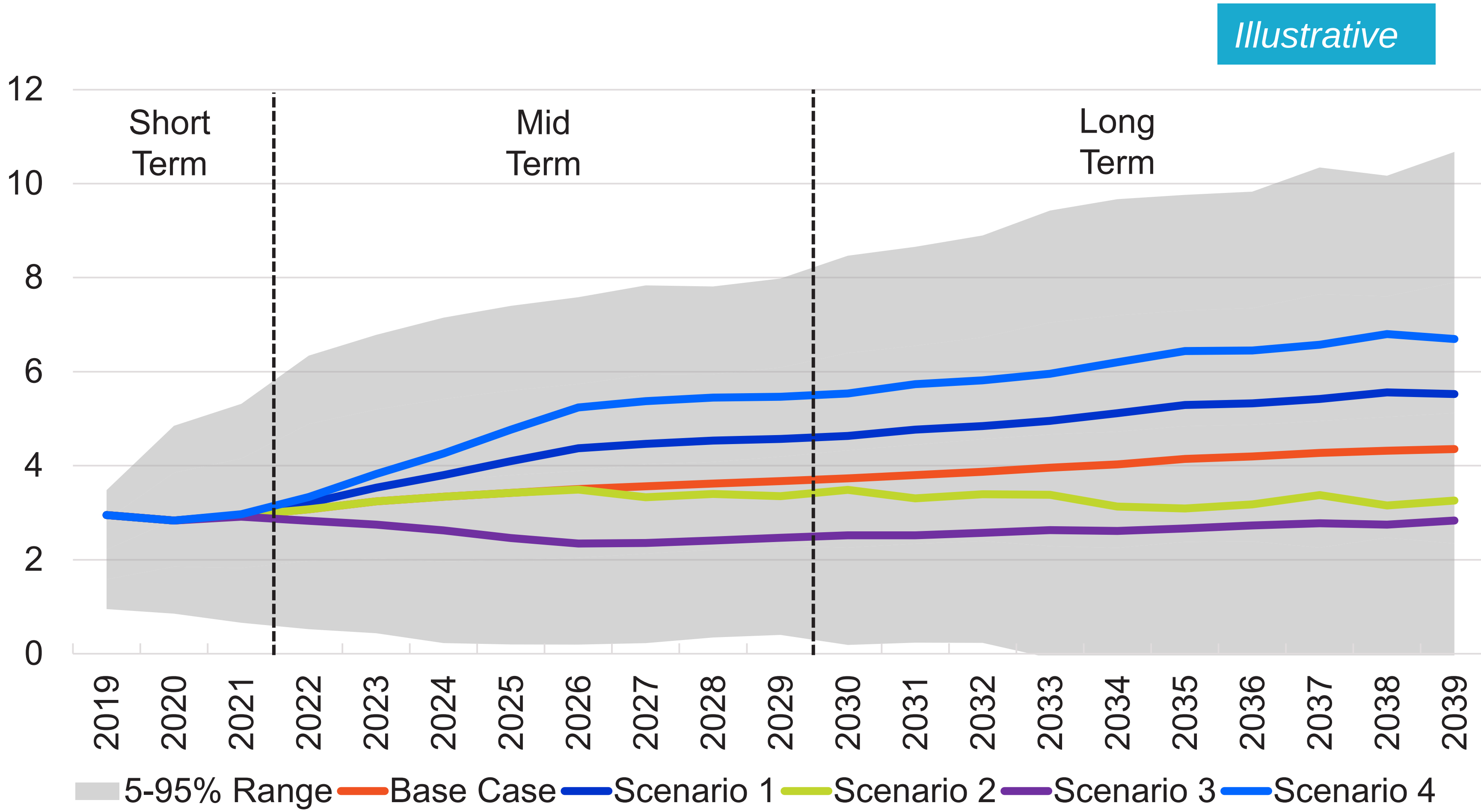


# SCENARIO DEVELOPMENT

Vectren worked with Pace to develop a base case and four alternative, internally consistent scenarios (potential futures), to test which portfolios are optimal over a wide range of future market and regulatory conditions.

- Subjecting portfolios to a range of deterministic scenarios can test portfolio performance in key risk areas important to management and stakeholders alike
- Portfolios would still be run through a stochastic risk analysis to measure performance across a large number of future scenarios
- Scenarios include a low regulatory case, a high technology case, an 80% $CO_2$ reduction by 2050 case, and high regulatory case. Each is described in the following pages with narratives of the major drivers that characterize the scenario
- The framework was developed to ensure internal consistency with the scenario by first developing directional changes for each variable (load, gas prices, coal prices, carbon prices, and capital costs) relative to the base case forecast in the near, mid and long term

# RANGE OF BOUNDARY CONDITIONS



# DRAFT SCENARIOS

VECTREN
A CenterPoint Energy Company

Vectren will utilize scenario based modeling to evaluate various regulatory constructs. The base case is considered the most likely future. The alternative scenarios are shown as higher than, lower than, or the same as the base case.

Increasing Regulation

| | CO2 | Gas Reg. | Water Reg. | Economy | Load | Gas Price | Coal Price | Renewables and Storage Cost | EE Cost |
|---|---|---|---|---|---|---|---|---|---|
| Base Case | ACE | | ELG | Base | Base | Base | Base | Base | Base |
| Low Reg. | ACE Delay** | | ELG Light* | Higher | Higher | Higher | Base | Base | Base |
| High Tech | Low CO2 Tax | | ELG | Higher | Higher | Lower | Lower | Lower | Lower |
| 80% CO2 Reduction by 2050 | Cap and Trade | Methane | ELG | Lower | Lower | Base | Lower | Higher | Higher |
| High Reg. | High CO2 Tax | Fracking Ban | ELG | Lower | Lower | Higher | Lower | Higher | Higher |

*No bottom ash conversion required based on size of the unit and delay requirement for 2 years
**ACE Delayed for 3 years

# SCENARIO NARRATIVES

**Base Case**

- The base case is the "most likely" case, built with commodity forecasts based on industry expert averages
- Load forecast is being developed by Itron and will be submitted to MISO this fall
- The ACE (Affordable Clean Energy) rule, which was finalized as the replacement of the Clean Power Plan, has been promulgated and is included in the base case
- All other scenarios reference the base case (individual uncertainties are at the same levels or are higher or lower than the base case)
- In the base case:
  - Coal prices remain relatively flat over the 20 year forecast horizon in constant dollars
  - Natural gas prices move upward in real dollars to 2039
  - Energy and Demand increase moderately through 2039
  - Capital costs generally decline slightly for fossil resources and decline more for wind and approximately 35% or more for solar and storage resources

# SCENARIO NARRATIVES

**Low Regulatory**

- In the low regulatory scenario, there is a delay of the ACE rule for three years due to legal challenges, but ultimately remains in place. Indiana implements a lenient interpretation of the rule. ELG is partially repealed with bottom ash conversations not required for some smaller units and is delayed for two years (this does not apply to FB Culley 3)
- Fewer regulations lead to a better economy and higher load
- Gas prices edge up slightly with increased demand
- Coal prices continue to remain at base levels as demand for coal continues to decline nationally due to investor pressure and demand for cleaner alternatives
- Technology costs continue to decline at base case levels
- EE costs net to the base level. There is downward pressure with fewer codes and standards being implemented, leaving some low hanging fruit, but upward pressure with increasing load, netting to no change from the base level

# SCENARIO NARRATIVES

## High Technology

- This scenario assumes that technology costs decline faster than in the base case, allowing renewables and battery storage to be more competitive
- A low $CO_2$ tax is implemented. The economic outlook is better than in the base case as lower technology costs and lower energy prices offset the impact of the $CO_2$ tax
- Increased demand for natural gas is more than met with advances in key technologies that unlock more shale gas, increasing supply and lowering gas prices relative to the base case
- Less demand for coal results in lower prices relative to the base case
- Utility-sponsored energy efficiency costs rise early in the forecast but ultimately fall back to below base levels due to technology advances, allowing for new and innovative ways to partner with customers to save energy
- As technology costs fall, customers begin to move towards electrification, driving more electric vehicles and higher adoption of rooftop solar/energy storage and trend towards highly efficient electric heat pumps in new homes

# SCENARIO NARRATIVES

**80% $CO_2$ Reduction by 2050 (aka 2 degrees scenario)**

- This scenario assumes a carbon regulation mandating 80% reduction of $CO_2$ from 2005 levels by 2050 is implemented. A glide path would be set using a cap and trade system similar to the CPP, gradually ratcheting down $CO_2$ emissions and driving $CO_2$ allowance costs up
- Load decreases as the costs for energy and backup power increase and as the energy mix transitions
- In this scenario, regulations on methane emissions initially drive up gas prices, but are partially offset by increased supply. The price of natural gas is slightly higher in the mid term, then decreases back to base levels by the end of the forecast
- There is less demand for coal, driving prices lower than the base case; however, some large and efficient coal plants remain as large fleets are able to comply with the regulation on a fleet wide basis
- Renewables and battery storage technology are widely implemented to help meet the mandated $CO_2$ reductions, increasing prices relative to the base case
- Market based solutions are implemented to lower $CO_2$. Innovation occurs, but is offset by more codes and standards with no incentives, energy efficiency costs rise as a result

# SCENARIO NARRATIVES

**High Regulatory**

- The social cost of carbon is implemented via a high $CO_2$ tax early in the scenario
- A fracking ban is imposed, driving up the cost of natural gas as supply dramatically shrinks
- Tighter regulations are implemented in all aspects coal production and use. As these costs are imposed, prices for coal decrease
- High regulation costs are a drag on the economy and load decreases relative to the base case
- As renewables and battery storage are widely implemented to avoid paying high $CO_2$ prices, prices are driven up
- Utility-sponsored energy efficiency costs are higher as more codes and standards are implemented, leaving less low hanging fruit

# FEEDBACK AND DISCUSSION

VECTREN
A CenterPoint Energy Company

# STAKEHOLDER PROCESS RECAP AND Q&A

# STAKEHOLDER PROCESS RECAP

| August 15, 2019 | October 10, 2019 | December 12, 2019 | March 19, 2020 |
|---|---|---|---|
| • 2019/2020 IRP Process<br>• Objectives and Measures<br>• All-Source RFP<br>• Environmental Update<br>• Draft Base Case Market Inputs & Scenarios | • All-Source RFP Update<br>• Draft Tech Assessment Forecasts<br>• Sales and Demand Forecast<br>• DSM MPS/ Modeling Inputs<br>• Scenario Modeling Inputs<br>• Portfolio Development | • Draft Portfolios<br>• Draft Base Case Modeling Results<br>• All-Source RFP Results and Final Modeling Inputs<br>• Probabilistic Modeling Approach and Assumptions | • Final Base Case Modeling<br>• Probabilistic Modeling Results<br>• Risk Analysis Results<br>• Preview the Preferred Portfolio |

# Q&A

A CenterPoint Energy Company

# APPENDIX

# DEFINITIONS

| Term | Definition |
|---|---|
| ACE | Affordable Clean Energy (ACE) Rule, establishes emission guidelines for states to develop plans to address greenhouse gas emissions from existing coal-fired power plants |
| All-Source RFP | Request for proposals, regardless of source (renewable, thermal, storage, demand response) |
| Aurora | Electric modeling forecasting and analysis software. Allows for model consistency in capacity expansion, chronological dispatch, and stochastic functions |
| Base Case | The most expected future scenario that is designed to include a current consensus view of key drivers in power and fuel markets |
| Baseload | The minimum level of demand on an electrical grid over a span of time |
| Cap and Trade | Emissions trading program aimed at reducing pollution |
| Capacity | The maximum output of electricity that a generator can produce under ideal conditions (megawatts) |
| CCGT | A combined-cycle power plant uses both a gas and a steam turbine together to produce up to 50 percent more electricity from the same fuel than a traditional simple-cycle plant. The waste heat from the gas turbine is routed to the nearby steam turbine, which generates extra power |
| CERCLA | The Comprehensive Environmental Response, Compensation, and Liability Act (Commonly known as Superfund) |
| CO2 | Carbon dioxide |
| CPCN | A Certificate of Public Convenience and Necessity is required to be granted by the Commission for significant generation projects |
| CPP | Clean Power Plan |
| Deterministic Modeling | Simulated dispatch of a portfolio in a determined future. Often computer generated portfolios are created by optimizing on cost to the customer |

# DEFINITIONS CONT.

| Term | Definition |
|---|---|
| DSM | Demand side management includes both Energy Efficiency and Demand Response programs to reduce customer demand for electricity |
| EE | Energy Efficiency |
| ELG | Effluent Limitation Guidelines are U.S. national standards for wastewater discharges to surface waters and publicly owned treatment works |
| Energy | Amount of electricity (megawatt-hours) produced over a specific time period |
| EPA | Environmental Protection Agency |
| GW | Giga watt (1,000 million watt), unit of electric power |
| Henry Hub | Point of interconnection of interstate and intrastate natural gas pipelines as well as other related infrastructure in Erath, Louisiana |
| Installed Capacity (ICAP) | Refers to generating capacity after ambient weather adjustments and before forced outages adjustments |
| Intermittent | An intermittent energy source is any source of energy that is not continuously available for conversion into electricity and outside direct control |
| IRP | Integrated Resource Plan is a comprehensive plan to meet customer load expectations |
| IURC | The Indiana Utility Regulatory Commission is the public utilities commission of the State of Indiana. The commission regulates electric, natural gas, telecommunications, steam, water and sewer utilities |
| LCOE | Levelized Cost of Energy, A measure that looks at cost and energy production over the life of an asset so different resources can be compared. Does not account for capacity value. |

# DEFINITIONS CONT.

| Term | Definition |
|---|---|
| LMR | Load Modifying Resource |
| Local Clearing Requirement (LCR) | Capacity needs to be fulfilled by local resource zone |
| LRZ6 | MISO Local Resource Zone 6 |
| Mine Mouth | At the mine location |
| MISO | Midcontinent Independent System Operator, an Independent System Operator (ISO) and Regional Transmission Organization(RTO) providing open-access transmission service and monitoring the high-voltage transmission system in the Midwest United States and Manitoba, Canada and a southern United States region which includes much of Arkansas, Mississippi, and Louisiana. MISO also operates one of the world's largest real-time energy markets |
| MPS | Market potential study - Determines the total market size (value/volume) for a DSM at a give period of time |
| MW | Mega watt (million watt), unit of electric power |
| Name Plate Capacity | The intended full-load sustained output of a generation facility |
| NDA | Non-Disclosure Agreement |
| NOI | Notice of Intent |

# DEFINITIONS CONT.

| Term | Definition |
|---|---|
| NPDES | National Pollutant Discharge Elimination System |
| OMS | Organization of MISO States, was established to represent the collective interests of state and local utility regulators in the Midcontinent Independent System Operator (MISO) region and facilitate informed and efficient participation in related issues. |
| Peaking | Power plants that generally run only when there is a high demand, known as peak demand, for electricity |
| Planning Reserve Margin Requirement | Total capacity obligation each load serving entity needs to meet |
| Portfolio | A group of resources to meet customer load |
| PPA | Purchase power agreement |
| Preferred Portfolio | The IRP rule requires that utilities select the portfolio that performs the best, with consideration for cost, risk, reliability, and sustainability |
| Probabilistic modeling | Simulate dispatch of portfolios for a number of randomly generated potential future states, capturing performance measures |
| RA (Resource Adequacy) | RA is a regulatory construct developed to ensure that there will be sufficient resources available to serve electric demand under all but the most extreme conditions |
| Resource | Supply side (generation) or demand side (Energy Efficiency, Demand Response, Load Shifting programs) to meet planning reserve margin requirements |

# DEFINITIONS CONT.

| Term | Definition |
|---|---|
| Scenario | Potential future State-of-the-World designed to test portfolio performance in key risk areas important to management and stakeholders alike |
| Sensitivity Analysis | Analysis to determine what risk factors portfolios are most sensitive to |
| Strategist | Strategic planning software application typically used for IRP analyses |
| Technology Assessment | An analysis that provides overnight and all-in costs and technical specifications for generation and storage resources |
| Unforced Capacity (UCAP) | A unit's generating capacity adjusted down for forced outage rates (thermal resources) or expected output during peak load (intermittent resources) |
| VAR Support | Unit by which reactive power is expressed in an AC electric power system |
| ZLD | Zero Liquid Discharge |

**Vectren 2019 IRP**
**1st Stakeholder Meeting Minutes Q&A**
*August 15, 2019, 9 am – 3 pm CDT*

**Lynnae Wilson** (CenterPoint Energy Indiana Electric Chief Business Officer) – Welcome, Safety Message, Introduction to CenterPoint Energy/ Vectren, Personal background and Vectren team introductions, Updates and Goals for this 2019 IRP

> Subject matter experts in the room: Natalie Hedde, Angie Casbon-Scheller, Justin Joiner, Christine Keck, Bob Heidorn, Wayne Games, Matt Rice, Ryan Wilhelmus, Rina Harris, Nick Kessler, Laurie Thornton, Jason Stephenson, Cas Swiz, Steve Rawlinson, Tom Bailey, Roland Rosario.

**Gary Vicinus** (Moderator, Managing Director for Utilities, Pace Global) – General Introduction to this IRP Process, Introductions for approximately 40 stakeholders in the room, List of affiliations include:

Country Mark
Deaconess Health Systems
EQ Research
Hallador Energy/Sunrise Coal
IBEW Local 702
IURC
NIPSCO
Orion Renewable Energy Group LLC
OUCC
Sierra Club
SUFG
Tr-State Creation Care
Valley Watch
Whole Sun Designs Inc.

More than 30 stakeholders attended on the phone. Those registered included representatives from:

Advanced Energy Economy
AECOM
AEMA
AEP
Applied Economics Clinic
Boardwalk Pipeline
CAC
Development Partners Group
Energy Futures Group
Enerwise Global Technologies, LLC d/b/a CPower; and Advanced Energy Management Alliance
Hoosier Energy
Indiana Distributed Energy Alliance

VECTREN
A CenterPoint Energy Company

IPL
IURC
Lewis Kappes
MEEA
Morton Solar & Electric
Orion Renewable Energy Group LLC
OUCC
Sierra Club
St. Joe
Vote Solar

**Matt Rice** (Vectren Manager of Resource Planning) – Discussed the feedback received since the 2016 IRP, the 2019/2020 IRP process, and the role of the all source request for proposals.

- Slide 8 Director's Report Feedback:
  - Question: What was the suggestion given consideration for Warrick 4, and what does it mean to maintain optionality?
    - Response: In the 2016 IRP, we hard coded an assumption in for Warrick 4 shutdown. With respect to Warrick 4 the Director's report comment referred to evaluating running the unit longer or shutting it down sooner. While not addressed in the meeting, in 2016 the Director provided praise for building scenario inputs in the short, mid, and long term, thus maintaining optionality.
  - Follow-up: After the smelter shutdown, there was higher risk to Warrick 4. So why was there an extension to the Warrick 4 agreement?
    - Response: The agreement was extended through 2023. Please see Wayne Games for more questions. While not stated in the meeting, the extension supported ALCOA's decision to reopen its smelter.
- Slide 13 Proposed 2019/2020 IRP Process:
  - Question: Will you provide preparatory material, list of potential strategies, etc. ahead of the next meeting?
    - Response: Yes, we will post the presentation and potential strategies one week ahead of next meeting. Below is a list of potential strategies for you to think about it in advance.
      - Minimize CO2
      - Minimize cost
      - Continue to run existing plants
      - Maximize Energy Efficiency (EE) and renewables
      - Balanced/Diverse mix of resources (don't put all of your eggs in one basket),
  - Question: Regarding Slide 8 (Director's Report Feedback), how will scoring be done this time?
    - Response: We will cover details in the Objectives and Measures section today.
  - Statement: Please differentiate among stakeholders. Additionally, I have a concern about the loss of industrial load and support for the community, particularly low income customers.
    - Response: There are many different stakeholders, and we try to make this IRP process relevant to all stakeholders. Tom Bailey can speak to economic development, and we have scenarios with higher load. We hear your concern on

price impact, and we'll address those concerns during Objectives & Measures discussion.

- Slide 14 Role of the All-Source RFP:
    - Question: Please explain how resources will be modeled on a tiered basis?
        - Response: We will group resources by cost and by like-resources.
    - Question: How much modeling of RFP responses has Pace and Vectren done to-date?
        - Response: None, as we are still gathering inputs. RFP bids just came in last week so there's been very little analysis to-date.
    - Question: CenterPoint has a vested interest in using natural gas. How do you not bias toward natural gas in this plan?
        - Response: Portfolios will be evaluated based on tradeoffs presented in the scorecard, which we will talk about today. Vectren has no preconceived notion of what the portfolio will be. We are taking an unbiased approach to selecting resources.
- Slide 15 Key Vendors:
    - Question: Since bids are done, doesn't that limit us?
        - Response: No, we will use the RFP as an input into the IRP. We are looking for your input on how we evaluate portfolios of resources.
    - Question: Will RFP data be made available to all stakeholders, and can we learn the total number and type of bids?
        - Response: We will summarize data. We must protect confidential information, but we will work with some groups to try and find a way to show certain groups, like the OUCC, bid information. We will provide some summary data later today, and we will continue to provide more detailed information as analysis is completed.
- Slide 16 2019/2020 Stakeholder Process:
    - Question: We have an ongoing concern with use of Aurora for IRP purposes. It is not possible to export input/output files according to Energy Exemplar, and costs are large even for a read-only model. Additionally, we cannot see the manual without having a license.
        - Response: We will provide all of the inputs, outputs, and talk about the constraints. We have also determined that the cost for a read only license is $5k. For those who obtain the license, we will provide modeling files for review. We will follow up about the owner's manual.
    - Follow-up: Still concerned about costs and would like to know if stakeholders can log-in using existing license.
        - Response: We can have a follow-up conversation and can discuss options. We chose Aurora based on capabilities, feedback, internal consistency, and run-times on the cloud.
    - Follow-up statement: We appreciate working with Vectren on how to gain access to data within Aurora, which will allow for a meaningful stakeholder process, no further questions here but we want to comment that this is critical.
        - Response: Vectren will work hard to provide useful information.
    - Statement: I am responding to the gentleman that said he has a concern about the loss of industrial load and support for the community, particularly low income customers. I have a concern that you will only try to encourage industrial growth. There are many businesses that we should be attracting.
        - Response: Vectren works to attract all types of customers.

**Gary Vicinus** – Discussed Objectives & Measures and gathered stakeholder feedback:

- Slide 23 Feedback and Discussion:

- Question: The concept of affordability is inclusive of all costs over time, including externalities. Clarify the concept of affordability.
  - Response: Cost is inclusive of relevant costs associated with portfolios. In the scenarios, we'll talk about costs of regulation (e.g., social cost of carbon in one scenario) where some of the costs considered go beyond direct cost of generation.
- Follow-up: Do we account for environmental and health impacts?
  - Response: In the high regulatory scenario, health impacts are one of the considerations that go into the social cost of carbon.
- Question: Where does the 15% band come from [for the Market Risk Minimization metric]?
  - Response: It was selected as a placeholder but we will continue to review to determine if it is reasonable, including looking at historical data.
- Question: How are you measuring impairment; how would it be calculated?
  - Response: We will run 200 iterations and track plant-level economics. We can determine how many scenarios would have shut down a unit for economics and track the number of MWhs over time that unit would have produced. The methodology for assessing potential asset impairment remains under review.
- Question: By only looking at CO2 emissions at a plant level, aren't we missing local impacts (ground level ozone, PM) and upstream impacts (methane fugitive emissions, flaring, etc.)?
  - Response: Would you have a suggestion for a better metric?
    - Response: You could use CO2-equivalent instead of CO2.
- Statement: It seems like MWh impairment is more of a price risk. Maybe this measure should be capital exposed rather than MWh.
- Question: I echo his questions and am also concerned that Market Risk measures. Would that bias toward excess sales/purchases?
  - Response: Just the opposite is the case. Excess sales and purchases above or below a band would be detrimental to portfolio performance.
- Statement: You should track other emissions within the modeling.
  - Response: CO2 isn't the only thing we'll track in the model. It is important to get the big picture, beyond the scorecard. We are going to be capturing a wide range of outputs from future scenarios going forward, including the implications of methane.
- Statement: It will be hard to quantify costs to methane emissions.
  - Response: It will be a challenge, and we'll bring our estimates to the next meeting and you will have a chance to comment if our inputs seem reasonable or not.
- Statement: CO2 emitted now is worse than CO2 emitted 20 years from now (as demonstrated by CCL models), so consider a NPV of CO2.
- Question: How do we incorporate feedback from initial steps to optimize the preferred portfolio? Are you considering feedback loops in determining the best or optimal portfolio?
  - Response: Can you clarify what you mean in "best" vs "optimal" portfolio?
  - Question: Yes, let's say we have 150 portfolios. How do you use something like Artificial Intelligence to improve the portfolio selection?
  - Response: IRPs are done every 3 years, which is in a way a feedback loop. We'd be interested in how to implement this within an IRP. If you have comments that you would like to send to us, we would be happy to look at it.
- Question: Are you measuring environmental harm from mining/ fracking? Also, if renewables costs are expensive, why does Vectren have the highest rates in the state despite using fossil generation?

- Response: Renewables costs may be more or less expensive. The RFP process provide inputs that will provide useful information regarding the cost of renewables. Also, fracking will be captured in the scenario analysis.
  - Question: Are you looking at measuring other GHGs (methane) and water pollution on a lifecycle basis? If so, where does that fit?
    - Response: We'll take into consideration CO2-equivalent and also will measure the impact of methane emissions regulations. If we don't answer your question within the scenario discussion, you will have a chance to ask again at the end of the day.
  - Question: Where is the optimal nexus of the Venn diagram on Slide 20 (Each Portfolio Will have Tradeoffs) to explore tradeoffs vs synergies?
    - Response: We are not just exploring tradeoffs but also synergies, which should point towards the optimal solution.
  - Statement: I have a concern with weighting metrics.
    - Response: We have presented the metrics, and we will talk about how we plan to evaluate the metrics over time.
  - Statement: On slide 72 (Definitions Cont.) the definition of optimal portfolio includes consideration for sustainability. My comment is that fossil fuel is inherently unsustainable.
  - Question: Why did Vectren not do an open source RFP last IRP (2016)?
    - Response: The traditional approach for an IRP is to utilize a technology assessment. There is a very large cost difference between a technology assessment [a study of costs and operating characteristics of various resources] and a RFP. Also, it's only recently that IRPs have begun to incorporate the use of RFPs.
  - Question: Is 15% on slide 21 (IRP Objectives and Measures) based on expected load or expected purchases and sales?
    - Response: It's based on a range around expected purchases/ sales with +/- 15% from those levels.

**Matt Lind** – Discussed the Request For Proposals (RFP) methodology, scoring, role, and provided high level statistics for Vectren's RFP.

- Slide 25 [RFP] Overview:
  - Question: Are you considering existing resources with alternatives? Does that include the OVEC contract? I'm concerned about ratepayers being impacted by extra cost now that FirstEnergy has pulled out of that contract. Also, is Vectren involved in the decision on coal ash ponds?
    - Response: FirstEnergy is not out of the contract yet.
  - Question: Is it covered in the IRP?
    - Response: To the extent all resources are considered, yes.
- Slide 32 Proposal Requirements:
  - Question: Why set the limit at 10 MW when you already have two 2 MW projects.
    - Response: Those two 2 MW projects are pilot projects.
  - Question: Will you share the bidder list, and will there be an opportunity to bid in again later on?
    - Response: We will share a list with bidder names. We do not plan to obtain bids again for this IRP.
  - Question: Were there any bidders that came too late or any that were rejected because they were unacceptable?
    - Response: At this point no bids have been rejected because they were deemed unacceptable. We accepted bids from all that provided bids on time with an NOI and NDA.
  - Question: Were bidders allowed to offer in existing resources in the RFP?
    - Response: Yes.

- Question: Did you provide information on your existing situation?
    - Response: No.
  - Question: Why was the RFP deadline extended?
    - Response: We did not get responses back regarding credit review to bidders within our stated timeframe on the RFP, so we extended the due date proportionately.
  - Question: Can you tell us how many respondents NIPSCO had to its RFP?
    - Response: We believe somewhere close to 90 proposals.
- Slide 33 Preliminary RFP Statistics:
  - Question: How big is the solar portion of the pie to the right?
    - Response: Solar is about 19,500 MW, but there is double counting here (multiple PPA vs build options).
  - Question: Is this nameplate capacity or accredited capacity?
    - Response: This is ICAP (nameplate), not UCAP (accredited).
  - Question: Did Vectren or its related companies submit proposals to the RFP.
    - Response: No.
- Slide 37 [RFP] Evaluation Summary:
  - Question: I'm afraid that the way you are conducting this RFP process won't allow the most affordable options to rise to the top.
    - Response: The RFP at this point is providing information about the cost of each resource and will feed IRP modeling. The IRP will be the process that picks the preferred portfolio mix. Gas is not competing with solar and wind within the RFP scoring. Like groups of resources will be grouped so that solar resources are competing with solar within the RFP and gas is competing with gas.
- Slide 40 Feedback and Discussion:
  - Question: Why do projects within your service territory get 100 points? I would like to get more clarity about how this may hamper projects not within this area.
    - Response: Potential local points are additive to the 500 points. It is not a given that they will be applied. It is an option to apply 100 additional points based on a preference for local resources and the benefits that local resources provide to transmission reliability, lower congestion risk, and economic development. In terms of the local preference, we will provide the criteria at a later date. If we apply it, we will give rational.
  - Question: I have a concern over delivery date, why penalize based on early delivery (before 2023/24 date)?
    - Response: To the extent capacity is needed early, we'll capture that in the IRP process.
  - Question: Fuel sources have to compete with one another in this process. Is that what is being done in the IRP?
    - Response: Yes. The resources compete with one another within the IRP.
  - Question: You mentioned that there is an Import/Export limit on resources, who sets the value and what is the limit?
    - Response MISO does an annual (public) LOLE study that determines I/E limits for Local Resource Zone-6. Currently about 70% of Vectren resources need to be located within MISO zone 6.
  - Question: Will point scoring be an input in any way or via weighting in the Aurora Model?
    - Response: No.
  - Follow-up: How are local vs. non-local resources going to be evaluated?
    - Response: Cost information from bids will be evaluated in Aurora based on the cost to deliver energy to Vectren's load node. Burns and McDonnel will also do an evaluation of congestion costs for RFP scoring.
  - Follow-up: I'm still unclear on RFP scoring and how it relates to the IRP.

- Response: The IRP will identify a preferred resource mix [portfolio] and then we may go back to the RFP proposals for best offers within each resource category.
- Question: I'm concerned about options from the RFP. Two nearby dams can provide approximately 700 MWs of hydroelectric power. So why is hydro not in bids?
  - Response: No hydro bids were received. Within IRP modeling, we will supplement bid information with technology assessment information for resources where we did not receive a bid, including hydro.

**<u>Angila Retherford</u>** – Discussed the current regulatory environment as it pertains to generation, including, but not limited to, CCR, ELG, the Clean Water Act 316B, and ACE.

- Slide 48 Affordable Clean Energy (ACE) Rule:
  - Question: What is the conversion rate that you are using for $CO_2$?
    - Response: We will have to verify, but it is around 26x. We will clarify at the next meeting.
  - Question: Are you talking about $CO_2$-equivalence as a measured life-cycle or at the stack?
    - Response: At the stack, but we will get closer to life-cycle with one of our scenarios.
  - Question: How do you justify the ACE rule will stand for 20 years?
    - Response: The ACE is the current regulation for $CO_2$ and is therefore included as the base case. Your question is focused around a base case. We're going to construct scenarios around more stringent regulations. This is a business as usual scenario.
  - Question: Have you evaluated compliance costs for 100% solar?
    - Response: No, but we would need to also consider upstream environmental costs of renewable energy the same as we consider them for fossil.
  - Question: Are you accounting for methane leaks in Vectren's system?
    - Response: Not in terms of the distribution system, but the high reg scenario will capture higher methane costs for regulations.

**<u>Gary Vicinus</u>** – Discussed base case inputs and draft scenarios and asked for feedback.

- Slide 53 Base Case Consensus Fuel Forecasts [Coal]:
  - Question: Can you provide delivered coal prices to compare to these forecasts?
    - Response: Yes. We will provide delivered historic prices compared to these projections. Note that delivered prices are included in modeling.
  - Question: Some coal plants are designated as "must-run" due to take-or-pay coal contracts. Do you designate your plants under must run status? Is that how any of your coal contracts are set up?
    - Response: No, we do not designate our plants as must run unless there is a reliability issue and our system operator tells us we need to run a plant. It is not a function of coal supply contracts.
  - Question: Gary mentioned both coal and gas have a $1/MMBtu difference [between the high and low inputs], but in absolute terms these are very different. Comment?
    - Response: These consensus forecasts are showing a difference of about a $1/MMBtu. The distinction though is that one is off of a three dollar base and the other is off of about a dollar and a half base.
  - Question: Is Vectren's gas price similar to Henry Hub?
    - Response: We're showing commodity only, but we'll factor in transportation costs.
  - Question: 4/5 vendors gas forecasts were close. One was quite different. Do you know why?

        - Response: One of the benefits of a consensus forecast is that it is a best guess, but the drawback is you can't always look at underlying assumptions. Vectren's view is that these are all credible vendor forecasts.
- Slide 55 Base Case Renewables and Storage Long Term Cost Curves:
    - Question: Am I interpreting this chart correctly, that solar cost will decline ~30% and storage ~40%?
        - Response: Yes.
    - Question: Are capital cost decline indices a combo of NREL, B&M, and Pace?
        - Response: Yes.
    - Comment: At some point technology advances are less important to cost because of other costs, like land, become larger.
        - Response: Absolutely correct.
    - Question: We've historically underestimated solar costs. How do you account for that? Will you consider a steeper decline curve.
        - Response: We will evaluate bid costs and assess if these curves still make sense. Additionally, a steeper decline curve will be assessed in the high technology scenario.
- Slide 58 Draft Scenarios:
    - Question: How did you determine Economy? What is higher and lower and how did you determine?
        - Response: These are all in relation to the Base Case.
    - Follow-up: Please look at the Economy again. It may not be valid that a High Regulation case leads to Lower-than-Base-Case economy.
        - Response: Perfectly valid concerns. That is why we want your input.
    - Question: What are the ACE rule implications?
        - Response: ACE means there is greater investment to increase efficiency to meet targets in the rule.
    - Comment: I want to echo the concern that correlates High Reg with Low Economy. I think that it is a false assumption. There is a bipartisan bill in congress that has been analyzed using REMI analysis that says High Reg (carbon dividend, specifically) would in fact *improve* the economy.
        - Response: That is the kind of input that we are looking for. We will look into the study/bill that you suggest.
    - Question: Where is the 100% clean energy scenario? NIPSCO, Xcel, others have committed to 100% renewable.
        - Response: There is a distinction between scenario and strategy. You described a strategy. Here, we're looking at scenarios, but portfolio construction can be designed to achieve 100% renewable energy. You could construct a scenario with a high 80-100% renewable portfolio standard.
- Slide 62 Scenario Narratives [80% CO2 Reduction by 2050 (aka 2 degrees scenario)]:
    - Comment: I disagree in the 80% scenario that you'd see that battery storage prices would increase with more demand, just like computer prices didn't increase with greater demand.
        - Response: We will consider, but we need to make sure to capture boundary conditions within scenarios. These are not cast in stone. We appreciate your input.
- Slide 63 Scenario Narratives:
    - Comment: Please don't set boundaries to disadvantage renewables.
        - Response: Remember that we'll also expose the portfolios not only to these scenarios but also 200 iterations.
    - Question: The base case is supposed to be most likely, so the idea that in the Base Case that the ACE rule will last 20 years is not realistic. Also, I don't think we would

raise solar prices due to higher regulatory restrictions, particularly over 30 years to 2050.
    - Response: Fair point, that feedback is valuable. Keep in mind that when you see higher, this is higher relative to the base case. In other words, the costs will decline more slowly.
  - Comment: Again, Base Case assumption of ACE rule is unrealistic.
    - Response: The most likely future is probably a misnomer, but it is the rule on the books. Don't focus too much on this since we are modeling lots of other scenarios. Ignoring the CO2 law on the books that exists now is problematic from a process standpoint.

**Open Q&A Session**

- Question: I have a question on the October 10th meeting on what portfolios are vs. strategies.
  - Response: We will be looking for your input on strategies for portfolio development.
- Question: How reliable are your coal plants?
  - Response: There are a couple of ways to measure reliability. Capacity factor is around 60-65% over last 4-5 years. Our forced outage rate is around 4.5%.
- Question: Can you confirm that each tiered resource modeled in Aurora will consist of the average price of the prices from each tier, and will each tier consist of the sum of MWs within that tier, and will all tiers compete with one other simultaneously? Will the price of each tier simply be the average or will there be adders of any kind from congestion layered on top of them.
  - Response: Within each category there will be tiers to the extent that there are multiple proposals represented within that tier. Not in every case (e.g., DR, which had one response), but yes - we'll capture in the tiers various cost levels that may include congestion. We'll revisit in next meeting. To add with our own experience, we have a wind PPA that sits in the northern part of the state. So when the transmission system is loaded, we have to pay MISO to get that energy. The congestion component based on where these plants are is a big deal. We will do the best we can to capture the costs that our customers are going to see.
- Question: How are you using stakeholder input in IRP process; will it be tangibly used?
  - Response: We will be transparent in how we use or not use stakeholder inputs. If we chose not to use a suggestion, we will tell you why.
- Question: How do Objectives & Measures work, and will they be weighted?
  - Response: At this point nothing is weighted. We are looking at tradeoffs for portfolios. The balanced scorecard is a tool to understand tradeoffs. At the end of the day, the scorecard is not going to produce a score and rank order portfolios. It is a tool to understand where the differences lie and how each portfolio meets these multiple objectives. We can place an emphasis on certain measures but that is in the realm of judgement. We can't take ultimate decision-making out of management's hands and reduce it down to a formula. The tradeoffs have to be considered fully by management, with transparency of the body of evidence of performance and implications among tradeoffs.
- Comment: We received a serious warning one year ago from the IPCC. I appreciate your expertise, and we need your knowledge and skills. But I also want you to inject a morale urgency into your decision-making to ensure we're creating a pathway to respond to the warnings of climate experts. We would like to see you indicate which portfolios meet the IPCC standards.

VECTREN
A CenterPoint Energy Company

# VECTREN PUBLIC STAKEHOLDER MEETING

OCTOBER 10, 2019

# WELCOME AND SAFETY SHARE

**LYNNAE WILSON**

INDIANA ELECTRIC CHIEF BUSINESS OFFICER

# SAFETY SHARE

VECTREN
A CenterPoint Energy Company

**Tips to Avoid Distractions While Driving**

- Make adjustments before your get underway. Address vehicle systems like your GPS, seats, mirrors, climate controls and sound systems before hitting the road. Decide on your route and check traffic conditions ahead of time.
- Snack smart. If possible, eat meals or snacks before or after your trip, not while driving. On the road, avoid messy foods that can be difficult to manage.
- Secure children and pets before getting underway. If they need your attention, pull off the road safely to care for them. Reaching into the backseat can cause you to lose control of the vehicle.
- Put aside your electronic distractions. Don’t use cell phones while driving – handheld or hands-free – except in absolute emergencies. Never use text messaging, email functions, video games or the internet with a wireless device, including those built into the vehicle, while driving.
- If another activity demands your attention, instead of trying to attempt it while driving, pull off the road and stop your vehicle in a safe place. To avoid temptation, power down or stow devices before heading out.
- As a general rule, if you cannot devote your full attention to driving because of some other activity, it’s a distraction. Take care of it before or after your trip, not while behind the wheel.

# 2019/2020 STAKEHOLDER PROCESS

| August 15, 2019 | October 10, 2019 | December 13, 2019[1] | March 19, 2020 |
| --- | --- | --- | --- |
| • 2019/2020 IRP Process<br>• Objectives and Measures<br>• All-Source RFP<br>• Environmental Update<br>• Draft Base Case Market Inputs & Scenarios | • RFP Update<br>• Draft Resource Costs<br>• Sales and Demand Forecast<br>• DSM MPS/ Modeling Inputs<br>• Scenario Modeling Inputs<br>• Portfolio Development | • Draft Portfolios<br>• Draft Base Case Modeling Results<br>• All-Source RFP Results and Final Modeling Inputs<br>• Probabilistic Modeling Approach and Assumptions | • Final Base Case Modeling<br>• Probabilistic Modeling Results<br>• Risk Analysis Results<br>• Preview the Preferred Portfolio |

1 Snow date is December 19, 2019

# AGENDA

| Time | | |
|---|---|---|
| **9:00 a.m.** | Sign-in/Refreshments | |
| **9:30 a.m.** | Welcome, Safety Message | Lynnae Wilson, CenterPoint Energy Indiana Electric Chief Business Officer |
| **9:40 a.m.** | Follow-up Information Since Our Last Stakeholder Meeting | Matt Rice, Vectren Manager of Resource Planning and Gary Vicinus, Managing Director for Utilities, Pace Global |
| **10:10 a.m.** | MISO Considerations | Justin Joiner, Vectren Director Power Supply Services |
| **10:40 a.m.** | Break | |
| **10:50 a.m.** | Scenario Modeling Inputs | Gary Vicinus, Managing Director for Utilities, Pace Global |
| **11:30 a.m.** | Lunch | |
| **12:00 p.m.** | Long-term Base Energy and Demand Forecast | Mike Russo, Senior Forecasting Analyst, Itron |
| **12:30 p.m.** | Existing Resource Overview | Wayne Games, Vectren Vice President Power Generation Operations |
| **1:00 p.m.** | Potential New Resources and MISO Accreditation | Matt Lind, Resource Planning & Market Assessments Business Lead, Burns and McDonnell |
| **1:40 p.m.** | Break | |
| **1:50 p.m.** | DSM Modeling in the IRP | Jeffrey Huber, Managing Director, GDS Associates |
| **2:20 p.m.** | Portfolio Development Workshop | Moderated by Gary Vicinus, Managing Director for Utilities, Pace Global |
| **3: 00 p.m.** | Adjourn | |

# MEETING GUIDELINES

1. Please hold most questions until the end of each presentation. Time will be allotted for questions following each presentation. (Clarifying questions about the slides are fine throughout)
2. For those on the webinar, please place your phone and computer on mute. We will open the phone lines for questions within the allotted time frame. You may also type in questions via the chat feature. Only questions sent to 'All-Entire Audience' will be seen and answered during the session.
3. There will be a parking lot for items to be addressed at a later time.
4. Vectren does not authorize the use of cameras or video recording devices of any kind during this meeting.
5. Questions asked at this meeting will be answered here or later.
6. We will do our best to capture notes but request that you provide written feedback (concepts, inputs, methodology, etc.) at IRP@CenterPointEnergy.com following the meeting. Additional questions can also be sent to this e-mail address.

# FOLLOW-UP INFORMATION SINCE OUR LAST STAKEHOLDER MEETING

**MATT RICE**

VECTREN MANAGER OF RESOURCE PLANNING

**GARY VICINUS**

MANAGING DIRECTOR FOR UTILITIES, PACE GLOBAL

# VECTREN COMMITMENTS FOR 2019/2020 IRP

VECTREN
A CenterPoint Energy Company

By the end of the second stakeholder meeting Vectren will have made significant progress towards the following commitments

- ✓ Utilizing an All-Source RFP to gather market pricing & availability data
- ✓ Including a balanced, less qualitative risk score card; draft was shared at the first public stakeholder meeting
- ✓ Performing an exhaustive look at existing resource options
- ✓ Using one model for consistency in optimization, simulated dispatch, and probabilistic functions
- ✓ Working with stakeholders on portfolio development

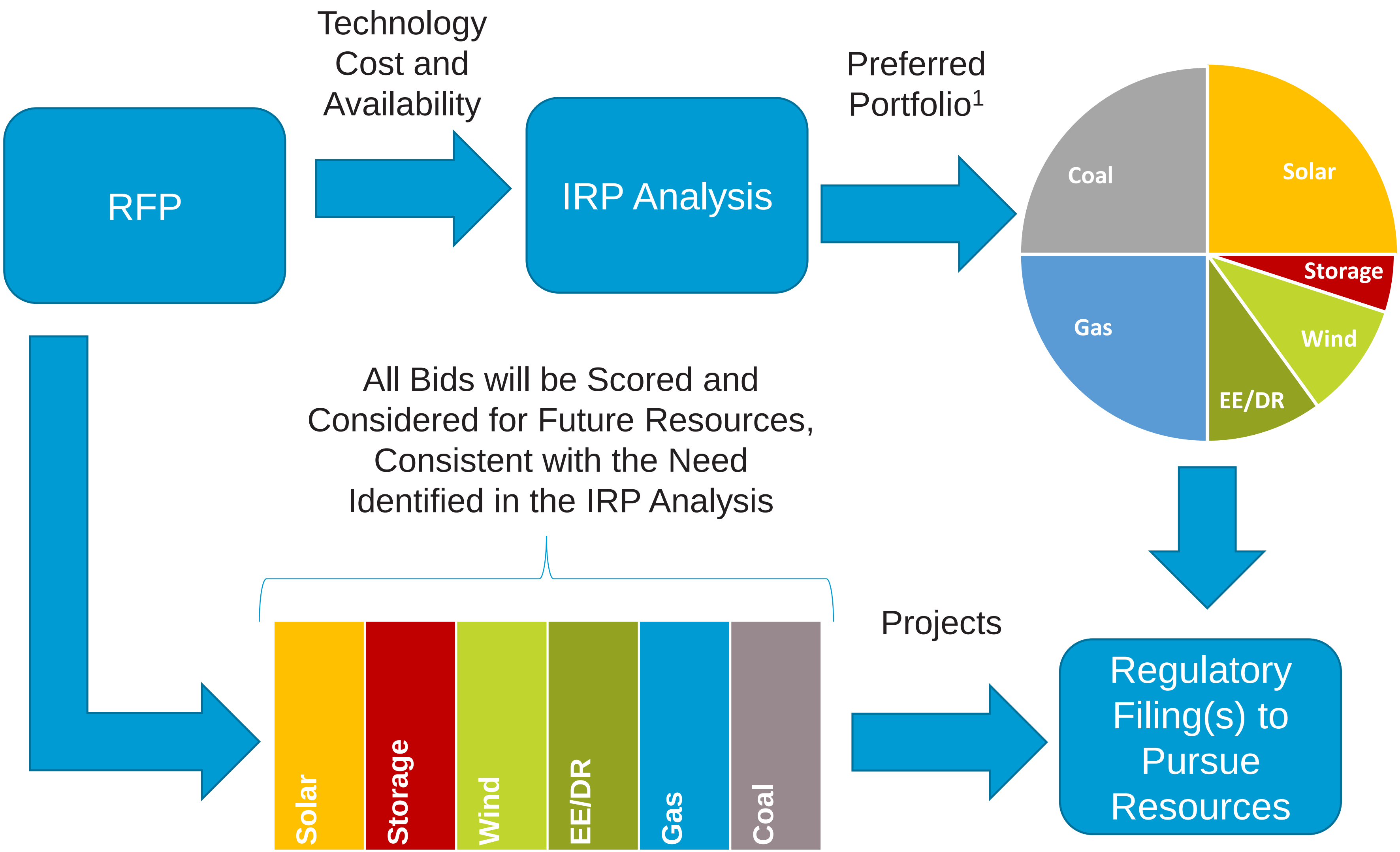
Vectren will continue to work towards the remaining commitments over the next several months

- Providing a data release schedule and provide modeling data ahead of filing for evaluation
- Striving to make every encounter meaningful for stakeholders and for us
- Ensuring the IRP process informs the selection of the preferred portfolio
- Modeling more resources simultaneously
- Testing a wide range of portfolios in scenario modeling and ultimately in the risk analysis
- Conducting a sensitivity analysis
- Including information presented for multiple audiences (technical and non-technical)

# PROPOSED 2019/2020 IRP PROCESS

1. Conduct an All Source RFP
2. Create Objectives, Risk Perspectives and Scorecard Development
3. Create Base Case Assumptions and Scenario Development
4. Portfolio Development Based on Various Strategies, Utilizing Optimization to Create a Wide Range of Portfolios and Refine with All Source RFP Data
5. Portfolio Testing in Scenarios, Focused on Potential Regulatory Risks
6. Portfolio Testing Using Probabilistic Modeling of 200 Potential Futures
7. Utilize the Probabilistic Modeling to Conduct Sensitivity Analysis
8. Populate the Risk Scorecard that was Developed Early in the Process and Evaluate Portfolios
9. Select the Preferred Portfolio

# REVIEW ROLE OF THE ALL SOURCE RFP




1 Illustrative example

# STAKEHOLDER FEEDBACK

| Request | Response |
| --- | --- |
| Scenario: Update the High Regulatory scenario to include a carbon dividend. Concern was expressed that the economic outlook would not necessarily grow worse under a high CO2 tax scenario. | Economic outlook is correlated with the load forecast. We have updated the High Regulatory scenario load forecast direction from lower than the base case forecast to equal with the base. The High Regulatory scenario includes other regulations, which we assume will net out any positive impact created from a carbon dividend. |
| Scenario: Update a scenario to have renewables costs lower than the base due to innovation and removal of waste from the value chain. The example provided was that the price of laptops declined as demand went up. | We have updated the 80% $CO_2$ Reduction and the High Regulatory scenarios to be lower cost than base. |
| Modeling: Options to view Aurora modeling files. Additionally, provide an understanding of “industry-supplied data” Include these modeling assumptions. | Read only copy of Aurora costs $5k and includes a help function and basic self learning slides. Additionally, we will provide Aurora release notes to those that request and sign an NDA. |
| Portfolio development: Fully explore the use of hydro resources, given Vectren’s proximity to the Ohio River. | Vectren reviewed available materials provided to better understand/compare to our technology assessment provided by Burns and McDonnell. While we did not receive a bid and costs are high, hydro could be included within portfolio development. |

# STAKEHOLDER FEEDBACK CONT.

| Request | Response |
|---|---|
| Scorecard: Update Environmental Risk Minimization measure to report $CO_2$ equivalent and consider utilizing life cycle emissions by electric generation technology | Utilize NREL Life Cycle Greenhouse Gas Emissions (upstream and downstream) from Electricity Generation by resource analysis. NREL $CO_2$e rates per MWh will be applied to both retail sales covered by Vectren portfolios, as well as a $CO_2$e emissions estimate when relying on the market. |
| Scorecard: Consider sunk costs in Future Flexibility measure. Change basis from MWhs of impairment by asset to $ to better reflect uneconomic asset risk | Will update this measure to reflect dollars. Will measure when costs to run an asset do not cover energy and capacity revenues in three consecutive years. Methodology will be described later in this presentation. |
| Scorecard: Market Risk Minimization metric bounds of 15% rational needs to be described. | We reviewed the +/-15% deadband for energy and capacity market purchases for reasonableness and feel this is a reasonable assumption. We will discuss again today. |
| RFP/IRP costs: Concern was expressed that we could lose opportunities to include low cost resources within Integrated Resource Plan (IRP) modeling if we only include Request for Proposals bids with a delivered cost. | For modeling, we will include firm bids on our system and those with a delivered cost. Additionally, Burns and McDonnell will review other bids and assess potential congestion costs. Such evaluated resources (including congestion estimate) may also be included within IRP modeling. |

# STAKEHOLDER FEEDBACK CONT.

| Request | Response |
| --- | --- |
| Scenarios: Include an RPS standard scenario. | There are several mandates that could be imposed in the future, from renewables interests to coal interests. The primary purpose of scenarios in this IRP will be to help determine how portfolios perform in various future states. We would like your feedback on portfolio development. We can develop various portfolios utilizing an RPS, coal portfolio mandate, etc. within the model. The performance of these portfolios will be assessed within the scenarios and probabilistic modeling. |
| Scorecard: Include a health benefits measure. | We reviewed a recent EPA report titled "Public Health Benefits per kWh of Energy Efficiency and Renewable Energy in the United States: A Technical Report[1]," which included a screening level estimate of Benefits-per-KWh value for EE, wind, and solar projects. The report noted that there are no comprehensive national studies available with data of this kind. Values from this report cannot be used for this analysis as estimates are explicitly only good through 2022. |

1 Source: https://www.epa.gov/sites/production/files/2019-07/documents/bpk-report-final-508.pdf

# AURORAxmp TOOL

AURORA
BY ENERGY EXEMPLAR

VECTREN
A CenterPoint Energy Company

- AURORAxmp (Aurora) is an industry standard model for electricity production costing and market simulations
- Aurora is licensed by approximately 100 clients in North America, ranging from consultants to full-scale utilities to traders to Indiana's State Utility Forecasting Group (SUFG)
- Aurora is accepted in many regulatory jurisdictions
- Vectren will use the Aurora model in the IRP to provide the following analysis:
  - Least cost optimization of different portfolios, including decisions to build, purchase, or retire plants
  - Simulation of the performance of different portfolios under a variety of market conditions
  - Production cost modeling to provide market prices for energy
  - Emissions tracking based on unit dispatch
  - A comparative analysis of various regulatory structures
- A primary output is portfolio cost performance in terms of Net Present Value

For more information: https://energyexemplar.com/solutions/aurora/

# ACCESSING THE AURORA MODEL

VECTREN
A CenterPoint Energy Company

- A one year, read-only End User License Agreement for AURORAxmp is available for $5k from Energy Exemplar; this purchase entitles access the library of modeling presentations via the web login
- The model's Help menu features material similar to a user manual
- IRP databases would include input and output tables used in the modeling and will require an NDA with Siemens
- The model database will be available for review but Siemens will not provide any review support beyond clearly-defined naming conventions (data key)

# DRAFT SCENARIOS UPDATE

VECTREN
A CenterPoint Energy Company

Vectren has updated scenarios based on stakeholder feedback. Scenario modeling will evaluate various regulatory constructs. As a reminder, the Base Case serves as a benchmark. Alternative scenarios are shown as higher than, lower than, or the same as the Base Case

|  | $CO_2$ | Gas Reg. | Water Reg. | Economy | Load | Gas Price | Coal Price | Renewables and Storage Cost | EE Cost |
|---|---|---|---|---|---|---|---|---|---|
| Base Case | ACE | none | ELG | Base | Base | Base | Base | Base | Base |
| Low Reg. | ACE Delay** | none | ELG Light* | Higher | Higher | Higher | Base | Base | Base |
| High Tech | Low CO2 Tax | none | ELG | Higher | Higher | Lower | Lower | Lower | Lower |
| 80% $CO_2$ Reduction by 2050 | Cap and Trade | Methane | ELG | Lower | Lower | Base | Lower | Lower | Higher |
| High Reg. | High $CO_2$ Tax w/ Dividend | Fracking Ban | ELG | Base | Base | Highest (+2 SD) | Lower | Lower | Higher |

Increasing Environmental Regulation

*No bottom ash conversion required based on size of the unit and delay requirement for 2 years
**ACE Delayed for 3 years

Revised from last meeting

# SCENARIO NARRATIVES

VECTREN
A CenterPoint Energy Company

**80% $CO_2$ Reduction by 2050 (aka 2 degrees scenario)**

- This scenario assumes a carbon regulation mandating 80% reduction of $CO_2$ from 2005 levels by 2050 is implemented. A glide path would be set using a cap and trade system similar to the CPP, gradually ratcheting down $CO_2$ emissions and driving $CO_2$ allowance costs up.
- Load decreases as the costs for energy and backup power increase and as the energy mix transitions.
- In this scenario, regulations on methane emissions initially drive up gas prices, but are partially offset by increased supply. The price of natural gas remains on par with the Base Case.
- There is less demand for coal, driving prices lower than the Base Case; however, some large and efficient coal plants remain as large fleets are able to comply with the regulation on a fleet wide basis.
- Renewables and battery storage technology are widely implemented to help meet the mandated $CO_2$ reductions. Despite this demand, costs are lower than the Base Case due to subsidies or similar public support to address climate change.
- Market based solutions are implemented to lower $CO_2$. Innovation occurs, but is offset by more codes and standards with no incentives, energy efficiency costs rise as a result.

Revised from last meeting

# SCENARIO NARRATIVES

VECTREN
A CenterPoint Energy Company

**High Regulatory (Revised)**

- The social cost of carbon is implemented via a high $CO_2$ tax early in the scenario. Monthly rebate checks (dividend) redistribute revenues from the tax to American households based on number of people in the household.
- A fracking ban is imposed, driving up the cost of natural gas to +2 standard deviations in the long-term as supply dramatically shrinks.
- A strong decline in demand puts downward pressure on coal prices.
- The economic outlook remains at the Base Case level as any potential benefit of the CO2 dividend is offset by the drag on the economy imposed by additional regulations, including the fracking ban.
- Innovation occurs as renewables and battery storage are widely implemented to avoid paying high $CO_2$ prices, allowing costs to fall even as demand for these technologies increases.
- Utility-sponsored energy efficiency costs rise over time as the cost for regulatory compliance rises

Revised from last meeting

# IRP OBJECTIVES & MEASURES UPDATE

VECTREN
A CenterPoint Energy Company

For each resource portfolio, the objectives are tracked and measured to evaluate portfolio performance in the Base Case, in four alternative scenarios, and across a wide range of possible future market conditions. All measures of portfolio performance are based on probabilistic modeling of 200 futures.

| Objective | Measure | Unit |
|---|---|---|
| Affordability | 20-Year NPVRR | $ |
| Price Risk Minimization | 95th percentile value of NPVRR | $ |
| Environmental Risk Minimization | ~~$CO_2$ Emissions~~<br>Life Cycle Greenhouse Gas Emissions | Tons $CO_2e$ |
| Market Risk Minimization | Energy Market Purchases or Sales outside of a +/- 15% Band | % |
| | Capacity Market Purchases or Sales outside of a +/- 15% Band | % |
| Future Flexibility | ~~MWh of impairment by asset~~<br>Uneconomic Asset Risk | ~~MWh~~<br>$ |

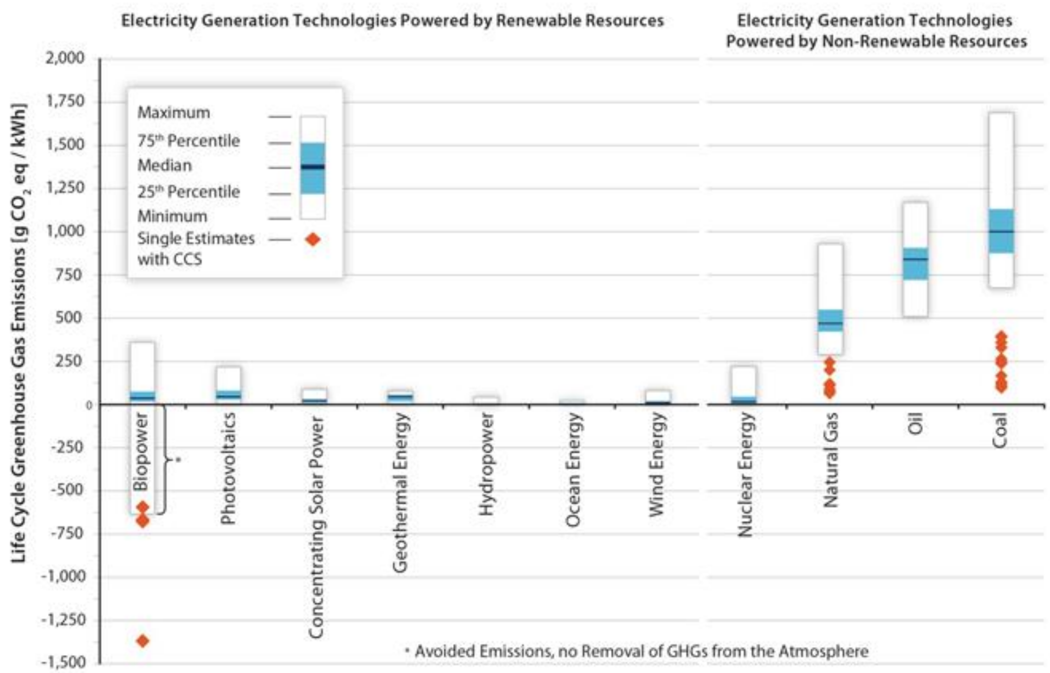
Revised from last meeting

# ENVIRONMENTAL RISK MINIMIZATION
# LIFE CYCLE GREENHOUSE GAS EMISSIONS

VECTREN
A CenterPoint Energy Company

- Stakeholders requested a Life Cycle Analysis (LCA) and $CO_2$ equivalent on the scorecard
- LCA can help determine environmental burdens from "cradle to grave" and facilitate more consistent comparisons of energy technologies, including upstream, fuel cycle, operation, and downstream emissions
- NREL conducted a systematic review[1] of 2,100 life cycle greenhouse gas emissions studies for electricity generating technologies and screened down the list to about 300 credible references

## Life Cycle GHG Emissions




| | Biopower | Photovoltaics | Concentrating Solar Power | Geothermal Energy | Hydropower | Ocean Energy | Wind Energy | Nuclear Energy | Natural Gas | Oil | Coal |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Count of Estimates | 222(+4) | 124 | 36 | 8 | 28 | 10 | 126 | 125 | 83(+7) | 24 | 169(+12) |
| Count of References | 52(+0) | 26 | 10 | 6 | 11 | 5 | 49 | 32 | 36(+4) | 10 | 50(+10) |

NREL NATIONAL RENEWABLE ENERGY LABORATORY

ipcc INTERGOVERNMENTAL PANEL ON climate change

1 Source: https://www.nrel.gov/analysis/life-cycle-assessment.html

# ENVIRONMENTAL RISK MINIMIZATION
# LIFE CYCLE GHG EMISSIONS CONTINUED…

VECTREN
A CenterPoint Energy Company

- NREL utilizes median values[2] listed in the table to the right for life cycle analyses
- We plan to apply NREL rates (g $CO_2$e/kWh) to simulated portfolio generation emissions to serve retail load using specific technology rates
- In order to obtain a full picture of emissions, we must also estimate total emissions when customer load is being served by the market using the market rates and an average buildout of resources based on the MISO Transmission Expansion Plan (MTEP)
- Total $CO_2$ equivalent will be calculated for each portfolio based on emissions it generates and emissions generated from reliance on the market

**Life Cycle GHG Emissions[1]**
**(grams of $CO_2$e per kWh)**

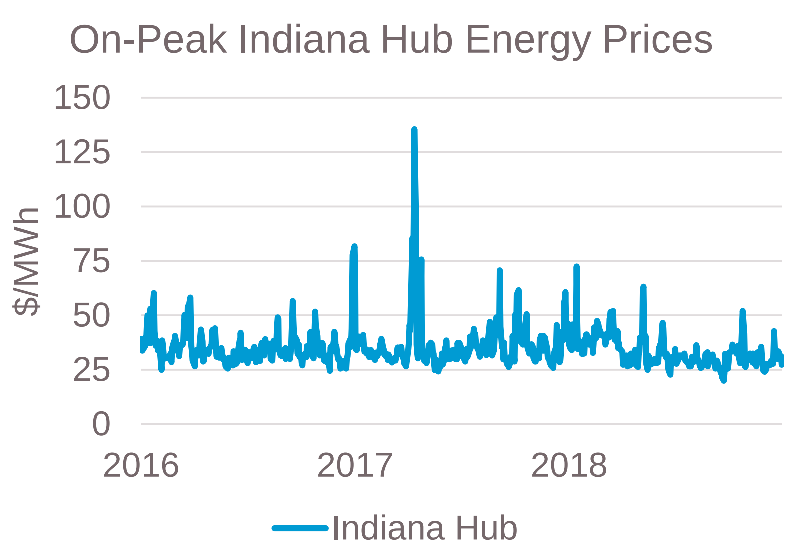
| | Specific Technology | Market |
|---|---|---|
| All Coal | | 1,002 |
| Sub Critical | 1,062 | |
| Super Critical | 863 | |
| All Gas | | 474 |
| Gas CT | 599 | |
| Gas CC[3] | 481 | |
| All Nuclear | | 16 |
| Onshore Wind | 12 | 12 |
| All PV | | 54 |
| Thin Film | 35 | |
| Crystalline | 57 | |
| All hydropower | 7 | 7 |
| Bio Power | 43 | 43 |

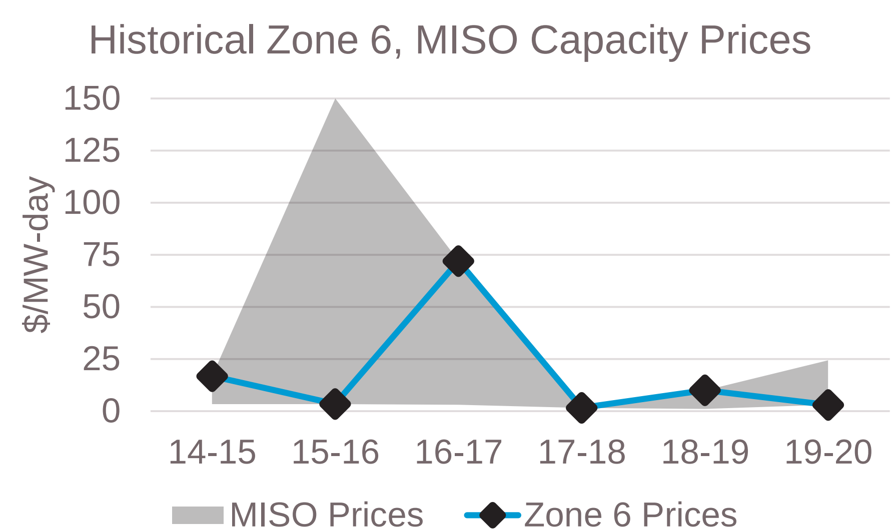
1 Battery storage was not included in the NREL report. Evaluating options for this resource.
Source: https://www.nrel.gov/analysis/life-cycle-assessment.html
2 Values derived from graphs included for each resource type.
3 Assumes 70% shale gas, 30% conventional

# +/-15% ENERGY AND CAPACITY PURCHASES AND SALES BAND JUSTIFICATION

- Market transactions carry the risk for Vectren of buying when prices are high and selling when price are low.
- Vectren energy purchases are 1-2% of regional volumes* and 10-30% below regional prices for similar long-term transactions. On-peak power prices demonstrate ongoing volatility. To reduce exposure to this risk, we seek to minimize net energy sales and purchases  to +/-15% of annual total sales.
- Capacity prices also fluctuate broadly in MISO and Zone 6 (Indiana). Exposure to price swings should be minimized to a range of +/-15% around forecasted demand.

| Reliability First Corporation 2018 Energy Purchases by Contract Type (GWh) | |
|---|---|
| Short-Term | 23,700 |
| Intermediate-Term | 14,500 |
| Long-Term | 53,100 |
| of which Vectren | 750 |
| Other | 298,000 |
| Total | 389,300 |




* 2016-2018; Reliability First Corporation NERC Subregion

# UNECONOMIC ASSET RISK ANALYSIS

VECTREN
A CenterPoint Energy Company

- Following from stakeholder feedback, we changed the uneconomic asset risk objective measure from a MWh basis to a dollar cost basis
- Definition of an uneconomic asset: when going forward costs of the asset, which include annual variable costs (fuel + variable operations & maintenance or VOM + emissions) plus annual fixed operations & maintenance or FOM costs, are collectively greater than the total annual revenues (including both energy revenues and capacity revenues) in three successive years. By equation:

$$\textit{Going Forward Costs}\left(\frac{\$}{kW-yr}\right)=\frac{[VOM+Fuel+Emissions+FOM]\left(\frac{\$}{yr}\right)}{\textit{Nameplate Capacity}\ (kW)}$$

- We then identify in each stochastic model run:
  – Year when asset is deemed uneconomic
  – Undepreciated book value as of first uneconomic year
  – Revenues less going forward costs as of first uneconomic year for each year it is negative
- The resulting cost is weighted by frequency of occurrence across the iterations

# FEEDBACK AND DISCUSSION

A CenterPoint Energy Company

# MISO CONSIDERATIONS


**JUSTIN JOINER**

VECTREN DIRECTOR OF POWER SUPPLY SERVICES

# MISO SUMMARY

- Based on feedback from the last stakeholder meeting we felt it necessary to go over some of the MISO principles and considerations Vectren must take into account during the IRP process.
- This section is aimed at conveying four main points:
  - 1) MISO ensures low cost and reliable energy by enforcing market and planning rules that its members must adhere to; specifically:
    - Sufficient capacity to meet peak load
    - Adequate transmission to deliver the energy
  - 2) These rules focus on generator cost and ability to reach needed load; if the generation is not cost efficient or it can not be safely delivered on the MISO transmission system, MISO will not dispatch it
  - 3) MISO is undergoing a changing resource mix that has led to an increase in emergency events and a review of accrediting resources
  - 4) Because of these principles Vectren must fully evaluate the transmission components of a project and the expected output and accreditation it will receive in order to accurately evaluate the cost and efficiency of a project

# WHAT IS MISO?

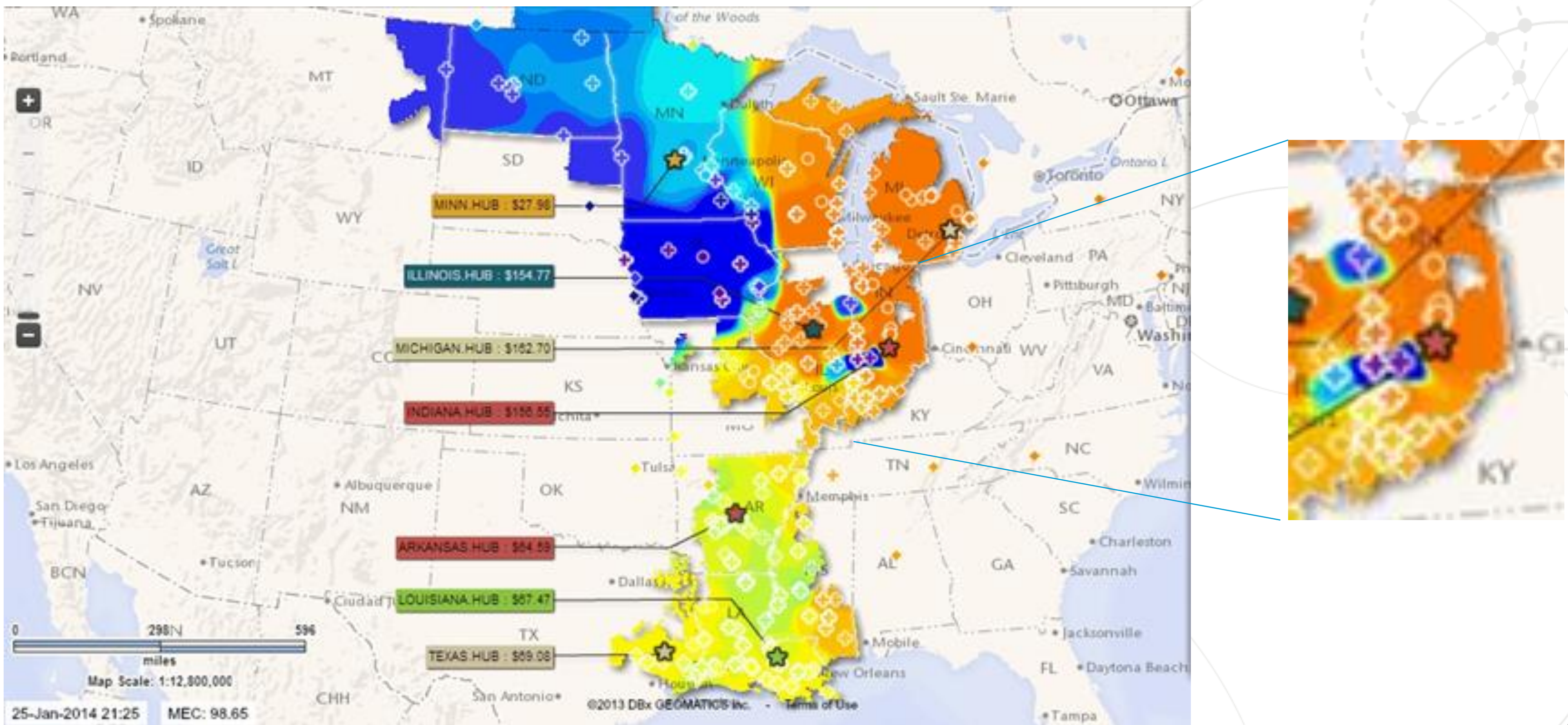
**M**idcontinent **I**ndependent Transmission **S**ystem **O**perator

- In 2001, MISO was approved as the first Regional Transmission Organization (RTO)
  - MISO has operational authority: the authority to control transmission facilities and coordinate security for its region to ensure reliability
  - MISO is responsible for dispatch of lowest cost generation units: MISO's energy market dispatches the most cost effective generation to meet load needs
- MISO is divided into 11 Local Resources Zones (LRZ), Indiana is part of Zone 6, which includes northwest Kentucky (Big Rivers Electric Cooperative)
- Each LRZ has its own planning requirements in regards to energy and capacity
- Each Zone's ability to rely on neighboring Zones depends largely on transmission infrastructure. Based on MISO's Local Clearing Requirement (LCR), approximately 70% of Vectren's generation must be physically located within MISO Zone 6

Source: MISO

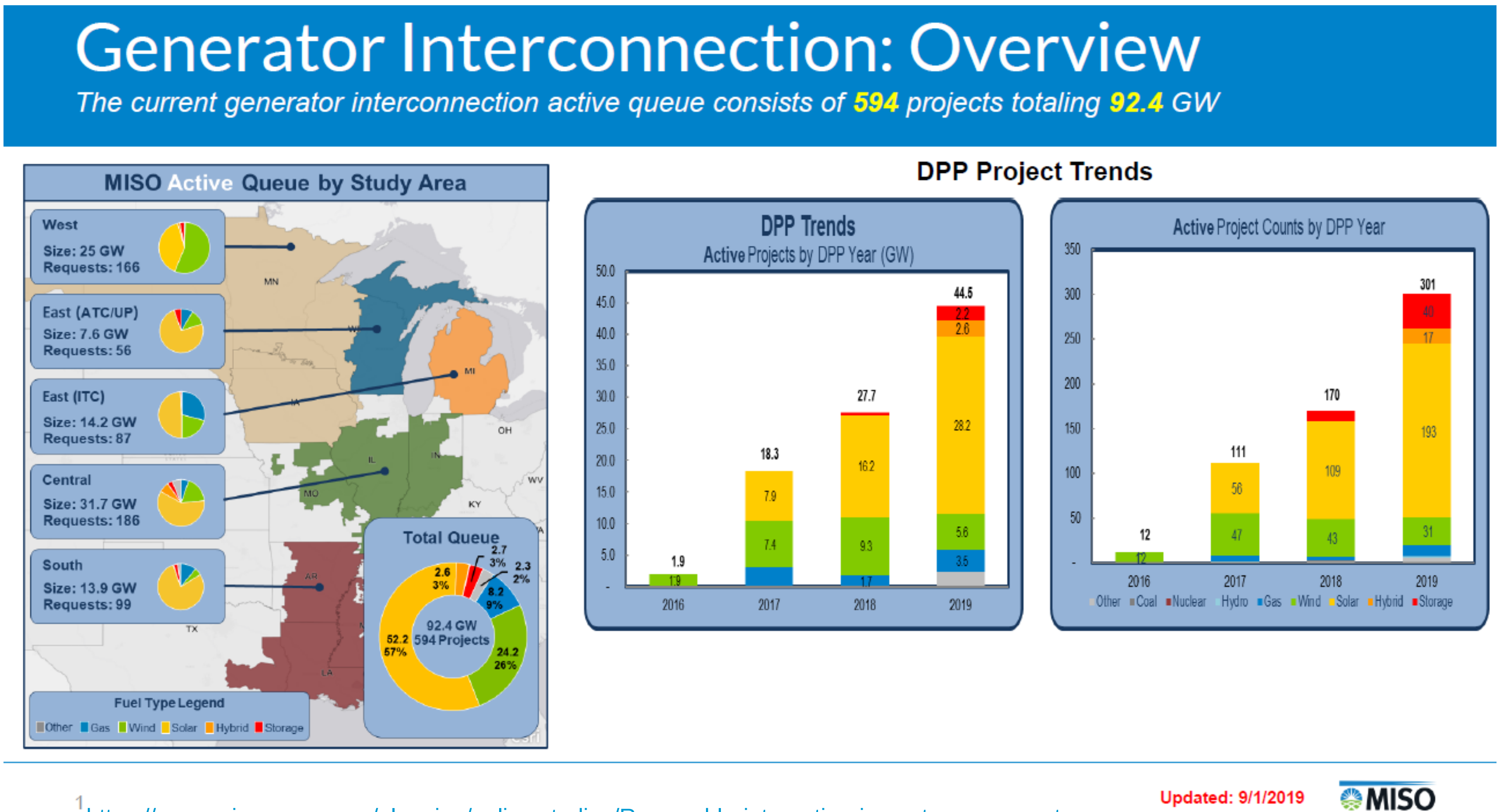
# CONGESTION

- Congestion on the MISO system during a period when energy in MN was $27.98 while at that same time energy in IN was $156.55; thereby, generators in MN received $128.57 less than load was paying in IN
  - Vectren experiences price separation for wind resource power purchase agreements within IN zone 6
  - Throughout the year there is a $5 price spread that magnifies over night during periods of low load
- Important consideration for long-term energy supplies as over time and depending on transmission build-out, generation retirements and additions and congestion could change the economics and reliability of a project



# MISO INTERCONNECTION SNAPSHOT

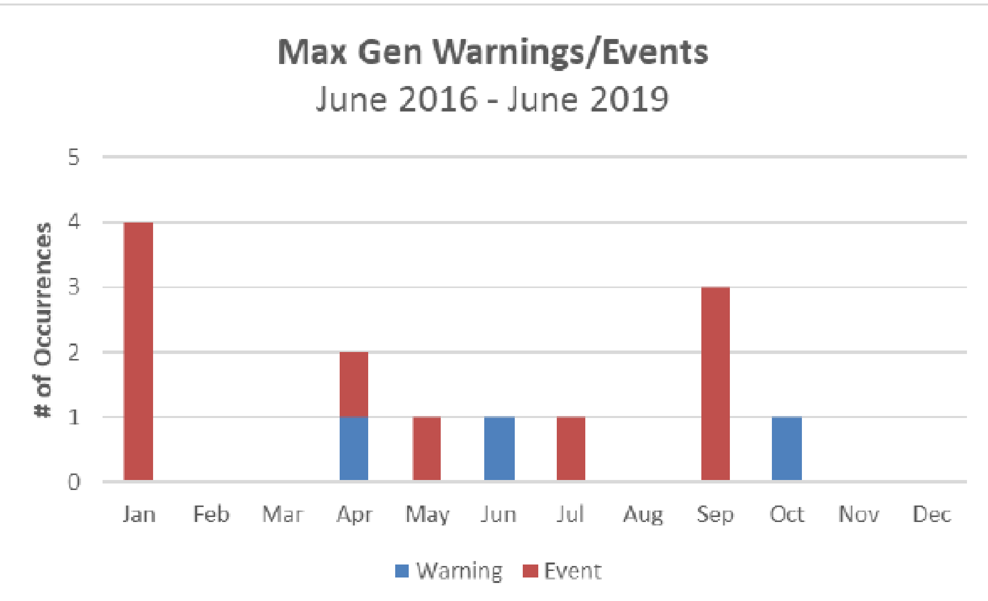
- Lengthy process that involves studies that are susceptible to many variables and cost allocation based on position in queue
- MISO Interconnection is predominantly composed of renewables (76%), followed by natural gas
- MISO's Renewable Integration Impact Assessment[1] is studying system impacts as renewables penetrate the grid and has determined that significant transmission upgrades will be necessary to reach 30% to 40% renewable penetration levels; this could lead to additional and substantial transmission investment




[1] https://www.misoenergy.org/planning/policy-studies/Renewable-integration-impact-assessment

# MISO RESOURCE AVAILABILITY AND NEED (RAN) INITIATIVE

- Less capacity and lower generator availability have led to tighter operating conditions in all four seasons
- MISO has experienced 10 Max Generation Events in the last 4 years; a Max Gen Event used to occur once every couple years
- As such, the RAN Initiative is to ensure resource accreditation aligns with actual available generation throughout the year




| Year | Warnings* | Events | Total |
|---|---|---|---|
| 2009 | 0 | 0 | 0 |
| 2010 | 0 | 0 | 0 |
| 2011 | 0 | 1 | 1 |
| 2012 | 2 | 1 | 3 |
| 2013 | 0 | 0 | 0 |
| 2014 | 1 | 1 | 2 |
| 2015 | 0 | 0 | 0 |
| 2016 | 1 | 1 | 2 |
| 2017 | 1 | 3 | 4 |
| 2018 | 0 | 3 | 3 |
| 2019 | 1 | 3 | 4 |
| Total | 6 | 13 | 19 |

4

*Warnings occurring on the same day as an Event are not included

https://www.misoenergy.org/stakeholder-engagement/issue-tracking/resource-availability-and-need-ran/

# ALL MISO CONSIDERATIONS NEED TO BE ACCOUNTED FOR DURING THE IRP

- Due to MISO planning requirements being based on NERC reliability standards, generator location is an important consideration
- Location is also an important consideration from a financial perspective as congestion can add or reduce considerable costs to delivered energy costs
- Furthermore, a changing resource mix in MISO has led to an increase in emergency events and a review of accrediting resources
- The IRP must review and consider actual energy sources and not simply financial representations or obligations
  - Energy must be deliverable from a congestion standpoint and must be interconnected to the MISO transmission system
  - Energy credits from projects not connected to MISO will not provide needed low-cost energy to meet our customer needs during peak conditions
  - A seasonal construct will change the expected capacity credit for generating resources and the benefit Vectren customers can receive from a project
- Due to these multiple and complex considerations, we must carefully review all RFP responses and resource mixes in order to meet MISO requirements and appropriately value the costs and benefits of projects

# FEEDBACK AND DISCUSSION

# SCENARIO MODELING INPUTS

**GARY VICINUS**

MANAGING DIRECTOR FOR UTILITIES, PACE GLOBAL

# SUMMARY

- Pace Global utilized the qualitative draft scenarios discussed in the first stakeholder meeting to develop quantitative forecasts of key inputs
- Probabilistic modeling was utilized to develop higher and lower forecasts, relative to the base case for gas, $CO_2$, coal, load, and renewables/storage capital cost trajectories
- Coal and gas price forecasts have much wider ranges than the 2019 Energy Information Administration (EIA) Annual Energy Outlook (AEO)
- Note that capital cost forecasts will be adjusted to reflect RFP results. Final capital cost forecasts will be shared in the third public stakeholder meeting

# SCENARIO MODELING

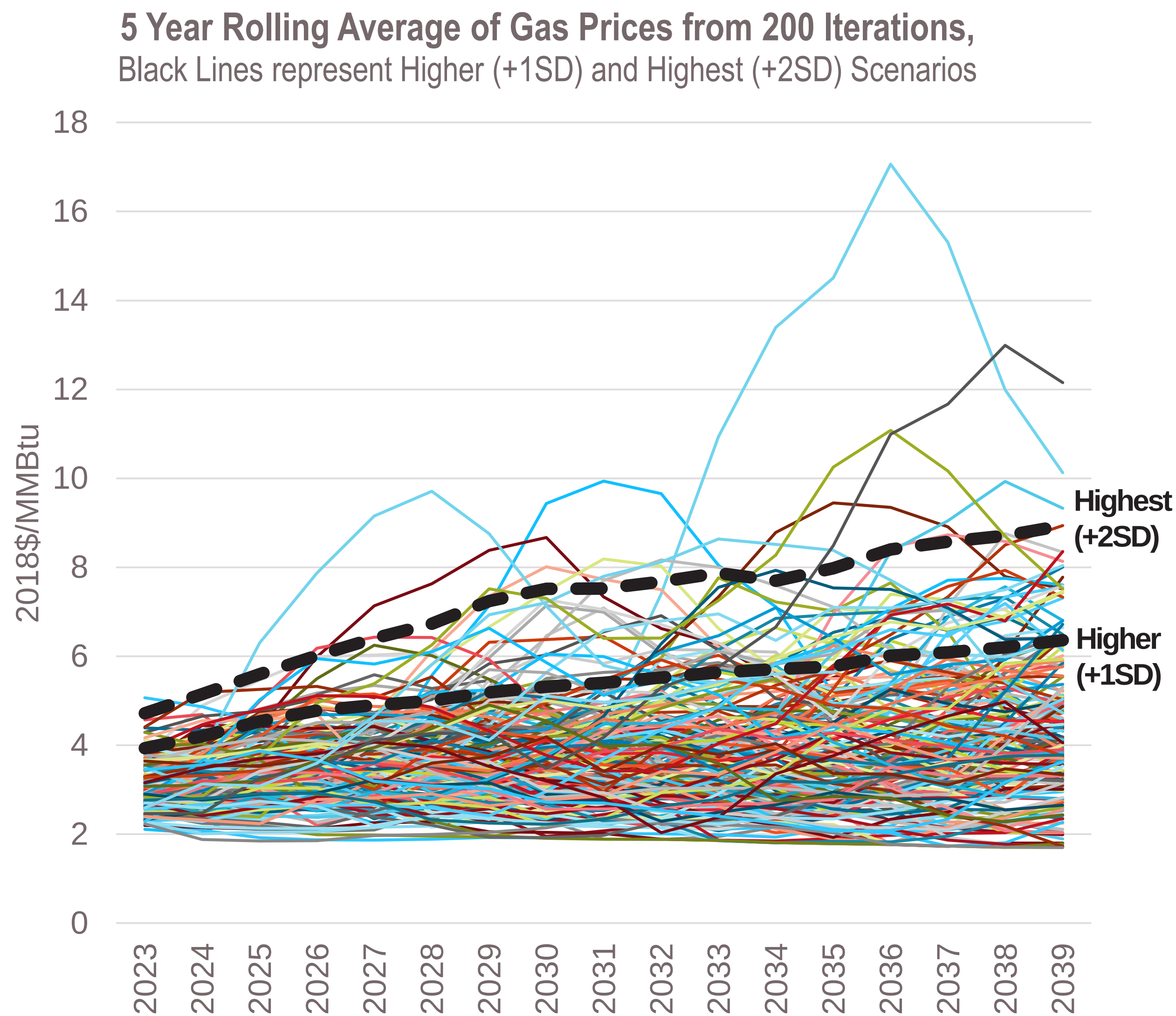
- In addition to the Base Case, four scenarios are being modeled. This will result in a least cost portfolio for each of the five cases. Additional portfolios will be developed beginning with today's stakeholder breakout session
- The Base Case inputs were shown in the first stakeholder presentation. To develop the scenario inputs, we begin with Base Case inputs and then shift into base, higher and lower ranges
- The higher and lower ranges are developed using a Monte Carlo (referred to as probabilistic or stochastic) simulation that creates 200 future paths for each variable
- A Base Case and Scenarios Assumptions Book in Excel format will be made available to intervenors
- Scenario data sheets included in the Appendix

# PROBABILISTIC MODELING

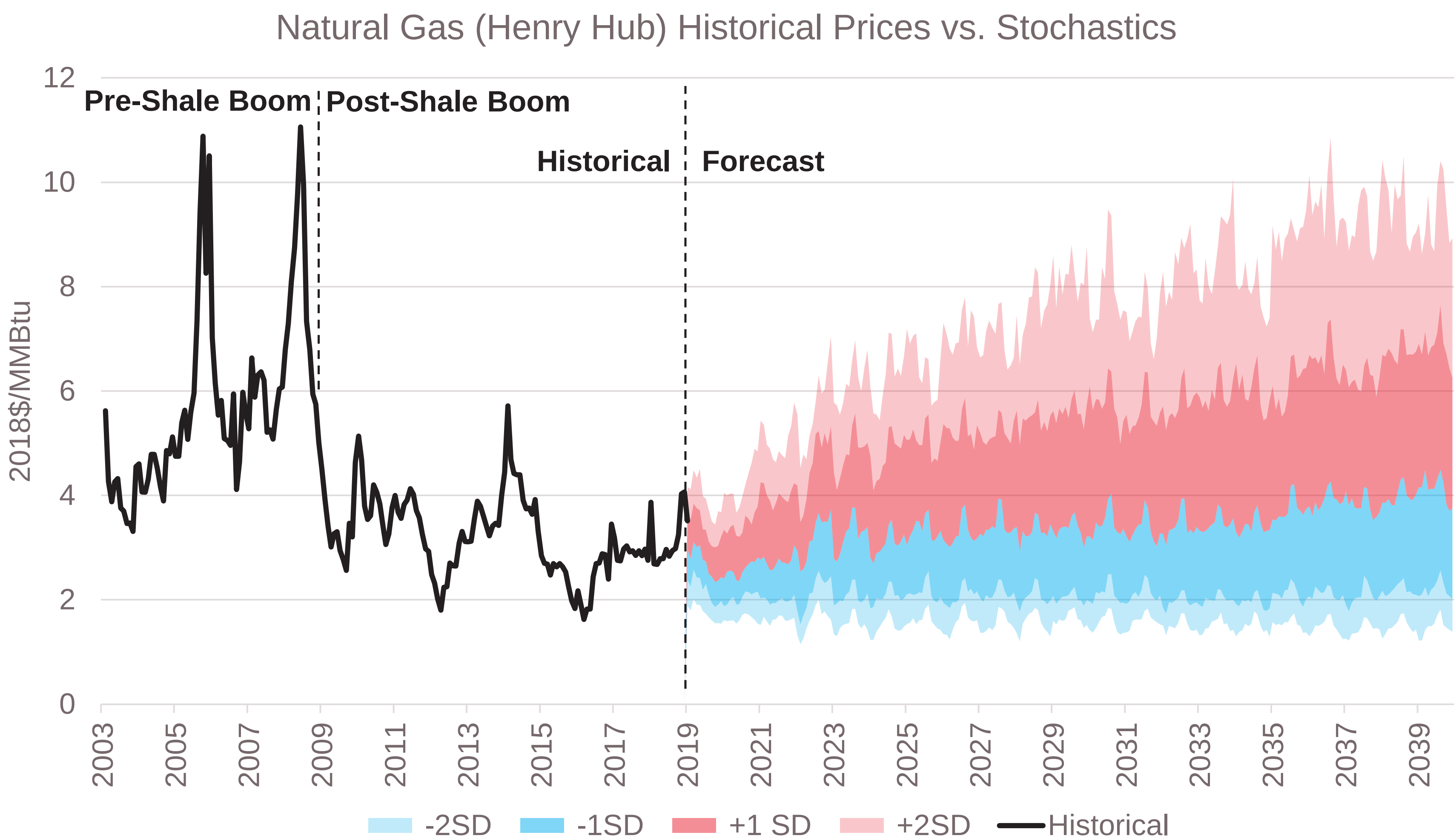
- Probabilistic modeling helps to measure risk from two hundred potential future paths for each stochastic variable
- These iterations provide percentile bands that can be used to measure the probability that a variable will be above (or below) a given percentile in a given time period and relative to the Base Case
  - For +1 Standard Deviation (+1SD) in a normal distribution, it is 84.2%
  - For -1 Standard Deviation (-1SD) in a normal distribution, it is 15.8%
  - For +2 or -2 SD, it is 97.8% and 2.2%, respectively
- Scenarios are assumed to remain the same as the Base Case in the short-term (2019-2021). In the medium-term (2022-2028), they grow or decline to +/-1SD or (+/-2SD) by 2025 (midpoint of medium-term). After 2025, the variable stays at +/-1SD (or +/-2SD) into the long-term to 2039
- Because our price path remains at the one (or two) standard deviation(s) path for the entire planning horizon, these levels have a low probability and are very conservative

# PROBABILISTIC MODELING CONT.

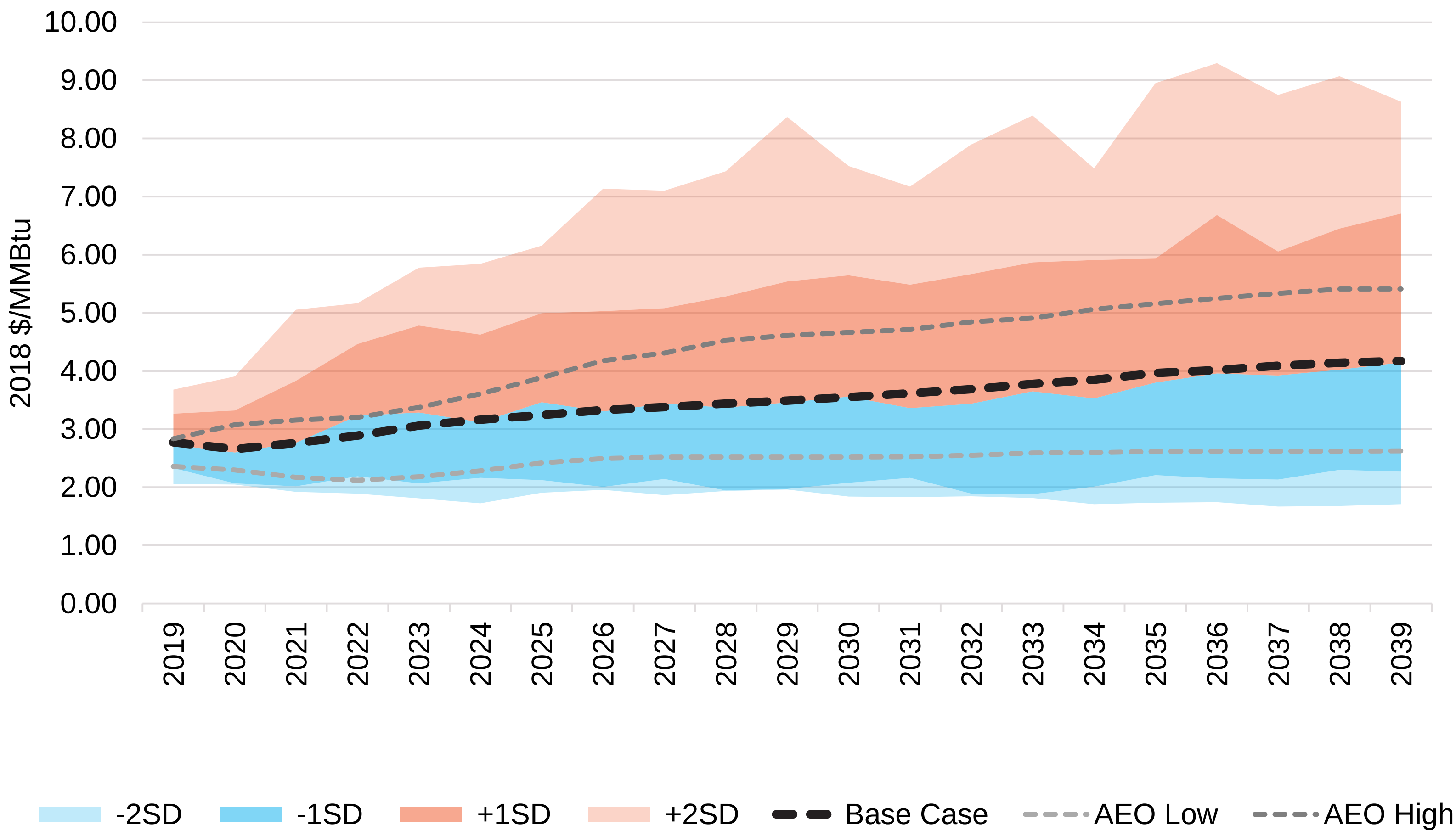
- This spaghetti diagram shows a 5-year rolling average of all 200 gas price iterations against the Higher and Highest gas price scenarios.
- In any given year, about 16% of prices are above the Higher line and about 2% are above the Highest line.
- Looking at the 20 year price average, about 7% of the 200 iterations were above the Higher line and none were above the Highest line.



# HISTORICAL PRICES VS. STOCHASTICS



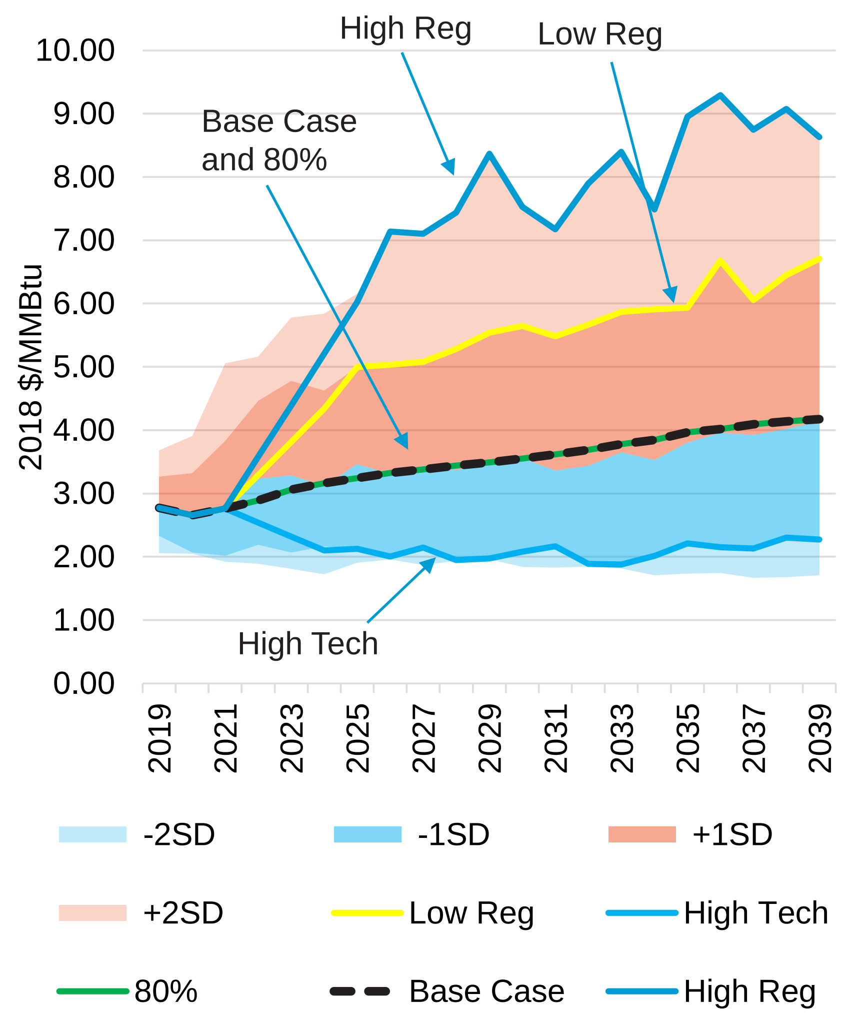
# HENRY HUB GAS PRICE DISTRIBUTIONS AND: COMPARISON TO EIA AEO[1] 2019




1Source:Energy Information Administration (EIA) Annual Energy Outlook (AEO) https://www.eia.gov/outlooks/aeo/
EIA Low = AEO 2019: High Oil & Gas Resource and Technology scenario
EIA High = AEO 2019: Low Oil & Gas Resource and Technology scenario

# SCENARIO INPUTS: NATURAL GAS HENRY HUB (2018$/MMBTU)[1]

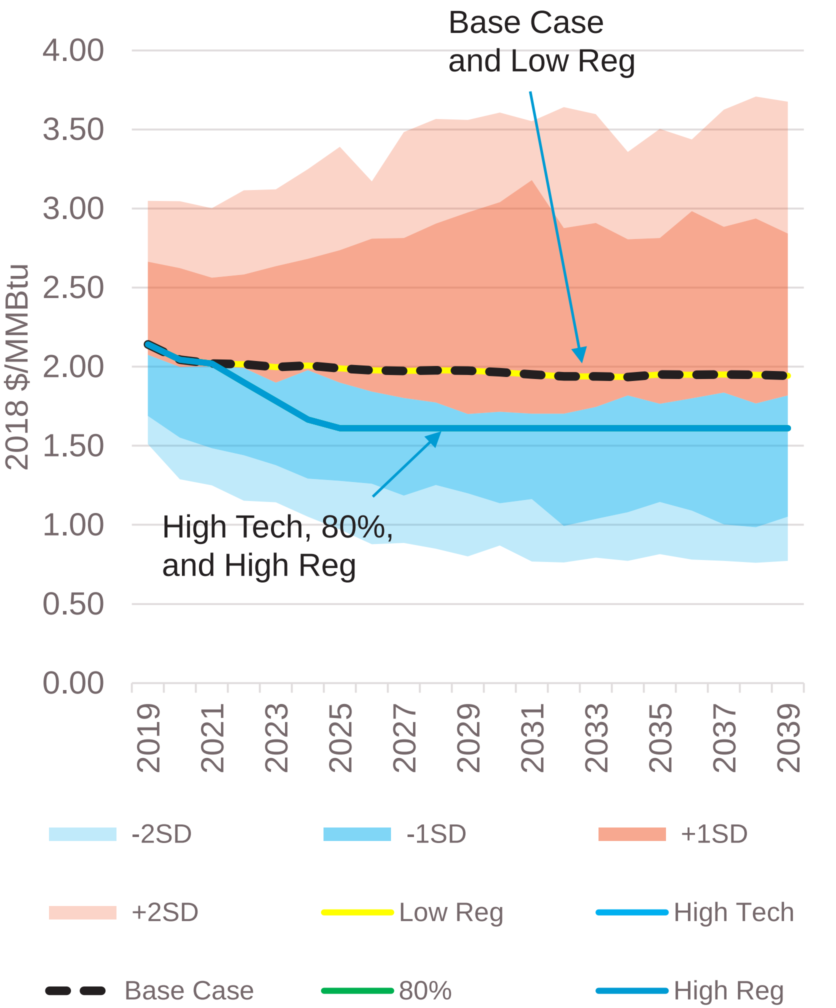
| | Base Case | Low Reg | High Tech | 80% Reduction | High Reg |
|---|---|---|---|---|---|
| 2019 | 2.77 | 2.77 | 2.77 | 2.77 | 2.77 |
| 2020 | 2.66 | 2.66 | 2.66 | 2.66 | 2.66 |
| 2021 | 2.76 | 2.76 | 2.76 | 2.76 | 2.76 |
| 2022 | 2.89 | 3.46 | 3.01 | 2.89 | 3.58 |
| 2023 | 3.06 | 4.10 | 2.82 | 3.06 | 4.39 |
| 2024 | 3.16 | 4.75 | 2.64 | 3.16 | 5.21 |
| 2025 | 3.24 | 5.12 | 2.33 | 3.24 | 6.03 |
| 2026 | 3.33 | 5.27 | 2.08 | 3.33 | 7.14 |
| 2027 | 3.38 | 5.20 | 2.13 | 3.38 | 7.10 |
| 2028 | 3.44 | 5.45 | 2.06 | 3.44 | 7.43 |
| 2029 | 3.49 | 5.62 | 2.04 | 3.49 | 8.37 |
| 2030 | 3.55 | 5.77 | 2.12 | 3.55 | 7.53 |
| 2031 | 3.62 | 5.60 | 2.13 | 3.62 | 7.17 |
| 2032 | 3.69 | 5.76 | 1.97 | 3.69 | 7.89 |
| 2033 | 3.78 | 5.95 | 2.02 | 3.78 | 8.40 |
| 2034 | 3.85 | 6.02 | 1.95 | 3.85 | 7.49 |
| 2035 | 3.96 | 6.12 | 2.12 | 3.96 | 8.95 |
| 2036 | 4.02 | 6.64 | 2.12 | 4.02 | 9.29 |
| 2037 | 4.09 | 6.23 | 2.07 | 4.09 | 8.75 |
| 2038 | 4.14 | 6.77 | 2.19 | 4.14 | 9.07 |
| 2039 | 4.17 | 6.85 | 2.20 | 4.17 | 8.63 |




1 Modeling will include estimated inflation of 2.2% per year

# SCENARIO INPUTS: ILLINOIS BASIN COAL DELIVERED TO BROWN (2018$/MMBTU) [1]

| | Base Case | Low Reg | High Tech | 80% Reduction | High Reg |
|---|---|---|---|---|---|
| 2019 | 2.14 | 2.14 | 2.14 | 2.14 | 2.14 |
| 2020 | 2.04 | 2.04 | 2.04 | 2.04 | 2.04 |
| 2021 | 2.02 | 2.02 | 2.02 | 2.02 | 2.02 |
| 2022 | 2.02 | 2.02 | 1.90 | 1.90 | 1.90 |
| 2023 | 2.00 | 2.00 | 1.78 | 1.78 | 1.78 |
| 2024 | 2.01 | 2.01 | 1.67 | 1.67 | 1.67 |
| 2025 | 1.99 | 1.99 | 1.61 | 1.61 | 1.61 |
| 2026 | 1.98 | 1.98 | 1.61 | 1.61 | 1.61 |
| 2027 | 1.97 | 1.97 | 1.61 | 1.61 | 1.61 |
| 2028 | 1.98 | 1.98 | 1.61 | 1.61 | 1.61 |
| 2029 | 1.97 | 1.97 | 1.61 | 1.61 | 1.61 |
| 2030 | 1.97 | 1.97 | 1.61 | 1.61 | 1.61 |
| 2031 | 1.95 | 1.95 | 1.61 | 1.61 | 1.61 |
| 2032 | 1.94 | 1.94 | 1.61 | 1.61 | 1.61 |
| 2033 | 1.94 | 1.94 | 1.61 | 1.61 | 1.61 |
| 2034 | 1.93 | 1.93 | 1.61 | 1.61 | 1.61 |
| 2035 | 1.95 | 1.95 | 1.61 | 1.61 | 1.61 |
| 2036 | 1.95 | 1.95 | 1.61 | 1.61 | 1.61 |
| 2037 | 1.95 | 1.95 | 1.61 | 1.61 | 1.61 |
| 2038 | 1.95 | 1.95 | 1.61 | 1.61 | 1.61 |
| 2039 | 1.94 | 1.94 | 1.61 | 1.61 | 1.61 |



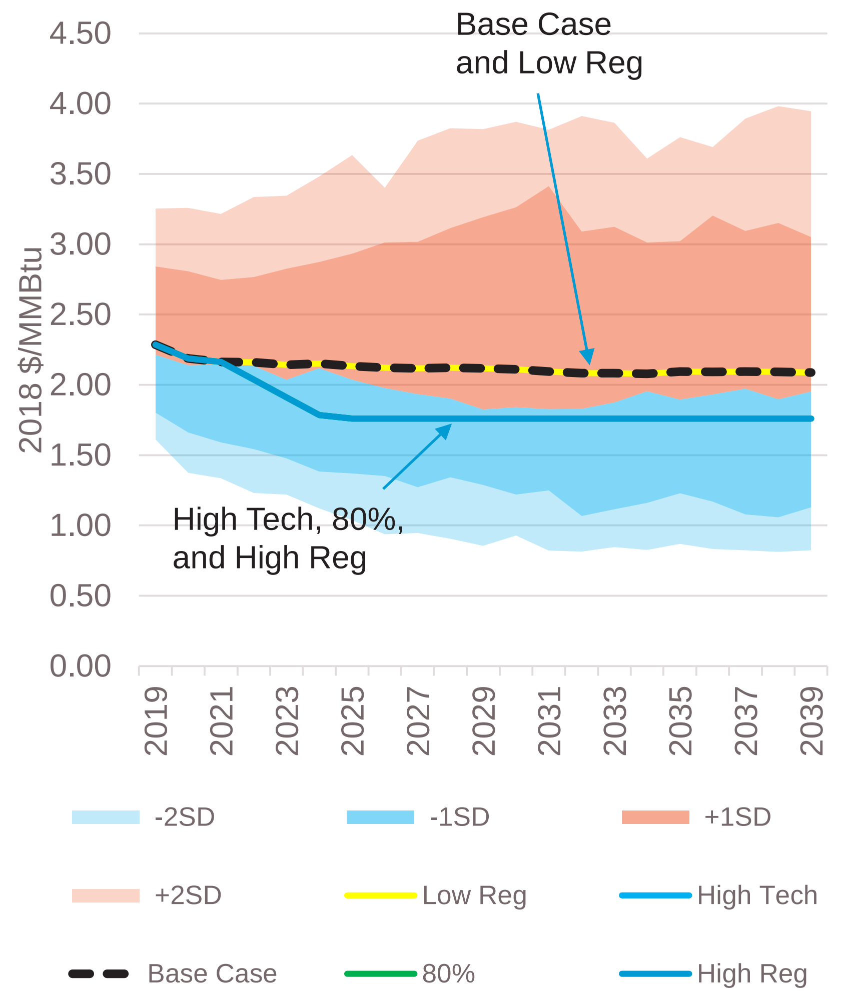

*A price floor is set at $1.61/MMBtu*

1 Modeling will include estimated inflation of 2.2% per year

# SCENARIO INPUTS: ILLINOIS BASIN COAL DELIVERED TO CULLEY (2018$/MMBTU) [1]

VECTREN
A CenterPoint Energy Company

| | Base Case | Low Reg | High Tech | 80% Reduction | High Reg |
|---|---|---|---|---|---|
| 2019 | 2.29 | 2.29 | 2.29 | 2.29 | 2.29 |
| 2020 | 2.19 | 2.19 | 2.19 | 2.19 | 2.19 |
| 2021 | 2.16 | 2.16 | 2.16 | 2.16 | 2.16 |
| 2022 | 2.16 | 2.16 | 2.04 | 2.04 | 2.04 |
| 2023 | 2.14 | 2.14 | 1.91 | 1.91 | 1.91 |
| 2024 | 2.15 | 2.15 | 1.78 | 1.78 | 1.78 |
| 2025 | 2.13 | 2.13 | 1.76 | 1.76 | 1.76 |
| 2026 | 2.12 | 2.12 | 1.76 | 1.76 | 1.76 |
| 2027 | 2.12 | 2.12 | 1.76 | 1.76 | 1.76 |
| 2028 | 2.12 | 2.12 | 1.76 | 1.76 | 1.76 |
| 2029 | 2.12 | 2.12 | 1.76 | 1.76 | 1.76 |
| 2030 | 2.11 | 2.11 | 1.76 | 1.76 | 1.76 |
| 2031 | 2.09 | 2.09 | 1.76 | 1.76 | 1.76 |
| 2032 | 2.08 | 2.08 | 1.76 | 1.76 | 1.76 |
| 2033 | 2.08 | 2.08 | 1.76 | 1.76 | 1.76 |
| 2034 | 2.08 | 2.08 | 1.76 | 1.76 | 1.76 |
| 2035 | 2.09 | 2.09 | 1.76 | 1.76 | 1.76 |
| 2036 | 2.09 | 2.09 | 1.76 | 1.76 | 1.76 |
| 2037 | 2.10 | 2.10 | 1.76 | 1.76 | 1.76 |
| 2038 | 2.09 | 2.09 | 1.76 | 1.76 | 1.76 |
| 2039 | 2.09 | 2.09 | 1.76 | 1.76 | 1.76 |

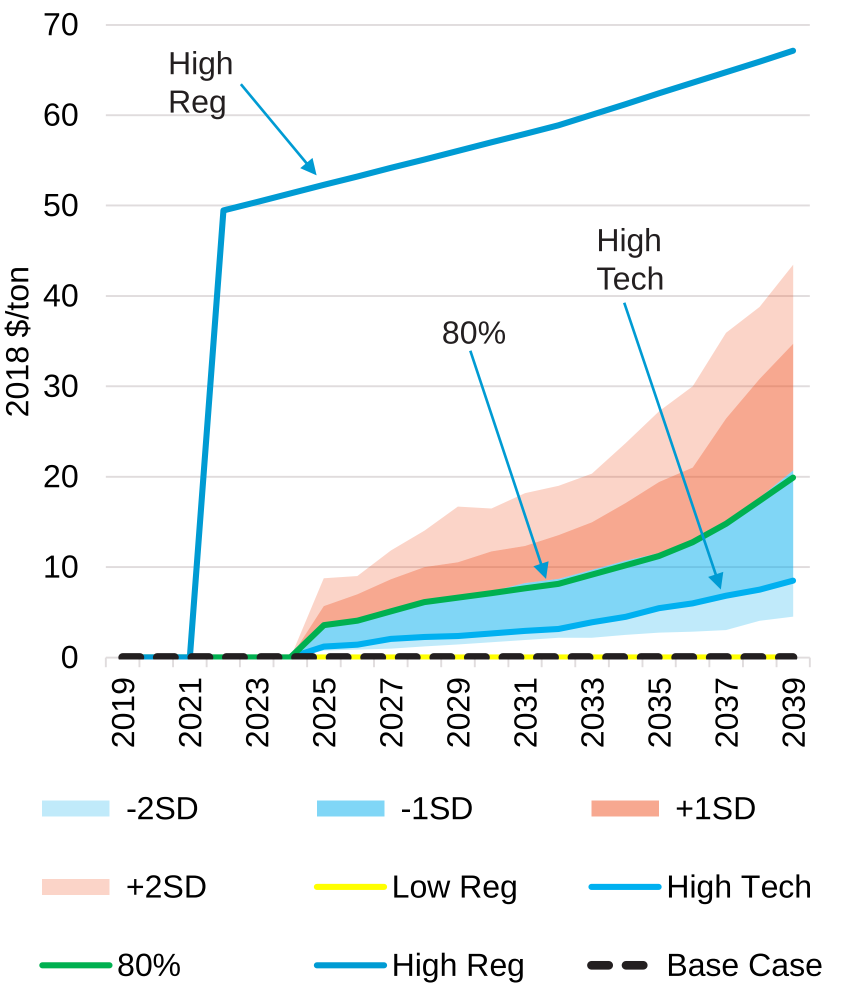



*A price floor is set at $1.76/MMBtu*

1 Modeling will include estimated inflation of 2.2% per year

# SCENARIO INPUTS: CO2 PRICE (2018$/TON) [1]

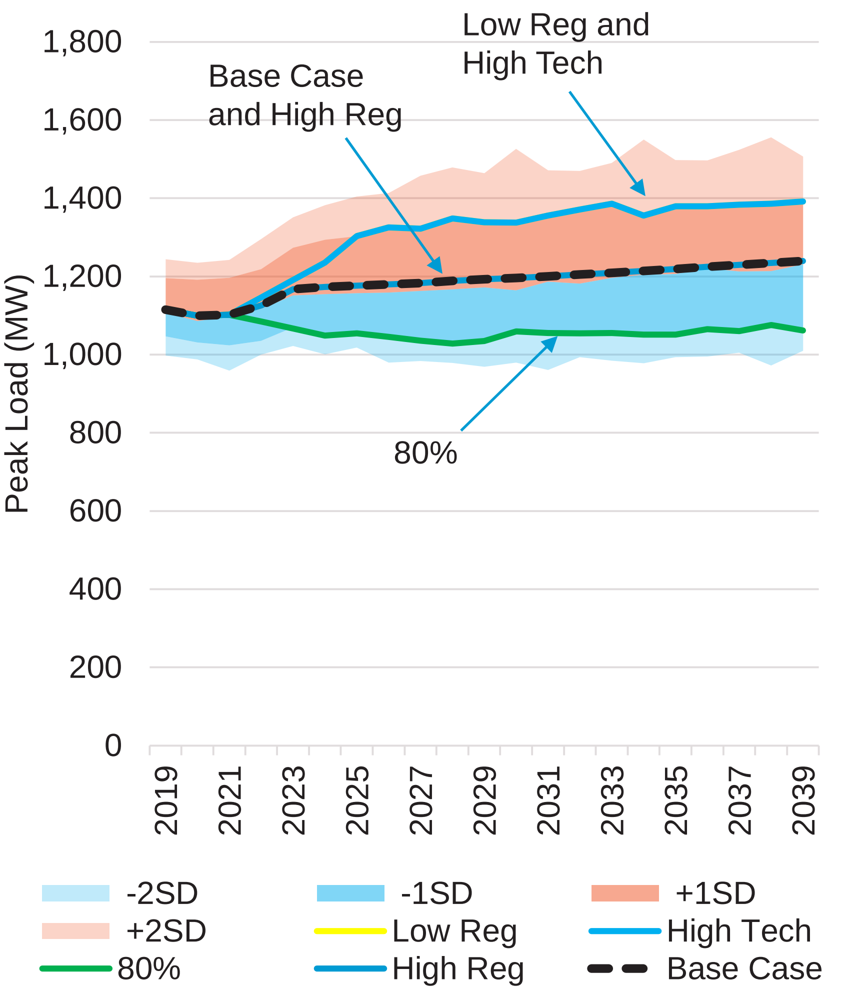
| | Base Case | Low Reg | High Tech | 80% Reduction | High Reg |
|---|---|---|---|---|---|
| 2019 | 0 | 0 | 0 | 0 | 0 |
| 2020 | 0 | 0 | 0 | 0 | 0 |
| 2021 | 0 | 0 | 0 | 0 | 0 |
| 2022 | 0 | 0 | 0 | 0 | 49.46 |
| 2023 | 0 | 0 | 0 | 0 | 50.40 |
| 2024 | 0 | 0 | 0 | 0 | 51.34 |
| 2025 | 0 | 0 | 1.20 | 3.57 | 52.28 |
| 2026 | 0 | 0 | 1.44 | 4.08 | 53.23 |
| 2027 | 0 | 0 | 2.06 | 5.10 | 54.17 |
| 2028 | 0 | 0 | 2.28 | 6.12 | 55.11 |
| 2029 | 0 | 0 | 2.38 | 6.63 | 56.05 |
| 2030 | 0 | 0 | 2.68 | 7.14 | 56.99 |
| 2031 | 0 | 0 | 2.94 | 7.65 | 57.94 |
| 2032 | 0 | 0 | 3.17 | 8.16 | 58.88 |
| 2033 | 0 | 0 | 3.89 | 9.18 | 60.06 |
| 2034 | 0 | 0 | 4.49 | 10.20 | 61.23 |
| 2035 | 0 | 0 | 5.46 | 11.22 | 62.41 |
| 2036 | 0 | 0 | 6.01 | 12.75 | 63.59 |
| 2037 | 0 | 0 | 6.85 | 14.79 | 64.77 |
| 2038 | 0 | 0 | 7.52 | 17.34 | 65.94 |
| 2039 | 0 | 0 | 8.50 | 19.89 | 67.12 |




1 Modeling will include estimated inflation of 2.2% per year

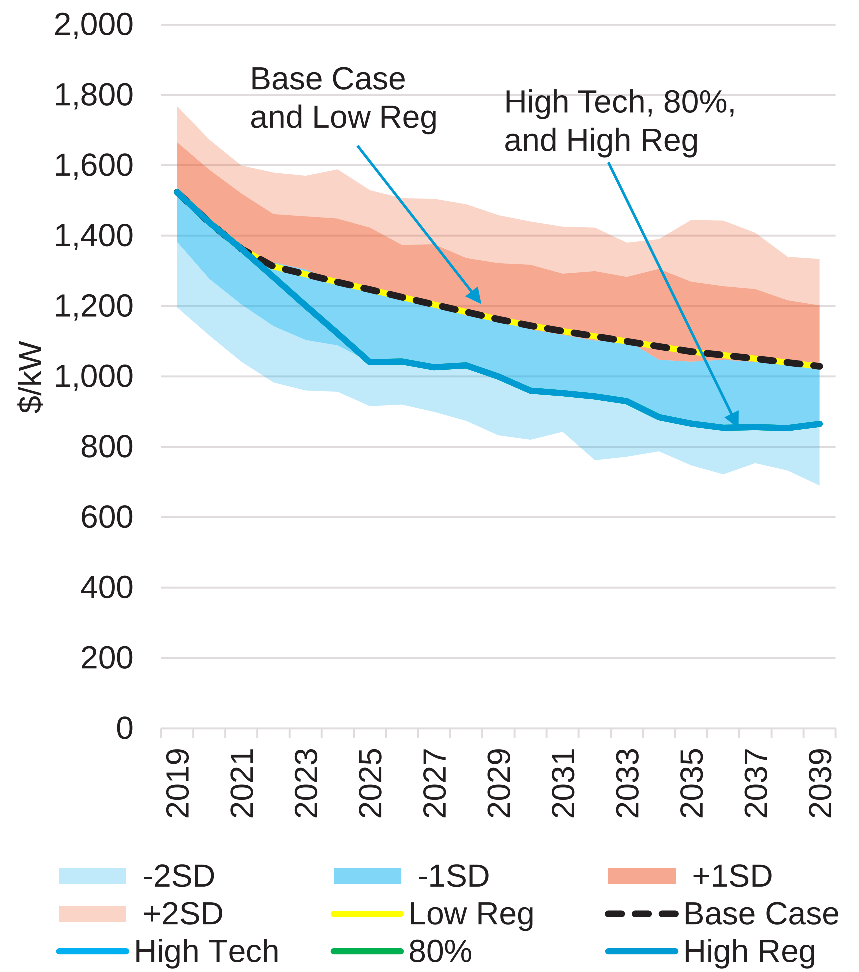
# SCENARIO INPUTS:
# VECTREN PEAK LOAD (MW)

| | Base Case | Low Reg | High Tech | 80% Reduction | High Reg |
|---|---|---|---|---|---|
| 2019 | 1,115 | 1,115 | 1,115 | 1,115 | 1,115 |
| 2020 | 1,100 | 1,100 | 1,100 | 1,100 | 1,100 |
| 2021 | 1,102 | 1,102 | 1,102 | 1,102 | 1,102 |
| 2022 | 1,126 | 1,146 | 1,146 | 1,084 | 1,126 |
| 2023 | 1,168 | 1,191 | 1,191 | 1,066 | 1,168 |
| 2024 | 1,173 | 1,235 | 1,235 | 1,049 | 1,173 |
| 2025 | 1,176 | 1,303 | 1,303 | 1,055 | 1,176 |
| 2026 | 1,179 | 1,325 | 1,325 | 1,045 | 1,179 |
| 2027 | 1,183 | 1,322 | 1,322 | 1,036 | 1,183 |
| 2028 | 1,189 | 1,348 | 1,348 | 1,028 | 1,189 |
| 2029 | 1,192 | 1,338 | 1,338 | 1,035 | 1,192 |
| 2030 | 1,196 | 1,337 | 1,337 | 1,059 | 1,196 |
| 2031 | 1,200 | 1,356 | 1,356 | 1,055 | 1,200 |
| 2032 | 1,205 | 1,371 | 1,371 | 1,055 | 1,205 |
| 2033 | 1,209 | 1,386 | 1,386 | 1,056 | 1,209 |
| 2034 | 1,214 | 1,356 | 1,356 | 1,051 | 1,214 |
| 2035 | 1,219 | 1,379 | 1,379 | 1,051 | 1,219 |
| 2036 | 1,225 | 1,379 | 1,379 | 1,065 | 1,225 |
| 2037 | 1,229 | 1,383 | 1,383 | 1,060 | 1,229 |
| 2038 | 1,234 | 1,386 | 1,386 | 1,076 | 1,234 |
| 2039 | 1,239 | 1,391 | 1,391 | 1,062 | 1,239 |



# SCENARIO INPUTS: CAPITAL COST SOLAR (100 MW) (2018$/KW) [1]

| | Base Case | Low Reg | High Tech | 80% Reduction | High Reg |
|---|---|---|---|---|---|
| 2019 | 1,524 | 1,524 | 1,524 | 1,524 | 1,524 |
| 2020 | 1,438 | 1,438 | 1,438 | 1,438 | 1,438 |
| 2021 | 1,362 | 1,362 | 1,362 | 1,362 | 1,362 |
| 2022 | 1,313 | 1,313 | 1,282 | 1,282 | 1,282 |
| 2023 | 1,290 | 1,290 | 1,202 | 1,202 | 1,202 |
| 2024 | 1,268 | 1,268 | 1,121 | 1,121 | 1,121 |
| 2025 | 1,247 | 1,247 | 1,041 | 1,041 | 1,041 |
| 2026 | 1,225 | 1,225 | 1,042 | 1,042 | 1,042 |
| 2027 | 1,204 | 1,204 | 1,026 | 1,026 | 1,026 |
| 2028 | 1,183 | 1,183 | 1,031 | 1,031 | 1,031 |
| 2029 | 1,162 | 1,162 | 999 | 999 | 999 |
| 2030 | 1,144 | 1,144 | 960 | 960 | 960 |
| 2031 | 1,129 | 1,129 | 952 | 952 | 952 |
| 2032 | 1,114 | 1,114 | 944 | 944 | 944 |
| 2033 | 1,100 | 1,100 | 929 | 929 | 929 |
| 2034 | 1,085 | 1,085 | 884 | 884 | 884 |
| 2035 | 1,070 | 1,070 | 866 | 866 | 866 |
| 2036 | 1,061 | 1,061 | 854 | 854 | 854 |
| 2037 | 1,050 | 1,050 | 856 | 856 | 856 |
| 2038 | 1,040 | 1,040 | 853 | 853 | 853 |
| 2039 | 1,029 | 1,029 | 865 | 865 | 865 |

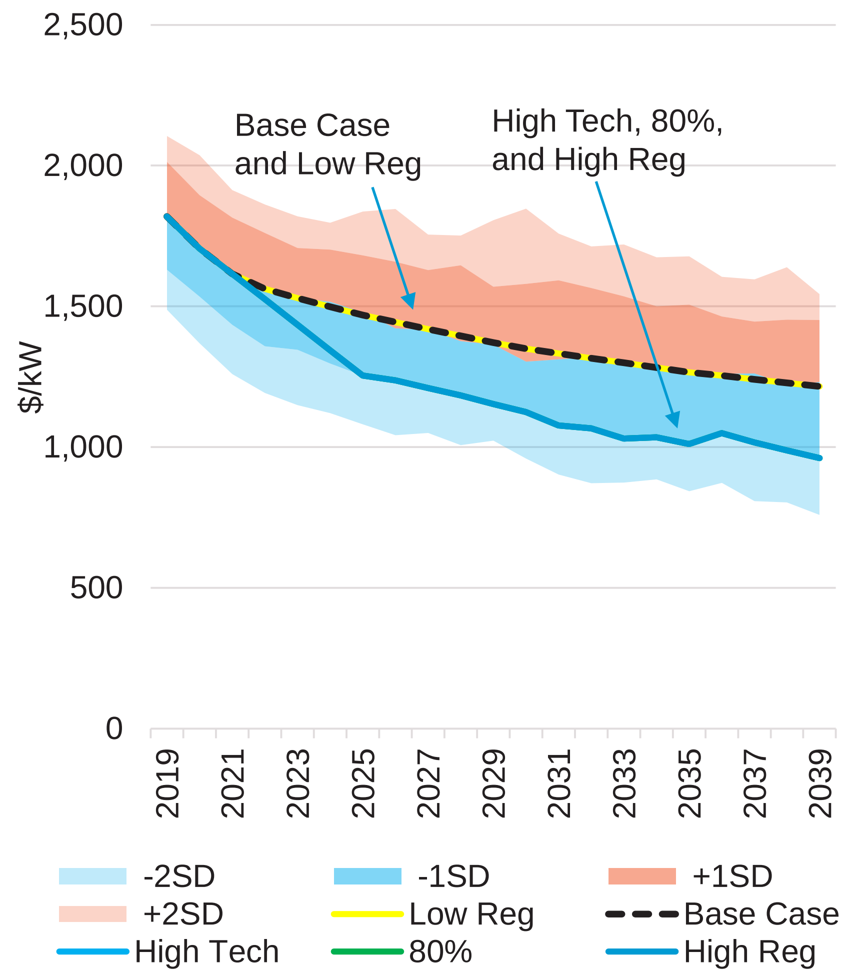



1 Modeling will include estimated inflation of 2.2% per year

# SCENARIO INPUTS: CAPITAL COST

## SOLAR+STORAGE (50 MW PV + 10 MW/ 40 MWH STORAGE) [1]

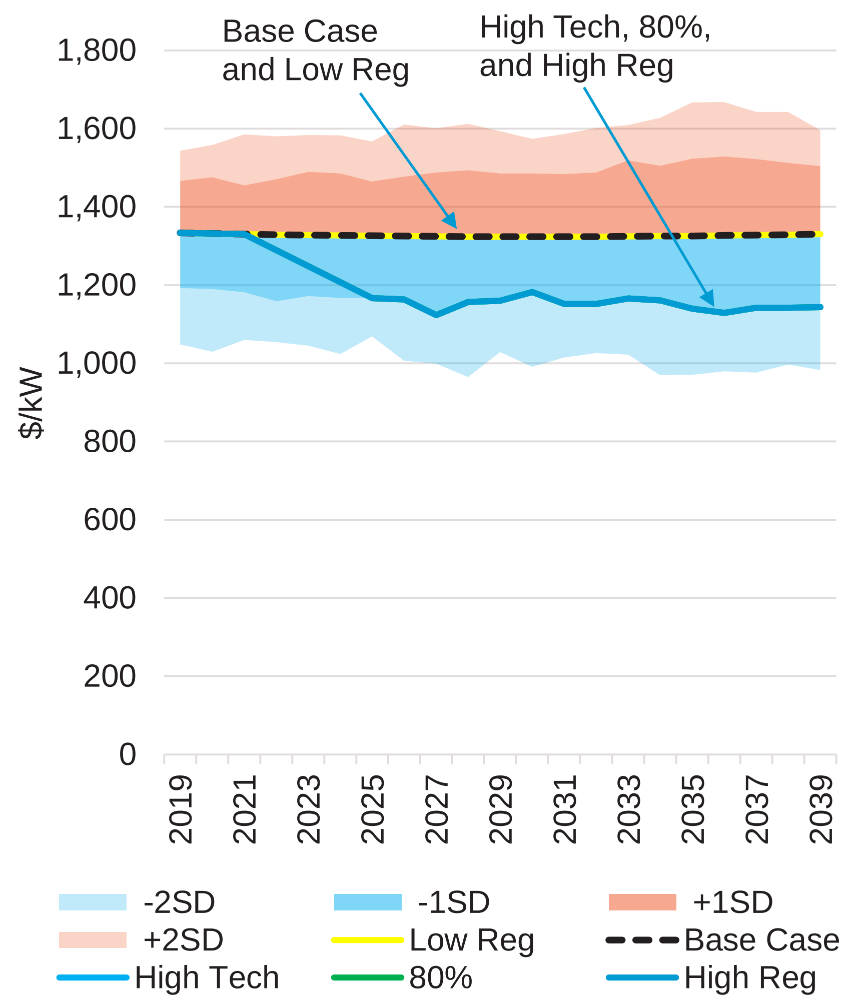
| | Base Case | Low Reg | High Tech | 80% Reduction | High Reg |
|---|---|---|---|---|---|
| 2019 | 1,820 | 1,820 | 1,820 | 1,820 | 1,820 |
| 2020 | 1,705 | 1,705 | 1,705 | 1,705 | 1,705 |
| 2021 | 1,616 | 1,616 | 1,616 | 1,616 | 1,616 |
| 2022 | 1,562 | 1,562 | 1,526 | 1,526 | 1,526 |
| 2023 | 1,529 | 1,529 | 1,435 | 1,435 | 1,435 |
| 2024 | 1,499 | 1,499 | 1,344 | 1,344 | 1,344 |
| 2025 | 1,469 | 1,469 | 1,254 | 1,254 | 1,254 |
| 2026 | 1,443 | 1,443 | 1,237 | 1,237 | 1,237 |
| 2027 | 1,419 | 1,419 | 1,210 | 1,210 | 1,210 |
| 2028 | 1,395 | 1,395 | 1,183 | 1,183 | 1,183 |
| 2029 | 1,371 | 1,371 | 1,153 | 1,153 | 1,153 |
| 2030 | 1,349 | 1,349 | 1,124 | 1,124 | 1,124 |
| 2031 | 1,332 | 1,332 | 1,077 | 1,077 | 1,077 |
| 2032 | 1,316 | 1,316 | 1,066 | 1,066 | 1,066 |
| 2033 | 1,299 | 1,299 | 1,031 | 1,031 | 1,031 |
| 2034 | 1,282 | 1,282 | 1,034 | 1,034 | 1,034 |
| 2035 | 1,266 | 1,266 | 1,011 | 1,011 | 1,011 |
| 2036 | 1,254 | 1,254 | 1,049 | 1,049 | 1,049 |
| 2037 | 1,241 | 1,241 | 1,016 | 1,016 | 1,016 |
| 2038 | 1,228 | 1,228 | 988 | 988 | 988 |
| 2039 | 1,215 | 1,215 | 961 | 961 | 961 |




1 Modeling will include estimated inflation of 2.2% per year

# SCENARIO INPUTS: CAPITAL COST WIND (200 MW) (2018$/KW) [1]

| | Base Case | Low Reg | High Tech | 80% Reduction | High Reg |
|---|---|---|---|---|---|
| 2019 | 1,334 | 1,334 | 1,334 | 1,334 | 1,334 |
| 2020 | 1,332 | 1,332 | 1,332 | 1,332 | 1,332 |
| 2021 | 1,330 | 1,330 | 1,330 | 1,330 | 1,330 |
| 2022 | 1,329 | 1,329 | 1,289 | 1,289 | 1,289 |
| 2023 | 1,328 | 1,328 | 1,249 | 1,249 | 1,249 |
| 2024 | 1,327 | 1,327 | 1,208 | 1,208 | 1,208 |
| 2025 | 1,326 | 1,326 | 1,167 | 1,167 | 1,167 |
| 2026 | 1,325 | 1,325 | 1,163 | 1,163 | 1,163 |
| 2027 | 1,324 | 1,324 | 1,123 | 1,123 | 1,123 |
| 2028 | 1,324 | 1,324 | 1,157 | 1,157 | 1,157 |
| 2029 | 1,324 | 1,324 | 1,160 | 1,160 | 1,160 |
| 2030 | 1,324 | 1,324 | 1,182 | 1,182 | 1,182 |
| 2031 | 1,324 | 1,324 | 1,152 | 1,152 | 1,152 |
| 2032 | 1,324 | 1,324 | 1,152 | 1,152 | 1,152 |
| 2033 | 1,324 | 1,324 | 1,166 | 1,166 | 1,166 |
| 2034 | 1,325 | 1,325 | 1,161 | 1,161 | 1,161 |
| 2035 | 1,326 | 1,326 | 1,139 | 1,139 | 1,139 |
| 2036 | 1,327 | 1,327 | 1,129 | 1,129 | 1,129 |
| 2037 | 1,328 | 1,328 | 1,142 | 1,142 | 1,142 |
| 2038 | 1,329 | 1,329 | 1,142 | 1,142 | 1,142 |
| 2039 | 1,330 | 1,330 | 1,143 | 1,143 | 1,143 |




1 Modeling will include estimated inflation of 2.2% per year

# FEEDBACK AND DISCUSSION

# LONG-TERM BASE ENERGY AND DEMAND FORECAST

**Michael Russo, Sr. Forecast Consultant**

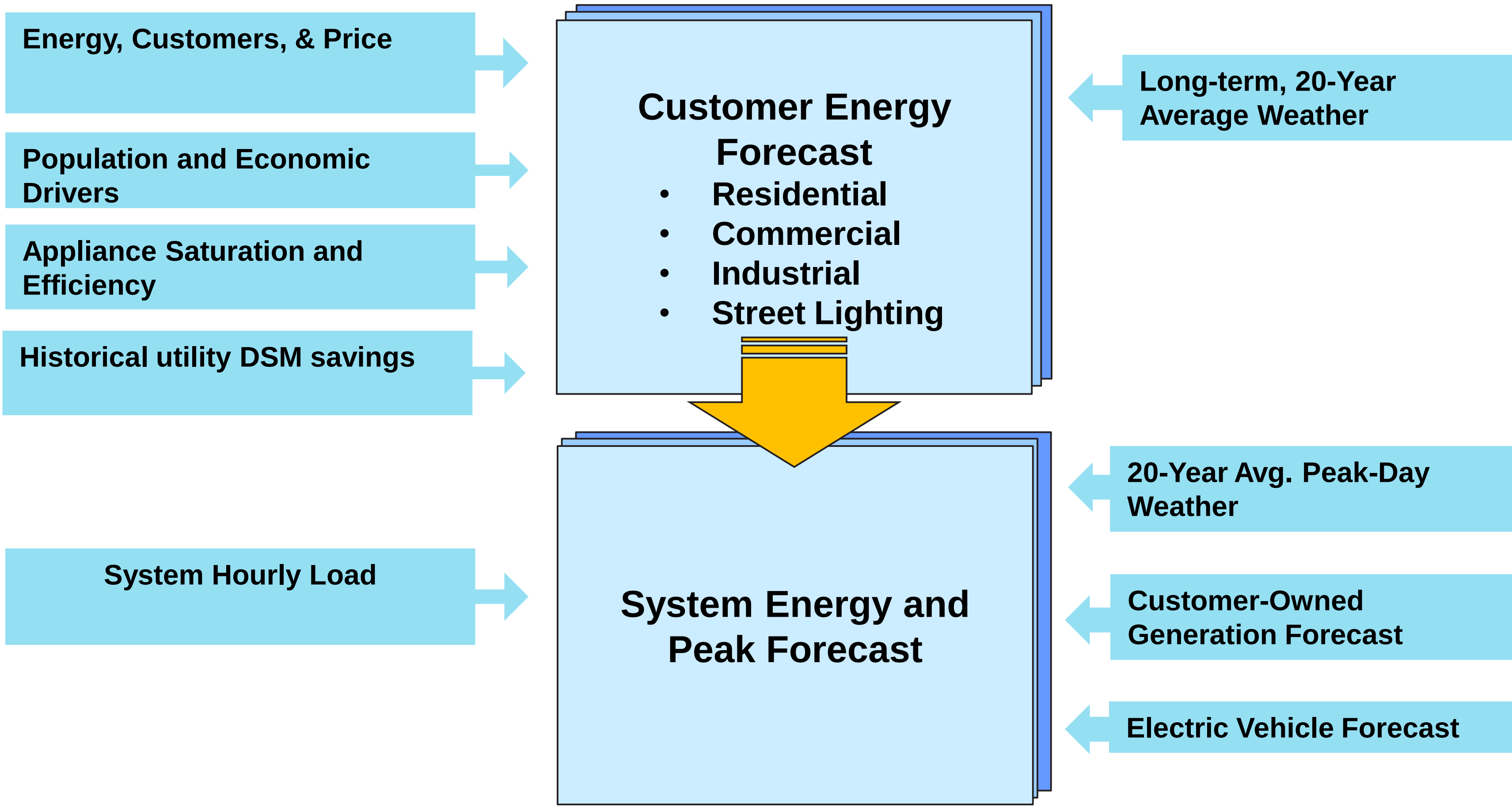
**Itron**

# FORECAST SUMMARY

- Moderate energy growth
  - Annual energy and demand growth of 0.6%[1]
  - Slow long-term population growth (0.2% annual growth) & moderate output growth (1.7% annual growth)
  - Strong end-use efficiency gains reflecting new and existing Federal codes and standards
    - Air conditioning, heating, lighting, refrigeration, cooking, etc. are becoming more efficient over time
  - Market-driven solar adoption
  - Electric vehicle projections based on EIA 2019 Annual Energy Outlook

[1] Future energy efficiency programs are not included in the sales and demand forecast and will be considered a resource option

# BOTTOM-UP FORECAST APPROACH

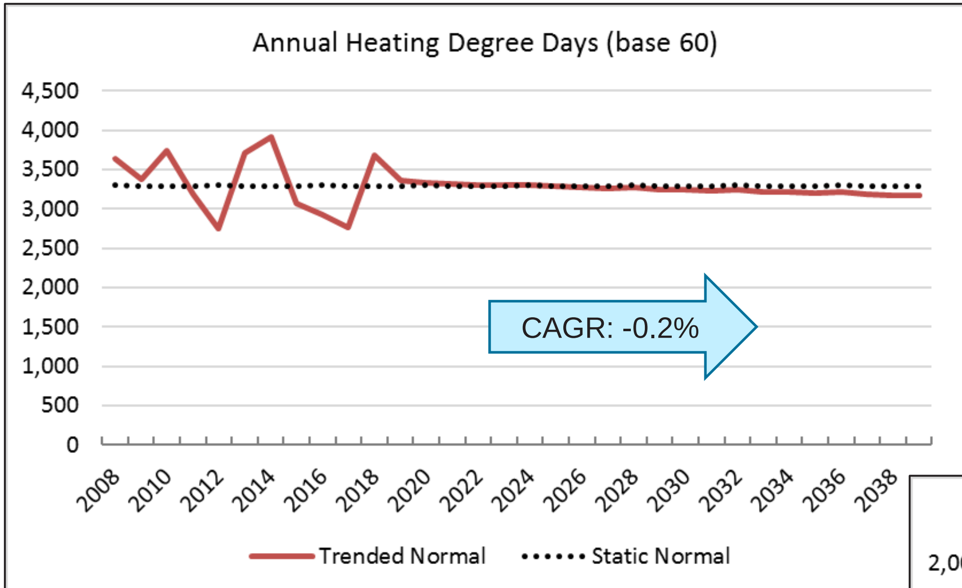


# ECONOMIC DRIVERS

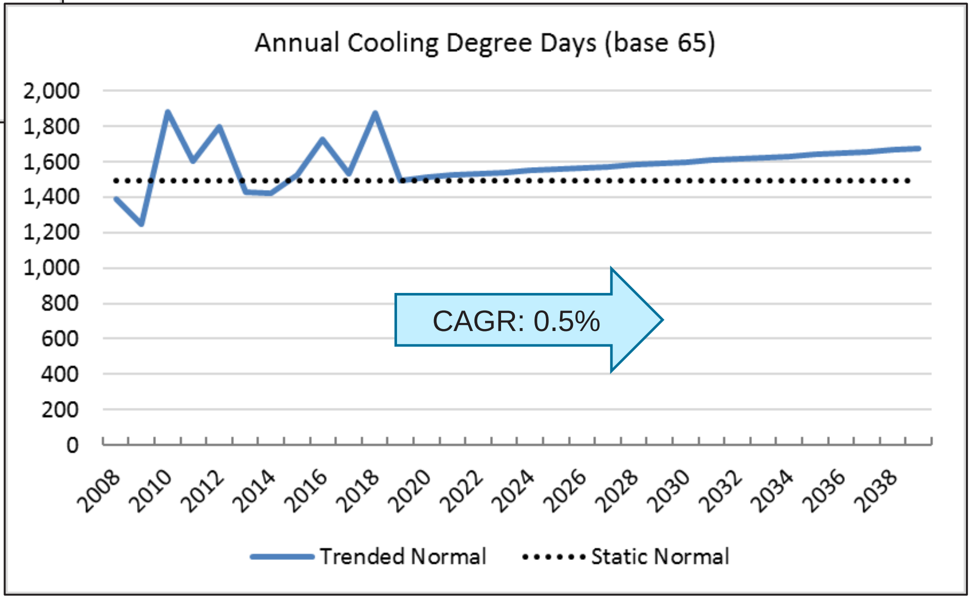
Moody's Analytic forecast for the Evansville MSA

- Residential Sector
  - Households: 0.4% CAGR
  - Real Household Income: 1.6% CAGR
  - Household Size -0.3% CAGR
- Commercial Sector
  - Non-Manufacturing Output: 1.7% CAGR
  - Non-Manufacturing Employment : 0.6% CAGR
  - Population 0.2% CAGR
- Industrial Sector
  - Manufacturing Output: 1.8% CAGR
  - Manufacturing Employment: -0.5% CAGR

# TRENDED NORMAL WEATHER

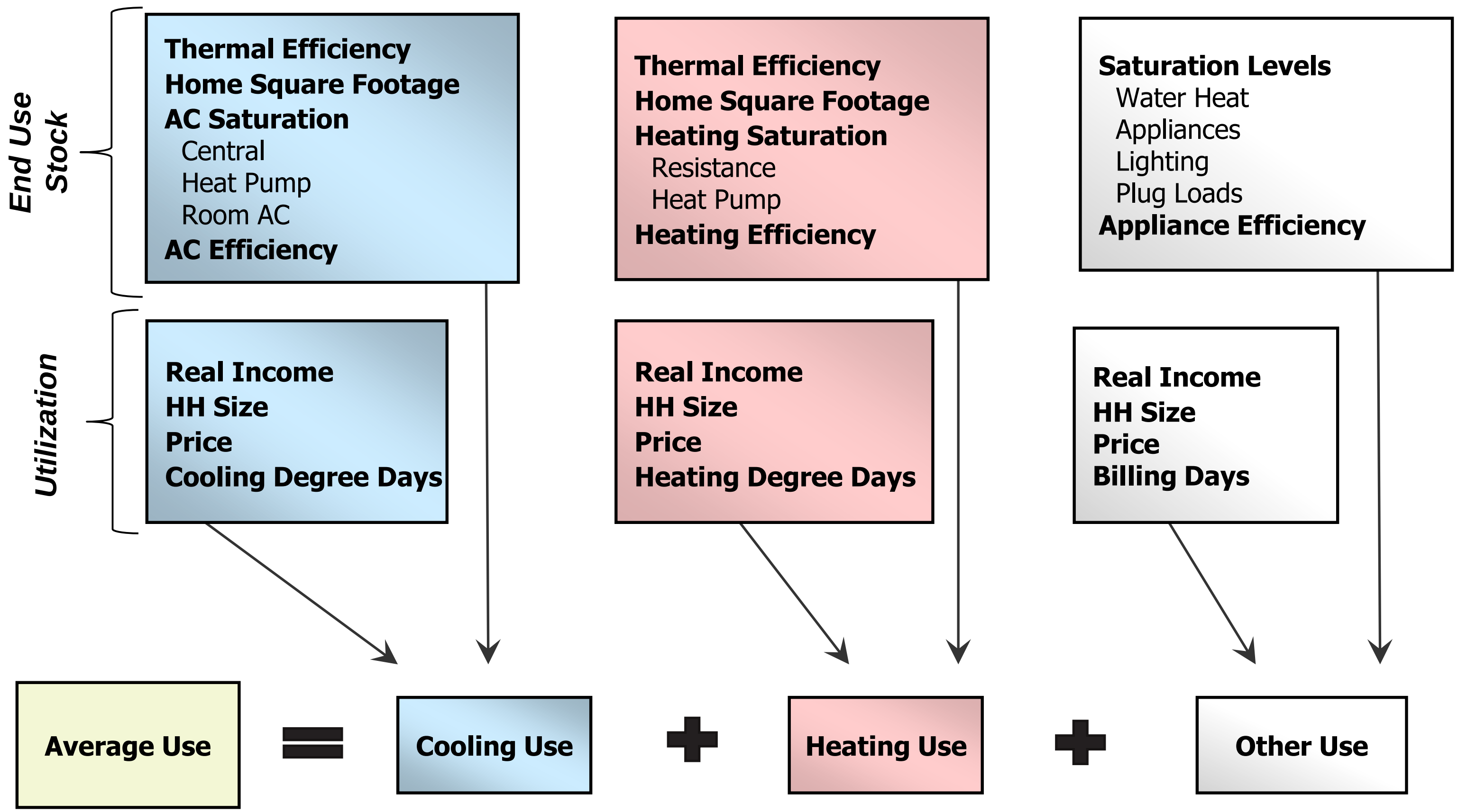



- Average temperature is increasing
  - Decline in HDD (warmer winters)
  - Increase in CDD (hotter summers)

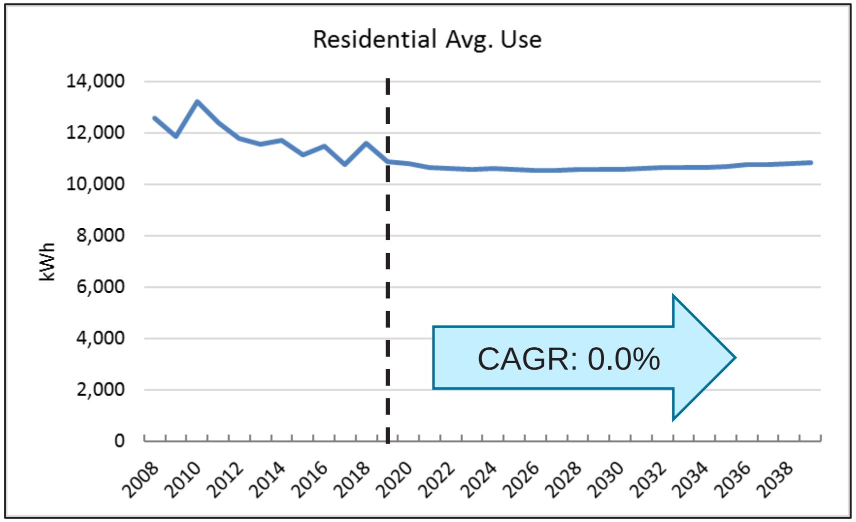


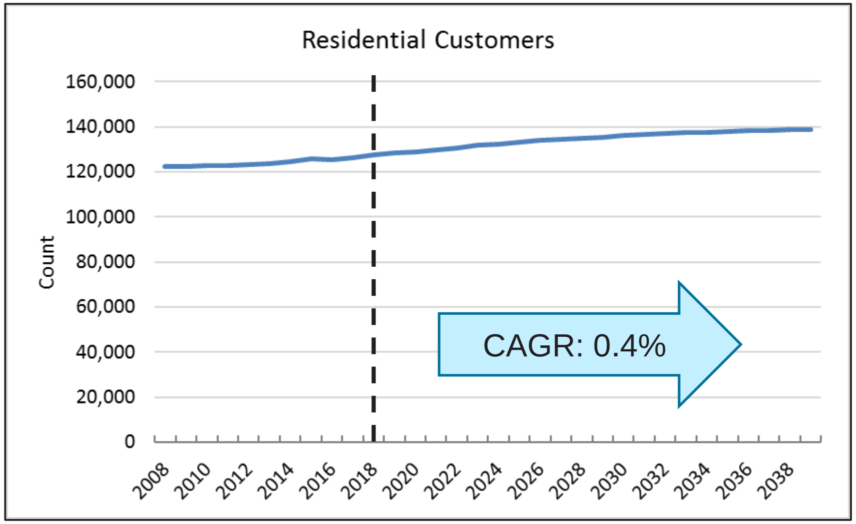

- Temperature trend based on statistical analysis of historical temperature data (1988 to 2018)

# RESIDENTIAL AVERAGE USE MODEL

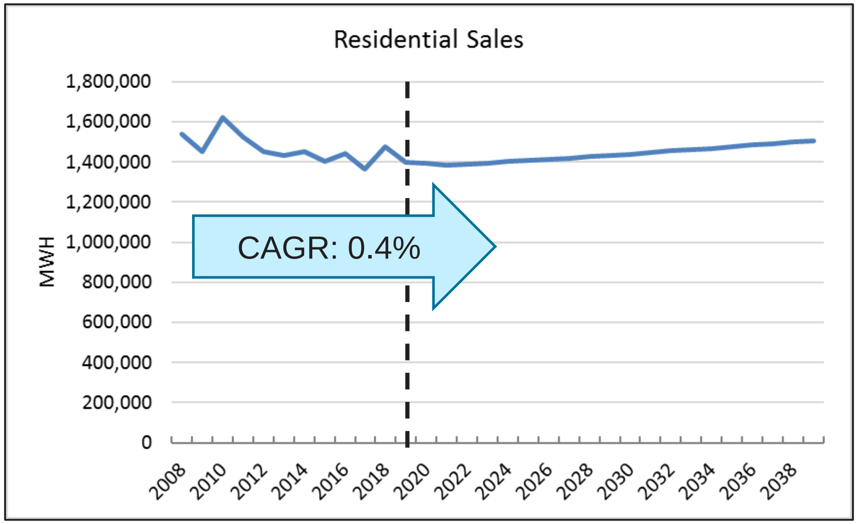


# RESIDENTIAL FORECAST

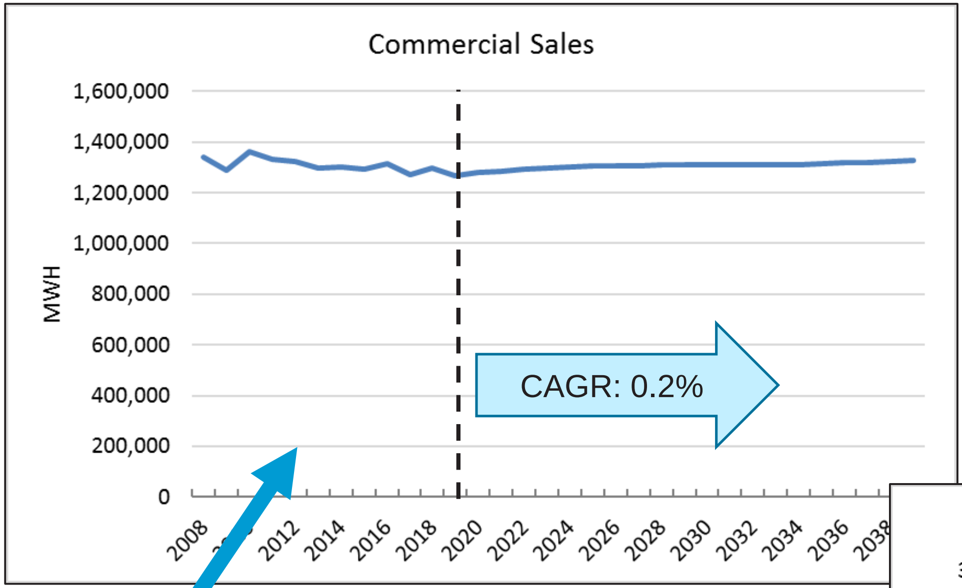


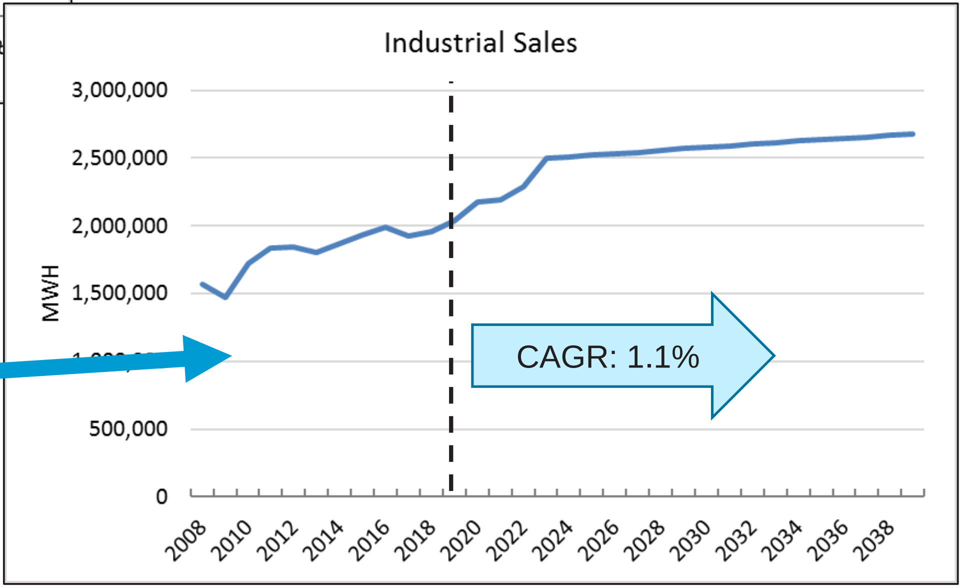




- Flat average use forecast, does not include the impact of future DSM program activity



# C&I SALES FORECAST

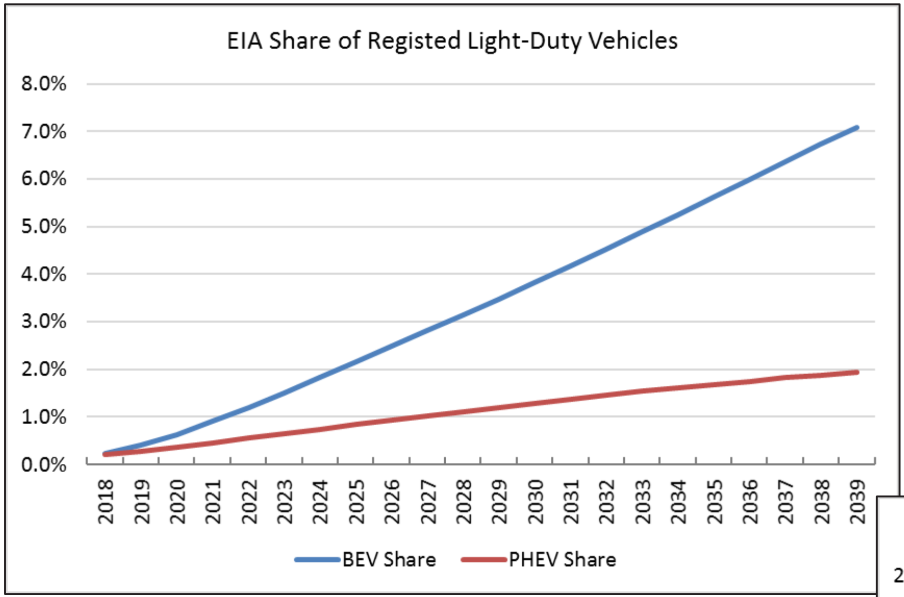


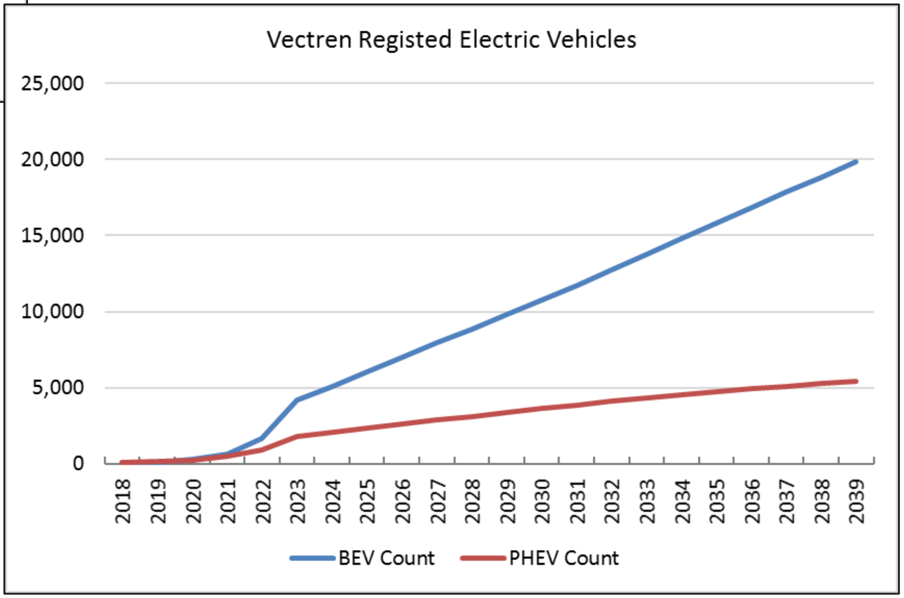

- Increase in commercial business activity countered by end-use efficiency gains
- Strong industrial sales growth related to near-term expected industrial expansion

* Excludes future energy efficiency program impacts and customer-owned DG

# ELECTRIC VEHICLES

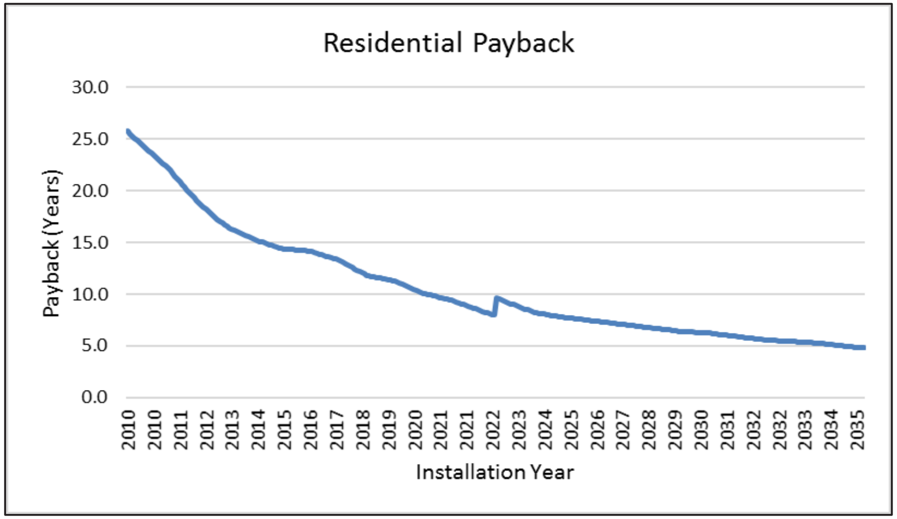



- Energy Information Administration (EIA) forecast based on share of total registered vehicles; differentiating between all electric (BEV) and plug-in hybrid electric (PHEV)

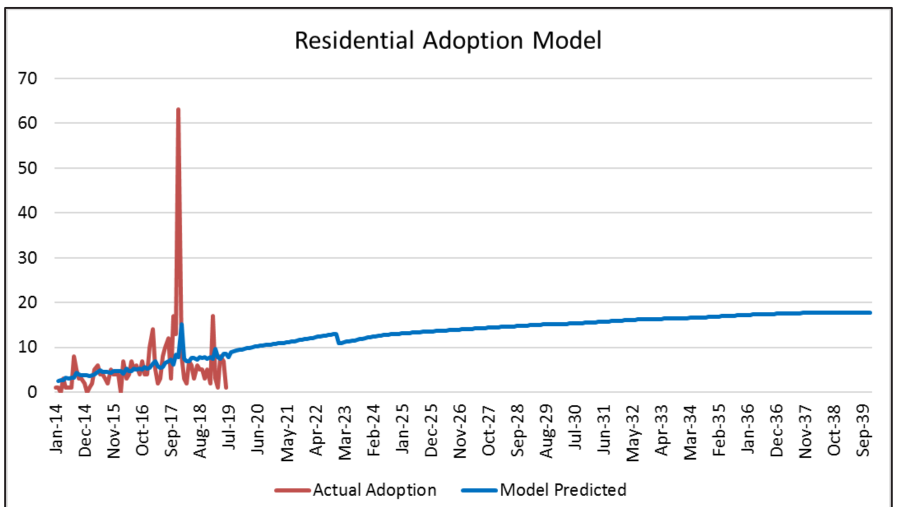



- Average annual kWh per vehicle based on weighted average of current registered BEV/PHEV
  - 3,752 kWh per BEV
  - 2,180 kWh per PHEV

# CUSTOMER OWNED PV

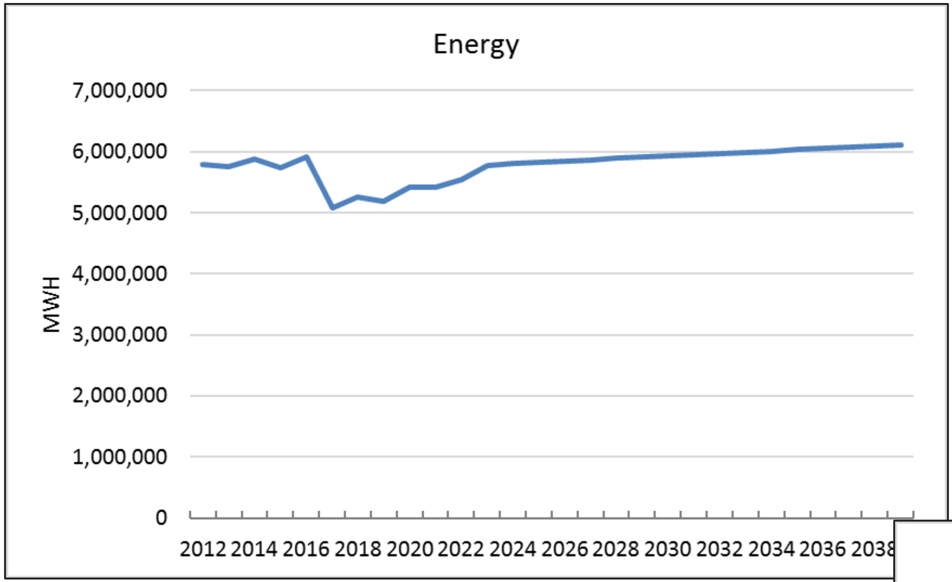


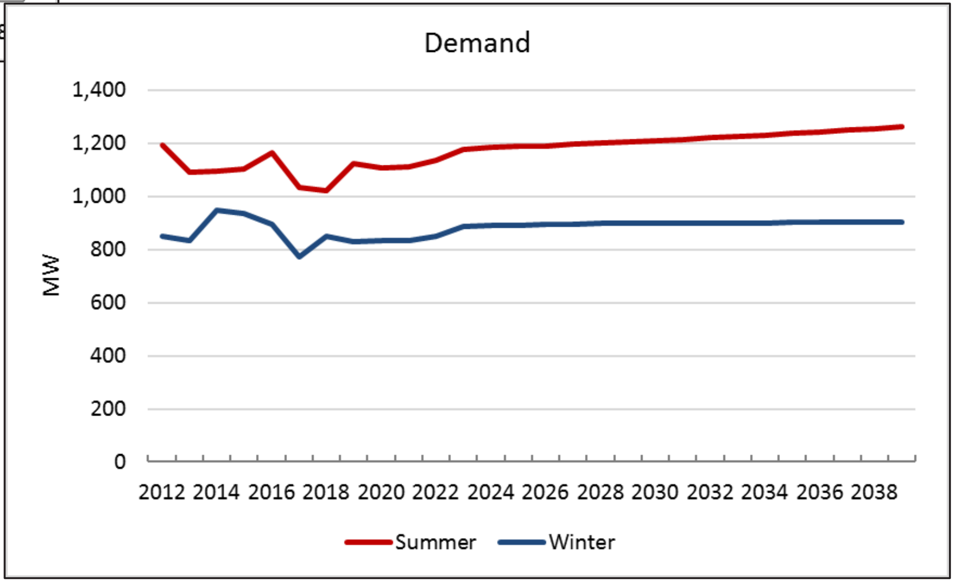

- Customer economics defined using simple payback
  - incorporates declining solar system costs, electric price projections, changes in net metering laws, and federal incentives




- Monthly adoption based on simple payback

# ENERGY & DEMAND FORECAST




- Combining economic growth, end-use efficiency, and adoption of new technologies, and trended weather results in 0.6% long-term energy and summer demand CAGR (2020-2039)*

* Excludes future energy efficiency programs. Includes a forecast of customer owned solar generation and forecast for electric vehicle penetration.  Excludes company owned generation on the distribution system

# FEEDBACK AND DISCUSSION

# EXISTING RESOURCE OVERVIEW

**WAYNE GAMES**

VECTREN VICE PRESIDENT POWER GENERATION OPERATIONS

# EXISTING RESOURCE SUMMARY

- Vectren is doing an exhaustive look at options for existing coal resources, including continued operation, retirement and coal to gas conversion of units
- Vectren must comply with EPA regulations; as such we are performing several studies to determine compliance options
- There is risk for Vectren in continued joint operation or sole ownership options as it pertains to Warrick 4

# DEFINITIONS

- ACE – Affordable Clean Energy Rule; Carbon rule that establishes emission guidelines for states to use when developing plans to limit $CO_2$ (improve heat rate) at their coal fired power plants
  - Heat rate improvements can be achieved through equipment upgrades or operation & maintenance practices
  - State of Indiana expected to issue requirement to comply in 2021
- Capacity Factor – The amount of energy a resource produces in a given period of time divided by the maximum amount of energy the resource is capable of producing during the same period of time
- CCR – Coal Combustion Residuals
- $EFOR_d$ – Equivalent Forced Outage Rate Demand; reliability measure used by MISO in the calculation of capacity accreditation for thermal resources
- Heat Rate – Measure of efficiency of a thermal generating resource; lower values represent better efficiency
- ICAP – Installed capacity of a resource
- MW – Megawatt
- PPA – Purchase Power Agreement
- UCAP – Unforced capacity; capacity credit a market participant receives from MISO for their resources
  - Thermal resources are based on tested unit output and 3 year historical $EFOR_d$ (Takes into account forced outages and forced derates)
  - Intermittent resources are based on historical output during peak summer hours
    - Solar resources without operating data default to a credit of 50% of installed capacity
    - Wind resources without operating default to the MISO system wide wind capacity credit from the effective load carrying capability (ELCC) study
      - Received 8% and 9.2% capacity credit for current wind PPA's in 2019-2020 planning year
- FGD – Flue gas desulfurization

# SUMMARY OF CURRENT RESOURCE UCAP ACCREDITATION FOR SUMMER PEAK

| Resource | Fuel \ Technology | Installed Net Capacity (MW) | 2019-2020 MISO Planning Year UCAP[2] (MW) | 2020-2021 MISO Planning Year UCAP[2] Projection (MW) | ICAP Conversion to UCAP (%) – 2020-2021 Planning Year Projection |
|---|---|---|---|---|---|
| A.B. Brown 1 | Coal (24x7 Power) | 245 | 209 | 232 | Coal Fleet 92% |
| A.B. Brown 2 | Coal (24x7 Power) | 245 | 225 | 234 | |
| F.B. Culley 2 | Coal (24x7 Power) | 90 | 86 | 86 | |
| F.B. Culley 3 | Coal (24x7 Power) | 270 | 251 | 247 | |
| Warrick 4 | Coal (24x7 Power) | 150[1] | 127 | 118 | |
| OVEC | Coal (24x7 Power) | 32 | 30 | 30 | |
| A.B. Brown 3 | Natural Gas (Peaking) | 85 | 71 | 73 | Natural Gas (Peaking) 85% |
| A.B. Brown 4 | Natural Gas (Peaking) | 85 | 71 | 72 | |
| Demand Response | N/A | 62 | 62 | 62 | Demand Response 100% |
| Benton County | Wind (Intermittent) | 30 | 2 | 2 | Wind 9% |
| Fowler Ridge | Wind (Intermittent) | 50 | 5 | 5 | |
| 50 MW Solar | Solar (Intermittent) | 50 | 0 | 0[3] | N/A |
| **Total** | | **1,344** | **1,139** | **1,161** | |

1 – Vectren Share
2 – Unforced capacity
3 – 25MW of UCAP projected for 2021-2022 MISO planning year

# IRP OPTIONS FOR EXISTING COAL RESOURCES

- Continued operation of existing solely owned coal units –
  - Brown 1 & 2 and Culley 2
    - Cost to comply with CCR/ELG environmental requirements
    - Cost to comply with ACE requirements
    - AB Brown FGD replacement (Study performed to estimate cost for different technologies to identify best path forward)
  - Culley 3
    - IURC approval to install technologies to comply with CCR/ELG
    - Cost to comply with ACE requirement
- Retirement of Brown 1 & Brown 2 in 2029
    - Cost to comply with CCR/ELG environmental requirements
    - Cost to comply with ACE requirements[1]
    - Continue existing FGD operation
- Natural gas conversion for Brown 1, Brown 2, and Culley 2
- Retirement of Brown 1, Brown 2, and Culley 2 in 2023
- Extend or exit Warrick Unit 4 partnership; (agreement currently set to expire at the end of 2023)

1 - Costs are estimates pending the final IDEM implementation plan for Indiana.

# RENEWABLES

- Solar (54 MW installed capacity)
  - Two 2 MW solar fields (behind the meter generation)
    - Both fields went in service late in 2018
    - 1 MW/4 MWH energy storage system connected at Volkman Road site
  - 50 MW solar field
    - Finalizing engineering & design and preparing to order materials
    - Currently scheduled for commercial operation in late 2020 to early 2021
- Wind PPA contracts (80 MW installed capacity)
  - Benton County
    - Contract for 30 MW of installed capacity expires in 2028
  - Fowler Ridge
    - Contract for 50 MW of installed capacity expires in 2030
- Blackfoot Landfill Gas (behind the meter generation)
  - Units are capable of producing 3 MW combined

# COMBUSTION TURBINES (NATURAL GAS PEAKING UNITS)

- Broadway Avenue Generating Station 1; 53 MW installed capacity
  - Retired in 2018
- Northeast units 1 and 2 (10 MW installed capacity each)
  - Retired in early 2019
- Broadway Avenue Generating Station 2; 65 MW installed capacity
  - Currently in process of retirement through MISO process
    - Typical life is 30-40 years; Unit has been in service for 38 years
    - Highest heat rate (least efficient) of current generating fleet
    - Recent five year capacity factor just over 1%
    - Several millions dollars needed for known repairs
    - High probability of additional expenses in the near future given current age and condition
- Brown 3; 85 MW installed capacity
  - Black start capabilities (able to burn fuel oil)
  - No upgrades required for continued operation
- Brown 4; 85 MW installed capacity
  - No upgrades required for continued operation

# F.B. CULLEY OPTIONS

- Culley 2; 90 MW installed coal capacity
  - Business as usual (continue beyond 2023)
    - Requires CCR (Coal Combustion Residuals) and Effluent Limit Guidelines (ELG) compliance
    - Compliance with ACE (Affordable Clean Energy) rule; unit upgrades & improvements
  - Natural Gas Conversion
    - Preserve existing capacity
    - High cost energy
    - Anticipate low capacity factor with high reliance on market
  - Retirement in 2023 to avoid environmental investments

**Business As Usual**

| Regulation | Upgrade | Estimated Cost | Potential Efficiency Improvement |
|---|---|---|---|
| CCR/ELG | Dry Bottom Ash Conversion | $6 million | N/A |

**Business As Usual**

| Regulation | Potential Upgrade/Projects | Estimated Cost | Potential Efficiency Improvement |
|---|---|---|---|
| ACE | • Turbine Upgrade<br>• Air heater<br>• Variable Frequency Drives<br>• Boiler program<br>• Condenser work<br>• O&M Practices | $30 million[1] | ~4-4.5% |

**Natural Gas Conversion**

| Item | Estimated Cost |
|---|---|
| Modifications to convert unit to natural gas firing | $46 million |
| Gas pipeline construction | $11 million |
| **Total** | **$57 million** |

1 – Costs are estimates pending the final IDEM implementation plan for Indiana

# F.B. CULLEY OPTIONS (CONT.)

- Culley 3; 270 MW installed coal capacity
  - Moving forward with upgrades approved in cause 45052 to comply with CCR (Coal Combustion Residuals) and ELG (Effluent Limitations Guidelines)[1]
  - Compliance with ACE (Affordable Clean Energy) rule; requires unit upgrades to improve efficiency

## Business As Usual

| Regulation | Potential Upgrade/Projects | Estimated Cost | Potential Efficiency Improvement |
|---|---|---|---|
| ACE | • Turbine upgrades<br>• Air heater Upgrade<br>• Variable Frequency Drives<br>• Boiler Program<br>• Condenser Upgrade<br>• O&M Practices | $35 million[1] | ~3% |

1 - Costs are estimates pending the final IDEM implementation plan for Indiana

# WARRICK GENERATING STATION UNIT 4

VECTREN
A CenterPoint Energy Company

- Warrick 4; 150 MW installed capacity (Vectren share of a 300 MW jointly owned coal fired unit)
  - Current operating agreement expires in 2023
  - Either party can exit earlier with sufficient notice
  - Alcoa currently evaluating future options. Committed to respond in 4th quarter
- Risks of continued joint operation
  - Lack of operational control
  - Environmental upgrades (cost and liability)
  - Alcoa can exit agreement after giving notice
    - Smelter future reliant on global aluminum market
- Ramifications of Alcoa exiting the operation agreement
  - Vectren takes ownership
    - 100% of environmental upgrade costs (lose benefit of industrial classification for water discharge and CCR)
    - 100% capital and O&M investment responsibility
    - Operational challenges of taking over facility
    - Future decommissioning costs
    - Increase percentage of coal capacity
  - Retire the unit
    - Procure replacement capacity

# A.B. BROWN

- Brown 1 & 2; 245 MW installed coal capacity (each)
  - Natural Gas Conversion
    - Preserve existing capacity
    - High cost energy
    - Anticipate low capacity factor with high reliance on market

| Item | Brown 1 Estimated Cost ($) | Brown 2 Estimated Cost ($) | Total |
|---|---|---|---|
| Modification to convert unit to gas | $89 million | $97 million | $186 million |
| Gas pipeline construction[1] | $50 million | $50 million | $100 million |
| **Total** | $139 million | $147 million | $286 million |

1- Values shown assume both units are converted. Single unit conversion is approximately $77 million

# A.B. BROWN (CONT.)

VECTREN
A CenterPoint Energy Company

- Brown 1 & 2; 245 MW (each)
  - Business as usual
    - Requires dry bottom ash conversion and dry flyash system upgrades for CCR (Coal Combustion Residuals) and ELG (Effluent Limitations Guidelines) compliance
    - A new landfill would be needed for disposal of FGD (Flue Gas Desulphurization) by-products and fly ash
    - FGD replacement is included in continued operation plan
    - Compliance with ACE (Affordable Clean Energy) rule; requires unit upgrades & improvements based on IDEM ruling

## Business As Usual

| Regulation | Upgrade Projects | Brown Unit 1 Estimated Cost | Brown Unit 2 Estimated Cost | Total Estimated Cost |
|---|---|---|---|---|
| CCR\ELG | • Dry bottom ash conversion<br>• Dry Fly Ash Conversion<br>• Water treatment | $53 million | $53 million | $106 million[2] |

| Regulation | Potential Upgrade/Projects | Brown Unit 1 Estimated Cost | Brown Unit 2 Estimated Cost | Total Estimated Cost | Potential Efficiency Improvement | Potential Efficiency Improvement |
|---|---|---|---|---|---|---|
| ACE | • Air heater<br>• Variable Frequency Drives<br>• Boiler program<br>• Condenser work<br>• O&M Practices | $13 million[1] | $13 million[1] | $26 million[1] | ~2.2% | ~2.6% |

1 - ACE costs are estimates pending the final IDEM implementation plan for Indiana
2 – Does not include landfill cost for FGD by-products and ash. New landfill required to operate beyond 2023. Size and cost to be determined based on future FGD technology

# NEW FGD OPTIONS

Eight FGD technologies reviewed; four chosen for further analysis

- Market analysis being conducted for potential by-products sales
- Will perform Net Present Value (NPV) screening analysis in modeling to determine low cost option
- NPV results along with operating considerations will help determine the preferred FGD replacement technology

| FGD Technology | Primary Reagent | Estimated Initial Capital Investment[1] | Estimated Landfill Capital and O&M | Estimated Variable O&M Cost/MWHr (2019$) | Marketable Fly Ash | Community Right-To-Know Emergency Action Plan | Marketable By-Product |
|---|---|---|---|---|---|---|---|
| Limestone Forced Oxidation (LSFO) | **Limestone** | **$596 million[2,4]** | **TBD Based on Gypsum and Ash Market** | **$4.44/MWHr** | **Yes** | **No** | **Gypsum** |
| Lime Inhibited Oxidation (LSIO) | **Lime Quicklime** | **$450 million[2,4]** | **$119 million** | **$9.39/MWHr** | **Yes (Limited)** | **No** | **No** |
| Ammonia Based (JET) | **Anhydrous Ammonia** | **$411 million[2,3,4,5]** | **TBD Based on Ammonium Sulfate Market** | **$11.67/MWHr** | **Yes** | **Yes** | **Ammonium Sulfate Fertilizer[6]** |
| Circulating Dry Scrubber (CDS) | **Lime** | **$387 million[2,3,5]** | **$125 million** | **$14.92/MWHr** | **Yes** | **No** | **No** |

1 – Values represent estimated total cost for both A.B. Brown units
2 – Includes new wastewater treatment system
3 - Includes new mercury mitigation system
4 – Includes new $SO_3$ mitigation system
5 – Includes new particulate matter collection system
6 – Also produces unmarketable by-product (brominated powder activated carbon and mercury)

# A.B. BROWN FGD OPTIONS (CONT.)

VECTREN
A CenterPoint Energy Company

- Replacement of existing FGD's (cont.)
  - Spray Dryer FGD and Flash Dryer FGD
    - Neither option can meet emission criteria based on 1 hour SO2 limit for Posey County and Illinois Basin Coal supply
- Conversion of existing FGD's to limestone based technologies
  - Lime Inhibited Oxidation (LSIO) or Limestone Forced Oxidation (LSFO)
    - Neither option can meet emissions criteria based on 1 hour SO2 limit for Posey County

- Continued operation of current Brown dual alkali FGD's through 2029

| FGD Technology | Estimated 10 Year Capital | Estimated 10 Year O&M | Estimated Landfill Capital and O&M | Estimated Variable O&M Cost/MWHr (2019$) | Marketable Fly Ash | Community Right-To-Know Emergency Action Plan | Marketable By-Product |
|---|---|---|---|---|---|---|---|
| Dual Alkali | **$137 million** | **$58 million** | **$49 million** | **5.72** | **Yes** | **No** | **No** |

# FEEDBACK AND DISCUSSION

VECTREN
A CenterPoint Energy Company

# POTENTIAL NEW RESOURCES AND MISO ACCREDITATION

MATT LIND,

RESOURCE PLANNING & MARKET ASSESSMENTS BUSINESS LEAD, BURNS & MCDONNELL

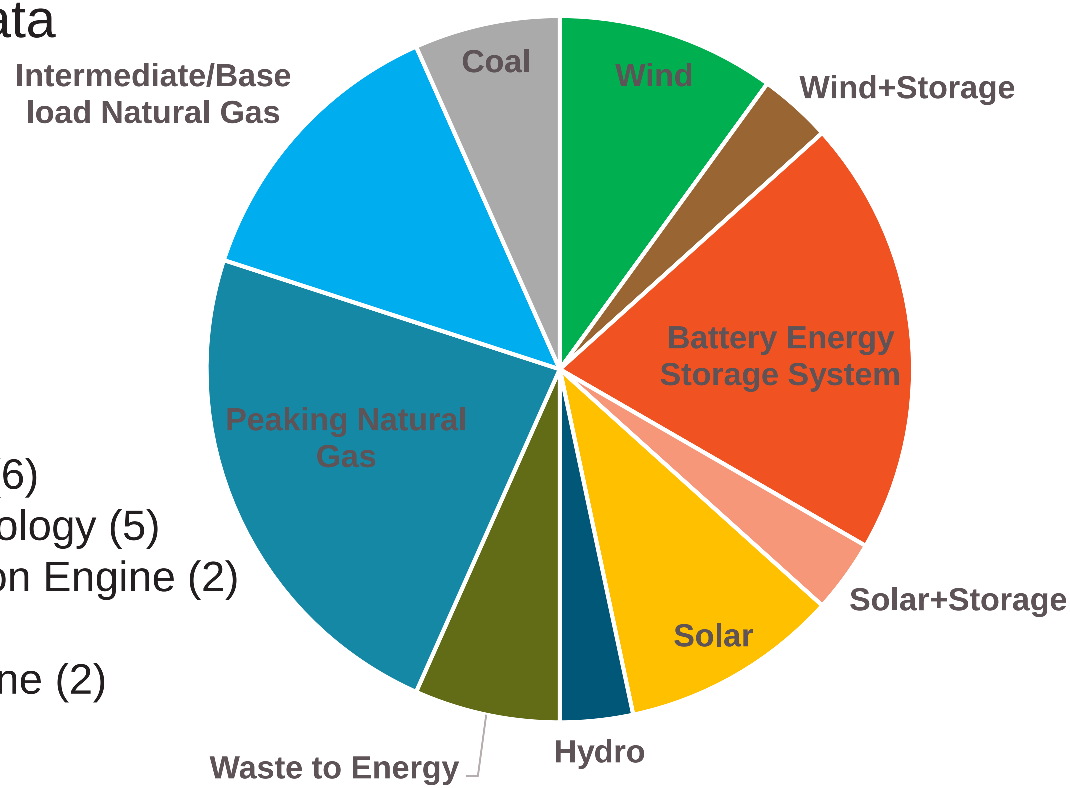
# NEW RESOURCE AND MISO ACCREDITATION SUMMARY

VECTREN
A CenterPoint Energy Company

- Vectren initially plans to model new potential resources with draft technology assessment information as RFP modeling inputs are being completed
- Technology costs will be updated with bid information, where applicable; final modeling inputs will be shared in December
- Intermittent resources lack dispatch flexibility, as penetration increases, MISO projects lower capacity accreditation
- MISO is planning for seasonal capacity accreditation (summer/winter), some resources will receive varying levels of capacity credit depending on differences in seasonal availability

# BACKGROUND

- Base Case Inputs for new power supply options
- Consensus estimates from Burns & McDonnell, Pace Global, and NREL for solar and storage resources
- Supplemental to RFP Bid data
- Resource Options (30):
  - Wind (3)
  - Wind + Storage (1)
  - Solar Photovoltaic (3)
  - Solar + Storage (1)
  - Hydro (1)
  - Landfill Gas (2)
  - Battery Energy Storage System (6)
  - Simple Cycle Gas Turbine Technology (5)
  - Reciprocating Internal Combustion Engine (2)
  - Combined Cycle Gas Turbine (2)
  - Combined Heat and Power Turbine (2)
  - Coal (2)



# TECHNOLOGY DETAILS

## Examples of candidates for natural gas peaking generation:

| Gas Simple Cycle (Peaking Units) | Example 1 | Example 2 | Example 3 | Example 4 |
|---|---|---|---|---|
| Combustion Turbine Type | LM6000 | LMS100 | E-Class | F-Class |
| Size (MW) | 41.6 MW | 97.2 MW | 84.7 MW | 236.6 MW |
| Fixed O&M (2019 $/kW-yr) | $36 | $16 | $21 | $8 |
| Total Project Costs (2019 $/kW) | ~$2,400 | ~$1,700 | ~$1,500 | ~$800 |

## Examples of candidates for natural gas combined cycle generation:

| Gas Combined Cycle (Base / Intermediate Load Units) | Example 1 | Example 2 |
|---|---|---|
| Combustion Turbine Type | 1x1 F-Class[1] | 1x1 G/H-Class[1] |
| Size (MW) | 357.2 MW | 410.6 MW |
| Fixed O&M (2019 $/kW-yr) | $13 | $12 |
| Total Project Costs (2019 $/kW) | ~$1,400 | ~$1,300 |

[1] 1x1 Combined Cycle Plant is one combustion turbine with heat recovery steam generator and one steam turbine utilizing the unused exhaust heat from the combustion turbine.

# TECHNOLOGY DETAILS

Examples of candidate combined heat and power gas generation:

| Gas Combined Heat and Power[1] | 2 x 10 MW Recip Engines | 20 MW Combustion Turbine |
|---|---|---|
| Net Plant Electrical Output (MW) | 17.9 MW | 21.7 MW |
| Fixed O&M (2019 $/kW-yr) | $42 | $35 |
| Total Project Costs (2019 $/kW) | ~$2,800 | ~$4,600 |

[1] Utility owned and sited at a customer facility

Examples of candidates for renewable energy and energy storage:

| Renewable Generation & Storage Technologies | Solar Photovoltaic | Solar + Storage | Indiana Wind Energy | Lithium Ion Battery Storage |
|---|---|---|---|---|
| Base Load Net Output (kW) | 100 MW (Scalable Option) | 50 MW + 10MW/40 MWh | 200 MW | 10 MW/40 MWh (Scalable Option) |
| Fixed O&M (2019 $/kW-yr) | $20 | $27 | $44 | $19 |
| Total Project Costs (2019 $/kW)[1] | ~$1,600 | ~$1,900 | ~$1,700 | ~$2,000 |

[1]Total Project Costs (2019 $/kW) may change based on economies of scale. The Technology Assessment contains unique costs for the different scales of the projects.

# TECHNOLOGY DETAILS

VECTREN
A CenterPoint Energy Company

## Example of candidates for hydroelectric generation:

| | Low Head Hydroelectric Generation |
|---|---|
| Base Load Net Output (kW) | 50 MW |
| Fixed O&M (2019 $/kW-yr) | $92 |
| Total Project Costs (2019 $/kW) | ~$5,900 |

## Potential local resources:

| Dam | 2012 DOE[1] Estimated Potential Capacity (MW) | 2013 U.S. Army Corps of Engineers Estimated Feasible Potential Capacity (MW) | 2013 U.S. Army Corps of Engineers Estimated Optimal Potential Capacity (MW) |
|---|---|---|---|
| John T. Myers (Uniontown) | 395 | 24-115 | 36 |
| Newburgh | 319 | 15-97 | 22 |

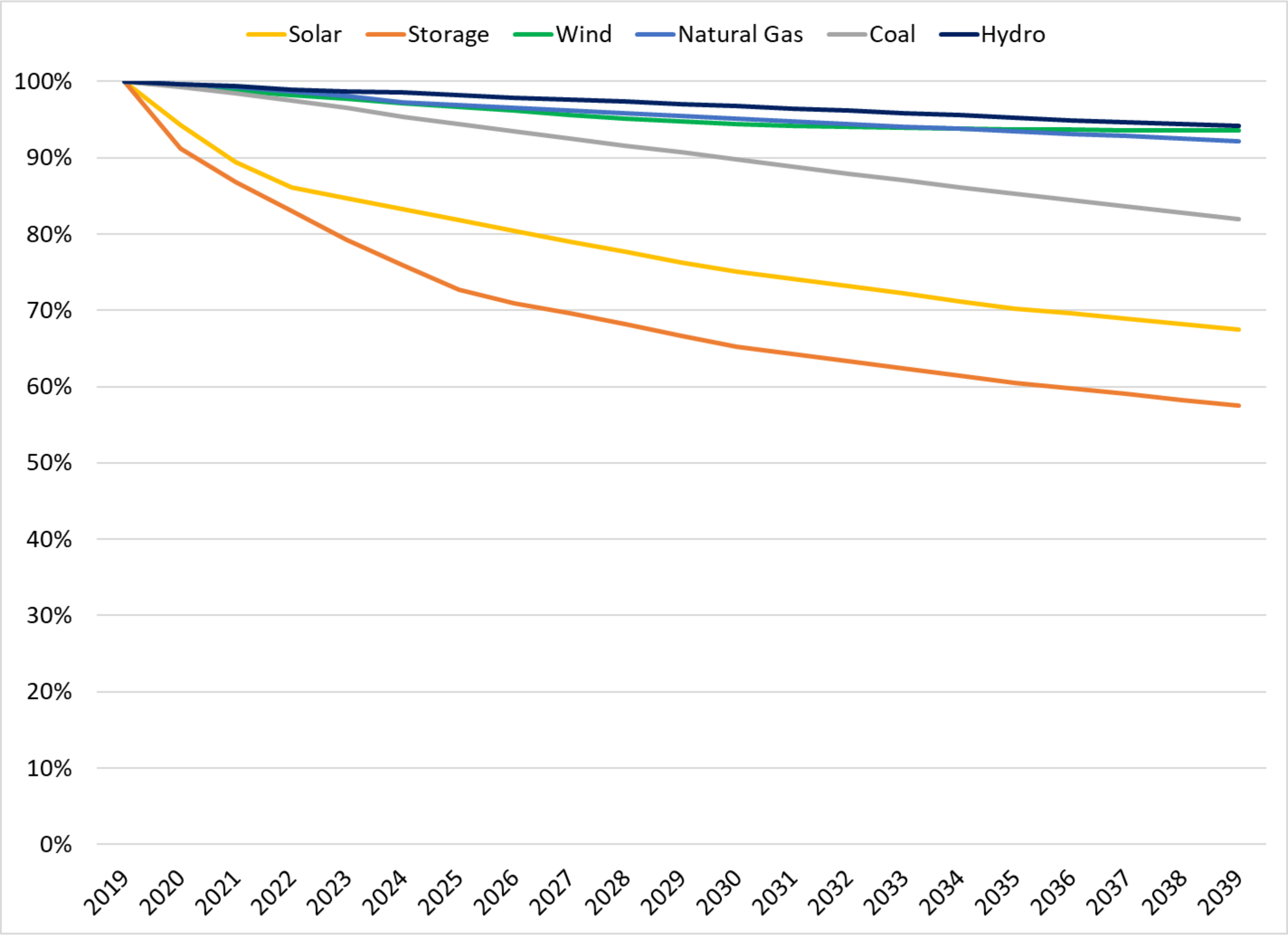
Notes:
In 2019 dollars, the Cannelton hydro project (~84 MW) total cost was approximately $5,500/kW (US Army Corps of Engineers press release)
Transmission upgrades required for the Uniontown dam are estimated at $14 million
Transmission upgrades required for the Newburgh dam are estimated at $10 million

# TECHNOLOGY DETAILS

Examples of candidates for coal generation:

| Coal Fired | Example 1 | Example 2 |
|---|---|---|
| Combustion Turbine Type | Supercritical Pulverized Coal with Carbon Capture | Ultra-Supercritical Pulverized Coal with Carbon Capture |
| Size (MW) | 506 MW | 747 MW |
| Fixed O&M (2019 $/kW-yr) | $29 | $29 |
| Total Project Costs (2019 $/kW) | ~$6,100 | ~$5,500 |

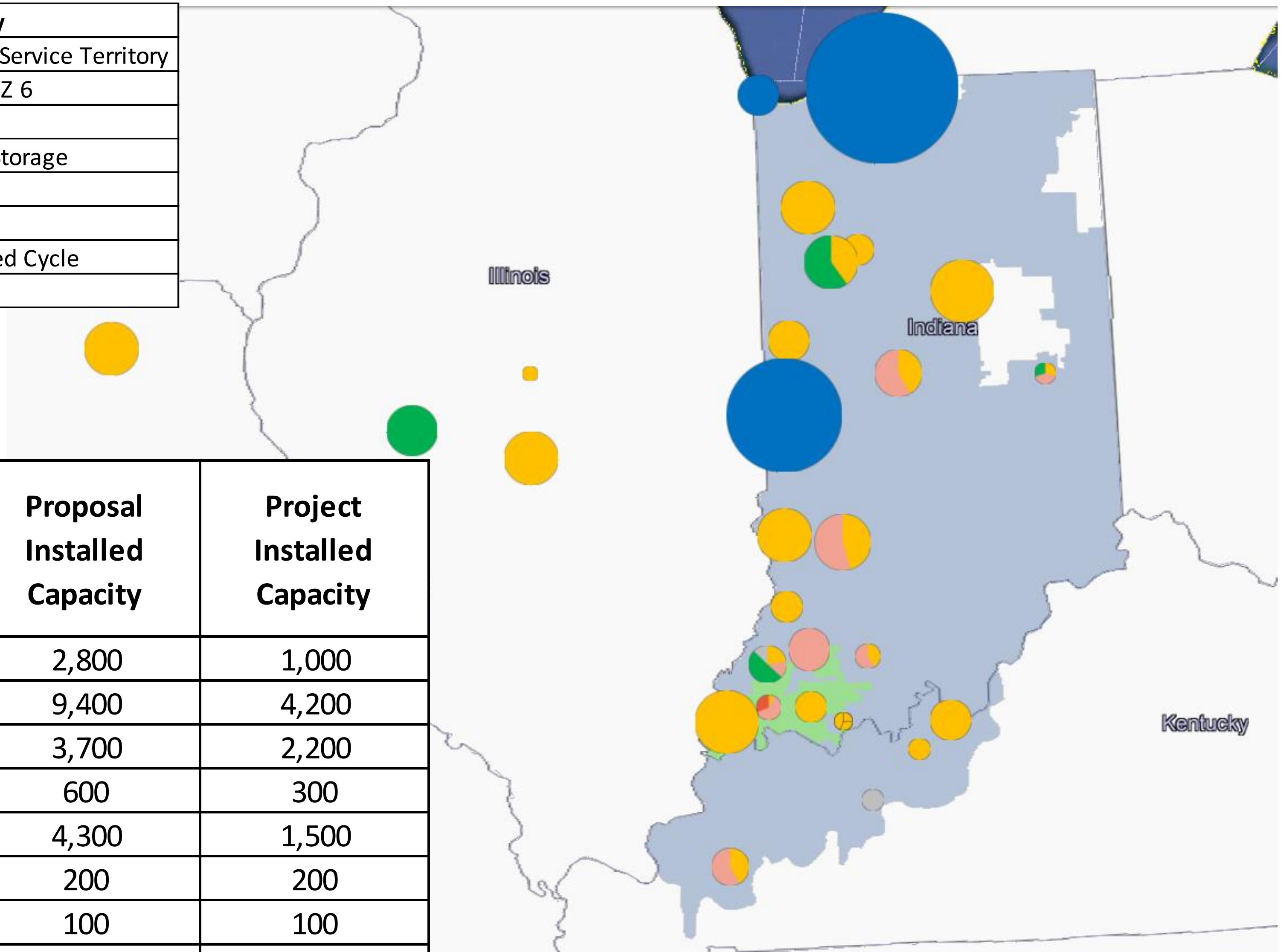
# FORWARD COST ESTIMATES




# PROPOSAL LOCATION REVIEW

VECTREN
A CenterPoint Energy Company

| Key | |
|---|---|
| | Vectren Service Territory |
| | MISO LRZ 6 |
| | Solar |
| | Solar + Storage |
| | Storage |
| | Wind |
| | Combined Cycle |
| | Coal |




| 2019 RFP Responses (MW) | Proposal Installed Capacity | Project Installed Capacity |
|---|---|---|
| **Wind** | 2,800 | 1,000 |
| **Solar** | 9,400 | 4,200 |
| **Solar + Storage** | 3,700 | 2,200 |
| **Storage** | 600 | 300 |
| **Combined Cycle** | 4,300 | 1,500 |
| **Coal** | 200 | 200 |
| **LMR/DR** | 100 | 100 |
| **System Energy** | 300 | 100 |
| **Total** | **21,400** | **9,600** |

# PARTICIPATING COMPANIES

VECTREN
A CenterPoint Energy Company

bp
ST. JOSEPH energy center
Origis Energy POWERING THE SOLAR REVOLUTION
S·POWER An AES and AIMCo Company
EmberClear
RANGER POWER
Constellation. An Exelon Company
APEX CLEAN ENERGY
NEXTera ENERGY RESOURCES
Clēnera
edp renewables
e·on
CALPINE
lightsource bp
DUKE ENERGY.
enel x
ORION RENEWABLE ENERGY GROUP LLC
ENGIE
Big Rivers ELECTRIC CORPORATION
res
Invenergy
Capital Dynamics TRULY INVESTED.
TENASKA

# PROPOSAL GROUPING

| Potential Grouping | | RFP Count | Tier 1 Proposals | Tier 2 Proposals |
|---|---|---|---|---|
| 1 | Coal PPA | 2 | 0 | 2 |
| 2 | LMR/DR PPA | 1 | 1 | 0 |
| 3 | CCGT PPA | 2 | 0 | 2 |
| 4 | CCGT Purchase | 5 | 0 | 5 |
| 5 | Wind Purchase | 2 | 0 | 2 |
| 6 | 12-15 Year Wind PPA | 9 | 4 | 5 |
| 7 | 20 Year Wind PPA | 2 | 1 | 1 |
| 8 | Storage Purchase | 4 | 4 | 0 |
| 9 | Storage PPA | 4 | 4 | 0 |
| 10 | Solar + Storage PPA | 6 | 5 | 1 |
| 11 | Solar + Storage Purchase | 9 | 5 | 4 |
| 12 | Solar + Storage Purchase/PPA | 4 | 1 | 3 |
| 13 | Solar Purchase/PPA | 6 | 1 | 5 |
| 14 | 12-15 Year Solar PPA | 8 | 3 | 5 |
| 15 | 20 Year Solar PPA | 16 | 7 | 9 |
| 16 | 25-30 Year Solar PPA | 9 | 3 | 6 |
| 17 | Solar Purchase | 18 | 4 | 14 |
| N/A | Energy Only | 3 | 0 | 3 |
| | **Total** | **110** | **43** | **67** |

**110**
**Proposals**

**Tier 1**
- Binding Pricing
- Delivered to SIGE.SIGW OR On System

IRP Inputs

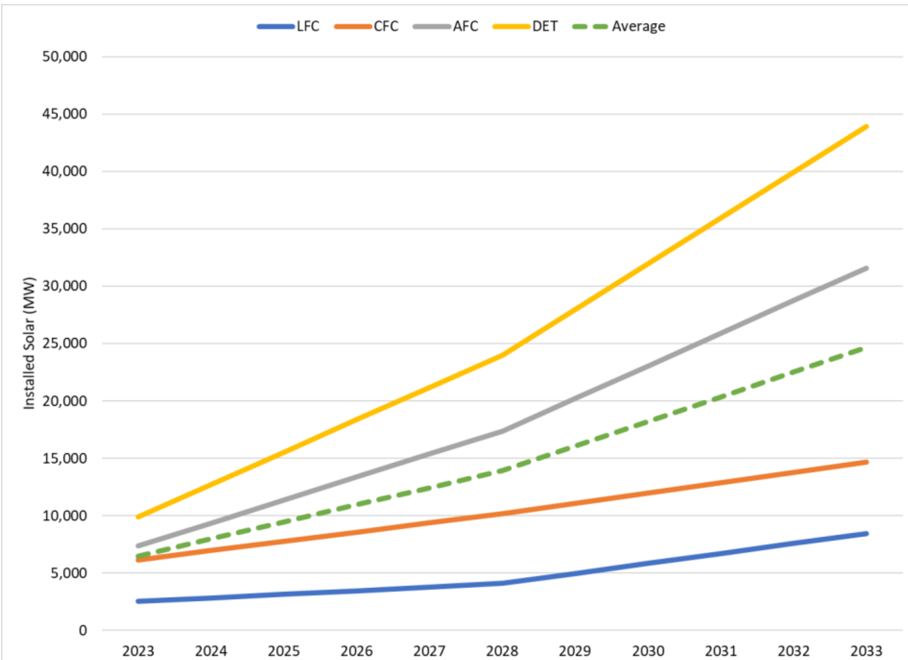
**Tier 2**
- Non-Binding Pricing
- Congestion / delivery risk

Potential IRP Inputs Based on Evaluation

- Total installed capacity of RFP bids in Tier 1 ~5X greater than Vectren's peak load
- Resource options from the technology assessment will supplement these options as needed

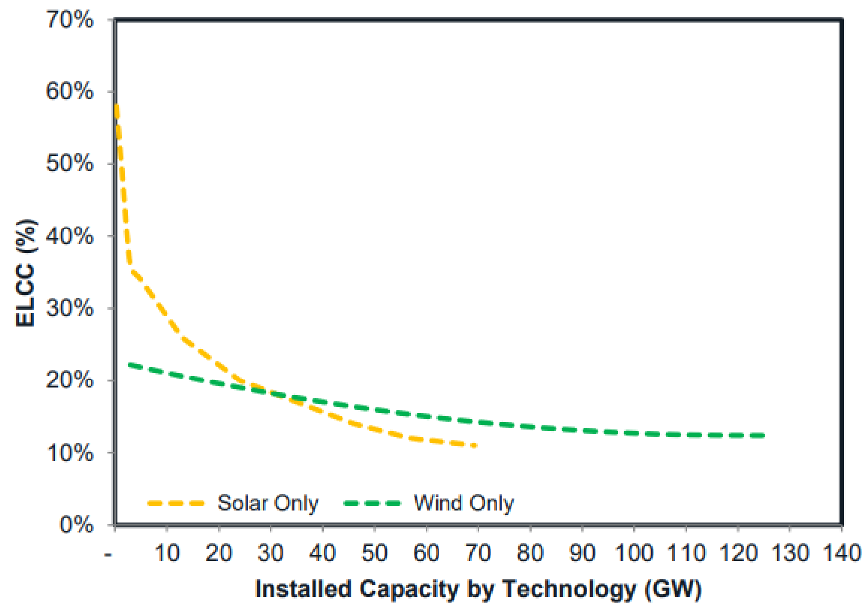
# MISO RENEWABLE PENETRATION TRENDS

MTEP19 future solar capacity projections




https://cdn.misoenergy.org/MTEP19%20Futures%20Summary291183.pdf
MISO Transmission Expansion Plan (MTEP) study years 2023, 2028, and 2033. Data between study years is linearly interpolated.

Effects of increasing installations

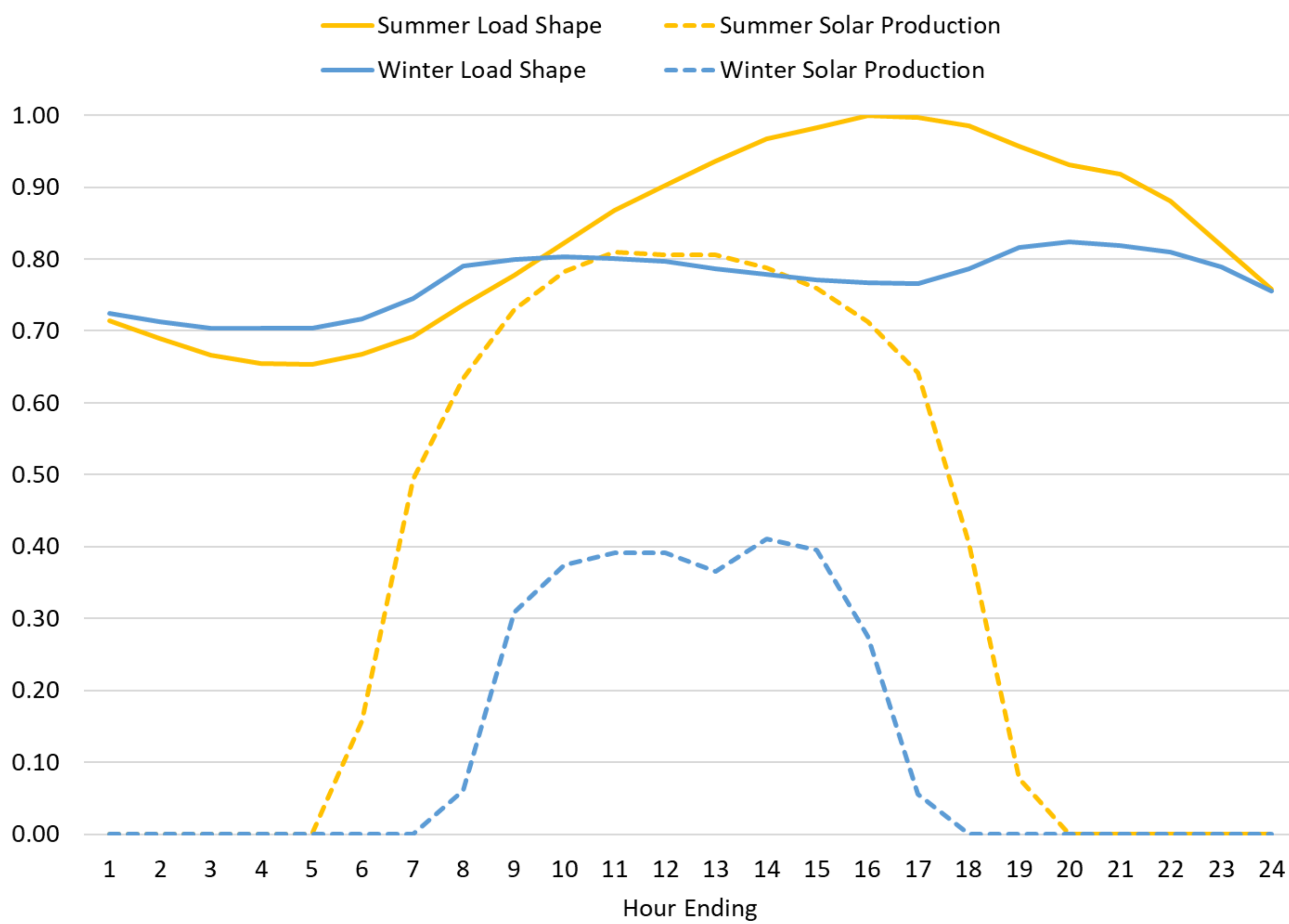



https://cdn.misoenergy.org/RIIA%20Assumptions%20Doc_v7429759.pdf

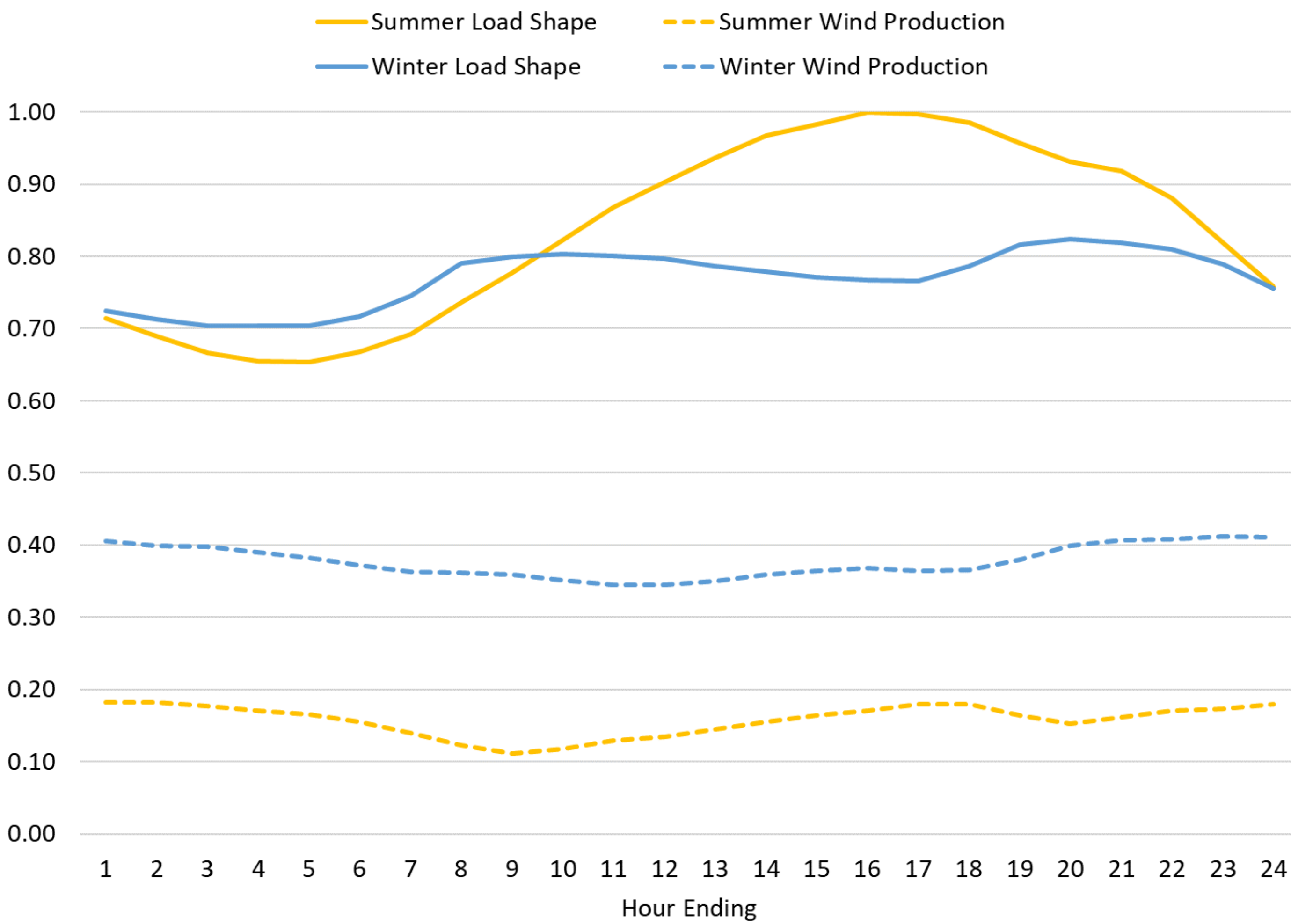
As installed capacity (ICAP) goes ⬆… Accreditable capacity (UCAP) goes ⬇

ELCC – Effective Load Carrying Capability

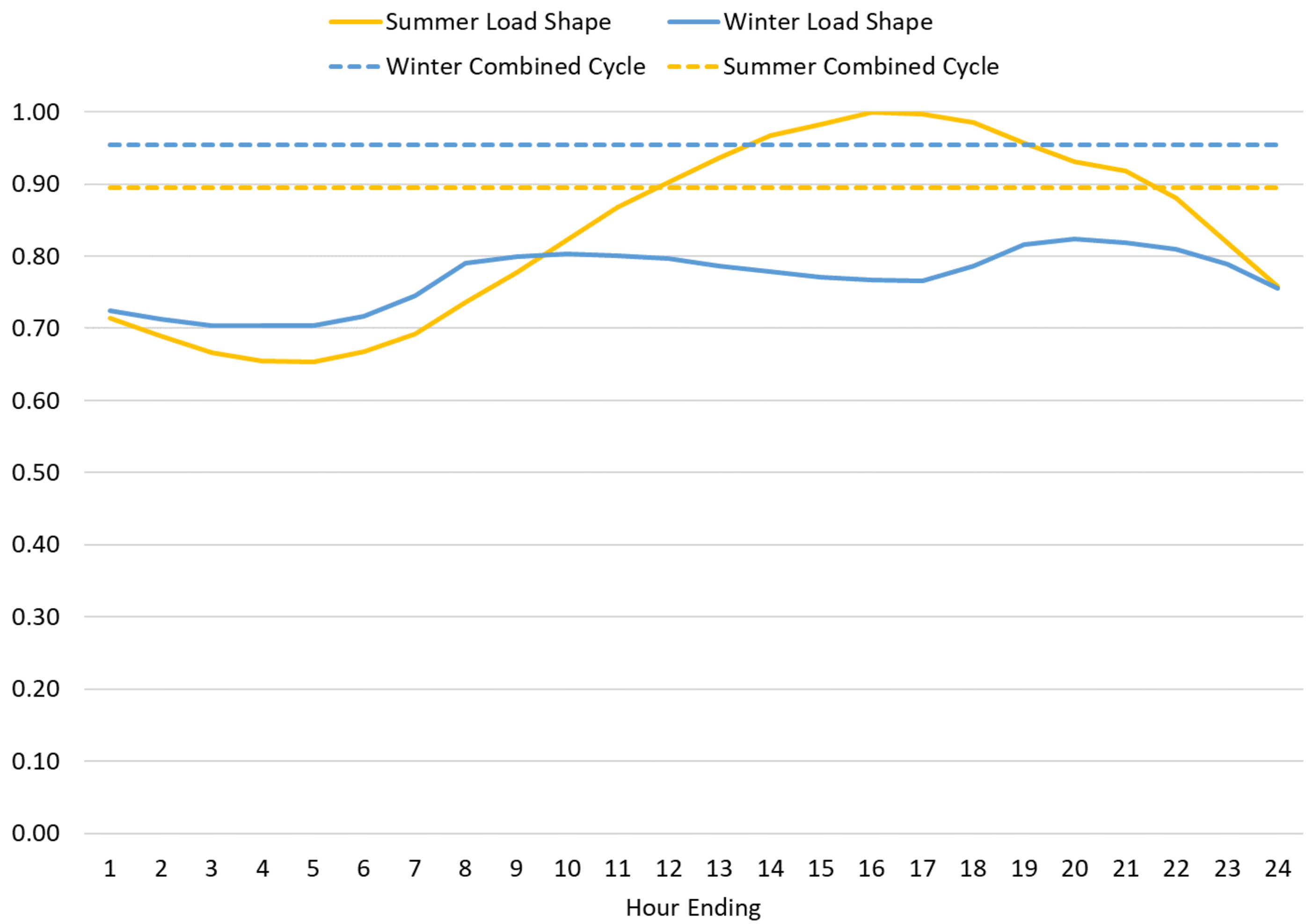
# SOLAR SEASONAL DIFFERENCES



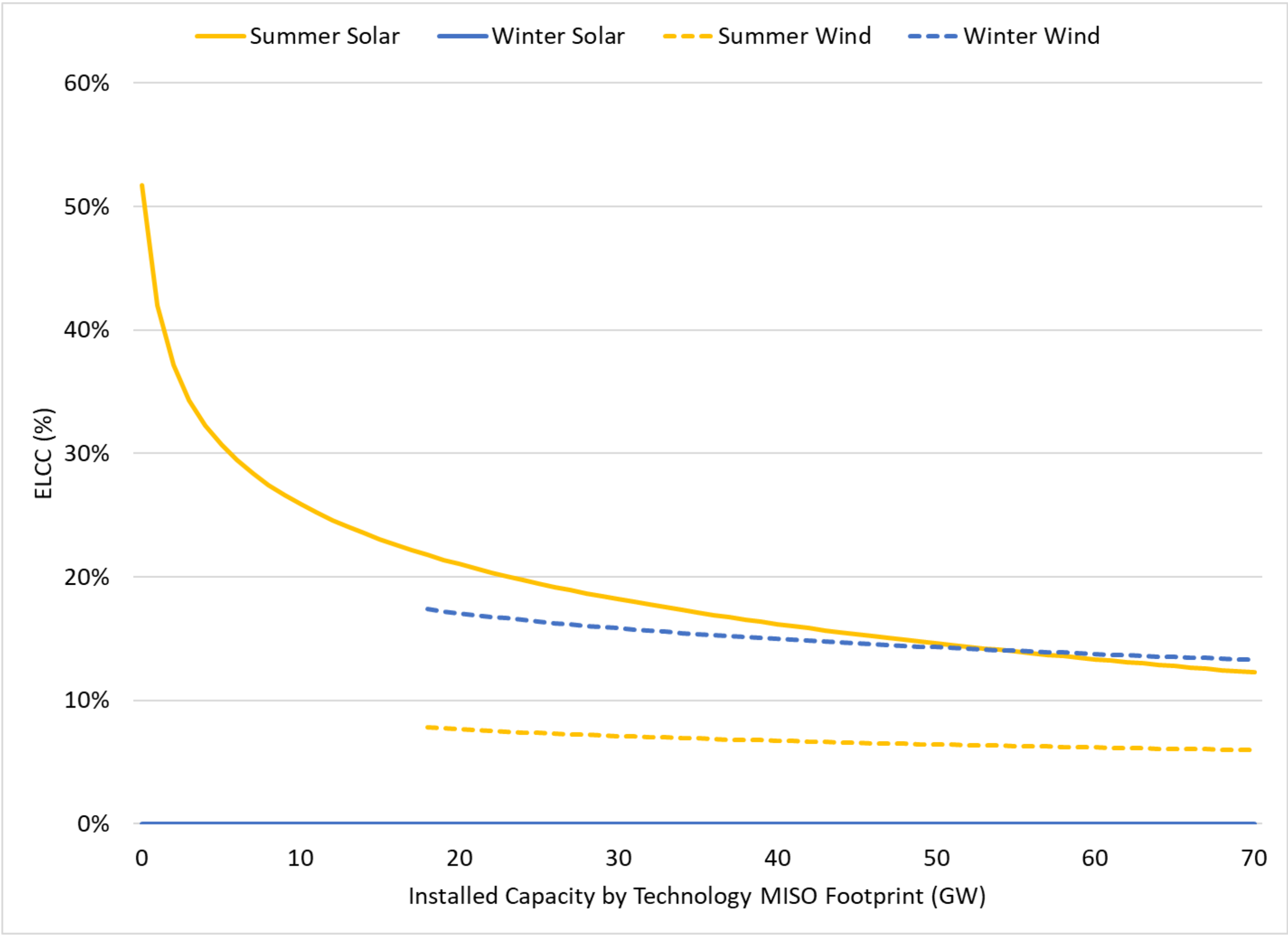
# WIND SEASONAL DIFFERENCES



# COMBINED CYCLE SEASONAL DIFFERENCES

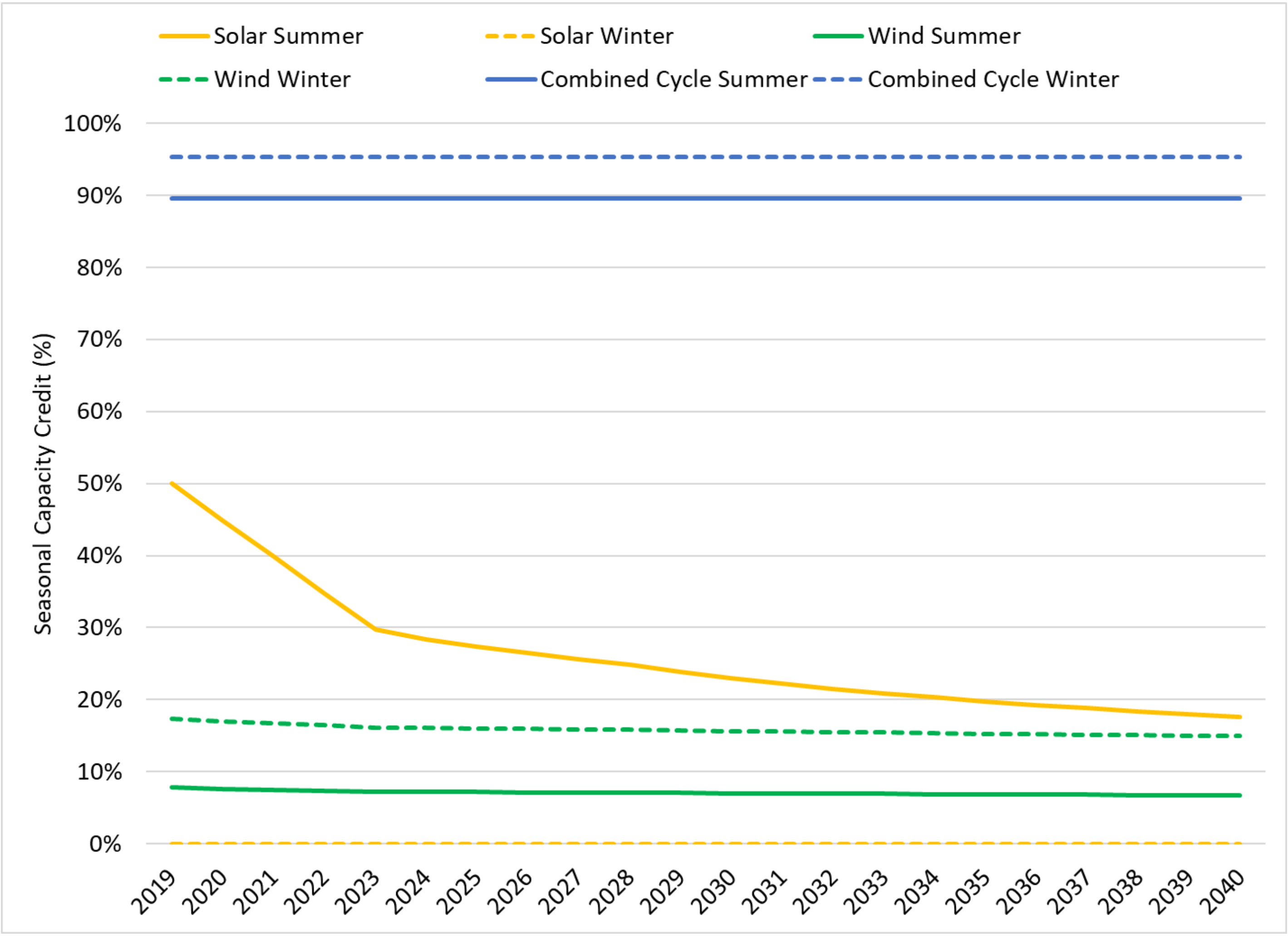


# ZONE 6 SEASONAL ACCREDITATION




Winter accreditation based on similar methodology to summer

# SEASONAL CAPACITY CREDIT FORECAST

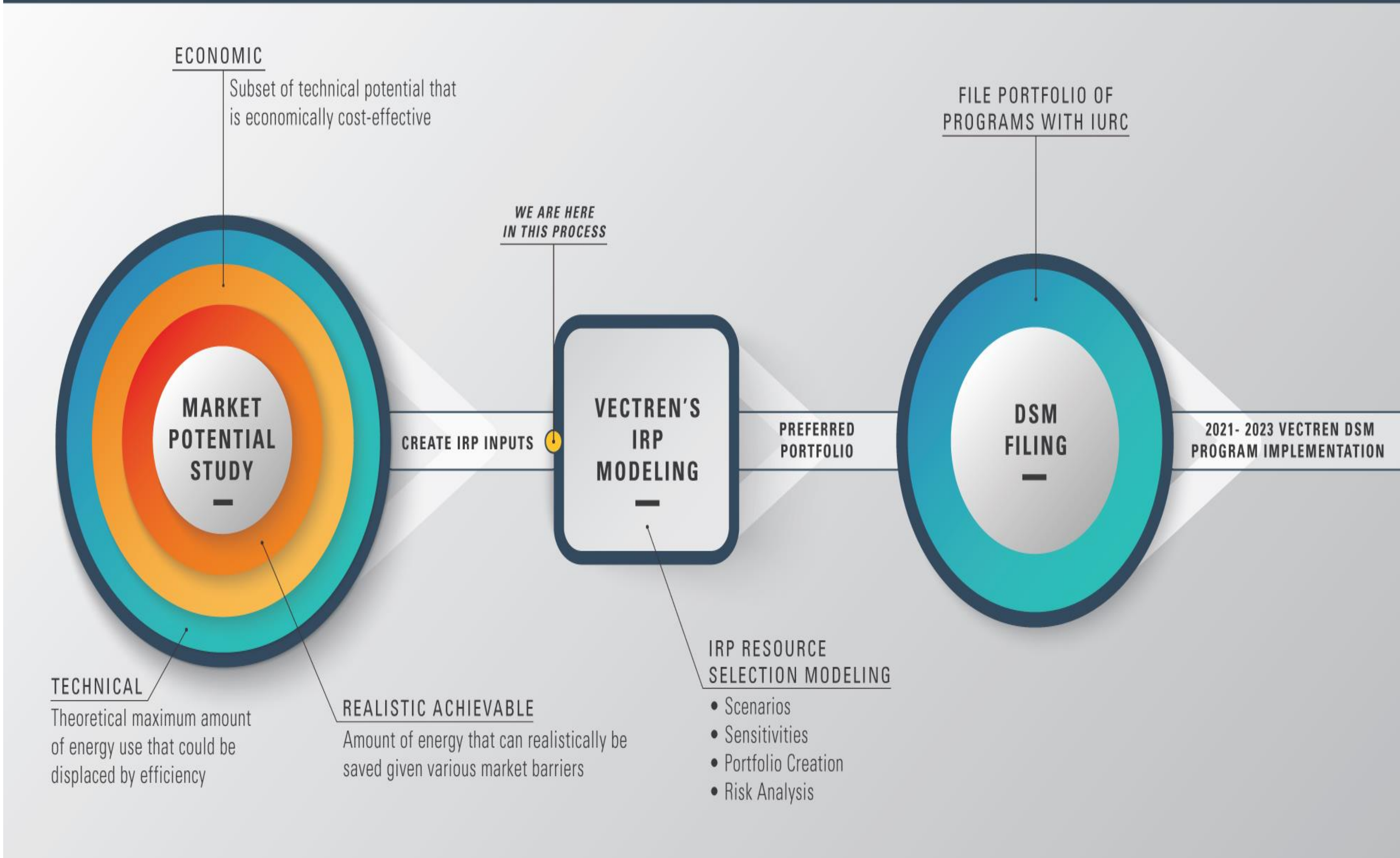


# DSM MODELING IN THE IRP

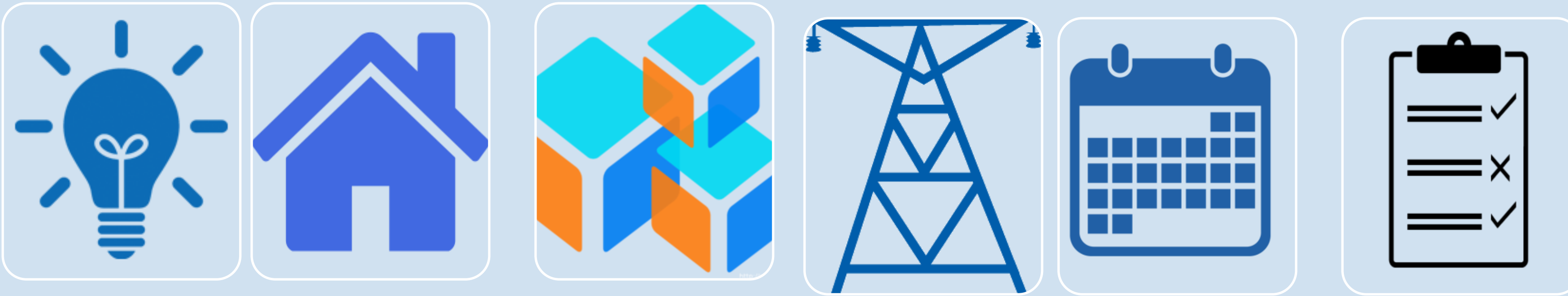
**JEFFREY HUBER**

MANAGING DIRECTOR, GDS ASSOCIATES

# Demand Side Management Process (DSM) and the Integrated Resources Plan (IRP)



# ENERGY EFFICIENCY MODELING ASSUMPTIONS



No minimum level of EE has been embedded into our sales and demand forecast

EE savings for 2018-2020 will be based on EE plan approved in Cause 44927

Total of 10 bundles, of which 8 can be selected including DR.

7 EE bundles are available at 0.25% of eligible sales

The model may select up to 1.75% of eligible sales annually. Aligns with realistic achievable potential in MPS

EE bundles represent bundle of low cost to high cost programs

For optimization runs, EE bundle selection will run for a 3 year period for the 1st 6 years

# IMPROVEMENTS SUMMARY

- 2019 modeled savings and costs will tie directly to latest Market Potential Study (completed 2019)
  - MPS analysis reliant on empirical/historical data derived from DSM effects by Vectren customers
- Initial years savings disconnected from later years
- Utilize bundle specific load shapes
- Include demand response bundles
- Conduct sensitivities

# DSM BUNDLES IN IRP MODELING APPROACH OVERVIEW

***BASE CASE***

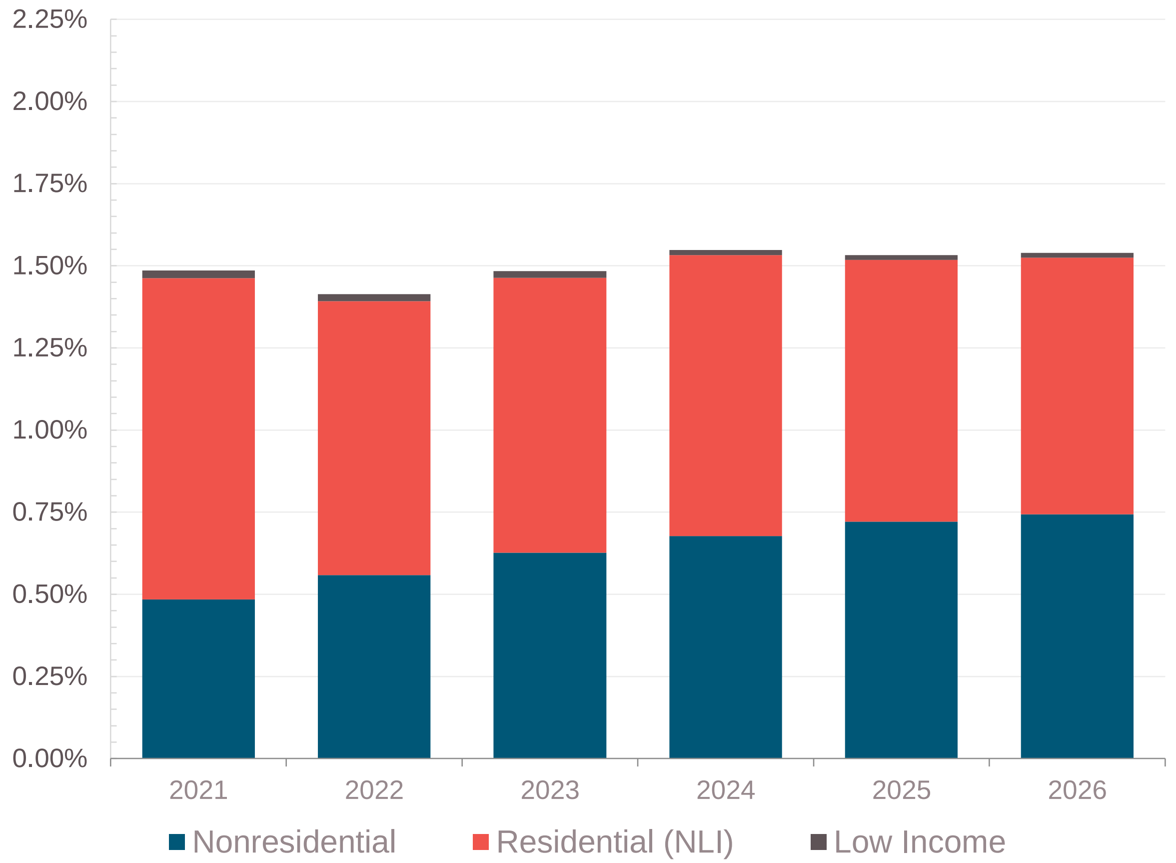
- DSM Bundles are 0.25% of annual load excluding opt-out sales
- Bundles are developed using the results from the 2018 Market Potential Study's (MPS) Realistic Achievable Potential
- Each bundle can have a mixture of residential and non-residential electric energy efficiency measures
- Each bundle has an associated loadshape and cost/MWh that serves as inputs into the IRP model
- Up to 10 bundles will be included as a selectable resource in the IRP model
    - 7 Energy Efficiency
    - 1 Low income
    - 2 Demand Response

# DSM BUNDLES IN IRP MODELING INCREMENTAL SAVINGS FROM MPS

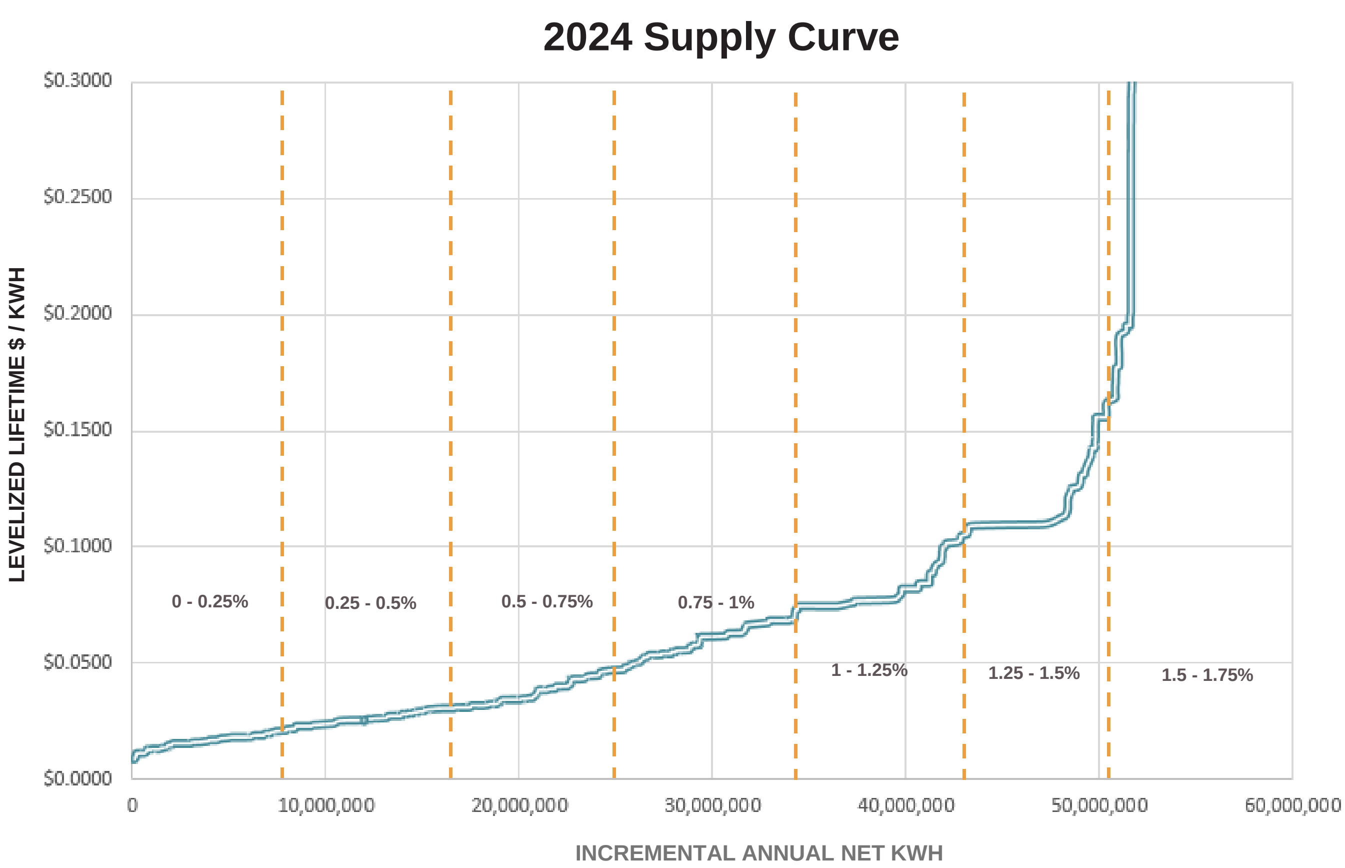
***Step 1:*** ***Initial RAP Potential Estimates from MPS***

***Step 2:*** ***Apply NTG Ratios (used latest evaluated NTG ratios)***

***Step 3:*** ***Align Low Income Savings based on Historcal Spend***



# DSM BUNDLES IN IRP MODELING
# SUPPLY CURVE BUNDLE DEVELOPMENT




- Residential and Non-residential electric energy efficiency measures were ranked from cheapest to most expensive
- Measures were then bundled into groups of roughly 0.25% ***net*** energy savings, with each progressive bundle more expensive then the prior bundle
- Total amount of savings (and # of bundles) is dependent on the realistic achievable potential identified each year
- In 2024 example, the RAP allows for 6 complete bundles, and a partial 7th bundle

# DSM BUNDLES IN IRP MODELING
# BASE CASE LEVELIZED COST PER KWH

VECTREN
A CenterPoint Energy Company

| | 1 | 2 | 3 | 4 | 5 | 6 | 7 | LI |
|---|---|---|---|---|---|---|---|---|
| | Gross Projected Cost per KWh; Cumulative by Bundle | | | | | | | |
| 2021 | $0.0144 | $0.0189 | $0.0209 | $0.0240 | $0.0279 | $0.0328 | | $0.1517 |
| 2022 | $0.0144 | $0.0189 | $0.0226 | $0.0266 | $0.0300 | $0.0347 | | $0.1670 |
| 2023 | $0.0147 | $0.0190 | $0.0226 | $0.0271 | $0.0314 | $0.0359 | | $0.1839 |
| 2024 | $0.0151 | $0.0188 | $0.0228 | $0.0279 | $0.0326 | $0.0348 | $0.0374 | $0.2115 |
| 2025 | $0.0156 | $0.0204 | $0.0244 | $0.0298 | $0.0346 | $0.0381 | $0.0390 | $0.2265 |
| 2026 | $0.0160 | $0.0212 | $0.0258 | $0.0312 | $0.0360 | $0.0396 | $0.0406 | $0.2398 |
| 2027 | $0.0166 | $0.0223 | $0.0269 | $0.0329 | $0.0376 | $0.0411 | $0.0421 | $0.2583 |
| 2028 | $0.0172 | $0.0235 | $0.0288 | $0.0342 | $0.0393 | $0.0429 | $0.0442 | $0.2630 |
| 2029 | $0.0181 | $0.0245 | $0.0306 | $0.0367 | $0.0410 | $0.0454 | | $0.2648 |
| 2030 | $0.0190 | $0.0268 | $0.0318 | $0.0371 | $0.0424 | $0.0474 | | $0.2608 |
| 2031 | $0.0198 | $0.0277 | $0.0325 | $0.0390 | $0.0436 | $0.0482 | | $0.2686 |
| 2032 | $0.0208 | $0.0286 | $0.0353 | $0.0409 | $0.0455 | $0.0506 | | $0.2459 |
| 2033 | $0.0220 | $0.0297 | $0.0373 | $0.0439 | $0.0470 | $0.0520 | | $0.2494 |
| 2034 | $0.0228 | $0.0307 | $0.0394 | $0.0455 | $0.0487 | $0.0539 | | $0.2164 |
| 2035 | $0.0188 | $0.0243 | $0.0294 | $0.0366 | $0.0420 | $0.0441 | $0.0491 | $0.2411 |
| 2036 | $0.0190 | $0.0241 | $0.0291 | $0.0363 | $0.0413 | $0.0441 | $0.0491 | $0.2538 |
| 2037 | $0.0190 | $0.0242 | $0.0291 | $0.0357 | $0.0412 | $0.0442 | $0.0490 | $0.2064 |
| 2038 | $0.0198 | $0.0233 | $0.0294 | $0.0353 | $0.0406 | $0.0452 | $0.0499 | $0.2118 |
| 2039 | $0.0206 | $0.0238 | $0.0302 | $0.0354 | $0.0415 | $0.0459 | $0.0505 | $0.2175 |

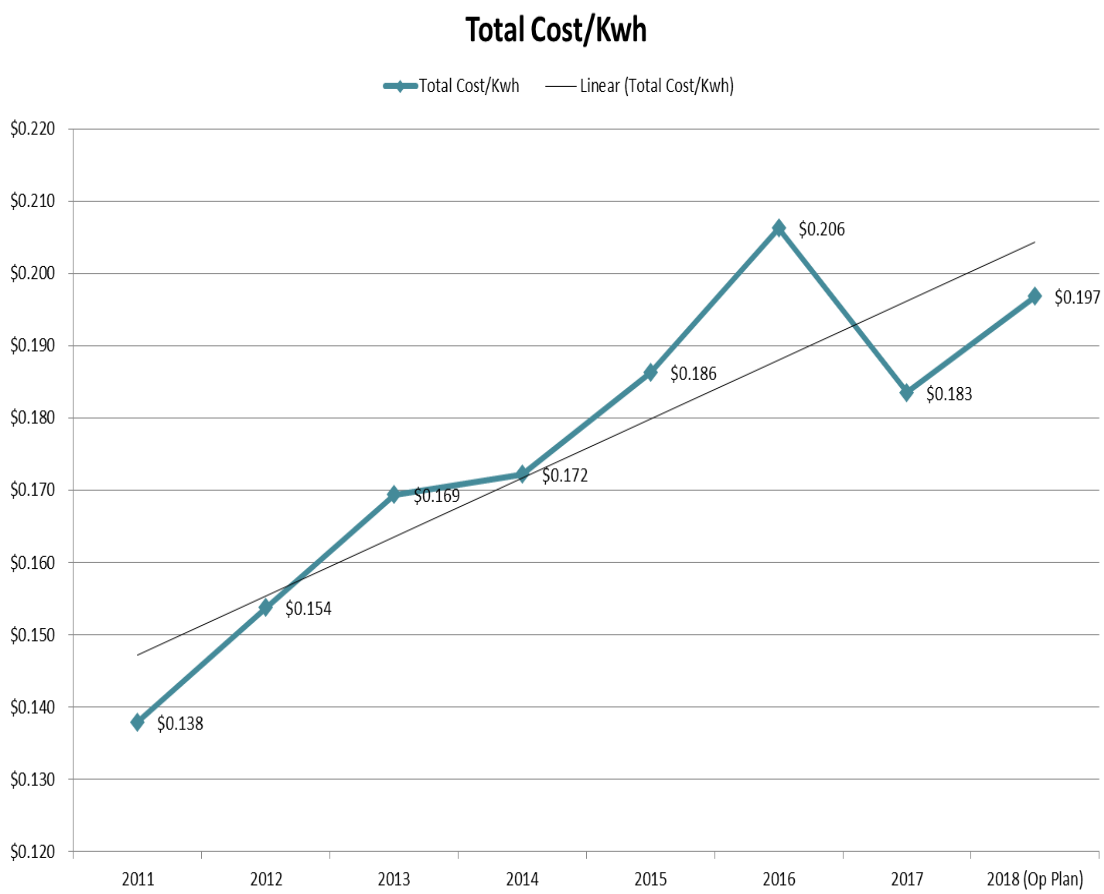
- LI Costs reflect paying 100% incentives for measures.
- Aligned to historical levels to produce an annual budget of $1.15 million per year
- Annual savings range from 457 MWh to 889 MWh

- Cost per bundle and annual costs are based on 2018 MPS costs, with two exceptions:
- IRP bundles reduced non-residential incentive costs in early years to more closely align with historical and 2019 planned Vectren data
- Non-incentive program costs were escalated at an annual estimated rate of inflation of 2.2% (in lieu of 1.6%) to be consistent with other IRP planning assumptions

# DSM BUNDLES IN IRP MODELING
# DSM BUNDLE SENSITIVITIES

***HIGH/LOW CASE***

- Sensitivity to reflect alternative DSM Costs
- Used 2011-2018 actual portfolio costs
  Calculated one standard deviation from the mean ($0.02097)
- Results in 11.9% increase/reduction in levelized cost
- No sensitivity performed on low-income potential



# DSM BUNDLES IN IRP MODELING
# DEMAND RESPONSE BUNDLES

- Two Demand Response bundles
- First bundle includes AC DLC as well as Smart Thermostat DR (from Smart Cycle Program) (fixed)
  - Slow phase out of DLC Switch and replacement with Thermostat-controlled DR through 2039
  - Projected Summer Peak impacts range from 17.5 MW (2020) to 36.9 MW (2039)
- Second bundle include BYOT Thermostat DR (selectable)

# FEEDBACK AND DISCUSSION

# STAKEHOLDER BREAKOUT SESSION: STRATEGY DEVELOPMENT

**GARY VICINUS**

MANAGING DIRECTOR FOR UTILITIES, PACE GLOBAL

# STAKEHOLDER BREAKOUT SESSION

- The purpose of this breakout session is to allow stakeholders to discuss and develop several different strategies to meet load obligations over the next 20 years
- Specifically, stakeholders are asked to collaborate to develop alternative or additional strategies to the ones already being modeled, i.e. 80% reduction in $CO_2$ by 2050
- We will run a least-cost portfolio run for various strategies
- Breakout Process:

1. Separate into groups
2. Discuss potential strategies to meet load obligations over the next 20 years, i.e. least cost, minimizing $CO_2$, diversification, etc.
3. Designate a spokes person for each table (those on the phone are welcome to send in suggestions at irp@centerpointenergy.com)
4. In the next meeting, strategies will be defined as model structures
5. Structures will be consolidated into several portfolios for further evaluation. We will take your into consideration and ultimately develop 10-15 portfolios for modeling. Final portfolios will be discussed in the third stakeholder meeting

# PORTFOLIO STRATEGY WORKSHEET

Create a set of strategies for a portfolio and the timeframe for implementation:

| Strategy | Timeframe |
|---|---|
| | |
| | |
| | |
| | |
| | |

Short-term=2019-2021; Medium-term=2022-2028; Long-term=2029-2039

# FEEDBACK AND DISCUSSION

# APPENDIX

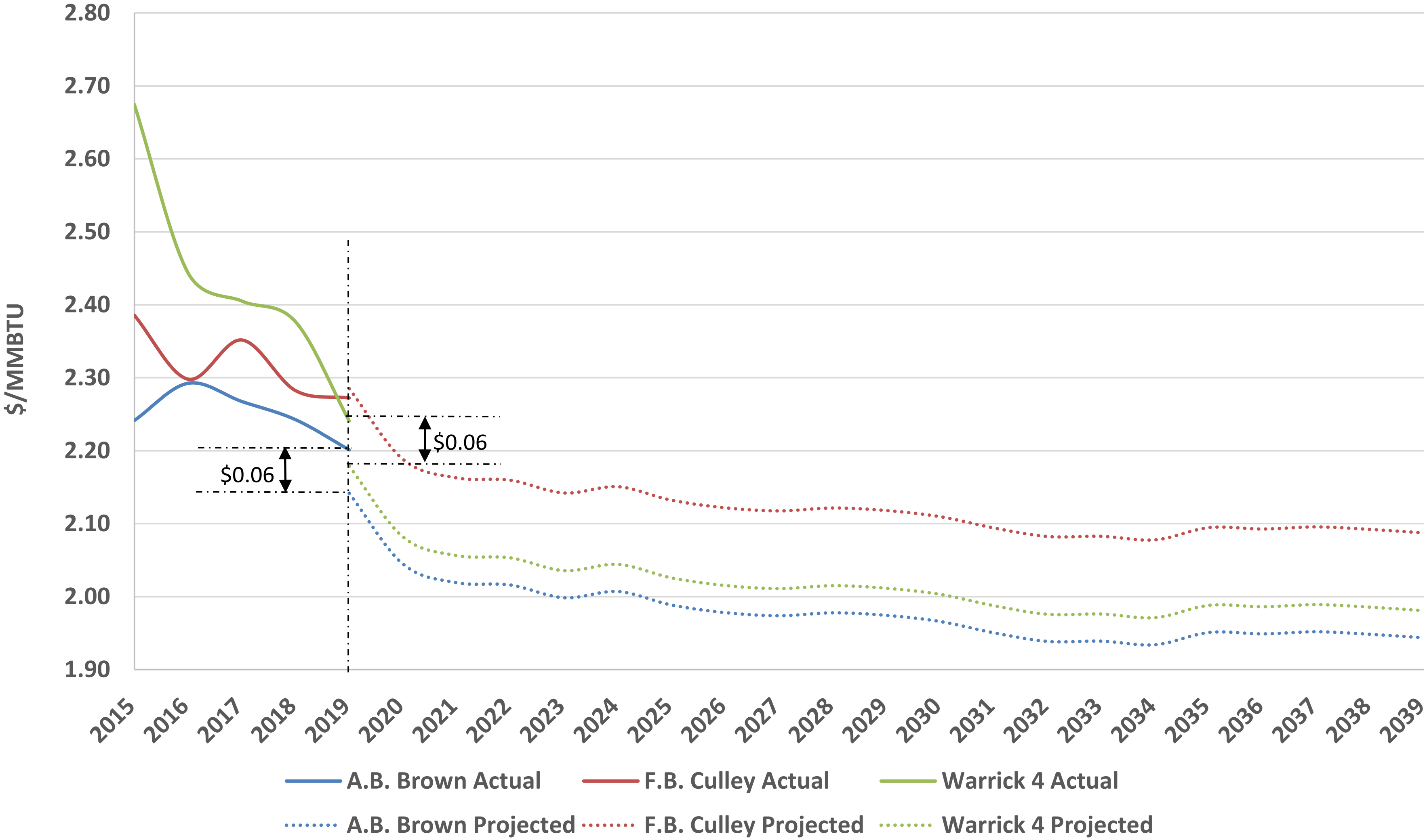
VECTREN
A CenterPoint Energy Company

# ADDITIONAL STAKEHOLDER FEEDBACK

| Request | Response |
|---|---|
| Scenarios: Include the social cost of carbon. | Included in the High Regulatory scenario. |
| Portfolio development: Provide a list of potential portfolio strategies within the Q&A document to help groups prepare for the portfolio development workshop. | Included within meeting minutes Q&A posted to vectren.com/irp |
| Portfolio development: Flag portfolios that meet Intergovernmental Panel on Climate Change (IPCC) criteria. | IPCC criteria can be raised during the portfolio development discussion to ensure that we build portfolios that meet the criteria. |
| Listen to a local talk on Indiana Climate Change (Purdue). | Vectren attended the local meeting. |
| Please provide historic delivered coal prices, compared to projections | Please see the appendix for this slide. |
| Identify impacts on different customer groups (e.g. disadvantaged) | Price impacts are a big consideration within portfolio evaluation, captured in the scorecard. However, impacts of eventual rate making proceedings are not within scope of an IRP. |
| Post meeting minutes in Q&A format | Meeting minutes Q&A posted to vectren.com/irp |

# FOLLOW-UP QUESTION
# DELIVERED COAL COST

VECTREN
A CenterPoint Energy Company



# DRAFT BASE CASE INPUTS

| Input | Unit | 2019 | 2021 | 2023 | 2025 | 2027 | 2029 | 2031 | 2033 | 2035 | 2037 | 2039 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Coal (ILB mine) | 2018$/MMBtu | 1.78 | 1.66 | 1.64 | 1.63 | 1.61 | 1.61 | 1.59 | 1.58 | 1.59 | 1.59 | 1.58 |
| CO2 | 2018$/ton | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| Gas (Henry Hub) | 2018$/MMBtu | 2.77 | 2.76 | 3.06 | 3.24 | 3.38 | 3.49 | 3.62 | 3.78 | 3.96 | 4.09 | 4.17 |
| Vectren Peak Load | MW | 1,115 | 1,102 | 1,168 | 1,176 | 1,183 | 1,192 | 1,200 | 1,209 | 1,219 | 1,229 | 1,239 |
| Wind (200 MW) | 2018$/kW | 1,334 | 1,330 | 1,328 | 1,326 | 1,324 | 1,324 | 1,324 | 1,324 | 1,326 | 1,328 | 1,330 |
| Solar (100 MW) | 2018$/kW | 1,524 | 1,362 | 1,290 | 1,247 | 1,204 | 1,162 | 1,129 | 1,100 | 1,070 | 1,050 | 1,029 |
| Li-Ion Battery (50 MW, 4 hr) | 2018$/kW | 2,088 | 1,811 | 1,654 | 1,518 | 1,452 | 1,391 | 1,342 | 1,301 | 1,263 | 1,232 | 1,201 |
| Flow Battery (50 MW, 6 hr) | 2018$/kW | 2,968 | 2,665 | 2,450 | 2,242 | 2,116 | 1,996 | 1,892 | 1,803 | 1,719 | 1,651 | 1,586 |
| Gas CC (442 MW + DF) | 2018$/kW | 1,122 | 1,114 | 1,100 | 1,088 | 1,079 | 1,072 | 1,063 | 1,056 | 1,049 | 1,042 | 1,034 |
| Gas CT (237 MW) | 2018$/kW | 548 | 544 | 536 | 529 | 525 | 521 | 517 | 513 | 510 | 506 | 502 |
| USC Coal w/ CCS | 2018$/kW | 5,421 | 5,339 | 5,231 | 5,121 | 5,016 | 4,916 | 4,814 | 4,717 | 4,624 | 4,531 | 4,445 |

# DRAFT LOW REGULATORY CASE INPUTS

| Input | Unit | 2019 | 2021 | 2023 | 2025 | 2027 | 2029 | 2031 | 2033 | 2035 | 2037 | 2039 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Coal (ILB mine) | 2018$/MMBtu | 1.78 | 1.66 | 1.64 | 1.63 | 1.61 | 1.61 | 1.59 | 1.58 | 1.59 | 1.59 | 1.58 |
| CO2 | 2018$/ton | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| Gas (Henry Hub) | 2018$/MMBtu | 2.77 | 2.76 | 4.10 | 5.12 | 5.20 | 5.62 | 5.60 | 5.95 | 6.12 | 6.23 | 6.85 |
| Vectren Peak Load | MW | 1,115 | 1,102 | 1,217 | 1,311 | 1,314 | 1,352 | 1,357 | 1,390 | 1,381 | 1,386 | 1,423 |
| Wind (200 MW) | 2018$/kW | 1,334 | 1,330 | 1,328 | 1,326 | 1,324 | 1,324 | 1,324 | 1,324 | 1,326 | 1,328 | 1,330 |
| Solar (100 MW) | 2018$/kW | 1,524 | 1,362 | 1,290 | 1,247 | 1,204 | 1,162 | 1,129 | 1,100 | 1,070 | 1,050 | 1,029 |
| Li-Ion Battery (50 MW, 4 hr) | 2018$/kW | 2,088 | 1,811 | 1,654 | 1,518 | 1,452 | 1,391 | 1,342 | 1,301 | 1,263 | 1,232 | 1,201 |
| Flow Battery (50 MW, 6 hr) | 2018$/kW | 2,968 | 2,665 | 2,450 | 2,242 | 2,116 | 1,996 | 1,892 | 1,803 | 1,719 | 1,651 | 1,586 |
| Gas CC (442 MW + DF) | 2018$/kW | 1,122 | 1,114 | 1,100 | 1,088 | 1,079 | 1,072 | 1,063 | 1,056 | 1,049 | 1,042 | 1,034 |
| Gas CT (237 MW) | 2018$/kW | 548 | 544 | 536 | 529 | 525 | 521 | 517 | 513 | 510 | 506 | 502 |
| USC Coal w/ CCS | 2018$/kW | 5,421 | 5,339 | 5,231 | 5,121 | 5,016 | 4,916 | 4,814 | 4,717 | 4,624 | 4,531 | 4,445 |

# DRAFT HIGH TECHNOLOGY CASE INPUTS

VECTREN
A CenterPoint Energy Company

| Input | Unit | 2019 | 2021 | 2023 | 2025 | 2027 | 2029 | 2031 | 2033 | 2035 | 2037 | 2039 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Coal (ILB mine) | 2018$/MMBtu | 1.78 | 1.66 | 1.49 | 1.27 | 1.25 | 1.25 | 1.25 | 1.25 | 1.25 | 1.25 | 1.25 |
| CO2 | 2018$/ton | 0.00 | 0.00 | 0.00 | 1.20 | 2.06 | 2.38 | 2.94 | 3.89 | 5.46 | 6.85 | 8.50 |
| Gas (Henry Hub) | 2018$/MMBtu | 2.77 | 2.76 | 2.82 | 2.33 | 2.13 | 2.04 | 2.13 | 2.02 | 2.12 | 2.07 | 2.20 |
| Vectren Peak Load | MW | 1,115 | 1,102 | 1,217 | 1,311 | 1,314 | 1,352 | 1,357 | 1,390 | 1,381 | 1,386 | 1,423 |
| Wind (200 MW) | 2018$/kW | 1,334 | 1,330 | 1,249 | 1,167 | 1,123 | 1,160 | 1,152 | 1,166 | 1,139 | 1,142 | 1,143 |
| Solar (100 MW) | 2018$/kW | 1,524 | 1,362 | 1,202 | 1,041 | 1,026 | 999 | 952 | 929 | 866 | 856 | 865 |
| Li-Ion Battery (50 MW, 4 hr) | 2018$/kW | 2,088 | 1,811 | 1,513 | 1,214 | 1,156 | 1,096 | 1,042 | 965 | 928 | 901 | 894 |
| Flow Battery (50 MW, 6 hr) | 2018$/kW | 2,968 | 2,665 | 2,220 | 1,774 | 1,678 | 1,538 | 1,408 | 1,231 | 1,268 | 1,124 | 1,020 |
| Gas CC (442 MW + DF) | 2018$/kW | 1,122 | 1,114 | 1,100 | 1,088 | 1,079 | 1,072 | 1,063 | 1,056 | 1,049 | 1,042 | 1,034 |
| Gas CT (237 MW) | 2018$/kW | 548 | 544 | 536 | 529 | 525 | 521 | 517 | 513 | 510 | 506 | 502 |
| USC Coal w/ CCS | 2018$/kW | 5,421 | 5,339 | 5,231 | 5,121 | 5,016 | 4,916 | 4,814 | 4,717 | 4,624 | 4,531 | 4,445 |

# 80% REDUCTION CASE INPUTS

| Input | Unit | 2019 | 2021 | 2023 | 2025 | 2027 | 2029 | 2031 | 2033 | 2035 | 2037 | 2039 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Coal (ILB mine) | 2018$/MMBtu | 1.78 | 1.66 | 1.49 | 1.27 | 1.25 | 1.25 | 1.25 | 1.25 | 1.25 | 1.25 | 1.25 |
| CO2 | 2018$/ton | 0.00 | 0.00 | 0.00 | 3.57 | 5.10 | 6.63 | 7.65 | 9.18 | 11.22 | 14.79 | 19.89 |
| Gas (Henry Hub) | 2018$/MMBtu | 2.77 | 2.76 | 3.06 | 3.24 | 3.38 | 3.49 | 3.62 | 3.78 | 3.96 | 4.09 | 4.17 |
| Vectren Peak Load | MW | 1,115 | 1,102 | 1,131 | 1,060 | 1,025 | 1,039 | 1,038 | 1,038 | 1,053 | 1,053 | 1,065 |
| Wind (200 MW) | 2018$/kW | 1,334 | 1,330 | 1,249 | 1,167 | 1,123 | 1,160 | 1,152 | 1,166 | 1,139 | 1,142 | 1,143 |
| Solar (100 MW) | 2018$/kW | 1,524 | 1,362 | 1,202 | 1,041 | 1,026 | 999 | 952 | 929 | 866 | 856 | 865 |
| Li-Ion Battery (50 MW, 4 hr) | 2018$/kW | 2,088 | 1,811 | 1,513 | 1,214 | 1,156 | 1,096 | 1,042 | 965 | 928 | 901 | 894 |
| Flow Battery (50 MW, 6 hr) | 2018$/kW | 2,968 | 2,665 | 2,220 | 1,774 | 1,678 | 1,538 | 1,408 | 1,231 | 1,268 | 1,124 | 1,020 |
| Gas CC (442 MW + DF) | 2018$/kW | 1,122 | 1,114 | 1,100 | 1,088 | 1,079 | 1,072 | 1,063 | 1,056 | 1,049 | 1,042 | 1,034 |
| Gas CT (237 MW) | 2018$/kW | 548 | 544 | 536 | 529 | 525 | 521 | 517 | 513 | 510 | 506 | 502 |
| USC Coal w/ CCS | 2018$/kW | 5,421 | 5,339 | 5,231 | 5,121 | 5,016 | 4,916 | 4,814 | 4,717 | 4,624 | 4,531 | 4,445 |

# DRAFT HIGH REGULATORY CASE INPUTS

| Input | Unit | 2019 | 2021 | 2023 | 2025 | 2027 | 2029 | 2031 | 2033 | 2035 | 2037 | 2039 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Coal (ILB mine) | 2018$/MMBtu | 1.78 | 1.66 | 1.49 | 1.27 | 1.25 | 1.25 | 1.25 | 1.25 | 1.25 | 1.25 | 1.25 |
| CO2 | 2018$/ton | 0.00 | 0.00 | 50.40 | 52.28 | 54.17 | 56.05 | 57.94 | 60.06 | 62.41 | 64.77 | 67.12 |
| Gas (Henry Hub) | 2018$/MMBtu | 2.77 | 2.76 | 4.39 | 6.03 | 7.10 | 8.37 | 7.17 | 8.40 | 8.95 | 8.75 | 8.63 |
| Vectren Peak Load | MW | 1,115 | 1,102 | 1,168 | 1,176 | 1,183 | 1,192 | 1,200 | 1,209 | 1,219 | 1,229 | 1,239 |
| Wind (200 MW) | 2018$/kW | 1,334 | 1,330 | 1,249 | 1,167 | 1,123 | 1,160 | 1,152 | 1,166 | 1,139 | 1,142 | 1,143 |
| Solar (100 MW) | 2018$/kW | 1,524 | 1,362 | 1,202 | 1,041 | 1,026 | 999 | 952 | 929 | 866 | 856 | 865 |
| Li-Ion Battery (50 MW, 4 hr) | 2018$/kW | 2,088 | 1,811 | 1,513 | 1,214 | 1,156 | 1,096 | 1,042 | 965 | 928 | 901 | 894 |
| Flow Battery (50 MW, 6 hr) | 2018$/kW | 2,968 | 2,665 | 2,220 | 1,774 | 1,678 | 1,538 | 1,408 | 1,231 | 1,268 | 1,124 | 1,020 |
| Gas CC (442 MW + DF) | 2018$/kW | 1,122 | 1,114 | 1,100 | 1,088 | 1,079 | 1,072 | 1,063 | 1,056 | 1,049 | 1,042 | 1,034 |
| Gas CT (237 MW) | 2018$/kW | 548 | 544 | 536 | 529 | 525 | 521 | 517 | 513 | 510 | 506 | 502 |
| USC Coal w/ CCS | 2018$/kW | 5,421 | 5,339 | 5,231 | 5,121 | 5,016 | 4,916 | 4,814 | 4,717 | 4,624 | 4,531 | 4,445 |

# DSM BUNDLES IN IRP MODELING
# DSM BUNDLE SENSITIVITIES

| | 1 | 2 | 3 | 4 | 5 | 6 | 7 |
|---|---|---|---|---|---|---|---|
| | Gross Projected Cost per KWh; Cumulative by Bundle (LOW CASE) | | | | | | |
| 2021 | $0.01270 | $0.01668 | $0.01840 | $0.02112 | $0.02461 | $0.02891 | |
| 2022 | $0.01265 | $0.01660 | $0.01992 | $0.02346 | $0.02643 | $0.03053 | |
| 2023 | $0.01298 | $0.01676 | $0.01994 | $0.02385 | $0.02764 | $0.03165 | |
| 2024 | $0.01332 | $0.01654 | $0.02009 | $0.02460 | $0.02868 | $0.03064 | $0.03291 |
| 2025 | $0.01374 | $0.01798 | $0.02149 | $0.02623 | $0.03043 | $0.03356 | $0.03434 |
| 2026 | $0.01408 | $0.01872 | $0.02274 | $0.02744 | $0.03172 | $0.03487 | $0.03578 |
| 2027 | $0.01461 | $0.01964 | $0.02373 | $0.02895 | $0.03316 | $0.03623 | $0.03708 |
| 2028 | $0.01515 | $0.02067 | $0.02537 | $0.03010 | $0.03460 | $0.03783 | $0.03895 |
| 2029 | $0.01593 | $0.02158 | $0.02695 | $0.03237 | $0.03616 | $0.03999 | |
| 2030 | $0.01671 | $0.02358 | $0.02804 | $0.03272 | $0.03732 | $0.04174 | |
| 2031 | $0.01742 | $0.02439 | $0.02864 | $0.03436 | $0.03838 | $0.04250 | |
| 2032 | $0.01829 | $0.02515 | $0.03111 | $0.03605 | $0.04009 | $0.04459 | |
| 2033 | $0.01942 | $0.02617 | $0.03285 | $0.03866 | $0.04136 | $0.04582 | |
| 2034 | $0.02010 | $0.02701 | $0.03467 | $0.04009 | $0.04292 | $0.04749 | |
| 2035 | $0.01656 | $0.02140 | $0.02586 | $0.03225 | $0.03697 | $0.03889 | $0.04328 |
| 2036 | $0.01674 | $0.02122 | $0.02561 | $0.03197 | $0.03641 | $0.03886 | $0.04329 |
| 2037 | $0.01670 | $0.02129 | $0.02566 | $0.03146 | $0.03627 | $0.03897 | $0.04315 |
| 2038 | $0.01742 | $0.02048 | $0.02591 | $0.03110 | $0.03577 | $0.03984 | $0.04399 |
| 2039 | $0.01814 | $0.02097 | $0.02656 | $0.03122 | $0.03652 | $0.04043 | $0.04449 |

| | 1 | 2 | 3 | 4 | 5 | 6 | 7 |
|---|---|---|---|---|---|---|---|
| | Gross Projected Cost per KWh; Cumulative by Bundle (HIGH CASE) | | | | | | |
| 2021 | $0.01613 | $0.02119 | $0.02337 | $0.02682 | $0.03126 | $0.03673 | |
| 2022 | $0.01607 | $0.02109 | $0.02530 | $0.02979 | $0.03357 | $0.03877 | |
| 2023 | $0.01649 | $0.02129 | $0.02533 | $0.03029 | $0.03510 | $0.04020 | |
| 2024 | $0.01691 | $0.02100 | $0.02552 | $0.03125 | $0.03643 | $0.03892 | $0.04181 |
| 2025 | $0.01745 | $0.02283 | $0.02730 | $0.03332 | $0.03866 | $0.04262 | $0.04362 |
| 2026 | $0.01788 | $0.02377 | $0.02888 | $0.03486 | $0.04029 | $0.04429 | $0.04544 |
| 2027 | $0.01856 | $0.02495 | $0.03014 | $0.03677 | $0.04212 | $0.04601 | $0.04710 |
| 2028 | $0.01924 | $0.02626 | $0.03222 | $0.03823 | $0.04394 | $0.04805 | $0.04947 |
| 2029 | $0.02023 | $0.02742 | $0.03423 | $0.04111 | $0.04593 | $0.05080 | |
| 2030 | $0.02122 | $0.02995 | $0.03561 | $0.04156 | $0.04740 | $0.05302 | |
| 2031 | $0.02212 | $0.03098 | $0.03638 | $0.04364 | $0.04875 | $0.05398 | |
| 2032 | $0.02323 | $0.03195 | $0.03951 | $0.04579 | $0.05092 | $0.05663 | |
| 2033 | $0.02466 | $0.03324 | $0.04173 | $0.04911 | $0.05253 | $0.05820 | |
| 2034 | $0.02553 | $0.03431 | $0.04404 | $0.05092 | $0.05452 | $0.06032 | |
| 2035 | $0.02103 | $0.02718 | $0.03284 | $0.04096 | $0.04696 | $0.04939 | $0.05498 |
| 2036 | $0.02126 | $0.02695 | $0.03253 | $0.04060 | $0.04625 | $0.04936 | $0.05499 |
| 2037 | $0.02121 | $0.02704 | $0.03259 | $0.03996 | $0.04607 | $0.04949 | $0.05480 |
| 2038 | $0.02212 | $0.02601 | $0.03291 | $0.03950 | $0.04544 | $0.05060 | $0.05587 |
| 2039 | $0.02304 | $0.02663 | $0.03374 | $0.03965 | $0.04638 | $0.05135 | $0.05650 |

# DSM BUNDLES IN IRP MODELING BASE CASE LEVELIZED COST PER KWH

VECTREN
A CenterPoint Energy Company

| | 1 | 2 | 3 | 4 | 5 | 6 | 7 |
|---|---|---|---|---|---|---|---|
| | Gross Projected Cost per KWh; Cumulative by Bundle | | | | | | |
| 2021 | $0.0144 | $0.0189 | $0.0209 | $0.0240 | $0.0279 | $0.0328 | |
| 2022 | $0.0144 | $0.0189 | $0.0226 | $0.0266 | $0.0300 | $0.0347 | |
| 2023 | $0.0147 | $0.0190 | $0.0226 | $0.0271 | $0.0314 | $0.0359 | |
| 2024 | $0.0151 | $0.0188 | $0.0228 | $0.0279 | $0.0326 | $0.0348 | $0.0374 |
| 2025 | $0.0156 | $0.0204 | $0.0244 | $0.0298 | $0.0346 | $0.0381 | $0.0390 |
| 2026 | $0.0160 | $0.0212 | $0.0258 | $0.0312 | $0.0360 | $0.0396 | $0.0406 |
| 2027 | $0.0166 | $0.0223 | $0.0269 | $0.0329 | $0.0376 | $0.0411 | $0.0421 |
| 2028 | $0.0172 | $0.0235 | $0.0288 | $0.0342 | $0.0393 | $0.0429 | $0.0442 |
| 2029 | $0.0181 | $0.0245 | $0.0306 | $0.0367 | $0.0410 | $0.0454 | |
| 2030 | $0.0190 | $0.0268 | $0.0318 | $0.0371 | $0.0424 | $0.0474 | |
| 2031 | $0.0198 | $0.0277 | $0.0325 | $0.0390 | $0.0436 | $0.0482 | |
| 2032 | $0.0208 | $0.0286 | $0.0353 | $0.0409 | $0.0455 | $0.0506 | |
| 2033 | $0.0220 | $0.0297 | $0.0373 | $0.0439 | $0.0470 | $0.0520 | |
| 2034 | $0.0228 | $0.0307 | $0.0394 | $0.0455 | $0.0487 | $0.0539 | |
| 2035 | $0.0188 | $0.0243 | $0.0294 | $0.0366 | $0.0420 | $0.0441 | $0.0491 |
| 2036 | $0.0190 | $0.0241 | $0.0291 | $0.0363 | $0.0413 | $0.0441 | $0.0491 |
| 2037 | $0.0190 | $0.0242 | $0.0291 | $0.0357 | $0.0412 | $0.0442 | $0.0490 |
| 2038 | $0.0198 | $0.0233 | $0.0294 | $0.0353 | $0.0406 | $0.0452 | $0.0499 |
| 2039 | $0.0206 | $0.0238 | $0.0302 | $0.0354 | $0.0415 | $0.0459 | $0.0505 |

| | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 |
|---|---|---|---|---|---|---|---|---|
| | 2016 Projected Cost per kWh (Cumulative) | | | | | | | |
| 2017 | $0.03462 | $0.03480 | $0.03498 | $0.03516 | $0.04402 | $0.04998 | $0.05429 | $0.05756 |
| 2018 | $0.03607 | $0.03626 | $0.03645 | $0.03664 | $0.04547 | $0.05142 | $0.05572 | $0.05899 |
| 2019 | $0.03759 | $0.03779 | $0.03798 | $0.03818 | $0.04698 | $0.05291 | $0.05720 | $0.06046 |
| 2020 | $0.03917 | $0.03938 | $0.03958 | $0.03979 | $0.04855 | $0.05446 | $0.05873 | $0.06197 |
| 2021 | $0.04082 | $0.04103 | $0.04124 | $0.04146 | $0.05018 | $0.05606 | $0.06030 | $0.06354 |
| 2022 | $0.04254 | $0.04276 | $0.04298 | $0.04320 | $0.05187 | $0.05771 | $0.06193 | $0.06514 |
| 2023 | $0.04433 | $0.04456 | $0.04479 | $0.04502 | $0.05362 | $0.05942 | $0.06361 | $0.06680 |
| 2024 | $0.04619 | $0.04643 | $0.04667 | $0.04691 | $0.05544 | $0.06118 | $0.06534 | $0.06851 |
| 2025 | $0.04813 | $0.04837 | $0.04862 | $0.04888 | $0.05732 | $0.06301 | $0.06713 | $0.07027 |
| 2026 | $0.05016 | $0.05042 | $0.05068 | $0.05094 | $0.05928 | $0.06491 | $0.06898 | $0.07209 |
| 2027 | $0.05227 | $0.05254 | $0.05281 | $0.05309 | $0.06132 | $0.06687 | $0.07090 | $0.07397 |
| 2028 | $0.05447 | $0.05475 | $0.05503 | $0.05532 | $0.06343 | $0.06890 | $0.07286 | $0.07589 |
| 2029 | $0.05676 | $0.05705 | $0.05735 | $0.05765 | $0.06562 | $0.07101 | $0.07491 | $0.07789 |
| 2030 | $0.05914 | $0.05945 | $0.05976 | $0.06007 | $0.06789 | $0.07318 | $0.07702 | $0.07995 |
| 2031 | $0.06163 | $0.06195 | $0.06227 | $0.06260 | $0.07026 | $0.07544 | $0.07920 | $0.08207 |
| 2032 | $0.06422 | $0.06456 | $0.06489 | $0.06523 | $0.07271 | $0.07777 | $0.08145 | $0.08426 |
| 2033 | $0.06693 | $0.06728 | $0.06758 | $0.06795 | $0.07524 | $0.08017 | $0.08376 | $0.08651 |
| 2034 | $0.06974 | $0.07010 | $0.07046 | $0.07083 | $0.07790 | $0.08269 | $0.08618 | $0.08885 |
| 2035 | $0.07268 | $0.07306 | $0.07343 | $0.07382 | $0.08066 | $0.08529 | $0.08867 | $0.09127 |
| 2036 | $0.07573 | $0.07613 | $0.07652 | $0.07692 | $0.08351 | $0.08798 | $0.09125 | $0.09375 |

**Vectren 2019 IRP**
**2nd Stakeholder Meeting Minutes Q&A**
*October 10, 2019, 9:00 a.m. – 3:00 p.m.*

**Lynnae Wilson** (CenterPoint Energy Indiana Electric Chief Business Officer) – Welcome and Safety Message (distracted driving) and Vectren introductions

> Subject Matter Experts in the room: Anna Nightingale, Justin Joiner, Ryan Wilhelmus, Matt Rice, Wayne Games, Tom Bailey, Steve Rawlinson, Rina Harris, Shane Bradford, Heather Watts, Angie Bell, Natalie Hedde, Angie Casbon-Scheller, Bob Heidorn, Cas Swiz.

**Gary Vicinus** (Moderator, Managing Director for Utilities, Pace Global) discussed the agenda and provided a summary of stakeholder process (last meeting and present meeting). Approximately 35 stakeholders attended in person. List of affiliations include the following:

- CAC
- Country Mark
- Hallador Energy
- IBEW Local 702
- Inovateus Solar LLC
- IURC
- NIPSCO
- Orion Renewable Energy Group LLC
- OUCC
- Sierra Club
- Solarpack Development, Inc.
- SUFG
- Valley Watch

Approximately 35 registered to attend the webinar; several participated. Those registered included representatives from:

- Advanced Energy Economy
- AEP
- Boardwalk Pipeline Partners
- Development Partners Group
- Ecoplexus
- Energy and Policy Institute
- Energy Futures Group
- EQ Research
- First Solar
- Hoosier Energy
- ICC
- Indiana Distributed Energy Alliance
- IPL
- IURC

juwi Inc.

Lewis Kappes

MEEA

Morton Solar & Electric

NextEra

NextEra Energy Resources

OUCC

Sierra Club

Vote Solar

**Matt Rice** (Vectren Manager of Resource Planning) and **Gary Vicinus** (Pace Global, Managing Director for Utilities) – presented Follow-up Information Since Our Last Stakeholder Meeting - Slides 9-13

- Slide 13 Stakeholder Feedback Cont.:
    - Request for folks to introduce themselves in the room and on the phone
        - Response: We have a full agenda; maybe we can take 5 minutes if there is time.
- Slide 13 Stakeholder Feedback Cont.:
    - Question: Can we send you additional health benefits studies for your consideration?
        - Response: Yes
- Slides 17-18 Scenario Narratives:
    - Clarifying question: Can we focus more on these two slides, as I'm interested in discussing the changes?
        - Response: Yes, we can discuss at the end of this session.
- Slide 24: Feedback and Discussion:
    - Question: With regards to the uneconomic asset risk analysis, you mentioned that you would be running 200 iterations. Will you be considering an earthquake in one of those iterations when assessing a portfolio?
        - Response: We will be assessing changing market conditions; I would not say earthquakes. We will be assessing the costs of various portfolios to determine if a portfolio becomes uneconomic under various market conditions, including fuel, load, technology costs, etc.
    - Question: Last meeting, you said you would consider a carbon fee and dividend scenario. But what you've included doesn't look like what we proposed. It's apples and oranges. I'm suggesting a carbon dividend is national and would affect gas, coal, etc. right here in Indiana. By definition, a carbon dividend is Low Regulatory but it is lumped in here with High Regulatory. HR 763 is a pending bill at national level with 60+ co-sponsors that may very well become law [link: https://www.congress.gov/bill/116th-congress/house-bill/763]. This was recently highlighted in a January Wall Street Journal article [WSJ article link: https://www.wsj.com/articles/economists-statement-on-carbon-dividends-11547682910] with a letter signed by 3,500 prominent economists advocating for a carbon dividend that will happen within 20 year timeframe of IRP. You've put it in High Reg but it looks more like the 80% case. No one is talking about cap & trade anymore. Rather than generic terms, why not put in this pending legislation and why not put it in the Low Reg scenario? Use what the bill proposed: $15/ton in first year, escalates by $10/ton each year thereafter?
        - Response: We'll consider that feedback. We need to consider a range of carbon prices, and maybe what you've suggested will align better with another scenario.
    - Question: Why not use actual pending legislation based on Paris Accord?
        - Response: We are going to capture a very wide range of carbon prices in the analysis. We do consider the Paris Accord in our analysis; you will see the $CO_2$ graph that demonstrates this. You'll see very high carbon prices in one scenario,

a 2% solution, ACE, and we're also considering adding a carbon price to the Base Case.

- Question: You mentioned using global warming potential of methane. Does $CO_2$ -e capture this?
  - Response: $CO_2$ -e will be captured in the stochastic runs (risk analysis and included in the scorecard). But within the scenario analysis, it is $CO_2$ .
- Question: On Slide 21, Life Cycle Green House Gas (GHG) Emissions, what it really boils down to is methane. Credible reports show 2.3% methane leakage. Math is simple. Gas isn't any better than coal in terms of GHG emissions.
  - Response: This is based on an NREL study that considers upstream and downstream emissions, which includes methane leaks.
- Statement: It's not complicated, 2.3% leakage and 87x more global warming potential. You can do it on a scratch pad.
  - Response: We are including methane leakage. We want to have quantitative measures in our scorecard. This rate includes what you're asking for.
- Question: Are there only five possible scenarios in your modeling software? Can you add more, e.g., Lani Ethridge's scenario [HR 763]?
  - Response: I would like to hold this question until we discuss the scenario inputs and show you the wide range of scenarios that we've created. Additionally, we will gather strategies to create other portfolios later today.
- Question: Please let folks on phone ask questions. Thank you for the tentative 10/24 Aurora call with Energy Exemplar. However, the $5k cost raises incredibly grave concerns for us, particularly as this process is supposed to lessen disputes before we enter litigation phase. This cost forecloses stakeholder participation and charging us for transparency is problematic. Also, according to Indiana Administrative Code 170 IAC 4-7-2.5, Vectren doesn't comply if we can't access the model at this cost. In Michigan, a utility was granted ~10 licenses within their subscription.
  - Response: We'll talk about that during the call on 10/24.
- Question: On Slide 21, happy to see Life Cycle GHG emissions; however, the NREL study is very dated, especially on solar. Can I provide updated studies?
  - Response: Yes, please send, though what we liked about the NREL study was that it considered many other studies and multiple perspectives, even if it is a little dated.
- Question: All the closures and retirements in the 2016 IRP, is that the base case in this IRP?
  - Response: This IRP is an update, and we are re-evaluating. Wayne Games will discuss how we will be evaluating existing resources.
- Question: So, it's possible that AB Brown could stay open?
  - Response: Yes.
- Question: Can we please try again for the phone?
  - Response: Please type questions. We do not see any typed questions at the moment.

**Justin Joiner** (Director of Power Supply Services) – MISO Considerations – slides 25-32:

- Slide 26 MISO Summary
  - Question: Why do you attribute changing resource mix to accreditation when weather, forced outages at fossil fuels plants, etc. can also be a driver?
    - Response: We'll address in detail shortly but changing resource mix is one of the main drivers. Outrages or load are other contributing factors.
  - Question: Wouldn't an increase in emergency events change accreditation?
    - Response: No, let's address shortly.
- Slide 28 Congestion
  - Question: Please explain price separation in zone 6.
    - Response: Overnight when there are low load periods and high wind output, MISO sends a negative price signal, which lowers the price that we are receiving

there. The $5 price difference is a simple average over the last 12 months on an hourly basis.

- Question: Do we need more transmission since we're talking about congestion?
  - Response: Yes, the next slide discusses MISO planning. MISO has two processes. (Slide 29) Interconnection queue (paid by new generators) and transmission planning process (paid for by all MISO participants, thus socialized across MISO footprint) helps to plan for new transmission needs to remedy congestion.

- Slide 31 All MISO Considerations Need to Be Accounted for During the IRP
  - Question: Which zones saw maximum generation events?
    - Response: Most recent maximum generation event was several zones (the North Central Region), including LRZ6 but up to Minnesota. The prior maximum generation events were more in MISO-South. We can follow-up on other events, if needed.
  - Question: How, within Aurora, does Vectren intend to try to account for seasonal accreditation?
    - Response – Pace can speak to this in more detail if needed, but you can set UCAP values in Aurora and the PRM requirement monthly.
  - Question: You mentioned one event was due to non-firm gas delivery. Wasn't the gas line to supply your formerly proposed gas plant with a non-firm contract?
    - Response: We were planning on serving that plant with firm delivery to ensure that we had high priority on delivery list.
  - Question: For transmission over 345 kW you mentioned costs would be distributed across MISO participants. Would that be true if a hydro unit was installed at the Meyers dam?
    - Response: I apologize, we're talking about 345 kV, so transmission delivery, not energy. We are talking about the rating of the line (line size).
  - Question: Were you involved with Duff Coleman transmission? I was involved as a property owner. Looking at current transmission corridors, and the effect of eminent domain on property owners. I think Vectren needs to consider corridors, competitor lines. How can you consider existing corridors?
    - Response: Planning is typically to use existing corridors. Vectren is not involved in the construction of the Duff Coleman transmission line (MISO opened it up to bids). MISO must consider all of this when planning transmission Right of Ways.
  - Comment: It is premature to modify reserve margin requirement based on max gen events. There are other options besides a seasonal resource adequacy construct. Could it help to address those issues with coordinated outage/maintenance schedules? It is perfectly fine to model as a base case sensitivity but not a base case assumption.
    - Response: MISO already implemented coordinated maintenance schedule reporting, which Vectren is already complying with. On seasonal construct, this is driven by MISO and we can't ignore or avoid; Vectren is only one stakeholder among many. Four season construct is already planned for implementation in 2021 by MISO. Vectren is looking at two seasons, not four, which is a conservative assumption that could potentially limit impact.
  - Question: Will recorded NPVs be based on deterministic modeling or stochastic modeling?
    - Response: Both. We'll look at portfolio performance on an expected (probabilistic) basis (from 200 iterations in the risk analysis) as well as deterministic NPV results (from the scenario analysis).
  - Question: Can you count on MISO to fill gaps for a year or two after coal is retired but before new resources are online? It seems like that would create some flexibility in how you move forward.
    - Response: We do have the ability to account for purchases to fill in gaps. That's part of the economic analysis.
  - Question: Does MISO plan to mitigate max gen events with solar+storage or even stand-alone storage?

- Response: MISO requires four consecutive hours of output. So, if nameplate storage is 100 MW, then accreditation is 25 MW over four hours. To your question, MISO seasonal accreditation planning is meant to better align actual output with accreditation.
    - Question: When is MISO planning on incorporating new technology resources into their planning?
        - Response: They try to be as responsive but given all the stakeholders they can be a little slow at times for the latest technologies. They are responsive. To get changes done in the marketplace, that process usually takes 12-18 months to implement in new tariffs, etc. They also try to make market rules (with a year lag) based on annual transmission planning process, with respect to state planning processes.

**Gary Vicinus** (Pace Managing Director for Utilities) - Scenario Modeling Inputs – slides 33-48:
Slide 48 Feedback and Discussion:

- Question: You're showing these inputs, but what about distributed generation? If you lift policy caps on solar, your demand would drop a lot with solar as well as behind-the-meter storage. Don't the caps limit solar DG (in schools, etc.)? We could get there at a reasonable cost because the investment comes from individuals.
    - Response: We don't cap the amount of distributed solar considered, but payback calculation within the model is affected by net metering structure. We are going to analyze a wide range for peak loads; Itron did a sensitivity on rooftop solar that falls within this range.
- Comment: I'd like to see intentional changes in policy to promote distributed energy and how would that affect the rest of your modeling (and Behind The Meter, bi-directional batteries)? I would like to see incentives.
    - Response: I would suggest that this be one of the strategies for the group breakout session.
- Comment: Under Energy Innovation and Carbon Dividend Act being considered in congress right now, in 2022 $CO_2$ would be $15 but in 2039 it would be $185. That would change the outlook considerably.
- Question: Also, why is coal price lower if costs are higher?
    - Response: Lower coal prices follow from lower coal demand. With reduced demand, only the most efficient will survive.
- Question: The peaks and valleys on these graphs would indicate to me that the same distribution is not being assumed in any given year. For example, the distribution is not always normal. For the capital costs in particular, that strikes me as a level of precision that does not actually exist. For example, why would two standard deviations give you a wider range of distributions in 2033 vs. 2036 for solar? In general, I would reiterate the feedback that we have given previously. Stochastic simulation is not a good tool for capex (just for volatile variables like gas). Will these standard deviations be applied to the bids received from the RFP?
    - Response: Distributions do vary over time, as one would expect, as uncertainty increases over time. It's correct to say the distributions are not always normal (e.g., gas wouldn't fall below $2 because costs must be recovered). Market conditions drive the upper end. Many of our distribution are skewed to the upward side. To say that stochastic simulation is not a good test, I would say that is a point of view. We use stochastics in many jurisdictions and it is widely accepted. It is intended to reflect not only the volatility but also the uncertainty as we go forward.
- Question: Why do distributions widen, narrow, widen, etc., if uncertainty grows? And using stochastics for solar capital costs standard deviations doesn't reflect how actual capital costs move. Why not use sensitivities, which is what is typically seen in IRPs?
    - Response: A lot of these graph reflect monthly variations as opposed to annual. They tend to smooth out when you look at them on an annual basis. Ultimately, we will do some annual smoothing. I agree that the monthly variations are not easily explained, but they tend to level out on an annual basis.
    - Question: Will you apply distributions to bid prices?

        - Response: We will use for the various years where we have bid information as an input at base levels. After the bid years, the stochastic distributions will be reflected.
    - Question: If a bid resource would come online in 2022, you wouldn't apply distributions there?
        - Response: In your example, we will utilize the bid information for 2022 and use the distributions going forward (beyond 2022). We will set up a follow-up conversation.
- Question: How did you come up with 2.2% inflation assumption?
    - Response: It is a projection from Moodys.com.
- Question: When do the probability distributions come into effect (after bids)?
    - Response: Bids come in in different years, then we start uncertainty shortly thereafter.

**Michael Russo** (Sr. Forecast Consultant, Itron) – Long term Base Energy and Demand Forecast – slides 49-60:

- Slide 57 C&I Sales Forecast:
    - Question: Can you pull out Electric Vehicle (EV) owners who have solar Distributed Generation (DG)? EV owners aren't adding to load given that they have solar DG too.
        - Response: We start with 200 registered EV owners but Itron doesn't have info on who also has solar distributed generation. Theimpact won't be large given the small starting number.
- Slide 60 Feedback and Discussion:
    - Question: You did the forecasts for the 2016 IRP. How accurate were those forecasts?
        - Response: We did not specifically look at the last couple of years, but in general we do look at forecasting error. We do hold out the last year of the model and compare how well the model performs, now that we have the actuals. Our Mean Absolute Percentage Errors (MAPE) on the residential and commercial side is typically around 2%. They are higher on the industrial and peak models.
    - Question: On Slide 59, you show significant drops in both energy and demand that don't seem to be reflected in residential and C&I.
        - Response: That is a large industrial customer that is modeled separately (and not included on Slide 56 C&I Sales Forecast).
    - Question: The industrial growth is very significant. Can you say more?
        - Response: We can't comment on individual load additions publicly. What we can say is that there are two public projects in Southwest Indiana that received air permits in the past two years (in public domain). We have formulated expected MWs and MWhs from potential customers that have come to us. We have signed NDAs for projects (required for all economic development opportunities), but large industrials account for the majority of industrial uptick. We have an obligation to serve this load.
    - Question: How will these load forecasts be translated into high/low load forecasts, particularly given large industrial customers? I have similar concern to the CAC.
        - Response: The answer depends upon the component. Looking at higher/lower EV forecast, we take that input in developing upper/lower boundary scenarios. Pace starts with what Vectren/Itron provides us, then we look at uncertainties around this. Even when individual components such as EV or solar, we're still within the boundaries showed earlier. We haven't finalized load, so we'll look at individual components and adjust accordingly.
    - Question: Is the coal to diesel plant reflected in to the two permits that you discussed earlier?
        - We are not going to comment on those two specific permits.
    - Question: Is Southern Indiana petrochemical facility included in industrial outlook?
        - Response: Cannot comment on specific projects.
    - Comment: The coal-to-diesel plant won't happen, so if you're considering this in the forecast, you need a new forecast. If they're already permitted, why can't you discuss them?

        - Response: We have signed NDAs with perspective customers at their request. and so, we can't discuss their load for competitive reasons.
    - Comment: I've been having a moment at these meetings. It struck me when we looked the slide about trended normal weather. It feels to me like we're rearranging deck chairs on the Titanic. I think that the issue that we need to be basing our decisions on is around that exact fact. Climate crisis demands we act, not because we're forced to by any rule, but because we need to act for our children. I feel like what we're talking about is not what is important.
        - We're basing off historical weather trends, which is used by government and others.

**Wayne Games** (Vice President power Generation Operations) – Existing Resource Overview – slides 61-75:

- Slide 75 Feedback and Discussion:
    - Question: (Clarification on solar resources) Do you plan to build 54 MWs of solar or over 100 MWs (referring to slides 64 Summary of Current Resource UCAP Accreditation for Summer Peak and 66 Renewables)?
        - Response: We have two 2 MW projects and plan to build an additional 50 MWs.
    - Comment: These options for AB Brown, etc.…these plants are obsolete now. It seems awkward to invest more in dying technologies.
        - Response: I'm not saying we should or shouldn't. We're required to look at all options and some stakeholders have asked us to look at these options.
    - Comment: Even when you show 80% carbon reduction by Paris Treaty, that doesn't reflect what we face now. Right now, there is a lake in Siberia that is bubbling up methane because we under-projected. We need a Greta Thunberg portfolio, which means we put everything possible into cutting carbon emissions. We need a crisis scenario.
    - Comment: On carbon, Vectren should be looking into technology to sequester carbon. Where can Vectren use science, like Duke Energy, to get today's youth involved in STEM classes. You need to look at the bigger environmental picture.
    - Comment: There were a lot of numbers and analysis. We'd like to work with you to get access to your numbers, including Slide 74 A.B. Brown FGD Options, derived from outside engineering studies.
    - Question: Where will 50 MW solar plant be built?
        - Response: East side of Spencer County.
    - Question: I don't understand why you use historical weather when Purdue University. uses different projections? I don't understand why your projections don't look like their projections.
        - Response: What we use is consistent with what EIA uses. We did not use the Purdue data set.
    - Question: So, you're saying you should use historical approach because you expect nothing out of the usual?
        - Response: Our forecast is different than what we've done in the past to address the trended weather concern.
    - Comment: Have you looked at Purdue report?
        - Response: We attended the talk the other night and looked at the website. If you'd like to send me the report, we'll look. We will reach out to Purdue to understand their dataset.

**Matt Lind** (Resource Planning & Market Assessments Business Lead, Burns and McDonnell) Potential New Resources and MISO Accreditation – slides 76-92:

    - Question (Slide 81 Technology Details): Can you explain difference between estimated potential capacity and estimate feasible capacity and estimated optimal capacity?

- Response: We would need to look more closely, but I believe that the Estimated Potential Capacity is the technical potential, not necessarily the most economic option.
  - Question: On slide 84 & 80, does solar+storage mean exclusively charged by solar or charged by grid?
    - Response: The former (exclusively supplied by the sun) is generally the case, depending on the bids.
  - Question: On slide 84 Proposal Location Review, what is the difference between proposal installed and project installed capacities?
    - Response: Proposal includes double- and triple-counting.
  - Question: On Slide 85 Participating Companies, is Duke Energy a participant?
    - Response: Yes
- Slide 87 MISO Renewable Penetration Trends
  - Question: Counterintuitive – Your credit to solar shouldn't go down as installed capacity goes up. It's counterintuitive to me.
    - Response: As more solar, a non-dispatchable resource, is added to the system accreditation goes down. As you add more solar, the risk of being deficient from a resource perspective shifts to the evening hours. ELCC is a calculation that MISO has been using for wind resources for several years.
  - Question: Is the ELCC based on fixed or tracking solar?
    - Response: Orientation, geography, etc. are all considered, but accreditation (the amount of credit MISO is projected to provide for resource) will still decline over time.
  - Question: Prices are higher than I've seen. Are these prices typical or representative of actual bids?
    - Response: This is technology assessment data, not bid data.
  - Question: Wouldn't MISO accreditation change with storage?
    - Response: Yes, though even standalone storage would be affected given the duration of storage. To be eligible for full accreditation for storage, you need more than 4 hours of storage. This reinforces the diversity of resources and the location of resources.
- Slide 89 Wind Seasonal Differences
  - Question: So, you're making changes for Southern Indiana based on MISO which encompasses Canada to Gulf of Mexico. Doesn't this skew things?
    - Response: MISO provides a unique geographic accreditation to each Local Resource Zone, though it is still tied to the MISO peak.

Feedback and Discussion slide 92:

- Comment: I noticed a combination that may be cost effective. We worked on this during the prior CCGT case. That is repowering one of the Brown units coupled with the smaller CCGT. The new gas pipeline doesn't need to be double-counted. You could use one pipeline to serve both units.
- Question: When does wind and solar become dispatchable (with sufficient storage)?
  - Response: Storage round-trip efficiency is a net load to the system. Today's technology is not there yet. You'd have to add a lot of storage, but there would still be a net load. It depends on technology, consumer behavior, etc. Battery experts are researching this. I don't see it in the near term.
- Question: Would bigger installations of PV panels or turbines lead to less need for storage?
  - Response: That is a strategy people are looking at, particularly to take advantage of tax credits.
- Question: Why does solar capacity credit start at 50% and not 60% on Slide 87 MISO Renewable Penetration Trends? Also, can you show us specific data showing forecast for renewable and storage penetration?
  - Response: We took the average across the MISO Transmission Expansion Plan (MTEP) futures. The average installation grows from 6,000 MW in 2023 to about 25,000 MW by 2033. We extrapolated that trend line beyond 2033. On slide 91 Zone

6 Seasonal Accreditation, we used 50% during the first year of operation, per MISO ELCC figures.
    - Question: What is the basis for 0% capacity accreditation in winter?
        - Response: Peak hours are in the H20-H22 range when there is no solar production.

**Jeffrey Huber** (Managing Director, GDS Associates) - DSM Modeling in the IRP – Slides 93-103:

Slide 103 Feedback and Discussion:

- Comment: Thank you Vectren and Jeff for working with the CAC on this through the Oversight Board. We look forward to seeing how this all works through the IRP process.
- Question: About interruptible tariff (not part of this DSM analysis), will we continue that process?
    - Response: We're in the process of truing up our interruptible tariff with MISO in mid- to late-November, which would true up notification times.
- Question: I'm interested in economic curtailment.
    - Response: We're working on language changes (ongoing) and we'll get back to you on that.

**Gary Vicinus** (Pace Managing Director of Utilities) – Stakeholder Breakout Session Strategy Development – Slides 104-107:

- Instructions given: Examples: Impose an Renewable Portfolio Standard (RPS) of X% by X year, or a portfolio with no coal by X year, etc.
- See Slide 106 Portfolio Strategy Worksheet – use this for strategies and timeframes
- Group 1: Six strategies:
    1. Plants scheduled in 2016 IRP – Do that by 2024 and replace closures with renewable energy capacity
    2. Culley 3 be closed by 2030, also replaced by renewable energy
    3. Lobby to extend net metering at 1-to-1 ratio, no cap, by 2022
    4. Close gas-fired plants by 2030 and replace with renewable energy (solar)
    5. Maximize Energy Efficiency efforts immediately (by 2020) through incentives
    6. Increase storage in timeframes to accommodate bringing on renewable energy (~5 years, timed to retirements, focused on Behind the Meter solar)
- Group 2:
    1. Do what NIPSCO is doing. As resources retire, replace with renewable energy. (Clarification from stakeholder – NIPSCO in 2026 is adding a price on carbon, whereas Vectren Base Case is $0 for 20 years)
    2. Go for 100% renewable energy by end of 2030
    3. Have 100% reduction in $CO_2$ and equivalents at the end of 20 years
    4. Have other experts review how you're using our recommendations (to ensure it is being treated fairly in the modeling)
- Group 3:
    1. We want to access all the runs under the Nondisclosure Agreement (NDA).

VECTREN
A CenterPoint Energy Company

# VECTREN PUBLIC STAKEHOLDER MEETING

DECEMBER 13, 2019

# WELCOME AND SAFETY SHARE

**LYNNAE WILSON**

INDIANA ELECTRIC CHIEF BUSINESS OFFICER

# SAFETY SHARE

**Holiday Safety Tips**

- Inspect electrical decorations for damage before use.  Cracked or damaged sockets, loose or bare wires, and loose connections may cause a serious shock or start a fire
- Do not overload electrical outlets.  Overloaded electrical outlets and faulty wires are a common cause of holiday fires. Avoid overloading outlets
- Use LED lights.  Never connect more than three strings of incandescent lights. More than three strands can cause a fire
- Use battery-operated candles. Candles start almost half of home decoration fires (National Fire Protection Association - NFPA)
- Keep combustibles at least three feet from heat sources.  Heat sources that are too close to a decoration are a common factor in home fires
- Protect cords from damage. To avoid shock or fire hazards, cords should never be pinched by furniture, forced into small spaces such as doors and windows, placed under rugs, located near heat sources, or attached by nails or staples
- Stay in the kitchen when something is cooking.  Unattended cooking equipment is the leading cause of home cooking fires (NFPA).
- Turn off, unplug, and extinguish all decorations when going to sleep or leaving the house. Half of home fire deaths occur between the hours of 11pm and 7am (NFPA).

# 2019/2020 STAKEHOLDER PROCESS

| August 15, 2019 | October 10, 2019 | December 13, 2019 | March 20, 2020[1] |
|---|---|---|---|
| • 2019/2020 IRP Process<br>• Objectives and Measures<br>• All-Source RFP<br>• Environmental Update<br>• Draft Reference Case Market Inputs & Scenarios | • RFP Update<br>• Draft Resource Costs<br>• Sales and Demand Forecast<br>• DSM MPS/ Modeling Inputs<br>• Scenario Modeling Inputs<br>• Portfolio Development | • Draft Portfolios<br>• Draft Reference Case Modeling Results<br>• All-Source RFP Results and Final Modeling Inputs<br>• Scenario Testing and Probabilistic Modeling Approach and Assumptions | • Final Reference Case and Scenario Modeling Results<br>• Probabilistic Modeling Results<br>• Risk Analysis Results<br>• Preview the Preferred Portfolio |

1 Updated

# AGENDA

| Time | | |
|---|---|---|
| **9:00 a.m.** | Sign-in/Refreshments | |
| **9:30 a.m.** | Welcome, Safety Message | Lynnae Wilson, CenterPoint Energy Indiana Electric Chief Business Officer |
| **9:50 a.m.** | Follow-up Information Since Our Last Stakeholder Meeting | Matt Rice, Vectren Manager of Resource Planning |
| **10:30 a.m.** | Break | |
| **10:40 a.m.** | Draft Reference Case Results | Peter Hubbard, Manager of Energy Business Advisory, Pace Global |
| **11:40 a.m.** | Lunch | |
| **12:40 p.m.** | Final RFP Modeling Inputs | Matt Lind, Resource Planning & Market Assessments Business Lead, Burns and McDonnell |
| **1:40 p.m.** | Break | |
| **1:50 p.m.** | Portfolio Development | Matt Rice, Vectren Manager of Resource Planning |
| **2:20 p.m.** | Scenario Testing and Probabilistic Modeling | Peter Hubbard, Manager of Energy Business Advisory, Pace Global |
| **2:50 p.m.** | Next Steps | Matt Rice, Vectren Manager of Resource Planning |
| **3: 00 p.m.** | Adjourn | |

# MEETING GUIDELINES

1. Please hold most questions until the end of each presentation. Time will be allotted for questions following each presentation. (Clarifying questions about the slides are fine throughout)
2. For those that wish to participate remotely, please log in via the link provided Link to join in your RSVP and follow the phone instructions when prompted. To speak during the meeting, please make a request in the chat function, and we will open up your individual line.
3. If you wish to listen only, you may call in with the phone number provided in your RSVP: 1-415-655-0003 | Access code: 806 147 760. You will not be able to speak during the meeting utilizing this option.
4. There will be a parking lot for items to be addressed at a later time.
5. Vectren does not authorize the use of cameras or video recording devices of any kind during this meeting.
6. Questions asked at this meeting will be answered here or later.
7. We will do our best to capture notes but request that you provide written feedback (concepts, inputs, methodology, etc.) at IRP@CenterPointEnergy.com following the meeting. Additional questions can also be sent to this e-mail address.

# FOLLOW-UP INFORMATION SINCE OUR LAST STAKEHOLDER MEETING

**MATT RICE**

VECTREN MANAGER OF RESOURCE PLANNING

# VECTREN COMMITMENTS FOR 2019/2020 IRP

By the end of this stakeholder meeting Vectren will have made significant progress towards the following commitments

- ✓ Utilizing an All-Source RFP to gather market pricing & availability data
- ✓ Including a balanced, less qualitative risk score card; draft was shared at the first public stakeholder meeting
- ✓ Performing an exhaustive look at existing resource options
- ✓ Using one model for consistency in optimization, simulated dispatch, and probabilistic functions
- ✓ Working with stakeholders on portfolio development
- ✓ **Modeling more resources simultaneously**
- ✓ **Testing a wide range of portfolios in scenario modeling and ultimately in the risk analysis**
- ✓ **Providing a data release schedule and provide modeling data ahead of filing for evaluation**
- ✓ **Striving to make every encounter meaningful for stakeholders and for us**

Vectren will continue to work towards the remaining commitments over the next several months

- Ensuring the IRP process informs the selection of the preferred portfolio
- Conducting a sensitivity analysis
- Including information presented for multiple audiences (technical and non-technical)

# 2019/2020 IRP PROCESS

Conduct an All Source RFP

Create Objectives, Risk Perspectives and Scorecard Development

Create Reference Case Assumptions and Scenario Development

Portfolio Development Based on Various Strategies, Utilizing Optimization to Create a Wide Range of Portfolios and Refine with All Source RFP Data

Portfolio Testing in Scenarios, Focused on Potential Regulatory Risks

Portfolio Testing Using Probabilistic Modeling of 200 Potential Futures

Utilize the Probabilistic Modeling to Conduct Sensitivity Analysis

Populate the Risk Scorecard that was Developed Early in the Process and Evaluate Portfolios

Select the Preferred Portfolio

# TENTATIVE DATA RELEASE SCHEDULE

- Modeling files
  - Reference Case modeling files (confidential – available February 2020)
  - Scenarios modeling files (confidential – available April 2020)
  - Probabilistic modeling files (confidential – available May 2020)
- Sales and Demand Forecast
  - Report (not confidential – available now)
- RFP
  - Bid information (confidential)
  - Report (confidential – available March 2020)
- Various Power Supply Reports
  - Conversion (confidential – available February 2020)
  - Scrubber options (confidential – available February 2020)
  - ACE Study (confidential – available February 2020)
  - ELG (confidential – available February 2020)
  - Brown 1x1 CCGT (confidential – available March 2020)
- Pipeline cost assumptions (confidential – available February 2020)

# STAKEHOLDER FEEDBACK

| Request | Response |
| --- | --- |
| Add a scenario or replace a scenario with a Carbon Dividend modeled after HB 763, which includes a $CO_2$ price in 2022 of $15, increasing by $10 per ton each year ($185 by 2039) | Our High regulatory case includes a high $CO_2$ fee and dividend. While there is no guarantee that a carbon dividend future would exactly mirror HB 763, we will run a sensitivity for portfolio development based on HB 763 to determine what type of portfolio it creates. Assuming that it is different than other portfolios that we are considering, we can include the portfolio in the risk analysis. We do not plan to create a 6th scenario |
| A cap and trade scenario is not a likely potential future | Cap and Trade is a real possibility. Beyond ACE, it was the only carbon compliance law in the US to date. The 80% reduction of $CO_2$ future, which is in alignment with the Paris Accord, is a reasonable potential future (our middle bound). Scenarios are not predictions of the future but provide plausible futures boundary conditions |
| It is premature to model a seasonal construct, referring to summer and winter (MISO) UCAP accreditation | As mentioned in the last meeting, MISO is moving to a seasonal construct. Vectren evaluated other potential calculations for accrediting solar with capacity in the winter. Determined that a weighted average of daily peak conditions could yield an 11% UCAP for solar in the winter, as opposed to 0%. Increased solar penetration would still reduce this amount of accreditation over time |

# STAKEHOLDER FEEDBACK

| Request | Response |
|---|---|
| Referring to hydro studies cited at the 2nd stakeholder meeting, please clarify what the difference between estimated potential capacity, estimate of feasible capacity, and estimated optimal capacity is. Additionally, there was a request to increase the Vectren hydro modeling assumption from 50 MWs at each nearby dam to 100 MWs each | The DOE/NREL study, which provided estimated potential capacity, is a high level estimate of potential using generic modeling assumptions and not taking economics into consideration. The Army Corp of Engineers uses specific conditions on the Ohio to refine the DOE/NREL initial estimates into realistic project potential. 50 MWs at each dam is more in line with the range provided in the Army Corp of Engineers study. Vectren will evaluate two blocks of 50 MWs within scenario modeling and portfolio development |
| The NREL Life Cycle GHG study is dated | We had a discussion with First Solar on their perspective regarding lifecycle of greenhouse gas emissions for solar resources. An IEA study with updated assumptions on solar found a similar result to the NREL study for local solar resources. Additionally, Vectren likes the fact that NREL's study is fairly comprehensive. Vectren plans to utilize the NREL Study for estimated life cycle $CO_2e$ for most resource types |
| NREL Life Cycle GHG study does not consider storage | Evaluating options |
| NREL Life Cycle GHG study does not consider gas resources and Vectren should simply utilize an alternate calculation for natural gas resources | The NREL study did consider gas resources. Various gas studies considered for the analysis included methane leaks as part of the study (see appendix) |

# STAKEHOLDER FEEDBACK

| Request | Response |
|---|---|
| Add a $CO_2$ price to the Reference Case | We have added the mid-range $CO_2$ price to the Reference Case. ACE runs for 8 years and is replaced (see slide 20) |
| Your trended weather projections do not look anything like Purdue's | We reached out to Purdue University. They provided some clarification on the differences between their study and ours, including using different set points for heating and cooling degree days. Itron reviewed and estimated that the HDD trend is the same, while the CDD trend is nearly two times higher in the Purdue dataset. Utilizing the Purdue CDD trend would add approximately 40 MWs to Vectren's forecast over the next 20 years, which is well within our high bound forecast. We do not plan to update our load forecast, based on this analysis |
| Follow-up on updates to Industrial DR tariff | Report back progress in the next IRP stakeholder meeting |
| $5k for Aurora is paying for transparency | Met with CAC, Pace, and Energy Exemplar (Aurora) on Oct. 24th. To address CAC's concern, Pace will work to provide relevant input tables from modeling, which include model settings. Each table will need to be exported separately. Additionally each relevant help function page will be exported separately. While time consuming, Pace will work to accommodate this request for stakeholders. Modeling files will be shared later in the process as timely analysis takes precedent |

# MISO UPDATE

- John Bear, CEO of MISO, recently testified before the Subcommittee on Energy. Reiterated the importance of the Renewable Integration Impact Assessment (RIAA) analysis
  - While MISO is fuel source neutral, they have learned that renewable penetration of 30% would challenge MISO's ability to maintain the planning reserve margin and operate the system within acceptable voltage and thermal limits
  - Maintaining reliability at 40% renewable level becomes significantly more complex. Currently MISO is studying 50% penetration level
  - Implications include tight operating conditions (need to utilize emergency procedures to manage reliability risk)
  - Requires a shift in market processes and protocols
    - We can no longer be confident that the system will be reliable year round based on peak demand in the summer. **All hours matter**
    - Resources must provide enough, and the right kinds of critical attributes needed to keep the system operating in a reliable, steady state, such as frequency response, voltage control, and black-start capability
    - We can no longer be confident that the existing transmission system can adapt to the new paradigm of smaller, decentralized intermittent renewable resources
  - Fleet of the future: improved availability, flexibility, and visibility. MISO is working to hold members responsible to deliver attributes and is developing incentives for these attributes

# CCR / ELG – PROPOSED RULE SUMMARIES

- CCR
  - Advances date the cease use of all unlined ponds by 2 months, from October 31, 2020 to **August 31, 2020**
  - Short-term extension available to November 30, 2020
  - Site-specific extension available which would allow continued use of pond until **October 15, 2023**. Requires submitting a demonstration and work plan to EPA for approval
  - Permanent Cessation of Boiler extension
    - AB Brown – use of pond until October 17, 2028 if closure is <u>completed</u> by same date
      - This extension option is not feasible for AB Brown due to size and scope of closure
    - FB Culley – use of pond until October 17, 2023 if closure is completed by same date
- ELG
  - No extension for Bottom Ash Transport Water (BATW)
  - Revised limits for BATW on an “as needed” basis
    - 10% volume discharge on a 30-day rolling average
  - Boilers retiring by 2028 would only be subject to TSS limits; however, the earlier CCR deadline to cease disposal by October 2023 is the driver for compliance at AB Brown

# CCGT STUDY

- No firm bids were received for gas CCGTs and nothing was on/near our system
- FERC recently updated a rule that allows for an expedited process within the MISO Queue to replace existing resources at or below existing interconnection rights
- As part of the IRP, it is prudent to study options with regards to existing resources, which includes existing Vectren sites
- Currently performing a study to obtain a +/- 10% cost estimate for a small/midsized 1x1 CCGT (F-class and H-class) at the Brown site to be included in final IRP modeling (consistent with CCGT units included within the tech. assessment at +/- 50%)
- Benefits of the Brown site
  – Electric infrastructure in place to support a 400-500 MW unit
  – Would allow Vectren to utilize existing assets at the site
  – Would preserve tax base and jobs in Posey County

# BAGS 2 RETIRED

- Retiring Broadway Avenue Generating Station 2 (65 MWs of installed capacity) by the end of the year
  - Typical life is 30-40 years; Unit has been in service for 38 years
  - Highest heat rate (least efficient) of current generating fleet
  - Recent five year capacity factor just over 1%
  - Several million dollars needed for known repairs
  - High probability of additional expenses in the near future given current age and condition

# DRAFT REFERENCE CASE MODELING RESULTS

**PETER HUBBARD**

MANAGER OF ENERGY BUSINESS ADVISORY, PACE GLOBAL

# WIDE RANGE OF PORTFOLIOS

The final reference case is 1 of 15 potential portfolios that will be analyzed over the coming months. The preferred portfolio will be selected based on the results of the full risk analysis

**Status Quo**
- 1) Business as Usual (BAU)

**Scenario Based**
- 2) Low Regulatory
- ***3) Reference Case***
- 4) High Tech
- 5) 80% $CO_2$ Reduction
- 6) High Regulatory

**Bridges**
- 7) Gas Conversion ABB1
- 8) Gas Conversion ABB1 & ABB2
- 9) Gas Conversion + CCGT
- 10) BAU 2029

**Diverse**
- 11) Small CCGT with renewables and coal
- 12) Mid CCGT with renewables and coal

**Renewables Focused**
- 13) Close All Fossil by 2030
- 14) Renewables + flexible gas (close coal by 2034 and no CCGT)
- 15) HB 763

**Risk Analysis**

# FINAL DRAFT REFERENCE CASE INPUTS

VECTREN
A CenterPoint Energy Company

| Input | Unit | 2019 | 2021 | 2023 | 2025 | 2027 | 2029 | 2031 | 2033 | 2035 | 2037 | 2039 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Coal (ILB mine) | 2018$/MMBtu | 1.78 | 1.66 | 1.64 | 1.63 | 1.61 | 1.61 | 1.59 | 1.58 | 1.59 | 1.59 | 1.58 |
| CO2 | 2018$/ton | 0.00 | 0.00 | 0.00 | 0.00 | 3.57 | 5.10 | 6.63 | 7.65 | 9.18 | 11.22 | 14.79 |
| Gas (Henry Hub) | 2018$/MMBtu | 2.77 | 2.76 | 3.06 | 3.24 | 3.38 | 3.49 | 3.62 | 3.78 | 3.96 | 4.09 | 4.17 |
| Vectren Peak Load | MW | 1,115 | 1,102 | 1,168 | 1,176 | 1,183 | 1,192 | 1,200 | 1,209 | 1,219 | 1,229 | 1,239 |
| Customer-Owned Solar DG Capacity* | MW | 9.3 | 14.6 | 20.7 | 27.1 | 34.2 | 41.7 | 49.6 | 57.7 | 66.3 | 75.1 | 84.3 |
| EV Peak Load** | MW | 0.4 | 2.0 | 9.8 | 13.8 | 17.8 | 21.8 | 25.9 | 30.0 | 34.2 | 38.3 | 42.3 |
| Energy Efficiency and Company DG | MW | 6.0 | 9.2 | 15.7 | 22.6 | 28.8 | 33.1 | 39.0 | 45.2 | 48.8 | 50.5 | 47.6 |
| Demand Response | MW | 35.2 | 51.7 | 52.7 | 61.6 | 64.4 | 67.3 | 70.1 | 73.0 | 75.8 | 78.7 | 81.5 |
| Wind (200 MW) | 2018$/kW | 1,334 | 1,330 | 1,328 | 1,326 | 1,324 | 1,324 | 1,324 | 1,324 | 1,326 | 1,328 | 1,330 |
| Solar (100 MW) | 2018$/kW | 1,414 | 1,264 | 1,205 | 1,168 | 1,130 | 1,096 | 1,064 | 1,038 | 1,012 | 993 | 973 |
| Li-Ion Battery (50 MW, 4 hr) | 2018$/kW | 2,088 | 1,811 | 1,654 | 1,518 | 1,452 | 1,391 | 1,342 | 1,301 | 1,263 | 1,232 | 1,201 |
| Flow Battery (50 MW, 6 hr) | 2018$/kW | 2,968 | 2,665 | 2,450 | 2,242 | 2,116 | 1,996 | 1,892 | 1,803 | 1,719 | 1,651 | 1,586 |
| Gas CC F-Class (442 MW with DF) | 2018$/kW | 1,301 | 1,291 | 1,275 | 1,261 | 1,251 | 1,242 | 1,233 | 1,224 | 1,216 | 1,207 | 1,199 |
| Gas CT F-Class (237 MW) | 2018$/kW | 712 | 707 | 697 | 688 | 683 | 677 | 672 | 667 | 662 | 657 | 653 |
| USC Coal w/ CCS | 2018$/kW | 5,621 | 5,536 | 5,424 | 5,309 | 5,201 | 5,097 | 4,992 | 4,891 | 4,794 | 4,698 | 4,605 |

** Res/Com Demand Impact = 0.295*
*** EV Coincident Factor = 0.211*

Revised from last meeting

# DRAFT REFERENCE CASE EXISTING RESOURCE OPTIONS

| | | | 2023 | | | | | 2026 | 2029 | 2039 |
|---|---|---|---|---|---|---|---|---|---|---|
| **Unit** | **Fuel** | **Installed Net Capacity (MW)** | **Upgrade Path 1 *(FGD, ELG, CCR, ACE)*** | **Upgrade Path 2 *(ELG, CCR, ACE )*** | **Convert to Gas** | **Continue Agreement / Exit Agreement** | **Retire** | **Exit Agreement** | | |
| ABB1 | Coal | 245 | Option | Option | Option | n/a | Option | n/a | If Upgrade Path 2, unit retires in 2029 | If Upgrade Path 1 or Convert, unit to run to 2039 |
| ABB2 | Coal | 245 | Option | Option | Option | n/a | Option | n/a | If Upgrade Path 2, unit retires in 2029 | If Upgrade Path 1 or Convert, unit to run to 2039 |
| ABB3 | Gas | 85 | Unit to run to 2039 | | | | | | | |
| ABB4 | Gas | 85 | Unit to run to 2039 | | | | | | | |
| FBC2 | Coal | 90 | n/a | Option | Option | n/a | Option | n/a | n/a | If Upgrade Path 2 or Convert, unit to run to 2039 |
| FBC3 | Coal | 270 | Unit to run to 2039 | | | | | | | |
| W4 | Coal | 150 | n/a | n/a | n/a | Option | n/a | Exit | n/a | n/a |
| OVEC | Coal | 32 | Ownership share to run to 2039 | | | | | | | |
| Benton | Wind | 30 | PPA for 30 MW thru 2028 | | | | | | | |
| Fowler | Wind | 50 | PPA for 50 MW thru 2030 | | | | | | | |
| Troy | Solar | 50 | Self-build solar to run to 2039 | | | | | | | |

# DRAFT REFERENCE CASE NEW RESOURCE OPTIONS

| Type | Resource | Limitations | Capacity Options | | | |
|---|---|---|---|---|---|---|
| RE and Storage | Hydroelectric | Max 2 units | 50 MW | | | |
| | Wind Energy | 400 MW per year | 200 MW | | | |
| | Wind plus Storage | 150 MW per Year | 50 MW wind (10 MW/40 MWh battery) | | | |
| | Solar Photovoltaic | 500 MW per year | 10 MW | 50 MW | 100 MW | |
| | Solar plus Storage | 150 MW per Year | 50 MW solar (10 MW / 40 MWh battery) | | | |
| | Lithium-Ion Battery Storage | 300 MW per year | 10 MW / 40 MWh | 50 MW / 200 MWh | | |
| | Flow Battery Storage | 400 MW per Year | 10 MW / 60 MWh | 10 MW / 80 MWh | 50 MW / 300 MWh | 50 MW / 400 MWh |
| Demand Side Management* | Low Income Energy Efficiency | Required | 0.7 MW | | | |
| | Optional Energy Efficiency | 7 optional resources | Bin 1: 2.2 MW | Bin 2: 2.3 MW | Bin 3: 2.4 MW | Bin 4: 2.5 MW |
| | | | Bin 5: 2.2 MW | Bin 6: 2.3 MW | Bin 7: 0.5 MW | |
| | Demand Response | 1 required, 1 optional | Bin 1: 21.1 MW | Bin 2: 5.8 MW | | |
| Coal | Supercritical with CCS | Max 1 unit | 500 MW | | | |
| | Ultrasupercritical with CCS | Max 1 unit | 750 MW | | | |
| Waste to Energy | Chipped Wood Biomass | 3 units per year | 50 MW | | | |
| | Landfill Gas | 3 units per year | 4.5 MW | | | |
| Combined Heat & Power | 2x 9MW Recip Wartsila | 4 units per year | 18 MW | | | |
| | 1 x Titan 250 CTG | 4 units per year | 20 MW | | | |
| Combined Cycle | 1x1 F Class CCGT Unfired | 1 Per Year | 357 MW | | | |
| | 1x1 F Class CCGT Fired | 1 Per Year | 443 MW | | | |
| | 1x1 G/H Class Unfired | 1 Per Year | 410 MW | | | |
| | 1x1 G/H Class Fired | 1 Per Year | 511 MW | | | |
| Simple Cycle | 1x E Class Frame SCGT | Max 3 units | 85 MW | | | |
| | 1x F Class Frame SCGT | | 237 MW | | | |
| | 1x G/H Class Frame SCGT | | 279 MW | | | |

* EE and DR bins are modeled as supply-side resources and are divided into 2020-2023, 2024-2026, and 2027-2039; Shown here is the max reduction averaged from 2020 to 2039

Note: Simple cycle aeroderivatives have been excluded from the resource options due to high pressure gas requirements. Reciprocating engines were excluded based on cost.

# DRAFT REFERENCE CASE MODELING PARAMETERS

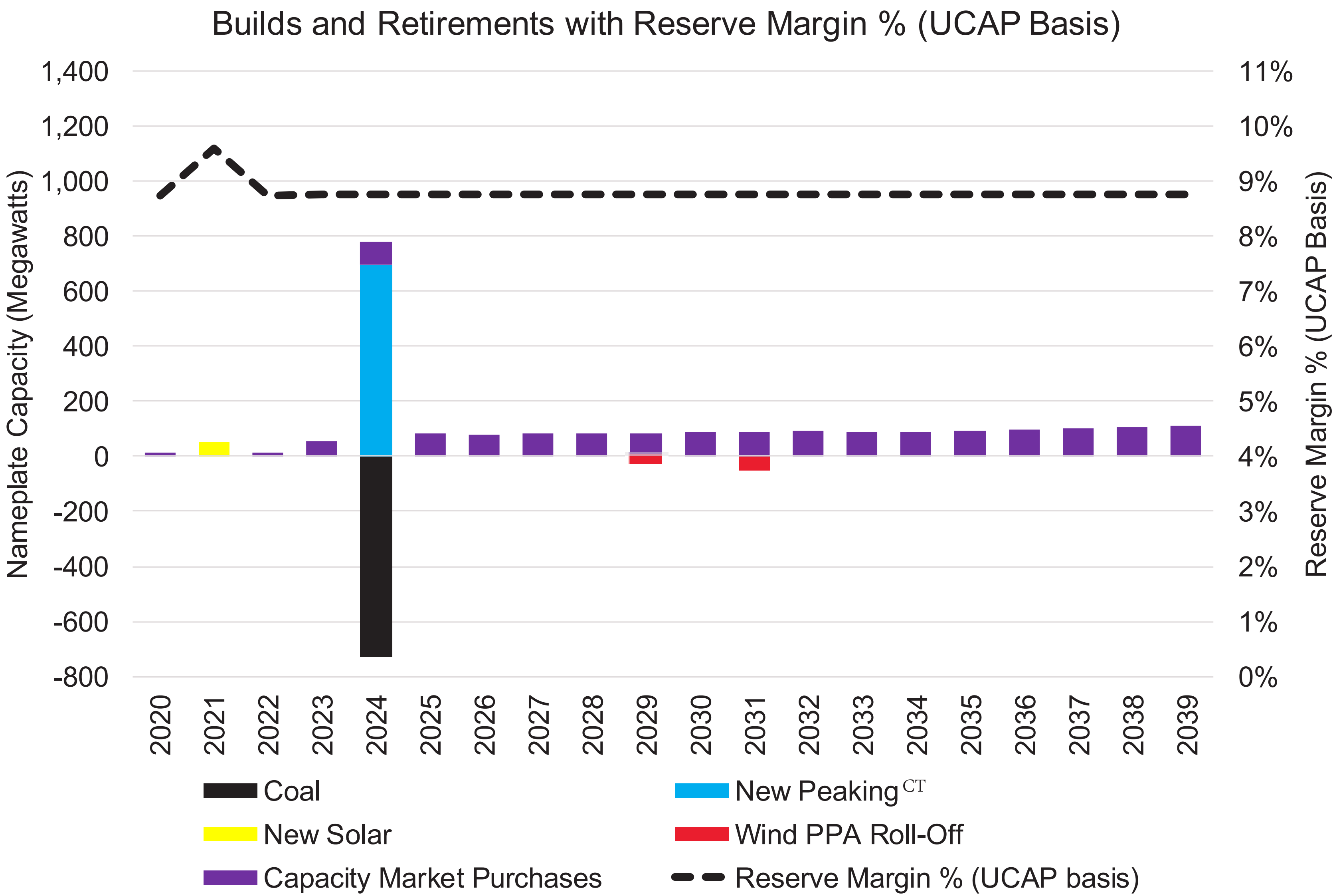
VECTREN
A CenterPoint Energy Company

- Maximum of 3 gas CTs (E/F/H class) are allowed as early as 1/1/2024
- Maximum of 1 gas CC is allowed as early as 6/1/2024. 2x1 CCGT (600-800 MW) is not included as a resource option
- Aeroderivative CTs are excluded from the resource options due to requirements for high-pressure gas supply. Reciprocating engines were excluded based on cost
- Capacity market purchases 2020-2023 are limited to 300 MW per year, after which they are limited to 180 MW per year
- Renewable energy builds can be as much as 400 MW wind per year, 500 MW solar per year, 300-400 MW storage per year, and 150 MW RE+storage per year, while hydroelectric plants are limited to 2 in total

# DRAFT REFERENCE CASE PERFORMANCE CHARACTERISTICS

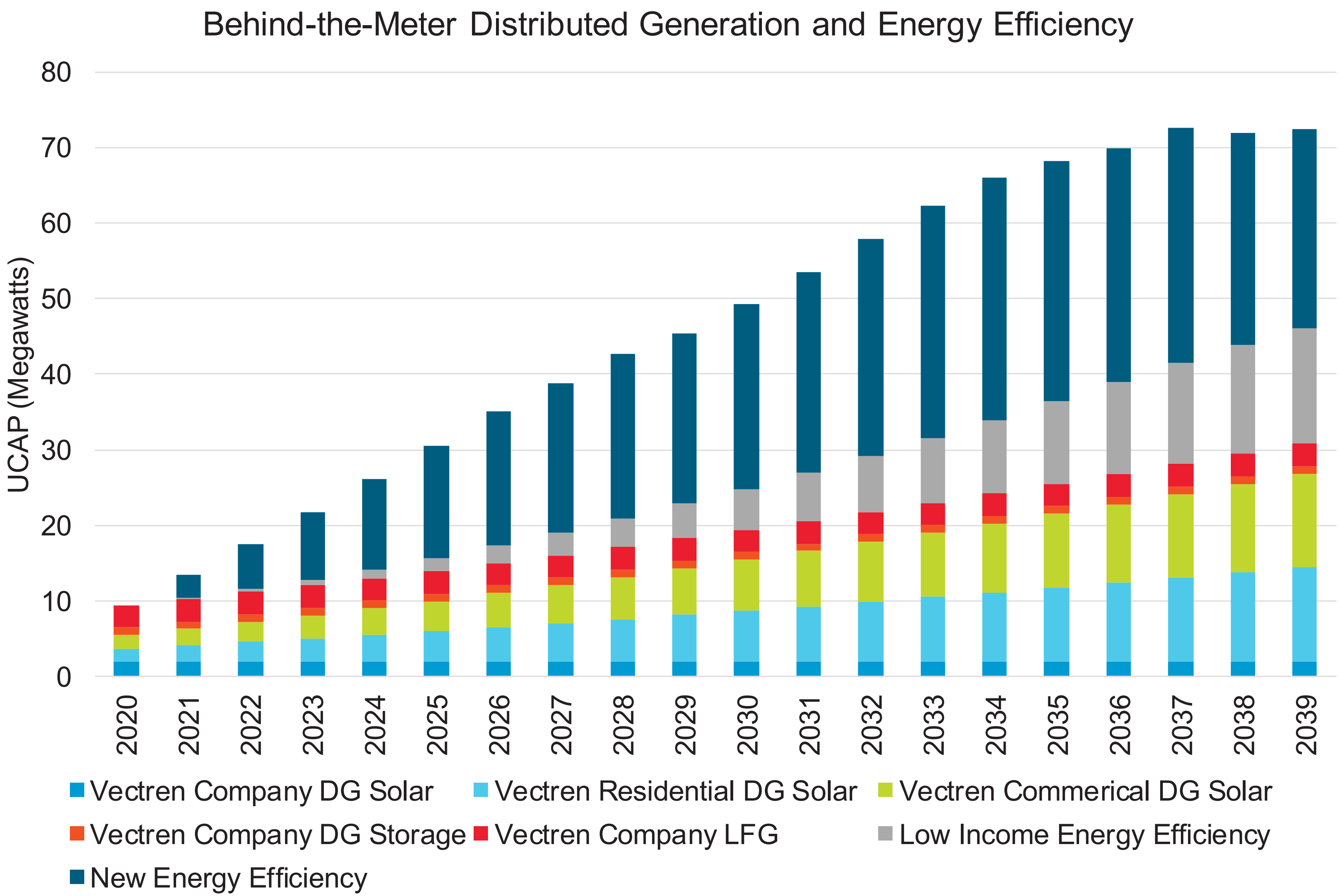
- All coal units except FB Culley 3 are retired at the end of 2023
- The 3 combustion turbine replacements for retired coal capacity operate at an average capacity factor of 7% over the forecast period
- The Planning Reserve Margin target (UCAP basis) is 8.9%. Apart from the CT's that replace coal capacity, the target is adhered to via capacity market purchases that average 90 MW from 2023-2039 or 8% of Vectren coincident (to MISO) peak demand
- Prior to coal retirements, Vectren is a net exporter of energy into MISO. After the coal retirements, Vectren would become a net importer of energy
- Relative to the first year of analysis (2019), $CO_2$ emissions decline by 47% in the year following coal retirements and decline by 61% by 2039
- Energy Efficiency was selected and equates to approximately 1% of sales

# DRAFT REFERENCE CASE SEES 3 F-CLASS CT'S (697 MW) REPLACE 730 MW OF COAL CAPACITY

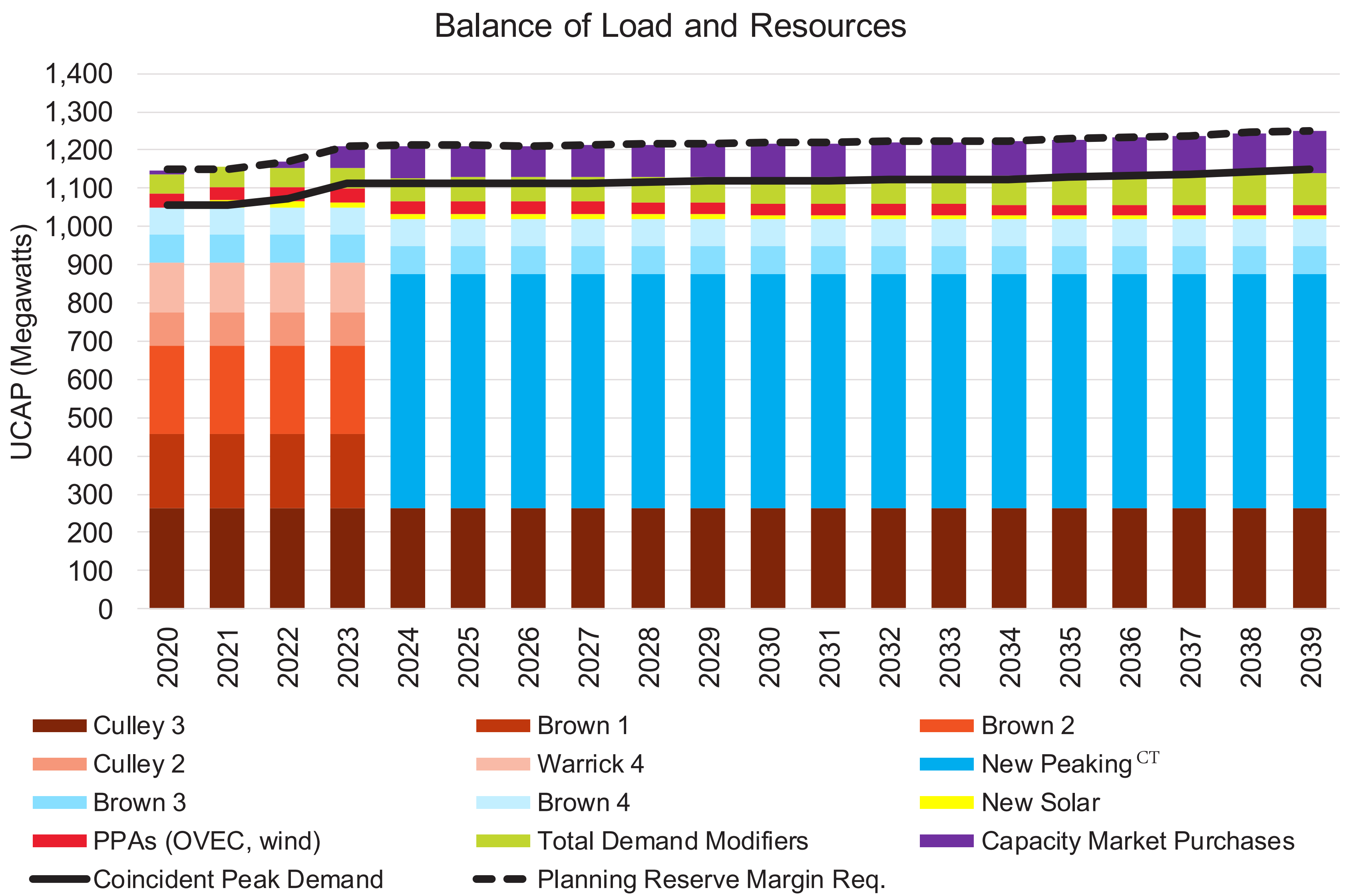


# DRAFT REFERENCE CASE DISTRIBUTED GENERATION AND ENERGY EFFICIENCY

VECTREN
A CenterPoint Energy Company



# DRAFT REFERENCE CASE PORTFOLIO



# SCENARIO MODELING CONSIDERATIONS

- Reference Case modeling will be updated.  Final results may vary
  - RFP results will be included
  - 1x1 CCGT costs will be refined with +/-10% estimates
  - Pipeline costs will be refined for CT options
- Other scenarios with lower costs for renewables and Energy Efficiency may select more of these resources
- Reference Case results show the least cost portfolio given the determined future.  This portfolio may not ultimately be least cost once subjected to probabilistic modeling (200 future states)
- Vectren will select a portfolio among approximately 15 based on the results of the full risk analysis

# DRAFT FGD SCRUBBER SENSITIVITY ANALYSIS

- All FGD scrubber options for replacing the Dual Alkali system were found to have significantly higher NPVs relative to the Reference Case
- Early results indicate that the Limestone Inhibited Oxidation scrubber has the lowest portfolio NPV of these 4 technologies
  - Four Flue Gas Desulfurization (FGD) scrubber technologies were evaluated in the reference case
  - Note that some options cause other environmental control systems to be modified or replaced. These cost estimates are included in the analysis.
  - Each of the four options was examined in an otherwise identical portfolio and modeled to 2039
- The lowest portfolio NPV of each option will be utilized for the Business as Usual (BAU) portfolio

| FGD Scrubber Option |
|---|
| Ammonia Based (NH3) |
| Circulating Dry Scrubber (CDS) |
| Limestone Forced Oxidation (LSFO) |
| Limestone Inhibited Oxidation (LSIO) |

Ammonia Based and LSFO have the potential for future by-product sales.

# FINAL RFP MODELING INPUTS

**MATT LIND**

RESOURCE PLANNING & MARKET ASSESSMENTS
BUSINESS LEAD, BURNS AND MCDONNELL

# RFP PROCESS UPDATE

Received Proposals

Initial Proposal Review

Clarified Information with Bidders

Group Proposals

Interconnection & Network Upgrade Analysis

Evaluation of Proposals

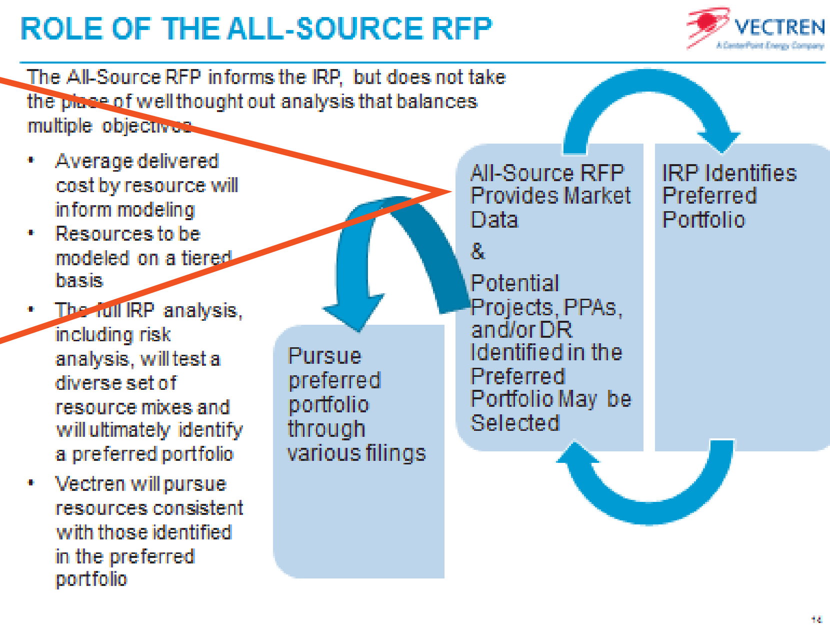
Aggregated Group Data for IRP

Receive Results from IRP

Due Diligence and Negotiations

Definitive Agreements Executed

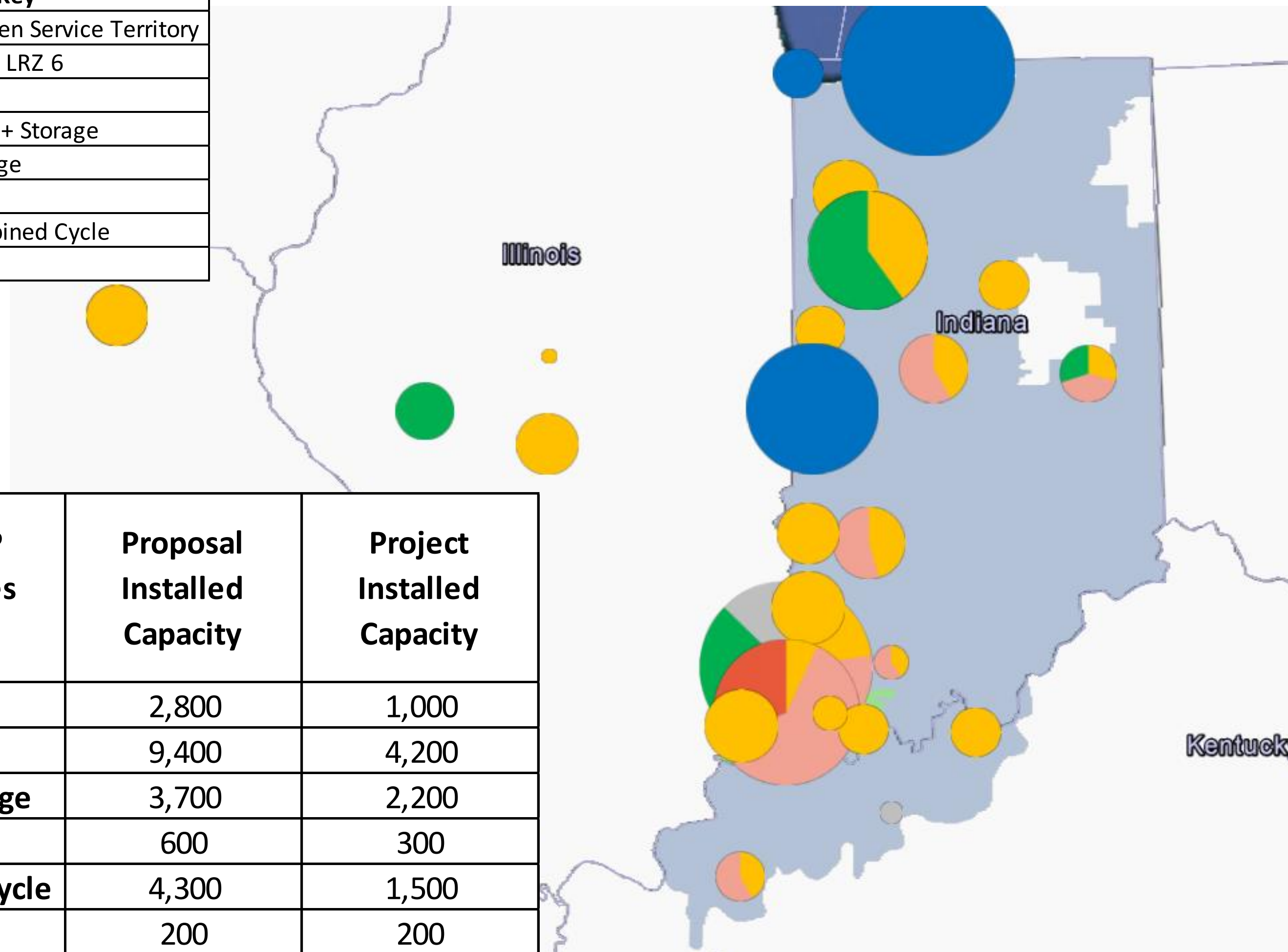
File Petitions with Regulatory Bodies



# RFP PROPOSALS

- Received Proposals
- Initial Proposal Review
- Clarified Information with Bidders
- Group Proposals
- Interconnection & Network Upgrade Analysis
- Evaluation of Proposals
- Aggregated Group Data for IRP
- Receive Results from IRP
- Due Diligence and Negotiations
- Definitive Agreements Executed
- File Petitions with Regulatory Bodies

| Key | |
|---|---|
| | Vectren Service Territory |
| | MISO LRZ 6 |
| | Solar |
| | Solar + Storage |
| | Storage |
| | Wind |
| | Combined Cycle |
| | Coal |

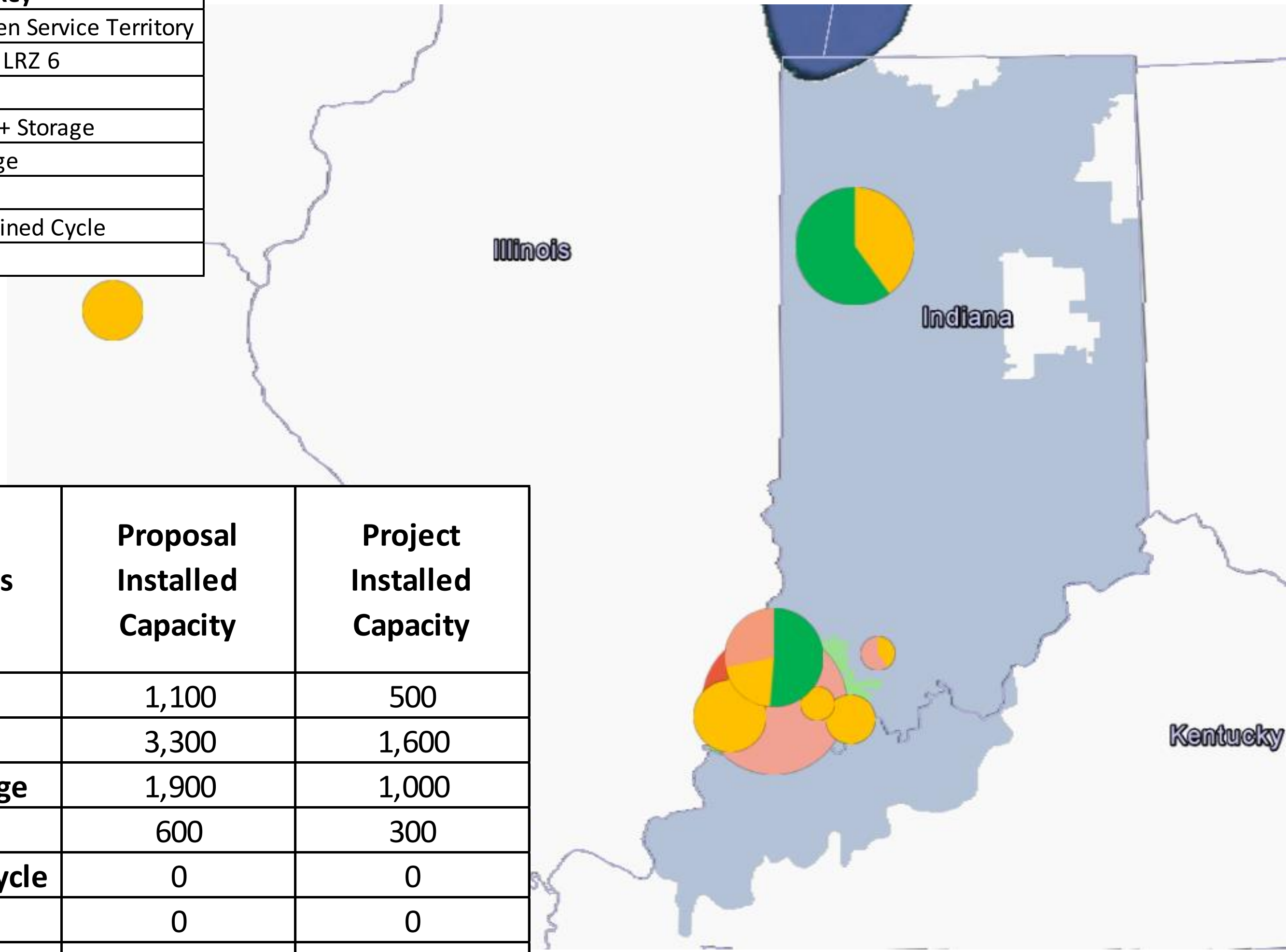



| 2019 RFP Responses (MW) | Proposal Installed Capacity | Project Installed Capacity |
|---|---|---|
| **Wind** | 2,800 | 1,000 |
| **Solar** | 9,400 | 4,200 |
| **Solar + Storage** | 3,700 | 2,200 |
| **Storage** | 600 | 300 |
| **Combined Cycle** | 4,300 | 1,500 |
| **Coal** | 200 | 200 |
| **LMR/DR** | 100 | 100 |
| **System Energy** | 300 | 100 |
| **Total** | **21,400** | **9,600** |

# RFP PROPOSALS - TIER 1

- Received Proposals
- Initial Proposal Review
- Clarified Information with Bidders
- Group Proposals
- Interconnection & Network Upgrade Analysis
- Evaluation of Proposals
- Aggregated Group Data for IRP
- Receive Results from IRP
- Due Diligence and Negotiations
- Definitive Agreements Executed
- File Petitions with Regulatory Bodies

| Key | |
|---|---|
| (light green) | Vectren Service Territory |
| (light blue) | MISO LRZ 6 |
| (yellow) | Solar |
| (pink) | Solar + Storage |
| (red) | Storage |
| (green) | Wind |
| (blue) | Combined Cycle |
| (grey) | Coal |




| 2019 RFP Responses (MW) | Proposal Installed Capacity | Project Installed Capacity |
|---|---|---|
| Wind | 1,100 | 500 |
| Solar | 3,300 | 1,600 |
| Solar + Storage | 1,900 | 1,000 |
| Storage | 600 | 300 |
| Combined Cycle | 0 | 0 |
| Coal | 0 | 0 |
| LMR/DR | 100 | 100 |
| System Energy | 0 | 0 |
| **Total** | **7,000** | **3,500** |

# PROPOSAL GROUPING

VECTREN
A CenterPoint Energy Company

- Received Proposals
- Initial Proposal Review
- Clarified Information with Bidders
- Group Proposals
- Interconnection & Network Upgrade Analysis
- Evaluation of Proposals
- Aggregated Group Data for IRP
- Receive Results from IRP
- Due Diligence and Negotiations
- Definitive Agreements Executed
- File Petitions with Regulatory Bodies

| | Grouping[1] | RFP Count | Tier 1 | Tier 2 |
|---|---|---|---|---|
| 1 | Coal PPA | 2 | 0 | 2 |
| 2 | LMR/DR PPA | 1 | 1 | 0 |
| 3 | CCGT PPA | 2 | 0 | 2 |
| 4 | CCGT Purchase | 5 | 0 | 5 |
| 5 | Wind Purchase | 2 | 0 | 2 |
| 6 | 12-15 Year Wind PPA | 9 | 4 | 5 |
| 7 | 20 Year Wind PPA | 2 | 1 | 1 |
| 8 | Storage Purchase | 4 | 4 | 0 |
| 9 | Storage PPA | 4 | 4 | 0 |
| 10 | Solar + Storage PPA | 6 | 5 | 1 |
| 11 | Solar + Storage Purchase | 9 | 5 | 4 |
| 12 | Solar + Storage Purchase/PPA | 4 | 1 | 3 |
| 13 | Solar Purchase/PPA | 6 | 1 | 5 |
| 14 | 12-15 Year Solar PPA | 8 | 3 | 5 |
| 15 | 20 Year Solar PPA | 16 | 10 | 6 |
| 16 | 25-30 Year Solar PPA | 9 | 3 | 6 |
| 17 | Solar Purchase | 18 | 7 | 11 |
| N/A | Energy Only | 3 | 0 | 3 |
| | **Total** | **110** | **49** | **61** |

**110 Proposals**

**Tier 1**
- Binding Pricing
- Delivered to SIGE.SIGW OR On System

IRP Inputs

**Tier 2**
- Non-Binding Pricing
- Congestion / delivery risk

Potential IRP Inputs Based on Evaluation

- Total installed capacity of RFP bids in Tier 1 ~5X greater than Vectren's peak load
- Resource options from the technology assessment will supplement these options as needed

1. Updated Tier 1 & Tier 2 classification based on interactions with bidders

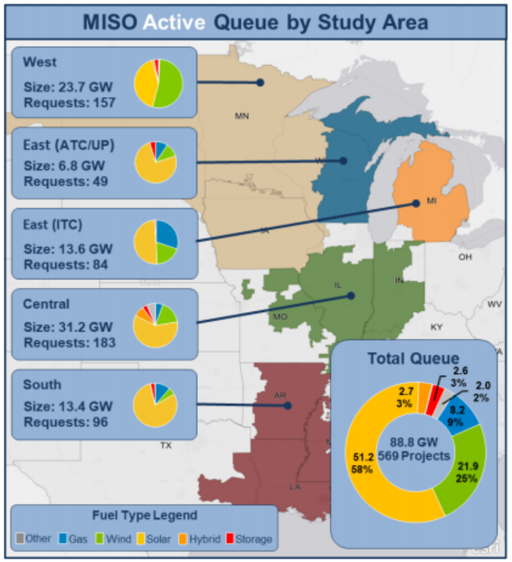
# TRANSMISSION INTERCONNECTION COSTS

VECTREN
A CenterPoint Energy Company

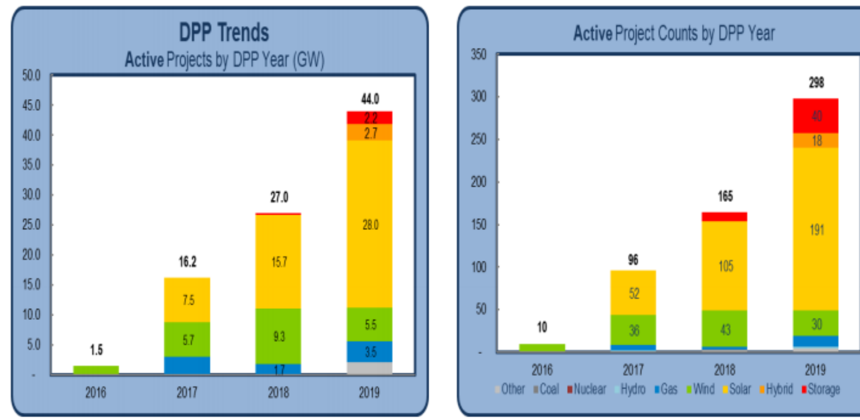
- Received Proposals
- Initial Proposal Review
- Clarified Information with Bidders
- Group Proposals
- **Interconnection & Network Upgrade Analysis**
- Evaluation of Proposals
- Aggregated Group Data for IRP
- Receive Results from IRP
- Due Diligence and Negotiations
- Definitive Agreements Executed
- File Petitions with Regulatory Bodies

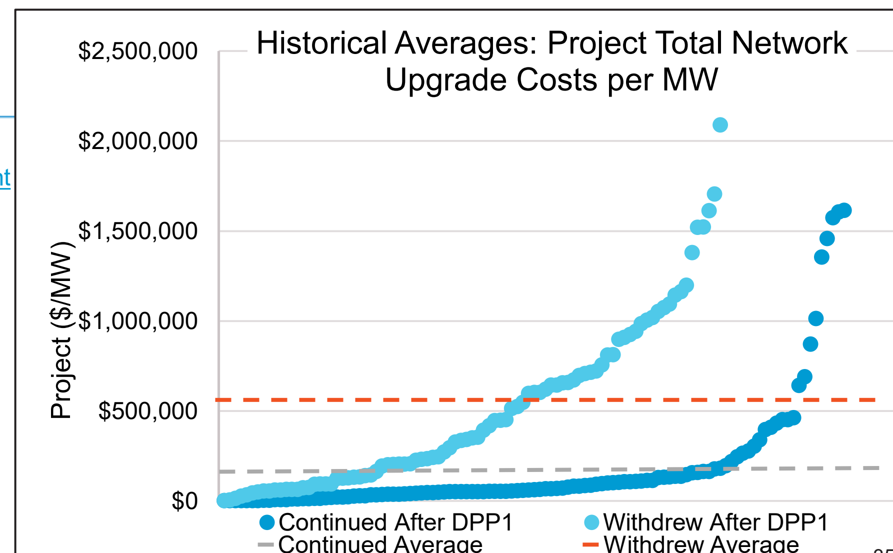
## Generator Interconnection: Overview

*The current generator interconnection active queue consists of **569** projects totaling **88.8** GW*




DPP Project Trends




https://www.misoenergy.org/planning/policy-studies/Renewable-integration-impact-assessment

# TIER 1 COST SUMMARY

VECTREN
A CenterPoint Energy Company

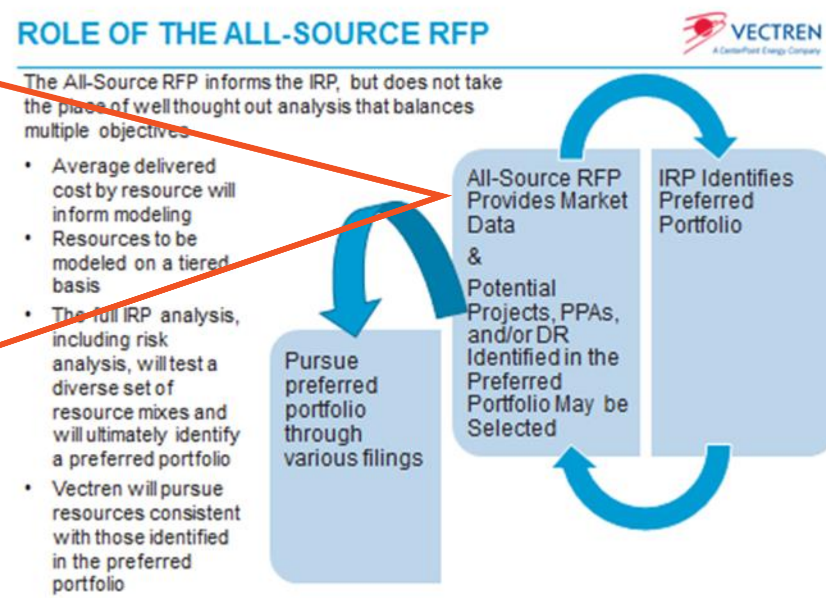
- Received Proposals
- Initial Proposal Review
- Clarified Information with Bidders
- Group Proposals
- Interconnection & Network Upgrade Analysis
- Evaluation of Proposals
- Aggregated Group Data for IRP
- Receive Results from IRP
- Due Diligence and Negotiations
- Definitive Agreements Executed
- File Petitions with Regulatory Bodies

| | Bid Group | # Proposals | # Projects | Proposal ICAP (MW) | Project ICAP (MW) | Capacity Weighted Average LCOE ($2019/MWh) | Capacity Weighted Purchase Price ($/kW)[2] |
|---|---|---|---|---|---|---|---|
| 1 | Coal PPA | 0 | | | | | |
| 2 | LMR/DR PPA | 0 | | | | | |
| 3 | CCGT PPA | 0 | | | | | |
| 4 | CCGT Purchase | 0 | | | | | |
| 5 | Wind Purchase | 0 | | | | | |
| 6 | 12-15 Year Wind PPA | 4 | 1 | 800 | 200 | | |
| 7 | 20 Year Wind PPA | 1 | 1 | 300 | 300 | | |
| 8 | Storage Purchase | 4 | 2 | 305 | 152 | $157 | |
| 9 | Storage PPA | 4 | 2 | 305 | 152 | $135 | |
| 10 | Solar + Storage PPA | 5 | 3 | 902 | 526 | $44 | |
| 11 | Solar + Storage Purchase | 5 | 3 | 862 | 486 | TBD[1] | $1,417[3] |
| 12 | Solar + Storage Purchase/PPA | 1 | 1 | 110 | 110 | | |
| 13 | Solar Purchase/PPA | 1 | 1 | 80 | 80 | | |
| 14 | 12-15 Year Solar PPA | 3 | 2 | 350 | 225 | $32 | |
| 15 | 20 Year Solar PPA | 10 | 8 | 1,522 | 1,227 | $35 | |
| 16 | 25-30 Year Solar PPA | 3 | 2 | 400 | 275 | $34 | |
| 17 | Solar Purchase | 7 | 6 | 902 | 732 | TBD[1] | $1,262 |

1. The method for realizing tax incentives is being reviewed by Vectren
2. $/kW costs are in COD$, purchase option cost is the purchase price unsubsidized by applicable tax incentives and does not reflect ongoing operations and maintenance costs
3. Cost based on simultaneous MW injectable to the grid

# RFP PROCESS UPDATE

- Received Proposals
- Initial Proposal Review
- Clarified Information with Bidders
- Group Proposals
- Interconnection & Network Upgrade Analysis
- Evaluation of Proposals
- Aggregated Group Data for IRP
- Receive Results from IRP
- Due Diligence and Negotiations
- Definitive Agreements Executed
- File Petitions with Regulatory Bodies



VECTREN
A CenterPoint Energy Company

# PORTFOLIO DEVELOPMENT

**MATT RICE**

VECTREN MANAGER OF RESOURCE PLANNING

# STAKEHOLDER PORTFOLIO FEEDBACK

| Request | Response |
|---|---|
| Small CCGT and conversion at Brown | We will run this portfolio with generic assumptions, but need to acknowledge some challenges. Should this portfolio look attractive, additional study would be needed around air permits, water use, and use of the switchyard. Additionally, this option does not benefit from expedited study at MISO due to capacity beyond current levels at the Brown site |
| HR 763 Portfolio | Will run a sensitivity to create a portfolio based on HR 763 $CO_2$ price assumptions and compare to other portfolios. If significantly different, we include in the risk analysis |
| 100% RPS by 2030 Portfolio | Will include this portfolio |
| NIPSCO like portfolio | We understand the environmental perspective that this means no new fossil and close coal as soon as possible. NIPSCO currently has a gas CCGT and two gas peaker plants. Each utility has different circumstances. We do not plan to run a portfolio that completely mirrors NIPSCO |
| Close all Coal by 2024 | We plan to move forward with approved upgrades for Culley 3 and therefore, do no plan to run this portfolio. We will include a portfolio that closes Culley 3 by 2030 and by 2034 in another portfolio |
| CT and Renewables, Close all coal by 2030 | Will include a similar portfolio |
| Business as Usual (BAU) portfolio | Will include this portfolio |
| BAU Until 2029 Portfolio | Will include this portfolio |
| 100% RPS by 2039 | Will include a similar portfolio |

# STAKEHOLDER PORTFOLIO FEEDBACK

| Request | Response |
|---|---|
| Lobby to Extend Net Metering (Remove cap) | If that the net metering law were to be updated to full, traditional net metering, Vectren's load forecast would decline. The IRP takes into account a low load forecast within probabilistic modeling and deterministic scenarios. Portfolios will be developed and tested in low load conditions |
| Distributed gen (rooftop solar + battery storage) | This option would require an extensive study to be conducted with attributes similar to an EE program. We know from experience that building distributed solar and storage is costly, complicated, and requires risk mitigation. We do not plan to run this portfolio. This could be evaluated in future IRPs |
| Various bridge portfolios to provide off ramps | We will model both short-term and long-term bridge options |

# WIDE RANGE OF PORTFOLIOS

VECTREN
A CenterPoint Energy Company

All portfolios considered include stakeholder input, directly or indirectly.

**Bridges**
- Gas Conversion ABB1
- Gas Conversion ABB1 & ABB2
- Gas Conversion + CCGT
- BAU 2029

**Scenario Based**
- Low Regulatory
- Reference Case
- High Tech
- 80% CO2 Reduction
- High Regulatory

**Diverse**
- Small CCGT with renewables and coal
- Mid CCGT with renewables and coal

**Status Quo**
- Business as Usual (BAU)

**Risk Analysis**

**Renewables Focused**
- Close All Fossil by 2030
- Renewables + flexible gas (close coal by 2034 and no CCGT)
- HB 763

We will consider short term bridge options (extension of W4 contract, market capacity purchase, short term ppa, etc.) for portfolio development in all scenarios and in other portfolios where it makes sense

# STATUS QUO

- The Business As Usual portfolio can be considered a reference portfolio
  - Vectren ends joint operations of W4 in 2024
  - Includes known costs to comply with known EPA rules (ELG/CCR, ACE, 316b) to continue to run Vectren coal plants through 2039
  - Resource need will be optimized based on least cost modeling (All resources available)

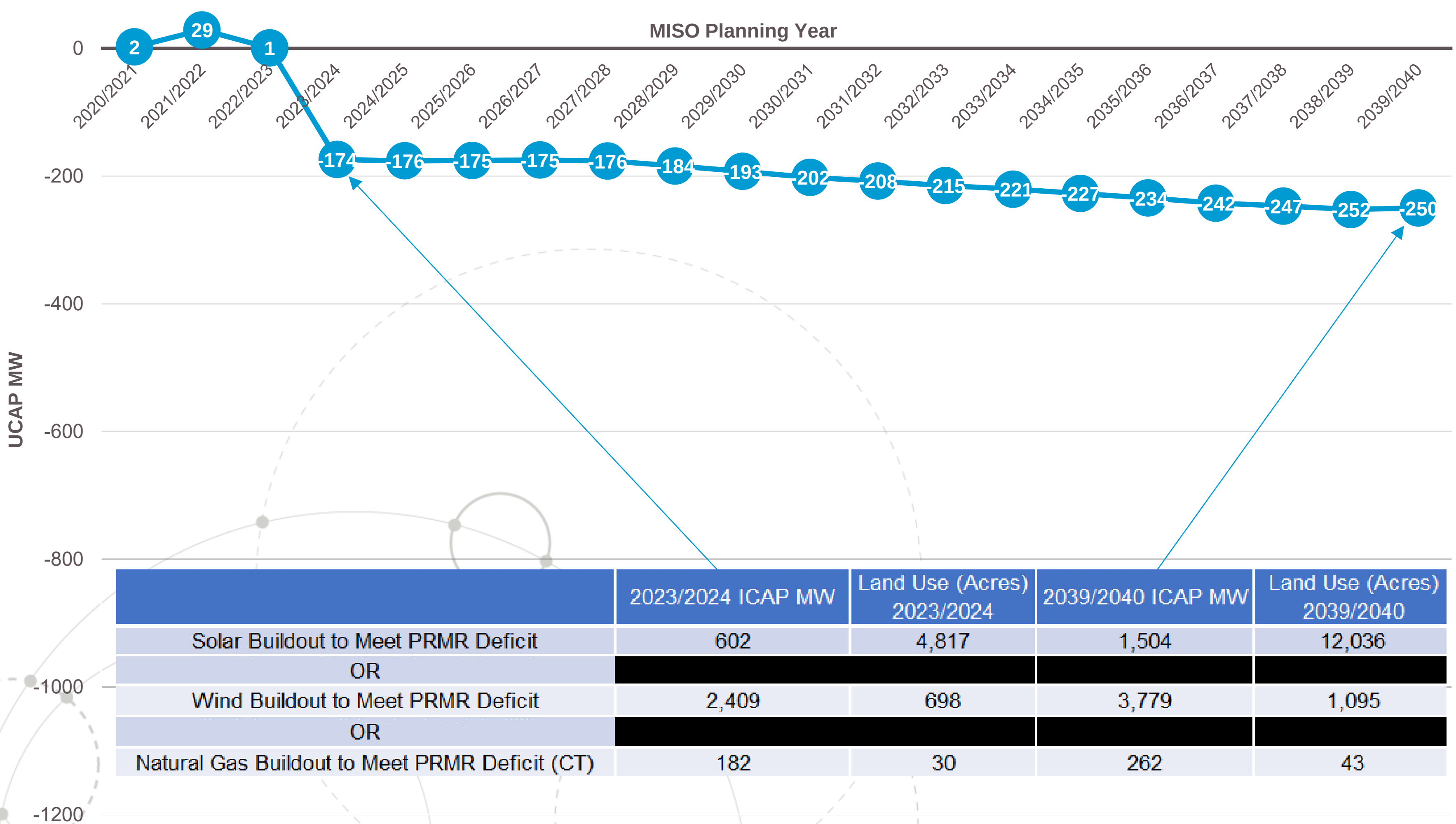
Stakeholder Input:
- Fully explore options at AB Brown plant

↓

Business As Usual (BAU)

# PLANNING RESERVE MARGIN REQUIREMENT SURPLUS\DEFICIT - BAU

VECTREN
A CenterPoint Energy Company




| | 2023/2024 ICAP MW | Land Use (Acres) 2023/2024 | 2039/2040 ICAP MW | Land Use (Acres) 2039/2040 |
|---|---|---|---|---|
| Solar Buildout to Meet PRMR Deficit | 602 | 4,817 | 1,504 | 12,036 |
| OR | | | | |
| Wind Buildout to Meet PRMR Deficit | 2,409 | 698 | 3,779 | 1,095 |
| OR | | | | |
| Natural Gas Buildout to Meet PRMR Deficit (CT) | 182 | 30 | 262 | 43 |

PRMR - Planning Reserve Margin Requirement

# SCENARIO BASED PORTFOLIOS

- Scenarios were created with stakeholder input. A portfolio will be created for each potential deterministic future based on least cost optimization. Insights will be gathered:
  - Potential selection of long and short-term bridge options
  - How resource mixes change given varying futures
  - Range of portfolio costs
- Once run, Vectren will utilize insights to help shape portfolio development
- Portfolios will be compared for similarities and differences. If each varies significantly, they will all be included in the risk analysis
- Insights gained may be included in developing other portfolios

Stakeholder Input:
- Reference Case $CO_2$
- Lower renewables and storage costs
- $CO_2$ Fee and Dividend

Scenario Based
- Low Reg.
- Reference Case
- High Tech
- 80% $CO_2$
- High Reg.

# BRIDGES

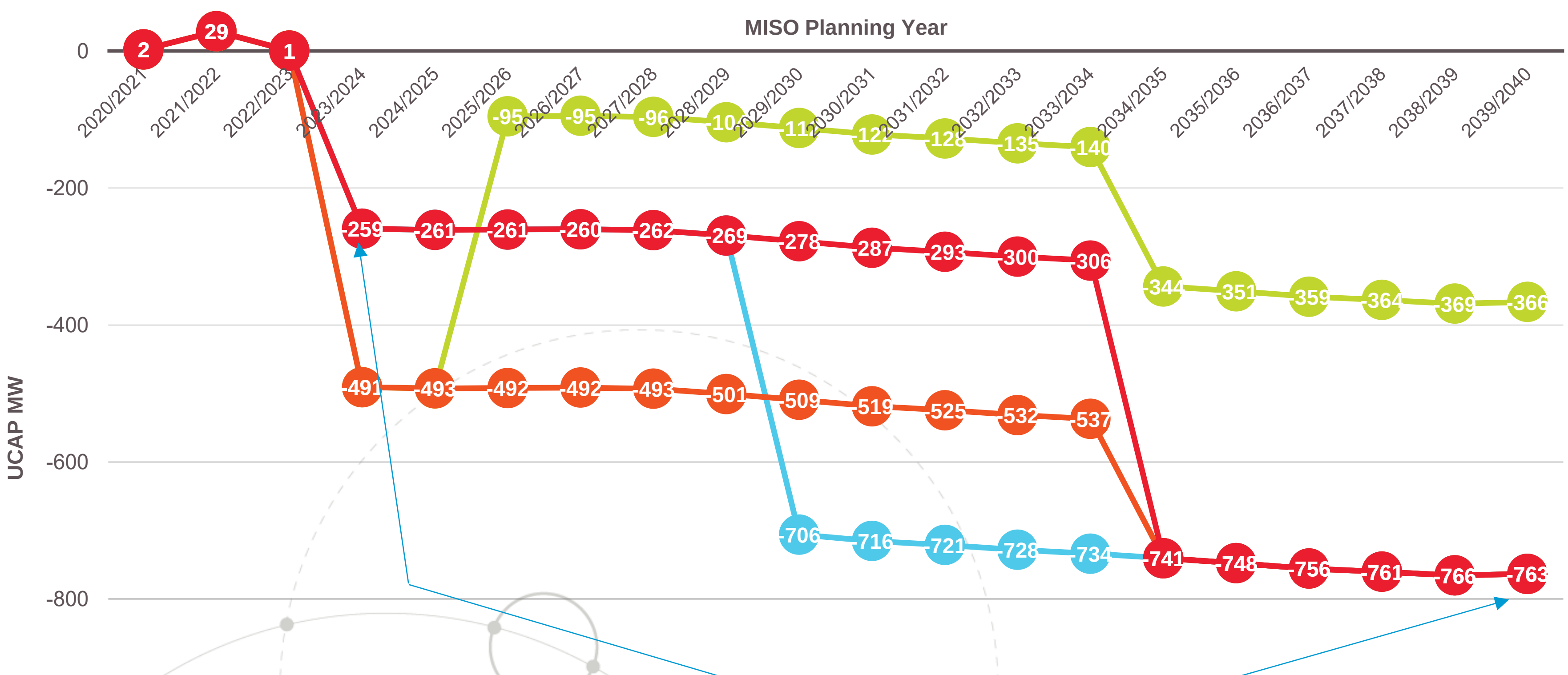
- Vectren is considering various bridge options, including converting coal units to gas
  - Convert AB Brown 1 & 2 by 2024 and run for 10 years. Close FB Culley 2 and end joint operations of Warrick 4 by 2024. Optimize for need (all resources available)
  - Convert AB Brown 1 and retire AB Brown 2 by 2024 + add a small CCGT in 2025. Optimize for need (All resources available). Short term bridge options will be considered
- Vectren will also create a portfolio that continues operation of existing coal units through 2029. We will allow the model to optimize (all resources available) beyond 2030

Stakeholder Input:
- Fully consider gas conversion
- Consider running coal until 2030
- Don't run coal beyond 2030
- Include a portfolio that converts ABB1 and adds a small CCGT
- Consider flexibility

- Gas Conversion
- Gas Conversion + CCGT
- BAU 2029

# PLANNING RESERVE MARGIN REQUIREMENT SURPLUS\DEFICIT - BRIDGE

VECTREN
A CenterPoint Energy Company




| Bridge - Convert Brown 1 & Brown 2 | 2023/2024 ICAP MW | Land Use (Acres) 2023/2024 | 2039/2040 ICAP MW | Land Use (Acres) 2039/2040 |
|---|---|---|---|---|
| Solar Buildout to Meet PRMR Deficit | 897 | 7,176 | 4,594 | 36,754 |
| OR | | | | |
| Wind Buildout to Meet PRMR Deficit | 3,589 | 1,040 | 11,541 | 3,345 |
| OR | | | | |
| Natural Gas Buildout to Meet PRMR Deficit (CCGT) | 272 | 44 | 800 | 131 |

PRMR - Planning Reserve Margin Requirement

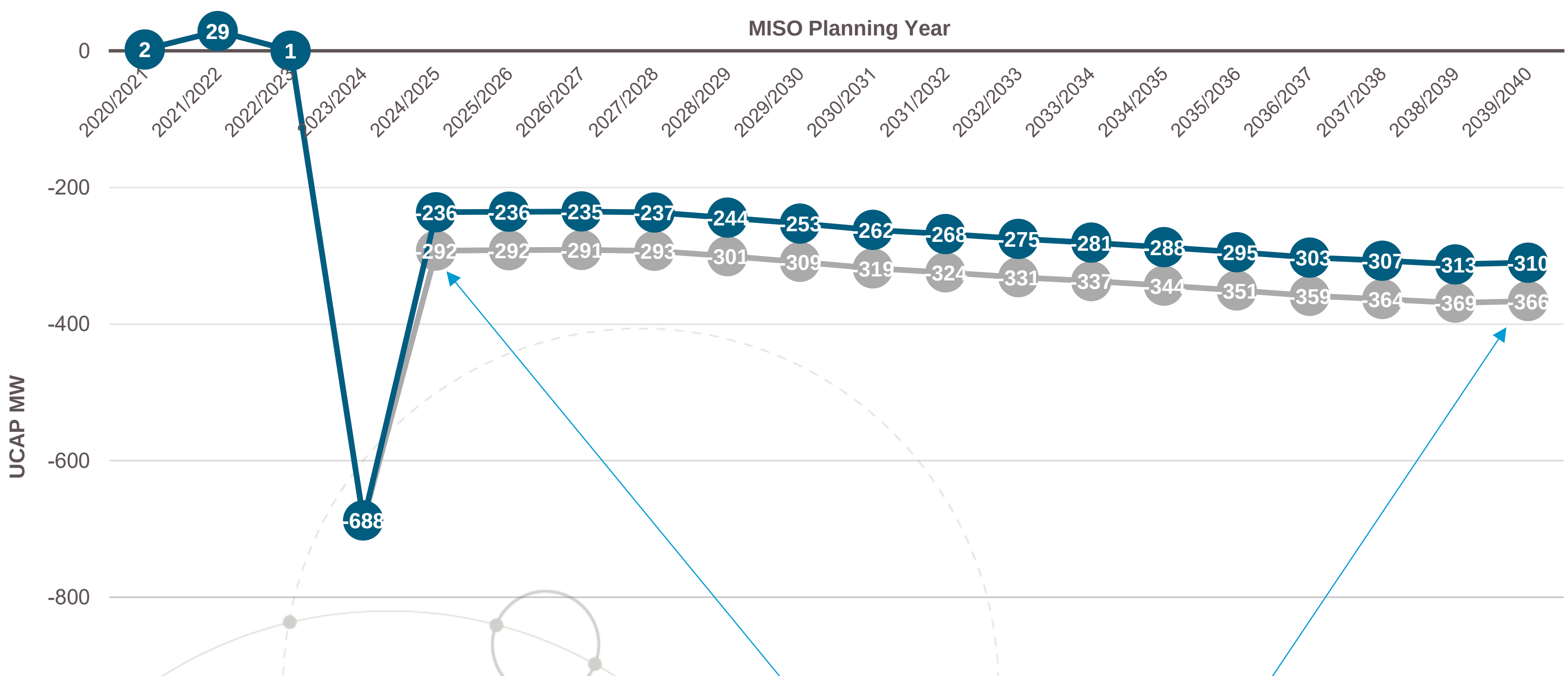
# DIVERSE

- One of Vectren's objectives is resource diversity. As such, Vectren is evaluating portfolios that contain some coal, some gas, and some renewables/DSM/storage options
  - Small CCGT ~400 MWs at the Brown site will be included, along with Culley 3. Optimize with renewables, DSM, and storage for remaining need
  - Mid-sized CCGT ~500 MWs will be included at the Brown site, along with Culley 3. Optimize with renewables, DSM, and storage for remaining need
- A 2x1 CCGT (600-800 MW) will not be considered in portfolio development
- The Brown site offers several advantages: existing interconnection rights, reuse of some equipment and facilities, tax base for Posey county, and jobs for existing employees
- Short term bridge options will be considered

Stakeholder Input:
- Gas plant too large for a small utility
- Did not consider smaller gas plant options in the risk analysis

-Small CCGT with renewables and coal
-Mid-sized CCGT with renewables and coal

# PLANNING RESERVE MARGIN REQUIREMENT SURPLUS\DEFICIT - DIVERSE




| Diverse 400 MW CCGT | 2024/2025 ICAP MW | Land Use (Acres) 2024/2025 | 2039/2040 ICAP MW | Land Use (Acres) 2039/2040 |
|---|---|---|---|---|
| Solar Buildout to Meet PRMR Deficit | 1,065 | 8,518 | 2,205 | 17,642 |
| OR | | | | |
| Wind Buildout to Meet PRMR Deficit | 4,065 | 1,178 | 5,540 | 1,606 |
| OR | | | | |
| Natural Gas Buildout to Meet PRMR Deficit (CCGT) | 306 | 50 | 384 | 63 |

PRMR - Planning Reserve Margin Requirement

# RENEWABLES FOCUSED

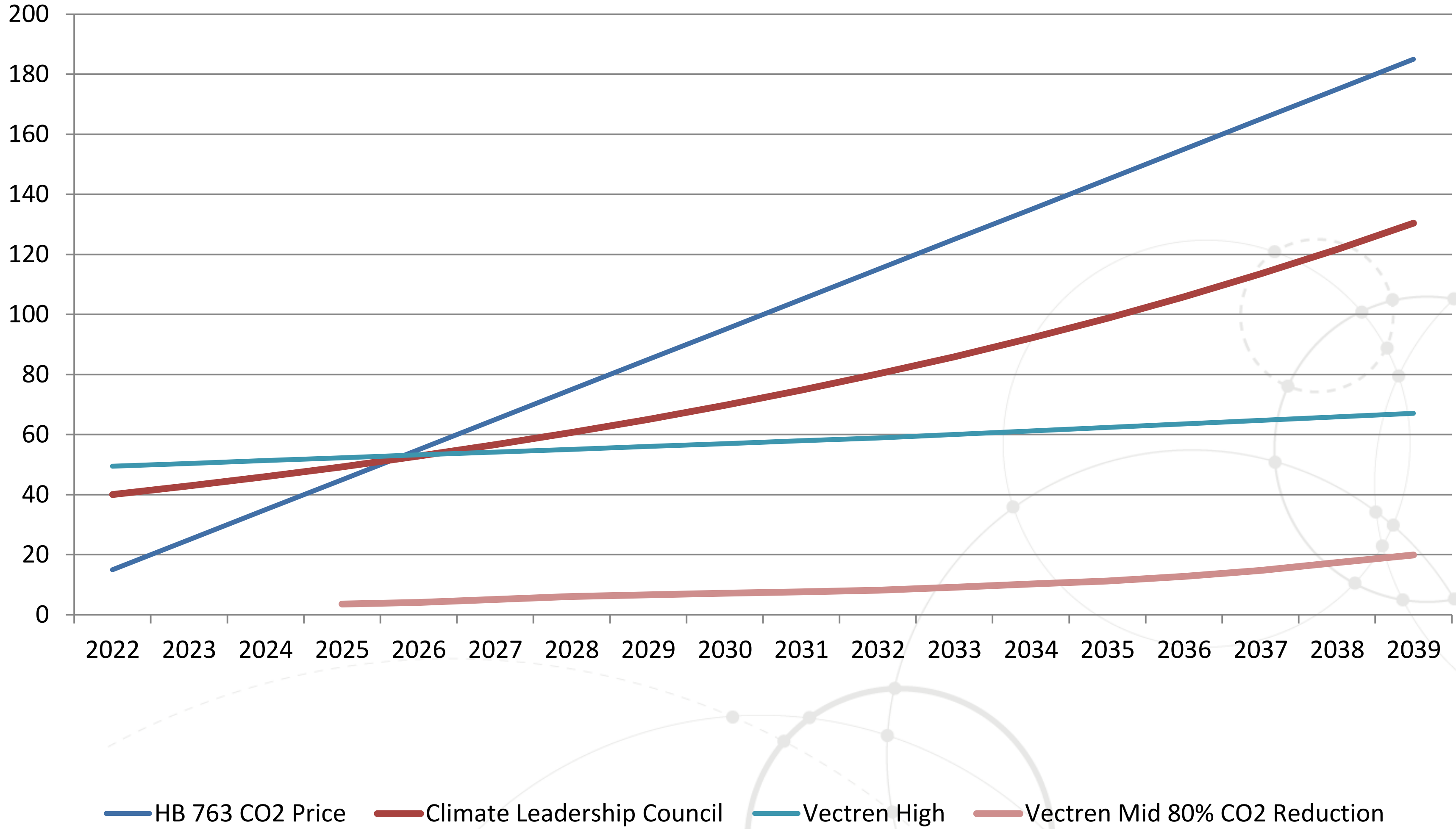
- Vectren continues to fully explore renewable resources through market pricing and portfolio development
  - Close all fossil generation by 2030. Will require voltage support. Optimize for renewables, demand response, energy efficiency, and storage
  - Close all coal by 2034 (All but Culley 3 are closed in 2024). Optimize for renewables, demand response, energy efficiency, and Storage. Flexible gas (CTs) will be allowed within the optimization for capacity (No CCGTs)
  - Build a portfolio based on House Bill 763, which includes a \$15 $CO_2$ price, escalating to \$185 by 2039. Compare and determine if portfolio is sufficiently different from other renewables portfolios. Optimize for need

Stakeholder Input:
- Fully consider renewable resources
- 100% renewable by 2030
- Consider flexible gas and renewables
- Include a scenario on HB763

- Close All Fossil by 2030
- Renewables + flexible gas (close all coal by 2034)
- HB 763

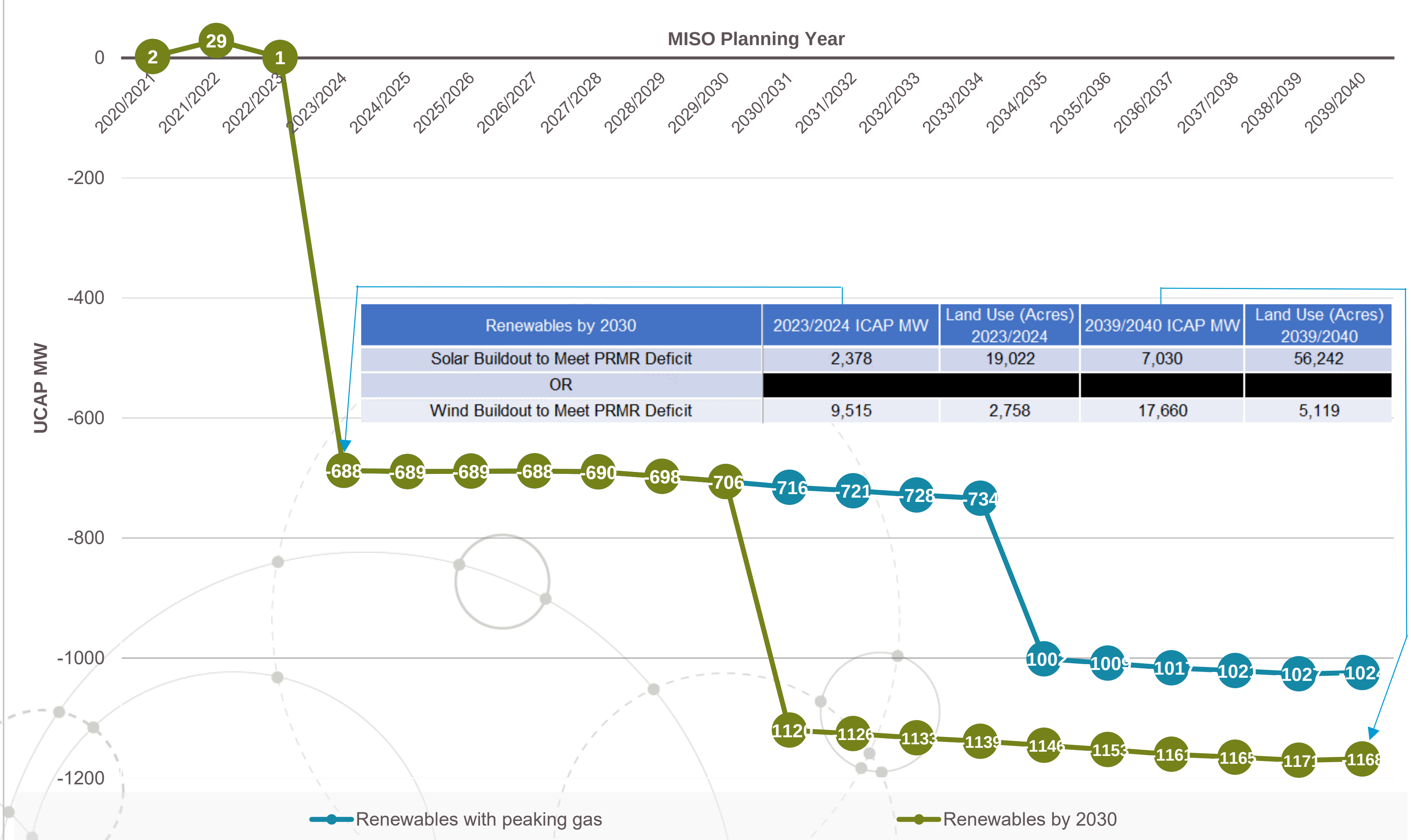
# $CO_2$ PRICE RANGES WITH HB 763

VECTREN
A CenterPoint Energy Company



# PLANNING RESERVE MARGIN REQUIREMENT SURPLUS\DEFICIT - RENEWABLES

VECTREN
A CenterPoint Energy Company




| Renewables by 2030 | 2023/2024 ICAP MW | Land Use (Acres) 2023/2024 | 2039/2040 ICAP MW | Land Use (Acres) 2039/2040 |
|---|---|---|---|---|
| Solar Buildout to Meet PRMR Deficit | 2,378 | 19,022 | 7,030 | 56,242 |
| OR | | | | |
| Wind Buildout to Meet PRMR Deficit | 9,515 | 2,758 | 17,660 | 5,119 |

PRMR - Planning Reserve Margin Requirement

# SCENARIO TESTING AND PROBABILISTIC MODELING

**PETER HUBBARD**

MANAGER OF ENERGY BUSINESS ADVISORY, PACE GLOBAL

# PORTFOLIOS WILL BE TESTED BOTH IN SCENARIOS AND PROBABILISTIC FRAMEWORK

VECTREN
A CenterPoint Energy Company

## Deterministic Modeling (Scenarios) and Probabilistic Modeling (Stochastics) Provide Complementary Analysis

### Probabilistic Modeling is the basis for Portfolio Risk Analysis and Balanced Scorecard results

**Advantages**

- Exhaustive potential futures can be analyzed
- Uses impartial statistical rules and correlations

**Disadvantages**

- Link between statistical realizations and the real world can be difficult to understand

### Deterministic Modeling complements Stochastics; Portfolios will be simulated in each Scenario

**Advantages**

- Well-suited for testing a wide range of regulatory req's
- Deterministic modeling is transparent, easy to understand

**Disadvantages**

- Does not capture the full range of key inputs
- Does not capture volatility
- Time consuming to run several potential futures

| Market Driver | Varied Stochastically |
|---|---|
| Load | ✔ |
| Natural Gas Prices | ✔ |
| Coal Prices | ✔ |
| CO2 Prices | ✔ |
| Capital Costs for New Entry | ✔ |

# LOW REGULATORY CASE INPUTS

VECTREN
A CenterPoint Energy Company

| Input | Unit | 2019 | 2021 | 2023 | 2025 | 2027 | 2029 | 2031 | 2033 | 2035 | 2037 | 2039 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Coal (ILB mine) | 2018$/MMBtu | 1.78 | 1.66 | 1.64 | 1.63 | 1.61 | 1.61 | 1.59 | 1.58 | 1.59 | 1.59 | 1.58 |
| CO2 | 2018$/ton | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| Gas (Henry Hub) | 2018$/MMBtu | 2.77 | 2.76 | 4.10 | 5.12 | 5.20 | 5.62 | 5.60 | 5.95 | 6.12 | 6.23 | 6.85 |
| Vectren Peak Load | MW | 1,115 | 1,102 | 1,217 | 1,311 | 1,314 | 1,352 | 1,357 | 1,390 | 1,381 | 1,386 | 1,423 |
| Customer-Owned Solar DG Capacity* | MW | 9.3 | 14.6 | 21.6 | 30.2 | 38.0 | 47.3 | 56.1 | 66.3 | 75.1 | 84.7 | 96.8 |
| EV Peak Load** | MW | 0.4 | 2.0 | 10.2 | 15.4 | 19.8 | 24.7 | 29.3 | 34.5 | 38.7 | 43.2 | 48.6 |
| Energy Efficiency and Company DG | MW | 6.0 | 9.2 | 15.7 | 22.6 | 28.8 | 33.1 | 39.0 | 45.2 | 48.8 | 50.5 | 47.6 |
| Demand Response | MW | 35.2 | 51.7 | 52.7 | 61.6 | 64.4 | 67.3 | 70.1 | 73.0 | 75.8 | 78.7 | 81.5 |
| Wind (200 MW) | 2018$/kW | 1,334 | 1,330 | 1,328 | 1,326 | 1,324 | 1,324 | 1,324 | 1,324 | 1,326 | 1,328 | 1,330 |
| Solar (100 MW) | 2018$/kW | 1,414 | 1,264 | 1,205 | 1,168 | 1,130 | 1,096 | 1,064 | 1,038 | 1,012 | 993 | 973 |
| Li-Ion Battery (50 MW, 4 hr) | 2018$/kW | 2,088 | 1,811 | 1,654 | 1,518 | 1,452 | 1,391 | 1,342 | 1,301 | 1,263 | 1,232 | 1,201 |
| Flow Battery (50 MW, 6 hr) | 2018$/kW | 2,968 | 2,665 | 2,450 | 2,242 | 2,116 | 1,996 | 1,892 | 1,803 | 1,719 | 1,651 | 1,586 |
| Gas CC F-Class (442 MW with DF) | 2018$/kW | 1,301 | 1,291 | 1,275 | 1,261 | 1,251 | 1,242 | 1,233 | 1,224 | 1,216 | 1,207 | 1,199 |
| Gas CT F-Class (237 MW) | 2018$/kW | 712 | 707 | 697 | 688 | 683 | 677 | 672 | 667 | 662 | 657 | 653 |
| USC Coal w/ CCS | 2018$/kW | 5,621 | 5,536 | 5,424 | 5,309 | 5,201 | 5,097 | 4,992 | 4,891 | 4,794 | 4,698 | 4,605 |

** Res/Com Demand Impact = 0.295*
*** EV Coincident Factor = 0.211*

Revised from last meeting

# HIGH TECHNOLOGY CASE INPUTS

VECTREN
A CenterPoint Energy Company

| Input | Unit | 2019 | 2021 | 2023 | 2025 | 2027 | 2029 | 2031 | 2033 | 2035 | 2037 | 2039 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Coal (ILB mine) | 2018$/MMBtu | 1.78 | 1.66 | 1.49 | 1.27 | 1.25 | 1.25 | 1.25 | 1.25 | 1.25 | 1.25 | 1.25 |
| CO2 | 2018$/ton | 0.00 | 0.00 | 0.00 | 1.20 | 2.06 | 2.38 | 2.94 | 3.89 | 5.46 | 6.85 | 8.50 |
| Gas (Henry Hub) | 2018$/MMBtu | 2.77 | 2.76 | 2.82 | 2.33 | 2.13 | 2.04 | 2.13 | 2.02 | 2.12 | 2.07 | 2.20 |
| Vectren Peak Load | MW | 1,115 | 1,102 | 1,217 | 1,311 | 1,314 | 1,352 | 1,357 | 1,390 | 1,381 | 1,386 | 1,423 |
| Customer-Owned Solar DG Capacity* | MW | 9.3 | 14.6 | 21.6 | 30.2 | 38.0 | 47.3 | 56.1 | 66.3 | 75.1 | 84.7 | 96.8 |
| EV Peak Load** | MW | 0.4 | 2.0 | 10.2 | 15.4 | 19.8 | 24.7 | 29.3 | 34.5 | 38.7 | 43.2 | 48.6 |
| Energy Efficiency and Company DG | MW | 6.0 | 9.2 | 15.7 | 22.6 | 28.8 | 33.1 | 39.0 | 45.2 | 48.8 | 50.5 | 47.6 |
| Demand Response | MW | 35.2 | 51.7 | 52.7 | 61.6 | 64.4 | 67.3 | 70.1 | 73.0 | 75.8 | 78.7 | 81.5 |
| Wind (200 MW) | 2018$/kW | 1,334 | 1,330 | 1,249 | 1,167 | 1,123 | 1,160 | 1,152 | 1,166 | 1,139 | 1,142 | 1,143 |
| Solar (100 MW) | 2018$/kW | 1,414 | 1,264 | 1,120 | 975 | 964 | 942 | 897 | 877 | 818 | 809 | 818 |
| Li-Ion Battery (50 MW, 4 hr) | 2018$/kW | 2,088 | 1,811 | 1,513 | 1,214 | 1,156 | 1,096 | 1,042 | 965 | 928 | 901 | 894 |
| Flow Battery (50 MW, 6 hr) | 2018$/kW | 2,968 | 2,665 | 2,220 | 1,774 | 1,678 | 1,538 | 1,408 | 1,231 | 1,268 | 1,124 | 1,020 |
| Gas CC F-Class (442 MW with DF) | 2018$/kW | 1,301 | 1,291 | 1,275 | 1,261 | 1,251 | 1,242 | 1,233 | 1,224 | 1,216 | 1,207 | 1,199 |
| Gas CT F-Class (237 MW) | 2018$/kW | 712 | 707 | 697 | 688 | 683 | 677 | 672 | 667 | 662 | 657 | 653 |
| USC Coal w/ CCS | 2018$/kW | 5,621 | 5,536 | 5,424 | 5,309 | 5,201 | 5,097 | 4,992 | 4,891 | 4,794 | 4,698 | 4,605 |

** Res/Com Demand Impact = 0.295*

*** EV Coincident Factor = 0.211*

Revised from last meeting

# 80% REDUCTION CASE INPUTS

VECTREN
A CenterPoint Energy Company

| Input | Unit | 2019 | 2021 | 2023 | 2025 | 2027 | 2029 | 2031 | 2033 | 2035 | 2037 | 2039 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Coal (ILB mine) | 2018$/MMBtu | 1.78 | 1.66 | 1.49 | 1.27 | 1.25 | 1.25 | 1.25 | 1.25 | 1.25 | 1.25 | 1.25 |
| CO2 | 2018$/ton | 0.00 | 0.00 | 0.00 | 3.57 | 5.10 | 6.63 | 7.65 | 9.18 | 11.22 | 14.79 | 19.89 |
| Gas (Henry Hub) | 2018$/MMBtu | 2.77 | 2.76 | 3.06 | 3.24 | 3.38 | 3.49 | 3.62 | 3.78 | 3.96 | 4.09 | 4.17 |
| Vectren Peak Load | MW | 1,115 | 1,102 | 1,131 | 1,060 | 1,025 | 1,039 | 1,038 | 1,038 | 1,053 | 1,053 | 1,065 |
| Customer-Owned Solar DG Capacity* | MW | 9.3 | 14.6 | 20.0 | 24.4 | 29.6 | 36.3 | 42.9 | 49.5 | 57.3 | 64.3 | 72.5 |
| EV Peak Load** | MW | 0.4 | 2.0 | 9.5 | 12.4 | 15.4 | 19.0 | 22.4 | 25.8 | 29.5 | 32.8 | 36.4 |
| Energy Efficiency and Company DG | MW | 6.0 | 9.2 | 15.7 | 22.6 | 28.8 | 33.1 | 39.0 | 45.2 | 48.8 | 50.5 | 47.6 |
| Demand Response | MW | 35.2 | 51.7 | 52.7 | 61.6 | 64.4 | 67.3 | 70.1 | 73.0 | 75.8 | 78.7 | 81.5 |
| Wind (200 MW) | 2018$/kW | 1,334 | 1,330 | 1,249 | 1,167 | 1,123 | 1,160 | 1,152 | 1,166 | 1,139 | 1,142 | 1,143 |
| Solar (100 MW) | 2018$/kW | 1,414 | 1,264 | 1,120 | 975 | 964 | 942 | 897 | 877 | 818 | 809 | 818 |
| Li-Ion Battery (50 MW, 4 hr) | 2018$/kW | 2,088 | 1,811 | 1,513 | 1,214 | 1,156 | 1,096 | 1,042 | 965 | 928 | 901 | 894 |
| Flow Battery (50 MW, 6 hr) | 2018$/kW | 2,968 | 2,665 | 2,220 | 1,774 | 1,678 | 1,538 | 1,408 | 1,231 | 1,268 | 1,124 | 1,020 |
| Gas CC F-Class (442 MW with DF) | 2018$/kW | 1,301 | 1,291 | 1,275 | 1,261 | 1,251 | 1,242 | 1,233 | 1,224 | 1,216 | 1,207 | 1,199 |
| Gas CT F-Class (237 MW) | 2018$/kW | 712 | 707 | 697 | 688 | 683 | 677 | 672 | 667 | 662 | 657 | 653 |
| USC Coal w/ CCS | 2018$/kW | 5,621 | 5,536 | 5,424 | 5,309 | 5,201 | 5,097 | 4,992 | 4,891 | 4,794 | 4,698 | 4,605 |

** Res/Com Demand Impact = 0.295*
*** EV Coincident Factor = 0.211*

Revised from last meeting

# HIGH REGULATORY CASE INPUTS

VECTREN
A CenterPoint Energy Company

| Input | Unit | 2019 | 2021 | 2023 | 2025 | 2027 | 2029 | 2031 | 2033 | 2035 | 2037 | 2039 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Coal (ILB mine) | 2018$/MMBtu | 1.78 | 1.66 | 1.49 | 1.27 | 1.25 | 1.25 | 1.25 | 1.25 | 1.25 | 1.25 | 1.25 |
| CO2 | 2018$/ton | 0.00 | 0.00 | 50.40 | 52.28 | 54.17 | 56.05 | 57.94 | 60.06 | 62.41 | 64.77 | 67.12 |
| Gas (Henry Hub) | 2018$/MMBtu | 2.77 | 2.76 | 4.39 | 6.03 | 7.10 | 8.37 | 7.17 | 8.40 | 8.95 | 8.75 | 8.63 |
| Vectren Peak Load | MW | 1,115 | 1,102 | 1,168 | 1,176 | 1,183 | 1,192 | 1,200 | 1,209 | 1,219 | 1,229 | 1,239 |
| Customer-Owned Solar DG Capacity* | MW | 9.3 | 14.6 | 20.7 | 27.1 | 34.2 | 41.7 | 49.6 | 57.7 | 66.3 | 75.1 | 84.3 |
| EV Peak Load** | MW | 0.4 | 2.0 | 9.8 | 13.8 | 17.8 | 21.8 | 25.9 | 30.0 | 34.2 | 38.3 | 42.3 |
| Energy Efficiency and Company DG | MW | 6.0 | 9.2 | 15.7 | 22.6 | 28.8 | 33.1 | 39.0 | 45.2 | 48.8 | 50.5 | 47.6 |
| Demand Response | MW | 35.2 | 51.7 | 52.7 | 61.6 | 64.4 | 67.3 | 70.1 | 73.0 | 75.8 | 78.7 | 81.5 |
| Wind (200 MW) | 2018$/kW | 1,334 | 1,330 | 1,249 | 1,167 | 1,123 | 1,160 | 1,152 | 1,166 | 1,139 | 1,142 | 1,143 |
| Solar (100 MW) | 2018$/kW | 1,414 | 1,264 | 1,120 | 975 | 964 | 942 | 897 | 877 | 818 | 809 | 818 |
| Li-Ion Battery (50 MW, 4 hr) | 2018$/kW | 2,088 | 1,811 | 1,513 | 1,214 | 1,156 | 1,096 | 1,042 | 965 | 928 | 901 | 894 |
| Flow Battery (50 MW, 6 hr) | 2018$/kW | 2,968 | 2,665 | 2,220 | 1,774 | 1,678 | 1,538 | 1,408 | 1,231 | 1,268 | 1,124 | 1,020 |
| Gas CC F-Class (442 MW with DF) | 2018$/kW | 1,301 | 1,291 | 1,275 | 1,261 | 1,251 | 1,242 | 1,233 | 1,224 | 1,216 | 1,207 | 1,199 |
| Gas CT F-Class (237 MW) | 2018$/kW | 712 | 707 | 697 | 688 | 683 | 677 | 672 | 667 | 662 | 657 | 653 |
| USC Coal w/ CCS | 2018$/kW | 5,621 | 5,536 | 5,424 | 5,309 | 5,201 | 5,097 | 4,992 | 4,891 | 4,794 | 4,698 | 4,605 |

** Res/Com Demand Impact = 0.295*
*** EV Coincident Factor = 0.211*

Revised from last meeting

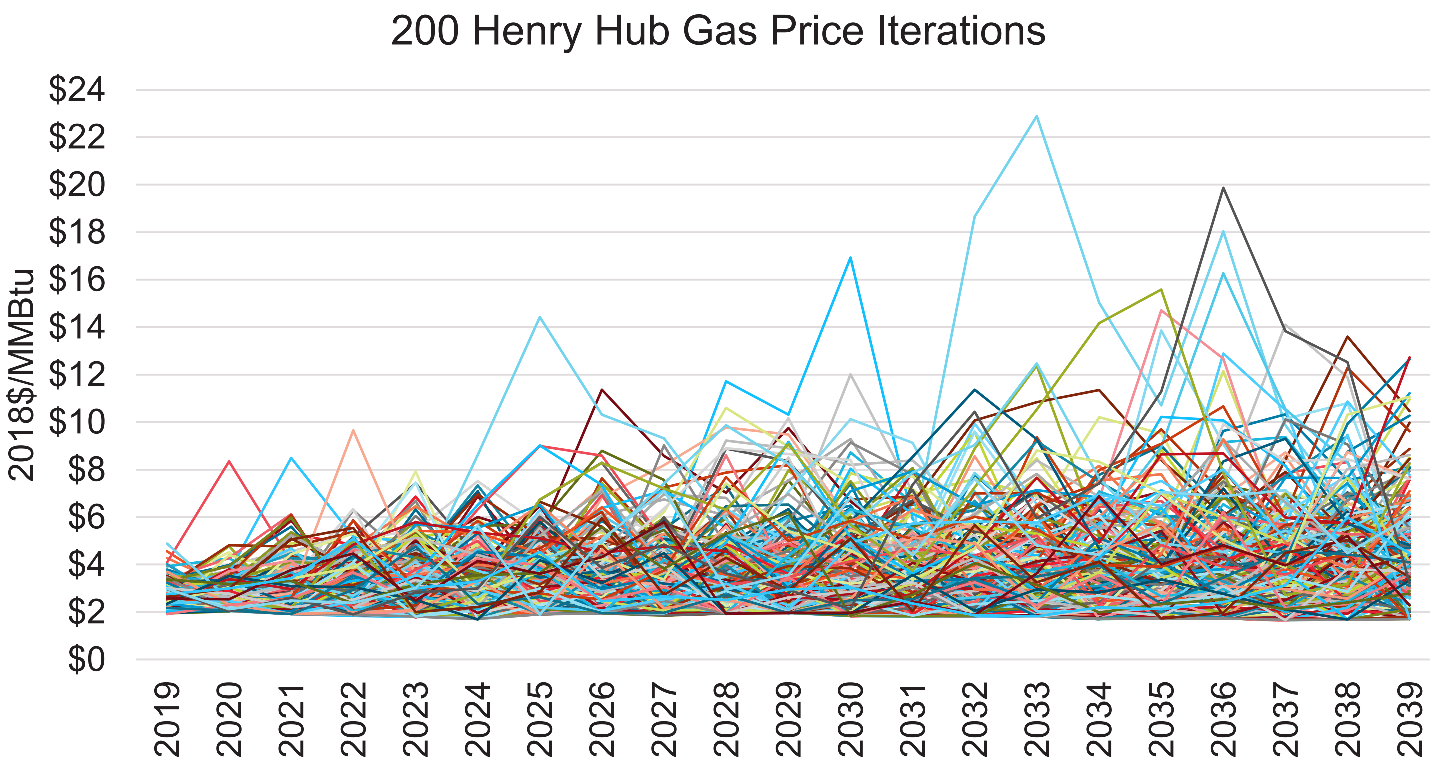
# PROBABILISTIC MODELING PROVIDES THE BASIS FOR IRP SCORECARD METRICS

- By measuring each portfolio's performance across 200 iterations, we can quantify each of the measures associated with IRP objectives
- This provides a direct comparison of portfolio performance that will be summarized in the Balanced Scorecard

| IRP Objective | Measure | Unit |
|---|---|---|
| Affordability | 20-Year NPVRR | $ |
| Price Risk Minimization | $95^{th}$ percentile value of NPVRR | $ |
| Environmental Risk Minimization | Life Cycle Greenhouse Gas Emissions | Tons $CO_2e$ |
| Market Risk Minimization | Energy Market Purchases or Sales outside of a +/- 15% Band | % |
| | Capacity Market Purchases or Sales outside of a +/- 15% Band | % |
| Future Flexibility | Uneconomic Asset Risk | $ |

# PROBABILISTIC MODELING

- Probabilistic modeling helps to measure risk from 200 potential future paths for each stochastic variable
- By running each portfolio through 200 iterations, each portfolio's performance and risk profile can be quantified across a wide range of potential futures



# PROBABILISTIC VARIABLES AND DRIVERS

### 1. Load

- Peak Load
- Average Load

Driver Variables:

- EV and Solar DG (also modeled stochastically)
- Weather
- GDP/ Personal Income
- Expert view on low, mid & high cases

### 2. Natural Gas

- Henry Hub
- Regional gas basis

Modeling based on:

- Historical Volatility
- Historical Mean Reversion
- Historical Correlation
- Expert view on low, mid & high cases

### 3. Coal

- ILB
- PRB
- CAPP & NAPP

Modeling based on:

- Historical Volatility
- Historical Mean Reversion
- Historical Correlation
- Expert view on low, mid & high cases

### 4. CO2

- National CO2 price

Modeling based on:

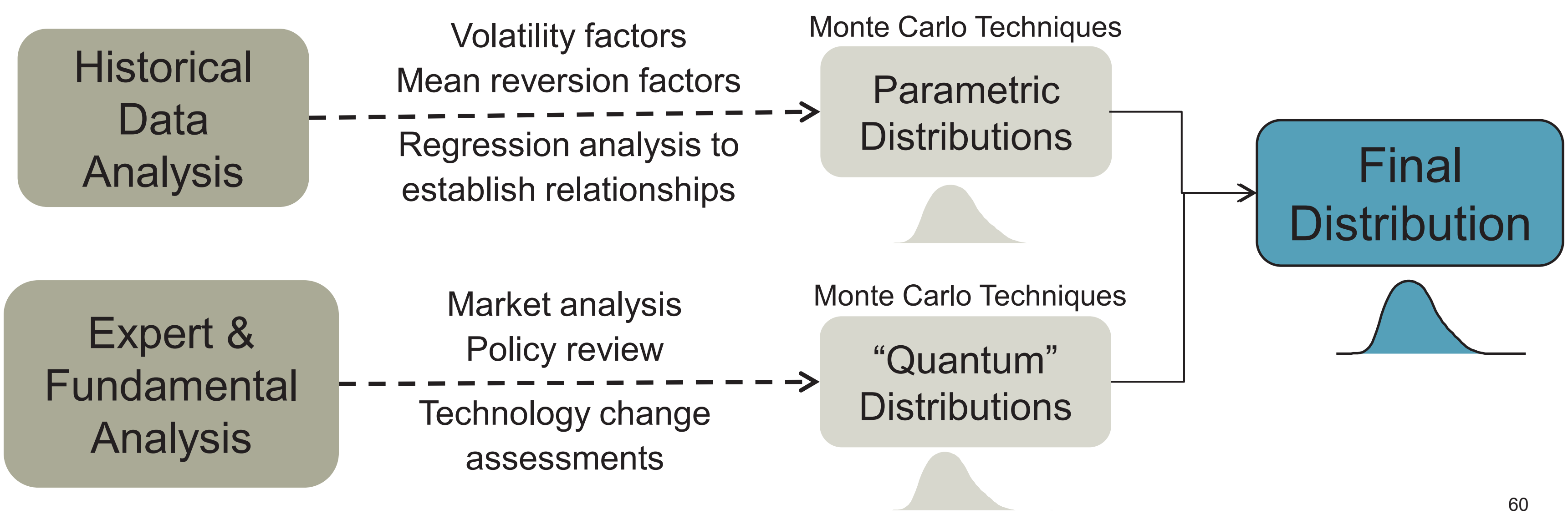
- Analysis of price required for Paris Agreement compliance
- Social cost of carbon analysis
- Expert view on low, mid & high cases

### 5. Capital Cost

- Relevant technologies included

Modeling based on:

- Expert view on low, mid & high cases



# NEXT STEPS

**MATT RICE**

VECTREN MANAGER OF RESOURCE PLANNING

# NEXT STEPS

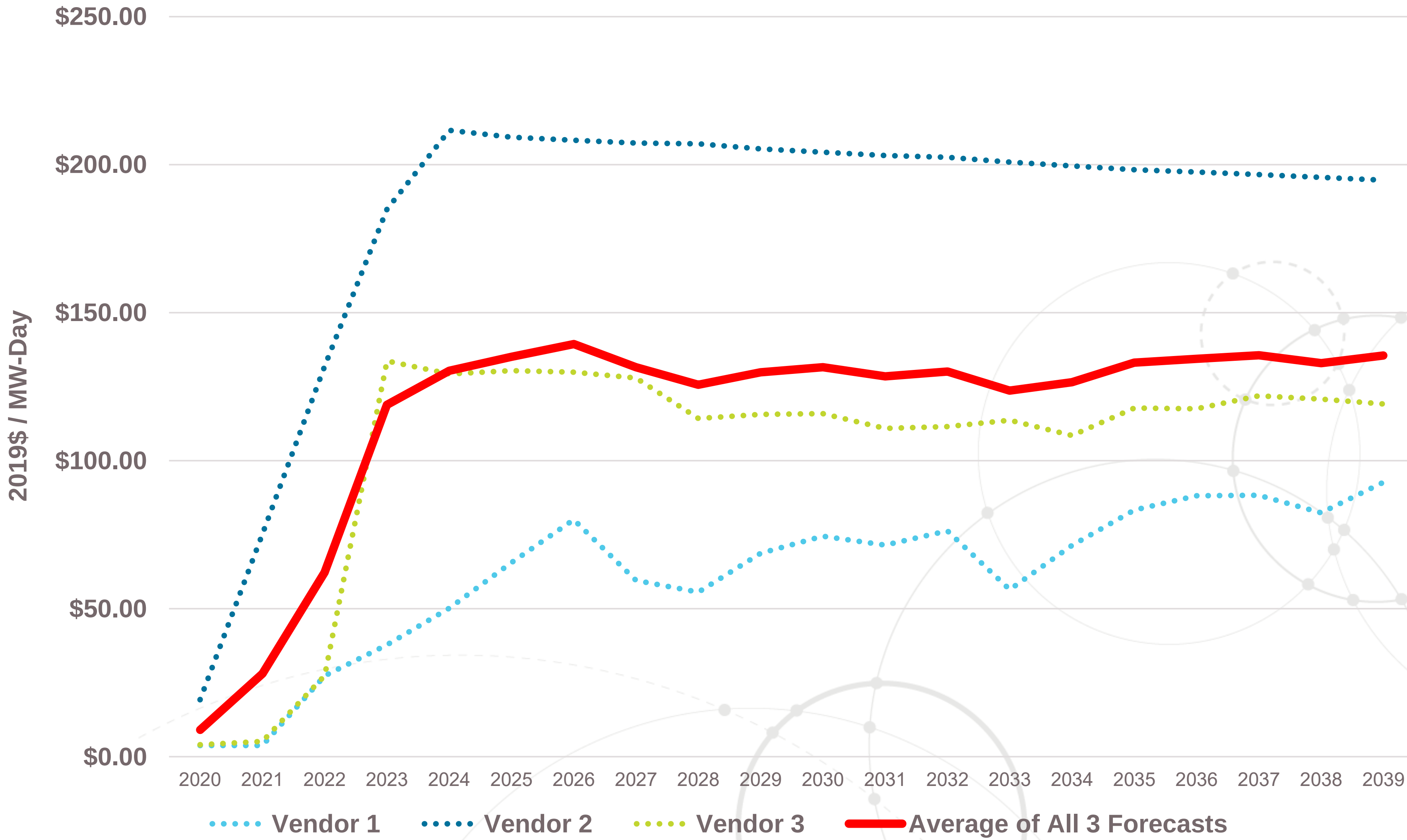
There is a tremendous amount of work to be done between now and our next meeting in March

- Finalize all modeling inputs
- Update Reference Case modeling, including RFP results
- Develop scenario based portfolios
- Finalize additional portfolios with insights produced through scenario modeling
- Test portfolios within scenarios and probabilistic modeling
- Analyze results
- Select the preferred portfolio

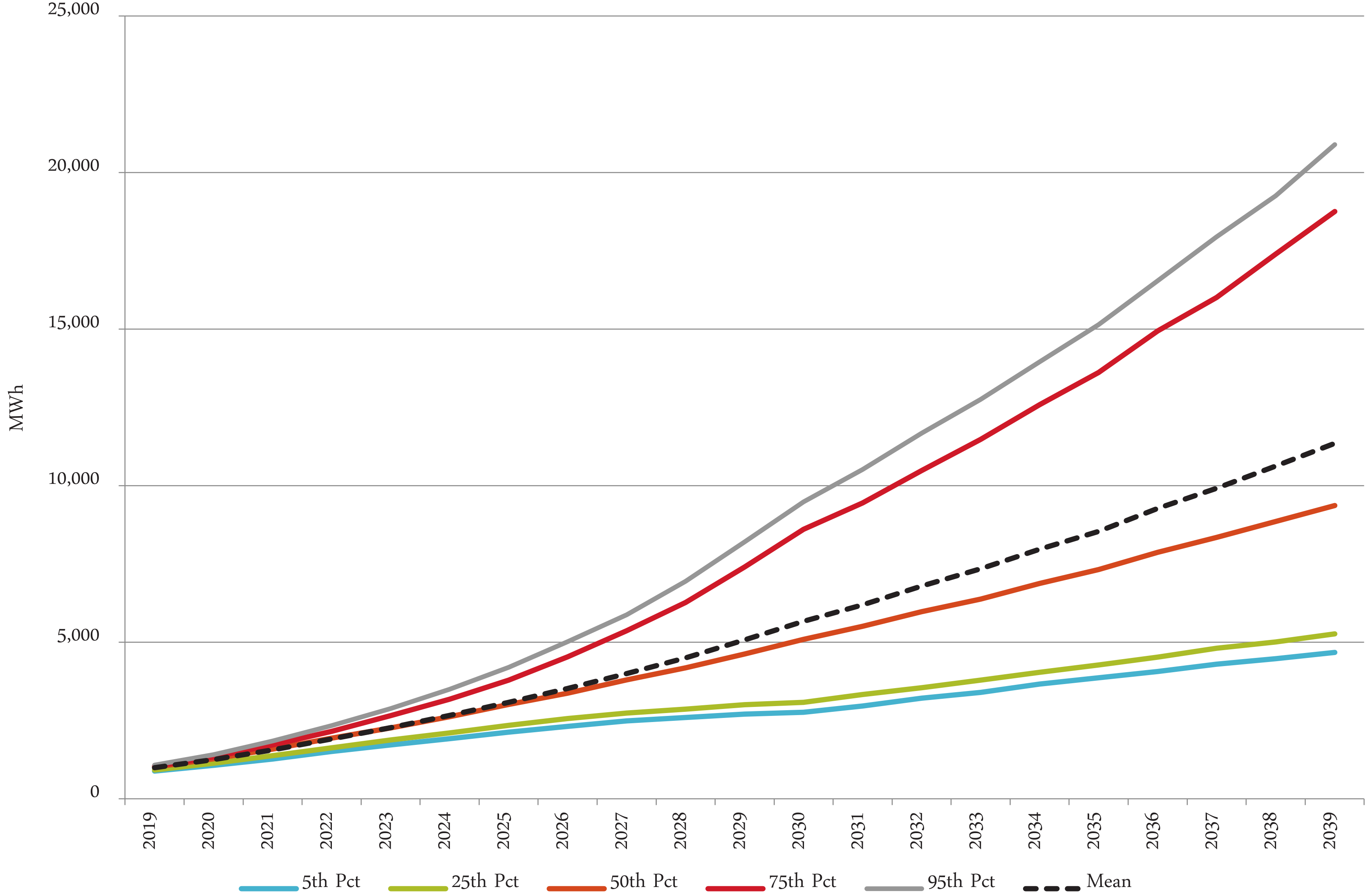
# APPENDIX

VECTREN
A CenterPoint Energy Company

# CONSENSUS CAPACITY PRICE FORECAST

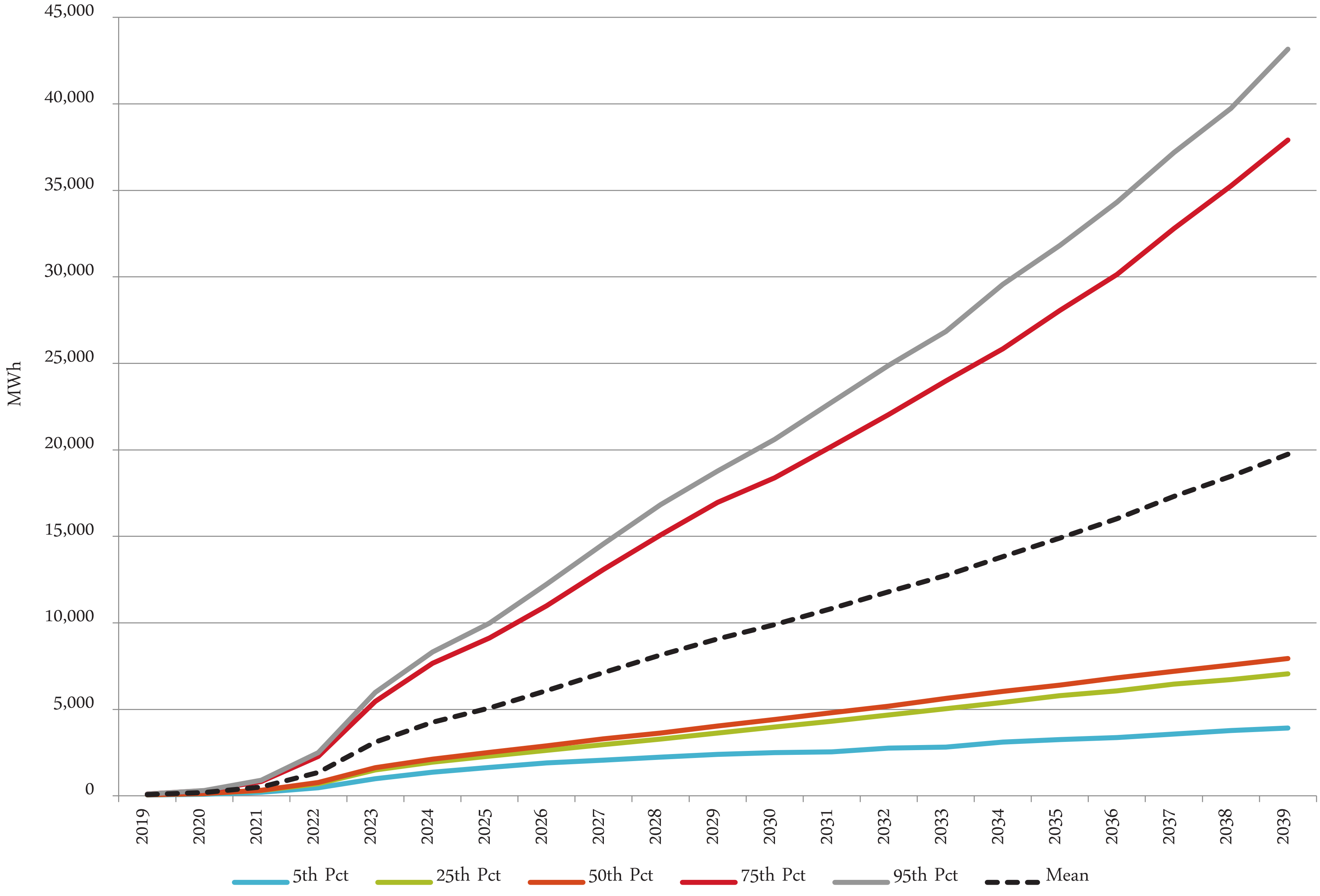


# VECTREN SOLAR DISTRIBUTED GENERATION IS A DECREMENT TO VECTREN LOAD

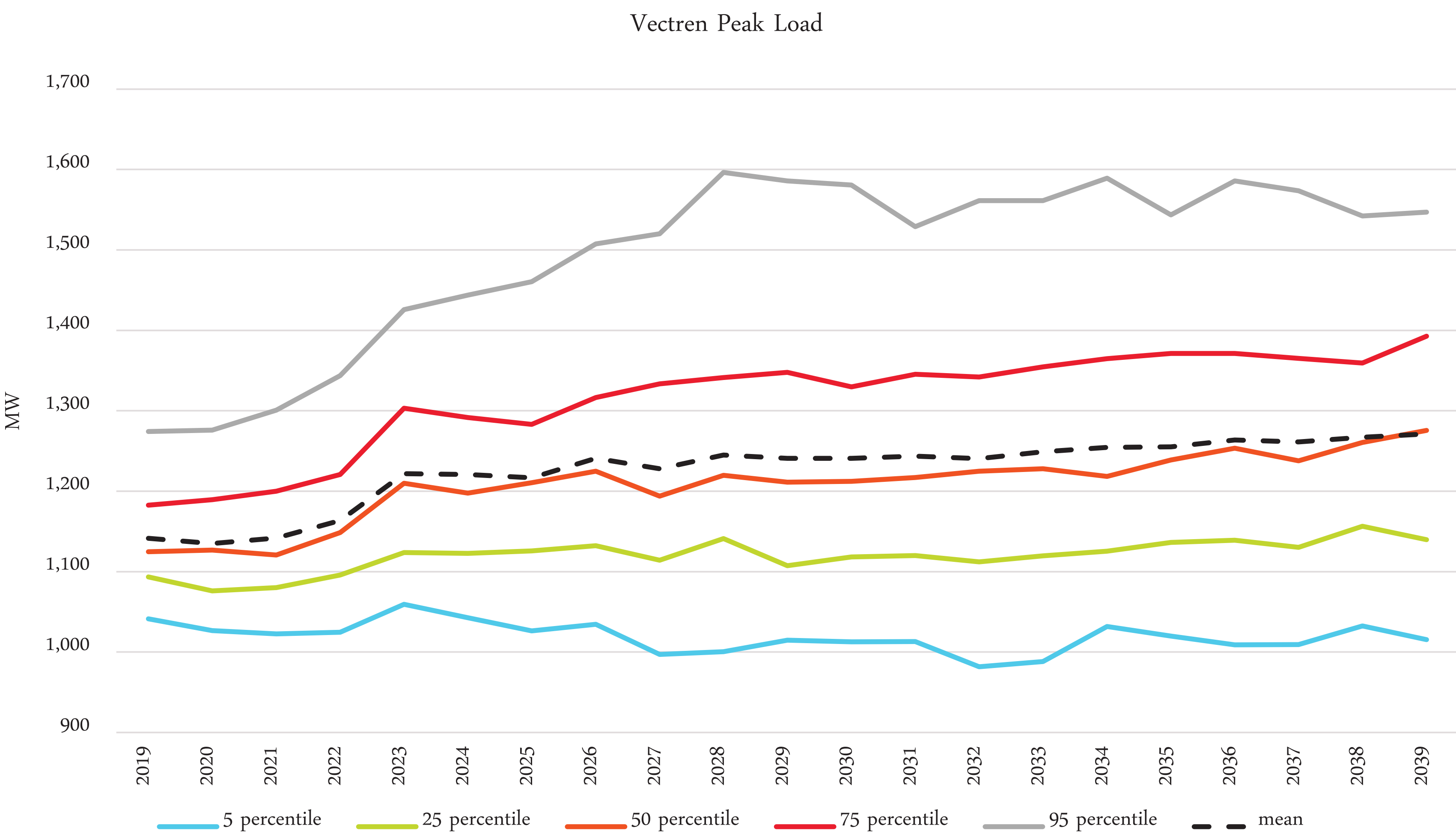


# VECTREN ELECTRIC VEHICLE LOAD IS AN INCREMENTAL TO VECTREN LOAD

VECTREN
A CenterPoint Energy Company



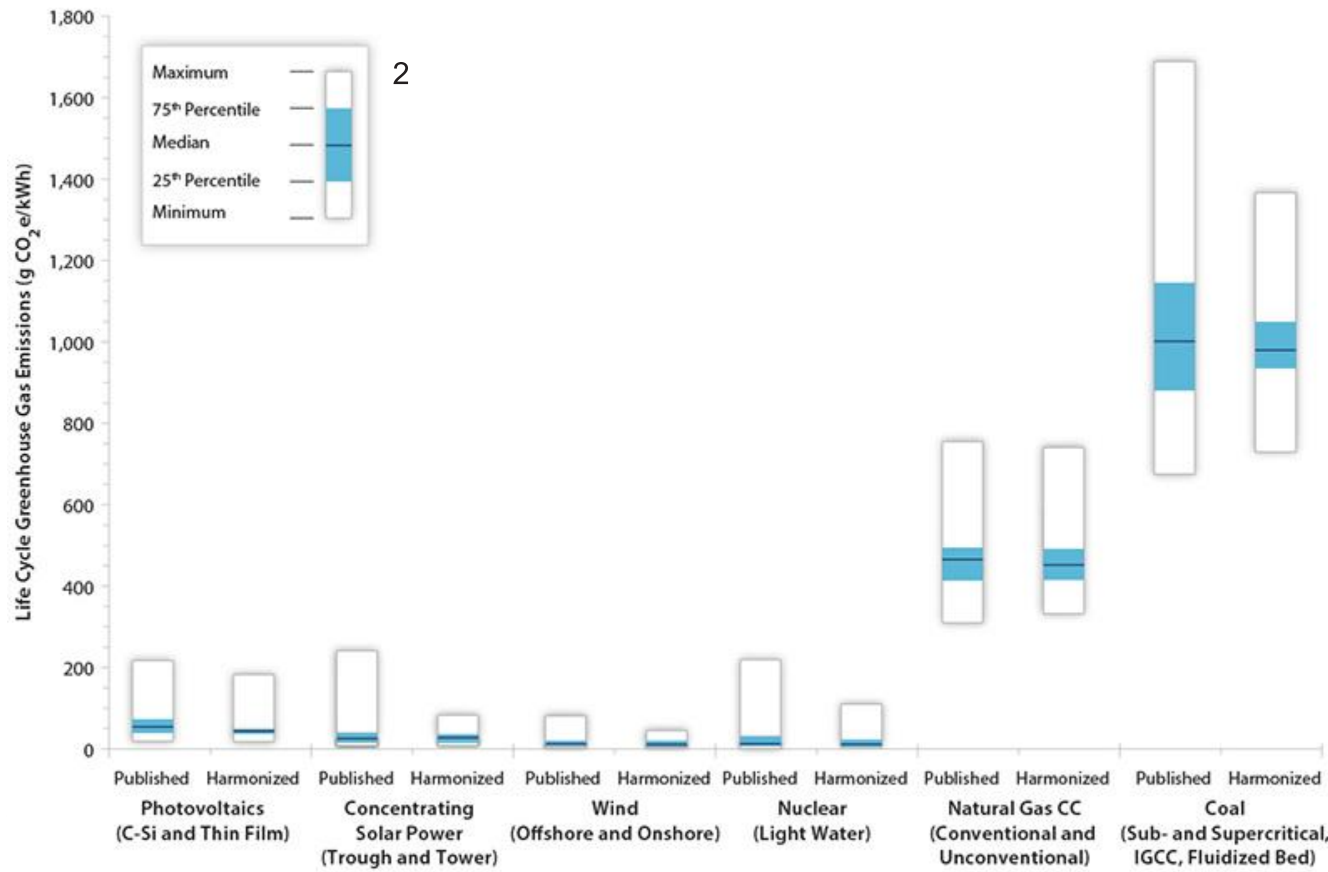
# DISTRIBUTIONS: VECTREN PEAK LOAD (NET OF SOLAR DG, EV LOAD)



# LCA FOR NATURAL GAS ELECTRICITY GEN.

Multiple studies were considered for the NREL study from July 2014[1]

- Methane leakage was considered. Methane emissions rates ranged from 0.66% to 6.2% $CH_4$ loss/NG produced[1]
- The study noted that there is the possibility of differences in the definition of methane leakage. Some studies include fugitive emissions; some included vented emissions; others might additionally also include methane from combustion
- The NREL study is meant to provide an estimate of life cycle green house gas emissions for various resources. The study did not attempt to fine tune the analysis to a common definition of methane leakage




2

| | Photovoltaics | Concentrating Solar Power | Wind | Nuclear | Natural Gas CC | Coal |
|---|---|---|---|---|---|---|
| Estimates | 46 | 36 | 126 | 99 | 61 | 164 |
| References | 17 | 10 | 49 | 27 | 45 | 53 |

*CC = combined cycle

1 Source: Harmonization of Initial Estimates of Shale Gas Life Cycle Greenhouse Gas Emissions for Electric Power Generation, 2014 Table 1 Page 3 https://www.pnas.org/content/pnas/111/31/E3167.full.pdf

*2 Source: https://www.nrel.gov/analysis/assets/images/lca_harm_ng_fig_2.jpg*

**Vectren 2019 IRP**
**3rd Stakeholder Meeting Minutes Q&A**
*December 13, 2019, 9:00 a.m. – 3:00 p.m.*

**Lynnae Wilson** (CenterPoint Energy Indiana Electric Chief Business Officer) – Welcome and Safety Message (holiday safety tips) and Vectren introductions.

> Subject Matter Experts in the room: Matt Rice, Cas Swiz, Nick Kessler, Rina Harris, Jason Williams, Angie Casbon Scheller, Matt Lind, Kyle Combes, Jamie Bundren, Alyssia Oshodi, Natalie Hedde, Ryan Wilhelmus, Justin Joiner, Justin Hage, Bob Heidorn, Wayne Games, Christine Keck, Brad Ellsworth, Angie Bell, Tom Bailey, Steve Rawlinson, Ryan Abshier.

**Stakeholders:** Approximately 37 stakeholders attended in person. List of affiliations include the following:

- Bowen Engineering
- Citizens Action Coalition (CAC)
- Earth Charter Indiana
- Indiana Coal Council (ICC)
- Indiana Utility Regulatory Commission (IURC)
- Orion Renewable Energy Group LLC
- Office of Utility Consumer Counselor (OUCC)
- Sierra Club
- Southwest Indiana Chamber of Commerce
- State Utility Forecasting Group (SUFG)
- Tri-State Creation Care
- Valley Watch
- Vermillion Rise Mega Park
- Vote Solar

Approximately 38 registered to attend the webinar; several participated. Those registered included representatives from:

- Advanced Energy Economy
- AEP
- Boardwalk Pipeline Partners
- Development Partners Group
- Earth Justice
- Energy and Policy Institute
- Energy Futures Group
- EQ Research
- First Solar
- Hoosier Energy
- ICC
- Indiana Distributed Energy Alliance
- Inovateus Solar LLC

IPL

IURC

Lewis & Kappes

Midwest Energy Efficiency Alliance (MEEA)

Morton Solar, LLC

NextEra

Orion Renewable Energy Group LLC

OUCC

Sierra Club

Solarpack Development, Inc.

Whole Sun Designs Inc.

**<u>Matt Rice</u>** (Vectren Manager of Resource Planning) Reviewed Stakeholder Process and Presented Follow-up Information Since Our Last Stakeholder Meeting - Slides 4-17.

- Slide 4: Matt Rice noted that the date for the next stakeholder meeting has been moved to March 20, 2020.
- Slide 12 Stakeholder Feedback\Questions:
    - Request: In $CO_2$ life cycle analysis I want you to capture all greenhouse gas emissions associated with a process. Specifically, when burning coal, you should capture green house gas emissions associated with coal hauling vehicles, as well as the emissions associated with manufacturing coal handling equipment.
        - Response: What you describe is the purpose of using a life cycle analysis. It considers mining the coal, transporting it, burning it, etc. but we would need to refer to the study to clarify [if manufacture of equipment is included].
    - Question: Regarding the size of the hydro resources available for selection in the model, if other hydro owners evaluate local dams and identify there is more potential than 50 MW's will you consider changing the size of hydro resources in the model?
        - Response: We plan to stick with 50 MW's for the size of hydro resources but keep in mind the IRP is a guide, and if hydro is selected as a resource [in the preferred portfolio] we would then initiate further evaluation of the potential of local dams and refine the projected output.
    - Question: You are going to model 50 MW's but will you perform an analysis to determine what size dam would work properly?
        - Response: Hydro would need to be selected first before further analysis is completed.
    - Statement: Modeling 50 MW's seems arbitrary and it seems that you want to dismiss it.
        - Response: Hydro will be evaluated within the model along with all other resources.
    - Statement: Regarding methane leakage I urge you to include the results from the Science Magazine article from 18 months ago. It is more current than the National Renewable Energy Laboratory (NREL) study being used.
        - Response: Life cycle analysis of carbon is one of many factors we are using to select a preferred portfolio. The NREL study is the best study we can find to show the relative differences among resources. When we spoke with NREL, we told them how we intended to use the study, and they agreed that their study was appropriate for our analysis. We can set up a separate meeting to discuss if needed.
- Slide 11 Stakeholder Feedback:

- Question: Can you tell me who you spoke with at MISO that indicated they are moving toward a seasonal construct?
    - Response: Based on conversations with MISO personnel and public presentations it is clear to us that MISO is planning to move to a seasonal construct [or other mechanisms to adapt to intermittent, renewable resources] in the coming years. We can schedule a group call to make sure we are all on the same page if needed.
  - Question: Can you share the documents you are looking at that indicate MISO is moving toward a seasonal construct.
    - Response: Yes, we will provide them.
- Slide 13 Stakeholder Feedback:
  - Statement: I appreciate that you are willing to export inputs and assumptions from Aurora to share with stakeholders that don't want to pay $5k for a read only license but I am concerned that the information exported will be difficult to interpret.
    - Response: There is a help function in the read only copy, and we will try to print as much of that information as we can to help provide a work around, but we cannot provide a read only copy [free of charge] of all the models we use to all stakeholders that want a copy. We will work to provide the transparency that is needed with this workaround.
- Slide 14 Stakeholder Question:
  - Questions: Can you explain the planning process between MISO and a utility? What does it mean that MISO is fuel source neutral? Isn't the planning reserve margin based on information you provide in your planning?
    - Response: Fuel source neutral means MISO doesn't care what fuel sources (coal, gas, solar, wind, hydro, etc.) we use to meet customer needs. They provide us with the planning reserve margin requirement.
    - Response: The planning reserve margin is the surplus power we need above expected customer peak demand. It is based on [load and performance] information of all resources in MISO.

**Peter Hubbard** (Manager of Energy Business Advisory, Pace Global) Presented Draft Reference Case Modeling Results - Slides 18-29.

- Slide 20 Stakeholder Questions:
  - Question: On slide 20 I don't see hydro. Is it included?
    - Response: This is not an all-inclusive list. It is included and is shown on slide 22.
  - Question: Can you explain what customer owned Distributed Generation (DG) capacity represents?
    - Response: It represents how much capacity is expected from solar installed by Vectren customers, over time in the reference case. These values can vary in different scenarios.
  - Question: Does this estimate include batteries?
    - Response: There could be a battery behind the customer owned solar, but this just represents the solar capacity.
- Slide 21 Stakeholder Question:
  - Question: Did House Bill 6 in Ohio have an impact on Vectren's ownership, operation, or cost of Ohio Valley Electric Corporation (OVEC) that would impact Vectren customers?
    - Response: No.
- Slide 22 Stakeholder Questions:
  - Question: Shouldn't hydro capacity be 100 MW's?
    - Response: It is 50 MW's for each resource, and 2 resources are available for selection (100 MW's total).
  - Question: How did you determine the solar and wind capacity limitations?
    - Response: It is based on what is a reasonable expectation for how many MW's can be constructed and brought on line in a year.
- Slide 24 Stakeholder Question:

- Question: Regarding $CO_2$ does your analysis include the potential use of the low sulfur diesel fuel that could be produced from the proposed coal to diesel facility in Spencer County?
  - Response: This analysis only includes natural gas as a fuel source [for resources that can be fired by natural gas or diesel].
- Statement: There is probably more carbon produced transforming coal to diesel than there is transforming oil to diesel.
  - Response: The Spencer County project is external to the IRP analysis.

- Slide 20 Stakeholder Questions:
  - Question: The amount of customer owned solar DG would depend upon net metering and how much customers are compensated. Are you putting caps on net metering and solar?
    - Response: The DG (solar) is looked at from a probabilistic point of view that determines what levels of DG could exist on the low end and on the high end. It captures a range of inputs for the model.
    - Response: We are also considering a low load forecast within scenarios that will produce a portfolio. We are considering a range. The assumptions in the reference case are based on existing law.
  - Question: So, you will only be as favorable to the homeowner as the law makes you be?
    - Response: We are modeling a wide range of load forecasts. Solar DG is accounted for as a reduction in load in the model. We've included existing law in the reference case but will also look at high and low bounds.
  - Question: When determining the cost of natural gas, do you assume the gas will come from CenterPoint Energy in Houston?
    - Response: There are several different sources for gas, so it would not necessarily come from CenterPoint. It would be on a low-cost basis and would come from one of the interstate gas pipelines.
  - Question: Does most of the gas come from the Texas area?
    - Response: It depends on the pipeline. Many pipelines that are in this area come from the Gulf Coast, but some come from other sources. The gas could from other areas (i.e. Pennsylvania).
    - Response: We have a diverse mix of gas interstate pipelines in Indiana. The gas could come from Canada, Ohio, New York, Pennsylvania, Colorado, or the Gulf Coast.
  - Question: Since a lot [of gas] comes from the Gulf Cost, is it figured in that climate change is likely to create record floods. The Houston area has had two 500-year floods in recent years. I assume more frequent and drastic flooding will impact the ability of the pipelines to work (for people to get to their jobs to do it). I hope that when you figure the cost and reliability of natural gas is, you consider the factor in the impact of climate change.
    - Response: When you look at the 2 flooding events in Houston, Vectren customers did not have an interruption. When you look at the interstate pipeline and the planning involved the diversity really helps [maintain reliability].
- Stakeholder Question:
  - Question: In April 2019, the IURC denied your proposal for an 850 MW gas plant. If the request for proposal that comes to fruition as a result of this IRP also gets rejected by the IURC will you continue to recommend oversized gas plants that favor CenterPoint's interests?
    - Response: Today, we are laying out the portfolios that we are considering. A large gas plant is not included. When you look at the planning reserve margin requirement graph [for the reference case] there is not a build larger than the requirement.
    - Response: It is important to note that meeting the planning reserve margin requirement is a capacity issue. When we retire base load coal capacity, we need to replace capacity. The model is picking gas peaking units, not a combined cycle [gas plant], which runs a lot. [In the reference case] the peaking

units are only projected to run 7% of the time. 90+% of the time other MISO units are being selected to run (create energy). When we evaluate all 15 portfolios through the risk analysis, the reference case may be low cost for capacity, but it is not a great energy selection. This leads to exposure to volatility of the energy market. The reference case is an option, but there are [up to] 14 other portfolios with 200 iterations of each, and all will be run through the risk analysis. That will lead us to a preferred plan. The preferred plan will perform [well] across all scenarios and [potential] costs.

- Slide 25 Stakeholder Question:
  - Question: How did you come up with 697 MWs to replace 730 MWs of coal capacity?
    - Response: The three combustion turbines selected by the model are 230 MW's each. The balance is made up for by purchasing capacity from the market.
- Slide 22 Stakeholder Question:
  - Question: Why is there a single 200 MW capacity option for wind energy? Is that a realistic capacity option viewed relative to the capacity of Vectren's existing wind resources (i.e., 30 MW and 50 MW)?
    - Response: Many wind farms are much larger than the 30 and 50 MW's that Vectren currently has contracted. The 200 MW size is reasonable from a tech assessment point of view, but it could be smaller.
- Stakeholder Question:
  - Question: What pipeline costs were included in the reference case modeling?
    - Response: Pipeline costs were included. Costs are subject to refinement but were included in the reference case.
- Slide 22 Stakeholder Question:
  - Question: Why did you constrain the reference case? It seems like it makes the most sense to let the model do as much optimization as possible.
    - Response: There are operational and commercial constraints that need to be considered. The analysis is meant to be least cost but subject to reasonable considerations.
  - Comment: I've seen other utilities use a max reserve margin instead of resource specific constraints. For renewables it does matter because the cost changes by year pending tax credits. Rather than you telling us it is reasonable, it would be nice if we could evaluate if it is reasonable too.
    - Response: We are preparing to put Request for Proposals (RFP) information into the model so we can evaluate what projects are out there and see if we need to change the limitations.
- Slide 23 Stakeholder Question:
  - Question: Why are aeroderivatives excluded from the model? I've seen that they are modeled in Puerto Rico, so why isn't is an option to Vectren?
    - Response: The required pressure is 900 psi which is higher than other potential resources. They have a higher pipeline cost and they are smaller resources [expensive] so we decided to screen them out.
  - Question: Do you have any data on the pipeline cost differences?
    - Response: It is subject to non-disclosure agreement but we can discuss.
  - Question: CenterPoint could hold the contract to supply gas to any unit that Vectren may build. Is that something you intend to do an RFP for?
    - Response: Currently, our practice is to go out for bid for fuel source supply for our generating facilities.
- Tri-State Creation Care (along with the Sierra Club) presented a petition with approximately 600 signatures encouraging Vectren to take future risk of $CO_2$ emissions on future generations into consideration. Emphasis was added that this is a moral decision to stop $CO_2$ production; it is not just an economic decision.
- A residential customer presented a petition of approximately 600 people effected by a large [600 acre] solar project in Vanderburgh County, requesting that Vectren consider land use in portfolio development. Emphasis was added that solar plants are large, industrial facilities and should be

zoned as such. Vectren should maximize use of brownfield sites and not pursue large solar projects on productive farm land near residential homes.

**Matt Lind** (Resource Planning & Market Assessments Business Lead, Burns and McDonnell) Presented Final RFP Modeling Inputs - Slides 30-37.

- Slide 36 Stakeholder Question
  - Question: Is cost incorporated over the life of the asset including initial build cost and O&M?
    - Response: It includes initial build and O&M.
  - Question: Some resources, depending on the fuel source, will have an increase in price that will be difficult to model. I suspect that as some resources become more scarce their cost will increase exponentially. How are those types of variables accounted for?
    - Response: In the RFP we are focused on specific projects. To the extent that some of these resources are going to burn fuel, the IRP risk analysis will consider and evaluate that.
- Stakeholder Comment
  - Comment: Every day a river or aquifer is destroyed, and the cost can't be determined; it can't be replaced.
    - Response: Thank you for your comment. In the IRP, the assumption is that all resources meet existing regulations which include costs associated with avoiding instances that you described.
- Slide 34 Stakeholder Question
  - Question: Was there a particular duration in hours [for storage] that made it into Tier 1 where as others didn't?
    - Response: Duration did not go into categorizing resources into tier 1 or tier 2. It was based on [firm bids and] if the energy was settled at Vectren's load node or located on their system. There was not a distinction on duration to qualify for tier 1.
- Slide 36 Stakeholder Question
  - Question: How does the project shown in group 13 [Solar Purchase/PPA] compare to projects in group 14 [12-15 Year Solar PPA]? Is that where you are purchasing from homeowners?
    - Response: No. That project was a hybrid where some portion of it would be owned and some would be a PPA with the developer. There was only one bid in that category, so we didn't show cost to keep it confidential.
- Slide 36 Stakeholder Question
  - Question: Is solar+storage only charged by solar? How are you accounting for carbon footprint if charged by the grid?
    - Response: With solar+storage and how tax credits are structured, it is favorable to charge based on renewable energy. It is bid specific; they may have the ability to be grid charged and discharged to the grid.
    - Response: Carbon is accounted for in the energy price. We are still determining the best way to apply the life cycle of carbon analysis to storage.

**Matt Rice** (Vectren Manager of Resource Planning) Presented Portfolio Development - Slides 38-51.

- Slide 40 Stakeholder Question
  - Question: If the net metering cap were to be doubled, tripled, or quadrupled do you have a factor that incorporates the increase in the cap into different portfolios?
    - Response: Indirectly, yes. We will run a scenario that has a lower load than the reference case.
  - Comment: But the lower load would vary based on what the cap is.

- Response: If there is something that induces more solar on rooftops, that would result in a reduction to our load. We are considering reduction to load within the scenarios and probabilistic modeling.
  - Comment: But the lower load could be 5-20% lower so you don't know what that reduction is.
    - Response: Our bounds are very wide.
- Slide 41 Stakeholder Question
  - Question: How many portfolios do you think this will end up being?
    - Response: We are planning for up to 15.
- Slide 50 Stakeholder Comment:
  - Comment: Thank you for including the HB 763 but on the chart on slide 50 the cost should be $45 in 2025 and $205 by 2039.
    - Reply: Thank you, please see me at the end of the day.
- Slide 43 Stakeholder Question
  - Question: Why does it take so much solar ICAP (installed capacity) to meet 174 MW UCAP (accredited capacity of approximately 29%)? I thought MISO offered 50% accreditation starting off but could be even higher, particularly with tracking.
    - Response: As more solar penetrates the MISO footprint, the solar is netted out which shifts the [net] peak hour out into the evening hours. Then resources other than solar must serve that net peak load. The projection for UCAP declines over time as more solar penetrates the MISO footprint.
  - Question: In California the same thing has happened, but the simple solution is to add 4 hours of storage to get the solar back to a high capacity value. In your lists you include solar+storage but in these lists you didn't include solar+storage as a potential buildout.
    - Response: We are just showing these as reference points. We will evaluate solar+storage consistent with the bids received in our RFP.
- Stakeholder Feedback:
  - Comment: In Germany they put a lot of solar on rooftops and we should do that here. There are a lot of buildings here that don't have solar.
    - Response: That is an option, but it is more expensive and more complex. We have seen this with the Urban Living Research Center. We had to work with the developer on the design of the building to make sure it would support the amount of solar we wanted to install on it. We are modeling utility scale [universal solar] that is much more cost effective.
- Stakeholder Question
  - Question: Can you explain how peak load can shift to the evening?
    - Response: It is the net peak that shifts which is the peak load less the renewable generation (how MISO calculates). The remaining load must be served by something that is dispatchable.
- Stakeholder Question:
  - Question: When you are projecting into the future, do you extend today's values into the future or have other sources?
    - Response: It depends on the input. Some inputs we develop ourselves, some by others but we are diligent to have a basis for all assumptions that are fed into the models.
- Stakeholder Question:
  - Question: How does Vectren's profitability plan into the analysis?
    - Response: When each portfolio is analyzed, it will have a net present value [over the planning period]. The net present value includes a rate of return on resources that we own.
- Stakeholder Statement:
  - Statement: In the last IRP you chose a large CCGT which was going to be highly profitable because it was a large capital investment. It doesn't seem like there is an incentive to go to the lowest cost because profits would be lower.

        - Response: In the last IRP each scenario produced a gas plant as the lowest cost option to serve customer load. In a few slides we will show that affordability is one of the objectives in this IRP to be balanced against other objectives.
- Stakeholder Question:
    - Question: You said that hydro is very expensive initially but it seemed like you said we can't carry that cost over the 50-100 years that it would operate?
        - Response: We will need to review the tech assessment and see what the life is expected to be and put it in the notes. [Upon review, 40 years is included in the tech. assessment. It would not necessarily lower cost by extending the life to 50-100 years as this would take further capital investment that is not included in our estimate.]

**Peter Hubbard** (Manager of Energy Business Advisory, Pace Global) Presented Scenario Testing and Probabilistic Modeling - Slides 52-60.

- Stakeholder Question:
    - Question: Are there any incremental solutions where you reassess every 2 years and add resources as needed?
        - Response: Every three years the IRP analysis is revisited and updated based on current assumptions.
- Slide 55 Stakeholder Question:
    - Question: In the high regulatory case how were the natural gas prices determined?
        - Response: It is based on a fracking ban. We used historical pricing (pre-shale gas boom) and sustained those high gas prices throughout the forecast (the 95th percentile every year of the forecast).
- Slide 58 Stakeholder Question:
    - Question: There is more to environmental risk minimization than greenhouse gas emissions. There is ecosystem destruction from coal mining and fracking as well as health issues from burning those fuels. How are you modeling those factors?
        - Response: It isn't just carbon; $CO_2$ equivalent considers emissions involved from cradle to grave for each technology. Additionally, we are also assuming compliance with EPA regulations. We are accounting for a lot of potential impacts.
- Slide 54-57 Stakeholder Question\Comment:
    - Question: Are you modeling variable O&M probabilistically?
        - Response: We are modeling fuel and $CO_2$ emissions probabilistically. We are not varying non-fuel variable O&M probabilistically.
    - Question: The list shows $CO_2$ prices and capital cost (will be varied). I am concerned because I don't think we have enough data to develop a stochastic distribution for $CO_2$ price. For capital costs, the RFP should provide certainty for those costs and you should be able to extrapolate those costs going forward.
        - Response: The RFP response will tighten up the short-range distribution of capital costs. There is less uncertainty in the short term. However, over 20 years we don't know where those costs will go. The capital cost could be higher or lower than the reference case in the long term.
    - Comment: I think the only thing that lends itself to stochastics are load and fuel prices. I don't think you should test capital costs and $CO_2$ prices.
        - Response: Thank you for your feedback.
- Stakeholder Question:
    - Question: In essence the IRP is a 3-year plan because you will have another IRP in 3 years. What is going to be done in the next three years that becomes irreversible?
        - Response: Long term there is a bit of uncertainty that goes into this but the IRP incorporates specific market feedback on what the short term might look like. In the very short term, it is based on real figures the market can provide. There is a wide range of technologies that came out of the RFP, and you want to look at

how they perform in the long term. We will look at how they perform in a wide range of conditions.

- Feedback: I think this process is a short-term planning process but would prefer that it be a long-term planning process.
    - Response: We are looking at a wide range of portfolios, and in each case, we are looking at how those portfolios will perform over a 20-year horizon.

- Stakeholder Question:
    - Question: Have you asked your rate payers if they would be willing to pay a higher rate for renewable energy?
        - Response: Yes. We do survey our customers to understand their needs. There is a segment of the population that is willing to pay more for renewables.
- Stakeholder Question:
    - Question: Vectren ratepayers pay some of the highest rates in the state for a fleet primarily fueled by fossil fuels. I wonder why there is a high value on fossil fuels when utilities that are opting for renewables have lower rates.
        - Response: We are working on a long-term plan, and affordability will be on the scorecard.
    - Question: Has affordability not been on the scorecard in the past? Why do we pay higher rates than others in the state?
        - Response: Affordability is always on the scorecard for the IRP.
- Stakeholder Question:
    - Question: Does Vectren have a renewable energy rider? If not, that could be a consideration and a benchmark to see how many customers are interested in renewable energy.
        - Response: We do not [currently have a renewable energy rider]. We performed an analysis on community solar in recent years to gauge the interest of our customers. At the time, there was slight interest, but we will look at this again as we move forward.
- Stakeholder Comment:
    - Comment: The CAC disagrees that renewable energy riders can gauge customer interest in renewable energy. Buying into these programs does not change the energy portfolio of the utility serving that customer.
        - Response: Thank you for your feedback.
- Slide 16 Stakeholder Question:
    - Question: There was a mention that there weren't any bids received for combined cycle units. I thought I had heard through press releases that you did receive bids for Combined Cycle Gas Turbine (CCGT) projects. Is purchasing power from independent sources woven into your analysis?
        - Response: On slide 32 it shows that we did have some bids for CCGT projects, but they did not qualify to be considered tier 1 projects based on the criteria to be a firm bid, be on our system, or have a delivered price. We are evaluating attractive tier 2 bids and are performing congestion analysis to determine the congestion cost to get the energy to our customers.
- Slide 33 Stakeholder Question:
    - Question: Why are some of the values [in the table] on slide 33 shown on the screen different than the handouts?
        - Response: There was a typo on the slide that we originally posted/printed for this meeting. What is on the screen is accurate. We will post an update to the website.

# VECTREN PUBLIC STAKEHOLDER MEETING

JUNE 15, 2020

# WELCOME AND SAFETY SHARE

**LYNNAE WILSON**

INDIANA ELECTRIC CHIEF BUSINESS OFFICER

# SAFETY SHARE – FIREWORK SAFETY

VECTREN
A CenterPoint Energy Company

In 2017, eight people died (half children and young adults under age 20) and over 12,000 were injured badly enough to require medical treatment after fireworks-related incidents

- According to the National Fire Protection Association, sparklers alone account for more than 25% of emergency room visits for fireworks injuries

If consumer fireworks are legal to buy where you live and you choose to use them, be sure to follow the following safety tips:

- Never allow young children to handle fireworks
- Older children should use them only under close adult supervision
- Never use fireworks while impaired by drugs or alcohol
- Anyone using fireworks or standing nearby should wear protective eyewear
- Never hold lighted fireworks in your hands
- Only use them away from people, houses and flammable material
- Only light one device at a time and maintain a safe distance after lighting
- Do not try to re-light or handle malfunctioning fireworks
- Soak both spent and unused fireworks in water for a few hours before discarding
- Keep a bucket of water nearby to fully extinguish fireworks that don't go off or in case of fire

Source: https://www.nsc.org/home-safety/tools-resources/seasonal-safety/summer/fireworks


3

# MEETING GUIDELINES, AGENDA, AND FOLLOW-UP INFORMATION

**MATT RICE**

VECTREN MANAGER OF RESOURCE PLANNING

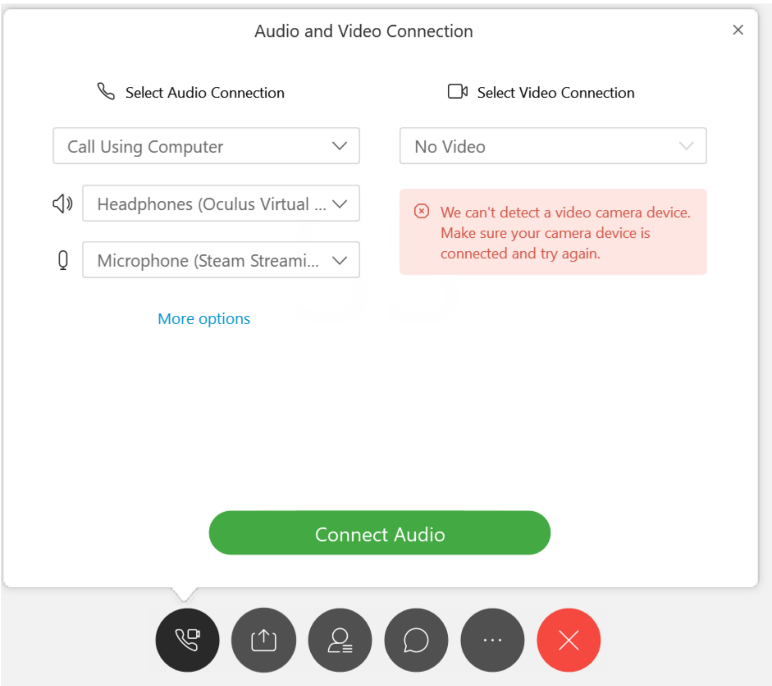
# AGENDA

| Time | | |
|---|---|---|
| **1:00 p.m.** | Welcome, Safety Message | Lynnae Wilson, Indiana Electric Chief Business Officer |
| **1:10 p.m.** | Meeting Guidelines and Stakeholder Process Review | Matt Rice, Manager of Resource Planning |
| **1:20 p.m.** | Presentation of the Preferred Portfolio | Lynnae Wilson, Indiana Electric Chief Business Officer & Matt Rice, Manager of Resource Planning |
| **1:50 p.m.** | Portfolio Analysis and Balanced Scorecard | Peter Hubbard, Pace Global, Siemens Energy Business Advisory |
| **2:20 p.m.** | Next Steps | Justin Joiner, Director of Power Supply Services |
| **2:30 p.m.** | Stakeholder Questions/Comments | |
| **3:30 p.m.** | Adjourn | |

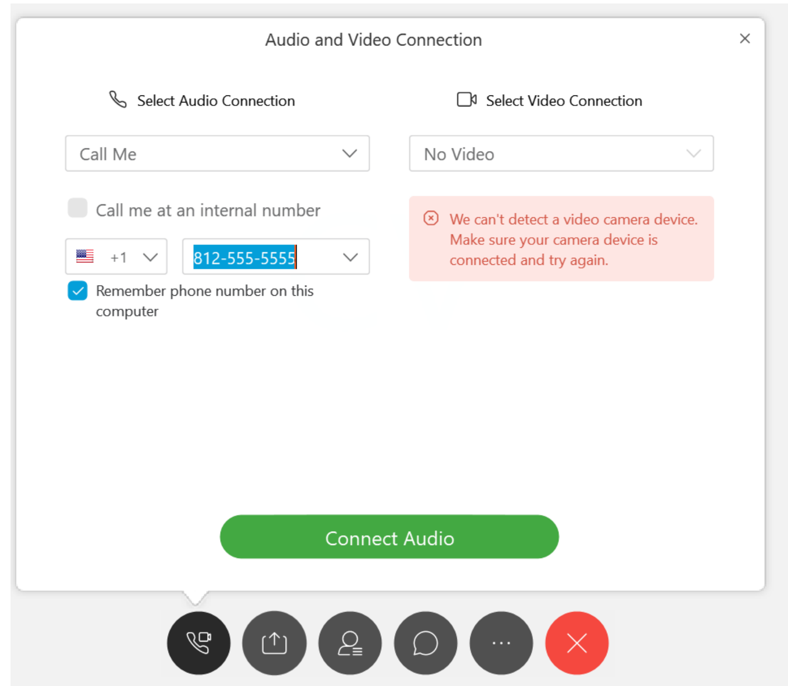
# MEETING GUIDELINES

- Meeting participants must enter their name when logging into WebEx to facilitate question responses and improve communication
- Please type all questions into the chat function
  - If you would like to follow-up on your question, please use the raise hand function (to the right of your name on the participant list). Your phone line will be opened
  - One follow up question at a time will be allowed to give everyone an opportunity to have their questions answered
  - Any unanswered questions will be addressed after the meeting
  - Additional questions can be sent to: IRP@CenterPointEnergy.com
- Stakeholders may request 2 minutes at the end of the meeting to offer any additional comments. Those that have signed up ahead of the meeting will go first.

# HOW TO CONNECT AUDIO




or

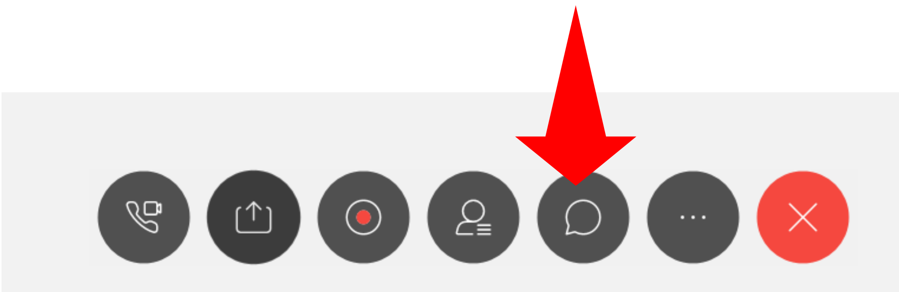


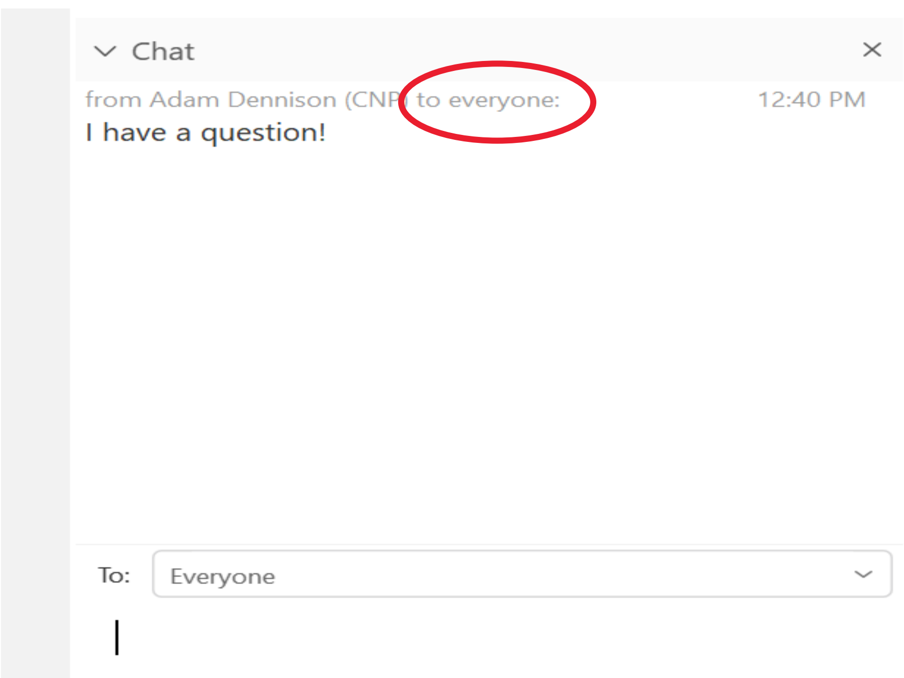

**Call Using Computer** if you would like to use your computer's microphone and speakers

**Call Me** if you would like to use a phone to connect. Enter in phone number and WebEx automatically call

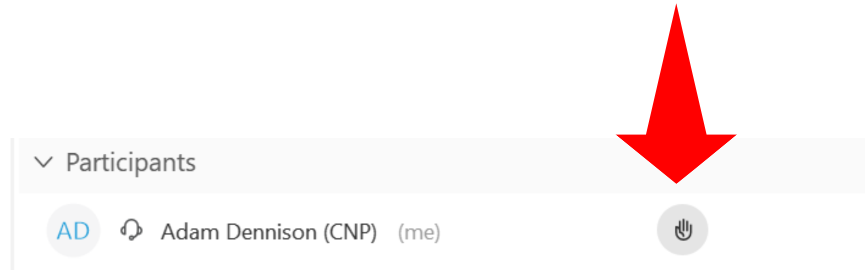
# HAVE A QUESTION?

Ask “everyone” in chat.

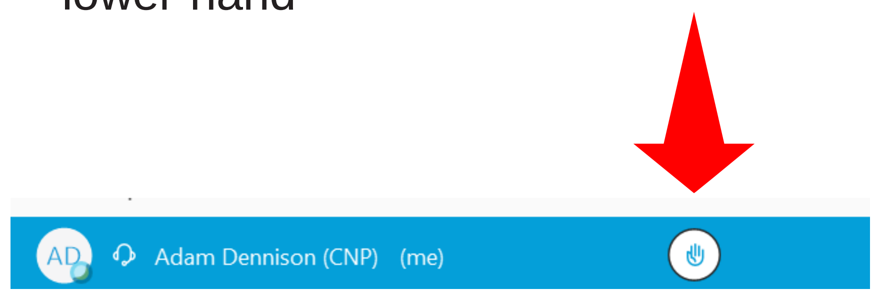





Raise Hand for a Follow-up




After question has been answered, lower hand



# 2019/2020 STAKEHOLDER PROCESS

## August 15, 2019

- 2019/2020 IRP Process
- Objectives and Measures
- All-Source RFP
- Environmental Update
- Draft Reference Case Market Inputs & Scenarios

## October 10, 2019

- RFP Update
- Draft Resource Costs
- Sales and Demand Forecast
- DSM MPS/ Modeling Inputs
- Scenario Modeling Inputs
- Portfolio Development

## December 13, 2019

- Draft Portfolios
- Draft Reference Case Modeling Results
- All-Source RFP Results and Final Modeling Inputs
- Scenario Testing and Probabilistic Modeling Approach and Assumptions

## June 15, 2020

- Final Reference Case and Scenario Modeling Results
- Probabilistic Modeling Results
- Risk Analysis Results
- Preview the Preferred Portfolio

1. All Source RFP
2. Create Objectives, Risk Perspectives and Scorecard Development
3. Create Reference Case Assumptions and Scenario Development
4. Portfolio Development
5. Portfolio Testing in Scenarios, Focused on Potential Regulatory Risks
6. Portfolio Testing Using Probabilistic Modeling of 200 Potential Futures
7. Conduct Sensitivity Analysis
8. Evaluate Portfolios
9. Select the Preferred Portfolio

# VECTREN COMMITMENTS FOR 2019/2020 IRP

- ✓ Utilized an All-Source RFP to gather market pricing & availability data
- ✓ Included a balanced, less qualitative risk score card; draft was shared at the first public stakeholder meeting
- ✓ Performed an exhaustive look at existing resource options
- ✓ Used one model for consistency in optimization, simulated dispatch, and probabilistic functions
- ✓ Worked with stakeholders on portfolio development
- ✓ Modeled more resources simultaneously
- ✓ Tested a wide range of portfolios in scenario modeling and ultimately in the risk analysis
- ✓ Conducted a sensitivity analysis
- ✓ Provided a data release schedule and provide modeling data ahead of filing for evaluation
- ✓ Ensured the IRP process informs the selection of the preferred portfolio
- ✓ Included information presented for multiple audiences (technical and non-technical)
- ✓ Strived to make every encounter meaningful for stakeholders and for us

# BACKGROUND

Vectren continually monitors major developments in the energy industry. While the IRP is developed at a point in time, Vectren works to evaluate current and expected future environments. Recently, several developments have helped to shape our view on what to expect in the near, mid, and long-term.

– The generation mix continues to transition towards renewables and gas resources due to economics

– Evolving MISO market rules to ensure reliability, signaling future incentives for resources that are dispatchable, flexible, and visible

– Energy storage is an emerging flexible resource with great potential. Price continues to come down, but there are still no cost-effective long duration storage options

– The need for flexibility to mitigate risk in an uncertain future

– Customer desire for local renewable resources while maintaining reliability

– Guidance from recent Commission orders and the Director's Report that called for diversity, local resources, risk mitigation, and flexibility

# PREFERRED PORTFOLIO

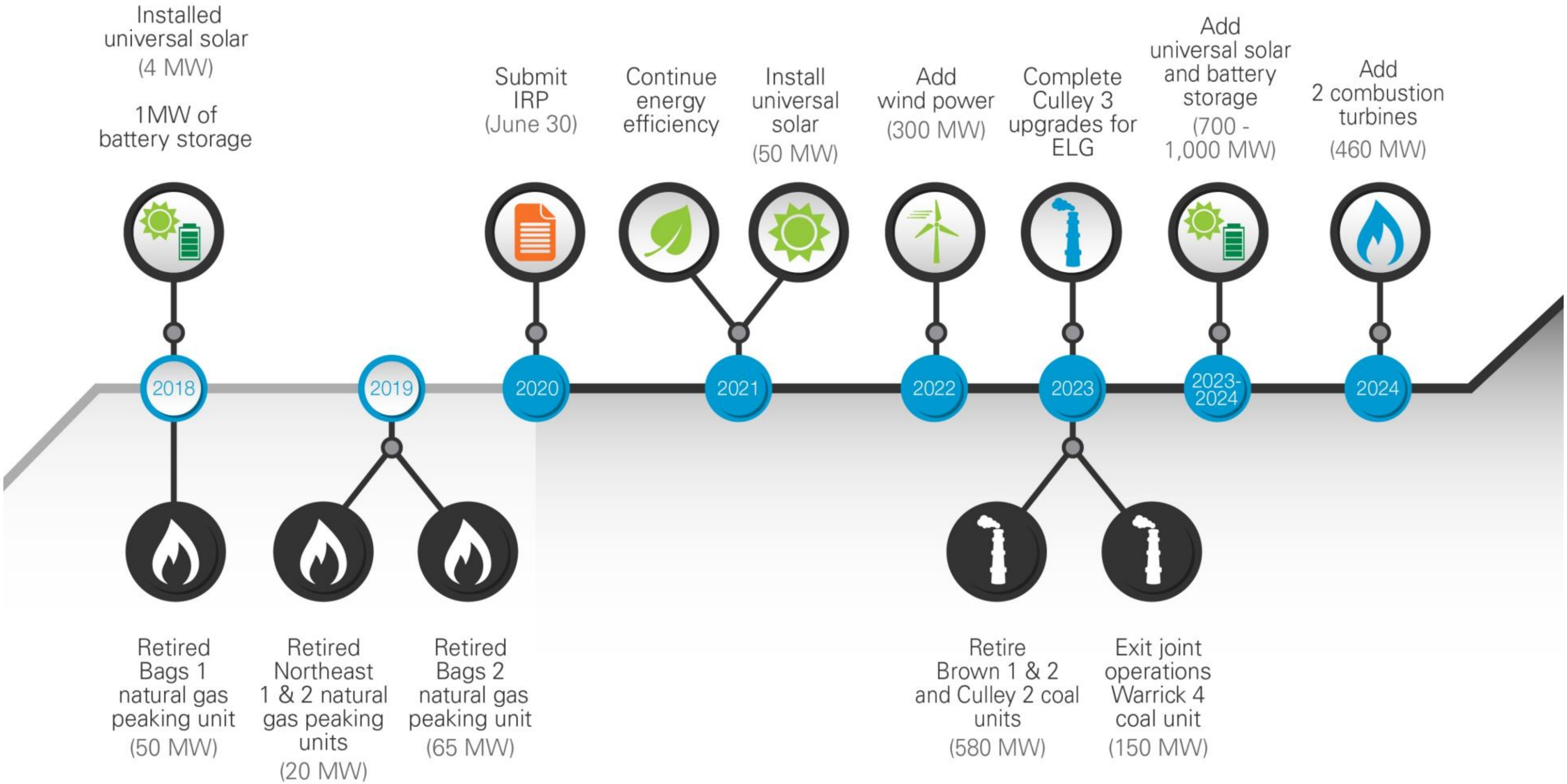
**LYNNAE WILSON**

INDIANA ELECTRIC CHIEF BUSINESS OFFICER

**MATT RICE**

VECTREN MANAGER OF RESOURCE PLANNING

# VECTREN PREFERRED IRP PORTFOLIO[1]




Bags = Broadway Avenue Gas Turbines

ELG = Effluent Limitations Guidelines

MW = Megawatt

[1]Subject to change based on availability and approval

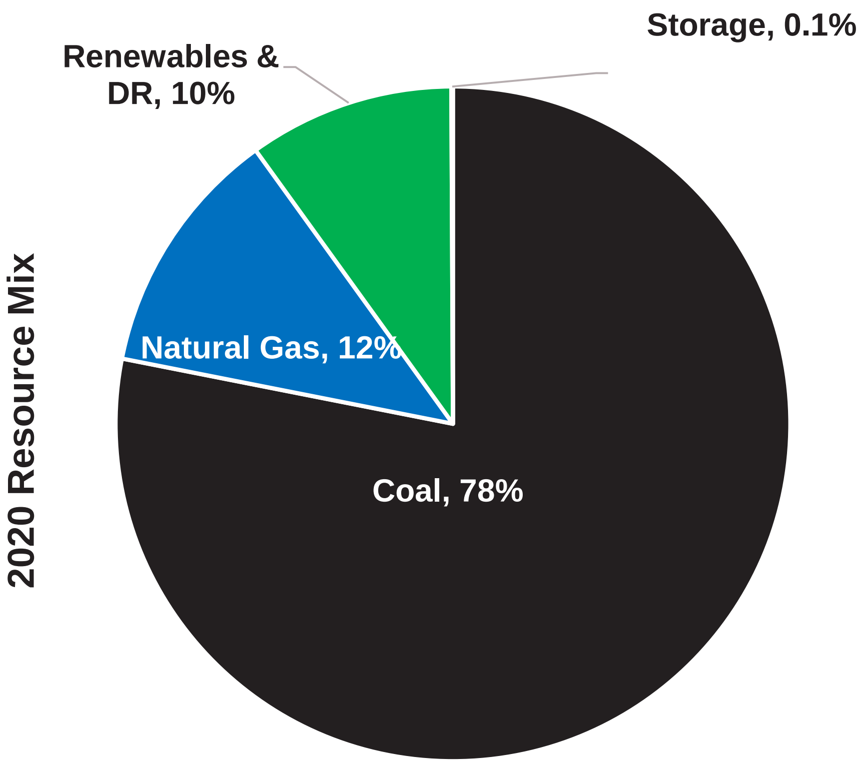
# WHY WAS THIS PORTFOLIO CHOSEN?

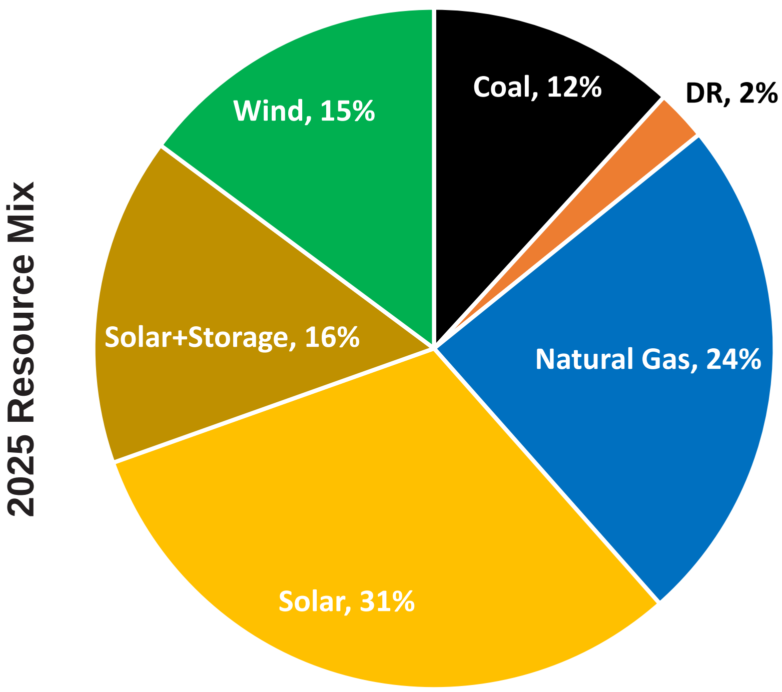
- Preferred portfolio[1] replaces 730 MWs of coal with approximately 700-1,000 MWs of Solar & Solar + Storage, 300 MWs of Wind, 460 MWs of gas Combustion Turbines (CT) and 30 MWs of Demand Response (DR) (aka High Technology Portfolio[2])
- Preferred portfolio provides the following characteristics:
  - Reliability: dispatchable capacity and energy that is available on demand
  - Cost effective: net present value (NPV) that is among the lowest portfolios in the near, mid, and long-term; saving up to $320 million over the next 20 years
  - Flexibility: ability to meet future load needs via additional resources, including renewables
  - Diversity: capacity and energy from a blend of renewables, coal and natural gas
  - Regulatory risk mitigation and sustainability: a lower NPV and reduces $CO_2$ nearly 75% by 2035 over 2005 levels
  - Timely: CTs can come online in 2024, thereby reducing market reliance and in-service lag, to replace coal generation that retires in 2023

[1]Large build out of renewable generation helps to replace energy from coal generation., while combustion turbines help to replace a portion of dispatchable capacity from the coal units.
[2] The preferred portfolio was created utilizing the High Technology future scenario. The preferred portfolio is also referenced as the High Technology Portfolio throughout this presentation.

# PREFERRED PORTFOLIO RESOURCE MIX

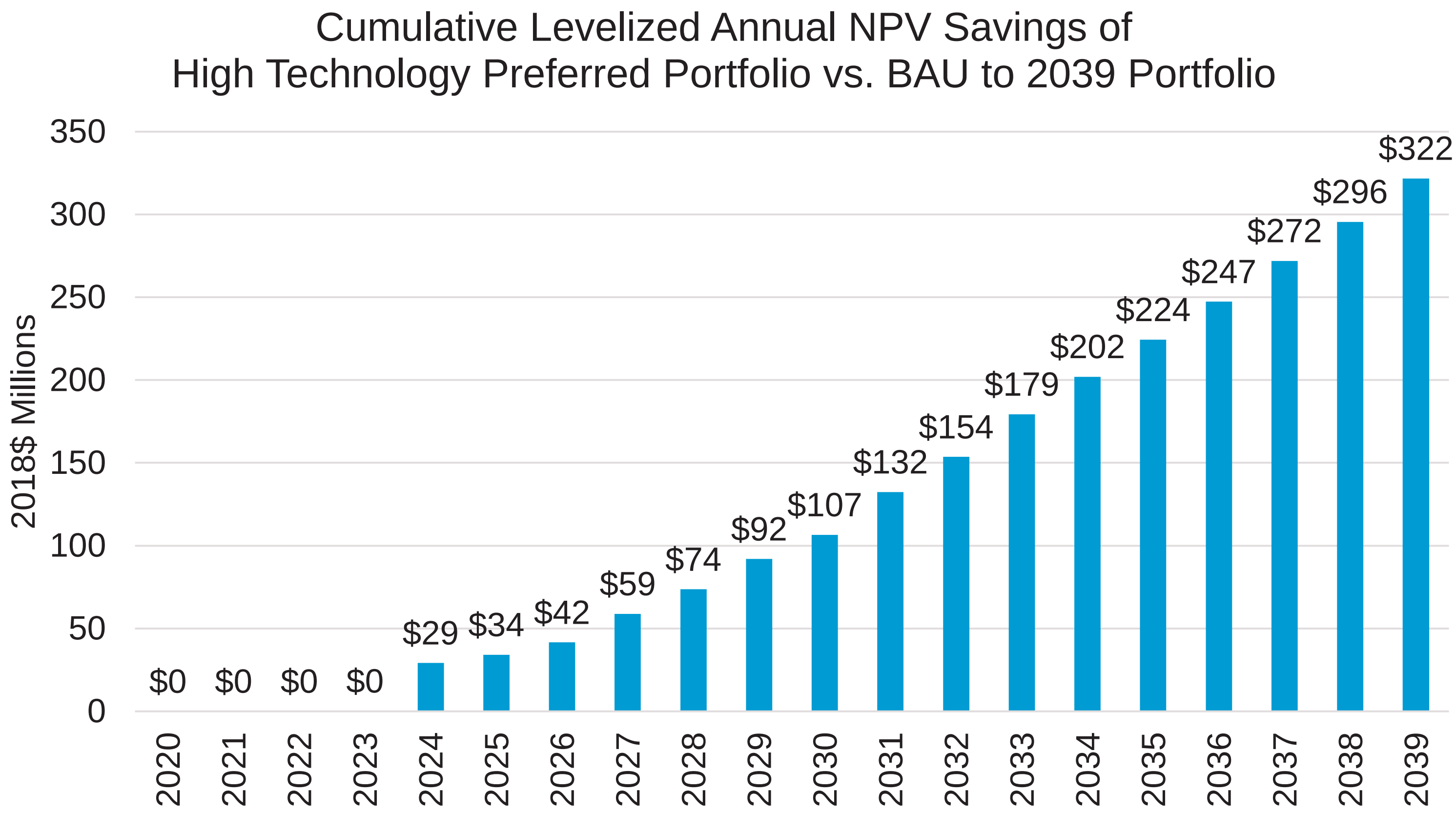
Shift in total installed capacity from 90% fossil to 36%, while renewables and DR increase from 10% to 64%.  Near term transition  to a diverse set of resources better positions Vectren for the future by 2025, while maintaining the reliability that our customers expect



# PREFERRED PORTFOLIO SAVINGS VS. BAU TO 2039 PORTFOLIO

The High Technology (preferred) portfolio provides an annual average savings of $20 million (2024-2039) compared to the Business as Usual to 2039 portfolio and a cumulative savings of more than $320 million in constant NPVRR 2018$.



# DIFFERENT DIRECTION FROM 2016 IRP

VECTREN
A CenterPoint Energy Company

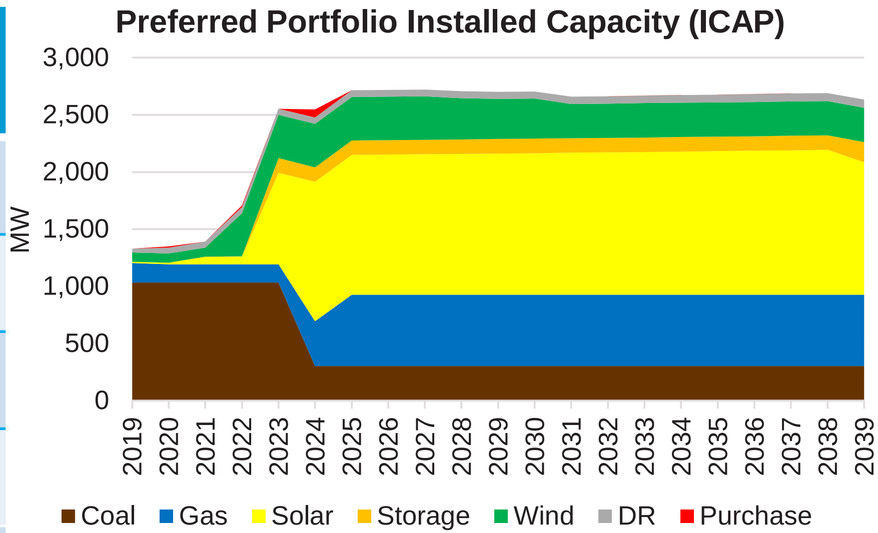
In 2016, Vectren selected a Large 2x1 CCGT (700-850 MWs). In 2020, the preferred portfolio includes a large build out of renewable resources, providing low cost energy, backed up by 2 highly flexible combustion turbines that provide low cost capacity.

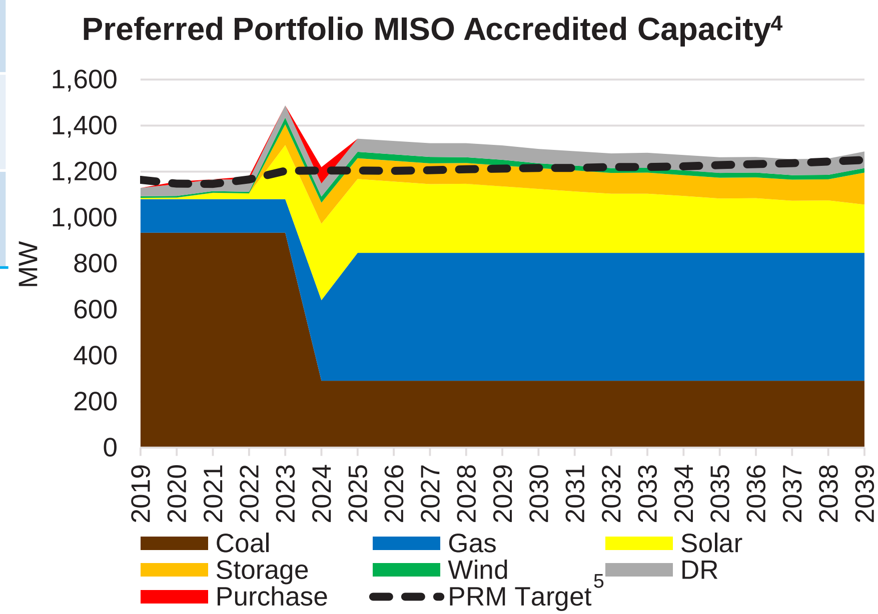
- Lower relative customer impact than many of the portfolio options
- More diverse set of resources, including wind, solar, battery energy storage, EE, DR, gas, and coal
- Faster construction than a CCGT, offsetting market risk more quickly
- Less greenhouse gas emissions and water usage
- Lower dependence on expected market sales to lower cost to customer
- Better support in a high intermittent solar penetration environment (faster ramp)
- Modern CTs have a better heat rate than existing Vectren CTs and coal units

# PREFERRED PORTFOLIO ADDITIONS AND RETIREMENTS

| 2025-2026 Planning Year | ICAP (MW) | % ICAP | Accred-itation[1] | 2025-2026 UCAP (MW) | % UCAP |
|---|---|---|---|---|---|
| Coal | 302 | 12% | 96% | 290 | 22% |
| DR[1] | 62 | 2% | 100% | 62 | 5% |
| Natural Gas | 622 | 24% | 89% | 553 | 41% |
| Solar[2] | 796 | 31% | 26% | 207 | 16% |
| Solar+ Storage[3] | 400 | 16% | 48% | 194 | 15% |
| Wind | 380 | 15% | 7% | 28 | 2% |
| Total Resources | 2,562 | 100% | | 1,333 | 100% |

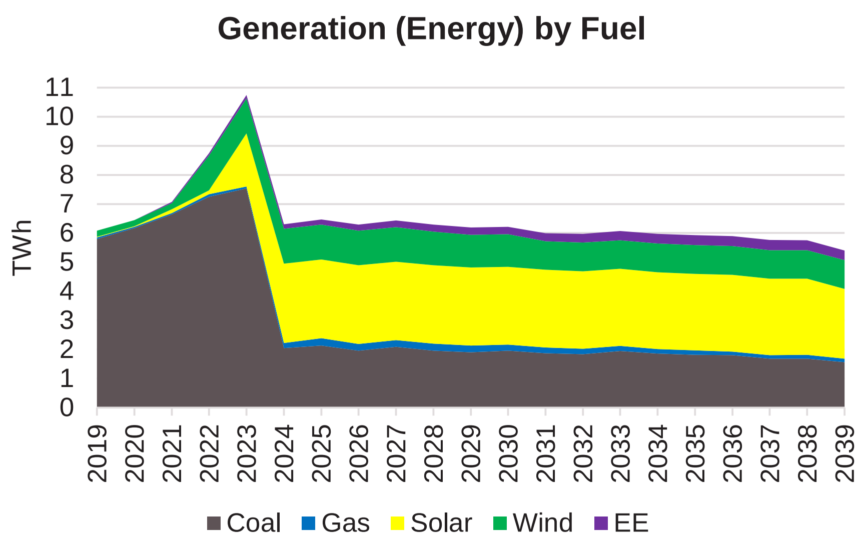
[1] ≈35 MWs at risk due to MISO operational changes
[2] Solar accreditation may vary depending on penetration
[3] UCAP credit includes 90 MW 4-hour battery. Modeled as 126 MW 3-hour battery, consistent with bids
[4] Unforced Capacity (UCAP)
[5] Assumes coincident peak factor of 95.99%, PRM% 8.9%, and Transmission losses of 1.7%

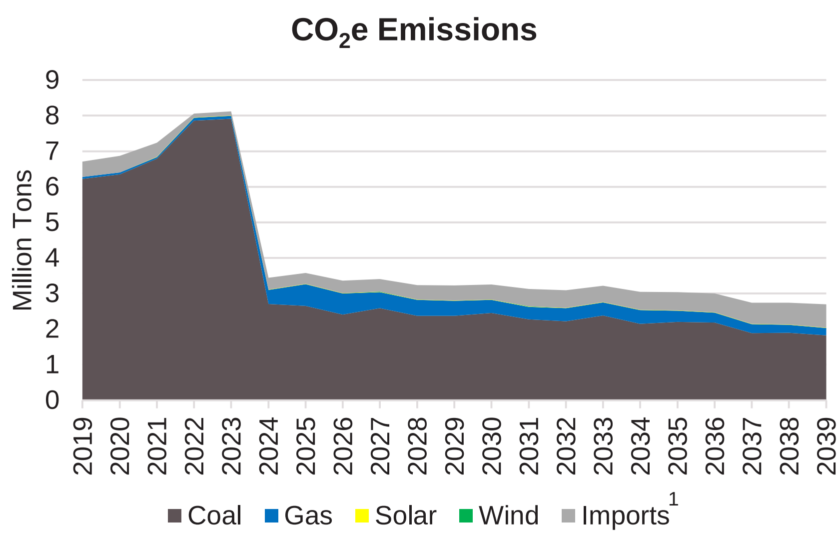


# PREFERRED PORTFOLIO ANNUAL GENERATION AND EMISSIONS

- Generation will shift significantly from coal to renewable resources in the near term, reducing variable fuel costs. Nearly two thirds of total energy produced by 2025 will come from renewable resources.
- The coal retirements and exit by December 31, 2023 result in a significant decline in lifecycle $CO_2e$ emissions. Market imports are estimated to comprise a quarter of portfolio $CO_2e$ emissions by the end of the forecast period



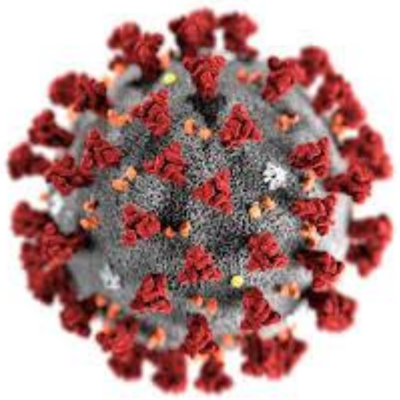




[1] Not produced by Vectren generating resources. Estimate based on projected market reliance, MISO buildout, and NREL lifecycle GHG study

# COVID AND THE PLAN

VECTREN
A CenterPoint Energy Company

- Vectren will continue to monitor the COVID-19 situation
- Too soon to understand all of the long term impacts; however, the plan is well positioned to meet customer needs in the near, mid, and long-term



  - Flexible
    - Mix of owned resources and term-based PPAs
  - Performed well across multiple future states
  - Numerous resources in spread over several locations and most resources can be operated remotely
  - Less costly to customers than the status quo

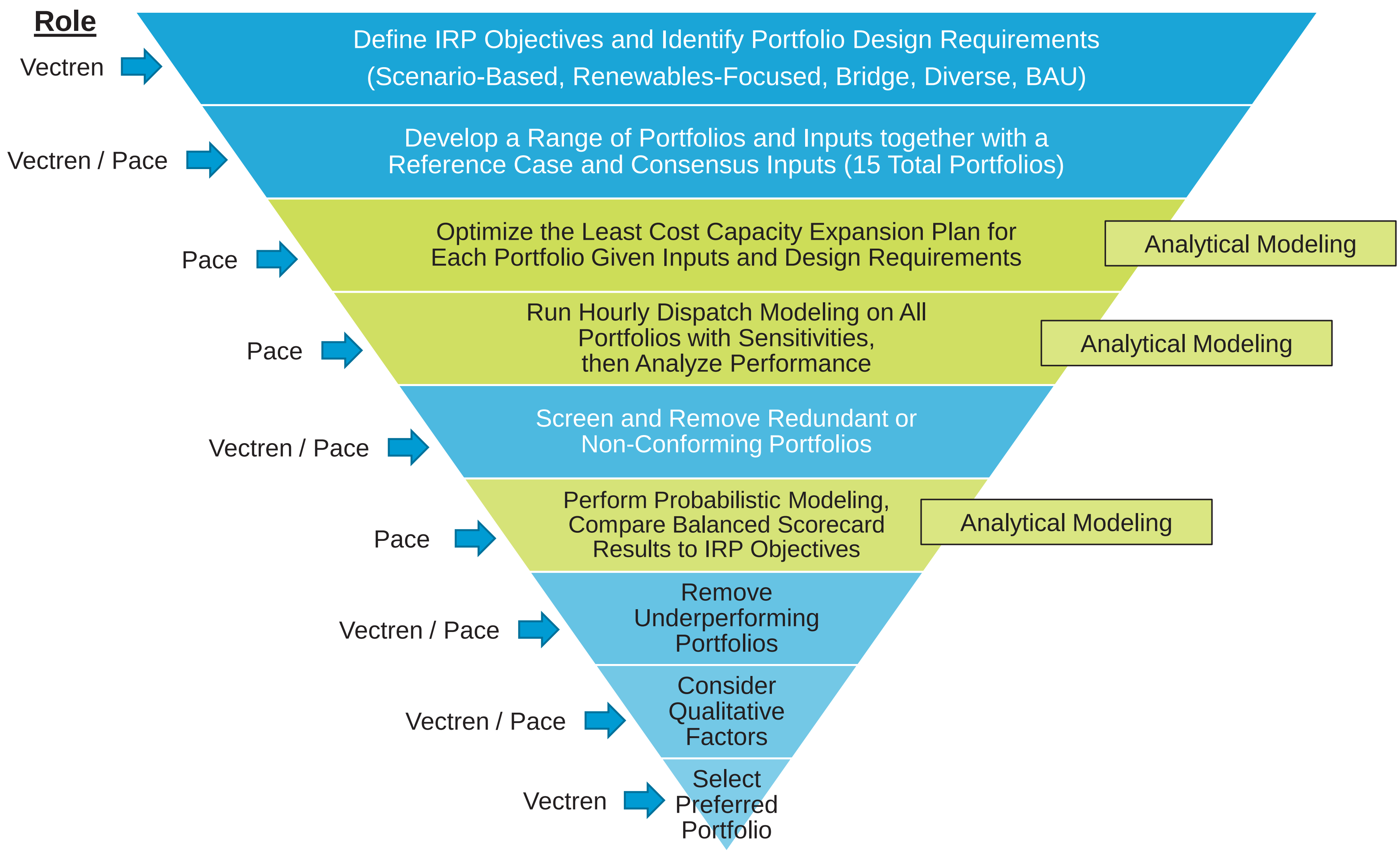
VECTREN
A CenterPoint Energy Company

# RISK ANALYSIS

**PETER HUBBARD**

PACE GLOBAL, MANAGER SIEMENS ENERGY BUSINESS ADVISORY

# IRP PORTFOLIO EVALUATION AND SELECTION PROCESS



# STRUCTURED SCREENING PROCESS TO ADDRESS ISSUES EFFICIENTLY

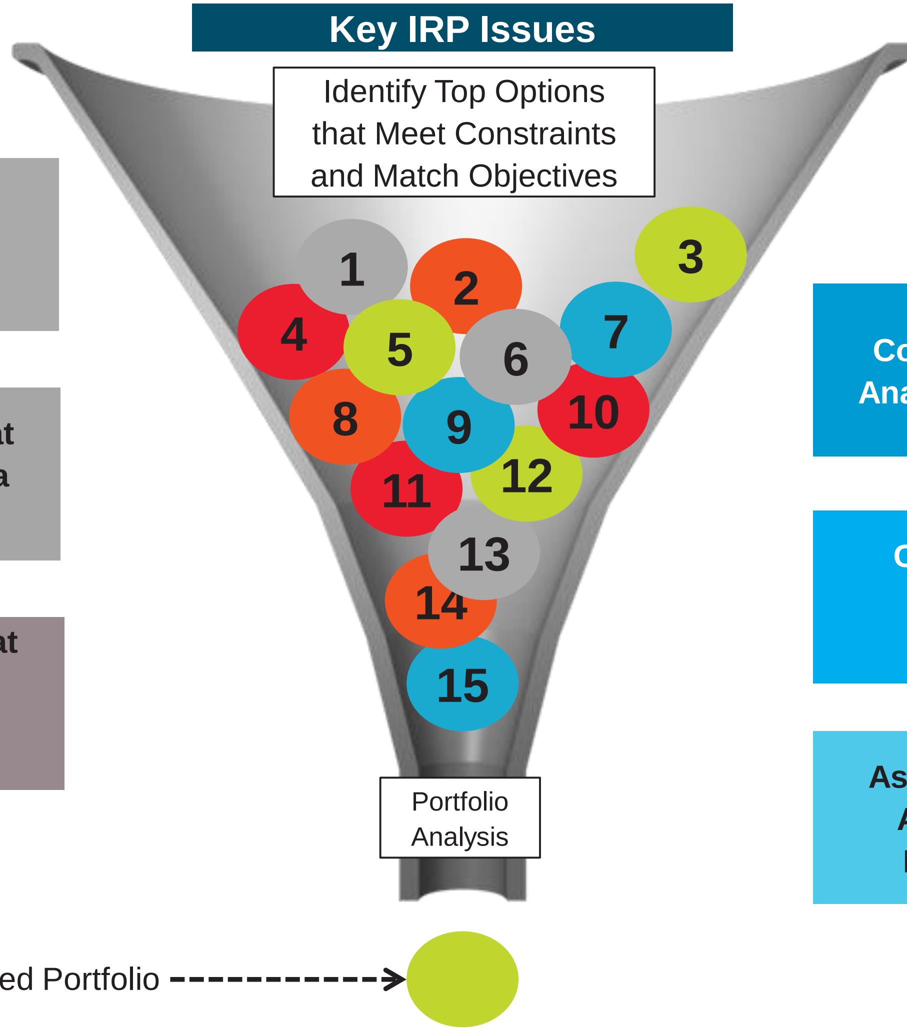
VECTREN
A CenterPoint Energy Company

***Task***

**Identify Portfolios (15)**

**Eliminate Portfolios that do not meet key criteria (10 remain)**

**Eliminate Portfolios that Exhibit Poorer Performance (4 remain)**




Select Preferred Portfolio

***Approach***

**Conduct Deterministic Analysis of 15 portfolios**

**Conduct Stochastic Analysis (200 iterations)**

**Assess Most Important Attributes to Select Preferred Portfolio**

# 15 OPTIMIZED PORTFOLIOS DEVELOPED

| Portfolio | Group | Portfolio |
|---|---|---|
| 1 | Reference | Optimized Portfolio in Reference Case conditions |
| 2 | BAU | Business as Usual to 2039 |
| 3 | | Business as Usual to 2029 |
| 4 | Bridge | ABB1 Conversion to Gas |
| 5 | | ABB1 + ABB2 Conversions to Gas |
| 6 | | ABB1 Conversion to Gas + Small CCGT |
| 7 | Diverse | Diverse with Renewables, Coal, Small CCGT |
| 8 | | Diverse with Renewables, Coal, Medium CCGT |
| 9 | Renewables | Renewables + Flexible Gas |
| 10 | | All Renewable by 2030 (No Fossil) |
| 11 | | HB 763 (High $CO_2$ Price)[1] |
| 12 | Scenario-Based | Optimized Portfolio in Low Regulatory conditions, Dispatched with Ref Case |
| 13 | | Optimized Portfolio in High Technology conditions, Dispatched with Ref Case |
| 14 | | Optimized Portfolio in 80% Reduction conditions, Dispatched with Ref Case |
| 15 | | Optimized Portfolio in High Regulatory conditions, Dispatched with Ref Case |

1 Created based upon stakeholder request. Utilized reference case assumptions with updated $CO_2$ price based on House Bill 763

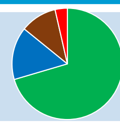
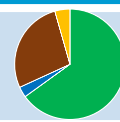
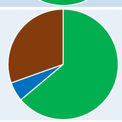
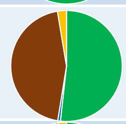
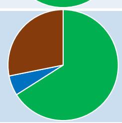
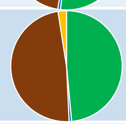
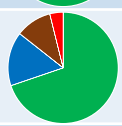
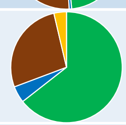
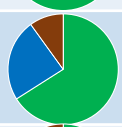
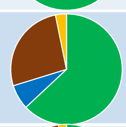
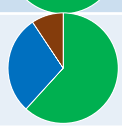
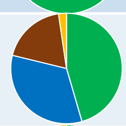
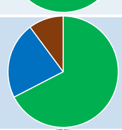
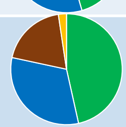
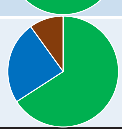
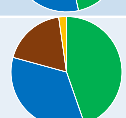
# STRATEGIES CONSISTENT ACROSS MAJORITY OF PORTFOLIOS

The full analytical process informed the development of several strategies that are consistent across portfolios:

- Optimized results
  - Pursue universal solar capacity of up to ~1,000 MW through 2024
  - Pursue universal wind capacity of up to 300 MW by 2023
  - Retire A B Brown 1 and 2 and F B Culley 2 units by the end of 2023
- Pursue Energy Efficiency at 1.25% of eligible sales (+ Low Income measures) for the first three years and Demand Response resources (Summer Cycler switch out to Wi-Fi thermostats). Applied to all portfolios.
  - Did not want to rely solely on reference case conditions to decide the appropriate level of EE. The reference case selected 0.75% EE, while other scenarios selected 1.25%
  - 1.25% More consistent with historic levels
  - 1.25% vs 0.75% increases NPVRR by only 0.15%

# SUMMARY RESULTS FROM ALL PORTFOLIO DETERMINISTIC RUNS

- Renew
- Gas
- Coal
- EE,DG
- Purchase

| | Portfolio | Portfolio Capacity Mix in 2026 | Generation in 2026 | NPV $Billion * (% vs. Ref Case) | Net Sales as % of Generation | Average Capacity Mkt Purchases (2024-39) |
|---|---|---|---|---|---|---|
| Ref. | Reference Case |  |  | $2.625 | 7% | 138 MW |
| BAU | Business as Usual to 2039 |  |  | $3.140 (+19.6%) | 23% | 0 MW |
| | Business as Usual to 2029 |  |  | $2.835 (+8.0%) | 19% | 102 MW |
| Bridge | Gas Conversion ABB1 |  |  | $2.727 (+3.9%) | 9% | 133 MW |
| | Gas Conversion ABB1 + ABB2 |  |  | $2.887 (+10.0%) | 11% | 56 MW |
| | Gas Conversion ABB1 + CCGT |  |  | $2.954 (+12.6%) | 37% | 16 MW |
| Diverse | Diverse Small CCGT |  |  | $2.763 (+5.2%) | 38% | 23 MW |
| | Diverse Medium CCGT |  |  | $2.785 (+6.1%) | 41% | 18 MW |

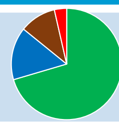
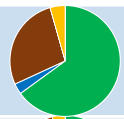
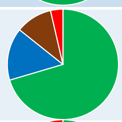
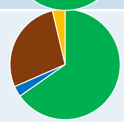
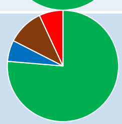
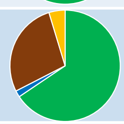
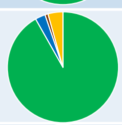
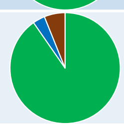
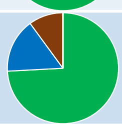
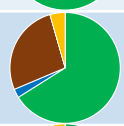
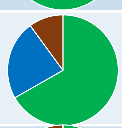
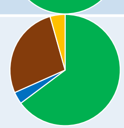
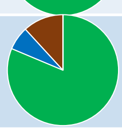
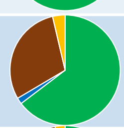
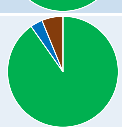
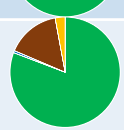
Increasing CCGT size added cost and market exposure without an increase in portfolio reliability or other value

* Deterministic NPV not used for final Affordability metric

# SUMMARY RESULTS FROM ALL PORTFOLIO DETERMINISTIC RUNS

Renew
Gas
Coal
EE,DG
Purchase

VECTREN
A CenterPoint Energy Company

| | Portfolio | Portfolio Capacity Mix in 2026 | Generation in 2026 | NPV $Billion * (% vs. Ref Case) | Net Sales as % of Generation | Average Capacity Mkt Purchases (2024-39) |
|---|---|---|---|---|---|---|
| Ref. | Reference Case |  |  | $2.625 | 7% | 138 MW |
| Renewables | Renewables + Flexible Gas |  |  | $2.600 (-1.0%) | 6% | 135 MW |
| | Renewable 2030 |  |  | $2.679 (+2.1%) | 10% | 170 MW |
| | HB 763 |  |  | $1.425 (-45.7%) | 105% | 10 MW |
| Scenario | Low Regulatory |  |  | $2.762 (+5.2%) | 46% | 12 MW |
| | High Technology (Preferred Portfolio) |  |  | $2.686 (+2.3%) | 6% | 4 MW |
| | 80% Reduction |  |  | $2.642 (+0.7%) | 36% | 203 MW |
| | High Regulatory |  |  | $4.196 (+59.9%) | 117% | 10 MW |

Unrealistic Net Sales Revenue

High Net Sales

Market Exposure

High Cost and High Net Sales

* Deterministic NPV not used for final Affordability metric

# STRUCTURED SCREENING PROCESS TO ADDRESS ISSUES EFFICIENTLY

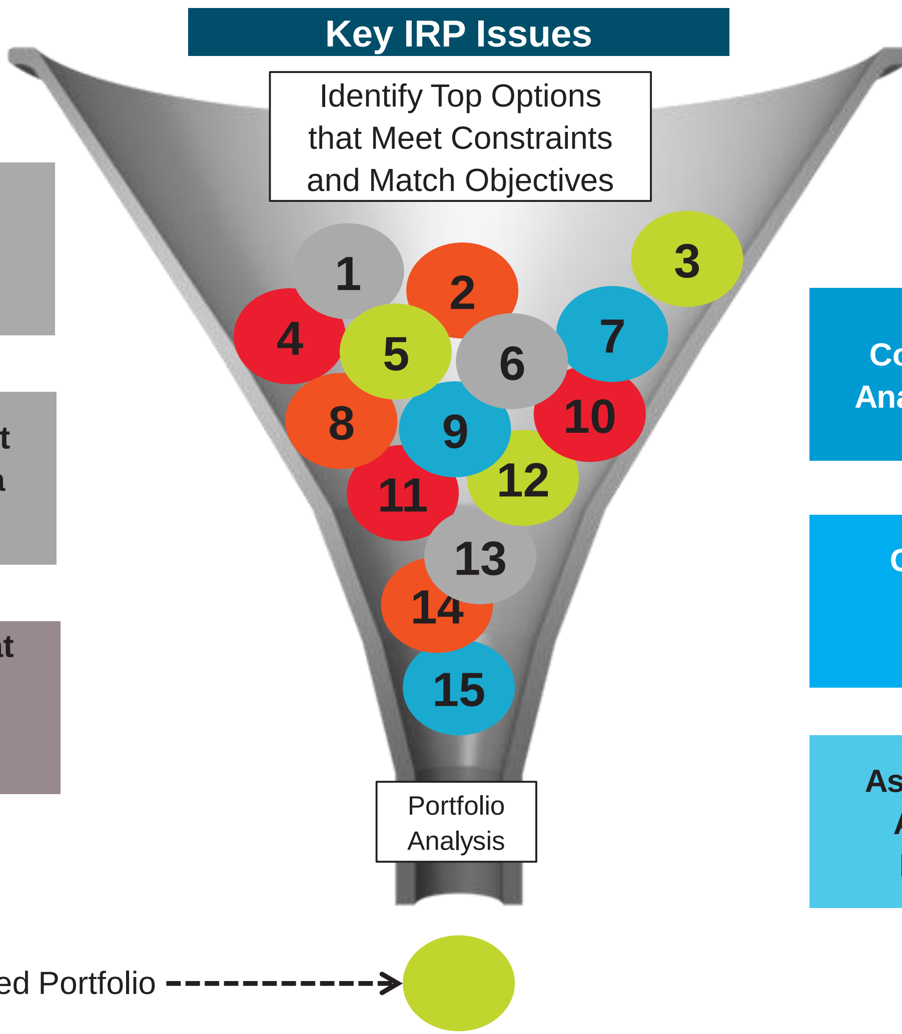
VECTREN
A CenterPoint Energy Company

## *Task*

**Identify Portfolios (15)**

**Eliminate Portfolios that do not meet key criteria (10 remain)**

**Eliminate Portfolios that Exhibit Poorer Performance (4 remain)**




## *Approach*

**Conduct Deterministic Analysis of 15 portfolios**

**Conduct Stochastic Analysis (200 iterations)**

**Assess Most Important Attributes to Select Preferred Portfolio**

# SENSITIVITIES WERE CONDUCTED TO FURTHER UNDERSTAND AND REFINE THE PORTFOLIOS

- Each portfolio was optimized on a seasonal peak demand construct to ensure resource adequacy as peak capacity credit declines for renewables. All portfolios had sufficient seasonal resources
- Solar costs were increased 30% to determine continued economic selection and were found to be economic
- Sensitivities on the Reference Case by replacing the only CT capacity with battery storage:
  - Replacing the CT with battery storage increased portfolio costs by $51 million
  - CT provided long-duration capacity vs. 4 hour limit with battery storage

# SENSITIVITY: NPV COST OF PORTFOLIOS DISPATCHED IN ALTERNATIVE SCENARIOS

VECTREN
A CenterPoint Energy Company

## 20-Year Net Present Value - Percentage of Reference Case

| | Reference Case | Low Regulation | High Technology | 80% Reduction of CO2 by 2050 | High Regulation |
|---|---|---|---|---|---|
| Reference Case | 100.0% | 100.0% | 100.0% | 100.0% | 100.0% |
| Business as Usual to 2039 | 119.7% | 101.2% | 120.7% | 117.1% | 112.5% |
| Business as Usual to 2029 | 108.0% | 100.9% | 108.5% | 106.4% | 104.8% |
| ABB1 Conversion + Small CCGT | 112.6% | 112.6% | 111.5% | 111.2% | 107.4% |
| ABB1 Conversion | 103.9% | 104.5% | 104.5% | 103.9% | 102.0% |
| ABB1 + ABB2 Conversions | 110.0% | 110.0% | 110.1% | 109.9% | 105.5% |
| Diverse Small CCGT | 105.3% | 105.3% | 104.2% | 103.5% | 102.7% |
| Renewables + Flexible Gas | 98.4% | 101.4% | 98.2% | 98.1% | 97.7% |
| All Renewables by 2030 | 101.4% | 108.2% | 105.0% | 100.5% | 94.3% |
| Preferred Portfolio | 102.3% | 102.6% | 101.3% | 102.1% | 102.2% |

*Alternative Scenario Changes vs. Ref Case*

| Scenario | Load | CO2 Prices | Gas Prices | Coal Prices | RE Cost |
|---|---|---|---|---|---|
| Low Reg | Higher | N/A | Higher | Ref | Ref |
| High Tech | Higher | Lower | Lower | Lower | Lower |
| 80% | Lower | Ref | Ref | Lower | Lower |
| High Reg | Ref | Higher | Very High | Lower | Lower |

# STRUCTURED SCREENING PROCESS TO ADDRESS ISSUES EFFICIENTLY

VECTREN
A CenterPoint Energy Company

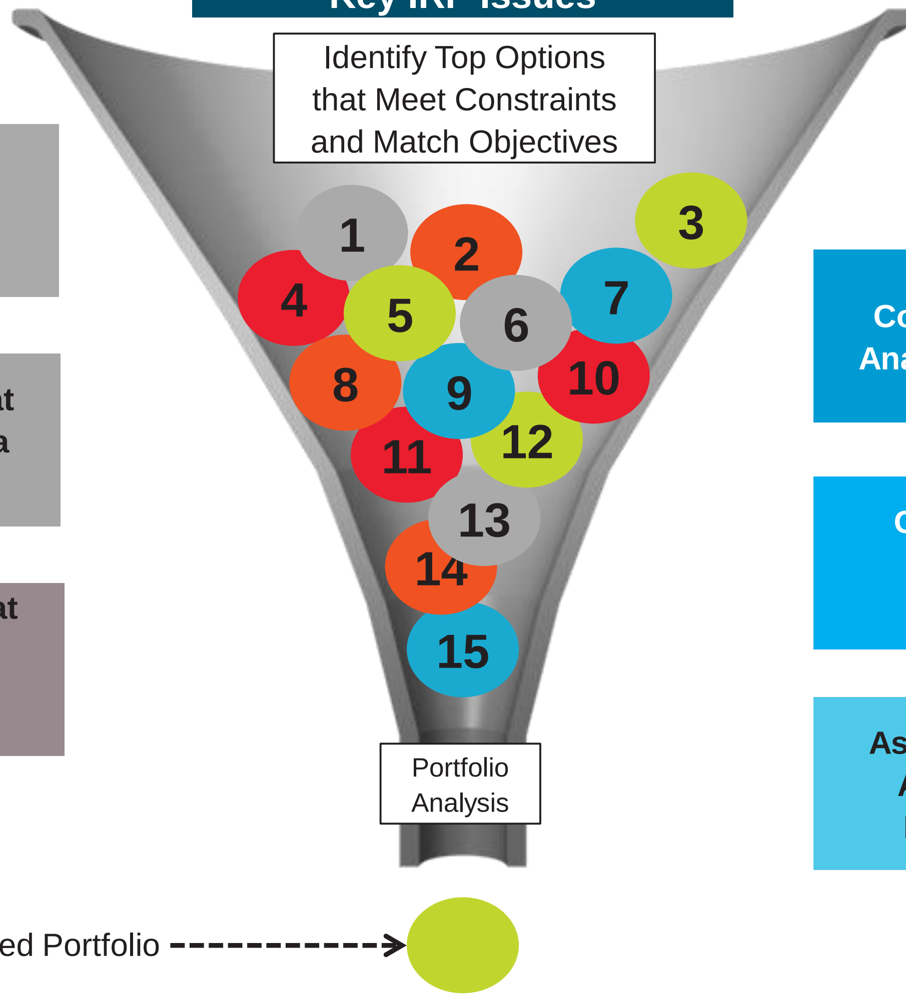
## *Task*

**Identify Portfolios (15)**

**Eliminate Portfolios that do not meet key criteria (10 remain)**

**Eliminate Portfolios that Exhibit Poorer Performance (4 remain)**

## Key IRP Issues




Select Preferred Portfolio

## *Approach*

**Conduct Deterministic Analysis of 15 portfolios**

**Conduct Stochastic Analysis (200 iterations)**

**Assess Most Important Attributes to Select Preferred Portfolio**

# BALANCED SCORECARD RESULTS OF PROBABILISTIC ANALYSIS

VECTREN
A CenterPoint Energy Company

- Each portfolio was then dispatched 200 times under varying market conditions, with results populating a Balanced Scorecard (green=better scoring).

| Balanced Scorecard | Stochastic Mean 20-Year NPVRR | 95th Percentile Value of NPVRR | % Reduction of CO2e (2019-2039) | Energy Purchases as a % of Generation | Energy Sales as a % of Generation | Capacity Purchases as a % of Peak Demand | Capacity Sales as a % of Peak Demand |
|---|---|---|---|---|---|---|---|
| Reference Case | $2,536 | $2,919 | 58.1% | 16.8% | 26.8% | 9.7% | 1.2% |
| Business as Usual to 2039 | $2,912 | $3,307 | 35.2% | 12.0% | 36.5% | 0.1% | 11.1% |
| Business as Usual to 2029 | $2,689 | $3,090 | 61.9% | 15.2% | 31.4% | 7.1% | 4.3% |
| ABB1 Conversion + Small CCGT | $2,872 | $3,268 | 47.9% | 6.6% | 31.8% | 1.3% | 10.1% |
| ABB1 Conversion | $2,675 | $3,045 | 61.5% | 19.2% | 26.4% | 9.3% | 1.2% |
| ABB1 + ABB2 Conversions | $2,834 | $3,212 | 61.5% | 18.5% | 27.5% | 4.0% | 5.6% |
| Diverse Small CCGT | $2,680 | $3,071 | 47.9% | 6.4% | 31.1% | 1.7% | 3.7% |
| Renewables + Flexible Gas | $2,526 | $2,926 | 77.4% | 21.5% | 27.7% | 9.4% | 1.2% |
| All Renewables by 2030 | $2,613 | $3,002 | 79.3% | 26.1% | 31.9% | 11.9% | 1.7% |
| High Technology (Preferred Portfolio) | $2,590 | $2,978 | 59.8% | 16.7% | 26.9% | 0.4% | 4.6% |

- Several portfolios (marked in red) were not considered further due to high cost, high price risk, over-reliance on the market for sales and associated revenues, or over-exposure to market purchases and associated costs.

# REMAINING OPTIONS A BETTER OPTION FOR CUSTOMERS THAN CONTINUING COAL OR CONVERSION

VECTREN
A CenterPoint Energy Company

Continuing use of the Brown units with Coal or Bridge options (Conversion) did not perform well in our analysis.

- Less Affordable – BAU and Conversion options cost customers more over the twenty year period than 4 remaining portfolios in all scenarios.
  - Higher O&M –requires more people to operate
  - Higher on-going capital expenditures to keep the units running
  - Less flexibility to capture benefits of the market
- Continuing to utilize coal has a higher initial capital investment than remaining options. Conversion has slightly less upfront capital investment. Due to On-going capital expenditures to keep these options running, the remaining book life of these assets do not fully depreciate
- Less Flexible – slow start time (8-24 hrs.) and slow ramp rate (2-3 MW/Min) do not position us well to support our customers in a future with high solar penetration
- Less Reliable – converted units continue to utilize old equipment that is prone to break down more than new equipment
- Less efficient – conversion is of units designed to burn coal has a worse heat rate (11,200) than modern combustion turbines. New CTs (9,900) have a better heat rate than existing Brown coal units (10,500) and existing peaking units (12,200)

# OPTIMIZED PORTFOLIO BUILDOUTS & RETIREMENTS

| Year | Reference Case | Renewables + Flexible Gas | Renewables 2030 | High Technology |
|---|---|---|---|---|
| **2021-23** | 1.25% Energy Efficiency | 1.25% Energy Efficiency | 1.25% Energy Efficiency | 1.25% Energy Efficiency |
| **2022** | New Wind (300 MW) | New Wind (300 MW) | New Wind (300 MW) | New Wind (300 MW) |
| **2023** | New Solar (731 MW), New Storage (126 MW) | New Solar (731 MW) New Storage (126 MW) | New Solar (731 MW) New Storage (278 MW) | New Solar (731 MW) New Storage (126 MW) |
| **2023** | Retire ABB1, ABB2, FBC2, Exit Warrick (730 MW) | Retire ABB1, ABB2, FBC2, Exit Warrick (730 MW) | Retire ABB1, ABB2, FBC2, Exit Warrick (730 MW) | Retire ABB1, ABB2, FBC2, Exit Warrick (730 MW) |
| **2024** | New Combustion Turbine (236 MW) | New Combustion Turbine (236 MW) | - | New Combustion Turbine (236 MW) |
| **2024** | New Solar (415 MW) and Demand Response | New Solar (415 MW) and Demand Response | New Solar (415 MW) and Demand Response | New Solar (415 MW) and Demand Response |
| **2024-26** | 0.75% Energy Efficiency | 0.75% Energy Efficiency | 1.00% Energy Efficiency | 0.75% Energy Efficiency |
| **2025** | | - | - | New Combustion Turbine (236 MW) |
| **2027-39** | 0.75% Energy Efficiency | 0.75% Energy Efficiency | 1.00% Energy Efficiency | 0.75% Energy Efficiency |
| **2029-32** | - | - | Retire FBC3, ABB3, ABB4 (427 MW), New Storage (360 MW), Solar (700 MW) | - |
| **2033-39** | New Solar (250 MW) | Retire FBC3 (270 MW), New Combustion Turbine (236 MW) | New Solar (450 MW) | New Storage (50 MW) |
| **2024-39** | Average Annual Capacity Market Purchases (137 MW) | Average Annual Capacity Market Purchases (135 MW) | Average Annual Capacity Market Purchases (170 MW) | Average Annual Capacity Market Purchases (4 MW) |

# BALANCED SCORECARD RESULTS OF PROBABILISTIC ANALYSIS

VECTREN
A CenterPoint Energy Company

The four remaining portfolios were evaluated under a range of factors including metrics and other factors.

| Balanced Scorecard | Stochastic Mean 20-Year NPVRR | 95th Percentile Value of NPVRR | % Reduction of CO2e (2019-2039) | Energy Purchases as a % of Generation | Energy Sales as a % of Generation | Capacity Purchases as a % of Peak Demand | Capacity Sales as a % of Peak Demand |
|---|---|---|---|---|---|---|---|
| Reference Case | $2,536 | $2,919 | 58.1% | 16.8% | 26.8% | 9.7% | 1.2% |
| Renewables + Flexible Gas | $2,526 | $2,926 | 77.4% | 21.5% | 27.7% | 9.4% | 1.2% |
| All Renewables by 2030 | $2,613 | $3,002 | 79.3% | 26.1% | 31.9% | 11.9% | 1.7% |
| High Technology (Preferred Portfolio) | $2,590 | $2,978 | 59.8% | 16.7% | 26.9% | 0.4% | 4.6% |

The High Technology portfolio performed well across all factors in the balanced scorecard and was selected as the preferred portfolio.  It hedges risk well against the energy and capacity markets relative to the remaining portfolios and maintains the flexibility.

- The reference case has a long term reliance on the capacity market, is less reliable (1 CT vs 2), less able to ramp in high renewables penetration environment, and provides less flexibility in the future
- The principal difference between the renewables + flexible gas portfolio and the preferred portfolio was a heavy reliance on market capacity purchases and the retirement date of Culley 3. Would lose $50M in construction efficiencies on building the 2$^{nd}$ CT (not reflected in NPVRR)
- The all renewables portfolio by 2030 would require an additional $20-30M in reliability upgrades (not reflected in NPVRR), relies heavily on emerging technology, and is very exposed to the capacity and energy markets

# QUALITATIVE CONSIDERATIONS: THE PREFERRED PORTFOLIO IS A GOOD OPTION FOR CUSTOMERS

The preferred portfolio offers a transition pathway away from coal while providing the optionality to adapt to future technology and market changes. This diverse set of resources offers customers the benefit of clean renewable energy, with the reliability required by our customers.

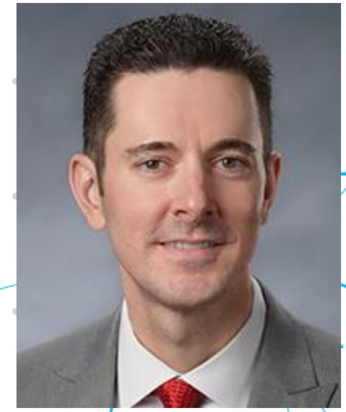
- Two highly dispatchable combustion turbines (460 MW) allow for a high penetration of renewables, ensuring reliability and hedges against the energy and capacity markets
  - Assurance of reliable service. Thermal resources are still needed to maintain reliable service in multiday periods of cloud cover and no wind
  - Two CTs provide better support than one. Better coverage should a unit go down to provide a hedge against high energy prices and provide system support when issues arise
  - Two CTs keeps existing interconnection rights, which shields customers from potential transmission upgrade costs in the future should Vectren have to re-enter the MISO Queue (a three year process)
  - Two CTs provide fast start (10 min) & more fast ramping capability (80 MW/minute vs 40 MW/minute) to support for intermittent solar and allows for a smooth transition into a renewables future locally and regionally as the MISO system adapts to higher levels of renewables across the system
  - Two CTs replace required capacity and shields customers from potential future high capacity prices in the MISO market
  - Two CTs built at the same time provide $50M in construction cost savings vs. a 10 year delay of the 2$^{nd}$ CT (Renewables + Flexible Gas Portfolio – not reflected in NPVRR)
  - Two CTs provide a high degree of flexibility in the future

VECTREN
A CenterPoint Energy Company

# NEXT STEPS

**JUSTIN JOINER**

VECTREN DIRECTOR OF
POWER SUPPLY SERVICES



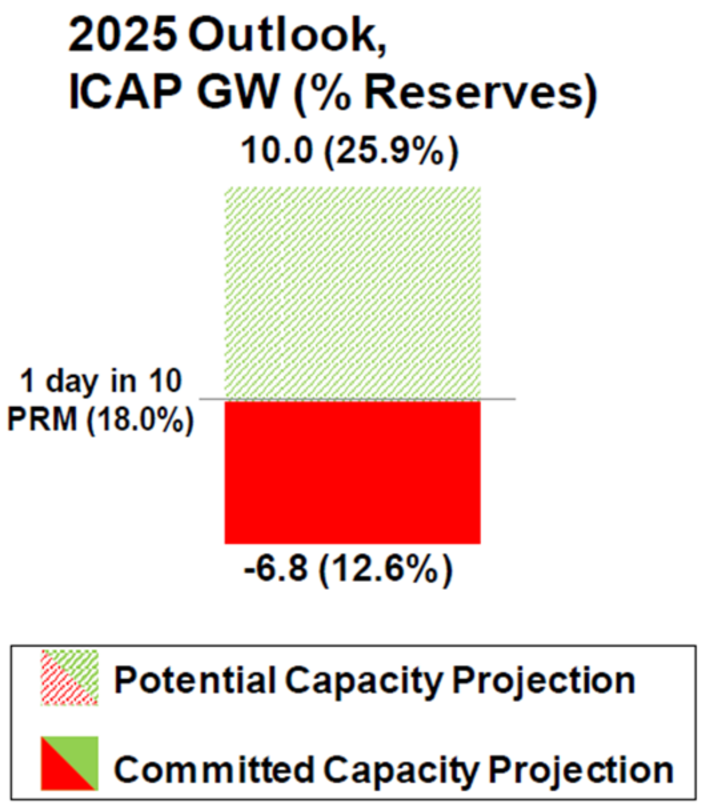
# CONTINUE MONITORING EXTERNAL DEVELOPMENTS AND FACTORS

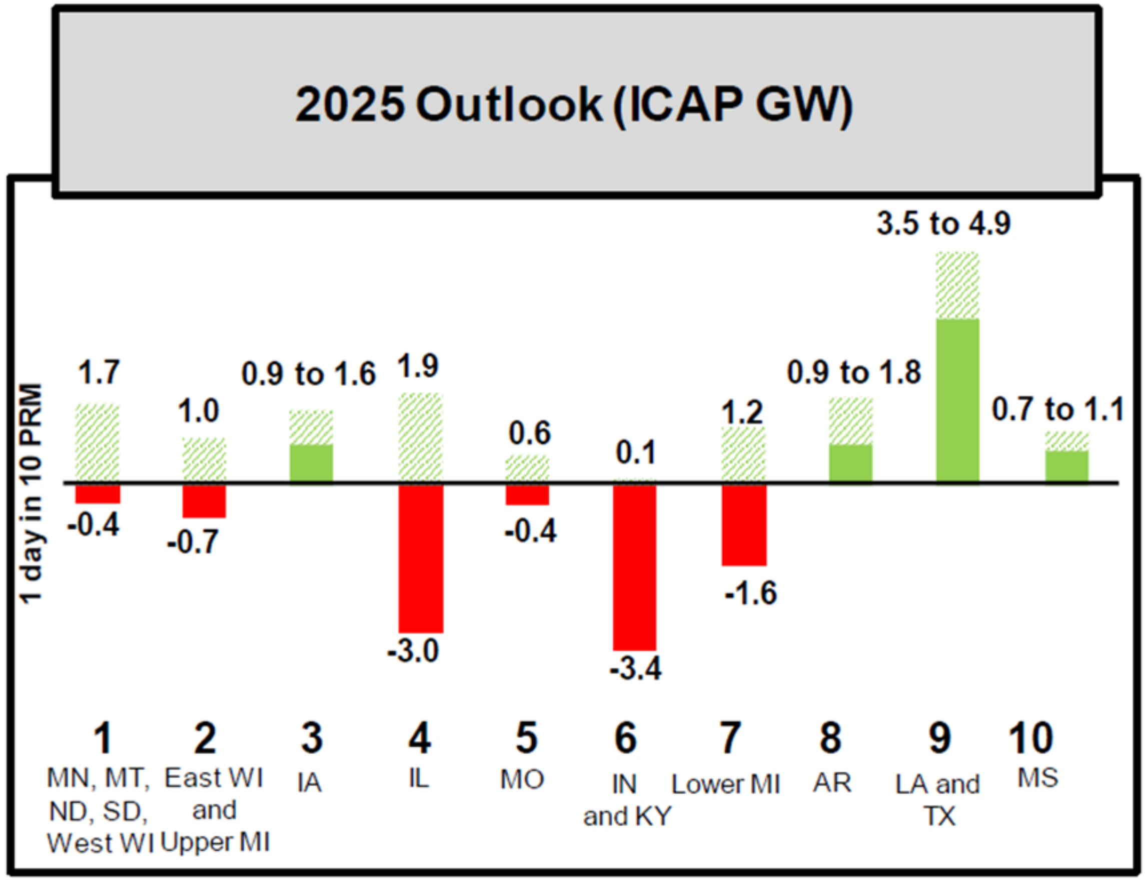
Will continue to evaluate the paradigm shift underway in the industry towards renewables, while the Preferred Portfolio provides needed flexibility, reliability, diversity and affordability that is needed to accommodate

- **Customer**
  - Demand for clean energy and emerging technology
  - ESG goals and requirements
- **State of Indiana**
  - Announced and recently completed generation retirements
  - Legislative taskforce
  - Economic development
- **MISO**
  - Resource adequacy now and in the future
  - Wholesale energy market construct now and in the future
  - Transmission system configuration ability to meet needs now and in the future

# 2020 OMS-MISO SURVEY RESULTS

Latest Resource Adequacy results demonstrate the generation shift underway MISO-wide and that is carried out through unit retirements and new generation builds, thus producing less certainty in future years around available capacity




*Per June MISO presentation of 2020 OMS-MISO Survey results

- Regional surpluses and potential resources will be critical for all zones to serve their deficits while meeting local requirements
- Positions include reported inter-zonal transfers, but do not reflect other possible transfers between zones
- Exports from Zones 8, 9, and 10 were limited by the Sub-regional Power Balance Constraint

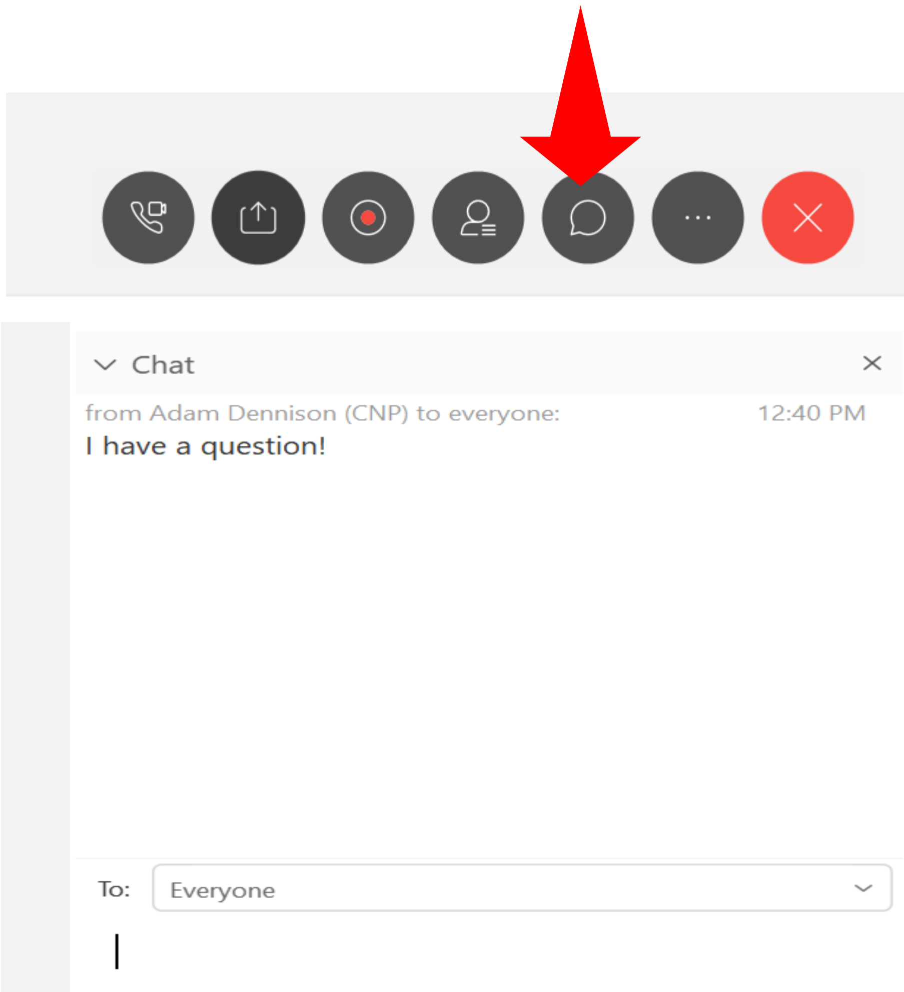
# NEXT STEPS

To maximize the $320M in customer savings that the Preferred Portfolio presents, an action plan is in place that is focused on two phases

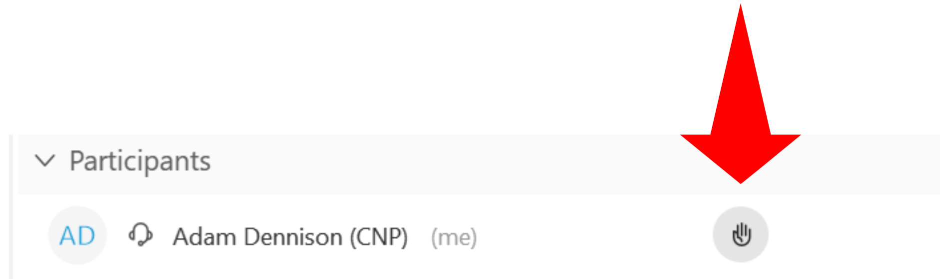
- **Near-term: next 6 months**
  - – Enter into agreements with the most attractive projects received from 2019 All-Source RFP
    - To maximize tax credits for our customers, projects must be under-construction/in-service soon
  - – Conduct a second RFP in the Fall to address remaining renewable needs identified in IRP
  - – Continue monitoring state developments; Statewide Resource Plan, Legislative Taskforce, COVID-19
- **Mid-term: next 12 months**
  - – File Certificate of Public Convenience and Necessity (CPCN) in 2021
  - – Begin permitting, civil engineering and preliminary site work for Combustion Turbines
    - Multi-year process
  - – Continue advancement and refinement of renewable energy expertise
    - Work with developers to understand project attributes and ensure quality control and price certainty
    - Evaluate pricing of battery and determine appropriate timing install
    - Apply insights gained to future projects

# Q&A

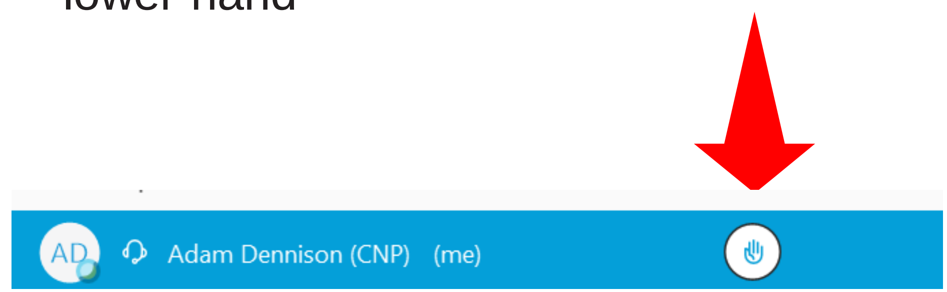
Ask “everyone” in chat.




Raise Hand for a Follow-up




After question has been answered, lower hand



# STAKEHOLDER COMMENT PERIOD

Speakers who have signed up ahead of the meeting will be allotted time to verbally provide comments (consider designating a speaker for each organization). Please type, I would like to make a comment in chat if you did not sign up early. We will accommodate as many requests as possible. Please pay attention to the on-screen prompts in order to allow for as many comments as possible.

One Minute

Two Minutes

Next Speaker

# APPENDIX

# OPTIMIZED PORTFOLIO BUILDOUTS & RETIREMENTS

| Year | Reference Case | Business as Usual to 2039 | Business as Usual to 2029 | Gas Conversion ABB1 | Gas Conversion ABB1 + ABB2 |
|---|---|---|---|---|---|
| 2021-23 | 1.25% Energy Efficiency | 1.25% Energy Efficiency | 1.25% Energy Efficiency | 1.25% Energy Efficiency | 1.25% Energy Efficiency |
| 2022 | New Wind (300 MW) | New Wind (300 MW) | New Wind (300 MW) | New Wind (300 MW) | New Wind (300 MW) |
| 2023 | New Solar (731 MW), New Storage (126 MW) | New Solar (731 MW), New Storage (126 MW) | New Solar (731 MW), New Storage (126 MW) | New Solar (731 MW), New Storage (126 MW) | New Solar (731 MW), New Storage (126 MW) |
| 2023 | Retire ABB1, ABB2, FBC2, Exit Warrick (730 MW) | Scrubber control on ABB1 and ABB2, Exit Warrick (150 MW) | Exit Warrick (150 MW) | Retire ABB2, FBC2, Exit Warrick (485 MW) | Retire FBC2, Exit Warrick (240 MW) |
| 2024 | New Combustion Turbine (236 MW) | - | - | ABB1 Conversion (245 MW) | ABB1+ABB2 Conversions (490 MW) |
| 2024 | New Solar (415 MW) and Demand Response | New Solar (415 MW) and Demand Response | New Solar (415 MW) and Demand Response | New Solar (415 MW) and Demand Response | New Solar (415 MW) and Demand Response |
| 2024-26 | 0.75% Energy Efficiency | 0.75% Energy Efficiency | 0.75% Energy Efficiency | 0.75% Energy Efficiency | 0.75% Energy Efficiency |
| 2027-39 | 0.75% Energy Efficiency | 0.25% Energy Efficiency | 0.50% Energy Efficiency | 0.75% Energy Efficiency | 0.50% Energy Efficiency |
| 2029-30 | - | - | Retire ABB1, ABB2, FBC2 (580 MW), New Combustion Turbine (236 MW) | - | - |
| 2033-34 | - | - | - | Retire ABB1, New Combustion Turbine (279 MW) | Retire ABB1+ABB2, New Combustion Turbine (279 MW) |
| 2037-39 | New Solar (250 MW) | - | - | - | - |
| 2024-39 | Avg Annual Capacity Mkt Purchases (137 MW) | No Capacity Market Purchases | Avg Annual Capacity Mkt Purchases (101 MW) | Avg Annual Capacity Mkt Purchases (133 MW) | Avg Annual Capacity Mkt Purchases (56 MW) |

# OPTIMIZED PORTFOLIO BUILDOUTS & RETIREMENTS

VECTREN
A CenterPoint Energy Company

| Year | Gas Conversion ABB1 + CCGT | Diverse Small CCGT | Diverse Medium CCGT | Renewables + Flexible Gas | Renewables 2030 |
|---|---|---|---|---|---|
| 2021-23 | 1.25% Energy Efficiency | 1.25% Energy Efficiency | 1.25% Energy Efficiency | 1.25% Energy Efficiency | 1.25% Energy Efficiency |
| 2022 | New Wind (300 MW) | New Wind (300 MW) | New Wind (300 MW) | New Wind (300 MW) | New Wind (300 MW) |
| 2023 | New Solar (731 MW) New Storage (126 MW) | New Solar (731 MW) New Storage (126 MW) | New Solar (731 MW) New Storage (126 MW) | New Solar (731 MW) New Storage (126 MW) | New Solar (731 MW) New Storage (278 MW) |
| 2023 | Retire ABB2, FBC2, Exit Warrick (485 MW) | Retire ABB1, ABB2, FBC2, Exit Warrick (730 MW) | Retire ABB1, ABB2, FBC2, Exit Warrick (730 MW) | Retire ABB1, ABB2, FBC2, Exit Warrick (730 MW) | Retire ABB1, ABB2, FBC2, Exit Warrick (730 MW) |
| 2024 | ABB1 Conversion (245 MW) | - | - | New Combustion Turbine (236 MW) | - |
| 2024 | New Solar (415 MW) and Demand Response | New Solar (415 MW) and Demand Response | New Solar (415 MW) and Demand Response | New Solar (415 MW) and Demand Response | New Solar (415 MW) and Demand Response |
| 2024-26 | 0.75% Energy Efficiency | 0.75% Energy Efficiency | 0.75% Energy Efficiency | 1.00% Energy Efficiency | 0.75% Energy Efficiency |
| 2025 | - | New Small CCGT (433 MW) | New Medium CCGT (497 MW) | - | - |
| 2026 | New Small CCGT (433 MW) | - | - | - | - |
| 2024-26 | 0.50% Energy Efficiency | 0.50% Energy Efficiency | 0.25% Energy Efficiency | 1.00% Energy Efficiency | 0.75% Energy Efficiency |
| 2029-32 | - | - | - | - | Retire FBC3, ABB3, ABB4 (427 MW), New Storage (360 MW), Solar (700 MW) |
| 2033-34 | - | - | - | Retire FBC3 (270 MW), New Combustion Turbine (236 MW) | New Solar (450 MW) |
| 2024-39 | Avg Annual Capacity Mkt Purchases (16 MW) | Avg Annual Capacity Mkt Purchases (23 MW) | Avg Annual Capacity Mkt Purchases (18 MW) | Avg Annual Capacity Mkt Purchases (135 MW) | Avg Annual Capacity Mkt Purchases (170 MW) |

# OPTIMIZED PORTFOLIO BUILDOUTS & RETIREMENTS

| Year | HB 763 | Low Regulatory | High Technology | 80% Reduction of CO2 by 2050 | High Regulatory |
|---|---|---|---|---|---|
| 2021-23 | 1.25% Energy Efficiency | 1.25% Energy Efficiency | 1.25% Energy Efficiency | 1.25% Energy Efficiency | 1.25% Energy Efficiency |
| 2022 | New Wind (300 MW) | New Wind (300 MW) | New Wind (300 MW) | New Wind (300 MW) | New Wind (300 MW) |
| 2023 | New Solar (731 MW) New Storage (278 MW) | New Solar (731 MW) New Storage (278 MW) | New Solar (731 MW) New Storage (126 MW) | New Solar (731 MW) New Storage (202 MW) | New Solar (731 MW) New Storage (278 MW) |
| 2023 | Retire ABB1, ABB2, FBC2, Exit Warrick (730 MW) | Retire ABB1, ABB2, FBC2, Exit Warrick (730 MW) | Retire ABB1, ABB2, FBC2, Exit Warrick (730 MW) | Retire ABB1, ABB2, FBC2, Exit Warrick (730 MW) | Retire ABB1, ABB2, FBC2, Exit Warrick (730 MW) |
| 2024 | New Landfill Gas (27 MW) | New Combustion Turbine (279 MW) | New Combustion Turbine (236 MW) | - | - |
| 2024 | New Solar (415 MW) and Demand Response | New Solar (415 MW) and Demand Response | New Solar (415 MW) and Demand Response | New Solar (415 MW) and Demand Response | New Solar (415 MW) and Demand Response |
| 2024-26 | 1.50% Energy Efficiency | 1.25% Energy Efficiency | 0.75% Energy Efficiency | 0.75% Energy Efficiency | 1.25% Energy Efficiency |
| 2025 | New Solar (550 MW) New Wind (650 MW) New Storage (50 MW) | - | New Combustion Turbine (236 MW) | - | New Solar (550 MW) New Wind (650 MW) New Storage (50 MW) |
| 2026-39 | New Solar (1,100 MW) New Wind (2,500 MW) New Storage (220 MW) | New Solar (1,000 MW) New Wind (2,400 MW) | - | - | New Solar (1,260 MW) New Wind (2,650 MW) New Storage (290 MW) |
| 2027-39 | 1.25% Energy Efficiency | 1.00% Energy Efficiency | 0.75% Energy Efficiency | 0.5% Energy Efficiency | 0.50% Energy Efficiency |
| 2033-39 | - | - | New Storage (50 MW) | New Solar (800 MW) New Wind (2,750 MW) New Storage (190 MW) | - |
| 2024-39 | Avg Annual Capacity Mkt Purchases (10 MW) | Avg Annual Capacity Mkt Purchases (12 MW) | Avg Annual Capacity Mkt Purchases (4 MW) | Avg Annual Capacity Mkt Purchases (203 MW) | Avg Annual Capacity Mkt Purchases (11 MW) |

# STAKEHOLDER FEEDBACK

| Request | Response |
|---|---|
| Will you please provide documents that lead you to believe that MISO is moving to a seasonal (sub-annual) construct? | Below are two examples: one from 2019 and the most recent<br><br>https://cdn.misoenergy.org/20191106%20RASC%20Item%204b%20RAN%20Capacity%20Accreditation397077.pdf<br><br>https://cdn.misoenergy.org/20200601%20RAN%20Workshop%20Item%2002%20PDP%20and%20RAN%20Overview449826.pdf |
| Will you consider modeling a larger hydro resource? | We plan to model the option for 2 - 50 MW projects, consistent with the tech assessment and reasonable assumptions for nearby dams. |
| Will you please provide the user manual for Aurora? | It is included in the read only copy of the model. Provided a work-around pdfs for help function material and put interested parties in touch with Aurora for access to on-line help function. |
| RFP provides price certainty for projects. I'm concerned that you are varying capital costs within stochastic modeling | We did not vary capital costs in the near term for stochastic modeling. It should be noted the on-going discussions with several bidders indicate higher prices than initially provided within bids. |

# CANDIDATE PORTFOLIOS FOR PROBABILISTIC ANALYSIS

| Selected as Candidate |
|---|
| Not Selected |

| Portfolio | Group | Portfolio | Reason |
|---|---|---|---|
| 1 | Reference | Reference Case | Serves as a baseline for other portfolios |
| 2 | BAU | BAU to 2039 | Evaluate continued coal operation, capacity value |
| 3 | | BAU to 2029 | Evaluate limited coal operations, capacity value |
| 4 | Bridge | ABB1 | Evaluate limited bridge option (1 conversion) |
| 5 | | ABB1+ABB2 | Evaluate performance of 2 conversions |
| 6 | | ABB1+CCGT | Evaluate interaction with market, capacity value |
| 7 | Diverse | Diverse Small CCGT | Evaluate diverse mix, capacity value |
| 8 | | Diverse Medium CCGT | Higher cost than small CCGT; no additional value |
| 9 | Renewables | Renewables+ Flexible Gas | Evaluate a mix of options, heavy with renewables |
| 10 | | Renewable 2030 | Evaluate a storage- and renewables-heavy portfolio |
| 11 | | HB 763 | Overbuilt with 6.2 GW renewables, high LMPs |
| 12 | Scenario-Based | Low Regulatory | Overbuilt with 4.8 GW renewables |
| 13 | | High Technology (Preferred Portfolio | Evaluate performance of portfolio with 2 CTs |
| 14 | | 80% Reduction | Overbuilt with 5 GW renewables |
| 15 | | High Regulatory | Overbuilt with 6.6 GW renewables, high LMPs |

# UNECONOMIC ASSET MEASURE CONSIDERED, BUT REMOVED FROM SCORECARD

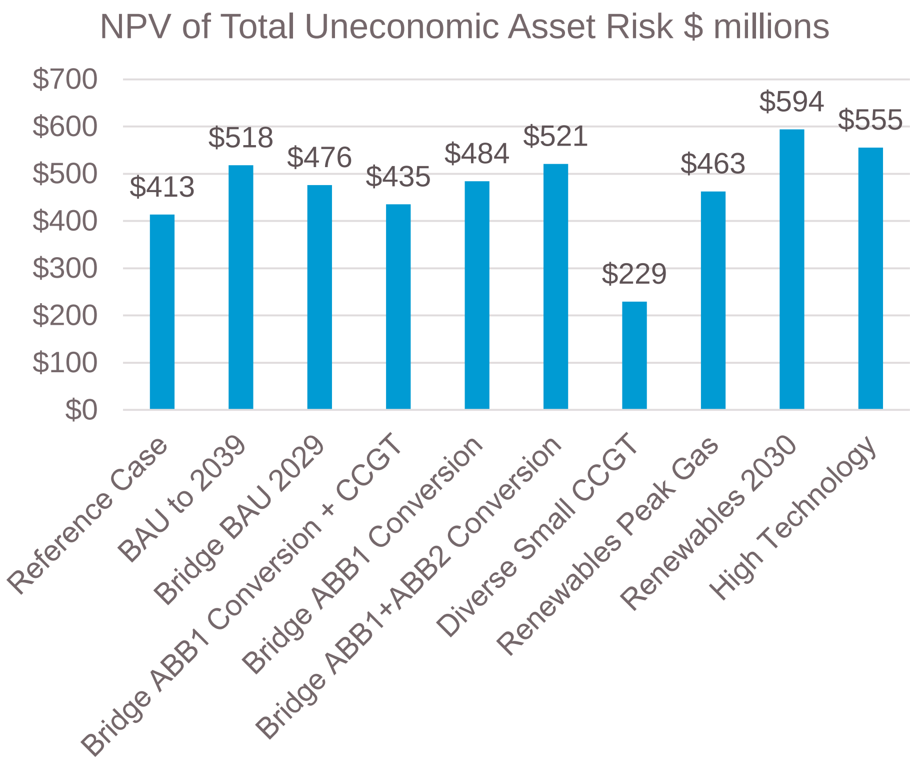
Following the recent order on the 2x1 CCGT, Vectren worked with Pace Global and the stakeholders, to develop the following approach to address the concern over recovering large capital investments:

- Determine in any iteration (scenario) when for three years in succession, revenues (capacity + energy) did not cover costs (fixed and variable).
- Then calculate remaining undepreciated costs plus future losses. This is the uneconomic cost for that iteration, which is multiplied by 1/200 to calculate the Expected Value of the uneconomic cost for the portfolio.

The results were not anticipated - Portfolios with plants with large energy revenues (coal and combined cycle) performed better than combustion turbines, even though they require a larger capital spend than CTs.

CTs were immediately considered potentially uneconomic assets. This occurred for 3 reasons:

1. CTs were a hedge against an illiquid capacity market – but capacity prices were not a stochastic variable
2. Capacity prices averaged about 50% of CONE. This is less than the cost to recover CT investment.
3. CTs have low CFs, which result in low energy revenues



**Vectren 2019 IRP**
**4th Stakeholder Meeting Minutes Q&A**
*June 15, 2020, 1:00 p.m. – 3:30 p.m.*

**Lynnae Wilson** (CenterPoint Energy Indiana Electric Chief Business Officer) – Welcome, Safety Message (Firework Safety Tips), and Vectren Introductions

> Subject Matter Experts in the Room: Matt Rice, Justin Joiner, Natalie Hedde, Bob Heidorn, Wayne Games, Angila Retherford, Jason Stephenson, Ryan Wilhelmus
>
> Subject Matter Experts Participating Via Webex: Ryan Abshier, Rina Harris, Shane Bradford, Angie Casbon-Scheller, Tom Bailey, Steve Rawlinson, Chris Leslie, Heather Watts, Cas Swiz, Matt Lind, and Gary Vicinus

**Stakeholders:** Approximately 180 stakeholders registered to participate in the Webex meeting. List of affiliations include the following:

| | | |
|---|---|---|
| ACES | First Solar | NextEra Energy Resources |
| Advanced Energy Economy | GE Gas Power | NIPSCO |
| AECOM | GSG Communications LLC | Origis Energy |
| AEP | Hallador Energy | Orion Renewable Energy Group |
| AES/IPL | Hoosier Energy | Ranger Power |
| Air Quality Services | I&M | Repower IN and Solarize Evansville |
| Alcoa Corp | IBEW Local 702 | Shell Energy |
| Arevon Energy Management | Indeck Energy Services, Inc. | Sierra Club |
| AstraZeneca Pharmaceuticals | Indiana Coal Council | Solarize Indiana Inc |
| Boardwalk Pipelines | Indiana Office of Utility Consumer Counselor | Solarpack Development, Inc. |
| Bowen Engineering | Indiana DG | Southern Illinois Generation Company |
| Citizens Action Coalition of IN | Indivisible Evansville | Southwest Indiana Chamber of Commerce |
| City of Evansville | Inovateus Solar LLC | St. Joseph Phase II, LLC |
| Community Energy | Invenergy | State Utility Forecasting Group |
| CountryMark | IURC | Valley Watch |
| Earthjustice | juwi Inc. | Vectren Industrial Group |
| Economic Development Coalition of Southwest Indiana | MEEA | Vermillion Rise Mega Park |
| Energy Futures Group | Midwest Fertilizer | Vote Solar |
| Energy Ventures Analysis Inc | Morton Solar | Whole Sun Designs |
| ENGIE Solar | New Master Development LLC | |

**Presentation Summary:**

**Lynnae Wilson** (CenterPoint Energy Indiana Electric Chief Business Officer) **/ Matt Rice** (Vectren Manager of Resource Planning) Meeting Guidelines, Agenda, IRP Stakeholder Process, and the presenting of the Preferred Portfolio

**Peter Hubbard** (Manager of Energy Business Advisory, Pace Global) Risk Analysis Process and Results

**Justin Joiner** (Vectren Director of Power Supply Services) Future Considerations, MISO OMS Survey Results, and Next Steps

**Lynnae Wilson** (CenterPoint Energy Indiana Electric Chief Business Officer) Closing Comments

**Stakeholder Q&A:**

**Question:**
Wendy Bredhold: When do you plan to share the slides?
Jean Webb: I'd like to have it now to print out and mark up.
Suzanne Escudier: Will the PPT be available after the meeting?
Wendy Bredhold: Can you post slides now since we are done?
**Answer**:
The slides will be posted today at www.vectren.com\irp at 3:30 Central.

**Question:**
Wendy Bredhold: Are you building that wind in 2022?
**Answer:**
We will continue to evaluate this resource, and there could be a second RFP(timing is yet to be determined).

**Question:**
John Blair: Are you planning ownership or PPA for both wind and solar? If so, are you also prepared to use your power of eminent domain to secure the necessary sites for both? Last are you considering using useless, non-productive stripper pits as sites for your solar plants?
**Answer:**
Eminent domain would be a last resort.
**Answer to Second Question**:
We are looking at all of the above. We are looking at all of the land around us trying to determine the best plan forward.

**Question:**
Mike Mullett: Please define "universal solar" in relation to transmission-connected vs. distribution-connected solar and/or above/below 10 mw facilities.
**Answer:**
Universal solar is utility scale solar, which is the most cost-effective option for our customers. Customer owned solar connected to the distribution system was accounted for in our load forecast as a load reduction, reducing the resources needed to serve our customers. That forecast is included in a report at www.Vectren.com\irp, titled 2019 Long Term Electric Energy and Demand Forecast Report.
https://www.vectren.com/assets/downloads/planning/irp/IRP-2019-Vectren-Sales-and-Demand-Forecast-Documentation.pdf

**Question:**
Wendy Bredhold: What is the retirement date for Culley 3 in this plan?
**Answer:**
The preferred portfolio continues to run Culley 3 throughout the forecast, but that can be determined at a later date.

**Question:**
Laura Arnold: Are there any phone numbers available for someone to call who is experiencing Internet difficulties?
**Answer:**
Phone number: 1-415-655-0003, access code: 1332773493

**Question:**
Emily Medine: What is assumed about MISO dispatchability of wind and solar?
**Answer:**
For solar it was assumed capacity factor would be around 24% and 38% for wind.

**Question:**
Emily Medine: No. MISO's right to dispatch
**Answer:**
We use MISO’s current practices and provide a forecast and then MISO dispatches our units based on that forecast.

**Question:**
Mike Mullett: Please comment on the Forum Energy - Great River Energy Agreement re very long duration storage -- see, e.g. , https://www.greentechmedia.com/articles/read/form-energys-first-project-pushes-long-duration-storage-to-new-heights-150-hour-duration
**Answer:**
We will review this after the meeting. We did model 8-hour flow batteries but they were not cost effective, thus not selected.

**Question:**
Mike Mullett: Please comment on the Vectren Electric capex requirements for the Preferred Portfolio, especially regarding BAU and other portfolios evaluated.
**Answer:**
There aren’t any capital requirements for the preferred portfolio but all paths forward cost money, including BAU which would require a large investment. We don’t know what capital spend will be at this point because we haven’t determined how much solar and wind will be PPA vs. an ownership option.

**Question:**
Michael Smith: With renewables and DR increasing to 64% of portfolio, what percentage of that 64% renewables will be Vectren-owned resources or will the energy be procured through 3rd party PPAs?
**Answer:**
This is yet to be determined.

**Question:**
John Haselden: Will the gas pipeline to the CT's be sized for additional future resources?

**Answer:**
This is yet to be determined.

**Question:**
Suzanne Escudier: Can you type in the website where we can find the presentation after the meeting?
**Answer:**
www.vectren.com\irp. At this site you will also find all materials from past meetings. The deck will be posted today at 3:30 p.m.

**Question:**
Jean Webb: So, the reason for not selecting the renewables by 2030 portfolio is because of your limits on market sales/purchases? How much is now purchased from market as a reference.
**Answer:**
This portfolio had a heavy reliance on the market for both capacity and energy and we felt that the preferred portfolio performed better overall. This portfolio also relies heavily on battery storage which is an emerging technology. It also requires an additional $20-$30 million in transmission system upgrades. With renewables it is important to have dispatchable resources to back them up when not available. [In 2019, Vectren purchased approximately 9% of its need as a percentage of generation].

**Question:**
Jean Webb: Will the current wind contracts be renewed? Benton and Fowler Ridge.
**Answer:**
We will look at all resource available in the RFP. Also, these contracts don't expire for several more years (late 2020's).

**Question:**
John Blair: What are your current plans for Warrick 4?
**Answer:**
We currently plan to exit joint operation of Warrick 4 in 2023.

**Question:**
Mary Lyn Stoll: As noted in the presentation, technology and renewable energy markets are in a period of rapid growth and transition. Given how quickly these changes occur, does Vectren have a formal policy in place to continue to actively review the latest updates and changes to quickly determine whether and when a higher proportion of renewables would become the best option given Vectren's goals?
**Answer:**
This IRP is a first step in this process, and the analysis will be performed again in 2022.

**Question:**
Anna Sommer: Where do you stand with respect to negotiations with respondents to the RFP? Are you planning to acquire these planned new resources from those respondents and the question is whether those acquisitions are PPA or asset transfers? Or is there some other resource acquisition process anticipated?
**Answer:**
We've been in communication with respondents to gain more clarity on the status of the projects. We are still working to determine what projects will be PPA and which will be utility owned. A second RFP would be the other resource acquisition process at this point.

**Question:**
Crystal Young: Is there any plan for electric vehicle infrastructure buildout?
**Answer:**
We are actively investigating this enterprise wide to determine our best steps forward for both the Houston area, as well as southern Indiana. We did include an EV forecast as an addition to load so we've thought through what the need would be from a generation standpoint.

**Question:**
Mike Mullett: How is OVEC contract being modeled, and for how long in the Preferred Portfolio?
**Answer:**
OVEC was modeled as a PPA and is included as a resource in the preferred portfolio throughout the forecast.

**Question:**
Michael Smith: Assuming the 2 each, GTs (460MW) are simple cycle and not a 2 x 1 CCGT with HRSTG boiler and steam turbine for waste heat?
**Answer:**
Correct. These are 2 simple cycle gas turbines.

**Question:**
Sadie Holzmeyer: Since it is currently financially beneficial for business and homeowners to invest in their own solar panels to not only sustain their own energy needs by generating their own renewable energy independent from Vectren's energy production, but also save money into the future, could Vectren not consider something like incorporating rooftop solar to supplement their renewable energy demands?
**Answer:**
We modeled universal solar because it is the most cost-effective solution for our customers.

**Question:**
Jean Webb: I had asked about modeling expanding net-metering so that rooftop solar expanded, and therefore less capacity would need to be built. Was that done?
**Answer:**
We modeled about 84 MW's of installed capacity from rooftop solar as a reduction to our load. There was not a portfolio where we modeled leasing space on customer roofs to install solar. There is a lot of cost and legal issues with this approach. Large scale solar is more efficient; plus, we would not get capacity credit from MISO with rooftop solar.

**Question:**
Mike Mullett: When will next all-source RFP be conducted? Will there be stakeholder engagement on the terms and conditions of that RFP?
**Answer:**
The RFP in the fall would not be all-source. The next all-source would potentially be for the next IRP but we've found there are many difficulties with this process. The long time frame makes it difficult for developers to hold their projects and pricing plus many projects are picked up by other groups while the IRP analysis is being performed.

**Question:**
Niles Rosenquist: On an annual basis, how much of the power production did you show earlier is projected to be from the gas turbines?

**Answer:**
Matt Rice reviewed the generation graph on slide 19 showing a small amount of generation from combustion turbines.

**Question:**
Anna Sommer: When does Vectren anticipate coming in for regulatory approvals for these new resources? And what steps remain before that happens?
**Answer:**
We are working on evaluating the best time to make our submissions, but it will likely be done over a period of time. We will likely start with some of the renewable resources we need later this year and the gas CT's will likely be in 2021.

**Question:**
Jean Webb: What years will the gas plants open?
**Answer:**
We are projecting they will be in service in the 2024-2025 planning year.

**Question:**
Jean Webb: Where will they be built?
**Answer:**
This is yet to be determined, but the A.B. Brown site offers many benefits including close proximity to the 345 KV transmission line, existing equipment that can be utilized by the CT's, as well as existing interconnection rights.

**Question:**
Jean Webb: Update on coal ash ponds there?
**Answer:**
We have contracts in place to recycle the ash from the Brown ash pond for use in a concrete application. We would anticipate filing our application with IDEM for approval probably in 2021. The west pond at Culley is almost complete and should be complete later this year. We are currently evaluating the east pond at Culley to determine how we will close it.

**Question:**
Pam Locker: Can you remind me of the expected cost of the natural gas plant?
**Answer:**
Two CT's are around $300-$320 million. We will have a better idea after the equipment is sent out for bids.

**Question:**
Jean Webb: Does that cost include the gas lines our will that go on our bills as a rider?
**Answer:**
If a pipeline is needed then yes, it would be part of customer rates. We won't know exact cost until we determine where the CT's will be built. [Pipeline cost estimates were included in the modeling as a firm gas service.]

**Question:**
Wendy Bredhold: How do you justify to continue to run Culley 3 when it isn't a least cost option?
**Answer:**
When we looked at Culley 3 in 2016 there was a little bit of premium to run that unit but we received approval to upgrade the plant and plan to implement those upgrades for diversity of our fleet.

**Stakeholder Feedback:**

Mike Mullett: Thank you for a very informative and interactive presentation, especially given the virtual nature of the meeting. For me, at least, the internet quality was very high, both in terms of the slides and the audio. The use of the Chat for Q&A was also very helpful.

Pam Locker: Thank you for increasing the percentage of renewable resources.

# Attachment 4.1 2019 Vectren Long-Term Electric Energy and Demand Forecast Report

Knowledge to Shape Your Future

Electric | Gas | Water
information collection, analysis and application

# 2019 Long-Term Electric Energy and Demand Forecast Report

## Vectren

*Submitted to:*

Vectren, a CenterPoint Energy Company
Evansville, Indiana

*Submitted by:*


Itron, Inc.
20 Park Plaza
Suite 428
Boston, Massachusetts 02116
(617) 423-7660


October 2019

# Contents

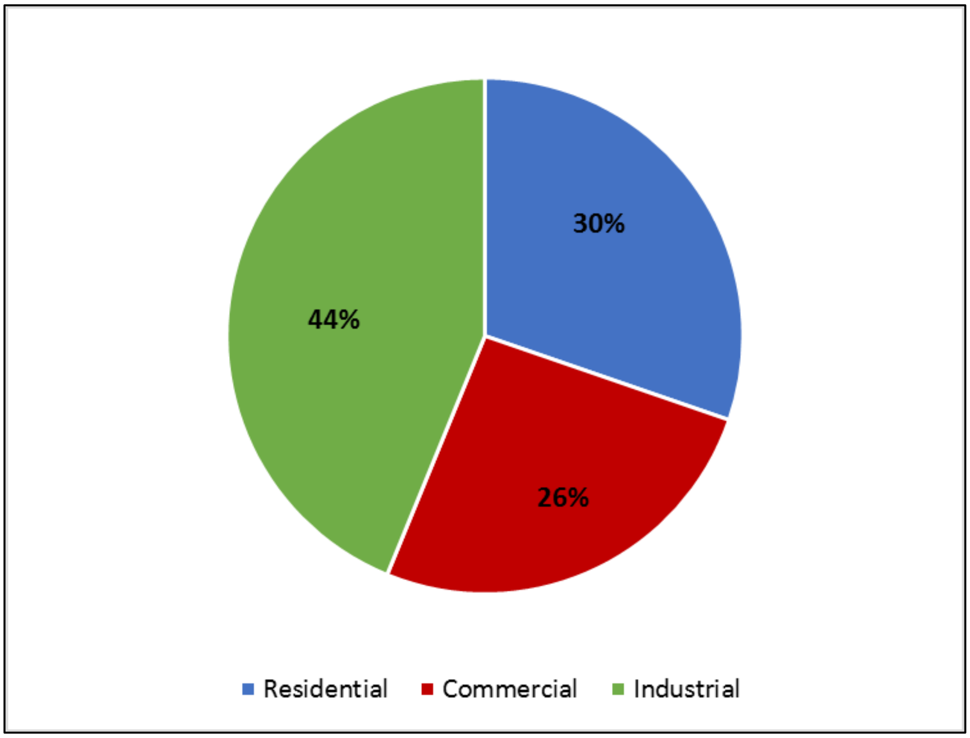
# 1 Overview

Itron, Inc. was contracted by Vectren to develop a long-term load forecast to support the 2019/20 Integrated Resource Plan. The energy and demand forecasts extend through 2039. It is based on a bottom-up approach that starts with residential, commercial, and industrial load forecasts that then drive system energy and peak demand. In addition, the forecast includes developing long-term behind-the-meter solar and electric vehicle load forecasts. This report presents the results, assumptions, and overview of the forecast methodology.

## 1.1 VECTREN Service Area

Vectren serves approximately 146,000 electric customers in Southwest Indiana; Evansville is the largest city within the service area. The service area includes a large industrial base with industrial customers accounting for approximately 44% of sales in 2018. The residential class accounts for 30% of sales with approximately 128,000 customers and the commercial class 26% of sales; there are approximately 18,000 nonresidential customers. System 2018 energy requirements are 5,308 GWh with non-weather normalized system peak reaching 1,039.2 MW. Figure 1 shows 2018 class-level sales distribution.

**Figure 1: 2018 Annual Sales Breakdown**




Despite relatively weak economic growth, since 2010, customer growth has been modest with residential customer growth averaging 0.5% and commercial customer growth 0.3%. GDP has averaged 1.2% growth until recently with 2018 GDP increasing to 3.9% and an expected 3.6% increase in 2019. GDP growth slows to expected 1.9% growth over the next twenty years with employment growth of 0.6%. Steady economic and employment growth contributes to continued moderate long-term customer growth.

Appliance efficiency standards coupled with DSM program activity has held sales growth in check. Since 2010 weather-normalized average use has declined on average 1.4% per year; this translates into 0.9% annual decline in residential sales. Commercial sales have also been falling; normalized sales have declined 0.6% per year. The industrial sector is the only sector showing positive growth with industrial sales averaging 1.8% average annual growth (excluding loss of a large customer account). When combined, total normalized sales have averaged 0.3% annual growth.

While DSM activity has had a significant impact on sales, for the IRP filing, the energy and demand forecasts do not include future DSM energy savings; DSM savings are treated as a resource in determining the most cost-effective options. Excluding future DSM, energy requirements and peak demand are expected to increase on average 0.6% over the next twenty years. Table 1-1 shows the VECTREN energy and demand forecasts. The forecast excludes future DSM savings, but includes the impact of customer-owned distributed generation (mostly behind-the-meter solar) and electric vehicles. Vectren utility scale solar and other distributed generation are not included in this report but are accounted for within the IRP and the forecast submitted to MISO.

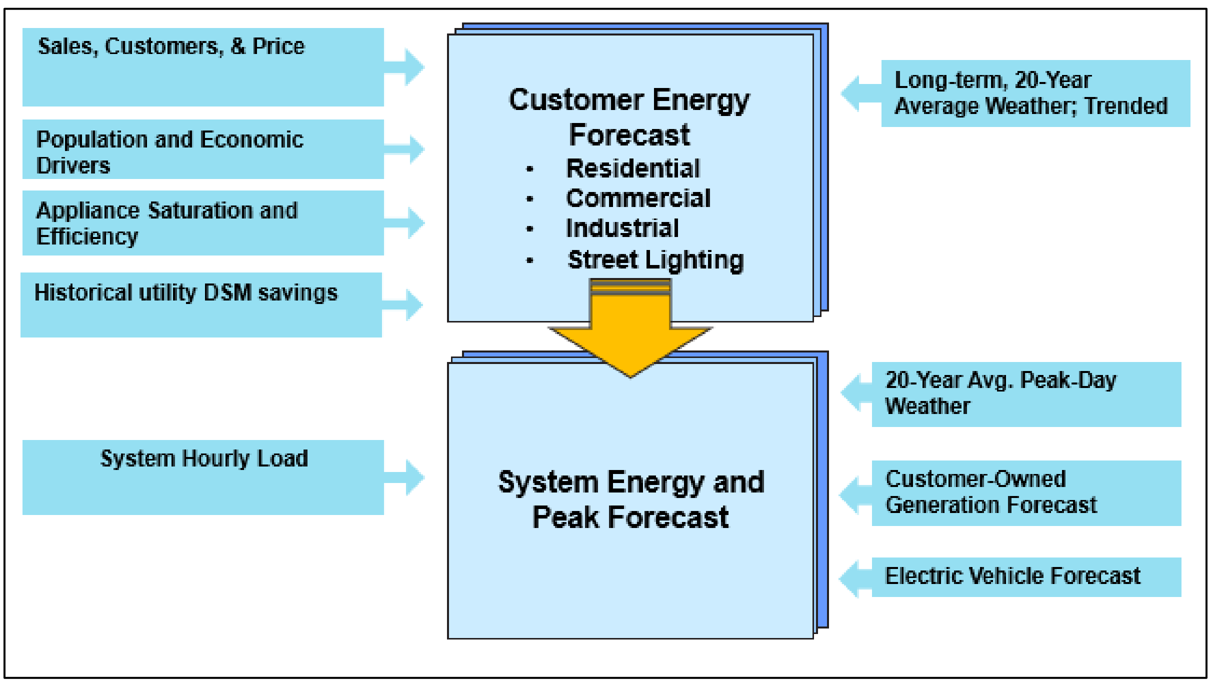
**Table 1-1: Energy and Demand Forecast (Excluding DSM Program Savings)**

| Year | Energy (MWh) | | Summer Peak (MW) | | Winter Peak (MW) | |
|---|---|---|---|---|---|---|
| 2019 | 5,169,366 | | 1,075 | | 786 | |
| 2020 | 5,395,568 | 4.4% | 1,105 | 2.7% | 834 | 6.1% |
| 2021 | 5,402,326 | 0.1% | 1,107 | 0.2% | 831 | -0.3% |
| 2022 | 5,527,069 | 2.3% | 1,131 | 2.1% | 850 | 2.2% |
| 2023 | 5,763,459 | 4.3% | 1,173 | 3.7% | 888 | 4.5% |
| 2024 | 5,795,986 | 0.6% | 1,178 | 0.5% | 891 | 0.4% |
| 2025 | 5,811,218 | 0.3% | 1,181 | 0.3% | 891 | 0.0% |
| 2026 | 5,828,820 | 0.3% | 1,184 | 0.3% | 892 | 0.1% |
| 2027 | 5,849,607 | 0.4% | 1,188 | 0.3% | 894 | 0.2% |
| 2028 | 5,880,148 | 0.5% | 1,194 | 0.5% | 897 | 0.4% |
| 2029 | 5,895,966 | 0.3% | 1,197 | 0.3% | 897 | 0.0% |
| 2030 | 5,912,671 | 0.3% | 1,201 | 0.3% | 897 | 0.0% |
| 2031 | 5,930,819 | 0.3% | 1,205 | 0.3% | 898 | 0.0% |
| 2032 | 5,955,984 | 0.4% | 1,210 | 0.4% | 899 | 0.2% |
| 2033 | 5,970,297 | 0.2% | 1,214 | 0.3% | 899 | -0.1% |
| 2034 | 5,991,229 | 0.4% | 1,219 | 0.4% | 900 | 0.1% |
| 2035 | 6,013,551 | 0.4% | 1,224 | 0.4% | 901 | 0.1% |
| 2036 | 6,040,644 | 0.5% | 1,230 | 0.5% | 903 | 0.3% |
| 2037 | 6,055,140 | 0.2% | 1,234 | 0.4% | 902 | -0.1% |
| 2038 | 6,074,726 | 0.3% | 1,239 | 0.4% | 903 | 0.1% |
| 2039 | 6,093,472 | 0.3% | 1,244 | 0.4% | 904 | 0.1% |
| CAGR 20-39 | | 0.6% | | 0.6% | | 0.4% |

# 2 Forecast Approach

The long-term energy and demand forecasts are based on a build-up approach. End-use sales derived from the customer class sales models (residential, commercial, industrial, and street lighting) drive system energy and peak demand. Energy requirements are calculated by adjusting sales forecast upwards for line losses. Peak demand is forecasted through a monthly peak-demand linear regression model that relates peak demand to peak-day weather conditions and end-use energy requirements (heating, cooling, and other use). System energy and peak are adjusted for residential and commercial PV adoption and EV charging impacts. Figure 2 shows the general framework and model inputs.

**Figure 2: Class Build-up Model**




In the long-term, both economic growth and structural changes drive energy and demand requirements. Structural changes include the impact of changing appliance owner-ship trends, end-use efficiency changes, increasing housing square footage, and thermal shell efficiency improvements. Changing structural components are captured in the residential and commercial sales forecast models through a specification that combines economic drivers with end-use energy intensity trends. This type of model is known as a Statistically Adjusted End-Use (SAE) model. The SAE model variables explicitly incorporate end-use saturation and efficiency projections, as well as changes in population, economic conditions, price, and weather. Both residential and commercial sales are forecasted using an SAE specification. Industrial sales are forecasted using a two-step approach, which includes a generalized econometric model that relates industrial sales to seasonal patterns and industrial economic activity. Streetlight sales are forecasted using a simple trend and seasonal model.

## 2.1 Residential Model

Residential average use and customers are modeled separately. The residential sales forecast is then generated as the product of the average use and customer forecasts.

**Average Use.** The residential average use model relates customer monthly average use to a customer's heating requirements (XHeat), cooling requirements (XCool), other use (XOther), and DSM activity per customer:

$$ResAvgUse_{ym} = (B_1 \times XHeat_{ym}) + (B_2 \times XCool_{ym}) + (B_3 \times XOther_{ym}) + (B_4 \times DSM_{ym}) + e_{ym}$$

Where:

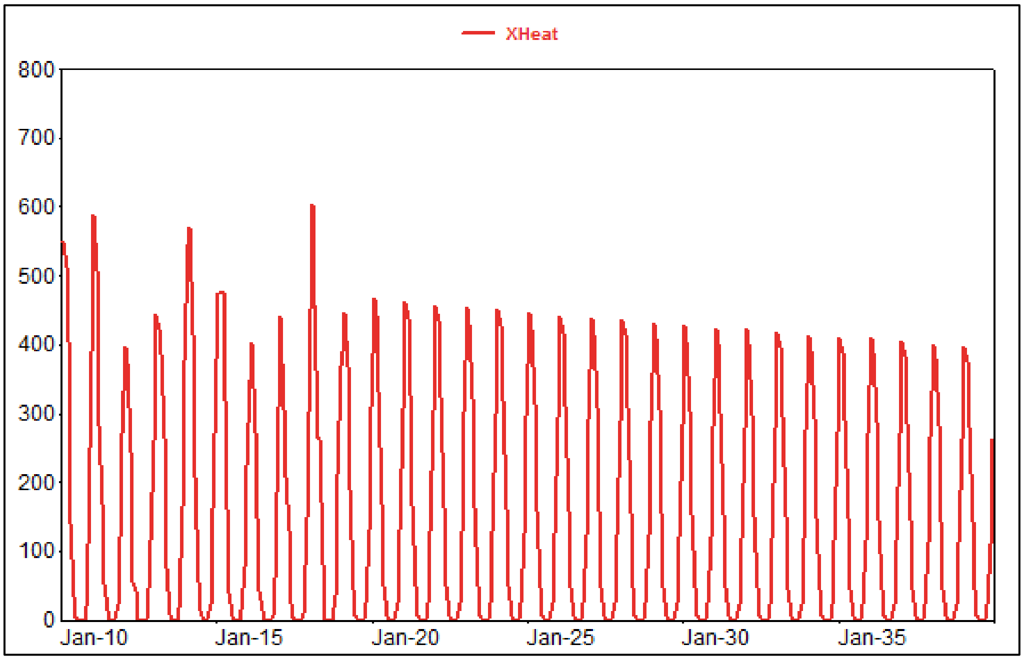
$y$ = year
$m$ = month

The model coefficients ($B_1$, $B_2$, $B_3$, and $B_4$) are estimated using a linear regression model. Monthly average use data is derived from historical monthly billed sales and customer data from January 2010 to June 2019.

The model variables incorporate end-use saturation and efficiency projections, as well as changes in household size, household income, price, weather, and DSM activity. The model result is an estimate of monthly heating, cooling, and other use energy requirements on a kWh per household basis, which includes the impact of DSM. Incremental future DSM is then added back to the model results to arrive at an average use forecast that does not include the impact of future DSM.

Figure 3 to Figure 5 show the constructed monthly heating, cooling, and other end-use variables. The specific calculations of the end-use variables are presented in Appendix B.

### Figure 3: Residential XHeat




### Figure 4: Residential XCool

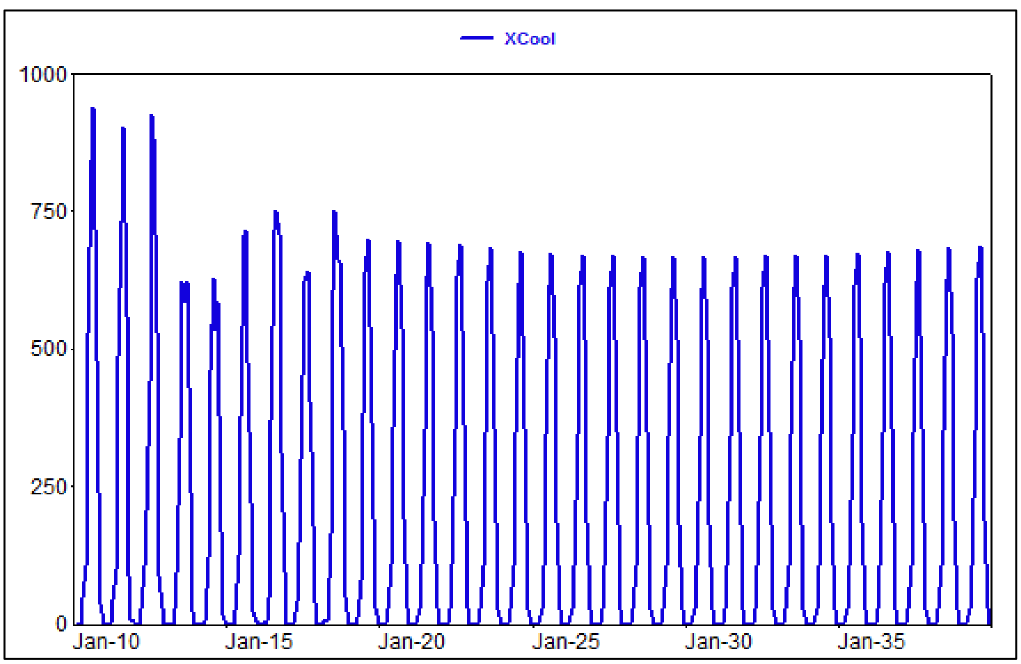
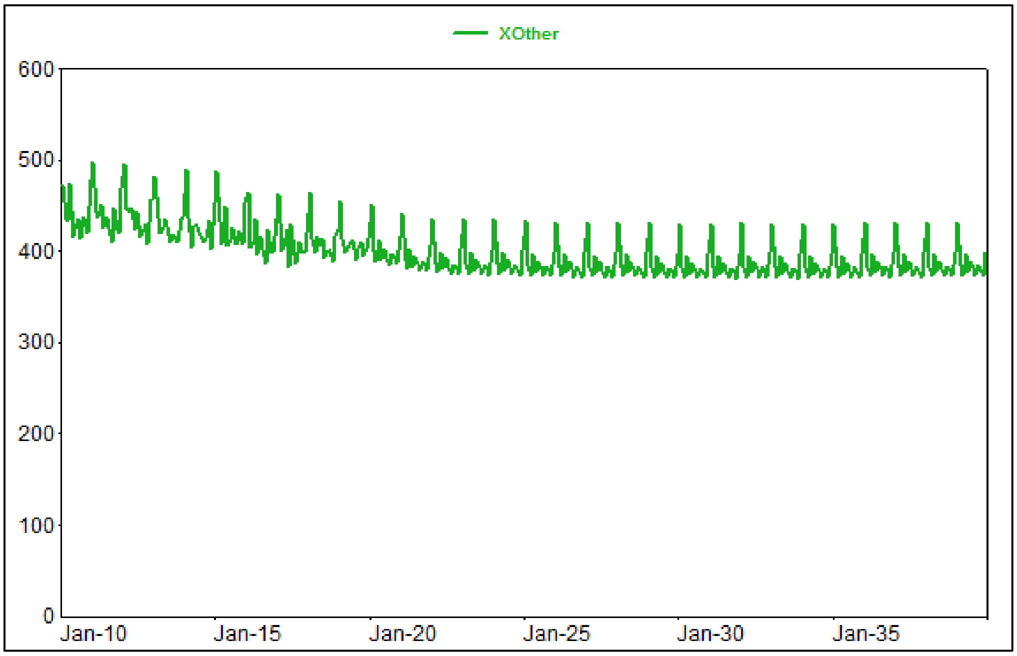


**Figure 5: Residential XOther**




The average use model is estimated over the period January 2010 through June 2019. The model explains historical average use well with an Adjusted $R^2$ of 0.98 and in-sample Mean Absolute Percent Error (MAPE) of 1.9%. Model coefficients are statistically significant at the 95% level of confidence and higher. Model coefficients and statistics are provided in Appendix A.

***Customer Forecast***

The customer forecast is based on a monthly regression model that relates the number of customers to Evansville MSA (Metropolitan Statistical Area) household projections. The model results in 0.4% long-term customer growth.

***Sales Forecast***

Excluding future DSM savings, average use through the forecast period is flat. With flat average use and 0.4% customer growth, residential sales averages 0.4% growth between 2020 and 2039. Table 2-1 summarizes the residential forecast.

**Table 2-1: Residential Forecast (Excluding Future DSM)**

| Year | Sales (MWh) | | Customers | | AvgUse (kWh) | |
|---|---|---|---|---|---|---|
| 2019 | 1,397,951 | | 128,325 | | 10,894 | |
| 2020 | 1,394,147 | -0.3% | 129,037 | 0.6% | 10,804 | -0.8% |
| 2021 | 1,385,056 | -0.7% | 129,808 | 0.6% | 10,670 | -1.2% |
| 2022 | 1,389,250 | 0.3% | 130,762 | 0.7% | 10,624 | -0.4% |
| 2023 | 1,393,879 | 0.3% | 131,653 | 0.7% | 10,588 | -0.3% |
| 2024 | 1,403,897 | 0.7% | 132,458 | 0.6% | 10,599 | 0.1% |
| 2025 | 1,406,700 | 0.2% | 133,214 | 0.6% | 10,560 | -0.4% |
| 2026 | 1,412,868 | 0.4% | 133,887 | 0.5% | 10,553 | -0.1% |
| 2027 | 1,419,111 | 0.4% | 134,474 | 0.4% | 10,553 | 0.0% |
| 2028 | 1,429,310 | 0.7% | 135,002 | 0.4% | 10,587 | 0.3% |
| 2029 | 1,432,393 | 0.2% | 135,503 | 0.4% | 10,571 | -0.2% |
| 2030 | 1,439,085 | 0.5% | 136,007 | 0.4% | 10,581 | 0.1% |
| 2031 | 1,446,125 | 0.5% | 136,473 | 0.3% | 10,596 | 0.1% |
| 2032 | 1,456,783 | 0.7% | 136,902 | 0.3% | 10,641 | 0.4% |
| 2033 | 1,460,392 | 0.2% | 137,288 | 0.3% | 10,637 | 0.0% |
| 2034 | 1,467,666 | 0.5% | 137,619 | 0.2% | 10,665 | 0.3% |
| 2035 | 1,475,665 | 0.5% | 137,942 | 0.2% | 10,698 | 0.3% |
| 2036 | 1,487,624 | 0.8% | 138,236 | 0.2% | 10,761 | 0.6% |
| 2037 | 1,492,228 | 0.3% | 138,459 | 0.2% | 10,777 | 0.1% |
| 2038 | 1,499,727 | 0.5% | 138,624 | 0.1% | 10,819 | 0.4% |
| 2039 | 1,506,655 | 0.5% | 138,751 | 0.1% | 10,859 | 0.4% |
| CAGR 20-39 | | 0.4% | | 0.4% | | 0.0% |

## 2.2 Commercial Model

The commercial sales model is also estimated using an SAE specification. The difference is that in the commercial sector, the sales forecast is based on a total sales model, rather than an average use and customer model. Commercial sales are expressed as a function of heating requirements, cooling requirements, other commercial use, and DSM activity:

$$ComSales_{ym} = (B_1 \times XHeat_{ym}) + (B_2 \times XCool_{ym}) + (B_3 \times XOther_{ym}) + (B_4 \times DSM_{ym}) + e_{ym}$$

Where:

$y$ = year
$m$ = month

The constructed model variables include Heating Degree Days (HDD), Cooling Degree Days (CDD), billing days, commercial economic activity variable, price, end-use intensity trends, and DSM activity. Figure 6 to Figure 8 show the constructed model variables. The specific variable construction is provided in Appendix B.

**Figure 6: Commercial XHeat**

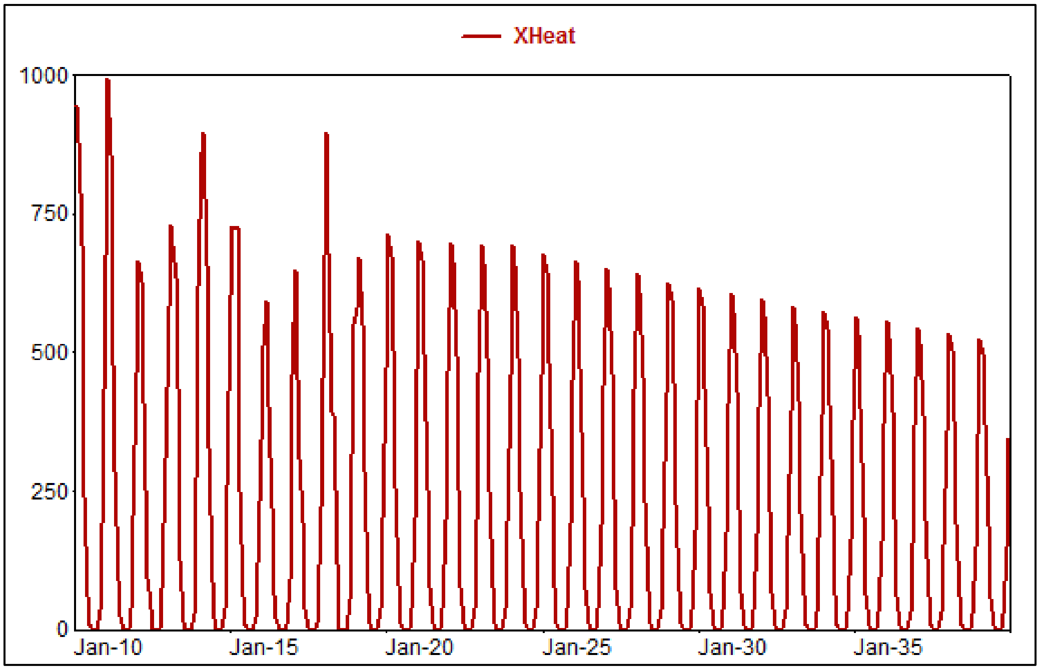


**Figure 7: Commercial XCool**

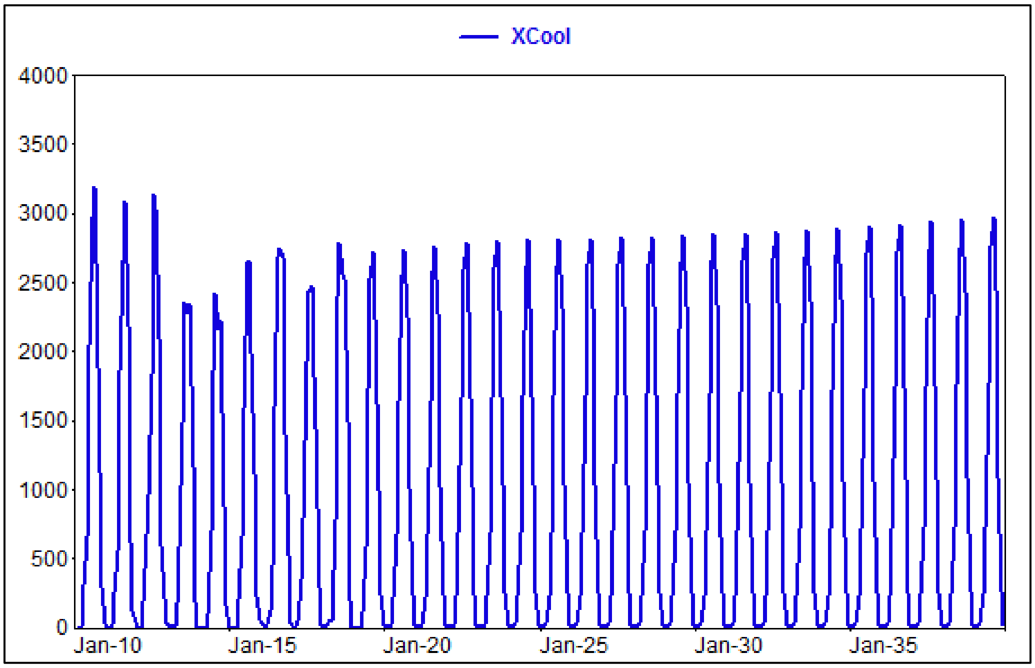
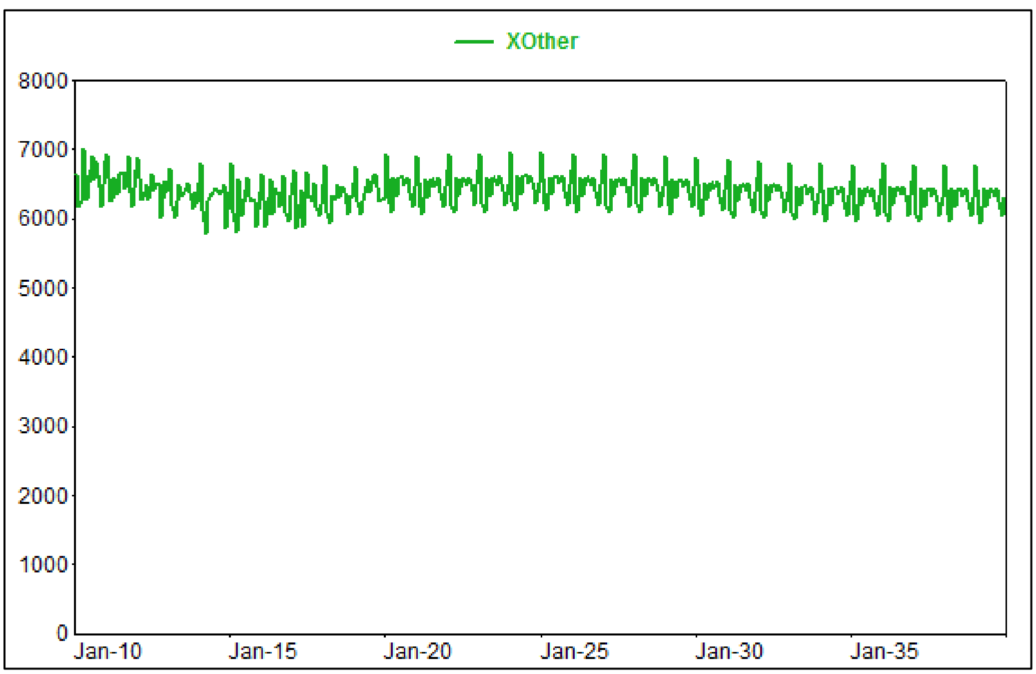



**Figure 8: Commercial XOther**




The estimated model coefficients ($B_1$, $B_2$, $B_3$, and $B_4$) calibrate the model to actual commercial sales data. The commercial sales model performs well with an Adjusted $R^2$ of 0.96 and an in-sample MAPE of 1.8%. The model is estimated with monthly billed sales data from January 2010 to June 2019. The model results include the impact of DSM. Incremental future DSM is then added back to the model results to arrive at a sales forecast that does not include the impact of future DSM.

Commercial sales average 0.2% annual growth through 2039, excluding the impact of future DSM savings. Commercial sales are driven by moderate residential customer and economic growth. Economic activity is captured by combining non-manufacturing output, non-manufacturing employment, and population through a weighted commercial economic variable called *ComVar*. *ComVar* is defined as:

$$ComVar_{ym} = \left(GDP_{ym}^{0.25}\right) \times \left(Employment_{ym}^{0.25}\right) \times \left(Population_{ym}^{0.5}\right)$$

Where:

$y$ = year
$m$ = month

The weights are determined by testing alternative sets of weights that generate the best in-sample and out-of-sample model statistics.

A separate model is estimated for commercial customers; customer projections are based on a monthly regression model that relates the number of customers to non-manufacturing employment in the Evansville MSA. The forecast excludes future DSM savings. Table 2-2 summarizes the commercial forecast.

**Table 2-2: Commercial Forecast**

| Year | Sales (MWh) | | Customers | |
|---|---|---|---|---|
| 2019 | 1,268,993 | | 18,731 | |
| 2020 | 1,281,221 | 1.0% | 18,817 | 0.5% |
| 2021 | 1,285,272 | 0.3% | 18,870 | 0.3% |
| 2022 | 1,292,595 | 0.6% | 18,935 | 0.3% |
| 2023 | 1,297,044 | 0.3% | 18,999 | 0.3% |
| 2024 | 1,303,746 | 0.5% | 19,060 | 0.3% |
| 2025 | 1,304,199 | 0.0% | 19,122 | 0.3% |
| 2026 | 1,305,034 | 0.1% | 19,184 | 0.3% |
| 2027 | 1,306,083 | 0.1% | 19,247 | 0.3% |
| 2028 | 1,310,084 | 0.3% | 19,309 | 0.3% |
| 2029 | 1,309,689 | 0.0% | 19,371 | 0.3% |
| 2030 | 1,308,851 | -0.1% | 19,434 | 0.3% |
| 2031 | 1,308,792 | 0.0% | 19,496 | 0.3% |
| 2032 | 1,311,763 | 0.2% | 19,560 | 0.3% |
| 2033 | 1,310,653 | -0.1% | 19,624 | 0.3% |
| 2034 | 1,312,270 | 0.1% | 19,689 | 0.3% |
| 2035 | 1,314,615 | 0.2% | 19,754 | 0.3% |
| 2036 | 1,319,551 | 0.4% | 19,820 | 0.3% |
| 2037 | 1,320,643 | 0.1% | 19,887 | 0.3% |
| 2038 | 1,324,172 | 0.3% | 19,954 | 0.3% |
| 2039 | 1,327,364 | 0.2% | 20,021 | 0.3% |
| CAGR 20-39 | | 0.2% | | 0.3% |

## 2.3 Industrial Model

The industrial sales forecast is developed with a two-step approach. The first five years of the forecast is derived from Vectren's expectation of specific customer activity. The forecast after the first five years is based on the industrial forecast model. Vectren determines a baseline volume based on historical consumption use. The baseline use is then adjusted to reflect expected closures and expansions. Near-term sales are also adjusted for the addition of new industrial customers. After five years, the forecast is derived from the industrial sales model; forecasted growth is applied to the fifth-year industrial sales forecast.

The industrial sales model is a generalized linear regression model that relates monthly historical industrial billed to manufacturing employment, manufacturing output, CDD, and monthly binaries to capture seasonal load variation and shifts in sales data. The industrial economic driver is a weighted combination of manufacturing employment and manufacturing output. The industrial economic (*IndVar*) variable is defined as:

$$IndVar_{ym} = \left(ManufEmploy_{ym}^{0.5}\right) \times \left(ManufOutput_{ym}^{0.5}\right)$$

Where:

$y$ = year
$m$ = month

The imposed weights are determined by evaluating in-sample and out-of-sample statistics for alternative weighting schemes. The model Adjusted $R^2$ is 0.74 with a MAPE of 5.2%. The relatively low Adjusted $R^2$ and high MAPE are a result of the large month-to-month variations in industrial billing data. The industrial model excludes sales to one of VECTREN's largest customers, which is currently meeting most of its load through onsite cogeneration.

Excluding DSM, industrial sales average 1.0% annual growth with strong near-term growth. After 2023, industrial sales average 0.4% annual growth. Table 2-3 summarizes the industrial sales forecast.

**Table 2-3: Industrial Forecast (Excluding Future DSM)**

| Year | Total Industrial | |
|---|---|---|
| 2019 | 2,159,155 | |
| 2020 | 2,347,543 | 8.7% |
| 2021 | 2,360,025 | 0.5% |
| 2022 | 2,463,638 | 4.4% |
| 2023 | 2,669,566 | 8.4% |
| 2024 | 2,682,185 | 0.5% |
| 2025 | 2,693,010 | 0.4% |
| 2026 | 2,702,706 | 0.4% |
| 2027 | 2,715,218 | 0.5% |
| 2028 | 2,730,260 | 0.6% |
| 2029 | 2,742,862 | 0.5% |
| 2030 | 2,753,258 | 0.4% |
| 2031 | 2,763,983 | 0.4% |
| 2032 | 2,774,906 | 0.4% |
| 2033 | 2,786,352 | 0.4% |
| 2034 | 2,797,969 | 0.4% |
| 2035 | 2,809,553 | 0.4% |
| 2036 | 2,819,333 | 0.3% |
| 2037 | 2,828,251 | 0.3% |
| 2038 | 2,837,072 | 0.3% |
| 2039 | 2,846,045 | 0.3% |
| CAGR 20-39 | | 1.0% |

## 2.4 Street Lighting Model

Streetlight sales are fitted with a simple exponential smoothing model with a trend and seasonal component. Street lighting sales are increasing at 0.2% annually throughout the forecast horizon. Table 2-4 shows the streetlight forecast.

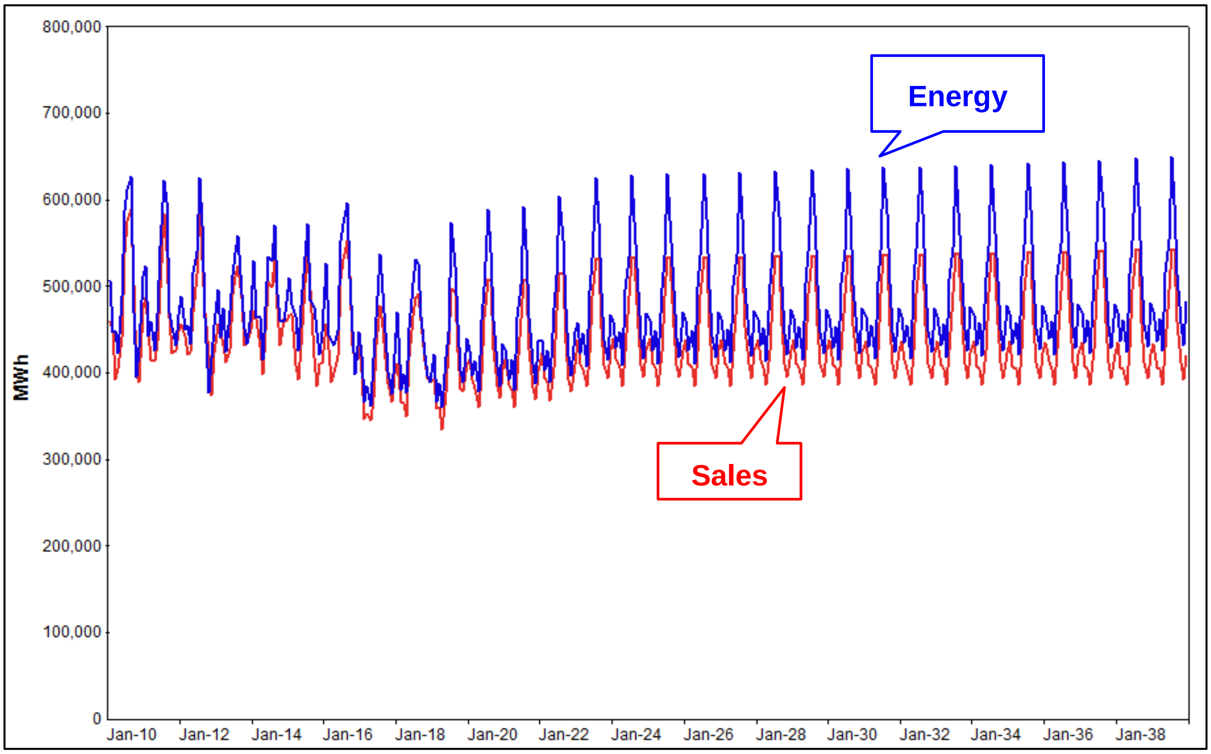
**Table 2-4: Street Lighting Forecast**

| Year | Sales (MWh) | |
|---|---|---|
| 2019 | 21,526 | |
| 2020 | 21,645 | 0.6% |
| 2021 | 21,680 | 0.2% |
| 2022 | 21,715 | 0.2% |
| 2023 | 21,749 | 0.2% |
| 2024 | 21,784 | 0.2% |
| 2025 | 21,819 | 0.2% |
| 2026 | 21,854 | 0.2% |
| 2027 | 21,889 | 0.2% |
| 2028 | 21,924 | 0.2% |
| 2029 | 21,959 | 0.2% |
| 2030 | 21,994 | 0.2% |
| 2031 | 22,029 | 0.2% |
| 2032 | 22,064 | 0.2% |
| 2033 | 22,098 | 0.2% |
| 2034 | 22,133 | 0.2% |
| 2035 | 22,168 | 0.2% |
| 2036 | 22,203 | 0.2% |
| 2037 | 22,238 | 0.2% |
| 2038 | 22,273 | 0.2% |
| 2039 | 22,308 | 0.2% |
| CAGR 20-39 | | 0.2% |

## 2.5 Energy Forecast Model

The energy forecast is derived directly from the sales forecast by applying a monthly energy adjustment factor to the sales forecast. The energy adjustment factor includes line losses and any differences in timing between monthly sales estimates and delivered energy (*unaccounted for energy*). Monthly adjustment factors are calculated based on the historical relationship between energy and sales. The energy forecast is adjusted for rooftop solar generation and electric vehicles. Figure 9 shows the monthly sales and energy forecast, excluding the impact of future DSM.

**Figure 9: Energy and Sales Forecast (Excluding DSM)**




## 2.6 Peak Forecast Model

The long-term system peak forecast is derived through a monthly peak regression model that relates peak demand to heating, cooling, and base load requirements:

$$Peak_{ym} = B_0 + B_1 HeatVar_{ym} + B_2 CoolVar_{ym} + B_3 BaseVar_{ym} + e_{ym}$$

Where:

$y$ = year
$m$ = month

End-use energy requirements are estimated from class sales forecast models.

***Heating and Cooling Model Variables***

The residential and commercial SAE model coefficients are used to isolate historical and projected weather-normal heating and cooling requirements. Heating requirements are interacted with peak-day HDD and cooling requirements with peak-day CDD; this interaction allows peak-day weather impacts to change over time with changes in heating and cooling requirements. The peak model heating and cooling variables are calculated as:

- $HeatVar_{ym} = HeatLoadIdx_{ym} \times PkHDD_{ym}$
- $CoolVar_{ym} = CoolLoadIdx_{ym} \times PkCDD_{ym}$

 Where $HeatLoadIdx_{ym}$ is an index of total system heating requirements in year $y$ and month $m$ and $CoolLoadIdx_{ym}$ is an index of total system cooling requirements in year $y$ and month $m$. $PkHDD_{ym}$ is the peak-day HDD in year $y$ and month $m$ and $PkCDD_{ym}$ is the peak-day CDD in year y and month $m$.

Figure 10 and Figure 11 show *HeatVar* and *CoolVar*. The variation in the historical period is a result of variation in peak-day HDD and CDD.

**Figure 10: Peak-Day Heating Variable**

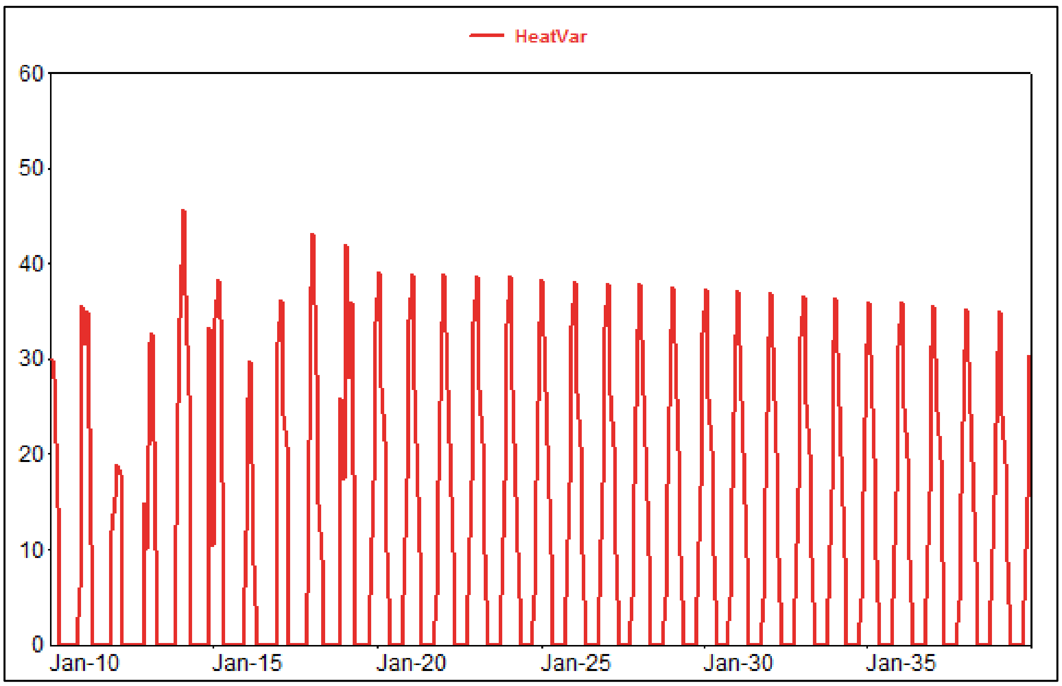
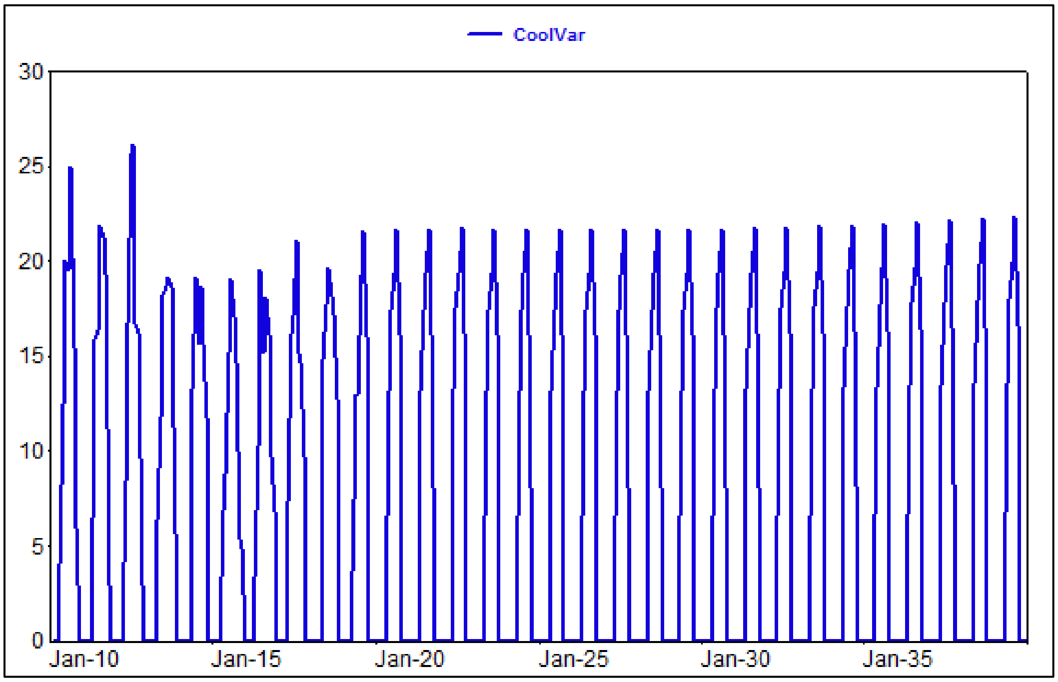


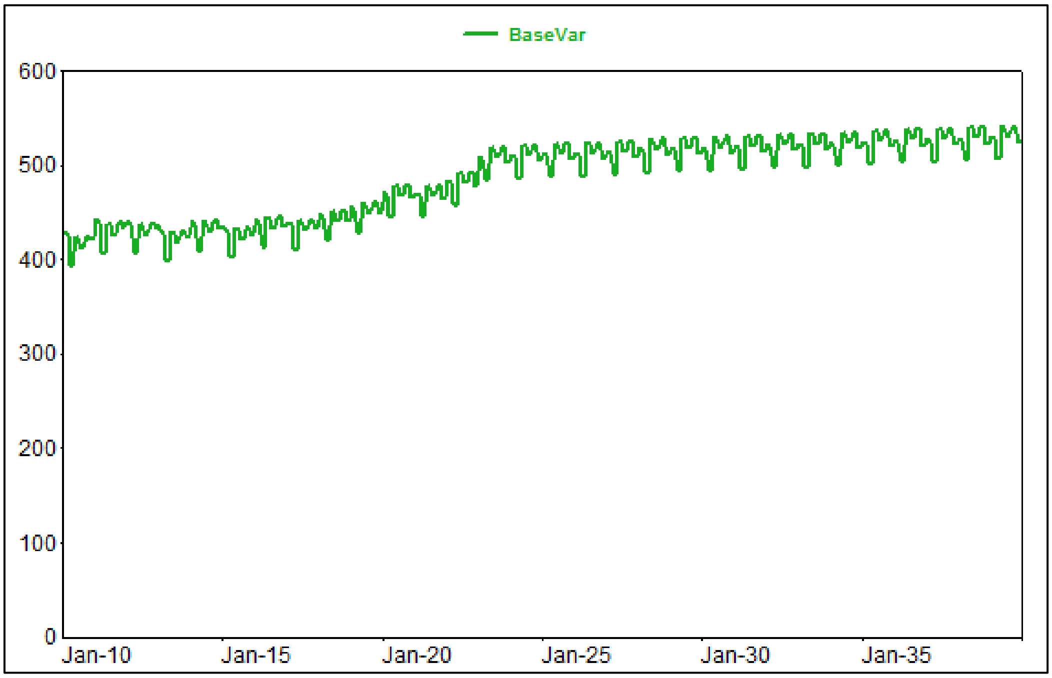
**Figure 11: Peak-Day Cooling Variable**




***Base Load Variable***

The base-load variable (*BaseVar*$_{ym}$) captures non-weather sensitive load at the time of the monthly peak. Monthly base-load estimates are calculated by allocating non-weather sensitive energy requirements to end-use estimates at the time of peak. End-use allocation factors are based on a set of end-use profiles developed by Itron. Figure 12 shows the non-weather sensitive peak-model variable.

**Figure 12: Peak-Day Base-Use Variable**




***Model Results***

The peak model is estimated over the period January 2010 to June 2019. The model explains monthly peak variation well with an adjusted $R^2$ of 0.95 and an in-sample MAPE of 2.81%. The end-use variables – *HeatVar*, *CoolVar*, and *BaseVar* are all highly statistically significant. Model statistics and parameters are included in Appendix A.

The peak demand forecast is adjusted for solar load and electric vehicle impacts, but excludes the impact of future DSM savings. Table 2-5 shows total energy and peak demand.

### Table 2-5: Energy and Peak Forecast[1]

| Year | Energy (MWh) | | Summer Peak (MW) | | Winter Peak (MW) | |
|---|---|---|---|---|---|---|
| 2019 | 5,169,366 | | 1,075 | | 786 | |
| 2020 | 5,395,568 | 4.4% | 1,105 | 2.7% | 834 | 6.1% |
| 2021 | 5,402,326 | 0.1% | 1,107 | 0.2% | 831 | -0.3% |
| 2022 | 5,527,069 | 2.3% | 1,131 | 2.1% | 850 | 2.2% |
| 2023 | 5,763,459 | 4.3% | 1,173 | 3.7% | 888 | 4.5% |
| 2024 | 5,795,986 | 0.6% | 1,178 | 0.5% | 891 | 0.4% |
| 2025 | 5,811,218 | 0.3% | 1,181 | 0.3% | 891 | 0.0% |
| 2026 | 5,828,820 | 0.3% | 1,184 | 0.3% | 892 | 0.1% |
| 2027 | 5,849,607 | 0.4% | 1,188 | 0.3% | 894 | 0.2% |
| 2028 | 5,880,148 | 0.5% | 1,194 | 0.5% | 897 | 0.4% |
| 2029 | 5,895,966 | 0.3% | 1,197 | 0.3% | 897 | 0.0% |
| 2030 | 5,912,671 | 0.3% | 1,201 | 0.3% | 897 | 0.0% |
| 2031 | 5,930,819 | 0.3% | 1,205 | 0.3% | 898 | 0.0% |
| 2032 | 5,955,984 | 0.4% | 1,210 | 0.4% | 899 | 0.2% |
| 2033 | 5,970,297 | 0.2% | 1,214 | 0.3% | 899 | -0.1% |
| 2034 | 5,991,229 | 0.4% | 1,219 | 0.4% | 900 | 0.1% |
| 2035 | 6,013,551 | 0.4% | 1,224 | 0.4% | 901 | 0.1% |
| 2036 | 6,040,644 | 0.5% | 1,230 | 0.5% | 903 | 0.3% |
| 2037 | 6,055,140 | 0.2% | 1,234 | 0.4% | 902 | -0.1% |
| 2038 | 6,074,726 | 0.3% | 1,239 | 0.4% | 903 | 0.1% |
| 2039 | 6,093,472 | 0.3% | 1,244 | 0.4% | 904 | 0.1% |
| CAGR 20-39 | | 0.6% | | 0.6% | | 0.4% |

[1] Does not include Vectren owned distributed generation or projected DSM

# 3 Customer Owned Distributed Generation

The energy and peak forecasts incorporate the impact of customer-owned photovoltaic systems. System adoption is expected to increase as solar system costs decline, which is partially offset by changes in net metering laws that will credit excess generation at a rate lower than retail rates in the future. As of June 2019, VECTREN had 421 residential solar customers and 65 commercial solar customers, with an approximate installed capacity of 8.9 MW.

## 3.1 Monthly Adoption Model

The primary factor driving system adoption is a customer's return-on-investment. A simple payback model is used as proxy. Simple payback reflects the length of time needed to recover the cost of installing a solar system - the shorter the payback, the higher the system adoption rate. From the customer's perspective, this is the number of years until electricity is "free." Simple payback also works well to explain leased system adoption as return on investment drives the leasing company's decision to offer leasing programs. Solar investment payback is calculated as a function of system costs, federal and state tax credits and incentive payments, retail electric rates, and treatment of excess generation (solar generation returned to the grid). Currently, excess generation is credited at the customer's retail rate. In the next few years excess solar generation will be credited at the wholesale cost plus 25%.

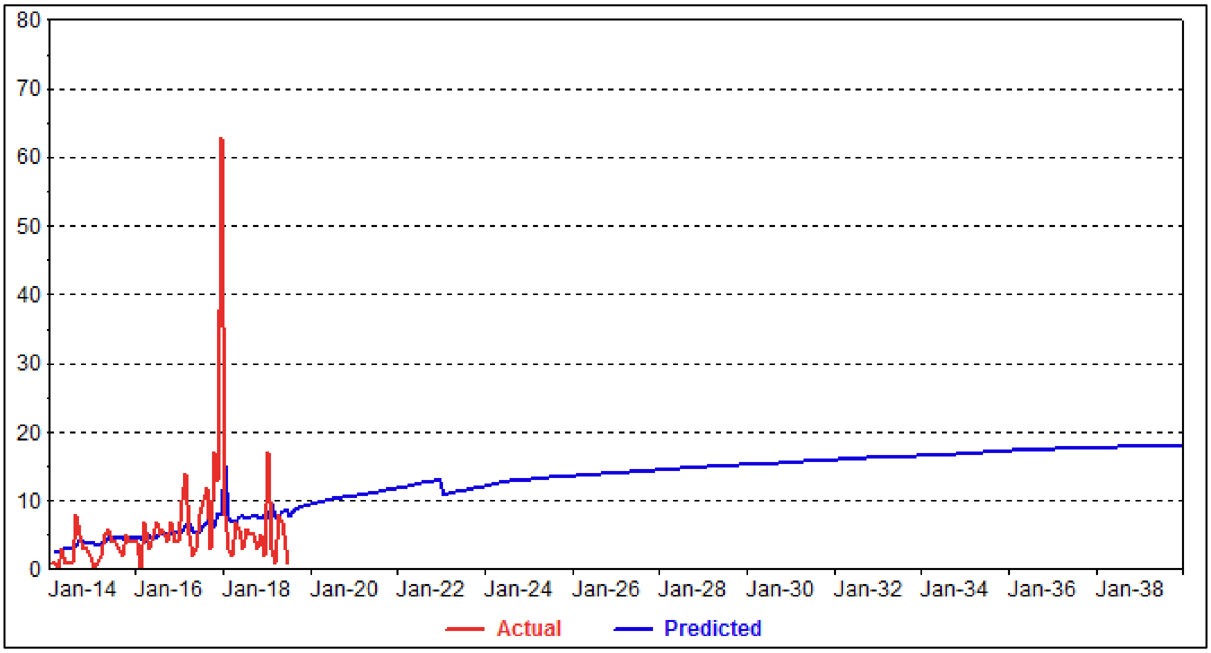
One of the most significant factors driving adoption is declining system costs; costs have been declining rapidly over the last five years. In 2010, residential solar system cost was approximately $7.00 per watt. By 2017 costs had dropped to $3.70 per watt. For the forecast period, we assume system costs continue to decline 10% annually through 2024 and an additional 3% annually after 2024. Cost projections are consistent with the U.S. Dept. of Energy's Sun Shot Solar goals and the Energy Information Administration's (EIA), most recent cost projections.[2]

The solar adoption model relates monthly residential solar adoptions to simple payback. Figure 13 shows the resulting residential solar adoption forecast.

---

[2] "Tracking the Sun". Lawrence Berkeley National Laboratory. September 2018.

**Figure 13: Residential Solar Share Forecast**




In the commercial sector, there have been too few adoptions to estimate a robust model; commercial system adoption has been low across the country. Limited commercial adoption reflects higher investment hurdle rates, building ownership issues (i.e., the entity that owns the building often does not pay the electric bill), and physical constraints as to the placement of the system. For this forecast, we assume there continues to be some commercial rooftop adoption by allowing commercial adoption to increase over time, based on the current relationship between commercial and residential adoptions rates.

Declining solar costs continue to drive solar adoption through 2022. Adoptions drop after 2023 with the change in the net metering law, but then continue to increase with declining system costs. Table 3-1 shows projected solar adoption.

**Table 3-1: Solar Customer Forecast**

| Year | Residential Systems | Commercial Systems | Total Systems |
|---|---|---|---|
| 2019 | 431 | 67 | 498 |
| 2020 | 541 | 84 | 624 |
| 2021 | 671 | 104 | 775 |
| 2022 | 814 | 126 | 939 |
| 2023 | 957 | 148 | 1,105 |
| 2024 | 1,104 | 170 | 1,274 |
| 2025 | 1,260 | 194 | 1,454 |
| 2026 | 1,424 | 220 | 1,644 |
| 2027 | 1,592 | 246 | 1,838 |
| 2028 | 1,766 | 273 | 2,038 |
| 2029 | 1,946 | 300 | 2,246 |
| 2030 | 2,126 | 328 | 2,454 |
| 2031 | 2,313 | 357 | 2,670 |
| 2032 | 2,505 | 387 | 2,892 |
| 2033 | 2,697 | 416 | 3,113 |
| 2034 | 2,897 | 447 | 3,344 |
| 2035 | 3,101 | 479 | 3,579 |
| 2036 | 3,305 | 510 | 3,815 |
| 2037 | 3,515 | 543 | 4,058 |
| 2038 | 3,731 | 576 | 4,307 |
| 2039 | 3,947 | 609 | 4,556 |
| CAGR 20-39 | 11.0% | 11.0% | 11.0% |

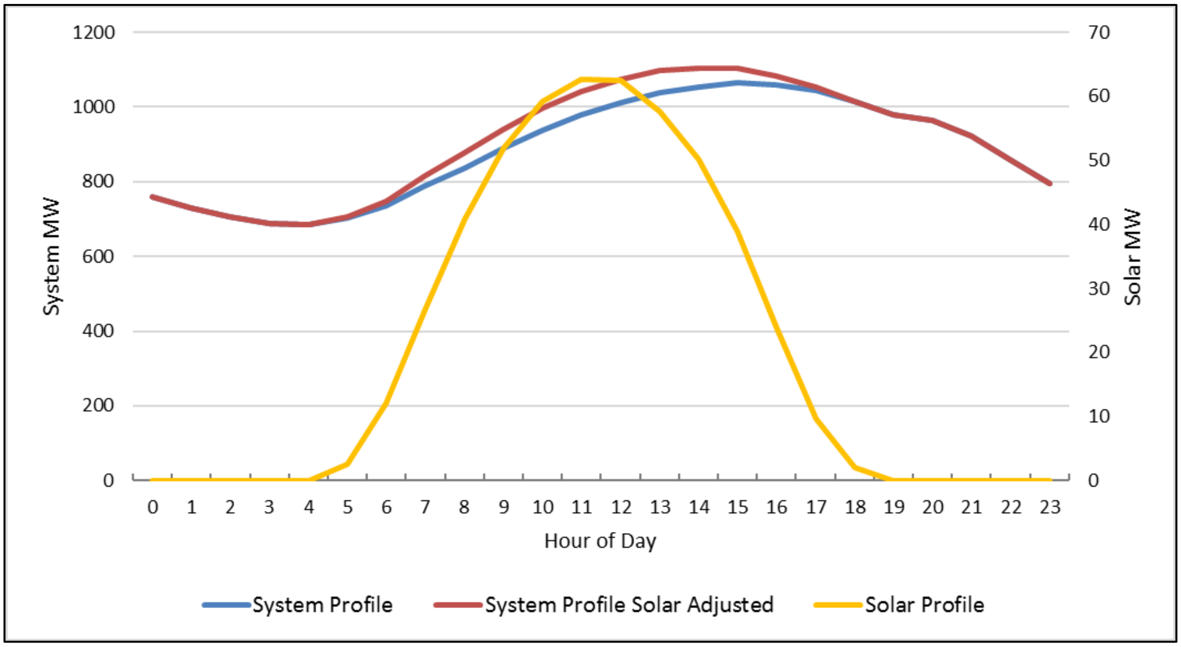
## 3.2 Solar Capacity and Generation

Installed solar capacity forecast is the product of the solar customer forecast and average system size (measured in kW). Based on recent solar installation data, the residential average size is 10.47 KW, and commercial average system size is 69.5 KW.

The capacity forecast (MW) is translated into system generation (MWh) forecast by applying monthly solar load factors to the capacity forecast. Monthly load factors are derived from a typical PV load profile for Evansville, IN. The PV shape is from the National Renewable Energy Laboratory (NREL) and represents a typical meteorological year (TMY).

The impact of solar generation on system peak demand is a function of the timing between solar load generation and system hourly demand. Solar output peaks during the mid-day while system peaks later in the afternoon. Figure 14 shows the system profile, solar adjusted system profile, and solar profile for a peak producing summer day.

**Figure 14: Solar Hourly Load Impact**




Based on system and solar load profiles, 1.0 MW of solar capacity reduces summer peak demand by approximately 0.29 MW. This adjustment factor is applied to the solar capacity forecast to yield the summer peak demand impact. Solar capacity has no impact on the winter peak demand as the winter peak is late in the evening when there is no solar generation.

Table 3-2 shows the PV capacity forecast, expected annual generation, and demand at time of peak.

### Table 3-2: Solar Capacity and Generation

| Year | Total Generation MWh | Installed Capacity MW (Aug) | Demand Impact MW |
|---|---|---|---|
| 2019 | 12,084 | 9.3 | 2.7 |
| 2020 | 15,241 | 11.8 | 3.5 |
| 2021 | 18,877 | 14.6 | 4.3 |
| 2022 | 22,895 | 17.6 | 5.2 |
| 2023 | 26,943 | 20.7 | 6.1 |
| 2024 | 31,139 | 23.8 | 7.0 |
| 2025 | 35,469 | 27.1 | 8.0 |
| 2026 | 40,099 | 30.6 | 9.0 |
| 2027 | 44,835 | 34.2 | 10.1 |
| 2028 | 49,831 | 37.9 | 11.2 |
| 2029 | 54,796 | 41.7 | 12.3 |
| 2030 | 59,872 | 45.6 | 13.4 |
| 2031 | 65,153 | 49.6 | 14.6 |
| 2032 | 70,721 | 53.6 | 15.8 |
| 2033 | 75,979 | 57.7 | 17.0 |
| 2034 | 81,598 | 62.0 | 18.3 |
| 2035 | 87,349 | 66.3 | 19.5 |
| 2036 | 93,306 | 70.6 | 20.8 |
| 2037 | 99,030 | 75.1 | 22.1 |
| 2038 | 105,119 | 79.7 | 23.5 |
| 2039 | 111,208 | 84.3 | 24.8 |
| CAGR 20-39 | 11.0% | 10.9% | 10.9% |

# 4 Electric Vehicle Forecast

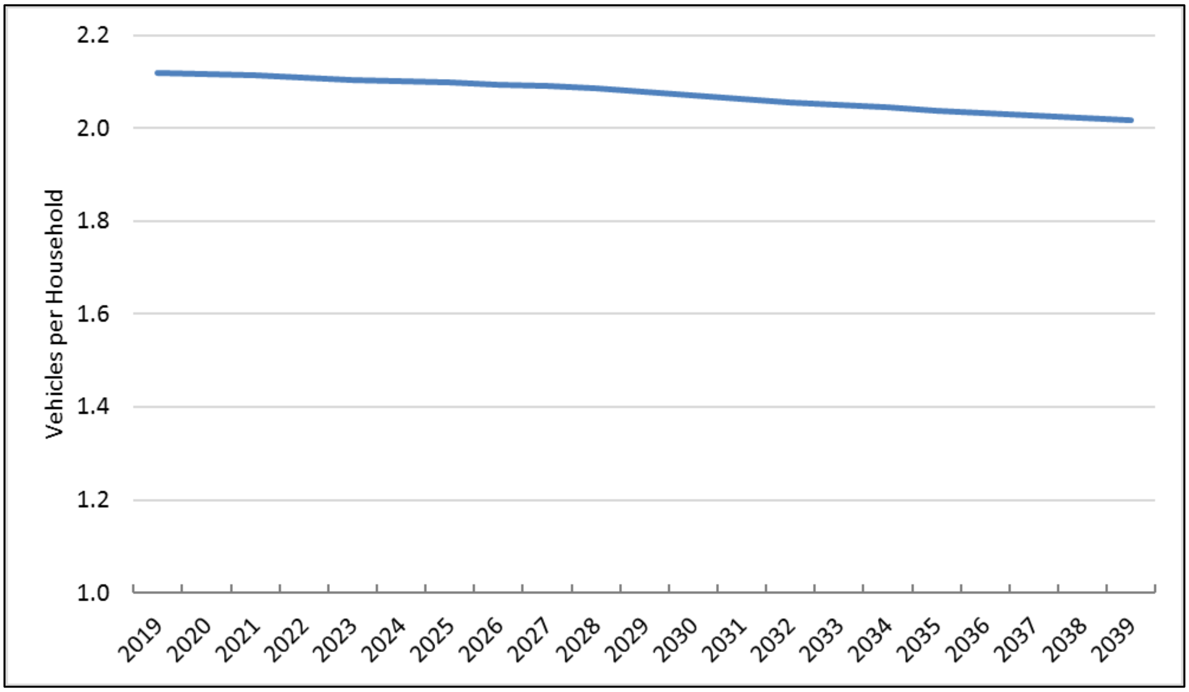
The 2019 Long-Term forecast also includes the impact of electric vehicle adoption. Currently Vectren has relatively few electric vehicles, but this is expected to increase significantly over the next twenty years with improvements in EV technology and declines in battery and vehicle costs. At the time of the forecast Vectren had 238 registered electric vehicles in the counties that Vectren serves: this included full electric (i.e., battery electric vehicles - BEV) as well as plug-in hybrid electric (PHEV) vehicles. The 238 vehicles were comprised of 105 BEVs and 133 PHEVs, with a total of 23 different make/model vehicles represented.

## 4.1 Methodology

The Energy Information Administration (EIA) produces a transportation forecast as part of their Annual Energy Outlook. One component of this forecast is a vehicle stock forecast by technology type, including electric vehicles. Using these data, we are able to calculate the average number of cars per household and projected electric vehicle share - BEV and PHEV.

Figure 15 shows projected number of vehicles per household. The number of vehicles declines over time as the number of persons per household declines and demand for car services such as Uber and Lyft increases.

**Figure 15: EIA Vehicle Per Household**

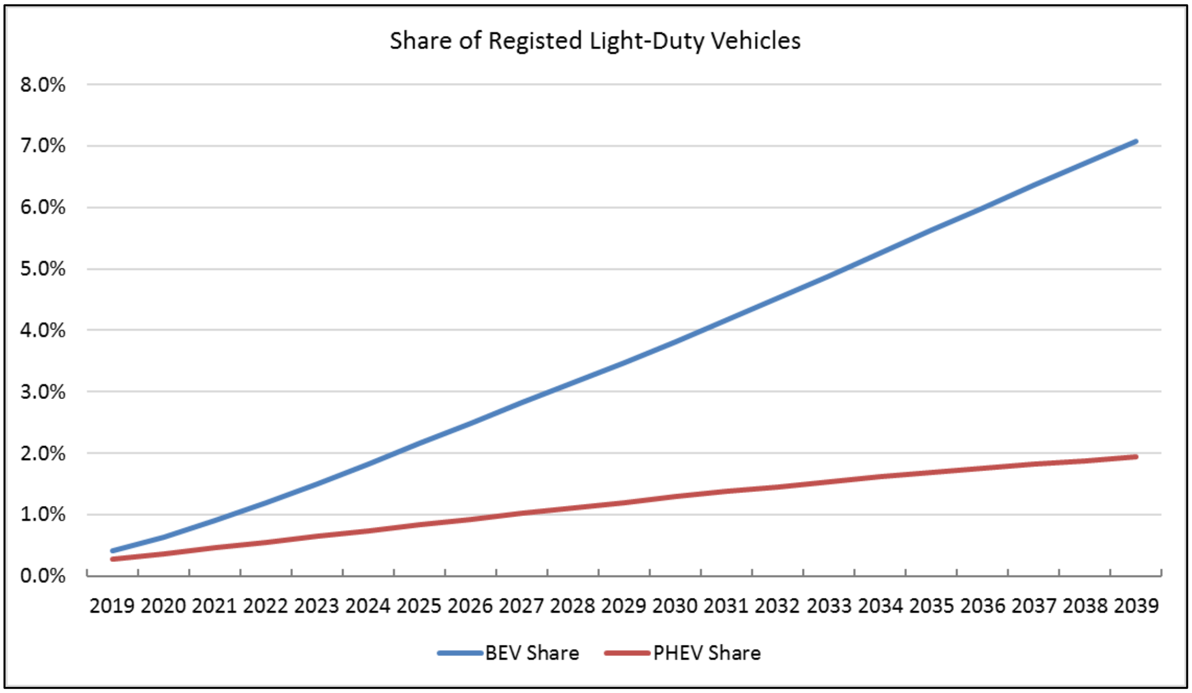



Total service area vehicles are calculated as the product of forecasted customers times EIA projected vehicles per household:

$$Ttl\ Vehicles = \ Custs_{yr} \times EIA\ Vehicle\ Per\ HH_{yr}$$

The number of BEV and PHEV are calculated by applying EIA's projected BEV and PHEV saturation to the service area total vehicle forecast. The share of electric vehicles are projected to increase from 0.5% to 7.1% BEV and 1.9% PHEV by 2039. The BEV and PHEV saturation forecast is shown in Figure 16.

### Figure 16: EV & PHEV Market Share




The resulting electric vehicle forecast is summarized in Table 4-1:

**Table 4-1: Electric Vehicle Forecast**

| Year | BEV Count | PHEV Count |
|---|---|---|
| 2019 | 115 | 140 |
| 2020 | 283 | 266 |
| 2021 | 711 | 509 |
| 2022 | 1,783 | 974 |
| 2023 | 3,936 | 1,712 |
| 2024 | 5,112 | 2,065 |
| 2025 | 6,069 | 2,342 |
| 2026 | 7,015 | 2,613 |
| 2027 | 7,953 | 2,878 |
| 2028 | 8,884 | 3,136 |
| 2029 | 9,827 | 3,390 |
| 2030 | 10,785 | 3,639 |
| 2031 | 11,771 | 3,878 |
| 2032 | 12,772 | 4,109 |
| 2033 | 13,789 | 4,329 |
| 2034 | 14,816 | 4,538 |
| 2035 | 15,848 | 4,736 |
| 2036 | 16,875 | 4,926 |
| 2037 | 17,887 | 5,108 |
| 2038 | 18,887 | 5,279 |
| 2039 | 19,885 | 5,445 |

## 4.2 Electric Vehicle Energy & Load Forecast

Electric vehicles' impact on VECTREN's load forecast depends on the amount of energy a vehicle consumes annually and the timing of vehicle charging. BEVs consume more electricity than PHEVs and accounting for this distinction is important. An EV weighted annual kWh use is calculated based on the current mix of EV models. EV usage is derived from manufacturers' reported fuel efficiency to the federal government (www.fueleconomy.gov). The average annual kWh for the current mix of EVs registered in Vectren's service territory is 3,752kWh for BEV and 2,180 kWh for PHEV based on annual mileage of 12,000 miles.

Electric vehicles' impact on peak demand depends on when and where EVs are charged. Since Vectren does not have incentivized BEV/PHEV off-peak charging rates, it is assumed that the majority of charging will occur at home in the evening hours; this has a minimal impact on summer peak demand. Table 4-2 shows the electric vehicle forecast.

**Table 4-2: Electric Vehicle Load Forecast**

| Year | BEV MWh | PHEV MWh | Total EV MWh | Demand Impact MW (Aug) |
|---|---|---|---|---|
| 2019 | 432 | 305 | 737 | 0.1 |
| 2020 | 1,063 | 580 | 1,643 | 0.2 |
| 2021 | 2,667 | 1,110 | 3,777 | 0.4 |
| 2022 | 6,691 | 2,124 | 8,815 | 1.0 |
| 2023 | 14,769 | 3,732 | 18,501 | 2.1 |
| 2024 | 19,178 | 4,503 | 23,681 | 2.5 |
| 2025 | 22,770 | 5,106 | 27,876 | 2.9 |
| 2026 | 26,320 | 5,697 | 32,017 | 3.3 |
| 2027 | 29,838 | 6,275 | 36,113 | 3.8 |
| 2028 | 33,334 | 6,837 | 40,171 | 4.2 |
| 2029 | 36,869 | 7,392 | 44,261 | 4.6 |
| 2030 | 40,467 | 7,933 | 48,400 | 5.0 |
| 2031 | 44,164 | 8,455 | 52,619 | 5.5 |
| 2032 | 47,920 | 8,959 | 56,878 | 5.9 |
| 2033 | 51,735 | 9,438 | 61,173 | 6.3 |
| 2034 | 55,591 | 9,895 | 65,486 | 6.8 |
| 2035 | 59,461 | 10,327 | 69,788 | 7.2 |
| 2036 | 63,315 | 10,741 | 74,056 | 7.7 |
| 2037 | 67,111 | 11,137 | 78,248 | 8.1 |
| 2038 | 70,863 | 11,510 | 82,373 | 8.5 |
| 2039 | 74,607 | 11,872 | 86,479 | 8.9 |

# 5 Forecast Assumptions

## 5.1 Weather Data

Historical and normal HDD and CDD are derived from daily temperature data for the Evansville airport. Normal degree-days are calculated by averaging the historical daily HDD and CDD over the last twenty years. In past forecasts, we assumed normal HDD and CDD will occur in each of the forecast years. Recent analysis suggests an alternative approach. In reviewing historical weather data, we found a statistically significant positive, but slow, increase in average temperature. This translates into fewer HDD and more CDD over time. Our analysis showed HDD are decreasing 0.2% per year while CDD are increasing 0.5% per year. These trends are incorporated into the forecast. Starting normal HDD are allowed to decrease 0.2% over the forecast period while CDD increase 0.5% per year through 2039. Figure 17 and Figure 18 show historical and forecasted monthly HDD and CDD.

**Figure 17: Heating Degree Days**

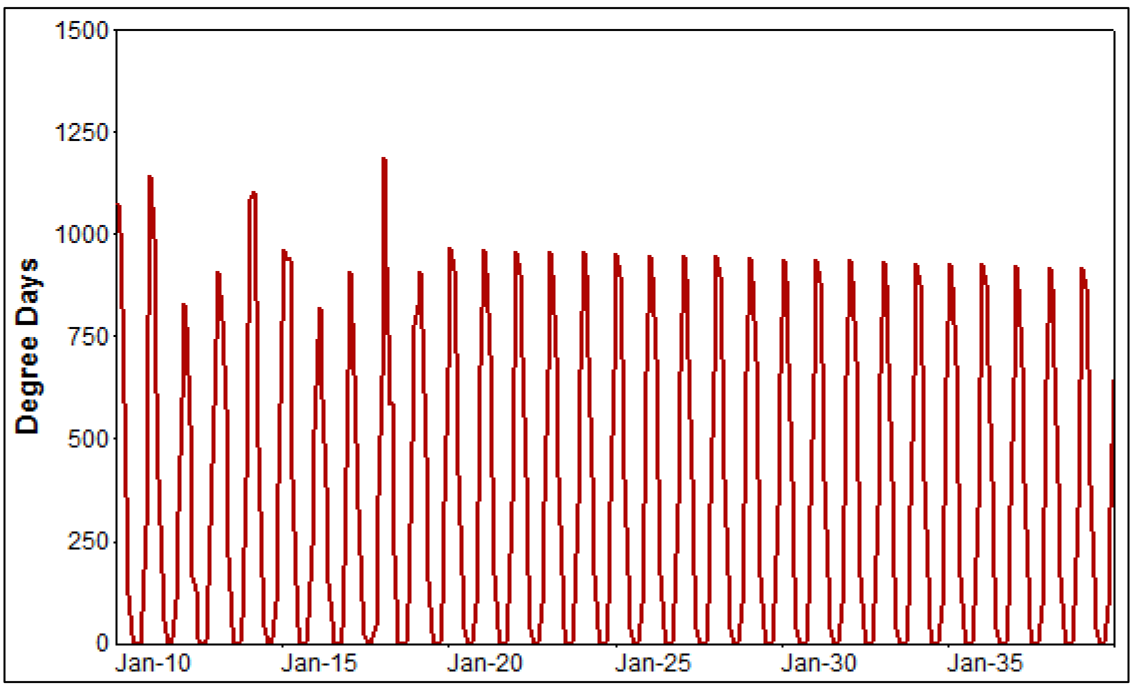
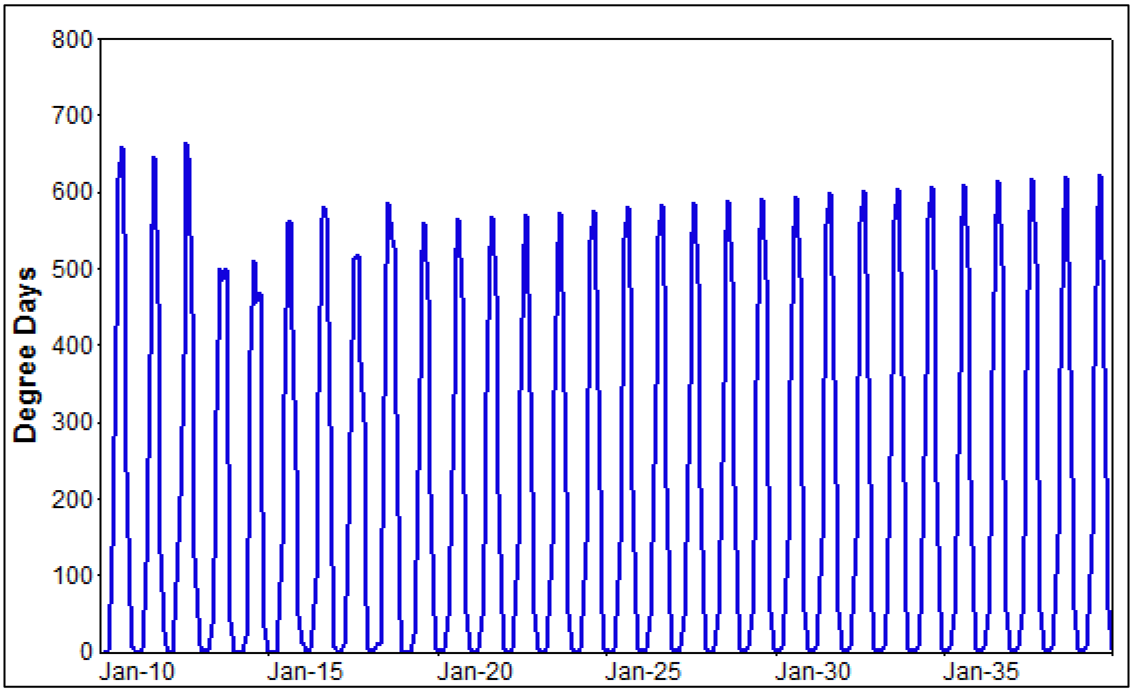


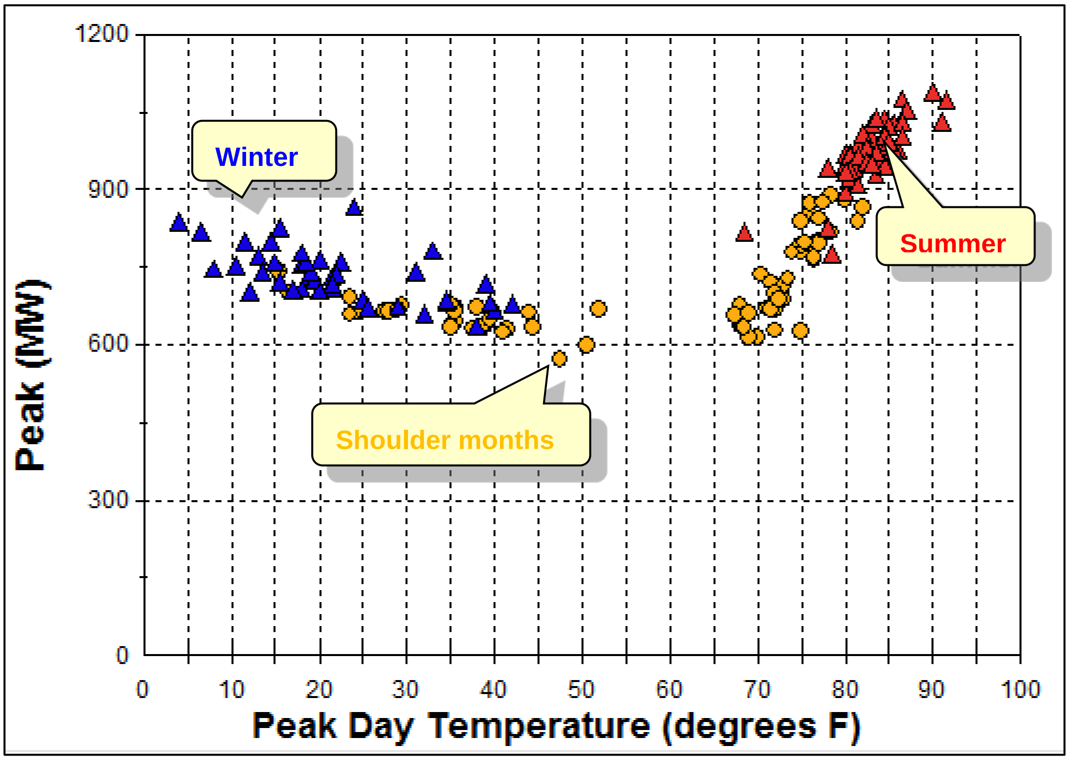
**Figure 18: Cooling Degree Days**




***Peak-Day Weather Variables***

Peak-day CDD and HDD are used in forecasting system peak demand. Peak-day HDD and CDD are derived by finding the daily HDD and CDD that occurred on the peak day in each month. The appropriate breakpoints for defining peak-day HDD and CDD are determined by evaluating the relationship between monthly peak and the peak-day average temperature, as shown in Figure 19.

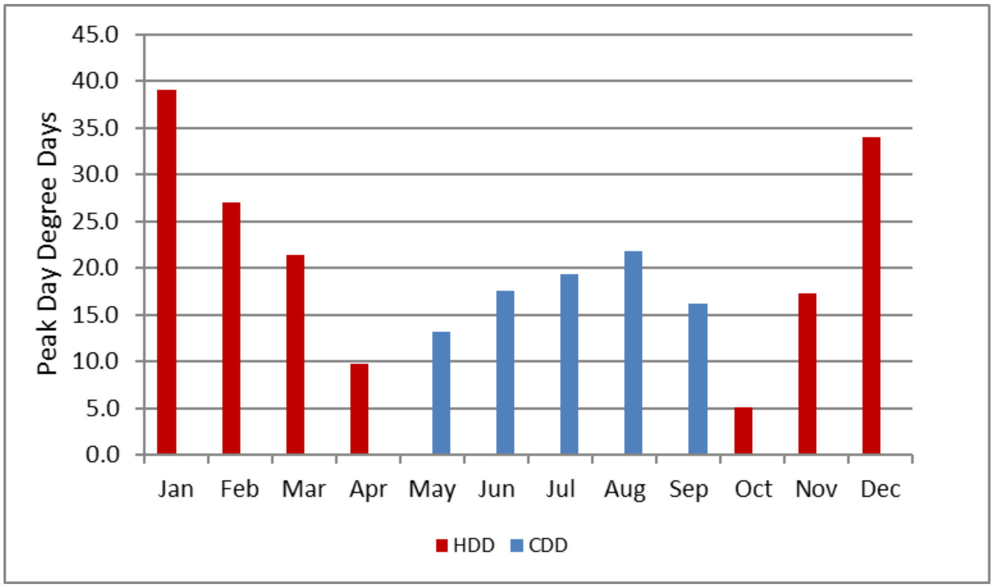
**Figure 19: Monthly Peak Demand /Temperature Relationship**




Peak-day cooling occurs when temperatures are above 65 degrees and peak-day heating occurs when temperatures are below 55 degrees.

Normal peak-day HDD and CDD are calculated using 20 years of historical weather data, based on a rank and average approach, these are not trended. The underlying rate class sales models incorporate trended normal weather; derived heating and cooling sales from these models are an input into the peak model. Using a trended peak weather would double count the impact of increasing temperatures. Normal peak-day HDD and CDD are based on the hottest and coldest days that occurred in each month over the historical time period. Figure 20 shows the normal peak-day HDD and CDD values used in the forecast.

**Figure 20: Normal Peak-Day HDD & CDD**




## 5.2 Economic Data

The class sales forecasts are based on *Moody's Economy.com* May 2019 economic forecast for the Evansville Metropolitan Statistical Area (MSA). The primary economic drivers in the residential sector are household income and the number of new households. Household formation is stable and increasing consistently though the forecast period with 0.4% average annual growth. Real household income growth is modest, averaging 1.6% over the forecast period.

Commercial sales are driven by nonmanufacturing output, nonmanufacturing employment, and population. Non-manufacturing output is forecasted to grow at 1.7% per year through the forecast period with non-manufacturing employment is growing 0.6% per year and population a little over 0.1% per year.

The industrial model relates sales to manufacturing output and employment. Manufacturing output is projected to increase more rapidly over the next 5 years, with output increasing 2.3% per year, over the long-term manufacturing output averages 1.8% annual growth. While output increases, associated manufacturing employment is projected to decline at a 0.5% annual rate.

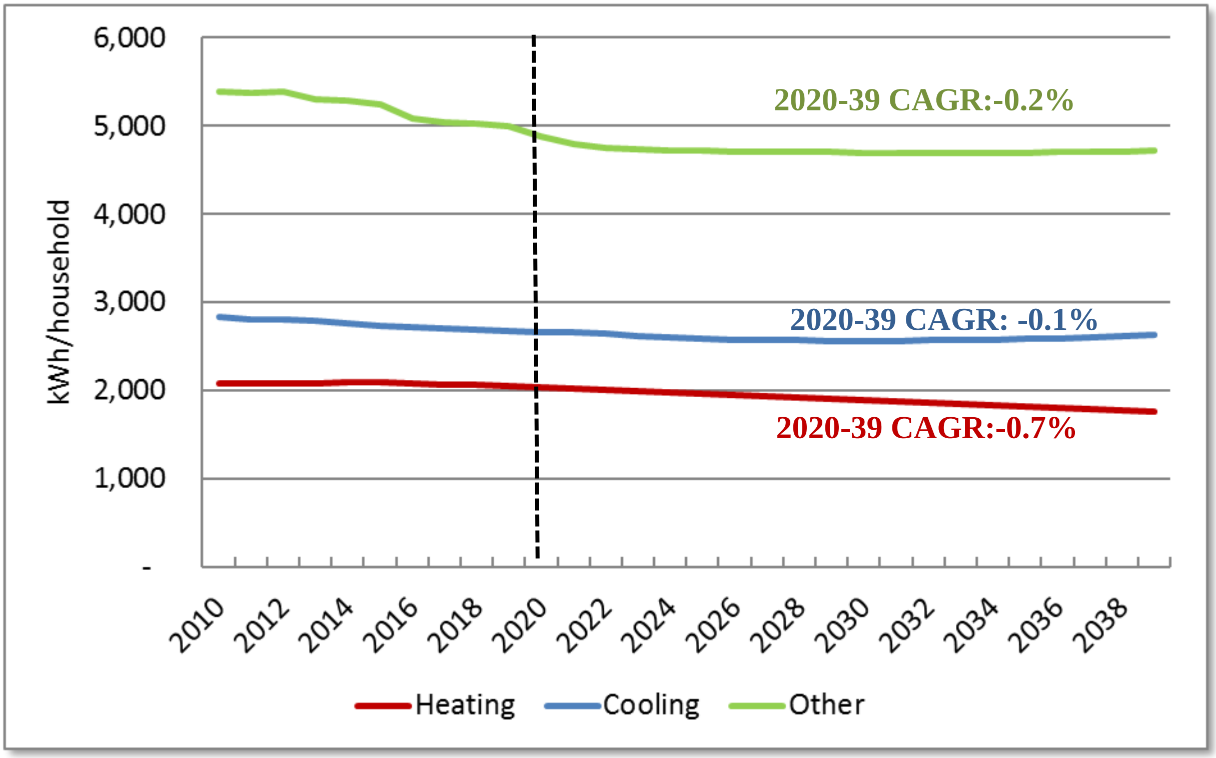
Historical electric prices (in real dollars) are derived from billed sales and revenue data. Historical prices are calculated as a 12-month moving average of the average rate (revenues divided by sales); prices are expressed in real dollars. Prices impact residential and commercial sales through imposed short-term price elasticities. Short-term price elasticities are small; residential and commercial price elasticities are set at -0.10. Price is not an input to the industrial sales model. Price projections are based on the Energy Information Administration's (EIA) long-term real growth rates. Over the forecast period, prices increase 1.5% annually.

## 5.3 Appliance Saturation and Efficiency Trends

Over the long-term, changes in end-use saturation and stock efficiency impact class sales, system energy, and peak demand. End-use energy intensities, expressed in kWh per household for the residential sector and kWh per square foot for the commercial sectors, are incorporated into the constructed forecast model variables. Energy intensities reflect both change in ownership (saturation) and average stock efficiency. In general, efficiency is improving faster than end-use saturation resulting in declining end-use energy use. Energy intensities are derived from Energy Information Administration's (EIA) 2019 Annual Energy Outlook and Vectren's appliance saturation surveys. The residential sector incorporates saturation and efficiency trends for seventeen end-uses. The commercial sector captures end-use intensity projections for ten end-use classifications across ten building types.

Residential end-use intensities are used in constructing the model end-use variables. Figure 21 shows the resulting aggregated end-use intensity projections.

**Figure 21: Residential End-Use Energy Intensities**

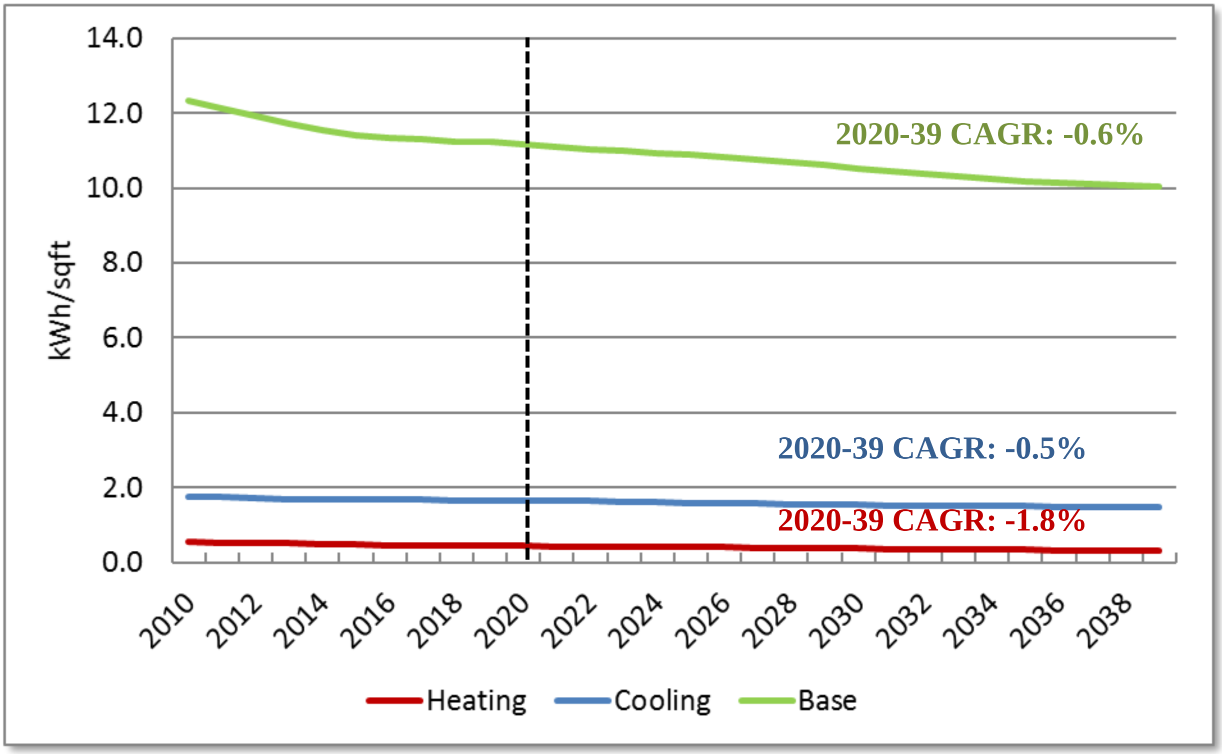



*CAGR=Compound Average Growth Rate

Heating intensity declines 0.7% annually through the forecast period, reflecting declining share in electric heat saturation. Cooling intensity declines 0.1% annually through the forecast period as overall air conditioning efficiency improvements outweigh increase in saturation. Total non-weather sensitive end-use intensity declines 0.2% annually.

Commercial end-use intensities (expressed in kWh per sqft) are based on the EIA's East South Central Census Division forecast; the starting intensity estimates are calibrated to Vectren commercial sales. As in the residential sector, end-use energy use has been declining as a result of new codes and standards and utility DSM programs. Figure 22 shows commercial end-use energy intensity forecasts for total heating, cooling, and non-weather sensitive loads.

**Figure 22: Commercial End-Use Energy Intensity**




Commercial usage is dominated by non-weather sensitive (Base) end-uses, which over the forecast period are projected to decline 0.6% per year. Cooling intensity declines 0.5% annually through the forecast period. Heating intensity declines even stronger at 1.8% annual rate though commercial electric heating is relatively small.

# Appendix A: Model Statistics

***Residential Average Use Model***

| Variable | Coefficient | StdErr | T-Stat | P-Value |
|---|---|---|---|---|
| mStructRev.XHeat | 1.131 | 0.024 | 47.002 | 0.00% |
| mStructRev.XCool | 1.102 | 0.015 | 72.536 | 0.00% |
| mStructRev.XOther | 1.247 | 0.019 | 64.464 | 0.00% |
| mBin.Jan | 41.217 | 10.23 | 4.029 | 0.01% |
| mBin.Aug | 42.865 | 11.411 | 3.756 | 0.03% |
| mBin.Sep | 34.721 | 10.421 | 3.332 | 0.12% |
| mBin.Oct | 30.013 | 9.805 | 3.061 | 0.28% |
| mDSMF.DSM | -0.628 | 0.098 | -6.44 | 0.00% |

| Model Statistics | |
|---|---|
| Iterations | 1 |
| Adjusted Observations | 111 |
| Deg. of Freedom for Error | 103 |
| R-Squared | 0.989 |
| Adjusted R-Squared | 0.988 |
| Model Sum of Squares | 6,162,873.25 |
| Sum of Squared Errors | 70,284.55 |
| Mean Squared Error | 682.37 |
| Std. Error of Regression | 26.12 |
| Mean Abs. Dev. (MAD) | 19.03 |
| Mean Abs. % Err. (MAPE) | 1.93% |
| Durbin-Watson Statistic | 1.81 |

***Residential Customer Model***

| Variable | Coefficient | StdErr | T-Stat | P-Value |
|---|---|---|---|---|
| Economics.PopEV | 960.574 | 2.859 | 335.981 | 0.00% |
| AR(1) | 0.958 | 0.02 | 47.011 | 0.00% |
| MA(1) | 0.438 | 0.086 | 5.101 | 0.00% |

| Model Statistics | |
|---|---|
| Iterations | 8 |
| Adjusted Observations | 113 |
| Deg. of Freedom for Error | 110 |
| R-Squared | 0.996 |
| Adjusted R-Squared | 0.996 |
| Model Sum of Squares | 322,162,685.79 |
| Sum of Squared Errors | 1,295,103.33 |
| Mean Squared Error | 11,773.67 |
| Std. Error of Regression | 108.51 |
| Mean Abs. Dev. (MAD) | 87.12 |
| Mean Abs. % Err. (MAPE) | 0.07% |
| Durbin-Watson Statistic | 1.91 |

***Commercial Sales Model***

| Variable | Coefficient | StdErr | T-Stat | P-Value |
|---|---|---|---|---|
| mStructRev.XOther | 9.238 | 1.188 | 7.776 | 0.00% |
| mStructRev.XCool | 15.486 | 0.442 | 35.027 | 0.00% |
| mStructRev.XHeat | 20.148 | 1.804 | 11.165 | 0.00% |
| mBin.Yr14 | 2763.076 | 860.831 | 3.21 | 0.18% |
| mBin.Feb | 2174.958 | 1122.048 | 1.938 | 5.54% |
| mBin.Jun | -4324.45 | 995.223 | -4.345 | 0.00% |
| mBin.Oct | 3652.067 | 1025.239 | 3.562 | 0.06% |
| mBin.Nov | 2720.101 | 1042.823 | 2.608 | 1.05% |
| mBin.Aug09Plus | 29960.933 | 7537.599 | 3.975 | 0.01% |
| mDSM.DSM | -0.498 | 0.13 | -3.826 | 0.02% |

| Model Statistics | |
|---|---|
| Iterations | 1 |
| Adjusted Observations | 110 |
| Deg. of Freedom for Error | 100 |
| R-Squared | 0.964 |
| Adjusted R-Squared | 0.961 |
| Model Sum of Squares | 18,976,689,674.96 |
| Sum of Squared Errors | 712,451,460.27 |
| Mean Squared Error | 7,124,514.60 |
| Std. Error of Regression | 2,669.18 |
| Mean Abs. Dev. (MAD) | 1,974.42 |
| Mean Abs. % Err. (MAPE) | 1.82% |
| Durbin-Watson Statistic | 1.586 |

## *Industrial Sales Model*

| Variable | Coefficient | StdErr | T-Stat | P-Value |
|---|---|---|---|---|
| mEcon.IndVar | 118487.802 | 2254.45 | 52.557 | 0.00% |
| mWthrRev.CDD65 | 57.963 | 6.069 | 9.551 | 0.00% |
| mBin.Jul09Plus | 29846.553 | 2190.612 | 13.625 | 0.00% |
| mBin.Feb | 11020.029 | 3029.515 | 3.638 | 0.04% |
| mBin.Apr | 7543.537 | 3000.036 | 2.514 | 1.32% |
| mBin.Sep | 19778.485 | 3582.861 | 5.52 | 0.00% |
| mBin.Nov | 17466.878 | 3505.353 | 4.983 | 0.00% |
| mBin.Yr09 | -16514.547 | 3068.532 | -5.382 | 0.00% |
| mBin.Yr16Plus | 11358.694 | 1919.002 | 5.919 | 0.00% |

| Model Statistics | |
|---|---|
| Iterations | 1 |
| Adjusted Observations | 137 |
| Deg. of Freedom for Error | 128 |
| R-Squared | 0.757 |
| Adjusted R-Squared | 0.742 |
| Model Sum of Squares | 37,889,478,247.99 |
| Sum of Squared Errors | 12,146,223,745.81 |
| Mean Squared Error | 94,892,373.01 |
| Std. Error of Regression | 9,741.27 |
| Mean Abs. Dev. (MAD) | 7,706.07 |
| Mean Abs. % Err. (MAPE) | 5.24% |
| Durbin-Watson Statistic | 1.714 |

***Residential Solar Adoption Model***

| Variable | Coefficient | StdErr | T-Stat | P-Value |
|---|---|---|---|---|
| CONST | 23.491 | 11.774 | 1.995 | 5.04% |
| Payback.ResPayback | -1.31 | 0.866 | -1.512 | 13.55% |
| AR(1) | 0.144 | 0.126 | 1.143 | 25.75% |

| Model Statistics | |
|---|---|
| Iterations | 6 |
| Adjusted Observations | 65 |
| Deg. of Freedom for Error | 62 |
| R-Squared | 0.068 |
| Adjusted R-Squared | 0.038 |
| Model Sum of Squares | 286.23 |
| Sum of Squared Errors | 3,925.31 |
| Mean Squared Error | 63.31 |
| Std. Error of Regression | 7.96 |
| Mean Abs. Dev. (MAD) | 3.71 |
| Mean Abs. % Err. (MAPE) | 91.11% |
| Durbin-Watson Statistic | 2.009 |

***Peak Model***

| Variable | Coefficient | StdErr | T-Stat | P-Value |
|---|---|---|---|---|
| mCPkEndUses.HeatVar | 3.147 | 0.335 | 9.405 | 0.00% |
| mCPkEndUses.CoolVar | 18.522 | 0.542 | 34.196 | 0.00% |
| mCPkEndUses.BaseVar | 1.519 | 0.024 | 62.389 | 0.00% |
| mBin.Jan16 | 148.429 | 30.989 | 4.79 | 0.00% |
| mBin.Nov16 | -86.871 | 31.195 | -2.785 | 0.64% |
| mBin.Yr15 | 47.869 | 10.315 | 4.641 | 0.00% |
| mBin.May | -49.483 | 10.624 | -4.658 | 0.00% |
| mBin.Oct | -48.783 | 11.583 | -4.212 | 0.01% |
| mBin.Yr12Plus | -35.439 | 7.391 | -4.795 | 0.00% |

| Model Statistics | |
|---|---|
| Iterations | 1 |
| Adjusted Observations | 111 |
| Deg. of Freedom for Error | 102 |
| R-Squared | 0.952 |
| Adjusted R-Squared | 0.949 |
| Model Sum of Squares | 1,908,789.28 |
| Sum of Squared Errors | 95,539.47 |
| Mean Squared Error | 936.66 |
| Std. Error of Regression | 30.6 |
| Mean Abs. Dev. (MAD) | 22 |
| Mean Abs. % Err. (MAPE) | 2.81% |
| Durbin-Watson Statistic | 1.855 |

# Appendix B: Residential SAE Modeling Framework

The traditional approach to forecasting monthly sales for a customer class is to develop an econometric model that relates monthly sales to weather, seasonal variables, and economic conditions. From a forecasting perspective, econometric models are well suited to identify historical trends and to project these trends into the future. In contrast, the strength of the end-use modeling approach is the ability to identify the end-use factors that are drive energy use. By incorporating end-use structure into an econometric model, the statistically adjusted end-use (SAE) modeling framework exploits the strengths of both approaches.

There are several advantages to this approach.

- The equipment efficiency and saturation trends, dwelling square footage, and thermal shell integrity changes embodied in the long-run end-use forecasts are introduced explicitly into the short-term monthly sales forecast. This provides a strong bridge between the two forecasts.
- By explicitly introducing trends in equipment saturations, equipment efficiency, dwelling square footage, and thermal integrity levels, it is easier to explain changes in usage levels and changes in weather-sensitivity over time.
- Data for short-term models are often not sufficiently robust to support estimation of a full set of price, economic, and demographic effects. By bundling these factors with equipment-oriented drivers, a rich set of elasticities can be incorporated into the final model.

This section describes the SAE approach, the associated supporting SAE spreadsheets, and the *MetrixND* project files that are used in the implementation. The source for the SAE spreadsheets is the 2019 Annual Energy Outlook (AEO) database provided by the Energy Information Administration (EIA).

## Residential Statistically Adjusted End-Use Modeling Framework

The statistically adjusted end-use modeling framework begins by defining energy use ($USE_{y,m}$) in year (y) and month (m) as the sum of energy used by heating equipment ($Heat_{y,m}$), cooling equipment ($Cool_{y,m}$), and other equipment ($Other_{y,m}$). Formally,

$$USE_{y,m} = Heat_{y,m} + Cool_{y,m} + Other_{y,m} \qquad (1)$$

Although monthly sales are measured for individual customers, the end-use components are not. Substituting estimates for the end-use elements gives the following econometric equation.

$$\text{USE}_m = a + b_1 \times \text{XHeat}_m + b_2 \times \text{XCool}_m + b_3 \times \text{XOther}_m + \varepsilon_m \qquad (2)$$

$XHeat_m$, $XCool_m$, and $XOther_m$ are explanatory variables constructed from end-use information, dwelling data, weather data, and market data. As will be shown below, the equations used to construct these X-variables are simplified end-use models, and the X-variables are the estimated usage levels for each of the major end uses based on these models. The estimated model can then be thought of as a statistically adjusted end-use model, where the estimated slopes are the adjustment factors.

### *Constructing XHeat*

As represented in the SAE spreadsheets, energy use by space heating systems depends on the following types of variables.

- Heating degree days
- Heating equipment saturation levels
- Heating equipment operating efficiencies
- Thermal integrity and footage of homes
- Average household size, household income, and energy prices

The heating variable is represented as the product of an annual equipment index and a monthly usage multiplier. That is,

$$XHeat_{y,m} = HeatIndex_{y,m} \times HeatUse_{y,m} \qquad (3)$$

Where:

- $XHeat_{y,m}$ is estimated heating energy use in year (*y*) and month (*m*)
- $HeatIndex_{y,m}$ is the monthly index of heating equipment
- $HeatUse_{y,m}$ is the monthly usage multiplier

The heating equipment index is defined as a weighted average across equipment types of equipment saturation levels normalized by operating efficiency levels. Given a set of fixed weights, the index will change over time with changes in equipment saturations (*Sat*), operating efficiencies (*Eff*), building structural index (*StructuralIndex*), and energy prices. Formally, the equipment index is defined as:

$$HeatIndex_y = StructuralIndex_y \times \sum_{Type} Weight^{Type} \times \frac{\left( Sat_y^{Type} \middle/ Eff_y^{Type} \right)}{\left( Sat_{2015}^{Type} \middle/ Eff_{2015}^{Type} \right)} \tag{4}$$

The *StructuralIndex* is constructed by combining the EIA's building shell efficiency index trends with surface area estimates, and then it is indexed to the 2015 value:

$$StructuralIndex_y = \frac{BuildingShellEfficiencyIndex_y \times SurfaceArea_y}{BuildingShellEfficiencyIndex_{2015} \times SurfaceArea_{2015}} \tag{5}$$

The *StructuralIndex* is defined on the *StructuralVars* tab of the SAE spreadsheets. Surface area is derived to account for roof and wall area of a standard dwelling based on the regional average square footage data obtained from EIA. The relationship between the square footage and surface area is constructed assuming an aspect ratio of 0.75 and an average of 25% two-story and 75% single-story. Given these assumptions, the approximate linear relationship for surface area is:

$$SurfaceArea_y = 892 + 1.44 \times Footage_y \tag{6}$$

For electric heating equipment, the SAE spreadsheets contain two equipment types: electric resistance furnaces/room units and electric space heating heat pumps. Examples of weights for these two equipment types for the U.S. are given in Table 1.

**Table 1: Electric Space Heating Equipment Weights**

| Equipment Type | Weight (kWh) |
|---|---|
| Electric Resistance Furnace/Room units | 767 |
| Electric Space Heating Heat Pump | 127 |

Data for the equipment saturation and efficiency trends are presented on the *Shares* and *Efficiencies* tabs of the SAE spreadsheets. The efficiency for electric space heating heat pumps are given in terms of Heating Seasonal Performance Factor [BTU/Wh], and the efficiencies for electric furnaces and room units are estimated as 100%, which is equivalent to 3.41 BTU/Wh.

**Heating system usage** levels are impacted on a monthly basis by several factors, including weather, household size, income levels, prices, and billing days. The estimates for space heating equipment usage levels are computed as follows:

$$HeatUse_{y,m} = \left(\frac{HDD_{y,m}}{HDD_{05}}\right) \times \left(\frac{HHSize_{y}}{HHSize_{05,7}}\right)^{0.25} \times \left(\frac{Income_{y}}{Income_{05,7}}\right)^{0.10} \times \left(\frac{Elec\,Pr\,ice_{y,m}}{Elec\,Pr\,ice_{05,7}}\right)^{-0.10} \quad (7)$$

Where:

- *HDD* is the number of heating degree days in year (*y*) and month (*m*).
- *HHSize* is average household size in a year (*y*)
- *Income* is average real income per household in year (*y*)
- *ElecPrice* is the average real price of electricity in month (*m*) and year (*y*)

By construction, the $HeatUse_{y,m}$ variable has an annual sum that is close to 1.0 in the base year (2005). The first term, which involves heating degree days, serve to allocate annual values to months of the year. The remaining terms average to 1.0 in the base year. In other years, the values will reflect changes in the economic drivers, as transformed through the end-use elasticity parameters. The price impacts captured by the Usage equation represent short-term price response.

### *Constructing XCool*

The explanatory variable for cooling loads is constructed in a similar manner. The amount of energy used by cooling systems depends on the following types of variables.

- Cooling degree days
- Cooling equipment saturation levels
- Cooling equipment operating efficiencies
- Thermal integrity and footage of homes
- Average household size, household income, and energy prices

The cooling variable is represented as the product of an equipment-based index and monthly usage multiplier. That is,

$$XCool_{y,m} = CoolIndex_{y} \times CoolUse_{y,m} \quad (8)$$

Where

- $XCool_{y,m}$ is estimated cooling energy use in year (*y*) and month (*m*)

- $CoolIndex_y$ is an index of cooling equipment
- $CoolUse_{y,m}$ is the monthly usage multiplier

As with heating, the cooling equipment index is defined as a weighted average across equipment types of equipment saturation levels normalized by operating efficiency levels. Formally, the cooling equipment index is defined as:

$$CoolIndex_y = StructuralIndex_y \times \sum_{Type} Weight^{Type} \times \frac{\left(Sat_y^{Type} \big/ Eff_y^{Type}\right)}{\left(Sat_{2015}^{Type} \big/ Eff_{2015}^{Type}\right)} \qquad (9)$$

For cooling equipment, the SAE spreadsheets contain three equipment types: central air conditioning, space cooling heat pump, and room air conditioning. Examples of weights for these three equipment types for the U.S. are given in Table 2.

### Table 2: Space Cooling Equipment Weights

| Equipment Type | Weight (kWh) |
|---|---|
| Central Air Conditioning | 1,219 |
| Space Cooling Heat Pump | 240 |
| Room Air Conditioning | 177 |

The equipment saturation and efficiency trends data are presented on the *Shares* and *Efficiencies* tabs of the SAE spreadsheets. The efficiency for space cooling heat pumps and central air conditioning (A/C) units are given in terms of Seasonal Energy Efficiency Ratio [BTU/Wh], and room A/C units efficiencies are given in terms of Energy Efficiency Ratio [BTU/Wh].

**Cooling system usage** levels are impacted on a monthly basis by several factors, including weather, household size, income levels, and prices. The estimates of cooling equipment usage levels are computed as follows:

$$CoolUse_{y,m} = \left(\frac{CDD_{y,m}}{CDD_{05}}\right) \times \left(\frac{HHSize_y}{HHSize_{05,7}}\right)^{0.25} \times \left(\frac{Income_y}{Income_{05,7}}\right)^{0.10} \times \left(\frac{Elec\,Price_{y,m}}{Elec\,Price_{05,7}}\right)^{-0.10} \qquad (10)$$

Where:

- *CDD* is the number of cooling degree days in year (*y*) and month (*m*).

- *HHSize* is average household size in a year (*y*)
- *Income* is average real income per household in year (*y*)
- *ElecPrice* is the average real price of electricity in month (*m*) and year (*y*)

By construction, the *CoolUse* variable has an annual sum that is close to 1.0 in the base year (2005). The first term, which involves cooling degree days, serve to allocate annual values to months of the year. The remaining terms average to 1.0 in the base year. In other years, the values will change to reflect changes in the economic driver changes.

### Constructing XOther

Monthly estimates of non-weather sensitive sales can be derived in a similar fashion to space heating and cooling. Based on end-use concepts, other sales are driven by:

- Appliance and equipment saturation levels
- Appliance efficiency levels
- Average number of days in the billing cycle for each month
- Average household size, real income, and real prices

The explanatory variable for other uses is defined as follows:

$$XOther_{y,m} = OtherEqpIndex_{y,m} \times OtherUse_{y,m} \tag{11}$$

The first term on the right-hand side of this expression ($OtherEqpIndex_y$) embodies information about appliance saturation and efficiency levels and monthly usage multipliers. The second term (*OtherUse*) captures the impact of changes in prices, income, household size, and number of billing-days on appliance utilization.

End-use indices are constructed in the SAE models. A separate end-use index is constructed for each end-use equipment type using the following function form.

$$ApplianceIndex_{y,m} = Weight^{Type} \times \frac{\left( Sat_y^{Type} \Big/ \frac{1}{UEC_y^{Type}} \right)}{\left( Sat_{2015}^{Type} \Big/ \frac{1}{UEC_{2015}^{Type}} \right)} \times MoMult_m^{Type} \times \tag{12}$$

Where:

- *Weight* is the weight for each appliance type
- *Sat* represents the fraction of households, who own an appliance type
- $MoMult_m$ is a monthly multiplier for the appliance type in month ($m$)
- *Eff* is the average operating efficiency the appliance
- *UEC* is the unit energy consumption for appliances

This index combines information about trends in saturation levels and efficiency levels for the main appliance categories with monthly multipliers for lighting, water heating, and refrigeration.

The appliance saturation and efficiency trends data are presented on the *Shares* and *Efficiencies* tabs of the SAE spreadsheets.

Further monthly variation is introduced by multiplying by usage factors that cut across all end uses, constructed as follows:

$$ApplianceUse_{y,m} = \left(\frac{BDays_{y,m}}{30.5}\right) \times \left(\frac{HHSize_y}{HHSize_{05,7}}\right)^{0.25} \times \left(\frac{Income_y}{Income_{05,7}}\right)^{0.10} \times \left(\frac{ElecPrice_{y,m}}{ElecPrice_{05,7}}\right)^{-0.10} \quad (13)$$

The index for other uses is derived then by summing across the appliances:

$$OtherEqpIndex_{y,m} = \sum_k ApplianceIndex_{y,m} \times ApplianceUse_{y,m} \quad (14)$$

# Appendix C: Commercial SAE Modeling Framework

The traditional approach to forecasting monthly sales for a customer class is to develop an econometric model that relates monthly sales to weather, seasonal variables, and economic conditions. From a forecasting perspective, the strength of econometric models is that they are well suited to identifying historical trends and to projecting these trends into the future. In contrast, the strength of the end-use modeling approach is the ability to identify the end-use factors that are driving energy use. By incorporating end-use structure into an econometric model, the statistically adjusted end-use (SAE) modeling framework exploits the strengths of both approaches.

There are several advantages to this approach.

- The equipment efficiency trends and saturation changes embodied in the long-run end-use forecasts are introduced explicitly into the short-term monthly sales forecast. This provides a strong bridge between the two forecasts.
- By explicitly introducing trends in equipment saturations and equipment efficiency levels, it is easier to explain changes in usage levels and changes in weather-sensitivity over time.
- Data for short-term models are often not sufficiently robust to support estimation of a full set of price, economic, and demographic effects. By bundling these factors with equipment-oriented drivers, a rich set of elasticities can be built into the final model.

This document describes this approach, the associated supporting Commercial SAE spreadsheets, and *MetrixND* project files that are used in the implementation. The source for the commercial SAE spreadsheets is the 2019 Annual Energy Outlook (AEO) database provided by the Energy Information Administration (EIA).

## Commercial Statistically Adjusted End-Use Model Framework

The commercial statistically adjusted end-use model framework begins by defining energy use ($USE_{y,m}$) in year (y) and month (m) as the sum of energy used by heating equipment ($Heat_{y,m}$), cooling equipment ($Cool_{y,m}$) and other equipment ($Other_{y,m}$). Formally,

$$\text{USE}_{y,m} = \text{Heat}_{y,m} + \text{Cool}_{y,m} + \text{Other}_{y,m} \tag{1}$$

Although monthly sales are measured for individual customers, the end-use components are not. Substituting estimates for the end-use elements gives the following econometric equation.

$$USE_m = a + b_1 \times XHeat_m + b_2 \times XCool_m + b_3 \times XOther_m + \varepsilon_m \qquad (2)$$

Here, $XHeat_m$, $XCool_m$, and $XOther_m$ are explanatory variables constructed from end-use information, weather data, and market data. As will be shown below, the equations used to construct these X-variables are simplified end-use models, and the X-variables are the estimated usage levels for each of the major end uses based on these models. The estimated model can then be thought of as a statistically adjusted end-use model, where the estimated slopes are the adjustment factors.

### *Constructing XHeat*

As represented in the Commercial SAE spreadsheets, energy use by space heating systems depends on the following types of variables.

- Heating degree days,
- Heating equipment saturation levels,
- Heating equipment operating efficiencies,
- Commercial output, employment, population, and energy price.

The heating variable is represented as the product of an annual equipment index and a monthly usage multiplier. That is,

$$XHeat_{y,m} = HeatIndex_y \times HeatUse_{y,m} \qquad (3)$$

Where:

- *$XHeat_{y,m}$ is estimated heating energy use in year (y) and month (m),*
- *$HeatIndex_y$ is the annual index of heating equipment, and*
- *$HeatUse_{y,m}$ is the monthly usage multiplier.*

The heating equipment index is composed of electric space heating equipment saturation levels normalized by operating efficiency levels. The index will change over time with changes in heating equipment saturations (*HeatShare*) and operating efficiencies (*Eff*). Formally, the equipment index is defined as:

$$HeatIndex_y = HeatSales_{2013} \times \frac{\left(HeatShare_y / Eff_y\right)}{\left(HeatShare_{2013} / Eff_{2013}\right)} \tag{4}$$

In this expression, 2013 is used as a base year for normalizing the index. The ratio on the right is equal to 1.0 in 2004. In other years, it will be greater than one if equipment saturation levels are above their 201

level. This will be counteracted by higher efficiency levels, which will drive the index downward. Base year space heating sales are defined as follows.

$$HeatSales_{2013} = \left(\frac{kWh}{Sqft}\right)_{Heating} \times \left(\frac{CommercialSales_{2013}}{\sum_e kWh/Sqft_e}\right) \tag{5}$$

Here, base-year sales for space heating is the product of the average space heating intensity value and the ratio of total commercial sales in the base year over the sum of the end-use intensity values. In the Commercial SAE Spreadsheets, the space heating sales value is defined on the *BaseYrInput* tab. The resulting $HeatIndex_y$ value in 2013 will be equal to the estimated annual heating sales in that year. Variations from this value in other years will be proportional to saturation and efficiency variations around their base values.

Heating system usage levels are impacted on a monthly basis by several factors, including weather, commercial level economic activity, prices and billing days. Using the COMMEND default elasticity parameters, the estimates for space heating equipment usage levels are computed as follows:

$$HeatUse_{y,m} = \left(\frac{HDD_{y,m}}{HDD_{05}}\right) \times \left(\frac{EconVar_{y,m}}{EconVar_{05,7}}\right) \times \left(\frac{Price_{y,m}}{Price_{05,7}}\right)^{-0.10} \tag{6}$$

Where:

- *HDD* is the number of heating degree days in month (m) and year (y).
- *EconVar* is the weighted commercial economic variable that blends Output, Employment, and Population in month (m), and year (y).
- *Price* is the average real price of electricity in month (m) and year (y).

By construction, the $HeatUse_{y,m}$ variable has an annual sum that is close to one in the base year (2004). The first term, which involves heating degree days, serve to allocate annual values to months of the year. The remaining terms average to one in the base year. In other years, the values will reflect changes in commercial output and prices, as transformed through the end-use elasticity parameters. For example, if the real price of electricity goes up

10% relative to the base year value, the price term will contribute a multiplier of about .98 (computed as 1.10 to the -0.18 power).

### *Constructing XCool*

The explanatory variable for cooling loads is constructed in a similar manner. The amount of energy used by cooling systems depends on the following types of variables.

- Cooling degree days,
- Cooling equipment saturation levels,
- Cooling equipment operating efficiencies,
- Commercial output, employment, population and energy price.

The cooling variable is represented as the product of an equipment-based index and monthly usage multiplier. That is,

$$\mathrm{XCool}_{y,m} = \mathrm{CoolIndex}_{y} \times \mathrm{CoolUse}_{y,m} \tag{7}$$

Where:

- $XCool_{y,m}$ is estimated cooling energy use in year (y) and month (m),
- $CoolIndex_y$ is an index of cooling equipment, and
- $CoolUse_{y,m}$ is the monthly usage multiplier.

As with heating, the cooling equipment index depends on equipment saturation levels (*CoolShare*) normalized by operating efficiency levels (*Eff*). Formally, the cooling equipment index is defined as:

$$CoolIndex_y = CoolSales_{2013} \times \frac{\left( {CoolShare_y}/{Eff_y} \right)}{\left( {CoolShare_{2013}}/{Eff_{2013}} \right)} \tag{8}$$

Data values in 2013 are used as a base year for normalizing the index, and the ratio on the right is equal to 1.0 in 2013. In other years, it will be greater than one if equipment saturation levels are above their 2013 level. This will be counteracted by higher efficiency levels, which will drive the index downward. Estimates of base year cooling sales are defined as follows.

$$CoolSales_{2013} = \left( \frac{kWh}{Sqft} \right)_{Cooling} \times \left( \frac{CommercialSales_{2013}}{\sum_e {kWh}/{Sqft_e}} \right) \tag{9}$$

Here, base-year sales for space cooling is the product of the average space cooling intensity value and the ratio of total commercial sales in the base year over the sum of the end-use intensity values. In the Commercial SAE Spreadsheets, the space cooling sales value is defined on the *BaseYrInput* tab. The resulting *CoolIndex* value in 2013 will be equal to the estimated annual cooling sales in that year. Variations from this value in other years will be proportional to saturation and efficiency variations around their base values.

Cooling system usage levels are impacted on a monthly basis by several factors, including weather, economic activity levels and prices. Using the COMMEND default parameters, the estimates of cooling equipment usage levels are computed as follows:

$$CoolUse_{y,m} = \left(\frac{CDD_{y,m}}{CDD_{05}}\right) \times \left(\frac{EconVar_{y,m}}{EconVar_{05,7}}\right) \times \left(\frac{Price_{y,m}}{Price_{05,7}}\right)^{-0.10} \quad (10)$$

Where:

- *HDD* is the number of heating degree days in month (m) and year (y).
- *EconVar* is the weighted commercial economic variable that blends Output, Employment, and Population in month (m), and year (y).
- *Price* is the average real price of electricity in month (m) and year (y).

By construction, the *CoolUse* variable has an annual sum that is close to one in the base year (2004). The first term, which involves cooling degree days, serve to allocate annual values to months of the year. The remaining terms average to one in the base year. In other years, the values will change to reflect changes in commercial output and prices.

### *Constructing XOther*

Monthly estimates of non-weather sensitive sales can be derived in a similar fashion to space heating and cooling. Based on end-use concepts, other sales are driven by:

- Equipment saturation levels,
- Equipment efficiency levels,
- Average number of days in the billing cycle for each month, and
- Real commercial output and real prices.

The explanatory variable for other uses is defined as follows:

$$XOther_{y,m} = OtherIndex_{y,m} \times OtherUse_{y,m} \quad (11)$$

The second term on the right-hand side of this expression embodies information about equipment saturation levels and efficiency levels. The equipment index for other uses is defined as follows:

$$OtherIndex_{y,m} = \sum_{Type} Weight_{2013}^{Type} \times \left( \frac{Share_y^{Type} / Eff_y^{Type}}{Share_{2013}^{Type} / Eff_{2013}^{Type}} \right) \qquad (12)$$

Where:

- *Weight* is the weight for each equipment type,
- *Share* represents the fraction of floor stock with an equipment type, and
- *Eff* is the average operating efficiency.

This index combines information about trends in saturation levels and efficiency levels for the main equipment categories. The weights are defined as follows:

$$Weight_{2013}^{Type} = \left(\frac{kWh}{Sqft}\right)_{Type} \times \left(\frac{CommercialSales_{04}}{\sum_e {}^{kWh}/_{Sqft_e}}\right) \qquad (13)$$

Further monthly variation is introduced by multiplying by usage factors that cut across all end uses, constructed as follows:

$$OtherUse_{y,m} = \left(\frac{BDays_{y,m}}{30.5}\right) \times \left(\frac{EconVar_{y,m}}{EconVar_{05,7}}\right) \times \left(\frac{Price_{y.m}}{Price_{05,7}}\right)^{-0.10} \qquad (14)$$

# Attachment 4.2 Vectren Hourly System Load Data

| Dt | Hour1 | Hour2 | Hour3 | Hour4 | Hour5 | Hour6 | Hour7 | Hour8 | Hour9 | Hour10 | Hour11 | Hour12 | Hour13 | Hour14 | Hour15 | Hour16 | Hour17 | Hour18 | Hour19 | Hour20 | Hour21 | Hour22 | Hour23 | Hour24 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1/1/2018 | 664 | 641 | 649 | 632 | 642 | 650 | 652 | 667 | 662 | 669 | 665 | 658 | 658 | 644 | 637 | 630 | 632 | 671 | 712 | 722 | 718 | 718 | 703 | 684 |
| 1/2/2018 | 673 | 665 | 667 | 675 | 680 | 703 | 772 | 779 | 790 | 787 | 770 | 759 | 724 | 715 | 695 | 688 | 695 | 718 | 749 | 763 | 770 | 767 | 744 | 723 |
| 1/3/2018 | 700 | 684 | 691 | 679 | 676 | 684 | 709 | 742 | 759 | 739 | 748 | 717 | 695 | 681 | 682 | 690 | 694 | 705 | 694 | 720 | 719 | 734 | 711 | 684 |
| 1/4/2018 | 676 | 676 | 671 | 682 | 685 | 710 | 740 | 789 | 798 | 795 | 770 | 747 | 735 | 728 | 721 | 703 | 711 | 725 | 772 | 754 | 767 | 750 | 728 | 706 |
| 1/5/2018 | 677 | 671 | 668 | 658 | 666 | 671 | 706 | 740 | 748 | 752 | 748 | 752 | 726 | 719 | 707 | 698 | 697 | 706 | 741 | 738 | 743 | 739 | 728 | 719 |
| 1/6/2018 | 698 | 693 | 697 | 688 | 703 | 693 | 718 | 733 | 742 | 730 | 717 | 699 | 679 | 653 | 631 | 631 | 620 | 653 | 688 | 695 | 685 | 691 | 683 | 663 |
| 1/7/2018 | 640 | 635 | 624 | 619 | 611 | 616 | 606 | 626 | 631 | 633 | 640 | 614 | 604 | 587 | 587 | 578 | 588 | 603 | 628 | 625 | 621 | 595 | 578 | 556 |
| 1/8/2018 | 532 | 525 | 518 | 512 | 523 | 540 | 589 | 706 | 723 | 716 | 723 | 716 | 718 | 713 | 707 | 705 | 708 | 711 | 732 | 728 | 724 | 714 | 683 | 657 |
| 1/9/2018 | 634 | 619 | 609 | 610 | 607 | 627 | 656 | 692 | 723 | 716 | 723 | 719 | 707 | 708 | 699 | 694 | 693 | 699 | 717 | 716 | 633 | 612 | 594 | 556 |
| 1/10/2018 | 528 | 513 | 509 | 499 | 504 | 503 | 539 | 570 | 585 | 576 | 583 | 585 | 577 | 573 | 567 | 566 | 572 | 576 | 586 | 589 | 576 | 569 | 553 | 518 |
| 1/11/2018 | 490 | 480 | 470 | 459 | 468 | 467 | 500 | 541 | 563 | 566 | 570 | 576 | 566 | 566 | 570 | 564 | 573 | 563 | 589 | 581 | 575 | 567 | 538 | 528 |
| 1/12/2018 | 511 | 508 | 513 | 532 | 540 | 568 | 593 | 631 | 663 | 672 | 693 | 702 | 701 | 694 | 696 | 681 | 671 | 680 | 699 | 687 | 680 | 660 | 636 | 606 |
| 1/13/2018 | 589 | 575 | 563 | 567 | 568 | 579 | 589 | 606 | 602 | 618 | 622 | 659 | 659 | 650 | 633 | 627 | 631 | 659 | 706 | 706 | 710 | 705 | 701 | 679 |
| 1/14/2018 | 673 | 666 | 667 | 670 | 673 | 685 | 691 | 714 | 719 | 712 | 694 | 686 | 666 | 658 | 651 | 651 | 662 | 684 | 718 | 707 | 701 | 700 | 679 | 658 |
| 1/15/2018 | 646 | 638 | 637 | 640 | 639 | 657 | 679 | 708 | 725 | 742 | 741 | 752 | 743 | 731 | 739 | 726 | 742 | 738 | 777 | 769 | 772 | 753 | 739 | 729 |
| 1/16/2018 | 709 | 715 | 714 | 718 | 726 | 743 | 772 | 809 | 823 | 825 | 818 | 808 | 808 | 799 | 752 | 746 | 754 | 772 | 800 | 797 | 791 | 780 | 756 | 730 |
| 1/17/2018 | 708 | 701 | 696 | 700 | 702 | 706 | 734 | 770 | 769 | 779 | 761 | 740 | 724 | 719 | 707 | 690 | 693 | 714 | 750 | 767 | 761 | 755 | 741 | 720 |
| 1/18/2018 | 698 | 688 | 690 | 683 | 683 | 694 | 729 | 762 | 767 | 749 | 730 | 719 | 686 | 678 | 673 | 662 | 658 | 668 | 710 | 713 | 719 | 706 | 691 | 651 |
| 1/19/2018 | 638 | 618 | 614 | 617 | 617 | 632 | 660 | 689 | 696 | 687 | 670 | 651 | 639 | 631 | 607 | 609 | 598 | 604 | 644 | 642 | 632 | 627 | 602 | 587 |
| 1/20/2018 | 557 | 552 | 540 | 538 | 536 | 545 | 543 | 550 | 558 | 555 | 550 | 538 | 525 | 526 | 520 | 516 | 521 | 531 | 551 | 552 | 545 | 535 | 515 | 496 |
| 1/21/2018 | 467 | 458 | 447 | 446 | 444 | 440 | 456 | 464 | 477 | 486 | 499 | 501 | 496 | 501 | 498 | 496 | 497 | 507 | 540 | 536 | 536 | 515 | 495 | 469 |
| 1/22/2018 | 439 | 440 | 431 | 424 | 429 | 448 | 489 | 547 | 563 | 582 | 582 | 581 | 596 | 590 | 582 | 569 | 564 | 562 | 589 | 595 | 597 | 583 | 571 | 537 |
| 1/23/2018 | 510 | 495 | 503 | 491 | 509 | 514 | 556 | 600 | 624 | 627 | 623 | 628 | 619 | 623 | 630 | 629 | 638 | 647 | 668 | 663 | 657 | 646 | 621 | 590 |
| 1/24/2018 | 560 | 549 | 549 | 540 | 545 | 554 | 594 | 629 | 638 | 645 | 640 | 624 | 616 | 603 | 599 | 586 | 579 | 600 | 635 | 648 | 652 | 645 | 629 | 600 |
| 1/25/2018 | 589 | 587 | 582 | 577 | 588 | 603 | 627 | 682 | 679 | 659 | 646 | 624 | 615 | 602 | 594 | 581 | 574 | 580 | 607 | 621 | 616 | 615 | 590 | 566 |
| 1/26/2018 | 539 | 537 | 528 | 530 | 530 | 540 | 572 | 618 | 632 | 612 | 606 | 595 | 579 | 585 | 568 | 562 | 556 | 553 | 577 | 586 | 583 | 572 | 562 | 537 |
| 1/27/2018 | 508 | 493 | 479 | 481 | 477 | 484 | 486 | 502 | 519 | 530 | 545 | 554 | 555 | 553 | 546 | 540 | 546 | 541 | 556 | 567 | 551 | 562 | 546 | 526 |
| 1/28/2018 | 506 | 494 | 491 | 492 | 499 | 505 | 507 | 525 | 531 | 531 | 524 | 510 | 504 | 496 | 488 | 478 | 485 | 495 | 542 | 552 | 558 | 549 | 534 | 509 |
| 1/29/2018 | 494 | 483 | 475 | 478 | 495 | 506 | 561 | 614 | 634 | 639 | 653 | 654 | 653 | 652 | 657 | 654 | 663 | 663 | 684 | 675 | 682 | 669 | 642 | 615 |
| 1/30/2018 | 589 | 570 | 568 | 566 | 576 | 600 | 631 | 682 | 686 | 682 | 666 | 652 | 633 | 629 | 610 | 612 | 606 | 612 | 658 | 667 | 671 | 658 | 643 | 615 |
| 1/31/2018 | 591 | 578 | 573 | 569 | 567 | 583 | 617 | 661 | 671 | 649 | 650 | 640 | 617 | 608 | 597 | 592 | 579 | 583 | 619 | 616 | 618 | 612 | 586 | 560 |
| 2/1/2018 | 526 | 513 | 513 | 507 | 503 | 524 | 546 | 583 | 607 | 612 | 617 | 616 | 613 | 628 | 635 | 652 | 655 | 664 | 674 | 692 | 692 | 695 | 668 | 636 |
| 2/2/2018 | 625 | 610 | 617 | 614 | 623 | 632 | 673 | 718 | 721 | 710 | 694 | 687 | 663 | 655 | 641 | 632 | 615 | 629 | 667 | 677 | 684 | 687 | 661 | 631 |
| 2/3/2018 | 615 | 596 | 599 | 587 | 595 | 591 | 589 | 599 | 604 | 609 | 619 | 621 | 598 | 585 | 567 | 556 | 561 | 572 | 596 | 593 | 591 | 576 | 550 | 519 |
| 2/4/2018 | 512 | 485 | 487 | 472 | 478 | 481 | 488 | 499 | 510 | 511 | 520 | 512 | 509 | 517 | 523 | 545 | 559 | 584 | 604 | 615 | 611 | 617 | 606 | 594 |
| 2/5/2018 | 585 | 568 | 568 | 563 | 579 | 601 | 645 | 709 | 722 | 704 | 682 | 683 | 663 | 650 | 635 | 629 | 622 | 647 | 681 | 686 | 688 | 672 | 644 | 598 |
| 2/6/2018 | 580 | 562 | 571 | 558 | 564 | 580 | 613 | 650 | 665 | 669 | 667 | 670 | 643 | 630 | 613 | 616 | 610 | 621 | 646 | 656 | 653 | 646 | 620 | 595 |
| 2/7/2018 | 571 | 549 | 555 | 548 | 559 | 575 | 614 | 645 | 663 | 672 | 682 | 694 | 676 | 658 | 656 | 653 | 649 | 642 | 671 | 639 | 657 | 664 | 638 | 611 |
| 2/8/2018 | 596 | 593 | 592 | 593 | 602 | 619 | 656 | 695 | 706 | 684 | 673 | 651 | 621 | 624 | 605 | 594 | 598 | 593 | 626 | 645 | 642 | 642 | 624 | 589 |
| 2/9/2018 | 571 | 559 | 555 | 550 | 549 | 560 | 582 | 623 | 635 | 623 | 614 | 605 | 592 | 576 | 577 | 560 | 552 | 554 | 568 | 576 | 562 | 564 | 543 | 525 |
| 2/10/2018 | 501 | 497 | 490 | 484 | 484 | 478 | 485 | 494 | 508 | 524 | 546 | 555 | 546 | 544 | 542 | 535 | 532 | 540 | 566 | 562 | 559 | 548 | 530 | 516 |
| 2/11/2018 | 495 | 477 | 476 | 464 | 471 | 480 | 486 | 513 | 524 | 546 | 559 | 571 | 578 | 583 | 591 | 589 | 598 | 604 | 625 | 633 | 626 | 614 | 598 | 568 |
| 2/12/2018 | 548 | 548 | 545 | 546 | 556 | 575 | 628 | 681 | 694 | 685 | 672 | 661 | 646 | 629 | 627 | 611 | 610 | 613 | 637 | 660 | 665 | 656 | 633 | 608 |
| 2/13/2018 | 580 | 578 | 574 | 578 | 580 | 590 | 624 | 673 | 679 | 679 | 671 | 657 | 638 | 626 | 615 | 599 | 586 | 584 | 614 | 622 | 622 | 605 | 582 | 558 |
| 2/14/2018 | 529 | 524 | 516 | 507 | 507 | 512 | 540 | 581 | 594 | 599 | 599 | 594 | 589 | 590 | 585 | 575 | 578 | 577 | 581 | 583 | 576 | 571 | 550 | 523 |
| 2/15/2018 | 497 | 484 | 474 | 468 | 469 | 475 | 501 | 545 | 557 | 565 | 574 | 570 | 570 | 569 | 575 | 575 | 568 | 557 | 577 | 591 | 586 | 574 | 555 | 519 |
| 2/16/2018 | 495 | 480 | 463 | 462 | 461 | 456 | 482 | 530 | 551 | 573 | 581 | 589 | 588 | 585 | 589 | 595 | 583 | 589 | 593 | 597 | 587 | 585 | 563 | 543 |
| 2/17/2018 | 519 | 508 | 501 | 507 | 501 | 512 | 511 | 519 | 526 | 540 | 564 | 580 | 575 | 578 | 561 | 561 | 553 | 560 | 565 | 570 | 558 | 544 | 534 | 520 |
| 2/18/2018 | 498 | 497 | 494 | 495 | 495 | 503 | 512 | 527 | 526 | 532 | 518 | 499 | 495 | 490 | 477 | 473 | 477 | 483 | 518 | 540 | 532 | 527 | 501 | 473 |
| 2/19/2018 | 459 | 448 | 441 | 432 | 435 | 461 | 488 | 536 | 543 | 546 | 560 | 569 | 559 | 566 | 566 | 559 | 551 | 560 | 567 | 577 | 582 | 567 | 537 | 510 |
| 2/20/2018 | 488 | 474 | 463 | 457 | 457 | 462 | 496 | 528 | 539 | 554 | 559 | 573 | 571 | 578 | 578 | 589 | 573 | 569 | 580 | 595 | 593 | 580 | 556 | 526 |
| 2/21/2018 | 496 | 475 | 460 | 447 | 442 | 454 | 480 | 530 | 554 | 563 | 574 | 581 | 585 | 590 | 595 | 586 | 593 | 599 | 613 | 618 | 606 | 599 | 575 | 548 |
| 2/22/2018 | 522 | 515 | 513 | 511 | 510 | 518 | 542 | 583 | 591 | 596 | 593 | 594 | 582 | 578 | 587 | 580 | 565 | 571 | 582 | 584 | 584 | 579 | 555 | 532 |
| 2/23/2018 | 506 | 492 | 492 | 478 | 482 | 493 | 519 | 554 | 561 | 573 | 569 | 570 | 571 | 568 | 567 | 564 | 565 | 553 | 558 | 566 | 561 | 561 | 544 | 519 |
| 2/24/2018 | 491 | 479 | 468 | 464 | 463 | 466 | 476 | 490 | 506 | 525 | 547 | 546 | 547 | 547 | 541 | 537 | 534 | 545 | 566 | 564 | 561 | 544 | 525 | 502 |
| 2/25/2018 | 481 | 457 | 452 | 452 | 446 | 446 | 454 | 452 | 464 | 484 | 489 | 495 | 487 | 483 | 471 | 476 | 476 | 493 | 511 | 546 | 536 | 535 | 510 | 486 |
| 2/26/2018 | 474 | 468 | 464 | 470 | 465 | 499 | 535 | 586 | 590 | 578 | 574 | 569 | 559 | 560 | 557 | 548 | 545 | 544 | 551 | 578 | 579 | 579 | 560 | 529 |
| 2/27/2018 | 515 | 504 | 504 | 497 | 506 | 524 | 556 | 591 | 595 | 580 | 564 | 568 | 551 | 558 | 551 | 549 | 539 | 543 | 557 | 577 | 566 | 568 | 539 | 514 |
| 2/28/2018 | 485 | 471 | 463 | 462 | 467 | 477 | 497 | 542 | 550 | 554 | 560 | 562 | 556 | 557 | 560 | 559 | 561 | 552 | 567 | 578 | 569 | 558 | 532 | 505 |
| 3/1/2018 | 471 | 465 | 458 | 449 | 440 | 445 | 475 | 522 | 532 | 542 | 553 | 555 | 542 | 553 | 549 | 551 | 552 | 542 | 565 | 574 | 569 | 571 | 542 | 527 |
| 3/2/2018 | 497 | 488 | 491 | 490 | 491 | 506 | 544 | 575 | 578 | 562 | 559 | 550 | 538 | 537 | 534 | 524 | 517 | 514 | 524 | 535 | 547 | 547 | 539 | 517 |
| 3/3/2018 | 499 | 483 | 479 | 481 | 483 | 488 | 507 | 502 | 508 | 498 | 493 | 490 | 479 | 464 | 460 | 455 | 445 | 449 | 464 | 484 | 490 | 486 | 478 | 456 |
| 3/4/2018 | 433 | 428 | 424 | 425 | 427 | 436 | 445 | 459 | 466 | 471 | 475 | 464 | 459 | 454 | 451 | 444 | 448 | 455 | 481 | 506 | 504 | 501 | 487 | 461 |
| 3/5/2018 | 449 | 445 | 443 | 442 | 446 | 466 | 502 | 547 | 559 | 572 | 579 | 572 | 581 | 577 | 572 | 577 | 576 | 579 | 584 | 591 | 588 | 563 | 550 | 523 |
| 3/6/2018 | 495 | 495 | 487 | 483 | 484 | 509 | 545 | 573 | 575 | 564 | 564 | 548 | 551 | 552 | 542 | 546 | 547 | 559 | 561 | 593 | 590 | 583 | 565 | 534 |

| Dt | Hour1 | Hour2 | Hour3 | Hour4 | Hour5 | Hour6 | Hour7 | Hour8 | Hour9 | Hour10 | Hour11 | Hour12 | Hour13 | Hour14 | Hour15 | Hour16 | Hour17 | Hour18 | Hour19 | Hour20 | Hour21 | Hour22 | Hour23 | Hour24 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 3/7/2018 | 515 | 510 | 500 | 509 | 517 | 519 | 550 | 592 | 608 | 596 | 598 | 608 | 605 | 598 | 591 | 595 | 593 | 594 | 603 | 626 | 614 | 607 | 593 | 566 |
| 3/8/2018 | 544 | 533 | 532 | 525 | 529 | 545 | 585 | 624 | 629 | 613 | 618 | 612 | 603 | 594 | 589 | 577 | 571 | 577 | 598 | 609 | 625 | 627 | 608 | 585 |
| 3/9/2018 | 560 | 558 | 557 | 561 | 562 | 580 | 607 | 643 | 646 | 636 | 624 | 611 | 588 | 576 | 562 | 570 | 554 | 556 | 566 | 583 | 577 | 574 | 564 | 539 |
| 3/10/2018 | 507 | 504 | 486 | 491 | 484 | 492 | 498 | 502 | 515 | 520 | 520 | 507 | 498 | 478 | 482 | 472 | 469 | 477 | 488 | 519 | 513 | 509 | 497 | 472 |
| 3/11/2018 | 447 | 440 | 429 | 432 | 430 | 446 | 460 | 466 | 482 | 486 | 490 | 499 | 503 | 506 | 517 | 530 | 547 | 554 | 569 | 587 | 575 | 559 | 518 | 498 |
| 3/12/2018 | 493 | 479 | 489 | 495 | 512 | 551 | 591 | 614 | 618 | 616 | 609 | 608 | 621 | 634 | 627 | 622 | 619 | 608 | 610 | 632 | 629 | 606 | 573 | 553 |
| 3/13/2018 | 538 | 542 | 533 | 538 | 553 | 587 | 641 | 655 | 635 | 623 | 613 | 596 | 614 | 595 | 588 | 577 | 588 | 585 | 599 | 624 | 619 | 607 | 573 | 554 |
| 3/14/2018 | 543 | 543 | 544 | 554 | 567 | 608 | 654 | 681 | 652 | 642 | 612 | 606 | 589 | 582 | 580 | 571 | 559 | 558 | 570 | 604 | 617 | 593 | 564 | 538 |
| 3/15/2018 | 538 | 515 | 512 | 518 | 526 | 552 | 599 | 611 | 596 | 585 | 577 | 573 | 564 | 561 | 545 | 558 | 544 | 533 | 542 | 566 | 562 | 548 | 521 | 498 |
| 3/16/2018 | 488 | 483 | 475 | 480 | 486 | 518 | 569 | 587 | 596 | 600 | 608 | 593 | 587 | 572 | 579 | 561 | 554 | 547 | 560 | 575 | 573 | 560 | 538 | 505 |
| 3/17/2018 | 485 | 474 | 477 | 477 | 480 | 491 | 514 | 514 | 533 | 547 | 540 | 529 | 528 | 519 | 511 | 498 | 495 | 505 | 516 | 529 | 529 | 522 | 504 | 489 |
| 3/18/2018 | 467 | 466 | 453 | 455 | 456 | 453 | 468 | 477 | 482 | 486 | 498 | 485 | 482 | 475 | 468 | 471 | 467 | 478 | 483 | 517 | 514 | 500 | 470 | 453 |
| 3/19/2018 | 446 | 441 | 445 | 450 | 473 | 512 | 564 | 585 | 585 | 582 | 577 | 570 | 571 | 569 | 578 | 566 | 580 | 567 | 585 | 597 | 588 | 565 | 528 | 500 |
| 3/20/2018 | 480 | 481 | 480 | 484 | 506 | 535 | 576 | 613 | 613 | 620 | 631 | 623 | 626 | 625 | 625 | 625 | 622 | 622 | 632 | 641 | 638 | 615 | 582 | 557 |
| 3/21/2018 | 543 | 538 | 540 | 532 | 543 | 573 | 613 | 633 | 625 | 630 | 614 | 616 | 600 | 595 | 575 | 567 | 557 | 552 | 563 | 594 | 600 | 578 | 550 | 527 |
| 3/22/2018 | 515 | 519 | 516 | 519 | 542 | 575 | 623 | 632 | 618 | 600 | 587 | 571 | 564 | 556 | 546 | 542 | 536 | 526 | 538 | 566 | 574 | 554 | 529 | 492 |
| 3/23/2018 | 488 | 478 | 471 | 475 | 492 | 508 | 572 | 576 | 591 | 589 | 583 | 582 | 571 | 569 | 549 | 545 | 533 | 535 | 547 | 563 | 555 | 549 | 527 | 508 |
| 3/24/2018 | 484 | 490 | 478 | 480 | 481 | 489 | 508 | 514 | 545 | 559 | 567 | 566 | 564 | 554 | 562 | 560 | 557 | 559 | 553 | 575 | 561 | 546 | 523 | 510 |
| 3/25/2018 | 487 | 473 | 471 | 471 | 463 | 484 | 489 | 505 | 524 | 536 | 531 | 520 | 507 | 497 | 500 | 495 | 504 | 510 | 514 | 534 | 530 | 522 | 498 | 471 |
| 3/26/2018 | 468 | 456 | 456 | 460 | 494 | 519 | 565 | 577 | 578 | 575 | 582 | 581 | 574 | 569 | 569 | 567 | 571 | 575 | 573 | 586 | 581 | 559 | 524 | 503 |
| 3/27/2018 | 486 | 476 | 478 | 467 | 478 | 493 | 532 | 547 | 557 | 567 | 572 | 569 | 573 | 567 | 570 | 565 | 570 | 555 | 563 | 564 | 570 | 546 | 519 | 487 |
| 3/28/2018 | 472 | 463 | 462 | 454 | 467 | 487 | 518 | 543 | 571 | 569 | 572 | 573 | 565 | 569 | 564 | 555 | 554 | 541 | 551 | 565 | 565 | 549 | 519 | 493 |
| 3/29/2018 | 474 | 472 | 465 | 455 | 470 | 491 | 529 | 542 | 553 | 565 | 569 | 576 | 569 | 561 | 566 | 556 | 552 | 545 | 559 | 570 | 570 | 549 | 517 | 482 |
| 3/30/2018 | 465 | 465 | 446 | 455 | 460 | 483 | 509 | 530 | 538 | 545 | 525 | 518 | 517 | 510 | 502 | 502 | 488 | 492 | 490 | 507 | 522 | 514 | 488 | 471 |
| 3/31/2018 | 459 | 458 | 452 | 461 | 468 | 466 | 470 | 472 | 481 | 480 | 478 | 472 | 467 | 457 | 459 | 457 | 465 | 464 | 476 | 476 | 478 | 464 | 454 | 425 |
| 4/1/2018 | 408 | 403 | 398 | 398 | 401 | 410 | 431 | 445 | 464 | 463 | 469 | 454 | 450 | 431 | 435 | 441 | 459 | 476 | 499 | 521 | 525 | 511 | 503 | 488 |
| 4/2/2018 | 564 | 560 | 556 | 554 | 583 | 623 | 677 | 692 | 707 | 710 | 700 | 700 | 693 | 691 | 682 | 679 | 680 | 672 | 681 | 702 | 700 | 665 | 628 | 607 |
| 4/3/2018 | 575 | 565 | 570 | 559 | 571 | 589 | 630 | 637 | 639 | 640 | 646 | 647 | 655 | 655 | 655 | 644 | 646 | 648 | 656 | 650 | 639 | 615 | 589 | 575 |
| 4/4/2018 | 556 | 563 | 570 | 571 | 593 | 626 | 677 | 691 | 697 | 703 | 692 | 688 | 684 | 675 | 664 | 654 | 653 | 660 | 663 | 657 | 664 | 680 | 652 | 631 |
| 4/5/2018 | 629 | 622 | 622 | 639 | 645 | 680 | 719 | 725 | 709 | 687 | 675 | 657 | 656 | 647 | 639 | 628 | 548 | 533 | 538 | 568 | 583 | 560 | 525 | 518 |
| 4/6/2018 | 504 | 486 | 489 | 480 | 495 | 523 | 560 | 564 | 568 | 551 | 554 | 544 | 546 | 538 | 530 | 536 | 527 | 521 | 531 | 558 | 561 | 558 | 544 | 515 |
| 4/7/2018 | 508 | 509 | 508 | 509 | 509 | 520 | 540 | 537 | 554 | 561 | 560 | 534 | 528 | 508 | 503 | 490 | 489 | 488 | 494 | 516 | 527 | 526 | 505 | 488 |
| 4/8/2018 | 481 | 479 | 475 | 481 | 481 | 495 | 507 | 514 | 524 | 514 | 506 | 503 | 497 | 492 | 484 | 484 | 504 | 505 | 526 | 537 | 539 | 517 | 496 | 464 |
| 4/9/2018 | 469 | 470 | 471 | 473 | 495 | 528 | 585 | 597 | 596 | 587 | 572 | 561 | 554 | 545 | 529 | 539 | 529 | 525 | 546 | 571 | 569 | 553 | 522 | 491 |
| 4/10/2018 | 484 | 478 | 476 | 479 | 498 | 536 | 574 | 587 | 587 | 580 | 580 | 573 | 567 | 572 | 560 | 561 | 561 | 552 | 564 | 579 | 595 | 579 | 550 | 521 |
| 4/11/2018 | 518 | 518 | 516 | 510 | 528 | 541 | 587 | 586 | 575 | 570 | 563 | 562 | 554 | 550 | 550 | 535 | 533 | 525 | 522 | 557 | 562 | 541 | 516 | 478 |
| 4/12/2018 | 468 | 459 | 453 | 452 | 461 | 490 | 528 | 541 | 546 | 547 | 556 | 556 | 558 | 566 | 564 | 561 | 555 | 556 | 545 | 569 | 569 | 542 | 509 | 483 |
| 4/13/2018 | 458 | 446 | 444 | 438 | 449 | 475 | 511 | 526 | 548 | 562 | 567 | 567 | 577 | 573 | 564 | 565 | 570 | 559 | 560 | 571 | 572 | 567 | 527 | 493 |
| 4/14/2018 | 477 | 462 | 456 | 445 | 438 | 442 | 450 | 462 | 474 | 492 | 499 | 503 | 492 | 494 | 495 | 492 | 488 | 492 | 494 | 499 | 501 | 476 | 460 | 438 |
| 4/15/2018 | 410 | 405 | 396 | 394 | 390 | 403 | 405 | 434 | 449 | 459 | 470 | 474 | 478 | 472 | 473 | 474 | 484 | 498 | 505 | 521 | 518 | 508 | 487 | 467 |
| 4/16/2018 | 462 | 458 | 459 | 465 | 486 | 527 | 582 | 606 | 622 | 662 | 674 | 623 | 632 | 622 | 620 | 618 | 616 | 615 | 610 | 614 | 620 | 605 | 571 | 540 |
| 4/17/2018 | 532 | 530 | 544 | 535 | 557 | 587 | 624 | 612 | 601 | 586 | 580 | 565 | 563 | 556 | 549 | 541 | 532 | 534 | 530 | 546 | 563 | 538 | 507 | 481 |
| 4/18/2018 | 473 | 462 | 463 | 469 | 480 | 513 | 538 | 555 | 554 | 558 | 550 | 561 | 524 | 567 | 584 | 572 | 572 | 548 | 543 | 550 | 555 | 525 | 494 | 466 |
| 4/19/2018 | 457 | 455 | 454 | 456 | 474 | 513 | 545 | 576 | 577 | 584 | 580 | 577 | 537 | 552 | 549 | 535 | 536 | 514 | 521 | 538 | 559 | 541 | 511 | 489 |
| 4/20/2018 | 484 | 478 | 475 | 474 | 492 | 524 | 557 | 561 | 561 | 551 | 545 | 540 | 532 | 531 | 523 | 519 | 512 | 507 | 497 | 496 | 518 | 514 | 479 | 457 |
| 4/21/2018 | 447 | 437 | 431 | 441 | 445 | 454 | 462 | 481 | 483 | 491 | 492 | 485 | 487 | 487 | 480 | 478 | 478 | 476 | 475 | 499 | 508 | 489 | 469 | 432 |
| 4/22/2018 | 413 | 414 | 397 | 393 | 391 | 385 | 390 | 405 | 425 | 427 | 435 | 442 | 438 | 448 | 447 | 447 | 450 | 469 | 465 | 480 | 476 | 467 | 438 | 415 |
| 4/23/2018 | 411 | 390 | 396 | 397 | 426 | 446 | 503 | 526 | 535 | 558 | 557 | 550 | 551 | 550 | 548 | 540 | 546 | 537 | 544 | 553 | 555 | 531 | 505 | 474 |
| 4/24/2018 | 454 | 447 | 437 | 440 | 446 | 473 | 502 | 525 | 532 | 538 | 541 | 543 | 547 | 542 | 539 | 543 | 539 | 541 | 544 | 555 | 543 | 533 | 494 | 471 |
| 4/25/2018 | 453 | 452 | 443 | 441 | 458 | 476 | 517 | 528 | 519 | 538 | 538 | 543 | 547 | 545 | 559 | 554 | 542 | 531 | 538 | 539 | 555 | 533 | 491 | 469 |
| 4/26/2018 | 452 | 437 | 436 | 432 | 432 | 467 | 540 | 511 | 530 | 532 | 534 | 533 | 541 | 540 | 545 | 541 | 533 | 531 | 524 | 530 | 541 | 520 | 487 | 445 |
| 4/27/2018 | 448 | 423 | 424 | 429 | 437 | 469 | 499 | 522 | 515 | 525 | 530 | 530 | 535 | 542 | 530 | 524 | 523 | 508 | 509 | 509 | 525 | 509 | 476 | 443 |
| 4/28/2018 | 429 | 415 | 407 | 408 | 407 | 409 | 419 | 422 | 435 | 448 | 447 | 437 | 444 | 446 | 435 | 444 | 443 | 446 | 442 | 451 | 464 | 442 | 427 | 407 |
| 4/29/2018 | 392 | 382 | 380 | 384 | 387 | 398 | 408 | 414 | 431 | 434 | 439 | 434 | 435 | 436 | 434 | 430 | 438 | 452 | 451 | 464 | 467 | 462 | 427 | 413 |
| 4/30/2018 | 398 | 402 | 402 | 407 | 427 | 458 | 513 | 518 | 567 | 612 | 617 | 611 | 619 | 622 | 621 | 630 | 578 | 547 | 538 | 541 | 556 | 538 | 490 | 457 |
| 5/1/2018 | 441 | 429 | 428 | 426 | 433 | 452 | 494 | 520 | 525 | 545 | 554 | 562 | 573 | 578 | 589 | 605 | 595 | 601 | 595 | 597 | 606 | 581 | 538 | 501 |
| 5/2/2018 | 471 | 459 | 452 | 449 | 449 | 473 | 516 | 530 | 561 | 576 | 602 | 612 | 637 | 661 | 662 | 674 | 677 | 668 | 659 | 664 | 676 | 650 | 597 | 557 |
| 5/3/2018 | 534 | 513 | 501 | 498 | 491 | 519 | 552 | 581 | 599 | 606 | 620 | 621 | 628 | 628 | 620 | 608 | 598 | 596 | 587 | 599 | 596 | 569 | 539 | 502 |
| 5/4/2018 | 484 | 477 | 470 | 464 | 471 | 497 | 527 | 556 | 589 | 603 | 616 | 633 | 631 | 639 | 636 | 639 | 608 | 595 | 585 | 591 | 585 | 564 | 524 | 490 |
| 5/5/2018 | 463 | 453 | 442 | 436 | 426 | 436 | 431 | 441 | 459 | 476 | 479 | 478 | 485 | 477 | 480 | 476 | 479 | 470 | 470 | 476 | 484 | 474 | 445 | 418 |
| 5/6/2018 | 399 | 389 | 378 | 378 | 370 | 381 | 373 | 398 | 421 | 443 | 454 | 473 | 495 | 508 | 516 | 527 | 540 | 552 | 541 | 542 | 546 | 514 | 477 | 434 |
| 5/7/2018 | 409 | 397 | 392 | 400 | 406 | 438 | 467 | 506 | 538 | 542 | 565 | 569 | 589 | 598 | 607 | 616 | 614 | 605 | 600 | 586 | 597 | 556 | 516 | 477 |
| 5/8/2018 | 453 | 438 | 424 | 426 | 425 | 453 | 475 | 502 | 521 | 537 | 560 | 563 | 583 | 593 | 609 | 620 | 616 | 619 | 611 | 596 | 610 | 568 | 520 | 476 |
| 5/9/2018 | 457 | 442 | 431 | 425 | 436 | 451 | 478 | 510 | 533 | 562 | 587 | 611 | 639 | 643 | 639 | 655 | 677 | 661 | 659 | 651 | 668 | 627 | 588 | 542 |
| 5/10/2018 | 516 | 496 | 476 | 472 | 461 | 487 | 515 | 554 | 581 | 620 | 645 | 672 | 702 | 726 | 758 | 766 | 775 | 719 | 684 | 673 | 665 | 620 | 582 | 536 |

| Dt | Hour1 | Hour2 | Hour3 | Hour4 | Hour5 | Hour6 | Hour7 | Hour8 | Hour9 | Hour10 | Hour11 | Hour12 | Hour13 | Hour14 | Hour15 | Hour16 | Hour17 | Hour18 | Hour19 | Hour20 | Hour21 | Hour22 | Hour23 | Hour24 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 5/11/2018 | 506 | 476 | 476 | 469 | 470 | 491 | 519 | 561 | 593 | 625 | 650 | 678 | 703 | 741 | 759 | 784 | 766 | 760 | 713 | 685 | 686 | 646 | 609 | 549 |
| 5/12/2018 | 522 | 496 | 478 | 470 | 466 | 454 | 440 | 480 | 512 | 557 | 601 | 629 | 660 | 652 | 675 | 693 | 710 | 692 | 676 | 658 | 652 | 617 | 567 | 526 |
| 5/13/2018 | 486 | 461 | 449 | 419 | 423 | 429 | 419 | 452 | 497 | 550 | 602 | 638 | 660 | 685 | 711 | 728 | 734 | 741 | 718 | 706 | 685 | 647 | 597 | 548 |
| 5/14/2018 | 517 | 495 | 479 | 465 | 480 | 506 | 553 | 607 | 651 | 701 | 747 | 789 | 822 | 856 | 882 | 898 | 900 | 886 | 860 | 829 | 813 | 764 | 697 | 624 |
| 5/15/2018 | 586 | 554 | 541 | 519 | 509 | 534 | 569 | 613 | 643 | 687 | 711 | 752 | 778 | 814 | 846 | 856 | 856 | 827 | 811 | 794 | 779 | 737 | 666 | 609 |
| 5/16/2018 | 574 | 547 | 530 | 524 | 521 | 548 | 583 | 604 | 611 | 628 | 640 | 644 | 677 | 717 | 746 | 762 | 783 | 787 | 771 | 748 | 735 | 699 | 631 | 582 |
| 5/17/2018 | 551 | 527 | 512 | 504 | 509 | 539 | 570 | 615 | 642 | 677 | 697 | 719 | 752 | 774 | 788 | 803 | 809 | 788 | 761 | 743 | 724 | 680 | 628 | 580 |
| 5/18/2018 | 539 | 534 | 519 | 513 | 510 | 530 | 564 | 592 | 611 | 623 | 630 | 628 | 629 | 641 | 651 | 671 | 661 | 661 | 646 | 643 | 637 | 618 | 576 | 530 |
| 5/19/2018 | 496 | 478 | 468 | 457 | 453 | 456 | 448 | 476 | 507 | 520 | 548 | 576 | 602 | 629 | 647 | 679 | 690 | 687 | 658 | 632 | 636 | 607 | 572 | 522 |
| 5/20/2018 | 489 | 456 | 439 | 428 | 419 | 415 | 423 | 458 | 497 | 548 | 572 | 602 | 643 | 679 | 708 | 732 | 734 | 718 | 694 | 665 | 644 | 618 | 566 | 525 |
| 5/21/2018 | 498 | 481 | 464 | 462 | 476 | 508 | 550 | 593 | 625 | 652 | 674 | 712 | 748 | 793 | 785 | 769 | 739 | 713 | 708 | 703 | 702 | 713 | 621 | 577 |
| 5/22/2018 | 546 | 521 | 514 | 506 | 508 | 529 | 568 | 615 | 647 | 689 | 722 | 757 | 794 | 820 | 843 | 860 | 861 | 851 | 821 | 787 | 766 | 722 | 662 | 596 |
| 5/23/2018 | 567 | 534 | 515 | 508 | 506 | 523 | 556 | 595 | 624 | 665 | 701 | 731 | 778 | 789 | 820 | 836 | 839 | 834 | 814 | 775 | 759 | 711 | 652 | 595 |
| 5/24/2018 | 558 | 532 | 515 | 501 | 499 | 514 | 542 | 584 | 625 | 664 | 702 | 738 | 759 | 796 | 822 | 835 | 828 | 830 | 798 | 769 | 746 | 698 | 640 | 591 |
| 5/25/2018 | 545 | 520 | 496 | 491 | 494 | 500 | 531 | 577 | 624 | 667 | 714 | 745 | 789 | 820 | 844 | 830 | 793 | 763 | 729 | 699 | 698 | 668 | 617 | 567 |
| 5/26/2018 | 537 | 513 | 497 | 493 | 483 | 476 | 477 | 505 | 529 | 587 | 619 | 656 | 689 | 722 | 745 | 767 | 773 | 776 | 758 | 728 | 710 | 676 | 629 | 594 |
| 5/27/2018 | 548 | 523 | 497 | 478 | 474 | 463 | 466 | 504 | 549 | 615 | 673 | 720 | 749 | 779 | 800 | 810 | 803 | 779 | 757 | 729 | 712 | 680 | 629 | 566 |
| 5/28/2018 | 534 | 500 | 478 | 463 | 461 | 466 | 462 | 494 | 536 | 604 | 656 | 701 | 741 | 762 | 779 | 799 | 809 | 779 | 730 | 688 | 681 | 645 | 596 | 558 |
| 5/29/2018 | 529 | 513 | 506 | 501 | 518 | 533 | 573 | 618 | 654 | 669 | 709 | 755 | 794 | 836 | 844 | 814 | 783 | 756 | 732 | 763 | 728 | 710 | 663 | 617 |
| 5/30/2018 | 591 | 566 | 559 | 562 | 559 | 569 | 610 | 635 | 664 | 676 | 711 | 730 | 748 | 735 | 795 | 820 | 827 | 822 | 809 | 782 | 775 | 749 | 686 | 635 |
| 5/31/2018 | 597 | 577 | 562 | 555 | 547 | 574 | 601 | 646 | 705 | 734 | 790 | 756 | 694 | 672 | 678 | 684 | 697 | 712 | 697 | 700 | 698 | 669 | 626 | 586 |
| 6/1/2018 | 554 | 534 | 515 | 507 | 520 | 576 | 629 | 671 | 712 | 768 | 798 | 847 | 886 | 920 | 948 | 959 | 934 | 902 | 780 | 742 | 730 | 703 | 661 | 604 |
| 6/2/2018 | 570 | 548 | 528 | 522 | 512 | 504 | 508 | 540 | 603 | 659 | 715 | 753 | 793 | 819 | 817 | 823 | 814 | 811 | 797 | 773 | 749 | 716 | 669 | 618 |
| 6/3/2018 | 582 | 542 | 512 | 502 | 492 | 487 | 490 | 521 | 559 | 590 | 608 | 623 | 643 | 655 | 660 | 682 | 692 | 694 | 673 | 650 | 633 | 608 | 552 | 512 |
| 6/4/2018 | 480 | 463 | 443 | 439 | 450 | 467 | 501 | 550 | 585 | 612 | 640 | 654 | 670 | 690 | 703 | 709 | 712 | 694 | 679 | 655 | 665 | 626 | 586 | 544 |
| 6/5/2018 | 510 | 496 | 484 | 476 | 479 | 493 | 520 | 565 | 606 | 634 | 666 | 686 | 713 | 748 | 771 | 794 | 801 | 802 | 784 | 753 | 733 | 692 | 630 | 573 |
| 6/6/2018 | 544 | 520 | 501 | 493 | 491 | 502 | 530 | 580 | 614 | 649 | 693 | 732 | 764 | 797 | 827 | 857 | 857 | 847 | 828 | 795 | 774 | 733 | 668 | 614 |
| 6/7/2018 | 575 | 548 | 528 | 522 | 516 | 523 | 561 | 615 | 657 | 713 | 766 | 813 | 857 | 882 | 914 | 924 | 927 | 904 | 891 | 861 | 838 | 789 | 734 | 680 |
| 6/8/2018 | 634 | 601 | 580 | 556 | 557 | 560 | 597 | 647 | 700 | 750 | 808 | 853 | 884 | 918 | 944 | 936 | 937 | 909 | 887 | 851 | 838 | 799 | 740 | 683 |
| 6/9/2018 | 640 | 605 | 585 | 557 | 544 | 528 | 535 | 569 | 633 | 683 | 738 | 787 | 809 | 825 | 809 | 751 | 694 | 659 | 647 | 628 | 618 | 603 | 575 | 538 |
| 6/10/2018 | 504 | 482 | 471 | 452 | 455 | 450 | 460 | 484 | 529 | 570 | 581 | 608 | 641 | 676 | 730 | 776 | 795 | 795 | 761 | 684 | 654 | 615 | 581 | 541 |
| 6/11/2018 | 501 | 494 | 485 | 480 | 495 | 514 | 552 | 589 | 635 | 679 | 704 | 734 | 758 | 781 | 818 | 854 | 875 | 883 | 867 | 822 | 794 | 756 | 690 | 619 |
| 6/12/2018 | 577 | 551 | 541 | 527 | 528 | 549 | 578 | 612 | 634 | 649 | 654 | 686 | 731 | 792 | 844 | 859 | 798 | 739 | 706 | 695 | 687 | 663 | 619 | 580 |
| 6/13/2018 | 555 | 533 | 524 | 518 | 521 | 531 | 560 | 611 | 637 | 671 | 723 | 761 | 806 | 840 | 879 | 890 | 906 | 900 | 874 | 841 | 830 | 788 | 722 | 661 |
| 6/14/2018 | 623 | 587 | 569 | 544 | 547 | 555 | 582 | 631 | 676 | 725 | 765 | 813 | 837 | 862 | 882 | 899 | 895 | 886 | 855 | 809 | 791 | 748 | 685 | 634 |
| 6/15/2018 | 596 | 575 | 555 | 550 | 551 | 559 | 580 | 628 | 654 | 702 | 770 | 820 | 863 | 908 | 933 | 941 | 937 | 921 | 903 | 865 | 839 | 808 | 749 | 688 |
| 6/16/2018 | 647 | 610 | 588 | 565 | 553 | 530 | 534 | 583 | 641 | 705 | 767 | 814 | 839 | 868 | 880 | 890 | 875 | 859 | 843 | 823 | 804 | 761 | 721 | 673 |
| 6/17/2018 | 619 | 587 | 553 | 532 | 522 | 512 | 522 | 564 | 626 | 691 | 756 | 804 | 828 | 864 | 879 | 885 | 894 | 891 | 868 | 849 | 825 | 801 | 744 | 692 |
| 6/18/2018 | 656 | 619 | 603 | 586 | 594 | 606 | 645 | 704 | 755 | 817 | 875 | 898 | 931 | 951 | 967 | 978 | 975 | 965 | 946 | 912 | 893 | 856 | 796 | 737 |
| 6/19/2018 | 687 | 658 | 632 | 610 | 610 | 611 | 650 | 708 | 762 | 802 | 855 | 890 | 914 | 943 | 962 | 967 | 967 | 951 | 930 | 896 | 876 | 839 | 787 | 728 |
| 6/20/2018 | 680 | 641 | 618 | 600 | 603 | 609 | 644 | 704 | 748 | 800 | 843 | 880 | 905 | 930 | 929 | 891 | 909 | 895 | 873 | 832 | 820 | 791 | 738 | 685 |
| 6/21/2018 | 655 | 625 | 609 | 589 | 594 | 599 | 628 | 649 | 661 | 685 | 695 | 722 | 721 | 751 | 788 | 799 | 795 | 773 | 755 | 734 | 719 | 697 | 648 | 603 |
| 6/22/2018 | 568 | 549 | 529 | 522 | 528 | 536 | 563 | 589 | 615 | 635 | 672 | 695 | 721 | 736 | 743 | 739 | 733 | 719 | 700 | 683 | 671 | 662 | 618 | 577 |
| 6/23/2018 | 544 | 519 | 509 | 498 | 486 | 476 | 473 | 505 | 549 | 581 | 619 | 637 | 656 | 670 | 674 | 694 | 720 | 728 | 724 | 693 | 675 | 654 | 610 | 569 |
| 6/24/2018 | 540 | 515 | 490 | 480 | 472 | 468 | 472 | 510 | 569 | 618 | 668 | 700 | 749 | 775 | 780 | 762 | 771 | 748 | 736 | 725 | 711 | 668 | 610 | 576 |
| 6/25/2018 | 544 | 531 | 519 | 512 | 519 | 555 | 583 | 617 | 641 | 665 | 666 | 659 | 696 | 735 | 759 | 785 | 806 | 797 | 792 | 774 | 758 | 729 | 676 | 633 |
| 6/26/2018 | 603 | 580 | 563 | 554 | 552 | 568 | 600 | 655 | 714 | 765 | 746 | 688 | 667 | 702 | 751 | 785 | 803 | 812 | 807 | 784 | 748 | 711 | 615 | 565 |
| 6/27/2018 | 550 | 528 | 519 | 506 | 517 | 520 | 553 | 584 | 615 | 636 | 683 | 709 | 754 | 819 | 859 | 878 | 921 | 919 | 913 | 888 | 867 | 831 | 784 | 734 |
| 6/28/2018 | 696 | 656 | 640 | 636 | 628 | 647 | 677 | 724 | 771 | 824 | 852 | 897 | 926 | 956 | 977 | 983 | 976 | 972 | 943 | 918 | 904 | 824 | 769 | 703 |
| 6/29/2018 | 667 | 633 | 623 | 607 | 594 | 609 | 631 | 689 | 733 | 788 | 828 | 878 | 909 | 955 | 974 | 988 | 976 | 979 | 942 | 924 | 902 | 857 | 796 | 741 |
| 6/30/2018 | 690 | 658 | 630 | 610 | 589 | 571 | 575 | 618 | 671 | 743 | 785 | 825 | 855 | 879 | 891 | 904 | 909 | 895 | 881 | 853 | 832 | 795 | 751 | 699 |
| 7/1/2018 | 659 | 624 | 591 | 577 | 564 | 551 | 562 | 614 | 678 | 730 | 788 | 834 | 855 | 889 | 895 | 913 | 915 | 924 | 909 | 883 | 856 | 830 | 767 | 730 |
| 7/2/2018 | 691 | 660 | 632 | 617 | 627 | 647 | 687 | 729 | 792 | 834 | 897 | 935 | 979 | 989 | 996 | 946 | 880 | 856 | 843 | 820 | 812 | 795 | 738 | 695 |
| 7/3/2018 | 660 | 643 | 623 | 618 | 614 | 622 | 657 | 710 | 765 | 814 | 868 | 904 | 928 | 905 | 913 | 919 | 924 | 877 | 829 | 799 | 788 | 759 | 721 | 676 |
| 7/4/2018 | 649 | 621 | 608 | 592 | 577 | 566 | 566 | 593 | 659 | 724 | 804 | 851 | 881 | 899 | 911 | 928 | 931 | 926 | 907 | 870 | 849 | 808 | 774 | 727 |
| 7/5/2018 | 688 | 644 | 626 | 604 | 604 | 618 | 659 | 733 | 796 | 873 | 925 | 968 | 1009 | 1029 | 1039 | 1023 | 1030 | 1025 | 1006 | 963 | 935 | 894 | 829 | 763 |
| 7/6/2018 | 715 | 685 | 658 | 639 | 634 | 640 | 656 | 699 | 743 | 792 | 839 | 880 | 909 | 927 | 938 | 936 | 912 | 888 | 863 | 824 | 788 | 752 | 706 | 644 |
| 7/7/2018 | 605 | 570 | 546 | 516 | 517 | 496 | 488 | 520 | 551 | 593 | 619 | 653 | 684 | 703 | 729 | 745 | 758 | 754 | 734 | 700 | 668 | 640 | 605 | 561 |
| 7/8/2018 | 525 | 500 | 489 | 478 | 480 | 470 | 473 | 515 | 553 | 613 | 672 | 718 | 761 | 800 | 827 | 850 | 865 | 888 | 861 | 837 | 803 | 785 | 730 | 672 |
| 7/9/2018 | 640 | 610 | 595 | 582 | 595 | 611 | 648 | 704 | 759 | 815 | 862 | 903 | 946 | 970 | 967 | 936 | 925 | 917 | 898 | 867 | 833 | 808 | 742 | 690 |
| 7/10/2018 | 643 | 612 | 593 | 581 | 574 | 582 | 613 | 669 | 732 | 798 | 846 | 876 | 915 | 937 | 954 | 972 | 972 | 967 | 948 | 922 | 897 | 854 | 793 | 733 |
| 7/11/2018 | 686 | 658 | 626 | 615 | 604 | 601 | 625 | 674 | 716 | 774 | 831 | 870 | 913 | 939 | 938 | 952 | 956 | 941 | 917 | 889 | 854 | 808 | 744 | 675 |
| 7/12/2018 | 626 | 592 | 560 | 540 | 540 | 542 | 569 | 626 | 664 | 707 | 750 | 790 | 829 | 863 | 884 | 905 | 920 | 906 | 884 | 842 | 818 | 782 | 716 | 658 |
| 7/13/2018 | 617 | 589 | 566 | 548 | 548 | 547 | 579 | 629 | 675 | 713 | 769 | 808 | 853 | 887 | 908 | 930 | 924 | 923 | 893 | 849 | 828 | 780 | 731 | 668 |
| 7/14/2018 | 622 | 586 | 560 | 540 | 524 | 517 | 521 | 551 | 603 | 669 | 749 | 794 | 851 | 891 | 910 | 922 | 902 | 852 | 789 | 762 | 726 | 700 | 655 | 604 |

| Dt | Hour1 | Hour2 | Hour3 | Hour4 | Hour5 | Hour6 | Hour7 | Hour8 | Hour9 | Hour10 | Hour11 | Hour12 | Hour13 | Hour14 | Hour15 | Hour16 | Hour17 | Hour18 | Hour19 | Hour20 | Hour21 | Hour22 | Hour23 | Hour24 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 7/15/2018 | 578 | 552 | 534 | 531 | 522 | 526 | 520 | 543 | 562 | 596 | 630 | 642 | 663 | 688 | 715 | 743 | 771 | 767 | 750 | 733 | 723 | 700 | 651 | 613 |
| 7/16/2018 | 571 | 558 | 543 | 538 | 537 | 564 | 595 | 633 | 659 | 706 | 758 | 813 | 851 | 885 | 918 | 938 | 941 | 939 | 914 | 876 | 849 | 818 | 746 | 686 |
| 7/17/2018 | 651 | 617 | 589 | 586 | 575 | 585 | 620 | 670 | 730 | 784 | 828 | 869 | 893 | 924 | 935 | 939 | 939 | 916 | 887 | 839 | 812 | 768 | 709 | 652 |
| 7/18/2018 | 612 | 586 | 547 | 549 | 538 | 547 | 570 | 611 | 645 | 685 | 727 | 763 | 798 | 835 | 858 | 869 | 876 | 865 | 832 | 793 | 760 | 717 | 649 | 596 |
| 7/19/2018 | 562 | 531 | 513 | 496 | 502 | 511 | 539 | 583 | 627 | 665 | 720 | 771 | 816 | 837 | 872 | 880 | 884 | 876 | 864 | 825 | 809 | 773 | 718 | 666 |
| 7/20/2018 | 625 | 603 | 571 | 571 | 558 | 577 | 608 | 657 | 709 | 759 | 821 | 854 | 886 | 911 | 945 | 960 | 966 | 955 | 927 | 893 | 864 | 819 | 747 | 676 |
| 7/21/2018 | 625 | 588 | 559 | 535 | 518 | 517 | 521 | 556 | 604 | 647 | 692 | 713 | 721 | 740 | 746 | 744 | 737 | 722 | 708 | 696 | 672 | 654 | 615 | 577 |
| 7/22/2018 | 542 | 523 | 505 | 491 | 486 | 491 | 489 | 509 | 530 | 548 | 579 | 587 | 608 | 630 | 656 | 669 | 668 | 674 | 658 | 631 | 630 | 616 | 579 | 549 |
| 7/23/2018 | 525 | 508 | 501 | 501 | 506 | 533 | 551 | 600 | 636 | 678 | 705 | 733 | 768 | 785 | 790 | 786 | 801 | 813 | 789 | 764 | 761 | 725 | 678 | 605 |
| 7/24/2018 | 595 | 574 | 561 | 542 | 545 | 556 | 581 | 623 | 677 | 716 | 775 | 810 | 841 | 875 | 887 | 900 | 903 | 890 | 864 | 831 | 807 | 753 | 690 | 638 |
| 7/25/2018 | 591 | 569 | 547 | 536 | 539 | 553 | 580 | 621 | 676 | 727 | 774 | 808 | 834 | 865 | 877 | 896 | 888 | 874 | 852 | 801 | 777 | 734 | 679 | 625 |
| 7/26/2018 | 584 | 558 | 533 | 524 | 519 | 531 | 556 | 608 | 677 | 737 | 780 | 807 | 856 | 890 | 922 | 927 | 920 | 881 | 855 | 824 | 799 | 764 | 713 | 654 |
| 7/27/2018 | 619 | 586 | 562 | 545 | 547 | 556 | 571 | 614 | 659 | 695 | 712 | 753 | 773 | 802 | 814 | 836 | 831 | 823 | 794 | 755 | 739 | 695 | 651 | 594 |
| 7/28/2018 | 554 | 529 | 505 | 497 | 482 | 479 | 473 | 495 | 531 | 573 | 614 | 649 | 671 | 699 | 724 | 735 | 741 | 741 | 724 | 693 | 676 | 638 | 595 | 555 |
| 7/29/2018 | 528 | 497 | 495 | 470 | 468 | 462 | 468 | 493 | 537 | 592 | 634 | 665 | 698 | 729 | 736 | 746 | 730 | 728 | 694 | 662 | 650 | 621 | 576 | 548 |
| 7/30/2018 | 516 | 505 | 501 | 496 | 511 | 538 | 569 | 609 | 636 | 663 | 686 | 694 | 705 | 709 | 703 | 698 | 689 | 679 | 677 | 672 | 680 | 666 | 622 | 585 |
| 7/31/2018 | 559 | 547 | 544 | 531 | 535 | 555 | 582 | 609 | 637 | 652 | 673 | 696 | 731 | 761 | 792 | 801 | 795 | 779 | 751 | 740 | 728 | 704 | 651 | 601 |
| 8/1/2018 | 564 | 545 | 534 | 527 | 523 | 538 | 566 | 601 | 635 | 664 | 714 | 744 | 770 | 796 | 821 | 832 | 839 | 825 | 809 | 775 | 765 | 724 | 664 | 602 |
| 8/2/2018 | 578 | 555 | 538 | 527 | 522 | 536 | 564 | 603 | 653 | 703 | 745 | 783 | 821 | 848 | 877 | 887 | 895 | 880 | 851 | 762 | 800 | 748 | 699 | 641 |
| 8/3/2018 | 602 | 565 | 552 | 537 | 533 | 543 | 576 | 615 | 668 | 716 | 762 | 798 | 831 | 877 | 914 | 934 | 934 | 924 | 899 | 856 | 850 | 799 | 745 | 688 |
| 8/4/2018 | 636 | 603 | 583 | 562 | 549 | 542 | 531 | 558 | 621 | 666 | 739 | 778 | 824 | 849 | 872 | 885 | 896 | 883 | 860 | 819 | 797 | 755 | 715 | 655 |
| 8/5/2018 | 610 | 582 | 557 | 538 | 528 | 520 | 520 | 549 | 599 | 652 | 719 | 780 | 827 | 862 | 884 | 899 | 895 | 872 | 823 | 783 | 781 | 737 | 686 | 629 |
| 8/6/2018 | 596 | 568 | 554 | 545 | 558 | 583 | 613 | 680 | 734 | 793 | 853 | 897 | 943 | 988 | 1004 | 1003 | 1000 | 976 | 949 | 927 | 906 | 869 | 793 | 736 |
| 8/7/2018 | 696 | 668 | 643 | 631 | 625 | 641 | 671 | 709 | 735 | 776 | 811 | 853 | 869 | 879 | 902 | 924 | 914 | 872 | 838 | 826 | 815 | 770 | 725 | 669 |
| 8/8/2018 | 638 | 613 | 598 | 594 | 584 | 614 | 648 | 669 | 702 | 732 | 754 | 790 | 832 | 866 | 884 | 901 | 917 | 900 | 887 | 864 | 853 | 800 | 745 | 688 |
| 8/9/2018 | 654 | 628 | 593 | 587 | 581 | 597 | 629 | 664 | 708 | 751 | 799 | 813 | 826 | 834 | 842 | 846 | 840 | 819 | 814 | 795 | 792 | 749 | 691 | 633 |
| 8/10/2018 | 609 | 587 | 567 | 562 | 561 | 584 | 614 | 647 | 685 | 727 | 750 | 771 | 786 | 809 | 820 | 835 | 859 | 859 | 843 | 807 | 779 | 745 | 692 | 645 |
| 8/11/2018 | 603 | 576 | 558 | 546 | 535 | 542 | 532 | 545 | 586 | 642 | 697 | 747 | 772 | 803 | 827 | 843 | 838 | 839 | 800 | 755 | 729 | 689 | 644 | 595 |
| 8/12/2018 | 554 | 528 | 512 | 498 | 488 | 484 | 481 | 505 | 556 | 613 | 658 | 696 | 737 | 782 | 801 | 820 | 833 | 837 | 809 | 778 | 746 | 702 | 640 | 578 |
| 8/13/2018 | 549 | 514 | 511 | 505 | 512 | 546 | 579 | 624 | 657 | 719 | 757 | 814 | 854 | 882 | 900 | 907 | 913 | 895 | 867 | 840 | 822 | 771 | 707 | 644 |
| 8/14/2018 | 607 | 577 | 563 | 539 | 541 | 559 | 597 | 625 | 667 | 721 | 773 | 814 | 860 | 887 | 916 | 930 | 910 | 877 | 856 | 836 | 827 | 774 | 720 | 662 |
| 8/15/2018 | 623 | 605 | 574 | 572 | 568 | 593 | 635 | 655 | 668 | 689 | 710 | 728 | 719 | 719 | 755 | 794 | 773 | 740 | 712 | 708 | 712 | 679 | 645 | 597 |
| 8/16/2018 | 580 | 563 | 559 | 556 | 557 | 586 | 625 | 660 | 679 | 682 | 737 | 748 | 763 | 776 | 793 | 835 | 857 | 862 | 853 | 839 | 825 | 784 | 730 | 677 |
| 8/17/2018 | 639 | 627 | 611 | 617 | 613 | 615 | 636 | 660 | 683 | 723 | 759 | 800 | 821 | 851 | 844 | 859 | 862 | 854 | 825 | 796 | 777 | 747 | 696 | 642 |
| 8/18/2018 | 615 | 600 | 575 | 570 | 553 | 556 | 544 | 570 | 595 | 631 | 679 | 725 | 744 | 756 | 760 | 789 | 797 | 788 | 761 | 730 | 717 | 673 | 634 | 589 |
| 8/19/2018 | 553 | 528 | 504 | 502 | 489 | 489 | 489 | 505 | 557 | 613 | 653 | 707 | 744 | 767 | 801 | 809 | 822 | 817 | 799 | 777 | 761 | 715 | 665 | 622 |
| 8/20/2018 | 595 | 579 | 553 | 553 | 568 | 596 | 645 | 685 | 706 | 737 | 772 | 803 | 814 | 828 | 839 | 847 | 860 | 855 | 835 | 815 | 808 | 759 | 707 | 632 |
| 8/21/2018 | 600 | 572 | 557 | 544 | 548 | 571 | 601 | 637 | 648 | 672 | 688 | 707 | 727 | 751 | 774 | 806 | 810 | 787 | 766 | 741 | 735 | 702 | 657 | 611 |
| 8/22/2018 | 575 | 549 | 536 | 531 | 537 | 554 | 594 | 614 | 630 | 650 | 671 | 679 | 696 | 716 | 743 | 757 | 761 | 734 | 711 | 686 | 681 | 638 | 588 | 538 |
| 8/23/2018 | 516 | 497 | 495 | 485 | 485 | 510 | 530 | 485 | 594 | 621 | 645 | 678 | 702 | 718 | 742 | 767 | 763 | 754 | 736 | 713 | 698 | 652 | 604 | 556 |
| 8/24/2018 | 518 | 506 | 496 | 487 | 490 | 517 | 535 | 563 | 578 | 588 | 608 | 619 | 622 | 625 | 620 | 613 | 605 | 598 | 603 | 606 | 611 | 606 | 576 | 549 |
| 8/25/2018 | 524 | 517 | 504 | 507 | 492 | 502 | 503 | 523 | 553 | 592 | 633 | 684 | 733 | 768 | 811 | 838 | 842 | 846 | 817 | 805 | 766 | 731 | 688 | 636 |
| 8/26/2018 | 597 | 570 | 544 | 534 | 522 | 521 | 515 | 543 | 591 | 652 | 697 | 753 | 806 | 841 | 864 | 892 | 892 | 889 | 872 | 831 | 808 | 754 | 704 | 656 |
| 8/27/2018 | 625 | 590 | 570 | 567 | 577 | 607 | 652 | 685 | 732 | 792 | 843 | 891 | 936 | 973 | 982 | 996 | 986 | 997 | 944 | 906 | 885 | 820 | 765 | 693 |
| 8/28/2018 | 661 | 632 | 609 | 581 | 595 | 599 | 651 | 678 | 725 | 790 | 842 | 890 | 934 | 975 | 990 | 1013 | 1005 | 990 | 965 | 929 | 898 | 836 | 789 | 715 |
| 8/29/2018 | 677 | 642 | 615 | 638 | 601 | 629 | 664 | 700 | 749 | 780 | 795 | 826 | 799 | 797 | 805 | 807 | 810 | 809 | 792 | 787 | 780 | 733 | 664 | 614 |
| 8/30/2018 | 592 | 564 | 549 | 540 | 542 | 567 | 616 | 635 | 660 | 701 | 749 | 800 | 841 | 882 | 900 | 896 | 893 | 879 | 851 | 836 | 806 | 767 | 715 | 648 |
| 8/31/2018 | 608 | 578 | 566 | 563 | 559 | 582 | 614 | 649 | 680 | 725 | 768 | 818 | 848 | 888 | 917 | 911 | 864 | 842 | 811 | 784 | 764 | 720 | 681 | 628 |
| 9/1/2018 | 590 | 572 | 555 | 542 | 525 | 514 | 519 | 531 | 562 | 608 | 657 | 714 | 754 | 778 | 783 | 802 | 822 | 818 | 787 | 750 | 727 | 688 | 651 | 611 |
| 9/2/2018 | 580 | 541 | 523 | 497 | 486 | 488 | 488 | 508 | 550 | 624 | 674 | 736 | 779 | 805 | 831 | 847 | 867 | 851 | 814 | 789 | 757 | 720 | 668 | 632 |
| 9/3/2018 | 585 | 559 | 531 | 524 | 516 | 512 | 506 | 532 | 576 | 649 | 714 | 764 | 808 | 831 | 854 | 864 | 874 | 868 | 841 | 810 | 788 | 733 | 681 | 631 |
| 9/4/2018 | 603 | 578 | 548 | 548 | 549 | 574 | 611 | 655 | 704 | 763 | 824 | 882 | 925 | 962 | 981 | 988 | 980 | 974 | 941 | 920 | 881 | 832 | 770 | 715 |
| 9/5/2018 | 676 | 654 | 632 | 617 | 609 | 627 | 658 | 681 | 734 | 775 | 847 | 889 | 930 | 967 | 980 | 970 | 934 | 906 | 885 | 863 | 834 | 791 | 739 | 683 |
| 9/6/2018 | 647 | 621 | 600 | 593 | 592 | 610 | 649 | 674 | 705 | 758 | 820 | 860 | 882 | 898 | 825 | 812 | 786 | 763 | 745 | 745 | 731 | 706 | 643 | 600 |
| 9/7/2018 | 570 | 551 | 535 | 533 | 532 | 563 | 611 | 651 | 662 | 701 | 744 | 797 | 852 | 888 | 904 | 889 | 831 | 766 | 737 | 728 | 708 | 687 | 662 | 614 |
| 9/8/2018 | 592 | 577 | 561 | 561 | 556 | 558 | 562 | 560 | 590 | 604 | 631 | 635 | 634 | 638 | 650 | 651 | 664 | 628 | 619 | 613 | 603 | 580 | 551 | 510 |
| 9/9/2018 | 488 | 473 | 457 | 456 | 457 | 454 | 456 | 474 | 495 | 508 | 516 | 525 | 526 | 534 | 532 | 532 | 531 | 537 | 528 | 545 | 544 | 514 | 489 | 465 |
| 9/10/2018 | 451 | 437 | 432 | 425 | 446 | 485 | 532 | 546 | 567 | 556 | 587 | 598 | 603 | 630 | 633 | 654 | 658 | 647 | 636 | 647 | 635 | 603 | 563 | 527 |
| 9/11/2018 | 503 | 488 | 483 | 480 | 483 | 502 | 536 | 558 | 586 | 616 | 635 | 656 | 674 | 678 | 685 | 682 | 683 | 669 | 655 | 660 | 651 | 619 | 589 | 550 |
| 9/12/2018 | 527 | 513 | 501 | 496 | 494 | 507 | 550 | 566 | 584 | 608 | 627 | 646 | 671 | 691 | 708 | 704 | 701 | 682 | 682 | 683 | 675 | 645 | 600 | 568 |
| 9/13/2018 | 540 | 520 | 520 | 507 | 509 | 530 | 572 | 596 | 626 | 673 | 711 | 745 | 786 | 827 | 861 | 888 | 893 | 881 | 846 | 824 | 798 | 746 | 685 | 632 |
| 9/14/2018 | 591 | 574 | 541 | 530 | 535 | 557 | 598 | 620 | 652 | 698 | 754 | 796 | 834 | 869 | 897 | 911 | 915 | 892 | 854 | 816 | 788 | 754 | 701 | 652 |
| 9/15/2018 | 612 | 585 | 557 | 547 | 536 | 525 | 517 | 533 | 578 | 625 | 689 | 747 | 803 | 842 | 868 | 884 | 879 | 872 | 832 | 805 | 767 | 729 | 681 | 641 |
| 9/16/2018 | 595 | 566 | 550 | 531 | 519 | 508 | 513 | 528 | 562 | 617 | 673 | 715 | 757 | 777 | 790 | 800 | 804 | 797 | 769 | 766 | 725 | 685 | 625 | 584 |
| 9/17/2018 | 555 | 534 | 517 | 518 | 523 | 559 | 604 | 629 | 653 | 683 | 745 | 786 | 831 | 863 | 893 | 905 | 907 | 901 | 861 | 836 | 800 | 751 | 690 | 635 |

| Dt | Hour1 | Hour2 | Hour3 | Hour4 | Hour5 | Hour6 | Hour7 | Hour8 | Hour9 | Hour10 | Hour11 | Hour12 | Hour13 | Hour14 | Hour15 | Hour16 | Hour17 | Hour18 | Hour19 | Hour20 | Hour21 | Hour22 | Hour23 | Hour24 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 9/18/2018 | 596 | 572 | 567 | 542 | 548 | 564 | 604 | 633 | 650 | 705 | 764 | 819 | 872 | 901 | 904 | 894 | 898 | 888 | 851 | 845 | 801 | 743 | 684 | 630 |
| 9/19/2018 | 603 | 563 | 538 | 532 | 527 | 556 | 601 | 611 | 661 | 717 | 779 | 835 | 888 | 933 | 950 | 954 | 943 | 915 | 879 | 862 | 820 | 775 | 713 | 655 |
| 9/20/2018 | 622 | 590 | 575 | 564 | 569 | 590 | 629 | 662 | 715 | 768 | 834 | 886 | 927 | 969 | 976 | 982 | 975 | 946 | 895 | 881 | 842 | 791 | 753 | 719 |
| 9/21/2018 | 677 | 653 | 634 | 624 | 608 | 629 | 664 | 691 | 742 | 787 | 843 | 886 | 927 | 929 | 930 | 935 | 912 | 872 | 840 | 812 | 791 | 743 | 682 | 626 |
| 9/22/2018 | 588 | 559 | 539 | 522 | 517 | 503 | 509 | 508 | 523 | 531 | 539 | 539 | 535 | 535 | 528 | 531 | 518 | 519 | 529 | 527 | 521 | 509 | 489 | 475 |
| 9/23/2018 | 460 | 450 | 434 | 429 | 429 | 444 | 444 | 457 | 467 | 489 | 475 | 513 | 530 | 534 | 537 | 541 | 544 | 548 | 551 | 566 | 555 | 539 | 511 | 493 |
| 9/24/2018 | 478 | 469 | 463 | 462 | 476 | 510 | 559 | 602 | 616 | 613 | 631 | 654 | 658 | 685 | 672 | 672 | 681 | 680 | 679 | 694 | 690 | 674 | 628 | 595 |
| 9/25/2018 | 568 | 561 | 544 | 541 | 550 | 578 | 624 | 647 | 663 | 689 | 691 | 690 | 683 | 683 | 727 | 744 | 760 | 762 | 749 | 761 | 747 | 714 | 676 | 617 |
| 9/26/2018 | 590 | 574 | 563 | 557 | 550 | 573 | 602 | 610 | 620 | 616 | 632 | 645 | 653 | 668 | 683 | 689 | 681 | 666 | 642 | 639 | 625 | 592 | 560 | 525 |
| 9/27/2018 | 512 | 502 | 492 | 484 | 497 | 511 | 549 | 563 | 569 | 573 | 581 | 577 | 578 | 582 | 583 | 581 | 578 | 577 | 569 | 590 | 580 | 564 | 529 | 502 |
| 9/28/2018 | 481 | 479 | 465 | 468 | 471 | 483 | 521 | 538 | 544 | 558 | 567 | 571 | 586 | 594 | 593 | 607 | 605 | 586 | 581 | 581 | 572 | 548 | 528 | 499 |
| 9/29/2018 | 472 | 461 | 456 | 446 | 444 | 438 | 441 | 450 | 460 | 482 | 495 | 505 | 532 | 541 | 556 | 572 | 583 | 579 | 566 | 561 | 547 | 522 | 493 | 468 |
| 9/30/2018 | 442 | 433 | 422 | 411 | 414 | 415 | 417 | 425 | 445 | 470 | 505 | 535 | 560 | 592 | 613 | 642 | 652 | 649 | 624 | 630 | 590 | 562 | 521 | 487 |
| 10/1/2018 | 460 | 447 | 437 | 439 | 447 | 482 | 534 | 553 | 581 | 618 | 644 | 678 | 704 | 747 | 759 | 760 | 749 | 741 | 730 | 734 | 709 | 671 | 623 | 582 |
| 10/2/2018 | 557 | 536 | 536 | 525 | 533 | 554 | 606 | 624 | 641 | 670 | 717 | 753 | 798 | 825 | 856 | 869 | 885 | 837 | 818 | 800 | 769 | 715 | 670 | 616 |
| 10/3/2018 | 581 | 570 | 546 | 545 | 543 | 566 | 609 | 629 | 664 | 696 | 752 | 795 | 836 | 853 | 882 | 881 | 879 | 853 | 829 | 816 | 788 | 749 | 714 | 661 |
| 10/4/2018 | 624 | 607 | 584 | 573 | 568 | 599 | 634 | 660 | 688 | 722 | 757 | 787 | 810 | 834 | 847 | 844 | 833 | 803 | 769 | 759 | 725 | 687 | 644 | 604 |
| 10/5/2018 | 564 | 543 | 528 | 520 | 521 | 547 | 600 | 624 | 652 | 706 | 774 | 812 | 848 | 879 | 881 | 898 | 881 | 852 | 822 | 792 | 753 | 719 | 681 | 633 |
| 10/6/2018 | 606 | 568 | 548 | 537 | 525 | 521 | 524 | 525 | 572 | 628 | 667 | 705 | 750 | 773 | 797 | 804 | 793 | 768 | 744 | 712 | 688 | 652 | 604 | 565 |
| 10/7/2018 | 534 | 498 | 482 | 464 | 458 | 457 | 467 | 477 | 515 | 566 | 618 | 664 | 718 | 741 | 765 | 782 | 786 | 769 | 744 | 723 | 698 | 652 | 606 | 574 |
| 10/8/2018 | 538 | 524 | 503 | 508 | 517 | 537 | 582 | 607 | 641 | 695 | 744 | 793 | 826 | 846 | 866 | 877 | 872 | 844 | 819 | 802 | 777 | 732 | 687 | 639 |
| 10/9/2018 | 605 | 587 | 565 | 552 | 553 | 571 | 602 | 621 | 654 | 694 | 730 | 763 | 799 | 839 | 844 | 852 | 842 | 821 | 794 | 782 | 750 | 705 | 665 | 608 |
| 10/10/2018 | 579 | 569 | 548 | 556 | 542 | 561 | 620 | 632 | 637 | 645 | 657 | 678 | 689 | 697 | 712 | 750 | 747 | 724 | 723 | 720 | 701 | 667 | 615 | 559 |
| 10/11/2018 | 529 | 509 | 493 | 486 | 484 | 493 | 543 | 557 | 557 | 568 | 582 | 584 | 589 | 593 | 592 | 595 | 588 | 584 | 587 | 589 | 576 | 551 | 518 | 481 |
| 10/12/2018 | 477 | 465 | 468 | 458 | 466 | 483 | 533 | 542 | 545 | 541 | 546 | 550 | 549 | 547 | 551 | 540 | 531 | 535 | 538 | 545 | 528 | 529 | 501 | 470 |
| 10/13/2018 | 459 | 455 | 455 | 449 | 445 | 449 | 460 | 466 | 486 | 492 | 502 | 494 | 482 | 483 | 471 | 474 | 476 | 480 | 498 | 500 | 492 | 475 | 454 | 437 |
| 10/14/2018 | 417 | 416 | 402 | 403 | 404 | 413 | 427 | 439 | 455 | 467 | 475 | 476 | 480 | 478 | 481 | 483 | 492 | 502 | 511 | 505 | 500 | 479 | 454 | 430 |
| 10/15/2018 | 421 | 416 | 410 | 418 | 431 | 459 | 499 | 533 | 537 | 549 | 552 | 561 | 563 | 566 | 571 | 566 | 562 | 564 | 586 | 582 | 573 | 561 | 525 | 501 |
| 10/16/2018 | 490 | 481 | 467 | 474 | 481 | 508 | 556 | 566 | 574 | 566 | 566 | 563 | 566 | 561 | 562 | 555 | 563 | 556 | 577 | 590 | 581 | 561 | 527 | 514 |
| 10/17/2018 | 501 | 501 | 491 | 493 | 496 | 524 | 569 | 574 | 556 | 563 | 566 | 557 | 551 | 556 | 552 | 551 | 551 | 539 | 562 | 570 | 565 | 545 | 520 | 493 |
| 10/18/2018 | 482 | 468 | 457 | 467 | 465 | 502 | 544 | 554 | 555 | 557 | 549 | 548 | 552 | 553 | 549 | 554 | 546 | 544 | 566 | 566 | 567 | 548 | 527 | 491 |
| 10/19/2018 | 492 | 488 | 476 | 493 | 492 | 510 | 556 | 573 | 562 | 561 | 564 | 557 | 558 | 568 | 551 | 557 | 545 | 548 | 556 | 554 | 547 | 530 | 512 | 480 |
| 10/20/2018 | 464 | 457 | 453 | 442 | 441 | 438 | 454 | 447 | 463 | 474 | 478 | 477 | 473 | 477 | 473 | 465 | 466 | 463 | 483 | 483 | 482 | 474 | 457 | 446 |
| 10/21/2018 | 431 | 429 | 426 | 425 | 433 | 447 | 463 | 475 | 486 | 488 | 479 | 479 | 472 | 465 | 469 | 464 | 468 | 489 | 512 | 527 | 525 | 508 | 493 | 479 |
| 10/22/2018 | 464 | 458 | 462 | 470 | 485 | 515 | 574 | 587 | 585 | 572 | 569 | 558 | 562 | 557 | 551 | 546 | 544 | 544 | 564 | 572 | 561 | 544 | 515 | 487 |
| 10/23/2018 | 484 | 477 | 468 | 473 | 480 | 499 | 552 | 561 | 558 | 558 | 557 | 550 | 558 | 545 | 550 | 541 | 538 | 536 | 560 | 566 | 557 | 540 | 508 | 488 |
| 10/24/2018 | 479 | 469 | 470 | 476 | 483 | 507 | 556 | 540 | 541 | 554 | 538 | 553 | 558 | 553 | 552 | 551 | 546 | 548 | 567 | 567 | 567 | 545 | 517 | 498 |
| 10/25/2018 | 485 | 474 | 474 | 476 | 486 | 500 | 548 | 567 | 569 | 568 | 571 | 566 | 569 | 566 | 555 | 557 | 555 | 555 | 578 | 569 | 559 | 538 | 511 | 493 |
| 10/26/2018 | 469 | 462 | 460 | 460 | 462 | 488 | 531 | 551 | 550 | 552 | 558 | 567 | 558 | 552 | 550 | 549 | 542 | 540 | 549 | 549 | 543 | 532 | 506 | 481 |
| 10/27/2018 | 453 | 454 | 455 | 447 | 451 | 454 | 460 | 467 | 484 | 487 | 496 | 478 | 473 | 471 | 469 | 462 | 459 | 474 | 489 | 488 | 480 | 480 | 457 | 437 |
| 10/28/2018 | 428 | 424 | 420 | 416 | 414 | 423 | 435 | 442 | 452 | 469 | 463 | 468 | 464 | 468 | 468 | 468 | 476 | 483 | 503 | 506 | 499 | 477 | 452 | 439 |
| 10/29/2018 | 422 | 411 | 420 | 430 | 450 | 482 | 546 | 568 | 572 | 561 | 558 | 560 | 551 | 557 | 559 | 551 | 556 | 546 | 571 | 558 | 561 | 532 | 514 | 486 |
| 10/30/2018 | 473 | 469 | 467 | 459 | 469 | 497 | 543 | 557 | 562 | 550 | 561 | 552 | 567 | 566 | 572 | 576 | 560 | 560 | 570 | 568 | 563 | 547 | 516 | 497 |
| 10/31/2018 | 478 | 465 | 457 | 461 | 466 | 482 | 525 | 548 | 553 | 569 | 570 | 571 | 583 | 585 | 573 | 579 | 563 | 568 | 569 | 567 | 556 | 551 | 498 | 480 |
| 11/1/2018 | 463 | 463 | 458 | 449 | 460 | 486 | 530 | 562 | 560 | 578 | 570 | 567 | 576 | 578 | 570 | 571 | 560 | 576 | 583 | 590 | 572 | 562 | 544 | 505 |
| 11/2/2018 | 491 | 485 | 479 | 475 | 483 | 511 | 559 | 566 | 569 | 571 | 563 | 561 | 556 | 552 | 542 | 534 | 527 | 527 | 556 | 555 | 555 | 527 | 512 | 487 |
| 11/3/2018 | 481 | 467 | 468 | 469 | 476 | 481 | 493 | 491 | 498 | 493 | 488 | 481 | 472 | 476 | 465 | 472 | 474 | 485 | 504 | 494 | 497 | 488 | 467 | 450 |
| 11/4/2018 | 433 | 429 | 419 | 472 | 422 | 426 | 436 | 448 | 453 | 477 | 480 | 482 | 487 | 485 | 493 | 492 | 497 | 513 | 528 | 526 | 525 | 500 | 488 | 468 |
| 11/5/2018 | 448 | 438 | 436 | 443 | 434 | 455 | 482 | 521 | 549 | 560 | 561 | 561 | 554 | 559 | 570 | 573 | 575 | 591 | 602 | 595 | 587 | 579 | 559 | 535 |
| 11/6/2018 | 502 | 491 | 488 | 484 | 489 | 495 | 511 | 555 | 557 | 569 | 575 | 582 | 575 | 587 | 577 | 573 | 573 | 566 | 580 | 588 | 595 | 578 | 557 | 534 |
| 11/7/2018 | 506 | 498 | 492 | 492 | 504 | 500 | 527 | 573 | 579 | 588 | 579 | 582 | 582 | 571 | 568 | 570 | 564 | 571 | 593 | 589 | 593 | 588 | 569 | 547 |
| 11/8/2018 | 518 | 518 | 513 | 513 | 514 | 529 | 551 | 593 | 608 | 620 | 617 | 616 | 614 | 619 | 607 | 602 | 612 | 606 | 632 | 621 | 614 | 606 | 580 | 562 |
| 11/9/2018 | 533 | 530 | 511 | 514 | 512 | 523 | 551 | 582 | 593 | 609 | 611 | 617 | 617 | 619 | 624 | 624 | 636 | 637 | 641 | 638 | 638 | 634 | 622 | 598 |
| 11/10/2018 | 586 | 579 | 579 | 579 | 582 | 591 | 598 | 598 | 602 | 590 | 587 | 578 | 557 | 552 | 534 | 536 | 540 | 556 | 591 | 593 | 590 | 596 | 589 | 571 |
| 11/11/2018 | 556 | 555 | 557 | 551 | 566 | 561 | 564 | 564 | 574 | 592 | 575 | 556 | 539 | 486 | 532 | 531 | 540 | 559 | 584 | 577 | 574 | 567 | 549 | 539 |
| 11/12/2018 | 526 | 510 | 515 | 504 | 513 | 525 | 552 | 591 | 613 | 620 | 625 | 636 | 635 | 645 | 637 | 633 | 637 | 655 | 661 | 665 | 658 | 652 | 619 | 600 |
| 11/13/2018 | 577 | 569 | 562 | 568 | 573 | 590 | 626 | 666 | 676 | 683 | 695 | 700 | 700 | 699 | 691 | 700 | 696 | 715 | 733 | 725 | 728 | 712 | 694 | 660 |
| 11/14/2018 | 635 | 644 | 630 | 627 | 634 | 644 | 673 | 712 | 725 | 717 | 727 | 715 | 722 | 703 | 699 | 678 | 674 | 673 | 687 | 676 | 668 | 667 | 641 | 604 |
| 11/15/2018 | 587 | 553 | 551 | 544 | 540 | 563 | 574 | 615 | 627 | 633 | 622 | 629 | 630 | 635 | 602 | 630 | 628 | 635 | 635 | 656 | 639 | 629 | 606 | 581 |
| 11/16/2018 | 559 | 557 | 549 | 550 | 552 | 563 | 587 | 629 | 623 | 609 | 593 | 585 | 573 | 564 | 560 | 549 | 547 | 559 | 587 | 580 | 593 | 584 | 569 | 556 |
| 11/17/2018 | 530 | 526 | 529 | 521 | 524 | 532 | 541 | 539 | 547 | 545 | 530 | 512 | 502 | 480 | 481 | 476 | 478 | 485 | 513 | 510 | 498 | 501 | 489 | 472 |
| 11/18/2018 | 465 | 446 | 453 | 439 | 444 | 447 | 462 | 479 | 479 | 498 | 481 | 477 | 463 | 461 | 471 | 456 | 468 | 498 | 519 | 525 | 524 | 519 | 490 | 475 |
| 11/19/2018 | 460 | 442 | 437 | 437 | 442 | 457 | 493 | 545 | 554 | 573 | 575 | 578 | 577 | 577 | 579 | 580 | 584 | 599 | 603 | 597 | 593 | 588 | 565 | 542 |
| 11/20/2018 | 521 | 508 | 503 | 505 | 499 | 504 | 539 | 582 | 602 | 610 | 618 | 626 | 618 | 619 | 620 | 630 | 634 | 628 | 644 | 638 | 631 | 628 | 607 | 593 |
| 11/21/2018 | 571 | 567 | 555 | 563 | 564 | 576 | 604 | 633 | 635 | 621 | 610 | 588 | 569 | 561 | 553 | 546 | 535 | 544 | 578 | 581 | 578 | 572 | 554 | 510 |

| Dt | Hour1 | Hour2 | Hour3 | Hour4 | Hour5 | Hour6 | Hour7 | Hour8 | Hour9 | Hour10 | Hour11 | Hour12 | Hour13 | Hour14 | Hour15 | Hour16 | Hour17 | Hour18 | Hour19 | Hour20 | Hour21 | Hour22 | Hour23 | Hour24 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 11/22/2018 | 480 | 473 | 463 | 455 | 442 | 451 | 458 | 464 | 475 | 464 | 470 | 453 | 438 | 403 | 384 | 373 | 376 | 385 | 405 | 414 | 416 | 418 | 414 | 406 |
| 11/23/2018 | 397 | 391 | 391 | 387 | 394 | 399 | 411 | 421 | 437 | 443 | 454 | 459 | 452 | 447 | 445 | 443 | 454 | 462 | 472 | 472 | 464 | 459 | 451 | 432 |
| 11/24/2018 | 414 | 404 | 388 | 390 | 391 | 394 | 400 | 424 | 437 | 456 | 464 | 466 | 462 | 452 | 450 | 443 | 445 | 456 | 483 | 488 | 482 | 476 | 478 | 458 |
| 11/25/2018 | 441 | 425 | 422 | 421 | 419 | 429 | 435 | 447 | 459 | 459 | 461 | 461 | 465 | 462 | 464 | 476 | 478 | 498 | 532 | 519 | 515 | 508 | 487 | 467 |
| 11/26/2018 | 458 | 450 | 459 | 460 | 479 | 501 | 541 | 602 | 616 | 625 | 629 | 636 | 644 | 638 | 640 | 641 | 648 | 664 | 671 | 673 | 672 | 653 | 633 | 608 |
| 11/27/2018 | 581 | 570 | 572 | 561 | 575 | 592 | 613 | 660 | 663 | 668 | 663 | 670 | 674 | 671 | 673 | 675 | 682 | 695 | 709 | 706 | 701 | 690 | 663 | 637 |
| 11/28/2018 | 608 | 609 | 604 | 598 | 611 | 624 | 667 | 708 | 692 | 687 | 676 | 662 | 631 | 628 | 625 | 613 | 625 | 643 | 662 | 665 | 656 | 640 | 622 | 590 |
| 11/29/2018 | 559 | 561 | 540 | 537 | 538 | 550 | 561 | 601 | 620 | 598 | 600 | 593 | 579 | 581 | 582 | 569 | 566 | 587 | 596 | 588 | 579 | 572 | 550 | 519 |
| 11/30/2018 | 491 | 472 | 470 | 469 | 460 | 472 | 499 | 529 | 542 | 563 | 555 | 564 | 554 | 550 | 555 | 551 | 546 | 556 | 578 | 563 | 560 | 549 | 546 | 514 |
| 12/1/2018 | 476 | 446 | 459 | 456 | 450 | 448 | 453 | 465 | 463 | 480 | 497 | 509 | 503 | 491 | 498 | 497 | 501 | 521 | 526 | 530 | 510 | 501 | 486 | 465 |
| 12/2/2018 | 446 | 426 | 407 | 409 | 416 | 424 | 427 | 444 | 450 | 455 | 465 | 468 | 465 | 466 | 469 | 469 | 483 | 509 | 537 | 541 | 533 | 530 | 504 | 478 |
| 12/3/2018 | 459 | 444 | 436 | 440 | 446 | 466 | 498 | 557 | 573 | 588 | 599 | 621 | 616 | 613 | 616 | 615 | 619 | 633 | 642 | 641 | 633 | 630 | 609 | 577 |
| 12/4/2018 | 560 | 540 | 538 | 530 | 541 | 551 | 564 | 612 | 626 | 637 | 641 | 637 | 628 | 624 | 620 | 619 | 627 | 644 | 660 | 654 | 651 | 643 | 625 | 588 |
| 12/5/2018 | 587 | 569 | 572 | 576 | 571 | 589 | 606 | 644 | 659 | 646 | 639 | 644 | 624 | 629 | 622 | 605 | 595 | 624 | 649 | 648 | 649 | 643 | 627 | 596 |
| 12/6/2018 | 572 | 556 | 543 | 550 | 545 | 564 | 585 | 631 | 631 | 628 | 623 | 625 | 603 | 601 | 606 | 602 | 606 | 616 | 622 | 621 | 625 | 610 | 604 | 566 |
| 12/7/2018 | 546 | 537 | 532 | 527 | 525 | 549 | 578 | 605 | 628 | 635 | 616 | 605 | 594 | 585 | 588 | 578 | 583 | 598 | 620 | 611 | 621 | 621 | 608 | 590 |
| 12/8/2018 | 564 | 542 | 542 | 537 | 543 | 536 | 544 | 568 | 580 | 595 | 608 | 610 | 603 | 607 | 598 | 594 | 600 | 619 | 626 | 612 | 608 | 592 | 581 | 559 |
| 12/9/2018 | 536 | 524 | 519 | 507 | 515 | 516 | 519 | 532 | 543 | 554 | 547 | 541 | 527 | 524 | 517 | 521 | 526 | 563 | 591 | 594 | 588 | 592 | 565 | 542 |
| 12/10/2018 | 529 | 519 | 517 | 522 | 537 | 562 | 600 | 641 | 650 | 642 | 630 | 615 | 595 | 576 | 576 | 579 | 568 | 608 | 640 | 641 | 642 | 654 | 637 | 615 |
| 12/11/2018 | 596 | 596 | 599 | 602 | 603 | 614 | 645 | 682 | 674 | 645 | 615 | 619 | 603 | 588 | 618 | 571 | 579 | 597 | 633 | 630 | 640 | 631 | 608 | 586 |
| 12/12/2018 | 551 | 542 | 547 | 538 | 543 | 553 | 575 | 622 | 619 | 614 | 604 | 590 | 570 | 569 | 555 | 555 | 551 | 575 | 597 | 586 | 588 | 582 | 566 | 531 |
| 12/13/2018 | 507 | 488 | 484 | 481 | 479 | 490 | 517 | 564 | 577 | 581 | 586 | 586 | 574 | 584 | 562 | 570 | 571 | 588 | 585 | 584 | 590 | 574 | 559 | 527 |
| 12/14/2018 | 492 | 479 | 473 | 469 | 474 | 487 | 504 | 550 | 566 | 571 | 577 | 572 | 571 | 572 | 569 | 565 | 569 | 581 | 583 | 574 | 574 | 566 | 551 | 524 |
| 12/15/2018 | 499 | 479 | 480 | 468 | 467 | 467 | 468 | 474 | 487 | 490 | 509 | 507 | 509 | 504 | 492 | 500 | 504 | 529 | 530 | 531 | 523 | 510 | 503 | 484 |
| 12/16/2018 | 456 | 448 | 433 | 427 | 435 | 432 | 441 | 462 | 467 | 470 | 473 | 464 | 470 | 453 | 458 | 451 | 455 | 482 | 520 | 530 | 529 | 528 | 511 | 496 |
| 12/17/2018 | 475 | 467 | 467 | 464 | 480 | 494 | 531 | 590 | 593 | 588 | 569 | 560 | 549 | 533 | 546 | 528 | 539 | 552 | 579 | 587 | 584 | 586 | 573 | 544 |
| 12/18/2018 | 516 | 509 | 503 | 508 | 520 | 529 | 558 | 611 | 614 | 603 | 581 | 567 | 560 | 543 | 540 | 535 | 540 | 554 | 582 | 595 | 598 | 598 | 593 | 557 |
| 12/19/2018 | 535 | 520 | 515 | 512 | 521 | 525 | 540 | 581 | 590 | 575 | 569 | 550 | 547 | 536 | 530 | 528 | 528 | 552 | 580 | 572 | 566 | 563 | 546 | 521 |
| 12/20/2018 | 489 | 479 | 471 | 467 | 461 | 472 | 494 | 531 | 543 | 548 | 556 | 554 | 548 | 542 | 546 | 551 | 546 | 567 | 572 | 573 | 566 | 559 | 547 | 512 |
| 12/21/2018 | 477 | 462 | 453 | 454 | 454 | 468 | 482 | 524 | 532 | 552 | 569 | 566 | 566 | 564 | 568 | 566 | 557 | 574 | 583 | 577 | 567 | 554 | 539 | 502 |
| 12/22/2018 | 486 | 463 | 462 | 444 | 451 | 442 | 460 | 466 | 481 | 478 | 483 | 479 | 464 | 462 | 457 | 441 | 444 | 468 | 498 | 499 | 499 | 494 | 484 | 479 |
| 12/23/2018 | 454 | 450 | 432 | 429 | 440 | 440 | 452 | 467 | 473 | 493 | 510 | 504 | 506 | 506 | 500 | 486 | 484 | 510 | 527 | 521 | 519 | 519 | 500 | 485 |
| 12/24/2018 | 458 | 438 | 432 | 429 | 427 | 436 | 452 | 469 | 468 | 476 | 462 | 451 | 440 | 423 | 410 | 402 | 405 | 420 | 444 | 436 | 430 | 439 | 432 | 415 |
| 12/25/2018 | 403 | 384 | 375 | 371 | 376 | 382 | 388 | 403 | 415 | 425 | 430 | 429 | 403 | 390 | 369 | 367 | 374 | 387 | 423 | 425 | 435 | 434 | 431 | 417 |
| 12/26/2018 | 404 | 396 | 388 | 400 | 401 | 418 | 448 | 477 | 495 | 498 | 492 | 484 | 480 | 469 | 472 | 462 | 475 | 490 | 515 | 517 | 506 | 497 | 479 | 458 |
| 12/27/2018 | 441 | 427 | 413 | 416 | 412 | 427 | 435 | 471 | 488 | 496 | 512 | 506 | 509 | 506 | 507 | 512 | 514 | 512 | 529 | 521 | 512 | 500 | 479 | 456 |
| 12/28/2018 | 430 | 418 | 408 | 405 | 392 | 403 | 423 | 457 | 472 | 480 | 486 | 497 | 499 | 496 | 495 | 490 | 493 | 510 | 536 | 537 | 528 | 518 | 518 | 496 |
| 12/29/2018 | 475 | 458 | 455 | 443 | 451 | 455 | 469 | 489 | 491 | 508 | 516 | 519 | 522 | 519 | 517 | 508 | 507 | 523 | 550 | 541 | 524 | 528 | 513 | 493 |
| 12/30/2018 | 476 | 461 | 443 | 448 | 445 | 451 | 471 | 482 | 498 | 498 | 501 | 485 | 468 | 468 | 441 | 451 | 451 | 483 | 515 | 516 | 509 | 501 | 486 | 459 |
| 12/31/2018 | 447 | 422 | 413 | 411 | 412 | 420 | 418 | 446 | 462 | 473 | 487 | 491 | 495 | 502 | 490 | 478 | 482 | 483 | 493 | 485 | 469 | 458 | 445 | 429 |

**Attachment 4.3 2019 MISO LOLE Study Report**

# Planning Year 2019-2020 Loss of Load Expectation Study Report

Loss of Load Expectation Working Group

MISO

## Contents

## Tables



## Figures



## Equations

Revision History

| Reason for Revision | Revised by: | Date: |
|---|---|---|
| Draft Posted | MISO | 10/03/2018 |
| Final Posted | MISO | 10/17/2018 |
| | | |

# 1 Executive Summary

Midcontinent Independent System Operator (MISO) conducts an annual Loss of Load Expectation (LOLE) study to determine a Planning Reserve Margin Unforced Capacity (PRM UCAP), zonal per-unit Local Reliability Requirements (LRR), Zonal Import Ability (ZIA), Zonal Export Ability (ZEA), Capacity Import Limits (CIL) and Capacity Export Limits (CEL). The results of the study and its deliverables supply inputs to the MISO Planning Resource Auction (PRA).

The 2019-2020 Planning Year LOLE Study:

- Establishes a PRM UCAP of 7.9 percent to be applied to the Load Serving Entity (LSE) coincident peaks for the planning year starting June 2019 and ending May 2020
- Uses the Strategic Energy Risk Valuation Model (SERVM) software for Loss of Load analysis to provide results applicable across the MISO market footprint
- Provides initial zonal ZIA, ZEA, CIL and CEL for each Local Resource Zone (LRZ) (Figure 1-1). These values may be adjusted in March 2019 based on changes to MISO units with firm capacity commitments to non-MISO load, and equipment rating changes since the LOLE analysis. The Simultaneous Feasibility Test (SFT) process can further adjust CIL and CEL to assure the resources cleared in the auction are simultaneously reliable.
- Determines a minimum planning reserve margin that would result in the MISO system experiencing a less than one-day loss of load event every 10 years, as per the MISO Tariff.[1] The MISO analysis shows that the system would achieve this reliability level when the amount of installed capacity available is 1.168 times that of the MISO system coincident peak.
- Sets forth initial zonal-based (Table 1-1) PRA deliverables in the LOLE charter.

The stakeholder review process played an integral role in this study. The MISO staff would like to thank the Loss of Load Expectation Working Group (LOLEWG) for its help. Stakeholder advice led to revisions in LOLE results, including updated transfer limits due to improved redispatch, use of existing Op Guides, and constraint invalidation.

| PRA and LOLE Metrics | LRZ 1 | LRZ 2 | LRZ 3 | LRZ 4 | LRZ 5 | LRZ 6 | LRZ 7 | LRZ 8 | LRZ 9 | LRZ 10 |
|---|---|---|---|---|---|---|---|---|---|---|
| **PRM UCAP** | 7.90% | 7.90% | 7.90% | 7.90% | 7.90% | 7.90% | 7.90% | 7.90% | 7.90% | 7.90% |
| **LRR UCAP per-unit of LRZ Peak Demand** | 1.151 | 1.161 | 1.156 | 1.244 | 1.251 | 1.152 | 1.172 | 1.358 | 1.127 | 1.472 |
| **Capacity Import Limit** (CIL) (MW) | 4,078 | 1,713 | 3,037 | 6,845 | 5,013 | 7,066 | 3,211 | 4,424 | 3,950 | 3,906 |
| **Capacity Export Limit** (CEL) (MW) | 3,048 | 979 | 4,440 | 3,693 | 2,122 | 1,435 | 1,358 | 5,089 | 1,905 | 1,607 |
| **Zonal Import Ability (ZIA) (MW)** | 3,747 | 1,713 | 2,813 | 5,210 | 5,013 | 6,924 | 3,211 | 4,185 | 3,631 | 3,792 |
| **Zonal Export Ability (ZEA) (MW)** | 3,379 | 979 | 4,664 | 5,332 | 2,122 | 1,577 | 1,358 | 5,328 | 2,224 | 1,721 |

**Table 1-1: Initial Planning Resource Auction Deliverables**

[1] A one-day loss of load in 10 years (0.1 day/year) is not necessarily equal to 24 hours loss of load in 10 years (2.4 hours/year).

| Local Resource Zone | Local Balancing Authorities |
|---|---|
| 1 | DPC, GRE, MDU, MP, NSP, OTP, SMP |
| 2 | ALTE, MGE, MIUP, UPPC, WEC, WPS |
| 3 | ALTW, MEC, MPW |
| 4 | AMIL, CWLP, SIPC |
| 5 | AMMO, CWLD |
| 6 | BREC, CIN, HE, IPL, NIPSCO, SIGE |
| 7 | CONS, DECO |
| 8 | EAI |
| 9 | CLEC, EES, LAFA, LAGN, LEPA |
| 10 | EMBA, SME |

**Figure 1-1: Local Resource Zones (LRZ)**

## 2 LOLE Study Process Overview

In compliance with Module E-1 of the MISO Tariff, MISO performed its annual LOLE study to determine the 2019-2020 PY MISO system unforced capacity (UCAP) Planning Reserve Margin (PRM) and the per-unit Local Reliability Requirements (LRR) of Local Resource Zone (LRZ) Peak Demand.

In addition to the LOLE analysis, MISO performed transfer analysis to determine initial Zonal Import Ability (ZIA), Zonal Export Ability (ZEA), Capacity Import Limits (CIL) and Capacity Export Limits (CEL). CIL,CEL, and ZIA  are used, in conjunction with the LOLE analysis results, in the Planning Resource Auction (PRA). ZEA is informational and not used in the PRA.

The 2019-2020 per-unit LRR UCAP multiplied by the updated LRZ Peak Demand forecasts submitted for the 2019-2020 PRA determines each LRZ's LRR. Once the LRR is determined, the ZIA values and non-pseudo tied exports are subtracted from the LRR to determine each LRZ's Local Clearing Requirement (LCR) consistent with Section 68A.6[2] of Module E-1. An example calculation pursuant to Section 68A.6 of the current effective Module E-1[3] shows how these values are reached (Table 2-1).

The actual effective PRM Requirement (PRMR) will be determined after the updated LRZ Peak Demand forecasts are submitted by November 1, 2018, for the 2019-2020 PRA. The ZIA, ZEA, CIL and CEL values are subject to updates in March 2019 based on changes to exports of MISO resources to non-

[2] https://www.misoenergy.org/Library/Tariff/Pages/Tariff.aspx#
[3] Effective Date: September 21, 2015

MISO load, changes to pseudo tied commitments, and updates to facility ratings since completion of the LOLE.

Finally, the simultaneous feasibility test (SFT) is performed as part of the PRA to ensure reliability and is maintained by adjusting CIL and CEL values as needed.

| Local Resource Zone (LRZ) EXAMPLE | Example LRZ | Formula Key |
|---|---|---|
| **Installed Capacity** (ICAP) | 17,442 | [A] |
| **Unforced Capacity** (UCAP) | 16,326 | [B] |
| **Adjustment to UCAP** (1d in 10yr) | 50 | [C] |
| **Local Reliability Requirement** (LRR) (UCAP) | 16,376 | [D]=[B]+[C] |
| **LRZ Peak Demand** | 14,270 | [E] |
| **LRR UCAP per-unit of LRZ Peak Demand** | 114.8% | [F]=[D]/[E] |
| **Zonal Import Ability (ZIA)** | 3,469 | [G] |
| **Zonal Export Ability (ZEA)** | 2,317 | [H] |
| **Proposed PRA (UCAP) EXAMPLE** | **Example LRZ** | **Formula Key** |
| **Forecasted LRZ Peak Demand** | 14,270 | [I] |
| **Forecasted LRZ Coincident Peak Demand** | 13,939 | [J] |
| **Non-Pseudo Tied Exports** UCAP | 150 | [K] |
| **Local Reliability Requirement** (LRR) UCAP | 16,376 | [L]=[F]x[I] |
| **Local Clearing Requirement** (LCR) | 12,757 | [M]=[L]-[G]-[K] |
| **Zone's System Wide PRMR** | 15,040 | [N]=[1.079]X[J] |
| **PRMR** | 15,040 | [O] = Higher of [M] or [N] |
| **Planning Reserve Margin (PRM)** | 7.9% | [P]=[O]/[J]-1 |

**Table 2-1: Example LRZ Calculation**

## 2.1 Locational Tariff LOLE Study Enhancements

The Tariff filing referred to as the “Locational” filing resulted in several changes to the LOLE study process for the 2019-2020 Planning Year. The filing aligned CILs and CELs with the Zones where resources are accredited in the Planning Resource Auction (PRA). It also adjusted these limits to represent the share of transfers which can clear in the PRA. Below are more details regarding the filing’s effect on the LOLE study:

- Updates to match how resources are accredited in the PRA
    - Resources outside the MISO boundary (External Resources) will continue to be modeled at their physical location
    - External Resources which meet physical and operational criteria to obtain credit within a MISO LRZ will be included as generation within that Zone for LRR and transfer analysis
- Adjusted limits to represent the share of transfer which can clear in the PRA
    - Two new values, Zonal Import Ability (ZIA) and Zonal Export Ability (ZEA) represent the transfer ability prior to making adjustments for exports to non-MISO load
    - Exports to non-MISO load are removed from these values to determine the transfer limits available for the PRA
    - Adjustment applied to both CEL and CIL; previously only applied to CIL

- Updates to the Local Clearing Requirement calculation aligned with the above changes
    - ZIA replaces CIL
    - Non-pseudo tied exports expanded to reference ‘controllable exports’

## 2.2 Future Study Improvement Considerations

In response to stakeholder feedback received through the LOLEWG, MISO has committed to reviewing two aspects of the transfer analysis process. MISO will examine the redispatch process for external constraints and the Generation Limited Transfer methodology with stakeholders early next year. MISO and stakeholders will consider any identified improvement for the next LOLE study.

# 3 Transfer Analysis

## 3.1 Calculation Methodology and Process Description

Transfer analyses determined initial ZIA, ZEA, CIL and CEL for LRZs for the 2019-2020 Planning Year. The objective of transfer analysis is to determine constraints caused by the transfer of capacity between zones and the associated transfer capability. Multiple factors impacted the analysis when compared to previous studies, including:

- Completion of MTEP transmission projects
- Generation retirements and commissioning of new units
- External system dispatch changes

### 3.1.1 Generation pools

To determine an LRZ’s import or export limit, a transfer is modeled by ramping generation up in a source subsystem and ramping generation down in a sink subsystem. The source and sink definitions depend on the limit being tested. The LRZ studied for import limits is the sink subsystem and the adjacent MISO areas are the source subsystem. The LRZ studied for export limits is the source subsystem and the rest of MISO is the sink subsystem.

Transfers can cause potential issues, which are addressed through the study assumptions. First, an abundantly large source pool spreads the impact of the transfer widely, which potentially masks constraints. Second, ramping up generation from remote areas could cause electrically distant constraints for any given LRZ, which should not determine a zone’s limit. For example, export constraints due to dispatch of LRZ 1 generation in the northwest portion of the footprint should not limit the import capability of LRZ 10, which covers the MISO portion of Mississippi.

To address these potential issues, the transfer studies limit the source pool for the import studies to the areas adjacent to the study zone. Since export study subsystems are defined by the LRZ, these issues only apply to import studies. Generation within the zone studied for an export limit is ramped up and constraints are expected to be near the zone because the ramped-up generation concentrates in a particular area.

### 3.1.2 Redispatch

Limited redispatch is applied after performing transfer analyses to mitigate constraints. Redispatch ensures constraints are not caused by the base dispatch and aligns with potential actions that can be implemented for the constraint in MISO operations. Redispatch scenarios can be designed to address multiple constraints as required and may be used for constraints that are electrically close to each other or to further optimize transfer limits for several constraints requiring only minor redispatch. The redispatch assumptions include:

- The use of no more than 10 conventional fuel units or wind plants
- Redispatch limit at 2,000 MW total (1,000 MW up and 1,000 MW down)
- No adjustments to nuclear units
- No adjustments to the portions of pseudo-tied units committed to non-MISO load

### 3.1.3 Generation Limited Transfer for CIL/CEL and ZIA/ZEA

When conducting transfer analysis to determine import or export limits, the source subsystem might run out of generation to dispatch before identifying a constraint caused by a transmission limit. MISO developed a Generation Limited Transfer (GLT) process to identify transmission constraints in these situations, when possible, for both imports and exports.

After running the First Contingency Incremental Transfer Capability (FCITC) analysis to determine limits for each LRZ, MISO will determine whether a zone is experiencing a GLT (e.g. whether the first constraint would only occur after all the generation is dispatched at its maximum amount). If the LRZ experiences a GLT, MISO will adjust the base model based on whether it is an import or export analysis and re-run the transfer analysis.

For an export study, when a transmission constraint has not been identified after dispatching all generation within the exporting system (LRZ under study) MISO will decrease load and generation dispatch in the study zone. The adjustment creates additional capacity to export from the zone. After the adjustments are complete, MISO will rerun the transfer analysis. If a GLT reappears, MISO will make further adjustments to the load and generation of the study zone.

For an import study, when a transmission constraint has not been identified after dispatching all generation within the source subsystem, MISO will adjust load and generation in the source subsystem. This increases the import capacity for the study zone. After the adjustments are complete, MISO will run the transfer analysis again. If a GLT reappears, MISO will make further adjustments to the model's load and generation in the source subsystem.

FCITC could indicate the transmission system can support larger thermal transfers than would be available based on installed generation for some zones. However, large variations in load and generation for any zone may lead to unreliable limits and constraints. Therefore, MISO limits load scaling for both import and export studies to 50 percent of the zone's load.

Upon further review of LRZ-5 export GLT by the LOLEWG, it was determined that the ZEA value would be set at last year's value of 2,122 MWs.

### 3.1.4 Voltage Limited Transfer for CIL/CEL and ZIA/ZEA

Zonal imports may be limited by voltage constraints due to a decrease in the generation in the zone prior to the thermal limits determined by linear FCITC. LOLE studies may evaluate Power-Voltage curves for LRZs with known voltage-based transfer limitations identified through prior MISO or Transmission Owner studies. Such evaluation may also happen if an LRZ's import reaches a level where the majority of the zone's load would be served using imports from resources outside of the zone. MISO will coordinate with stakeholders as it encounters these scenarios.

## 3.2 Powerflow Models and Assumptions

### 3.2.1 Tools used

MISO used the Siemens PTI Power System Simulator for Engineering (PSS E) and Transmission Adequacy and Reliability Assessment (TARA) as transfer analysis tools.

### 3.2.2 Inputs required

Thermal transfer analysis requires powerflow models and input files. MISO used contingency files from MTEP[4] reliability assessment studies. Single-element contingencies in MISO/seam areas were also evaluated.

MISO developed a subsystem file to monitor its footprint and seam areas. LRZ definitions were developed as sources and sinks in the study. See Appendix B for maps containing adjacent area definitions (Tiers 1 and 2) used for this study. The monitored file includes all facilities under MISO functional control and single elements in the seam areas of 100 kV and above.

### 3.2.3 Powerflow Modeling

The summer peak 2019 study model was built using MISO's Model on Demand (MOD) model data repository, with the following base assumptions (Table 3-1).

| Scenario | Effective Date | Projects Applied | External Modeling | Load and Generation Profile |
|---|---|---|---|---|
| 2019 | 6/1/2019 | MTEP18 Appendix A and Target A | 2017 Series 2019 Summer ERAG MMWG | Summer Peak |

**Table 3-1: Model assumptions**

MISO excluded several types of units from the transfer analysis dispatch; these units' base dispatch remained fixed.

- Nuclear dispatch does not change for any transfer
- Intermittent resources can be ramped down, but not up
- Pseudo-tied resources were modeled at their expected commitments to non-MISO load, although portions of these units committed to MISO could participate in transfer analyses

System conditions such as load, dispatch, topology and interchange have an impact on transfer capability. The model was reviewed as part of the base model build for MTEP18 analyses, with study files made available on the MTEP ftp site. MISO worked closely with transmission owners and stakeholders in order to model the transmission system accurately, as well as to validate constraints and redispatch. Like other planning studies, transmission outage schedules were not included in the analysis. This is driven partly by limited availability of outage information as well as by current standard requirements. Although no outage schedules were evaluated, all single element contingencies were evaluated. This includes BES lines, transformers, and generators. Contingency coverage covers most of category P1 and some of category P2.

### 3.2.4 General Assumptions

MISO uses TARA to process the powerflow model and associated input files to determine the import and export limits of each LRZ by determining the transfer capability. Transfer capability measures the ability of interconnected power systems to reliably transfer power from one area to another under specified system conditions. The incremental amount of power that can be transferred will be determined through FCITC analysis. FCITC analysis and base power transfers provide the information required to calculate the First Contingency Total Transfer Capability (FCTTC), which indicates the total amount of transferrable power before a constraint is identified. FCTTC is the base power transfer plus the incremental transfer capability (Equation 3-1). All published limits are based on the zone's FCTTC and may be adjusted for capacity exports.

[4] Refer to the Transmission Planning BPM for more information regarding MTEP input files. https://www.misoenergy.org/_layouts/MISO/ECM/Redirect.aspx?ID=19215

$$First\ Contingency\ Total\ Transfer\ Capability\ (FCTTC) = FCITC + Base\ Power\ Transfer$$

**Equation 3-1: Total Transfer Capability**

Facilities were flagged as potential constraints for loadings of 100 percent or more in two scenarios: the normal rating for system intact conditions and the emergency rating for single event contingencies. Linear FCITC analysis identifies the limiting constraints using a minimum transfer Distribution Factor (DF) cutoff of 3 percent, meaning the transfer and contingency must increase the loading on the overloaded element by 3 percent or more.

A pro-rata dispatch is used, which ensures all available generators will reach their maximum dispatch level at the same time. The pro-rata dispatch is based on the MW reserve available for each unit and the cumulative MW reserve available in the subsystem. The MW reserve is found by subtracting a unit's base model generation dispatch from its maximum dispatch, which reflects the available capacity of the unit.

Table 3-2 and Equation 3-2 show an example of how one unit's dispatch is set, given all machine data for the source subsystem.

| Machine | Base Model Unit Dispatch (MW) | Minimum Unit Dispatch (MW) | Maximum Unit Dispatch (MW) | Reserve MW (Unit Dispatch Max – Unit Dispatch Min) |
|---|---|---|---|---|
| 1 | 20 | 20 | 100 | 80 |
| 2 | 50 | 10 | 150 | 100 |
| 3 | 20 | 20 | 100 | 80 |
| 4 | 450 | 0 | 500 | 50 |
| 5 | 500 | 100 | 500 | 0 |
| | | | **Total Reserve** | **310** |

**Table 3-2: Example subsystem**

$$\boldsymbol{Machine\ 1\ Incremental\ Post\ Transfer\ Dispatch = \frac{Machine\ 1\ Reserve\ MW}{Source\ Subsystem\ Reserve\ MW} \times Transfer\ Level\ MW}$$

$$Machine\ 1\ Incremental\ Post\ Transfer\ Dispatch = \frac{80}{310} \times 100 = 25.8$$

$$Machine\ 1\ Incremental\ Post\ Transfer\ Dispatch = 25.8$$

**Equation 3-2: Machine 1 dispatch calculation for 100 MW transfer**

## 3.3 Results for CIL/CEL and ZIA/ZEA

Constraints limiting transfers and the associated ZIA, ZEA, CIL, and CEL for each LRZ were presented and reviewed through the LOLEWG. Preliminary results for Planning Year 2019/20 were presented in the September 2018 meeting and updates were presented in an October 2018 WebEx/conference call.

Detailed constraint and redispatch information for all limits is found in the Transfer Analysis section of this report. Table 3-3 presents a summary of the Planning Year 2019-20 Capacity Import Limits.

| LRZ | Tier | 19-20 CIL (MW)[5] | 19-20 ZIA (MW) | Monitored Element | Contingent Element | Figure 3.3-1 Map ID | GLT applied | Generation Redispatch (MW) | 18-19 CIL (MW)[6] |
|---|---|---|---|---|---|---|---|---|---|
| 1 | 1&2 | 4,078 | 3,747 | Sherman Street to Sunnyvale 115 kV | Arpin to Rocky Run 115 kV | 1 | No | 1,992 | 4,546 |
| 2 | 1&2 | 1,713 | 1,713 | University Park to East Frankfort 345 kV | Dumont to Wilton 765 kV | 2 | No | 2,000 | 2,317 |
| 3 | 1&2 | 3,037 | 2,813 | Sub 3458 to Sub 3456 345 kV | Sub 3455 to Sub 3740 345 kV | 3 | No | 2,000 | 2,812 |
| 4 | N/A | 6,845 | 5,210 | Hallock Bus 138 kV voltage | Clinton Generation | 4 | No | N/A | 6,278 |
| 5 | 1&2 | 5,013 | 5,013 | Joppa 345/161 kV | Shawnee 500/345 kV | 5 | No | 1,820 | 3,580 |
| 6 | 1&2 | 7,066 | 6,924 | Paradise to BRTAP 161 kV | Phipps Bend to Volunteer 500 kV | 6 | No | 2,000 | 7,375 |
| 7 | N/A | 3,211 | 3,211 | Pioneer 120 kV bus voltage | Wayne – Monroe 345 kV | 7 | No | N/A | 3,785 |
| 8 | 1&2 | 4,424 | 4,185 | Moon Lake-Ritchie 230 kV | Cordova TN to Benton MS500 kV | 8 | No | 2,000 | 4,778 |
| 9 | 1&2 | 3,950 | 3,631 | Sterlington to Downsville 115 kV | Mt. Olive to El Dorado 500 kV | 9 | No | 2,000 | 3,679 |
| 10 | 1 | 3,906 | 3,792 | Freeport to Twinkletown 230 kV | Freeport to Horn Lake 230 kV | 10 | No | 2,000 | 2,618 |

**Table 3-3: Planning Year 2019–2020 Import Limits**

[5] Results after applying redispatch and adjusted for exports to non-MISO load per the FERC locational filing.
[6] Results after applying redispatch and shift factor adjustments for the Dec. 31, 2015, FERC order.

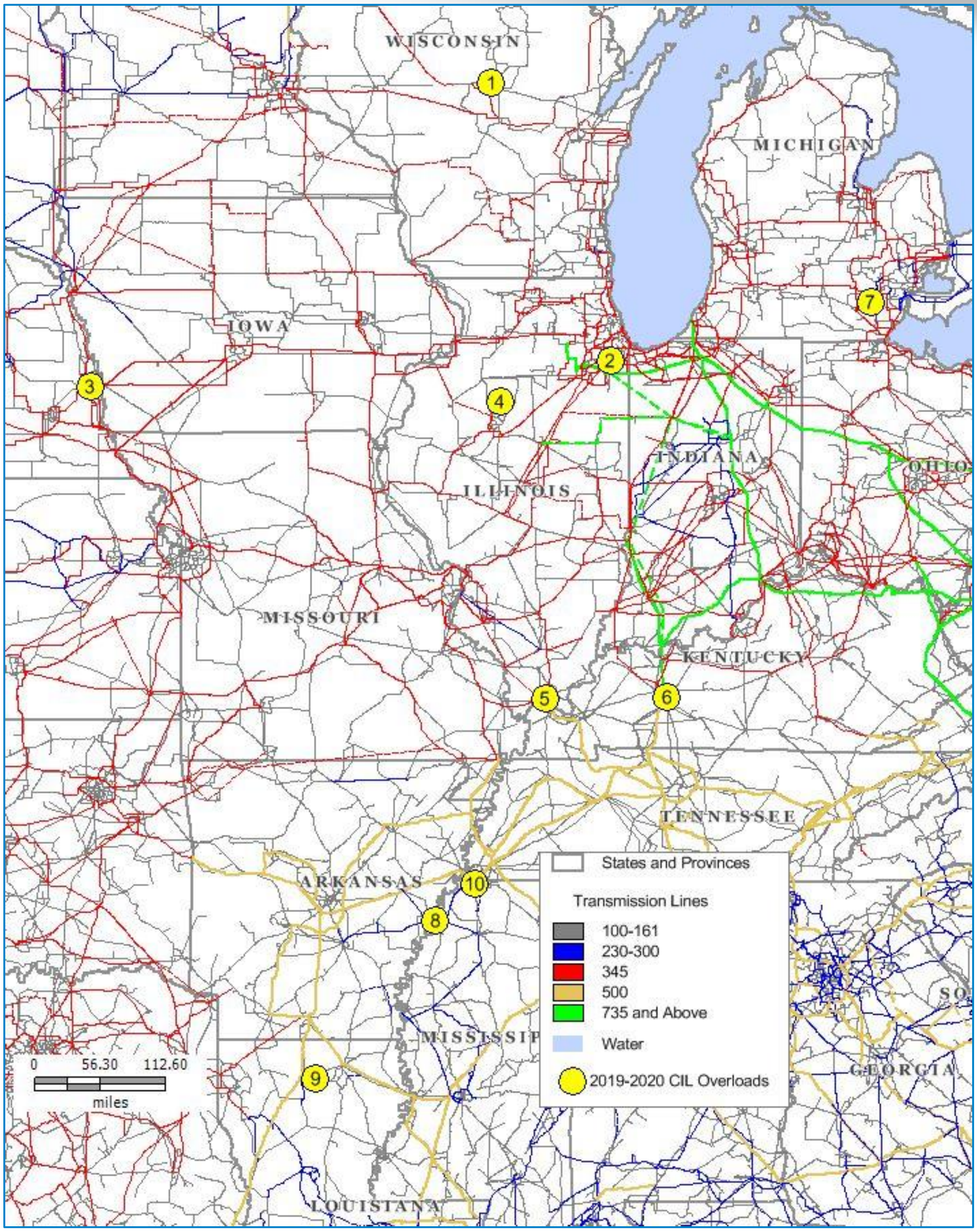



Figure 3-1: Planning Year 2019-20 Import Constraint Map

Capacity Exports Limits were found by increasing generation in the zone being studied and decreasing generation in the rest of the MISO footprint. Table 3-4 summarizes Planning Year 2019-20 Capacity Export Limits.

| LRZ | 19-20 CEL (MW) | 19-20 ZEA (MW) | Monitored Element | Contingent Element | Figure 3.3-2 Map ID | Generation Redispatch (MW) | GLT applied | 18-19 CEL (MW) |
|---|---|---|---|---|---|---|---|---|
| 1 | 3,048 | 3,379 | Seneca to Gran Grae 161 kV | Arpin to Eau Claire 345 kV | 1 | 400 | Yes | 516 |
| 2 | 979 | 979 | Wempleton 345/138 kV | Cherry Valley 345/138 kV | 2 | 1,208 | Yes | 2,017 |
| 3 | 4,440 | 4,664 | Fargo 345/138 kV | Mapleridge to Tazwell 345 kV | 3 | 350 | Yes | 5,430 |
| 4 | 3,693 | 5,332 | Pontiac to Brokaw 345 kV | Pontiac to Bluemond 345 kV | 4 | 350 | Yes | 4,280 |
| 5 | 2,122 | 2,122 | No Constraint found | System Intact | 5 | 0 | Yes | 2,122 |
| 6 | 1,435 | 1,577 | University Park to East Frankfort 345 kV | Dumont to Wilton 765 kV | 7 | 0 | Yes | 3,249 |
| 7 | 1,358 | 1,358 | University Park to East Frankfort 345 kV | Dumont to Wilton 765 kV | 6 | 1400 | No | 2,578 |
| 8 | 5,089 | 5,328 | Russelville South to Dardanelle 161 kV | Arkansas Nuclear to Fort Smith 500 kV | 8 | 0 | Yes | 2,424 |
| 9 | 1,905 | 2,224 | Addis to Tiger 230 kV | Dow meter to Chenango 230 kV | 9 | 800 | No | 2,149 |
| 10 | 1,607 | 1,721 | Batesville to Tallahachie 161 kV | Choctaw to Clay 500 kV | 10 | 100 | Yes | 1,824 |

**Table 3-4: Planning Year 2019–2020 Export Limits**

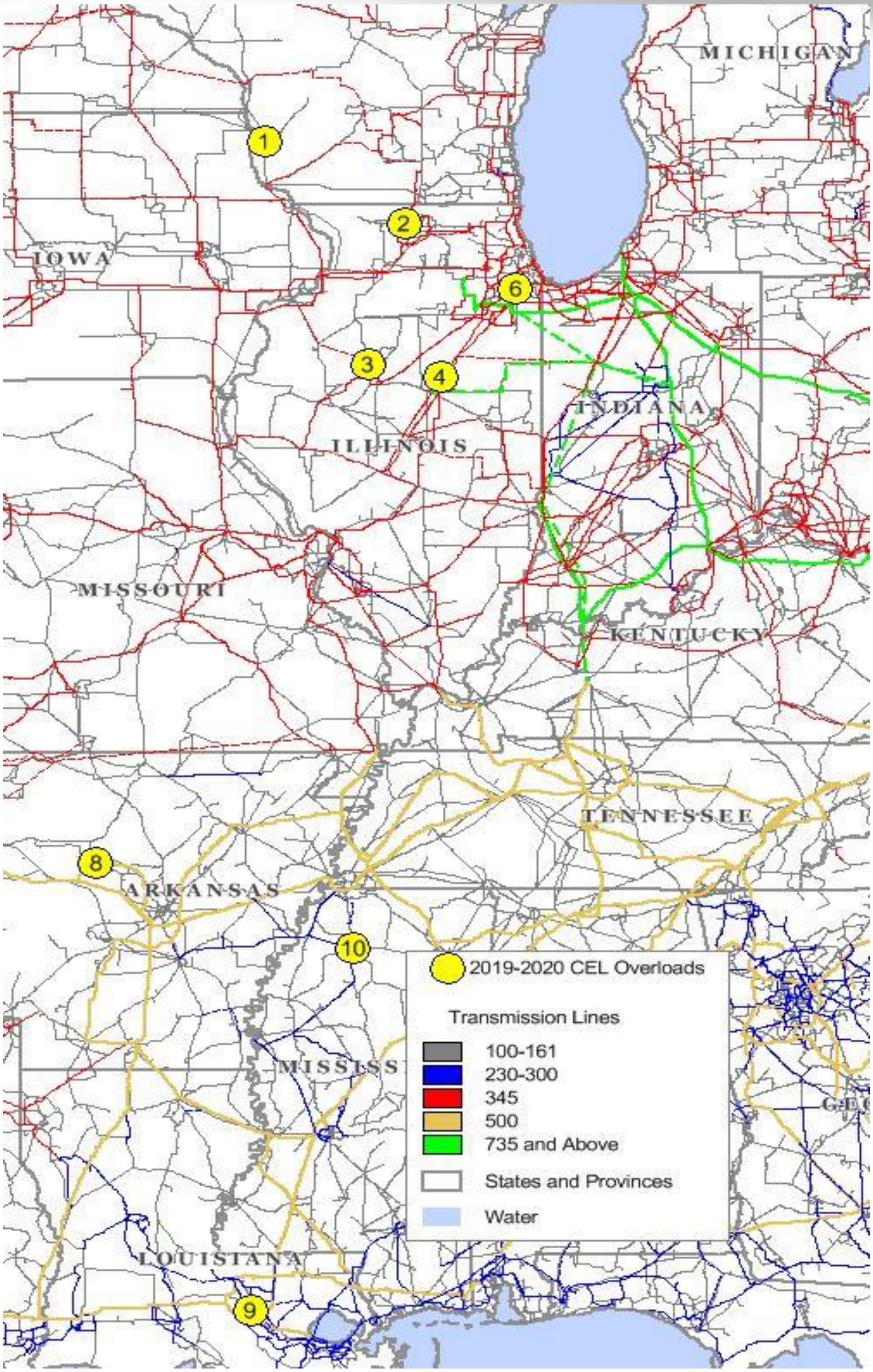



**Figure 3-2: Planning Year 2019-20 Export Constraint Map**

### 3.3.1 Out-Year Analysis

In 2018, MISO and its stakeholders redesigned the out-year LOLE transfer analysis process through the LOLEWG and Resource Adequacy Subcommittee (RASC). The out-year analysis will now be performed after the near-term analyses are complete. The out-year results will be documented outside of the LOLE report and recorded in LOLEWG meeting materials.

# 4 Loss of Load Expectation Analysis

## 4.1 LOLE Modeling Input Data and Assumptions

MISO uses a program managed by Astrapé Consulting called SERVM to calculate the LOLE for the applicable planning year. SERVM uses a sequential Monte Carlo simulation to model a generation system and to assess the system's reliability based on any number of interconnected areas. SERVM calculates the annual LOLE for the MISO system and each LRZ by stepping through the year chronologically and taking into account generation, load, load modifying and energy efficiency resources, equipment forced outages, planned and maintenance outages, weather and economic uncertainty, and external support.

Building the SERVM model is the most time-consuming task of the PRM study. Many scenarios are built in order to determine how certain variables impact the results. The base case models determine the MISO PRM Installed Capacity (ICAP), PRM UCAP and the LRRs for each LRZ for years one, four and six.

## 4.2 MISO Generation

### 4.2.1 Thermal Units

The 2019-2020 planning year LOLE study used the 2018 PRA converted capacity as a starting point for which resources to include in the study. This ensured that only resources eligible as a Planning Resources were included in the LOLE study. An exception was made for resources with a signed GIA with an anticipated in-service date for the 2019-2020 PY. These resources were also included. All internal Planning Resources were modeled in the LRZ in which they are physically located. Additionally, Coordinating Owners and Border External Resources were modeled as being internal to the LRZ in which they are committed to serving load.

Forced outage rates and planned maintenance factors were calculated over a five-year period (January 2013 to December 2017) and modeled as one value for each unit. Some units did not have five years of historical data in MISO's Generator Availability Data System (PowerGADS). However, if they had at least 12 consecutive months of data then unit-specific information was used to calculate their forced outage rates and maintenance factors. Units with fewer than 12 consecutive months of unit-specific data were assigned the corresponding MISO class average forced outage rate and planned maintenance factor based on their fuel type. Any MISO class with fewer than 30 units were assigned the overall MISO weighted class average forced outage rate of 9.28 percent.

Nuclear units have a fixed maintenance schedule, which was pulled from publicly available information and was modeled for each of the study years.

The historical class average outage rates as well as the MISO fleet wide weighted average forced outage rate are in Table 4-1.

| Pooled EFORd GADS Years | 2013-2017 (%) | 2012-2016 (%) | 2011-2015 (%) | 2010-2014 (%) | 2009-2013 (%) | 2008-2012 (%) |
|---|---|---|---|---|---|---|
| LOLE Study Planning Year | 2019-2020 PY LOLE Study | 2018-2019 PY LOLE Study | 2017-2018 PY LOLE Study | 2016-2017 PY LOLE Study | 2015-2016 PY LOLE Study | 2014-2015 PY LOLE Study |
| Combined Cycle | 5.37 | 4.62 | 3.56 | 3.78 | 3.92 | 4.74 |
| Combustion Turbine (0-20 MW) | 23.18 | 29.02 | 24.2 | 23.58 | 18.39 | 27.22 |
| Combustion Turbine (20-50 MW) | 15.76 | 13.48 | 13.94 | 16.03 | 53.12 | 25.27 |
| Combustion Turbine (50+ MW) | 5.18 | 6.19 | 5.94 | 5.69 | 5.61 | 5.76 |
| Diesel Engines | 10.26 | 10.42 | 13.12 | 12.51 | 14.00 | 9.83 |
| Fluidized Bed Combustion | * | * | * | * | ** | ** |
| HYDRO (0-30MW) | * | * | * | * | ** | ** |
| HYDRO (30+ MW) | * | * | * | * | ** | ** |
| Nuclear | * | * | * | * | ** | ** |
| Pumped Storage | * | * | * | * | ** | ** |
| Steam - Coal (0-100 MW) | 4.60 | 5.14 | 5.99 | 7.12 | 8.45 | 8.82 |
| Steam - Coal (100-200 MW) | * | * | * | * | 6.39 | 6.85 |
| Steam - Coal (200-400 MW) | 9.82 | 9.77 | 8.64 | 8.46 | 8.44 | 8.33 |
| Steam - Coal (400-600 MW) | * | * | * | 7.04 | 6.99 | 6.98 |
| Steam - Coal (600-800 MW) | 8.22 | 7.90 | 7.42 | 7.58 | 7.36 | ** |
| Steam - Coal (800-1000 MW) | * | * | * | * | ** | ** |
| Steam - Gas | 11.56 | 11.94 | 11.68 | 10.18 | 8.79 | ** |
| Steam - Oil | * | * | * | * | ** | ** |
| Steam - Waste Heat | * | * | * | * | ** | ** |
| Steam - Wood | * | * | * | * | ** | ** |
| MISO System Wide Weighted | 9.28 | 9.16 | 8.21 | 7.98 | 7.67 | 7.55 |

*MISO system-wide weighted forced outage rate used in place of class data for those with less than 30 units reporting 12 or more months of data

**Prior to 2015-2016PY the NERC class average outage rate was used for units with less than 30 units reporting 12 or more months of data

**Table 4-1: Historical Class Average Forced Outage Rates**

### 4.2.2 Behind-the-Meter Generation

Behind-the-Meter generation data came from the Module E Capacity Tracking (MECT) tool. These resources were explicitly modeled just as any other thermal generator with a monthly capacity and forced outage rate. Performance data was pulled from PowerGADS.

### 4.2.3 Sales

This year's LOLE analysis incorporated firm sales to neighboring capacity markets as well as firm transactions off system where information was available. For units with capacity sold off-system, the monthly capacities were reduced by the megawatt amount sold. This totaled 3,195 MW UCAP for Planning Year 2019-2020. See Section 4.4 for a more detailed breakdown. These values came from PJM's Reliability Pricing Model (RPM) as well as exports to other external areas taken from the Independent Market Monitor (IMM) exclusion list.

### 4.2.4 Attachment Y

For the 2019-2020 planning year, generating units with approved suspensions or retirements (as of June 1, 2018) through MISO's Attachment Y process were removed from the LOLE analysis. Any unit retiring, suspending, or coming back online at any point during the planning year was excluded from the year-one analysis. This same methodology is used for the four- and six-year analyses.

### 4.2.5 Future Generation

Future thermal generation and upgrades were added to the LOLE model based on unit information in the MISO Generator Interconnection Queue. The LOLE model included units with a signed interconnection agreement (as of June 1, 2018). These new units were assigned class-average forced outage rates and planned maintenance factors based on their particular unit class. Units upgraded during the study period reflect the megawatt increase for each month, beginning the month the upgrade was finished. The LOLE analysis also included future wind and solar generation at the MISO capacity accreditation amount (wind at 15.2 percent and solar at 50 percent).

### 4.2.6 Intermittent Resources

Intermittent resources such as run-of-river hydro, biomass and wind were explicitly modeled as demand-side resources. Non-wind intermittent resources, such as run-of-river hydro and biomass, provide MISO with up to 15 years of historical summer output data for the hours ending 15:00 EST through 17:00 EST. This data is averaged and modeled in the LOLE analysis as UCAP for all months. Each individual unit is modeled and put in the corresponding LRZ.

Each wind-generator Commercial Pricing Node (CPNode) received a capacity credit based on its historical output from MISO's top eight peak days in each of the past years for which data were available. The megawatt value corresponding to each CPNode's wind capacity credit was used for each month of the year. Units new to the commercial model without a wind capacity credit as part of the 2018 Wind Capacity Credit analysis received the MISO-wide wind capacity credit of 15.2 percent as established by the 2018 Wind Capacity Credit Effective Load Carrying Capability (ELCC) study. The capacity credit established by the ELCC analysis determines the maximum percent of the wind unit that can receive credit in the PRA while the actual amount could be less due to other factors such as transmission limitations. Each wind CPNode receives its actual wind capacity credit based on the capacity eligible to participate in the PRA. Only Network Resource Interconnection Service or Energy Resource Interconnection Service with firm point-to-point is considered an eligible capacity resource. The final value from the 2018 PRA for each wind unit was modeled at a flat capacity profile for the planning year. The detailed methodology for establishing the MISO-wide and individual CPNode Wind Capacity Credits can be found in the 2018 Wind Capacity Credit Report.

### 4.2.7 Demand Response

Demand response data came from the MECT tool. These resources were explicitly modeled as dispatch-limited resources. Each demand response program was modeled individually with a monthly capacity, limited to the number of times each program can be called upon, and limited by duration.

## 4.3 MISO Load Data

The 2019-2020 LOLE analysis used a load training process with neural net software to create a neural-net relationship between historical weather and load data. This relationship was then applied to 30 years of hourly historical weather data to create 30 different load shapes for each LRZ in order to capture both load diversity and seasonal variations. The average monthly loads of the predicted load shapes were adjusted to match each LRZ's Module E 50/50 monthly zonal peak load forecasts for each study year. The results of this process are shown as the MISO System Peak Demand (Table 5-1) and LRZ Peak Demands (Table 6-1).

Direct Control Load Management and Interruptible Demand types of demand response were explicitly included in the LOLE model as resources. These demand resources are implemented in the LOLE simulation before accumulating LOLE or shedding of firm load.

### 4.3.1 Weather Uncertainty

MISO has adopted a six-step load training process in order to capture the weather uncertainty associated with the 50/50 load forecasts. The first step of this process requires the collection of five years of historical real-time load modifying resource (LMR) performance and load data, as well as the collection of 30 years of historical weather data. Both the LMR and load data are taken from the MISO market for each LBA, while the historical weather data is collected from the National Oceanic and Atmospheric Administration (NOAA) for each LRZ. After collecting the data the hourly gross load for each LRZ is calculated using the five years of historical data.

The second step of the process is to normalize the five years of load data to consistent economics. With the load growth due to economics removed from 5 years of historical LRZ load, the third step of the process utilizes neural network software to establish functional relationships between the five years of historical weather and load data. In the fourth step of the process the neural network relationships are applied to the 30 years of historical weather data in order to predict/create 30 years' worth of load shapes for each LRZ.

In the fifth step of the load training process, MISO undertakes extreme temperature verification on the 30 years of load shapes to ensure that the hourly load data is accurate at extremely hot or cold temperatures. This is required since there are fewer data points available at the temperature extremes when determining the neural network functional relationships. This lack of data at the extremes can result in inaccurate predictions when creating load shapes, which will need to be corrected before moving forward.

The sixth and final step of the load training process is to average the monthly peak loads of the predicted load shapes and adjust them to match each LRZ's Module E 50/50 monthly zonal peak load forecasts for each study year. In order to calculate this adjustment, the ratio of the first year's non-coincident peak forecast to the zonal coincident peak forecast is applied to future year's non-coincident peak forecast.

By adopting this new methodology for capturing weather uncertainty MISO is able to model multiple load shapes based off a functional relationship with weather. This modeling approach provides a variance in load shapes, as well as the peak loads observed in each load shape. This approach also provides the ability to capture the frequency and duration of severe weather patterns.

### 4.3.2 Economic Load Uncertainty

To account for economic load uncertainty in the 2019-2020 planning year LOLE model MISO utilized a normal distribution of electric utility forecast error accounting for projected and actual Gross Domestic Product (GDP), as well as electricity usage. The historic projections for GDP growth were taken from the Congressional Budget Office (CBO), the actual GDP growth was taken from the Bureau of Economic Analysis (BEA), and the electric use was taken from the U.S. Energy Information Administration (EIA). Due to lack of statewide projected GDP data MISO relied on United States aggregate level data when calculating the economic uncertainty.

In order to calculate the electric utility forecast error, MISO first calculated the forecast error of GDP between the projected and actual values. The resulting GDP forecast error was then translated into electric utility forecast error by multiply by the rate at which electric load grows in comparison to the GDP. Finally, a standard deviation is calculated from the electric utility forecast error and used to create a normal distribution representing the probabilities of the load forecast errors (LFE) as shown in Table 4-2.

| | LFE Levels | | | | |
|---|---|---|---|---|---|
| | -2.0% | -1.0% | 0.0% | 1.0% | 2.0% |
| Standard Deviation in LFE | Probability assigned to each LFE | | | | |
| 1.19% | 10.4% | 23.3% | 32.6% | 23.3% | 10.4% |

**Table 4-2: Economic Uncertainty**

As a result of stakeholder feedback MISO is exploring possible alternative methods for determining economic uncertainty to be used in the LOLE process.

## 4.4 External System

Within the LOLE study, a 1 MW increase of non-firm support from external areas leads to a 1 MW decrease in the reserve margin calculation. It is important to account for the benefit of being part of the eastern interconnection while also providing a stable result. In order to provide a more stable result and remove the false sense of precision, the external non-firm support was set at an ICAP of 2,987 MW and a UCAP of 2,331 MW.

Firm imports from external areas to MISO are modeled at the individual unit level. The specific external units were modeled with their specific installed capacity amount and their corresponding Equivalent Forced Outage Rate demand (EFORd). This better captures the probabilistic reliability impact of firm external imports. These units are only modeled within the MISO PRM analysis and are not modeled when calculating the LRZ LRRs. Due to the locational Tariff filing, Border External Resources and Coordinating Owners are no longer considered firm imports. Instead, these resources are modeled as internal MISO units and are included in the PRM and LRR analysis. The external resources to include for firm imports were based on the amount offered into the 2018-19 planning year PRA. This is a historically accurate indicator of future imports. For 2018-19 planning year this amount was 1,883 MW ICAP.

Firm exports from MISO to external areas were modeled the same as previous years. As stated in Section 4.2.3, capacity ineligible as MISO capacity due to transactions with external areas is removed from the model. Table 4-3 shows the amount of firm imports and exports in this year's study.

| Contracts | ICAP (MW) | UCAP (MW) |
|---|---|---|
| Imports (MW) | 1,883 | 1,809 |
| Exports (MW) | 3,526 | 3,195 |
| **Net** | **-1,643** | **-1,386** |

**Table 4-3: 2018 Planning Year Firm Imports and Exports**

## 4.5 Loss of Load Expectation Analysis and Metric Calculations

Upon completion of the SERVM database, MISO determined the appropriate PRM ICAP and PRM UCAP for the 2019-2020 planning year as well as the appropriate Local Reliability Requirement for each of the 10 LRZ's. These metrics were determined by a probabilistic LOLE analysis such that the LOLE for the planning year was one day in 10 years, or 0.1 day per year.

### 4.5.1 MISO-Wide LOLE Analysis and PRM Calculation

For the MISO-wide analysis, generating units were modeled as part of their appropriate LRZ as a subset of a larger MISO pool. The MISO system was modeled with no internal transmission limitations. In order to meet the reliability criteria of 0.1 day per year LOLE, capacity is either added or removed from the MISO pool. The minimum amount of capacity above the 50/50 net internal MISO Coincident Peak Demand required to meet the reliability criteria was used to establish the PRM values.

The minimum PRM requirement is determined using the LOLE analysis by either adding or removing capacity until the LOLE reaches 0.1 day per year. If the LOLE is less than 0.1 day per year, a perfect negative unit with zero forced outage rate is added until the LOLE reaches 0.1 day per year. The perfect negative unit adjustment is akin to adding load to the model. If the LOLE is greater than 0.1 day per year, proxy units based on a unit of typical size and forced outage rate will be added to the model until the LOLE reaches 0.1 day per year.

For the 2019-2020 planning year, the MISO PRM analysis removed capacity (6,250 MW) using the perfect unit adjustment.

The formulas for the PRM values for the MISO system are:

PRM ICAP = ((Installed Capacity + Firm External Support ICAP + ICAP Adjustment to meet a LOLE of 0.1 days per year) – MISO Coincident Peak Demand)/MISO Coincident Peak Demand

PRM UCAP = (Unforced Capacity + Firm External Support UCAP + UCAP Adjustment to meet a LOLE of 0.1 days per year) – MISO Coincident Peak Demand)/MISO Coincident Peak Demand

Where Unforced Capacity (UCAP) = Installed Capacity (ICAP) x (1 – XEFORd)

### 4.5.2 LRZ LOLE Analysis and Local Reliability Requirement Calculation

For the LRZ analysis, each LRZ included only the generating units within the LRZ (including Coordinating Owners and Border External Resources) and was modeled without consideration of the benefit of the LRZ's import capability. Much like the MISO analysis, unforced capacity is either added or removed in each LRZ such that a LOLE of 0.1 day per year is achieved. The minimum amount of unforced capacity above each LRZ's Peak Demand that was required to meet the reliability criteria was used to establish each LRZ's LRR.

The 2019-2020 LRR is determined using the LOLE analysis by either adding or removing capacity until the LOLE reaches 0.1 day per year for the LRZ. If the LOLE is less than 0.1 day per year, a perfect negative unit with zero forced outage rate will be added until the LOLE reaches 0.1 day per year. If the LOLE is greater than 0.1 day per year, proxy units based on a unit of typical size and forced outage rate will be added to the model until the LOLE reaches 0.1 day per year.

For the 2019-2020 planning year, only LRZ-3 and LRZ-8 had sufficient capacity, internal to the LRZ to achieve the LOLE of 0.1 day per year as an island. In the eight zones without sufficient capacity as an island, proxy units of typical size (160 MW) and class-average EFORd (5.17 percent) were added to the LRZ. When needed, a fraction of the final proxy unit was added to achieve the exact LOLE of 0.1 day per year for the LRZ.

# 5 MISO System Planning Reserve Margin Results

## 5.1 Planning Year 2019-2020 MISO Planning Reserve Margin Results

For the 2019-2020 planning year, the ratio of MISO capacity to forecasted MISO system peak demand yielded a planning ICAP reserve margin of 16.8 percent and a planning UCAP reserve margin of 7.9 percent. These PRM values assume 1,809 MW UCAP of firm and 2,331 MW UCAP of non-firm external support. Numerous values and calculations went into determining the MISO system PRM ICAP and PRM UCAP (Table 5-1).

| MISO Planning Reserve Margin (PRM) | **2019/2020 PY** (June 2019 - May 2020) | Formula Key |
|---|---|---|
| **MISO System Peak Demand** (MW) | 125,501 | [A] |
| **Installed Capacity** (ICAP) (MW) | 153,896 | [B] |
| **Unforced Capacity** (UCAP) (MW) | 142,132 | [C] |
| **Firm External Support** (ICAP) (MW) | 1,883 | [D] |
| **Firm External Support** (UCAP) (MW) | 1,809 | [E] |
| **Adjustment to ICAP** {1d in 10yr} (MW) | -6,250 | [F] |
| **Adjustment to UCAP** {1d in 10yr} (MW) | -6,250 | [G] |
| **Non-Firm External Support** (ICAP) (MW) | 2,987 | [H] |
| **Non-Firm External Support** (UCAP) (MW) | 2,331 | [I] |
| **ICAP PRM Requirement** (PRMR) (MW) | 146,543 | [J]=[B]+[D]+[F]-[H] |
| **UCAP PRM Requirement** (PRMR) (MW) | 135,360 | [K]=[C]+[E]+[G]-[I] |
| **MISO PRM ICAP** | **16.8%** | [L]=([J]-[A])/[A] |
| **MISO PRM UCAP** | **7.9%** | [M]=([K]-[A])/[A] |

**Table 5-1: Planning Year 2019-2020 MISO System Planning Reserve Margins**

### 5.1.1 LOLE Results Statistics

In addition to the LOLE results SERVM has the ability to calculate several other probabilistic metrics (Table 5-2). These values are given when MISO is at its PRM UCAP of 7.9 percent. The LOLE of 0.1 day/year is what the model is driven to and how the PRM is calculated. The loss of load hours is defined as the number of hours during a given time period where system demand will exceed the generating capacity during a given period. Expected Unserved Energy (EUE) is energy-centric and analyzes all hours of a particular planning year. Results are calculated in megawatt-hours (MWh). EUE is the summation of the expected number of MWh of load that will not be served in a given planning year as a result of demand exceeding the available capacity across all hours.

| MISO LOLE Statistics | |
|---|---|
| Loss of Load Expectation - LOLE [Days/Yr] | 0.100 |
| Loss of Load Hours - LOLH [hrs/yr] | 0.339 |
| Expected Unserved Energy - EUE [MWh/yr] | 732.9 |

**Table 5-2: MISO Probabilistic Model Statistics**

## 5.2 Comparison of PRM Targets Across Eight Years

Figure 5-1 compares the PRM UCAP values over the last nine planning years. The last endpoint of the blue line shows the Planning Year 2019-2020 PRM value.

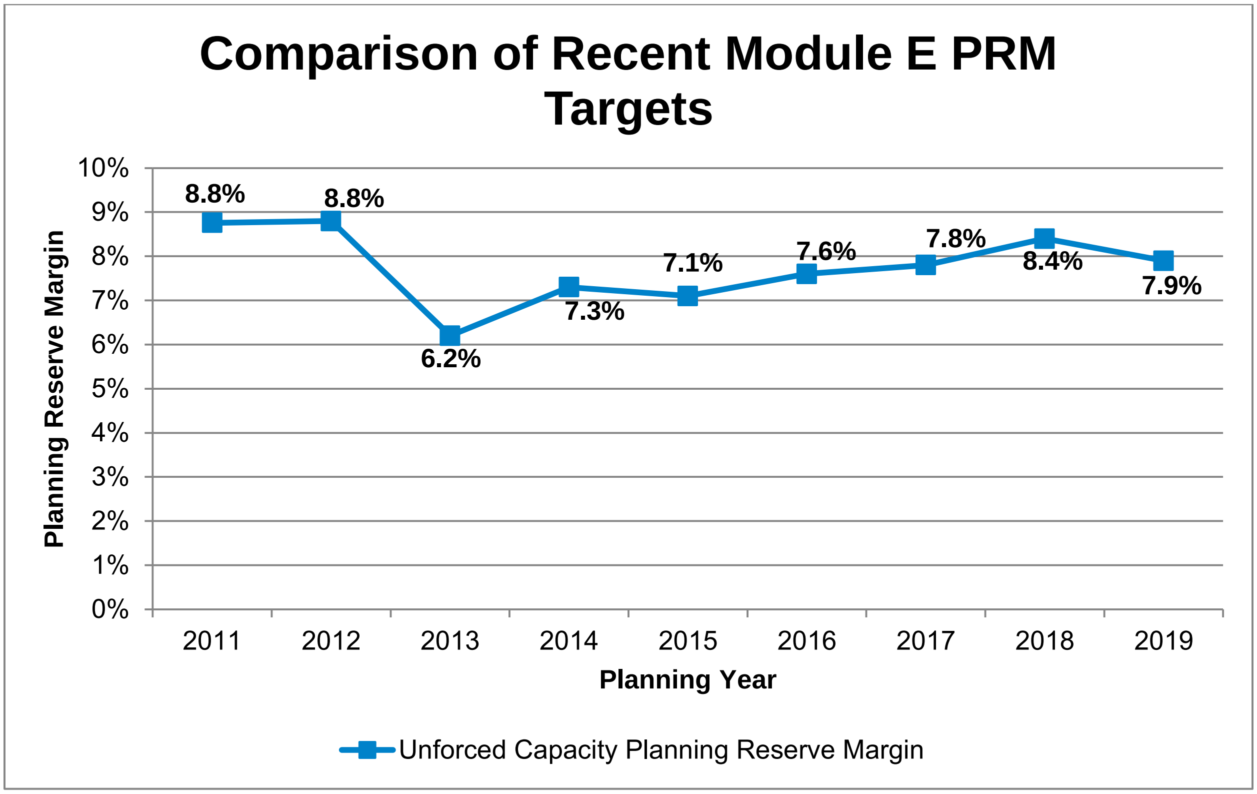



**Figure 5-1: Comparison of PRM targets across eight years**

## 5.3 Future Years 2019 through 2028 Planning Reserve Margins

Beyond the planning year 2019-2020 LOLE study analysis, an LOLE analysis was performed for the four-year-out planning year of 2022-2023, and the six-year-out planning year of 2024-2025. Table 5-3 shows all the values and calculations that went into determining the MISO system PRM ICAP and PRM UCAP values for those years. Those results are shown as the underlined values of Table 5-4. The values from the intervening years result from interpolating the 2019, 2022, and 2024 results. Note that the MISO system PRM results assume no limitations on transfers within MISO.

The 2022-2023 planning year PRM increased slightly from the 2019-2020 planning year driven mainly by new unit additions and retirements. The forecasts for the 2024-2025 Planning Year PRM decreased primarily because of LSE load forecasts.

| MISO Planning Reserve Margin (PRM) | 2022/2023 PY (June 2022 - May 2023) | 2024/2025 PY (June 2024 - May 2025) | Formula Key |
|---|---|---|---|
| **MISO System Peak Demand** (MW) | 126,768 | 127,259 | [A] |
| **Installed Capacity** (ICAP) (MW) | 156,422 | 156,686 | [B] |
| **Unforced Capacity** (UCAP) (MW) | 144,815 | 145,037 | [C] |
| **Firm External Support** (ICAP) (MW) | 1,883 | 1,883 | [D] |
| **Firm External Support** (UCAP) (MW) | 1,809 | 1,809 | [E] |
| **Adjustment to ICAP** {1d in 10yr} (MW) | -7,225 | -7,615 | [F] |
| **Adjustment to UCAP** {1d in 10yr} (MW) | -7,225 | -7,615 | [G] |
| **Non-Firm External Support** (ICAP) (MW) | 2,987 | 2,987 | [H] |
| **Non-Firm External Support** (UCAP) (MW) | 2,331 | 2,331 | [I] |
| **ICAP PRM Requirement** (PRMR) (MW) | 148,093 | 147,967 | [J]=[B]+[D]+[F]-[H] |
| **UCAP PRM Requirement** (PRMR) (MW) | 137,068 | 136,900 | [K]=[C]+[E]+[G]-[I] |
| **MISO PRM ICAP** | 16.8% | 16.3% | [L]=([J]-[A])/[A] |
| **MISO PRM UCAP** | 8.1% | 7.6% | [M]=([K]-[A])/[A] |

**Table 5-3: Future Planning Year MISO System Planning Reserve Margins**

| Metric | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 |
|---|---|---|---|---|---|---|---|---|---|---|
| PRM ICAP | <u>16.8%</u> | 16.8% | 16.8% | <u>16.8%</u> | 16.8% | <u>16.3%</u> | 16.3% | 16.2% | 16.1% | 16.1% |
| PRM UCAP | <u>7.9%</u> | 8.0% | 8.0% | <u>8.1%</u> | 8.1% | <u>7.6%</u> | 7.7% | 7.7% | 7.6% | 7.6% |

**Table 5-4: MISO System Planning Reserve Margins 2019 through 2028**
**(Years without underlined results indicate values that were calculated through interpolation)**

# 6 Local Resource Zone Analysis – LRR Results

## 6.1 Planning Year 2019-2020 Local Resource Zone Analysis

MISO calculated the per-unit LRR of LRZ Peak Demand for years one, four and six (Table 6-1, Table 6-2, and Table 6-3). The UCAP values in Table 6-1 reflect the UCAP within each LRZ, including Border External Resources and Coordinating Owners. The adjustment to UCAP values are the megawatt adjustments needed in each LRZ so that the reliability criterion of 0.1 days per year LOLE is met. The LRR is the summation of the UCAP and adjustment to UCAP megawatts. The LRR is then divided by each LRZ's Peak Demand to determine the per-unit LRR UCAP. The 2019-2020 per unit LRR UCAP values will be multiplied by the updated demand forecasts submitted for the 2019-2020 PRA to determine each LRZ's LRR.

| Local Resource Zone (LRZ) | LRZ-1 MN/ND | LRZ-2 WI | LRZ-3 IA | LRZ-4 IL | LRZ-5 MO | LRZ-6 IN | LRZ-7 MI | LRZ-8 AR | LRZ-9 LA/TX | LRZ-10 MS | Formula Key |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **2019-2020 Planning Reserve Margin (PRM) Study** | | | | | | | | | | | |
| **Installed Capacity** (ICAP) (MW) | 20,794 | 14,439 | 11,394 | 12,382 | 8,699 | 19,835 | 24,228 | 11,529 | 24,492 | 6,096 | [A] |
| **Unforced Capacity** (UCAP) (MW) | 19,762 | 13,629 | 10,863 | 11,012 | 7,766 | 18,529 | 22,171 | 10,823 | 22,509 | 5,061 | [B] |
| **Adjustment to UCAP** {1d in 10yr} (MW) | 702 | 1,038 | -12 | 702 | 2,342 | 1,731 | 2,674 | -273 | 811 | 2,025 | [C] |
| **LRR** (UCAP) (MW) | 20,464 | 14,667 | 10,851 | 11,713 | 10,108 | 20,259 | 24,845 | 10,550 | 23,320 | 7,086 | [D]=[B]+[C] |
| **Peak Demand** (MW) | 17,780 | 12,629 | 9,391 | 9,415 | 8,079 | 17,584 | 21,208 | 7,770 | 20,693 | 4,814 | [E] |
| **LRR UCAP per-unit of LRZ Peak Demand** | **115.1%** | **116.1%** | **115.6%** | **124.4%** | **125.1%** | **115.2%** | **117.2%** | **135.8%** | **112.7%** | **147.2%** | [F]=[D]/[E] |

**Table 6-1: Planning Year 2019-2020 LRZ Local Reliability Requirements**

| Local Resource Zone (LRZ) | LRZ-1 MN/ND | LRZ-2 WI | LRZ-3 IA | LRZ-4 IL | LRZ-5 MO | LRZ-6 IN | LRZ-7 MI | LRZ-8 AR | LRZ-9 LA/TX | LRZ-10 MS | Formula Key |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **2022-2023 Planning Reserve Margin (PRM) Study** | | | | | | | | | | | |
| **Installed Capacity** (ICAP) (MW) | 20,976 | 15,211 | 11,600 | 13,115 | 8,721 | 20,540 | 22,924 | 11,617 | 25,612 | 6,096 | [A] |
| **Unforced Capacity** (UCAP) (MW) | 19,942 | 14,364 | 11,064 | 11,717 | 7,787 | 19,196 | 21,224 | 10,910 | 23,542 | 5,061 | [B] |
| **Adjustment to UCAP** {1d in 10yr} (MW) | 1,091 | 479 | 90 | 223 | 2,380 | 1,348 | 3,177 | -195 | 391 | 1,974 | [C] |
| **LRR** (UCAP) (MW) | 21,032 | 14,843 | 11,154 | 11,940 | 10,167 | 20,544 | 24,401 | 10,715 | 23,933 | 7,036 | [D]=[B]+[C] |
| **Peak Demand** (MW) | 18,303 | 12,761 | 9,648 | 9,394 | 8,119 | 17,827 | 21,038 | 7,990 | 20,763 | 4,839 | [E] |
| **LRR UCAP per-unit of LRZ Peak Demand** | **114.9%** | **116.3%** | **115.6%** | **127.1%** | **125.2%** | **115.2%** | **116.0%** | **134.1%** | **115.3%** | **145.4%** | [F]=[D]/[E] |

**Table 6-2: Planning Year 2022-2023 LRZ Local Reliability Requirements**

| Local Resource Zone (LRZ) | LRZ-1 MN/ND | LRZ-2 WI | LRZ-3 IA | LRZ-4 IL | LRZ-5 MO | LRZ-6 IN | LRZ-7 MI | LRZ-8 AR | LRZ-9 LA/TX | LRZ-10 MS | Formula Key |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **2024-2025 Planning Reserve Margin (PRM) Study** | | | | | | | | | | | |
| **Installed Capacity** (ICAP) (MW) | 20,976 | 15,211 | 11,600 | 13,115 | 8,721 | 20,540 | 23,188 | 11,617 | 25,612 | 6,096 | [A] |
| **Unforced Capacity** (UCAP) (MW) | 19,942 | 14,364 | 11,064 | 11,717 | 7,787 | 19,196 | 21,446 | 10,910 | 23,542 | 5,061 | [B] |
| **Adjustment to UCAP** {1d in 10yr} (MW) | 1,313 | 578 | 261 | 114 | 2,487 | 1,181 | 2,323 | -220 | 711 | 2,010 | [C] |
| **LRR** (UCAP) (MW) | 21,255 | 14,942 | 11,324 | 11,831 | 10,274 | 20,377 | 23,769 | 10,690 | 24,253 | 7,072 | [D]=[B]+[C] |
| **Peak Demand** (MW) | 18,519 | 12,837 | 9,809 | 9,287 | 8,173 | 17,663 | 20,982 | 8,055 | 20,999 | 4,875 | [E] |
| **LRR UCAP per-unit of LRZ Peak Demand** | **114.8%** | **116.4%** | **115.5%** | **127.4%** | **125.7%** | **115.4%** | **113.3%** | **132.7%** | **115.5%** | **145.1%** | [F]=[D]/[E] |

**Table 6-3: Planning Year 2024-2025 LRZ Local Reliability Requirements**

| Weather Year Time of Peak Demand (ESTHE) | MISO | LRZ-1 MN/ND | LRZ-2 WI | LRZ-3 IA | LRZ-4 IL | LRZ-5 MO | LRZ-6 IN | LRZ-7 MI | LRZ-8 AR | LRZ-9 LA/TX | LRZ-10 MS |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 1988 | 8/1/88 16:00 | 8/1/88 16:00 | 8/1/88 16:00 | 7/31/88 16:00 | 8/16/88 16:00 | 8/15/88 17:00 | 7/9/88 17:00 | 7/6/88 18:00 | 7/19/88 15:00 | 8/15/88 15:00 | 7/2/88 18:00 |
| 1989 | 7/10/89 16:00 | 7/9/89 18:00 | 7/9/89 18:00 | 7/10/89 19:00 | 7/10/89 17:00 | 7/10/89 19:00 | 7/10/89 16:00 | 6/26/89 16:00 | 8/27/89 16:00 | 12/24/89 9:00 | 8/27/89 16:00 |
| 1990 | 7/3/90 17:00 | 7/3/90 18:00 | 8/27/90 16:00 | 7/3/90 16:00 | 9/6/90 16:00 | 9/6/90 16:00 | 7/9/90 17:00 | 8/28/90 15:00 | 7/10/90 16:00 | 8/6/90 16:00 | 8/27/90 18:00 |
| 1991 | 7/19/91 16:00 | 7/18/91 17:00 | 7/18/91 15:00 | 7/17/91 18:00 | 7/6/91 18:00 | 8/2/91 17:00 | 8/2/91 17:00 | 7/19/91 16:00 | 7/24/91 16:00 | 8/20/91 18:00 | 8/2/91 16:00 |
| 1992 | 8/10/92 16:00 | 8/9/92 17:00 | 8/10/92 18:00 | 7/8/92 16:00 | 7/2/92 15:00 | 7/2/92 16:00 | 7/14/92 16:00 | 8/27/92 15:00 | 7/16/92 17:00 | 8/10/92 16:00 | 7/11/92 17:00 |
| 1993 | 8/27/93 15:00 | 8/11/93 16:00 | 8/24/93 16:00 | 8/22/93 19:00 | 7/17/93 17:00 | 7/27/93 16:00 | 7/25/93 16:00 | 8/27/93 15:00 | 7/28/93 15:00 | 8/19/93 16:00 | 8/20/93 17:00 |
| 1994 | 7/6/94 14:00 | 6/14/94 19:00 | 6/15/94 16:00 | 7/19/94 18:00 | 7/5/94 18:00 | 7/5/94 17:00 | 7/20/94 15:00 | 6/18/94 18:00 | 8/14/94 16:00 | 8/14/94 16:00 | 1/19/94 9:00 |
| 1995 | 7/13/95 17:00 | 7/13/95 17:00 | 7/13/95 17:00 | 7/12/95 16:00 | 7/13/95 17:00 | 7/13/95 16:00 | 7/13/95 16:00 | 7/13/95 17:00 | 7/14/95 16:00 | 8/16/95 16:00 | 8/31/95 16:00 |
| 1996 | 8/6/96 17:00 | 8/6/96 17:00 | 6/29/96 17:00 | 7/18/96 17:00 | 7/18/96 18:00 | 7/18/96 17:00 | 7/19/96 17:00 | 8/7/96 15:00 | 7/1/96 15:00 | 2/5/96 7:00 | 7/3/96 16:00 |
| 1997 | 7/16/97 16:00 | 7/16/97 18:00 | 7/16/97 17:00 | 7/26/97 20:00 | 7/27/97 17:00 | 7/26/97 17:00 | 7/27/97 15:00 | 7/16/97 16:00 | 7/22/97 15:00 | 8/31/97 17:00 | 7/25/97 16:00 |
| 1998 | 7/20/98 16:00 | 7/13/98 18:00 | 6/25/98 16:00 | 7/20/98 18:00 | 7/20/98 16:00 | 7/20/98 17:00 | 7/19/98 17:00 | 6/25/98 16:00 | 7/7/98 15:00 | 8/28/98 17:00 | 8/28/98 17:00 |

| | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 1999 | 7/30/99 15:00 | 7/25/99 15:00 | 7/30/99 15:00 | 7/25/99 17:00 | 7/19/99 0:00 | 7/26/99 19:00 | 7/30/99 15:00 | 7/30/99 14:00 | 7/28/99 15:00 | 8/5/99 16:00 | 8/20/99 18:00 |
| 2000 | 8/15/00 16:00 | 8/14/00 19:00 | 7/17/00 17:00 | 8/31/00 19:00 | 8/29/00 16:00 | 8/17/00 18:00 | 9/2/00 16:00 | 8/9/00 15:00 | 8/29/00 18:00 | 8/30/00 16:00 | 8/30/00 17:00 |
| 2001 | 8/9/01 15:00 | 8/7/01 16:00 | 8/9/01 17:00 | 7/31/01 18:00 | 7/23/01 17:00 | 7/23/01 17:00 | 8/7/01 16:00 | 8/8/01 16:00 | 7/12/01 15:00 | 1/4/01 8:00 | 7/20/01 17:00 |
| 2002 | 7/2/02 16:00 | 7/6/02 18:00 | 8/1/02 15:00 | 7/20/02 19:00 | 7/9/02 17:00 | 8/1/02 16:00 | 8/3/02 15:00 | 7/3/02 16:00 | 7/30/02 16:00 | 8/7/02 17:00 | 7/10/02 16:00 |
| 2003 | 8/21/03 16:00 | 8/24/03 17:00 | 8/21/03 16:00 | 7/26/03 18:00 | 8/21/03 16:00 | 8/21/03 18:00 | 8/27/03 17:00 | 8/21/03 16:00 | 7/29/03 16:00 | 1/24/03 7:00 | 7/17/03 17:00 |
| 2004 | 7/13/04 16:00 | 6/7/04 18:00 | 6/8/04 17:00 | 7/20/04 17:00 | 7/13/04 16:00 | 7/13/04 16:00 | 1/31/04 4:00 | 7/22/04 15:00 | 7/14/04 15:00 | 8/1/04 17:00 | 7/24/04 16:00 |
| 2005 | 7/24/05 17:00 | 7/17/05 17:00 | 7/24/05 16:00 | 7/25/05 17:00 | 7/24/05 17:00 | 7/24/05 17:00 | 7/25/05 16:00 | 7/24/05 18:00 | 7/27/05 15:00 | 8/20/05 17:00 | 8/21/05 15:00 |
| 2006 | 7/31/06 17:00 | 7/31/88 17:00 | 7/31/06 15:00 | 7/19/06 18:00 | 7/31/06 18:00 | 8/2/06 17:00 | 7/31/06 16:00 | 8/3/06 15:00 | 8/10/06 18:00 | 8/15/06 18:00 | 8/15/06 17:00 |
| 2007 | 8/1/07 17:00 | 8/10/07 17:00 | 8/2/07 16:00 | 7/17/07 15:00 | 8/15/07 18:00 | 8/15/07 17:00 | 8/7/07 16:00 | 7/31/07 18:00 | 8/14/07 16:00 | 8/21/07 15:00 | 8/14/07 18:00 |
| 2008 | 7/17/08 15:00 | 7/11/08 18:00 | 7/7/08 17:00 | 8/3/08 16:00 | 7/20/08 16:00 | 7/20/08 17:00 | 8/23/08 15:00 | 8/24/08 12:00 | 7/22/08 15:00 | 8/6/08 18:00 | 7/22/08 16:00 |
| 2009 | 6/25/09 16:00 | 6/22/09 19:00 | 6/25/09 16:00 | 7/24/09 18:00 | 8/9/09 17:00 | 8/9/09 16:00 | 1/16/09 4:00 | 6/25/09 16:00 | 7/11/09 19:00 | 7/2/09 16:00 | 7/11/09 17:00 |
| 2010 | 8/3/10 18:00 | 8/8/10 18:00 | 8/20/10 14:00 | 7/17/10 18:00 | 8/10/10 17:00 | 8/3/10 16:00 | 8/13/10 16:00 | 9/1/10 15:00 | 7/21/10 15:00 | 8/1/10 17:00 | 8/2/10 16:00 |
| 2011 | 7/20/11 16:00 | 7/18/11 17:00 | 7/20/11 16:00 | 7/20/11 16:00 | 9/1/11 16:00 | 8/2/11 18:00 | 7/20/11 16:00 | 7/2/11 16:00 | 8/3/11 16:00 | 8/18/11 16:00 | 8/31/11 17:00 |
| 2012 | 7/6/12 17:00 | 7/31/88 17:00 | 7/13/95 17:00 | 7/25/12 17:00 | 7/6/12 18:00 | 7/24/12 18:00 | 7/5/12 17:00 | 7/6/12 17:00 | 7/30/12 17:00 | 8/16/12 17:00 | 7/3/12 16:00 |
| 2013 | 7/17/13 17:00 | 8/27/13 15:00 | 8/27/13 17:00 | 7/18/13 17:00 | 9/10/13 16:00 | 8/31/13 17:00 | 8/31/13 15:00 | 7/19/13 14:00 | 7/18/13 16:00 | 8/7/13 16:00 | 8/9/13 16:00 |
| 2014 | 7/22/14 16:00 | 7/21/14 17:00 | 7/7/14 16:00 | 7/22/14 16:00 | 8/24/14 16:00 | 7/26/14 15:00 | 1/24/14 9:00 | 7/22/14 16:00 | 7/14/14 16:00 | 1/8/14 3:00 | 8/24/14 17:00 |
| 2015 | 7/29/15 16:00 | 8/14/15 16:00 | 8/14/15 17:00 | 7/13/15 16:00 | 9/2/15 16:00 | 9/9/15 16:00 | 7/29/15 16:00 | 7/29/15 16:00 | 7/28/15 15:00 | 8/12/15 16:00 | 7/21/15 15:00 |
| 2016 | 7/20/16 15:00 | 6/25/16 15:00 | 8/11/16 14:00 | 7/20/16 14:00 | 9/7/16 15:00 | 9/7/16 16:00 | 9/8/16 16:00 | 9/7/16 14:00 | 7/22/16 15:00 | 8/23/16 15:00 | 8/3/16 15:00 |
| 2017 | 7/20/17 16:00 | 7/6/17 17:00 | 9/25/17 15:00 | 7/20/17 16:00 | 7/12/17 14:00 | 7/20/17 14:00 | 9/22/17 15:00 | 9/25/17 15:00 | 7/21/17 16:00 | 8/20/17 15:00 | 7/20/17 16:00 |

**Table 6-4: Time of Peak Demand for all 30 weather years**

# Appendix A: Comparison of Planning Year 2018 to 2019

Multiple study sensitivity analyses were performed to compute changes in the PRM target on an UCAP basis, from the 2018-2019 planning year to the 2019-2020 planning year. These sensitivities included one-off incremental changes of input parameters to quantify how each change affected the PRM result independently. Note the impact of the incremental PRM changes from 2018 to 2019 in the waterfall chart of Figure A-1; see Section A.1 Waterfall Chart Details for an explanation.

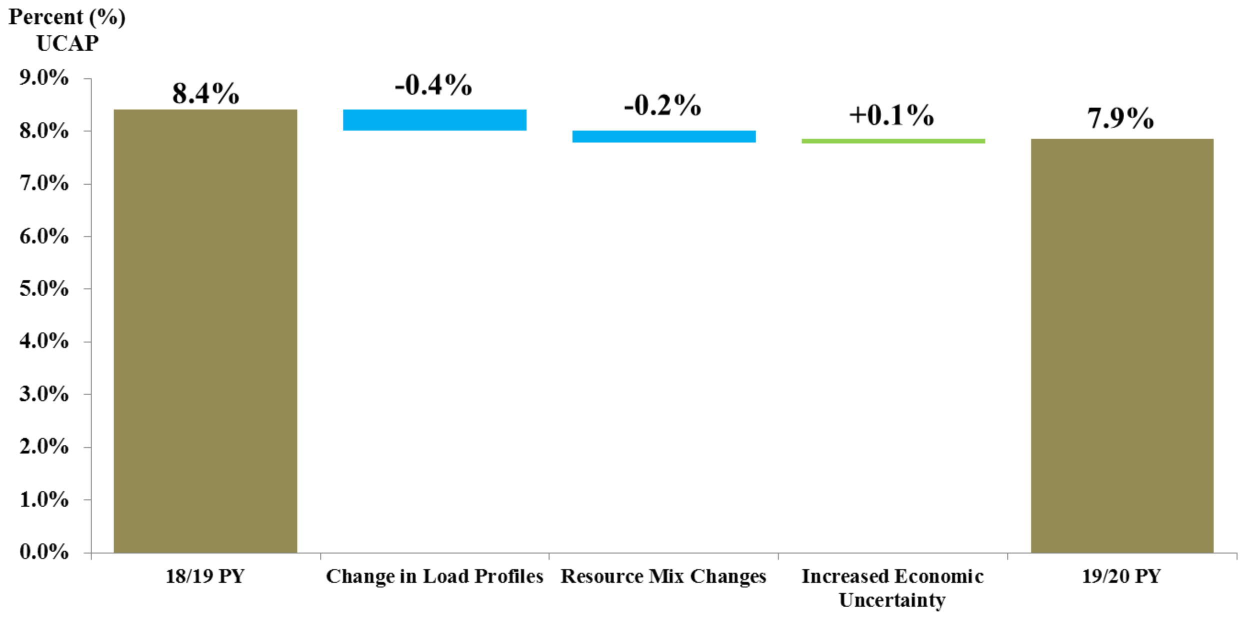



**Figure A-1: Waterfall Chart of 2018 PRM UCAP to 2019 PRM UCAP**

## A.1 Waterfall Chart Details

### A.1.1 Load

The MISO Coincident Peak Demand decreased from the 2018-2019 planning year, which was driven by the updated actual load forecasts submitted by the LSEs. The reduction was mainly driven by reduction in anticipated load growth and changes in diversity. The monthly load profiles submitted by LSE's resulted in more peaked load shapes compared to the 2018-2019 PY. This caused a 0.4 percentage point decrease to the PRM.

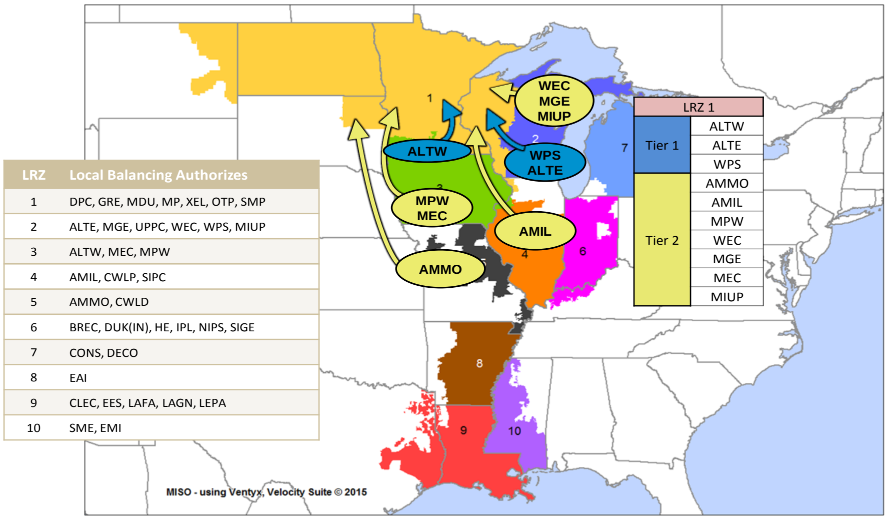
An increase of economic load uncertainty, detailed in Section 4.3.2, in the 2019-2020 planning year resulted in a 0.1 percentage point increase in the PRM UCAP. The modeling of economic load uncertainty effectively increases the risk associated with high peak loads, thus resulting in larger adjustment to UCAP for the same MISO peak load. Upon incorporating the increased adjustment into the equations of Section 4.5.1 of the report, the mathematical calculations result in a higher PRM in percentage.

### A.1.2 Units

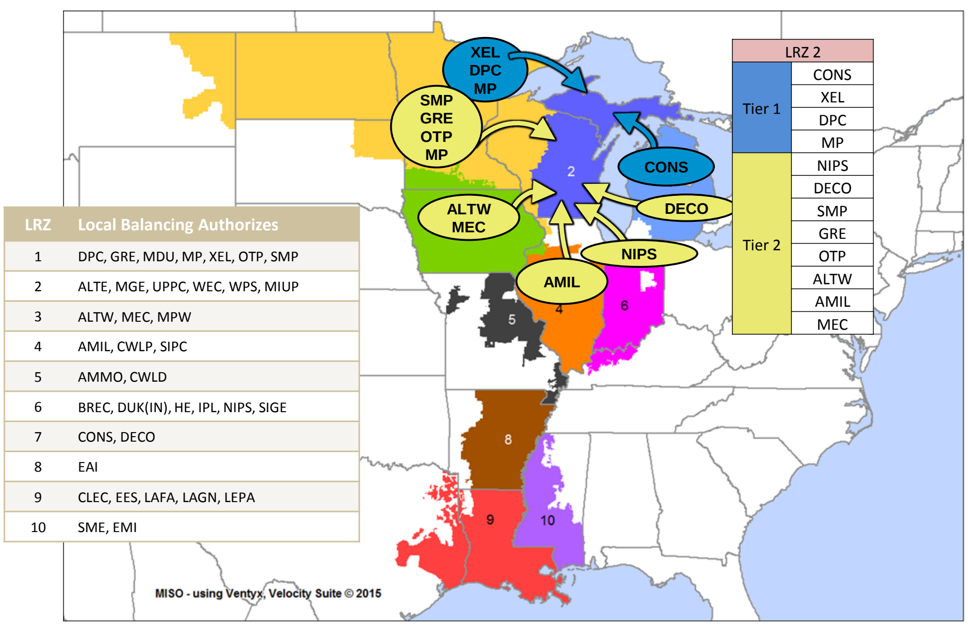
Changes from 2018-2019 planning year values are due to changes in Generation Verification Test Capacity (GVTC); EFORd or equivalent forced outage rate demand with adjustment to exclude events outside management control (XEFORd); new units; retirements; suspensions; and changes in the resource mix. The MISO fleet weighted average forced outage rate increased from 9.16 percent to 9.28 percent from the previous study to this study. An increase in unit outage rates will generally lead to an increase in reserve margin in order to cover the increased risk of loss of load. Although the MISO-wide average EFORd increased slightly for the 2019-2020 PY, new units and retirements led to a resource mix that improved reliability overall.

# Appendix B: Capacity Import Limit source subsystem definitions (Tiers 1 & 2)

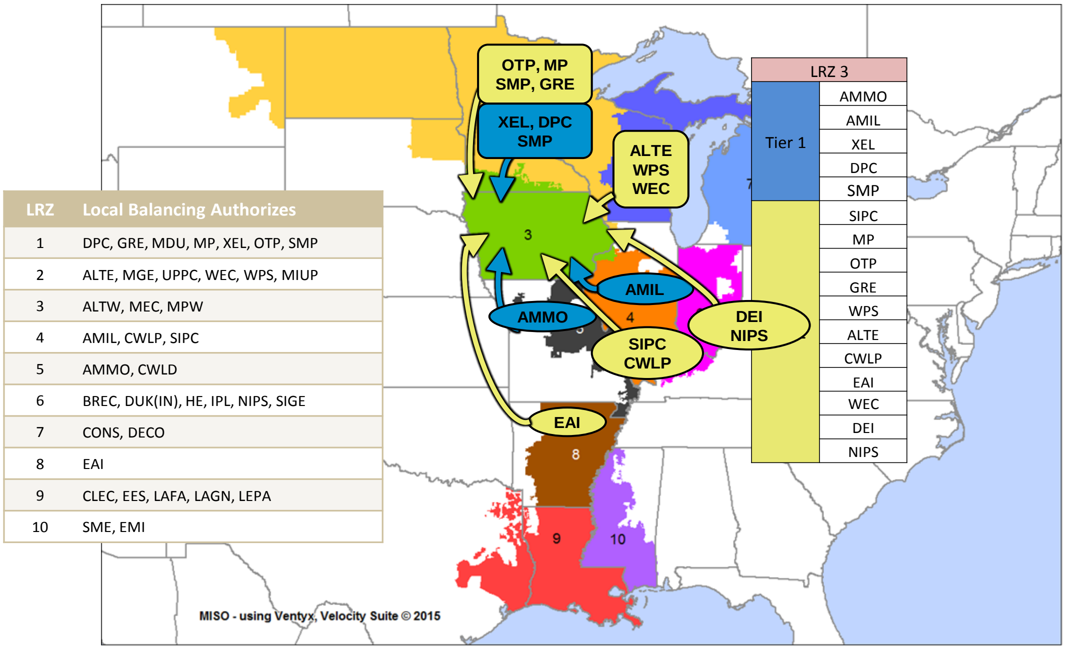
## MISO Local Resource Zone 1



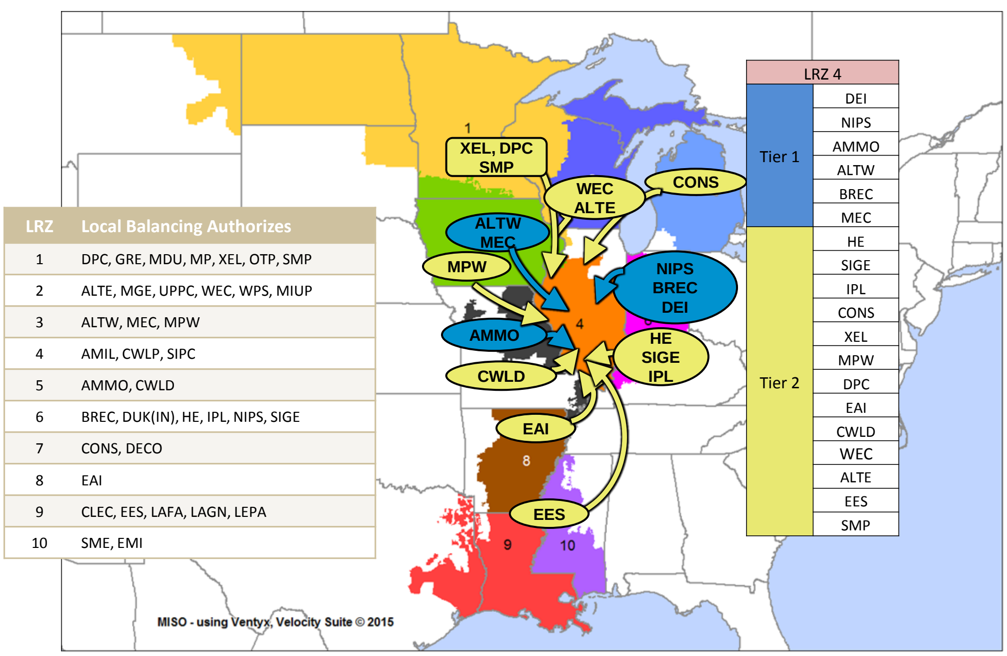

## MISO Local Resource Zone 2



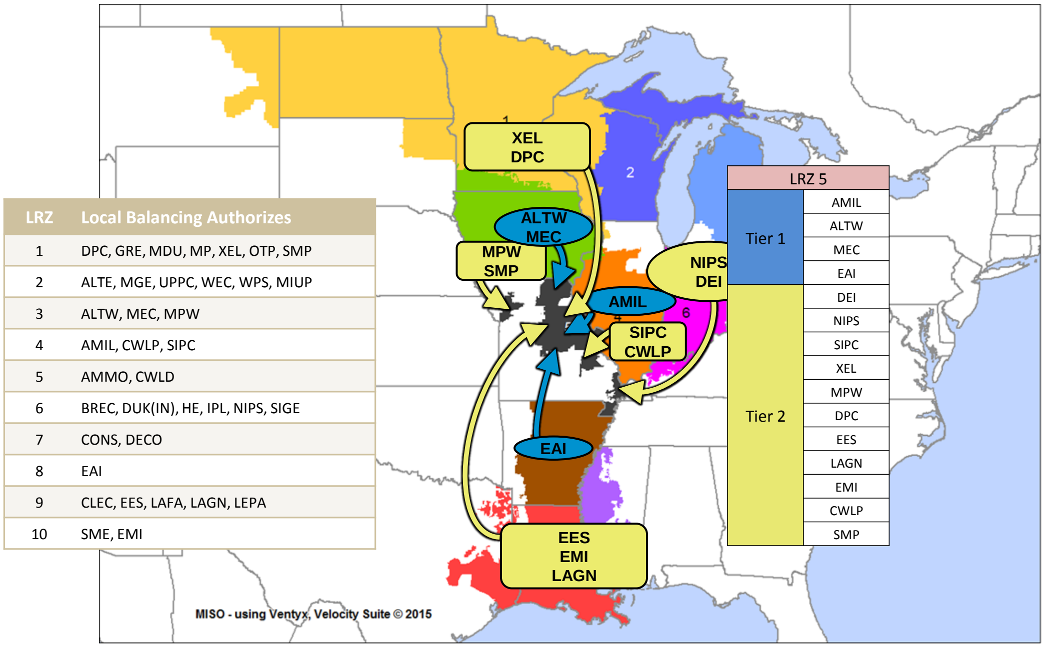
# MISO Local Resource Zone 3



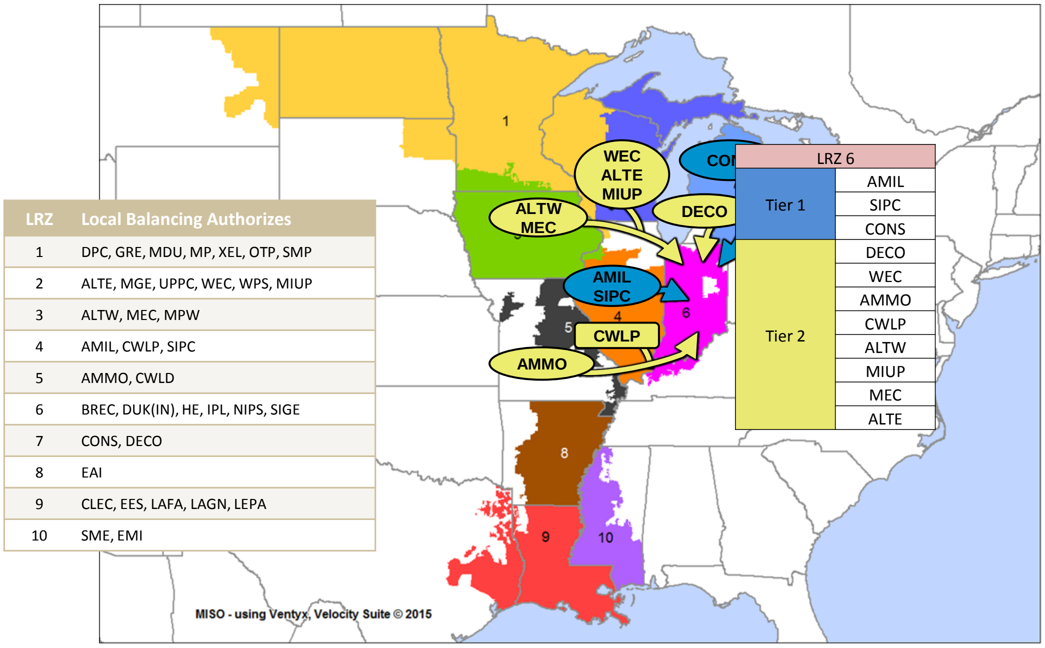

# MISO Local Resource Zone 4



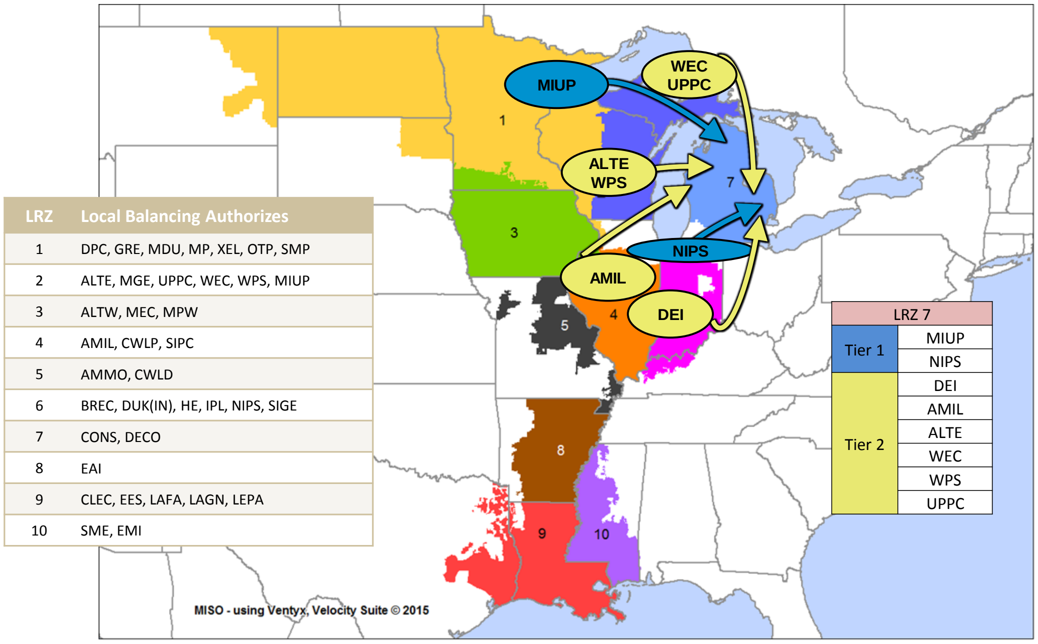
# MISO Local Resource Zone 5




# MISO Local Resource Zone 6



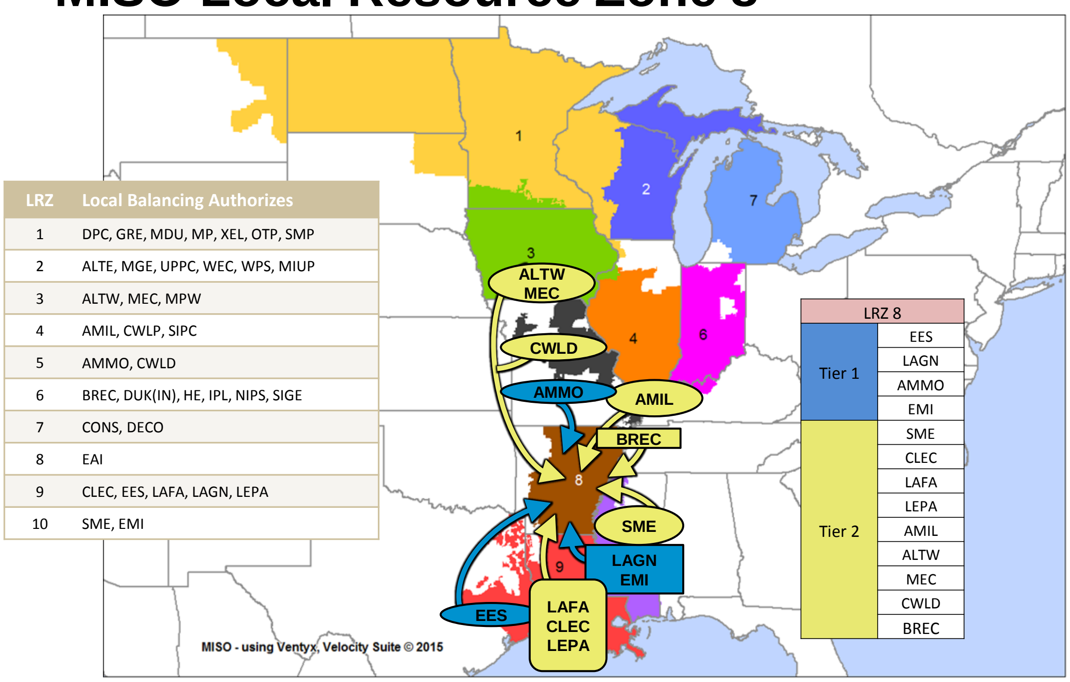
# MISO Local Resource Zone 7




| LRZ | Local Balancing Authorizes |
|---|---|
| 1 | DPC, GRE, MDU, MP, XEL, OTP, SMP |
| 2 | ALTE, MGE, UPPC, WEC, WPS, MIUP |
| 3 | ALTW, MEC, MPW |
| 4 | AMIL, CWLP, SIPC |
| 5 | AMMO, CWLD |
| 6 | BREC, DUK(IN), HE, IPL, NIPS, SIGE |
| 7 | CONS, DECO |
| 8 | EAI |
| 9 | CLEC, EES, LAFA, LAGN, LEPA |
| 10 | SME, EMI |

| LRZ 7 | |
|---|---|
| Tier 1 | MIUP |
| | NIPS |
| Tier 2 | DEI |
| | AMIL |
| | ALTE |
| | WEC |
| | WPS |
| | UPPC |

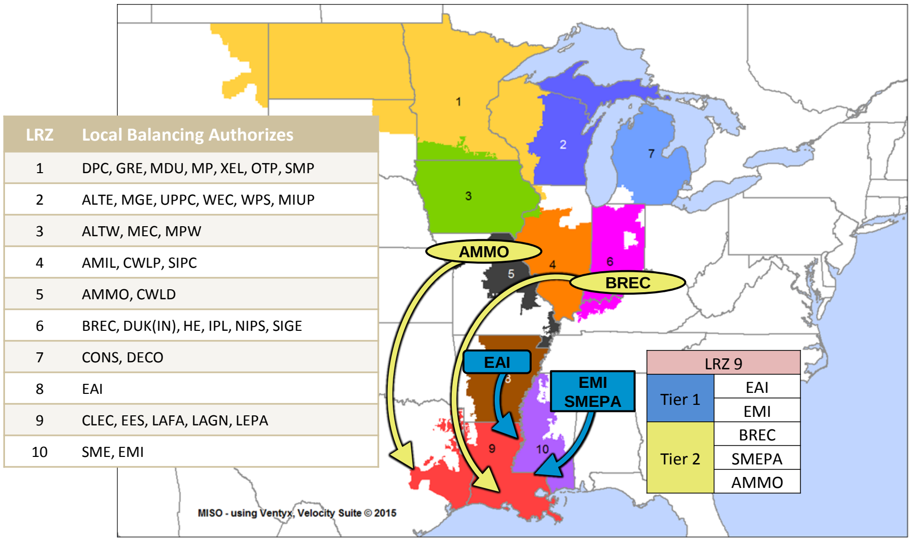
# MISO Local Resource Zone 8




| LRZ | Local Balancing Authorizes |
|---|---|
| 1 | DPC, GRE, MDU, MP, XEL, OTP, SMP |
| 2 | ALTE, MGE, UPPC, WEC, WPS, MIUP |
| 3 | ALTW, MEC, MPW |
| 4 | AMIL, CWLP, SIPC |
| 5 | AMMO, CWLD |
| 6 | BREC, DUK(IN), HE, IPL, NIPS, SIGE |
| 7 | CONS, DECO |
| 8 | EAI |
| 9 | CLEC, EES, LAFA, LAGN, LEPA |
| 10 | SME, EMI |

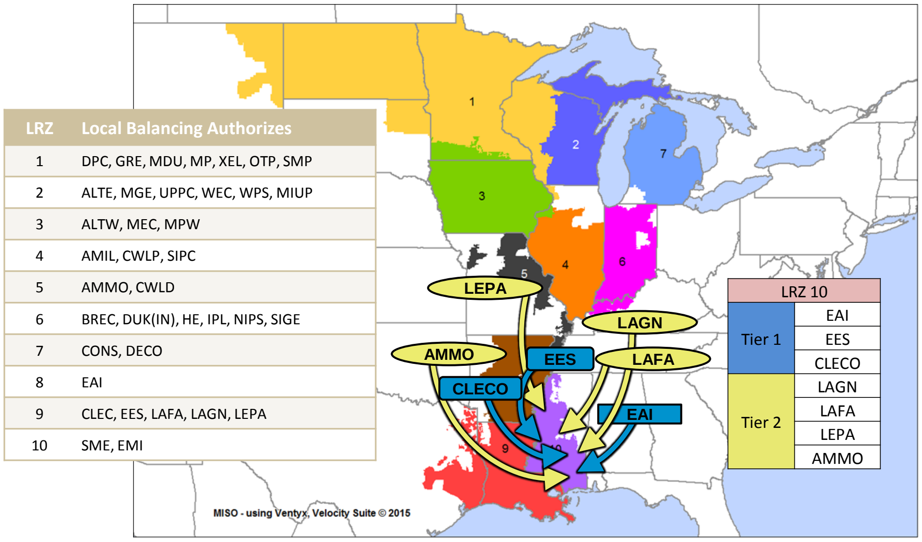
| LRZ 8 | |
|---|---|
| Tier 1 | EES |
| | LAGN |
| | AMMO |
| | EMI |
| Tier 2 | SME |
| | CLEC |
| | LAFA |
| | LEPA |
| | AMIL |
| | ALTW |
| | MEC |
| | CWLD |
| | BREC |

# MISO Local Resource Zone 9




* BRAZ, DERS, EES-EMI, and BCA now modeled in EES power flow area

# MISO Local Resource Zone 10



## Appendix C: Compliance Conformance Table

| Requirements under: Standard BAL-502-RF-03 | Response |
|---|---|
| **R1** The Planning Coordinator shall perform and document a Resource Adequacy analysis annually. The Resource Adequacy analysis shall: | The Planning Year 2019 LOLE Study Report is the annual Resource Adequacy Analysis for the peak season of June 2019 through May 2020 and beyond.<br><br>Analysis of Planning Year 2019 is in Sections 5.1 and 6.1<br><br>Analysis of Future Years 2020-2028 is in Sections 5.3 and 6.1 |
| **R1.1** Calculate a planning reserve margin that will result in the sum of the probabilities for loss of Load for the integrated peak hour for all days of each planning year[1] analyzed (per R1.2) being equal to 0.1. (This is comparable to a "one day in 10 year" criterion). | Section 4.5 of this report outlines the utilization of LOLE in the reserve margin determination.<br><br>"These metrics were determined by a probabilistic LOLE analysis such that the LOLE for the planning year was one day in 10 years, or 0.1 day per year." |
| **R1.1.1** The utilization of Direct Control Load Management or curtailment of Interruptible Demand shall not contribute to the loss of Load probability. | Section 4.3 of this report.<br><br>"Direct Control Load Management and Interruptible Demand types of demand response were explicitly included in the LOLE model as resources. These demand resources are implemented in the LOLE simulation before accumulating LOLE or shedding of firm load." |
| **R1.1.2** The planning reserve margin developed from R1.1 shall be expressed as a percentage of the median forecast peak Net Internal Demand (planning reserve margin). | Section 4.5.1 of this report.<br><br>"The minimum amount of capacity above the 50/50 net internal MISO Coincident Peak Demand required to meet the reliability criteria was used to establish the PRM values." |
| **R1.2** Be performed or verified separately for each of the following planning years. | Covered in the segmented R1.2 responses below. |
| **R1.2.1** Perform an analysis for Year One. | In Sections 5.1 and 6.1, a full analysis was performed for planning year 2019. |
| **R1.2.2** Perform an analysis or verification at a minimum for one year in the 2 through 5 year period and at a minimum one year in the 6 though 10 year period. | Sections 5.3 and 6.1 show a full analysis was performed for future planning years 2022 and 2024. |
| **R1.2.2.1** If the analysis is verified, the verification must be supported by current or past studies for the same planning year. | Analysis was performed. |
| **R1.3** Include the following subject matter and documentation of its use: | Covered in the segmented R1.3 responses below. |

| | |
|---|---|
| **R1.3.1** Load forecast characteristics:<br>• Median (50:50) forecast peak load<br>• Load forecast uncertainty (reflects variability in the Load forecast due to weather and regional economic forecasts).<br>• Load diversity.<br>• Seasonal Load variations.<br>• Daily demand modeling assumptions (firm, interruptible).<br>• Contractual arrangements concerning curtailable/Interruptible Demand. | Median forecasted load – In Section 4.3 of this report: "The average monthly loads of the predicted load shapes were adjusted to match each LRZ's Module E 50/50 monthly zonal peak load forecasts for each study year."<br><br>Load Forecast Uncertainty – A detailed explanation of the weather and economic uncertainties are given in Sections 4.3.1 and 4.3.2.<br><br>Load Diversity/Seasonal Load Variations — In Section 4.3 of this report: "For the 2019-2020 LOLE analysis, a load training process utilizing neural net software was used to create a neural-net relationship between historical weather and load data. This relationship was then applied to 30 years of hourly historical weather data in order to create 30 different load shapes for each LRZ in order to capture both load diversity and seasonal variations."<br><br>Demand Modeling Assumptions/Curtailable and Interruptible Demand — All Load Modifying Resources must first meet registration requirements through Module E. As stated in Section 4.2.7: "Each demand response program was modeled individually with a monthly capacity and was limited to the number of times each program can be called upon as well as limited by duration." |
| **R1.3.2** Resource characteristics:<br>• Historic resource performance and any projected changes<br>• Seasonal resource ratings<br>• Modeling assumptions of firm capacity purchases from and sales to entities outside the Planning Coordinator area.<br>• Resource planned outage schedules, deratings, and retirements.<br>• Modeling assumptions of intermittent and energy limited resource such as wind and cogeneration.<br>• Criteria for including planned resource additions in the analysis. | Section 4.2 details how historic performance data and seasonal ratings are gathered, and includes discussion of future units and the modeling assumptions for intermittent capacity resources.<br><br>A more detailed explanation of firm capacity purchases and sales is in Section 4.4. |
| **R1.3.3** Transmission limitations that prevent the delivery of generation reserves | Annual MTEP deliverability analysis identifies transmission limitations preventing delivery of generation reserves. Additionally, Section 3 of this report details the transfer analysis to capture transmission constraints limiting capacity transfers. |
| **R1.3.3.1** Criteria for including planned Transmission Facility additions in the analysis | Inclusion of the planned transmission addition assumptions is detailed in Section 3.2.3. |
| **R1.3.4** Assistance from other interconnected systems including multi-area assessment considering Transmission limitations into the study area. | Section 4.4 provides the analysis on the treatment of external support assistance and limitations. |

| | |
|---|---|
| **R1.4** Consider the following resource availability characteristics and document how and why they were included in the analysis or why they were not included:<br>• Availability and deliverability of fuel.<br>• Common mode outages that affect resource availability.<br>• Environmental or regulatory restrictions of resource availability.<br>• Any other demand (Load) response programs not included in R1.3.1.<br>• Sensitivity to resource outage rates.<br>• Impacts of extreme weather/drought conditions that affect unit availability.<br>• Modeling assumptions for emergency operation procedures used to make reserves available.<br>• Market resources not committed to serving Load (uncommitted resources) within the Planning Coordinator area. | Fuel availability, environmental restrictions, common mode outage and extreme weather conditions are all part of the historical availability performance data that goes into the unit's EFORd statistic. The use of the EFORd values is covered in Section 4.2.<br><br>The use of demand response programs are mentioned in Section 4.2.<br><br>The effects of resource outage characteristics on the reserve margin are outlined in Section 4.5.2 by examining the difference between PRM ICAP and PRM UCAP values. |
| **R1.5** Consider Transmission maintenance outage schedules and document how and why they were included in the Resource Adequacy analysis or why they were not included | Transmission maintenance schedules were not included in the analysis of the transmission system due to the limited availability of reliable long-term maintenance schedules and minimal impact to the results of the analysis. However, Section 3 treats worst-case theoretical outages by Perform First Contingency Total Transfer Capability (FCTTC) analysis for each LRZ, by modeling NERC Category P0 (system intact) and Category P1 (N-1) contingencies. |
| **R1.6** Document that capacity resources are appropriately accounted for in its Resource Adequacy analysis | MISO internal resources are among the quantities documented in the tables provided in Sections 5 and 6. |
| **R1.7** Document that all Load in the Planning Coordinator area is accounted for in its Resource Adequacy analysis | MISO load is among the quantities documented in the tables provided in Sections 5 and 6. |
| **R2** The Planning Coordinator shall annually document the projected Load and resource capability, for each area or Transmission constrained sub-area identified in the Resource Adequacy analysis. | In Sections 5 and 6, the peak load and estimated amount of resources for planning years 2019, 2022, and 2024 are shown. This includes the detail for each transmission constrained sub-area. |
| **R2.1** This documentation shall cover each of the years in Year One through ten. | Section 5.3 and Table 5-4 shows the three calculated years, and in-between years estimated by interpolation. Estimated transmission limitations may be determined through a review of the 2019 LOLE study transfer analysis shown in Section 3 of this report, along with the results from previous LOLE studies. |
| **R2.2** This documentation shall include the Planning Reserve margin calculated per requirement R1.1 for each of the three years in the analysis. | Section 5.3 and Table 5-4 shows the three calculated years underlined. |
| **R2.3** The documentation as specified per requirement R2.1 and R2.2 shall be publicly posted no later than 30 calendar days prior to the beginning of Year One. | The 2019 LOLE Study Report documentation is posted on November 1 prior to the planning year. |

| | |
|---|---|
| **R3** The Planning Coordinator shall identify any gaps between the needed amount of planning reserves defined in Requirement R1, Part 1.1 and the projected planning reserves documented in Requirement R2. | In Sections 5 and 6, the difference between the needed amount and the projected planning reserves for planning years 2019, 2022, and 2024 are shown the adjustments to ICAP and UCAP in Table 5-1, Table 5-3, Table 6-1, Table 6-2, and Table 6-3. |

## Appendix D: Acronyms List Table

| | |
|---|---|
| CEL | Capacity Export Limit |
| CIL | Capacity Import Limit |
| CPNode | Commercial Pricing Node |
| DF | Distribution Factor |
| EFORd | Equivalent Forced Outage Rate demand |
| ELCC | Effective Load Carrying Capability |
| ERZ | External Resource Zone |
| EUE | Expected Unserved Energy |
| FERC | Federal Energy Regulatory Commission |
| FCITC | First Contingency Incremental Transfer Capability |
| FCTTC | First Contingency Total Transfer Capability |
| GADS | Generator Availability Data System |
| GLT | Generation Limited Transfer |
| GVTC | Generation Verification Test Capacity |
| ICAP | Installed Capacity |
| LBA | Local Balancing Authority |
| LCR | Local Clearing Requirement |
| LFE | Load Forecast Error |
| LFU | Load Forecast Uncertainty |
| LOLE | Loss of Load Expectation |
| LOLEWG | Loss of Load Expectation Working Group |
| LRR | Local Reliability Requirement |
| LRZ | Local Resource Zones |
| LSE | Load Serving Entity |
| MARS | Multi-Area Reliability Simulation |
| MECT | Module E Capacity Tracking |
| MISO | Midcontinent Independent System Operator |
| MOD | Model on Demand |
| MTEP | MISO Transmission Expansion Plan |
| MW | Megawatt |
| MWh | Megawatt hours |
| NERC | North American Electric Reliability Corp. |
| PRA | Planning Resource Auction |
| PRM | Planning Reserve Margin |
| PRM ICAP | PRM Installed Capacity |

| | |
|---|---|
| PRM UCAP | PRM Unforced Capacity |
| PRMR | Planning Reserve Margin Requirement |
| PSS E | Power System Simulator for Engineering |
| RCF | Reciprocal Coordinating Flowgate |
| RPM | Reliability Pricing Model |
| SERVM | Strategic Energy & Risk Valuation Model |
| SPS | Special Protection Scheme |
| TARA | Transmission Adequacy and Reliability Assessment |
| UCAP | Unforced Capacity |
| XEFORd | Equivalent forced outage rate demand with adjustment to exclude events outside management control |
| ZIA | Zonal Import Ability |
| ZEA | Zonal Export Ability |

# Attachment 6.1 Vectren Electric 2018-2020 DSM Plan

# Vectren South 2018-2020
# Electric Energy Efficiency Plan

Prepared by:
Southern Indiana Gas & Electric Company d/b/a Vectren Energy Delivery of Indiana Inc. (Vectren South)

4/7/2017

## Table of Contents

## List of Acronyms & Abbreviations

| Acronym | Description |
|---|---|
| AEG | Applied Energy Group |
| ARCA | Appliance Recycling Centers of America Inc. |
| BAS | Building Automation System |
| BTU | Building Tune-Up |
| BYOT | Bring Your Own Thermostat |
| C&I | Commercial and Industrial |
| CAC | Central Air Conditioning |
| CFL | Compact Fluorescent Lamp |
| CVR | Conservation Voltage Reduction |
| DLC | Direct Load Control |
| DR | Demand Response |
| DSM | Demand Side Management |
| EAD | Energy Design Assistance |
| EAP | Energy Assistance Program |
| ECM | Electronically Commutated Motors |
| EE | Energy Efficiency |
| EISA | Energy Independence and Security Act |
| EM&V | Evaluation, Measurement and Verification |
| ES | ENERGY STAR |
| HEA | Home Energy Assessment & Weatherization |
| HERS | Home Efficiency Rating System |
| HVAC | Heating, Ventilation and Air Conditioning |
| IQW | Income Qualified & Weatherization |
| IRP | Integrated Resource Plan |
| IURC | Indiana Utility Regulatory Commission |
| kW/kWh | Kilowatt, Kilowatt hour |
| LED | Light Emitting Diode |
| MISO | Midcontinent Independent Transmission System Operator, Inc. |
| MPS | Market Potential Study |
| MW,MWh | Megawatt, Megawatt hour |
| NEF | National Energy Foundation |
| NPV | Net Present Value |
| O&M | Operations and Maintenance |
| PCT | Participant Cost Test |
| RFQ | Request for Qualification |
| RIM | Ratepayer Impact Measure |
| RNC | Residential New Construction |
| TRM | Technical Reference Manual |
| UCT | Utility Cost Test |

## 1. Introduction

Southern Indiana Gas and Electric Company d/b/a Vectren Energy Delivery of Indiana, Inc. ("Vectren South") provides energy delivery services to approximately 144,000 electric customers and 111,000 natural gas customers located in Southwestern Indiana. Vectren South is a direct, wholly owned subsidiary of Vectren Utility Holdings, Inc. and an indirect subsidiary of Vectren Corporation ("Vectren"), headquartered in Evansville, IN. This Vectren South 2018-2020 Electric Demand Side Management (DSM) Plan ("2018-2020 Plan" or "Plan") describes the details of the electric Energy Efficiency (EE) and Demand Response (DR) programs Vectren South plans to offer in its service territory in 2018-2020.

Vectren South is proposing a 2018-2020 Plan designed to cost effectively reduce energy use by approximately 1% of eligible retail sales each year over the three-year plan. The EE savings goals are consistent with Vectren South's 2016 Integrated Resource Plan ("2016 IRP"), reasonably achievable and cost effective. The Plan includes program budgets, including the direct and indirect costs of energy efficiency programs. The 2018-2020 Plan recommends electric EE and DR programs for the residential and commercial & industrial (C&I) sectors in Vectren South's service territory. Where appropriate, it also describes opportunities for coordination with some of Vectren South's gas EE programs to leverage the best total EE and DR opportunities for customers and to share costs of delivery. Vectren South utilizes a portfolio of DSM programs to achieve demand reductions and energy savings, thereby providing reliable electric service to its customers. Vectren's DSM programs have been approved by the Indiana Utility Regulatory Commission ("Commission" or "IURC") and implemented pursuant to various IURC orders over the years.

## 2. Vectren South DSM Strategy

Energy efficiency remains at the core of Vectren's culture as the utility strives to partner with customers to help them use energy wisely. The company's tagline, Live Smart, originated from Vectren's turn toward energy efficiency in 2006 with the emergence natural gas energy efficiency programs, and then that effort was bolstered when electric energy efficiency programs were launched in 2010. Vectren employees receive regular communication on the progress toward the company's annual energy efficiency goals and rely on their workforce to serve as ambassadors in driving participation in its energy efficiency programs. One of the utility's goals is to "Be a leader in customer conservation and energy efficiency," and Vectren proactively works with its oversight boards in each state it serves to assemble progressive, cost-effective programs that work toward achieving that objective.

The preferred portfolio of Vectren South's recently filed 2016 Integrated Resource Plan ("2016 IRP") includes EE programs for all customer classes and sets an annual savings target of 1% of retail sales for 2018-2020. The framework for the 2018 - 2020 Plan was modeled at a savings level of 1% of retail sales adjusted for an opt-out rate of 73% eligible load, as provided for in Indiana Code § 8-1-8.5-10 ("Section 10"). The load forecast also includes an ongoing level of EE related to codes and standards embedded in the load forecast projections. Ongoing EE and DR programs are also important given the integration of Vectren South's natural gas and electric EE and DR programs.

## A. Integration with Vectren South Gas

Opportunities exist to gain both natural gas and electric savings from some EE programs and measures. In these instances, energy savings will be captured by the respective utility. For the programs where integration opportunities exist, Vectren South has allocated implementation costs based on the net benefits split between natural gas and electric. Below is a list of programs that Vectren South has identified as integrated:

- Residential Prescriptive
- Residential New Construction
- Home Energy Assessment & Weatherization
- Income Qualified Weatherization
- Energy Efficient Schools
- Residential Behavioral Savings
- Commercial and Industrial (C&I) Custom
- Small Business Direct Install
- C&I New Construction
- Building Tune-up
- Multi-Family Retrofit

### B. Vectren Oversight Board

The Vectren Oversight Board (VOB) provides input into the planning and evaluation of Vectren South's EE programs. The VOB was formed in 2010 pursuant to the Final Order issued in Cause No. 43427 and included the Indiana Office of the Utility Consumer Counselor (OUCC) and Vectren South as voting members. The Citizens Action Coalition (CAC) was added as a voting member of the VOB in 2013 pursuant to the Final Order issued in Cause No. 44318. In 2014, the Vectren South Electric Oversight Board merged with the Vectren South Gas Oversight Board and Vectren North Gas Oversight to form one governing body, the VOB. Vectren and the VOB have worked collaboratively over the last several years and Vectren requests to continue the current voting structure.

## 3. Vectren South Planning Process

Vectren South has offered a variety of EE programs since April 2010 and has engaged in a similar planning process each time a new portfolio is presented to the Commission for approval.

The 2018-2020 Plan was developed in conjunction with the 2016 IRP planning process and therefore the 2016 IRP served as a key input into the 2018-2020 Plan. As such, this process aligns with Indiana Code § 8-1-8.5-10 ("Section 10"), which requires that EE goals be consistent with an electricity supplier's IRP.

Consistent with the 2016 IRP preferred portfolio, the framework for the 2018 - 2020 Plan was modeled at a savings level of 1% of retail sales with opt-out assumptions incorporated. Once the level of EE programs to be offered from 2018 through 2020 was established, Vectren South engaged in a process to develop the 2018-2020 Plan. The objective of the planning process was to develop a plan based upon market-specific information for Vectren South's territory, which could be successfully implemented utilizing realistic assessments of achievable market potential.

The program design used an Electric Market Potential Study (MPS) for guidance to validate that the plan estimates were reasonable. While building from the bottom up with estimates from program implementers to help determine participation, this comparison to the MPS allowed the planning team to determine if the results were reasonable.

In 2013, Vectren South engaged EnerNOC, Inc., to conduct an MPS and Action Plan. For this effort, EnerNOC evaluated electric energy efficiency resources in the residential, commercial, and industrial sectors for the years 2015-2019. The study included a detailed, bottom-up assessment of the Vectren South market in the Evansville metropolitan area to deliver a projection of baseline electric energy use, forecasts of the energy savings achievable through efficiency measures, and program designs and strategies to optimally deliver those savings. The study assessed various tiers of technical, economic and achievable potential by sector, customer type and measure.

Given this Plan 2018 through 2020, and the most recent MPS ended in 2019, Vectren South, with VOB approval, engaged Applied Energy Group (AEG), previously EnerNOC, to refresh the MPS for 2018 and 2019 and to extend the analysis to include 2020. Several key data elements of the analysis were updated as part of this effort, specifically:

- Load forecast, which is approximately 4% lower in 2018-2020 than the load forecast used for those years in the original analysis
- The impact of large customer opt-outs on the market potential for the commercial and industrial (C&I) sectors, where 73% of eligible C&I load has elected to opt out of energy efficiency programs and the accompanying surcharge that would otherwise appear on their bill
- LED lighting measures cost and performance data
- Vectren South EE Program performance and budgets
- Projections of avoided energy, capacity, and transmission and distribution (T&D) infrastructure costs
- Vectren South retail rates, discount rates, and line losses

In addition, vendors and other implementation partners who operate the current programs were involved in the planning process by providing suggestions for program changes and enhancements. The vendors and partners also provided technical information about measures to include recommended incentives, estimated participation and estimated implementation costs. This data provided a foundation for the 2018-2020 Plan based on actual experience within Vectren South's territory. These companies also bring their experience operating programs for other utilities. Once the draft version of the 2018-2020 Plan was developed, Vectren South solicited feedback from the VOB for consideration in the final design.

Other sources of program information were also considered. Current evaluations and the Indiana Technical Resource Manual (TRM) were used for adjustments to inputs. In addition, best practices were researched and reviewed to gain insights into the program design of successful EE and DR programs implemented by other utility companies.

VOB feedback was incorporated into the planning process, as applicable.

## 4. Cost Effectiveness Analysis

Vectren South's last step of the planning process was the cost benefit analysis. Vectren South retained Dr. Richard Stevie, Vice President of Forecasting with Integral Analytics, to complete the cost benefit modeling. Utilizing DSMore, the measures and programs were analyzed for cost effectiveness. The DSMore tool is nationally recognized and used in many states across the country to determine cost-effectiveness. Developed and licensed by Integral Analytics based in Cincinnati, OH, the DSMore cost-effectiveness modeling tool takes hourly prices and hourly energy savings from the specific measures/technologies being considered for the EE program, and then correlates both to weather. This tool looks at more than 30 years of historic weather variability to get the full weather variances appropriately modeled. In turn, this allows the model to capture the low probability, but high consequence weather events and apply appropriate value to them. Thus, a more accurate view of the value of the efficiency measure can be captured in comparison to other alternative supply options.

The outputs of DSMore include all the California Standard Practice Manual results including Total Resource Cost (TRC), Utility Cost Test (UCT), Participant Cost Test (PCT) and Ratepayer Impact Measure (RIM) tests. Inputs into the model include the following: participation rates, incentives paid, energy savings of the measure, life of the measure, implementation costs, and administrative costs, incremental costs to the participant of the high efficiency measure, and escalation rates and discount rates. Vectren South considers the results of each test and ensures that the portfolio passes the TRC test as it includes the total costs and benefits to both the utility and the consumer. The model includes a full range of economic perspectives typically used in EE and DSM analytics. The perspectives include:

- Total Resource Cost Test - shows the combined perspective of the utility and the participating customers. This test compares the level of benefits associated with the reduced energy supply costs to utility programs and participant costs.
- Utility Cost Test - shows the value of the program considering only avoided utility supply cost (based on the next unit of generation) in comparison to program costs.
- Participant Cost Test - shows the value of the program from the perspective of the utility's customer participating in the program. The test compares the participant's bill savings over the life of the EE/DR program to the participant's cost of participation.
- Ratepayer Impact Measure Test - shows the impact of a program on all utility customers through impacts in average rates. This perspective also includes the estimates of revenue losses, which may be experienced by the utility as a result of the program.

The cost effectiveness analysis produces two types of resulting metrics:

- Net Benefits (dollars) = NPV ∑ benefits – NPV ∑ costs
- Benefit Cost Ratio = NPV ∑ benefits ÷ NPV ∑ costs

Cost effectiveness analysis is performed using each of the four primary tests. The results of each test reflect a distinct perspective and have a separate set of inputs demonstrating the treatment of costs and benefits. A summary of benefits and costs included in each cost effectiveness test can be found in Appendix A.

## 5. 2018 - 2020 Plan Objectives and Impact

The framework for the 2018-2020 Plan aligns with the preferred portfolio as filed in the 2016 IRP and was designed to reach a reduction in sales of approximately 1% of eligible retail sales with opt-out assumptions incorporated. Table 1 below provides an overview of energy savings and demand impacts, participation and budget by the residential and C&I sectors and for the total portfolio. Table 2 provides an overview of budget and energy savings by program and by year.

**Table 1: 2018-2020 Portfolio Summary of Participation, Impacts & Budget**

**Residential**

| Program Year | Participants/ Measures | Annual Energy Savings kWh | Annual Demand Savings kW | Direct Program Budget | First Year Cost/Kwh* |
|---|---|---|---|---|---|
| 2018 | 327,374 | 21,520,612 | 5,782 | $4,663,152 | $0.22 |
| 2019 | 347,909 | 22,025,627 | 6,021 | $4,865,148 | $0.22 |
| 2020 | 217,427 | 19,294,127 | 5,977 | $4,649,484 | $0.24 |

**Commercial & Industrial**

| Program Year | Participants/ Measures | Annual Energy Savings kWh | Annual Demand Savings kW | Direct Program Budget | First Year Cost/Kwh* |
|---|---|---|---|---|---|
| 2018 | 7,252 | 15,135,729 | 1,648 | $3,387,238 | $0.22 |
| 2019 | 6,211 | 16,043,561 | 1,585 | $3,568,128 | $0.22 |
| 2020 | 7,638 | 17,053,515 | 1,773 | $3,720,882 | $0.22 |

**Portfolio Participation, Impacts & Budget**

| Program Year | Participants/ Measures | Annual Energy Savings kWh | Annual Demand Savings kW | Res & C&I Direct Program Budget | Indirect Portfolio Level Budget | Other Costs Budget | Portfolio Total Budget Including Indirect & Other | First Year Cost/Kwh* |
|---|---|---|---|---|---|---|---|---|
| 2018 | 334,626 | 36,656,341 | 7,430 | $8,050,391 | $937,436 | $500,000 | $9,487,827 | $0.23 |
| 2019 | 354,120 | 38,069,188 | 7,607 | $8,433,276 | $960,110 | $200,000 | $9,593,386 | $0.23 |
| 2020 | 225,065 | 36,347,642 | 7,750 | $8,370,366 | $960,225 | $200,000 | $9,530,591 | $0.24 |

*Cost per kWh includes program and indirect costs for budget. First year costs are calculated by dividing total cost by total savings and do not include carry forward costs related to smart thermostat, BYOT and CVR programs.

**Table 2: Vectren South 2018 - 2020 Plan Overview by Program**

| | Total Budget ($) | | | Total Savings (kWh) | | | Total Demand (kW) | | |
|---|---|---|---|---|---|---|---|---|---|
| **Residential Programs** | **2018** | **2019** | **2020** | **2018** | **2019** | **2020** | **2018** | **2019** | **2020** |
| Residential Lighting | $ 942,125 | $ 930,451 | $ 691,256 | 7,610,617 | 8,340,595 | 6,075,005 | 942 | 1,029 | 791 |
| Residential Prescriptive | $ 635,925 | $ 681,609 | $ 694,362 | 1,747,547 | 1,918,174 | 1,979,280 | 1,558 | 1,775 | 1,910 |
| Residential New Construction | $ 85,345 | $ 87,132 | $ 88,940 | 187,038 | 187,038 | 187,038 | 118 | 118 | 118 |
| Home Energy Assessment & Weatherization | $ 526,473 | $ 533,934 | $ 541,669 | 863,991 | 863,991 | 863,991 | 192 | 192 | 192 |
| Income Qualified Weatherization | $ 841,848 | $ 899,806 | $ 958,593 | 959,988 | 1,046,148 | 1,130,945 | 459 | 499 | 540 |
| Food Bank - LED Bulb Distribution | $ 174,141 | $ 175,308 | $ - | 1,401,264 | 1,401,264 | - | 149 | 149 | 0 |
| Energy Efficient Schools | $ 131,696 | $ 136,805 | $ 119,995 | 899,706 | 937,194 | 645,216 | 53 | 53 | 53 |
| Residential Behavioral Savings | $ 305,622 | $ 285,585 | $ 286,545 | 6,470,000 | 5,970,000 | 5,600,000 | 1,351 | 1,248 | 1,153 |
| Appliance Recycling | $ 174,759 | $ 180,648 | $ 186,532 | 913,771 | 894,534 | 884,915 | 121 | 118 | 117 |
| Smart Thermostat Program | $ 97,639 | $ 98,222 | $ 98,798 | - | - | - | - | - | - |
| CVR Residential | $ 118,786 | $ 114,907 | $ 230,134 | - | - | 1,461,047 | - | - | 263 |
| SmartDLC - Wifi DR/DLC Change-out | $ 517,759 | $ 562,148 | $ 606,532 | 466,690 | 466,690 | 466,690 | 600 | 600 | 600 |
| BYOT (Bring Your Own Thermostat) | $ 111,036 | $ 178,592 | $ 146,128 | - | - | - | 240 | 240 | 240 |
| **Residential Subtotal** | **$ 4,663,152** | **$4,865,148** | **$4,649,484** | **21,520,612** | **22,025,627** | **19,294,127** | **5,782** | **6,021** | **5,977** |
| **C&I Programs** | **2018** | **2019** | **2020** | **2018** | **2019** | **2020** | **2018** | **2019** | **2020** |
| Commercial Prescriptive | $ 729,398 | $ 655,370 | $ 731,330 | 4,999,125 | 4,501,186 | 5,002,621 | 378 | 325 | 369 |
| Commercial Custom | $ 1,019,072 | $ 1,022,184 | $ 1,160,256 | 5,000,000 | 5,000,000 | 5,500,000 | 476 | 476 | 524 |
| Small Business Direct Install | $ 1,149,640 | $ 1,182,037 | $ 1,173,133 | 4,032,934 | 3,905,372 | 3,900,306 | 667 | 645 | 567 |
| Commercial New Construction | $ 214,536 | $ 386,092 | $ 222,628 | 502,080 | 1,835,413 | 502,080 | 108 | 120 | 108 |
| Building Tune-up | $ 130,880 | $ 182,074 | $ 261,266 | 500,000 | 700,000 | 1,000,000 | 1 | 1 | 1 |
| Multi-Family Retrofit | $ 34,880 | $ 35,074 | $ 35,266 | 101,590 | 101,590 | 115,853 | 18 | 18 | 18 |
| CVR Commercial | $ 108,834 | $ 105,297 | $ 137,003 | - | - | 1,032,655 | - | - | 186 |
| **Commercial Subtotal** | **$ 3,387,238** | **$3,568,128** | **$3,720,882** | **15,135,729** | **16,043,561** | **17,053,515** | **1,648** | **1,585** | **1,773** |
| **Residential & Commercial Subtotal** | **$ 8,050,391** | **$8,433,276** | **$8,370,366** | **36,656,341** | **38,069,188** | **36,347,642** | **7,430** | **7,607** | **7,750** |
| Portfolio Level Costs Subtotal* | $ 937,436 | $ 960,110 | $ 960,225 | | | | | | |
| Other Costs Subtotal** | $ 500,000 | $ 200,000 | $ 200,000 | | | | | | |
| **DSM Portfolio Total including Other Costs** | **$ 9,487,827** | **$9,593,386** | **$9,530,591** | **36,656,341** | **38,069,188** | **36,347,642** | **7,430** | **7,607** | **7,750** |

*Portfolio level costs include: Contact Center, Online Audit, Outreach & Education, and Evaluation.

**Other Costs include Market Potential Study and Emerging Markets.

## A. Plan Savings

The planned savings goal for 2018-2020 was calculated based on a percentage of forecasted weather normalized electric sales for 2018 to 2020 with a target of 1% of eligible retail sales. The forecast is consistent with Vectren South's 2016 IRP sales forecast. Goals are based on gross energy savings with opt-out assumptions incorporated. Table 3 demonstrates the portfolio, residential and C&I energy savings targets at the 1% eligible retail sales level. Table 4 demonstrates the portfolio energy and demand savings by program and by year.

**Table 3: Vectren South 2018 - 2020 Plan Portfolio Summary Planned Energy Savings**

| Portfolio Summary | kWh Savings | | | kW Savings | | |
|---|---|---|---|---|---|---|
| | **2018** | **2019** | **2020** | **2018** | **2019** | **2020** |
| Residential Total | 21,520,612 | 22,025,627 | 19,294,127 | 5,782 | 6,021 | 5,977 |
| Commercial & Industrial Total | 15,135,729 | 16,043,561 | 17,053,515 | 1,648 | 1,585 | 1,773 |
| Portfolio Total | 36,656,341 | 38,069,188 | 36,347,642 | 7,430 | 7,607 | 7,750 |

**Table 4: Vectren South 2018 - 2020 Plan Portfolio Planned Energy Savings**

| **Residential** | **2018 kWh** | **2018 kW** | **2019 kWh** | **2019 kW** | **2020 kWh** | **2020 kW** |
|---|---|---|---|---|---|---|
| Residential Lighting | 7,610,617 | 942 | 8,340,595 | 1,029 | 6,075,005 | 791 |
| Residential Prescriptive | 1,747,547 | 1,558 | 1,918,174 | 1,775 | 1,979,280 | 1,910 |
| Residential New Construction | 187,038 | 118 | 187,038 | 118 | 187,038 | 118 |
| Home Energy Assessment & Weatherization | 863,991 | 192 | 863,991 | 192 | 863,991 | 192 |
| Income Qualified Weatherization | 959,988 | 459 | 1,046,148 | 499 | 1,130,945 | 540 |
| Food Bank - LED Bulb Distribution | 1,401,264 | 149 | 1,401,264 | 149 | 0 | 0 |
| Energy Efficient Schools | 899,706 | 53 | 937,194 | 53 | 645,216 | 53 |
| Residential Behavioral Savings | 6,470,000 | 1,351 | 5,970,000 | 1,248 | 5,600,000 | 1,153 |
| Appliance Recycling | 913,771 | 121 | 894,534 | 118 | 884,915 | 117 |
| Smart Thermostat Program | - | - | - | - | - | - |
| CVR Residential | - | - | - | - | 1,461,047 | 263 |
| SmartDLC - Wifi DR/DLC Change-out | 466,690 | 600 | 466,690 | 600 | 466,690 | 600 |
| BYOT (Bring Your Own Thermostat) | - | 240 | - | 240 | - | 240 |
| **Residential Total** | **21,520,612** | **5,782** | **22,025,627** | **6,021** | **19,294,127** | **5,977** |
| | | | | | | |
| **Commercial & Industrial** | **2018 kWh** | **2018 kW** | **2019 kWh** | **2019 kW** | **2020 kWh** | **2020 kW** |
| Commercial Prescriptive | 4,999,125 | 378 | 4,501,186 | 325 | 5,002,621 | 369 |
| Commercial Custom | 5,000,000 | 476 | 5,000,000 | 476 | 5,500,000 | 524 |
| Small Business Direct Install | 4,032,934 | 667 | 3,905,372 | 645 | 3,900,306 | 567 |
| Commercial New Construction | 502,080 | 108 | 1,835,413 | 120 | 502,080 | 108 |
| Building Tune-up | 500,000 | 1 | 700,000 | 1 | 1,000,000 | 1 |
| Multi-Family Retrofit | 101,590 | 18 | 101,590 | 18 | 115,853 | 18 |
| CVR Commercial | - | - | - | - | 1,032,655 | 186 |
| **Commercial & Industrial Total** | **15,135,729** | **1,648** | **16,043,561** | **1,585** | **17,053,515** | **1,773** |
| | | | | | | |
| **Portfolio Total** | **36,656,341** | **7,430** | **38,069,188** | **7,607** | **36,347,642** | **7,750** |

## B. Plan Budget

The total planned program budget includes the direct and indirect costs of implementing Vectren South's electric energy efficiency programs. In addition, a budget for other costs are being requested as described below.

**Direct program costs** include three main categories: vendor implementation, program incentives and administration costs. The program budgets were built based upon multiple resources. Program budgets were discussed with program implementers as a basis for the development of this plan. Vendor implementation budgets were estimated using historical data and estimates provided by the current vendors. This helps to assure that the estimates are realistic for successful delivery. Program incentives were calculated by assigning measures with appropriate incentive values based upon existing program incentives, evaluation results and vendor recommendations. Lastly, administrative costs are comprised of internal costs for Vectren South's management and oversight of the programs. Administrative costs were allocated back to programs based on the percent of savings these programs represent as well as estimated staff time spent on programs.

**Indirect costs** are costs that are not directly tied to a single program, but rather support multiple programs or the entire portfolio. These include: Contact Center, Online Audit, Outreach & Education, and Evaluation, Measurement and Verification (EM&V). These costs are budgeted at the portfolio level.

**Other costs** are also being requested in the 2018-2020 filed plan. Vectren South requests approval of a budget to include a Market Potential Study for 2020 and beyond and funding for Emerging Markets, which is discussed later in the Plan. Emerging Markets funding allows Vectren's EE portfolio to offer leading-edge program designs for next-generation technologies, services, and engagement strategies to growing markets in the Vectren South territory. This funding will not be used to support existing measures or programs, but rather support new program development or new measures within an existing program. Tables 5 through 8 below list the summary budgets by year, program and category.

**Table 5: Vectren South 2018 – 2020 Summary Budgets by Year**

| Residential | 2018 | 2019 | 2020 | Total Budget |
|---|---|---|---|---|
| Residential Lighting | $942,125 | $930,451 | $691,256 | $2,563,832 |
| Residential Prescriptive | $635,925 | $681,609 | $694,362 | $2,011,896 |
| Residential New Construction | $85,345 | $87,132 | $88,940 | $261,417 |
| Home Energy Assessment & Weatherization | $526,473 | $533,934 | $541,669 | $1,602,076 |
| Income Qualified Weatherization | $841,848 | $899,806 | $958,593 | $2,700,247 |
| Food Bank - LED Bulb Distribution | $174,141 | $175,308 | $0 | $349,449 |
| Energy Efficient Schools | $131,696 | $136,805 | $119,995 | $388,496 |
| Residential Behavioral Savings | $305,622 | $285,585 | $286,545 | $877,752 |
| Appliance Recycling | $174,759 | $180,648 | $186,532 | $541,939 |
| Smart Thermostat Program | $97,639 | $98,222 | $98,798 | $294,659 |
| CVR Residential | $118,786 | $114,907 | $230,134 | $463,827 |
| SmartDLC - Wifi DR/DLC Change-out | $517,759 | $562,148 | $606,532 | $1,686,439 |
| BYOT (Bring Your Own Thermostat) | $111,036 | $178,592 | $146,128 | $435,756 |
| **Residential Total** | **$4,663,152** | **$4,865,148** | **$4,649,484** | **$14,177,784** |
| | | | | |
| **Commercial & Industrial** | **2018** | **2019** | **2020** | **Total Budget** |
| Commercial Prescriptive | $729,398 | $655,370 | $731,330 | $2,116,098 |
| Commercial Custom | $1,019,072 | $1,022,184 | $1,160,256 | $3,201,512 |
| Small Business Direct Install | $1,149,640 | $1,182,037 | $1,173,133 | $3,504,810 |
| Commercial New Construction | $214,536 | $386,092 | $222,628 | $823,256 |
| Building Tune-up | $130,880 | $182,074 | $261,266 | $574,220 |
| Multi-Family Retrofit | $34,880 | $35,074 | $35,266 | $105,220 |
| CVR Commercial | $108,834 | $105,297 | $137,003 | $351,134 |
| **Commercial & Industrial Total** | **$3,387,238** | **$3,568,128** | **$3,720,882** | **$10,676,248** |
| | | | | |
| **Total Direct Program Costs** | **$8,050,391** | **$8,433,276** | **$8,370,366** | **$24,854,032** |
| | | | | |
| **Indirect Portfolio Level Costs** | **2018** | **2019** | **2020** | **Total Budget** |
| Contact Center | $63,000 | $63,000 | $63,000 | $189,000 |
| Online Audit | $36,444 | $39,806 | $42,911 | $119,161 |
| Outreach & Education | $410,000 | $410,000 | $410,000 | $1,230,000 |
| Evaluation | $427,992 | $447,304 | $444,314 | $1,319,610 |
| **Indirect Portfolio Level Costs Subtotal** | **$937,436** | **$960,110** | **$960,225** | **$2,857,771** |
| | | | | |
| **Total Portfolio** | **$8,987,827** | **$9,393,386** | **$9,330,591** | **$27,711,803** |
| | | | | |
| **Other Costs** | **2018** | **2019** | **2020** | **Total Budget** |
| Emerging Markets | $200,000 | $200,000 | $200,000 | $600,000 |
| Market Potential Study | $300,000 | $0 | $0 | $300,000 |
| **Other Costs Subtotal** | **$500,000** | **$200,000** | **$200,000** | **$900,000** |
| **DSM Portfolio Total including Other Costs** | **$9,487,827** | **$9,593,386** | **$9,530,591** | **$28,611,803** |

**Table 6: Vectren South 2018 Summary Budgets by Category**

| Residential | Administrative | Implementation | Incentives | Total Budget |
|---|---|---|---|---|
| Residential Lighting | $ 94,072 | $ 225,000 | $ 623,053 | $ 942,125 |
| Residential Prescriptive | $ 5,880 | $ 219,860 | $ 410,185 | $ 635,925 |
| Residential New Construction | $ 17,639 | $ 39,856 | $ 27,850 | $ 85,345 |
| Home Energy Assessment & Weatherization | $ 47,036 | $ 479,437 | $ - | $ 526,473 |
| Income Qualified Weatherization | $ 35,277 | $ 806,571 | $ - | $ 841,848 |
| Food Bank - LED Bulb Distribution | $ 35,277 | $ 138,864 | $ - | $ 174,141 |
| Energy Efficient Schools | $ 44,096 | $ 87,600 | $ - | $ 131,696 |
| Residential Behavioral Savings | $ 29,398 | $ 276,224 | $ - | $ 305,622 |
| Appliance Recycling | $ 11,759 | $ 115,500 | $ 47,500 | $ 174,759 |
| Smart Thermostat Program | $ 17,639 | $ 40,000 | $ 40,000 | $ 97,639 |
| CVR Residential | $ 2,940 | $ 115,846 | $ - | $ 118,786 |
| SmartDLC - Wifi DR/DLC Change-out | $ 11,759 | $ 484,000 | $ 22,000 | $ 517,759 |
| BYOT (Bring Your Own Thermostat) | $ 47,036 | $ 26,000 | $ 38,000 | $ 111,036 |
| **Residential Subtotal** | **$ 399,806** | **$ 3,054,758** | **$1,208,588** | **$ 4,663,152** |
| | | | | |
| **Commercial & Industrial** | **Administrative** | **Implementation** | **Incentives** | **Total Budget** |
| Commercial Prescriptive | $ 29,398 | $ 200,000 | $ 500,000 | $ 729,398 |
| Commercial Custom | $ 94,072 | $ 325,000 | $ 600,000 | $ 1,019,072 |
| Small Business Direct Install | $ 2,940 | $ 321,700 | $ 825,000 | $ 1,149,640 |
| Commercial New Construction | $ 47,036 | $ 102,500 | $ 65,000 | $ 214,536 |
| Building Tune-up | $ 5,880 | $ 100,000 | $ 25,000 | $ 130,880 |
| Multi-Family Retrofit | $ 5,880 | $ 10,000 | $ 19,000 | $ 34,880 |
| CVR Commercial | $ 2,940 | $ 105,894 | $ - | $ 108,834 |
| **Commercial Subtotal** | **$ 188,144** | **$ 1,165,094** | **$2,034,000** | **$ 3,387,238** |
| **Residential & Commercial Subtotal** | **$ 587,950** | **$ 4,219,853** | **$3,242,588** | **$ 8,050,391** |
| | | | | |
| **Indirect Costs** | | | | **Total Budget** |
| Contact Center | | | | $ 63,000 |
| Online Audit | | | | $ 36,444 |
| Outreach & Education | | | | $ 410,000 |
| Evaluation | | | | $ 427,992 |
| **DSM Portfolio Total** | | | | **$ 8,987,827** |
| | | | | |
| **Other Costs** | | | | **Total Budget** |
| Emerging Markets | | | | $ 200,000 |
| Market Potential Study | | | | $ 300,000 |
| **Other Costs Subtotal** | | | | **$ 500,000** |
| **DSM Portfolio Total including Other Costs** | | | | **$ 9,487,827** |

**Table 7: Vectren South 2019 Summary Budgets by Category**

| Residential | Administrative | Implementation | Incentives | Total Budget |
|---|---|---|---|---|
| Residential Lighting | $ 97,184 | $ 225,000 | $ 608,267 | $ 930,451 |
| Residential Prescriptive | $ 6,074 | $ 226,800 | $ 448,735 | $ 681,609 |
| Residential New Construction | $ 18,222 | $ 41,060 | $ 27,850 | $ 87,132 |
| Home Energy Assessment & Weatherization | $ 48,592 | $ 485,342 | $ - | $ 533,934 |
| Income Qualified Weatherization | $ 36,444 | $ 863,362 | $ - | $ 899,806 |
| Food Bank - LED Bulb Distribution | $ 36,444 | $ 138,864 | $ - | $ 175,308 |
| Energy Efficient Schools | $ 45,555 | $ 91,250 | $ - | $ 136,805 |
| Residential Behavioral Savings | $ 30,370 | $ 255,215 | $ - | $ 285,585 |
| Appliance Recycling | $ 12,148 | $ 122,000 | $ 46,500 | $ 180,648 |
| Smart Thermostat Program | $ 18,222 | $ 40,000 | $ 40,000 | $ 98,222 |
| CVR Residential | $ 3,037 | $ 111,870 | $ - | $ 114,907 |
| SmartDLC - Wifi DR/DLC Change-out | $ 12,148 | $ 506,000 | $ 44,000 | $ 562,148 |
| BYOT (Bring Your Own Thermostat) | $ 48,592 | $ 84,000 | $ 46,000 | $ 178,592 |
| **Residential Subtotal** | **$ 413,032** | **$ 3,190,764** | **$1,261,352** | **$ 4,865,148** |
| | | | | |
| **Commercial & Industrial** | **Administrative** | **Implementation** | **Incentives** | **Total Budget** |
| Commercial Prescriptive | $ 30,370 | $ 200,000 | $ 425,000 | $ 655,370 |
| Commercial Custom | $ 97,184 | $ 325,000 | $ 600,000 | $ 1,022,184 |
| Small Business Direct Install | $ 3,037 | $ 319,000 | $ 860,000 | $ 1,182,037 |
| Commercial New Construction | $ 48,592 | $ 112,500 | $ 225,000 | $ 386,092 |
| Building Tune-up | $ 6,074 | $ 141,000 | $ 35,000 | $ 182,074 |
| Multi-Family Retrofit | $ 6,074 | $ 10,000 | $ 19,000 | $ 35,074 |
| CVR Commercial | $ 3,037 | $ 102,260 | $ - | $ 105,297 |
| **Commercial Subtotal** | **$ 194,368** | **$ 1,209,760** | **$2,164,000** | **$ 3,568,128** |
| **Residential & Commercial Subtotal** | **$ 607,400** | **$ 4,400,524** | **$3,425,352** | **$ 8,433,276** |
| | | | | |
| **Indirect Costs** | | | | **Total Budget** |
| Contact Center | | | | $ 63,000 |
| Online Audit | | | | $ 39,806 |
| Outreach & Education | | | | $ 410,000 |
| Evaluation | | | | $ 447,304 |
| **DSM Portfolio Total** | | | | **$ 9,393,386** |
| | | | | |
| **Other Costs** | | | | **Total Budget** |
| Emerging Markets | | | | $ 200,000 |
| Market Potential Study | | | | $ - |
| **Other Costs Subtotal** | | | | **$ 200,000** |
| **DSM Portfolio Total including Other Costs** | | | | **$ 9,593,386** |

**Table 8: Vectren South 2020 Summary Budgets by Category**

| **Residential** | **Administrative** | **Implementation** | **Incentives** | **Total Budget** |
|---|---|---|---|---|
| Residential Lighting | $ 100,256 | $ 150,000 | $ 441,000 | $ 691,256 |
| Residential Prescriptive | $ 6,266 | $ 234,111 | $ 453,985 | $ 694,362 |
| Residential New Construction | $ 18,798 | $ 42,292 | $ 27,850 | $ 88,940 |
| Home Energy Assessment & Weatherization | $ 50,128 | $ 491,541 | $ - | $ 541,669 |
| Income Qualified Weatherization | $ 37,596 | $ 920,997 | $ - | $ 958,593 |
| Food Bank - LED Bulb Distribution | $ - | $ - | $ - | $ - |
| Energy Efficient Schools | $ 46,995 | $ 73,000 | $ - | $ 119,995 |
| Residential Behavioral Savings | $ 31,330 | $ 255,215 | $ - | $ 286,545 |
| Appliance Recycling | $ 12,532 | $ 128,000 | $ 46,000 | $ 186,532 |
| Smart Thermostat Program | $ 18,798 | $ 40,000 | $ 40,000 | $ 98,798 |
| CVR Residential | $ 40,729 | $ 189,405 | $ - | $ 230,134 |
| SmartDLC - Wifi DR/DLC Change-out | $ 12,532 | $ 528,000 | $ 66,000 | $ 606,532 |
| BYOT (Bring Your Own Thermostat) | $ 50,128 | $ 42,000 | $ 54,000 | $ 146,128 |
| **Residential Subtotal** | **$ 426,088** | **$ 3,094,561** | **$1,128,835** | **$ 4,649,484** |
| | | | | |
| **Commercial & Industrial** | **Administrative** | **Implementation** | **Incentives** | **Total Budget** |
| Commercial Prescriptive | $ 31,330 | $ 250,000 | $ 450,000 | $ 731,330 |
| Commercial Custom | $ 100,256 | $ 400,000 | $ 660,000 | $ 1,160,256 |
| Small Business Direct Install | $ 3,133 | $ 345,000 | $ 825,000 | $ 1,173,133 |
| Commercial New Construction | $ 50,128 | $ 107,500 | $ 65,000 | $ 222,628 |
| Building Tune-up | $ 6,266 | $ 205,000 | $ 50,000 | $ 261,266 |
| Multi-Family Retrofit | $ 6,266 | $ 10,000 | $ 19,000 | $ 35,266 |
| CVR Commercial | $ 3,133 | $ 133,870 | $ - | $ 137,003 |
| **Commercial Subtotal** | **$ 200,512** | **$ 1,451,370** | **$2,069,000** | **$ 3,720,882** |
| **Residential & Commercial Subtotal** | **$ 626,600** | **$ 4,545,931** | **$3,197,835** | **$ 8,370,366** |
| | | | | |
| **Indirect Costs** | | | | **Total Budget** |
| Contact Center | | | | $ 63,000 |
| Online Audit | | | | $ 42,911 |
| Outreach & Education | | | | $ 410,000 |
| Evaluation | | | | $ 444,314 |
| **DSM Portfolio Total** | | | | **$ 9,330,591** |
| | | | | |
| **Other Costs** | | | | **Total Budget** |
| Emerging Markets | | | | $ 200,000 |
| Market Potential Study | | | | $ - |
| **Other Costs Subtotal** | | | | **$ 200,000** |
| **DSM Portfolio Total including Other Costs** | | | | **$ 9,530,591** |

## C. Cost Effectiveness Results

The total portfolio for the Vectren South programs passes the TRC and UCT test for both the Residential and Commercial & Industrial sectors. Table 9 below confirms that all programs pass the TRC at greater than one. In completing the cost effectiveness testing, Vectren South used 7.29% as the weighted average cost of capital (WACC) as approved by the Commission on April 27, 2011 in Cause No. 43839. For the 2018 - 2020 Plan, Vectren South utilized the avoided costs from the 2016 IRP.

**Table 9: Vectren South 2018-2020 Plan Cost Effectiveness Results without Performance Incentive**

| **Residential** | **TRC** | **UCT** | **RIM** | **Participant** | **TRC NPV $** | **UCT NPV $** | **Lifetime Cost/kWh** | **1st Year Cost/kWh** |
|---|---|---|---|---|---|---|---|---|
| Residential Lighting | 4.20 | 6.19 | 0.86 | 5.18 | $ 11,354,267 | $ 12,498,117 | $0.01 | $0.12 |
| Residential Prescriptive | 1.28 | 2.68 | 0.99 | 1.04 | $ 1,113,799 | $ 3,153,088 | $0.05 | $0.36 |
| Residential New Construction | 1.25 | 2.02 | 0.79 | 1.39 | $ 98,697 | $ 248,511 | $0.06 | $0.47 |
| Home Energy Assessment & Weatherization | 1.19 | 1.19 | 0.48 | n/a | $ 277,622 | $ 277,622 | $0.06 | $0.62 |
| Income Qualified Weatherization | 1.30 | 1.30 | 0.59 | n/a | $ 752,131 | $ 752,131 | $0.08 | $0.86 |
| Food Bank - LED Bulb Distribution | 8.42 | 8.42 | 0.88 | n/a | $ 2,503,138 | $ 2,503,138 | $0.01 | $0.12 |
| Energy Efficient Schools | 3.28 | 3.28 | 0.53 | n/a | $ 829,622 | $ 829,622 | $0.02 | $0.16 |
| Residential Behavioral Savings | 1.54 | 1.54 | 0.50 | n/a | $ 440,606 | $ 440,606 | $0.04 | $0.05 |
| Appliance Recycling | 1.19 | 1.02 | 0.36 | n/a | $ 83,146 | $ 12,513 | $0.05 | $0.20 |
| Smart Thermostat Program | - | - | - | n/a | $ (162,984) | $ (275,015) | n/a | n/a |
| CVR Residential | 1.59 | 1.59 | 0.66 | n/a | $ 580,613 | $ 580,613 | $0.07 | $0.16 |
| SmartDLC - Wifi DR/DLC Change-out | 1.90 | 1.75 | 0.92 | n/a | $ 1,301,580 | $ 1,181,234 | $0.10 | $1.11 |
| BYOT (Bring Your Own Thermostat) | 2.80 | 1.92 | 1.92 | n/a | $ 498,223 | $ 370,438 | n/a | n/a |
| **Residential Portfolio** | **2.18** | **2.64** | **0.76** | **4.06** | **$19,670,459** | **$22,572,616** | **$0.04** | **$0.21** |
| | | | | | | | | |
| **Commercial & Industrial** | **TRC** | **UCT** | **RIM** | **Participant** | **TRC NPV $** | **UCT NPV $** | **Lifetime Cost/kWh** | **1st Year Cost/kWh** |
| Commercial Prescriptive | 1.63 | 3.68 | 0.51 | 2.70 | $ 2,811,420 | $ 5,291,462 | $0.02 | $0.15 |
| Commercial Custom | 2.05 | 3.27 | 0.52 | 3.59 | $ 5,003,931 | $ 6,772,616 | $0.02 | $0.21 |
| Small Business Direct Install | 5.34 | 2.38 | 0.53 | 24.51 | $ 6,333,499 | $ 4,520,941 | $0.03 | $0.30 |
| Commercial New Construction | 2.01 | 1.69 | 0.45 | 9.55 | $ 652,266 | $ 530,199 | $0.03 | $0.29 |
| Building Tune-up | 1.09 | 1.13 | 0.34 | 9.35 | $ 46,816 | $ 67,027 | $0.04 | $0.26 |
| Multi-Family Retrofit | 3.99 | 2.28 | 0.53 | 24.86 | $ 167,808 | $ 125,751 | $0.03 | $0.33 |
| CVR Commercial | 1.30 | 1.30 | 0.55 | n/a | $ 219,929 | $ 219,929 | $0.07 | $0.13 |
| **Commercial & Industrial Total** | **2.21** | **2.69** | **0.51** | **4.57** | **$15,235,668** | **$17,527,926** | **$0.02** | **$0.22** |
| Indirect Portfolio Level Costs | | | | | $ (2,666,479) | $ (2,666,479) | | |
| **Total Portfolio** | **2.01** | **2.40** | **0.61** | **4.31** | **$32,239,647** | **$37,434,062** | **$0.03** | **$0.24** |

First year costs are calculated by diving total cost by total savings and do not include carry forward costs related to smart thermostat, BYOT and CVR programs.

**Table 9.1: Vectren South 2018-2020 Plan Cost Effectiveness Results including Performance Incentive**

| **Including Performance Incentive** | **TRC** | **UCT** | **RIM** | **Participant** | **TRC NPV $** | **UCT NPV $** | **Lifetime Cost/kWh** | **1st Year Cost/kWh** |
|---|---|---|---|---|---|---|---|---|
| **Total Portfolio** | **1.80** | **2.11** | **0.59** | **4.31** | **$28,624,007** | **$33,818,421** | **$0.04** | **$0.27** |

*Utility Performance Incentive does not include IQW, 2016 Smart Tstat, or CVR.

# 6. New or Modified Program Initiatives

Vectren South's 2018-2020 filing largely extends the existing momentum of the portfolio of programs from 2016-2017 while applying the lessons learned from Vectren's program experience and evaluations as well as making refinements to key data and assumptions as described in this document.

Below is a summary which outlines notable changes for the 2018-2020 Plan from previous filings. More in depth details on the following topics can be found within the Program Descriptions portion of this document.

## A. Residential Lighting

All programs within this filing will utilize light emitting diode (LED) lighting technologies per evaluation recommendations. This shift began in 2016 and the 2017 portfolio, as a whole, shifted focus from Compact Fluorescent Lamp (CFL) lamps to LED bulbs where performance, price and market readiness have all improved dramatically in recent years.

Additionally, new light bulbs standards are proposed to go into effect in 2020 due to the Energy Independence and Security Act (EISA). As proposed, this legislation would change the baseline and available savings for general service bulbs. The future of the 2020 EISA legislation is uncertain, thus Vectren will include LED bulbs in the plan for all three years. The incorporation of LED bulbs in 2020 is with the understanding that the measure's inclusion is pending regulatory outcomes.

There is still significant opportunity in the residential lighting market and thus Vectren plans to continue this offering as long as the market and legislation will allow. Lighting programs are consistently highly cost-effective and critical to the advancement of increased efficiency.

## B. LED Food Bank

The LED Food Bank program was first offered in 2016 to help meet goals and serve the IQW population. This program will be part of the standard portfolio offering in 2018-2019 (2020 is not included due to EISA uncertainty). The program has been well received by food banks and pantries and Vectren South expects to see continued participation in 2018 and 2019.

## C. Residential Prescriptive

Starting in 2018, duct sealing measure within the residential prescriptive program will require a small co-pay of $50 by the customer. The purpose of the duct sealing measure change is to increase participation and promotion of deeper retrofit measures in homes.

## D. Smart Thermostat Program Expansion

In 2016, Vectren South conducted a field study designed to analyze the EE and DR benefits associated with smart thermostats. Between the months of April and May 2016, Vectren South installed approximately 2,000 smart thermostats (1,000 Honeywell and 1,000 Nest) in customer homes. The program is currently under evaluation to measure effectiveness. Vectren South anticipates continuing to pay incentives to these 2,000 customers, who are currently enrolled in Vectren South's Summer Cycler program. In addition, and as a result of the field study, Vectren South anticipates expanding its Smart Thermostat program by offering the following two new programs during 2018 through 2020: (1) DLC Change-out program and (2) Bring Your Own Thermostat (BYOT) program. A description of these new programs is included.

## E. Commercial & Industrial Prescriptive

Based upon input from the VOB during the planning process, Vectren South added several agricultural measures to the prescriptive measure offering list including:

- Livestock Waterer
- Agriculture - Poultry Farm LED Lighting
- VSD Milk Pump
- High Volume Low Speed Fans
- High Speed Fans (Ventilation and Circulation)
- Dairy Plate Cooler
- Heat Mat (Single, ~14x60")
- Automatic Milker Take Off
- HE Diary Scroll Compressor
- Heat Reclaimer (No Pre-cooler Installed)

## F. Commercial & Industrial Targeted Outreach

Vectren South's Commercial & Industrial Programs will seek out higher participation levels from schools, civic/government buildings and non-profit organizations and through a concentrated outreach approach. The concerted outreach will directly engage these segments to inform them of energy-saving opportunities and the available rebates through existing programs. Additional consideration can be provided to align program engagement with peak times to undertake energy efficiency projects: for schools, this means helping them schedule projects to be completed during summer vacations; for government institutions, this means planning around their fiscal cycles.

With this targeted outreach approach, Vectren South plans to assist 30 schools, 15 governmental buildings and 60 non-profit organizations in 2018-2020. Schools will likely receive support through the Prescriptive and Custom programs, while civic/government buildings and non-profit organizations may qualify for the Small Business Energy Savings program benefits.

## G. Multi-Family Retrofit

The Multi-Family Retrofit program was offered as a small pilot starting in 2017 and will continue to be available to the Commercial & Industrial sector in 2018-2020. This program was initiated to continue to serve the multi-family sector as the integrated Multi-Family Direct Install program was discontinued in 2017 due to market saturation.

## H. Emerging Markets

The Emerging Markets funding allows Vectren South's DSM portfolio to offer leading-edge program designs for next-generation technologies, services, and engagement strategies to growing markets in the Vectren South territory. Incentives promoted through this program may range from innovative rebate offerings to engineering and trade ally assistance to demand-control services that encourage early adoption of new, efficient technologies in high-impact market sectors. Depending on the development of certain technologies and growth areas in the service territory, a wide variety of projects and services are eligible. Because this program will focus on innovative new approaches and leading the DSM market, the exact list of measures cannot be set at this time. However, potential measures and services include: new technologies, such as Advanced Lighting Controls; new strategies for achieving significant energy savings, such as midstream incentives, contractor bids to provide energy efficiency projects, and targeting high-impact market sectors; and integrated DSM (iDSM) approaches, such as demand response, combined energy efficiency and demand response measures, and load shifting. This funding will not be used to support existing measures or programs, but rather support new program development or new measures within an existing program

# 7. Program Descriptions

## A. Residential Lighting

The Residential Lighting Program is a market-based residential EE program designed to reach residential customers through retail outlets. The program consists of a buy-down strategy that provides incentives to consumers to facilitate the purchase of EE lighting products. The overall program goal is to increase the penetration of ENERGY STAR qualified lighting products based on the most up-to-date standards. As of 2017, the Residential Lighting program shifted 100% to LED bulbs.

There is still significant opportunity in the residential lighting market and thus Vectren plans to continue this offering as long as the market and legislation will allow. Lighting programs are consistently highly cost-effective and critical to the advancement of increased efficiency.

The future of the 2020 EISA legislation is uncertain, thus Vectren will include LED bulbs in the plan for all three years. The incorporation of LED bulbs in 2020 is with the understanding that the measure's inclusion is pending regulatory outcomes and uses conservative estimates.

**Table 11: Residential Lighting Program Budget & Energy Savings Targets**

| Market | Program | 2018 | 2019 | 2020 | Total Program |
|---|---|---|---|---|---|
| **Residential** | **Residential Lighting** | | | | |
| | Number of Measures | 222,863 | 246,086 | 163,416 | 632,365 |
| | Energy Savings kWh | 7,610,617 | 8,340,595 | 6,075,005 | 22,026,217 |
| | Peak Demand kW | 942.2 | 1,028.9 | 791.4 | 2,762.4 |
| | Total Program Budget $ | 942,125 | 930,451 | 691,256 | 2,563,832 |
| | Per Participant Avg Energy Savings (kWh)* | 34.1 | 33.9 | 37.2 | 34.8 |
| | Per Participant Avg Demand Savings (kW)* | | | | 0.004 |
| | Weighted Avg Measure Life* | | | | 15 |
| | Net To Gross Ratio | | | | 67% |

### Eligible Customers

Any customer of a participating retailer in Vectren South's electric territory.

### Marketing Plan

The program is designed to reach residential customers through retail outlets. Proposed marketing efforts include point of purchase promotional activities, the use of utility bill inserts and customer emails, utility web site and social media promotions and coordinated advertising with selected manufacturers and retail outlets.

**Barriers/Theory**

The program addresses the market barriers by empowering customers to take advantage of new lighting technologies through education and availability in the marketplace; accelerating the adoption of proven energy efficient technologies through incentives to lower price; and working with retailers to allow them to sell more high efficient products.

**Initial Measures, Products and Services**

The measures will include a variety of ENERGY STAR qualified lighting products currently available at retailers in Indiana, including LED bulbs, fixtures and ceiling fans.

**Program Delivery**

Vectren South will oversee the program and partner with Ecova to deliver the program.

**Evaluation, Measurement and Verification**

The implementation contractor will verify the paperwork of the participating retail stores. They will also spot check stores to assure that the program guidelines are being followed. A third party evaluator will evaluate the program using standard EM&V protocols.

## B. Residential Prescriptive

**Program Description**

The program, also called Residential Efficient Products, is designed to incent customers to purchase energy efficient equipment by covering part of the incremental cost. The program also offers home weatherization rebates to residential customers for attic insulation, wall insulation and duct sealing. If a product vendor or contractor chooses to do so, the rebates can be presented as an "instant discount" to Vectren South residential customers on their invoice.

**Table 12: Budget & Energy Savings Targets**

| Market | Program | 2018 | 2019 | 2020 | Total Program |
|---|---|---|---|---|---|
| **Residential** | **Residential Prescriptive** | | | | |
| | Number of Measures | 4,093 | 6,445 | 6,595 | 17,133 |
| | Energy Savings kWh | 1,747,547 | 1,918,174 | 1,979,280 | 5,645,001 |
| | Peak Demand kW | 1,558.1 | 1,775.2 | 1,910.2 | 5,243.5 |
| | Total Program Budget $ | 635,925 | 681,609 | 694,362 | 4,037 |
| | Per Participant Avg Energy Savings (kWh)* | | | | 329.5 |
| | Per Participant Avg Demand Savings (kW)* | | | | 0.306 |
| | Weighted Avg Measure Life* | | | | 17 |
| | Net To Gross Ratio | | | | 52% |

**Eligible Customers**

Any residential customer located in the Vectren South electric service territory. For the equipment rebates, the applicant must reside in a single-family home or multi-family complex with up to 12 units. Only single-family homes are eligible for insulation and duct sealing remediation measures.

**Marketing Plan**

The marketing plan includes program specific materials that will target contractors, trade allies, distributors, manufacturers, industry organizations and appropriate retail outlets in the Heating, Ventilation and Air Conditioning (HVAC) industry. Marketing outreach medium include targeted direct marketing, direct contact by vendor personnel, trade shows and trade associations. Vectren will also use web banners, bill inserts, customer emails, social media outreach, press releases and mass market advertising. Program marketing will direct customers and contractors to the Vectren South website or call center for additional information.

**Barriers/Theory**

The initial cost is one of the key barriers. Customers do not always understand the long-term benefits of the energy savings from efficient alternatives. Trade allies are also often reluctant to sell the higher cost items as they do not want to be the high cost bidder. Incentives help address the initial cost issue and provide a good reason for Trade Allies to promote these higher efficient options.

**Initial Measures, Products and Services**

Details of the measures, savings, and incentives can be found in Appendix B. Measures included in the program will change over time as baselines change, new technologies become available and customer needs are identified.

**Program Delivery**

Vectren South will oversee the program and will partner with CLEAResult to deliver the program.

**Integration with Vectren South Gas**

Vectren South will offer this integrated natural gas/electric EE program in its combined natural gas and electric service territory. Vectren South has allocated implementation costs based on the net benefits split between natural gas and electric.

**Evaluation, Measurement and Verification**

As part of the Quality Assurance/Quality Control process, the vendor will provide 100% paper verification that the equipment/products purchased meet the program efficiency standards and a field verification of 5% of the measures installed. A third party evaluator will review the program using appropriate EM&V protocols.

## C. Residential New Construction

### Program Description

The Residential New Construction (RNC) program produces long-term energy savings by encouraging the construction of single-family homes, duplexes, or end-unit townhomes with only one shared wall that are inspected and evaluated through the Home Efficiency Rating System (HERS). Builders can select from two rebate tiers for participation. Gold Star homes must achieve a HERS rating of 61 to 65. Platinum Star homes must meet a HERS rating of 60 or less.

The RNC Program provides incentives and encourages home builders to construct homes that are more efficient than current building codes and address the lost opportunities in this customer segment by promoting EE at the time the initial decisions are being made. The Residential New Construction Program will work closely with builders, educating them on the benefits of energy efficient new homes. Homes may feature additional insulation, better windows, and higher efficiency appliances. The homes should also be more efficient and comfortable than standard homes constructed to current building codes.

**Table 13: Program Budget & Energy Savings Targets**

| Market | Program | 2018 | 2019 | 2020 | Total Program |
|---|---|---|---|---|---|
| **Residential** | **Residential New Construction** | | | | |
| | Number of Homes | 139 | 139 | 139 | 417 |
| | Energy Savings kWh | 187,038 | 187,038 | 187,038 | 561,114 |
| | Peak Demand kW | 118.0 | 118.0 | 118.0 | 354.0 |
| | Total Program Budget $ | 85,345 | 87,132 | 88,940 | 261,417 |
| | Per Participant Avg Energy Savings (kWh)* | | | | 1345.6 |
| | Per Participant Avg Demand Savings (kW)* | | | | 0.849 |
| | Weighted Avg Measure Life* | | | | 25 |
| | Net To Gross Ratio | | | | 50% |

### Eligible Customers

Any customer or home builder constructing an eligible home in the Vectren South service territory.

### Marketing Plan

In order to move the market toward an improved home building standard, education will be required for home builders, architects and designers as well as customers buying new homes. A combination of in-person meetings with these market participants as well as other educational methods will be necessary.

### Barriers/Theory

The Residential New Construction program addresses the primary barriers of first cost as well as builder and customer knowledge. First cost is addressed by program incentives to help reduce the cost of the EE upgrades. The program provides opportunities for builders and developers to gain knowledge and skills concerning EE building practices and coaches them on application of these skills. The HERS rating system allows customers to understand building design and construction improvements through a rating system completed by professionals.

**Incentive Strategy**

Program incentives are designed to be paid to both all-electric and combination homes that have natural gas heating. It is important to note that the program is structured such that an incentive will not be paid for an all-electric home that has natural gas available to the home site. Incentives can be paid to either the home builder or the customer/account holder. Incentives will be based on the rating tier qualification. For all-electric homes, where Vectren South natural gas service is not available, the initial incentives will be:

| Tier | HERS Rating | Total Incentive |
|---|---|---|
| Platinum | 60 or less | $800 |
| Gold | 61 to 65 | $700 |

For homes with central air conditioning and Vectren South natural gas space heating, the electric portion of the incentive will be:

| Tier | HERS Rating | Total Incentive | Gas Portion | Electric Portion |
|---|---|---|---|---|
| Platinum | 60 or less | $800 | $600 | $200 |
| Gold | 61 to 65 | $700 | $525 | $175 |

**Program Delivery**

Vectren South will oversee the program and will partner with CLEAResult to deliver the program.

**Integration with Vectren South Gas**

Vectren South will offer this integrated natural gas/electric EE program in its combined natural gas and electric service territory.

**Evaluation, Measurement and Verification**

Field inspections will occur at least once during construction and upon completion by a certified HERS Rater. As part of the Quality Assurance/Quality Control process, the vendor will provide 100% paper verification that the equipment/products purchased meet the program efficiency standards. A third party evaluator will evaluate the program using standard EM&V protocols.

## D. Home Energy Assessments & Weatherization

**Program Description**

The Home Energy Assessment and Weatherization Program will be offered jointly by Vectren South Gas and Electric. This program targets a hybrid phased approach that combines helping customers analyze and understand their energy use via an on-site energy assessment, providing direct installation of energy efficient measures including low-flow water fixtures, LED bulbs and thermostats, as well as provide deeper retrofit measures.

- Phase 1 - Assessors will perform a walk-through assessment of the home, collecting data for use in identifying cost-effective energy efficient improvements and appropriate direct install measures. Audit report provided to customer onsite will showcase deeper retrofit measure opportunities within the home.

- Phase 2 - If the home is eligible for air sealing and/or duct sealing, the Assessor will provide the information to the customer for scheduling the Phase 2 appointment via the online scheduling portal for a co-pay of $50. Customers who choose to install attic insulation will be referred to the Residential Energy Efficient Rebate Program.

Customers can schedule an assessment appointment in one of the following two ways: (1) by visiting vectren.com/saveenergy to schedule an appointment through self-booking tool; or (2) calling the call center to speak with a program representative. Customers who opt to receive email notifications will receive confirmation and appointment reminders prior to the assessment.

**Table 14: Home Energy Assessments & Weatherization Budget & Energy Savings Targets**

| Market | Program | 2018 | 2019 | 2020 | Total Program |
|---|---|---|---|---|---|
| **Residential** | **Home Energy Assessment & Weatherization** | | | | |
| | Number of Homes | 1,210 | 1,210 | 1,210 | 3,630 |
| | Energy Savings kWh | 863,991 | 863,991 | 863,991 | 2,591,973 |
| | Peak Demand kW | 191.6 | 192.0 | 192.0 | 575.6 |
| | Total Program Budget $ | 526,473 | 533,934 | 541,669 | 1,602,076 |
| | Per Participant Avg Energy Savings (kWh)* | | | | 714.0 |
| | Per Participant Avg Demand Savings (kW)* | | | | 0.159 |
| | Weighted Avg Measure Life* | | | | 12 |
| | Net To Gross Ratio | | | | 98% |

**Eligible Customers**

Vectren South residential customers with electric service at a single-family residence, provided the home was not built within the past five years and has not had an audit within the last three years. Additionally, the home should be owner-occupied (or renter where occupants have the electric service in their name).

**Marketing Plan**

Proposed marketing efforts include utilizing direct mailers, email blasts, Vectren South online audit tools, bill inserts, social media outreach, as well as other outreach and education efforts and promotional campaigns throughout the year to ensure participation levels are maintained.

**Barriers/Theory**

The primary barrier addressed through this program is customer education and awareness. Often customers do not understand what opportunities exist to reduce their home energy use. This program not only informs the customer but helps them start down the path of energy savings by directly installing low-cost measures. The program is also a "gateway" to other Vectren South gas and electric programs.

**Initial Measures, Products and Services**

The direct install measures available for installation at no cost include:

- Kitchen & Bathroom Aerators
- Filter Whistle
- LED bulbs
- Low Flow Showerhead
- Pipe Wrap
- Water Heater Temperature Setback
- Wi-fi Thermostat

For customers who elect to move forward with Phase 2, Duct Sealing and Air Sealing are available for a $50 co-pay.

**Program Delivery**

Vectren South will oversee the program and will partner with CLEAResult to deliver the program.

**Integration with Vectren South Gas**

Vectren South will offer this integrated natural gas/electric EE program in its combined natural gas and electric service territory. Vectren South has allocated implementation costs based on the net benefits split between natural gas and electric.

**Evaluation, Measurement and Verification**

To assure compliance with program guidelines, field visits with auditors will occur as well as spot check verifications of measure installations. A third party evaluator will evaluate the program using standard EM&V protocols.

## E. Income Qualified Weatherization

### Program Description

The Income Qualified Weatherization program is designed to produce long-term energy and demand savings in the residential market. The program is designed to provide weatherization upgrades to low-income homes that otherwise would not have been able to afford the energy saving measures. The program provides direct installation of energy-saving measures and educates consumers on ways to reduce energy consumption. Customers eligible through the Income Qualified Weatherization Program will have opportunity to receive deeper retrofit measures including refrigerators, attic insulation, duct sealing, and air infiltration reduction. This year, we will engage with the manufactured homes population and offer the same measures offered to single family homes.

Collaboration and coordination between gas and electric low-income programs along with state and federal funding is recommended to provide the greatest efficiencies among all programs. The challenge of meeting the goals set for this program have centered on health and safety as well as customer cancellations and scheduling. Vectren South is committed to finding innovative solutions to these areas. A health and safety budget has been established, and we continue to work on improving methods of customer engagement with various confirmations via phone and email reminders prior to the appointment.

**Table 15: Income Qualified Weatherization Budget & Energy Savings Targets**

| Market | Program | 2018 | 2019 | 2020 | Total Program |
|---|---|---|---|---|---|
| **Residential** | **Income Qualified Weatherization** | | | | |
| | Number of Homes | 475 | 500 | 525 | 1,500 |
| | Energy Savings kWh | 959,988 | 1,046,148 | 1,130,945 | 3,137,081 |
| | Peak Demand kW | 458.8 | 499.4 | 540.2 | 1,498.4 |
| | Total Program Budget $ | 841,848 | 899,806 | 958,593 | 2,700,247 |
| | Per Participant Avg Energy Savings (kWh)* | | | | 2091.4 |
| | Per Participant Avg Demand Savings (kW)* | | | | 0.999 |
| | Weighted Avg Measure Life* | | | | 14 |
| | Net To Gross Ratio | | | | 100% |

### Eligible Customers

The Residential Low Income Weatherization Program targets single-family and manufactured homeowners and tenants who have electric service in their name with Vectren South and a total household income up to 200% of the federally-established poverty level.

### Marketing Plan

Vectren South will provide a list to the implementation contractor of high consumption customers who have received Energy Assistance Program (EAP) funds within the past 12 months to help prioritize those customers who will benefit most from the program. This will also help in any direct marketing activities to specifically target those customers.

**Barriers/Theory**

Lower-income homeowners do not have the money to make even simple improvements to lower their energy usage and often live in homes with the most need for EE improvements.  They may also lack the knowledge, experience, or capability to do the work. Health and safety can also be at risk for low-income homeowners, as their homes typically are not as "tight", and indoor air quality can be compromised. In order to increase participation and eligibility, Vectren South has incorporated a Health and Safety budget of $250 per home. This program provides those customers with basic improvements to help them start saving energy without needing to make the investment themselves.

**Initial Measures, Products and Services**

Measures available for installation will vary based on the home and include:

- LED bulbs/lamps
- Low flow kitchen and bath aerators
- Low flow showerheads
- Pipe wrap
- Filter whistles
- Infiltration reduction
- Attic insulation
- Duct repair, seal and insulation
- Refrigerator replacement
- Programmable/Smart thermostat
- Smart power strips

**Program Delivery**

Vectren South will oversee the program and will partner with CLEAResult to deliver the program.

**Integration with Vectren South Gas**

Vectren South will offer this integrated natural gas/electric EE program in its combined natural gas and electric service territory.  Vectren South has allocated implementation costs based on the net benefits split between natural gas and electric.

**Evaluation, Measurement and Verification**

To assure quality installations, 5% of the installations will be field inspected.  A third party evaluator will evaluate the program using standard EM&V protocols.

## F. LED Food Bank

### Program Description

The food bank program provides LED bulbs to food pantries in Vectren South's electric service territory. This program targets hard to reach, low income customers in the Vectren South electric territory. All food pantry recipients must provide proof of income qualification to receive the food baskets.

The program implementer purchases bulbs from a manufacturer and bulbs are shipped in bulk to the partner food bank. Food banks then distribute the bulbs to the respective food pantries in its network. Pantries include bulbs when assembling food packages and bulbs are provided to food recipients.

**Table 16: LED Food Bank Budget & Energy Savings Targets**

| Market | Program | 2018 | 2019 | 2020 | Total Program |
|---|---|---|---|---|---|
| **Residential** | **Food Bank - LED Bulb Distribution** | | | | |
| | Number of Measures | 50,496 | 50,496 | 0 | 100,992 |
| | Energy Savings kWh | 1,401,264 | 1,401,264 | 0 | 2,802,528 |
| | Peak Demand kW | 148.8 | 148.8 | 0.0 | 297.6 |
| | Total Program Budget $ | | | | 349,449 |
| | Per Participant Avg Energy Savings (kWh)* | | | | 27.8 |
| | Per Participant Avg Demand Savings (kW)* | | | | 0.003 |
| | Weighted Avg Measure Life* | | | | 15 |
| | Net To Gross Ratio | | | | 100% |

### Eligible Customers

Any participant visiting a food pantry in Vectren South's electric territory.

### Marketing Plan

The program will be marketed directly to food banks in the Vectren South electric service territory as well as other channels identified by the implementation contractor.

### Barriers/Theory

Lower-income homeowners do not have the money to make even simple improvements to lower their energy usage and often live in homes with the most need for EE improvements. They may also lack the knowledge, experience, or capability to do the work. This program also addresses the barrier of education and awareness of EE opportunities. Working through food banks, participants receive LED bulbs and are educated about opportunities to save energy.

### Initial Measures, Products and Services

Each participating food pantry will place a bundle of four (4) LED bulbs in food packages.

### Program Delivery

Vectren South will oversee the program and will partner with CLEAResult and the Tri-State Area Food Bank to deliver the program.

**Evaluation, Measurement and Verification**

A third party evaluator will evaluate the program using standard EM&V protocols. A postcard will be provided to each participant to help acquire necessary information for EM&V. The postcard will be a postage paid reply card and ‘drop box’ will also be provided for customers to voluntarily supply their information for verification.

## G. Energy Efficient Schools

**Program Description**

The Energy Efficient Schools Program is designed to impact students by teaching them how to conserve energy and to produce cost effective electric savings by influencing students and their families to focus on the efficient use of electricity.

The program consists of a school education program for 5th grade students attending schools served by Vectren South. To help in this effort, each child that participates will receive a take-home energy kit with various energy saving measures for their parents to install in the home. The kits, along with the in-school teaching materials, are designed to make a lasting impression on the students and help them learn ways to conserve energy.

**Table 17: Energy Efficient Schools Budget & Energy Savings Targets**

| Market | Program | 2018 | 2019 | 2020 | Total Program |
|---|---|---|---|---|---|
| **Residential** | **Energy Efficient Schools** | | | | |
| | Number of Kits | 2,400 | 2,500 | 2,600 | 7,500 |
| | Energy Savings kWh | 899,706 | 937,194 | 645,216 | 2,482,115 |
| | Peak Demand kW | 52.8 | 52.8 | 52.8 | 158.4 |
| | Total Program Budget $ | 131,696 | 136,805 | 119,995 | 388,496 |
| | Per Participant Avg Energy Savings (kWh)* | | | | 330.9 |
| | Per Participant Avg Demand Savings (kW)* | | | | 0.021 |
| | Weighted Avg Measure Life* | | | | 10 |
| | Net To Gross Ratio | | | | 100% |

**Eligible Customers**

The program will be available to selected 5th grade students/schools in the Vectren South electric service territory.

**Marketing Plan**

The program will be marketed directly to elementary schools in Vectren South electric service territory as well as other channels identified by the implementation contractor. A list of the eligible schools will be provided by Vectren South to the implementation contractor for direct marketing to the schools via email, phone, and mail (if necessary) to obtain desired participation levels in the program.

**Barriers/Theory**

This program addresses the barrier of education and awareness of EE opportunities. Working through schools, both students and families are educated about opportunities to save. As well, the families receive energy savings devices they can install to begin their savings.

**Initial Measures, Products and Services**

The kits for students will include:

- Low flow showerhead
- Low flow kitchen aerator
- Low flow bathroom aerator (2)
- LED bulbs (2)
- LED nightlight
- Filter whistle

**Program Delivery**

Vectren South will oversee the program and will partner with National Energy Foundation (NEF) to deliver the program.

**Integration with Vectren South Gas**

Vectren South will offer this integrated natural gas/electric EE program in its combined natural gas and electric service territory. Vectren South has allocated implementation costs based on the net benefits split between natural gas and electric.

**Evaluation, Measurement and Verification**

Classroom participation will be tracked. A third party evaluator will evaluate the program using standard EM&V protocols.

## H. Residential Behavior Savings

### Program Description

The Residential Behavioral Savings Program motivates behavior change and provides relevant, targeted information to the consumer through regularly scheduled direct contact via mailed and emailed home energy reports. The report and web portal include a comparison against a group of similarly sized and equipped homes in the area, usage history comparisons, goal setting tools, and progress trackers. The Home Energy Report program anonymously compares customers' energy use with that of other customers with similar home size and demographics. Customers can view the past 12 months of their energy usage and compare and contrast their energy consumption and costs with others in the same neighborhood. Once a consumer understands better how they use energy, they can then start conserving energy.

Program data and design was provided by OPower, the implementation vendor for the program. OPower provides energy usage insight that drives customers to take action by selecting the most relevant information for each particular household, which ensures maximum relevancy and high response rate to recommendations.

**Table 18: Residential Behavior Savings Program Budget & Energy Savings Targets**

| Market | Program | 2018 | 2019 | 2020 | Total Program |
|---|---|---|---|---|---|
| **Residential** | **Residential Behavioral Savings** | | | | |
| | Number of Participants | 41,348 | 38,203 | 35,298 | 114,849 |
| | Energy Savings kWh | 6,470,000 | 5,970,000 | 5,600,000 | 18,040,000 |
| | Peak Demand kW | 1,351 | 1,248 | 1,153 | 3,752 |
| | Total Program Budget $ | 305,622 | 285,585 | 286,545 | 877,752 |
| | Per Participant Avg Energy Savings (kWh)* | | | | 157.1 |
| | Per Participant Avg Demand Savings (kW)* | | | | 0.033 |
| | Weighted Avg Measure Life* | | | | 1 |
| | Net To Gross Ratio | | | | 100% |

### Eligible Customers

Residential customers who receive electric service from Vectren South are eligible to participate in this integrated natural gas and electric EE program.

### Barriers/Theory

The Residential Behavioral Savings program provides residential customers with better energy information through personalized reports delivered by mail, email and an integrated web portal to help them put their energy usage in context and make better energy usage decisions. Behavioral science research has demonstrated that peer-based comparisons are highly motivating ways to present information. The program will leverage a dynamically created comparison group for each residence and compare it to other similarly sized and located households.

**Implementation & Delivery Strategy**

The program will be delivered by OPower and include energy reports and a web portal. Customers typically receive between 4 to 6 reports annually and monthly emailed reports. These reports provide updates on energy consumption patterns compared to similar homes and provide energy savings strategies to reduce energy use. They also promote other Vectren South programs to interested customers. The web portal is an interactive system for customers to perform a self-audit, monitor energy usage over time, access energy savings tips and be connected to other Vectren South gas and electric programs.

**Program Delivery**

Vectren South will oversee the program and partner with OPower to deliver the program.

**Integration with Vectren South Gas**

Vectren South will offer this integrated natural gas/electric EE program in its combined natural gas and electric service territory. Vectren South has allocated implementation costs based on the net benefits split between natural gas and electric.

**Evaluation, Measurement and Verification**

A third party evaluator will complete the evaluation of this program and work with Vectren South to select the participant and non-participant groups.

## I. Appliance Recycling

### Program Description

The Residential Appliance Recycling program encourages customers to recycle their old inefficient refrigerators and freezers in an environmentally safe manner. The program recycles operable refrigerators and freezers so the appliance no longer uses electricity, and keeps 95% of the appliance out of landfills. An older refrigerator can use up to three times the amount of energy as new efficient refrigerators. An incentive of $50 will be provided to the customer for each operational unit picked up.

**Table 19: Appliance Recycling Budget & Energy Savings Targets**

| Market | Program | 2018 | 2019 | 2020 | Total Program |
|---|---|---|---|---|---|
| **Residential** | **Appliance Recycling** | | | | |
| | Number of Measures | 950 | 930 | 920 | 2,800 |
| | Energy Savings kWh | 913,771 | 894,534 | 884,915 | 2,693,219 |
| | Peak Demand kW | 120.7 | 118.1 | 116.8 | 355.6 |
| | Total Program Budget $ | 174,759 | 180,648 | 186,532 | 541,939 |
| | Per Participant Avg Energy Savings (kWh)* | | | | 961.9 |
| | Per Participant Avg Demand Savings (kW)* | | | | 0.127 |
| | Weighted Avg Measure Life* | | | | 8 |
| | Net To Gross Ratio | | | | 54% |

### Eligible Customers

Any residential customer with an operable secondary refrigerator or freezer receiving electric service from Vectren South.

### Marketing Plan

The program will be marketed through a variety of mediums, including the use of utility bill inserts and customer emails, press releases, retail campaigns coordinated with appliance sales outlets as well as the potential for direct mail, web and social and mass media promotional campaigns.

### Barriers/Theory

Many homes have second refrigerators and freezers that are very inefficient. Customers are not aware of the high energy consumption of these units. Customers also often have no way to move and dispose of the units, so they are kept in homes past their usefulness. This program educates customers about the waste of these units and provides a simple way for customers to dispose of the units.

### Program Delivery

Vectren South will work directly with Appliance Recycling Centers of America Inc. (ARCA), to implement this program.

### Evaluation, Measurement and Verification

Recycled units will be logged and tracked to assure proper handling and disposal. The utility will monitor the activity for disposal. Customer satisfaction surveys will also be used to understand the customer experience with the program. A third party evaluator will evaluate the program using standard EM&V protocols.

## J. Smart Thermostat Program

### Program Description

In 2016, Vectren South conducted a field study designed, in part, to analyze the different approaches to DR that are available through smart thermostats. Between the months of April and May, Vectren South installed approximately 2,000 smart thermostats (1,000 Honeywell and 1,000 Nest) in customer homes. Vectren South leveraged these thermostats to manage DR events during the summer in an effort to evaluate the reduction in peak system loads. These smart devices are connected to Wi-Fi and reside on the customer's side of the electric meter and are used to communicate with customer's air conditioning systems. The program provides Vectren South with increased customer contact opportunities and the ability to facilitate customers' shift of their energy usage to reduce peak system loads. Vectren South will not install additional thermostats pursuant to this program; however, incentives will continue to be paid to participating customers.

**Table 20: Smart Thermostat Program Budget & Energy Savings Targets**

| Market | Program | 2018 | 2019 | 2020 | Total Program |
|---|---|---|---|---|---|
| **Residential** | **Smart Thermostat Program** | | | | |
| | Number of Measures | 0 | 0 | 0 | 0 |
| | Energy Savings kWh | | | | |
| | Peak Demand kW | 0 | 0 | 0 | 0 |
| | Total Program Budget $ | 97,639 | 98,222 | 98,798 | 294,659 |
| | Per Participant Avg Energy Savings (kWh)* | | | | 0.0 |
| | Per Participant Avg Demand Savings (kW)* | | | | 0.000 |
| | Weighted Avg Measure Life* | | | | 15 |
| | Net To Gross Ratio | | | | 100% |

*No additional kWh or demand savings will be recorded.

### Incentive Strategy

The program budget is for incentives for existing customers to participate in the Demand Response events for 2018-2020.

### Program Delivery

Vectren South will oversee the program.

### Evaluation, Measurement and Verification

A third party evaluator will evaluate the program using standard EM&V protocols.

## K. Smart DLC – Wi-Fi/DLC Switchout Program

**Program Description**

Since 1992, Vectren South has operated a Direct Load Control (DLC) program called Summer Cycler that reduces residential and small commercial air-conditioning and water heating electricity loads during summer peak hours. While this technology still helps lower peak load demand for electricity, this aging technology will be phased out over time. Vectren's Summer Cycler program has served Vectren and its customers well for more than two decades, but emerging technology is now making the program obsolete.

By installing connected devices in customer homes rather than using one-way signal switches, Vectren will be able to provide its customer base deeper energy savings opportunities and shift future energy focus to customer engagement rather than traditional program goals and rules. The most recent Vectren electric DSM evaluation has demonstrated that smart thermostats outperform standard programmable thermostats and are a practical option to transition into future customer engagement strategies.

Smart thermostat installations are also a feasible solution to multiple utility and customer quandaries. Past Vectren evaluations have discovered that its customers program less than half of all programmable thermostats installed, hindering potential savings and acting a disincentive for customers to become involved in how their home uses energy. This issue is coupled with the uncertainty of whether standard DLC switches in the field are in working order and the fact that the switches cannot record or yield any savings data. With these issues mitigated, utility management burden is reduced, customer engagement and satisfaction is increased, and Vectren will be able to obtain better home usage data for creation and implementation of future DSM programs.

If approved by the Commission, Vectren South anticipates replacing DLC switches with smart thermostats over time, as the benefits associated with this emerging technology far outweigh the benefits associated with DLC switches. In 2018, Vectren South will begin its phase out of the Summer Cycler program by removing approximately 1,000 Sumer Cycler devices and replacing them with Wi-Fi thermostats that utilize demand response technology. Customers will receive a professionally installed Wi-Fi thermostat at no additional cost and a monthly bill credit of $5 during the months of June to September.  The current monthly credit for Summer Cycler is also $5; therefore the annual bill credit by customer does not change.

By replacing the Summer Cycler devices, Vectren South will eliminate the annual inspection and maintenance ("I&M costs") for the Summer Cycler program, and thus offer a more reliable DR program. Long-term, Vectren South will almost eliminate the annual ongoing inspection and maintenance cost. By replacing 1,000 switches each year, Vectren continues to have resources to manage peak demand for electricity during the summer months.

**Table 22: SmartDLC – Wi-Fi/DLC Switchout Program& Energy Savings Targets**

| Market | Program | 2018 | 2019 | 2020 | Total Program |
|---|---|---|---|---|---|
| **Residential** | **SmartDLC - Wifi DR/DLC Changeout** | | | | |
| | Number of Participants | 1,000 | 1,000 | 1,000 | 3,000 |
| | Energy Savings kWh | 466,690 | 466,690 | 466,690 | 1,400,070 |
| | Peak Demand kW | 600.0 | 600.0 | 600.0 | 1,800.0 |
| | Total Program Budget $ | 517,759 | 562,148 | 606,532 | 1,686,439 |
| | Per Participant Avg Energy Savings (kWh)* | | | | 466.7 |
| | Per Participant Avg Demand Savings (kW)* | | | | 0.600 |
| | Weighted Avg Measure Life* | | | | 15 |
| | Net To Gross Ratio | | | | 100% |

**Eligible Customers**

Customers in the Vectren South territory who currently participate in the DLC Summer Cycler program and have access to Wi-Fi.

**Marketing Plan**

Proposed marketing efforts include utilizing direct mailers, email blasts, Vectren South online audit tools, bill inserts as well as other outreach and education efforts and promotional campaigns throughout the year to ensure participation levels are maintained.

**Incentive Strategy**

Customers will receive a professionally installed Wi-Fi thermostat at no additional cost and a monthly bill credit of $5 during the months of June to September.

**Program Delivery**

Vectren South will oversee the program.

**Evaluation, Measurement and Verification**

A third party evaluator will evaluate the program using standard EM&V protocols.

## L. Bring Your Own Thermostat (BYOT)

**Program Description**

The Bring Your Own Thermostat ("BYOT") program is a further expansion of the residential smart thermostat initiative. BYOT allows customers to purchase their own device from multiple vendors and participate in DR with Vectren South and other load curtailing programs managed through the utility. Taking advantage of two-way communicating smart thermostats, the BYOT program can help reduce acquisition costs for load curtailment programs and improve customer satisfaction.

**Table 23: BYOT Program Budget & Energy Savings Targets**

| Market | Program | 2018 | 2019 | 2020 | Total Program |
|---|---|---|---|---|---|
| **Residential** | **BYOT (Bring Your Own Thermostat)** | | | | |
| | Number of Participants | 400 | 400 | 400 | 1,200 |
| | Energy Savings kWh | | | | |
| | Peak Demand kW | 240.0 | 240.0 | 240.0 | 720.0 |
| | Total Program Budget $ | 111,036 | 178,592 | 146,128 | 435,756 |
| | Per Participant Avg Energy Savings (kWh)* | | | | 0.0 |
| | Per Participant Avg Demand Savings (kW)* | | | | 0.600 |
| | Weighted Avg Measure Life* | | | | 15 |
| | Net To Gross Ratio | | | | 100% |

**Eligible Customers**

Residential single or multi-family customers in the Vectren South territory with access to Wi-Fi and who own a qualifying compatible Wi-Fi thermostat that operates the central air-conditioning cooling system.

**Marketing Plan**

Proposed marketing efforts include utilizing direct mailers, email blasts, Vectren South online audit tools, bill inserts as well as other outreach and education efforts and promotional campaigns throughout the year to ensure participation levels are maintained.

**Incentive Strategy**

Customers will receive a one-time enrollment incentive of $75 and a bill credit of $5 during the months of June to September. The enrollment incentive will be provided in the first year to new enrollees only.

**Program Delivery**

Vectren South will oversee the program.

**Evaluation, Measurement and Verification**

A third party evaluator will evaluate the program using standard EM&V protocols.

## M. Conservation Voltage Reduction - Residential and Commercial and Industrial

**Program Description**

Conservation Voltage Reduction (CVR) is a technology that reduces energy usage and peak demand through automated monitoring and control of voltage levels provided on distribution circuits. End use customers realize lower energy and demand consumption when CVR is applied to the distribution circuit from which they are served.

A distribution circuit facilitates electric power transfer from an electric substation to utility meters located at electric customer premises. Electric power customers employ end-use electric devices (loads) that consume electrical power. At any point along a single distribution circuit, voltage levels vary based upon several parameters, mainly including, but not exclusive of, the actual electrical conductors that comprise the distribution circuit, the size and location of electric loads along the circuit, the type of end-use loads being served, the distance of loads from the power source, and losses incurred inherent to the distribution circuit itself. All end-use loads require certain voltage levels to operate and standards exist to regulate the levels of voltage delivered by utilities. In Indiana, Vectren South is required to maintain a steady state +/- 5% of the respective baseline level as specified by ANSI C84.1 (120 volt baseline yields acceptable voltage range of 114 volts to 126 volts).

Historically, utilities including Vectren South have set voltage levels near the upper limit at the distribution circuit source (substation) and have applied voltage support devices such as voltage regulators and capacitors along the circuit to assure that all customers are provided voltages within the required range. This basic design economically met the requirements by utilizing the full range (+/- 5%) of allowable voltages while only applying independent voltage support where needed. This basic design has worked well for many years. However, in the 1980's, utilities recognized that loads on the circuits would actually consume less energy if voltages in the lower portion of the acceptable range were provided. In fact, many utilities, including Vectren South, established emergency operating procedures to lower voltage at distribution substations by 5% during power shortage conditions.

The recent focus on EE and the availability of technology that allows monitoring and tighter control of circuit voltage conditions has led to development of automated voltage control schemes which coordinate the operation of voltage support devices and allow more customers on the circuit to be served at voltages in the lower portion of the acceptable range.

Once applied, a step change in energy and demand consumption by customers is realized, dependent upon where customer loads are located within the voltage zones, the load characteristics of the circuit, and how end-use loads respond to the voltage reduction. The resultant energy and demand consumption reduction persist at the new levels as long as tighter voltage bandwidth operation is applied. As a result, ongoing energy and demand savings persists for the duration of the life of the CVR equipment and as long as the equipment is maintained and operated in the voltage bandwidth mode.

With Commission approval, Vectren South will capitalize the costs to implement the CVR program and seek to recover through the annual Demand Side Management Adjustment (DSMA) mechanism the carrying costs and depreciation expense associated with the implementation along with annual, ongoing Operation and Maintenance (O&M) expense, a representative share of Vectren South's DSM support staff and administration costs and related EM&V cost. The budget below is reflective of this request.

**Table 21: Conservation Voltage Reduction Energy Savings Targets**

| Market | Program | 2018 | 2019 | 2020 | Total Program |
|---|---|---|---|---|---|
| **Residential** | **CVR Residential** | | | | |
| | Number of Participants | | | 5,324 | 5,324 |
| | Energy Savings kWh | | | 1,461,047 | 1,461,047 |
| | Peak Demand kW | | | 263 | 263 |
| | Total Program Budget $ | 118,786 | 114,907 | 230,134 | 463,827 |
| | Per Participant Avg Energy Savings (kWh)* | | | | 274.4 |
| | Per Participant Avg Demand Savings (kW)* | | | | 0.049 |
| | Weighted Avg Measure Life* | | | | 15 |
| | Net To Gross Ratio | | | | 100% |

| Market | Program | 2018 | 2019 | 2020 | Total Program |
|---|---|---|---|---|---|
| **Commercial & Industrial** | **CVR Commercial** | | | | |
| | Number of Participants | | | 558 | 558 |
| | Energy Savings kWh | | | 1,032,655 | 1,032,655 |
| | Peak Demand kW | | | 185.9 | 185.9 |
| | Total Program Budget $ | 108,834 | 105,297 | 137,003 | 351,134 |
| | Per Participant Avg Energy Savings (kWh)* | | | | 1850.6 |
| | Per Participant Avg Demand Savings (kW)* | | | | 0.333 |
| | Weighted Avg Measure Life* | | | | 15 |
| | Net To Gross Ratio | | | | 100% |

### Program Delivery

Vectren South will oversee the program and will partner with an implementer to deliver the program. One unit installation will be completed in 2017, and as an expansion of this program, one additional unit will be installed in 2020.

### Eligible Customers

Vectren South has identified substations that will benefit from the CVR program. For this program, one substation will be installed in 2020.

### Barriers/Theory

CVR is both a DR and an EE program. First, it seeks to cost effectively deploy new technology to targeted distribution circuits, in part to reduce the peak demand experienced on Vectren South's electrical power supply system. The voltage reduction stemming from the CVR program operates to effectively reduce consumption during the times in which system peaks are set and as a result directly reduces peak demand. CVR also cost effectively reduces the level of ongoing energy consumption by end-use devices located on the customer side of the utility meter as many end-use devices consume less energy with lower voltages consistently applied. Like an equipment maintenance service program, the voltage optimization allows the customer’s equipment to operate at optimum levels which saves energy without requiring direct customer intervention or change.

**Initial Measures, Products and Services**

Vectren South will install the required communication and control equipment on the appropriate circuits from the substation. No action is required of the customers.

## N. Commercial and Industrial Prescriptive

**Program Description**

The Commercial & Industrial (C&I) Prescriptive Program is designed to provide financial incentives on qualifying products to produce greater energy savings in the C&I market. The rebates are designed to promote lower electric energy consumption, assist customers in managing their energy costs, and build a sustainable market around EE.

Program participation is achieved by offering incentives structured to cover a portion of the customer's incremental cost of installing prescriptive efficiency measures.

**Table 24: Commercial & Industrial Prescriptive Budget & Energy Savings Targets**

| Market | Program | 2018 | 2019 | 2020 | Total Program |
|---|---|---|---|---|---|
| **Commercial & Industrial** | **Commercial Prescriptive** | | | | |
| | Number of Measures | 7,024 | 5,981 | 6,856 | 19,861 |
| | Energy Savings kWh | 4,999,125 | 4,501,186 | 5,002,621 | 14,502,932 |
| | Peak Demand kW | 378.2 | 325.4 | 369.0 | 1,072.6 |
| | Total Program Budget $ | 729,398 | 655,370 | 731,330 | 2,116,098 |
| | Per Participant Avg Energy Savings (kWh)* | | | | 730.2 |
| | Per Participant Avg Demand Savings (kW)* | | | | 0.054 |
| | Weighted Avg Measure Life* | | | | 14 |
| | Net To Gross Ratio | | | | 87% |

**Eligible Customers**

Any eligible participating commercial or industrial customer receiving Vectren South electric service.

**Marketing Plan**

Proposed marketing efforts include trade ally outreach, trade ally meetings, direct mail, face-to-face meetings with customers, marketing campaigns and bonuses, web-based marketing, and coordination with key account executives.

**Barriers/Theory**

Customers often have the barrier of higher first cost for EE measures, which precludes them from purchasing the more expensive EE alternative. They also lack information on high-efficiency alternatives. Trade allies often run into the barrier of not being able to promote more EE alternatives because of first cost or lack of knowledge. Trade allies also gain credibility with customers for their EE claims when a measure is included in a utility prescriptive program. Through the program the Trade allies can promote EE measures directly to their customers encouraging them to purchase more efficient equipment while helping customers get over the initial cost barrier.

**Initial Measures, Products and Services**

Measures will include high efficient lighting and lighting controls, HVAC equipment including variable frequency drives, commercial kitchen equipment including electronically commutated motors (ECMs), and miscellaneous items including compressed air equipment.

Note that measures included in the program will change over time as baselines change, new technologies become available and customer needs are identified. Detailed measure listings, participation and incentives are in Appendix B.

**Implementation & Delivery Strategy**

The program will be delivered primarily through the trade allies working with their customers. Vectren South and its implementation partners will work with the trade allies to make them aware of the offerings and help them promote the program to their customers. The implementation partner will provide training and technical support to the trade allies to become familiar with the EE technologies offered through the program. The program will be managed by the same implementation provider as the Commercial & Industrial Custom program so that customers can seamlessly receive assistance and all incentives can be efficiently processed through a single procedure.

**Incentive Strategy**

Incentives are provided to customers to reduce the difference in first cost between the lower efficient technology and the high efficient option. There is no fixed incentive percentage amount based on the difference in price because some technologies are newer and need higher amounts. Others have been available in the marketplace longer and do not need as much to motivate customers. Incentives will be adjusted to respond to market activity and bonuses may be available for limited time, if required, to meet goals.

**Program Delivery**

Vectren South will oversee the program partner Nexant to deliver the program.

**Evaluation, Measurement and Verification**

Site visits will be made on 5% of the installations, as well as all projects receiving incentive greater than $20,000, to verify the correct equipment was installed. Standard EM&V protocols will be used for the third party evaluation of the program.

## O. Commercial and Industrial Custom

### Program Description

The Commercial & Industrial (C&I) Custom Program promotes the implementation of customized energy saving measures at qualifying customer facilities. Incentives promoted through this program serve to reduce the cost of implementing energy saving projects and upgrading to high-efficiency equipment. Due to the nature of a custom EE program, a wide variety of projects are eligible.

**Table 25: Commercial & Industrial Custom Budget & Energy Savings Targets**

| Market | Program | 2018 | 2019 | 2020 | Total Program |
|---|---|---|---|---|---|
| **Commercial & Industrial** | **Commercial Custom** | | | | |
| | Number of Measures | 50 | 50 | 55 | 155 |
| | Energy Savings kWh | 5,000,000 | 5,000,000 | 5,500,000 | 15,500,000 |
| | Peak Demand kW | 476.0 | 476.0 | 524.0 | 1,476.0 |
| | Total Program Budget $ | 1,019,072 | 1,022,184 | 1,160,256 | 3,201,512 |
| | Per Participant Avg Energy Savings (kWh)* | | | | 100000.0 |
| | Per Participant Avg Demand Savings (kW)* | | | | 9.523 |
| | Weighted Avg Measure Life* | | | | 15 |
| | Net To Gross Ratio | | | | 100% |

### Eligible Customers

Any participating commercial or industrial customer receiving electric service from Vectren South.

### Marketing Plan

Proposed marketing efforts include coordination with key account representatives to leverage the contacts and relationships they have with the customers. Direct mail, media outreach, trade shows, marketing campaigns and bonuses, trade ally meetings, and educational seminars could also be used to promote the program.

### Barriers/Theory

Applications of some specific EE technologies are unique to that customer's application or process. The energy savings estimates for these measures are highly variable and cannot be assessed without an engineering estimation of that application; however, they offer a large opportunity for energy savings. To promote the installation of these high efficient technologies or measures, the Commercial & Industrial Custom program will provide incentives based on the kWh saved as calculated by the engineering analysis. To assure savings, these projects will require program engineering reviews and pre approvals. The custom energy assessments offered will help remove customer barriers regarding opportunity identification and determining energy savings potential.

### Initial Measures, Products and Services

All technologies or measures that save kWh qualify for the program. Facility energy assessments will be offered to customers who are eligible and encouraged to implement multiple EE measures. Detailed measure listings, participation and incentives are in Appendix B.

**Implementation & Delivery Strategy**

The implementation partner will work collaboratively with Vectren South staff to recruit and screen customers for receiving facility energy assessments. The implementation partner will also provide engineering field support to customers and trade allies to calculate the energy savings. Customers or trade allies with a proposed project will complete an application form with the energy savings calculations for the project. The implementation team will review all calculations and where appropriate complete site visits to assess and document pre-installation conditions. Customers will be informed and funds will be reserved for the project. Implementation engineering staff will review the final project information as installed and verify the energy savings. Incentives are then paid on the verified savings.

The implementation partner will work collaboratively with Vectren South staff to recruit and screen customers for receiving facility energy assessments, technical assistance and energy management education. The program will seek to gain customer commitment towards setting up an energy management process and implementing multiple EE improvements. The implementation partner will help customers achieve agreed upon milestones in support for their commitment.

**Incentive Strategy**

Incentives will be calculated on a per kWh basis. The initial kWh rate will be $0.12/kWh and is paid based on the first year annual savings reduction. Rates may change over time and vary with some of the special initiatives. Incentives will not pay more than 50% of the project cost nor provide incentives for projects with paybacks less than 12 months. Vectren South will offer a cost share on facility energy assessments that will cover up to 100% of the assessment cost.

**Program Delivery**

Vectren South will oversee the program partner Nexant to deliver the program.

**Evaluation, Measurement and Verification**

Given the variability and uniqueness of each project, all projects will be pre-approved. Pre and post visits to the site to verify installation and savings will be performed as defined by the program implementation partner. Monitoring and verification may occur on the largest projects. A third party evaluator will be used for this project and use standard EM&V protocols.

## P. Small Business Direct Install

### Program Description

The Small Business Direct Install Program provides value by directly installing EE products such as high efficiency lighting, pre-rinse sprayers, refrigeration controls, electrically-commutated motors, smart thermostats and vending machine controls. The program helps businesses identify and install cost effective energy saving measures by providing an on-site energy assessment customized for their business.

**Table 26: Small Business Direct Install Budget & Energy Savings Targets**

| Market | Program | 2018 | 2019 | 2020 | Total Program |
|---|---|---|---|---|---|
| **Commercial & Industrial** | **Small Business Direct Install** | | | | |
| | Number of Projects | 146 | 142 | 127 | 415 |
| | Energy Savings kWh | 4,032,934 | 3,905,372 | 3,900,306 | 11,838,612 |
| | Peak Demand kW | 667.0 | 645.0 | 567.0 | 1,879.0 |
| | Total Program Budget $ | 1,149,640 | 1,182,037 | 1,173,133 | 3,504,810 |
| | Per Participant Avg Energy Savings (kWh)* | | | | 28526.8 |
| | Per Participant Avg Demand Savings (kW)* | | | | 4.528 |
| | Weighted Avg Measure Life* | | | | 15 |
| | Net To Gross Ratio | | | | 95% |

### Eligible Customers

Any participating Vectren South business customer with a maximum peak energy demand of less than 400 kW.

### Marketing Plan

The Small Business Direct Install Program will be marketed primarily through in-network trade ally outreach. The program implementer will provide trade ally-specific marketing collateral to support trade allies as they connect with customers.

The program will provide targeted marketing efforts as needed to individual customer segments (e.g., hospitality, grocery stores, and retail) to increase participation in under-performing segments, including direct customer outreach and enhanced incentive campaigns. Additional program marketing may occur through direct mail, trade associations, local business organizations, marketing campaigns and bonuses, educational seminars, and direct personal communication from Vectren South staff and third-party contractors.

### Barriers/Theory

Small business customers generally do not have the knowledge, time or money to invest in EE upgrades. This program assists these small businesses with direct installation and turn-key services to get measures installed at no or low out-of-pocket cost.

There is an implementation contractor in place providing suggested additions and changes to the program based on results and local economics.

**Implementation & Delivery Strategy**

Trade Ally Network: Trained trade ally energy advisors will provide energy assessments to business customers with less than 400 kW of annual peak demand. The program implementer will issue an annual Request for Qualification (RFQ) to select the trade allies with the best ability to provide high-quality and cost-effective service to small businesses, and provide training to Small Business Energy Solutions trade allies on the program process, with an emphasis on improving energy efficiency sales.

Energy Assessment: Trade allies will walk through small businesses and record site characteristics and energy efficiency opportunities at no cost to the customer. They will provide an energy assessment report that will detail customer-specific opportunities, costs, energy savings, incentives, and simple payback periods. The trade ally will then review the report with the customer, presenting the program benefits and process, while addressing any questions.

**Initial Measures, Products and Services**

Details of the measures, savings, and incentives can be found in Appendix B. The program will have two types of measures provided. The first are measures that will be installed at no cost to the customer. Some available measures will include, but are not limited to the following:

- LEDs: 8-12W
- LEDs: MR16 track light
- LEDs: > 12 W flood light
- Wifi-enabled thermostats
- Programmable thermostats
- Pre-rinse sprayers
- Faucet aerators

The second types of measures require the customer to pay a portion of the labor and materials. Some available measures will include, but are not limited to the following:

- Interior LED lighting (replacing incandescent, high bays and linear fluorescents)
- High-efficiency linear fluorescent lighting
- Linear fluorescent delamping
- LED exit signs
- Exterior LED lighting
- ECMs in refrigeration equipment

- Anti-sweat heater controls
- LED lighting for display cases

**Incentive Strategy**

In addition to the no-cost measures identified during the audit, the program will also pay a cash incentive on every recommended improvement identified through the assessment. Incentive rates may change over time and vary with special initiatives.

**Program Delivery**

Vectren South will oversee the program partner Nexant to deliver the program.

**Integration with Vectren South Gas**

Vectren South will offer this integrated natural gas and electric EE program in its combined natural gas and electric service territory.

**Evaluation, Measurement and Verification**

On-site verification will be provided for the first three projects completed by each trade ally, in addition to the program standard 5% of all completed projects and all projects receiving incentives greater than $20,000. These verifications allow the program to validate energy savings, in addition to providing an opportunity to ensure the trade allies are providing high-quality customer services and the incentivized equipment satisfies program requirements. A third party evaluator will evaluate the program using standard EM&V protocols.

## Q. Commercial & Industrial New Construction

**Program Description**

The Commercial and Industrial New Construction Program provides value by promoting EE designs with the goal of developing projects that are more energy efficient than current Indiana building code. This program applies to new construction and major renovation projects. Major renovation is defined as the replacement of at least two systems within an existing space (e.g. lighting, HVAC, controls, building envelope). The program provides incentives as part of the facility design process to explore opportunities in modeling EE options to craft an optimal package of investments. The program also offers customers the opportunity to receive prescriptive or custom rebates toward eligible equipment in order to reduce the higher capital cost for the EE solutions.

**Table 27: Commercial & Industrial New Construction Budget & Energy Savings Targets**

| Market | Program | 2018 | 2019 | 2020 | Total Program |
|---|---|---|---|---|---|
| **Commercial & Industrial** | **Commercial New Construction** | | | | |
| | Number of Projects | 18 | 20 | 18 | 56 |
| | Energy Savings kWh | 502,080 | 1,835,413 | 502,080 | 2,839,573 |
| | Peak Demand kW | 108.0 | 120.0 | 108.0 | 336.0 |
| | Total Program Budget $ | 214,536 | 386,092 | 222,628 | 823,256 |
| | Per Participant Avg Energy Savings (kWh)* | | | | 50706.7 |
| | Per Participant Avg Demand Savings (kW)* | | | | 6.000 |
| | Weighted Avg Measure Life* | | | | 10 |
| | Net To Gross Ratio | | | | 100% |

**Eligible Customers**

Any commercial or industrial customer who receives or intends to receive electric service from Vectren South.

**Marketing Plan**

The Commercial & Industrial New Construction Program will be marketed through trade ally meetings, trade association training, marketing campaigns and bonuses, educational seminars, and direct personal communication from Vectren South staff and third party contractors.

**Barriers/Theory**

There are three primary barriers addressed by the C&I New Construction program. The first is knowledge. For commercial and industrial buildings it is the knowledge and experience of the design team including the owner, architect, lighting and HVAC engineers, general contractor and others. This team may not understand new technologies and EE options that could be considered. The second barrier is cost. There is a cost during the design phase of the project in modeling EE options to see what can cost-effectively work within the building. The program provides design team incentives to help reduce the design cost for the consideration of EE upgrades. The third barrier is the first cost of the high efficiency upgrades in equipment and materials. The program provides prescriptive or custom rebates toward eligible equipment to help reduce this first cost.

**Implementation & Delivery Strategy**

The new construction program is designed as a proactive, cost-effective way to achieve energy efficiency savings and foster economic growth. Typically, program participants face time and cost constraints throughout the project that make it difficult to invest in sustainable building practices. Participants need streamlined and informed solutions that are specific to their projects and locations. This scenario is particularly true for small to medium-sized new construction projects, where design fees and schedules provide for a very limited window of opportunity.

To help overcome the financial challenge for small-medium size projects, we offer a Standard Energy Design Assistance (EDA). EDA targets buildings that are less than 100,000 square feet, but is also available for larger new buildings that are beyond the schematic design phase or are on an accelerated schedule. Commercial and industrial projects for buildings greater than 100,000 square feet still in the conceptual design phase qualify for Vectren South's Enhanced EDA incentives. The Vectren South implementation partner staff expert will work with the design team through the conceptual design, schematic design and design development processes providing advice and counsel on measures that should be considered and EE modeling issues. Incentives will be paid after the design team submits completed construction documents for review to verify that the facility design reflects the minimum energy savings requirements.

For those projects that are past the phase where EDA can be of benefit, the C&I New Construction program offers the opportunity to receive prescriptive or custom rebates towards eligible equipment.

**Incentive Strategy**

Incentives are provided to help offset some of the expenses for the design team's participation in the EDA process with the design team incentive. The design team incentive is a fixed amount based on the new/renovated conditioned square footage and is paid when the proposed EE projects associated with the construction documents exceed a minimum energy savings threshold. The program also offers customers the opportunity to receive prescriptive or custom rebates toward eligible equipment in order to reduce the higher capital cost for the EE solutions. Program specific savings and incentive include:

| Facility Size – Square Feet | Design Team Incentives | Minimum Savings |
|---|---|---|
| Small <25,000 | $750 | 25,000 kWh |
| Medium 25,000 - 100,000 | $2,250 | 75,000 kWh |
| Large >100,000 | $3,750 | 150,000 kWh |
| Enhance Large >100,000 | $5,000 | 10% beyond code |

**Program Delivery**

Vectren South will oversee the program and partner with Nexant to deliver the program.

**Integration with Vectren South Gas**

Vectren South will offer this integrated natural gas and electric EE program in its combined natural gas and electric service territory. Vectren South has allocated implementation costs based on the net benefits split between natural gas and electric.

**Evaluation, Measurement and Verification**

All construction documents will be reviewed and archived. A third party evaluator will evaluate the program using standard EM&V protocols.

## R. Commercial Building Tune-Up

### Program Description

The Building Tune-Up (BTU) program provides a targeted, turnkey, and cost-effective retrocommissioning solution for small- to mid-sized customer facilities.

It is designed as a comprehensive customer solution that will identify, validate, quantify, and encourage the installation of both operational and capital measures. The majority of these measures will be no- or low-cost with low payback periods and will capture energy savings from a previously untapped source: building automation systems.

**Table 28: Building Tune-Up Budget & Energy Savings Targets**

| Market | Program | 2018 | 2019 | 2020 | Total Program |
|---|---|---|---|---|---|
| **Commercial & Industrial** | **Building Tune-up** | | | | |
| | Number of Projects | 10 | 14 | 20 | 44 |
| | Energy Savings kWh | 500,000 | 700,000 | 1,000,000 | 2,200,000 |
| | Peak Demand kW | 1.0 | 1.0 | 1.0 | 3.0 |
| | Total Program Budget $ | 130,880 | 182,074 | 261,266 | 574,220 |
| | Per Participant Avg Energy Savings (kWh)* | | | | 50000.0 |
| | Per Participant Avg Demand Savings (kW)* | | | | 0.068 |
| | Weighted Avg Measure Life* | | | | 7 |
| | Net To Gross Ratio | | | | 100% |

### Eligible Customers

Applicants must be both an active Vectren South electric customer on a qualifying commercial rate and an active natural gas General Service customer on Rate 120 or 125. The program will target customers with buildings between 50,000 square feet and 150,000 square feet.

### Marketing Plan

The BTU Program will be marketed primarily through in-network service provider outreach and direct personal communication from Vectren South staff and third-party contractors. The program implementer will provide service provider specific-marketing collateral to support these companies as they connect with customers.

The program will provide targeted marketing efforts to recruit quality participants. Additional program marketing may occur through direct mailing, trade associations, marketing campaigns and bonuses, local business organizations, and educational seminars.

**Barriers/Theory**

The program will typically target customers with buildings between 50,000 square feet and 150,000 square feet. Customers in this size range face unique barriers to energy efficiency. For example, although they are large enough to have a Building Automation System (BAS), they are usually too small to have a dedicated facility manager or staff with experience achieving operational efficiency. Also, most retrocommissioning service companies prefer larger projects and their services often are too expensive for small-to-midsized customers. We have specifically tailored the incentive structure and program design to eliminate these barriers. The BTU program is designed as a comprehensive customer solution that will identify, validate, quantify, and encourage the installation of both operational and capital measures eligible for incentive offerings.

**Implementation & Delivery Strategy**

The BTU program is designed to encourage high levels of implementation by customers seeking to optimize the operation of their existing HVAC system. Key elements of the program approach are:

- Service Provider Network: Service providers play a key role in program marketing and outreach. Their existing relationships with building owners and knowledge of customer facilities give them an easy starting point to begin program marketing efforts. For this reason, recruiting quality providers, training them on program processes, and making the BTU program profitable for them are key strategies that drive program participation. The program implementer will issue an annual RFQ to select those service providers with the best ability to provide high-quality and cost-effective services.

- Fully Funded Service Offering: The BTU program fully funds the investigation of opportunities by the program implementer and service providers. The program also provides a cash incentive on implemented improvements.

- Customer Commitment: BTU program participants are required to commit to a spending minimum to implement a group, or "bundle," of agreed-upon energy saving measures. This bundle of measures will have a collective estimated simple payback of 1.5 years or less based upon energy savings identified, which ensures that it benefits customers as well as the program.

- Technical Services: The program will provide the following technical services to successfully implement each BTU project:

Application Phase: Each application will be screened to verify that the customer's facility has enough energy savings potential for the BTU study. After being accepted into the program, the customer will sign the Customer Agreement to spend the minimum amount of money on a bundle of measures with a simple payback of 1.5 years or less. This agreement ensures that both the customer and Vectren South will achieve energy savings from the project.

Investigation and Implementation Phase: During the investigation and implementation phase, the program implementer and the customers' preferred in-network service provider will perform a BTU study to identify and install measures for the customer. They will generate a study report to summarize findings from the investigation and present the results to the customer. The customer will select the bundle of measures to install that meet the program minimum and payback requirements, and work with their service provider to install the selected measures.

Verification Phase: The program implementer revisits the customer's facility as needed. If any of the measures were incorrectly installed, the service provider works with the customer to fix it. The implementer and service provider calculate the final estimated energy savings from the BTU project and share those results with both the customer and Vectren South, thus ensuring that the most accurate energy savings estimate is reported.

**Initial Measures, Products and Services**

The BTU program will specifically target measures that provide no- and low-cost operational savings. Customized measures will be identified for each building, these could include:

- Scheduling air handling units
- Optimizing economizer and outdoor air control
- Reducing/resetting duct static pressure
- Resetting chilled water temperature

Most measures involve optimizing the building automation system (BAS) settings but the program will also investigate related capital measures, like controls, operations, processes, and HVAC.

**Incentive Strategy**

The BTU program fully funds the investigation of opportunities by the program implementer and service provider. The program also provides a cash incentive on implemented improvements.

**Program Delivery**

Vectren South will oversee the program and partner with Nexant to deliver the program.

**Integration with Vectren South Gas**

Vectren South will offer this integrated natural gas and electric EE program in its combined natural gas and electric service territory. Vectren South has allocated implementation costs based on the net benefits split between natural gas and electric.

**Evaluation, Measurement and Verification**

A third party evaluator will evaluate the program using standard EM&V protocols.

## S. Multi-Family Retrofit

### Program Description

The Multi-Family Retrofit Program provides value by directly installing EE products such as high efficiency lighting, water-saving measures, thermostats, and vending machine controls into multi-family common areas. The program helps multi-family facilities identify and install cost-effective energy-saving measures by providing an on-site energy assessment customized for their business.

**Table 29: Multi-Family Retrofit Budget & Energy Savings Targets**

| Market | Program | 2018 | 2019 | 2020 | Total Program |
|---|---|---|---|---|---|
| **Commercial & Industrial** | **Multi-Family Retrofit** | | | | |
| | Number of Projects | 4 | 4 | 4 | 12 |
| | Energy Savings kWh | 101,590 | 101,590 | 115,853 | 319,033 |
| | Peak Demand kW | 18.0 | 18.0 | 18.0 | 54.0 |
| | Total Program Budget $ | 34,880 | 35,074 | 35,266 | 105,220 |
| | Per Participant Avg Energy Savings (kWh)* | | | | 26586.1 |
| | Per Participant Avg Demand Savings (kW)* | | | | 4.500 |
| | Weighted Avg Measure Life* | | | | 15 |
| | Net To Gross Ratio | | | | 100% |

### Eligible Customers

Applicants must be both an active Vectren South electric customer on a qualifying commercial rate and an active natural gas General Service customer on Rate 120 or 125.

### Marketing Plan

The Multi-Family Retrofit Program will be marketed primarily through in-network trade ally outreach. The program implementer will provide trade ally-specific marketing collateral to support trade allies as they connect with customers.

The program will provide targeted marketing efforts as needed to increase participation, including direct customer outreach and enhanced incentive campaigns.

Additional program marketing may occur through direct mail, trade associations, local business organizations, marketing campaigns and bonuses, educational seminars, and direct personal communication from Vectren South staff and third-party contractors.

### Barriers/Theory

Multi-family landlords generally do not have the knowledge, time or money to invest in EE upgrades. This program assists these customers with direct installation and turn-key services to get measures installed at no or low out-of-pocket cost.

There is an implementation contractor in place providing suggested additions and changes to the program based on results and local economics.

**Implementation & Delivery Strategy**

Trade Ally Network: Trained trade ally energy advisors will provide energy assessments to customers. The program implementer will issue an annual RFQ to select the trade allies with the best ability to provide high-quality and cost-effective service to customers, and provide training to trade allies on the program process, with an emphasis on improving energy efficiency sales.

Energy Assessments: Trade allies will walk through the multi-family common areas and record site characteristics and energy efficiency opportunities at no cost to the customer. They will provide an energy assessment report that will detail customer-specific opportunities, costs, energy savings, incentives, and simple payback periods. The trade ally will then review the report with the customer, presenting the program benefits and process, while addressing any questions.

**Initial Measures, Products and Services**

The program will have two types of measures provided. The first are measures that will be installed at no cost to the customer. They will include but are not limited to the following:

- LEDs: 8-12W
- LEDs: MR16 track light
- LEDs: > 12 W flood light
- Wi-fi enabled thermostats
- Programmable thermostats
- Pre-rinse sprayers
- Faucet aerators

The second types of measures require the customer to pay a portion of the labor and materials. These measures include:

- Interior LED lighting (replacing incandescent, high bays and linear fluorescents)
- High-efficiency linear fluorescent lighting
- Linear fluorescent delamping
- Electronically commutated motors (ECM)
- Anti-sweat heater controls
- LED exit signs
- Exterior LED lighting

**Incentive Strategy**

In addition to the no-cost measures identified during the audit, the program will also pay a cash incentive for all recommended improvements identified through the assessment.

**Program Delivery**

Vectren South will oversee the program and will partner with Nexant to deliver the program.

**Integration with Vectren South Gas**

Vectren South will offer this integrated natural gas and electric EE program in its combined natural gas and electric service territory.  Vectren South has allocated implementation costs based on the net benefits split between natural gas and electric.

**Evaluation, Measurement and Verification**

On-site verification will be provided for the first three projects completed by each trade ally, in addition to the program standard 5% of all completed projects and all projects receiving incentives greater than $20,000. These verifications allow the program to validate energy savings, in addition to providing an opportunity to ensure the trade allies are providing high-quality customer services and the incentivized equipment satisfies program requirements. A third party evaluator will evaluate the program using standard EM&V protocols.

## 8. Program Administration

As in previous years, Vectren South will continue to serve as the program administrator for the 2018-2020 Plan. Vectren South will utilize third party program implementers to deliver specific programs or program components where specialty expertise is required. Contracting directly with specialty vendors avoids an unnecessary layer of management, oversight and expense that occurs when utilizing a third-party administration approach.

Program administration costs are allocated at the program level and include costs associated with program support and internal labor. Program support includes costs associated with outside consulting and annual license and maintenance fees for DSMore, Data Management, and Esource. Based upon the EE and DR programs proposed in the 2018 - 2020 Plan, Vectren South is proposing to maintain the staffing levels that were previously approved to support the portfolio. The major responsibilities associated with these FTEs are as follows:

- **Portfolio Management and Implementation -** Oversees the overall portfolio and staff necessary to support program administration. Serves as primary contact for regulatory and oversight of programs.
- **Reporting and Analysis -** Responsible for all aspects of program reporting including, budget analysis/reporting, scorecards and filings.
- **Outreach and Education -** Serves as contact to trade allies regarding program awareness. Also serves as point of contact for residential and commercial/industrial customers to assist with responding to program inquiries.
- **Research and Evaluation -** Works with the selected EM&V Administrator and facilitates measurement and verification efforts, assists with program reporting/tracking.

## 9. Support Services

Support services are considered indirect costs which support the entire portfolio and include: Contact Center, Online Audit, Outreach & Education, and Evaluation, Measurement and Verification (EM&V). These costs are budgeted at the portfolio level.

**Table 30: Portfolio Level Costs by Year**

| Indirect Portfolio Level Costs | 2018 | 2019 | 2020 |
|---|---|---|---|
| Contact Center | $63,000 | $63,000 | $63,000 |
| Online Audit | $36,444 | $39,806 | $42,911 |
| Outreach & Education | $410,000 | $410,000 | $410,000 |
| Evaluation | $427,992 | $447,304 | $444,314 |
| **Total Indirect Portfolio Level Costs** | **$937,436** | **$960,110** | **$960,225** |

### A. Contact Center

The Vectren Contact Center, called the Energy Efficiency Advisory Team, fields referrals from the company's general call center and serves as a resource for interested customers. A toll-free number is provided on all outreach and education materials. Direct calls are initial contacts from customers or market providers coming through the dedicated toll free number printed on all Vectren South's energy efficiency materials. Transferred calls are customers that have spoken with a Vectren Contact Center representative and have either asked or been offered a transfer to an Energy Efficiency Advisor who is trained to respond to energy efficiency questions or conduct the on-line energy audit.

These customer communication channels provide support mechanisms for Vectren South customers to receive the following services:

- Provide general guidance on energy saving behaviors and investments using customer specific billing data via the on-line tool (bill analyzer and energy audit).
- Respond to questions about the residential and general service programs.
- Facilitate the completion of and provide a hard copy report from the online audit tool for customers without internet access or who have difficulty understanding how to use the tool.
- Respond to inquiries about rebate fulfillment status.

## B. Online Audit

The Online Energy Audit tool is a customer engagement and messaging tool that uses actual billing data from a customer's energy bills to pinpoint ways to save energy in their home. Data collected drives account messaging through providing tips and rebates relevant to that customer's situation. Additionally, data collected from the online energy audit is used to validate neighbor comparison data, which illustrates how the customer's monthly energy use compares to their neighbors and is designed to inspire customers to try and save more energy than their efficient neighbors. This tool provides the online ability and means to communicate, cross promote, and educate customers about energy efficiency and Vectren's energy efficiency programs. The Online Energy Audit tool provides tools and messaging to educate customers and provide suggestions, tips, and advice on energy usage.

## C. Outreach & Education

Vectren South's Customer Outreach and Education program serves to raise awareness and drive customer participation as well as educate customers on how to manage their energy bills. The program includes the following goals as objectives:

- Build awareness;
- Educate consumers on how to conserve energy and reduce demand;
- Educate customers on how to manage their energy costs and reduce their bill;
- Communicate support of customer EE needs; and
- Drive participation in the EE and DR programs.

The marketing approach includes paid media as well as web-based tools to help analyze bills, energy audit tools, EE and DSM program education and information. Informational guides and sales promotion materials for specific programs are included in this budget.

This effort is the key to achieving greater energy savings by convincing the families and businesses making housing/facility, appliance and equipment investments to opt for greater EE. The first step in convincing the public and businesses to invest in EE is to raise their awareness.

It is essential that a broad public education and outreach campaign not only raise awareness of what consumers can do to save energy and control their energy bills, but also prime them for participation in the various EE and DR programs.

Vectren South will oversee outreach and education for the programs and work closely with implementation partners to provide consistent messaging across different program outreach and education efforts. Vectren South will utilize the services of communication and EE experts to deliver the EE and DR message.

The Outreach budget also includes funds for program development and staff training. Examples of these costs include memberships to EE related organizations, outreach for home/trade shows and travel and training related to EE associated staff development.

## D. Evaluation

Vectren South will work with an independent third party evaluator, selected by the VOB, to conduct an evaluation of DSM programs approved as part of its 2018-2020 Plan. The evaluation will include standard EM&V analyses, such as a process, impact, and/or market effects evaluation of Vectren South's portfolio of DSM programs. Gas impacts will be calculated for all of Vectren South's integrated gas programs. EM&V costs are based on 5% of the budget and allocated at the portfolio level.

## 10. Other Costs

Other costs being requested in the 2018-2020 filed plan include a Market Potential Study and funding for Emerging Markets.

**Table 31: Other Costs by Year**

| Other Costs | 2018 | 2019 | 2020 |
|---|---|---|---|
| Emerging Markets | $200,000 | $200,000 | $200,000 |
| Market Potential Study | $300,000 | $0 | $0 |
| **Total** | **$500,000** | **$200,000** | **$200,000** |

### A. Emerging Markets

The Emerging Markets funding allows Vectren's DSM portfolio to offer leading-edge program designs for next-generation technologies, services, and engagement strategies to growing markets in the Vectren territory. The budget will be $200,000 each year for 2018-2020 and will not be used to support existing programs, but rather support new program development or new measures within an existing program.

Incentives promoted through this program may range from innovative rebate offerings to engineering and trade ally assistance to demand-control services that encourage early adoption of new, efficient technologies in high-impact market sectors. Depending on the development of certain technologies and growth areas in the service territory, a wide variety of projects and services are eligible.

To offset the risks of oversaturation of common prescriptive measures and redefined prescriptive baselines, this program will bring to market next generation technologies and energy-saving strategies that have significant savings and cost-effectiveness potential. As new technologies develop towards lower costs and higher efficiency, their market penetration and energy-savings potential will increase. This program will allow Vectren to be on the forefront of emerging technologies to understand the market disruption a new product may cause, test strategies for capturing their energy-saving opportunities, and plan for future program savings growth. This offering will supplement the other DSM programs that do not easily fit into other program offerings. Additionally, growing segments of Vectren South electric customers may require tailored offerings to accommodate their needs in order to participate.

Because this program will focus on innovative new approaches and leading the DSM market, the exact list of measures cannot be set at this time. However, potential measures and services include: new technologies, such as Advanced Lighting Controls; new strategies for achieving significant energy savings, such as midstream incentives, contractor bids to provide energy efficiency projects, and targeting high-impact market sectors; and integrated DSM (iDSM) approaches, such as demand response, combined energy efficiency and demand response measures, and load shifting.

Emerging technologies and measures will be reviewed and may be offered using this funding as long as they do not fall into a current program offering. Innovative engagement and incentivizing approaches may also be used as a tool to provide reduced costs to new systems, equipment and/or services to help reduce peak demand and electric usage. This program also allows Vectren to take steps toward an integrated Demand Side Management approach to address both energy efficiency and demand response together.

### B. Market Potential Study

Vectren South is requesting $300,000 to complete a full blown Market Potential Study (MPS) for the years of 2020 and beyond, which is scheduled for 2018. Vectren will issue a Request for Quote to select a consultant to perform this work.

## 11. Conclusion

Vectren South has developed a 2018-2020 Electric Energy Efficiency Plan that is aligned with the 2016 Integrated Resource Plan and is reasonably achievable and cost effective. The cost effectiveness analysis was performed for 2018-2020 using the DSMore model – a nationally recognized economic analysis tool that is specifically designed to evaluate the cost effectiveness of implementing energy efficiency and demand response programs.

Program costs were determined by referencing 2016 program delivery costs, based on prior contracts and performance in the field and consultation with the program vendors that will deliver the DSM Plan. Energy and demand savings were primarily determined by using recent EM&V results and the IN TRM version 2.2. For measures that were not addressed in the IN TRM or EM&V, Vectren South used Technical Resource Manual resources from nearby states or vendor input. Vectren South utilized the avoided costs from Figure 10.13 in the 2016 IRP.

Based on this information, Vectren South requests IURC approval of this 2018-2020 DSM Plan as well as the costs associated with Emerging Markets and the Market Potential study for 2020 and beyond.

## 12. Appendix A: Cost Effectiveness Tests Benefits & Costs Summary

| Test | Benefits | Costs |
|---|---|---|
| Participant Cost Test | • Incentive payments<br>• Annual bill savings<br>• Applicable tax credits | • Incremental technology/equipment costs<br>• Incremental installation costs |
| Utility Cost Test (Program Administrator Cost Test) | • Avoided energy costs<br>• Avoided capacity costs | • All program costs (startup, marketing, labor, evaluation, promotion, etc.)<br>• Utility/Administrator incentive costs |
| Rate Impact Measure Test | • Avoided energy costs<br>• Avoided capacity costs | • All program costs (startup, marketing, labor, evaluation, promotion, etc.)<br>• Utility/Administrator incentive costs<br>• Lost revenue due to reduced energy bills |
| Total Resource Cost Test | • Avoided energy costs<br>• Avoided capacity costs<br>• Applicable participant tax credits | • All program costs (not including incentive costs)<br>• Incremental technology/equipment costs (whether paid by the participant or the utility) |

# 13. Appendix B: Program Measure Detail

| Program | Measure | Measure Life | Average Savings per Unit (kWh | Demand per Unit (KW) | 2018 Participation | 2019 Participation | 2020 Participation | Avg Incentive Paid Per Unit | Average Incremental Cost | 2018 kWh Savings | 2019 kWh Savings | 2020 kWh Savings |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Residential Programs** | | | | | | | | | | | | |
| Residential Lighting | Standard Units | | 27.75 | 0.00 | 146,465 | 164,424 | 80,000 | | $ 3 | 4,064,403 | 4,562,766 | 2,220,000 |
| Residential Lighting | Specialty Units | | 44.00 | 0.01 | 62,698 | 67,962 | 69,716 | | $ 4 | 2,758,712 | 2,990,328 | 3,067,504 |
| Residential Lighting | LED Fixtures | | 57.48 | 0.01 | 13,700 | 13,700 | 13,700 | | $ 20 | 787,501 | 787,501 | 787,501 |
| | | | | | | | | | | | | |
| **Total Residential Lighting** | | | | | **222,863** | **246,086** | **163,416** | | | **7,610,617** | **8,340,595** | **6,075,005** |
| | | | | | | | | | | | | |
| Residential Prescriptive | Air Source Heat Pump 16 SEER | 18 | 1,154.92 | 0.30 | 52 | 52 | 52 | $ 300 | $ 870 | 60,056 | 60,056 | 60,056 |
| Residential Prescriptive | Air Source Heat Pump 18 SEER | 18 | 1,625.77 | 0.35 | 9 | 9 | 9 | $ 500 | $ 870 | 14,632 | 14,632 | 14,632 |
| Residential Prescriptive | Attic Insulation - Elec Heated | 25 | 3,382.75 | 0.30 | 13 | 13 | 13 | $ 450 | $ 500 | 43,976 | 43,976 | 43,976 |
| Residential Prescriptive | Attic Insulation - Gas Heated South (Electric) | 25 | 339.71 | 0.30 | 36 | 36 | 36 | $ 450 | $ 500 | 12,229 | 12,229 | 12,229 |
| Residential Prescriptive | Central Air Conditioner 16 SEER | 18 | 294.63 | 0.35 | 644 | 644 | 644 | $ 200 | $ 400 | 189,745 | 189,745 | 189,745 |
| Residential Prescriptive | Central Air Conditioner 18 SEER | 18 | 573.88 | 0.33 | 76 | 76 | 76 | $ 400 | $ 800 | 43,615 | 43,615 | 43,615 |
| Residential Prescriptive | Dual Fuel Air Source Heat Pump 16 SEER | 18 | 767.06 | 0.34 | 0 | 0 | 0 | $ 300 | $ 1,000 | 0 | 0 | 0 |
| Residential Prescriptive | Duct Sealing Electric Heat Pump - South | 20 | 829.21 | 0.44 | 7 | 7 | 7 | $ 350 | $ 400 | 5,804 | 5,804 | 5,804 |
| Residential Prescriptive | Duct Sealing Electric Resistive Furnace - South | 20 | 1,351.93 | 0.40 | 0 | 0 | 0 | $ 350 | $ 400 | 0 | 0 | 0 |
| Residential Prescriptive | Duct Sealing Gas Heating with A/C - South (Electric) | 20 | 228.61 | 0.40 | 77 | 77 | 77 | $ 175 | $ 200 | 17,603 | 17,603 | 17,603 |
| Residential Prescriptive | Ductless Heat Pump 17 SEER 9.5 HSPF | 18 | 3,847.40 | 0.29 | 2 | 2 | 2 | $ 500 | $ 1,667 | 7,695 | 7,695 | 7,695 |
| Residential Prescriptive | Ductless Heat Pump 19 SEER 9.5 HSPF | 18 | 3,919.89 | 0.40 | 7 | 7 | 7 | $ 500 | $ 2,333 | 27,439 | 27,439 | 27,439 |
| Residential Prescriptive | Ductless Heat Pump 21 SEER 10.0 HSPF | 18 | 3,924.75 | 0.29 | 2 | 2 | 2 | $ 500 | $ 2,833 | 7,850 | 7,850 | 7,850 |
| Residential Prescriptive | Ductless Heat Pump 23 SEER 10.0 HSPF | 18 | 4,032.45 | 0.31 | 11 | 11 | 11 | $ 500 | $ 3,333 | 44,357 | 44,357 | 44,357 |
| Residential Prescriptive | Duel Fuel Air Source Heat Pump 18 SEER | 18 | 1,498.67 | 0.13 | 0 | 0 | 0 | $ 500 | $ 1,667 | 0 | 0 | 0 |
| Residential Prescriptive | ECM HVAC Motor | 20 | 384.72 | 0.10 | 1,107 | 1,107 | 1,107 | $ 100 | $ 97 | 425,884 | 425,884 | 425,884 |
| Residential Prescriptive | Heat Pump Water Heater | 10 | 2,291.38 | 0.31 | 2 | 2 | 2 | $ 300 | $ 1,000 | 4,583 | 4,583 | 4,583 |
| Residential Prescriptive | Nest On-Line Store (Electric) | 15 | 466.69 | 0.90 | 300 | 350 | 400 | $ 75 | $ 39 | 140,007 | 163,342 | 186,676 |
| Residential Prescriptive | Nest On-Line Store (Dual) | 15 | 377.71 | 0.90 | 900 | 1,000 | 1,100 | $ 15 | $ 175 | 339,939 | 377,710 | 415,481 |
| Residential Prescriptive | Pool Heater | 10 | 666.87 | 0.00 | 1 | 1 | 1 | $ 1,000 | $ 3,333 | 667 | 667 | 667 |
| Residential Prescriptive | Wifi Thermostat - South (Electric) | 15 | 405.09 | 0.00 | 264 | 264 | 264 | $ 10 | $ 21 | 106,944 | 106,944 | 106,944 |
| Residential Prescriptive | Smart Programmable Thermostat - South (Electric) | 15 | 412.19 | 0.00 | 428 | 428 | 428 | $ 15 | $ 39 | 176,417 | 176,417 | 176,417 |
| Residential Prescriptive | Variable Speed Pool Pump | 15 | 1,173.00 | 1.72 | 18 | 18 | 18 | $ 300 | $ 750 | 21,114 | 21,114 | 21,114 |
| Residential Prescriptive | Wall Insulation - Elec Heated | 25 | 1,158.34 | 0.04 | 5 | 5 | 5 | $ 450 | $ 500 | 5,792 | 5,792 | 5,792 |
| Residential Prescriptive | Wall Insulation - Gas Heated - South (Electric) | 25 | 60.29 | 0.04 | 32 | 32 | 32 | $ 450 | $ 500 | 1,929 | 1,929 | 1,929 |
| Residential Prescriptive | AC Tune Up | 5 | 75.64 | 0.12 | 0 | 644 | 644 | $ 50 | $ 64 | 0 | 48,710 | 48,710 |
| Residential Prescriptive | ASHP Tune Up | 5 | 284.99 | 0.12 | 0 | 22 | 22 | $ 50 | $ 64 | 0 | 6,270 | 6,270 |
| Residential Prescriptive | Air Purifier | 9 | 492.70 | 0.06 | 100 | 100 | 100 | $ 25 | $ 70 | 49,270 | 49,270 | 49,270 |
| Residential Prescriptive | Furnace Tune Up | 2 | 35.51 | 0.00 | 0 | 1,536 | 1,536 | $ - | $ - | 0 | 54,543 | 54,543 |
| | | | | | | | | | | | | |
| **Total Residential Prescriptive** | | | | | **4,093** | **6,445** | **6,595** | | | **1,747,547** | **1,918,174** | **1,979,280** |
| | | | | | | | | | | | | |
| Residential New Construction | Gold Star: HERS Index Score ≤ 65 - EH | 25 | 954.15 | 0.64 | 0 | 0 | 0 | $ 700 | $ 2,504 | 0 | 0 | 0 |
| Residential New Construction | Gold Star: HERS Index Score ≤ 65 - Gas Heated | 25 | 954.15 | 0.64 | 22 | 22 | 22 | $ 175 | $ 1,573 | 20,991 | 20,991 | 20,991 |
| Residential New Construction | Platinum Star: HERS Index Score ≤ 60 - EH | 25 | 1,419.20 | 0.89 | 1 | 1 | 1 | $ 800 | $ 3,079 | 1,419 | 1,419 | 1,419 |
| Residential New Construction | Platinum Star: HERS Index Score ≤ 60-Gas Heated | 25 | 1,419.20 | 0.89 | 116 | 116 | 116 | $ 200 | $ 1,778 | 164,627 | 164,627 | 164,627 |
| | | | | | | | | | | | | |
| **Total Residential New Construction** | | | | | **139** | **139** | **139** | | | **187,038** | **187,038** | **187,038** |

| Program | Measure | Measure Life | Average Savings per Unit (kWh | Demand per Unit (KW) | 2018 Participation | 2019 Participation | 2020 Participation | Avg Incentive Paid Per Unit | Average Incremental Cost | 2018 kWh Savings | 2019 kWh Savings | 2020 kWh Savings |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| HEA & Weatherization | Water Heater Temperature Setback - Elec DHW | 4 | 86.40 | 0.01 | 15 | 15 | 15 | | $ 7 | 1,296 | 1,296 | 1,296 |
| HEA & Weatherization | Wifi Thermostat - South (Electric) | 15 | 405.09 | 0.00 | 399 | 399 | 399 | | $ 21 | 161,631 | 161,631 | 161,631 |
| HEA & Weatherization | Exterior LED Lamp | 15 | 91.98 | 0.00 | 1,210 | 1,210 | 1,210 | | $ 8 | 111,296 | 111,296 | 111,296 |
| HEA & Weatherization | Duct Sealing Gas Heating with A/C | 15 | 228.61 | 0.40 | 64 | 64 | 64 | | $ 200 | 14,631 | 14,631 | 14,631 |
| HEA & Weatherization | Duct Sealing Electric Heat Pump | 15 | 829.21 | 0.44 | 8 | 8 | 8 | | $ 400 | 6,634 | 6,634 | 6,634 |
| HEA & Weatherization | Duct Sealing Electric Resistive Furnace | 15 | 1,351.93 | 0.40 | 4 | 4 | 4 | | $ 400 | 5,408 | 5,408 | 5,408 |
| HEA & Weatherization | Air Sealing Gas Furnace w/ CAC | 15 | 140.27 | 0.39 | 258 | 258 | 258 | | $ 100 | 36,190 | 36,190 | 36,190 |
| HEA & Weatherization | Air Sealing Heat Pump | 15 | 1,501.47 | 0.28 | 30 | 30 | 30 | | $ 200 | 45,044 | 45,044 | 45,044 |
| HEA & Weatherization | Air Sealing Electric Furnace w/ CAC | 15 | 4,687.85 | 0.92 | 15 | 15 | 15 | | $ 200 | 70,318 | 70,318 | 70,318 |
| HEA & Weatherization | AC Tune Up | 5 | 75.64 | 0.12 | 0 | 0 | 0 | | $ 175 | 0 | 0 | 0 |
| HEA & Weatherization | ASHP Tune Up | 5 | 284.99 | 0.12 | 0 | 0 | 0 | | $ 350 | 0 | 0 | 0 |
| HEA & Weatherization | Furnace Tune Up | 2 | 35.51 | 0.00 | 0 | 0 | 0 | | $ - | 0 | 0 | 0 |
| | | | | | | | | | | | | |
| **Total HEA & Weatherization** | | | | | **15,158** | **15,158** | **15,158** | | | **863,991** | **863,991** | **863,991** |
| | Number of Homes | | | | 1,210 | 1,210 | 1,210 | | | | | |
| | | | | | | | | | | | | |
| Income Qualified Weatherization | Water Heater Temperature Setback - Gas DHW | 4 | -34.20 | 0.00 | 0 | 0 | 0 | | $ 7 | 0 | 0 | 0 |
| Income Qualified Weatherization | Attic Insulation - Electric Resistance Heated | 25 | 828.28 | 0.03 | 24 | 25 | 26 | | $ 1,413 | 19,879 | 20,707 | 21,535 |
| Income Qualified Weatherization | Attic Insulation - Gas Heated (Electric) | 25 | 138.64 | 0.14 | 238 | 250 | 263 | | $ 706 | 32,997 | 34,661 | 36,463 |
| Income Qualified Weatherization | Audit Recommendations - dual (Electric) | 1 | 67.87 | 0.01 | 475 | 500 | 525 | | $ 26 | 32,239 | 33,936 | 35,633 |
| Income Qualified Weatherization | Audit Recommendations - Electric Only | 1 | 67.87 | 0.01 | 0 | 0 | 0 | | $ 106 | 0 | 0 | 0 |
| Income Qualified Weatherization | Bathroom Aerator 1.0 gpm - Elec DHW | 10 | 12.03 | 0.00 | 145 | 153 | 160 | | $ 1 | 1,744 | 1,841 | 1,925 |
| Income Qualified Weatherization | 9W LED | 15 | 18.66 | 0.00 | 2,170 | 2,284 | 2,399 | | $ 3 | 40,501 | 42,628 | 44,775 |
| Income Qualified Weatherization | LED 5W Globe | 15 | 10.37 | 0.00 | 93 | 98 | 102 | | $ 9 | 964 | 1,016 | 1,058 |
| Income Qualified Weatherization | LED R30 Dimmable | 15 | 52.98 | 0.01 | 365 | 385 | 404 | | $ 12 | 19,337 | 20,396 | 21,403 |
| Income Qualified Weatherization | Exterior LED Lamps | 15 | 91.98 | 0.00 | 285 | 300 | 315 | | $ 7 | 26,214 | 27,594 | 28,974 |
| Income Qualified Weatherization | Filter Whistle | 15 | 54.72 | 0.00 | 190 | 200 | 210 | | $ 2 | 10,397 | 10,944 | 11,491 |
| Income Qualified Weatherization | Kitchen Flip Aerator 1.5 gpm - Elec DHW | 10 | 120.03 | 0.01 | 42 | 44 | 47 | | $ 1 | 5,041 | 5,281 | 5,641 |
| Income Qualified Weatherization | LED Nightlight | 16 | 13.64 | 0.00 | 887 | 933 | 980 | | $ 3 | 12,095 | 12,723 | 13,364 |
| Income Qualified Weatherization | Low Flow Showerhead 1.5 gpm - Elec DHW | 5 | 299.86 | 0.01 | 89 | 93 | 98 | | $ 3 | 26,688 | 27,887 | 29,386 |
| Income Qualified Weatherization | Pipe Wrap - Elec DHW (per home) | 15 | 148.16 | 0.02 | 42 | 44 | 47 | | $ 2 | 6,223 | 6,519 | 6,964 |
| Income Qualified Weatherization | Wifi Thermostat - South (Electric) | 15 | 405.19 | 0.00 | 262 | 276 | 290 | | $ 25 | 106,160 | 111,832 | 117,505 |
| Income Qualified Weatherization | Refrigerator Replacement | 8 | 441.56 | 0.07 | 63 | 67 | 70 | | $ 580 | 27,818 | 29,584 | 30,909 |
| Income Qualified Weatherization | Smart Power Strips | 4 | 23.00 | 0.00 | 570 | 600 | 630 | | $ 35 | 13,110 | 13,800 | 14,490 |
| Income Qualified Weatherization | Smart Thermostat (Electric) | 15 | 412.19 | 0.00 | 47 | 49 | 52 | | $ 125 | 19,373 | 20,197 | 21,434 |
| Income Qualified Weatherization | Water Heater Temperature Setback - Elec DHW | 4 | 86.40 | 0.01 | 135 | 142 | 150 | | $ 7 | 11,664 | 12,269 | 12,960 |
| Income Qualified Weatherization | Duct Sealing Gas Heating with A/C | 15 | 228.61 | 0.40 | 303 | 319 | 335 | | $ 225 | 69,270 | 72,928 | 76,585 |
| Income Qualified Weatherization | Duct Sealing Electric Heat Pump | 15 | 829.21 | 0.44 | 36 | 38 | 39 | | $ 450 | 29,852 | 31,510 | 32,339 |
| Income Qualified Weatherization | Duct Sealing Electric Resistive Furnace | 15 | 1,351.93 | 0.40 | 18 | 19 | 20 | | $ 450 | 24,335 | 25,687 | 27,039 |
| Income Qualified Weatherization | Air Sealing Gas Furnace w/ CAC | 15 | 140.27 | 0.39 | 303 | 319 | 335 | | $ 100 | 42,502 | 44,746 | 46,990 |
| Income Qualified Weatherization | Air Sealing Heat Pump | 15 | 1,501.47 | 0.28 | 36 | 38 | 39 | | $ 200 | 54,053 | 57,056 | 58,557 |
| Income Qualified Weatherization | Air Sealing Electric Furnace w/ CAC | 15 | 4,687.85 | 0.92 | 18 | 19 | 20 | | $ 200 | 84,381 | 89,069 | 93,757 |
| Income Qualified Weatherization | AC Tune Up | 5 | 75.64 | 0.12 | 0 | 0 | 0 | | $ 200 | 0 | 0 | 0 |
| Income Qualified Weatherization | ASHP Tune Up | 5 | 284.99 | 0.12 | 0 | 0 | 0 | | $ 400 | 0 | 0 | 0 |
| Income Qualified Weatherization | 9W LED | 15 | 18.66 | 0.00 | 766 | 919 | 1,072 | | $ 3 | 14,297 | 17,152 | 20,008 |
| Income Qualified Weatherization | LED 5W Globe | 15 | 10.37 | 0.00 | 45 | 54 | 64 | | $ 9 | 467 | 560 | 664 |
| Income Qualified Weatherization | LED R30 Dimmable | 15 | 52.98 | 0.01 | 179 | 215 | 251 | | $ 12 | 9,483 | 11,390 | 13,297 |
| Income Qualified Weatherization | Wifi Thermostat - South (Electric) | 15 | 405.19 | 0.00 | 29 | 35 | 40 | | $ 25 | 11,751 | 14,182 | 16,208 |
| Income Qualified Weatherization | Site Visit and DI - dual (Electric) | 1 | 0.00 | 0.00 | 100 | 120 | 140 | | $ 23 | 0 | 0 | 0 |
| Income Qualified Weatherization | 9W LED | 15 | 18.66 | 0.00 | 1,250 | 1,500 | 1,750 | | $ 3 | 23,330 | 27,996 | 32,662 |
| Income Qualified Weatherization | LED 5W Globe | 15 | 10.37 | 0.00 | 114 | 136 | 159 | | $ 9 | 1,182 | 1,410 | 1,649 |
| Income Qualified Weatherization | LED R30 Dimmable | 15 | 52.98 | 0.01 | 250 | 300 | 350 | | $ 12 | 13,244 | 15,893 | 18,542 |
| Income Qualified Weatherization | Bathroom Aerator 1.0 gpm - Electric DHW | 10 | 12.03 | 0.00 | 23 | 28 | 32 | | $ 1 | 277 | 337 | 385 |
| Income Qualified Weatherization | Kitchen Flip Aerator 1.5 gpm - Electric DHW | 10 | 120.03 | 0.01 | 11 | 13 | 15 | | $ 1 | 1,320 | 1,560 | 1,800 |
| Income Qualified Weatherization | Low Flow Showerhead 1.5 gpm - Electric DHW | 5 | 299.86 | 0.01 | 29 | 35 | 40 | | $ 3 | 8,696 | 10,495 | 11,994 |
| Income Qualified Weatherization | Wifi Thermostat - South (Electric) | 15 | 405.19 | 0.00 | 72 | 87 | 101 | | $ 25 | 29,174 | 35,252 | 40,924 |
| Income Qualified Weatherization | Duct Sealing Gas Heating with A/C | 15 | 114.31 | 0.20 | 213 | 255 | 298 | | $ 225 | 24,347 | 29,148 | 34,063 |
| Income Qualified Weatherization | Duct Sealing Electric Heat Pump | 15 | 414.61 | 0.22 | 13 | 15 | 18 | | $ 450 | 5,390 | 6,219 | 7,463 |
| Income Qualified Weatherization | Duct Sealing Electric Resistive Furnace | 15 | 675.96 | 0.20 | 25 | 30 | 35 | | $ 450 | 16,899 | 20,279 | 23,659 |
| Income Qualified Weatherization | Air Sealing Gas Furnace w/ CAC | 15 | 70.14 | 0.19 | 213 | 255 | 298 | | $ 100 | 14,939 | 17,884 | 20,900 |

| Program | Measure | Measure Life | Average Savings per Unit (kWh) | Demand per Unit (KW) | 2018 Participation | 2019 Participation | 2020 Participation | Avg Incentive Paid Per Unit | Average Incremental Cost | 2018 kWh Savings | 2019 kWh Savings | 2020 kWh Savings |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Income Qualified Weatherization | Air Sealing Heat Pump | 15 | 1,501.47 | 0.28 | 36 | 38 | 39 | | $ 200 | 54,053 | 57,056 | 58,557 |
| Income Qualified Weatherization | Air Sealing Electric Furnace w/ CAC | 15 | 4,687.85 | 0.92 | 18 | 19 | 20 | | $ 200 | 84,381 | 89,069 | 93,757 |
| Income Qualified Weatherization | AC Tune Up | 5 | 75.64 | 0.12 | 0 | 0 | 0 | | $ 200 | 0 | 0 | 0 |
| Income Qualified Weatherization | ASHP Tune Up | 5 | 284.99 | 0.12 | 0 | 0 | 0 | | $ 400 | 0 | 0 | 0 |
| Income Qualified Weatherization | 9W LED | 15 | 18.66 | 0.00 | 766 | 919 | 1,072 | | $ 3 | 14,297 | 17,152 | 20,008 |
| Income Qualified Weatherization | LED 5W Globe | 15 | 10.37 | 0.00 | 45 | 54 | 64 | | $ 9 | 467 | 560 | 664 |
| Income Qualified Weatherization | LED R30 Dimmable | 15 | 52.98 | 0.01 | 179 | 215 | 251 | | $ 12 | 9,483 | 11,390 | 13,297 |
| Income Qualified Weatherization | Wifi Thermostat - South (Electric) | 15 | 405.19 | 0.00 | 29 | 35 | 40 | | $ 25 | 11,751 | 14,182 | 16,208 |
| Income Qualified Weatherization | Site Visit and DI - dual (Electric) | 1 | 0.00 | 0.00 | 100 | 120 | 140 | | $ 23 | 0 | 0 | 0 |
| Income Qualified Weatherization | 9W LED | 15 | 18.66 | 0.00 | 1,250 | 1,500 | 1,750 | | $ 3 | 23,330 | 27,996 | 32,662 |
| Income Qualified Weatherization | LED 5W Globe | 15 | 10.37 | 0.00 | 114 | 136 | 159 | | $ 9 | 1,182 | 1,410 | 1,649 |
| Income Qualified Weatherization | LED R30 Dimmable | 15 | 52.98 | 0.01 | 250 | 300 | 350 | | $ 12 | 13,244 | 15,893 | 18,542 |
| Income Qualified Weatherization | Bathroom Aerator 1.0 gpm - Electric DHW | 10 | 12.03 | 0.00 | 23 | 28 | 32 | | $ 1 | 277 | 337 | 385 |
| Income Qualified Weatherization | Kitchen Flip Aerator 1.5 gpm - Electric DHW | 10 | 120.03 | 0.01 | 11 | 13 | 15 | | $ 1 | 1,320 | 1,560 | 1,800 |
| Income Qualified Weatherization | Low Flow Showerhead 1.5 gpm - Electric DHW | 5 | 299.86 | 0.01 | 29 | 35 | 40 | | $ 3 | 8,696 | 10,495 | 11,994 |
| Income Qualified Weatherization | Wifi Thermostat - South (Electric) | 15 | 405.19 | 0.00 | 72 | 87 | 101 | | $ 25 | 29,174 | 35,252 | 40,924 |
| Income Qualified Weatherization | Duct Sealing Gas Heating with A/C | 15 | 114.31 | 0.20 | 213 | 255 | 298 | | $ 225 | 24,347 | 29,148 | 34,063 |
| Income Qualified Weatherization | Duct Sealing Electric Heat Pump | 15 | 414.61 | 0.22 | 13 | 15 | 18 | | $ 450 | 5,390 | 6,219 | 7,463 |
| Income Qualified Weatherization | Duct Sealing Electric Resistive Furnace | 15 | 675.96 | 0.20 | 25 | 30 | 35 | | $ 450 | 16,899 | 20,279 | 23,659 |
| Income Qualified Weatherization | Air Sealing Gas Furnace w/ CAC | 15 | 70.14 | 0.19 | 213 | 255 | 298 | | $ 100 | 14,939 | 17,884 | 20,900 |
| Income Qualified Weatherization | Air Sealing Heat Pump | 15 | 750.74 | 0.14 | 13 | 15 | 18 | | $ 200 | 9,760 | 11,261 | 13,513 |
| Income Qualified Weatherization | Air Sealing Electric Furnace w/ CAC | 15 | 2,343.93 | 0.46 | 25 | 30 | 35 | | $ 200 | 58,598 | 70,318 | 82,037 |
| Income Qualified Weatherization | Mobile Home Audit (Dual) | 1 | 0.00 | 0.00 | 213 | 255 | 298 | | $ 26 | 0 | 0 | 0 |
| Income Qualified Weatherization | Mobile Home Audit (Electric) | 1 | 0.00 | 0.00 | 38 | 45 | 53 | | $ 106 | 0 | 0 | 0 |
| | | | | | | | | | | | | |
| **Total Income Qualified Weatherization** | | | | | **10,457** | **11,537** | **12,623** | | | **959,988** | **1,046,148** | **1,130,945** |
| | Number of Homes | | | | 475 | 500 | 525 | | | | | |
| | | | | | | | | | | | | |
| **Foodbank** | **9W LED** | **15** | **27.75** | **0.00** | **50,496** | **50,496** | **0** | | **$ 3** | **1,401,264** | **1,401,264** | **0** |
| | | | | | | | | | | | | |
| Energy Efficient Schools | 15-watt LED x1 | 15 | 39.33 | | 2,400 | 2,500 | | | | 94,403 | 98,336 | 0 |
| Energy Efficient Schools | 11-watt LED | 15 | 43.69 | | 2,400 | 2,500 | | | | 104,863 | 109,232 | 0 |
| Energy Efficient Schools | 11-watt LED | 15 | 43.69 | | 2,400 | 2,500 | | | | 104,863 | 109,232 | 0 |
| Energy Efficient Schools | Showerheads | 5 | 122.64 | | 2,400 | 2,500 | 2,600 | | | 294,330 | 306,594 | 318,864 |
| Energy Efficient Schools | Kitchen aerators | 10 | 55.83 | | 2,400 | 2,500 | 2,600 | | | 133,987 | 139,569 | 145,152 |
| Energy Efficient Schools | Bathroom aerators | 10 | 20.04 | | 2,400 | 2,500 | 2,600 | | | 48,094 | 50,098 | 52,102 |
| Energy Efficient Schools | Bathroom aerators | 10 | 20.04 | | 2,400 | 2,500 | 2,600 | | | 48,094 | 50,098 | 52,102 |
| Energy Efficient Schools | Filter Whistle | 5 | 22.60 | | 2,400 | 2,500 | 2,600 | | | 54,240 | 56,500 | 58,760 |
| Energy Efficient Schools | LED Night Light | 16 | 7.01 | | 2,400 | 2,500 | 2,600 | | | 16,833 | 17,534 | 18,236 |
| | | | | | | | | | | | | |
| **Total Energy Efficient Schools** | | | | | **2,400** | **2,500** | **2,600** | | | **899,706** | **937,194** | **645,216** |
| | | | | | | | | | | | | |
| **Residential Behavorial Savings** | | **1** | **157.08** | | **41,348** | **38,203** | **35,298** | | | **6,470,000** | **5,970,000** | **5,600,000** |
| | | | | | | | | | | | | |
| | | | | | | | | | | | | |
| Appliance Recycling | Refrigerator Recycling | 8 | 1,000.09 | 0.14 | 760 | 744 | 736 | $ 50 | | 760,068 | 744,067 | 736,066 |
| Appliance Recycling | Freezer Recycling | 8 | 808.96 | 0.10 | 190 | 186 | 184 | $ 50 | | 153,702 | 150,467 | 148,849 |
| | | | | | | | | | | | | |
| **Total Appliance Recycling** | | | | | **950** | **930** | **920** | | | **913,771** | **894,534** | **884,915** |
| | | | | | | | | | | | | |
| Smart Thermostat Program (Incentive) | | 15 | | | 2,000 | 2,000 | 2,000 | $ 20 | | | | |
| | | | | | | | | | | | | Savings |
| **Conservation Voltage Reduction - Residential** | | **15** | | | | | | | | | | **1,461,047** |
| | | | | | | | | | | | | |
| **Smart DLC - Wifi DR/DLC Changeout** | | **15** | **466.69** | **0.90** | **1,000** | **1,000** | | **$ 20** | | **466,690** | **466,690** | **466,690** |
| | | | | | | | | | | | | |
| **BYOT (Bring Your Own Thermostat)** | | **15** | | **0.90** | **300** | **300** | **300** | **$ 20** | | | | |
| | | | | | | | | | | | | |
| **Sub-Total Residential** | | | | | | | | | | **21,520,612** | **22,025,627** | **19,294,126** |

| Program | Measure | Measure Life | Average Savings per Unit (kWh | Demand per Unit (KW) | 2018 Participation | 2019 Participation | 2020 Participation | Avg Incentive Paid Per Unit | Average Incremental Cost | 2018 kWh Savings | 2019 kWh Savings | 2020 kWh Savings |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| C&I Prescriptive | Lighting Power Density Reduction | 15 | 0.9 | 0.0002 | 4 | 3 | 4 | 15754.5 | - | 4 | 3 | 4 |
| C&I Prescriptive | LED Decoratives | 10 | 147.0 | 0.0460 | 2231 | 1892 | 2170 | 10 | 20.62 | 327,957 | 278,124 | 318,990 |
| C&I Prescriptive | T12/T8 4 Lamp 4' To LED Panel | 15 | 288.0 | 0.0755 | 1069 | 907 | 1040 | 40 | 91.64 | 307,872 | 261,216 | 299,520 |
| C&I Prescriptive | T12/T8 3 Lamp 4' To LED Panel | 15 | 261.0 | 0.0485 | 578 | 491 | 563 | 40 | 81.80 | 150,858 | 128,151 | 146,943 |
| C&I Prescriptive | T12/T8 2 Lamp 4' To LED Panel | 15 | 226.0 | 0.0350 | 513 | 435 | 499 | 40 | 37.41 | 115,938 | 98,310 | 112,774 |
| C&I Prescriptive | T12/T8 Lamp 4' to LED Tube (includes U-tube) | 15 | 105.0 | 0.0174 | 398 | 338 | 388 | 5 | 22.85 | 41,790 | 35,490 | 40,740 |
| C&I Prescriptive | Fixture Mounted Occupancy Sensor | 8 | 150.1 | 0.0182 | 360 | 305 | 350 | 15 | 125.00 | 54,035 | 45,780 | 52,534 |
| C&I Prescriptive | High Bay HID to LED 175W+ | 16 | 780.2 | 0.2351 | 293 | 249 | 285 | 90 | 340.61 | 228,610 | 194,279 | 222,368 |
| C&I Prescriptive | Bonus Incentive - Electric | 0 | - | - | 259 | 750 | 0 | 50 | - | - | - | - |
| C&I Prescriptive | 1000W HID to Exterior LED | 15 | 3,143.7 | - | 250 | 212 | 244 | 200 | 330.07 | 785,916 | 666,457 | 767,054 |
| C&I Prescriptive | T12/T8 48” 1 Lamp To Delamp (includes U-tubes) | 11 | 116.0 | 0.0460 | 202 | 171 | 196 | 5 | 15.02 | 23,439 | 19,842 | 22,743 |
| C&I Prescriptive | 251-400W Post Fixture LED | 15 | 1,122.0 | - | 148 | 126 | 144 | 120 | 543.96 | 166,063 | 141,378 | 161,574 |
| C&I Prescriptive | <= 175W Parking Garage or Canopy Fixture to LED | 15 | 524.6 | 0.0194 | 94 | 80 | 91 | 50 | 240.34 | 49,314 | 41,970 | 47,740 |
| C&I Prescriptive | 251-400W Parking Garage or Canopy Fixture to LED | 15 | 1,360.7 | 0.0693 | 90 | 76 | 87 | 120 | 257.23 | 122,466 | 103,416 | 118,384 |
| C&I Prescriptive | <= 175W Wallpack to LED | 15 | 583.4 | 0.0148 | 86 | 73 | 84 | 50 | 227.82 | 50,170 | 42,586 | 49,004 |
| C&I Prescriptive | 176-250W Wallpack to LED | 15 | 873.6 | - | 67 | 57 | 65 | 65 | 316.05 | 58,534 | 49,798 | 56,787 |
| C&I Prescriptive | Occupancy Sensor - Wall Mounted <500W | 8 | 420.4 | 0.0114 | 65 | 55 | 63 | 20 | 42.00 | 27,324 | 23,120 | 26,483 |
| C&I Prescriptive | 251-400W Wallpack to LED 75W+ | 15 | 1,438.2 | - | 56 | 48 | 55 | 120 | 354.13 | 80,538 | 69,033 | 79,100 |
| C&I Prescriptive | T12 or T8 2-Lamp 8-Foot to LED Panel or Kit | 15 | 217.5 | 0.0457 | 46 | 39 | 45 | 40 | 175.56 | 10,005 | 8,483 | 9,788 |
| C&I Prescriptive | T12 96" 4 Lamp To T8 96" 4 Lamp | 15 | 348.4 | 0.1018 | 34 | 29 | 33 | 12 | 202.04 | 11,846 | 10,104 | 11,497 |
| C&I Prescriptive | <= 175W Post Fixture LED | 16 | 556.7 | - | 33 | 28 | 32 | 50 | 278.89 | 18,371 | 15,588 | 17,814 |
| C&I Prescriptive | 2 Lamp 4ft T12 to 2 Lamp 4ft HPT8 | 15 | 46.1 | 0.0228 | 28 | 24 | 28 | 6 | 47.68 | 1,290 | 1,105 | 1,290 |
| C&I Prescriptive | 176-250W Post Fixture LED | 15 | 988.8 | - | 28 | 24 | 27 | 65 | 398.61 | 27,686 | 23,731 | 26,697 |
| C&I Prescriptive | T12 6' To Refrigerated Display Case Lighting 6' LED - Cooler | 8.1 | 496.9 | 0.0494 | 27 | 23 | 26 | 30 | 137.14 | 13,418 | 11,430 | 12,921 |
| C&I Prescriptive | Fluorescent Exit Sign To LED Exit Sign | 16 | 92.3 | 0.0106 | 23 | 19 | 22 | 30 | 24.91 | 2,124 | 1,754 | 2,031 |
| C&I Prescriptive | 176-250W Parking Garage or Canopy Fixture to LED | 15 | 916.1 | - | 19 | 16 | 19 | 65 | 295.80 | 17,405 | 14,657 | 17,405 |
| C&I Prescriptive | T8 5' To Refrigerated Display Case Lighting 5' LED - Cooler | 8.1 | 332.5 | 0.0500 | 17 | 15 | 17 | 15 | 150.00 | 5,652 | 4,987 | 5,652 |
| C&I Prescriptive | Cooler - Walk-In Electronically Commutated (EC) Motor | 15 | 357.0 | 0.0500 | 13 | 11 | 13 | 35 | 50.00 | 4,641 | 3,927 | 4,641 |
| C&I Prescriptive | Occupancy Sensor - Ceiling Mounted <500w | 8 | 604.2 | 0.0144 | 10 | 8 | 9 | 20 | 66.00 | 6,042 | 4,834 | 5,438 |
| C&I Prescriptive | Split System Unitary Air Conditioner <65,000 BtuH | 15 | 638.9 | 0.0682 | 10 | 8 | 9 | 120 | 282.11 | 6,389 | 5,111 | 5,750 |
| C&I Prescriptive | T12/T8 U-Tube 2 Lamp 2' To LED Panel | 15 | 185.0 | 0.0267 | 8 | 7 | 8 | 30 | 179.14 | 1,480 | 1,295 | 1,480 |
| C&I Prescriptive | T12 48" 4 Lamp To T8 48" 28W 4 Lamp | 15 | 240.1 | 0.0440 | 8 | 7 | 8 | 14 | 36.19 | 1,921 | 1,681 | 1,921 |
| C&I Prescriptive | Wifi Thermostat - Electric Only | 15 | 4,720.3 | - | 8 | 7 | 16 | 100 | 200.00 | 37,763 | 33,042 | 75,526 |
| C&I Prescriptive | Programmable Thermostat - Electric Only | 15 | 4,720.3 | - | 8 | 7 | 16 | 100 | 200.00 | 37,763 | 33,042 | 75,526 |
| C&I Prescriptive | Occupancy Sensor - Ceiling Mounted 500W+ | 8 | 176.7 | 0.0617 | 7 | 6 | 7 | 40 | 66.00 | 1,237 | 1,060 | 1,237 |
| C&I Prescriptive | T12/T8 1 Lamp 4' To LED Panel | 15 | 129.4 | 0.0436 | 7 | 6 | 7 | 30 | 83.42 | 906 | 776 | 906 |
| C&I Prescriptive | 2 Lamp 8ft T12 to 4 Lamp 4ft HPT8 | 15 | 41.1 | 0.0110 | 7 | 6 | 7 | 25 | 132.19 | 288 | 247 | 288 |
| C&I Prescriptive | ENERGY STAR Commercial Ice Machine < 500 lb/day harvest rate | 9 | 230.4 | 0.0338 | 5 | 5 | 5 | 100 | 296.00 | 1,152 | 1,152 | 1,152 |
| C&I Prescriptive | Delamp 2' T12 | 11 | 36.4 | 0.0200 | 5 | 4 | 5 | 2.5 | - | 182 | 146 | 182 |
| C&I Prescriptive | VFD Supply Fan <100hp | 15 | 35,640.0 | 0.0149 | 4 | 3 | 4 | 900 | 10,915.00 | 142,560 | 106,920 | 142,560 |
| C&I Prescriptive | Interior 1000W HID to LED | 16 | 898.6 | 0.0199 | 4 | 3 | 4 | 110 | - | 3,594 | 2,696 | 3,594 |
| C&I Prescriptive | 2x2 Panel | 15 | 144.0 | 0.0377 | 4 | 3 | 4 | 20 | 45.82 | 576 | 432 | 576 |
| C&I Prescriptive | Split System Unitary Air Conditioner 65,000-135,000 BtuH | 15 | 1,689.3 | 0.0424 | 3 | 2 | 3 | 240 | 666.67 | 5,068 | 3,379 | 5,068 |
| C&I Prescriptive | ENERGY STAR Commercial Hot Holding Cabinets Full Size | 12 | 5,256.0 | 0.8100 | 3 | 2 | 3 | 420 | 1,110.00 | 15,768 | 10,512 | 15,768 |
| C&I Prescriptive | Split System Unitary Air Conditioner 135,000-240,000 BtuH | 15 | 4,865.3 | 0.0442 | 2 | 2 | 2 | 600 | 1,100.00 | 9,731 | 9,731 | 9,731 |
| C&I Prescriptive | ENERGY STAR CEE Tier 2 Window\Sleeve\Room AC < 14,000 BTUH | 15 | 232.2 | 0.2248 | 1 | 1 | 1 | 20 | - | 232 | 232 | 232 |
| C&I Prescriptive | ENERGY STAR CEE Tier 2 Window\Sleeve\Room AC >= 14,000 BTUH | 15 | 363.3 | 0.4430 | 1 | 1 | 1 | 22 | - | 363 | 363 | 363 |
| C&I Prescriptive | Split System Unitary Air Conditioner 240,000-760,000 BtuH | 15 | 27,827.4 | 0.2015 | 1 | 1 | 1 | 1200 | 2,000.00 | 27,827 | 27,827 | 27,827 |
| C&I Prescriptive | Split System Unitary Air Conditioner >760,000 BtuH | 15 | 81,970.0 | 2.8190 | 1 | 1 | 1 | 1050 | - | 81,970 | 81,970 | 81,970 |
| C&I Prescriptive | ENERGY STAR Window\Sleeve\Room AC < 14,000 BTUH | 15 | 189.8 | 0.1628 | 1 | 1 | 1 | 12 | - | 190 | 190 | 190 |
| C&I Prescriptive | ENERGY STAR Window\Sleeve\Room AC >= 14,000 BTUH | 15 | 293.3 | 0.3208 | 1 | 1 | 1 | 14 | - | 293 | 293 | 293 |
| C&I Prescriptive | ENERGY STAR CEE Tier 1 Window\Sleeve\Room AC < 14,000 BTUH | 15 | 189.8 | 0.1135 | 1 | 1 | 1 | 16 | - | 190 | 190 | 190 |
| C&I Prescriptive | ENERGY STAR CEE Tier 1 Window\Sleeve\Room AC >= 14,000 BTUH | 15 | 293.3 | 0.2237 | 1 | 1 | 1 | 18 | - | 293 | 293 | 293 |
| C&I Prescriptive | Electric Chiller - Air cooled, with condenser | 20 | 9,606.6 | 0.0031 | 1 | 1 | 1 | 1500 | - | 9,607 | 9,607 | 9,607 |
| C&I Prescriptive | Electric Chiller Tune-up - Air cooled, without condenser | 5 | 8,153.0 | 0.0013 | 1 | 1 | 1 | 400 | - | 8,153 | 8,153 | 8,153 |

| Program | Measure | Measure Life | Average Savings per Unit (kWh | Demand per Unit (KW) | 2018 Participation | 2019 Participation | 2020 Participation | Avg Incentive Paid Per Unit | Average Incremental Cost | 2018 kWh Savings | 2019 kWh Savings | 2020 kWh Savings |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| C&I Prescriptive | Electric Chiller Tune-up - Water Cooled, Centrifugal | 5 | 21,430.9 | 0.0002 | 1 | 1 | 1 | 1600 | - | 21,431 | 21,431 | 21,431 |
| C&I Prescriptive | Electric Chiller Tune-up - Water Cooled, Rotary Screw | 5 | 5,073.1 | 0.0425 | 1 | 1 | 1 | 1600 | 1,790.00 | 5,073 | 5,073 | 5,073 |
| C&I Prescriptive | Chilled Water Reset Control | 10 | 173.0 | 0.0133 | 1 | 1 | 1 | 1.5 | - | 173 | 173 | 173 |
| C&I Prescriptive | Electric Chiller - Air cooled, without condenser | 20 | 2,923.7 | 0.0013 | 1 | 1 | 1 | 500 | - | 2,924 | 2,924 | 2,924 |
| C&I Prescriptive | Electric Chiller - Water Cooled, Rotary Screw <150 tons | 20 | 5,814.1 | 0.0011 | 1 | 1 | 1 | 1500 | - | 5,814 | 5,814 | 5,814 |
| C&I Prescriptive | Electric Chiller - Water Cooled, Rotary Screw 150-300 tons | 20 | 17,632.9 | 0.0000 | 1 | 1 | 1 | 4500 | - | 17,633 | 17,633 | 17,633 |
| C&I Prescriptive | Electric Chiller - Water Cooled, Rotary Screw >300 tons | 20 | 33,449.4 | 0.0003 | 1 | 1 | 1 | 9000 | - | 33,449 | 33,449 | 33,449 |
| C&I Prescriptive | Electric Chiller - Water Cooled, Centrifugal <150 tons | 20 | 6,969.9 | 0.0033 | 1 | 1 | 1 | 1500 | - | 6,970 | 6,970 | 6,970 |
| C&I Prescriptive | Electric Chiller - Water Cooled, Centrifugal 150-300 tons | 20 | 17,438.9 | 0.0006 | 1 | 1 | 1 | 4500 | - | 17,439 | 17,439 | 17,439 |
| C&I Prescriptive | Electric Chiller - Water Cooled, Centrifugal >300 tons | 20 | 18,656.4 | 0.0416 | 1 | 1 | 1 | 9000 | 13,833.00 | 18,656 | 18,656 | 18,656 |
| C&I Prescriptive | Electric Chiller Tune-up - Air cooled, with condenser | 5 | 9,222.3 | 0.0015 | 1 | 1 | 1 | 400 | - | 9,222 | 9,222 | 9,222 |
| C&I Prescriptive | Central Lighting Control | 8 | 224.7 | 0.0270 | 1 | 1 | 1 | 30 | - | 225 | 225 | 225 |
| C&I Prescriptive | Daylight Dimming Control <500w | 8 | 337.1 | 0.0135 | 1 | 1 | 1 | 20 | - | 337 | 337 | 337 |
| C&I Prescriptive | Occupancy Sensor - Wall Mounted 500W+ | 8 | 344.9 | 0.0270 | 1 | 1 | 1 | 40 | - | 345 | 345 | 345 |
| C&I Prescriptive | Daylight Dimming Control 500W+ | 8 | 674.2 | 0.0270 | 1 | 1 | 1 | 40 | - | 674 | 674 | 674 |
| C&I Prescriptive | Fixture Mounted daylight dimming control | 8 | 168.6 | 0.0068 | 1 | 1 | 1 | 15 | - | 169 | 169 | 169 |
| C&I Prescriptive | Switching Control for Multi-Level Lighting 500W+ | 8 | 168.6 | 0.0068 | 1 | 1 | 1 | 30 | - | 169 | 169 | 169 |
| C&I Prescriptive | ENERGY STAR Griddles | 12 | 6,995.7 | 1.3416 | 1 | 1 | 1 | 550 | - | 6,996 | 6,996 | 6,996 |
| C&I Prescriptive | ENERGY STAR Combination Oven | 12 | 18,431.7 | 3.5348 | 1 | 1 | 1 | 1000 | - | 18,432 | 18,432 | 18,432 |
| C&I Prescriptive | ENERGY STAR Convection Oven | 12 | 3,234.8 | 0.6204 | 1 | 1 | 1 | 350 | - | 3,235 | 3,235 | 3,235 |
| C&I Prescriptive | ENERGY STAR Commercial Dishwasher - Door Type, High Temp | 15 | 14,143.0 | 0.6889 | 1 | 1 | 1 | 1100 | - | 14,143 | 14,143 | 14,143 |
| C&I Prescriptive | ENERGY STAR Commercial Dishwasher - Door Type, Low Temp | 15 | 12,135.0 | 0.5911 | 1 | 1 | 1 | 1000 | - | 12,135 | 12,135 | 12,135 |
| C&I Prescriptive | ENERGY STAR Commercial Dishwasher - Multi-Tank Conveyor, High Temp | 20 | 34,153.0 | 1.6635 | 1 | 1 | 1 | 2700 | - | 34,153 | 34,153 | 34,153 |
| C&I Prescriptive | ENERGY STAR Commercial Dishwasher - Multi-Tank Conveyor, Low Temp | 20 | 17,465.0 | 0.8507 | 1 | 1 | 1 | 1400 | - | 17,465 | 17,465 | 17,465 |
| C&I Prescriptive | ENERGY STAR Commercial Dishwasher - Single Tank Conveyor, High Temp | 20 | 19,235.0 | 0.9369 | 1 | 1 | 1 | 1500 | - | 19,235 | 19,235 | 19,235 |
| C&I Prescriptive | ENERGY STAR Commercial Ice Machine >=500 and <1000 lb/day harvest rate | 9 | 702.4 | 0.1100 | 1 | 1 | 1 | 175 | 1,485.00 | 702 | 702 | 702 |
| C&I Prescriptive | ENERGY STAR Commercial Dishwasher - Single Tank Conveyor, Low Temp | 20 | 11,384.0 | 0.5545 | 1 | 1 | 1 | 900 | - | 11,384 | 11,384 | 11,384 |
| C&I Prescriptive | ENERGY STAR Commercial Dishwasher - Under Counter, High Temp | 10 | 7,471.0 | 0.3639 | 1 | 1 | 1 | 600 | - | 7,471 | 7,471 | 7,471 |
| C&I Prescriptive | ENERGY STAR Commercial Dishwasher - Under Counter, Low Temp | 10 | 1,213.0 | 0.0591 | 1 | 1 | 1 | 100 | - | 1,213 | 1,213 | 1,213 |
| C&I Prescriptive | ENERGY STAR Commercial Ice Machine >=1000 lb/day harvest rate | 9 | 1,227.5 | 0.1898 | 1 | 1 | 1 | 250 | - | 1,227 | 1,227 | 1,227 |
| C&I Prescriptive | ENERGY STAR Commercial Hot Holding Cabinets Half Size | 12 | 1,795.8 | 0.2755 | 1 | 1 | 1 | 150 | - | 1,796 | 1,796 | 1,796 |
| C&I Prescriptive | ENERGY STAR Commercial Hot Holding Cabinets Three Quarter Size | 12 | 2,825.1 | 0.4334 | 1 | 1 | 1 | 230 | - | 2,825 | 2,825 | 2,825 |
| C&I Prescriptive | ENERGY STAR Commercial Fryer | 12 | 1,526.2 | 0.2195 | 1 | 1 | 1 | 80 | - | 1,526 | 1,526 | 1,526 |
| C&I Prescriptive | ENERGY STAR Commercial Steam Cookers | 12 | 2,200.0 | 0.4400 | 1 | 1 | 1 | 200 | - | 2,200 | 2,200 | 2,200 |
| C&I Prescriptive | Air Source Heat Pump <65,000 BtuH | 15 | 555.3 | 0.0136 | 1 | 1 | 1 | 120 | 221.67 | 555 | 555 | 555 |
| C&I Prescriptive | Air Source Heat Pump≥65,000 Btu/h and <135,000 Btu/h | 15 | 492.0 | - | 1 | 1 | 1 | 240 | - | 492 | 492 | 492 |
| C&I Prescriptive | Air Source Heat Pump≥135,000 Btu/h and <240,000 Btu/h | 15 | 1,350.0 | - | 1 | 1 | 1 | 600 | - | 1,350 | 1,350 | 1,350 |
| C&I Prescriptive | Air Source Heat Pump≥240,000 Btu/h and <760,000 Btu/h | 15 | 6,949.0 | - | 1 | 1 | 1 | 1200 | - | 6,949 | 6,949 | 6,949 |
| C&I Prescriptive | Water Source Heat Pump <17,000Btu/hr | 15 | 160.0 | 0.0500 | 1 | 1 | 1 | 30 | - | 160 | 160 | 160 |
| C&I Prescriptive | Water Source Heat Pump >=17,000Btu/hr - 65,000Btu/hr | 15 | 596.6 | 0.0475 | 1 | 1 | 1 | 120 | - | 597 | 597 | 597 |
| C&I Prescriptive | Water Source Heat Pump >65,000Btu/hr and <135,000Btu/hr | 15 | 1,193.2 | 0.0463 | 1 | 1 | 1 | 240 | - | 1,193 | 1,193 | 1,193 |
| C&I Prescriptive | Ground Source Heat Pump <135,000 Btu/hr | 15 | 1,322.4 | - | 1 | 1 | 1 | 30 | - | 1,322 | 1,322 | 1,322 |
| C&I Prescriptive | Ground Water Source Heat Pump <135,000 Btu/hr | 15 | 41,712.0 | 0.0350 | 1 | 1 | 1 | 240 | - | 41,712 | 41,712 | 41,712 |
| C&I Prescriptive | High Bay HID to LED <175W | 16 | 303.5 | 0.0067 | 1 | 1 | 1 | 35 | - | 303 | 303 | 303 |
| C&I Prescriptive | T12 or T8 1-Lamp 8-Foot to LED Panel or Kit | 15 | 118.0 | 0.0228 | 1 | 1 | 1 | 40 | - | 118 | 118 | 118 |
| C&I Prescriptive | T12/T8 Lamp 8' to LED Tube | 15 | 210.0 | - | 1 | 1 | 1 | 10 | - | 210 | 210 | 210 |
| C&I Prescriptive | Clothes Washer ENERGY STAR/CEE Tier 1 | 11 | 541.5 | - | 1 | 1 | 1 | 50 | - | 542 | 542 | 542 |
| C&I Prescriptive | Pellet Dryers duct insulation | 5 | 297.7 | 0.0450 | 1 | 1 | 1 | 30 | - | 298 | 298 | 298 |
| C&I Prescriptive | Clothes Washer CEE Tier 2 | 11 | 541.5 | - | 1 | 1 | 1 | 60 | - | 542 | 542 | 542 |
| C&I Prescriptive | Clothes Washer CEE Tier 3 | 11 | 541.5 | - | 1 | 1 | 1 | 70 | - | 542 | 542 | 542 |
| C&I Prescriptive | Smart Strip Plug Outlet | 8 | 23.6 | - | 1 | 1 | 1 | 8 | - | 24 | 24 | 24 |
| C&I Prescriptive | Plug Load Occupancy sensor with Smart Strip | 8 | 169.0 | - | 1 | 1 | 1 | 20 | - | 169 | 169 | 169 |
| C&I Prescriptive | Compressed Air Engineered Nozzles (1/8") | 15 | 429.8 | 0.1631 | 1 | 1 | 1 | 5 | - | 430 | 430 | 430 |
| C&I Prescriptive | Compressed Air Engineered Nozzles (1/4") | 15 | 1,346.6 | 0.5111 | 1 | 1 | 1 | 8 | - | 1,347 | 1,347 | 1,347 |
| C&I Prescriptive | VFD compressor | 15 | 31,875.0 | 0.0011 | 1 | 1 | 1 | 5625 | - | 31,875 | 31,875 | 31,875 |
| C&I Prescriptive | Barrel Wraps (Inj Mold Only) | 5 | 983.3 | 0.0306 | 1 | 1 | 1 | 30 | - | 983 | 983 | 983 |

| Program | Measure | Measure Life | Average Savings per Unit (kWh) | Demand per Unit (KW) | 2018 Participation | 2019 Participation | 2020 Participation | Avg Incentive Paid Per Unit | Average Incremental Cost | 2018 kWh Savings | 2019 kWh Savings | 2020 kWh Savings |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| C&I Prescriptive | Electric Chiller Tune-up - Water Cooled, Centrifugal | 5 | 21,430.9 | 0.0002 | 1 | 1 | 1 | 1600 | - | 21,431 | 21,431 | 21,431 |
| C&I Prescriptive | T12/T8 96” 1 Lamp To Delamp | 11 | 157.2 | 0.0684 | 1 | 1 | 1 | 10 | - | 157 | 157 | 157 |
| C&I Prescriptive | Incandescent Traffic Signal To LED Traffic Signal Round 8" Red | 10 | 298.7 | 0.0341 | 1 | 1 | 1 | 30 | - | 299 | 299 | 299 |
| C&I Prescriptive | Incandescent Traffic Signal To LED Traffic Signal Pedestrian 12" | 10 | 946.1 | 0.1080 | 1 | 1 | 1 | 50 | - | 946 | 946 | 946 |
| C&I Prescriptive | Packaged Terminal Air Conditioner (PTAC) <7000 BtuH | 15 | 138.0 | 0.2284 | 1 | 1 | 1 | 35 | - | 138 | 138 | 138 |
| C&I Prescriptive | Packaged Terminal Air Conditioner (PTAC) 7,000-15,000 BtuH | 15 | 1,702.4 | 0.9600 | 1 | 1 | 1 | 70 | 35.00 | 1,702 | 1,702 | 1,702 |
| C&I Prescriptive | Packaged Terminal Air Conditioner (PTAC) >15,000 BtuH | 15 | 506.0 | 0.7715 | 1 | 1 | 1 | 105 | - | 506 | 506 | 506 |
| C&I Prescriptive | Packaged Terminal Heat Pump (PTHP) <7,000 BtuH | 15 | 395.4 | 0.3945 | 1 | 1 | 1 | 35 | 48.97 | 395 | 395 | 395 |
| C&I Prescriptive | Packaged Terminal Heat Pump (PTHP) 7,000 - 15,000 BtuH | 15 | 385.0 | 0.1000 | 1 | 1 | 1 | 70 | - | 385 | 385 | 385 |
| C&I Prescriptive | Packaged Terminal Heat Pump (PTHP) > 15,000 BtuH | 15 | 639.8 | 0.1133 | 1 | 1 | 1 | 105 | - | 640 | 640 | 640 |
| C&I Prescriptive | Cooler <15 vol | 12 | 3,671.3 | 0.0593 | 1 | 1 | 1 | 375 | - | 3,671 | 3,671 | 3,671 |
| C&I Prescriptive | T12 6' To Refrigerated Display Case Lighting 6' LED - Cooler With Connected Motion Sensor | 8.1 | 825.7 | 0.0856 | 1 | 1 | 1 | 45 | - | 826 | 826 | 826 |
| C&I Prescriptive | T12 6' To Refrigerated Display Case Lighting 6' LED - Freezer | 8.1 | 622.5 | 0.0923 | 1 | 1 | 1 | 30 | - | 622 | 622 | 622 |
| C&I Prescriptive | T12 6' To Refrigerated Display Case Lighting 6' LED - Freezer With Connected Motion Sensor | 8.1 | 890.2 | 0.0923 | 1 | 1 | 1 | 45 | - | 890 | 890 | 890 |
| C&I Prescriptive | T8 5' To Refrigerated Display Case Lighting 5' LED - Cooler With Connected Motion Sensor | 8.1 | 475.4 | 0.0493 | 1 | 1 | 1 | 25 | - | 475 | 475 | 475 |
| C&I Prescriptive | T8 5' To Refrigerated Display Case Lighting 5' LED - Freezer | 8.1 | 358.4 | 0.0531 | 1 | 1 | 1 | 15 | - | 358 | 358 | 358 |
| C&I Prescriptive | T8 5' To Refrigerated Display Case Lighting 5' LED - Freezer With Connected Motion Sensor | 8.1 | 512.5 | 0.0531 | 1 | 1 | 1 | 25 | - | 513 | 513 | 513 |
| C&I Prescriptive | Cooler - Reach-In Electronically Commutated (EC) Motor | 15 | 328.0 | 0.0330 | 1 | 1 | 1 | 35 | - | 328 | 328 | 328 |
| C&I Prescriptive | Freezer - Reach-In Electronically Commutated (EC) Motor | 15 | 411.0 | 0.0350 | 1 | 1 | 1 | 45 | - | 411 | 411 | 411 |
| C&I Prescriptive | Cooler 15-30 vol | 12 | 14,411.1 | 0.0500 | 1 | 1 | 1 | 1650 | 164.00 | 14,411 | 14,411 | 14,411 |
| C&I Prescriptive | Freezer - Walk-In Electronically Commutated (EC) Motor | 15 | 532.0 | 0.0360 | 1 | 1 | 1 | 45 | - | 532 | 532 | 532 |
| C&I Prescriptive | Cooler Anti-Sweat Heater Controls | 12 | 614.5 | - | 1 | 1 | 1 | 50 | - | 615 | 615 | 615 |
| C&I Prescriptive | Freezer Anti-Sweat Heater Controls | 12 | 1,302.5 | - | 1 | 1 | 1 | 100 | - | 1,303 | 1,303 | 1,303 |
| C&I Prescriptive | Refrigerated Case Covers | 5 | 157.5 | - | 1 | 1 | 1 | 10 | - | 158 | 158 | 158 |
| C&I Prescriptive | Cooler - Glass Door 30-50 vol | 12 | 38,943.5 | 0.0800 | 1 | 1 | 1 | 3000 | 164.00 | 38,944 | 38,944 | 38,944 |
| C&I Prescriptive | Cooler - Glass Door >50 vol | 12 | 91,487.5 | 0.1000 | 1 | 1 | 1 | 7000 | 249.00 | 91,488 | 91,488 | 91,488 |
| C&I Prescriptive | Freezer - Glass Door <15 vol | 12 | 5,837.7 | 0.0800 | 1 | 1 | 1 | 750 | 142.00 | 5,838 | 5,838 | 5,838 |
| C&I Prescriptive | Freezer - Glass Door 15-30 vol | 12 | 26,061.0 | 0.0900 | 1 | 1 | 1 | 4500 | 166.00 | 26,061 | 26,061 | 26,061 |
| C&I Prescriptive | Freezer - Glass Door 30-50 vol | 12 | 164,834.0 | 0.4400 | 1 | 1 | 1 | 8000 | 166.00 | 164,834 | 164,834 | 164,834 |
| C&I Prescriptive | Freezer - Glass Door >50 vol | 12 | 715,400.0 | 0.7667 | 1 | 1 | 1 | 35000 | 407.00 | 715,400 | 715,400 | 715,400 |
| C&I Prescriptive | T12 48" 1 Lamp To T5 46" 1 Lamp | 15 | 25.3 | 0.0100 | 1 | 1 | 1 | 4 | - | 25 | 25 | 25 |
| C&I Prescriptive | 175 - 250W HID To T5 46" 2 Lamp HO | 15 | 377.7 | 0.1049 | 1 | 1 | 1 | 45 | - | 378 | 378 | 378 |
| C&I Prescriptive | 175 - 250W HID To T5 46" 3 Lamp HO | 15 | 167.5 | 0.0465 | 1 | 1 | 1 | 40 | - | 168 | 168 | 168 |
| C&I Prescriptive | 400W HID To T5 46" 4 Lamp HO | 15 | 702.9 | 0.1952 | 1 | 1 | 1 | 85 | - | 703 | 703 | 703 |
| C&I Prescriptive | 400W HID To T5 46" 6 Lamp HO | 15 | 318.6 | 0.0885 | 1 | 1 | 1 | 50 | - | 319 | 319 | 319 |
| C&I Prescriptive | 1000W HID To T5 46" 10 Lamp HO | 15 | 1,652.2 | 0.4587 | 1 | 1 | 1 | 115 | - | 1,652 | 1,652 | 1,652 |
| C&I Prescriptive | 1000W HID To T5 46" 12 Lamp HO | 15 | 1,215.3 | 0.3374 | 1 | 1 | 1 | 105 | - | 1,215 | 1,215 | 1,215 |
| C&I Prescriptive | T12 48" 2 Lamp To T5 46" 2 Lamp | 15 | 18.4 | 0.0073 | 1 | 1 | 1 | 6 | - | 18 | 18 | 18 |
| C&I Prescriptive | T12 48" 3 Lamp To T5 46" 3 Lamp | 15 | 43.7 | 0.0173 | 1 | 1 | 1 | 8 | - | 44 | 44 | 44 |
| C&I Prescriptive | T12 48" 4 Lamp To T5 46" 4 Lamp | 15 | 36.8 | 0.0146 | 1 | 1 | 1 | 12 | - | 37 | 37 | 37 |
| C&I Prescriptive | HID 75W-100W To T5 Garage 1 Lamp | 15 | 301.7 | 0.1104 | 1 | 1 | 1 | 8 | - | 302 | 302 | 302 |
| C&I Prescriptive | HID 101W-175W To T5 Garage 2 Lamp | 15 | 275.4 | 0.1008 | 1 | 1 | 1 | 12 | - | 275 | 275 | 275 |
| C&I Prescriptive | HID 176W+ To T5 Garage 3 Lamp | 15 | 367.2 | 0.1344 | 1 | 1 | 1 | 16 | - | 367 | 367 | 367 |
| C&I Prescriptive | Up to 175W HID To T5 46" 2 Lamp HO | 15 | 239.8 | 0.0666 | 1 | 1 | 1 | 35 | - | 240 | 240 | 240 |
| C&I Prescriptive | Up to 175W HID To T5 46" 3 Lamp HO | 15 | 88.7 | 0.0246 | 1 | 1 | 1 | 30 | - | 89 | 89 | 89 |
| C&I Prescriptive | Up to 175W HID to T8VHO 48" 3 Lamp | 15 | 197.1 | 0.0547 | 1 | 1 | 1 | 35 | - | 197 | 197 | 197 |
| C&I Prescriptive | T12 48" 1 Lamp To T8 48" 25W 1 Lamp | 15 | 48.3 | 0.0192 | 1 | 1 | 1 | 8 | - | 48 | 48 | 48 |
| C&I Prescriptive | T12 48" 2 Lamp To T8 48" 25W 2 Lamp | 15 | 71.3 | 0.0283 | 1 | 1 | 1 | 10 | - | 71 | 71 | 71 |
| C&I Prescriptive | T12 48" 3 Lamp To T8 48" 25W 3 Lamp | 15 | 123.5 | 0.0490 | 1 | 1 | 1 | 12 | - | 123 | 123 | 123 |
| C&I Prescriptive | T12 48" 4 Lamp To T8 48" 25W 4 Lamp | 15 | 146.0 | 0.0579 | 1 | 1 | 1 | 16 | - | 146 | 146 | 146 |
| C&I Prescriptive | 1 Lamp 4ft T12 to 1 Lamp 4ft HPT8 | 15 | 41.4 | 0.0164 | 1 | 1 | 1 | 4 | - | 41 | 41 | 41 |
| C&I Prescriptive | 3 Lamp 4ft T12 to 3 Lamp 4ft HPT8 | 15 | 96.6 | 0.0383 | 1 | 1 | 1 | 8 | - | 97 | 97 | 97 |
| C&I Prescriptive | 4 Lamp 4ft T12 to 4 Lamp 4ft HPT8 | 15 | 110.4 | 0.0438 | 1 | 1 | 1 | 12 | - | 110 | 110 | 110 |
| C&I Prescriptive | T12 96" 1 Lamp To T8 96" 1 Lamp | 15 | 39.1 | 0.0155 | 1 | 1 | 1 | 6 | - | 39 | 39 | 39 |
| C&I Prescriptive | T12 96" 2 Lamp To T8 96" 2 Lamp | 15 | 32.2 | 0.0128 | 1 | 1 | 1 | 8 | - | 32 | 32 | 32 |
| C&I Prescriptive | 176-250W HID to T8VHO 48" 4 Lamp | 15 | 266.1 | 0.0739 | 1 | 1 | 1 | 50 | - | 266 | 266 | 266 |
| C&I Prescriptive | 1 Lamp 8ft T12 to 2 Lamp 4ft HPT8 | 15 | 62.1 | 0.0246 | 1 | 1 | 1 | 20 | - | 62 | 62 | 62 |

| Program | Measure | Measure Life | Average Savings per Unit (kWh) | Demand per Unit (KW) | 2018 Participation | 2019 Participation | 2020 Participation | Avg Incentive Paid Per Unit | Average Incremental Cost | 2018 kWh Savings | 2019 kWh Savings | 2020 kWh Savings |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| C&I Prescriptive | Electric Chiller Tune-up - Water Cooled, Centrifugal | 5 | 21,430.9 | 0.0002 | 1 | 1 | 1 | 1600 | - | 21,431 | 21,431 | 21,431 |
| C&I Prescriptive | T12/T8 96" 1 Lamp To Delamp | 11 | 157.2 | 0.0684 | 1 | 1 | 1 | 10 | - | 157 | 157 | 157 |
| C&I Prescriptive | 400W HID to T8VHO 4ft 6 Lamp | 15 | 762.0 | 0.2116 | 1 | 1 | 1 | 85 | - | 762 | 762 | 762 |
| C&I Prescriptive | 400W HID to T8VHO 4ft 8 Lamp | 15 | 558.4 | 0.1550 | 1 | 1 | 1 | 60 | - | 558 | 558 | 558 |
| C&I Prescriptive | MH 1000W To T8VHO 48" 8 Lamp (2 fixtures) | 15 | 1,655.5 | 0.4596 | 1 | 1 | 1 | 125 | - | 1,655 | 1,655 | 1,655 |
| C&I Prescriptive | T12 48" 1 Lamp To T8 48" 28W 1 Lamp | 15 | 45.3 | 0.0180 | 1 | 1 | 1 | 6 | - | 45 | 45 | 45 |
| C&I Prescriptive | T12 48" 2 Lamp To T8 48" 28W 2 Lamp | 15 | 57.5 | 0.0228 | 1 | 1 | 1 | 8 | - | 57 | 57 | 57 |
| C&I Prescriptive | T12 48" 3 Lamp To T8 48" 28W 3 Lamp | 15 | 103.7 | 0.0411 | 1 | 1 | 1 | 10 | - | 104 | 104 | 104 |
| C&I Prescriptive | Vending Machine Occ Sensor - Refrigerated Beverage | 5 | 1,611.8 | - | 1 | 1 | 1 | 50 | - | 1,612 | 1,612 | 1,612 |
| C&I Prescriptive | Snack Machine Controller (Non-refrigerated vending) | 5 | 342.5 | - | 1 | 1 | 1 | 25 | - | 343 | 343 | 343 |
| C&I Prescriptive | Vending Machine Occ Sensor - Refrigerated Glass Front Cooler | 5 | 1,208.9 | - | 1 | 1 | 1 | 50 | - | 1,209 | 1,209 | 1,209 |
| C&I Prescriptive | VFD Return Fan <100hp | 15 | 60,000.0 | - | 1 | 1 | 1 | 900 | - | 60,000 | 60,000 | 60,000 |
| C&I Prescriptive | VFD Tower Fan <100hp | 15 | 19,220.0 | - | 1 | 1 | 1 | 900 | - | 19,220 | 19,220 | 19,220 |
| C&I Prescriptive | VFD CW Pump <100hp | 15 | 26,800.0 | - | 1 | 1 | 1 | 900 | - | 26,800 | 26,800 | 26,800 |
| C&I Prescriptive | VFD HW Pump <100hp | 15 | 88,620.0 | 0.9790 | 1 | 1 | 1 | 900 | - | 88,620 | 88,620 | 88,620 |
| C&I Prescriptive | VFD CHW Pump <100hp | 15 | 74,020.0 | 0.3900 | 1 | 1 | 1 | 900 | - | 74,020 | 74,020 | 74,020 |
| C&I Prescriptive | Heat Pump Water Heater 10-50 MBH | 10 | 3,534.0 | 0.5000 | 1 | 1 | 1 | 500 | - | 3,534 | 3,534 | 3,534 |
| C&I Prescriptive | Window Film | 10 | 3.7 | 0.0010 | 1 | 1 | 1 | 1 | - | 4 | 4 | 4 |
| C&I Prescriptive | Pre-Rinse Sprayer - Electric | 5 | 3,727.2 | - | 1 | 1 | 1 | 50 | - | 3,727 | 3,727 | 3,727 |
| C&I Prescriptive | Livestock Waterer | 10 | 266.1 | 0.5250 | 1 | 1 | 1 | 110 | 787.50 | 266 | 266 | 266 |
| C&I Prescriptive | Agriculture - Poultry Farm LED Lighting | 7 | 292.0 | 0.0500 | 1 | 1 | 1 | 10 | 30.00 | 292 | 292 | 292 |
| C&I Prescriptive | VSD Milk Pump | 15 | 33.9 | 0.0116 | 1 | 1 | 1 | 5 | 4,000.00 | 34 | 34 | 34 |
| C&I Prescriptive | High Volume Low Speed Fans | 10 | 8,543.0 | 3.1000 | 1 | 1 | 1 | 1000 | 4,180.00 | 8,543 | 8,543 | 8,543 |
| C&I Prescriptive | High Speed Fans (Ventilation and Ciculation) | 7 | 625.0 | 0.1980 | 1 | 1 | 1 | 50 | 150.00 | 625 | 625 | 625 |
| C&I Prescriptive | Dairy Plate Cooler | 15 | 76.2 | 0.0163 | 1 | 1 | 1 | 8 | - | 76 | 76 | 76 |
| C&I Prescriptive | Heat Mat (Single, ~14x60") | 5 | 657.0 | - | 1 | 1 | 1 | 65 | 225.00 | 657 | 657 | 657 |
| C&I Prescriptive | Automatic Milker Take Off | 15 | 556.0 | 0.1165 | 1 | 1 | 1 | 5 | - | 556 | 556 | 556 |
| C&I Prescriptive | HE Diary Scroll Compressor | 12 | 279.5 | 0.0689 | 1 | 1 | 1 | 250 | - | 279 | 279 | 279 |
| C&I Prescriptive | Heat Reclaimer (No Precooler Installed) | 14 | 152.7 | - | 1 | 1 | 1 | 5 | - | 153 | 153 | 153 |
| C&I Prescriptive | Prescriptive Other | 15 | | | | | | | | 132,109 | 99,082 | 132,110 |
| **Total C&I Prescriptive** | | | | | **7,024** | **5,981** | **6,856** | | | **4,999,125** | **4,501,186** | **5,002,621** |
| | | | | | | | | | | | | |
| Small Business Direct Install (SBDI) | Lamp & Ballast Retrofit: 1-Lamp 4' T12 to HP, 28W or 25W T8 | 15 | 64.0 | 0.0171 | 80 | 77 | 68 | 12 | 51 | 5,122 | 4,930 | 4,353 |
| Small Business Direct Install (SBDI) | Lamp & Ballast Retrofit: 2-Lamp 4' T12 to HP, 28W or 25W T8 | 15 | 85.4 | 0.0228 | 119 | 116 | 102 | 15 | 56 | 10,158 | 9,902 | 8,707 |
| Small Business Direct Install (SBDI) | Lamp & Ballast Retrofit: 3-Lamp 4' T12 to HP, 28W or 25W T8 | 15 | 104.1 | 0.0383 | 2 | 2 | 1 | 20 | 70 | 208 | 208 | 104 |
| Small Business Direct Install (SBDI) | Lamp & Ballast Retrofit: 4-Lamp 4' T12 to HP, 28W or 25W T8 | 15 | 116.5 | 0.0390 | 159 | 154 | 136 | 24 | 78 | 18,523 | 17,940 | 15,843 |
| Small Business Direct Install (SBDI) | Lamp & Ballast Retrofit: 1-Lamp 8' T12 to 2-Lamp 4' or 1-Lamp 8' HP, 28W or 25W T8 w/ reflector | 15 | 153.9 | 0.0246 | 2 | 2 | 1 | 20 | 93 | 308 | 308 | 154 |
| Small Business Direct Install (SBDI) | Lamp & Ballast Retrofit: 2-Lamp 8' T12 to 4-Lamp 4' or 2-Lamp 8' HP, 28W or 25W T8 w/ reflector | 15 | 59.3 | 0.0230 | 192 | 185 | 164 | 25 | 108 | 11,381 | 10,966 | 9,721 |
| Small Business Direct Install (SBDI) | Lamp & Ballast Retrofit: 1-Lamp 8' T12 to 2-Lamp 4' or 1-Lamp 8' HP, 28W or 25W T8 | 15 | 110.7 | 0.0246 | 2 | 2 | 1 | 22 | 88 | 221 | 221 | 111 |
| Small Business Direct Install (SBDI) | Lamp & Ballast Retrofit: 2-Lamp 8' T12 to 4-Lamp 4' or 2-Lamp 8' HP, 28W or 25W T8 | 15 | 41.6 | 0.0208 | 256 | 248 | 218 | 27 | 103 | 10,653 | 10,320 | 9,072 |
| Small Business Direct Install (SBDI) | 400W HID to High Bay Fluorescent 6-Lamp 4' HP, 28W or 25W T8 | 7 | 703.4 | 0.2116 | 2 | 2 | 1 | 125 | 300 | 1,407 | 1,407 | 703 |
| Small Business Direct Install (SBDI) | 250W HID to High Bay Fluorescent 4-Lamp 4' HP, 28W or 25W T8 | 7 | 519.9 | 0.1778 | 2 | 2 | 1 | 90 | 255 | 1,040 | 1,040 | 520 |
| Small Business Direct Install (SBDI) | Delamping with Lamp & Ballast Retrofit: 4-Lamp 4' T12 to 3-Lamp 4' HP, 28W or 25W T8 | 15 | 211.2 | 0.0648 | 2 | 2 | 1 | 35 | 75 | 422 | 422 | 211 |
| Small Business Direct Install (SBDI) | Delamping with Lamp & Ballast Retrofit: 4-Lamp 4' T12 to 2-Lamp 4' HP, 28W or 25W T8 | 15 | 264.9 | 0.0876 | 2 | 2 | 1 | 45 | 75 | 530 | 530 | 265 |
| Small Business Direct Install (SBDI) | Delamping with Lamp & Ballast Retrofit: 3-Lamp 4' T12 to 2-Lamp 4' HP, 28W or 25W T8 | 15 | 199.8 | 0.0611 | 2 | 2 | 1 | 35 | 57 | 400 | 400 | 200 |
| Small Business Direct Install (SBDI) | Delamping with Lamp & Ballast Retrofit: 2-Lamp 4' T12 to 1-Lamp 4' HP, 28W or 25W T8 | 15 | 137.3 | 0.0246 | 2 | 2 | 1 | 25 | 50 | 275 | 275 | 137 |
| Small Business Direct Install (SBDI) | Delamping with Lamp & Ballast Retrofit: 4-Lamp 8' T12 to 4-Lamp 4' or 2-Lamp 8' HP, 28W or 25W T8 | 15 | 360.0 | 0.1368 | 2 | 2 | 1 | 60 | 105 | 720 | 720 | 360 |
| Small Business Direct Install (SBDI) | Delamping with Lamp & Ballast Retrofit w/Reflector: 4-Lamp 4' T12 to 3-Lamp 4' HP, 28W or 25W T8 | 15 | 247.1 | 0.0716 | 2 | 2 | 1 | 35 | 90 | 494 | 494 | 247 |
| Small Business Direct Install (SBDI) | Delamping with Lamp & Ballast Retrofit w/Reflector: 4-Lamp 4' T12 to 2-Lamp 4' HP, 28W or 25W T8 | 15 | 341.5 | 0.0910 | 1152 | 1115 | 984 | 60 | 58.51 | 393,353 | 380,719 | 335,989 |
| Small Business Direct Install (SBDI) | Delamping with Lamp & Ballast Retrofit w/Reflector: 3-Lamp 4' T12 to 2-Lamp 4' HP, 28W or 25W T8 | 15 | 225.7 | 0.0675 | 2 | 2 | 1 | 40 | 88 | 451 | 451 | 226 |
| Small Business Direct Install (SBDI) | Delamping with Lamp & Ballast Retrofit w/Reflector: 2-Lamp 4' T12 to 1-Lamp 4' HP, 28W or 25W T8 | 15 | 149.2 | 0.0404 | 2 | 2 | 1 | 25 | 57 | 298 | 298 | 149 |
| Small Business Direct Install (SBDI) | Delamping with Lamp & Ballast Retrofit w/Reflector: 2-Lamp 8' T12 to 2-Lamp 4' or 1-Lamp 8' HP, 28W or 25W T8 | 15 | 275.9 | 0.0631 | 2 | 2 | 1 | 50 | 110 | 552 | 552 | 276 |
| Small Business Direct Install (SBDI) | Delamping with Lamp & Ballast Retrofit w/Reflector: 4-Lamp 8' T12 to 4-Lamp 4' or 2-Lamp 8' HP, 28W or 25W T8 | 15 | 505.3 | 0.1368 | 2 | 2 | 1 | 90 | 140 | 1,011 | 1,011 | 505 |
| Small Business Direct Install (SBDI) | Lamp & Ballast Retrofit: 1-Lamp 4' T12/T8 to 4' LED Tube | 15 | 112.9 | 0.0232 | 80 | 77 | 68 | 18 | 80 | 9,036 | 8,697 | 7,680 |
| Small Business Direct Install (SBDI) | Lamp & Ballast Retrofit: 2-Lamp 4' T12/T8 to 4' LED Tube | 15 | 74.4 | - | 2 | 2 | 1 | 25 | 100 | 149 | 149 | 74 |
| Small Business Direct Install (SBDI) | Lamp & Ballast Retrofit: 3-Lamp 4' T12/T8 to 4' LED Tube | 15 | 81.8 | - | 2 | 2 | 1 | 25 | 120 | 164 | 164 | 82 |
| Small Business Direct Install (SBDI) | Lamp & Ballast Retrofit: 4-Lamp 4' T12/T8 to 4' LED Tube | 15 | 314.3 | 0.0645 | 437 | 423 | 374 | 50 | 140 | 137,340 | 132,940 | 117,541 |
| Small Business Direct Install (SBDI) | Lamp & Ballast Retrofit: 1-Lamp 8' T12/T8 to 2-Lamp 4' or 1-Lamp 8' LED Tube | 15 | 171.9 | 0.0353 | 675 | 654 | 577 | 30 | 132 | 116,013 | 112,404 | 99,170 |
| Small Business Direct Install (SBDI) | Lamp & Ballast Retrofit: 2-Lamp 8' T12/T8 to 4-Lamp 4' or 2-Lamp 8' LED Tube | 15 | 214.5 | 0.0433 | 40 | 39 | 34 | 40 | 175 | 8,580 | 8,366 | 7,293 |

| Program | Measure | Measure Life | Average Savings per Unit (kWh) | Demand per Unit (KW) | 2018 Participation | 2019 Participation | 2020 Participation | Avg Incentive Paid Per Unit | Average Incremental Cost | 2018 kWh Savings | 2019 kWh Savings | 2020 kWh Savings |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Small Business Direct Install (SBDI) | Delamping with Lamp & Ballast Retrofit: 4-Lamp 4' T12/T8 to 3-Lamp 4' LED Tube | 15 | 190.4 | - | 2 | 2 | 1 | 30 | 130 | 381 | 381 | 190 |
| Small Business Direct Install (SBDI) | Delamping with Lamp & Ballast Retrofit: 4-Lamp 4' T12/T8 to 2-Lamp 4' LED Tube | 15 | 353.6 | 0.0726 | 80 | 77 | 68 | 60 | 120 | 28,285 | 27,225 | 24,042 |
| Small Business Direct Install (SBDI) | Delamping with Lamp & Ballast Retrofit: 3-Lamp 4' T12/T8 to 2-Lamp 4' LED Tube | 15 | 158.1 | - | 2 | 2 | 1 | 30 | 100 | 316 | 316 | 158 |
| Small Business Direct Install (SBDI) | Delamping with Lamp & Ballast Retrofit: 2-Lamp 4' T12/T8 to 1-Lamp 4' LED Tube | 15 | 213.5 | - | 2 | 2 | 1 | 40 | 75 | 427 | 427 | 214 |
| Small Business Direct Install (SBDI) | Delamping with Lamp & Ballast Retrofit: 4-Lamp 8' T12/T8 to 4-Lamp 4' or 2-Lamp 8' LED Tube | 15 | 364.8 | - | 2 | 2 | 1 | 65 | 250 | 730 | 730 | 365 |
| Small Business Direct Install (SBDI) | Delamping with Lamp & Ballast Retrofit w/Reflector: 2-Lamp 2' T12 U-tube to 2-Lamp 2' HP, 28W or 25W T8 | 15 | 108.0 | 0.0329 | 2 | 2 | 1 | 19 | 89 | 216 | 216 | 108 |
| Small Business Direct Install (SBDI) | 400W HID to High Bay LED ≤250W | 15 | 589.9 | 0.1797 | 172 | 166 | 147 | 220 | 480 | 101,461 | 97,921 | 86,714 |
| Small Business Direct Install (SBDI) | 250W HID to High Bay LED ≤100W | 15 | 716.6 | 0.1778 | 2 | 2 | 1 | 160 | 460 | 1,433 | 1,433 | 717 |
| Small Business Direct Install (SBDI) | LED Exit Sign Fixture with Battery Backup | 16 | 87.2 | 0.0077 | 641 | 621 | 548 | 60 | 88 | 55,923 | 54,178 | 47,810 |
| Small Business Direct Install (SBDI) | 4-Lamp 4' T12/T8 to LED Panel | 15 | 286.6 | - | 2 | 2 | 1 | 50 | 155 | 573 | 573 | 287 |
| Small Business Direct Install (SBDI) | 3-Lamp 4' T12/T8 to LED Panel | 15 | 214.9 | - | 2 | 2 | 1 | 40 | 145 | 430 | 430 | 215 |
| Small Business Direct Install (SBDI) | 2-Lamp 4' T12/T8 to LED Panel | 15 | 93.3 | - | 2 | 2 | 1 | 40 | 135 | 187 | 187 | 93 |
| Small Business Direct Install (SBDI) | ENERGY STAR® LED lamps 40W Equivalent | 15 | 64.3 | 0.0293 | 279 | 270 | 238 | 12 | 33 | 17,951 | 17,372 | 15,313 |
| Small Business Direct Install (SBDI) | ENERGY STAR® LED lamps 60W Equivalent | 15 | 120.8 | 0.0337 | 913 | 884 | 780 | 22 | 7.38 | 110,272 | 106,769 | 94,208 |
| Small Business Direct Install (SBDI) | ENERGY STAR® LED lamps 75W+ Equivalent | 15 | 179.2 | 0.0536 | 2 | 2 | 1 | 32 | 35 | 358 | 358 | 179 |
| Small Business Direct Install (SBDI) | ENERGY STAR® LED downlights - 40W Equivalent | 15 | 94.3 | 0.0285 | 2 | 2 | 1 | 18 | 52 | 189 | 189 | 94 |
| Small Business Direct Install (SBDI) | ENERGY STAR® LED downlights - 60W Equivalent | 15 | 132.3 | 0.0371 | 5 | 5 | 4 | 27 | 57 | 661 | 661 | 529 |
| Small Business Direct Install (SBDI) | ENERGY STAR® LED downlights - 75W+ Equivalent | 15 | 205.3 | 0.0412 | 398 | 385 | 340 | 35 | 39 | 81,698 | 79,029 | 69,792 |
| Small Business Direct Install (SBDI) | Delamp 1 lamp 8ft T12 lamp and ballast | 10 | 278.1 | - | 2 | 2 | 1 | 50 | 34 | 556 | 556 | 278 |
| Small Business Direct Install (SBDI) | Delamp 2 lamp 8ft T12 lamp and ballast | 10 | 417.2 | - | 2 | 2 | 1 | 75 | 36 | 834 | 834 | 417 |
| Small Business Direct Install (SBDI) | Delamp 4 lamp 8ft T12 lamp and ballast | 10 | 834.3 | - | 2 | 2 | 1 | 75 | 38 | 1,669 | 1,669 | 834 |
| Small Business Direct Install (SBDI) | Vending Machine Occ Sensor - Refrigerated Glass Front Cooler | 5 | 1,208.9 | - | 2 | 2 | 1 | 200 | 178 | 2,418 | 2,418 | 1,209 |
| Small Business Direct Install (SBDI) | Vending Machine Occ Sensor - Refrigerated Beverage | 5 | 1,602.5 | - | 2 | 2 | 1 | 250 | 208 | 3,205 | 3,205 | 1,602 |
| Small Business Direct Install (SBDI) | Occupancy Sensors - Ceiling Mount (must control 350 watts) | 8 | 299.3 | 0.0630 | 5 | 5 | 4 | 60 | 170 | 1,496 | 1,496 | 1,197 |
| Small Business Direct Install (SBDI) | Occupancy Sensors - Wall Mount (must control at least 200 watts) | 8 | 250.2 | 0.0108 | 2 | 2 | 1 | 40 | 115 | 500 | 500 | 250 |
| Small Business Direct Install (SBDI) | Occupancy Sensors - Fixture Mount (must control at least 100 watts) | 8 | 154.6 | 0.0054 | 2 | 2 | 1 | 25 | 37 | 309 | 309 | 155 |
| Small Business Direct Install (SBDI) | Exterior Wallpack: 175W HID to LED | 15 | 470.4 | 0.0251 | 972 | 941 | 830 | 100 | 225.5 | 457,246 | 442,663 | 390,447 |
| Small Business Direct Install (SBDI) | Exterior Wallpack: 176 W-250 W HID to LED | 15 | 639.2 | 0.1236 | 172 | 166 | 147 | 115 | 310 | 109,946 | 106,111 | 93,965 |
| Small Business Direct Install (SBDI) | Exterior Wallpack: 251 W-400 W HID to LED | 15 | 1,066.7 | 0.0900 | 2 | 2 | 1 | 185 | 600 | 2,133 | 2,133 | 1,067 |
| Small Business Direct Install (SBDI) | Exterior Canopy: less than 175W HID to LED | 15 | 470.4 | 0.0251 | 632 | 612 | 540 | 100 | 190.4 | 297,304 | 287,896 | 254,025 |
| Small Business Direct Install (SBDI) | Exterior Canopy: 176 W-250 W HID to LED | 15 | 639.2 | 0.1236 | 132 | 128 | 113 | 115 | 272 | 84,377 | 81,820 | 72,232 |
| Small Business Direct Install (SBDI) | Exterior Canopy: 251 W-400 W HID to LED | 15 | 1,066.7 | 0.0900 | 2 | 2 | 1 | 185 | 600 | 2,133 | 2,133 | 1,067 |
| Small Business Direct Install (SBDI) | Exterior Flood: less than 175W HID to LED | 15 | 470.4 | 0.0251 | 778 | 753 | 664 | 100 | 188.33 | 365,985 | 354,224 | 312,357 |
| Small Business Direct Install (SBDI) | Exterior Flood: 176 W-250 W HID to LED | 15 | 639.2 | 0.1236 | 146 | 141 | 125 | 115 | 310 | 93,326 | 90,130 | 79,903 |
| Small Business Direct Install (SBDI) | Exterior Flood: 251 W-400 W HID to LED | 15 | 1,066.7 | 0.0900 | 2 | 2 | 1 | 185 | 600 | 2,133 | 2,133 | 1,067 |
| Small Business Direct Install (SBDI) | Exterior Pole Mount: less than 175W HID to LED | 15 | 470.4 | 0.0251 | 680 | 658 | 581 | 100 | 187.5 | 319,884 | 309,535 | 273,313 |
| Small Business Direct Install (SBDI) | Exterior Pole Mount: 176 W-250 W HID to LED | 15 | 639.2 | 0.1236 | 146 | 141 | 125 | 115 | 310 | 93,326 | 90,130 | 79,903 |
| Small Business Direct Install (SBDI) | Exterior Pole Mount: 251 W-400 W HID to LED | 15 | 1,066.7 | 0.0900 | 2 | 2 | 1 | 185 | 600 | 2,133 | 2,133 | 1,067 |
| Small Business Direct Install (SBDI) | Exterior Pole Mount: 1000W HID to LED | 15 | 3,536.6 | 0.6745 | 2 | 2 | 1 | 500 | 615 | 7,073 | 7,073 | 3,537 |
| Small Business Direct Install (SBDI) | Exterior Other: less than 175W HID to LED | 15 | 470.4 | 0.0251 | 534 | 517 | 456 | 100 | 63.75 | 251,203 | 243,206 | 214,510 |
| Small Business Direct Install (SBDI) | Exterior Other: 176 W-250 W HID to LED | 15 | 639.2 | 0.1236 | 119 | 116 | 102 | 115 | 140 | 76,067 | 74,150 | 65,200 |
| Small Business Direct Install (SBDI) | Exterior Other: 251 W-400 W HID to LED | 15 | 1,066.7 | 0.0900 | 2 | 2 | 1 | 185 | 600 | 2,133 | 2,133 | 1,067 |
| Small Business Direct Install (SBDI) | EC (electronically commutated) Motor, Reach-in Refrigerator | 15 | 325.0 | 0.0320 | 2 | 2 | 1 | 70 | 159 | 650 | 650 | 325 |
| Small Business Direct Install (SBDI) | EC (electronically commutated) Motor, Reach-in Freezer | 15 | 409.0 | 0.0340 | 2 | 2 | 1 | 90 | 159 | 818 | 818 | 409 |
| Small Business Direct Install (SBDI) | EC (electronically commutated) Motor, Walk-in Refrigerator | 15 | 354.0 | 0.0486 | 355 | 343 | 303 | 70 | 137 | 125,670 | 121,422 | 107,262 |
| Small Business Direct Install (SBDI) | EC (electronically commutated) Motor, Walk-in Freezer | 15 | 528.0 | 0.0560 | 4 | 4 | 3 | 90 | 180 | 2,112 | 2,112 | 1,584 |
| Small Business Direct Install (SBDI) | Anti-Sweat Heater Controls - Refrigerator | 12 | 540.0 | - | 2 | 2 | 1 | 110 | 300 | 1,080 | 1,080 | 540 |
| Small Business Direct Install (SBDI) | Anti-Sweat Heater Controls - Freezer | 12 | 1,277.0 | - | 2 | 2 | 1 | 220 | 360 | 2,554 | 2,554 | 1,277 |
| Small Business Direct Install (SBDI) | Strip Curtain - Walk in Refrigerator | 6 | 13.2 | 0.0500 | 35 | 34 | 30 | 2.25 | 14.5 | 462 | 448 | 396 |
| Small Business Direct Install (SBDI) | Strip Curtain - Walk in Freezer | 6 | 92.9 | 0.3400 | 35 | 34 | 30 | 15 | 14.5 | 3,253 | 3,160 | 2,788 |
| Small Business Direct Install (SBDI) | Refrigerated Display Case Lighting 5' T12/T8 to LED - Refrigerator | 8.1 | 332.0 | 0.0493 | 2 | 2 | 1 | 55 | 180 | 664 | 664 | 332 |
| Small Business Direct Install (SBDI) | Refrigerated Display Case Lighting 5' T12/T8 to LED - Freezer | 8.1 | 358.0 | 0.0856 | 2 | 2 | 1 | 55 | 180 | 716 | 716 | 358 |
| Small Business Direct Install (SBDI) | Refrigerated Display Case Lighting 6' T12/T8 to LED - Refrigerator | 8.1 | 450.0 | 0.0531 | 2 | 2 | 1 | 70 | 200 | 900 | 900 | 450 |
| Small Business Direct Install (SBDI) | Refrigerated Display Case Lighting 6' T12/T8 to LED - Freezer | 8.1 | 498.0 | 0.0923 | 2 | 2 | 1 | 70 | 200 | 996 | 996 | 498 |
| Small Business Direct Install (SBDI) | Programmable Thermostat - Single Point - Electric Only | 15 | 2,037.5 | - | 272 | 263 | 464 | 250 | 5 | 554,200 | 535,863 | 945,400 |
| Small Business Direct Install (SBDI) | Programmable Thermostat - Multi Point - Electric Only | 15 | 4,658.0 | - | 2 | 2 | 2 | 325 | 10 | 9,316 | 9,316 | 9,316 |
| Small Business Direct Install (SBDI) | "Smart" Wi-Fi Thermostat - Single Point - Electric Only | 15 | 2,037.5 | - | 2 | 2 | 2 | 400 | 50 | 4,075 | 4,075 | 4,075 |
| Small Business Direct Install (SBDI) | "Smart" Wi-Fi Programmable Thermostat - Multi Point - Electric Only | 15 | 4,658.0 | - | 2 | 2 | 2 | 450 | 100 | 9,316 | 9,316 | 9,316 |
| Small Business Direct Install (SBDI) | Pre-Rinse Sprayer - Electric | 5 | 3,727.2 | - | 2 | 2 | 1 | 100 | 0 | 7,454 | 7,454 | 3,727 |
| Small Business Direct Install (SBDI) | Faucet Aerator - Electric | 10 | 391.0 | - | 0 | 0 | 0 | 50 | 0 | - | - | - |
| Small Business Direct Install (SBDI) | 2x2 Fluorescent Fixture to LED Panel | 15 | 144.0 | 0.0377 | 7 | 7 | 6 | 20 | 45.82 | 1,008 | 1,008 | 864 |
| | | | | | | | | | | | | |
| **Total SBDI** | | | | | **10,808** | **10,465** | **9,429** | | | **4,032,934** | **3,905,372** | **3,900,306** |

| Program | Measure | Measure Life | Average Savings per Unit (kWh) | Demand per Unit (KW) | 2018 Participation | 2019 Participation | 2020 Participation | Avg Incentive Paid Per Unit | Average Incremental Cost | 2018 kWh Savings | 2019 kWh Savings | 2020 kWh Savings |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Multifamily Retrofit | Pre-Rinse Sprayer - Electric | 5 | 3,727.2 | - | 0 | 0 | 0 | 100 | 0 | - | - | - |
| Multifamily Retrofit | Faucet Aerator - Electric | 10 | 391.0 | - | 1 | 1 | 1 | 50 | 0 | 391 | 391 | 391 |
| Multifamily Retrofit | Exterior Pole Mount: 1000W HID to LED | 15 | 3,536.6 | 0.6745 | 1 | 1 | 1 | 500 | 615 | 3,537 | 3,537 | 3,537 |
| Multifamily Retrofit | Exterior Wallpack: 251 W-400 W HID to LED | 15 | 1,066.7 | 0.0900 | 1 | 1 | 1 | 185 | 600 | 1,067 | 1,067 | 1,067 |
| Multifamily Retrofit | Exterior Canopy: 251 W-400 W HID to LED | 15 | 1,066.7 | 0.0900 | 1 | 1 | 1 | 185 | 600 | 1,067 | 1,067 | 1,067 |
| Multifamily Retrofit | Exterior Flood: 251 W-400 W HID to LED | 15 | 1,066.7 | 0.0900 | 1 | 1 | 1 | 185 | 600 | 1,067 | 1,067 | 1,067 |
| Multifamily Retrofit | Exterior Pole Mount: 251 W-400 W HID to LED | 15 | 1,066.7 | 0.0900 | 1 | 1 | 1 | 185 | 600 | 1,067 | 1,067 | 1,067 |
| Multifamily Retrofit | Exterior Other: 251 W-400 W HID to LED | 15 | 1,066.7 | 0.0900 | 1 | 1 | 1 | 185 | 600 | 1,067 | 1,067 | 1,067 |
| Multifamily Retrofit | 400W HID to High Bay LED ≤250W | 15 | 589.9 | 0.1797 | 1 | 1 | 1 | 220 | 480 | 590 | 590 | 590 |
| Multifamily Retrofit | 250W HID to High Bay LED ≤100W | 15 | 716.6 | 0.1778 | 0 | 0 | 0 | 160 | 460 | - | - | - |
| Multifamily Retrofit | Exterior Wallpack: 176 W-250 W HID to LED | 15 | 639.2 | 0.1236 | 4 | 4 | 4 | 115 | 310 | 2,557 | 2,557 | 2,557 |
| Multifamily Retrofit | Exterior Canopy: 176 W-250 W HID to LED | 15 | 639.2 | 0.1236 | 4 | 4 | 4 | 115 | 272 | 2,557 | 2,557 | 2,557 |
| Multifamily Retrofit | Exterior Flood: 176 W-250 W HID to LED | 15 | 639.2 | 0.1236 | 4 | 4 | 4 | 115 | 310 | 2,557 | 2,557 | 2,557 |
| Multifamily Retrofit | Exterior Pole Mount: 176 W-250 W HID to LED | 15 | 639.2 | 0.1236 | 4 | 4 | 4 | 115 | 310 | 2,557 | 2,557 | 2,557 |
| Multifamily Retrofit | Exterior Other: 176 W-250 W HID to LED | 15 | 639.2 | 0.1236 | 4 | 4 | 4 | 115 | 140 | 2,557 | 2,557 | 2,557 |
| Multifamily Retrofit | Anti-Sweat Heater Controls - Freezer | 12 | 1,277.0 | - | 0 | 0 | 0 | 220 | 360 | - | - | - |
| Multifamily Retrofit | Exterior Wallpack: 175W HID to LED | 15 | 470.4 | 0.0251 | 14 | 14 | 14 | 100 | 225.5 | 6,586 | 6,586 | 6,586 |
| Multifamily Retrofit | Exterior Canopy: less than 175W HID to LED | 15 | 470.4 | 0.0251 | 14 | 14 | 14 | 100 | 190.4 | 6,586 | 6,586 | 6,586 |
| Multifamily Retrofit | Exterior Flood: less than 175W HID to LED | 15 | 470.4 | 0.0251 | 14 | 14 | 14 | 100 | 188.33 | 6,586 | 6,586 | 6,586 |
| Multifamily Retrofit | Exterior Pole Mount: less than 175W HID to LED | 15 | 470.4 | 0.0251 | 14 | 14 | 14 | 100 | 187.5 | 6,586 | 6,586 | 6,586 |
| Multifamily Retrofit | Exterior Other: less than 175W HID to LED | 15 | 470.4 | 0.0251 | 14 | 14 | 14 | 100 | 63.75 | 6,586 | 6,586 | 6,586 |
| Multifamily Retrofit | 400W HID to High Bay Fluorescent 6-Lamp 4' HP, 28W or 25W T8 | 7 | 703.4 | 0.2116 | 1 | 1 | 1 | 125 | 300 | 703 | 703 | 703 |
| Multifamily Retrofit | Anti-Sweat Heater Controls - Refrigerator | 12 | 540.0 | - | 0 | 0 | 0 | 110 | 300 | - | - | - |
| Multifamily Retrofit | 250W HID to High Bay Fluorescent 4-Lamp 4' HP, 28W or 25W T8 | 7 | 519.9 | 0.1778 | 0 | 0 | 0 | 90 | 255 | - | - | - |
| Multifamily Retrofit | Delamping with Lamp & Ballast Retrofit: 4-Lamp 8' T12/T8 to 4-Lamp 4' or 2-Lamp 8' LED Tube | 15 | 364.8 | - | 0 | 0 | 0 | 65 | 250 | - | - | - |
| Multifamily Retrofit | Vending Machine Occ Sensor - Refrigerated Beverage | 5 | 1,602.5 | - | 0 | 0 | 0 | 250 | 208 | - | - | - |
| Multifamily Retrofit | Refrigerated Display Case Lighting 6' T12/T8 to LED - Refrigerator | 8.1 | 450.0 | 0.0531 | 0 | 0 | 0 | 70 | 200 | - | - | - |
| Multifamily Retrofit | Refrigerated Display Case Lighting 6' T12/T8 to LED - Freezer | 8.1 | 498.0 | 0.0923 | 0 | 0 | 0 | 70 | 200 | - | - | - |
| Multifamily Retrofit | EC (electronically commutated) Motor, Walk-in Refrigerator | 15 | 354.0 | 0.0486 | 0 | 0 | 0 | 70 | 137 | - | - | - |
| Multifamily Retrofit | EC (electronically commutated) Motor, Walk-in Freezer | 15 | 528.0 | 0.0560 | 0 | 0 | 0 | 90 | 180 | - | - | - |
| Multifamily Retrofit | Refrigerated Display Case Lighting 5' T12/T8 to LED - Refrigerator | 8.1 | 332.0 | 0.0493 | 0 | 0 | 0 | 55 | 180 | - | - | - |
| Multifamily Retrofit | Refrigerated Display Case Lighting 5' T12/T8 to LED - Freezer | 8.1 | 358.0 | 0.0856 | 0 | 0 | 0 | 55 | 180 | - | - | - |
| Multifamily Retrofit | Vending Machine Occ Sensor - Refrigerated Glass Front Cooler | 5 | 1,208.9 | - | 0 | 0 | 0 | 200 | 178 | - | - | - |
| Multifamily Retrofit | Lamp & Ballast Retrofit: 2-Lamp 8' T12/T8 to 4-Lamp 4' or 2-Lamp 8' LED Tube | 15 | 214.5 | 0.0433 | 2 | 2 | 2 | 40 | 175 | 429 | 429 | 429 |
| Multifamily Retrofit | Occupancy Sensors - Ceiling Mount (must control 350 watts) | 8 | 299.3 | 0.0630 | 1 | 1 | 1 | 60 | 170 | 299 | 299 | 299 |
| Multifamily Retrofit | EC (electronically commutated) Motor, Reach-in Refrigerator | 15 | 325.0 | 0.0320 | 0 | 0 | 0 | 70 | 159 | - | - | - |
| Multifamily Retrofit | EC (electronically commutated) Motor, Reach-in Freezer | 15 | 409.0 | 0.0340 | 0 | 0 | 0 | 90 | 159 | - | - | - |
| Multifamily Retrofit | 4-Lamp 4' T12/T8 to LED Panel | 15 | 286.6 | - | 0 | 0 | 0 | 50 | 155 | - | - | - |
| Multifamily Retrofit | Lamp & Ballast Retrofit: 1-Lamp 8' T12/T8 to 2-Lamp 4' or 1-Lamp 8' LED Tube | 15 | 171.9 | 0.0353 | 21 | 21 | 21 | 30 | 132 | 3,609 | 3,609 | 3,609 |
| Multifamily Retrofit | 3-Lamp 4' T12/T8 to LED Panel | 15 | 214.9 | - | 0 | 0 | 0 | 40 | 145 | - | - | - |
| Multifamily Retrofit | Delamping with Lamp & Ballast Retrofit w/Reflector: 4-Lamp 8' T12 to 4-Lamp 4' or 2-Lamp 8' HP, 28W or 25W T8 | 15 | 505.3 | 0.1368 | 0 | 0 | 0 | 90 | 140 | - | - | - |
| Multifamily Retrofit | Lamp & Ballast Retrofit: 4-Lamp 4' T12/T8 to 4' LED Tube | 15 | 314.3 | 0.0645 | 14 | 14 | 14 | 50 | 140 | 4,400 | 4,400 | 4,400 |
| Multifamily Retrofit | 2-Lamp 4' T12/T8 to LED Panel | 15 | 93.3 | - | 0 | 0 | 0 | 40 | 135 | - | - | - |
| Multifamily Retrofit | Delamping with Lamp & Ballast Retrofit: 4-Lamp 4' T12/T8 to 3-Lamp 4' LED Tube | 15 | 190.4 | - | 0 | 0 | 0 | 30 | 130 | - | - | - |
| Multifamily Retrofit | Lamp & Ballast Retrofit: 3-Lamp 4' T12/T8 to 4' LED Tube | 15 | 81.8 | - | 0 | 0 | 0 | 25 | 120 | - | - | - |
| Multifamily Retrofit | Delamping with Lamp & Ballast Retrofit: 4-Lamp 4' T12/T8 to 2-Lamp 4' LED Tube | 15 | 353.6 | 0.0726 | 3 | 3 | 3 | 60 | 120 | 1,061 | 1,061 | 1,061 |
| Multifamily Retrofit | Occupancy Sensors - Wall Mount (must control at least 200 watts) | 8 | 250.2 | 0.0108 | 0 | 0 | 0 | 40 | 115 | - | - | - |
| Multifamily Retrofit | Delamping with Lamp & Ballast Retrofit w/Reflector: 2-Lamp 8' T12 to 2-Lamp 4' or 1-Lamp 8' HP, 28W or 25W T8 | 15 | 275.9 | 0.0631 | 1 | 1 | 1 | 50 | 110 | 276 | 276 | 276 |
| Multifamily Retrofit | Lamp & Ballast Retrofit: 2-Lamp 8' T12 to 4-Lamp 4' or 2-Lamp 8' HP, 28W or 25W T8 w/ reflector | 15 | 59.3 | 0.0230 | 1 | 1 | 1 | 25 | 108 | 59 | 59 | 59 |
| Multifamily Retrofit | Delamping with Lamp & Ballast Retrofit: 4-Lamp 8' T12 to 4-Lamp 4' or 2-Lamp 8' HP, 28W or 25W T8 | 15 | 360.0 | 0.1368 | 0 | 0 | 0 | 60 | 105 | - | - | - |
| Multifamily Retrofit | Lamp & Ballast Retrofit: 2-Lamp 8' T12 to 4-Lamp 4' or 2-Lamp 8' HP, 28W or 25W T8 | 15 | 41.6 | 0.0208 | 1 | 1 | 1 | 27 | 103 | 42 | 42 | 42 |
| Multifamily Retrofit | Delamping with Lamp & Ballast Retrofit w/Reflector: 4-Lamp 4' T12 to 2-Lamp 4' HP, 28W or 25W T8 | 15 | 341.5 | 0.0910 | 35 | 35 | 35 | 60 | 58.51 | 11,951 | 11,951 | 11,951 |
| Multifamily Retrofit | Lamp & Ballast Retrofit: 2-Lamp 4' T12/T8 to 4' LED Tube | 15 | 74.4 | - | 0 | 0 | 0 | 25 | 100 | - | - | - |
| Multifamily Retrofit | Delamping with Lamp & Ballast Retrofit: 3-Lamp 4' T12/T8 to 2-Lamp 4' LED Tube | 15 | 158.1 | - | 0 | 0 | 0 | 30 | 100 | - | - | - |
| Multifamily Retrofit | "Smart" Wi-Fi Programmable Thermostat - Multi Point - Electric Only | 15 | 4,658.0 | - | 0 | 0 | 0 | 450 | 100 | - | - | - |

| Program | Measure | Measure Life | Average Savings per Unit (kWh) | Demand per Unit (KW) | 2018 Participation | 2019 Participation | 2020 Participation | Avg Incentive Paid Per Unit | Average Incremental Cost | 2018 kWh Savings | 2019 kWh Savings | 2020 kWh Savings |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Multifamily Retrofit | Lamp & Ballast Retrofit: 1-Lamp 8' T12 to 2-Lamp 4' or 1-Lamp 8' HP, 28W or 25W T8 w/ reflector | 15 | 153.9 | 0.0246 | 1 | 1 | 1 | 20 | 93 | 154 | 154 | 154 |
| Multifamily Retrofit | Delamping with Lamp & Ballast Retrofit w/Reflector: 4-Lamp 4' T12 to 3-Lamp 4' HP, 28W or 25W T8 | 15 | 247.1 | 0.0716 | 1 | 1 | 1 | 35 | 90 | 247 | 247 | 247 |
| Multifamily Retrofit | Delamping with Lamp & Ballast Retrofit w/Reflector: 2-Lamp 2' T12 U-tube to 2-Lamp 2' HP, 28W or 25W T8 | 15 | 108.0 | 0.0329 | 1 | 1 | 1 | 19 | 89 | 108 | 108 | 108 |
| Multifamily Retrofit | Lamp & Ballast Retrofit: 1-Lamp 8' T12 to 2-Lamp 4' or 1-Lamp 8' HP, 28W or 25W T8 | 15 | 110.7 | 0.0246 | 0 | 0 | 0 | 22 | 88 | - | - | - |
| Multifamily Retrofit | Delamping with Lamp & Ballast Retrofit w/Reflector: 3-Lamp 4' T12 to 2-Lamp 4' HP, 28W or 25W T8 | 15 | 225.7 | 0.0675 | 1 | 1 | 1 | 40 | 88 | 226 | 226 | 226 |
| Multifamily Retrofit | LED Exit Sign Fixture with Battery Backup | 16 | 87.2 | 0.0077 | 1 | 1 | 1 | 60 | 88 | 87 | 87 | 87 |
| Multifamily Retrofit | Lamp & Ballast Retrofit: 1-Lamp 4' T12/T8 to 4' LED Tube | 15 | 112.9 | 0.0232 | 3 | 3 | 3 | 18 | 80 | 339 | 339 | 339 |
| Multifamily Retrofit | Lamp & Ballast Retrofit: 4-Lamp 4' T12 to HP, 28W or 25W T8 | 15 | 116.5 | 0.0390 | 1 | 1 | 1 | 24 | 78 | 116 | 116 | 116 |
| Multifamily Retrofit | Delamping with Lamp & Ballast Retrofit: 4-Lamp 4' T12 to 3-Lamp 4' HP, 28W or 25W T8 | 15 | 211.2 | 0.0648 | 0 | 0 | 0 | 35 | 75 | - | - | - |
| Multifamily Retrofit | Delamping with Lamp & Ballast Retrofit: 4-Lamp 4' T12 to 2-Lamp 4' HP, 28W or 25W T8 | 15 | 264.9 | 0.0876 | 0 | 0 | 0 | 45 | 75 | - | - | - |
| Multifamily Retrofit | Delamping with Lamp & Ballast Retrofit: 2-Lamp 4' T12/T8 to 1-Lamp 4' LED Tube | 15 | 213.5 | - | 0 | 0 | 0 | 40 | 75 | - | - | - |
| Multifamily Retrofit | Lamp & Ballast Retrofit: 3-Lamp 4' T12 to HP, 28W or 25W T8 | 15 | 104.1 | 0.0383 | 0 | 0 | 0 | 20 | 70 | - | - | - |
| Multifamily Retrofit | Delamping with Lamp & Ballast Retrofit: 3-Lamp 4' T12 to 2-Lamp 4' HP, 28W or 25W T8 | 15 | 199.8 | 0.0611 | 0 | 0 | 0 | 35 | 57 | - | - | - |
| Multifamily Retrofit | Delamping with Lamp & Ballast Retrofit w/Reflector: 2-Lamp 4' T12 to 1-Lamp 4' HP, 28W or 25W T8 | 15 | 149.2 | 0.0404 | 1 | 1 | 1 | 25 | 57 | 149 | 149 | 149 |
| Multifamily Retrofit | ENERGY STAR® LED downlights - 60W Equivalent | 15 | 132.3 | 0.0371 | 1 | 1 | 1 | 27 | 57 | 132 | 132 | 132 |
| Multifamily Retrofit | ENERGY STAR® LED downlights - 75W+ Equivalent | 15 | 205.3 | 0.0412 | 12 | 12 | 12 | 35 | 39 | 2,463 | 2,463 | 2,463 |
| Multifamily Retrofit | Lamp & Ballast Retrofit: 2-Lamp 4' T12 to HP, 28W or 25W T8 | 15 | 85.4 | 0.0228 | 4 | 4 | 4 | 15 | 56 | 341 | 341 | 341 |
| Multifamily Retrofit | ENERGY STAR® LED downlights - 40W Equivalent | 15 | 94.3 | 0.0285 | 1 | 1 | 1 | 18 | 52 | 94 | 94 | 94 |
| Multifamily Retrofit | Lamp & Ballast Retrofit: 1-Lamp 4' T12 to HP, 28W or 25W T8 | 15 | 64.0 | 0.0171 | 3 | 3 | 3 | 12 | 51 | 192 | 192 | 192 |
| Multifamily Retrofit | Delamping with Lamp & Ballast Retrofit: 2-Lamp 4' T12 to 1-Lamp 4' HP, 28W or 25W T8 | 15 | 137.3 | 0.0246 | 0 | 0 | 0 | 25 | 50 | - | - | - |
| Multifamily Retrofit | "Smart" Wi-Fi Thermostat - Single Point - Electric Only | 15 | 2,037.5 | - | 0 | 0 | 0 | 400 | 50 | - | - | - |
| Multifamily Retrofit | 2x2 Fluorescent Fixture to LED Panel | 15 | 144.0 | 0.0377 | 1 | 1 | 1 | 20 | 45.82 | 144 | 144 | 144 |
| Multifamily Retrofit | Delamp 4 lamp 8ft T12 lamp and ballast | 10 | 834.3 | - | 0 | 0 | 0 | 75 | 38 | - | - | - |
| Multifamily Retrofit | Occupancy Sensors - Fixture Mount (must control at least 100 watts) | 8 | 154.6 | 0.0054 | 0 | 0 | 0 | 25 | 37 | - | - | - |
| Multifamily Retrofit | Delamp 2 lamp 8ft T12 lamp and ballast | 10 | 417.2 | - | 0 | 0 | 0 | 75 | 36 | - | - | - |
| Multifamily Retrofit | ENERGY STAR® LED lamps 60W Equivalent | 15 | 120.8 | 0.0337 | 28 | 28 | 28 | 22 | 7.38 | 3,382 | 3,382 | 3,382 |
| Multifamily Retrofit | ENERGY STAR® LED lamps 75W+ Equivalent | 15 | 179.2 | 0.0536 | 1 | 1 | 1 | 32 | 35 | 179 | 179 | 179 |
| Multifamily Retrofit | Delamp 1 lamp 8ft T12 lamp and ballast | 10 | 278.1 | - | 0 | 0 | 0 | 50 | 34 | - | - | - |
| Multifamily Retrofit | ENERGY STAR® LED lamps 40W Equivalent | 15 | 64.3 | 0.0293 | 9 | 9 | 9 | 12 | 33 | 579 | 579 | 579 |
| Multifamily Retrofit | Strip Curtain - Walk in Refrigerator | 6 | 13.2 | 0.0500 | 0 | 0 | 0 | 2.25 | 14.5 | - | - | - |
| Multifamily Retrofit | Strip Curtain - Walk in Freezer | 6 | 92.9 | 0.3400 | 0 | 0 | 0 | 15 | 14.5 | - | - | - |
| Multifamily Retrofit | Programmable Thermostat - Multi Point - Electric Only | 15 | 4,658.0 | - | 0 | 0 | 0 | 325 | 10 | - | - | - |
| Multifamily Retrofit | Programmable Thermostat - Single Point - Electric Only | 15 | 2,037.5 | - | 7 | 7 | 14 | 250 | 5 | 14,263 | 14,261.50 | 28,525 |
| | | | | | | | | | | | | |
| **Total Multifamily Retrofit** | | | | | **255** | **255** | **262** | | | **101,590** | **101,589** | **115,853** |
| | | | | | | | | | | | | |
| **CVR Commercial** | | **15** | **1,850.6** | **0.3330** | | | **558** | | | | | **1,032,656** |
| | | | | | | | | | | | | |
| **Total C&I** | | | | | | | | | | **15,135,729** | **16,043,561** | **17,053,516** |
| | | | | | | | | | | | | |
| **Portfolio Total** | | | | | | | | | | **36,656,341** | **38,069,187** | **36,347,642** |

# Attachment 6.2 2019 DSM Market Potential Study

prepared for

# VECTREN ENERGY DELIVERY OF INDIANA

## 2020-2025 Integrated **Electric** DSM Market Potential Study & Action Plan

January
2019

FINAL REPORT

prepared by
GDS ASSOCIATES INC
EMI CONSULTING

# EXECUTIVE SUMMARY



## *Executive Summary* ***List of Tables***



## *Executive Summary* ***List of Figures***

# VOLUME I *Electric DSM Market Potential Study*

## *Market Potential Study* ***List of Tables***

## *Market Potential Study* ***List of Figures***

# VOLUME II *Electric Action Plan*

## *Action Plan* ***List of Tables***

# VOLUME III *Electric Appendices*

## *Electric **DSM Market Potential Study***



## *Electric **Action Plan***

# Executive Summary

## OBJECTIVES & SCOPE

This project included a demand-side management (DSM) Market Potential Study and Action Plan for Vectren Energy Delivery of Indiana ("Vectren"). The study included assessments of electric energy efficiency and demand response potential. The results of the potential study were leveraged to develop a DSM Action Plan for Vectren's 2020-2025 planning horizon. This report provides the results of the electric energy efficiency and demand response potential analysis.

The energy efficiency potential study assessed potential by customer segment (residential, commercial, and industrial – with and without opt-out customers). The effort included several preliminary tasks to assess the Vectren market and develop foundational assumptions about the customer base, sales forecasts, and savings opportunities to order to then assess the overall energy efficiency potential in the Vectren services territories.

## APPROACH SUMMARY

The GDS team used a bottom-up approach to estimate energy efficiency potential in the residential sector. Bottom-up approaches begin with characterizing the eligible equipment stock, estimating savings and screening for cost-effectiveness first at the measure level, then summing savings at the end-use and service area levels. In the commercial and industrial sectors, GDS utilized the bottom-up modeling approach to first estimate measure-level savings and costs as well as cost-effectiveness, and then applied cost-effective measure savings to all applicable shares of energy load. The demand response potential assessment was conducted in a similar manner as the energy efficiency potential assessment. Below is the summary of the Maximum Achievable Potential (MAP), Realistic Achievable Potential (RAP) and Program Potential. More detail can be found in Section 1 of Volume I, Market Potential Study.

- ***Achievable Potential*** is the amount of energy that can realistically be saved given various market barriers. Achievable potential considers real-world barriers to encouraging end users to adopt efficiency measures; the non-measure costs of delivering programs (for administration, marketing, analysis, and EM&V); and the capability of programs and administrators to boost program activity over time. Barriers include financial, customer awareness and willingness to participate in programs, technical constraints, and other barriers the "program intervention" is modeled to overcome. Additional considerations include political and/or regulatory constraints. The potential study evaluated two achievable potential scenarios:
- ***Maximum Achievable Potential*** estimates achievable potential on paying incentives equal to 100% of measure incremental costs and aggressive adoption rates.
- ***Realistic Achievable Potential*** estimates achievable potential with Vectren paying incentive levels (as a percent of incremental measure costs) closely calibrated to historical levels but is not constrained by any previously determined spending levels.
- ***Program Potential*** refers to the efficiency potential possible given specific program funding levels and designs; in this study program potential is addressed by the DSM Action Plan, which further addresses issues such as market dynamics (net versus gross impacts), timeframe differences, proxy versus specific program delivery approaches, and budget realities.

## RESULTS

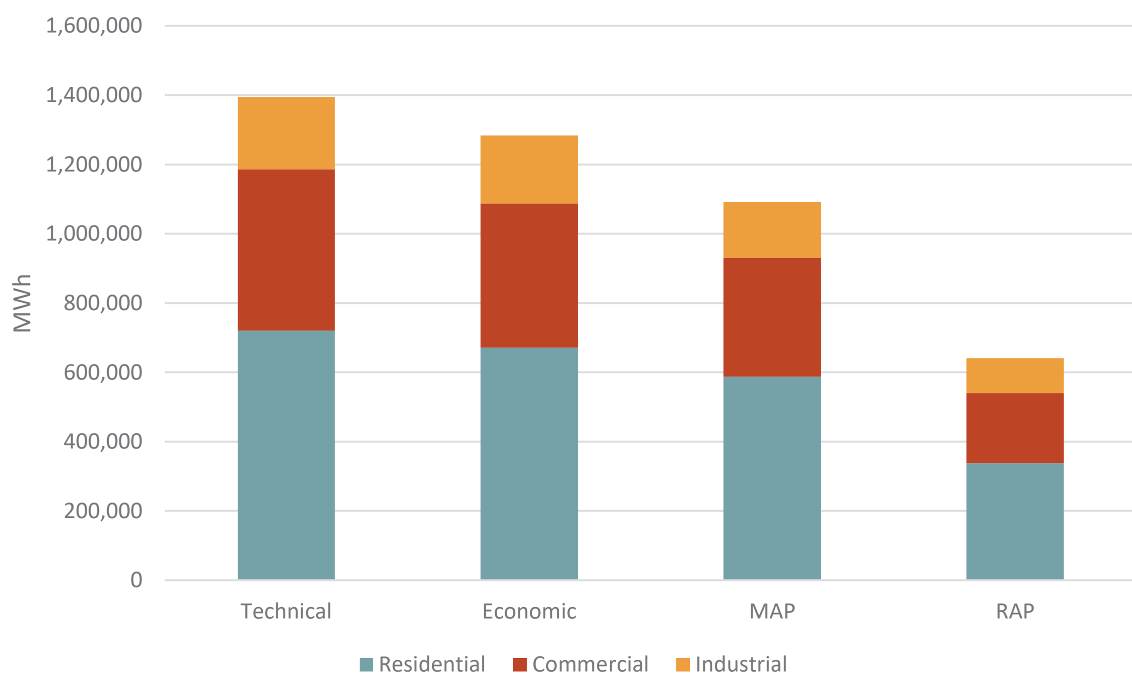
Table ES-1 summarizes the electric energy-efficiency savings for all measures at the different levels of potential relative to the baseline forecast. This provides cumulative annual technical, economic, MAP and RAP, and program potential energy savings, in total MWh and as a percentage of the sector-level sales forecast. Note that the steps of measure bundling, program design and program delivery refine the RAP results later into the Program Potential. The cumulative RAP increases to 9% cumulative annual savings over the next six years. The RAP savings estimates have a large residential sector low-income component.[1] Approximately 65% of the residential sector budget addresses the low-income market segment, with about 27% of the RAP savings are attributable to this segment.

TABLE ES-1 INCREMENTAL ANNUAL ENERGY EFFICIENCY POTENTIAL SUMMARY (NET OF LARGE CUSTOMER OPT-OUT LOAD)

| | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 |
|---|---|---|---|---|---|---|
| **MWh** | | | | | | |
| **Technical** | 179,992 | 209,578 | 199,765 | 194,021 | 182,130 | 169,589 |
| **Economic** | 167,372 | 192,143 | 183,629 | 179,315 | 168,500 | 156,910 |
| **MAP** | 91,970 | 135,273 | 134,335 | 135,296 | 133,380 | 126,777 |
| **RAP** | 57,005 | 69,699 | 66,105 | 67,277 | 68,583 | 67,330 |
| **Program** | 47,451 | 49,716 | 44,565 | 45,375 | 43,309 | 43,244 |
| **Forecasted Sales[2]** | 3,340,248 | 3,345,466 | 3,360,838 | 3,378,011 | 3,402,115 | 3,414,693 |
| **Energy Savings (as % of Forecast)** | | | | | | |
| **Technical** | 5.4% | 6.3% | 5.9% | 5.7% | 5.4% | 5.0% |
| **Economic** | 5.0% | 5.7% | 5.5% | 5.3% | 5.0% | 4.6% |
| **MAP** | 2.8% | 4.0% | 4.0% | 4.0% | 3.9% | 3.7% |
| **RAP** | 1.7% | 2.1% | 2.0% | 2.0% | 2.0% | 2.0% |
| **Program** | 1.4% | 1.5% | 1.3% | 1.3% | 1.3% | 1.3% |

Figure ES-1 provides the electric technical, economic, and achievable potential, by sector, by the end of the 20-year timeframe for the study (2020-2039). The residential sector contributes about half of the overall realistic achievable potential. Program potential only extends through 2025 and is not included in the figure below.

FIGURE ES-1 TWENTY (20)-YEAR CUMULATIVE ANNUAL ELECTRIC ENERGY EFFICIENCY POTENTIAL – ALL SECTORS COMBINED (NET OF LARGE CUSTOMER OPT-OUT LOAD)




[1] Low income households were characterized as homes that have household incomes at or below 200% of federal poverty guidelines. Based on data from the American Community 5-Year Public Use Microdata Set (PUMS), GDS used household income and number of people per household to identify the percent of the population at or below 200% of federal poverty guidelines for the Vectren South service area. 21% of single-family households and 48% of multifamily households were identified to meet the criteria.
[2] The forecasted sales here exclude opt-out customers. See Tables 1-2 through 1-5 for a comparison of the results with and without opt-out customers included in the analysis. Unless otherwise noted, the results in the report exclude opt-out sales and opt-out savings potential.

***Measure-Level Realistic Achievable Potential (Net of Opt-Outs)***

Table ES-2 provides the incremental RAP for each year by sector. The incremental annual savings potential ranges from 57 GWh to nearly 70 GWh. These results exclude load and savings attributed to large customers that have opted out of energy efficiency programs.

**TABLE ES-2 INCREMENTAL ELECTRIC MEASURE LEVEL REALISTIC ACHIEVABLE POTENTIAL – BY SECTOR (2020-2025)**

| Incremental Annual MWh | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 |
|---|---|---|---|---|---|---|
| **Sector** | | | | | | |
| Residential | 41,177 | 50,889 | 44,349 | 42,814 | 42,014 | 38,952 |
| Commercial | 10,311 | 12,122 | 13,911 | 15,609 | 16,770 | 17,811 |
| Industrial | 5,517 | 6,688 | 7,846 | 8,854 | 9,799 | 10,567 |
| **Total** | 57,005 | 69,699 | 66,105 | 67,277 | 68,583 | 67,330 |
| **Forecasted Sales (Net of Opt-Outs)** | 3,340,248 | 3,345,466 | 3,360,838 | 3,378,011 | 3,402,115 | 3,414,693 |
| **Incremental Annual Savings %** | | | | | | |
| **Sector** | | | | | | |
| Residential | 2.9% | 3.5% | 3.1% | 2.9% | 2.9% | 2.6% |
| Commercial | 0.8% | 1.0% | 1.1% | 1.2% | 1.3% | 1.4% |
| Industrial | 0.9% | 1.0% | 1.2% | 1.4% | 1.5% | 1.6% |
| **% of Forecasted Sales** | 1.7% | 2.1% | 2.0% | 2.0% | 2.0% | 2.0% |

Table ES-3 provides the cumulative RAP for each year across the 2020-2025 timeframe. The cumulative annual savings potential ranges from 57 GWh to nearly 309 GWh. These results assume that opt-out industrial customers do not provide any savings potential.

**TABLE ES-3 CUMULATIVE ELECTRIC MEASURE LEVEL REALISTIC ACHIEVABLE POTENTIAL – BY SECTOR (2020-2025)**

| Cumulative Annual MWh | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 |
|---|---|---|---|---|---|---|
| **Sector** | | | | | | |
| Residential | 41,177 | 84,538 | 105,533 | 134,072 | 159,025 | 184,648 |
| Commercial | 10,311 | 21,974 | 35,168 | 49,609 | 64,869 | 80,454 |
| Industrial | 5,517 | 11,982 | 19,336 | 27,377 | 35,449 | 43,566 |
| **Total** | 57,005 | 118,494 | 160,037 | 211,059 | 259,344 | 308,667 |
| **Forecasted Sales (Net of Opt-Outs)** | 3,340,248 | 3,345,466 | 3,360,838 | 3,378,011 | 3,402,115 | 3,414,693 |
| **Cumulative Annual Savings %** | | | | | | |
| **Sector** | | | | | | |
| Residential | 2.9% | 5.9% | 7.3% | 9.2% | 10.8% | 12.5% |
| Commercial | 0.8% | 1.8% | 2.8% | 4.0% | 5.1% | 6.3% |
| Industrial | 0.9% | 1.9% | 3.0% | 4.2% | 5.5% | 6.7% |
| **% of Forecasted Sales** | 1.7% | 3.5% | 4.8% | 6.2% | 7.6% | 9.0% |

Table ES-4 provides the annual budgets in the RAP scenario. The total RAP budgets across all sectors ranges from $24 million to $35 million during the 2020-2025 timeframe.

TABLE ES-4 ANNUAL BUDGETS (2020-2025) IN THE RAP SCENARIO ($ IN MILLIONS)

| RAP Budgets | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 |
|---|---|---|---|---|---|---|
| **Energy Efficiency** | | | | | | |
| Incentives | $16.2 | $21.1 | $22.8 | $24.0 | $24.8 | $24.6 |
| Admin | $4.8 | $6.2 | $6.4 | $6.6 | $7.0 | $7.0 |
| Energy Efficiency Sub-Total | $21.0 | $27.3 | $29.2 | $30.6 | $31.8 | $31.6 |
| **Demand Response / CVR** | | | | | | |
| Incentives | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 |
| Admin | $1.4 | $1.7 | $2.1 | $1.6 | $1.0 | $0.9 |
| Demand Response / CVR Sub-Total | $1.4 | $1.7 | $2.1 | $1.6 | $1.0 | $0.9 |
| | | | | | | |
| **Indirect[3]** | $1.4 | $1.8 | $1.7 | $1.9 | $2.0 | $2.1 |
| **Total** | | | | | | |
| **Total Costs** | $23.8 | $30.8 | $33.0 | $34.0 | $34.8 | $34.5 |

***Measure-Level Realistic Achievable Potential (Including Opt-Outs)***

Table ES-5 provides the incremental RAP for each year across the 2020-2025 timeframe, with sales and savings estimates from opt-out customers included. The incremental annual savings potential ranges from 72 GWh to 97 GWh. The incremental RAP increases by approximately 15 to 30 GWh across the timeframe, compared to the results with opt-out customers excluded.

TABLE ES-5 INCREMENTAL ELECTRIC REALISTIC ACHIEVABLE POTENTIAL – BY SECTOR (2020-2025)

| Incremental Annual MWh | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 |
|---|---|---|---|---|---|---|
| **Sector** | | | | | | |
| Residential | 41,177 | 50,889 | 44,349 | 42,814 | 42,014 | 38,952 |
| Commercial | 11,578 | 13,618 | 15,630 | 17,541 | 18,846 | 20,006 |
| Industrial | 19,324 | 23,576 | 27,883 | 31,695 | 35,218 | 38,149 |
| **Total** | 72,080 | 88,082 | 87,862 | 92,050 | 96,078 | 97,106 |
| **Forecasted Sales** | 5,163,888 | 5,174,499 | 5,196,938 | 5,221,660 | 5,253,393 | 5,273,051 |
| | | | | | | |
| **Sector** | | | | | | |
| Residential | 2.9% | 3.5% | 3.1% | 2.9% | 2.9% | 2.6% |
| Commercial | 0.8% | 1.0% | 1.1% | 1.2% | 1.3% | 1.4% |
| Industrial | 0.8% | 1.0% | 1.2% | 1.3% | 1.5% | 1.6% |
| **% of Forecasted Sales** | 1.4% | 1.7% | 1.7% | 1.8% | 1.8% | 1.8% |

Table ES-6 provides the cumulative RAP for each year across the 2020-2025 timeframe, with sales and savings estimates from opt-out customers included. The cumulative annual savings potential ranges from 72 GWh to 426 GWh. The cumulative annual RAP increases by more than 100 GWh across the 2020-2025 timeframe, compared to the results with opt-out customers excluded.

[3] Indirect costs represent costs that are not specifically attributed to individual programs and can include additional outreach, evaluation, and program planning activities.

TABLE ES-6 CUMULATIVE ELECTRIC REALISTIC ACHIEVABLE POTENTIAL – BY SECTOR (2020-2025)

| Cumulative Annual MWh | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 |
|---|---|---|---|---|---|---|
| **Sector** | | | | | | |
| Residential | 41,177 | 84,538 | 105,533 | 134,072 | 159,025 | 184,648 |
| Commercial | 11,578 | 24,685 | 39,512 | 55,740 | 72,884 | 90,391 |
| Industrial | 19,324 | 41,785 | 67,208 | 94,837 | 123,025 | 151,326 |
| **Total** | 72,080 | 151,009 | 212,254 | 284,649 | 354,935 | 426,364 |
| **Forecasted Sales** | 5,163,888 | 5,174,499 | 5,196,938 | 5,221,660 | 5,253,393 | 5,273,051 |
| | | | | | | |
| **Sector** | | | | | | |
| Residential | 2.9% | 5.9% | 7.3% | 9.2% | 10.8% | 12.5% |
| Commercial | 0.8% | 1.8% | 2.8% | 4.0% | 5.1% | 6.3% |
| Industrial | 0.8% | 1.8% | 2.9% | 4.0% | 5.2% | 6.4% |
| **% of Forecasted Sales** | 1.4% | 2.9% | 4.1% | 5.5% | 6.8% | 8.1% |

## DEMAND SAVINGS

The study also included an assessment of peak demand savings potential. Table ES-7 below provides the overall peak demand savings from energy efficiency, demand response, and CVR potential. The demand response potential assumes the energy efficiency peak demand reductions take precedent, and thereby reduce the baseline peak demand which can be further reduced by demand response.

TABLE ES-7 CUMULATIVE PEAK DEMAND SAVINGSPOTENTIAL – MAP AND RAP (2020-2025)

| MW | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 |
|---|---|---|---|---|---|---|
| **MAP** | | | | | | |
| Energy Efficiency | 12 | 28 | 43 | 58 | 72 | 85 |
| Demand Response | 22 | 61 | 103 | 121 | 124 | 123 |
| CVR | 0.4 | 0.4 | 0.4 | 1.1 | 1.1 | 1.1 |
| **Total** | 34 | 90 | 147 | 180 | 197 | 209 |
| **RAP** | | | | | | |
| Energy Efficiency | 8 | 16 | 23 | 31 | 38 | 45 |
| Demand Response | 7 | 19 | 37 | 47 | 51 | 51 |
| CVR | 0.4 | 0.4 | 0.4 | 1.1 | 1.1 | 1.1 |
| **Total** | 15 | 35 | 60 | 79 | 90 | 98 |

## ACTION PLAN

The results of the potential study were leveraged to develop a DSM Action Plan for the 2020-2025 timeframe. The achievable potential identified by the potential study formed the basis of the development of program potential, which further accounts for budgetary and market considerations. Furthermore, the Vectren Electric DSM Action Plan was developed as an integrated effort with the Vectren Gas DSM Action Plan, in order to optimize program design, budget, and cost-effectiveness considerations. Table ES-8 provides the incremental program potential for each year across the 2020-2025 timeframe. The incremental annual savings potential ranges from 43,244 MWh to 49,716 MWh.

TABLE ES-8 INCREMENTAL ELECTRIC PROGRAM POTENTIAL – BY SECTOR (2020-2025)

| Incremental Annual MWh | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 |
|---|---|---|---|---|---|---|
| **Sector** | | | | | | |
| Residential | 22,880 | 24,682 | 18,353 | 17,461 | 16,186 | 16,349 |
| Commercial and Industrial | 24,571 | 25,034 | 26,212 | 27,914 | 27,124 | 26,895 |
| **Total** | 47,451 | 49,716 | 44,565 | 45,375 | 43,309 | 43,244 |
| **Forecasted Sales (Net of Opt-Outs)** | 3,340,248 | 3,345,466 | 3,360,838 | 3,378,011 | 3,402,115 | 3,414,693 |
| **Incremental Annual Savings %** | | | | | | |
| **Sector** | | | | | | |
| Residential | 1.6% | 1.7% | 1.3% | 1.2% | 1.1% | 1.1% |
| Commercial and Industrial | 1.3% | 1.3% | 1.4% | 1.5% | 1.4% | 1.4% |
| **Incremental Annual Savings %** | | | | | | |
| **% of Forecasted Sales** | 1.4% | 1.5% | 1.3% | 1.3% | 1.3% | 1.3% |

Table ES-9 provides the cumulative Program Potential for each year across the 2020-2025 timeframe. The cumulative annual savings potential rises from 47,451 MWh to 273,660 MWh.

TABLE ES-9 CUMULATIVE ELECTRIC PROGRAM POTENTIAL – BY SECTOR (2020-2025)

| Cumulative MWh | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 |
|---|---|---|---|---|---|---|
| **Sector** | | | | | | |
| Residential | 22,880 | 47,562 | 65,915 | 83,376 | 99,562 | 115,911 |
| Commercial and Industrial | 24,571 | 49,605 | 75,817 | 103,730 | 130,854 | 157,749 |
| **Total** | 47,451 | 97,167 | 141,732 | 187,107 | 230,416 | 273,660 |
| **Forecasted Sales (Net of Opt-Outs)** | 3,340,248 | 3,345,466 | 3,360,838 | 3,378,011 | 3,402,115 | 3,414,693 |
| **Cumulative Annual Savings %** | | | | | | |
| **Sector** | | | | | | |
| Residential | 1.6% | 3.3% | 4.5% | 5.7% | 6.8% | 7.9% |
| Commercial and Industrial | 1.3% | 2.6% | 4.0% | 5.5% | 6.8% | 8.2% |
| **% of Forecasted Sales** | 1.4% | 2.9% | 4.2% | 5.5% | 6.8% | 8.0% |

Table ES-10 provides the annual budgets in the DSM Action Plan. The portfolio-level budgets range from $10.3 million to $11.2 million during the 2020-2025 timeframe.

TABLE ES-10 DSM ACTION PLAN ANNUAL BUDGETS (2020-2025)

| Annual Budgets | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 |
|---|---|---|---|---|---|---|
| **Residential** | | | | | | |
| Incentives | $1.3 | $1.4 | $1.3 | $1.1 | $1.2 | $1.2 |
| Admin | $0.4 | $0.4 | $0.4 | $0.4 | $0.4 | $0.4 |
| Implementation | $3.5 | $3.8 | $3.8 | $3.8 | $3.9 | $4.0 |
| **Residential Sub-total** | **$5.2** | **$5.5** | **$5.4** | **$5.3** | **$5.5** | **$5.6** |
| **Commercial and Industrial** | | | | | | |
| Incentives | $2.4 | $2.5 | $2.5 | $2.4 | $2.4 | $2.3 |
| Admin | $0.2 | $0.2 | $0.2 | $0.2 | $0.2 | $0.2 |
| Implementation | $1.3 | $1.4 | $1.4 | $1.5 | $1.6 | $1.6 |
| **Commercial and Industrial Sub-total** | **$3.9** | **$4.0** | **$4.1** | **$4.1** | **$4.2** | **$4.1** |
| Non-Sector Specific Costs | | | | | | |
| Indirect | $0.5 | $0.5 | $0.5 | $0.5 | $0.6 | $0.6 |
| Evaluation | $0.5 | $0.5 | $0.5 | $0.5 | $0.5 | $0.5 |
| Other | $0.2 | $0.5 | $0.2 | $0.2 | $0.5 | $0.2 |
| Total | | | | | | |
| **DSM Portfolio Total** | **$10.3** | **$11.1** | **$10.8** | **$10.7** | **$11.2** | **$11.0** |

## COST-EFFECTIVENESS

For planning purposes, each of the recommended programs must pass the Utility Cost Test (UCT) and the Total Resource Cost (TRC) tests, except for Income-Qualified Programs which do not need to meet cost-effectiveness tests in order to promote a greater social good. The cost-effectiveness results are reported for the UCT and the TRC tests. Each program is assessed separately to determine relative benefits and costs (in contrast to assessing each individual measure). The definitions for the four standard tests most commonly used in EE program design are described below.

- ***Total Resource Cost test (TRC).*** The benefits in this test are the lifetime avoided energy costs and avoided capacity costs. The costs in this test are the incremental measure costs plus all administrative costs spent by the program administrator.
- ***Utility Cost Test (UCT).*** The benefits in this test are the lifetime avoided energy costs and avoided capacity costs, the same as the TRC benefits. The costs in this test are the program administrator's incentive costs and administrative costs.
- ***Participant Cost Test (PCT).*** The benefits in this test are the lifetime value of retail rate savings (which is another way of saying "lost utility revenues"). The costs in this test are those seen by the participant; in other words: the incremental measure costs minus the value of incentives paid out.
- ***Rate Impact Measure test (RIM).*** The benefits of the RIM test are the same as the TRC benefits. The RIM costs are the same as the UCT, except for the addition of lost revenue. This test attempts to show the effects that EE programs will have on rates, which is almost always to raise them on a per unit basis. Thus, costs typically outweigh benefits from the point of view of this test, but the assumption is that absolute energy use decreases to a greater extent than per-unit rates are increased — resulting in lower average utility bills.

Table ES-11 provides the cost-benefit ratios for each of the major cost-effectiveness tests as well as the TRC Net Benefits by program and sector. Cost-benefit screening was performed using DSMore.

**TABLE ES-11 VECTREN RECOMMENDED ACTION PLAN COST-EFFECTIVENESS SUMMARY**

| Program | TRC Ratio | TRC NET Benefits | UCT Ratio | PCT Ratio | RIM Ratio |
|---|---|---|---|---|---|
| Res Lighting | 3.27 | $9,339,929 | 5.38 | 4.99 | 0.69 |
| Res HEA | 2.24 | $1,690,395 | 2.24 | | 0.64 |
| Res IQW | 1.07 | $507,171 | 1.14 | 9.65 | 0.66 |
| Res Schools | 4.79 | $2,469,620 | 4.79 | | 0.71 |
| Res Behavior | 1.82 | $1,503,965 | 1.82 | | 0.61 |
| Res Appliance Recycling | 2.50 | $1,700,461 | 2.07 | | 0.63 |
| Res CVR | 2.38 | $1,909,353 | 2.38 | | 0.78 |
| Res Food Bank | 8.29 | $1,535,163 | 8.29 | | 0.70 |
| Res HEMS | 1.01 | $11,100 | 1.01 | | 0.47 |
| Direct Load Control | 4.07 | $10,016,215 | 3.06 | | 2.28 |
| Res New Construction | 1.14 | $91,580 | 1.98 | 1.28 | 0.75 |
| Res Prescriptive | 1.41 | $3,069,767 | 1.91 | 2.01 | 0.77 |
| Res Portfolio ALL E | 2.12 | $33,844,720 | 2.35 | 4.90 | 0.81 |
| CI Prescriptive | 3.06 | $49,412,426 | 6.22 | 2.97 | 0.92 |
| CI Custom | 3.11 | $20,261,839 | 6.46 | 3.45 | 0.77 |
| CI Small Business | 1.74 | $4,065,481 | 2.49 | 3.09 | 0.53 |
| CI CVR | 2.55 | $1,538,199 | 2.55 | | 0.86 |
| **CI Portfolio ALL** | **2.88** | **$75,277,946** | **5.43** | **3.13** | **0.82** |
| ***Total Portfolio ALL*** | ***2.33*** | ***$102,456,927*** | ***3.25*** | ***3.56*** | ***0.79*** |

# VOLUME I

## *2020-2025 Integrated Electric DSM Market Potential Study*

*prepared for*

VECTREN
Live Smart

JANUARY 2019

# 1 Introduction

## 1.1 BACKGROUND & STUDY SCOPE

This Market Potential Study was conducted to support the development of a DSM Action Plan for Vectren. The study included primary market research and a comprehensive review of current programs, historical savings, and projected energy savings opportunities to develop estimates of technical, economic, and achievable potential. Separate estimates of electric energy efficiency and demand response potential were developed. The effort was highly collaborative, as the GDS Team worked closely alongside Vectren, as well as the Vectren Oversight Board, to produce reliable estimates of future saving potential, using the best available information and best practices for developing market potential saving estimates.

## 1.2 TYPES OF POTENTIAL ESTIMATED

The scope of this study distinguishes three types of energy efficiency potential: (1) technical, (2) economic, and (3) achievable.

- ***Technical Potential*** is the theoretical maximum amount of energy use that could be displaced by efficiency, disregarding all non-engineering constraints such as cost-effectiveness and the willingness of end users to adopt the efficiency measures. Technical potential is constrained only by factors such as technical feasibility and applicability of measures.
- ***Economic Potential*** refers to the subset of the technical potential that is economically cost-effective as compared to conventional supply-side energy resources. Economic potential follows the same adoption rates as technical potential. Like technical potential, the economic scenario ignores market barriers to ensuring actual implementation of efficiency. Finally, economic potential only considers the costs of efficiency measures themselves, ignoring any programmatic costs (e.g., marketing, analysis, administration) that would be necessary to capture them. This study uses the Utility Cost Test (UCT) to assess cost-effectiveness.
- ***Achievable Potential*** is the amount of energy that can realistically be saved given various market barriers. Achievable potential considers real-world barriers to encouraging end users to adopt efficiency measures; the non-measure costs of delivering programs (for administration, marketing, analysis, and EM&V); and the capability of programs and administrators to boost program activity over time. Barriers include financial, customer awareness and willingness to participate in programs, technical constraints, and other barriers the "program intervention" is modeled to overcome. Additional considerations include political and/or regulatory constraints. The potential study evaluated two achievable potential scenarios:
- ***Maximum Achievable Potential*** estimates achievable potential on paying incentives equal to 100% of measure incremental costs and aggressive adoption rates.
- ***Realistic Achievable Potential*** estimates achievable potential with Vectren paying incentive levels (as a percent of incremental measure costs) closely calibrated to historical levels but is not constrained by any previously determined spending levels.
- ***Program Potential*** refers to the efficiency potential possible given specific program funding levels and designs; in this study program potential is addressed by the DSM Action Plan, which further addresses issues such as market dynamics (net versus gross impacts), timeframe differences, proxy versus specific program delivery approaches, and budget realities.

## 1.3 STUDY LIMITATIONS

As with any assessment of energy efficiency potential, this study necessarily builds on various assumptions and data sources, including the following:

- Energy efficiency measure lives, savings, and costs
- Projected penetration rates for energy efficiency measures
- Projections of electric and natural gas avoided costs
- Future known changes to codes and standards

- Vectren load forecasts and assumptions on their disaggregation by sector, segment, and end use
- End-use saturations and fuel shares

While the GDS team has sought to use the best and most current available data, there are often reasonable alternative assumptions which would yield slightly different results.

## 1.4 ORGANIZATION OF REPORT

The remainder of this report is organized in seven sections as follows:

***Section 2 Methodology*** details the methodology used to develop the estimates of technical, economic, and achievable energy efficiency and demand response potential savings.

***Section 3 Market Characterization*** provides an overview of the Vectren service areas and a brief discussion of the forecasted energy sales by sector.

***Section 4 Residential Energy Efficiency Potential*** provides a breakdown of the technical, economic, and achievable potential in the residential sector.

***Section 5 Commercial Energy Efficiency Potential*** provides a breakdown of the technical, economic, and achievable potential in the commercial sector.

***Section 6 Industrial Energy Efficiency Potential*** provides a breakdown of the technical, economic, and achievable potential in the industrial sector.

***Section 7 Demand Response Potential*** provides a breakdown of the technical, economic, and achievable potential demand response by program type.

***Appendices*** for the DSM Market Potential are included in Volume III of this report. MPS appendices include a discussion of sources used for the analysis, detailed measure level assumptions by customer segment, nonresidential sector potential savings (including opt-out customers), and detailed demand response results.

# 2 Methodology

This section describes the overall methodology utilized to assess the electric energy efficiency and demand response potential in the Vectren service area. The main objectives of this Market Potential Study were to estimate the technical, economic, MAP and RAP of energy efficiency and demand response in the Vectren electric (Vectren South) service territory; and to quantify these estimates of potential in terms of MWh and MW savings, for each level of energy efficiency and demand response potential.

The development of the DSM Action Plan, and associated savings during the 2020-2025 timeframe, are discussed in Volume II of this report.

## 2.1 OVERVIEW OF APPROACH

For the residential sector, GDS took a bottom-up approach to the modeling, whereby measure-level estimates of costs, savings, and useful lives were used as the basis for developing the technical, economic, and achievable potential estimates. The measure data was used to build-up the technical potential, by applying the data to each relevant market segment. The measure data allowed for benefit-cost screening to assess economic potential, which was in turn used as the basis for achievable potential, which took into consideration incentives and estimates of annual adoption rates.

For the commercial and industrial sectors, GDS took a bottom-up modeling approach to first estimate measure-level savings and costs as well as cost-effectiveness, and then applied cost-effective measure savings to all applicable shares of energy load. Disaggregated forecast data served as the foundation for the development of the energy efficiency potential estimates. The creation of the disaggregation involved two steps. First, GDS looked at actual customer groupings based on NAICS code and then calibrated our top down load allocation based these codes to determine whether the customer was captured in the load forecast. Second, GDS determined the appropriate industry for industrial customers and the building type for commercial customers.

## 2.2 MARKET CHARACTERIZATION

The initial step in the analysis was to gather a clear understanding of the current market segments by fuel type in the Vectren service area. The GDS team coordinated with Vectren to gather utility sales and customer data and existing market research to define appropriate market sectors, market segments, vintages, saturation data and end uses for each fuel type. This information served as the basis for completing a forecast disaggregation and market characterization of both the residential and nonresidential sectors.

### *2.2.1 Forecast Disaggregation*

In the residential sector, GDS calibrated its building energy modeling simulations with Vectren's sales forecasts.[4] This process began with the construction of building energy models, using the BEopt™ (Building Energy Optimization)[5] software, which were specified in accordance with the most currently available data describing the residential building stock in the Vectren South service area. Models were constructed for both single-family and multifamily homes, as well as various types of heating and cooling equipment and fuel types. Key characteristics defining these models include conditioned square footage, typical building envelope conditions such as insulation levels and representative appliance and HVAC efficiency levels. The simulations yielded estimated energy consumption for each building prototype, including estimates of each key end use. These end use estimates were then multiplied by the estimated proportion of customers that applied to each end use, to calculate an estimated service territory total consumption for each end use. For example, when completing this process for the Vectren South electric potential analysis, the simulated heat

[4] Vectren's sales forecast in all sectors excludes the impact of future DSM savings. Excluding future DSM savings prevents under-estimating energy efficiency savings potential.
[5] BEopt can be used to analyze both new construction and existing home retrofits, as well as single-family detached and multi-family buildings, through evaluation of single building designs, parametric sweeps, and cost-based optimizations.

pump electric heating consumption was multiplied by the proportion of homes that rely on heat pumps for their electric heating needs, to calculate the total heat pump electric heating load in the Vectren South service territory.

The simulation process required several iterations. GDS collaborated with Vectren to verify and modify certain assumptions about the market characteristics, such as the heating fuel and equipment types. GDS adjusted its assumptions about key market characteristics and revised its BEopt models to calibrate its building energy models to within 1% of forecasted sales in 2020.

In the commercial and industrial sectors, disaggregated forecast data provides the foundation for the development of energy efficiency potential estimates. GDS disaggregated the nonresidential sector for Vectren into building or industry types using Vectren's commercial and industrial customer database and 2017 monthly sales data. GDS supplemented the Vectren customer database with a third-party dataset (purchased from InfoUSA) that provided additional SIC/NAICS code data by business.[6] This disaggregation involved two steps. First, the GDS team used rate codes to determine whether the customer was captured in either Vectren's commercial or industrial load forecast. Next, GDS determined the appropriate industry for industrial customers and the building type for commercial customers. We used the following information, either from Vectren's customer data or third-party dataset, to determine the appropriate building or industry type. Using these fields, GDS assigned customers Vectren's non-residential data sets to one of the commercial or industrial segments listed in Table 2-1.

TABLE 2-1 NON-RESIDENTIAL SEGMENTS

| COMMERCIAL | INDUSTRIAL | |
|---|---|---|
| ☑ Education | ☑ Chemicals | ☑ Paper |
| ☑ Food Sales | ☑ Fabricated Metals | ☑ Plastics and Rubber |
| ☑ Food Service | ☑ Food and Agriculture | ☑ Primary Metals |
| ☑ Health Care | ☑ Machinery | ☑ Transportation Equipment |
| ☑ Hospital | ☑ Mining | ☑ Wood |
| ☑ Large Office | ☑ Nonmetallic Mineral | |
| ☑ Large Retail | | |
| ☑ Lodging | | |
| ☑ Mercantile | | |
| ☑ Office | | |
| ☑ Public Assembly | | |
| ☑ Warehouse | | |

GDS further disaggregated sales for each of the segments into end uses. For commercial segments, GDS primarily used Vectren's 2016 end-use forecast planning models supplemented with updated EIA 2012 Commercial Building Energy Consumption Survey (CBECS) data for the East South-Central Census region. This information was used to determine energy use intensities, expressed in kWh per square foot, for each end use within each segment.[7] We then used data compiled from metering studies, Evaluation, Measurement and Verification (EM&V), and engineering algorithms to further disaggregate energy intensities into more granular end uses and technologies. For the industrial sector, the analysis relied on the EIA's Manufacturing Energy Consumption survey to disaggregate industry-specific estimates of consumption into end uses.[8]

---

[6] The Vectren dataset classifies businesses by Standard Industrial Classification (SIC) code, a four-digit standardized code, that has largely been replaced by the North American Industry Classification System (NAICS) code. The GDS Team converted the Vectren SIC codes to NAICS codes, then mapped NAICS/SIC codes to building and industry types considered in this study.
[7] U.S. Energy Information Agency. *Commercial Buildings Energy Consumption Survey (CBECS)*. May 20, 2016. https://www.eia.gov/consumption/commercial/. Although the Vectren service area officially resides in the East-North Central Census region, Vectren's long-term load forecast uses the East-South Central Census region as a more accurate representation of the Vectren service area.
[8] U.S. EIA. *Manufacturing Energy Consumption Survey (MECS) 2010.* March 2013. https://www.eia.gov/consumption/manufacturing/data/2010/.

Table 2-2 lists the electric end-uses considered in the forecast disaggregation and subsequent potential assessment.

TABLE 2-2 ELECTRIC END USES

| RESIDENTIAL | COMMERCIAL | INDUSTRIAL |
|---|---|---|
| ☑ Behavioural | ☑ Cooking | ☑ Agriculture |
| ☑ Clothes Washer/Dryer | ☑ Cooling | ☑ Computers & Office Equipment |
| ☑ Dishwasher | ☑ Lighting | ☑ CHP |
| ☑ Electronics | ☑ Office Equipment | ☑ Lighting |
| ☑ Hot Water | ☑ Refrigeration | ☑ Machine Drive |
| ☑ HVAC Equipment | ☑ Space Heating | ☑ Process Heating |
| ☑ HVAC Shell | ☑ Ventilation | ☑ Process Cooling |
| ☑ Lighting | ☑ Water Heating | ☑ Space Cooling |
| ☑ Pool/Spa | | ☑ Space Heating |
| | | ☑ Ventilation |
| | | ☑ Water Heating |

### *2.2.2 Eligible Opt-Out Customers*

In Indiana, commercial or industrial customers with a peak load greater than 1MW are eligible to opt out of utility-funded electric energy efficiency programs. In the Vectren service area, approximately 67% of C&I customers are eligible to opt-out. Of eligible customers, nearly 76% have chosen to opt-out. As a result, only 49% of total C&I sales have not presently opted out of funding Vectren's energy efficiency programs.[9]

FIGURE 2-1 OPT-OUT SALES BY C&I SECTOR

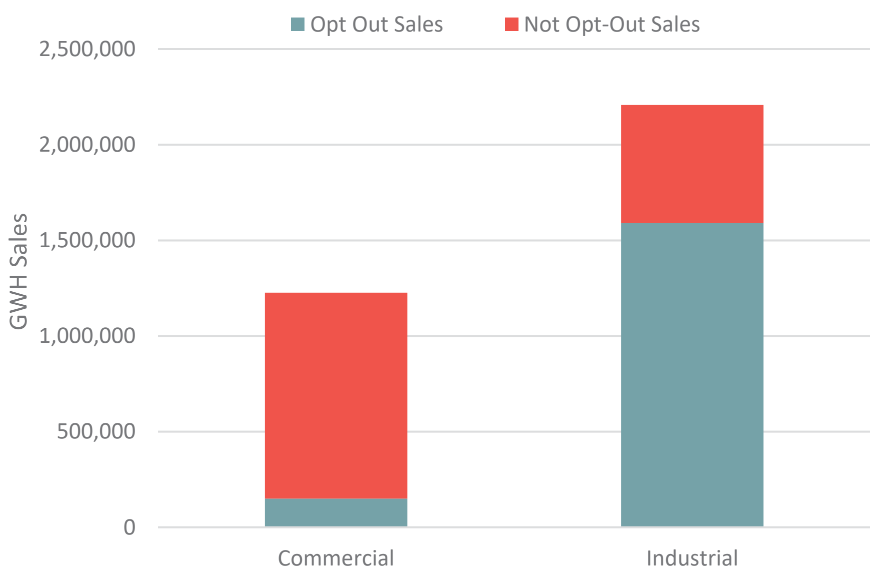



Figure 2-1 shows the total sales for the commercial and industrial sectors, as well as the sales, by sector, that have currently opted out of paying the charge levied to support utility-administered energy efficiency programs. The portion of sales that have not opted out include both ineligible load (i.e. does not meet the 1 MW monthly peak requirement) as well as eligible load that has not yet opted out.

The main body of this report focuses on the electric energy efficiency potential savings in the commercial and industrial sectors excluding sales from opt-out customers. Appendix E and Appendix F provide the respective results of commercial and industrial sector potential in a scenario that includes savings from Vectren's opt-out customers.

### *2.2.3 Building Stock/Equipment Saturation*

To assess the potential electric energy efficiency savings available, estimates of the current saturation of baseline equipment and energy efficiency measures are necessary.

[9] These percentages were calculated based on the 2017 Vectren non-residential customer data and 2017 billing history.

#### 2.2.3.1 Residential Sector

For the residential sector, GDS relied on several primary research efforts. The electric measure analysis was largely informed by a 2016 baseline survey of Vectren South customers. Nearly 500 responses to this survey provided a strong basis for many of the Vectren South electric measure baseline and efficient saturation estimates. A 2015 CFL and LED baseline study helped inform the saturation estimates for the lighting end use. A 2017 electric baseline thermostat survey of Vectren customers was leveraged to better characterize the increased prominence of smart and Wi-Fi-enabled thermostats.

EIA Residential Energy Consumption Survey (RECS) data from 2015 helped fill in data gaps that could not be directly informed by Vectren primary research. Other data sources included ENERGY STAR unit shipment data, Vectren evaluation reports, and baseline studies from other states. The ENERGY STAR unit shipment data filled data gaps related to the increased saturation of energy efficient equipment across the U.S. in the last decade.

#### 2.2.3.2 Commercial Sector

For the ***commercial sector***, data collected through on-site visits as part of this study was leveraged to develop remaining factors for many of the measures. GDS coordinated with Vectren and the Oversight Board to develop a research plan, sampling plan, and a survey questionnaire used to collect data.

The study included primary onsite research with 38 of Vectren's commercial customers across all building types considered in the study.[10] The on-site data collection included facility operation schedules and building characteristics, HVAC equipment type and efficiency levels, lighting fixture inventories, control systems and strategies, and related electric consuming equipment characteristics.

The survey data was used to inform two main assumptions for the potential study, the Base Case and the Remaining factors. The Base Case Factor is the fraction of the end use energy that is applicable for the efficient technology in a given market segment. Survey data was used to determine fractional energy use for most measures in the study. The survey data provided counts for equipment and energy usage levels for the lighting, heating, cooling, water heating, motors and refrigeration end-uses. For example, T8 lighting used 88% of the energy for interior fluorescent lamps and fixtures for the surveyed buildings. The remaining usage was a combination of T12s, T5s and LED linear tube lighting. In total, 60% of the base case allocations came directly from the survey data and the other 40% came from regional potential study data from other Indiana Utilities or from GDS estimates based upon past study experience.

The remaining factor is the fraction of applicable kWh sales that are associated with equipment that has not yet been converted to the energy efficiency measure. It can also be defined as one minus the fraction of the market segment that already have the energy-efficiency measure installed, or one minus the market saturation for the measures. The commercial survey data was used to determine the remaining factors for 60% of all measures in the study. For example, the survey found that 24% of linear fluorescent lamps have already been converted to LEDs. The remaining factor for this measure is 76%. The latest ENERGY STAR shipment data report also provided remaining factors for several measures. The other remaining factors are either 100% for emerging technologies measures or estimates are based on GDS past study experience.

#### 2.2.3.3 Industrial Sector

For the ***industrial sector***, Vectren survey data was leveraged to determine the remaining factors for several end-uses, including motors, interior and exterior lighting and fixture measures. GDS was able to approximate the percentage of remaining standard efficiency motors from the survey data (approximately 67% appear to be standard efficiency), as well as the approximate percentage of remaining constant speed motors (non-VFD) for the industrial survey group (approximately 65% constant speed). GDS was also able to determine a percentage of remaining fluorescent tube

[10] The full survey dataset was provided to Vectren as a deliverable.

fixture lighting and HID fixture lighting (non-LED) to be approximately 90% from the industrial survey responses. Other industrial process remaining factors were determined based on remaining factors used in previous studies, which were determined from baseline studies in other jurisdictions, the U.S. EIA 2013 Industrial Model Documentation Report, or GDS engineering estimates.

### *2.2.4 Remaining Factor*

The remaining factor is the proportion of a given market segment that is not yet efficient and can still be converted to an efficient alternative. If is by definition, the inverse of the saturation of an energy efficient measure, prior to any adjustments. For this study we made two key adjustments to recognize that the energy efficient saturation does not necessarily always fully represent the state of market transformation. In other words, while a percentage of installed measures may already be efficient, this does not preclude customers from backsliding, or reverting to standard technologies, or otherwise less efficient alternatives in the future, based on considerations like measure cost and availability and customer preferences (e.g. historically, some customers have disliked CFL light quality, and have reverted to incandescent and halogen bulbs after the CFLs burn out).

For measures categorized as market opportunity (i.e. replace-on-burnout), we assumed that 50% of the instances in which an efficient measure is already installed, the burnout or failure of those measures would be eligible for inclusion in the estimate of future savings potential. Essentially this adjustment implies that we are assuming that 50% of the market is transformed, and no future savings potential exists, whereas the remaining 50% of the market is not transformed and could backslide without the intervention of a Vectren program and an incentive. Similarly, for retrofit measures, we assumed that only 10% of the instances in which an efficient measure is already installed, the burnout or failure of those measures would be eligible for inclusion in the estimate of future savings potential. This recognizes the more proactive nature of retrofit measures, as the implementation of these measures are more likely to be elective in nature, compared to market opportunity measures, which are more likely to be needs-based. We recognize the uncertainty in these assumptions, but we believe these are appropriate assumptions, as they recognize a key component of the nature of customer decision making.

## 2.3 MEASURE CHARACTERIZATION

### *2.3.1 Measure Lists*

The study's sector-level energy efficiency measure lists were informed by a range of sources including the Indiana TRM, current Vectren program offerings, and commercially viable emerging technologies, among others. Measure list development was a collaborative effort in which GDS developed draft lists that were shared with Vectren and the Stakeholders. The final measure lists ultimately included in the study reflected the informed comments and considerations from the parties that participated in the measure list review process.

In total, GDS analyzed 538 measure types for Vectren South – Electric. Some measures save both electric and natural gas. For those measures, the savings of both fuels were included in the benefit-cost screening.[11] Many measures were included in the study as multiple permutations to account for different specific market segments, such as different building types, efficiency levels, and replacement options. GDS developed a total of 4,155 measure permutations for this study. Each permutation was, screened for cost-effectiveness according to the Utility Cost Test (UCT). The parameters for cost-effectiveness under the UCT are discussed in detail later in Section 2.4.3.

---

[11] Because electric and natural gas results are presented in separate reports, costs were apportioned between electric and gas based on the relative amount of savings from each fuel type.

TABLE 2-3 NUMBER OF MEASURES EVALUATED

| | # of Measures | Total # of Measure Permutations | # with UCT ≥ 1 |
|---|---|---|---|
| **Vectren South – Electric** | | | |
| **Residential** | 185 | 636 | 449 |
| **Commercial** | 219 | 2,190 | 1,890 |
| **Industrial** | 165 | 1,464 | 1,424 |
| ***Total*** | 550 | 4,155 | 3,681 |

### *2.3.2 Emerging Technologies*

GDS considered several specific emerging technologies as part of analyzing future potential. In the residential sector, these technologies include several smart technologies, including smart appliances, smart water heater (WH) tank controls, smart window coverings, smart ceiling fans, heat pump dryers and home automation/home energy management systems. In the non-residential sector, specific emerging technologies that were considered as part of the analysis include strategic energy management, advance lighting controls, advanced rooftop controls, cloud-based energy information systems ("EIS"), high performance elevators, and escalator motor controls. While this is likely not an exhaustive list of possible emerging technologies over the next twenty years it does consider many of the known technologies that are available today but may not yet have widespread market acceptance and/or product availability.

In addition to these specific technologies, GDS acknowledges that there could be future opportunities for new technologies as equipment standards improve and market trends occur. While this analysis does not make any explicit assumption about unknown future technologies, the methodology assumes that subsequent equipment replacement that occurs over the course of the 20-year study timeframe, and at the end of the initial equipment's useful life, will continue to achieve similar levels of energy savings, relative to improved baselines, at similar incremental costs.

### *2.3.3 Assumptions and Sources*

A significant amount of data is needed to estimate the electric savings potential for individual energy efficiency measures or programs across the residential and nonresidential customer sectors. GDS utilized data specific to Vectren when it was available and current. GDS used the most recent Vectren evaluation report findings (as well as Vectren program planning documents), 2015 Indiana Technical Reference Manual (IN TRM), the Illinois TRM, and the Michigan Energy Measures Database (MEMD) to a large amount of the data requirements. Evaluation report findings and the Indiana TRM were leveraged to the extent feasible – additional data sources were only used if these first two sources either did not address a certain measure or contained outdated information. The BEopt simulation modeling results formed the basis for most heating and cooling end use measure savings. The National Renewable Energy Laboratory (NREL) Energy Measures Database also served as a key data source in developing measure cost estimates. Additional source documents included American Council for an Energy-Efficient Economy (ACEEE) research reports covering topics like emerging technologies.

***Measure Savings:*** GDS relied on existing Vectren evaluation report findings and the 2015 IN TRM to inform calculations supporting estimates of annual measure savings as a percentage of base equipment usage. For custom measures and measures not included in the IN TRM, GDS estimated savings from a variety of sources, including:

- Illinois TRM, MEMD, and other regional/state TRMs
- Building energy simulation software (BEopt) and engineering analyses
- Secondary sources such as the ACEEE, Department of Energy (DOE), Energy Information Administration (EIA), ENERGY STAR©, and other technical potential studies

***Measure Costs:*** Measure costs represent either incremental or full costs. These costs typically include the incremental cost of measure installation, when appropriate based on the measure definition. For purposes of this study, nominal measure costs held constant over time.[12] One exception is an assumed decrease in costs for light emitting diode (LED) bulbs over the study horizon. LED bulb consumer costs have been declining rapidly over the last several years and future cost projections indicate a continued decrease in bulb costs.[13] GDS' treatment of LED bulb costs, LED lighting efficacy, and the impacts of the Energy Independence and Security Act ("EISA") are discussed in greater detail in Section 2.3.5, "Review of LED Lighting Assumptions."

GDS obtained measure cost estimates primarily from the Vectren program planning databases, and the 2015 IN TRM. GDS used the following data sources to supplement the IN TRM:

- Illinois TRM, MEMD, and other regional/state TRMs
- Secondary sources such as the ACEEE, ENERGY STAR, and National Renewable Energy Lab (NREL)
- Program evaluation and market assessment reports completed for utilities in other states

***Measure Life:*** Measure life represents the number of years that energy using equipment is expected to operate. GDS obtained measure life estimates from the 2015 IN TRM and Vectren program planning databases, and used the following data sources for measures not in the IN TRM:

- Illinois TRM, MEMD, and other regional/state TRMs
- Manufacturer data
- Savings calculators and life-cycle cost analyses

All measure savings, costs, and useful life assumption sources are documented in Appendices B-D.

### *2.3.4 Treatment of Codes and Standards*

Although this analysis does not attempt to predict how energy codes and standards will change over time, the analysis does account for the impacts of several known improvements to federal codes and standards. Although not exhaustive, key adjustments include[14]:

- The baseline efficiency for air source heat pumps (ASHP) is anticipated to improve to 14 SEER/8.2 HSPF[15] in 2015. As the existing stock of ASHPs was estimated to turn over and allowing for a sell-through period, the baseline efficiency was assumed to be the new federal standard, beginning in FY18.
- In 2015, the DOE makes amended standards effective for residential water heaters that required updated energy factors (EF) depending on the type of water heater and the rated storage volume. For electric storage water heaters with a volume greater than 55 gallons, the standards effectively require heat pumps for electric storage products. For storage tank water heaters with a volume of 55 gallons or less, the new standard (EF=0.948) becomes essentially the equivalent of today's efficient storage tank water heaters. [16]
- In March 2015, the DOE amended the standards for residential clothes washers. The new standards will require the Integrated Modified Energy Factor (MEF) ($ft^3$/kWh/cycle) to meet certain thresholds based on the machine configurations. The ENERGY STAR specifications for residential clothes washers will also be amended to increase the efficiency of units that can earn the ENERGY STAR label. Version 7.0 of the ENERGY STAR specification is scheduled to go into effect in March 2015. These amended federal and ENERGY STAR standards have been factored into the study.

---

[12] GDS reviewed the deemed measure cost assumptions included in the Illinois TRM from 2012 (v1) through 2018 (v7). Where a direct comparison of cost was applicable, GDS found no change in measure cost across 80% of residential and nonresidential measures. In a similar search of the Michigan Energy Measure Database (MEMD) from 2011 to 2018, GDS again found that most of incremental measure costs in 2018 were either the same or higher than the recorded incremental measure cost in 2011.

[13] LED Incremental Cost Study Overall Final Report. The Cadmus Group. February 2016

[14] Key adjustments for LED screw-in lighting are addressed separately later in this section.

[15] SEER: Seasonal Energy Efficiency Ratio; HSPF: Heating Seasonal Performance Factor.

[16] Ultimately, GDS did not incorporate the requirements for large capacity water heaters into the analysis due to recent legislation that allows grid-enabled water heaters to remain at lower efficiency levels.

- In line with the phase-in of 2005 EPAct regulations, the baseline efficiency for general service linear fluorescent lamps was moved from the T12 light bulb to a T8 light bulb effective June 1, 2016.
- New U.S. Department of Energy (DOE) standards require that all general service fluorescent lamps (GSFL) manufactured after Jan. 26, 2018, meet increased efficacy standards, or lumens per watt, to encourage the adoption of high-efficiency lighting products. In the T8 category, most lamps pass the standards. However, these are primarily reduced-wattage (e.g., 25W, 28W) lamps. The basic-grade 32W lamps do not comply. The standard provides a loophole which excludes fluorescent tubes with a color rendering index (CRI) of 87 or higher. Even with that loophole, there will be fewer T8 lamps to choose from going forward and it is likely that the move to linear LEDs will accelerate.

### *2.3.5 Review of LED Lighting Assumptions*

Recognizing that there remains significant uncertainty regarding the future potential of residential screw-in lighting, GDS reviewed the latest lighting-specific program designs and consulted with industry peers to develop critical assumptions regarding the future assumed baselines for LED screw base omnidirectional, specialty/decorative, and reflector/directional lamps over the study timeframe.

***EISA Impacts.*** LED screw base omnidirectional and decorative lamps are impacted by the EISA 2007 regulation backstop provision, which requires all non-exempt lamps to be 45 lumens/watt, beginning in 2020. Based on this current legislation, the federal baseline in 2020 will be roughly equivalent to a CFL bulb. However, in January 2017, the Department of Energy expanded the scope of the standard to include directional and specialty bulb but stated that they may delay enforcement based on ongoing dialog with industry stakeholders. Although there is uncertainty surrounding EISA and the backstop provision, the Market Potential Study assumes the backstop provision for standard (A-lamp) screw-in bulbs will take effect beginning in 2022. The analysis assumes the expanded definition of general service lamps to include specialty and reflector sockets will impact those sockets beginning in 2023.

***LED Bulb Costs.*** Based on EIA Technology Forecast Report, LED bulb costs were assumed to decrease over the analysis period. LED bulb costs ranged between $3 (standard) and $8.60 (reflector) in 2020, decreasing to $2-$3 by 2039. Incentives were modeled as a % of incremental cost, resulting in decreasing incentives over the analysis timeframe as well.

***LED Lighting Efficacy.*** Using the same EIA Technical Forecast Report, LED efficacy was also assumed to improve over the analysis timeframe. By 2040, the LED wattage of a bulb equivalent to a 60W incandescent will improve from 8W (today's typical LED) down to 4W.

### *2.3.6 Net to Gross (NTG)*

All estimates of technical, economic, and achievable potential, as well as measure level cost-effectiveness screening were conducted in terms of gross savings to reflect the absence of program design considerations in these phases of the analysis. The impacts of free-riders (participants who would have installed the high efficiency option in the absence of the program) and spillover customers (participants who install efficiency measures due to program activities, but never receive a program incentive) are considered in the DSM Action Plan component of this study.

## 2.4 ENERGY EFFICIENCY POTENTIAL

This section reviews the types of potential analyzed in this report, as well as some key methodological considerations in the development of technical, economic, and achievable potential.

### *2.4.1 Types of Potential*

Potential studies often distinguish between several types of energy efficiency potential: technical, economic, achievable, and program. However, because there are often important definitional issues between studies, it is important to understand the definition and scope of each potential estimate as it applies to this analysis.

The first two types of potential, technical and economic, provide a theoretical upper bound for energy savings from energy efficiency measures. Still, even the best-designed portfolio of programs is unlikely to capture 100% of the technical or economic potential. Therefore, achievable potential attempts to estimate what savings may realistically be achieved through market interventions, when it can be captured, and how much it would cost to do so. Figure 2-2 illustrates the types of energy efficiency potential considered in this analysis. Program potential, in the form of the DSM Action Plan, is discussed in Volume II of the report.

FIGURE 2-2 TYPE OF ENERGY EFFICIENCY POTENTIAL[17]

| | | | | |
|---|---|---|---|---|
| Not Technically Feasible | TECHNICAL POTENTIAL | | | |
| Not Technically Feasible | Not Cost-Effective | ECONOMIC POTENTIAL | | |
| Not Technically Feasible | Not Cost-Effective | Market Barriers | MAXIMUM ACHIEVABLE POTENTIAL | |
| Not Technically Feasible | Not Cost-Effective | Market Barriers | Partial Incentives | REALISTIC ACHIEVABLE POTENTIAL |

### 2.4.2 Technical Potential

Technical potential is the theoretical maximum amount of energy use that could be displaced by efficiency, disregarding all non-engineering constraints such as cost-effectiveness and the willingness of end users to adopt the efficiency measures. Technical potential is only constrained by factors such as technical feasibility and applicability of measures. Under technical potential, GDS assumed that 100% of new construction and market opportunity measures are adopted as those opportunities become available (e.g., as new buildings are constructed they immediately adopt efficiency measures, or as existing measures reach the end of their useful life). For retrofit measures, implementation was assumed to be resource constrained and that it was not possible to install all retrofit measures all at once. Rather, retrofit opportunities were assumed to be replaced incrementally until 100% of stock was converted to the efficient measure over a period of no more than 15 years.

#### 2.4.2.1 Competing Measures and Interactive Effects Adjustments

GDS prevents double-counting of savings, and accounts for competing measures and interactive savings effects, through three primary adjustment factors:

*Baseline Saturation Adjustment.* Competing measure shares may be factored into the baseline saturation estimates. For example, nearly all homes can receive insulation, but the analysis has created multiple measure permutations to account for varying impacts of different heating/cooling combinations and have applied baseline saturations to reflect proportions of households with each heating/cooling combination.

*Applicability Factor Adjustment.* Combined measures into measure groups, where total applicability factor across measures is set to 100%. For example, homes cannot receive a programmable thermostat, connected thermostat, and smart thermostat. In general, the models assign the measure with the most savings the greatest applicability factor in the measure group, with competing measures picking up any remaining share.

*Interactive Savings Adjustment.* As savings are introduced from select measures, the per-unit savings from other measures need to be adjusted (downward) to avoid over-counting. The analysis typically prioritizes market opportunity

[17] Reproduced from "Guide to Resource Planning with Energy Efficiency." November 2007. US Environmental Protection Agency (EPA). Figure 2-1.

equipment measures (versus retrofit measures that can be installed at any time). For example, the savings from a smart thermostat are adjusted down to reflect the efficiency gains of installing an efficient air source heat pump. The analysis also prioritizes efficiency measures relative to conservation (behavioral) measures.

### *2.4.3 Economic Potential*

Economic potential refers to the subset of the technical potential that is economically cost-effective (based on screening with the Utility Cost Test) as compared to conventional supply-side energy resources.

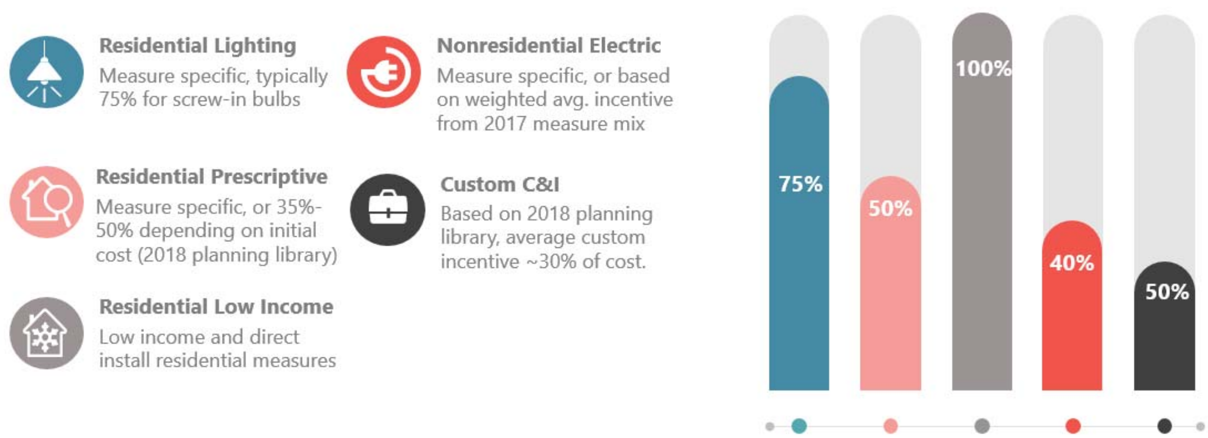
#### 2.4.3.1 Utility Cost Test and Incentive Levels

The economic potential assessment included a screen for cost-effectiveness using the Utility Cost Test (UCT) at the measure level. In the Vectren South territory, the UCT considers both electric and natural gas savings as benefits, and utility incentives and direct install equipment expenses as the cost. Consistent with application of economic potential according to the National Action Plan for Energy Efficiency, the measure level economic screening does not consider non-incentive/measure delivery costs (e.g. admin, marketing, evaluation etc.) in determining cost-effectiveness.[18]

Apart from the low-income segment of the residential sector, all measures were required to have a UCT benefit-cost ratio greater than 1.0 to be included in economic potential and all subsequent estimates of energy efficiency potential. Low-income measures were not required to be cost-effective; all low-income specific measures are included in the economic and achievable potential estimates.

For both the calculation of the measure-level UCT, as well as the determination of RAP, historical incentive levels (as a % of incremental measure cost) were calculated for current measure offerings. Figure 2-3 describes the incentive levels by key market segment within the residential and nonresidential sectors.

FIGURE 2-3 INCENTIVES BY SECTOR AND MARKET SEGMENT




GDS relied on Vectren's measure planning library and supporting DSM Operating Plan appendices to map current measure offerings to their historical incentive levels.[19] For study measures that did not map directly to a current offering, GDS calculated the weighted average incentive level (based on 2017 participation) by sector and/or program and applied these "typical" incentive levels to the new measures.

[18] National Action Plan for Energy Efficiency: Understanding Cost-Effectiveness of Energy Efficiency Programs. Note: Non-incentive delivery costs are included in the assessment of achievable potential and the DSM Action Plan.
[19] The measure planning library was leveraged primarily for determining current incentive levels rather than for developing estimates of future costs or savings potential.

- In the residential sector, lighting incentive levels were assumed to represent 75% of the measure cost. Remaining residential incentive levels were either 50% of the incremental measure cost, or 35% of the measure cost (for more expensive measures).
- Low income and direct install measures received incentives equal to 100% of the measure cost
- In the non-residential sector, prescriptive incentives were 50% of the measure cost, and custom measures received incentives equal to 30% of the measure cost 3
- In the MAP scenario, all incentives were set to 100% of the incremental measure cost.

#### 2.4.3.2 Avoided Costs

Avoided energy supply costs are used to assess the value of energy savings. Avoided cost values for electric energy, electric capacity, and avoided transmission and distribution (T&D) were provided by Vectren as part of an initial data request. Electric energy is based on an annual system marginal cost. For years outside of the avoided cost forecast timeframe, future year avoided costs are escalated by the rate of inflation.

### *2.4.4 Achievable Potential*

Achievable potential is the amount of energy that can realistically be saved given various market barriers. Achievable potential considers real-world barriers to encouraging end users to adopt efficiency measures; the non-measure costs of delivering programs (for administration, marketing, analysis, and EM&V); and the capability of programs and administrators to boost program activity over time. Barriers include financial, customer awareness and willingness to participate in programs, technical constraints, and other barriers the "program intervention" is modeled to overcome. Additional considerations include political and/or regulatory constraints. The potential study evaluated two achievable potential scenarios:

- ***Maximum Achievable Potential*** estimates achievable potential on paying incentives equal to 100% of measure incremental costs and aggressive adoption rates.
- ***Realistic Achievable Potential*** estimates achievable potential with Vectren paying incentive levels (as a percent of incremental measure costs) closely calibrated to historical levels but is not constrained by any previously determined spending levels.

#### 2.4.4.1 Market Adoption Rates

GDS assessed achievable potential on a measure-by-measure basis. In addition to accounting for the natural replacement cycle of equipment in the achievable potential scenario, GDS estimated measure specific maximum adoption rates that reflect the presence of possible market barriers and associated difficulties in achieving the 100% market adoption assumed in the technical and economic scenarios.

The initial step was to assess the long-term market adoption potential for energy efficiency technologies. Due to the wide variety of measures across multiple end-uses, GDS employed varied measure and end-use-specific ultimate adoption rates versus a singular universal market adoption curve. These long-term market adoption estimates were based on either Vectren-specific Willingness to Participate (WTP) market research or publicly available DSM research including market adoption rate surveys and other utility program benchmarking. These surveys included questions to residential homeowners and nonresidential facility managers regarding their perceived willingness to purchase and install energy efficient technologies across various end uses and incentive levels.

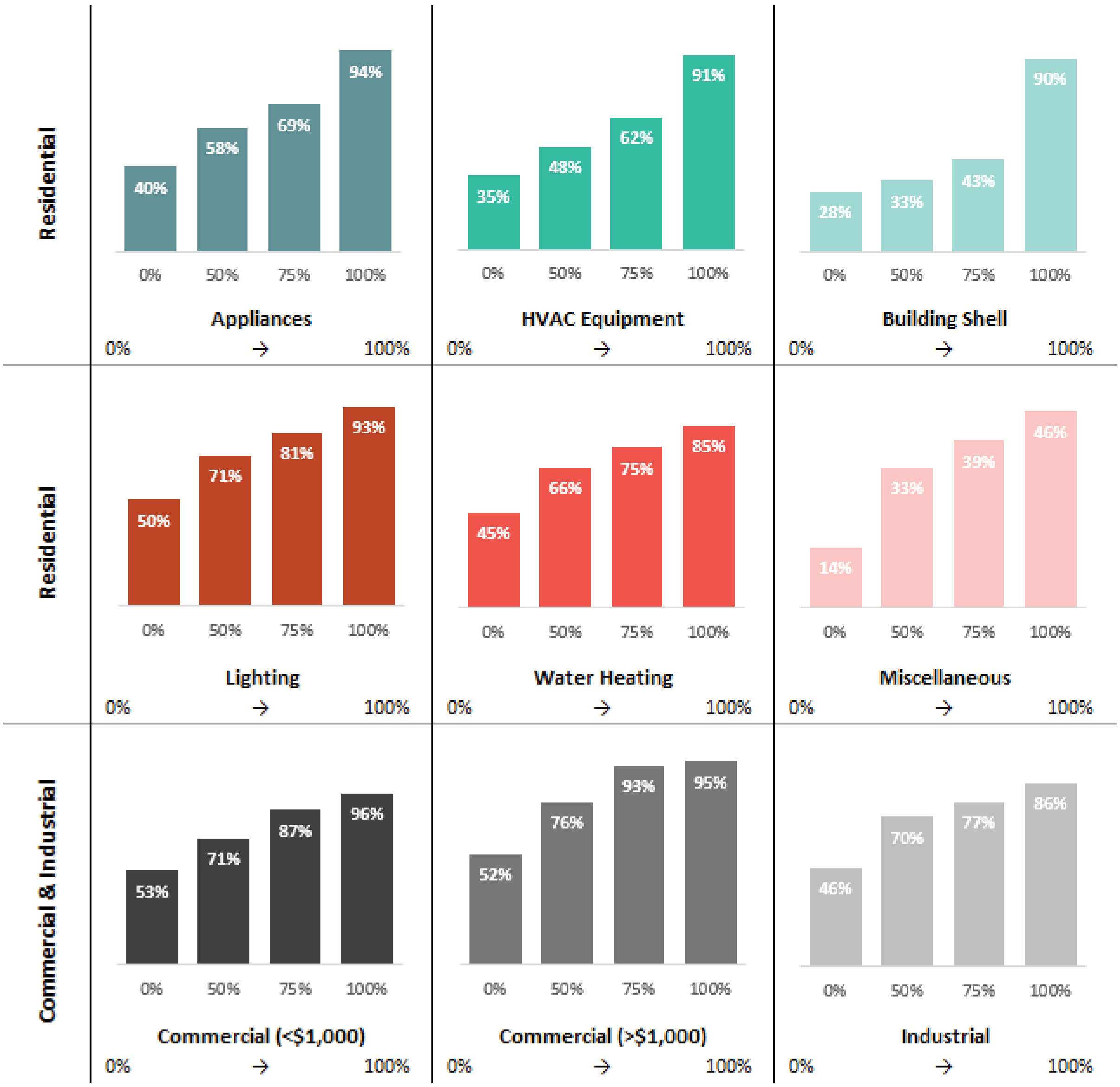
GDS utilized likelihood and willingness-to-participate data to estimate the long-term (20-year) market adoption potential for both the maximum and realistic achievable scenarios.[20] Table 2-4 presents the long-term market adoption rates at varied incentive levels used for both the residential and nonresidential sectors. When incentives are assumed to represent 100% of the measure cost (maximum achievable), the long-term market adoption ranged by sector and

[20] For the MAP Scenario, the long-term adoption rate was reached by Year15 (or earlier) and annual participation remained flat in the final five years of the analysis. In the RAP scenario, the analysis assumes the maximum adoption rate is reached over a period of 20-years or less.

end-use from 46% to 96%. For the RAP scenario, the incentive levels also varied by measure resulting in measure-specific market adoption rates.

TABLE 2-4 LONG-TERM MARKET ADOPTION RATES AT DISCRETE INCENTIVE LEVELS

*(based on Willingness-to-Participate Survey Results)*




GDS then estimated initial year adoption rates by reviewing the current saturation levels of efficient technologies and (if necessary) calibrating the estimates of 2020 annual potential to recent historical levels achieved by Vectren's current DSM portfolio. This calibration effort ensures that the forecasted achievable potential in 2020 is realistic and attainable. GDS then assumed a non-linear ramp rate from the initial year market adoption rate to the various long-term market adoption rates for each specific end-use.

One caveat to this approach is that the ultimate long-term adoption rate is generally a simple function of incentive levels and payback. There are other factors that may influence a customer's willingness to purchase an energy efficiency measure. For example, increased marketing and education programs can have a critical impact on the success of energy efficiency programs. Other benefits, such as increased comfort or safety and reduced maintenance costs could also factor into a customer's decision to purchase and install energy efficiency measures. To acknowledge these impacts, GDS considered the participant spillover and non-participant spillover rates (identified in prior Vectren evaluations) that demonstrate the impacts that efficiency program and their marketing/education components can have on increased technology adoption. GDS used these spillover rates to increase the long-term adoption rates (typically by 5%-7%) at each incentive level.

#### 2.4.4.2 Non-Incentive Costs

Consistent with National Action Plan for Energy Efficiency (NAPEE) guidelines[21], utility non-incentive costs were included in the overall assessment of cost-effectiveness at the realistic achievable potential scenario. 2020 direct measure/program non-incentive costs were calibrated to recent 2016-2018 historical levels and set at $0.045 per first year kWh saved for residential lighting, $0.01 per first year kWh saved for residential behavior, $0.145 for the remaining residential measures, and $0.07 per first year kWh saved in the non-residential sectors. Non-incentive costs were then escalated annually at the rate of inflation%. [22]

In addition to non-incentive costs attributed directly to programs and measures, the analysis also included indirect program delivery that are not specifically attributed to individual programs and can include additional outreach, evaluation, and program planning activities. These costs were calibrated to 2015-2018 historical levels of $0.024 per first year kWh, escalated 5% annually.[23]

## 2.5 DEMAND RESPONSE AND CVR POTENTIAL

This section provides an overview of the demand response and conservation voltage reduction ("CVR") potential methodology. Summary results of the demand response analysis are provided in Section 7. Additional results details are provided in Appendix G.

### *2.5.1 Demand Response Program Options*

Table 2-5 provides a brief description of the demand response (DR) program options considered and identifies the eligible customer segment for each demand response program that was considered in this study. This includes direct load control (DLC) and rate design options.

TABLE 2-5 DEMAND RESPONSE PROGRAM OPTIONS AND ELIGIBLE MARKETS

| DR Program Option | Program Description | Eligible Markets |
|---|---|---|
| DLC AC (Switch) | The compressor of the air conditioner is remotely shut off (cycled) by the system operator for periods that may range from 7 ½ to 15 minutes during every 30-minute period (i.e., 25%-50% duty cycle) | Residential and Non-Residential Customers |
| DLC AC (Thermostat) | The system operator can remotely raise the AC's thermostat set point during peak load conditions, lowering AC load. | Residential and Non-Residential Customers |

---

[21] National Action Plan for Energy Efficiency (2007). Guide for Conducting Energy Efficiency Potential Studies. Prepared by Optimal Energy. This study notes that economic potential only considers the cost of efficiency measures themselves, ignoring programmatic costs. Conversely, achievable potential should consider the non-measures costs of delivering programs. Pg. 2-4.
[22] As noted earlier in the report, measure costs and utility incentives were not escalated over the 20-year analysis timeframe to keep those costs constant in nominal dollars.
[23] The historic compound average annual growth rate (CAGR) over the same time is 22.6%. GDS used a more conservative escalation rate based on an expected slower growth rate in the future.

| DR Program Option | Program Description | Eligible Markets |
|---|---|---|
| DLC Pool Pumps | The swimming pool pump is remotely shut off by the system operator for periods normally ranging from 2 to 4 hours. | Residential Customers |
| DLC Water Heaters | The water heater is remotely shut off by the system operator for periods normally ranging from 2 to 8 hours. | Residential and Non-Residential Customers |
| Critical Peak Pricing with Enabling Technology | A retail rate in which an extra-high price for electricity is provided during a limited number of critical periods (e.g. 100 hours) of the year. Market-based prices are typically provided on a day-ahead basis, or an hour-ahead basis. Includes enabling technology that connects technologies within building. Only for customers with AC. | Residential and Non-Residential Customers |
| Critical Peak Pricing without Enabling Technology | A retail rate in which an extra-high price for electricity is provided during a limited number of critical periods (e.g. 100 hours) of the year. Market-based prices are typically provided on a day-ahead basis, or an hour-ahead basis. | Residential and Non-Residential Customers |
| Real Time Pricing | A retail rate in which customers pay electricity supply rates that vary by the hour. | Non-Residential Customers |
| Peak Time Rebates | A program where customers are rewarded if they reduce electricity consumption during peak times with monetary rebates. | Residential and Non-Residential Customers |
| Time of Use Rates | A retail rate in which customers are charged higher rates for the energy they use during specific peak demand times. | Residential and Non-Residential Customers |

Double-counting savings from demand response programs that affect the same end uses is a common issue that must be addressed when calculating the demand response savings potential. For example, a direct load control (DLC) program of air conditioning and a rate program both assume load reduction of the customers' air conditioners. For this reason, it is typically assumed that customers cannot participate in programs that affect the same end uses. As Vectren has offered a DLC program for many years, it was assumed that participation in this offering be prioritized before rate-based DR options. The order of the rest of the programs is based on savings where programs with higher savings per customer are prioritized.

### *2.5.2 Demand Response Potential Assessment Approach Overview*

The analysis of DR, where possible, closely followed the approach outlined for energy efficiency. The framework for assessing the cost-effectiveness of demand response programs is based *on A Framework for Evaluating the Cost-Effectiveness of Demand Response, prepared for the National Forum on the National Action Plan (NAPA) on Demand Response*.[24] Additionally, GDS reviewed the May 2017 National Standard Practice Manual published by the National Efficiency Screening Project.[25] GDS utilized this guide to define avoided ancillary services and energy and/or capacity price suppression benefits.

The demand response analysis was conducted using the GDS Demand Response Model. The Model determines the estimated savings for each demand response program by performing a review of all benefits and cost associated with each program. GDS developed the model such that the value of future programs could be determined and to help facilitate demand response program planning strategies. The model contains approximately 50 required inputs for each program including: expected life, coincident peak ("CP") kW load reductions, proposed rebate levels, program related expenses such as vendor service fees, marketing and evaluation cost and on-going O&M expenses. This model and future program planning features can be used to standardize the cost-effectiveness screening process between Vectren departments interested in the deployment of demand response resources.

The UCT was used to determine the cost-effectiveness of each demand response program. Benefits are based on avoided demand, energy (including load shifting), wholesale cost reductions and T&D costs. Costs include incremental program equipment costs (such as control switches or smart thermostats), fixed program capital costs (such as the cost of a central controller), program administrative, marketing, and evaluation costs. Incremental equipment program costs are included for both new and replacement units (such as control switches) to account for units that are replaced at the end of their useful life.

The demand response analysis includes estimates of technical, economic, and achievable potential. Achievable potential is broken into maximum and RAP in this study:

**MAP** represents an estimate of the maximum cost-effective demand response potential that can be achieved over the 15-year study period. For this study, this is defined as customer participation in demand response program options that reflect a "best practices" estimate of what could eventually be achieved. MAP assumes no barriers to effective delivery of programs.

**RAP** represents an estimate of the amount of demand response potential that can be realistically achieved over the 20-year study period. For this study, this is defined as achieving customer participation in demand response program options that reflect a realistic estimate of what could eventually be achieved assuming typical or "average" industry experience. RAP is a discounted MAP, by considering program barriers that limit participation, therefore reducing savings that could be achieved.

Last, the analysis evaluated direct load control of thermostat potential under two possible conditions: 1) a Bring Your Own Thermostat ***(BYOT) scenario*** where the customer provides their own thermostat and are monetarily incentivized; and 2) a ***utility incentivized scenario*** where the utility provides the smart thermostat and provides a smaller monetary incentive. These options are described in more detail in Appendix G.

### *2.5.3 Avoided Costs*

Demand response avoided costs were consistent with those utilized in the energy efficiency potential analysis and were provided by Vectren. The primary benefit of demand responses is avoided generation capacity, resulting from a

---

[24] Study was prepared by Synapse Energy Economics and the Regulatory Assistance Project, February 2013.
[25] National Standard Practice Manual for Assessing Cost-Effectiveness of Energy Efficiency Resources, May 18, 2017, Prepared by The National Efficiency Screening Project

reduction in the need for new peaking generation capacity. Demand response can also produce energy related benefits. If the demand response option is considered "load shifting", such as direct load control of electric water heating, the consumption of energy is shifted from the control period to the period immediately following the period of control. For this study, GDS assumed that the energy is shifted with no loss of energy. If the program is not considered to be "load shifting" the measure is turned off during peak control hours, and the energy is saved altogether. Demand response programs can also potentially delay the construction of new transmission and distribution lines and facilities, which is reflected in avoided T&D costs.

### 2.5.4 Demand Response Program Assumptions

This section briefly discusses the general assumptions and sources used to complete the demand response potential analysis. Appendix G provides additional detail by program and sector related to load reduction, program costs, and projected participation.

***Load Reduction:*** Demand reductions were based on load reductions found in Vectren's existing demand response programs, and various secondary data sources including the FERC and other industry reports, including demand response potential studies. DLC and thermostat-based DR options were typically calculated based on a per-unit kW demand reduction whereas rate-based DR options were typically assumed to reduce a percentage of the total facility peak load.

***Useful Life:*** The useful life of a smart thermostat is assumed to be 15 years . Load control switches have a useful life of 15 years. This life was used for all direct load control measures in this study.

***Program Costs:*** One-time program development costs included in the first year of the analysis for new programs. No program development costs are assumed for programs that already exist. Each new program includes an evaluation cost, with evaluation cost for existing programs already being included in the administration costs. It was assumed that there would be a cost of $50[26] per new participant for marketing for the DLC programs. Marketing costs are assumed to be 33.3% higher for MAP. All program costs were escalated each year by the general rate of inflation assumed for this study.

***Saturation:*** The number of control units per participant was assumed to be 1 for all direct load control programs using switches (such as water heaters and air conditioning switches), because load control switches can control up to two units. However, for controllable thermostats, some participants have more than one thermostat. The average number of residential thermostats per single family home was assumed to be 1.72 thermostats.

### 2.5.5 DR Program Adoption Levels

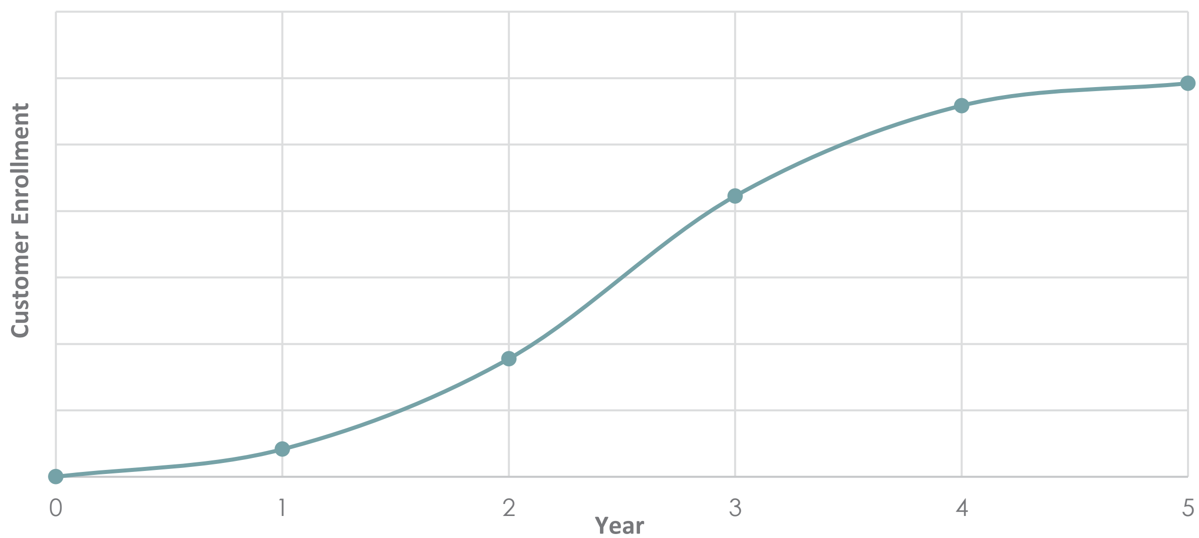
Long-term program adoption levels (or "steady state" participation) represent the enrollment rate once the fully achievable participation has been reached. GDS reviewed industry data and program adoption levels from several utility DR programs. The main sources of participant rates are several studies completed by the Brattle Group. Additional detail about participation rates and sources are shown in Appendix G. As noted earlier in this section, for direct load control programs, MAP participation rates rely on industry best adoption rates and RAP participation rates are based on industry average adoption levels. For the rate programs, the MAP steady-state participation rates assumed programs were opt-out based and RAP participation assumed opt-in status.

Customer participation in new demand response programs is assumed to reach the steady state take rate over a five-year period. The path to steady state customer participation follows an "S-shaped" curve, in which participation growth accelerates over the first half of the five-year period, and then slows over the second half of the period (see Figure 2-

[26] TVA Potential Study Volume III: Demand Response Potential, Global Energy Partners, December 2011

4). Existing programs have already gone through this ramp-up period, so they were escalated linearly to the final participation rate.

FIGURE 2-4 ILLUSTRATION OF S-SHAPED MARKET ADOPTION CURVE




### *2.5.6 Conservation Voltage Reduction (CVR)*

GDS evaluated CVR as a demand response program capable of providing avoided energy and demand cost benefits through reduction of voltages along circuits fed by two different substations. CVR has been demonstrated by Vectren in an existing application at the Buckwood substation. Vectren plans to expand its CVR program to the East Side substation in 2020 and the Broadview substation in 2023. GDS has modeled the potential of CVR as reflecting the East Side and Broadview implementations only.

Energy and demand impacts were estimated by GDS using a combination of data sources, including the EM&V analysis of the Buckwood pilot program, an engineering report prepared by Power Systems Engineering, and data summarizing the customer counts by sector and energy sales volumes for each of the three substations. When CVR is implemented, energy savings are achieved for the hours of reduction, and Vectren indicated they intend to continue to operate CVR for a number of hours throughout the year, leading to energy savings and demand savings for the expanded program. The East Side substation is projected to save 2.63% of its residential and 4.71% of its C&I annual energy sales through application of CVR. Analysis by Power Systems Engineering indicates that the Broadview substation would achieve greater potential energy savings relative to East Side, achieving a 3.25% reduction of residential energy sales and 4.86% of C&I energy sales. Table 2-6 shows these impact details.

TABLE 2-6 CVR IMPACTS BY SUBSTATION

| Substation | East Side | Broadview |
|---|---|---|
| **Residential** | | |
| Total Energy Sales (kWh) | 55,586,807 | 53,397,685 |
| % Savings Assumed from CVR | 2.63% | 3.25% |
| CVR Energy Savings (kWh) | 1,461,047 | 1,733,455 |
| CVR Demand Savings (kW) | 263 | 312 |
| **Commercial & Industrial** | | |
| Total Energy Sales (kWh) | 21,922,082 | 43,766,990 |
| % Savings Assumed from CVR | 4.71% | 4.86% |
| CVR Energy Savings (kWh) | 1,032,655 | 2,127,540 |
| CVR Demand Savings (kW) | 186 | 383 |

| Substation | East Side | Broadview |
|---|---|---|
| **Substation Total** | | |
| Total Energy Sales (kWh) | 77,508,888 | 97,164,675 |
| % Savings Assumed from CVR | 3.22% | 3.97% |
| CVR Energy Savings (kWh) | 2,493,702 | 3,860,995 |
| CVR Demand Savings (kW) | 449 | 695 |

Two sources of program costs are included in the cost effectiveness screening for CVR: implementation costs and administrative costs. Incentives are not necessary as voltage reduction is achieved without requiring participation or consent from customers and without sacrificing quality of service. Implementation costs are annualized based on a carrying cost factor that includes 30-years of straight-line depreciation, 4.0% interest for debt, and 3.2% for O&M.

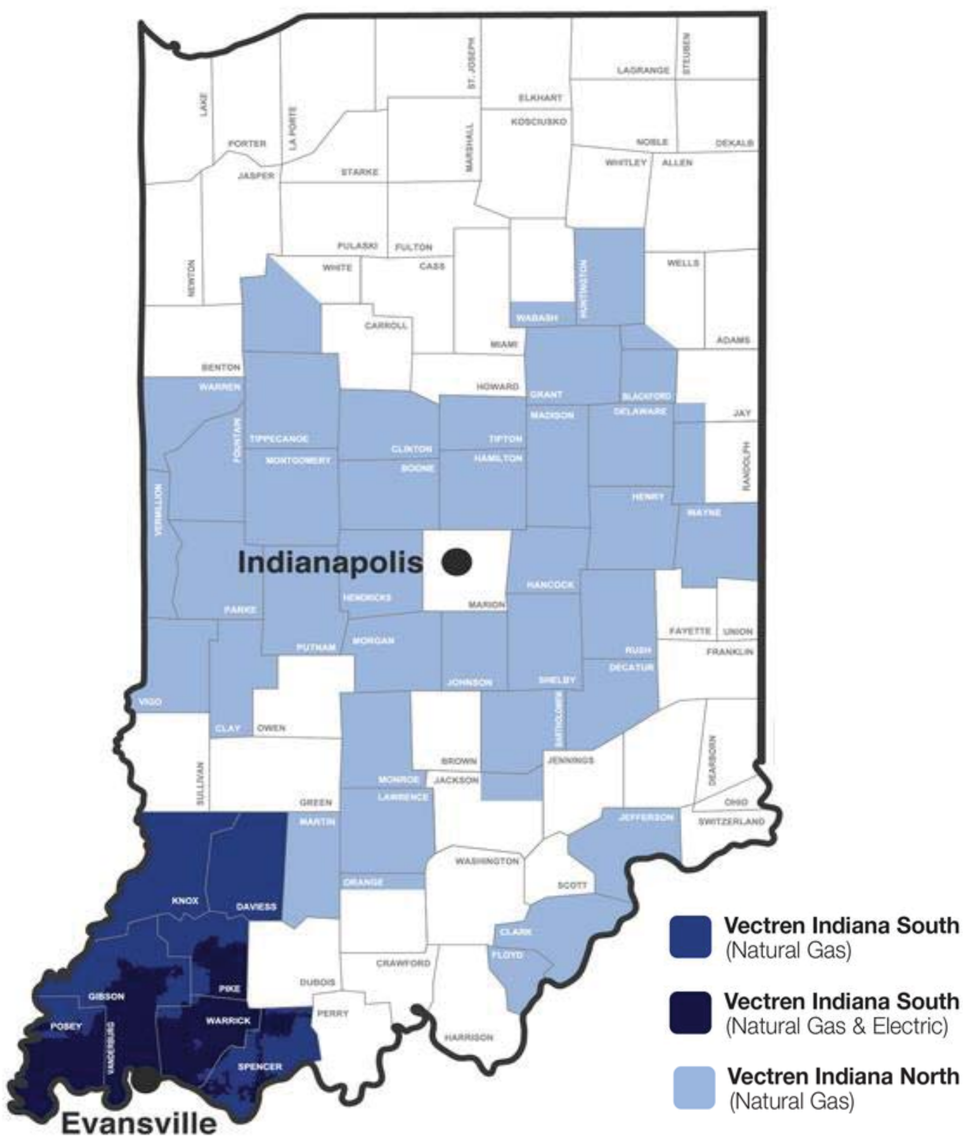
# 3 Market Characterization

Developing a market characterization in the context of utility electric consumption among each sector is a key foundational element to market potential studies. A market characterization describes how energy is used among the various end-uses and building types that are the subject of the potential study. This section provides a brief overview of the sales and customer forecasts for Vectren's electric customers. It also includes a more detailed breakdown of the end-use and building type consumption, along with an overview of how these segmentations were developed.

## 3.1 VECTREN INDIANA SERVICE AREAS

This study assessed the electric energy efficiency potential for Vectren South. Figure 3-1 provides the overall Vectren South and Vectren North territories in Indiana.

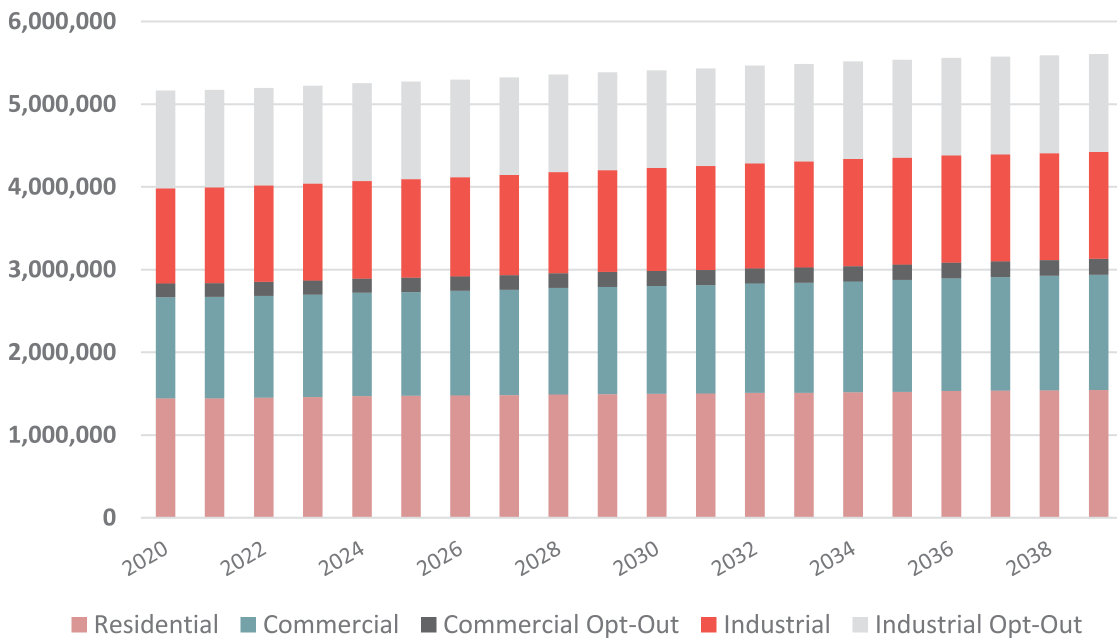
**FIGURE 3-1 VECTREN SERVICE TERRITORY MAP**



## 3.2 LOAD FORECASTS

Figure 3-2 provides the electric sales by sector across the 2020-2039 timeframe. Sales are forecasted to gradually increase from 5.2 million MWh to 5.6 million MWh from 2020 to 2039. The sales figure shows commercial and industrial sales break outs of the sales projections for opt-out customers.

FIGURE 3-2 20-YEAR ELECTRIC SALES (MWH) FORECAST BY SECTOR

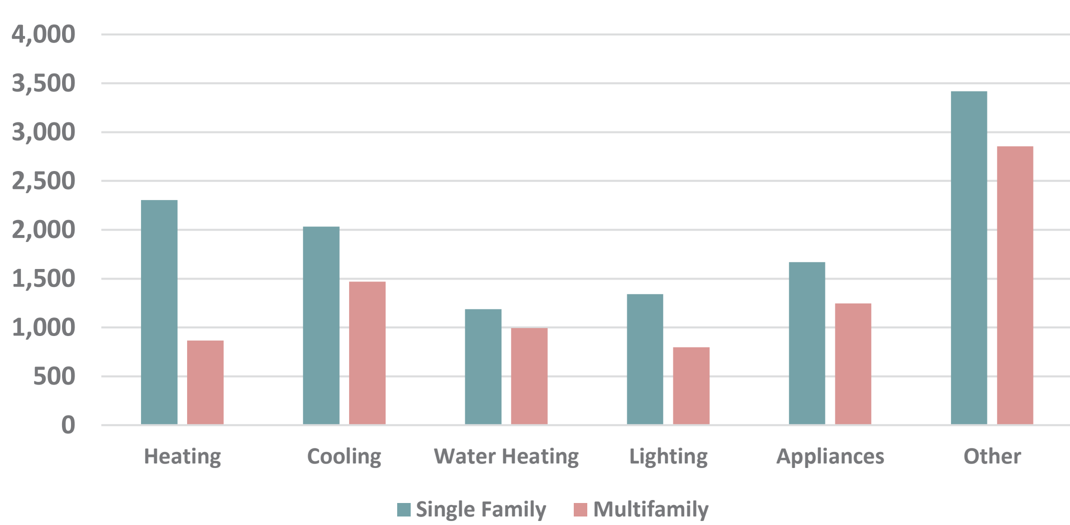



## 3.3 SECTOR LOAD DETAIL

### *3.3.1 Residential Sector*

The residential electric calibration effort led to a housing-type specific end-use intensity breakdown as shown below in Figure 3-3. Overall, we estimated single-family consumption to be just shy of 12,000 kWh per year, and multifamily homes to be about 8,200 kWh per year. The "Other" end use is the leading end-use among both housing types. This reflects the increasing prominence of electronics and other plug in devices.

FIGURE 3-3 RESIDENTIAL ELECTRIC END-USE BREAKDOWN BY HOUSING TYPE



### 3.3.2 Commercial Sector

Figure 3-4 provides a breakdown of commercial electric sales by building type. Mercantile (25%) and Office (20%) are the leading contributors of stand-alone building types to the total commercial electric sales.[27]

FIGURE 3-4 COMMERCIAL ELECTRIC SALES BREAKDOWN BY BUILDING TYPE

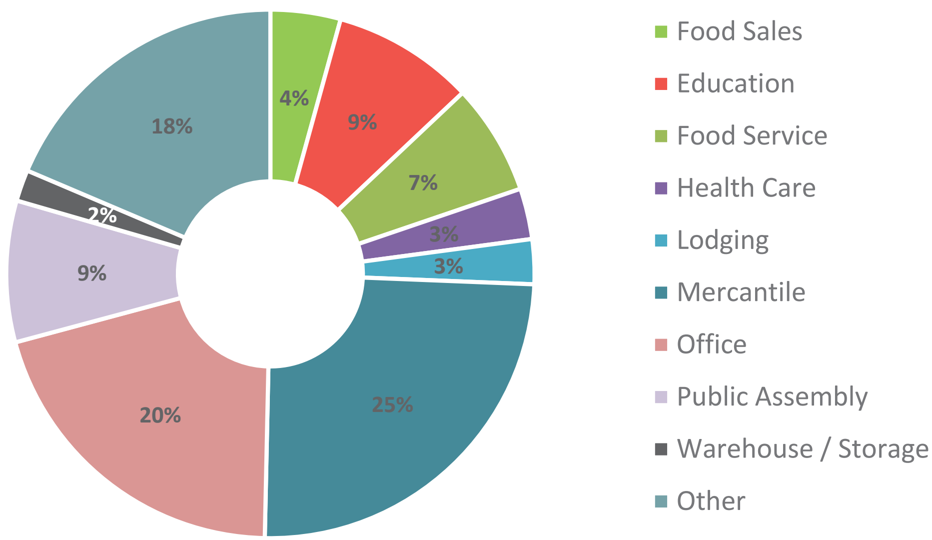
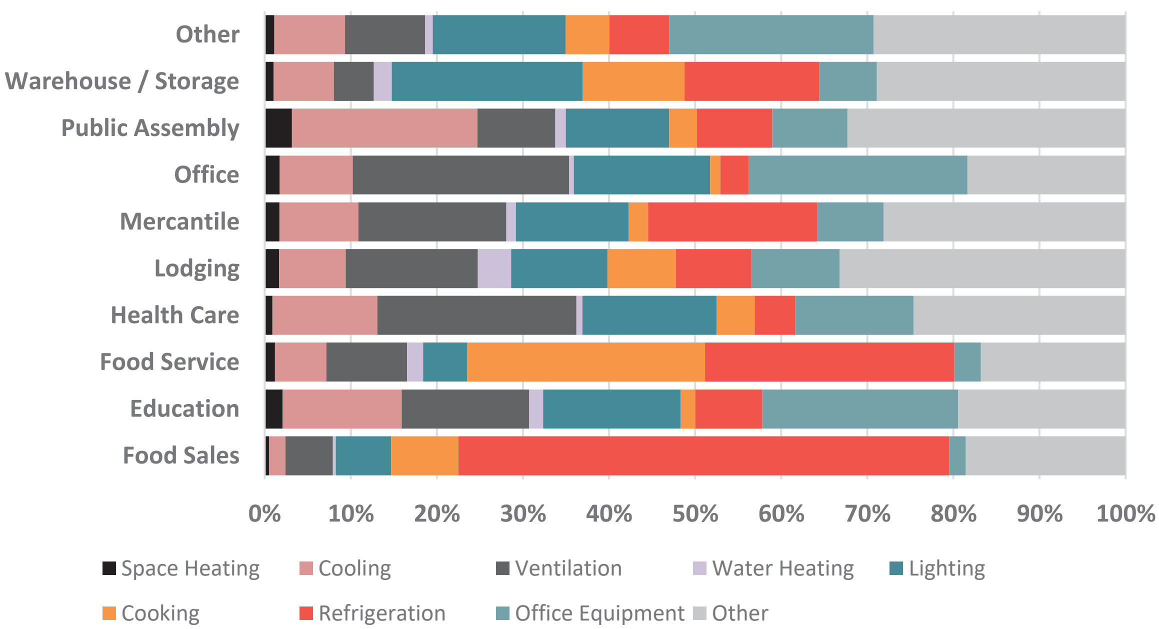



Figure 3-5 provides an illustration of the leading end-uses across all building types in the commercial sector. Ventilation, lighting, and refrigeration are prominent across most of the building types.

FIGURE 3-5 COMMERCIAL ELECTRIC END-USE BREAKDOWN BY BUILDING TYPE




[27] "Other" building types include buildings that engage in several different activities, a majority of which are commercial (e.g. retail space), though the single largest activity may be industrial or agricultural; "other" also includes miscellaneous buildings that do not fit into any other category.

### 3.3.3 Industrial Sector

Figure 3-6 provides a breakdown of industrial electric sales by industry type. Food (20%) and Plastics & Rubber (15%) are the leading industry types contributing to industrial electric sales.

FIGURE 3-6 INDUSTRIAL ELECTRIC INDUSTRY TYPE BREAKDOWN[28]

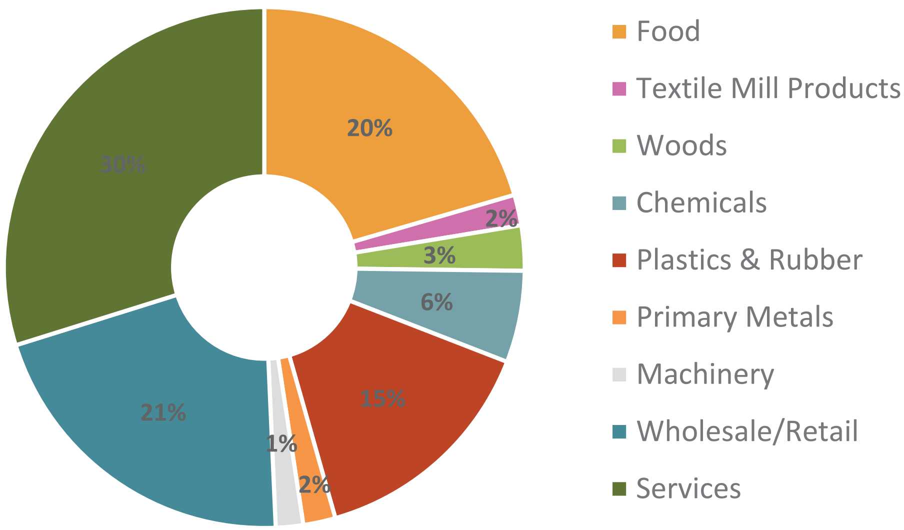
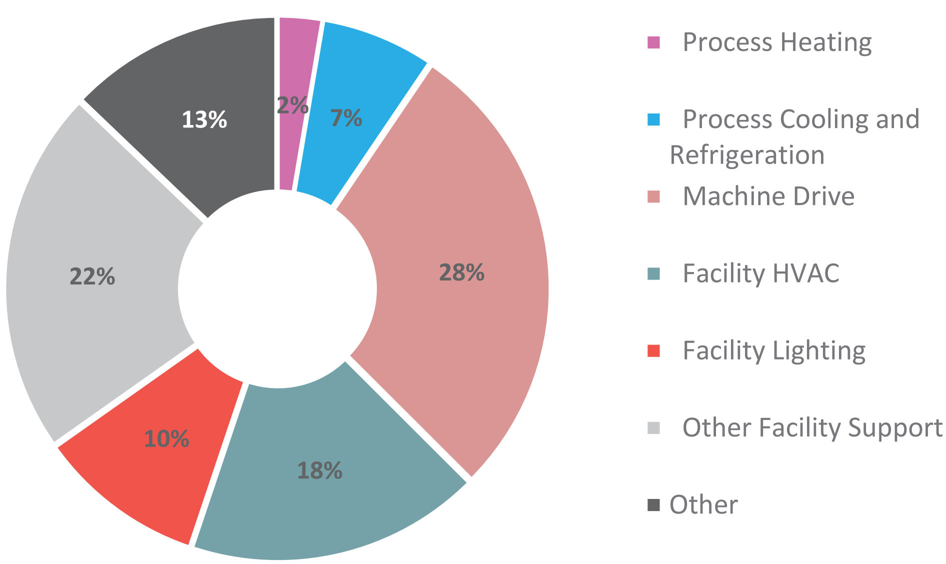



Figure 3-7 provides a breakdown of the industrial electric sales end use. Machine Drive (28%) and Facility HVAC (18%) are the leading end-uses.

FIGURE 3-7 INDUSTRIAL ELECTRIC END-USE BREAKDOWN




[28] "Wholesale/Retail" and "Services" industrial types include industrial buildings that devote a minority percentage of floor space to commercial activities like wholesale and retail trade, and construction, healthcare, education and accommodation & food service. Automotive related industries are divided between plastics, rubber, and machinery based on their NAICS codes.

# 4 Residential Energy Efficiency Potential

This section provides the potential results for technical, economic, MAP and RAP for the residential sector. Results are broken down by fuel type as well as end use. The cost-effectiveness results and budgets for the RAP scenario are also provided.

## 4.1 SCOPE OF MEASURES & END USES ANALYZED

There were 185 total unique electric measures included in the analysis. Table 4-1 provides the number of measures by end-use and fuel type (the full list of residential measures is provided in Appendix B). The measure list was developed based on a review of current Vectren programs, the Indiana TRM, other regional TRMs, and industry documents related to emerging technologies. Data collection activities to characterize measures formed the basis of the assessment of incremental costs, electric energy and demand savings, and measure life.

TABLE 4-1 RESIDENTIAL ENERGY EFFICIENCY MEASURES – BY END USE AND FUEL TYPE

| End-Use | Number of Unique Measures |
|---|---|
| Appliances | 26 |
| Audit | 6 |
| Behavioral | 9 |
| HVAC Equipment | 41 |
| Lighting | 15 |
| Miscellaneous | 6 |
| New Construction | 4 |
| Plug Loads | 9 |
| HVAC Shell | 55 |
| Water Heating | 14 |

## 4.2 RESIDENTIAL ELECTRIC POTENTIAL

Figure 4-1 provides the technical, economic, MAP and RAP results for the 6-year, 10-year, and 20-year timeframes. The 6-year technical potential is 35.0% of forecasted sales, and the economic potential is 32.3% of forecasted sales. The 6-year MAP is 24.0% and the RAP is 12.5%.

FIGURE 4-1 RESIDENTIAL ELECTRIC ENERGY CUMULATIVE ANNUAL POTENTIAL (AS A % OF RESIDENTIAL SALES)

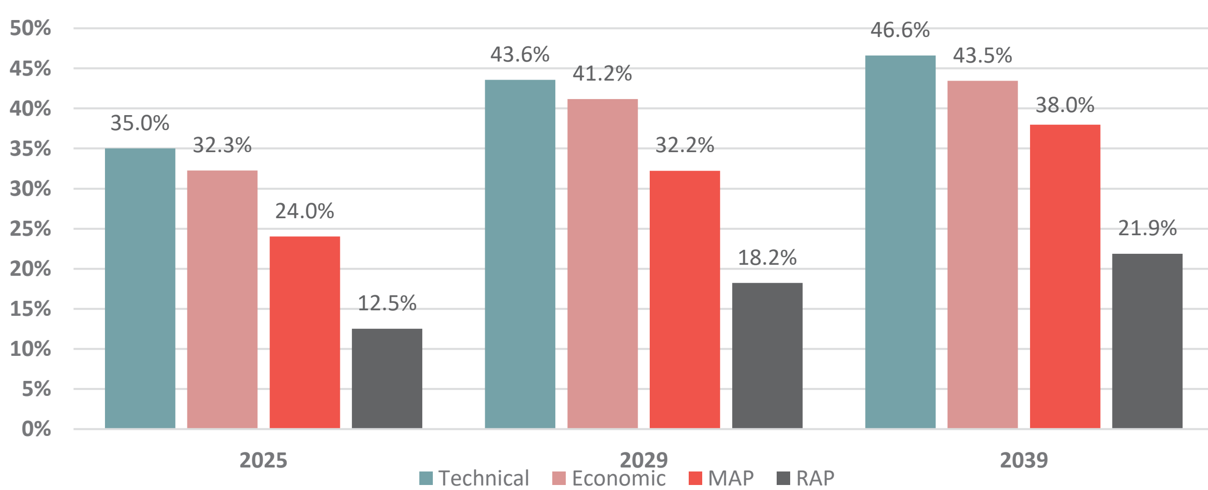


Table 4-2 provides cumulative annual technical, economic, MAP and RAP energy savings, in total MWh and as a percentage of the sector-level sales forecast. The RAP increases to more than 12% cumulative annual savings over the next six years.

TABLE 4-2 RESIDENTIAL CUMULATIVE ANNUAL ENERGY EFFICIENCY POTENTIAL SUMMARY

| | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 |
|---|---|---|---|---|---|---|
| **MWh** | | | | | | |
| **Technical** | 114,516 | 242,109 | 325,265 | 410,315 | 460,483 | 515,889 |
| **Economic** | 106,549 | 222,594 | 297,135 | 376,090 | 422,227 | 475,305 |
| **MAP** | 53,840 | 136,061 | 192,386 | 253,741 | 306,917 | 353,855 |
| **RAP** | 41,177 | 84,538 | 105,533 | 134,072 | 159,025 | 184,648 |
| **Forecasted Sales** | 1,443,774 | 1,444,794 | 1,451,508 | 1,458,672 | 1,469,169 | 1,473,649 |
| **Energy Savings (as % of Forecast)** | | | | | | |
| **Technical** | 7.9% | 16.8% | 22.4% | 28.1% | 31.3% | 35.0% |
| **Economic** | 7.4% | 15.4% | 20.5% | 25.8% | 28.7% | 32.3% |
| **MAP** | 3.7% | 9.4% | 13.3% | 17.4% | 20.9% | 24.0% |
| **RAP** | 2.9% | 5.9% | 7.3% | 9.2% | 10.8% | 12.5% |

Table 4-3 provides the incremental annual technical, economic, MAP and RAP energy savings, in total MWh and as a percentage of the sector-level sales forecast. The incremental RAP ranges from 2.6% to 3.5% per year over the next six years.

TABLE 4-3 RESIDENTIAL INCREMENTAL ANNUAL ENERGY EFFICIENCY POTENTIAL SUMMARY

| | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 |
|---|---|---|---|---|---|---|
| **MWh** | | | | | | |
| **Technical** | 114,516 | 136,960 | 120,797 | 111,329 | 99,306 | 86,829 |
| **Economic** | 106,549 | 124,856 | 110,653 | 103,092 | 92,493 | 81,164 |
| **MAP** | 53,840 | 90,090 | 82,609 | 79,096 | 75,741 | 68,596 |
| **RAP** | 41,177 | 50,889 | 44,349 | 42,814 | 42,014 | 38,952 |
| **Forecasted Sales** | 1,443,774 | 1,444,794 | 1,451,508 | 1,458,672 | 1,469,169 | 1,473,649 |
| **Energy Savings (as % of Forecast)** | | | | | | |
| **Technical** | 7.9% | 9.5% | 8.3% | 7.6% | 6.8% | 5.9% |
| **Economic** | 7.4% | 8.6% | 7.6% | 7.1% | 6.3% | 5.5% |
| **MAP** | 3.7% | 6.2% | 5.7% | 5.4% | 5.2% | 4.7% |
| **RAP** | 2.9% | 3.5% | 3.1% | 2.9% | 2.9% | 2.6% |

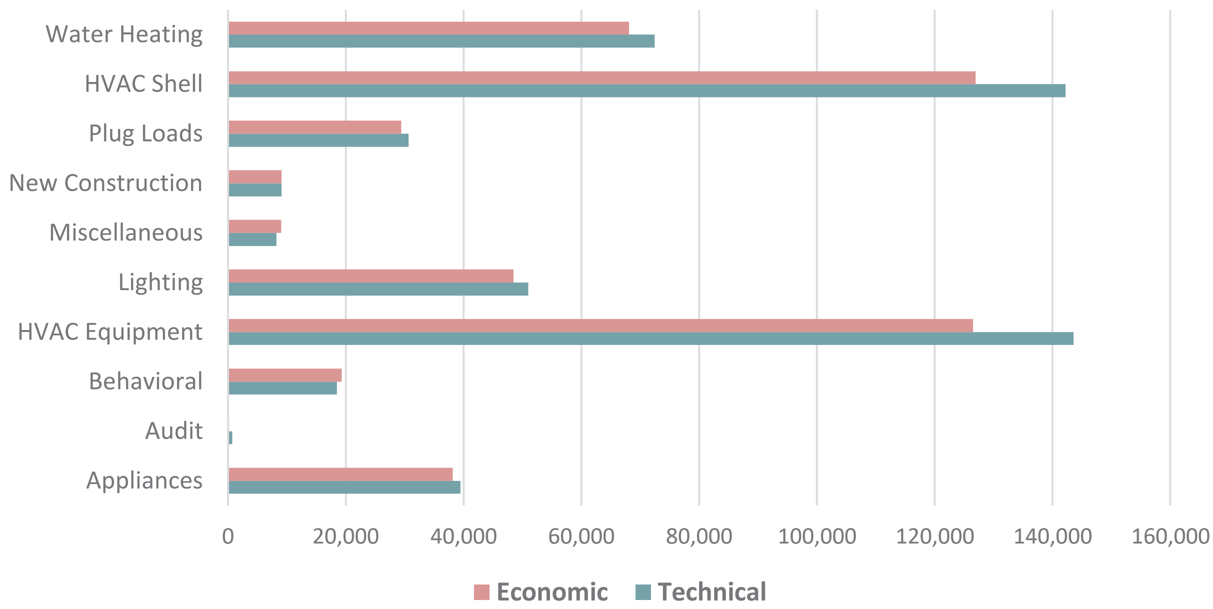
***Technical & Economic Potential***

Table 4-4 provides cumulative annual technical and economic potential results from 2020-2025. Figure 4-2 shows a comparison of the technical and economic potential (6-year) by end use. The HVAC Shell and HVAC Equipment are by far the leading end-uses among technical and economic potential.

TABLE 4-4 TECHNICAL AND ECONOMIC RESIDENTIAL ELECTRIC POTENTIAL

| | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 |
|---|---|---|---|---|---|---|
| **Energy (MWh)** | | | | | | |
| **Technical** | 114,516 | 242,109 | 325,265 | 410,315 | 460,483 | 515,889 |
| **Economic** | 106,549 | 222,594 | 297,135 | 376,090 | 422,227 | 475,305 |
| **Peak Demand (MW)** | | | | | | |
| **Technical** | 18.9 | 39.3 | 55.4 | 70.1 | 80.0 | 90.1 |
| **Economic** | 16.7 | 34.2 | 48.2 | 61.1 | 70.1 | 79.3 |

FIGURE 4-2 6-YEAR TECHNICAL AND ECONOMIC RESIDENTIAL ELECTRIC POTENTIAL – BY END-USE




*Maximum Achievable Potential*

Figure 4-3 illustrates the cumulative annual MAP results by end use across the 2020-2025 timeframe. Like technical and economic potential, HVAC Shell and HVAC Equipment are the leading end uses. Water Heating, Lighting and Appliances also have significant maximum achievable potential.

FIGURE 4-3 RESIDENTIAL ELECTRIC ENERGY (CUMULATIVE ANNUAL GWH) MAP POTENTIAL BY END-USE

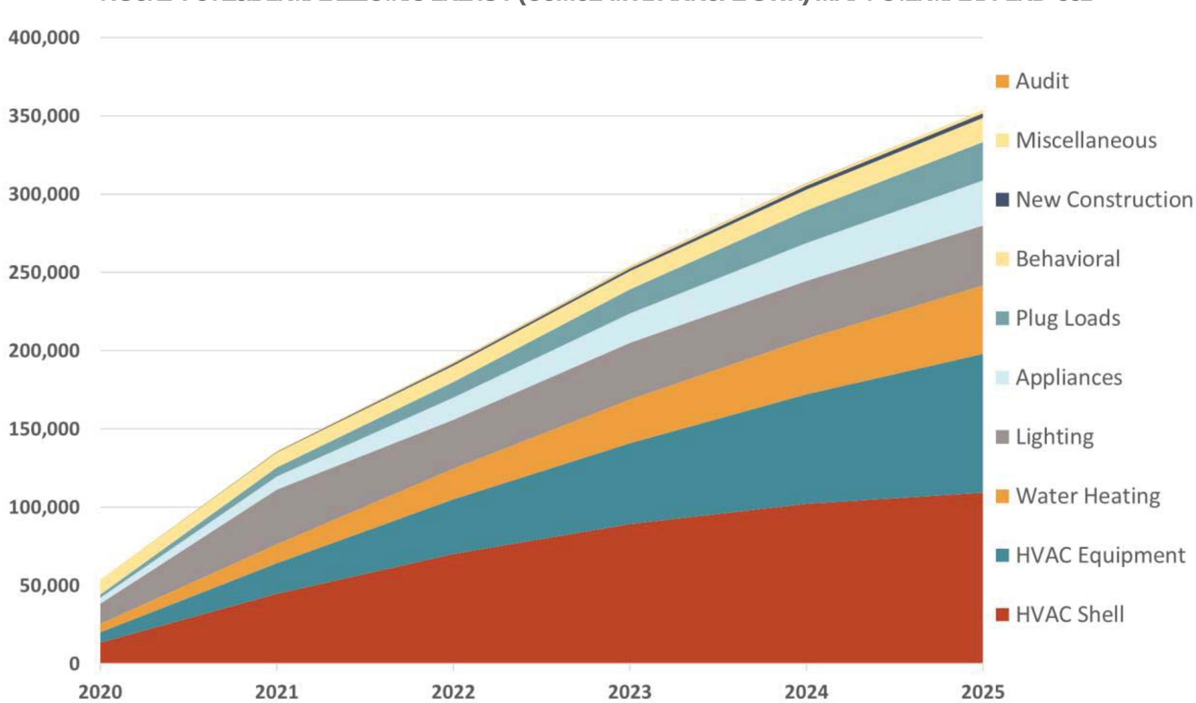



Table 4-5 provides the incremental and cumulative annual MAP across the 2020-2025 timeframe. The incremental MAP potential peaks in 2021 and declines slightly from 2022-2025 as the EISA backstop provision reduces lighting potential and the HVAC Shell end use declines after much of the retrofit measures have been exhausted quickly in the MAP scenario.

TABLE 4-5 RESIDENTIAL ELECTRIC MAP BY END-USE

| End Use | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 |
|---|---|---|---|---|---|---|
| **Incremental Annual MWh** | | | | | | |
| Appliances | 3,722 | 4,817 | 5,313 | 5,351 | 5,133 | 4,722 |
| Audit | 61 | 119 | 146 | 167 | 180 | 187 |
| Behavioral[29] | 9,042 | 8,056 | 8,175 | 8,344 | 8,597 | 9,884 |
| HVAC Equipment | 6,596 | 13,003 | 15,440 | 17,537 | 18,995 | 19,707 |
| Lighting | 13,134 | 21,487 | 13,717 | 11,990 | 10,085 | 6,389 |
| Miscellaneous[30] | 161 | 215 | 278 | 348 | 421 | 490 |
| New Construction | 255 | 345 | 473 | 587 | 677 | 849 |
| Plug Loads | 2,023 | 3,604 | 4,433 | 5,085 | 6,946 | 6,181 |
| HVAC Shell | 13,402 | 31,486 | 26,946 | 21,471 | 16,065 | 11,427 |
| Water Heating | 5,444 | 6,957 | 7,689 | 8,217 | 8,642 | 8,759 |
| **Total** | **53,840** | **90,090** | **82,609** | **79,096** | **75,741** | **68,596** |
| **% of Forecasted Sales** | **3.7%** | **6.2%** | **5.7%** | **5.4%** | **5.2%** | **4.7%** |
| **Incremental Annual MW** | | | | | | |
| **Total** | 7.4 | 12.7 | 12.0 | 11.4 | 10.9 | 10.2 |
| **% of Forecasted Demand** | 1.7% | 2.9% | 2.7% | 2.6% | 2.4% | 2.3% |
| **Cumulative Annual MWh[31]** | | | | | | |
| Appliances | 3,722 | 8,540 | 13,780 | 19,046 | 24,047 | 28,656 |
| Audit | 61 | 119 | 146 | 167 | 180 | 187 |
| Behavioral | 9,042 | 9,526 | 10,557 | 11,781 | 13,440 | 15,404 |
| HVAC Equipment | 6,596 | 19,544 | 34,785 | 51,794 | 70,076 | 88,670 |
| Lighting | 13,134 | 34,830 | 31,327 | 36,243 | 36,889 | 38,538 |
| Miscellaneous | 161 | 376 | 655 | 1,003 | 1,423 | 1,914 |
| New Construction | 255 | 600 | 1,072 | 1,659 | 2,337 | 3,186 |
| Plug Loads | 2,023 | 5,626 | 10,059 | 15,144 | 20,912 | 24,448 |
| HVAC Shell | 13,402 | 44,560 | 70,192 | 89,281 | 102,002 | 109,345 |
| Water Heating | 5,444 | 12,339 | 19,814 | 27,624 | 35,612 | 43,506 |
| **Total** | **53,840** | **136,061** | **192,386** | **253,741** | **306,917** | **353,855** |
| **% of Forecasted Sales** | **3.7%** | **9.4%** | **13.3%** | **17.4%** | **20.9%** | **24.0%** |
| **Cumulative Annual MW** | | | | | | |
| **Total** | 7.4 | 19.1 | 28.6 | 37.7 | 45.7 | 53.0 |
| **% of Forecasted Demand** | 1.7% | 4.3% | 6.4% | 8.4% | 10.2% | 11.7% |

### *Realistic Achievable Potential*

Figure 4-4 illustrates the cumulative annual RAP results by end use across the 2020-2025 timeframe. Like maximum achievable potential, HVAC Shell and HVAC Equipment are the leading end uses. Water Heating, Lighting and Appliances also have significant realistic achievable potential.

[29] The behavioral end-use includes home energy reports and home energy management systems (HEMs).
[30] Miscellaneous consists of pool heater, efficient pool pumps, motors and timers, and well pumps.
[31] Audit measures and most Behavioral measures have a one-year assumed measure life. For this reason, Audit savings are the same for both incremental and cumulative annual, and there is only a minor difference between incremental and cumulative annual savings for Behavioral measures.

FIGURE 4-4 RESIDENTIAL ELECTRIC ENERGY (CUMULATIVE ANNUAL GWH) RAP POTENTIAL BY END-USE

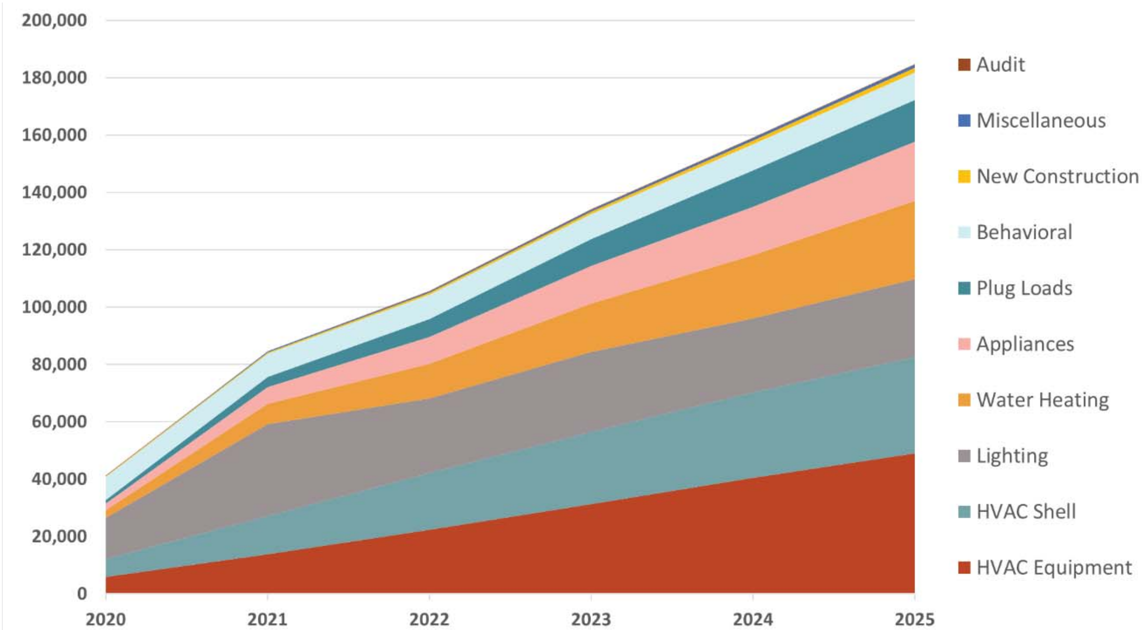



Table 4-6 provides the incremental and cumulative annual RAP across the 2020-2025 timeframe. Lighting and behavioral savings are leading end-uses of incremental RAP in the early years, and HVAC Shell, HVAC Equipment, and Water Heating increase throughout the six-year timeframe.

TABLE 4-6 RESIDENTIAL ELECTRIC RAP BY END-USE

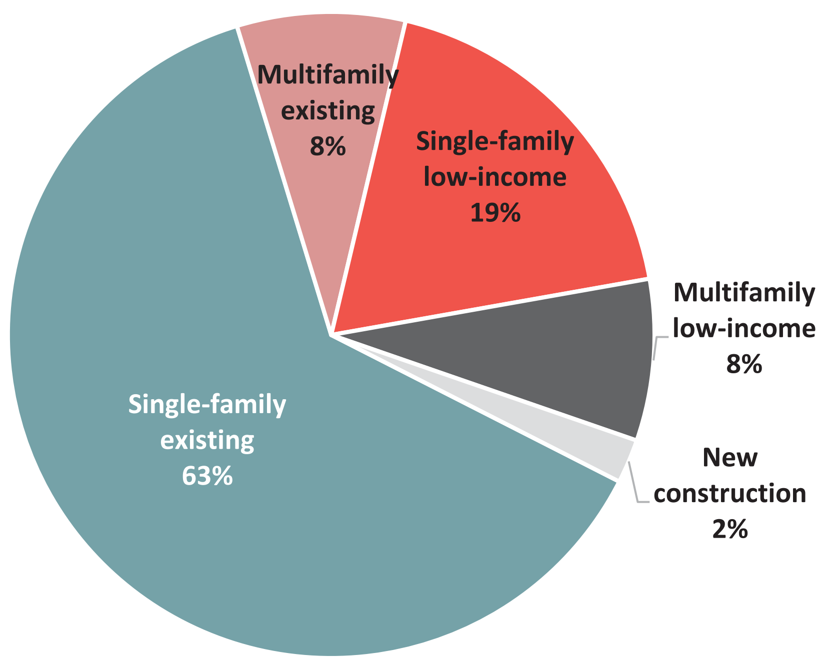
| End Use | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 |
|---|---|---|---|---|---|---|
| **Incremental Annual MWh** | | | | | | |
| Appliances | 2,364 | 3,363 | 3,692 | 3,844 | 3,902 | 3,794 |
| Audit | 39 | 78 | 93 | 108 | 121 | 131 |
| Behavioral[32] | 8,061 | 7,657 | 7,661 | 7,651 | 7,698 | 8,093 |
| HVAC Equipment | 5,848 | 7,985 | 8,594 | 9,039 | 9,321 | 9,579 |
| Lighting | 14,292 | 17,399 | 9,794 | 7,875 | 6,298 | 3,575 |
| Miscellaneous[33] | 128 | 153 | 176 | 200 | 226 | 252 |
| New Construction | 184 | 209 | 244 | 263 | 272 | 314 |
| Plug Loads | 1,267 | 2,394 | 2,688 | 2,922 | 3,799 | 3,433 |
| HVAC Shell | 6,246 | 7,198 | 6,529 | 5,752 | 4,960 | 4,234 |
| Water Heating | 2,748 | 4,454 | 4,880 | 5,160 | 5,417 | 5,547 |
| **Total** | **41,177** | **50,889** | **44,349** | **42,814** | **42,014** | **38,952** |
| **% of Forecasted Sales** | **2.9%** | **3.5%** | **3.1%** | **2.9%** | **2.9%** | **2.6%** |
| **Incremental Annual MW** | | | | | | |
| **Total** | 5.5 | 6.9 | 6.5 | 6.4 | 6.3 | 6.1 |
| **% of Forecasted Demand** | 1.2% | 1.6% | 1.5% | 1.4% | 1.4% | 1.3% |

32 The behavioral end-use includes home energy reports and home energy management systems (HEMs).
33 Miscellaneous consists of pool heater, efficient pool pumps, motors and timers, and well pumps.

| End Use | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 |
|---|---|---|---|---|---|---|
| **Cumulative Annual MWh[34]** | | | | | | |
| Appliances | 2,364 | 5,727 | 9,388 | 13,177 | 16,990 | 20,708 |
| Audit | 39 | 78 | 93 | 108 | 121 | 131 |
| Behavioral | 8,061 | 8,159 | 8,496 | 8,768 | 9,179 | 9,711 |
| HVAC Equipment | 5,848 | 13,820 | 22,375 | 31,268 | 40,402 | 49,002 |
| Lighting | 14,292 | 31,875 | 26,081 | 27,825 | 25,847 | 27,162 |
| Miscellaneous | 128 | 281 | 456 | 657 | 882 | 1,135 |
| New Construction | 184 | 393 | 636 | 899 | 1,171 | 1,485 |
| Plug Loads | 1,267 | 3,661 | 6,349 | 9,270 | 12,634 | 14,534 |
| HVAC Shell | 6,246 | 13,364 | 19,709 | 25,173 | 29,755 | 33,555 |
| Water Heating | 2,748 | 7,180 | 11,950 | 16,926 | 22,045 | 27,226 |
| **Total** | **41,177** | **84,538** | **105,533** | **134,072** | **159,025** | **184,648** |
| **% of Forecasted Sales** | **2.9%** | **5.9%** | **7.3%** | **9.2%** | **10.8%** | **12.5%** |
| **Cumulative Annual MW** | | | | | | |
| **Total** | 5.5 | 11.5 | 15.8 | 20.4 | 24.8 | 28.9 |
| **% of Forecasted Demand** | 1.2% | 2.6% | 3.6% | 4.6% | 5.5% | 6.4% |

Figure 4-5 illustrates a market segmentation of the RAP in the residential sector by 2025. Nearly two-thirds of the RAP is associated with single-family existing homes that are not low-income, whereas the total low-income potential is nearly 30% of the RAP.[35]

FIGURE 4-5 2025 RESIDENTIAL ELECTRIC ENERGY (CUMULATIVE ANNUAL) RAP POTENTIAL BY MARKET SEGMENT




[34] Audit measures and most Behavioral measures have a one-year assumed measure life. For this reason, Audit savings are the same for both incremental and cumulative annual, and there is only a minor difference between incremental and cumulative annual savings for Behavioral measures.
[35] The low-income measures in the RAP analysis did not have to pass the UCT.

***RAP Benefits & Costs***

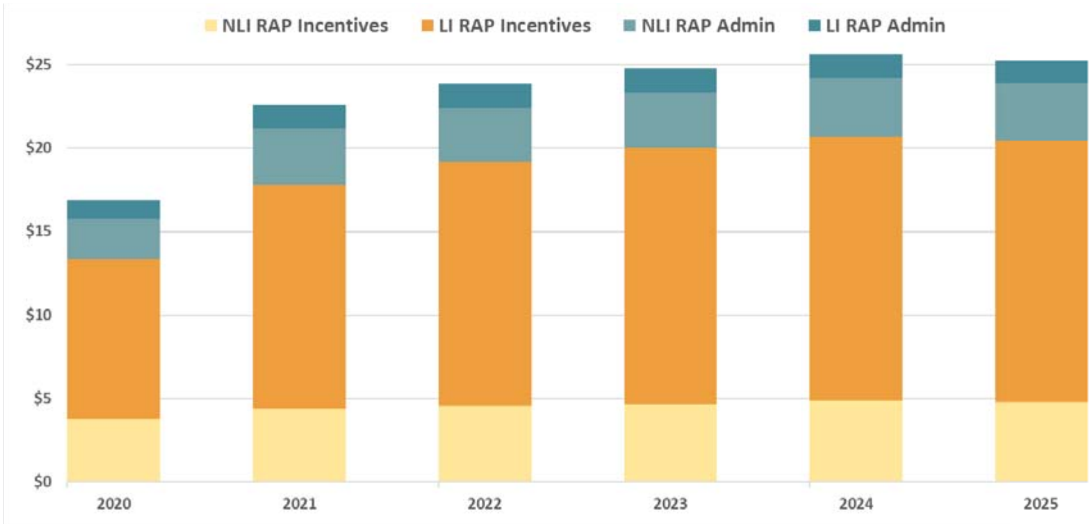
Table 4-7 provides the net present value benefits and cost, as calculated using the UCT, across the 2020-2025 timeframe for the RAP scenario. The overall UCT ratio is 1.1. However, if low-income measures were removed, the overall UCT ratio would be nearly 2.0.

TABLE 4-7 RESIDENTIAL NPV BENEFITS & COSTS RAP BY END-USE ($ IN MILLIONS)

| End Use | NPV Benefits | NPV Costs | UCT Ratio |
|---|---|---|---|
| **Overall Results** | | | |
| Appliances | $24.8 | $24.1 | 1.03 |
| Audit | $0.1 | $2.8 | 0.04 |
| Behavioral | $10.9 | $5.1 | 2.14 |
| HVAC Equipment | $88.5 | $107.3 | 0.82 |
| Lighting | $27.3 | $11.7 | 2.33 |
| Miscellaneous | $5.1 | $1.3 | 3.95 |
| New Construction | $3.1 | $0.7 | 4.11 |
| Plug Loads | $12.8 | $11.2 | 1.15 |
| HVAC Shell | $42.0 | $52.8 | 0.80 |
| Water Heating | $36.7 | $17.8 | 2.06 |
| **Total** | $251.3 | $234.8 | 1.07 |
| **Excluding Low-Income** | | | |
| Appliances | $18.0 | $10.0 | 1.80 |
| Audit | $0.0 | $0.0 | 0.00 |
| Behavioral | $10.9 | $5.1 | 2.14 |
| HVAC Equipment | $62.8 | $27.4 | 2.29 |
| Lighting | $25.4 | $10.4 | 2.44 |
| Miscellaneous | $5.1 | $1.3 | 3.95 |
| New Construction | $3.1 | $0.7 | 4.11 |
| Plug Loads | $12.6 | $9.8 | 1.29 |
| HVAC Shell | $17.2 | $13.8 | 1.25 |
| Water Heating | $34.5 | $17.0 | 2.02 |
| **Total** | $189.5 | $95.4 | 1.99 |

Figure 4-6 provides the budget for the RAP scenario. The budget is broken into incentive and admin budgets for each year of the 2020-2025 timeframe. These budgets are further divided into low-income (“LI”) and not low-income (“NLI”) components. The low-income incentive portion of the budget ranges from 57% to 62% of the total budget from 2020 to 2025. RAP budgets rise to about $25 million after four years.

FIGURE 4-6 ANNUAL BUDGETS FOR RESIDENTIAL RAP ($ IN MILLIONS)



# 5 Commercial Energy Efficiency Potential

This section provides the potential results for technical, economic, MAP and RAP for the commercial sector. Results are broken down by end use. The cost-effectiveness results and budgets for the RAP scenario are also provided.

## 5.1 SCOPE OF MEASURES & END USES ANALYZED

There were 222 total electric measures included in the analysis. Table 5-1 provides the number of measures by end-use and fuel type (the full list of commercial measures is provided in Appendix C). The measure list was developed based on a review of current Vectren programs, the Indiana TRM, other regional TRMs, and industry documents related to emerging technologies. Data collection activities to characterize measures formed the basis of the assessment of incremental costs, electric energy and demand savings, and measure life.

TABLE 5-1 COMMERCIAL ENERGY EFFICIENCY MEASURES – BY FUEL TYPE

| End-Use | Number of Unique Measures |
|---|---|
| Space Heating | 32 |
| Cooling | 76 |
| Ventilation | 8 |
| Water Heating | 14 |
| Lighting | 26 |
| Cooking | 7 |
| Refrigeration | 23 |
| Office Equipment | 14 |
| Behavioral | 3 |
| Other | 19 |

## 5.2 COMMERCIAL ELECTRIC POTENTIAL

Figure 5-1 provides the technical, economic, MAP and RAP results for the 6-year, 10-year, and 20-year timeframes. The 6-year technical potential is 22.1% of forecasted sales, and the economic potential is 20.0% of forecasted sales. The 6-year MAP is 14.8% and the RAP is 6.3%.

FIGURE 5-1 COMMERCIAL ELECTRIC ENERGY CUMULATIVE ANNUAL POTENTIAL (AS A % OF COMMERCIAL SALES)

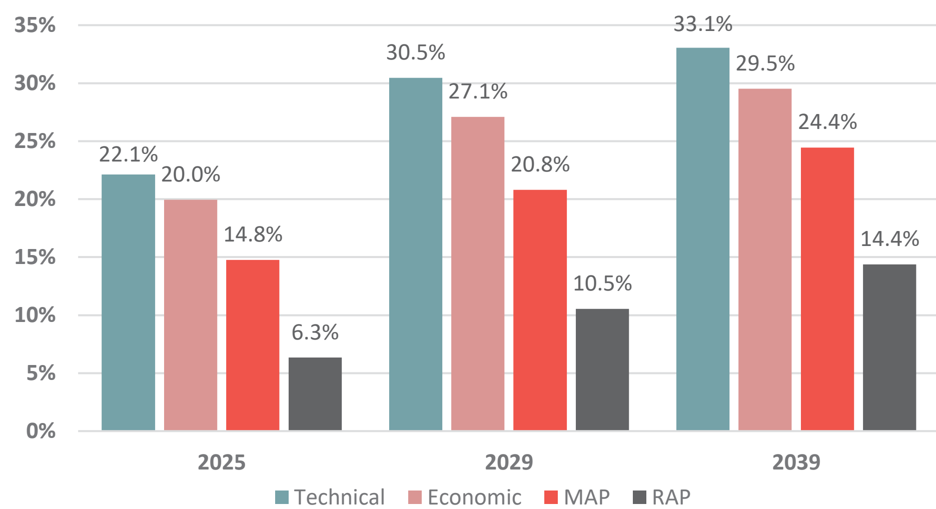



Table 5-2 provides cumulative annual technical, economic, MAP and RAP energy savings, in total MWh and as a percentage of the sector-level sales forecast. The RAP reaches 6.3% after six years.

TABLE 5-2 COMMERCIAL CUMULATIVE ANNUAL ENERGY EFFICIENCY POTENTIAL SUMMARY

| | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 |
|---|---|---|---|---|---|---|
| **MWh** | | | | | | |
| **Technical** | 44,537 | 90,258 | 139,200 | 189,608 | 237,091 | 280,925 |
| **Economic** | 41,327 | 83,264 | 127,773 | 173,145 | 215,118 | 253,284 |
| **MAP** | 26,345 | 55,895 | 88,639 | 123,072 | 156,473 | 187,460 |
| **RAP** | 10,311 | 21,974 | 35,168 | 49,609 | 64,869 | 80,454 |
| **Forecasted Sales** | 1,235,560 | 1,237,950 | 1,244,360 | 1,251,998 | 1,263,383 | 1,269,201 |
| **Energy Savings (as % of Forecast)** | | | | | | |
| **Technical** | 3.6% | 7.3% | 11.2% | 15.1% | 18.8% | 22.1% |
| **Economic** | 3.3% | 6.7% | 10.3% | 13.8% | 17.0% | 20.0% |
| **MAP** | 2.1% | 4.5% | 7.1% | 9.8% | 12.4% | 14.8% |
| **RAP** | 0.8% | 1.8% | 2.8% | 4.0% | 5.1% | 6.3% |

Table 5-3 provides the incremental annual technical, economic, MAP and RAP energy savings, in total MWh and as a percentage of the sector-level sales forecast. The incremental RAP ranges from 0.8% to 1.4% per year over the next six years.

TABLE 5-3 COMMERCIAL INCREMENTAL ANNUAL ENERGY EFFICIENCY POTENTIAL SUMMARY

| | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 |
|---|---|---|---|---|---|---|
| **MWh** | | | | | | |
| **Technical** | 44,537 | 48,599 | 52,397 | 54,755 | 54,631 | 55,436 |
| **Economic** | 41,327 | 44,816 | 47,926 | 49,670 | 49,022 | 49,453 |
| **MAP** | 26,345 | 30,503 | 34,404 | 37,095 | 37,636 | 38,255 |
| **RAP** | 10,311 | 12,122 | 13,911 | 15,609 | 16,770 | 17,811 |
| **Forecasted Sales** | 1,235,560 | 1,237,950 | 1,244,360 | 1,251,998 | 1,263,383 | 1,269,201 |
| **Energy Savings (as % of Forecast)** | | | | | | |
| **Technical** | 3.6% | 3.9% | 4.2% | 4.4% | 4.3% | 4.4% |
| **Economic** | 3.3% | 3.6% | 3.9% | 4.0% | 3.9% | 3.9% |
| **MAP** | 2.1% | 2.5% | 2.8% | 3.0% | 3.0% | 3.0% |
| **RAP** | 0.8% | 1.0% | 1.1% | 1.2% | 1.3% | 1.4% |

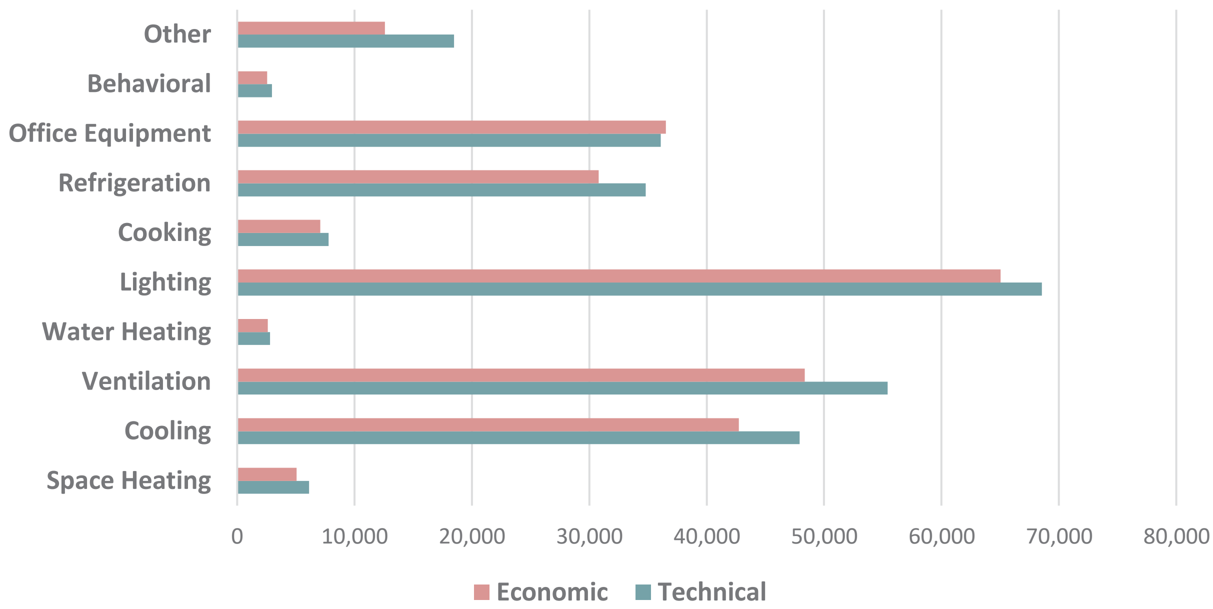
***Technical & Economic Potential***

Table 5-4 provides cumulative annual technical and economic potential results from 2020-2025. Figure 5-2 shows a comparison of the technical and economic potential (6-year) by end use. Lighting, Ventilation, and Cooling are the leading stand-alone end uses among technical and economic potential.

TABLE 5-4 TECHNICAL & ECONOMIC COMMERCIAL ELECTRIC POTENTIAL

| | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 |
|---|---|---|---|---|---|---|
| **Energy (MWh)** | | | | | | |
| **Technical** | 44,537 | 90,258 | 139,200 | 189,608 | 237,091 | 280,925 |
| **Economic** | 41,327 | 83,264 | 127,773 | 173,145 | 215,118 | 253,284 |
| **Peak Demand (MW)** | | | | | | |
| **Technical** | 6 | 12 | 18 | 24 | 30 | 35 |
| **Economic** | 4 | 9 | 14 | 19 | 23 | 28 |

FIGURE 5-2 6-YEAR TECHNICAL AND ECONOMIC COMMERCIAL ELECTRIC POTENTIAL – BY END-USE




### *Maximum Achievable Potential*

Figure 5-3 illustrates the cumulative annual MAP results by end use across the 2020-2025 timeframe. Like technical and economic potential, Lighting, Ventilation, and Cooling are the leading end uses. Refrigeration and Office Equipment also have significant maximum achievable potential.

FIGURE 5-3 COMMERCIAL ELECTRIC ENERGY (CUMULATIVE ANNUAL GWH) MAP POTENTIAL BY END-USE

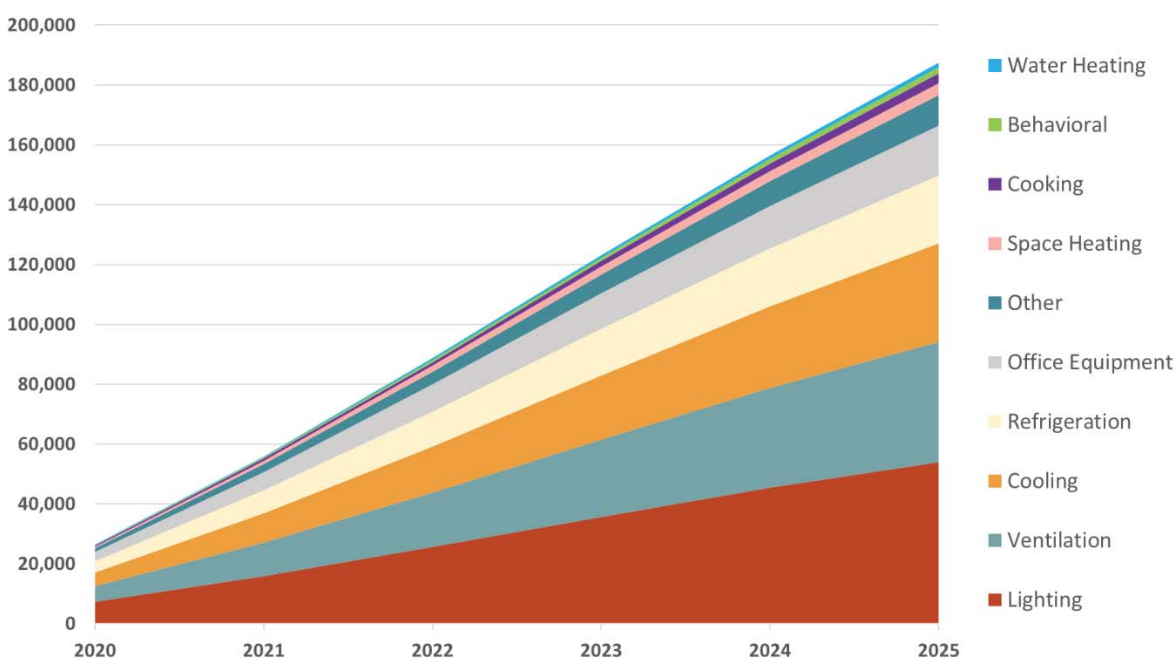



Table 5-5 provides the incremental and cumulative annual MAP across the 2020-2025 timeframe. The incremental MAP ranges from 2.1% to 3.0% of forecasted sales across the six-year timeframe. Cumulative annual MAP rises to 14.8% by 2025.

TABLE 5-5 COMMERCIAL ELECTRIC MAP BY END-USE

| End Use | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 |
|---|---|---|---|---|---|---|
| **Incremental Annual MWh** | | | | | | |
| **Space Heating** | 567 | 663 | 729 | 740 | 699 | 619 |
| **Cooling** | 4,588 | 5,218 | 5,739 | 6,375 | 6,441 | 6,118 |
| **Ventilation** | 5,063 | 6,071 | 7,004 | 7,569 | 7,496 | 6,806 |
| **Water Heating** | 140 | 183 | 228 | 268 | 301 | 336 |
| **Lighting** | 7,338 | 8,570 | 9,628 | 10,120 | 9,750 | 8,608 |
| **Cooking** | 292 | 390 | 495 | 600 | 696 | 780 |
| **Refrigeration** | 3,843 | 4,502 | 4,993 | 5,237 | 5,245 | 6,009 |
| **Office Equipment** | 3,157 | 3,002 | 2,882 | 2,853 | 2,956 | 4,530 |
| **Behavioral** | 201 | 264 | 533 | 676 | 1,045 | 1,277 |
| **Other** | 1,156 | 1,641 | 2,175 | 2,657 | 3,006 | 3,173 |
| **Total** | 26,345 | 30,503 | 34,404 | 37,095 | 37,636 | 38,255 |
| **% of Forecasted Sales** | 2.1% | 2.5% | 2.8% | 3.0% | 3.0% | 3.0% |
| **Incremental Annual MW** | | | | | | |
| **Total** | 2.1 | 2.5 | 2.9 | 3.0 | 3.1 | 2.9 |
| **% of Forecasted Demand** | 0.7% | 0.8% | 0.9% | 1.0% | 1.0% | 1.0% |
| **Cumulative Annual MWh** | | | | | | |
| **Space Heating** | 567 | 1,230 | 1,959 | 2,699 | 3,398 | 4,017 |
| **Cooling** | 4,588 | 9,806 | 15,545 | 21,516 | 27,457 | 32,979 |
| **Ventilation** | 5,063 | 11,134 | 18,138 | 25,707 | 33,203 | 40,009 |
| **Water Heating** | 140 | 323 | 551 | 819 | 1,120 | 1,441 |
| **Lighting** | 7,338 | 15,908 | 25,535 | 35,656 | 45,406 | 54,014 |
| **Cooking** | 292 | 683 | 1,178 | 1,777 | 2,474 | 3,254 |
| **Refrigeration** | 3,843 | 7,617 | 11,630 | 15,621 | 19,368 | 22,748 |
| **Office Equipment** | 3,157 | 6,159 | 9,040 | 11,893 | 14,152 | 16,551 |
| **Behavioral** | 201 | 452 | 769 | 1,161 | 1,648 | 2,219 |
| **Other** | 1,156 | 2,583 | 4,294 | 6,222 | 8,249 | 10,228 |
| **Total** | 26,345 | 55,895 | 88,639 | 123,072 | 156,473 | 187,460 |
| **% of Forecasted Sales** | 2.1% | 4.5% | 7.1% | 9.8% | 12.4% | 14.8% |
| **Cumulative Annual MW** | | | | | | |
| **Total** | 2.1 | 4.6 | 7.3 | 10.3 | 13.2 | 16.0 |
| **% of Forecasted Demand** | 0.7% | 1.5% | 2.4% | 3.4% | 4.4% | 5.3% |

### *Realistic Achievable Potential*

Figure 5-4 illustrates the cumulative annual RAP results by end use across the 2020-2025 timeframe. Like maximum achievable potential, Lighting, Ventilation, and Cooling are the leading end uses. Refrigeration and Office Equipment also have significant realistic achievable potential.

FIGURE 5-4 COMMERCIAL ELECTRIC ENERGY (CUMULATIVE ANNUAL GWH) RAP POTENTIAL BY END-USE

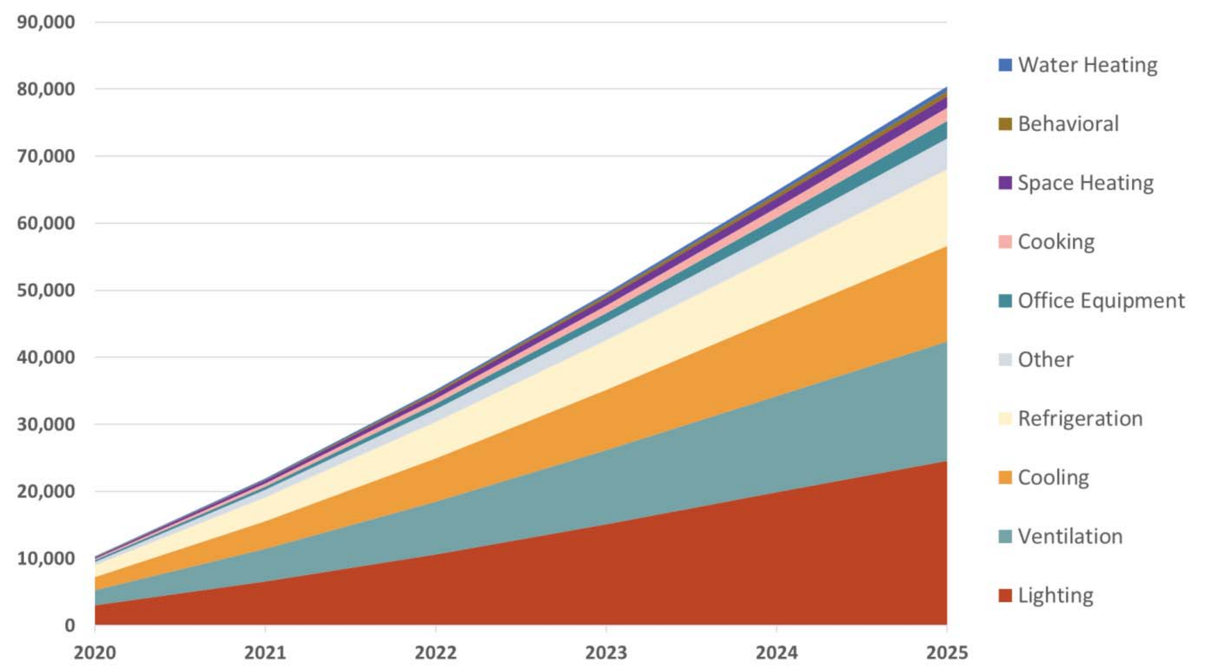



Table 5-6 provides the incremental and cumulative annual RAP across the 2020-2025 timeframe. The incremental RAP ranges from 0.8% to 1.4% of forecasted sales across the six-year timeframe. Cumulative annual RAP rises to 6.3% by 2025.

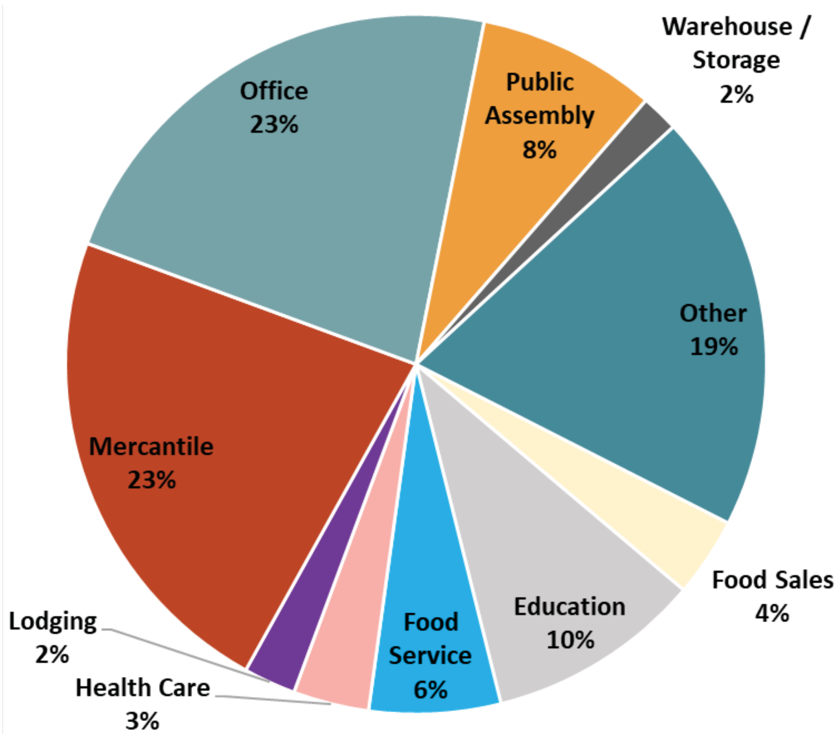
TABLE 5-6 COMMERCIAL ELECTRIC RAP BY END-USE

| End Use | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 |
|---|---|---|---|---|---|---|
| **Incremental Annual MWh** | | | | | | |
| **Space Heating** | 240 | 271 | 297 | 311 | 314 | 308 |
| **Cooling** | 1,955 | 2,170 | 2,379 | 2,738 | 2,852 | 2,874 |
| **Ventilation** | 2,232 | 2,616 | 2,951 | 3,231 | 3,377 | 3,387 |
| **Water Heating** | 77 | 97 | 117 | 137 | 156 | 180 |
| **Lighting** | 3,016 | 3,565 | 4,067 | 4,470 | 4,718 | 4,750 |
| **Cooking** | 198 | 247 | 299 | 352 | 404 | 455 |
| **Refrigeration** | 1,809 | 2,097 | 2,361 | 2,574 | 2,744 | 3,268 |
| **Office Equipment** | 220 | 280 | 364 | 463 | 571 | 701 |
| **Behavioral** | 57 | 80 | 169 | 227 | 353 | 456 |
| **Other** | 507 | 700 | 907 | 1,106 | 1,282 | 1,433 |
| **Total** | 10,311 | 12,122 | 13,911 | 15,609 | 16,770 | 17,811 |
| **% of Forecasted Sales** | 0.8% | 1.0% | 1.1% | 1.2% | 1.3% | 1.4% |
| **Incremental Annual MW** | | | | | | |
| **Total** | 0.9 | 1.0 | 1.3 | 1.9 | 2.9 | 4.6 |
| **% of Forecasted Demand** | 0.3% | 0.3% | 0.4% | 0.6% | 1.0% | 1.5% |
| **Cumulative Annual MWh** | | | | | | |
| **Space Heating** | 240 | 511 | 808 | 1,119 | 1,433 | 1,741 |
| **Cooling** | 1,955 | 4,125 | 6,504 | 9,030 | 11,641 | 14,251 |
| **Ventilation** | 2,232 | 4,848 | 7,799 | 11,029 | 14,406 | 17,793 |
| **Water Heating** | 77 | 174 | 291 | 428 | 584 | 756 |

| End Use | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 |
|---|---|---|---|---|---|---|
| Lighting | 3,016 | 6,581 | 10,648 | 15,117 | 19,835 | 24,585 |
| Cooking | 198 | 444 | 743 | 1,095 | 1,499 | 1,954 |
| Refrigeration | 1,809 | 3,530 | 5,407 | 7,380 | 9,403 | 11,423 |
| Office Equipment | 220 | 500 | 864 | 1,327 | 1,898 | 2,599 |
| Behavioral | 57 | 133 | 240 | 381 | 556 | 774 |
| Other | 507 | 1,127 | 1,864 | 2,702 | 3,614 | 4,577 |
| Total | 10,311 | 21,974 | 35,168 | 49,609 | 64,869 | 80,454 |
| % of Forecasted Sales | 0.8% | 1.8% | 2.8% | 4.0% | 5.1% | 6.3% |
| **Cumulative Annual MW** | | | | | | |
| Total | 0.9 | 1.9 | 3.1 | 4.3 | 5.7 | 7.0 |
| % of Forecasted Demand | 0.3% | 0.6% | 1.0% | 1.4% | 1.9% | 2.3% |

Figure 5-5 illustrates a market segmentation of the RAP in the commercial sector by 2025. Mercantile, Office, and Education are the leading building types.

FIGURE 5-5 2025 COMMERCIAL ELECTRIC ENERGY (CUMULATIVE ANNUAL) RAP POTENTIAL BY MARKET SEGMENT




### *RAP Benefits & Costs*

Table 5-7 provides the net present value benefits and cost, as calculated using the UCT, across the 2020-2025 timeframe for the RAP scenario. Lighting and Cooking are the most cost-effective end-uses, and Cooling also provides significant NPV benefits.

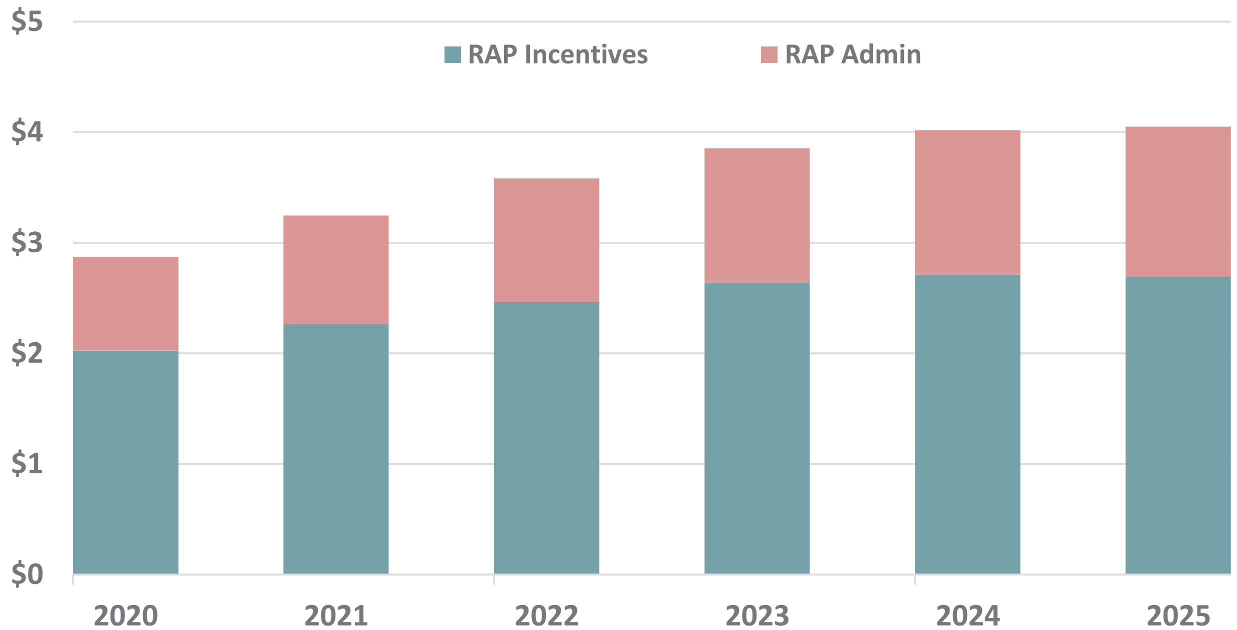
TABLE 5-7 COMMERCIAL NPV BENEFITS & COSTS RAP BY END-USE ($ IN MILLIONS)

| End Use | NPV Benefits | NPV Costs | UCT Ratio |
|---|---|---|---|
| Space Heating | $0.62 | $1.12 | 0.55 |
| Cooling | $9.94 | $3.09 | 3.21 |
| Ventilation | $7.94 | $5.05 | 1.57 |
| Water Heating | $0.21 | $0.08 | 2.60 |

| End Use | NPV Benefits | NPV Costs | UCT Ratio |
|---|---|---|---|
| **Lighting** | $11.03 | $6.03 | 1.83 |
| **Cooking** | $0.69 | $0.34 | 2.06 |
| **Refrigeration** | $3.45 | $1.33 | 2.59 |
| **Office Equipment** | $0.88 | $0.48 | 1.85 |
| **Behavioral** | $0.11 | $0.08 | 1.33 |
| **Other** | $1.95 | $0.53 | 3.67 |
| **Total** | **$36.8** | **$18.1** | **2.03** |

Figure 5-6 provides the budget for the RAP scenario. The budget is broken into incentive and admin budgets for each year of the 2020-2025 timeframe. The incentives rise from $2.0 million to $2.7 million, and overall budgets rise from $2.9 million to $4.1 million by 2025.

FIGURE 5-6 ANNUAL BUDGETS FOR COMMERCIAL RAP ($ IN MILLIONS)




## 5.3 COMMERCIAL POTENTIAL INCLUDING OPT-OUT CUSTOMERS

Table 5-8 provides the incremental annual technical, economic, MAP and RAP energy savings, in total MWh and as a percentage of the sector-level sales forecast, excluding opt-out customers. This is the same information provided in Section 5.2. The cumulative annual energy savings across the 20-year study timeframe are also shown in the far-right column. Table 5-9 provides the incremental annual technical, economic, MAP and RAP energy savings, in total MWh and as a percentage of the sector-level sales forecast, including opt-out customers. The cumulative annual energy savings across the 20-year study timeframe are also shown in the far-right column.

The 20-year RAP is 17.8 GWh excluding opt-out customers. This figure rises to 20.0 GWh with opt-out customers included.

TABLE 5-8 COMMERCIAL INCREMENTAL ANNUAL ENERGY EFFICIENCY POTENTIAL SUMMARY – EXCLUDING OPT-OUT CUSTOMERS

| | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2039 (cumulative) |
|---|---|---|---|---|---|---|---|
| **MWh** | | | | | | | |
| **Technical** | 44,537 | 48,599 | 52,397 | 54,755 | 54,631 | 55,436 | 465,610 |
| **Economic** | 41,327 | 44,816 | 47,926 | 49,670 | 49,022 | 49,453 | 415,838 |
| **MAP** | 26,345 | 30,503 | 34,404 | 37,095 | 37,636 | 38,255 | 344,315 |
| **RAP** | 10,311 | 12,122 | 13,911 | 15,609 | 16,770 | 17,811 | 202,365 |
| **Forecasted Sales** | 1,235,560 | 1,237,950 | 1,244,360 | 1,251,998 | 1,263,383 | 1,269,201 | 1,408,342 |
| | | | | | | | |
| **Technical** | 3.6% | 3.9% | 4.2% | 4.4% | 4.3% | 4.4% | 33.1% |
| **Economic** | 3.3% | 3.6% | 3.9% | 4.0% | 3.9% | 3.9% | 29.5% |
| **MAP** | 2.1% | 2.5% | 2.8% | 3.0% | 3.0% | 3.0% | 24.4% |
| **RAP** | 0.8% | 1.0% | 1.1% | 1.2% | 1.3% | 1.4% | 14.4% |

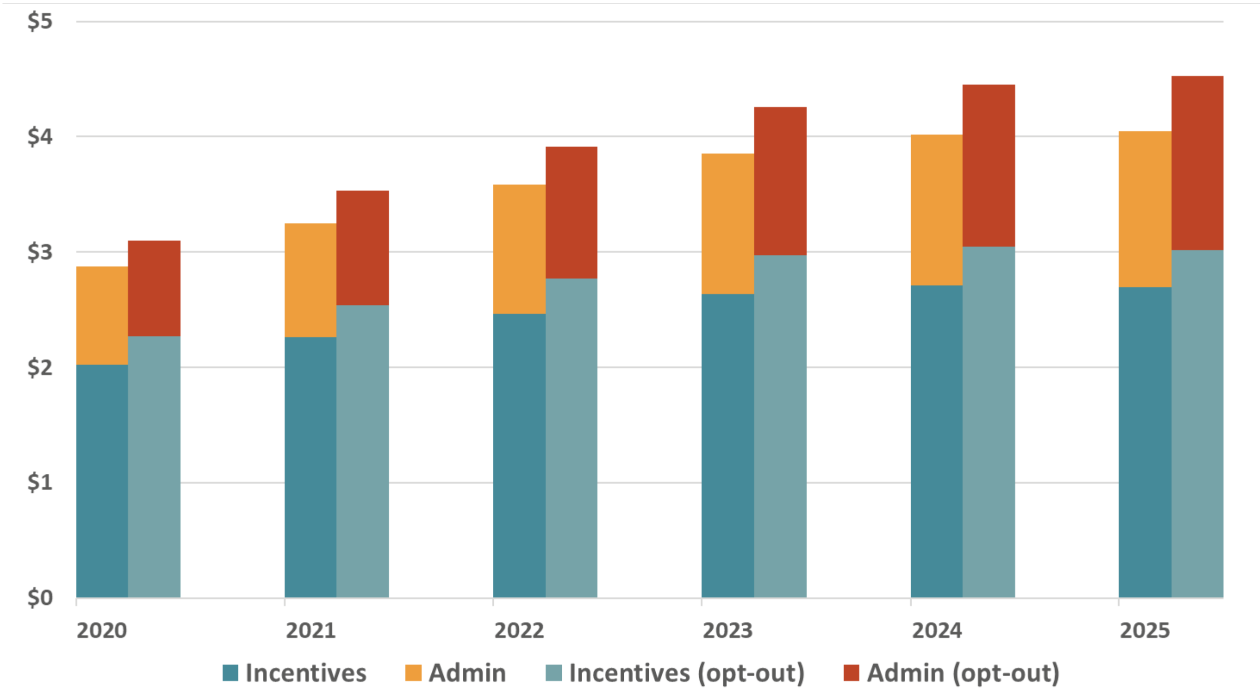
TABLE 5-9 COMMERCIAL INCREMENTAL ANNUAL ENERGY EFFICIENCY POTENTIAL SUMMARY – INCLUDING OPT-OUT CUSTOMERS[36]

| | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2039 (cumulative) |
|---|---|---|---|---|---|---|---|
| **MWh** | | | | | | | |
| **Technical** | 50,170 | 54,751 | 59,038 | 61,705 | 61,577 | 62,517 | 524,715 |
| **Economic** | 46,545 | 50,469 | 53,966 | 55,928 | 55,202 | 55,716 | 468,265 |
| **MAP** | 29,659 | 34,334 | 38,719 | 41,744 | 42,354 | 43,062 | 387,577 |
| **RAP** | 11,578 | 13,618 | 15,630 | 17,541 | 18,846 | 20,006 | 227,568 |
| **Forecasted Sales** | 1,390,224 | 1,392,929 | 1,400,166 | 1,408,787 | 1,421,633 | 1,428,202 | 1,585,207 |
| | | | | | | | |
| **Technical** | 3.6% | 3.9% | 4.2% | 4.4% | 4.3% | 4.4% | 33.1% |
| **Economic** | 3.3% | 3.6% | 3.9% | 4.0% | 3.9% | 3.9% | 29.5% |
| **MAP** | 2.1% | 2.5% | 2.8% | 3.0% | 3.0% | 3.0% | 24.4% |
| **RAP** | 0.8% | 1.0% | 1.1% | 1.2% | 1.3% | 1.4% | 14.4% |

Figure 5-7 provides the budget for the RAP scenario, with and without opt-out customers. The budget is broken into incentive and admin budgets for each year of the 2020-2025 timeframe. The overall budgets without opt-out customers rise from $2.9 million to $4.1 million by 2025. The budgets with opt-out customers included increase from $3.1 million to $4.5 million by 2025.

[36] Due to limited number of commercial opt-out customers and minor changes in building segmentation, savings as a percentage of sales is negligible out to three decimal places.

FIGURE 5-7 ANNUAL BUDGETS FOR COMMERCIAL RAP ($ IN MILLIONS) – WITH AND WITHOUT OPT-OUT CUSTOMERS



# 6 Industrial Energy Efficiency Potential

This section provides the potential results for technical, economic, MAP and RAP for the industrial sector. Results are broken down by end use. The cost-effectiveness results and budgets for the RAP scenario are also provided. The results in this section exclude the savings and sales forecast associated with opt-out customers

## 6.1 SCOPE OF MEASURES & END USES ANALYZED

There were 165 total unique electric measures included in the analysis. Table 6-1 provides number of measures by end-use (the full list of industrial measures is provided in Appendix D). The measure list was developed based on a review of current Vectren programs, the Indiana TRM, other regional TRMs, and industry documents related to emerging technologies. Data collection activities to characterize measures formed the basis of the assessment of incremental costs, electric energy and demand savings, and measure life.

TABLE 6-1 INDUSTRIAL ENERGY EFFICIENCY MEASURES – BY FUEL TYPE

| End-Use | Number of Unique Measures |
|---|---|
| Computers & Office Equipment | 6 |
| Water Heating | 6 |
| Ventilation | 7 |
| Space Cooling | 22 |
| Space Heating | 16 |
| Cooking | 7 |
| Refrigeration | 25 |
| Lighting | 20 |
| Other | 7 |
| Machine Drive | 21 |
| Process Heating and Cooling | 12 |
| Agriculture | 16 |

## 6.2 INDUSTRIAL ELECTRIC POTENTIAL

Figure 6-1 provides the technical, economic, MAP and RAP results for the 6-year, 10-year, and 20-year timeframes. The 6-year technical potential is 20.6% of forecasted sales, and the economic potential is 19.3% of forecasted sales. The 6-year MAP is 14.0% and the RAP is 6.7%.

FIGURE 6-1 INDUSTRIAL ELECTRIC ENERGY CUMULATIVE ANNUAL POTENTIAL (AS A % OF INDUSTRIAL SALES)

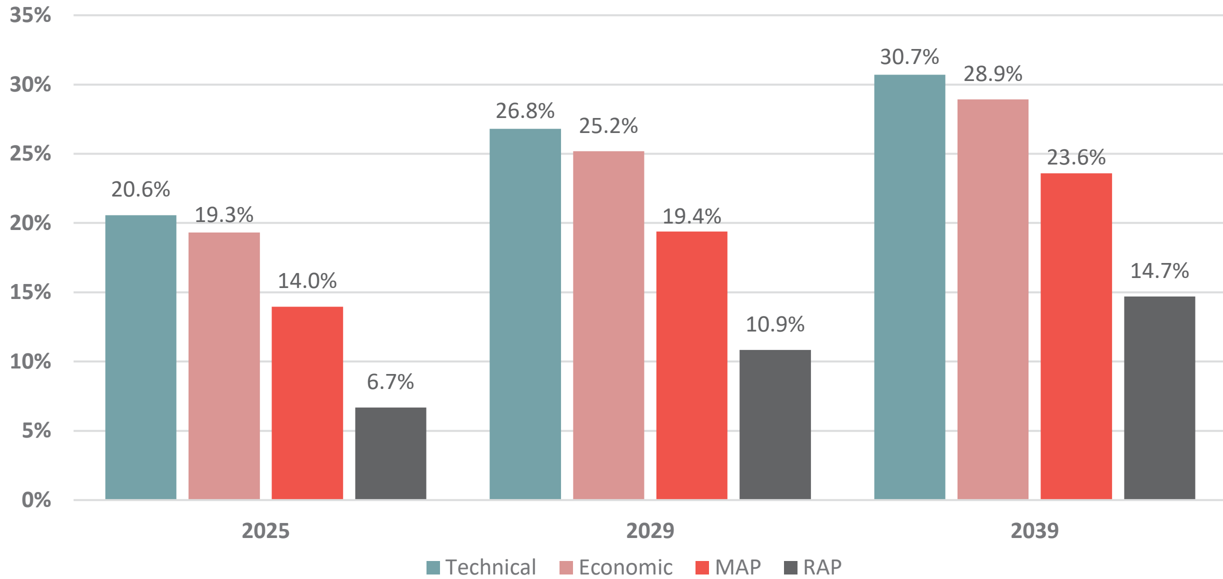



Table 6-2 provides cumulative annual technical, economic, MAP and RAP energy savings, in total MWh and as a percentage of the sector-level sales forecast. The RAP reaches 6.7% after six years.

TABLE 6-2 INDUSTRIAL CUMULATIVE ANNUAL ENERGY EFFICIENCY POTENTIAL SUMMARY

| | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 |
|---|---|---|---|---|---|---|
| **MWh** | | | | | | |
| **Technical** | 20,939 | 44,360 | 69,559 | 95,219 | 115,910 | 133,986 |
| **Economic** | 19,496 | 41,369 | 65,048 | 89,324 | 108,808 | 125,853 |
| **MAP** | 11,785 | 25,996 | 42,270 | 59,617 | 76,091 | 90,989 |
| **RAP** | 5,517 | 11,982 | 19,336 | 27,377 | 35,449 | 43,566 |
| **Forecasted Sales** | 640,023 | 641,915 | 644,247 | 646,702 | 649,006 | 651,371 |
| **Energy Savings (as % of Forecast)** | | | | | | |
| **Technical** | 3.3% | 6.9% | 10.8% | 14.7% | 17.9% | 20.6% |
| **Economic** | 3.0% | 6.4% | 10.1% | 13.8% | 16.8% | 19.3% |
| **MAP** | 1.8% | 4.0% | 6.6% | 9.2% | 11.7% | 14.0% |
| **RAP** | 0.9% | 1.9% | 3.0% | 4.2% | 5.5% | 6.7% |

Table 6-3 provides the incremental annual technical, economic, MAP and RAP energy savings, in total MWh and as a percentage of the sector-level sales forecast. The incremental RAP ranges from 0.9% to 1.6% per year over the next six years.

TABLE 6-3 INDUSTRIAL INCREMENTAL ANNUAL ENERGY EFFICIENCY POTENTIAL SUMMARY

| | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 |
|---|---|---|---|---|---|---|
| **MWh** | | | | | | |
| **Technical** | 20,939 | 24,019 | 26,570 | 27,937 | 28,192 | 27,324 |
| **Economic** | 19,496 | 22,471 | 25,050 | 26,553 | 26,985 | 26,293 |
| **MAP** | 11,785 | 14,679 | 17,322 | 19,105 | 20,003 | 19,927 |
| **RAP** | 5,517 | 6,688 | 7,846 | 8,854 | 9,799 | 10,567 |
| **Forecasted Sales** | 640,023 | 641,915 | 644,247 | 646,702 | 649,006 | 651,371 |
| **Energy Savings (as % of Forecast)** | | | | | | |
| **Technical** | 3.3% | 3.7% | 4.1% | 4.3% | 4.3% | 4.2% |
| **Economic** | 3.0% | 3.5% | 3.9% | 4.1% | 4.2% | 4.0% |
| **MAP** | 1.8% | 2.3% | 2.7% | 3.0% | 3.1% | 3.1% |

| | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 |
|---|---|---|---|---|---|---|
| **MWh** | | | | | | |
| **RAP** | 0.9% | 1.0% | 1.2% | 1.4% | 1.5% | 1.6% |

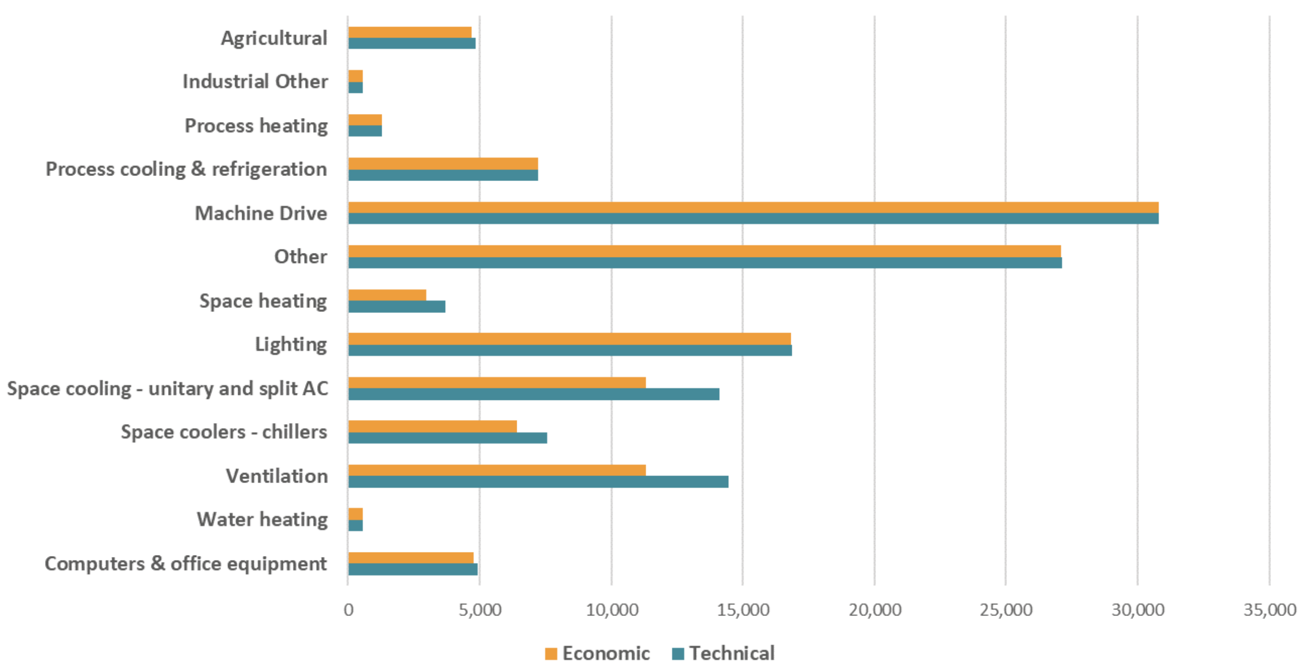
***Technical & Economic Potential***

Table 6-4 provides cumulative annual technical and economic potential results from 2020-2025. Figure 6-2 shows a comparison of the technical and economic potential (6-year) by end use. Machine drive, Lighting, and Ventilation are the leading stand-alone end uses among technical and economic potential.

TABLE 6-4 TECHNICAL AND ECONOMIC INDUSTRIAL ELECTRIC POTENTIAL

| | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 |
|---|---|---|---|---|---|---|
| **Energy (MWh)** | | | | | | |
| **Technical** | 20,939 | 44,360 | 69,559 | 95,219 | 115,910 | 133,986 |
| **Economic** | 19,496 | 41,369 | 65,048 | 89,324 | 108,808 | 125,853 |
| **Peak Demand (MW)** | | | | | | |
| **Technical** | 5 | 10 | 15 | 21 | 25 | 29 |
| **Economic** | 4 | 9 | 14 | 19 | 24 | 27 |

FIGURE 6-2 YEAR TECHNICAL AND ECONOMIC INDUSTRIAL ELECTRIC POTENTIAL – BY END-USE




***Maximum Achievable Potential***

Figure 6-3 illustrates the cumulative annual MAP results by end use across the 2020-2025 timeframe. Like technical and economic potential, Machine Drive, Lighting, and Ventilation are the leading end uses. Space cooling and process cooling & refrigeration also have significant maximum achievable potential.

FIGURE 6-3 INDUSTRIAL ELECTRIC ENERGY (CUMULATIVE ANNUAL GWH) MAP POTENTIAL BY END-USE

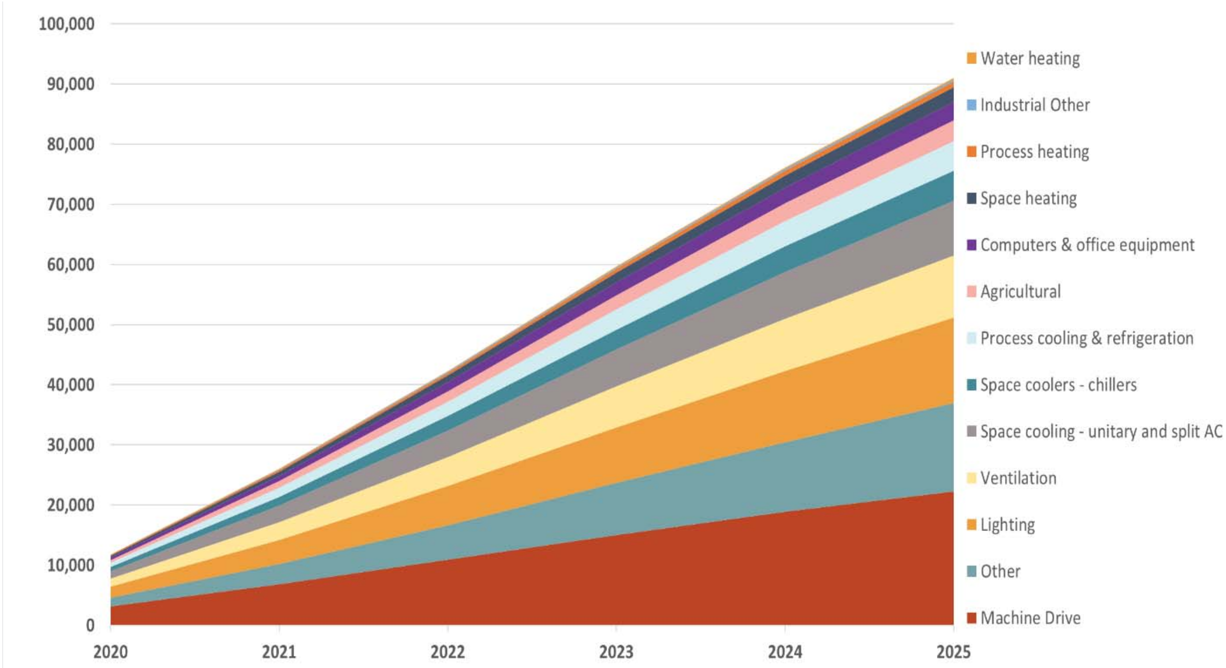



Table 6-5 provides the incremental and cumulative annual MAP across the 2020-2025 timeframe. The incremental MAP ranges from 1.8% to 3.1% of forecasted sales across the six-year timeframe. Cumulative annual MAP rises to 14.0% by 2025.

TABLE 6-5 INDUSTRIAL ELECTRIC MAP BY END-USE

| End Use | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 |
|---|---|---|---|---|---|---|
| **Incremental Annual MWh** | | | | | | |
| **Computers & office equipment** | 385 | 494 | 596 | 678 | 736 | 867 |
| **Water heating** | 40 | 41 | 44 | 49 | 55 | 60 |
| **Ventilation** | 1,311 | 1,626 | 1,898 | 2,011 | 1,926 | 1,675 |
| **Space coolers - chillers** | 677 | 808 | 912 | 949 | 971 | 886 |
| **Space cooling - unitary and split AC** | 1,271 | 1,503 | 1,696 | 1,768 | 1,814 | 1,631 |
| **Lighting** | 1,797 | 2,238 | 2,662 | 2,951 | 3,008 | 2,839 |
| **Space heating** | 328 | 390 | 444 | 464 | 480 | 435 |
| **Other** | 1,466 | 1,909 | 2,391 | 2,877 | 3,392 | 3,930 |
| **Machine Drive** | 3,166 | 3,928 | 4,588 | 5,017 | 5,150 | 5,093 |
| **Process cooling & refrigeration** | 681 | 931 | 1,165 | 1,362 | 1,511 | 1,617 |
| **Process heating** | 122 | 169 | 217 | 259 | 290 | 306 |
| **Industrial Other** | 47 | 56 | 64 | 73 | 83 | 93 |
| **Agricultural** | 494 | 587 | 644 | 645 | 588 | 495 |
| **Total** | 11,785 | 14,679 | 17,322 | 19,105 | 20,003 | 19,927 |
| **% of Forecasted Sales** | 1.8% | 2.3% | 2.7% | 3.0% | 3.1% | 3.1% |
| **Incremental Annual MW** | | | | | | |
| **Total** | 3 | 3 | 4 | 4 | 4 | 4 |
| **% of Forecasted Demand** | 2.3% | 2.8% | 3.3% | 3.7% | 3.8% | 3.8% |

| End Use | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 |
|---|---|---|---|---|---|---|
| **Cumulative Annual MWh** | | | | | | |
| **Computers & office equipment** | 385 | 878 | 1,474 | 2,153 | 2,630 | 3,056 |
| **Water heating** | 40 | 82 | 126 | 175 | 230 | 288 |
| **Ventilation** | 1,311 | 2,932 | 4,819 | 6,813 | 8,712 | 10,350 |
| **Space coolers - chillers** | 677 | 1,483 | 2,392 | 3,335 | 4,237 | 4,964 |
| **Space cooling - unitary and split AC** | 1,271 | 2,760 | 4,425 | 6,133 | 7,727 | 9,090 |
| **Lighting** | 1,797 | 3,972 | 6,492 | 9,204 | 11,859 | 14,223 |
| **Space heating** | 328 | 715 | 1,151 | 1,603 | 2,029 | 2,398 |
| **Other** | 1,466 | 3,374 | 5,764 | 8,638 | 11,542 | 14,682 |
| **Machine Drive** | 3,166 | 6,853 | 10,906 | 15,038 | 18,913 | 22,274 |
| **Process cooling & refrigeration** | 681 | 1,497 | 2,405 | 3,333 | 4,203 | 4,961 |
| **Process heating** | 122 | 271 | 443 | 625 | 801 | 956 |
| **Industrial Other** | 47 | 97 | 148 | 199 | 248 | 296 |
| **Agricultural** | 494 | 1,081 | 1,725 | 2,370 | 2,958 | 3,450 |
| **Total** | 11,785 | 25,996 | 42,270 | 59,617 | 76,091 | 90,989 |
| **% of Forecasted Sales** | 1.8% | 4.0% | 6.6% | 9.2% | 11.7% | 14.0% |
| **Cumulative Annual MW** | | | | | | |
| **Total** | 3 | 6 | 9 | 13 | 17 | 20 |
| **% of Forecasted Demand** | 2.3% | 5.0% | 8.2% | 11.6% | 14.6% | 17.4% |

***Realistic Achievable Potential***

Figure 6-4 illustrates the cumulative annual RAP results by end use across the 2020-2025 timeframe. Like maximum achievable potential, Machine Drive, Lighting, and Ventilation are the leading end uses. Space cooling and process cooling & refrigeration also have significant realistic achievable potential.

FIGURE 6-4 INDUSTRIAL ELECTRIC ENERGY (CUMULATIVE ANNUAL GWH) RAP POTENTIAL BY END-USE

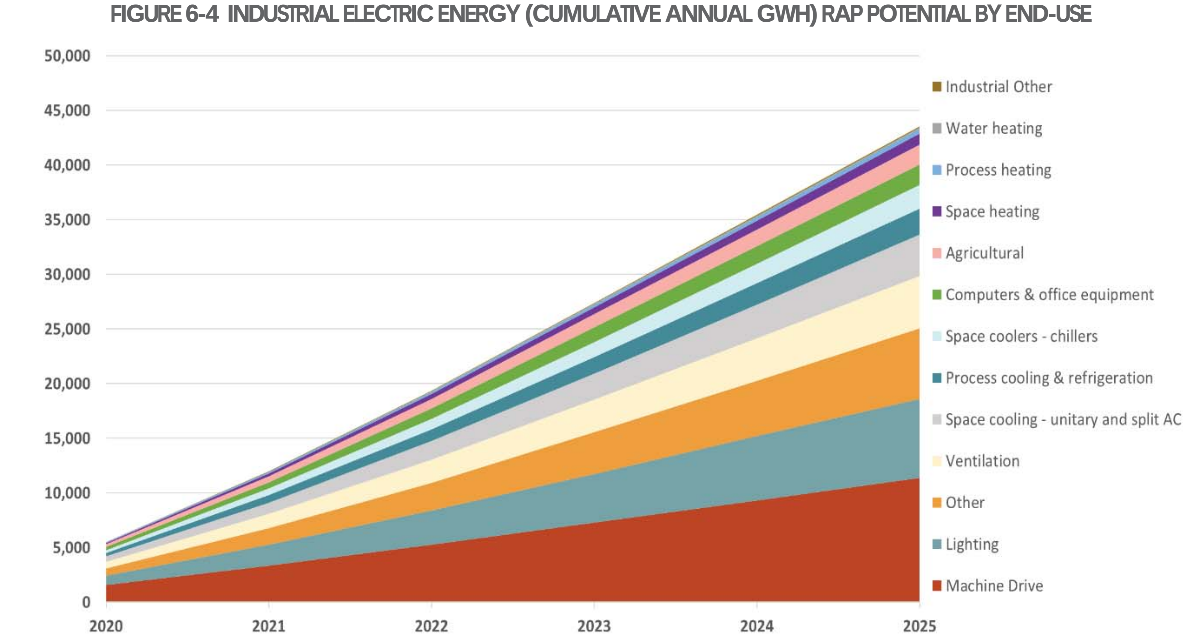


Table 6-6 provides the incremental and cumulative annual RAP across the 2020-2025 timeframe. The incremental RAP ranges from 0.9% to 1.6% of forecasted sales across the six-year timeframe. Cumulative annual RAP rises to 6.7% by 2025.

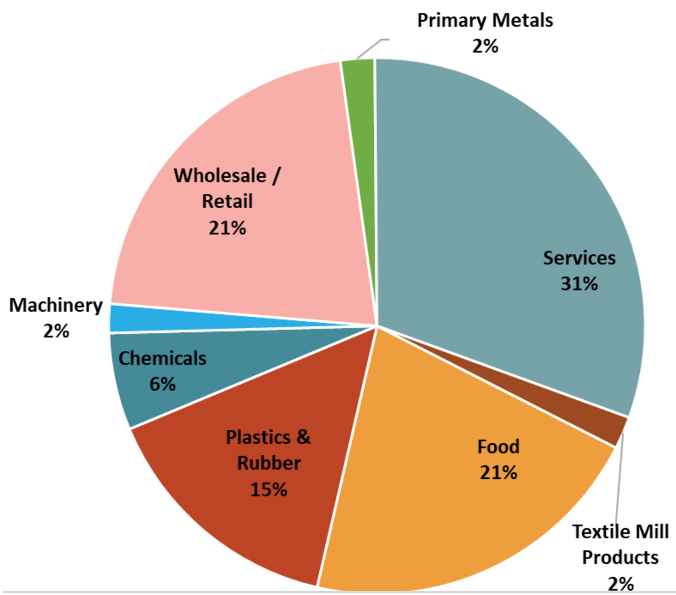
TABLE 6-6 INDUSTRIAL ELECTRIC RAP BY END-USE

| End Use | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 |
|---|---|---|---|---|---|---|
| **Incremental Annual MWh** | | | | | | |
| **Computers & office equipment** | 263 | 316 | 367 | 415 | 457 | 544 |
| **Water heating** | 9 | 12 | 16 | 20 | 25 | 29 |
| **Ventilation** | 599 | 713 | 818 | 883 | 915 | 911 |
| **Space coolers - chillers** | 271 | 323 | 372 | 406 | 453 | 465 |
| **Space cooling - unitary and split AC** | 477 | 570 | 655 | 711 | 801 | 815 |
| **Lighting** | 892 | 1,083 | 1,268 | 1,419 | 1,532 | 1,592 |
| **Space heating** | 125 | 150 | 173 | 189 | 213 | 218 |
| **Other** | 649 | 834 | 1,046 | 1,269 | 1,502 | 1,772 |
| **Machine Drive** | 1,575 | 1,881 | 2,183 | 2,456 | 2,683 | 2,888 |
| **Process cooling & refrigeration** | 326 | 421 | 517 | 619 | 724 | 826 |
| **Process heating** | 56 | 75 | 95 | 116 | 136 | 156 |
| **Industrial Other** | 13 | 17 | 23 | 29 | 36 | 44 |
| **Agricultural** | 262 | 292 | 312 | 323 | 321 | 307 |
| **Total** | 5,517 | 6,688 | 7,846 | 8,854 | 9,799 | 10,567 |
| **% of Forecasted Sales** | 0.9% | 1.0% | 1.2% | 1.4% | 1.5% | 1.6% |
| **Incremental Annual MW** | | | | | | |
| **Total** | 1 | 1 | 2 | 2 | 2 | 2 |
| **% of Forecasted Demand** | 1.1% | 1.3% | 1.5% | 1.7% | 1.9% | 2.0% |
| **Cumulative Annual MWh** | | | | | | |
| **Computers & office equipment** | 263 | 579 | 945 | 1,360 | 1,623 | 1,873 |
| **Water heating** | 9 | 21 | 37 | 57 | 82 | 110 |
| **Ventilation** | 599 | 1,311 | 2,124 | 3,000 | 3,904 | 4,799 |
| **Space coolers - chillers** | 271 | 593 | 964 | 1,367 | 1,790 | 2,177 |
| **Space cooling - unitary and split AC** | 477 | 1,041 | 1,683 | 2,372 | 3,081 | 3,783 |
| **Lighting** | 892 | 1,948 | 3,157 | 4,478 | 5,863 | 7,253 |
| **Space heating** | 125 | 273 | 443 | 627 | 817 | 1,007 |
| **Other** | 649 | 1,484 | 2,530 | 3,798 | 5,051 | 6,463 |
| **Machine Drive** | 1,575 | 3,334 | 5,252 | 7,275 | 9,335 | 11,358 |
| **Process cooling & refrigeration** | 326 | 694 | 1,093 | 1,516 | 1,948 | 2,373 |
| **Process heating** | 56 | 121 | 195 | 276 | 361 | 445 |
| **Industrial Other** | 13 | 27 | 44 | 63 | 84 | 107 |
| **Agricultural** | 262 | 554 | 867 | 1,189 | 1,511 | 1,817 |
| **Total** | 5,517 | 11,982 | 19,336 | 27,377 | 35,449 | 43,566 |
| **% of Forecasted Sales** | 0.9% | 1.9% | 3.0% | 4.2% | 5.5% | 6.7% |

| End Use | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 |
|---|---|---|---|---|---|---|
| **Cumulative Annual MW** | | | | | | |
| **Total** | 1 | 3 | 4 | 6 | 8 | 9 |
| **% of Forecasted Demand** | 1.1% | 2.3% | 3.7% | 5.3% | 6.8% | 8.4% |

Figure 6-5 illustrates a market segmentation of the RAP in the industrial sector by 2025. Food, plastics & rubber and chemicals are the leading market segments.

FIGURE 6-5 2025 INDUSTRIAL ELECTRIC ENERGY (CUMULATIVE ANNUAL) RAP POTENTIAL BY MARKET SEGMENT[37]




*RAP Benefits & Costs*

Table 6-7 provides the net present value benefits and cost, as calculated using the UCT, across the 2020-2025 timeframe for the RAP scenario. Machine Drive is the most cost-effective end-use, and Facility Lighting provides the greatest NPV benefits.

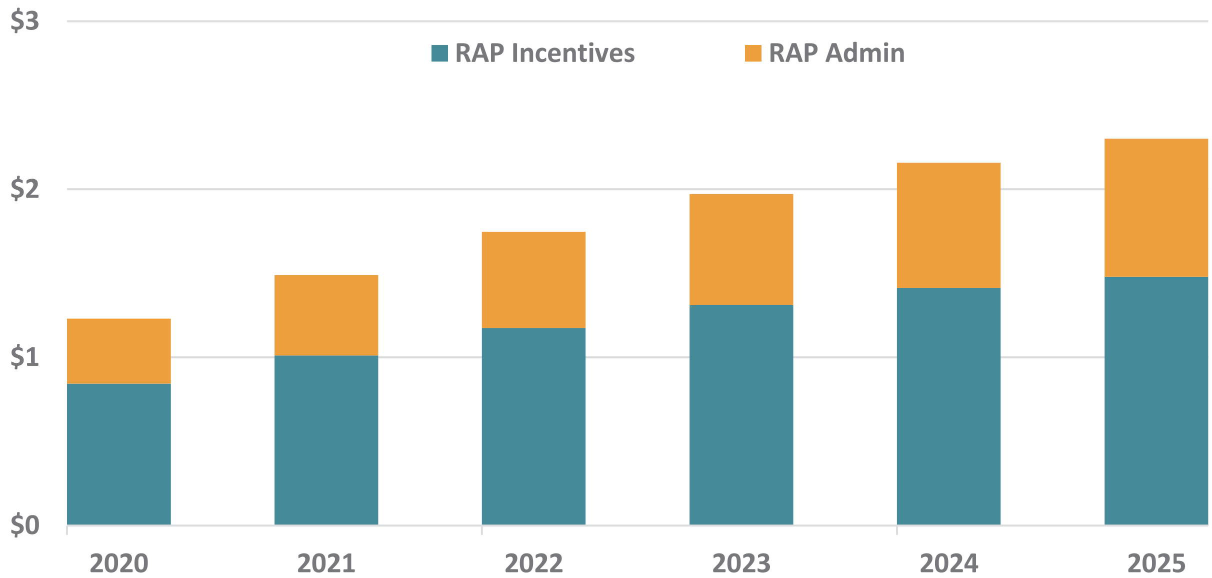
TABLE 6-7 INDUSTRIAL NPV BENEFITS AND COSTS RAP BY END-USE ($ IN MILLIONS)

| End Use | NPV Benefits | NPV Costs | UCT Ratio |
|---|---|---|---|
| Machine Drive | $7.4 | $1.3 | 5.90 |
| Facility HVAC | $5.9 | $1.4 | 4.18 |
| Facility Lighting | $9.9 | $3.7 | 2.64 |
| Other Facility Support | $2.9 | $1.2 | 2.45 |
| Process Cooling and Refrigeration | $1.3 | $0.4 | 3.64 |
| Process Heating | $0.2 | $0.0 | 4.59 |
| Other | $3.6 | $1.2 | 3.04 |
| **Total** | $31.2 | $9.2 | 3.40 |

[37] "Wholesale/Retail" and "Services" industrial types include industrial buildings that devote a minority percentage of floor space to commercial activities like wholesale and retail trade, and construction, healthcare, education and accommodation & food service. Automotive related industries are divided between plastics, rubber, and machinery based on their NAICS codes.

Figure 6-6 provides the budget for the RAP scenario. The budget is broken into incentive and admin budgets for each year of the 2020-2025 timeframe. The incentives rise from $0.8 million to $1.5 million, and overall budgets rise from $1.2 million to $2.3 million by 2025.

FIGURE 6-6 ANNUAL BUDGETS FOR INDUSTRIAL RAP ($ IN MILLIONS)




## 6.3 INDUSTRIAL POTENTIAL INCLUDING OPT-OUT CUSTOMERS

Table 6-8 provides the incremental annual technical, economic, MAP and RAP energy savings, in total MWh and as a percentage of the sector-level sales forecast, excluding opt-out customers. This is the same information provided in Section 6.2. The cumulative annual energy savings across the 20-year study timeframe are also shown in the far-right column. Table 6-9 provides the incremental annual technical, economic, MAP and RAP energy savings, in total MWh and as a percentage of the sector-level sales forecast, including opt-out customers.[38] The cumulative annual energy savings across the 20-year study timeframe are also shown in the far-right column.

The 20-year RAP is 14.7%, excluding opt-out customers. This figure drops to 13.5%, with opt-out customers included. Though the savings as a percentage of sales decreases, the energy savings of the RAP rises from 100,008 MWh to 334,101 MWh when the opt-out customers are included in the analysis.

TABLE 6-8 INDUSTRIAL INCREMENTAL ANNUAL ENERGY EFFICIENCY POTENTIAL SUMMARY – EXCLUDING OPT-OUT CUSTOMERS

| | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2039 (cumulative) |
|---|---|---|---|---|---|---|---|
| **MWh** | | | | | | | |
| **Technical** | 20,939 | 24,019 | 26,570 | 27,937 | 28,192 | 27,324 | 208,784 |
| **Economic** | 19,496 | 22,471 | 25,050 | 26,553 | 26,985 | 26,293 | 196,720 |
| **MAP** | 11,785 | 14,679 | 17,322 | 19,105 | 20,003 | 19,927 | 160,447 |
| **RAP** | 5,517 | 6,688 | 7,846 | 8,854 | 9,799 | 10,567 | 100,008 |
| **Forecasted Sales** | 640,023 | 641,915 | 644,247 | 646,702 | 649,006 | 651,371 | 679,928 |
| **Energy Savings (as % of Forecast)** | | | | | | | |
| **Technical** | 3.3% | 3.7% | 4.1% | 4.3% | 4.3% | 4.2% | 30.7% |
| **Economic** | 3.0% | 3.5% | 3.9% | 4.1% | 4.2% | 4.0% | 28.9% |
| **MAP** | 1.8% | 2.3% | 2.7% | 3.0% | 3.1% | 3.1% | 23.6% |
| **RAP** | 0.9% | 1.0% | 1.2% | 1.4% | 1.5% | 1.6% | 14.7% |

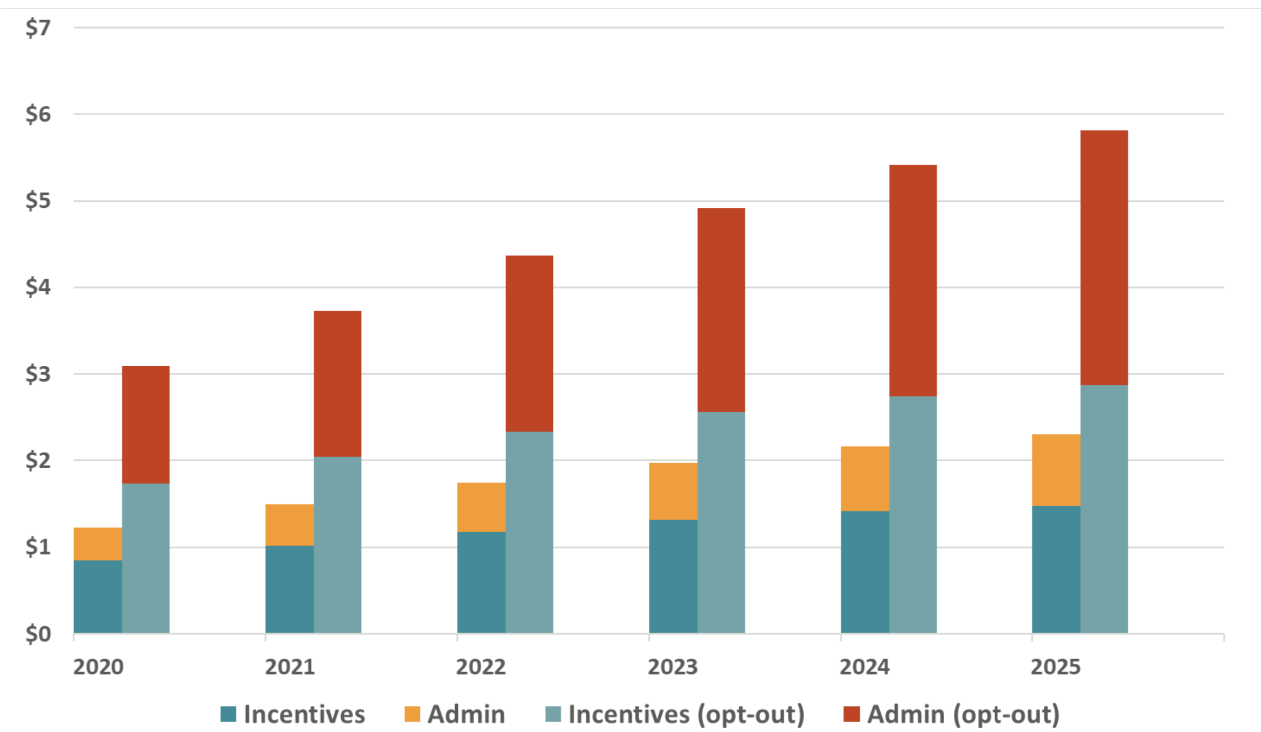
[38] Note the increase in the forecasted sales with opt-out customers included.

TABLE 6-9 INDUSTRIAL INCREMENTAL ANNUAL ENERGY EFFICIENCY POTENTIAL SUMMARY – INCLUDING OPT-OUT CUSTOMERS

| | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2039 (cumulative) |
|---|---|---|---|---|---|---|---|
| **MWh** | | | | | | | |
| **Technical** | 66,750 | 78,664 | 89,185 | 95,702 | 97,760 | 95,516 | 688,359 |
| **Economic** | 63,335 | 74,992 | 85,566 | 92,390 | 94,842 | 92,995 | 659,191 |
| **MAP** | 41,085 | 51,432 | 61,105 | 67,856 | 71,118 | 70,784 | 521,639 |
| **RAP** | 19,324 | 23,576 | 27,883 | 31,695 | 35,218 | 38,149 | 334,101 |
| **Forecasted Sales** | 2,329,890 | 2,336,776 | 2,345,264 | 2,354,201 | 2,362,591 | 2,371,200 | 2,475,157 |
| **Energy Savings (as % of Forecast)** | | | | | | | |
| **Technical** | 2.9% | 3.4% | 3.8% | 4.1% | 4.1% | 4.0% | 27.8% |
| **Economic** | 2.7% | 3.2% | 3.6% | 3.9% | 4.0% | 3.9% | 26.6% |
| **MAP** | 1.8% | 2.2% | 2.6% | 2.9% | 3.0% | 3.0% | 21.1% |
| **RAP** | 0.8% | 1.0% | 1.2% | 1.3% | 1.5% | 1.6% | 13.5% |

Figure 6-8 provides the budget for the RAP scenario, with and without opt-out customers. The budget is broken into incentive and admin budgets for each year of the 2020-2025 timeframe. The overall budgets without opt-out customers rise from $1.2 million to $2.3 million by 2025. The budgets with opt-out customers included increase from $3.1 million to $5.8 million by 2025.

FIGURE 6-7 ANNUAL BUDGETS FOR INDUSTRIAL RAP ($ IN MILLIONS) – WITH AND WITHOUT OPT-OUT CUSTOMERS



# 7 Demand Response and CVR Potential

This section provides the results of the technical, economic, MAP and RAP potential for the demand response analysis. Results are broken down by sector and program. The cost-effectiveness results and budgets for the MAP and RAP scenarios are also provided. Section 2.5 provides a description of the demand response methodology. Additional demand response results details are provided in Appendix G.

This section also provides the results of the CVR analysis. Energy and peak demand savings are provided, along with estimated budget requirements and the program benefits and costs.

## 7.1 TOTAL DEMAND RESPONSE POTENTIAL

Table 7-1 shows the technical, economic, and achievable (MAP and RAP) cumulative annual potential for the 2020-2025 timeframe. Achievable potential includes a participation rate to estimate the realistic number of customers that are expected to participate in each cost-effective demand response program option. These values are at the customer meter. The MAP assumes the maximum participation that would happen in the real-world, while the realistically achievable potential (RAP) discounts MAP by considering barriers to program implementation that could limit the amount of savings achieved.

TABLE 7-1 SUMMARY OF TECHNICAL, ECONOMIC, AND ACHIEVABLE POTENTIAL[39]

| Potential Level | 2020 Savings (MW) | 2021 Savings (MW) | 2022 Savings (MW) | 2023 Savings (MW) | 2024 Savings (MW) | 2025 Savings (MW) |
|---|---|---|---|---|---|---|
| Technical | 399 | 368 | 333 | 312 | 304 | 300 |
| Economic | 367 | 348 | 322 | 306 | 299 | 295 |
| MAP | 23 | 64 | 110 | 131 | 138 | 139 |
| RAP | 7 | 20 | 38 | 49 | 53 | 55 |

Table 7-2 and Table 7-3 show the achievable potential savings for the 2020-2025 timeframe. Only those programs that were found to be cost-effective are included. Critical Peak Pricing (with Enabling Technologies) are the leading programs in both the commercial and residential sectors.

TABLE 7-2 MAP SAVINGS BY PROGRAM

| | Program | 2020 Savings (MW) | 2021 Savings (MW) | 2022 Savings (MW) | 2023 Savings (MW) | 2024 Savings (MW) | 2025 Savings (MW) |
|---|---|---|---|---|---|---|---|
| Residential | DLC AC Thermostat (Utility Incentivized) | 2 | 3 | 5 | 7 | 8 | 10 |
| | DLC AC Thermostat (BYOT) | 2 | 3 | 5 | 7 | 8 | 10 |
| | Critical Peak Pricing (with Enabling Technologies) | 8 | 24 | 49 | 64 | 68 | 68 |
| | Critical Peak Pricing (without Enabling Technologies) | 4 | 11 | 17 | 19 | 19 | 18 |
| | Peak Time Rebates | 5 | 10 | 10 | 6 | 5 | 4 |
| | **Total** | 18 | 49 | 82 | 96 | 99 | 100 |

[39] The results in Table 7-1 do not account for any interactions with energy efficiency. In other words, the results are independent of the energy efficiency potential. Table 7-2 and Table 7-3 provide the DR total both without and with accounting for the interactions between energy efficiency potential and demand response potential. The "with energy efficiency interaction" results assume that energy efficiency potential comes first, then demand response.

| | Program | 2020 Savings (MW) | 2021 Savings (MW) | 2022 Savings (MW) | 2023 Savings (MW) | 2024 Savings (MW) | 2025 Savings (MW) |
|---|---|---|---|---|---|---|---|
| Commercial | DLC AC Thermostat (Utility Incentivized) | 0 | 1 | 1 | 1 | 1 | 2 |
| | DLC AC Thermostat (BYOT) | 0 | 1 | 1 | 1 | 1 | 2 |
| | Critical Peak Pricing (with Enabling Technologies) | 4 | 11 | 23 | 31 | 33 | 33 |
| | Critical Peak Pricing (without Enabling Technologies) | 1 | 2 | 3 | 3 | 3 | 3 |
| | Time of Use Rate | 0 | 1 | 1 | 1 | 1 | 1 |
| | **Total** | 5 | 15 | 28 | 36 | 38 | 39 |
| **Residential & Commercial Total (without energy efficiency interaction)** | | 23 | 64 | 110 | 131 | 138 | 139 |
| **Residential & Commercial Total (with energy efficiency interaction)** | | 22 | 61 | 103 | 121 | 124 | 123 |

TABLE 7-3 RAP SAVINGS BY PROGRAM

| | Program | 2020 Savings (MW) | 2021 Savings (MW) | 2022 Savings (MW) | 2023 Savings (MW) | 2024 Savings (MW) | 2025 Savings (MW) |
|---|---|---|---|---|---|---|---|
| Residential | DLC AC Thermostat (Utility Incentivized) | 1 | 2 | 3 | 3 | 4 | 5 |
| | DLC AC Thermostat (BYOT) | 1 | 2 | 3 | 3 | 4 | 5 |
| | Critical Peak Pricing (with Enabling Technologies) | 2 | 6 | 12 | 16 | 18 | 18 |
| | Critical Peak Pricing (without Enabling Technologies) | 1 | 3 | 5 | 7 | 7 | 7 |
| | Peak Time Rebates | 1 | 3 | 6 | 8 | 8 | 8 |
| | Time of Use Rate | 1 | 2 | 3 | 3 | 4 | 4 |
| | **Residential Total** | 5 | 16 | 30 | 38 | 41 | 42 |
| Commercial | DLC AC Thermostat (Utility Incentivized) | 0 | 0 | 0 | 0 | 0 | 1 |
| | DLC AC Thermostat (BYOT) | 0 | 0 | 0 | 0 | 0 | 1 |
| | Critical Peak Pricing (with Enabling Technologies) | 1 | 3 | 7 | 9 | 10 | 10 |
| | Critical Peak Pricing (without Enabling Technologies) | 0 | 1 | 1 | 2 | 2 | 2 |
| | **Commercial Total** | 1 | 4 | 8 | 11 | 12 | 12 |
| **Residential & Commercial Total (without energy efficiency interaction)** | | 7 | 20 | 38 | 49 | 53 | 55 |
| **Residential & Commercial Total (with energy efficiency interaction)** | | 7 | 19 | 37 | 47 | 51 | 51 |

***Benefits & Costs***

Table 7-4 and Table 7-5 show the MAP and RAP budget requirement (for only cost-effective programs) across the 2020-2025 timeframe that would be required to achieve the cumulative annual potential for each of the thermostat scenarios. GDS assumed that the Utility Incentivized Scenario would be combined with the existing energy efficiency smart thermostat program, so those customers would already have thermostats installed. Therefore, there would be no additional incentives or equipment costs for those customers. For the BYOT program, GDS assumed there would be a $75 one-time credit[40] for each new participant. The current and future hardware and software cost of a Demand Response Management System and the cost of non-equipment incentives are included in these budgets.

TABLE 7-4 SUMMARY OF MAP BUDGET REQUIREMENTS

| | Utility Incentivized | BYOT |
|---|---|---|
| 2020 | $2,603,899 | $2,903,578 |
| 2021 | $3,795,482 | $4,142,869 |
| 2022 | $3,491,247 | $3,886,512 |
| 2023 | $1,824,460 | $2,267,934 |
| 2024 | $795,194 | $1,286,975 |
| 2025 | $524,919 | $1,065,077 |

TABLE 7-5 SUMMARY OF RAP BUDGET REQUIREMENTS

| | Utility Incentivized | BYOT |
|---|---|---|
| 2020 | $1,214,023 | $1,366,348 |
| 2021 | $1,519,553 | $1,695,871 |
| 2022 | $1,874,090 | $2,074,485 |
| 2023 | $1,218,690 | $1,443,328 |
| 2024 | $687,836 | $936,763 |
| 2025 | $517,151 | $790,398 |

Table 7-6 and Table 7-7 show the MAP and RAP residential net present values of the total benefits, costs, and savings, along with the UCT ratio for each program for the length of the study. The study period is 2020 to 2034 for MAP (15 years) and 2020 to 2039 for RAP (20 years). Two scenarios were looked at for the demand response study: control of air conditioners by smart thermostats where the utility provides the thermostat (utility incentivized), or where the customer provides their own thermostat (BYOT).

TABLE 7-6 MAP NPV BENEFITS, COSTS, AND UCT RATIOS FOR EACH DEMAND RESPONSE PROGRAM

| | Program | NPV Benefits | NPV Costs | UCT Ratio |
|---|---|---|---|---|
| Residential | DLC AC Thermostat (Utility Incentivized) | $17,194,723 | $1,983,943 | 8.67 |
| | DLC AC Thermostat (BYOT) | $17,194,723 | $8,202,189 | 2.10 |
| | DLC AC Switch | $444,312 | $981,072 | 0.45 |
| | DLC Water Heaters | $70,254 | $909,399 | 0.08 |
| | DLC Pool Pumps | $3,606 | $932,923 | 0.00 |
| | Critical Peak Pricing (with Enabling Technologies) | $71,995,462 | $4,229,589 | 17.02 |
| | Critical Peak Pricing (without Enabling Technologies) | $22,495,433 | $3,296,084 | 6.82 |

40 Vectren South 2018 Electric DSM Operating Plan

| | Program | NPV Benefits | NPV Costs | UCT Ratio |
|---|---|---|---|---|
| | Peak Time Rebates | $7,465,909 | $2,061,985 | 3.62 |
| | Time of Use Rates | $827,243 | $1,655,665 | 0.50 |
| Commercial | DLC AC Thermostat (Utility Incentivized) | $2,808,364 | $740,617 | 3.79 |
| | DLC AC Thermostat (BYOT) | $2,808,364 | $1,217,479 | 2.31 |
| | DLC AC Switch | $7,448 | $888,343 | 0.01 |
| | DLC Water Heaters | $238 | $887,382 | 0.00 |
| | Critical Peak Pricing (with Enabling Technologies) | $36,360,268 | $1,072,797 | 33.89 |
| | Critical Peak Pricing (without Enabling Technologies) | $3,959,266 | $804,905 | 4.92 |
| | Real Time Pricing | $166,288 | $627,540 | 0.26 |
| | Peak Time Rebates | $327,957 | $818,521 | 0.40 |
| | Time of Use Rates | $960,336 | $826,947 | 1.16 |

TABLE 7-7 RAP NPV BENEFITS, COSTS, AND UCT RATIOS FOR EACH DEMAND RESPONSE PROGRAM

| | Program | NPV Benefits | NPV Costs | UCT Ratio |
|---|---|---|---|---|
| Residential | DLC AC Thermostat (Utility Incentivized) | $13,414,527 | $1,347,251 | 9.96 |
| | DLC AC Thermostat (BYOT) | $13,414,527 | $5,676,540 | 2.36 |
| | DLC AC Switch | $161,139 | $1,085,281 | 0.15 |
| | DLC Water Heaters | $24,158 | $1,058,798 | 0.02 |
| | DLC Pool Pumps | $703 | $1,101,271 | 0.00 |
| | Critical Peak Pricing (with Enabling Technologies) | $23,447,290 | $1,299,760 | 18.04 |
| | Critical Peak Pricing (without Enabling Technologies) | $10,175,975 | $1,383,206 | 7.36 |
| | Peak Time Rebates | $11,651,211 | $1,567,503 | 7.43 |
| | Time of Use Rates | $5,036,926 | $1,623,212 | 3.10 |
| Commercial | DLC AC Thermostat (Utility Incentivized) | $1,332,037 | $752,800 | 1.77 |
| | DLC AC Thermostat (BYOT) | $1,332,037 | $957,031 | 1.39 |
| | DLC AC Switch | $305 | $1,051,229 | 0.00 |
| | DLC Water Heaters | $41 | $1,051,193 | 0.00 |
| | Critical Peak Pricing (with Enabling Technologies) | $13,997,560 | $706,486 | 19.81 |
| | Critical Peak Pricing (without Enabling Technologies) | $2,562,131 | $697,914 | 3.67 |
| | Real Time Pricing | $715,458 | $745,708 | 0.96 |
| | Peak Time Rebates | $437,224 | $855,727 | 0.51 |
| | Time of Use Rates | $725,868 | $803,613 | 0.90 |

## 7.2 CVR POTENTIAL

Tables 7-8 and 7-9 show the respective incremental and cumulative annual CVR potential for the first six years of the study. Energy (MWh) and peak demand (kW) savings estimates are included in the tables.

TABLE 7-8. CVR INCREMENTAL ANNUAL POTENTIAL

| | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 |
|---|---|---|---|---|---|---|
| Projected MWh Savings | 2,494 | 0 | 0 | 3,861 | 0 | 0 |
| Projected kW Savings | 449 | 0 | 0 | 695 | 0 | 0 |

TABLE 7-9. CVR CUMULATIVE ANNUAL POTENTIAL

| | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 |
|---|---|---|---|---|---|---|
| Projected MWh Savings | 2,494 | 2,494 | 2,494 | 6,355 | 6,355 | 6,355 |
| Projected kW Savings | 449 | 449 | 449 | 1,144 | 1,144 | 1,144 |

Table 7-10 shows the annual budget requirements to run the CVR program with the East Side and Broadview substations. The capital cost of the East Side substation is $1,350,000, and initial equipment and software costs of the Broadview station is $1,550,000. The implementation costs for the East Side substation are $139,748 per year, and $163,225 for the Broadview substation (starting in 2023). Administrative costs are assumed to be $40,000 for the entire CVR program in 2020 and escalates by 1.5% per year thereafter.

TABLE 7-10. ANNUAL CVR BUDGET REQUIREMENTS

| | CVR Budget |
|---|---|
| 2020 | $179,748 |
| 2021 | $180,348 |
| 2022 | $180,957 |
| 2023 | $344,810 |
| 2024 | $345,437 |
| 2025 | $346,074 |

Table 3-9 shows the NPV benefits and costs associated with the CVR program across the 20-yr timeframe of the study. The UCT ratio is 1.38.

TABLE 7-11. NPV BENEFITS, COSTS, AND UCT RATIO FOR CVR PROGRAM

| Program | NPV Benefits | NPV Costs | UCT Ratio |
|---|---|---|---|
| CVR | $4,687,972 | $3,407,160 | 1.38 |

# VOLUME II

## *2020-2025 Integrated Electric Action Plan*

*prepared for*

VECTREN
Live Smart

JANUARY 2019

# 1 Summary of Results

## 1.1 VECTREN'S ACTION PLAN

The Market Potential Study serves as the basis for developing Vectren's Action Plan. The Action Plan is designed to extract the insights and data from the Market Potential Study and translate them into opportunities to deliver to customers. The Action Plan provides guidance to mobilize the results of the Market Potential Study research and design program initiatives that provide a pathway to advance efforts that are reasonable and relevant in developing Vectren's portfolio. The following section lays out the process, principles, and elements of Vectren's portfolio of programs. A summary of the results for the proposed portfolio is also provided.

## 1.2 GUIDING PLANNING PRINCIPLES IN DEVELOPING ACTION PLAN OFFERINGS

Vectren's Energy Efficiency Action Plan was developed in accordance with a number of guiding principles and considerations. The process was built on using the most recent Market Potential Study as the foundation, and was then designed to incorporate industry best standards, implementer experiences, and projected changes in the market (such as codes and standards) in order to translate the insights and knowledge from the Market Potential Study into actionable energy efficiency programs for Vectren's planning purposes and customers.

A review of the key planning guidelines and considerations used to frame the Action Plan follows:

TABLE 1-1 KEY PLANNING GUIDELINES IN DEVELOPING THE ACTION PLAN

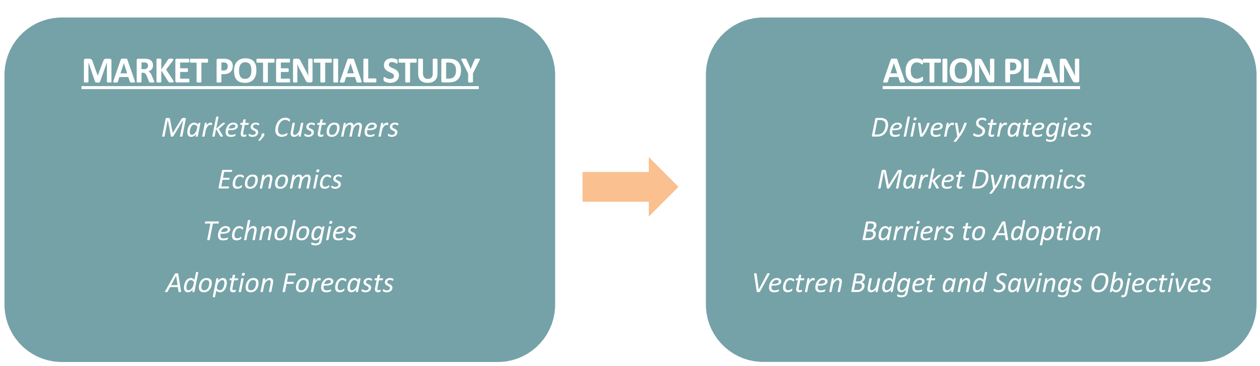
| Plan Consideration | Description |
|---|---|
| **Market Coverage** | Consideration was given to crafting a portfolio of programs that offers opportunities for savings across all of Vectren's customer groups. This includes residential (single, multifamily and income qualified) as well as commercial and industrial markets. |
| **Direct Link to the Market Potential Study** | The Action Plan is directly linked to the Market Potential Study by using its market and cost data. It is acknowledged that there are differences between market and achievable potential due to market dynamics (net versus gross impacts), timeframe differences, proxy versus specific program delivery approaches, and budget realities. Wherever possible, the Market Potential Study serves as a primary reference source making it easier for Vectren to return to the Market Potential Study for added insights as conditions in the market change. |
| **Leveraging Current Program Efforts** | Efforts were directed at leveraging existing Vectren offerings to take advantage of market and trade ally understanding, to utilize existing market relationships, retain the relevant elements of programs already working well, and to continue promotional efforts (where relevant). |
| **Introduce New Measures and Concepts** | The approach actively looked at incorporating new, applicable measures deemed cost effective and suitable for Vectren's portfolio. This included the introduction of selected new measures in the existing prescriptive-type programs. |
| **Cost Effectiveness Analysis** | For planning purposes, each of the recommended programs must pass the Utility Cost Test (UCT) and the Total Resource Cost (TRC) tests, except for Income-Qualified Programs which do not need to meet cost-effectiveness tests in order to promote a greater social good. The cost-effectiveness results are reported for the UCT and the TRC tests. Each program is assessed separately to determine relative benefits and costs (in contrast to assessing each individual measure). |
| **Income-Qualified Programs** | Because income-qualified programs are not required to be cost-effective, the Market Potential Study did not screen out measures for income qualified programs based on any cost-effectiveness tests. The team used alternate guidelines for determining which measures would be included in the program. The team chose a "quality over quantity" approach and provided more services to each individual customer than in previous program years. To ensure that income-qualified programs did not overwhelm other energy efficiency program priorities, the team ensured that the overall program budget did not vastly exceed previous program budgets. |
| **C&I Custom Program** | Because the C&I Custom program utilizes engineering estimates for each project, customers can submit a wide range of projects through the program. Typically, C&I customers submit large projects through the program to provide an economy of scale for the company taking the time to |

| Plan Consideration | Description |
|---|---|
| | complete program paperwork. The Market Potential Study, however, includes all measures that C&I customers may submit through the program no matter the size of the project. Due to this project sizing difference, the Market Potential Study estimates significantly higher savings than the team believed was achievable through the program. The team adjusted C&I Custom program participation and savings based on feedback from implementers and historical program participation. |
| **Adoption Forecasts** | Forecasts of customer adoption were reviewed and applied from the Market Potential Study in combination with the historical participation from Vectren's programs. Information was also captured from actual VEDI program experience from evaluation reporting, reliance on "like-utility" estimates in offering similar programs and discussions with implementers. |
| **Impact of Codes and Standards** | The savings presented in the Action Plan considers upcoming changes to the baseline. The residential lighting program serves as a good example, where the baseline is changing in 2020 due to the Energy Independence Security Act (EISA). Since 2010, first CFLs and then LEDs have claimed significant shares of the U.S. light bulb market. As a result, the energy efficiency of the average new light bulb sold in the U.S. has increased significantly. That means the savings that energy efficiency programs can claim for helping to install an efficient LED has decreased. Starting in 2020, LED (or equivalent lights) become the standard alternative, directly impacting the amount of savings available for customers changing out their bulbs. The elimination of savings from LED lighting is included in the Vectren portfolio starting in 2021-2022. A similar situation is evident in looking at savings estimates from electrically commutated motors (ECM) as part of furnaces. The standards for ECM motors are scheduled to increase in July 2019, resulting in a loss of reportable energy savings starting in 2020 from the measure. |
| **Program Costs and Budgets** | A budget that characterizes the estimated costs for delivering programs to customers is presented for each program. The costs include all participant incentive, planning, evaluation and implementation costs forecast for each year of program operation. |
| **Electric and Natural Gas Integration** | As a combination utility, some of Vectren's programs offer savings addressing both electric and natural gas reductions. Programs such as new construction, behavioral savings, multifamily, and income-qualified weatherization all include electric and gas savings. These programs follow the need to split program costs across fuel types while the cost-effectiveness results include benefits of electric and gas reductions. This effort was directed at areas of the Vectren service territory which offer both fuel types to customers. The specific impacts of these programs are provided in the individual program write-ups. |

## 1.3 VECTREN ENERGY EFFICIENCY ACTION PLAN BACKGROUND

The development of the Action Plan is designed to translate the insights and information from the broader Market Potential Study analysis into discrete and specific offerings for Vectren's customers. The Market Potential Study and the Action Plan are related and share common values, but the Action Plan provides more detail, specificity and mobilization strategies.

The Action Plan outlines recommended electric programs for 2020-2025, a shorter timeframe than the potential research. The Action Plan lays outs how to achieve the savings uncovered in the potential study research, shifting the broad and high-level forecast of savings opportunities in the Market Potential Study results into specific and actionable savings opportunities. An illustrative view between the Market Potential Study and the Action Plan elements follows:

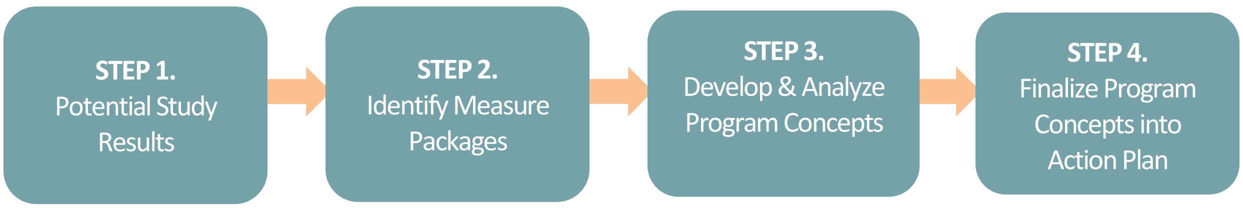


## 1.4 VECTREN ENERGY EFFICIENCY ACTION PLAN FRAMEWORK

The effort to develop Vectren's energy efficiency programs, for their planning purposes, follows a grounded and sequential process. The process was built on applying the recent market potential analytics as a starting point and, from there, developing program offerings that cost-effectively meet Vectren's planning and program objectives. An illustrative review of the process follows.

### *1.4.1 Approach*

Our approach was based on conducting a series of sequential activities that take the top measures from the potential analyses and develop more detailed and defined concepts to better reflect likely delivery strategies and actual experience. This included packaging measures into programs to analyze and forecast adoption, economic impacts, and savings estimates. This approach is consistent with similar energy efficiency potential efforts and is detailed in the Guide for Conducting Energy Efficiency Potential Studies, prepared by the National Action Plan for Energy Efficiency (2007). These activities are discussed in more detail below.




### *1.4.2 Action Plan Activities*

***Step 1. Potential Study Results***

The starting point for developing the programs in the Vectren Action Plan was the recently-completed Market Potential Study. This study provided a current assessment of the energy efficiency opportunities available in Vectren service territory and was built on the utility's most recent sales information, market characterization, and forecast of adoption using a number of scenarios and data on measure penetration, costs, energy savings, and overall economics. A key input used for the Action Plan was the identification of the relative savings impacts and cost and benefits for a large array of possible measures that were considered for the Vectren portfolio.

The focus on identifying relevant measures for further consideration in the Vectren portfolio was based on looking at the forecast impacts from both the Total Resource Cost (TRC) and the Utility Cost Test (UCT). Measures which passed either test were reviewed and screened to determine their applicability, market rationale, and viability to be packaged into programs for subsequent examination. The project team, working with Vectren, coordinated multiple meetings with staff and implementers to assist in our understanding of current and proposed DSM initiatives, details of Indiana and Vectren-specific markets, and the suitability of efficiency measures given the utility's customer base. For example, there were a number of retail consumer-related products that passed the relevant screening—such as energy efficient laptops, printers, SMART televisions, and monitors—but are not typically handled through utility intervention. Instead they are part of national standards and market efforts. The result was a list of 413 measures, deemed to be the most reasonable and relevant for further consideration by Vectren.

***Step 2. Identify Measure Packages***

Using the data and results of the MPS, relevant measures were bundled into packages to better reflect targeted end uses, typical trade ally involvement in customer transactions, and common delivery strategies. The combined packages of measures were designed to advance the analysis efforts and optimally spread delivery costs across a range of technologies. The packages were developed through discussions with Vectren staff, review of prior utility offerings and discussions with Vectren's implementors.

***Step 3. Develop and Analyze Program Concepts***

Measure packages were then combined into program concepts, designed to reflect program implementation. The concepts were developed through a series of interviews with Vectren's program implementers. These discussions were designed to capture their insights and suggestions as what works best in Vectren's market based on their experiences. Discussions were also conducted with Vectren staff to get a sense of prior offerings, to better understand program delivery experiences. Finally, effort was also directed at incorporating practices and findings from other utility experiences in Indiana and in the region. The results of this step provided inputs to the Action Plan modeling including: energy savings, program costs, participation and incentives. These elements are all key inputs into modeling the stream of benefits and costs and determine cost effectiveness.

### *Step 4. Finalize Offerings in Action Plan*

The final program concepts and relevant information were incorporated into Vectren's Action Plan document. The Action Plan provides the key information for required to implement desired programs.

A review of the key Action Plan data elements and sources follows:

TABLE 1-2 ACTION PLAN DATA ELEMENTS

| Action Plan Content | Description |
|---|---|
| **Energy Savings** | Each program contains savings estimates for kWh, kW, and therms developed from the Market Potential Study analysis. Additional sources for the savings estimates include: the Indiana TRM, prior evaluation results from VEDI, prior DSM filings, and discussions with relevant implementers. |
| **Technology Costs** | Technology cost was obtained from the Market Potential Study analysis. Additional sources included prior evaluation results from VEDI and prior DSM filings. |
| **Estimated Useful Lifetime** | Estimates of useful lifetime (EUL) were based on the Market Potential Study analytics and the Indiana Measure Library. For programs with multiple measures, the program EUL was calculated using a weighted average of the number of each measure implemented. |
| **Incentive Strategy** | The specific incentive strategy including type (rebate, loan, POS reduction, manufacturer payment), and amount was determined from discussions with Vectren. There is a good history from prior VEDI DSM efforts to detail incentive strategy and amounts to move the market. The cost economics from the Participant Test were also used to gauge impacts. |
| **Annual Adoption** | Forecasts of customer adoption from the Market Potential Study were reviewed and adjustments were applied based on historical participation in Vectren's programs, upcoming changes in codes and standards, actual performance reported in VEDI evaluation reporting, and "like-utility" estimates in offering similar programs. |
| **NTG Impacts** | NTG estimates from past evaluation studies were used for existing programs. Benchmarking against other Indiana utilities or "like utilities" was used for new initiatives. Discussions with implementers were also included. |
| **Program Costs** | Program budgets were developed using historical program cost data and past VEDI evaluations. Discussions with relevant implementation contractors also provided insight regarding typical utility management requirements and related costs. |
| **Benefit-Cost Impacts** | Each program concept also includes the impact of the relative costs and benefits for each initiative. The results include the forecast of benefit-costs from various perspectives: Participant test, Rate Impact test, Utility Cost test, and Total Resource Cost test. |

# 2 Overview of Vectren's Energy Efficiency Portfolio

The following section outlines the portfolio of programs developed by Vectren, EMI Consulting, and GDS (referred to hereafter as "the team"). The section begins with a high-level summary of the recommended programs and then provides detailed participation estimates for each year of the Action Plan.

## 2.1 RECOMMENDED VECTREN ENERGY EFFICIENCY PROGRAM PORTFOLIO

The following table presents the recommended Vectren proposed portfolio. A more detailed program-by-program write-up is also provided in Section 3 to define each program's overall design and incorporate relevant technology and market data to permit modeling of load impacts, budgets, and cost-effectiveness.

TABLE 2-1 SUMMARY OF DRAFT 2020-2025 ENERGY EFFICIENCY PROGRAMS

| Programs | Continuation from Previous Plan | New or Expanded Offering | Pilot Program | Participant Unit | Gas/Electric Integrated Savings |
|---|---|---|---|---|---|
| Residential Lighting | X | | | Bulb | |
| Residential Prescriptive | X | X | | Equipment / Appliance / Service | X |
| Residential New Construction | X | | | Home | X |
| Income Qualified Weatherization | X | | | Home | X |
| Energy Efficient Schools | X | | | Kit | X |
| Residential Behavioral Savings | X | X | | Home | X |
| Appliance Recycling | X | X | | Refrigerator/ Freezer | |
| Home Energy Assessment | X | | | Home | X |
| Food Bank | X | X | | Bulb | X |
| CVR Residential | X | | | NA | |
| Home Energy Management Systems | | X | X | Home | X |
| Smart Cycle (DLC Change Out) | X | | | Thermostat | |
| Bring Your Own Thermostat | X | | | Thermostat | |
| Commercial Prescriptive | X | X | | Equipment / Appliance / Service | X |
| Commercial Custom | X | X | | Project | X |
| Small Business | X | X | | Project | X |
| CVR C&I | X | | | NA | |

## 2.2 SUMMARY OF ENERGY EFFICIENCY IMPACTS

An overall summary of results reflecting savings and costs is shown in Table 2-2 below. These results present an aggregation of all the programs, as well as the results by portfolio (Residential and Commercial/Industrial).

TABLE 2-2 VECTREN INDIANA ELECTRIC DSM 2020-2025 SAVINGS- ALL PROGRAMS

| Year | New Participants in Year | Energy Savings in MWh Savings in Year | Summer kW Savings | Incentives, 000$ | Program Costs, 000$ | Indirect and Other Costs, 000$ | Budget, 000$ |
|---|---|---|---|---|---|---|---|
| 2020 | 345,916 | 47,451 | 10,758 | 3,731 | 5,342 | 1,207 | 10,279 |
| 2021 | 382,684 | 49,716 | 10,653 | 3,814 | 5,724 | 1,547 | 11,085 |
| 2022 | 216,286 | 44,565 | 10,262 | 3,787 | 5,714 | 1,251 | 10,752 |
| 2023 | 135,923 | 45,375 | 10,907 | 3,551 | 5,867 | 1,253 | 10,670 |
| 2024 | 137,955 | 43,309 | 10,405 | 3,565 | 6,063 | 1,570 | 11,198 |
| 2025 | 138,078 | 43,244 | 10,683 | 3,563 | 6,116 | 1,279 | 10,959 |
| **Total** | **1,356,842** | **273,660** | **63,667** | **22,011** | **34,826** | **8,107** | **64,944** |

TABLE 2-3 VECTREN INDIANA ELECTRIC DSM 2020-2025 SAVINGS- RESIDENTIAL

| Year | New Participants in Year | Energy Savings in MWh Savings in Year | Summer kW Savings | Incentives, 000$ | Program Costs, 000$ | Indirect and Other Costs, 000$ | Budget, 000$ |
|---|---|---|---|---|---|---|---|
| 2020 | 302,908 | 22,880 | 5,784 | 1,321 | 3,860 | 582 | 5,763 |
| 2021 | 333,657 | 24,682 | 5,569 | 1,358 | 4,185 | 768 | 6,312 |
| 2022 | 162,737 | 18,353 | 4,926 | 1,316 | 4,118 | 515 | 5,949 |
| 2023 | 80,062 | 17,461 | 5,215 | 1,103 | 4,166 | 482 | 5,752 |
| 2024 | 81,637 | 16,186 | 4,879 | 1,166 | 4,297 | 587 | 6,050 |
| 2025 | 83,617 | 16,349 | 5,216 | 1,236 | 4,356 | 483 | 6,076 |
| **Total** | **1,044,618** | **115,911** | **31,588** | **7,502** | **24,983** | **3,418** | **35,902** |

TABLE 2-4 VECTREN INDIANA ELECTRIC DSM 2020-2025 SAVINGS- COMMERCIAL AND INDUSTRIAL

| Year | New Participants in Year | Energy Savings in MWh Savings in Year | Summer kW Savings | Incentives, 000$ | Program Costs, 000$ | Indirect and Other Costs, 000$ | Budget, 000$ |
|---|---|---|---|---|---|---|---|
| 2020 | 43,008 | 24,571 | 4,975 | 2,410 | 1,482 | 625 | 4,516 |
| 2021 | 49,027 | 25,034 | 5,084 | 2,456 | 1,539 | 779 | 4,773 |
| 2022 | 53,549 | 26,212 | 5,336 | 2,471 | 1,596 | 736 | 4,803 |
| 2023 | 55,861 | 27,914 | 5,691 | 2,447 | 1,700 | 771 | 4,919 |
| 2024 | 56,318 | 27,124 | 5,526 | 2,399 | 1,766 | 983 | 5,148 |
| 2025 | 54,461 | 26,895 | 5,467 | 2,327 | 1,760 | 795 | 4,883 |
| **Total** | **312,224** | **157,749** | **32,079** | **14,510** | **9,843** | **4,689** | **29,042** |

## 2.3 PORTFOLIO TARGETS BY YEAR

The following tables present the portfolio participation, savings, and costs targets by each program year.

TABLE 2-5 2020 PORTFOLIO TARGETS

| | Participants | Total kWh Savings | Total kW (Demand) | Admin. | Implementation | Incentives | Total Budget |
|---|---|---|---|---|---|---|---|
| **Residential** | | | | | | | |
| Residential Lighting | 239,866 | 8,088,914 | 905.24 | $101,000 | $186,419 | $463,014 | $750,433 |
| Residential Prescriptive | 7,966 | 2,465,148 | 691.22 | $40,400 | $347,608 | $632,065 | $1,020,073 |
| Residential New Construction | 86 | 188,624 | 121.46 | $5,050 | $50,000 | $16,775 | $71,825 |
| Home Energy Assessment | 300 | 519,393 | 55.48 | $5,050 | $240,000 | - | $245,050 |
| Income Qualified Weatherization | 539 | 778,285 | 443.32 | $20,200 | $1,275,176 | - | $1,295,376 |
| Energy Efficient Schools | 2,600 | 1,149,200 | 136.50 | $20,200 | $113,589 | - | $133,789 |
| Residential Behavioral Savings | 49,000 | 7,049,208 | 1,574.28 | $40,400 | $323,803 | - | $364,203 |
| Appliance Recycling | 1,251 | 1,179,811 | 171.20 | $40,400 | $143,657 | $61,000 | $245,057 |
| CVR Residential | - | 1,461,047 | 430 | $30,300 | $218,023 | - | $248,323 |
| Smart Cycle (DLC Change Out) | 1,000 | - | 1,015.00 | $20,200 | $516,000 | $96,000 | $632,200 |
| BYOT (Bring Your Own Thermostat) | 300 | - | 240.00 | $20,200 | $22,280 | $52,280 | $94,760 |
| Food Bank | - | - | - | - | - | - | - |
| Home Energy Management Systems | - | - | - | $10,100 | $70,000 | - | $80,100 |
| **Residential Subtotal** | **302,908** | **22,879,629** | **5,783.70** | **$353,500** | **$3,506,555** | **$1,321,134** | **$5,181,189** |
| **Commercial & Industrial (C&I)** | | | | | | | |
| Commercial Prescriptive | 42,431 | 14,490,335 | 3,807.71 | $55,550 | $622,327 | $1,370,010 | $2,047,886 |
| Commercial Custom | 196 | 6,107,234 | 740.00 | $60,600 | $344,162 | $491,537 | $896,299 |
| Small Business | 381 | 2,940,932 | 213.00 | $5,050 | $215,618 | $548,167 | $768,835 |
| CVR Commercial | - | 1,032,656 | 214 | $30,300 | $148,233 | - | $178,533 |
| **Commercial & Industrial Subtotal** | **43,008** | **24,571,158** | **4,974.71** | **$151,500** | **$1,330,340** | **$2,409,714** | **$3,891,554** |
| **Indirect Costs** | | | | | | | |
| Contact Center | | | | | | | $63,000 |
| Online Audit | | | | | | | $42,911 |
| Outreach | | | | | | | $410,000 |
| **Portfolio Costs Subtotal** | | | | | | | **$515,911** |
| **Subtotal (Before Evaluation)** | | | | | | | **$9,588,653** |
| Evaluation | | | | | | | $490,728 |
| **DSM Portfolio Total** | | | | | | | **$10,079,381** |
| **Other Costs** | | | | | | | |
| Emerging Markets | | | | | | | $200,000 |
| Market Potential Study | | | | | | | - |
| Other Costs Subtotal | | | | | | | **$200,000** |
| **DSM Portfolio Total including Other Costs** | | | | | | | **$10,279,381** |

*Note: The team did not factor in the Energy Independence and Security Act (EISA) backstop provision until 2022. The team assumed that Vectren would continue to pilot the Home Energy Management Systems program through 2020.*

TABLE 2-6 2021 PORTFOLIO TARGETS

| | Participants | Total kWh Savings | Total kW (Demand) | Admin. | Implementation | Incentives | Total Budget |
|---|---|---|---|---|---|---|---|
| **Residential** | | | | | | | |
| Residential Lighting | 262,832 | 8,704,288 | 875.28 | $102,616 | $189,402 | $455,001 | $747,018 |
| Residential Prescriptive | 8,276 | 2,618,629 | 661.70 | $41,046 | $353,169 | $645,510 | $1,039,726 |
| Residential New Construction | 77 | 168,932 | 108.81 | $5,131 | $57,249 | $15,025 | $77,405 |
| Home Energy Assessment | 350 | 605,959 | 64.72 | $5,131 | $258,000 | - | $263,131 |
| Income Qualified Weatherization | 566 | 823,215 | 467.28 | $20,523 | $1,293,527 | - | $1,314,050 |
| Energy Efficient Schools | 2,600 | 1,149,200 | 136.50 | $20,523 | $117,253 | - | $137,776 |
| Residential Behavioral Savings | 49,000 | 7,049,208 | 1,574.28 | $20,523 | $328,984 | - | $349,507 |
| Appliance Recycling | 1,344 | 1,285,473 | 172.83 | $41,046 | $159,415 | $66,625 | $267,086 |
| CVR Residential | - | - | - | $30,785 | $197,378 | - | $228,163 |
| Smart Cycle (DLC Change Out) | 1,000 | 198,000 | 1,015 | $20,523 | $536,000 | $116,000 | $672,523 |
| BYOT (Bring Your Own Thermostat) | 300 | - | 240.00 | $20,523 | $30,280 | $60,280 | $111,083 |
| Food Bank | 6,312 | 1,564,332 | 172.21 | $20,523 | $92,517 | - | $113,041 |
| Home Energy Management Systems | 1,000 | 515,000 | 80.00 | $10,262 | $212,900 | - | $223,162 |
| **Residential Subtotal** | **333,657** | **24,682,235** | **5,568.60** | **$359,156** | **$3,826,074** | **$1,358,441** | **$5,543,671** |
| **Commercial & Industrial (C&I)** | | | | | | | |
| Commercial Prescriptive | 48,449 | 15,981,655 | 4,131.23 | $56,439 | $682,432 | $1,424,756 | $2,163,627 |
| Commercial Custom | 196 | 6,107,234 | 740.00 | $61,570 | $349,669 | $491,537 | $902,775 |
| Small Business | 382 | 2,944,615 | 213.00 | $5,131 | $219,172 | $539,573 | $763,876 |
| CVR Commercial | - | - | - | $30,785 | $133,547 | - | $164,332 |
| **Commercial & Industrial Subtotal** | **49,027** | **25,033,504** | **5,084.23** | **$153,924** | **$1,384,820** | **$2,455,867** | **$3,994,610** |
| **Indirect Costs** | | | | | | | |
| Contact Center | | | | | | | $64,008 |
| Online Audit | | | | | | | $43,598 |
| Outreach | | | | | | | $416,560 |
| **Portfolio Costs Subtotal** | | | | | | | **$524,166** |
| **Subtotal (Before Evaluation)** | | | | | | | **$10,062,446** |
| Evaluation | | | | | | | $522,653 |
| **DSM Portfolio Total** | | | | | | | **$10,585,099** |
| **Other Costs** | | | | | | | |
| Emerging Markets | | | | | | | $200,000 |
| Market Potential Study | | | | | | | $300,000 |
| Other Costs Subtotal | | | | | | | **$500,000** |
| **DSM Portfolio Total including Other Costs** | | | | | | | **$11,085,099** |

*Note: Participation and savings spike in 2021 due to: high Residential Prescriptive participation estimated by the Market Potential Study, the start of the Home Energy Management Systems program, the inclusion of the Food Bank program, and a final surge in participation in the Residential Lighting program estimated by the Market Potential Study.*

TABLE 2-7 2022 PORTFOLIO TARGETS

| | Participants | Total kWh Savings | Total kW (Demand) | Admin. | Implementation | Incentives | Total Budget |
|---|---|---|---|---|---|---|---|
| **Residential** | | | | | | | |
| Residential Lighting | 91,708 | 3,259,915 | 255.83 | $104,258 | $144,380 | $346,846 | $595,484 |
| Residential Prescriptive | 8,303 | 2,722,283 | 737.22 | $41,703 | $358,820 | $680,160 | $1,080,683 |
| Residential New Construction | 75 | 164,892 | 106.37 | $5,213 | $53,186 | $14,675 | $73,074 |
| Home Energy Assessment | 420 | 727,151 | 77.67 | $5,213 | $263,225 | - | $268,438 |
| Income Qualified Weatherization | 594 | 869,076 | 492.09 | $20,852 | $1,312,171 | - | $1,333,023 |
| Energy Efficient Schools | 2,600 | 670,800 | 93.60 | $20,852 | $92,229 | - | $113,080 |
| Residential Behavioral Savings | 49,000 | 7,049,208 | 1,574.28 | $20,852 | $334,248 | - | $355,099 |
| Appliance Recycling | 1,425 | 1,360,636 | 184.89 | $41,703 | $171,385 | $70,500 | $283,589 |
| CVR Residential | - | - | - | $31,277 | $190,034 | - | $221,311 |
| Smart Cycle (DLC Change Out) | 1,000 | 198,000 | 1,015 | $20,852 | $556,000 | $136,000 | $712,852 |
| BYOT (Bring Your Own Thermostat) | 300 | - | 240.00 | $20,852 | $38,280 | $68,280 | $127,412 |
| Food Bank | 6,312 | 816,353 | 69.09 | $20,852 | $18,800 | - | $39,651 |
| Home Energy Management Systems | 1,000 | 515,000 | 80.00 | $10,426 | $219,900 | - | $230,326 |
| **Residential Subtotal** | **162,737** | **18,353,314** | **4,926.04** | **$364,902** | **$3,752,658** | **$1,316,461** | **$5,434,021** |
| **Commercial & Industrial (C&I)** | | | | | | | |
| Commercial Prescriptive | 52,971 | 17,154,963 | 4,383.05 | $57,342 | $733,558 | $1,448,274 | $2,239,173 |
| Commercial Custom | 196 | 6,107,234 | 740.00 | $62,555 | $355,263 | $491,537 | $909,355 |
| Small Business | 382 | 2,949,771 | 213.00 | $5,213 | $222,721 | $530,824 | $758,758 |
| CVR Commercial | - | - | - | $31,277 | $128,261 | - | $159,538 |
| **Commercial & Industrial Subtotal** | **53,549** | **26,211,968** | **5,336.05** | **$156,387** | **$1,439,803** | **$2,470,635** | **$4,066,825** |
| **Indirect Costs** | | | | | | | |
| Contact Center | | | | | | | $65,032 |
| Online Audit | | | | | | | $44,295 |
| Outreach | | | | | | | $423,225 |
| **Portfolio Costs Subtotal** | | | | | | | **$532,552** |
| **Subtotal (Before Evaluation)** | | | | | | | **$10,033,398** |
| Evaluation | | | | | | | $518,856 |
| **DSM Portfolio Total** | | | | | | | **$10,552,254** |
| **Other Costs** | | | | | | | |
| Emerging Markets | | | | | | | $200,000 |
| Market Potential Study | | | | | | | - |
| Other Costs Subtotal | | | | | | | **$200,000** |
| **DSM Portfolio Total including Other Costs** | | | | | | | **$10,752,254** |

*Note: Savings and participation are down in 2022 as the team assumed that the EISA backstop provision would remove downstream standard screw-in lighting incentives from all programs except for direct installations.*

TABLE 2-8 2023 PORTFOLIO TARGETS

| | Participants | Total kWh Savings | Total kW (Demand) | Admin. | Implementation | Incentives | Total Budget |
|---|---|---|---|---|---|---|---|
| **Residential** | | | | | | | |
| Residential Lighting | 12,231 | 807,282 | 19.16 | $105,926 | $32,756 | $78,689 | $217,370 |
| Residential Prescriptive | 8,140 | 2,793,920 | 812.09 | $42,370 | $364,561 | $707,135 | $1,114,066 |
| Residential New Construction | 73 | 160,852 | 103.94 | $5,296 | $50,202 | $14,325 | $69,824 |
| Home Energy Assessment | 504 | 872,581 | 93.20 | $5,296 | $267,437 | - | $272,733 |
| Income-Qualified Weatherization | 623 | 917,290 | 518.75 | $21,185 | $1,331,114 | - | $1,352,299 |
| Energy-Efficient Schools | 2,600 | 670,800 | 93.60 | $21,185 | $98,274 | - | $119,460 |
| Residential Behavioral Savings | 49,000 | 7,049,208 | 1,574.28 | $21,185 | $339,596 | - | $360,781 |
| Appliance Recycling | 1,435 | 1,366,149 | 188.46 | $42,370 | $174,745 | $70,750 | $287,865 |
| CVR Residential | - | 1,461,047 | 430 | $31,778 | $270,252 | - | $302,029 |
| Smart Cycle (DLC Change Out) | 1,000 | 198,000 | 1,015 | $21,185 | $576,000 | $156,000 | $753,185 |
| BYOT (Bring Your Own Thermostat) | 300 | - | 240.00 | $21,185 | $46,280 | $76,280 | $143,745 |
| Food Bank | 3,156 | 649,158 | 46.71 | $21,185 | $9,550 | - | $30,735 |
| Home Energy Management Systems | 1,000 | 515,000 | 80.00 | $10,593 | $234,900 | - | $245,493 |
| **Residential Subtotal** | **80,062** | **17,461,286** | **5,215.19** | **$370,741** | **$3,795,666** | **$1,103,179** | **$5,269,586** |
| **Commercial & Industrial (C&I)** | | | | | | | |
| Commercial Prescriptive | 55,283 | 17,821,076 | 4,524.43 | $58,259 | $769,435 | $1,434,660 | $2,262,354 |
| Commercial Custom | 196 | 6,107,234 | 740.00 | $63,556 | $360,948 | $491,537 | $916,040 |
| Small Business | 382 | 2,952,715 | 213.00 | $5,296 | $226,003 | $521,287 | $752,586 |
| CVR Commercial | | 1,032,656 | 214 | $31,778 | $184,861 | - | $216,639 |
| **Commercial & Industrial Subtotal** | **55,861** | **27,913,681** | **5,691.43** | **$158,889** | **$1,541,248** | **$2,447,483** | **$4,147,620** |
| **Indirect Costs** | | | | | | | |
| Contact Center | | | | | | | $66,073 |
| Online Audit | | | | | | | $45,004 |
| Outreach | | | | | | | $429,997 |
| **Portfolio Costs Subtotal** | | | | | | | **$541,073** |
| **Subtotal (Before Evaluation)** | | | | | | | **$9,958,279** |
| Evaluation | | | | | | | $512,192 |
| **DSM Portfolio Total** | | | | | | | **$10,470,471** |
| **Other Costs** | | | | | | | |
| Emerging Markets | | | | | | | $200,000 |
| Market Potential Study | | | | | | | - |
| Other Costs Subtotal | | | | | | | **$200,000** |
| **DSM Portfolio Total including Other Costs** | | | | | | | **$10,670,471** |

*Note: The team assumed that the EISA backstop provision would remove downstream specialty screw-in lighting incentives from all programs except for direct installations.*

TABLE 2-9 2024 PORTFOLIO TARGETS

| | Participants | Total kWh Savings | Total kW (Demand) | Admin. | Implementation | Incentives | Total Budget |
|---|---|---|---|---|---|---|---|
| **Residential** | | | | | | | |
| Residential Lighting | 14,089 | 977,297 | 19.66 | $107,621 | $38,416 | $92,287 | $238,324 |
| Residential Prescriptive | 7,892 | 2,860,501 | 889.35 | $43,048 | $370,394 | $732,410 | $1,145,582 |
| Residential New Construction | 71 | 156,812 | 101.51 | $5,381 | $48,144 | $13,975 | $67,500 |
| Home Energy Assessment | 504 | 840,768 | 89.03 | $5,381 | $271,716 | - | $277,097 |
| Income-Qualified Weatherization | 653 | 967,302 | 546.35 | $21,524 | $1,350,360 | - | $1,371,884 |
| Energy-Efficient Schools | 2,600 | 670,800 | 93.60 | $21,524 | $106,392 | - | $127,916 |
| Residential Behavioral Savings | 49,000 | 7,049,208 | 1,574.28 | $21,524 | $345,029 | - | $366,554 |
| Appliance Recycling | 1,372 | 1,300,910 | 183.54 | $43,048 | $168,946 | $67,325 | $279,320 |
| CVR Residential | - | - | - | $32,286 | $315,241 | - | $347,528 |
| Smart Cycle (DLC Change Out) | 1,000 | 198,000 | 1,015 | $21,524 | $596,000 | $176,000 | $793,524 |
| BYOT (Bring Your Own Thermostat) | 300 | - | 240.00 | $21,524 | $54,280 | $84,280 | $160,084 |
| Food Bank | 3,156 | 649,158 | 46.71 | $21,524 | $9,703 | - | $31,227 |
| Home Energy Management Systems | 1,000 | 515,000 | 80.00 | $10,762 | $245,940 | - | $256,702 |
| **Residential Subtotal** | **81,637** | **16,185,755** | **4,879.02** | **$376,673** | **$3,920,561** | **$1,166,277** | **$5,463,511** |
| **Commercial & Industrial (C&I)** | | | | | | | |
| Commercial Prescriptive | 55,739 | 18,058,503 | 4,572.95 | $59,191 | $791,792 | $1,394,674 | $2,245,657 |
| Commercial Custom | 196 | 6,107,234 | 740.00 | $64,572 | $366,723 | $491,537 | $922,832 |
| Small Business | 383 | 2,957,870 | 213.00 | $5,381 | $229,663 | $512,537 | $747,582 |
| CVR Commercial | - | - | - | $32,286 | $216,561 | - | $248,848 |
| **Commercial & Industrial Subtotal** | **56,318** | **27,123,608** | **5,525.95** | **$161,431** | **$1,604,739** | **$2,398,748** | **$4,164,919** |
| **Indirect Costs** | | | | | | | |
| Contact Center | | | | | | | $67,130 |
| Online Audit | | | | | | | $45,724 |
| Outreach | | | | | | | $436,877 |
| **Portfolio Costs Subtotal** | | | | | | | **$549,730** |
| **Subtotal (Before Evaluation)** | | | | | | | **$10,178,160** |
| Evaluation | | | | | | | $520,077 |
| **DSM Portfolio Total** | | | | | | | **$10,698,237** |
| **Other Costs** | | | | | | | |
| Emerging Markets | | | | | | | $200,000 |
| Market Potential Study | | | | | | | $300,000 |
| Other Costs Subtotal | | | | | | | **$500,000** |
| **DSM Portfolio Total including Other Costs** | | | | | | | **$11,198,237** |

*Note: The team assumed that lighting direct installations would decrease from the previous year due to EISA.*

TABLE 2-10 2025 PORTFOLIO TARGETS

| | Participants | Total kWh Savings | Total kW (Demand) | Admin. | Implementation | Incentives | Total Budget |
|---|---|---|---|---|---|---|---|
| **Residential** | | | | | | | |
| Residential Lighting | 15,913 | 1,146,410 | 274.12 | $109,343 | $44,005 | $105,714 | $259,061 |
| Residential Prescriptive | 8,136 | 2,974,980 | 961.29 | $43,737 | $376,320 | $767,435 | $1,187,492 |
| Residential New Construction | 70 | 154,792 | 100.29 | $5,467 | $46,909 | $13,800 | $66,176 |
| Home Energy Assessment | 504 | 790,845 | 83.15 | $5,467 | $276,063 | - | $281,530 |
| Income-Qualified Weatherization | 685 | 1,018,544 | 575.34 | $21,869 | $1,369,913 | - | $1,391,782 |
| Energy-Efficient Schools | 2,600 | 670,800 | 93.60 | $21,869 | $117,023 | - | $138,891 |
| Residential Behavioral Savings | 49,000 | 7,049,208 | 1,574.28 | $21,869 | $350,550 | - | $372,418 |
| Appliance Recycling | 1,253 | 1,180,913 | 171.99 | $43,737 | $155,651 | $61,050 | $260,438 |
| CVR Residential | - | - | - | $32,803 | $282,073 | - | $314,876 |
| Smart Cycle (DLC Change Out) | 1,000 | 198,000 | 1,015 | $21,869 | $616,000 | $196,000 | $833,869 |
| BYOT (Bring Your Own Thermostat) | 300 | - | 240.00 | $21,869 | $62,280 | $92,280 | $176,429 |
| Food Bank | 3,156 | 649,158 | 46.71 | $21,869 | $9,858 | - | $31,727 |
| Home Energy Management Systems | 1,000 | 515,000 | 80.00 | $10,934 | $266,980 | - | $277,914 |
| **Residential Subtotal** | **83,617** | **16,348,650** | **5,215.76** | **$382,700** | **$3,973,626** | **$1,236,279** | **$5,592,604** |
| **Commercial & Industrial (C&I)** | | | | | | | |
| Commercial Prescriptive | 53,882 | 17,825,085 | 4,513.77 | $60,139 | $797,128 | $1,331,794 | $2,189,060 |
| Commercial Custom | 196 | 6,107,234 | 740.00 | $65,606 | $372,590 | $491,537 | $929,733 |
| Small Business | 383 | 2,963,026 | 213.00 | $5,467 | $233,383 | $503,787 | $742,637 |
| CVR Commercial | - | - | - | $32,803 | $193,019 | - | $225,821 |
| **Commercial & Industrial Subtotal** | **54,461** | **26,895,345** | **5,466.77** | **$164,014** | **$1,596,120** | **$2,327,118** | **$4,087,252** |
| **Indirect Costs** | | | | | | | |
| Contact Center | | | | | | | $68,204 |
| Online Audit | | | | | | | $46,456 |
| Outreach | | | | | | | $443,867 |
| **Portfolio Costs Subtotal** | | | | | | | **$558,526** |
| **Subtotal (Before Evaluation)** | | | | | | | **$10,238,382** |
| Evaluation | | | | | | | $520,203 |
| **DSM Portfolio Total** | | | | | | | **$10,758,585** |
| **Other Costs** | | | | | | | |
| Emerging Markets | | | | | | | $200,000 |
| Market Potential Study | | | | | | | - |
| Other Costs Subtotal | | | | | | | **$200,000** |
| **DSM Portfolio Total including Other Costs** | | | | | | | **$10,958,585** |

*Note: The team assumed that lighting direct installations would decrease from the previous year due to EISA.*

# 3 Program Concepts

This section provides an overview of each program, organized by the following topic areas: 1) Background, 2) Relationship to Vectren's Market Potential Study, 3) Methods and Associated Risks, and 4) Technology and Program Data.

## 3.1 RESIDENTIAL LIGHTING

### 3.1.1 Background

The Residential Lighting Program remains an upstream program designed to reach Vectren customers through retail outlets. The program is aimed at encouraging Vectren customers to install more energy-efficient bulbs in their homes. The program consists of a buy-down strategy at the point of purchase, so it is seamless to the participant. Any customer of a participating retailer in Vectren South's electric territory is eligible for the program.

Vectren will oversee the program and work with a partner organization on delivery. The implementation contractor will verify the paperwork of the participating retail stores and spot check stores to assure that the program guidelines are being followed.

The measures will include a variety of ENERGY STAR-qualified lighting products currently available at retailers in Indiana including:

- Standard units
- Specialty units
- LED fixtures
- Exterior lighting controls

### 3.1.2 Relationship to Vectren's Market Potential Study

The team cross-referenced measures from the Market Potential Study with measures included in the Residential Lighting Program. As measures from the Residential Lighting Program also appear in other Vectren residential programs, the team also compared the rate of sales in other programs to the Residential Lighting Program. From this analysis, the team estimated that measures from the Residential Lighting Program have market potential well above Action Plan participation estimates.

### 3.1.3 Program Considerations

The program, as designed, takes the Energy Independence and Security Act (EISA) policies into account. A backstop efficiency ruling is slated to take effect in 2020 and will shift the baseline efficiency of most screw-in LED bulbs from halogens to CFLs. Though there is speculation about the timeline and likelihood of this regulation taking effect, the team conservatively assumed the EISA backstop for standard LED bulbs would take effect in 2020 and the EISA backstop for specialty bulbs would take effect in 2021. The team also assumed that non-compliant products would still be sold for up to one year after the regulations take effect, as suggested by the Uniform Methods Project.[41] Therefore, the Residential Lighting Program will discontinue standard LED incentives beginning in 2022 and for specialty lighting products in 2023.

### 3.1.4 Technology and Program Data

The following table provides summary of the Residential Lighting Program energy impacts and budget.

[41] https://www.nrel.gov/docs/fy18osti/70472.pdf

TABLE 3-1 RESIDENTIAL LIGHTING – IMPACTS AND BUDGET

| | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 |
|---|---|---|---|---|---|---|
| Number of Participants | 239,866 | 262,832 | 91,708 | 12,231 | 14,089 | 15,913 |
| Energy Savings (kWh) | 8,088,914 | 8,704,288 | 3,259,915 | 807,282 | 977,297 | 1,146,410 |
| Summer Peak Demand Savings (kW) | 905 | 875 | 256 | 19 | 20 | 274 |
| Total Program Budget | $750,433 | $747,018 | $595,484 | $217,370 | $238,324 | $259,061 |
| Per Participant Energy Savings (kWh) | 34 | 33 | 36 | 66 | 69 | 72 |
| Per Participant Demand Savings (kW) | < 0.01 | < 0.01 | < 0.01 | < 0.01 | < 0.01 | 0.02 |
| Per Participant Average Incentive | $2 | $2 | $4 | $6 | $7 | $7 |
| Weighted Average Measure Life | 15 | 15 | 14 | 9 | 9 | 9 |
| Incremental Technology Cost | $4 | $4 | $6 | $26 | $26 | $26 |
| Net-to-Gross Ratio | 84% | 79% | 76% | 84% | 84% | 84% |

*Note: Number of participants, energy savings, and demand savings estimates based primarily on Market Potential Study results. Program budget estimate based on current schedule of work and projected rising costs from Vectren Program Cost and Measure Data spreadsheet. Per unit savings estimates based on the Market Potential Study results. Per participant energy savings, per participant demand savings, and incremental technology cost weighted by participant. Weighted average measure life and net to gross ratio weighted by kWh.*

## 3.2 RESIDENTIAL PRESCRIPTIVE

### *3.2.1 Background*

The Residential Prescriptive Program is designed to incent customers to purchase energy efficient equipment by covering part of the incremental cost. The program also offers home weatherization rebates to residential customers for attic and wall insulation. If a product vendor or contractor chooses to do so, they can present rebates as an “instant discount” to Vectren’s residential customers on their invoice. Vectren will oversee the program and work with an implementation partner on delivery.

Any residential customer located in the Vectren South electric service territory is eligible to participate in the program. For the equipment rebates, the applicant must reside in a single-family home or multi-family complex with up to 12 units. Only single-family homes are eligible for insulation measures.

Measures included in the program will change over time as baselines change, new technologies become available, and customer needs are identified. Measures include:

- ASHP Tune Ups
- Air Purifiers
- Air Source Heat Pumps
- Attic Insulation
- Central Air Conditioners
- Duct Sealing
- Ductless Heat Pumps
- Duel Fuel Air Source Heat Pumps
- ENERGY STAR Electric Clothes Washers (new in 2020)
- ENEGY STAR Dehumidifiers, Electric Clothes Dryers and Room Air Conditioners (new in 2020)
- Heat Pump Water Heaters

- Nest On-Line Store Thermostats
- Wi-Fi Thermostats
- Smart/CEE Tier3 Clothes Washers (new in 2020)
- Smart Programmable Thermostats
- Variable Speed Pool Pumps
- Wall Insulation
- Air Conditioning Tune Ups

### 3.2.2 Relation to Vectren's Market Potential Study

The team cross-referenced measures from the Market Potential Study with measures included in the existing Residential Prescriptive Program. As measures from the Residential Prescriptive Program also appear in other Vectren residential programs, the team also compared the rate of sales in other programs to the Residential Prescriptive Program. From this analysis, the team found that several Residential Prescriptive Program measures had already reached the full RAP estimated in the Market Potential Study (such as attic insulation), and the team capped future participation at the rates estimated by the potential study.

### 3.2.3 Program Considerations

A major change to the electric Residential Prescriptive program is the removal of the ECM HVAC motor and pool heaters measure due to changes in standards, low NTG, and low benefit-cost testing.

There are many measures are new to the program, including: dehumidifiers, clothes washers, clothes dryers, room air conditioners, water heaters, and tankless water heaters. The team provided escalating estimates for participation for these measures over the duration of the Action Plan.

### 3.2.4 Technology and Program Data

The following table provides summary of the Residential Prescriptive Program energy impacts and budget.

TABLE 3-2 RESIDENTIAL PRESCRIPTIVE – IMPACTS AND BUDGET (ELECTRIC)

| | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 |
|---|---|---|---|---|---|---|
| Number of Participants | 7,966 | 8,276 | 8,303 | 8,140 | 7,892 | 8,136 |
| Energy Savings kWh | 2,465,148 | 2,618,629 | 2,722,283 | 2,793,920 | 2,860,501 | 2,974,980 |
| Peak Demand kW | 691 | 662 | 737 | 812 | 889 | 961 |
| Total Program Budget | $1,020,073 | $1,039,726 | $1,080,683 | $1,114,066 | $1,145,852 | $1,187,492 |
| Per Participant Energy Savings (kWh) | 309 | 316 | 328 | 343 | 362 | 366 |
| Per Participant Demand Savings (kW) | 0.09 | 0.08 | 0.09 | 0.10 | 0.11 | 0.12 |
| Per Participant Average Incentive | $79 | $78 | $82 | $87 | $93 | $94 |
| Weighted Average Measure Life | 13 | 13 | 14 | 14 | 14 | 14 |
| Incremental Technology Cost | $148 | $146 | $160 | $174 | $191 | $199 |
| Net-to-Gross Ratio | 50% | 51% | 51% | 52% | 53% | 53% |

*Note: Number of participants, energy savings, and demand savings estimates based primarily on Market Potential Study results. Program budget estimate based on current schedule of work and projected rising costs from Vectren Program Cost and Measure Data spreadsheet. Per unit savings estimates based on the Market Potential Study results. Per participant energy savings, per participant demand savings, and incremental technology cost weighted by participant. Weighted average measure life and net to gross ratio weighted by kWh.*

## 3.3 RESIDENTIAL NEW CONSTRUCTION

### *3.3.1 Background*

The Residential New Construction (RNC) program will produce long-term electric and gas savings by encouraging the construction of single-family homes, duplexes, or end-unit townhomes with only one shared wall that are inspected and evaluated through the Home Efficiency Rating System (HERS). Two incentive levels have been defined by the HERS Index score the house achieves. As of 2018, Gold Star homes must achieve a HERS rating of 61 to 63. Platinum Star homes must meet a HERS rating of 60 or less.

Any customer or home builder constructing a home and meeting the program specifications in the Vectren South electric service territory is eligible to participate in the program. Program incentives are designed to be paid to both all-electric and combination homes that have natural gas heating and water heating. It is important to note that the program is structured such that an incentive will not be paid for an all-electric home that has natural gas available to the home site. Incentives can be paid to either the home builder or the customer/account holder. Incentives are based on the rating tier qualification. As part of the Quality Assurance/Quality Control process, the HERS Assessment is completed by a certified third party HERS Rater. As part of the Quality Assurance/Quality Control process, the vendor provided 100% paper verification that the equipment/products purchased meet the program efficiency standards.

### *3.3.2 Relation to Vectren's Market Potential Study*

The Market Potential Study indicated that the market for the Residential New Construction Program is shrinking in Vectren South and is expanding in Vectren North. The team used previous program participation to calibrate rates from the Market Potential Study.

### *3.3.3 Program Considerations*

The housing market is sensitive to market conditions and unforeseen economic circumstances may impact this program in the future.

### *3.3.4 Technology and Program Data*

The following table provides summary of the Residential New Construction Program energy impacts and budget.

TABLE 3-3 RESIDENTIAL NEW CONSTRUCTION – IMPACTS AND BUDGET

| | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 |
|---|---|---|---|---|---|---|
| Number of Homes | 86 | 77 | 75 | 73 | 71 | 70 |
| Energy Savings kWh | 188,624 | 168,932 | 164,892 | 160,852 | 156,812 | 154,792 |
| Peak Demand kW | 121 | 109 | 106 | 104 | 102 | 100 |
| Total Program Budget | $71,825 | $77,405 | $73,074 | $69,824 | $67,500 | $66,176 |
| Per Participant Energy Savings (kWh) | 2,193 | 2,194 | 2,199 | 2,203 | 2,209 | 2,211 |
| Per Participant Demand Savings (kW) | 1.41 | 1.41 | 1.42 | 1.42 | 1.43 | 1.43 |
| Per Participant Average Incentive | $195 | $195 | $196 | $196 | $197 | $197 |
| Weighted Average Measure Life | 25 | 25 | 25 | 25 | 25 | 25 |
| Incremental Technology Cost | $2,352 | $2,353 | $2,361 | $2,370 | $2,379 | $2,384 |
| Net-to-Gross Ratio | 50% | 50% | 50% | 50% | 50% | 50% |

*Note: Participant and energy savings estimates based primarily on Market Potential Study results. Program budget estimate based on current schedule of work and projected rising costs from Vectren Program Cost and Measure Data spreadsheet. Per*

| | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 |
|---|---|---|---|---|---|---|
| *unit savings estimates based on the Market Potential Study results. Per participant energy savings, per participant demand savings, and incremental technology cost weighted by participant. Weighted average measure life and net to gross ratio weighted by kWh.* | | | | | | |

## 3.4 HOME ENERGY ASSESSMENT

### 3.4.1 Background

The Home Energy Assessment (HEA) Program is offered jointly by Vectren South Gas and Electric. This program provides customers with an on-site energy assessment, providing direct installation of energy-efficient measures including high efficiency water fixtures, LED bulbs and smart thermostats. Assessors will perform a walk-through assessment of the home, collecting data for use in identifying cost-effective energy-efficient improvements and appropriate direct install measures. Assessors will then provide an audit report to the customer while assessors are onsite to outline other retrofit opportunities within the home.

Vectren South residential customers with electric service at a single-family residence, provided the home was not built within the past five years and has not had an audit within the last three years, are eligible to participate in the program. Additionally, the home should either be owner-occupied or, if renter-occupied, where occupants have the electric service in their name.

The direct install measures available for installation at no cost include:

- Audit & Education
- Kitchen & Bathroom Aerators
- Filter Whistle
- LED bulbs
- High efficiency Showerhead
- Pipe Wrap
- Water Heater Temperature Setback
- Smart Thermostat

### 3.4.2 Relation to Vectren's Market Potential Study

The team cross-referenced measures from the Market Potential Study with measures included in the Home Energy Assessment Program. As measures from the Home Energy Assessment program also appear in other Vectren residential programs, the team also compared the rate of sales in other programs to the Home Energy Assessment Program. From this analysis, the team estimated that measures from the Home Energy Assessment Program have market potential well above Action Plan participation estimates.

### 3.4.3 Program Considerations

The impact of the EISA backstop was considered in the inclusion of LED bulbs in the Home Energy Assessment program and affects the program beginning in 2024. Because of the direct install nature of the program, it was assumed that inefficient lighting will continue to be present in customer homes throughout the timeframe of the Action Plan. Thus, inefficient lighting found in customer homes would be eligible for replacement, though fewer inefficient bulbs would be found in customer homes after 2023.

### 3.4.4 Technology and Program Data

The following table provides summary of the Home Energy Assessment Program energy impacts and budget.

TABLE 3-4 HOME ENERGY ASSESSMENT – IMPACTS AND BUDGET

| | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 |
|---|---|---|---|---|---|---|
| Number of Participants | 300 | 350 | 420 | 504 | 504 | 504 |
| Energy Savings kWh | 519,393 | 605,959 | 727,151 | 872,581 | 840,768 | 790,845 |
| Peak Demand kW | 55 | 65 | 78 | 93 | 89 | 83 |
| Total Program Budget | $245,050 | $263,131 | $268,438 | $272,733 | $277,097 | $281,530 |
| Per Participant Energy Savings (kWh) | 1,731 | 1,731 | 1,731 | 1,731 | 1,668 | 1,569 |
| Per Participant Demand Savings (kW) | 0.18 | 0.18 | 0.18 | 0.18 | 0.18 | 0.16 |
| Weighted Average Measure Life | 13 | 13 | 13 | 13 | 13 | 13 |
| Net-to-Gross Ratio | 101% | 101% | 101% | 101% | 101% | 101% |

*Note: Number of participants estimated based on interview with the current program implementer, JE Shekell. Per unit savings estimated based on 2018 Operating Plan. Program costs estimated based on current SOW and projected rising costs described by JE Shekell. Kwh and kw savings estimated by dividing total savings by total participants. Incremental technology cost estimated by summing the incremental cost of each piece of equipment and divided by number of participants. Weighted average measure life and net to gross ratio weighted by kWh.*

## 3.5 INCOME-QUALIFIED WEATHERIZATION

### *3.5.1 Background*

The Income-Qualified Weatherization Program (IQW) is designed to provide direct install measures and weatherization upgrades to low-income homes that otherwise would not have been able to afford the energy saving measures. The program provides direct installation of energy-saving measures and educates consumers on ways to reduce energy consumption. Eligible customers will have opportunity to receive deeper retrofit measures including refrigerators, attic insulation, duct sealing, and air infiltration reduction. Vectren will oversee the program and partner with an implementation contractor to deliver the program. A list of high consumption customers who have received Energy Assistance Program (EAP) funds within the past 12 months will be used to help prioritize those customers. In addition to utilizing the EAP List, implementers will utilize census data to target low-income areas within Vectren territory.In future years, the IQW program will shift focus to providing a more quality and in-depth approach. The focus will be to provide deeper retrofit measures where needed to fewer participants, thus reaping greater savings and benefits to the customer.

Collaboration and coordination between gas and electric low-income programs along with state and federal funding is recommended to provide the greatest efficiencies among all programs. The challenge of meeting the goals set for this program have centered on health and safety as well as customer cancellations and scheduling. Vectren is committed to finding innovative solutions to these areas. A health and safety (H&S) budget has been established and we continue to work on improving methods of customer engagement with various confirmations via phone and email reminders prior to the appointment. Vectren will look for ways to do more of a qualitative approach within this program to ensure the maximum savings is reached and H&S issues are addressed appropriately.

Measures available for installation will vary based on the home and include:

- LED bulbs/lamps (interior/exterior)
- High Efficiency Showerheads (Standard or Handheld)
- High efficiency faucet aerators
- Filter whistles
- Infiltration reduction
- Attic insulation

- Duct repair, seal and insulation
- Refrigerator replacement
- Smart thermostats
- Water Heater Temperature Setback

### 3.5.2 Relation to Vectren's Market Potential Study

The team cross-referenced measures from the Market Potential Study with measures included in IQW. As measures from IQW also appear in other Vectren residential programs, the team also compared the rate of sales in other programs to IQW. From this analysis, the team estimated that measures from IQW have market potential well above Action Plan participation estimates.

### 3.5.3 Program Considerations

Measures for the Income-Qualified Weatherization Program do not need to be cost-effective at the program level and therefore the Market Potential Study did not screen measures based on a cost-effectiveness test. The team chose measures that they felt would provide the most value to customers. The team chose a "quality over quantity" approach and provided more services to each individual customer than in previous program years. To ensure that the program did not overwhelm other energy efficiency program priorities, the team ensured that the overall program budget did not vastly exceed previous program budgets. The team dropped smart power strips from the program as they had a very low cost-effectiveness score and seemed to provide less value than other measures.

The impact of the EISA backstop was considered in the inclusion of income-qualified LED bulbs in the program beginning in 2024. It was assumed that inefficient lighting will continue to be present in customer homes throughout the timeframe of the Action Plan. Thus, inefficient lighting found in customer homes would be eligible for replacement, though fewer inefficient bulbs would be found in customer homes after 2023.

### 3.5.4 Technology and Program Data

The following table provides summary of IQW energy impacts and budget.

TABLE 3-5 INCOME-QUALIFIED WEATHERIZATION – IMPACTS AND BUDGET

| | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 |
|---|---|---|---|---|---|---|
| Number of Participants | 539 | 566 | 594 | 623 | 653 | 685 |
| Energy Savings kWh | 778,285 | 823,215 | 869,076 | 917,290 | 967,302 | 1,018,544 |
| Peak Demand kW | 443 | 467 | 492 | 519 | 546 | 575 |
| Total Program Budget | $1,295,376 | $1,314,050 | $1,333,023 | $1,352,299 | $1,371,884 | $1,391,782 |
| Per Participant Energy Savings (kWh) | 1,444 | 1,454 | 1,463 | 1,472 | 1,481 | 1,487 |
| Per Participant Demand Savings (kW) | 0.82 | 0.83 | 0.83 | 0.83 | 0.84 | 0.84 |
| Weighted Average Measure Life | 16 | 16 | 16 | 16 | 16 | 16 |
| Incremental Technology Cost | $809 | $822 | $833 | $850 | $867 | $880 |
| Net-to-Gross Ratio | 100% | 100% | 100% | 100% | 100% | 100% |

*Note: Energy savings, and demand savings estimates primarily based on the Market Potential Study results and 2018 Operating Plan estimates and projected rising costs from 2018-20 filed Energy Efficiency Plan and Vectren Program Cost and Measure Data spreadsheet. Number of participants based on historical program participation. Per participant energy and demand savings calculated by dividing total savings by participation. Weighted average measure life and net to gross weighted by kWh. Incremental cost calculated by summing the incremental cost of each piece of equipment and divided by number of participants.*

## 3.6 ENERGY-EFFICIENT SCHOOLS

### 3.6.1 Background

The Energy-Efficient Schools Program is designed to produce cost-effective electric and gas savings by educating students and their families about conservation and the efficient use of electricity. The program consists of a school education program for fifth grade students attending schools served by Vectren South. To help in this effort, each child that participates will receive a take-home energy kit with various energy-saving measures for their parents to install in the home. The kits, along with the in-school teaching materials, are designed to make a lasting impression on the students and help them learn ways to conserve energy. Selected fifth grade students/schools in the Vectren South electric service territory are eligible for the program.

The kits for students will include:

- High efficiency showerheads
- High efficiency kitchen aerators
- High efficiency bathroom aerators
- LED bulbs
- LED nightlights
- Filter whistles

### 3.6.2 Relation to Vectren's Market Potential Study

Though the Market Potential Study estimated savings, only customers with enrolled fifth grade students will participate in the program. As such, the Market Potential Study did not serve as a useful estimate for future Energy-Efficient Schools Program participation. The team relied on previous participation and discussions with the implementer to arrive at useful estimates.

### 3.6.3 Program Considerations

The team assumed that previous participation is a good indicator of future participation and, in consultation with the implementer, assumed that the program had a little room to grow from the 2018-2020 filed Energy Efficiency plan. The Energy-Efficient Schools Program will discontinue standard LED incentives beginning in 2022 to account for the EISA backstop.

### 3.6.4 Technology and Program Data

The following table provides summary of the Energy-Efficient Schools Program energy impacts and budget.

TABLE 3-6 ENERGY-EFFICIENT SCHOOLS – IMPACTS AND BUDGET

| | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 |
|---|---|---|---|---|---|---|
| Number of Participants | 2,600 | 2,600 | 2,600 | 2,600 | 2,600 | 2,600 |
| Energy Savings kWh | 1,149,200 | 1,149,200 | 670,800 | 670,800 | 670,800 | 670,800 |
| Peak Demand kW | 137 | 137 | 94 | 94 | 94 | 94 |
| Total Program Budget | $133,789 | $137,776 | $113,080 | $119,460 | $127,916 | $138,891 |
| Per Participant Demand Savings (kWh) | 442 | 442 | 258 | 258 | 258 | 258 |
| Per Participant Demand Savings (kW) | 0.05 | 0.05 | 0.04 | 0.04 | 0.04 | 0.04 |
| Weighted Average Measure Life | 12 | 12 | 10 | 10 | 10 | 10 |

| | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 |
|---|---|---|---|---|---|---|
| Net-to-Gross Ratio | 100% | 100% | 100% | 100% | 100% | 100% |
| *Note: Number of participants, energy savings, and demand savings estimates primarily based on the 2018-20 filed Energy Efficiency Plan. and the 2018 Operating Plan. Program costs primarily based on current SOW and projected rising costs from 2018-20 filed Energy Efficiency Plan and Vectren Program Cost and Measure Data spreadsheet. Per participant energy savings and demand savings calculated by dividing total savings by total participation. Weighted measure life and net to gross ratio are weighted by kWh.* | | | | | | |

## 3.7 RESIDENTIAL BEHAVIOR SAVINGS

### *3.7.1 Background*

The Residential Behavioral Savings Program (RBS) motivates behavior change and provides relevant, targeted information to the consumer through regularly scheduled, direct contact via mailed and emailed home energy reports. The measures for this program consist of a Home Energy Report and web portal, which anonymously compares customers' energy use with that of other customers with similar-sized home and demographics, usage history comparisons, goal setting tools, and progress trackers. Customers can view the past twelve months of their energy usage and compare and contrast their energy consumption and costs with others in the same neighborhood. The logic for the program is that once a consumer understands better how they use energy, they can then start conserving energy. Residential customers who receive electric service from Vectren South are eligible for this integrated natural gas and electric EE program.

The program will be delivered by an implementation vendor and include energy reports and a web portal. Customers typically receive between 4-6 reports annually. Additionally, customers receive monthly emails. These reports provide updates on energy consumption patterns compared to similar homes and provide energy savings strategies to reduce energy use. These reports can also promote other Vectren programs to interested customers. The web portal is an interactive system for customers to perform a self-audit, monitor energy usage over time, access energy saving tips, and be connected to other Vectren South gas and electric programs. A third-party evaluator will complete the evaluation of this program.

In 2021, Vectren plans on introducing a new targeted income cohort of participants into the program. Vectren will work with the implementation contractor and the third-party evaluator to determine a participant and non-participant group for this new cohort.

### *3.7.2 Relation to Vectren's Market Potential Study*

The team assumed that restrictions stipulated within the current RBS implementation contract would continue through the timeframe of the Action Plan. As specified by the contract, Vectren can increase the number of treatment customers to the original contracted amount (49,000). The team ensured that this 49,000-participant estimate was below the estimate provided by the Market Potential Study.

### *3.7.3 Program Considerations*

The team assumed that past program performance is a reasonable indicator of future performance. As the third-party evaluator estimates savings for RBS using a billing analysis, the savings resulting from the program may shift from year to year, depending on the behavior of the program participants in any given year. The program also faces the risk of customers losing interest in the program and no longer attempting to curb their energy usage.

### *3.7.4 Technology and Program Data*

The following table provides summary of RBS energy impacts and budget.

TABLE 3-7 RESIDENTIAL BEHAVIOR SAVINGS – IMPACTS AND BUDGET

| | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 |
|---|---|---|---|---|---|---|
| Number of Participants | 49,000 | 49,000 | 49,000 | 49,000 | 49,000 | 49,000 |
| Energy Savings kWh | 7,049,208 | 7,049,208 | 7,049,208 | 7,049,208 | 7,049,208 | 7,049,208 |
| Peak Demand kW | 1,574 | 1,574 | 1,574 | 1,574 | 1,574 | 1,574 |
| Total Program Budget | $364,203 | $349,507 | $355,099 | $360,781 | $366,554 | $372,418 |
| Per Participant Energy Savings (kWh) | 144 | 144 | 144 | 144 | 144 | 144 |
| Per Participant Demand Savings (kW) | 0.03 | 0.03 | 0.03 | 0.03 | 0.03 | 0.03 |
| Weighted Average Measure Life | 1 | 1 | 1 | 1 | 1 | 1 |
| Net-to-Gross Ratio | 100% | 100% | 100% | 100% | 100% | 100% |

*Note: Number of participants, energy savings, and demand savings estimates primarily based on the 2018-20 filed Energy Efficiency Plan. and the 2018 Operating Plan. Program costs primarily based on current SOW and projected rising costs from 2018-20 filed Energy Efficiency Plan and Vectren Program Cost and Measure Data spreadsheet. Per participant energy savings and demand savings calculated by dividing total savings by total participation. Weighted measure life and net to gross ratio are weighted by kWh.*

## 3.8 APPLIANCE RECYCLING

### 3.8.1 Background

The Residential Appliance Recycling Program encourages customers to recycle their old inefficient refrigerators, freezers, and air conditioners in an environmentally safe manner. The program recycles these appliances so that they no longer use electricity and it keeps 95% of the appliance out of landfills.

Any residential customer with an operable secondary refrigerator, freezer, or air conditioner unit receiving electric service from Vectren South is eligible to participate in the program.

Vectren works directly with an implementer to administer this program. Recycled units are logged and tracked to assure proper handling and disposal. The utility monitors the activity for disposal. Customer satisfaction surveys are also used to understand the customer experience with the program.

Measures include:

- Refrigerator recycling
- Freezer recycling
- Room air conditioner recycling (new in 2020)

### 3.8.2 Relation to Vectren's Market Potential Study

The team cross-referenced measures from the Market Potential Study with measures included in the Appliance Recycling Program. From this analysis, the team estimated that measures from the Appliance Recycling Program have market potential well above Action Plan participation estimates.

### 3.8.3 Program Considerations

After reviewing the results of the Market Potential Study and conducting an interview with the current program implementer, the team decided to add room air conditioner recycling to the program. Based on the Market Potential Study, the team also projected growth in the Appliance Recycling Program in the region over the span of the Action Plan.

### 3.8.4 Technology and Program Data

The following table provides summary of the Appliance Recycling Program energy impacts and budget.

TABLE 3-8 APPLIANCE RECYCLING – IMPACTS AND BUDGET

| | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 |
|---|---|---|---|---|---|---|
| Number of Participants | 1,251 | 1,344 | 1,425 | 1,435 | 1,372 | 1,253 |
| Energy Savings kWh | 1,179,811 | 1,285,473 | 1,360,636 | 1,366,149 | 1,300,910 | 1,180,913 |
| Peak Demand kW | 171 | 173 | 185 | 188 | 184 | 172 |
| Total Program Budget | $245,057 | $267,086 | $283,589 | $287,865 | $279,320 | $260,438 |
| Per Participant Energy Savings (kWh) | 943 | 956 | 955 | 952 | 948 | 942 |
| Per Participant Demand Savings (kW) | 0.14 | 0.13 | 0.13 | 0.13 | 0.13 | 0.14 |
| Per Participant Average Incentive | $49 | $50 | $49 | $49 | $49 | $49 |
| Weighted Average Measure Life | 8 | 8 | 8 | 8 | 8 | 8 |
| Net-to-Gross Ratio | 71% | 71% | 71% | 71% | 71% | 71% |

*Note: Number of participants, energy savings, and demand savings estimated primarily based on the Market Potential Study and 2018 Operating Plan. Program costs estimated using the Market Potential Study, the current SOW, and projected rising costs from 2018-20 filed Energy Efficiency Plan and Program Cost and Participant Data spreadsheet. Per unit savings estimated based on 2018 Operating Plan. weighted average measure life and net to gross ratio weighted by kWh. Per participant incentive and incremental technology cost weighted by participant.*

## 3.9 FOOD BANK

### 3.9.1 Background

The Food Bank Program provides LED bulbs and high efficiency showerheads to food pantries in Vectren South's electric service territory. This program targets hard-to-reach, low-income customers in the Vectren South electric territory. All food pantry recipients must provide proof of income qualification to receive the food baskets.

Each participating food pantry will place a bundle of four LED bulbs and a single high efficiency showerhead in food packages. The program implementer purchases equipment from a manufacturer and the equipment is shipped in bulk to the partner food bank. Food banks then distribute the equipment to the respective food pantries in its network. Pantries include equipment when assembling food packages and equipment is provided to food recipients. Any customer visiting a food pantry in Vectren South's electric territory is eligible to participate in the program.

Measures include:

- LED bulbs
- High efficiency showerheads (new in 2021)

### 3.9.2 Relation to Vectren's Market Potential Study

Though the Market Potential Study estimated savings resulting from income-qualified measures, only a small portion of income-qualified customers will become food pantry recipients. As such, the Market Potential Study did not serve as a useful estimate for future Food Bank Program participation.

### 3.9.3 Program Considerations

Vectren expressed interest in continuing a Food Bank program after the EISA backstop was implemented. The team examined possible new measures and determined that showerheads could provide significant energy savings for food pantry recipients. The team used savings values from other income-qualified programs as a proxy for savings from the Food Bank Program.

### 3.9.4 Technology and Program Data

The following table provides summary of the Food Bank Program energy impacts and budget.

TABLE 3-9 FOOD BANK – IMPACTS AND BUDGET

| | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 |
|---|---|---|---|---|---|---|
| Number of Participants | - | 6,312 | 6,312 | 3,156 | 3,156 | 3,156 |
| Energy Savings kWh | - | 1,564,332 | 816,353 | 649,158 | 649,158 | 649,158 |
| Peak Demand kW | - | 172 | 69 | 47 | 47 | 47 |
| Total Program Budget | - | $113,041 | $39,651 | $30,735 | $31,227 | $31,727 |
| Per Participant Energy Savings (kWh) | - | 248 | 129 | 206 | 206 | 206 |
| Per Participant Demand Savings (kW) | - | 0.03 | 0.01 | 0.01 | 0.01 | 0.01 |
| Weighted Average Measure Life | - | 11 | 11 | 7 | 5 | 5 |
| Net-to-Gross Ratio | - | 100% | 100% | 100% | 100% | 100% |

*Note: Number of participants, energy savings, and demand savings estimated based on 2018 Operating Plan. Program costs estimated based on current SOW, projected rising costs from 2018-20 filed Energy Efficiency Plan, and Vectren Program Cost and Measure Data spreadsheet. Per unit energy savings and per unit demand savings calculated by dividing total savings by the total number of participants. Weighted average measure life and net to gross ratio weighted by kWh. Incremental technology cost calculated by summing the incremental cost of each piece of equipment and dividing by the total number of participants.*

## 3.10 HOME ENERGY MANAGEMENT SYSTEMS

### 3.10.1 Background

The Home Energy Management Systems (HEMS) program is a behavioral program that provides real time energy usage data to encourage customers to take action to reduce energy consumption. The objectives of this program include:

- Motivate customers to save energy by increasing customer awareness and engagement around energy consumption and their utility bill
- Increase customer knowledge of and participation in Company programs including, but not limited to, energy efficiency programs and advanced data analytics
- Deliver energy and demand savings

The HEMS program will be piloted using advanced metering infrastructure (AMI) data to communicate energy usage to customers. The platform will utilize a smart phone application to communicate with customers about their home energy usage and provide suggestions for ways customers can save energy. To enhance customer engagement, participants in the program will receive a smart thermostat at no cost, if they do not currently have one installed in their home. Pending EM&V Report results, the program will potentially be rolled out to additional participants.

Given a successful pilot and positive EM&V Report results of the HEMS program, Vectren plans to scale the program to include additional features. The additional features would allow customers to install a device that provides real-time home energy usage data.

All Vectren South electric customers are eligible to participate in this program.

### 3.10.2 Relation to Vectren's Market Potential Study

The Market Potential Study provided estimates on various smart home technologies including home energy management systems. The program model is very specific and initially only relies on a phone application, the energy management systems estimate in the Market Potential Study may not accurately reflect the total market size available to the Home Energy Management Systems Program.

The team relied on savings estimates from the implementation contractor. The team compared estimates provided by the implementation contractor to the estimated savings presented in the Market Potential Study and found that the implementation contractor estimates were well within the bounds of the Market Potential Study estimates.

### 3.10.3 Program Considerations

The team utilized savings estimates provided by a HEMS vendor as well as publicly available evaluation documents of home energy management systems. The vendor indicated that they had evaluation-verified savings estimates, although the evaluation results were not currently public. The team acknowledges that savings estimates provided by the implementing contractor are susceptible to bias and, thus, chose a conservative estimate to provide counterbalance.

### 3.10.4 Technology and Program Data

The following table provides summary of the Home Energy Management Systems Program energy impacts and budget.

TABLE 3-10 HOME ENERGY MANAGEMENT SYSTEMS – IMPACTS AND BUDGET

| | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 |
|---|---|---|---|---|---|---|
| Number of Participants | - | 1,000 | 1,000 | 1,000 | 1,000 | 1,000 |
| Energy Savings kWh | - | 515,000 | 515,000 | 515,000 | 515,000 | 515,000 |
| Peak Demand kW | - | 80 | 80 | 80 | 80 | 80 |
| Total Program Budget | $80,100 | $223,162 | $230,326 | $245,493 | $256,702 | $277,914 |
| Per Participant Energy Savings (kWh) | - | 515 | 515 | 515 | 515 | 515 |
| Per Participant Demand Savings (kW) | - | 0.08 | 0.08 | 0.08 | 0.08 | 0.08 |
| Weighted Average Measure Life | - | 6 | 6 | 6 | 6 | 6 |
| Net-to-Gross Ratio | - | 100% | 100% | 100% | 100% | 100% |

*Note: Number of participants, energy savings, demand savings, and program costs estimated based on interviews with the implementer. The team assumed the same weighted average measure life as the current behavioral program. The net to gross ratio is weighted by kWh.*

The following table provides summary of the cumulative participants in the Home Energy Management Systems Program over the course of the Action Plan.

TABLE 3-10 HOME ENERGY MANAGEMENT SYSTEMS – PARTICIPANTS AND CUMULATIVE PARTICIPANTS

| | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 |
|---|---|---|---|---|---|---|
| Number of Participants | - | 1,000 | 1,000 | 1,000 | 1,000 | 1,000 |
| Cumulative Number of Participants | - | 1,000 | 2,000 | 3,000 | 4,000 | 5,000 |

## 3.11 BRING YOUR OWN THERMOSTAT

### *3.11.1 Background*

The Bring Your Own Thermostat Program (BYOT) is a further expansion of the Residential Smart/Wi-Fi thermostat initiative approved in 2016. BYOT allows customers who have or will purchase their own thermostat from multiple potential vendors to participate in demand response (DR) and other load curtailing programs managed through the utility. The program allows the utility to avoid the costs of hardware, installation, and maintenance associated with traditional load control methods.

By taking advantage of two-way communicating smart Wi-Fi thermostats, BYOT programs can help utilities reduce acquisition costs for load curtailment programs and improve customer satisfaction. Through the use of smart/Wi-Fi enabled thermostats, the utility can remotely verify how many customers are connected to the network at any given time and determine which thermostats are participating in DR events.

Any residential customer who receives electric service from Vectren South at a single-family residence is eligible to participate in the program. Customers will receive a one-time enrollment incentive of $75 and a bill credit of $5 during the months of June through September. The enrollment incentive, the amount which was determined based on research of other utility BYOT programs, will be provided in the first year to new enrollees only.

### *3.11.2 Relation to Vectren's Market Potential Study*

The Market Potential Study indicated that there is substantial room in the market for this program.

## 3.12 SMART CYCLE

### *3.12.1 Background*

Since 1992, Vectren South has operated a Direct Load Control (DLC) program called Summer Cycler that reduces residential and small commercial air-conditioning and water heating electricity loads during summer peak hours.

The Smart Cycle program will replace traditional DLC switches with smart thermostats over time, as the benefits associated with smart thermostats far outweigh the benefits associated with DLC switches. Smart thermostats provide an alternative to traditional residential load control switches as well as enhance the way customers manage and understand their home energy use. By installing connected devices in customer homes rather than using one-way signal switches, Vectren will be able to provide its customer base with deeper energy savings opportunities and shift future energy focus to customer engagement rather than traditional program goals and rules. The most recent Vectren electric DSM evaluation has demonstrated that smart thermostats outperform standard programmable thermostats and are a practical option to transition into future customer engagement strategies.

Customers in the Vectren South territory who currently participate in the DLC Summer Cycler Program and have access to Wi-Fi are eligible for the program. Customers receive a professionally-installed Wi-Fi thermostat at no additional cost and a monthly bill credit of $5 during the months of June through September. The current monthly credit for Summer Cycler is also $5; therefore, the annual bill credit by customer does not change.

### *3.12.2 Relation to Vectren's Market Potential Study*

The Market Potential Study indicates that there is market potential well above Action Plan participation estimates in this program.

## 3.13 COMMERCIAL AND INDUSTRIAL PRESCRIPTIVE

### *3.13.1 Background*

The Commercial & Industrial (C&I) Prescriptive Program is designed to provide financial incentives on qualifying products to produce greater energy savings in the C&I market. The rebates are designed to promote lower electric energy consumption, assist customers in managing their energy costs, and build a sustainable market around energy efficiency (EE). Program participation is achieved by offering incentives structured to cover a portion of the customer's incremental cost of installing prescriptive efficiency measures. Any participating commercial or industrial customer receiving electric service from Vectren South is eligible to participate in the program.

Top performing measures include:

- High-efficiency lighting and lighting controls
- HVAC equipment such as air conditioners, air-source heat pumps, chillers, boilers, and furnaces

New measures will include:

- Smart thermostats
- Refrigerator strip curtains
- High-efficiency hand dryers
- Efficient low-temperature compressors for refrigerators
- Refrigeration tune-ups
- Duct sealing

The full list of measures can be found in the measure library in Appendix K.

The program is delivered primarily through trade allies. Vectren South and its implementation partners work with the trade allies to make them aware of the offerings and help them promote the program to their customers. The implementation partner will provide training and technical support to the trade allies to become familiar with the EE technologies offered through the program. The program will be managed by the same implementation provider as the C&I Custom Program so that customers can seamlessly receive assistance and all incentives can be efficiently processed through a single procedure.

Incentives are provided to customers to reduce the difference in first cost between the lower-efficiency technology and the high-efficiency option. There is no fixed incentive percentage amount based on the difference in price because some technologies are newer and need higher amounts. Others have been available in the marketplace longer and do not need as much incentive to motivate customers. To verify the correct equipment was installed, site visits will be made on 5% of the installations, as well as all projects receiving incentive greater than $20,000.

### *3.13.2 Relation to Vectren's Market Potential Study*

The team cross-referenced measures from the Market Potential Study with measures included in the C&I Prescriptive Program. As measures from the C&I Prescriptive Program also appear in the Small Business Program, the team also compared the rate of sales in this program to the C&I Prescriptive Program. From this analysis, the team estimated that most measures from the C&I Prescriptive Program have market potential well above Action Plan participation estimates. For a select few measures (high-bay and low-bay LED lighting, refrigerated LEDs, commercial dishwashers, and 90% TE boilers sized at or above 1,000 MBH), the Market Potential Study provided a lower estimate of future participants than previously experienced by the program. The team capped participation at the total number of participants estimated in the potential study for these measures.

### *3.13.3 Program Considerations*

Advances in technology pose a risk to estimates for the C&I Prescriptive Program, although the size, scope, and directionality of that impact are difficult to define. The team developed estimates to address the largest risks to program savings: overall participation and NTG. The team modeled previous NTG estimates and tried to fit Action Plan NTGs to the trend of these historical NTG estimates.

Due to low cost-effectiveness scores in the Market Potential Study, the team dropped plug load sensors, smart power strips, window film, 90% AFUE boilers sized at less than 400 MBH, gas convection ovens, gas griddles, fluorescent lighting, and steam boilers.

### *3.13.4 Technology and Program Data*

The following table provides summary of the C&I Prescriptive Program energy impacts and budget.

TABLE 3-11 COMMERCIAL AND INDUSTRIAL PRESCRIPTIVE – IMPACTS AND BUDGET

| | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 |
|---|---|---|---|---|---|---|
| Number of Participants | 42,431 | 48,449 | 52,971 | 55,283 | 55,739 | 53,882 |
| Energy Savings kWh | 14,490,335 | 15,981,655 | 17,154,963 | 17,821,076 | 18,058,503 | 17,825,085 |
| Peak Demand kW | 3,808 | 4,131 | 4,383 | 4,524 | 4,573 | 4,514 |
| Total Program Budget | $2,047,886 | $2,163,627 | $2,239,173 | $2,262,354 | $2,245,657 | $2,189,060 |
| Per Participant Energy Savings (kWh) | 342 | 330 | 324 | 322 | 324 | 330 |
| Per Participant Demand Savings (kW) | 0.09 | 0.08 | 0.08 | 0.08 | 0.08 | 0.08 |
| Per Participant Average Incentive | $32 | $29 | $27 | $26 | $25 | $25 |
| Weighted Average Measure Life | 15 | 15 | 15 | 15 | 14 | 14 |
| Incremental Technology Cost | $91 | $85 | $79 | $74 | $70 | $66 |
| Net-to-Gross Ratio | 80% | 80% | 80% | 80% | 80% | 80% |

*Note: Number of participants, energy savings, and demand savings estimates based primarily on Market Potential Study results and on estimates from Market Potential Study and 2017 EM&V report. Program budget estimate based on current schedule of work and projected rising costs from Vectren Program Cost and Measure Data spreadsheet. Per unit savings estimates based on the Market Potential Study results. Per participant energy savings, per participant demand savings, and incremental technology cost weighted by participant. Linear LED lighting incentives and incremental costs are discounted by 33% from 2020 to 2025 based on findings from the DOE's Energy Savings Forecast of Solid-State Lighting in General Illumination Applications 2016 report. Weighted average measure life and net to gross ratio weighted by kWh.*

## 3.14 COMMERCIAL AND INDUSTRIAL CUSTOM

### *3.14.1 Background*

The C&I Custom Program promotes the implementation of customized energy-saving projects at qualifying customer facilities. Incentives promoted through this program serve to reduce the cost of implementing energy-reducing projects and upgrading to high-efficiency equipment. Due to the nature of Vectren's custom program, a wide variety of projects are eligible, including conventional custom retrofit projects, new construction (Commercial New Construction) projects, and major renovation (Building Tune-Up) projects. Beginning in 2020, Vectren will pilot a Strategic Energy Management component, an Advanced Lighting Controls component, and a Midstream HVAC component. As the design of the pilots will depend on Vectren-specific market research into C&I customers, the team did not establish the precise program design of the pilots nor the precise incentive structure.

Any participating commercial or industrial customer receiving electric service from Vectren South is eligible to participate in the C&I Custom Program. In addition to this requirement, the Building Tune-Up component also requires buildings to be at least 50,000 square feet. For the pilot components, the implementer will target a small group of participants to test the viability of the concept in Vectren territory.

#### 3.14.1.1 Conventional Custom Projects

Similar to previous program years, customers may propose new custom retrofit projects. Customers or trade allies with a proposed project complete an application form with the energy savings calculations for the project. The implementation team reviews all calculations and, where appropriate, completes site visits to assess and document pre-installation conditions. The implementer then informs that their project has been pre-approved and their funds are reserved for the project. Implementation engineering staff review the final project information as installed and verify the energy savings. Incentives are then paid on the verified savings. Given the variability and uniqueness of each project, all projects are pre-approved. Pre- and post-installation visits to the site to verify installation and savings are performed as defined by the program implementation partner. Monitoring and verification may occur on the largest projects. This component provides incentives based on the kWh saved as calculated by the engineering analysis.

#### 3.14.1.2 Commercial New Construction

The Commercial New Construction (CNC) component promotes energy-efficient designs with the goal of developing projects that are more energy efficient than current Indiana building code. This program applies to new construction and major renovation projects. Major renovation is defined as the replacement of at least two systems within an existing space (e.g., lighting, HVAC, controls, building envelope). The program provides incentives as part of the facility design process to explore opportunities in modeling EE options to craft an optimal package of investments. The program also offers customers the opportunity to receive prescriptive or custom rebates toward eligible equipment in order to reduce the higher capital cost for an energy efficient solution.

To help overcome financial challenge of designing energy-efficient new construction projects, Vectren offers a Standard Energy Design Assistance ("EDA"). This provides additional engineering expertise during the design phase to identify energy-saving opportunities. C&I projects for buildings greater than 100,000 square feet still in the conceptual design phase qualify for Vectren South's Enhanced EDA incentives which include energy modeling. The Vectren South implementation partner staff expert works with the design team through the conceptual design, schematic design, and design development processes, providing advice and counsel on measures that should be considered and EE modeling issues. Incentives are paid after the design team submits completed construction documents for review to verify that the facility design reflects the minimum energy savings requirements.

CNC provides incentives to help offset some of the expenses for the design team's participation in the EDA process with the design team incentive. The design team incentive is a fixed amount based on the new/renovated conditioned square footage and is paid when the proposed EE projects associated with the construction documents exceed a minimum energy savings threshold. The program also offers customers the opportunity to receive prescriptive or custom rebates toward eligible equipment in order to reduce the higher capital cost for the EE solutions.

#### 3.14.1.3 Building Tune-Up (BTU)

The BTU component provides a targeted, turnkey, and cost-effective retro-commissioning solution for small- to mid-sized customer facilities. It is designed as a comprehensive customer solution that will identify, validate, quantify, and encourage the installation of both operational and capital measures. The majority of these measures will be no- or low-cost with low payback periods and will capture energy savings from a previously untapped source: building automation systems.

The BTU component is designed to encourage high levels of implementation by customers seeking to optimize the operation of their existing HVAC system. BTU typically targets customers with buildings between 50,000 square feet and 150,000 square feet. Facility energy assessments are offered to customers who are eligible and motivated to implement multiple energy efficiency measures. BTU specifically targets measures that provide no- and low-cost operational savings. Most measures involve optimizing the building automation system (BAS) settings, but the program also investigates related capital measures, like controls, operations, processes, and HVAC. The implementation partner works collaboratively with Vectren South staff to recruit and screen customers for receiving facility energy assessments.

The following table describes the specific savings requirements related to each incentive:

TABLE 3-12 INCENTIVE SAVINGS REQUIREMENTS

| Facility Size – Square Feet | Design Team Incentives | Minimum Savings |
|---|---|---|
| **Small <25,000** | $750 | 25,000 kWh |
| **Medium 25,000 - 100,000** | $2,250 | 75,000 kWh |
| **Large >100,000** | $3,750 | 150,000 kWh |
| **Enhance Large >100,000** | $5,000 | 10% beyond code |

### 3.14.1.4 Strategic Energy Management Pilot

The Strategic Energy Management Pilot (SEM) is a guided operations and maintenance program with benchmarking and regular follow-up meetings to chart customer performance. The implementer will recruit customers to participate in the program and achieve energy savings for their facilities. The implementer will then measure their performance over time (usually a period of 6 months or a year) using energy billing data to determine the amount of energy savings the customer achieved and provide incentives to the customer accordingly. Depending on market research, the SEM pilot may also include cohorts of participants and inter-cohort and intra-cohort competition. Vectren may require the SEM pilot to fit Department of Energy (DOE) 50,001 Ready specifications. This DOE program model attempts to standardize programs across states and jurisdictions to give companies with facilities in more than one utility jurisdiction the opportunity to participate in SEM programs using similar qualification criteria and with similar program applications.

### 3.14.1.5 Advanced Lighting Controls Pilot

The Advanced Lighting Controls Pilot (ALC) will incentivize networked lighting control systems that include daylighting and/or occupancy sensors in the lighting fixtures. Like conventional custom projects, engineers will review project applications to establish conventional energy savings. Unlike the conventional custom projects, ALC projects may also include additional estimates for reduced hours-of-use or hours of lower energy use resulting from daylighting and/or occupancy sensors in the networked lighting.

### 3.14.1.6 Midstream HVAC Pilot

The Midstream HVAC Pilot will provide incentives to actors at the distributor level (firms positioned between the manufacturer and the end user). The pilot will provide incentives for HVAC equipment such as package units, heat pumps, room AC, split systems, and chillers.

Through midstream HVAC incentives, the program aims to influence the equipment that distributors stock, fine-tune incentives to fit desired program outcomes, and address the needs of the replace-on-burnout market. Because distributors have a large influence on the HVAC equipment that C&I customers eventually install, the pilot will be able to encourage distributors to supply more energy-efficient options. Midstream HVAC incentives can be more easily adjusted, as C&I customers receive the discount at the time of equipment purchase, not after a lengthy application process. Because C&I customers receive a discount at the time of purchase, the pilot may influence more quick-fire purchasing decisions such as replace-on-burnout purchases. C&I customers will not be encumbered by a lengthy application process to replace their defunct HVAC equipment.

### 3.14.2 Relation to Vectren's Market Potential Study

The Market Potential Study identified room in C&I markets, but due to the unique nature of each custom program project, it is difficult to compare Market Potential Study opportunity to Action Plan estimates.

### 3.14.3 Program Considerations

The team assumed that average participation rates from the C&I Custom Program would produce a rough estimate of participation for the program in the future. Due to the wide variations in program savings and number of participating projects over the years, this estimate has a very wide error bound.

### 3.14.4 Technology and Program Data

The following table provides summary of the C&I Custom Program energy impacts and budget.

TABLE 3-13 COMMERCIAL AND INDUSTRIAL CUSTOM – IMPACTS AND BUDGET

| | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 |
|---|---|---|---|---|---|---|
| Number of Participants | 196 | 196 | 196 | 196 | 196 | 196 |
| Energy Savings kWh | 6,107,234 | 6,107,234 | 6,107,234 | 6,107,234 | 6,107,234 | 6,107,234 |
| Peak Demand kW | 740 | 740 | 740 | 740 | 740 | 740 |
| Total Program Budget | $896,299 | $902,775 | $909,355 | $916,040 | $922,832 | $929,733 |
| Per Participant Energy Savings (kWh) | 31,159 | 31,159 | 31,159 | 31,159 | 31,159 | 31,159 |
| Per Participant Demand Savings (kW) | 3.78 | 3.78 | 3.78 | 3.78 | 3.78 | 3.78 |
| Per Participant Average Incentive | $2,508 | $2,508 | $2,508 | $2,508 | $2,508 | $2,508 |
| Weighted Average Measure Life | 16 | 16 | 16 | 16 | 16 | 16 |
| Incremental Technology Cost | $26,185 | $26,185 | $26,185 | $26,185 | $26,185 | $26,185 |
| Net-to-Gross Ratio | 100% | 100% | 100% | 100% | 100% | 100% |

*Note: Number of participants, energy savings, and program costs estimated based on program estimates for the 2015-2017 energy efficiency scorecards. Demand savings estimated based on the 2018 Operating Plan. Weighted average measure life and net to gross ratio weighted by kWh.*

## 3.15 SMALL BUSINESS ENERGY SOLUTIONS

### 3.15.1 Background

The Small Business Energy Solutions Program (SBES) provides value by directly installing EE products such as high-efficiency lighting, pre-rinse sprayers, refrigeration controls, electrically-commutated motors, smart thermostats, and vending machine controls. The program helps small businesses and multi-family customers identify and install cost-effective energy-saving measures by providing an onsite energy assessment customized for their business.

Any participating Vectren South business customer with a maximum peak energy demand of less than 400 kW is eligible to participate in the program. Additionally, multi-family building owners with Vectren general electric service may qualify for the program, including apartment buildings, condominiums, cooperatives, duplexes, quadraplexes, townhomes, nursing homes, and retirement communities.

Trained trade ally energy advisors provide energy assessments to business customers with less than 400 kW peak demand and to multi-family buildings. The program implementer issues an annual Request for Qualification (RFQ) to select the trade allies with the best ability to provide high-quality and cost-effective service to small businesses and provide training to SBES trade allies on the program process, with an emphasis on improving energy efficiency sales.

Trade allies walk through small businesses and record site characteristics and energy efficiency opportunities at no cost to the customer. They provide an energy assessment report that details customer-specific opportunities, costs, energy savings, incentives, and simple payback periods. The trade ally then reviews the report with the customer, presenting the program benefits and process, while addressing any questions.

The program has two types of measures provided. The first type of measures are installed at no cost to the customer. They include, but are not limited to, the following:

- LEDs
- Wifi-enabled thermostats
- Programmable thermostats
- High efficiency pre-rinse sprayers
- Faucet aerators
- Weather stripping (exterior door)

The second types of measures require the customer to pay a portion of the labor and materials. These measures include:

- Interior LED lighting
- Exterior LED lighting
- EC Motors
- Anti-sweat heater controls
- Refrigerated LED lighting and case covers
- Lighting control
- Vending machine control
- Smart thermostats

In addition to the no-cost measures identified during the audit, the program also pays a cash incentive on every recommended and implemented improvement identified through the assessment. Incentive rates may change over time and vary with special initiatives.

Onsite verification is provided for the first three projects completed by each trade ally, in addition to the program standard of 5% of all completed projects and all projects receiving incentives greater than $20,000. These verifications allow the program to validate energy savings, in addition to providing an opportunity to ensure trade allies provide high-quality customer services and the incentivized equipment satisfies program requirements.

### *3.15.2 Relation to Vectren's Market Potential Study*

The Market Potential Study identified savings for the overall C&I sectors but provided less-specific estimates for the small business sector. As participation in the program is small, the team assumed that historic participation trends would continue through the timeline of the action plan.

### *3.15.3 Program Considerations*

The team reviewed estimates for the impact of the EISA backstop in other jurisdictions and found that the EISA backstop will have a much smaller impact on C&I programs compared to residential programs. This research also indicated that small businesses will face a larger impact from the backstop as their lighting characteristics more closely resemble the residential market. Because of this impact, the team assumed decreasing participation in lighting measures impacted by the EISA backstop after 2021.

The team dropped fluorescent lighting from the program as the technology will be superseded by linear LEDs and savings from LEDs are much more substantial.

### 3.15.4 Technology and Program Data

The following table provides summary of SBES energy impacts and budget.

TABLE 3-14 SMALL BUSINESS ENERGY SOLUTIONS – IMPACTS AND BUDGET

| | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 |
|---|---|---|---|---|---|---|
| Number of Participants | 381 | 382 | 382 | 382 | 383 | 383 |
| Energy Savings kWh | 2,940,932 | 2,944,615 | 2,949,771 | 2,952,715 | 2,957,870 | 2,963,026 |
| Peak Demand kW | 213 | 213 | 213 | 213 | 213 | 213 |
| Total Program Budget | $768,835 | $763,876 | $758,758 | $752,586 | $747,582 | $742,637 |
| Per Participant Energy Savings (kWh) | 7,719 | 7,708 | 7,722 | 7,730 | 7,723 | 7,736 |
| Per Participant Demand Savings (kW) | 0.56 | 0.56 | 0.56 | 0.56 | 0.56 | 0.56 |
| Per Participant Average Incentive | $1,439 | $1,412 | $1,390 | $1,365 | $1,338 | $1,315 |
| Weighted Average Measure Life | 15 | 15 | 15 | 15 | 15 | 15 |
| Incremental Technology Cost | $312 | $311 | $310 | $310 | $309 | $308 |
| Net-to-Gross Ratio | 91% | 91% | 91% | 91% | 91% | 91% |

*Note: Number of participants, energy savings, and demand savings estimated based on the 2018 Operating Plan. Program costs estimated using the current program SOW and projected rising costs from 2018-20 filed Energy Efficiency Plan and Vectren Program Cost and Measure Data spreadsheet. Per participant average incentive and incremental technology cost estimated by summing the values for each piece of equipment and dividing by the number of participants. Linear LED lighting incentives and incremental costs are discounted by 33% from 2020 to 2025 based on findings from the DOE's Energy Savings Forecast of Solid-State Lighting in General Illumination Applications 2016 report. Weighted average measure life and net to gross ratio are weighted by kWh.*

## 3.16 CONSERVATION VOLTAGE REDUCTION

### 3.16.1 Background

Conservation Voltage Reduction (CVR) achieves energy conservation through automated monitoring and control of voltage levels provided on distribution circuits. End use customers realize lower energy and demand consumption when CVR is applied to the distribution circuit from which they are served.

CVR is both a DR and an EE program. It targets distribution circuits, in part to reduce the peak demand experienced on Vectren's electrical power supply system. The voltage reduction stemming from the CVR program operates to effectively reduce consumption during the times in which system peaks are set and as a result directly reduces peak demand. CVR also cost-effectively reduces the level of ongoing energy consumption by end-use devices located on the customer side of the utility meter, as many end-use devices consume less energy with lower voltages consistently applied. Like an equipment maintenance service program, the voltage optimization allows the customer's equipment to operate at optimum levels which saves energy without requiring direct customer intervention or change.

Delivery of the CVR Program will be achieved through the installation of control logic, telecommunication equipment, and voltage control equipment in order to control the voltage bandwidth on CVR circuits within voltage compliance levels required by the Indiana Utility Regulatory Commission.

### 3.16.2 Program Considerations

The team assumed similar participation in conservation voltage reduction as in previous years.

# VOLUME III

## APPENDICES

*2020-2025 Integrated Electric DSM Market Potential Study & Action Plan*

*prepared for*

VECTREN
Live Smart

JANUARY 2019

# VOLUME III *Electric Appendices*

## *Electric* ***DSM Market Potential Study***



## *Electric* ***Action Plan***

# APPENDIX A *DSM Market Potential Study Sources*

This appendix catalogs many of the data sources used in this study, grouped by major activity. In general, GDS attempted to utilize Vectren-specific data, where available. When Vectren-specific data was not available or reliable, GDS leveraged secondary data from nearby or regional sources.

## A.1 MARKET RESEARCH

Market research studies were used to understand home and business characteristics and equipment stock characteristics. Vectren supplied GDS with several residential market research studies, and GDS conducted primary research in the small commercial sector to gather additional equipment and efficiency characteristics.

- ***Vectren Residential Market Research Studies:*** The electric measure analysis was largely informed by a 2016 baseline survey of Vectren South customers. Nearly 500 responses to this survey provided a strong basis for many of the Vectren South electric measure baseline and efficient saturation estimates. A 2015 CFL and LED baseline study helped inform the saturation estimates for the lighting end use. A 2017 electric baseline thermostat survey of Vectren customers was leveraged to better characterize the increased prominence of smart and Wi-Fi-enabled thermostats.
- ***Vectren Commercial Primary Market Research:*** GDS collected data in 38 commercial facilities to better understand electric and natural gas equipment saturation and efficiency characteristics.
- ***Industrial Surveys***: Vectren survey data was leveraged to determine the remaining factors for several end-uses, including motors, interior and exterior lighting and fixture measures.
- ***EIA/DOE Industrial Data:*** Including the DOE Industrial Electric Motor Systems Market Opportunities Report, the DOE Assessment of the Market for Compressed Air Efficiency Services, and EIA Industrial Demand Module of the National Energy Modeling System.
- ***US American Community Survey:*** Public Use Microdata Survey data was used to estimate the percent of low-income households (using annual household income and number of people per household) in the Vectren South and North territories.
- ***Energy Star Shipment Data:*** Energy Star shipment data provides a detailed historical estimate of the percent of shipped equipment/appliances that meet ENERGY STAR standards. Over the long-term, this serves as a proxy for the percent of the market that could be considered energy efficient.

## A.2 FORECAST CALIBRATION

The forecast calibration effort was used to create a detailed segmentation of Vectren's load forecast and ensure that estimated savings would not overstate future potential. Vectren supplied GDS with the most recent load forecast.

- ***Vectren Load Forecast:*** The 2016 Long-Term Electric Energy and Demand load forecast consists of the most recent ITRON load forecast completed for VEDI for 2016-2036. The natural gas forecast was provided directly from Vectren for the North and South territories from 2017 to 2027. Future years were escalated by a compound average annual growth rate.
- ***Vectren Commercial and Industrial Customer Forecast:*** The 2017 historical commercial and industrial data utilized rate codes and existing NAICS code to segment historical sales by commercial building type and/or industry type.
- ***InfoUSA***: GDS utilized a third-party dataset that provided additional commercial and industrial business information, including NAICS codes, to supplement the building/industry types codes supplied by Vectren
- ***EIA Commercial Building Energy Consumption Survey:*** GDS updated the ITRON load forecast to utilize more recent information for the East South-Central region from the EIA 2012 CBECS survey.

- ***EIA Manufacturing Energy Consumption Survey:*** GDS used the 2014 study to further refine the industrial load forecast by end-use.
- ***BEopt:*** GDS developed residential building prototypes from the market research effort to develop detailed consumption estimates by end-use and calibrated these models to Vectren's residential load forecasts.

## A.3 ENERGY EFFICIENCY MEASURE DATA

The energy efficiency measure analysis developed per unit savings, cost, and useful life assumptions for each energy efficiency measure in the residential, commercial, and industrial sectors. Preference was given to Vectren-specific evaluated savings and/or deemed savings/algorithms in the Indiana TRM.

- ***2017 Vectren EM&V Report (Cadmus):*** For the development of savings estimates of measures already offered by Vectren, GDS either used the estimates from the most recent evaluation reports or used the evaluation methodology to develop forward looking savings projections.
- ***Indiana TRM v2.2:*** In the absence of evaluation data, GDS attempted to leverage the Indiana TRM. Assumptions and algorithms were based off the IN TRM to the extent practical.
- ***Vectren Operating Plan:*** Historical incentive estimates and in some cases, incremental measure costs, were based on the Vectren Operating Plans.
- ***Other TRMs:*** In some cases, TRM's or deemed measure databases from other states were more applicable than the IN TRM due to more currently available estimates and the more appropriate use of updated federal standards. The Illinois TRM and the Michigan Energy Measures Database were the primary non-Indiana TRMs used.
- ***Other Secondary Sources:*** In some cases, following the source hierarchy listed above was not enough to develop savings estimates. In these cases, GDS leveraged other secondary research documents such as ACEEE emerging technology reports.

## A.4 DEMAND RESPONSE / CVR MEASURE ANALYSIS

The DR/CVR analysis developed per unit savings, cost, and useful life assumptions for select demand response programs, and included assumptions regarding future CVR potential from two additional substations.

- ***Vectren programs / 2012 FERC DR Survey:*** Demand reductions were based on load reductions found in Vectren's existing demand response programs, and various secondary data sources including the FERC and other industry reports, including demand response potential studies.
- ***Indiana TRM v2.2:*** In the absence of evaluation data, GDS attempted to leverage the Indiana TRM. Assumptions and algorithms were based off the IN TRM to the extent practical.
- ***Comverge:*** Comverge provided an estimate of the load control switch useful life.
- ***Nest and Ecobee:*** Nest and Ecobee product data was used to develop equipment cost assumptions.
- ***Other DR Potential Studies:*** the absence
- ***EM&V Analysis of Buckwood Pilot Program:*** Energy and demand impacts for the CVR analysis
- ***Power System Engineering Report:*** Energy and demand impacts for the CVR analysis

## A.5 AVOIDED COST/ECONOMIC ANALYSIS

Avoided costs and related economic assumptions were used to assess cost-effectiveness. In addition, historical incentive levels were tied to willingness-to-participate (WTP) research to assess long-term market adoption in the achievable potential scenario.

- ***Electric and Natural Gas Avoided Costs:*** Avoided cost values for electric energy, electric capacity, and avoided transmission and distribution (T&D) were provided by Vectren as part of an initial data request. Electric energy is based on an annual system marginal cost. For years outside of the avoided cost forecast timeframe, future year avoided costs are escalated by the rate of inflation. Natural gas avoided costs are calculated using EIA Annual Outlook reference tables combined with demand rates and basis differentials provided by Vectren Gas Supply.

- ***Other Economic Assumptions:*** Includes the discount rate, inflation rate, line loss assumptions and reserve margin requirement. All economic assumptions were provided by Vectren and consistent with economic modeling assumptions used for other utility planning efforts.
- ***Historical DSM Filings/Scorecards:*** Historical DSM costs and savings data from 2011 to 2017 were used to determine non-incentive program delivery costs as well as cross-cutting portfolio costs.
- ***Primary Market Research:*** Vectren conducted over 300 surveys in the residential sector (online only) and 38 on-site surveys in the commercial sector regarding customer willingness-to-purchase energy efficient equipment at various incentive levels. This Vectren-specific customer data was used to determine long-term adoption rates by end-use for the MAP and RAP achievable potential scenarios.

# APPENDIX B *DSM Market Potential Study Residential Measure Detail*

## Vectren Electric — Residential Measure Assumptions

| Measure # | End-Use | Measure Name | Home Type | Income Type | Replacement Type | Base Annual Electric | % Elec Savings | Per Unit Elec Savings | Per Unit Summer NCP kW | Useful Life | Initial Measure Cost | Historical Incentive Amount | UCT Ratio | Measure Description |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1001 | Appliances | ENERGY STAR Air Purifier | SF | N/A | MO | 733.0 | 67% | 488.0 | 0.084 | 9.0 | $70.00 | $25.00 | 9.24 | Air Purifier meeting ENERGY STAR spec |
| 1002 | Appliances | ENERGY STAR Refrigerator | SF | NLI | MO | 569.0 | 9% | 53.0 | 0.008 | 17.0 | $40.00 | $20.00 | 2.05 | ES Qualified Refrigator (~9% more efficient) |
| 1003 | Appliances | Smart Refrigerator_ET | SF | NLI | MO | 569.0 | 12% | 70.0 | 0.011 | 17.0 | $680.00 | $340.00 | 0.16 | ES Qualified Refrigerator w/ Smart Technology |
| 1004 | Appliances | ES Refrigerator Replacement | SF | LI | DI | 1,193.0 | 35% | 412.2 | 0.063 | 17.0 | $580.00 | $580.00 | 0.55 | Replace Existing Refrigerator with ES Qualified Unit |
| 1005 | Appliances | Refrigerator Recycling | SF | N/A | Recycle | 1,044.0 | 100% | 1,044.0 | 0.140 | 8.0 | $130.00 | $130.00 | 3.14 | Refrigerator Recycle (No Replacement) |
| 1006 | Appliances | ENERGY STAR Clothes Washer (Electrc WH/Dryer) | SF | N/A | MO | 522.0 | 22% | 112.4 | 0.430 | 14.0 | $84.00 | $40.00 | 1.95 | ES Qualified ClothesWasher (IMEF=2.23 ; 1.75 Baseline) |
| 1007 | Appliances | ENERGY STAR Clothes Washer (NG WH/E Dryer) | SF | N/A | MO | 383.7 | 27% | 101.8 | 0.390 | 14.0 | $84.00 | $40.00 | 1.82 | ES Qualified ClothesWasher (IMEF=2.23 ; 1.75 Baseline) |
| 1008 | Appliances | ENERGY STAR Clothes Washer (NG WH/NG Dryer) | SF | N/A | MO | 42.3 | 44% | 18.5 | 0.071 | 14.0 | $84.00 | $40.00 | 0.82 | ES Qualified ClothesWasher (IMEF=2.23 ; 1.75 Baseline) |
| 1009 | Appliances | Smart/CEE Tier3 Clothes Washer (Electrc WH/Dryer)_ET | SF | N/A | MO | 522.0 | 40% | 209.2 | 0.801 | 14.0 | $141.00 | $70.00 | 2.07 | CEE Tier 3 Qualified ClothesWasher (IMEF=2.92 ; 1.75 Baseline) |
| 1010 | Appliances | Smart/CEE Tier3 Clothes Washer (NG WH/E Dryer)_ET | SF | N/A | MO | 383.7 | 26% | 100.9 | 0.386 | 14.0 | $141.00 | $70.00 | 1.33 | CEE Tier 3 Qualified ClothesWasher (IMEF=2.92 ; 1.75 Baseline) |
| 1011 | Appliances | Smart/CEE Tier3 Clothes Washer (NG WH/NG Dryer)_ET | SF | N/A | MO | 42.3 | -3% | -1.2 | -0.005 | 14.0 | $141.00 | $70.00 | 0.62 | CEE Tier 3 Qualified ClothesWasher (IMEF=2.92 ; 1.75 Baseline) |
| 1012 | Appliances | ENERGY STAR Dishwasher (E WH) | SF | N/A | MO | 307.0 | 12% | 37.0 | 0.105 | 11.0 | $76.00 | $40.00 | 0.42 | ES Qualified Dishwasher (v3.0) |
| 1013 | Appliances | ENERGY STAR Dishwasher (NG WH) | SF | N/A | MO | 135.1 | 12% | 16.3 | 0.046 | 11.0 | $79.00 | $40.00 | 0.27 | ES Qualified Dishwasher (v3.0) |
| 1014 | Appliances | Smart Dishwasher (E WH)_ET | SF | N/A | MO | 307.0 | 15% | 45.5 | 0.129 | 11.0 | $395.00 | $200.00 | 0.10 | Smart ES Qualified Dishwasher (v3.0) |
| 1015 | Appliances | Smart Dishwasher (NG WH)_ET | SF | N/A | MO | 135.1 | 15% | 20.0 | 0.057 | 11.0 | $395.00 | $200.00 | 0.07 | Smart ES Qualified Dishwasher (v3.0) |
| 1016 | Appliances | ENERGY STAR Dehumidifier | SF | N/A | MO | 904.6 | 20% | 180.9 | 0.111 | 12.0 | $9.52 | $5.00 | 24.59 | ES Qualified Dehumidifer (L/kWh = 2.0) |
| 1017 | Appliances | ENERGY STAR Freezer | SF | N/A | MO | 349.5 | 10% | 35.1 | 0.006 | 22.0 | $35.00 | $20.00 | 1.64 | ES Qualified Freezer (10% more Efficient than NAECA) |
| 1018 | Appliances | Freezer Recycling | SF | N/A | Recycle | 927.0 | 100% | 927.0 | 0.100 | 8.0 | $130.00 | $130.00 | 2.62 | Freezer Recycle (No Replacement) |
| 1019 | Appliances | ENERGY STAR Clothes Dryer (Electric) | SF | NLI | MO | 768.9 | 21% | 160.4 | 0.567 | 16.0 | $152.00 | $75.00 | 1.52 | ES Qualified Dryer (CEF=3.93) |
| 1020 | Appliances | ENERGY STAR Clothes Dryer (NG) | SF | NLI | MO | 123.0 | 21% | 25.7 | 0.091 | 16.0 | $152.00 | $75.00 | 0.57 | ES Qualified Dryer (CEF=3.93) |
| 1021 | Appliances | Smart Clothes Dryer (Electric)_ET | SF | NLI | MO | 768.9 | 26% | 202.7 | 0.716 | 16.0 | $236.00 | $120.00 | 1.20 | Smart ES Qualified Dryer (5.5% additional energy savings) |
| 1022 | Appliances | Smart Clothes Dryer (NG)_ET | SF | NLI | MO | 123.0 | 26% | 32.4 | 0.115 | 16.0 | $236.00 | $120.00 | 0.45 | Smart ES Qualified Dryer (5.5% additional energy savings) |
| 1023 | Appliances | Heat Pump Dryer | SF | NLI | MO | 768.9 | 73% | 558.0 | 1.972 | 12.0 | $412.00 | $205.00 | 1.57 | Heat Pump Dryer (CEF=10.4) |
| 1024 | Appliances | Dryer Vent Cleaning (Electric) | SF | LI | DI | 768.9 | 6% | 42.3 | 0.149 | 2.0 | $80.00 | $80.00 | 0.06 | Dryer Vent Cleaning (5.5% Savings) |
| 1025 | Appliances | Dryer Vent Cleaning (NG) | SF | LI | DI | 123.0 | 6% | 6.8 | 0.024 | 2.0 | $80.00 | $80.00 | 0.02 | Dryer Vent Cleaning (5.5% Savings) |
| 1026 | Appliances | ENERGY STAR Water Cooler | SF | N/A | MO | 105.9 | 46% | 48.6 | 0.006 | 10.0 | $17.00 | $10.00 | 2.22 | ES Water Cooler (Cold Water Only) |
| 1027 | Appliances | ENERGY STAR Air Purifier | SF | N/A | NC | 733.0 | 67% | 488.0 | 0.084 | 9.0 | $70.00 | $25.00 | 9.24 | Air Purifier meeting ENERGY STAR spec |
| 1028 | Appliances | ENERGY STAR Refrigerator | SF | N/A | NC | 569.0 | 9% | 53.0 | 0.008 | 17.0 | $40.00 | $20.00 | 2.05 | ES Qualified Refrigator (~9% more efficient) |
| 1029 | Appliances | Smart Refrigerator_ET | SF | N/A | NC | 569.0 | 12% | 70.0 | 0.011 | 17.0 | $680.00 | $340.00 | 0.16 | ES Qualified Refrigerator w/ Smart Technology |
| 1030 | Appliances | ENERGY STAR Clothes Washer (Electrc WH/Dryer) | SF | N/A | NC | 522.0 | 22% | 112.4 | 0.430 | 14.0 | $84.00 | $40.00 | 1.95 | ES Qualified ClothesWasher (IMEF=2.23 ; 1.75 Baseline) |

| Vectren Electric | Residential Measure Assumptions | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Measure # | End-Use | Measure Name | Home Type | Income Type | Replacement Type | Base Annual Electric | % Elec Savings | Per Unit Elec Savings | Per Unit Summer NCP kW | Useful Life | Initial Measure Cost | Historical Incentive Amount | UCT Ratio | Measure Description |
| 1031 | Appliances | ENERGY STAR Clothes Washer (NG WH/E Dryer) | SF | N/A | NC | 383.7 | 27% | 101.8 | 0.390 | 14.0 | $84.00 | $40.00 | 1.82 | ES Qualified ClothesWasher (IMEF=2.23 ; 1.75 Baseline) |
| 1032 | Appliances | ENERGY STAR Clothes Washer (NG WH/NG Dryer) | SF | N/A | NC | 42.3 | 44% | 18.5 | 0.071 | 14.0 | $84.00 | $40.00 | 0.82 | ES Qualified ClothesWasher (IMEF=2.23 ; 1.75 Baseline) |
| 1033 | Appliances | Smart/CEE Tier3 Clothes Washer (Electrc WH/Dryer)_ET | SF | N/A | NC | 522.0 | 40% | 209.2 | 0.801 | 14.0 | $141.00 | $70.00 | 2.07 | CEE Tier 3 Qualified ClothesWasher (IMEF=2.92 ; 1.75 Baseline) |
| 1034 | Appliances | Smart/CEE Tier3 Clothes Washer (NG WH/E Dryer)_ET | SF | N/A | NC | 383.7 | 26% | 100.9 | 0.386 | 14.0 | $141.00 | $70.00 | 1.33 | CEE Tier 3 Qualified ClothesWasher (IMEF=2.92 ; 1.75 Baseline) |
| 1035 | Appliances | Smart/CEE Tier3 Clothes Washer (NG WH/NG Dryer)_ET | SF | N/A | NC | 42.3 | -3% | -1.2 | -0.005 | 14.0 | $141.00 | $70.00 | 0.62 | CEE Tier 3 Qualified ClothesWasher (IMEF=2.92 ; 1.75 Baseline) |
| 1036 | Appliances | ENERGY STAR Dishwasher (E WH) | SF | N/A | NC | 307.0 | 12% | 37.0 | 0.105 | 11.0 | $76.00 | $40.00 | 0.42 | ES Qualified Dishwasher (v3.0) |
| 1037 | Appliances | ENERGY STAR Dishwasher (NG WH) | SF | N/A | NC | 135.1 | 12% | 16.3 | 0.046 | 11.0 | $79.00 | $40.00 | 0.27 | ES Qualified Dishwasher (v3.0) |
| 1038 | Appliances | Smart Dishwasher (E WH)_ET | SF | N/A | NC | 307.0 | 15% | 45.5 | 0.129 | 11.0 | $395.00 | $200.00 | 0.10 | Smart ES Qualified Dishwasher (v3.0) |
| 1039 | Appliances | Smart Dishwasher (NG WH)_ET | SF | N/A | NC | 135.1 | 15% | 20.0 | 0.057 | 11.0 | $395.00 | $200.00 | 0.07 | Smart ES Qualified Dishwasher (v3.0) |
| 1040 | Appliances | ENERGY STAR Dehumidifier | SF | N/A | NC | 904.6 | 20% | 180.9 | 0.111 | 12.0 | $9.52 | $5.00 | 24.59 | ES Qualified Dehumidifer (L/kWh = 2.0) |
| 1041 | Appliances | ENERGY STAR Freezer | SF | N/A | NC | 349.5 | 10% | 35.1 | 0.006 | 22.0 | $35.00 | $20.00 | 1.64 | ES Qualified Freezer (10% more Efficient than NAECA) |
| 1042 | Appliances | ENERGY STAR Clothes Dryer (Electric) | SF | N/A | NC | 768.9 | 21% | 160.4 | 0.567 | 16.0 | $152.00 | $75.00 | 1.52 | ES Qualified Dryer (CEF=3.93) |
| 1043 | Appliances | ENERGY STAR Clothes Dryer (NG) | SF | N/A | NC | 123.0 | 21% | 25.7 | 0.091 | 16.0 | $152.00 | $75.00 | 0.57 | ES Qualified Dryer (CEF=3.93) |
| 1044 | Appliances | Smart Clothes Dryer (Electric)_ET | SF | N/A | NC | 768.9 | 26% | 202.7 | 0.716 | 16.0 | $236.00 | $120.00 | 1.20 | Smart ES Qualified Dryer (5.5% additional energy savings) |
| 1045 | Appliances | Smart Clothes Dryer (NG)_ET | SF | N/A | NC | 123.0 | 26% | 32.4 | 0.115 | 16.0 | $236.00 | $120.00 | 0.45 | Smart ES Qualified Dryer (5.5% additional energy savings) |
| 1046 | Appliances | Heat Pump Dryer | SF | N/A | NC | 768.9 | 73% | 558.0 | 1.972 | 12.0 | $412.00 | $205.00 | 1.57 | Heat Pump Dryer (CEF=10.4) |
| 1047 | Appliances | ENERGY STAR Water Cooler | SF | N/A | NC | 105.9 | 46% | 48.6 | 0.006 | 10.0 | $17.00 | $10.00 | 2.22 | ES Water Cooler (Cold Water Only) |
| 1048 | Appliances | ENERGY STAR Air Purifier | MF | N/A | MO | 733.0 | 67% | 488.0 | 0.084 | 9.0 | $70.00 | $25.00 | 9.24 | Air Purifier meeting ENERGY STAR spec |
| 1049 | Appliances | ENERGY STAR Refrigerator | MF | NLI | MO | 569.0 | 9% | 53.0 | 0.008 | 17.0 | $40.00 | $20.00 | 2.05 | ES Qualified Refrigator (~9% more efficient) |
| 1050 | Appliances | Smart Refrigerator_ET | MF | NLI | MO | 569.0 | 12% | 70.0 | 0.011 | 17.0 | $680.00 | $340.00 | 0.16 | ES Qualified Refrigerator w/ Smart Technology |
| 1051 | Appliances | ES Refrigerator Replacement | MF | LI | DI | 1,193.0 | 35% | 412.2 | 0.063 | 17.0 | $580.00 | $580.00 | 0.55 | Replace Existing Refrigerator with ES Qualified Unit |
| 1052 | Appliances | Refrigerator Recycling | MF | N/A | Recycle | 1,044.0 | 100% | 1,044.0 | 0.140 | 8.0 | $130.00 | $130.00 | 3.14 | Refrigerator Recycle (No Replacement) |
| 1053 | Appliances | ENERGY STAR Clothes Washer (Electrc WH/Dryer) | MF | N/A | MO | 522.0 | 22% | 112.4 | 0.430 | 14.0 | $84.00 | $40.00 | 1.95 | ES Qualified ClothesWasher (IMEF=2.23 ; 1.75 Baseline) |
| 1054 | Appliances | ENERGY STAR Clothes Washer (NG WH/E Dryer) | MF | N/A | MO | 383.7 | 27% | 101.8 | 0.390 | 14.0 | $84.00 | $40.00 | 1.82 | ES Qualified ClothesWasher (IMEF=2.23 ; 1.75 Baseline) |
| 1055 | Appliances | ENERGY STAR Clothes Washer (NG WH/NG Dryer) | MF | N/A | MO | 42.3 | 44% | 18.5 | 0.071 | 14.0 | $84.00 | $40.00 | 0.82 | ES Qualified ClothesWasher (IMEF=2.23 ; 1.75 Baseline) |
| 1056 | Appliances | Smart/CEE Tier3 Clothes Washer (Electrc WH/Dryer)_ET | MF | N/A | MO | 522.0 | 40% | 209.2 | 0.801 | 14.0 | $141.00 | $70.00 | 2.07 | CEE Tier 3 Qualified ClothesWasher (IMEF=2.92 ; 1.75 Baseline) |
| 1057 | Appliances | Smart/CEE Tier3 Clothes Washer (NG WH/E Dryer)_ET | MF | N/A | MO | 383.7 | 26% | 100.9 | 0.386 | 14.0 | $141.00 | $70.00 | 1.33 | CEE Tier 3 Qualified ClothesWasher (IMEF=2.92 ; 1.75 Baseline) |

**Vectren Electric** | **Residential Measure Assumptions**

| Measure # | End-Use | Measure Name | Home Type | Income Type | Replacement Type | Base Annual Electric | % Elec Savings | Per Unit Elec Savings | Per Unit Summer NCP kW | Useful Life | Initial Measure Cost | Historical Incentive Amount | UCT Ratio | Measure Description |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1058 | Appliances | Smart/CEE Tier3 Clothes Washer (NG WH/NG Dryer)_ET | MF | N/A | MO | 42.3 | -3% | -1.2 | -0.005 | 14.0 | $141.00 | $70.00 | 0.62 | CEE Tier 3 Qualified ClothesWasher (IMEF=2.92 ; 1.75 Baseline) |
| 1059 | Appliances | ENERGY STAR Dishwasher (E WH) | MF | N/A | MO | 307.0 | 12% | 37.0 | 0.105 | 11.0 | $76.00 | $40.00 | 0.42 | ES Qualified Dishwasher (v3.0) |
| 1060 | Appliances | ENERGY STAR Dishwasher (NG WH) | MF | N/A | MO | 135.1 | 12% | 16.3 | 0.046 | 11.0 | $79.00 | $40.00 | 0.27 | ES Qualified Dishwasher (v3.0) |
| 1061 | Appliances | Smart Dishwasher (E WH)_ET | MF | N/A | MO | 307.0 | 15% | 45.5 | 0.129 | 11.0 | $395.00 | $200.00 | 0.10 | Smart ES Qualified Dishwasher (v3.0) |
| 1062 | Appliances | Smart Dishwasher (NG WH)_ET | MF | N/A | MO | 135.1 | 15% | 20.0 | 0.057 | 11.0 | $395.00 | $200.00 | 0.07 | Smart ES Qualified Dishwasher (v3.0) |
| 1063 | Appliances | ENERGY STAR Dehumidifier | MF | N/A | MO | 904.6 | 27% | 246.7 | 0.151 | 12.0 | $75.00 | $40.00 | 4.19 | ES Qualified Dehumidifer (L/kWh = 2.2) |
| 1064 | Appliances | ENERGY STAR Freezer | MF | N/A | MO | 349.5 | 10% | 35.1 | 0.006 | 22.0 | $35.00 | $20.00 | 1.64 | ES Qualified Freezer (10% more Efficient than NAECA) |
| 1065 | Appliances | Freezer Recycling | MF | N/A | Recycle | 927.0 | 100% | 927.0 | 0.100 | 8.0 | $130.00 | $130.00 | 2.62 | Freezer Recycle (No Replacement) |
| 1066 | Appliances | ENERGY STAR Clothes Dryer (Electric) | MF | NLI | MO | 768.9 | 21% | 160.4 | 0.567 | 16.0 | $152.00 | $75.00 | 1.52 | ES Qualified Dryer (CEF=3.93) |
| 1067 | Appliances | ENERGY STAR Clothes Dryer (NG) | MF | NLI | MO | 123.0 | 21% | 25.7 | 0.091 | 16.0 | $152.00 | $75.00 | 0.57 | ES Qualified Dryer (CEF=3.93) |
| 1068 | Appliances | Smart Clothes Dryer (Electric)_ET | MF | NLI | MO | 768.9 | 26% | 202.7 | 0.716 | 16.0 | $236.00 | $120.00 | 1.20 | Smart ES Qualified Dryer (5.5% additional energy savings) |
| 1069 | Appliances | Smart Clothes Dryer (NG)_ET | MF | NLI | MO | 123.0 | 26% | 32.4 | 0.115 | 16.0 | $236.00 | $120.00 | 0.45 | Smart ES Qualified Dryer (5.5% additional energy savings) |
| 1070 | Appliances | Heat Pump Dryer | MF | NLI | MO | 768.9 | 73% | 558.0 | 1.972 | 12.0 | $412.00 | $205.00 | 1.57 | Heat Pump Dryer (CEF=10.4) |
| 1071 | Appliances | Dryer Vent Cleaning (Electric) | MF | LI | DI | 768.9 | 6% | 42.3 | 0.149 | 2.0 | $80.00 | $80.00 | 0.06 | Dryer Vent Cleaning (5.5% Savings) |
| 1072 | Appliances | Dryer Vent Cleaning (NG) | MF | LI | DI | 123.0 | 6% | 6.8 | 0.024 | 2.0 | $80.00 | $80.00 | 0.02 | Smart ES Qualified Dryer (5.5% additional energy savings) |
| 1073 | Appliances | ENERGY STAR Water Cooler | MF | N/A | MO | 105.9 | 46% | 48.6 | 0.006 | 10.0 | $17.00 | $10.00 | 2.22 | ES Water Cooler (Cold Water Only) |
| 1074 | Appliances | ENERGY STAR Air Purifier | MF | N/A | NC | 733.0 | 67% | 488.0 | 0.084 | 9.0 | $70.00 | $25.00 | 9.24 | Air Purifier meeting ENERGY STAR spec |
| 1075 | Appliances | ENERGY STAR Refrigerator | MF | N/A | NC | 569.0 | 9% | 53.0 | 0.008 | 17.0 | $40.00 | $20.00 | 2.05 | ES Qualified Refrigator (~9% more efficient) |
| 1076 | Appliances | Smart Refrigerator_ET | MF | N/A | NC | 569.0 | 12% | 70.0 | 0.011 | 17.0 | $680.00 | $340.00 | 0.16 | ES Qualified Refrigerator w/ Smart Technology |
| 1077 | Appliances | ENERGY STAR Clothes Washer (Electrc WH/Dryer) | MF | N/A | NC | 522.0 | 22% | 112.4 | 0.430 | 14.0 | $84.00 | $40.00 | 1.95 | ES Qualified ClothesWasher (IMEF=2.23 ; 1.75 Baseline) |
| 1078 | Appliances | ENERGY STAR Clothes Washer (NG WH/E Dryer) | MF | N/A | NC | 383.7 | 27% | 101.8 | 0.390 | 14.0 | $84.00 | $40.00 | 1.82 | ES Qualified ClothesWasher (IMEF=2.23 ; 1.75 Baseline) |
| 1079 | Appliances | ENERGY STAR Clothes Washer (NG WH/NG Dryer) | MF | N/A | NC | 42.3 | 44% | 18.5 | 0.071 | 14.0 | $84.00 | $40.00 | 0.82 | ES Qualified ClothesWasher (IMEF=2.23 ; 1.75 Baseline) |
| 1080 | Appliances | Smart/CEE Tier3 Clothes Washer (Electrc WH/Dryer)_ET | MF | N/A | NC | 522.0 | 40% | 209.2 | 0.801 | 14.0 | $141.00 | $70.00 | 2.07 | CEE Tier 3 Qualified ClothesWasher (IMEF=2.92 ; 1.75 Baseline) |
| 1081 | Appliances | Smart/CEE Tier3 Clothes Washer (NG WH/E Dryer)_ET | *MF* | N/A | NC | 383.7 | 26% | 100.9 | 0.386 | 14.0 | $141.00 | $70.00 | 1.33 | CEE Tier 3 Qualified ClothesWasher (IMEF=2.92 ; 1.75 Baseline) |
| 1082 | Appliances | Smart/CEE Tier3 Clothes Washer (NG WH/NG Dryer)_ET | *MF* | N/A | NC | 42.3 | -3% | -1.2 | -0.005 | 14.0 | $141.00 | $70.00 | 0.62 | CEE Tier 3 Qualified ClothesWasher (IMEF=2.92 ; 1.75 Baseline) |
| 1083 | Appliances | ENERGY STAR Dishwasher (E WH) | MF | N/A | NC | 307.0 | 12% | 37.0 | 0.105 | 11.0 | $76.00 | $40.00 | 0.42 | ES Qualified Dishwasher (v3.0) |
| 1084 | Appliances | ENERGY STAR Dishwasher (NG WH) | MF | N/A | NC | 135.1 | 12% | 16.3 | 0.046 | 11.0 | $79.00 | $40.00 | 0.27 | ES Qualified Dishwasher (v3.0) |
| 1085 | Appliances | Smart Dishwasher (E WH)_ET | MF | N/A | NC | 307.0 | 15% | 45.5 | 0.129 | 11.0 | $395.00 | $200.00 | 0.10 | Smart ES Qualified Dishwasher (v3.0) |

**Vectren Electric** **Residential Measure Assumptions**

| Measure # | End-Use | Measure Name | Home Type | Income Type | Replacement Type | Base Annual Electric | % Elec Savings | Per Unit Elec Savings | Per Unit Summer NCP kW | Useful Life | Initial Measure Cost | Historical Incentive Amount | UCT Ratio | Measure Description |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1086 | Appliances | Smart Dishwasher (NG WH)_ET | MF | N/A | NC | 135.1 | 15% | 20.0 | 0.057 | 11.0 | $395.00 | $200.00 | 0.07 | Smart ES Qualified Dishwasher (v3.0) |
| 1087 | Appliances | ENERGY STAR Dehumidifier | MF | N/A | NC | 904.6 | 27% | 246.7 | 0.151 | 12.0 | $75.00 | $40.00 | 4.19 | ES Qualified Dehumidifer (L/kWh = 2.2) |
| 1088 | Appliances | ENERGY STAR Freezer | MF | N/A | NC | 349.5 | 10% | 35.1 | 0.006 | 22.0 | $35.00 | $20.00 | 1.64 | ES Qualified Freezer (10% more Efficient than NAECA) |
| 1089 | Appliances | ENERGY STAR Clothes Dryer (Electric) | MF | N/A | NC | 768.9 | 21% | 160.4 | 0.567 | 16.0 | $152.00 | $75.00 | 1.52 | ES Qualified Dryer (CEF=3.93) |
| 1090 | Appliances | ENERGY STAR Clothes Dryer (NG) | MF | N/A | NC | 123.0 | 21% | 25.7 | 0.091 | 16.0 | $152.00 | $75.00 | 0.57 | ES Qualified Dryer (CEF=3.93) |
| 1091 | Appliances | Smart Clothes Dryer (Electric)_ET | MF | N/A | NC | 768.9 | 26% | 202.7 | 0.716 | 16.0 | $236.00 | $120.00 | 1.20 | Smart ES Qualified Dryer (5.5% additional energy savings) |
| 1092 | Appliances | Smart Clothes Dryer (NG)_ET | MF | N/A | NC | 123.0 | 26% | 32.4 | 0.115 | 16.0 | $236.00 | $120.00 | 0.45 | Smart ES Qualified Dryer (5.5% additional energy savings) |
| 1093 | Appliances | Heat Pump Dryer | MF | N/A | NC | 768.9 | 73% | 558.0 | 1.972 | 12.0 | $412.00 | $205.00 | 1.57 | Heat Pump Dryer (CEF=10.4) |
| 1094 | Appliances | ENERGY STAR Water Cooler | MF | N/A | NC | 105.9 | 46% | 48.6 | 0.006 | 10.0 | $17.00 | $10.00 | 2.22 | ES Water Cooler (Cold Water Only) |
| 2001 | Audit | Audit Recommendations (elec) - Single-family | SF | NLI | Retrofit | 19,402.4 | 0% | 32.0 | 0.006 | 1.0 | $80.00 | $80.00 | 0.02 | Walk through audit and recommendations for behavioral and installation measures |
| 2002 | Audit | Audit Recommendations (elec) - Single-family | SF | LI | DI | 19,402.4 | 0% | 32.0 | 0.006 | 1.0 | $80.00 | $80.00 | 0.02 | Walk through audit and recommendations for behavioral and installation measures |
| 2003 | Audit | Audit Recommendations (elec) - Multifamily | MF | NLI | Retrofit | 12,314.1 | 0% | 32.0 | 0.005 | 1.0 | $80.00 | $80.00 | 0.02 | Walk through audit and recommendations for behavioral and installation measures |
| 2004 | Audit | Audit Recommendations (elec) - Multifamily | MF | LI | DI | 12,314.1 | 0% | 32.0 | 0.005 | 1.0 | $80.00 | $80.00 | 0.02 | Walk through audit and recommendations for behavioral and installation measures |
| 2005 | Audit | Audit Recommendations (elec) - Mobile | *Mobile* | NLI | Retrofit | 19,402.4 | 0% | 32.0 | 0.006 | 1.0 | $80.00 | $80.00 | 0.02 | Walk through audit and recommendations for behavioral and installation measures |
| 2006 | Audit | Audit Recommendations (elec) - Mobile | *Mobile* | LI | DI | 19,402.4 | 0% | 32.0 | 0.006 | 1.0 | $80.00 | $80.00 | 0.02 | Walk through audit and recommendations for behavioral and installation measures |
| 2007 | Audit | Audit Recommendations (gas) - Single-family | SF | NLI | Retrofit | 9,318.6 | 0% | 32.0 | 0.007 | 1.0 | $80.00 | $80.00 | 0.07 | Walk through audit and recommendations for behavioral and installation measures |
| 2008 | Audit | Audit Recommendations (gas) - Single-family | SF | LI | DI | 9,318.6 | 0% | 32.0 | 0.007 | 1.0 | $80.00 | $80.00 | 0.07 | Walk through audit and recommendations for behavioral and installation measures |
| 2009 | Audit | Audit Recommendations (gas) - Multifamily | MF | NLI | Retrofit | 6,821.7 | 0% | 32.0 | 0.005 | 1.0 | $80.00 | $80.00 | 0.07 | Walk through audit and recommendations for behavioral and installation measures |
| 2010 | Audit | Audit Recommendations (gas) - Multifamily | MF | LI | DI | 6,821.7 | 0% | 32.0 | 0.005 | 1.0 | $80.00 | $80.00 | 0.07 | Walk through audit and recommendations for behavioral and installation measures |
| 2011 | Audit | Audit Recommendations (gas) - Mobile | Mobile | NLI | Retrofit | 9,318.6 | 0% | 32.0 | 0.007 | 1.0 | $80.00 | $80.00 | 0.07 | Walk through audit and recommendations for behavioral and installation measures |
| 2012 | Audit | Audit Recommendations (gas) - Mobile | Mobile | LI | DI | 9,318.6 | 0% | 32.0 | 0.007 | 1.0 | $80.00 | $80.00 | 0.07 | Walk through audit and recommendations for behavioral and installation measures |
| 3001 | Behavioral | Home Energy Reports (Heat pump) | SF | N/A | Opt-Out | 16,590.8 | 2% | 265.5 | 0.049 | 1.0 | $7.85 | $7.90 | 1.68 | Pre-pay billing |

**Vectren Electric** **Residential Measure Assumptions**

| Measure # | End-Use | Measure Name | Home Type | Income Type | Replacement Type | Base Annual Electric | % Elec Savings | Per Unit Elec Savings | Per Unit Summer NCP kW | Useful Life | Initial Measure Cost | Historical Incentive Amount | UCT Ratio | Measure Description |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 3002 | Behavioral | Home Energy Reports (Electric furnace/CAC) | SF | N/A | Opt-Out | 21,954.3 | 2% | 351.3 | 0.051 | 1.0 | $7.85 | $7.90 | 2.13 | Distribution of home energy reports encouraging adoption of energy-savings improvements |
| 3003 | Behavioral | Pre-pay (Heat pump) | SF | N/A | Opt-In | 16,590.8 | 11% | 1,825.0 | 0.334 | 3.0 | $40.00 | $0.00 | 3E+08 | Pre-pay billing |
| 3004 | Behavioral | Pre-pay (Electric furnace/CAC) | SF | N/A | Opt-In | 21,954.3 | 11% | 2,415.0 | 0.353 | 3.0 | $40.00 | $0.00 | 3.E+08 | Pre-pay billing |
| 3005 | Behavioral | Home Energy Management System (Heat pump) | SF | N/A | Retrofit | 16,590.8 | 3% | 532.6 | 0.097 | 5.0 | $90.00 | $45.00 | 2.66 | HEMS are hardware and software systems that can control and monitor one or more energy uses in the home |
| 3006 | Behavioral | Home Energy Management System (Electric furnace/CAC) | SF | N/A | Retrofit | 21,954.3 | 3% | 704.7 | 0.103 | 5.0 | $90.00 | $45.00 | 3.38 | HEMS are hardware and software systems that can control and monitor one or more energy uses in the home |
| 3007 | Behavioral | Home Energy Reports (Heat pump) | SF | N/A | NC | 15,337.8 | 2% | 245.4 | 0.036 | 1.0 | $7.85 | $7.90 | 1.55 | Pre-pay billing |
| 3008 | Behavioral | Pre-pay (Heat pump) | SF | N/A | NC | 15,337.8 | 11% | 1,687.2 | 0.245 | 3.0 | $40.00 | $0.00 | 2.E+08 | Pre-pay billing |
| 3009 | Behavioral | Home Energy Management System (Heat pump) | SF | N/A | NC | 15,337.8 | 3% | 365.0 | 0.044 | 5.0 | $90.00 | $45.00 | 1.75 | HEMS are hardware and software systems that can control and monitor one or more energy uses in the home |
| 3010 | Behavioral | Home Energy Reports (Heat pump) | MF | N/A | Opt-Out | 11,369.4 | 2% | 181.9 | 0.022 | 1.0 | $7.85 | $7.90 | 1.10 | Pre-pay billing |
| 3011 | Behavioral | Home Energy Reports (Electric furnace/CAC) | MF | N/A | Opt-Out | 13,171.6 | 2% | 210.7 | 0.025 | 1.0 | $7.85 | $7.90 | 1.27 | Distribution of home energy reports encouraging adoption of energy-savings improvements |
| 3012 | Behavioral | Pre-pay (Heat pump) | MF | N/A | Opt-In | 11,369.4 | 11% | 1,250.6 | 0.150 | 3.0 | $40.00 | $0.00 | 2.E+08 | Pre-pay billing |
| 3013 | Behavioral | Pre-pay (Electric furnace/CAC) | MF | N/A | Opt-In | 13,171.6 | 11% | 1,448.9 | 0.169 | 3.0 | $40.00 | $0.00 | 2E+08 | Pre-pay billing |
| 3014 | Behavioral | Home Energy Management System (Heat pump) | MF | N/A | Retrofit | 11,369.4 | 3% | 422.8 | 0.049 | 5.0 | $90.00 | $45.00 | 1.97 | HEMS are hardware and software systems that can control and monitor one or more energy uses in the home |
| 3015 | Behavioral | Home Energy Management System (Electric furnace/CAC) | MF | N/A | Retrofit | 13,171.6 | 3% | 492.3 | 0.071 | 5.0 | $90.00 | $45.00 | 2.39 | HEMS are hardware and software systems that can control and monitor one or more energy uses in the home |
| 3016 | Behavioral | Home Energy Reports (Heat pump) | MF | N/A | NC | 10,959.2 | 2% | 175.3 | 0.021 | 1.0 | $7.85 | $7.90 | 1.05 | Pre-pay billing |
| 3017 | Behavioral | Pre-pay (Heat pump) | MF | N/A | NC | 10,959.2 | 11% | 1,205.5 | 0.146 | 3.0 | $40.00 | $0.00 | 2E+08 | Pre-pay billing |
| 3018 | Behavioral | Home Energy Management System (Heat pump) | MF | N/A | NC | 10,959.2 | 3% | 351.8 | 0.043 | 5.0 | $90.00 | $45.00 | 1.67 | HEMS are hardware and software systems that can control and monitor one or more energy uses in the home |
| 3019 | Behavioral | Home Energy Reports (Gas furnace/CAC) | SF | N/A | Opt-Out | 9,318.6 | 1% | 121.1 | 0.045 | 1.0 | $7.85 | $7.90 | 1.48 | Distribution of home energy reports encouraging adoption of energy-savings improvements |
| 3020 | Behavioral | Pre-pay (Gas furnace/CAC) | SF | N/A | Opt-In | 9,318.6 | 11% | 1,025.0 | 0.377 | 3.0 | $40.00 | $0.00 | 3.E+08 | Pre-pay billing |
| 3021 | Behavioral | Home Energy Management System (Gas furnace/CAC) | SF | N/A | Retrofit | 9,318.6 | 3% | 299.1 | 0.110 | 5.0 | $90.00 | $45.00 | 2.98 | HEMS are hardware and software systems that can control and monitor one or more energy uses in the home |
| 3022 | Behavioral | Home Energy Reports (Gas furnace/CAC) | SF | N/A | NC | 8,582.1 | 1% | 111.6 | 0.032 | 1.0 | $7.85 | $7.90 | 1.09 | Distribution of home energy reports encouraging adoption of energy-savings improvements |
| 3023 | Behavioral | Pre-pay (Gas furnace/CAC) | SF | N/A | NC | 8,582.1 | 11% | 944.0 | 0.269 | 3.0 | $40.00 | $0.00 | 2E+08 | Pre-pay billing |
| 3024 | Behavioral | Home Energy Management System (Gas furnace/CAC) | SF | N/A | NC | 8,582.1 | 3% | 275.5 | 0.078 | 5.0 | $90.00 | $45.00 | 2.18 | HEMS are hardware and software systems that can control and monitor one or more energy uses in the home |

**Vectren Electric** **Residential Measure Assumptions**

| Measure # | End-Use | Measure Name | Home Type | Income Type | Replacement Type | Base Annual Electric | % Elec Savings | Per Unit Elec Savings | Per Unit Summer NCP kW | Useful Life | Initial Measure Cost | Historical Incentive Amount | UCT Ratio | Measure Description |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 3025 | Behavioral | Home Energy Reports (Gas furnace/CAC) | *MF* | N/A | Opt-Out | 6,821.7 | 1% | 88.7 | 0.022 | 1.0 | $7.85 | $7.90 | 0.91 | Distribution of home energy reports encouraging adoption of energy-savings improvements |
| 3026 | Behavioral | Pre-pay (Gas furnace/CAC) | *MF* | N/A | Opt-In | 6,821.7 | 11% | 750.4 | 0.183 | 3.0 | $40.00 | $0.00 | 2.E+08 | Pre-pay billing |
| 3027 | Behavioral | Home Energy Management System (Gas furnace/CAC) | *MF* | N/A | Retrofit | 6,821.7 | 3% | 219.0 | 0.053 | 5.0 | $90.00 | $45.00 | 1.82 | HEMS are hardware and software systems that can control and monitor one or more energy uses in the home |
| 3028 | Behavioral | Home Energy Reports (Gas furnace/CAC) | *MF* | N/A | NC | 10,165.2 | 1% | 132.1 | 0.021 | 1.0 | $7.85 | $7.90 | 0.96 | Distribution of home energy reports encouraging adoption of energy-savings improvements |
| 3029 | Behavioral | Pre-pay (Gas furnace/CAC) | *MF* | N/A | NC | 10,165.2 | 11% | 1,118.2 | 0.180 | 5.0 | $40.00 | $0.00 | 3E+08 | Pre-pay billing |
| 3030 | Behavioral | Home Energy Management System (Gas furnace/CAC) | *MF* | N/A | NC | 10,165.2 | 3% | 326.3 | 0.053 | 5.0 | $90.00 | $45.00 | 1.90 | HEMS are hardware and software systems that can control and monitor one or more energy uses in the home |
| 4001 | HVAC Equipment | ASHP Tune Up | *SF* | NLI | Retrofit | 6,321.2 | 5% | 316.1 | 0.152 | 5.0 | $64.00 | $64.00 | 1.53 | Air source heat pump tune up |
| 4002 | HVAC Equipment | Air Source Heat Pump 16 SEER - Heat pump baseline | *SF* | NLI | MO | 6,321.2 | 9% | 566.2 | 0.612 | 18.0 | $870.00 | $300.00 | 2.47 | 16 SEER 9.0 hspf air source heat pump |
| 4003 | HVAC Equipment | Air Source Heat Pump 16 SEER - Furnace baseline | *SF* | NLI | MO | 11,684.8 | 51% | 5,929.7 | 0.922 | 18.0 | $2,121.00 | $300.00 | 13.12 | 16 SEER 9.0 hspf air source heat pump |
| 4004 | HVAC Equipment | AC Tune Up | *SF* | NLI | Retrofit | 2,713.0 | 5% | 135.6 | 0.161 | 5.0 | $64.00 | $64.00 | 1.11 | Central air conditioner tune-up |
| 4005 | HVAC Equipment | Central Air Conditioner 16 SEER | *SF* | NLI | MO | 2,713.0 | 18% | 483.4 | 0.508 | 18.0 | $400.00 | $200.00 | 3.41 | 16 SEER central air conditioner |
| 4006 | HVAC Equipment | Smart Thermostat - Heat pump baseline | *SF* | NLI | Retrofit | 6,321.2 | 10% | 658.6 | 0.000 | 15.0 | $154.00 | $60.00 | 5.26 | Smart thermostat |
| 4007 | HVAC Equipment | WIFI Thermostat - Heat pump baseline | SF | NLI | Retrofit | 6,321.2 | 6% | 377.8 | 0.000 | 15.0 | $103.20 | $50.00 | 3.62 | WifI (non-smart) thermostat |
| 4008 | HVAC Equipment | Smart Thermostat - Furnace baseline | SF | NLI | Retrofit | 11,684.8 | 11% | 1,239.0 | 0.000 | 15.0 | $154.00 | $60.00 | 9.89 | Smart thermostat |
| 4009 | HVAC Equipment | WIFI Thermostat - Furnace baseline | SF | NLI | Retrofit | 11,684.8 | 5% | 568.0 | 0.000 | 15.0 | $103.20 | $50.00 | 5.44 | WifI (non-smart) thermostat |
| 4010 | HVAC Equipment | Filter Whistle | SF | NLI | Retrofit | 9,132.9 | 4% | 319.7 | 0.109 | 15.0 | $1.64 | $1.64 | 139.02 | Whistle to remind owners to change air filter |
| 4011 | HVAC Equipment | ASHP Tune Up | SF | LI | DI | 6,321.2 | 5% | 316.1 | 0.152 | 5.0 | $64.00 | $64.00 | 1.53 | Air source heat pump tune up |
| 4012 | HVAC Equipment | Air Source Heat Pump 16 SEER - Heat pump baseline | SF | LI | DI | 6,321.2 | 9% | 566.2 | 0.612 | 18.0 | $5,400.00 | $5,400.00 | 0.14 | 16 SEER 9.0 hspf air source heat pump |
| 4013 | HVAC Equipment | Air Source Heat Pump 16 SEER - Furnace baseline | SF | LI | DI | 11,684.8 | 51% | 5,929.7 | 0.922 | 18.0 | $5,400.00 | $5,400.00 | 0.73 | 16 SEER 9.0 hspf air source heat pump |
| 4014 | HVAC Equipment | AC Tune Up | SF | LI | DI | 2,713.0 | 5% | 135.6 | 0.161 | 5.0 | $64.00 | $64.00 | 1.11 | Central air conditioner tune-up |
| 4015 | HVAC Equipment | Central Air Conditioner 16 SEER | SF | LI | DI | 2,713.0 | 18% | 483.4 | 0.508 | 18.0 | $3,500.00 | $3,500.00 | 0.20 | 16 SEER central air conditioner |
| 4016 | HVAC Equipment | Smart Thermostat - Heat pump baseline | SF | LI | DI | 6,321.2 | 10% | 658.6 | 0.000 | 15.0 | $154.00 | $154.00 | 2.05 | Smart thermostat |
| 4017 | HVAC Equipment | WIFI Thermostat - Heat pump baseline | SF | LI | DI | 6,321.2 | 6% | 377.8 | 0.000 | 15.0 | $103.20 | $103.20 | 1.75 | WifI (non-smart) thermostat |
| 4018 | HVAC Equipment | Smart Thermostat - Furnace baseline | SF | LI | DI | 11,684.8 | 11% | 1,239.0 | 0.000 | 15.0 | $154.00 | $154.00 | 3.85 | Smart thermostat |
| 4019 | HVAC Equipment | WIFI Thermostat - Furnace baseline | SF | LI | DI | 11,684.8 | 5% | 568.0 | 0.000 | 15.0 | $103.20 | $103.20 | 2.64 | WifI (non-smart) thermostat |
| 4020 | HVAC Equipment | Filter Whistle | SF | LI | DI | 9,132.9 | 4% | 319.7 | 0.109 | 15.0 | $1.64 | $1.64 | 139.02 | Whistle to remind owners to change air filter |

## Vectren Electric — Residential Measure Assumptions

| Measure # | End-Use | Measure Name | Home Type | Income Type | Replacement Type | Base Annual Electric | % Elec Savings | Per Unit Elec Savings | Per Unit Summer NCP kW | Useful Life | Initial Measure Cost | Historical Incentive Amount | UCT Ratio | Measure Description |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 4021 | HVAC Equipment | Air Source Heat Pump 18 SEER - Heat pump baseline | SF | NLI | MO | 6,321.2 | 17% | 1,058.6 | 0.770 | 18.0 | $1,156.00 | $500.00 | 2.33 | 18 SEER air source heat pump |
| 4022 | HVAC Equipment | Ductless Heat Pump 17 SEER 9.5 HSPF - Heat pump baseline | SF | NLI | MO | 6,321.2 | 6% | 349.5 | 2.740 | 18.0 | $1,666.67 | $500.00 | 4.51 | 17 SEER / 9.5 hspf ductless heat pump |
| 4023 | HVAC Equipment | Ductless Heat Pump 19 SEER 9.5 HSPF - Heat pump baseline | SF | NLI | MO | 6,321.2 | 7% | 427.5 | 2.650 | 18.0 | $2,333.33 | $500.00 | 4.46 | 19 SEER / 9.5 hspf ductless heat pump |
| 4024 | HVAC Equipment | Ductless Heat Pump 21 SEER 10.0 HSPF - Heat pump baseline | SF | NLI | MO | 6,321.2 | 8% | 523.0 | 2.589 | 18.0 | $2,833.33 | $500.00 | 4.47 | 21 SEER / 10.0 hspf ductless heat pump |
| 4025 | HVAC Equipment | Ductless Heat Pump 23 SEER 10.0 HSPF - Heat pump baseline | SF | NLI | MO | 6,321.2 | 9% | 575.2 | 2.542 | 18.0 | $3,333.33 | $500.00 | 4.46 | 23 SEER / 10.0 hspf ductless heat pump |
| 4026 | HVAC Equipment | Dual Fuel Air Source Heat Pump 16 SEER - Heat pump baseline | SF | NLI | MO | 6,321.2 | 45% | 2,871.9 | 0.612 | 18.0 | $1,000.00 | $300.00 | 2.24 | 16 SEER Dual-fuel heat pump |
| 4027 | HVAC Equipment | Dual Fuel Air Source Heat Pump 18 SEER - Heat pump baseline | SF | NLI | MO | 6,321.2 | 50% | 3,171.0 | 0.770 | 18.0 | $1,286.00 | $500.00 | 1.97 | 18 SEER Dual-fuel heat pump |
| 4028 | HVAC Equipment | Ground Source Heat Pump - Heat pump baseline | SF | NLI | MO | 6,321.2 | 8% | 491.2 | -0.213 | 18.0 | $3,609.00 | $1,000.00 | 0.12 | Geothermal heat pump |
| 4029 | HVAC Equipment | Air Source Heat Pump 18 SEER - Furnace baseline | SF | NLI | MO | 11,684.8 | 55% | 6,422.1 | 1.059 | 18.0 | $2,407.00 | $500.00 | 8.71 | 18 SEER air source heat pump |
| 4030 | HVAC Equipment | Ductless Heat Pump 17 SEER 9.5 HSPF - Furnace baseline | SF | NLI | MO | 11,684.8 | 26% | 2,988.6 | 2.915 | 18.0 | $1,666.67 | $500.00 | 7.85 | 17 SEER / 9.5 hspf ductless heat pump |
| 4031 | HVAC Equipment | Ductless Heat Pump 19 SEER 9.5 HSPF - Furnace baseline | SF | NLI | MO | 11,684.8 | 26% | 3,066.6 | 2.825 | 18.0 | $2,333.33 | $500.00 | 7.80 | 19 SEER / 9.5 hspf ductless heat pump |
| 4032 | HVAC Equipment | Ductless Heat Pump 21 SEER 10.0 HSPF - Furnace baseline | SF | NLI | MO | 11,684.8 | 27% | 3,207.2 | 2.765 | 18.0 | $2,833.33 | $500.00 | 7.86 | 21 SEER / 10.0 hspf ductless heat pump |
| 4033 | HVAC Equipment | Ductless Heat Pump 23 SEER 10.0 HSPF - Furnace baseline | SF | NLI | MO | 11,684.8 | 28% | 3,259.3 | 2.718 | 18.0 | $3,333.33 | $500.00 | 7.85 | 23 SEER / 10.0 hspf ductless heat pump |
| 4034 | HVAC Equipment | Dual Fuel Air Source Heat Pump 16 SEER - Furnace baseline | SF | NLI | MO | 11,684.8 | 70% | 8,235.5 | 0.922 | 18.0 | $2,848.00 | $300.00 | 12.88 | 16 SEER Dual-fuel heat pump |
| 4035 | HVAC Equipment | Dual Fuel Air Source Heat Pump 18 SEER - Furnace baseline | SF | NLI | MO | 11,684.8 | 73% | 8,534.6 | 1.059 | 18.0 | $3,134.00 | $500.00 | 8.36 | 18 SEER Dual-fuel heat pump |
| 4036 | HVAC Equipment | Ground Source Heat Pump - Furnace baseline | SF | NLI | MO | 11,684.8 | 50% | 5,854.7 | 0.082 | 18.0 | $3,609.00 | $1,000.00 | 3.31 | Geothermal heat pump |
| 4037 | HVAC Equipment | Central Air Conditioner 18 SEER | SF | NLI | MO | 2,713.0 | 30% | 823.3 | 0.950 | 18.0 | $800.00 | $400.00 | 2.97 | 18 SEER central air conditioner |
| 4038 | HVAC Equipment | ECM HVAC Motor | SF | NLI | Retrofit | 9,132.9 | 5% | 412.0 | 0.000 | 10.0 | $97.00 | $50.00 | 2.73 | Electrically commutated motor |
| 4039 | HVAC Equipment | ENERGY STAR Room Air Conditioner | SF | N/A | MO | 489.9 | 10% | 49.0 | 0.110 | 9.0 | $40.00 | $10.00 | 4.83 | ENERGY STAR Room Air Conditioner in place of standard efficiency alternative |
| 4040 | HVAC Equipment | Smart Room AC_ET | SF | N/A | MO | 489.9 | 3% | 14.7 | 0.033 | 9.0 | $205.00 | $60.00 | 0.24 | Window-mounted AC unit with smart capability |
| 4041 | HVAC Equipment | Smart Room AC - controls retrofit_ET | SF | N/A | Retrofit | 489.9 | 3% | 14.7 | 0.033 | 9.0 | $110.00 | $30.00 | 0.48 | Smart control retrofit kit |
| 4042 | HVAC Equipment | Room Air Conditioner Recycling | SF | N/A | Recycle | 656.3 | 100% | 656.3 | 1.475 | 3.0 | $129.00 | $40.00 | 6.17 | Recycling of tertiary room air conditioner |
| 4043 | HVAC Equipment | Programmable Thermostat - Heat pump baseline | SF | N/A | Retrofit | 6,321.2 | 4% | 229.0 | 0.000 | 15.0 | $35.00 | $10.00 | 10.97 | Programmable thermostat |
| 4044 | HVAC Equipment | Programmable Thermostat - Furnace baseline | SF | N/A | Retrofit | 11,684.8 | 3% | 354.6 | 0.000 | 15.0 | $35.00 | $10.00 | 16.99 | Programmable thermostat |

## Vectren Electric — Residential Measure Assumptions

| Measure # | End-Use | Measure Name | Home Type | Income Type | Replacement Type | Base Annual Electric | % Elec Savings | Per Unit Elec Savings | Per Unit Summer NCP kW | Useful Life | Initial Measure Cost | Historical Incentive Amount | UCT Ratio | Measure Description |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 4045 | HVAC Equipment | Smart Vents/Sensors_ET | SF | N/A | Retrofit | 9,132.9 | 10% | 913.3 | 0.313 | 15.0 | $800.00 | $400.00 | 1.63 | Smart vents relay temperature and occupancy information to a smart thermostat (or other control device) to reduce energy waste in unoccupied areas of the home |
| 4046 | HVAC Equipment | Smart Ceiling Fan_ET | SF | N/A | Retrofit | 2,643.1 | 8% | 198.2 | 0.235 | 20.0 | $2,400.00 | $1,000.00 | 0.31 | Smart ceiling fans save energy by turning off when rooms are unoccupied and by helping the home's central HVAC maintain indoor comfort |
| 4047 | HVAC Equipment | Whole House Attic Fan | SF | N/A | Retrofit | 2,643.1 | 13% | 338.0 | 0.000 | 20.0 | $546.60 | $275.00 | 0.74 | Whole house attic fan |
| 4048 | HVAC Equipment | Attic Fan | SF | N/A | Retrofit | 2,643.1 | 10% | 264.3 | 0.000 | 20.0 | $120.48 | $40.00 | 3.96 | Attic fans can reduce the need for AC by reducing heat transfer from the attic through the ceiling of the house |
| 4049 | HVAC Equipment | Air Source Heat Pump 16 SEER - Heat pump baseline | SF | N/A | NC | 4,984.5 | 8% | 419.9 | 0.405 | 18.0 | $870.00 | $300.00 | 1.97 | 16 SEER 9.0 hspf air source heat pump |
| 4050 | HVAC Equipment | Air Source Heat Pump 18 SEER - Heat pump baseline | SF | N/A | NC | 4,984.5 | 17% | 825.1 | 0.576 | 18.0 | $1,156.00 | $500.00 | 1.92 | 18 SEER air source heat pump |
| 4051 | HVAC Equipment | Ductless Heat Pump 17 SEER 9.5 HSPF - Heat pump baseline | SF | N/A | NC | 4,984.5 | 6% | 319.4 | 1.931 | 18.0 | $1,666.67 | $500.00 | 3.57 | 17 SEER / 9.5 hspf ductless heat pump |
| 4052 | HVAC Equipment | Ductless Heat Pump 19 SEER 9.5 HSPF - Heat pump baseline | SF | N/A | NC | 4,984.5 | 8% | 397.4 | 1.841 | 18.0 | $2,333.33 | $500.00 | 3.51 | 19 SEER / 9.5 hspf ductless heat pump |
| 4053 | HVAC Equipment | Ductless Heat Pump 21 SEER 10.0 HSPF - Heat pump baseline | SF | N/A | NC | 4,984.5 | 10% | 485.0 | 1.780 | 18.0 | $2,833.33 | $500.00 | 3.51 | 21 SEER / 10.0 hspf ductless heat pump |
| 4054 | HVAC Equipment | Ductless Heat Pump 23 SEER 10.0 HSPF - Heat pump baseline | SF | N/A | NC | 4,984.5 | 11% | 537.1 | 1.733 | 18.0 | $3,333.33 | $500.00 | 3.48 | 23 SEER / 10.0 hspf ductless heat pump |
| 4055 | HVAC Equipment | Dual Fuel Air Source Heat Pump 16 SEER - Heat pump baseline | SF | N/A | NC | 4,984.5 | 36% | 1,797.4 | 0.405 | 18.0 | $1,000.00 | $300.00 | 2.09 | 16 SEER Dual-fuel heat pump |
| 4056 | HVAC Equipment | Dual Fuel Air Source Heat Pump 18 SEER - Heat pump baseline | SF | N/A | NC | 4,984.5 | 42% | 2,083.8 | 0.576 | 18.0 | $1,286.00 | $500.00 | 1.86 | 18 SEER Dual-fuel heat pump |
| 4057 | HVAC Equipment | Ground Source Heat Pump - Heat pump baseline | SF | N/A | NC | 4,984.5 | 7% | 368.9 | -0.084 | 18.0 | $3,609.00 | $1,000.00 | 0.14 | Geothermal heat pump |
| 4058 | HVAC Equipment | Central Air Conditioner 16 SEER | SF | N/A | NC | 2,364.4 | 18% | 432.6 | 0.429 | 18.0 | $400.00 | $200.00 | 3.06 | 16 SEER central air conditioner |
| 4059 | HVAC Equipment | Central Air Conditioner 18 SEER | SF | N/A | NC | 2,364.4 | 30% | 711.3 | 0.716 | 18.0 | $800.00 | $400.00 | 2.57 | 18 SEER central air conditioner |
| 4060 | HVAC Equipment | ENERGY STAR Room Air Conditioner | SF | N/A | NC | 489.9 | 10% | 49.0 | 0.110 | 9.0 | $40.00 | $10.00 | 4.83 | ENERGY STAR Room Air Conditioner in place of standard efficiency alternative |
| 4061 | HVAC Equipment | Smart Room AC_ET | SF | N/A | NC | 489.9 | 3% | 14.7 | 0.033 | 9.0 | $205.00 | $60.00 | 0.24 | Window-mounted AC unit with smart capability |
| 4062 | HVAC Equipment | Programmable Thermostat - Heat pump baseline | SF | N/A | NC | 4,984.5 | 4% | 185.1 | 0.000 | 15.0 | $35.00 | $10.00 | 8.87 | Programmable thermostat |
| 4063 | HVAC Equipment | Smart Thermostat - Heat pump baseline | SF | N/A | NC | 4,984.5 | 10% | 517.9 | 0.000 | 15.0 | $154.00 | $60.00 | 4.14 | Smart thermostat |
| 4064 | HVAC Equipment | WIFI Thermostat - Heat pump baseline | SF | N/A | NC | 4,984.5 | 6% | 306.6 | 0.000 | 15.0 | $103.20 | $50.00 | 2.94 | WifI (non-smart) thermostat |
| 4065 | HVAC Equipment | Filter Whistle | SF | N/A | NC | 4,984.5 | 4% | 174.5 | 0.078 | 15.0 | $1.64 | $1.64 | 86.34 | Whistle to remind owners to change air filter |

**Vectren Electric** **Residential Measure Assumptions**

| Measure # | End-Use | Measure Name | Home Type | Income Type | Replacement Type | Base Annual Electric | % Elec Savings | Per Unit Elec Savings | Per Unit Summer NCP kW | Useful Life | Initial Measure Cost | Historical Incentive Amount | UCT Ratio | Measure Description |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 4066 | HVAC Equipment | Smart Vents/Sensors_ET | SF | N/A | NC | 4,984.5 | 10% | 498.4 | 0.223 | 15.0 | $800.00 | $400.00 | 1.01 | Smart vents relay temperature and occupancy information to a smart thermostat (or other control device) to reduce energy waste in unoccupied areas of the home |
| 4067 | HVAC Equipment | ASHP Tune Up | MF | NLI | Retrofit | 3,171.0 | 5% | 158.5 | 0.068 | 5.0 | $64.00 | $64.00 | 0.82 | Air source heat pump tune up |
| 4068 | HVAC Equipment | Air Source Heat Pump 16 SEER - Heat pump baseline | MF | NLI | MO | 3,171.0 | 7% | 217.1 | 0.182 | 18.0 | $870.00 | $300.00 | 0.90 | 16 SEER 9.0 hspf air source heat pump |
| 4069 | HVAC Equipment | Air Source Heat Pump 16 SEER - Furnace baseline | MF | NLI | MO | 4,973.1 | 41% | 2,019.3 | 0.391 | 18.0 | $2,121.00 | $300.00 | 4.80 | 16 SEER 9.0 hspf air source heat pump |
| 4070 | HVAC Equipment | AC Tune Up | MF | NLI | Retrofit | 2,017.5 | 5% | 100.9 | 0.077 | 5.0 | $64.00 | $64.00 | 0.71 | Central air conditioner tune-up |
| 4071 | HVAC Equipment | Central Air Conditioner 16 SEER | MF | NLI | MO | 2,017.5 | 19% | 382.4 | 0.259 | 18.0 | $400.00 | $200.00 | 2.30 | 16 SEER central air conditioner |
| 4072 | HVAC Equipment | Smart Thermostat - Heat pump baseline | MF | NLI | Retrofit | 3,171.0 | 10% | 324.3 | 0.000 | 15.0 | $154.00 | $60.00 | 2.59 | Smart thermostat |
| 4073 | HVAC Equipment | WIFI Thermostat - Heat pump baseline | MF | NLI | Retrofit | 3,171.0 | 7% | 226.4 | 0.000 | 15.0 | $103.20 | $50.00 | 2.17 | WifI (non-smart) thermostat |
| 4074 | HVAC Equipment | Smart Thermostat - Furnace baseline | MF | NLI | Retrofit | 4,973.1 | 10% | 518.2 | 0.000 | 15.0 | $154.00 | $60.00 | 4.14 | Smart thermostat |
| 4075 | HVAC Equipment | WIFI Thermostat - Furnace baseline | MF | NLI | Retrofit | 4,973.1 | 6% | 297.1 | 0.000 | 15.0 | $103.20 | $50.00 | 2.85 | WifI (non-smart) thermostat |
| 4076 | HVAC Equipment | Filter Whistle | MF | NLI | Retrofit | 4,115.7 | 4% | 144.0 | 0.051 | 15.0 | $1.64 | $1.64 | 68.64 | Whistle to remind owners to change air filter |
| 4077 | HVAC Equipment | ASHP Tune Up | MF | LI | DI | 3,171.0 | 5% | 158.5 | 0.068 | 5.0 | $64.00 | $64.00 | 0.82 | Air source heat pump tune up |
| 4078 | HVAC Equipment | Air Source Heat Pump 16 SEER - Heat pump baseline | MF | LI | DI | 3,171.0 | 7% | 217.1 | 0.182 | 18.0 | $5,400.00 | $5,400.00 | 0.05 | 16 SEER 9.0 hspf air source heat pump |
| 4079 | HVAC Equipment | Air Source Heat Pump 16 SEER - Furnace baseline | MF | LI | DI | 4,973.1 | 41% | 2,019.3 | 0.391 | 18.0 | $5,400.00 | $5,400.00 | 0.27 | 16 SEER 9.0 hspf air source heat pump |
| 4080 | HVAC Equipment | AC Tune Up | MF | LI | DI | 2,017.5 | 5% | 100.9 | 0.077 | 5.0 | $64.00 | $64.00 | 0.71 | Central air conditioner tune-up |
| 4081 | HVAC Equipment | Central Air Conditioner 16 SEER | MF | LI | DI | 2,017.5 | 19% | 382.4 | 0.259 | 18.0 | $3,500.00 | $3,500.00 | 0.13 | 16 SEER central air conditioner |
| 4082 | HVAC Equipment | Smart Thermostat - Heat pump baseline | MF | LI | DI | 3,171.0 | 10% | 324.3 | 0.000 | 15.0 | $154.00 | $154.00 | 1.01 | Smart thermostat |
| 4083 | HVAC Equipment | WIFI Thermostat - Heat pump baseline | MF | LI | DI | 3,171.0 | 7% | 226.4 | 0.000 | 15.0 | $103.20 | $103.20 | 1.05 | WifI (non-smart) thermostat |
| 4084 | HVAC Equipment | Smart Thermostat - Furnace baseline | MF | LI | DI | 4,973.1 | 10% | 518.2 | 0.000 | 15.0 | $154.00 | $154.00 | 1.61 | Smart thermostat |
| 4085 | HVAC Equipment | WIFI Thermostat - Furnace baseline | MF | LI | DI | 4,973.1 | 6% | 297.1 | 0.000 | 15.0 | $103.20 | $103.20 | 1.38 | WifI (non-smart) thermostat |
| 4086 | HVAC Equipment | Filter Whistle | MF | LI | DI | 4,115.7 | 4% | 144.0 | 0.051 | 15.0 | $1.64 | $1.64 | 68.64 | Whistle to remind owners to change air filter |
| 4087 | HVAC Equipment | Air Source Heat Pump 18 SEER - Heat pump baseline | MF | NLI | MO | 3,171.0 | 16% | 500.3 | 0.330 | 18.0 | $1,156.00 | $500.00 | 1.10 | 18 SEER air source heat pump |
| 4088 | HVAC Equipment | Ductless Heat Pump 17 SEER 9.5 HSPF - Heat pump baseline | MF | NLI | MO | 3,171.0 | 9% | 270.4 | 1.065 | 18.0 | $1,666.67 | $500.00 | 2.34 | 17 SEER / 9.5 hspf ductless heat pump |
| 4089 | HVAC Equipment | Ductless Heat Pump 19 SEER 9.5 HSPF - Heat pump baseline | MF | NLI | MO | 3,171.0 | 11% | 348.4 | 0.975 | 18.0 | $2,333.33 | $500.00 | 2.25 | 19 SEER / 9.5 hspf ductless heat pump |
| 4090 | HVAC Equipment | Ductless Heat Pump 21 SEER 10.0 HSPF - Heat pump baseline | MF | NLI | MO | 3,171.0 | 13% | 422.8 | 0.914 | 18.0 | $2,833.33 | $500.00 | 2.22 | 21 SEER / 10.0 hspf ductless heat pump |

**Vectren Electric** **Residential Measure Assumptions**

| Measure # | End-Use | Measure Name | Home Type | Income Type | Replacement Type | Base Annual Electric | % Elec Savings | Per Unit Elec Savings | Per Unit Summer NCP kW | Useful Life | Initial Measure Cost | Historical Incentive Amount | UCT Ratio | Measure Description |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 4091 | HVAC Equipment | Ductless Heat Pump 23 SEER 10.0 HSPF - Heat pump baseline | MF | NLI | MO | 3,171.0 | 15% | 475.0 | 0.867 | 18.0 | $3,333.33 | $500.00 | 2.19 | 23 SEER / 10.0 hspf ductless heat pump |
| 4092 | HVAC Equipment | Dual Fuel Air Source Heat Pump 16 SEER - Heat pump baseline | MF | NLI | MO | 3,171.0 | 29% | 918.5 | 0.182 | 18.0 | $1,000.00 | $300.00 | 0.82 | 16 SEER Dual-fuel heat pump |
| 4093 | HVAC Equipment | Dual Fuel Air Source Heat Pump 18 SEER - Heat pump baseline | MF | NLI | MO | 3,171.0 | 36% | 1,141.1 | 0.330 | 18.0 | $1,286.00 | $500.00 | 0.99 | 18 SEER Dual-fuel heat pump |
| 4094 | HVAC Equipment | Air Source Heat Pump 18 SEER - Furnace baseline | MF | NLI | MO | 4,973.1 | 46% | 2,302.4 | 0.535 | 18.0 | $2,407.00 | $500.00 | 3.45 | 18 SEER air source heat pump |
| 4095 | HVAC Equipment | Ductless Heat Pump 17 SEER 9.5 HSPF - Furnace baseline | MF | NLI | MO | 4,973.1 | 23% | 1,137.5 | 1.242 | 18.0 | $1,666.67 | $500.00 | 3.64 | 17 SEER / 9.5 hspf ductless heat pump |
| 4096 | HVAC Equipment | Ductless Heat Pump 19 SEER 9.5 HSPF - Furnace baseline | MF | NLI | MO | 4,973.1 | 24% | 1,215.5 | 1.152 | 18.0 | $2,333.33 | $500.00 | 3.56 | 19 SEER / 9.5 hspf ductless heat pump |
| 4097 | HVAC Equipment | Ductless Heat Pump 21 SEER 10.0 HSPF - Furnace baseline | MF | NLI | MO | 4,973.1 | 26% | 1,304.1 | 1.091 | 18.0 | $2,833.33 | $500.00 | 3.54 | 21 SEER / 10.0 hspf ductless heat pump |
| 4098 | HVAC Equipment | Ductless Heat Pump 23 SEER 10.0 HSPF - Furnace baseline | MF | NLI | MO | 4,973.1 | 27% | 1,356.3 | 1.044 | 18.0 | $3,333.33 | $500.00 | 3.51 | 23 SEER / 10.0 hspf ductless heat pump |
| 4099 | HVAC Equipment | Dual Fuel Air Source Heat Pump 16 SEER - Furnace baseline | MF | NLI | MO | 4,973.1 | 55% | 2,720.7 | 0.391 | 18.0 | $2,848.00 | $300.00 | 4.72 | 16 SEER Dual-fuel heat pump |
| 4100 | HVAC Equipment | Dual Fuel Air Source Heat Pump 18 SEER - Furnace baseline | MF | NLI | MO | 4,973.1 | 59% | 2,943.3 | 0.535 | 18.0 | $3,134.00 | $500.00 | 3.33 | 18 SEER Dual-fuel heat pump |
| 4101 | HVAC Equipment | Central Air Conditioner 18 SEER | MF | NLI | MO | 2,017.5 | 31% | 631.3 | 0.470 | 18.0 | $800.00 | $400.00 | 1.91 | 18 SEER central air conditioner |
| 4102 | HVAC Equipment | ECM HVAC Motor | MF | NLI | Retrofit | 4,115.7 | 10% | 412.0 | 0.000 | 10.0 | $97.00 | $50.00 | 2.73 | Electrically commutated motor |
| 4103 | HVAC Equipment | ENERGY STAR Room Air Conditioner | MF | N/A | MO | 489.9 | 10% | 49.0 | 0.110 | 9.0 | $40.00 | $10.00 | 4.83 | ENERGY STAR Room Air Conditioner in place of standard efficiency alternative |
| 4104 | HVAC Equipment | Smart Room AC_ET | MF | N/A | MO | 489.9 | 3% | 14.7 | 0.033 | 9.0 | $205.00 | $60.00 | 0.24 | Window-mounted AC unit with smart capability |
| 4105 | HVAC Equipment | Smart Room AC - controls retrofit_ET | MF | N/A | Retrofit | 489.9 | 3% | 14.7 | 0.033 | 9.0 | $110.00 | $30.00 | 0.48 | Smart control retrofit kit |
| 4106 | HVAC Equipment | Room Air Conditioner Recycling | MF | N/A | Recycle | 656.3 | 100% | 656.3 | 1.475 | 3.0 | $129.00 | $40.00 | 6.17 | Recycling of tertiary room air conditioner |
| 4107 | HVAC Equipment | Programmable Thermostat - Heat pump baseline | MF | N/A | Retrofit | 3,171.0 | 4% | 134.3 | 0.000 | 15.0 | $35.00 | $10.00 | 6.43 | Programmable thermostat |
| 4108 | HVAC Equipment | Programmable Thermostat - Furnace baseline | MF | N/A | Retrofit | 4,973.1 | 4% | 180.1 | 0.000 | 15.0 | $35.00 | $10.00 | 8.63 | Programmable thermostat |
| 4109 | HVAC Equipment | Smart Vents/Sensors_ET | MF | N/A | Retrofit | 4,115.7 | 10% | 411.6 | 0.145 | 15.0 | $800.00 | $400.00 | 0.80 | Smart vents relay temperature and occupancy information to a smart thermostat (or other control device) to reduce energy waste in unoccupied areas of the home |
| 4110 | HVAC Equipment | Smart Ceiling Fan_ET | MF | N/A | Retrofit | 1,943.4 | 7% | 145.8 | 0.109 | 20.0 | $2,400.00 | $1,000.00 | 0.20 | Smart ceiling fans save energy by turning off when rooms are unoccupied and by helping the home's central HVAC maintain indoor comfort |
| 4111 | HVAC Equipment | Whole House Attic Fan | MF | N/A | Retrofit | 1,943.4 | 17% | 338.0 | 0.000 | 20.0 | $546.60 | $275.00 | 0.74 | Whole house attic fan |
| 4112 | HVAC Equipment | Attic Fan | MF | N/A | Retrofit | 1,943.4 | 10% | 194.3 | 0.000 | 20.0 | $120.48 | $40.00 | 2.91 | Attic fans can reduce the need for AC by reducing heat transfer from the attic through the ceiling of the house |

**Vectren Electric** **Residential Measure Assumptions**

| Measure # | End-Use | Measure Name | Home Type | Income Type | Replacement Type | Base Annual Electric | % Elec Savings | Per Unit Elec Savings | Per Unit Summer NCP kW | Useful Life | Initial Measure Cost | Historical Incentive Amount | UCT Ratio | Measure Description |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 4113 | HVAC Equipment | Air Source Heat Pump 16 SEER - Heat pump baseline | MF | N/A | NC | 2,870.1 | 6% | 185.4 | 0.185 | 18.0 | $870.00 | $300.00 | 0.81 | 16 SEER 9.0 hspf air source heat pump |
| 4114 | HVAC Equipment | Air Source Heat Pump 18 SEER - Heat pump baseline | MF | N/A | NC | 2,870.1 | 16% | 445.7 | 0.329 | 18.0 | $1,156.00 | $500.00 | 1.00 | 18 SEER air source heat pump |
| 4115 | HVAC Equipment | Ductless Heat Pump 17 SEER 9.5 HSPF - Heat pump baseline | MF | N/A | NC | 2,870.1 | 9% | 265.3 | 1.031 | 18.0 | $1,666.67 | $500.00 | 2.12 | 17 SEER / 9.5 hspf ductless heat pump |
| 4116 | HVAC Equipment | Ductless Heat Pump 19 SEER 9.5 HSPF - Heat pump baseline | MF | N/A | NC | 2,870.1 | 12% | 343.3 | 0.941 | 18.0 | $2,333.33 | $500.00 | 2.04 | 19 SEER / 9.5 hspf ductless heat pump |
| 4117 | HVAC Equipment | Ductless Heat Pump 21 SEER 10.0 HSPF - Heat pump baseline | MF | N/A | NC | 2,870.1 | 15% | 416.4 | 0.880 | 18.0 | $2,833.33 | $500.00 | 2.02 | 21 SEER / 10.0 hspf ductless heat pump |
| 4118 | HVAC Equipment | Ductless Heat Pump 23 SEER 10.0 HSPF - Heat pump baseline | MF | N/A | NC | 2,870.1 | 16% | 468.6 | 0.833 | 18.0 | $3,333.33 | $500.00 | 1.99 | 23 SEER / 10.0 hspf ductless heat pump |
| 4119 | HVAC Equipment | Dual Fuel Air Source Heat Pump 16 SEER - Heat pump baseline | MF | N/A | NC | 2,870.1 | 28% | 815.1 | 0.185 | 18.0 | $1,000.00 | $300.00 | 0.73 | 16 SEER Dual-fuel heat pump |
| 4120 | HVAC Equipment | Dual Fuel Air Source Heat Pump 18 SEER - Heat pump baseline | MF | N/A | NC | 2,870.1 | 36% | 1,020.9 | 0.329 | 18.0 | $1,286.00 | $500.00 | 0.89 | 18 SEER Dual-fuel heat pump |
| 4121 | HVAC Equipment | Central Air Conditioner 16 SEER | MF | N/A | NC | 1,897.8 | 20% | 378.3 | 0.295 | 18.0 | $400.00 | $200.00 | 2.36 | 16 SEER central air conditioner |
| 4122 | HVAC Equipment | Central Air Conditioner 18 SEER | MF | N/A | NC | 1,897.8 | 32% | 602.1 | 0.498 | 18.0 | $800.00 | $400.00 | 1.87 | 18 SEER central air conditioner |
| 4123 | HVAC Equipment | ENERGY STAR Room Air Conditioner | MF | N/A | NC | 489.9 | 10% | 49.0 | 0.110 | 9.0 | $40.00 | $10.00 | 4.83 | ENERGY STAR Room Air Conditioner in place of standard efficiency alternative |
| 4124 | HVAC Equipment | Smart Room AC_ET | MF | N/A | NC | 489.9 | 3% | 14.7 | 0.033 | 9.0 | $205.00 | $60.00 | 0.24 | Window-mounted AC unit with smart capability |
| 4125 | HVAC Equipment | Programmable Thermostat - Heat pump baseline | MF | N/A | NC | 2,870.1 | 4% | 122.7 | 0.000 | 15.0 | $35.00 | $10.00 | 5.88 | Programmable thermostat |
| 4126 | HVAC Equipment | Smart Thermostat - Heat pump baseline | MF | N/A | NC | 2,870.1 | 10% | 293.2 | 0.000 | 15.0 | $154.00 | $60.00 | 2.34 | Smart thermostat |
| 4127 | HVAC Equipment | WIFI Thermostat - Heat pump baseline | MF | N/A | NC | 2,870.1 | 7% | 207.0 | 0.000 | 15.0 | $103.20 | $50.00 | 1.98 | WifI (non-smart) thermostat |
| 4128 | HVAC Equipment | Filter Whistle | MF | N/A | NC | 2,870.1 | 4% | 100.5 | 0.046 | 15.0 | $1.64 | $1.64 | 51.70 | Whistle to remind owners to change air filter |
| 4129 | HVAC Equipment | Smart Vents/Sensors_ET | MF | N/A | NC | 2,870.1 | 10% | 287.0 | 0.133 | 15.0 | $800.00 | $400.00 | 0.61 | Smart vents relay temperature and occupancy information to a smart thermostat (or other control device) to reduce energy waste in unoccupied areas of the home |
| 4130 | HVAC Equipment | Smart Thermostat - Gas / CAC | SF | NLI | Retrofit | 2,939.6 | 10% | 292.7 | 0.000 | 15.0 | $154.00 | $60.00 | 7.41 | Smart thermostat |
| 4131 | HVAC Equipment | WIFI Thermostat - Gas / CAC | SF | NLI | Retrofit | 2,939.6 | 9% | 258.0 | 0.000 | 15.0 | $103.20 | $50.00 | 4.36 | WifI (non-smart) thermostat |
| 4132 | HVAC Equipment | Filter Whistle | SF | NLI | Retrofit | 2,939.6 | 3% | 95.2 | 0.120 | 15.0 | $1.64 | $1.64 | 105.83 | Whistle to remind owners to change air filter |
| 4133 | HVAC Equipment | Smart Thermostat - Gas / CAC | SF | LI | DI | 2,939.6 | 10% | 292.7 | 0.000 | 15.0 | $154.00 | $154.00 | 2.89 | Smart thermostat |
| 4134 | HVAC Equipment | WIFI Thermostat - Gas / CAC | SF | LI | DI | 2,939.6 | 9% | 258.0 | 0.000 | 15.0 | $103.20 | $103.20 | 2.11 | WifI (non-smart) thermostat |
| 4135 | HVAC Equipment | Filter Whistle | SF | LI | DI | 2,939.6 | 3% | 95.2 | 0.120 | 15.0 | $1.64 | $1.64 | 105.83 | Whistle to remind owners to change air filter |
| 4136 | HVAC Equipment | Programmable Thermostat - Gas / CAC | SF | N/A | Retrofit | 2,939.6 | 5% | 149.8 | 0.000 | 15.0 | $35.00 | $10.00 | 13.49 | Programmable thermostat |

| Vectren Electric | Residential Measure Assumptions | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Measure # | End-Use | Measure Name | Home Type | Income Type | Replacement Type | Base Annual Electric | % Elec Savings | Per Unit Elec Savings | Per Unit Summer NCP kW | Useful Life | Initial Measure Cost | Historical Incentive Amount | UCT Ratio | Measure Description |
| 4137 | HVAC Equipment | Smart Vents/Sensors_ET | SF | N/A | Retrofit | 2,939.6 | 10% | 294.0 | 0.343 | 15.0 | $800.00 | $400.00 | 1.60 | Smart vents relay temperature and occupancy information to a smart thermostat (or other control device) to reduce energy waste in unoccupied areas of the home |
| 4138 | HVAC Equipment | Programmable Thermostat - Gas / CAC | SF | N/A | NC | 2,479.3 | 5% | 129.5 | 0.000 | 18.0 | $35.00 | $10.00 | 11.87 | Programmable thermostat |
| 4139 | HVAC Equipment | Smart Thermostat - Gas / CAC | SF | N/A | NC | 2,479.3 | 10% | 245.9 | 0.000 | 15.0 | $154.00 | $60.00 | 5.28 | Smart thermostat |
| 4140 | HVAC Equipment | WIFI Thermostat - Gas / CAC | SF | N/A | NC | 2,479.3 | 9% | 223.6 | 0.000 | 15.0 | $103.20 | $50.00 | 3.38 | WifI (non-smart) thermostat |
| 4141 | HVAC Equipment | Filter Whistle | SF | N/A | NC | 2,479.3 | 3% | 81.9 | 0.107 | 15.0 | $1.64 | $1.64 | 83.65 | Whistle to remind owners to change air filter |
| 4142 | HVAC Equipment | Smart Vents/Sensors_ET | SF | N/A | NC | 2,479.3 | 10% | 247.9 | 0.305 | 15.0 | $800.00 | $400.00 | 1.21 | Smart vents relay temperature and occupancy information to a smart thermostat (or other control device) to reduce energy waste in unoccupied areas of the home |
| 4143 | HVAC Equipment | Smart Thermostat - Gas / CAC | MF | NLI | Retrofit | 2,163.0 | 10% | 213.2 | 0.000 | 15.0 | $154.00 | $60.00 | 3.27 | Smart thermostat |
| 4144 | HVAC Equipment | WIFI Thermostat - Gas / CAC | MF | NLI | Retrofit | 2,163.0 | 9% | 202.7 | 0.000 | 15.0 | $103.20 | $50.00 | 2.53 | WifI (non-smart) thermostat |
| 4145 | HVAC Equipment | Filter Whistle | MF | NLI | Retrofit | 2,163.0 | 3% | 73.4 | 0.058 | 15.0 | $1.64 | $1.64 | 61.32 | Whistle to remind owners to change air filter |
| 4146 | HVAC Equipment | Smart Thermostat - Gas / CAC | MF | LI | DI | 2,163.0 | 10% | 213.2 | 0.000 | 15.0 | $154.00 | $154.00 | 1.27 | Smart thermostat |
| 4147 | HVAC Equipment | WIFI Thermostat - Gas / CAC | MF | LI | DI | 2,163.0 | 9% | 202.7 | 0.000 | 15.0 | $103.20 | $103.20 | 1.22 | WifI (non-smart) thermostat |
| 4148 | HVAC Equipment | Filter Whistle | MF | LI | DI | 2,163.0 | 3% | 73.4 | 0.058 | 15.0 | $1.64 | $1.64 | 61.32 | Whistle to remind owners to change air filter |
| 4149 | HVAC Equipment | Programmable Thermostat - Gas / CAC | MF | N/A | Retrofit | 2,163.0 | 5% | 117.0 | 0.000 | 15.0 | $35.00 | $10.00 | 7.56 | Programmable thermostat |
| 4150 | HVAC Equipment | Smart Vents/Sensors_ET | MF | N/A | Retrofit | 2,163.0 | 10% | 216.3 | 0.166 | 15.0 | $800.00 | $400.00 | 0.83 | Smart vents relay temperature and occupancy information to a smart thermostat (or other control device) to reduce energy waste in unoccupied areas of the home |
| 4151 | HVAC Equipment | Programmable Thermostat - Gas / CAC | MF | N/A | NC | 1,964.8 | 5% | 106.0 | 0.000 | 15.0 | $35.00 | $10.00 | 7.20 | Programmable thermostat |
| 4152 | HVAC Equipment | Smart Thermostat - Gas / CAC | MF | N/A | NC | 1,964.8 | 10% | 193.8 | 0.000 | 15.0 | $154.00 | $60.00 | 3.25 | Smart thermostat |
| 4153 | HVAC Equipment | WIFI Thermostat - Gas / CAC | MF | N/A | NC | 1,964.8 | 9% | 183.6 | 0.000 | 15.0 | $103.20 | $50.00 | 2.40 | WifI (non-smart) thermostat |
| 4154 | HVAC Equipment | Filter Whistle | MF | N/A | NC | 1,964.8 | 3% | 66.5 | 0.057 | 15.0 | $1.64 | $1.64 | 57.41 | Whistle to remind owners to change air filter |
| 4155 | HVAC Equipment | Smart Vents/Sensors_ET | MF | N/A | NC | 1,964.8 | 10% | 196.5 | 0.164 | 15.0 | $800.00 | $400.00 | 0.79 | Smart vents relay temperature and occupancy information to a smart thermostat (or other control device) to reduce energy waste in unoccupied areas of the home |
| 5001 | Lighting | LED 9W (Standard) | SF | NLI | MO | 37.5 | 86% | 32.2 | 0.040 | 15.0 | $1.01 | $0.76 | 25.14 | Standard LED Replacing Standard Halogen/CFL Bulb |
| 5002 | Lighting | LED 5W Globe (Specialty) | SF | NLI | MO | 28.7 | 84% | 24.1 | 0.023 | 15.0 | $4.00 | $3.00 | 4.36 | Specialty LED Replacing Specialty Halogen/Incandescent Bulb |

| Vectren Electric | Residential Measure Assumptions | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Measure # | End-Use | Measure Name | Home Type | Income Type | Replacement Type | Base Annual Electric | % Elec Savings | Per Unit Elec Savings | Per Unit Summer NCP kW | Useful Life | Initial Measure Cost | Historical Incentive Amount | UCT Ratio | Measure Description |
| 5003 | Lighting | LED R30 Dimmable (Reflector) | SF | NLI | MO | 40.1 | 83% | 33.1 | 0.041 | 15.0 | $5.34 | $4.01 | 4.98 | Reflector LED Replacing Standard Halogen/Incandescent Bulb |
| 5004 | Lighting | LED Fixtures | SF | NLI | MO | 82.0 | 74% | 60.8 | 0.061 | 15.0 | $20.25 | $5.06 | 8.26 | Residential Occupancy Sensors (DIRECT INSTALL) |
| 5005 | Lighting | Linear LED | SF | NLI | Retrofit | 23.5 | 44% | 10.3 | 0.014 | 9.0 | $7.00 | $5.25 | 0.73 | T8 Linear Tube Fluorescent Replacing T12 LTF |
| 5006 | Lighting | Residential Occupancy Sensors | SF | NLI | Retrofit | 108.9 | 35% | 38.1 | 0.048 | 10.0 | $30.00 | $7.50 | 2.46 | Residential Occupancy Sensors |
| 5007 | Lighting | Smart Lighting Switch_ET | SF | NLI | Retrofit | 106.5 | 35% | 37.3 | 0.047 | 10.0 | $25.00 | $6.25 | 2.88 | Residential Occupancy Sensors |
| 5008 | Lighting | LED Nightlights | SF | NLI | Retrofit | 14.6 | 93% | 13.6 | 0.005 | 16.0 | $2.75 | $0.69 | 10.02 | LED Nightlights Replacing Incandescent Nightlights |
| 5009 | Lighting | LED 13W (Exterior) | SF | NLI | MO | 126.7 | 83% | 105.2 | 0.048 | 15.0 | $4.76 | $4.00 | 12.59 | Exterior LED Replacing Exterior Halogen/CFL Bulb |
| 5010 | Lighting | Exterior Lighting Controls | SF | NLI | Retrofit | 178.1 | 35% | 62.3 | 0.028 | 10.0 | $30.00 | $7.50 | 2.75 | Residential Occupancy Sensors |
| 5011 | Lighting | DI LED 9W (Standard) | SF | NLI | DI | 37.5 | 86% | 32.2 | 0.040 | 15.0 | $3.00 | $3.00 | 6.35 | Standard LED Replacing Standard Halogen/CFL Bulb |
| 5012 | Lighting | DI LED 5W Globe (Specialty) | SF | NLI | DI | 28.7 | 84% | 24.1 | 0.023 | 15.0 | $5.00 | $5.00 | 2.62 | Specialty LED Replacing Specialty Halogen/Incandescent Bulb (DIRECT INSTALL) |
| 5013 | Lighting | DI LED R30 Dimmable (Reflector) | SF | NLI | DI | 39.0 | 83% | 32.3 | 0.040 | 15.0 | $8.63 | $8.63 | 2.25 | Reflector LED Replacing Standard Halogen/Incandescent Bulb (DIRECT INSTALL) |
| 5014 | Lighting | DI LED Nightlights | SF | NLI | DI | 14.6 | 93% | 13.6 | 0.005 | 16.0 | $2.75 | $2.75 | 2.50 | LED Nightlights Replacing Incandescent Nightlights (DIRECT INSTALL) |
| 5015 | Lighting | DI LED 9W (Standard) | SF | LI | DI | 37.5 | 86% | 32.2 | 0.040 | 15.0 | $3.00 | $3.00 | 6.35 | Standard LED Replacing Standard Halogen/CFL Bulb |
| 5016 | Lighting | DI LED 5W Globe (Specialty) | SF | LI | DI | 28.7 | 84% | 24.1 | 0.023 | 15.0 | $5.00 | $5.00 | 2.62 | Specialty LED Replacing Specialty Halogen/Incandescent Bulb (DIRECT INSTALL) |
| 5017 | Lighting | DI LED R30 Dimmable (Reflector) | SF | LI | DI | 39.0 | 83% | 32.3 | 0.040 | 15.0 | $8.63 | $8.63 | 2.25 | Reflector LED Replacing Standard Halogen/Incandescent Bulb (DIRECT INSTALL) |
| 5018 | Lighting | DI LED Nightlights | SF | LI | DI | 14.6 | 93% | 13.6 | 0.005 | 16.0 | $2.75 | $2.75 | 2.50 | LED Nightlights Replacing Incandescent Nightlights (DIRECT INSTALL) |
| 5019 | Lighting | DI LED 13W (Exterior) | SF | LI | DI | 126.7 | 83% | 105.2 | 0.048 | 15.0 | $6.76 | $6.76 | 7.45 | Exterior LED Replacing Exterior Halogen/CFL Bulb |
| 5020 | Lighting | LED 9W (Standard) | SF | N/A | NC | 37.5 | 86% | 32.2 | 0.040 | 15.0 | $1.01 | $0.76 | 25.14 | Standard LED Replacing Standard Halogen/CFL Bulb |
| 5021 | Lighting | LED 5W Globe (Specialty) | SF | N/A | NC | 28.7 | 84% | 24.1 | 0.023 | 15.0 | $4.00 | $3.00 | 4.36 | Specialty LED Replacing Specialty Halogen/Incandescent Bulb |
| 5022 | Lighting | LED R30 Dimmable (Reflector) | SF | N/A | NC | 40.1 | 83% | 33.1 | 0.041 | 15.0 | $5.34 | $4.01 | 4.98 | Reflector LED Replacing Standard Halogen/Incandescent Bulb |
| 5023 | Lighting | LED Fixtures | SF | N/A | NC | 82.0 | 74% | 60.8 | 0.061 | 15.0 | $20.25 | $5.06 | 8.26 | Residential Occupancy Sensors (DIRECT INSTALL) |
| 5024 | Lighting | Linear LED | SF | N/A | NC | 23.5 | 44% | 10.3 | 0.014 | 9.0 | $2.50 | $1.88 | 2.06 | T8 Linear Tube Fluorescent Replacing T12 LTF |
| 5025 | Lighting | Residential Occupancy Sensors | SF | N/A | NC | 108.9 | 35% | 38.1 | 0.048 | 10.0 | $30.00 | $7.50 | 2.46 | Residential Occupancy Sensors |
| 5026 | Lighting | Smart Lighting Switch_ET | SF | N/A | NC | 106.5 | 35% | 37.3 | 0.047 | 10.0 | $25.00 | $6.25 | 2.88 | Residential Occupancy Sensors |
| 5027 | Lighting | LED Nightlights | SF | N/A | NC | 14.6 | 93% | 13.6 | 0.005 | 16.0 | $2.75 | $0.69 | 10.02 | LED Nightlights Replacing Incandescent Nightlights |
| 5028 | Lighting | LED 13W (Exterior) | SF | N/A | NC | 126.7 | 83% | 105.2 | 0.048 | 15.0 | $4.76 | $4.00 | 12.59 | Exterior LED Replacing Exterior Halogen/CFL Bulb |
| 5029 | Lighting | Exterior Lighting Controls | SF | N/A | NC | 178.1 | 35% | 62.3 | 0.028 | 10.0 | $30.00 | $7.50 | 2.75 | Residential Occupancy Sensors |

| Vectren Electric | Residential Measure Assumptions | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Measure # | End-Use | Measure Name | Home Type | Income Type | Replacement Type | Base Annual Electric | % Elec Savings | Per Unit Elec Savings | Per Unit Summer NCP kW | Useful Life | Initial Measure Cost | Historical Incentive Amount | UCT Ratio | Measure Description |
| 5030 | Lighting | LED 9W (Standard) | MF | NLI | MO | 37.5 | 86% | 32.2 | 0.040 | 15.0 | $1.01 | $0.76 | 25.14 | Standard LED Replacing Standard Halogen/CFL Bulb |
| 5031 | Lighting | LED 5W Globe (Specialty) | MF | NLI | MO | 28.7 | 84% | 24.1 | 0.023 | 15.0 | $4.00 | $3.00 | 4.36 | Specialty LED Replacing Specialty Halogen/Incandescent Bulb |
| 5032 | Lighting | LED R30 Dimmable (Reflector) | MF | NLI | MO | 40.1 | 83% | 33.1 | 0.041 | 15.0 | $5.34 | $4.01 | 4.98 | Reflector LED Replacing Standard Halogen/Incandescent Bulb |
| 5033 | Lighting | LED Fixtures | MF | NLI | MO | 82.0 | 74% | 60.8 | 0.061 | 15.0 | $20.25 | $5.06 | 8.26 | Residential Occupancy Sensors (DIRECT INSTALL) |
| 5034 | Lighting | Linear LED | MF | NLI | Retrofit | 23.5 | 44% | 10.3 | 0.014 | 9.0 | $7.00 | $5.25 | 0.73 | T8 Linear Tube Fluorescent Replacing T12 LTF |
| 5035 | Lighting | Residential Occupancy Sensors | MF | NLI | Retrofit | 108.9 | 35% | 38.1 | 0.048 | 10.0 | $30.00 | $7.50 | 2.46 | Residential Occupancy Sensors |
| 5036 | Lighting | Smart Lighting Switch_ET | MF | NLI | Retrofit | 106.5 | 35% | 37.3 | 0.047 | 10.0 | $25.00 | $6.25 | 2.88 | Residential Occupancy Sensors |
| 5037 | Lighting | LED Nightlights | MF | NLI | Retrofit | 14.6 | 93% | 13.6 | 0.005 | 16.0 | $2.75 | $0.69 | 10.02 | LED Nightlights Replacing Incandescent Nightlights |
| 5038 | Lighting | LED 13W (Exterior) | MF | NLI | MO | 126.7 | 83% | 105.2 | 0.048 | 15.0 | $4.76 | $4.00 | 12.59 | Exterior LED Replacing Exterior Halogen/CFL Bulb |
| 5039 | Lighting | Exterior Lighting Controls | MF | NLI | Retrofit | 178.1 | 35% | 62.3 | 0.028 | 10.0 | $30.00 | $7.50 | 2.75 | Residential Occupancy Sensors |
| 5040 | Lighting | DI LED 9W (Standard) | MF | NLI | DI | 37.5 | 86% | 32.2 | 0.040 | 15.0 | $3.00 | $3.00 | 6.35 | Standard LED Replacing Standard Halogen/CFL Bulb |
| 5041 | Lighting | DI LED 5W Globe (Specialty) | MF | NLI | DI | 28.7 | 84% | 24.1 | 0.023 | 15.0 | $5.00 | $5.00 | 2.62 | Specialty LED Replacing Specialty Halogen/Incandescent Bulb (DIRECT INSTALL) |
| 5042 | Lighting | DI LED R30 Dimmable (Reflector) | MF | NLI | DI | 39.0 | 83% | 32.3 | 0.040 | 15.0 | $8.63 | $8.63 | 2.25 | Reflector LED Replacing Standard Halogen/Incandescent Bulb (DIRECT INSTALL) |
| 5043 | Lighting | DI LED Nightlights | MF | NLI | DI | 14.6 | 93% | 13.6 | 0.005 | 16.0 | $2.75 | $2.75 | 2.50 | LED Nightlights Replacing Incandescent Nightlights (DIRECT INSTALL) |
| 5044 | Lighting | DI LED 9W (Standard) | MF | LI | DI | 37.5 | 86% | 32.2 | 0.040 | 15.0 | $3.00 | $3.00 | 6.35 | Standard LED Replacing Standard Halogen/CFL Bulb |
| 5045 | Lighting | DI LED 5W Globe (Specialty) | MF | LI | DI | 28.7 | 84% | 24.1 | 0.023 | 15.0 | $5.00 | $5.00 | 2.62 | Specialty LED Replacing Specialty Halogen/Incandescent Bulb (DIRECT INSTALL) |
| 5046 | Lighting | DI LED R30 Dimmable (Reflector) | MF | LI | DI | 39.0 | 83% | 32.3 | 0.040 | 15.0 | $8.63 | $8.63 | 2.25 | Reflector LED Replacing Standard Halogen/Incandescent Bulb (DIRECT INSTALL) |
| 5047 | Lighting | DI LED Nightlights | MF | LI | DI | 14.6 | 93% | 13.6 | 0.005 | 16.0 | $2.75 | $2.75 | 2.50 | LED Nightlights Replacing Incandescent Nightlights (DIRECT INSTALL) |
| 5048 | Lighting | DI LED 13W (Exterior) | MF | LI | DI | 126.7 | 83% | 105.2 | 0.048 | 15.0 | $6.76 | $6.76 | 7.45 | Exterior LED Replacing Exterior Halogen/CFL Bulb |
| 5049 | Lighting | LED 9W (Standard) | MF | N/A | NC | 37.5 | 86% | 32.2 | 0.040 | 15.0 | $1.01 | $0.76 | 25.14 | Standard LED Replacing Standard Halogen/CFL Bulb |
| 5050 | Lighting | LED 5W Globe (Specialty) | MF | N/A | NC | 28.7 | 84% | 24.1 | 0.023 | 15.0 | $4.00 | $3.00 | 4.36 | Specialty LED Replacing Specialty Halogen/Incandescent Bulb |
| 5051 | Lighting | LED R30 Dimmable (Reflector) | MF | N/A | NC | 40.1 | 83% | 33.1 | 0.041 | 15.0 | $5.34 | $4.01 | 4.98 | Reflector LED Replacing Standard Halogen/Incandescent Bulb |
| 5052 | Lighting | LED Fixtures | MF | N/A | NC | 82.0 | 74% | 60.8 | 0.061 | 15.0 | $20.25 | $5.06 | 8.26 | Residential Occupancy Sensors (DIRECT INSTALL) |
| 5053 | Lighting | Linear LED | MF | N/A | NC | 23.5 | 44% | 10.3 | 0.014 | 9.0 | $2.50 | $1.88 | 2.06 | T8 Linear Tube Fluorescent Replacing T12 LTF |
| 5054 | Lighting | Residential Occupancy Sensors | MF | N/A | NC | 108.9 | 35% | 38.1 | 0.048 | 10.0 | $30.00 | $7.50 | 2.46 | Residential Occupancy Sensors |
| 5055 | Lighting | Smart Lighting Switch_ET | MF | N/A | NC | 106.5 | 35% | 37.3 | 0.047 | 10.0 | $25.00 | $6.25 | 2.88 | Residential Occupancy Sensors |

**Vectren Electric** **Residential Measure Assumptions**

| Measure # | End-Use | Measure Name | Home Type | Income Type | Replacement Type | Base Annual Electric | % Elec Savings | Per Unit Elec Savings | Per Unit Summer NCP kW | Useful Life | Initial Measure Cost | Historical Incentive Amount | UCT Ratio | Measure Description |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 5056 | Lighting | LED Nightlights | MF | N/A | NC | 14.6 | 93% | 13.6 | 0.005 | 16.0 | $2.75 | $0.69 | 10.02 | LED Nightlights Replacing Incandescent Nightlights |
| 5057 | Lighting | LED 13W (Exterior) | MF | N/A | NC | 126.7 | 83% | 105.2 | 0.048 | 15.0 | $4.76 | $4.00 | 12.59 | Exterior LED Replacing Exterior Halogen/CFL Bulb |
| 5058 | Lighting | Exterior Lighting Controls | MF | N/A | NC | 178.1 | 35% | 62.3 | 0.028 | 10.0 | $30.00 | $7.50 | 2.75 | Residential Occupancy Sensors |
| 6001 | Miscellaneous | Pool Heater | SF | N/A | MO | 9,785.1 | 12% | 1,173.5 | 0.000 | 10.0 | $3,333.33 | $1,000.00 | 0.39 | Installation of high efficiency pool pump heater |
| 6002 | Miscellaneous | Pool Heater - Solar System | SF | N/A | MO | 9,785.1 | 38% | 3,735.8 | 0.000 | 10.0 | $3,500.00 | $1,000.00 | 1.24 | This measure replaces a conventional pool heater with a solar system |
| 6003 | Miscellaneous | Hot Tub/Spa | SF | N/A | MO | 0.0 | 0% | 417.3 | 0.048 | 15.0 | $350.00 | $122.50 | 2.11 | Installation of an efficient hot tub / spa |
| 6004 | Miscellaneous | Variable Speed Pool Pump | SF | N/A | MO | 1,363.5 | 86% | 1,172.6 | 2.068 | 10.0 | $750.00 | $300.00 | 7.62 | Installation of variable speed pool pump |
| 6005 | Miscellaneous | Pool Timer | SF | N/A | Retrofit | 0.0 | 0% | 129.0 | 0.063 | 25.0 | $115.00 | $30.00 | 6.38 | Installation of pool pump timer |
| 6006 | Miscellaneous | Well Pump | SF | N/A | MO | 0.0 | 0% | 187.0 | 0.022 | 20.0 | $110.00 | $30.00 | 4.80 | Installation of high efficiency well pump in place of typical efficiency unit |
| 6007 | Miscellaneous | Pool Heater | SF | N/A | NC | 9,785.1 | 12% | 1,173.5 | 0.000 | 10.0 | $3,333.33 | $1,000.00 | 0.39 | Installation of high efficiency pool pump heater |
| 6008 | Miscellaneous | Pool Heater - Solar System | SF | N/A | NC | 9,785.1 | 35% | 3,437.0 | 0.000 | 10.0 | $3,500.00 | $1,000.00 | 1.14 | Installation of a solar pool heater instead of a conventional pool heater |
| 6009 | Miscellaneous | Hot Tub/Spa | SF | N/A | NC | 0.0 | 0% | 417.3 | 0.048 | 15.0 | $350.00 | $110.00 | 2.35 | Installation of an efficient hot tub / spa |
| 6010 | Miscellaneous | Variable Speed Pool Pump | SF | N/A | NC | 1,363.5 | 86% | 1,172.6 | 2.068 | 10.0 | $750.00 | $300.00 | 7.62 | Installation of variable speed pool pump |
| 6011 | Miscellaneous | Pool Timer | SF | N/A | NC | 0.0 | 0% | 108.3 | 0.063 | 25.0 | $50.00 | $20.00 | 8.85 | Installation of pool pump timer |
| 6012 | Miscellaneous | Well Pump | SF | N/A | NC | 0.0 | 0% | 187.0 | 0.022 | 20.0 | $110.00 | $30.00 | 4.80 | Installation of high efficiency well pump in place of typical efficiency unit |
| 7001 | New Construction | Gold Star: HERS Index Score ≤ 63 - Electric Heated | SF | N/A | NC | 15,337.8 | 37% | 5,675.0 | 0.824 | 25.0 | $2,504.19 | $700.00 | 6.78 | Construction of home meeting Gold Star standard (HERS <=63) |
| 7002 | New Construction | Platinum Star: HERS Index Score ≤ 60 - Electric Heated | SF | N/A | NC | 15,337.8 | 40% | 6,135.1 | 0.891 | 25.0 | $3,079.19 | $800.00 | 6.41 | Construction of home meeting Platinum Star standard (HERS <=60) |
| 7003 | New Construction | Gold Star: HERS Index Score ≤ 63 - Electric Heated | MF | N/A | NC | 10,959.2 | 37% | 4,054.9 | 0.491 | 25.0 | $2,504.19 | $1,000.00 | 3.32 | Construction of home meeting Gold Star standard (HERS <=63) |
| 7004 | New Construction | Platinum Star: HERS Index Score ≤ 60 - Electric Heated | MF | N/A | NC | 10,959.2 | 40% | 4,383.7 | 0.531 | 25.0 | $3,079.19 | $1,000.00 | 3.59 | Construction of home meeting Platinum Star standard (HERS <=60) |
| 7005 | New Construction | Gold Star: HERS Index Score ≤ 63 - Gas Heated | SF | N/A | NC | 8,582.1 | 37% | 3,175.4 | 0.904 | 25.0 | $1,573.27 | $175.00 | 23.67 | Construction of home meeting Gold Star standard (HERS <=63) |
| 7006 | New Construction | Platinum Star: HERS Index Score ≤ 60 - Gas Heated | SF | N/A | NC | 8,582.1 | 40% | 3,432.8 | 0.977 | 25.0 | $1,778.27 | $200.00 | 22.40 | Construction of home meeting Platinum Star standard (HERS <=60) |
| 7007 | New Construction | Gold Star: HERS Index Score ≤ 63 - Gas Heated | MF | N/A | NC | 10,165.2 | 37% | 3,761.1 | 0.605 | 25.0 | $1,573.27 | $775.00 | 4.72 | Construction of home meeting Gold Star standard (HERS <=63) |
| 7008 | New Construction | Platinum Star: HERS Index Score ≤ 60 - Gas Heated | MF | N/A | NC | 10,165.2 | 40% | 4,066.1 | 0.655 | 25.0 | $1,778.27 | $900.00 | 4.40 | Construction of home meeting Platinum Star standard (HERS <=60) |
| 8001 | Plug Loads | Smart Power Strips - Tier 1 | SF | NLI | Retrofit | 197.0 | 12% | 23.0 | 0.003 | 4.0 | $35.00 | $35.00 | 0.10 | Use of a smart strip instead of a standard power strip |
| 8002 | Plug Loads | Smart Power Strips - Tier 1 | SF | LI | DI | 197.0 | 12% | 23.0 | 0.003 | 4.0 | $35.00 | $35.00 | 0.10 | Use of a smart strip instead of a standard power strip |
| 8003 | Plug Loads | Efficient Laptop | SF | N/A | MO | 50.3 | 72% | 36.0 | 0.004 | 4.0 | $8.00 | $5.00 | 1.22 | Installation of high-efficiency laptop computers in homes with laptop computers |
| 8004 | Plug Loads | Efficient Monitor | SF | N/A | MO | 66.2 | 61% | 40.2 | 0.020 | 5.0 | $10.00 | $5.00 | 3.83 | Installation of high-efficiency displays (50% more efficient than ENERGY STAR minimum spec) for desktop computers in homes with desktop computers |
| 8005 | Plug Loads | Efficient Personal Computer | SF | N/A | MO | 238.5 | 32% | 77.0 | 0.023 | 4.0 | $8.00 | $5.00 | 3.34 | Installation of high-efficiency desktop computers in homes with desktop computers |

**Vectren Electric** | **Residential Measure Assumptions**

| Measure # | End-Use | Measure Name | Home Type | Income Type | Replacement Type | Base Annual Electric | % Elec Savings | Per Unit Elec Savings | Per Unit Summer NCP kW | Useful Life | Initial Measure Cost | Historical Incentive Amount | UCT Ratio | Measure Description |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 8006 | Plug Loads | Efficient Multifunction | SF | N/A | MO | 70.1 | 66% | 46.4 | 0.011 | 6.0 | $1.00 | $5.00 | 2.71 | Installation of high efficiency multifunction device instead of a standard efficiency unit |
| 8007 | Plug Loads | Efficient TV | SF | N/A | MO | 664.4 | 27% | 179.4 | 0.098 | 6.0 | $10.00 | $5.00 | 10.48 | ENERGY STAR 7.0 television |
| 8008 | Plug Loads | Smart Television | SF | N/A | MO | 664.4 | 27% | 179.4 | 0.098 | 6.0 | $10.00 | $5.00 | 10.48 | ENERGY STAR 7.0 television |
| 8009 | Plug Loads | Smart Power Strips - Tier 2 | SF | N/A | Retrofit | 678.0 | 36% | 244.1 | 0.028 | 4.0 | $80.00 | $20.00 | 1.92 | Use of a advanced power strip instead of a standard power strip |
| 8010 | Plug Loads | Smart Plug or Outlet_ET | SF | N/A | Retrofit | 678.0 | 0% | 0.0 | 0.000 | 4.0 | $20.00 | $10.00 | 0.00 | Installation of smart plug to control plug loads |
| 8011 | Plug Loads | Efficient Laptop | SF | N/A | NC | 50.3 | 72% | 36.0 | 0.004 | 4.0 | $8.00 | $5.00 | 1.22 | Installation of high-efficiency laptop computers in homes with laptop computers |
| 8012 | Plug Loads | Efficient Monitor | SF | N/A | NC | 66.2 | 61% | 40.2 | 0.020 | 5.0 | $10.00 | $5.00 | 3.83 | Installation of high-efficiency displays (50% more efficient than ENERGY STAR minimum spec) for desktop computers in homes with desktop computers |
| 8013 | Plug Loads | Efficient Personal Computer | SF | N/A | NC | 238.5 | 32% | 77.0 | 0.023 | 4.0 | $8.00 | $5.00 | 3.34 | Installation of high-efficiency desktop computers in homes with desktop computers |
| 8014 | Plug Loads | Efficient Multifunction | SF | N/A | NC | 70.1 | 66% | 46.4 | 0.011 | 6.0 | $1.00 | $5.00 | 2.71 | Installation of high efficiency multifunction device instead of a standard efficiency unit |
| 8015 | Plug Loads | Efficient TV | SF | N/A | NC | 664.4 | 27% | 179.4 | 0.098 | 6.0 | $10.00 | $5.00 | 10.48 | ENERGY STAR 7.0 television |
| 8016 | Plug Loads | Smart Television | SF | N/A | NC | 664.4 | 27% | 179.4 | 0.098 | 6.0 | $10.00 | $5.00 | 10.48 | ENERGY STAR 7.0 television |
| 8017 | Plug Loads | Smart Power Strips - Tier 1 | SF | N/A | NC | 197.0 | 12% | 23.0 | 0.003 | 4.0 | $35.00 | $35.00 | 0.10 | Use of a smart strip instead of a standard power strip |
| 8018 | Plug Loads | Smart Power Strips - Tier 2 | SF | N/A | NC | 678.0 | 36% | 244.1 | 0.028 | 4.0 | $80.00 | $20.00 | 1.92 | Use of a advanced power strip instead of a standard power strip |
| 8019 | Plug Loads | Smart Plug or Outlet_ET | SF | N/A | NC | 678.0 | 0% | 0.0 | 0.000 | 4.0 | $20.00 | $10.00 | 0.00 | Installation of smart plug to control plug loads |
| 8020 | Plug Loads | Smart Power Strips - Tier 1 | MF | NLI | Retrofit | 197.0 | 12% | 23.0 | 0.003 | 4.0 | $35.00 | $35.00 | 0.10 | Use of a smart strip instead of a standard power strip |
| 8021 | Plug Loads | Smart Power Strips - Tier 1 | MF | LI | DI | 197.0 | 12% | 23.0 | 0.003 | 4.0 | $35.00 | $35.00 | 0.10 | Use of a smart strip instead of a standard power strip |
| 8022 | Plug Loads | Efficient Laptop | MF | N/A | MO | 50.3 | 72% | 36.0 | 0.004 | 4.0 | $8.00 | $5.00 | 1.22 | Installation of high-efficiency laptop computers in homes with laptop computers |
| 8023 | Plug Loads | Efficient Monitor | MF | N/A | MO | 66.2 | 61% | 40.2 | 0.020 | 5.0 | $10.00 | $5.00 | 3.83 | Installation of high-efficiency displays (50% more efficient than ENERGY STAR minimum spec) for desktop computers in homes with desktop computers |
| 8024 | Plug Loads | Efficient Personal Computer | MF | N/A | MO | 238.5 | 32% | 77.0 | 0.023 | 4.0 | $8.00 | $5.00 | 3.34 | Installation of high-efficiency desktop computers in homes with desktop computers |
| 8025 | Plug Loads | Efficient Multifunction | MF | N/A | MO | 70.1 | 66% | 46.4 | 0.011 | 6.0 | $1.00 | $5.00 | 2.71 | Installation of high efficiency multifunction device instead of a standard efficiency unit |
| 8026 | Plug Loads | Efficient TV | MF | N/A | MO | 664.4 | 27% | 179.4 | 0.098 | 6.0 | $10.00 | $5.00 | 10.48 | ENERGY STAR 7.0 television |
| 8027 | Plug Loads | Smart Television | MF | N/A | MO | 664.4 | 27% | 179.4 | 0.098 | 6.0 | $10.00 | $5.00 | 10.48 | ENERGY STAR 7.0 television |
| 8028 | Plug Loads | Smart Power Strips - Tier 2 | MF | N/A | Retrofit | 678.0 | 36% | 244.1 | 0.028 | 4.0 | $80.00 | $20.00 | 1.92 | Use of a advanced power strip instead of a standard power strip |
| 8029 | Plug Loads | Smart Plug or Outlet_ET | MF | N/A | Retrofit | 678.0 | 0% | 0.0 | 0.000 | 4.0 | $20.00 | $10.00 | 0.00 | Installation of smart plug to control plug loads |

**Vectren Electric** | **Residential Measure Assumptions**

| Measure # | End-Use | Measure Name | Home Type | Income Type | Replacement Type | Base Annual Electric | % Elec Savings | Per Unit Elec Savings | Per Unit Summer NCP kW | Useful Life | Initial Measure Cost | Historical Incentive Amount | UCT Ratio | Measure Description |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 8030 | Plug Loads | Efficient Laptop | MF | N/A | NC | 50.3 | 72% | 36.0 | 0.004 | 4.0 | $8.00 | $5.00 | 1.22 | Installation of high-efficiency laptop computers in homes with laptop computers |
| 8031 | Plug Loads | Efficient Monitor | MF | N/A | NC | 66.2 | 61% | 40.2 | 0.020 | 5.0 | $10.00 | $5.00 | 3.83 | Installation of high-efficiency displays (50% more efficient than ENERGY STAR minimum spec) for desktop computers in homes with desktop computers |
| 8032 | Plug Loads | Efficient Personal Computer | MF | N/A | NC | 238.5 | 32% | 77.0 | 0.023 | 4.0 | $8.00 | $5.00 | 3.34 | Installation of high-efficiency desktop computers in homes with desktop computers |
| 8033 | Plug Loads | Efficient Multifunction | MF | N/A | NC | 70.1 | 66% | 46.4 | 0.011 | 6.0 | $1.00 | $5.00 | 2.71 | Installation of high efficiency multifunction device instead of a standard efficiency unit |
| 8034 | Plug Loads | Efficient TV | MF | N/A | NC | 664.4 | 27% | 179.4 | 0.098 | 6.0 | $10.00 | $5.00 | 10.48 | ENERGY STAR 7.0 television |
| 8035 | Plug Loads | Smart Television | MF | N/A | NC | 664.4 | 27% | 179.4 | 0.098 | 6.0 | $10.00 | $5.00 | 10.48 | ENERGY STAR 7.0 television |
| 8036 | Plug Loads | Smart Power Strips - Tier 1 | MF | N/A | NC | 197.0 | 12% | 23.0 | 0.003 | 4.0 | $35.00 | $35.00 | 0.10 | Use of a smart strip instead of a standard power strip |
| 8037 | Plug Loads | Smart Power Strips - Tier 2 | MF | N/A | NC | 678.0 | 36% | 244.1 | 0.028 | 4.0 | $80.00 | $20.00 | 1.92 | Use of a advanced power strip instead of a standard power strip |
| 8038 | Plug Loads | Smart Plug or Outlet_ET | MF | N/A | NC | 678.0 | 0% | 0.0 | 0.000 | 4.0 | $20.00 | $10.00 | 0.00 | Installation of smart plug to control plug loads |
| 9001 | HVAC Shell | Duct Sealing - Average Sealing - Heat pump | SF | NLI | Retrofit | 7,269.4 | 3% | 242.8 | 0.064 | 20.0 | $200.00 | $175.00 | 1.14 | 15% to 10% leakage |
| 9002 | HVAC Shell | Duct Sealing - Inadequate Sealing - Heat pump | SF | NLI | Retrofit | 7,376.9 | 5% | 397.5 | 0.158 | 20.0 | $350.00 | $300.00 | 1.21 | 20% to 15% leakage |
| 9003 | HVAC Shell | Duct Sealing/Insulation - Poor Sealing - Heat pump | SF | NLI | Retrofit | 7,502.4 | 14% | 1,013.0 | 0.414 | 20.0 | $1,442.50 | $1,000.00 | 0.94 | 25% to 15% leakage |
| 9004 | HVAC Shell | Wall Insulation - Heat pump | SF | NLI | Retrofit | 8,887.1 | 29% | 2,565.9 | 0.867 | 25.0 | $2,746.80 | $450.00 | 5.67 | R0 to R11 wall insulation |
| 9005 | HVAC Shell | Air Sealing Average Sealing - Heat pump | SF | NLI | Retrofit | 6,321.2 | 11% | 709.6 | 0.179 | 15.0 | $624.65 | $200.00 | 2.32 | 10 ACH 50 to 7 ACH 50 |
| 9006 | HVAC Shell | Air Sealing Inadequate Sealing - Heat pump | SF | NLI | Retrofit | 7,284.2 | 13% | 963.0 | 0.251 | 15.0 | $967.20 | $200.00 | 3.15 | 14 ACH 50 to 10 ACH 50 |
| 9007 | HVAC Shell | Air Sealing Poor Sealing - Heat pump | SF | NLI | Retrofit | 8,949.1 | 19% | 1,664.9 | 0.389 | 15.0 | $967.20 | $200.00 | 5.46 | 20 ACH 50 to 14 ACH 50 |
| 9008 | HVAC Shell | Attic Insulation - Average Insulation - Heat pump | SF | NLI | Retrofit | 6,321.2 | 3% | 190.5 | 0.067 | 25.0 | $1,259.70 | $450.00 | 0.43 | R30 to R60 |
| 9009 | HVAC Shell | Attic Insulation - Inadequate Insulation - Heat pump | SF | NLI | Retrofit | 6,568.9 | 7% | 438.2 | 0.172 | 25.0 | $1,744.20 | $450.00 | 1.04 | R19 to R60 |
| 9010 | HVAC Shell | Attic Insulation - Poor Insulation - Heat pump | SF | NLI | Retrofit | 6,932.3 | 11% | 761.0 | 0.321 | 25.0 | $1,550.40 | $450.00 | 1.84 | R11 to R49 |
| 9011 | HVAC Shell | Duct Sealing - Average Sealing - Electric furnace | SF | NLI | Retrofit | 13,437.5 | 3% | 411.6 | 0.036 | 20.0 | $200.00 | $175.00 | 1.59 | 15% to 10% leakage |
| 9012 | HVAC Shell | Duct Sealing - Inadequate Sealing - Electric furnace | SF | NLI | Retrofit | 13,620.9 | 5% | 677.9 | 0.109 | 20.0 | $350.00 | $300.00 | 1.65 | 20% to 15% leakage |
| 9013 | HVAC Shell | Duct Sealing/Insulation - Poor Sealing - Electric furnace | SF | NLI | Retrofit | 13,842.1 | 13% | 1,759.1 | 0.282 | 20.0 | $1,442.50 | $1,000.00 | 1.29 | 25% to 15% leakage |
| 9014 | HVAC Shell | Wall Insulation - Electric furnace | SF | NLI | Retrofit | 17,267.5 | 32% | 5,582.7 | 0.887 | 25.0 | $2,746.80 | $450.00 | 10.41 | R0 to R11 wall insulation |
| 9015 | HVAC Shell | Air Sealing Average Sealing - Electric furnace | SF | NLI | Retrofit | 11,684.8 | 14% | 1,598.5 | 0.215 | 15.0 | $624.65 | $200.00 | 4.58 | 10 ACH 50 to 7 ACH 50 |
| 9016 | HVAC Shell | Air Sealing Inadequate Sealing - Electric furnace | SF | NLI | Retrofit | 13,876.8 | 16% | 2,192.0 | 0.294 | 15.0 | $967.20 | $200.00 | 6.27 | 14 ACH 50 to 10 ACH 50 |
| 9017 | HVAC Shell | Air Sealing Poor Sealing - Electric furnace | SF | NLI | Retrofit | 17,296.5 | 20% | 3,419.8 | 0.378 | 15.0 | $967.20 | $200.00 | 9.63 | 20 ACH 50 to 14 ACH 50 |

| Vectren Electric | Residential Measure Assumptions | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Measure # | End-Use | Measure Name | Home Type | Income Type | Replacement Type | Base Annual Electric | % Elec Savings | Per Unit Elec Savings | Per Unit Summer NCP kW | Useful Life | Initial Measure Cost | Historical Incentive Amount | UCT Ratio | Measure Description |
| 9018 | HVAC Shell | Attic Insulation - Average Insulation - Electric furnace | SF | NLI | Retrofit | 11,684.8 | 3% | 349.3 | 0.052 | 25.0 | $1,259.70 | $450.00 | 0.65 | R30 to R60 |
| 9019 | HVAC Shell | Attic Insulation - Inadequate Insulation - Electric furnace | SF | NLI | Retrofit | 12,144.6 | 7% | 809.2 | 0.133 | 25.0 | $1,744.20 | $450.00 | 1.53 | R19 to R60 |
| 9020 | HVAC Shell | Attic Insulation - Poor Insulation - Electric furnace | SF | NLI | Retrofit | 12,884.7 | 11% | 1,476.9 | 0.278 | 25.0 | $1,550.40 | $450.00 | 2.87 | R11 to R49 |
| 9021 | HVAC Shell | Duct Sealing - Average Sealing - Heat pump | SF | LI | DI | 7,269.4 | 3% | 242.8 | 0.064 | 20.0 | $200.00 | $200.00 | 1.00 | 15% to 10% leakage |
| 9022 | HVAC Shell | Duct Sealing - Inadequate Sealing - Heat pump | SF | LI | DI | 7,376.9 | 5% | 397.5 | 0.158 | 20.0 | $350.00 | $350.00 | 1.04 | 20% to 15% leakage |
| 9023 | HVAC Shell | Duct Sealing/Insulation - Poor Sealing - Heat pump | SF | LI | DI | 7,502.4 | 14% | 1,013.0 | 0.414 | 20.0 | $1,442.50 | $1,442.50 | 0.65 | 25% to 15% leakage |
| 9024 | HVAC Shell | Wall Insulation - Heat pump | SF | LI | DI | 8,887.1 | 29% | 2,565.9 | 0.867 | 25.0 | $2,746.80 | $2,746.80 | 0.93 | R0 to R11 wall insulation |
| 9025 | HVAC Shell | Air Sealing Average Sealing - Heat pump | SF | LI | DI | 6,321.2 | 11% | 709.6 | 0.179 | 15.0 | $624.65 | $624.65 | 0.74 | 10 ACH 50 to 7 ACH 50 |
| 9026 | HVAC Shell | Air Sealing Inadequate Sealing - Heat pump | SF | LI | DI | 7,284.2 | 13% | 963.0 | 0.251 | 15.0 | $967.20 | $967.20 | 0.65 | 14 ACH 50 to 10 ACH 50 |
| 9027 | HVAC Shell | Air Sealing Poor Sealing - Heat pump | SF | LI | DI | 8,949.1 | 19% | 1,664.9 | 0.389 | 15.0 | $967.20 | $967.20 | 1.13 | 20 ACH 50 to 14 ACH 50 |
| 9028 | HVAC Shell | Attic Insulation - Average Insulation - Heat pump | SF | LI | DI | 6,321.2 | 3% | 190.5 | 0.067 | 25.0 | $1,259.70 | $1,259.70 | 0.16 | R30 to R60 |
| 9029 | HVAC Shell | Attic Insulation - Inadequate Insulation - Heat pump | SF | LI | DI | 6,568.9 | 7% | 438.2 | 0.172 | 25.0 | $1,744.20 | $1,744.20 | 0.27 | R19 to R60 |
| 9030 | HVAC Shell | Attic Insulation - Poor Insulation - Heat pump | SF | LI | DI | 6,932.3 | 11% | 761.0 | 0.3 | 25.0 | $1,550.40 | $1,550.40 | 0.53 | R11 to R49 |
| 9031 | HVAC Shell | Duct Sealing - Average Sealing - Electric furnace | SF | LI | DI | 13,437.5 | 3% | 411.6 | 0.036 | 20.0 | $200.00 | $200.00 | 1.39 | 15% to 10% leakage |
| 9032 | HVAC Shell | Duct Sealing - Inadequate Sealing - Electric furnace | SF | LI | DI | 13,620.9 | 5% | 677.9 | 0.109 | 20.0 | $350.00 | $350.00 | 1.42 | 20% to 15% leakage |
| 9033 | HVAC Shell | Duct Sealing/Insulation - Poor Sealing - Electric furnace | SF | LI | DI | 13,842.1 | 13% | 1,759.1 | 0.282 | 20.0 | $1,442.50 | $1,442.50 | 0.89 | 25% to 15% leakage |
| 9034 | HVAC Shell | Wall Insulation - Electric furnace | SF | LI | DI | 17,267.5 | 32% | 5,582.7 | 0.887 | 25.0 | $2,746.80 | $2,746.80 | 1.71 | R0 to R11 wall insulation |
| 9035 | HVAC Shell | Air Sealing Average Sealing - Electric furnace | SF | LI | DI | 11,684.8 | 14% | 1,598.5 | 0.215 | 15.0 | $624.65 | $624.65 | 1.47 | 10 ACH 50 to 7 ACH 50 |
| 9036 | HVAC Shell | Air Sealing Inadequate Sealing - Electric furnace | SF | LI | DI | 13,876.8 | 16% | 2,192.0 | 0.294 | 15.0 | $967.20 | $967.20 | 1.30 | 14 ACH 50 to 10 ACH 50 |
| 9037 | HVAC Shell | Air Sealing Poor Sealing - Electric furnace | SF | LI | DI | 17,296.5 | 20% | 3,419.8 | 0.378 | 15.0 | $967.20 | $967.20 | 1.99 | 20 ACH 50 to 14 ACH 50 |
| 9038 | HVAC Shell | Attic Insulation - Average Insulation - Electric furnace | SF | LI | DI | 11,684.8 | 3% | 349.3 | 0.052 | 25.0 | $1,259.70 | $1,259.70 | 0.23 | R30 to R60 |
| 9039 | HVAC Shell | Attic Insulation - Inadequate Insulation - Electric furnace | SF | LI | DI | 12,144.6 | 7% | 809.2 | 0.133 | 25.0 | $1,744.20 | $1,744.20 | 0.40 | R19 to R60 |
| 9040 | HVAC Shell | Attic Insulation - Poor Insulation - Electric furnace | SF | LI | DI | 12,884.7 | 11% | 1,476.9 | 0.278 | 25.0 | $1,550.40 | $1,550.40 | 0.83 | R11 to R49 |
| 9041 | HVAC Shell | Radiant Barrier - Heat pump | SF | N/A | Retrofit | 6,321.2 | 1% | 82.5 | 0.1 | 20.0 | $416.67 | $130.00 | 0.90 | Installation of radiant barrier |
| 9042 | HVAC Shell | Cool Roof - Heat pump | SF | N/A | Retrofit | 6,321.2 | 2% | 111.1 | 0.1 | 20.0 | $3,876.00 | $1,000.00 | 0.18 | Installation of cool roof |
| 9043 | HVAC Shell | Wall Sheathing - Heat pump | SF | N/A | Retrofit | 6,321.2 | 14% | 879.9 | 0.269 | 20.0 | $2,943.00 | $1,000.00 | 0.77 | R12 polyiso |
| 9044 | HVAC Shell | ENERGY STAR Windows - Heat pump | SF | N/A | Retrofit | 6,321.2 | 9% | 548.8 | 0.372 | 25.0 | $13,601.25 | $1,000.00 | 0.74 | U=0.30; SHGC=0.40 |
| 9045 | HVAC Shell | Basement Sidewall Insulation - Heat pump | SF | N/A | Retrofit | 6,678.1 | 5% | 356.9 | 0.033 | 25.0 | $2,720.00 | $1,000.00 | 0.28 | R0 to R13 sidewall insulation |

## Vectren Electric — Residential Measure Assumptions

| Measure # | End-Use | Measure Name | Home Type | Income Type | Replacement Type | Base Annual Electric | % Elec Savings | Per Unit Elec Savings | Per Unit Summer NCP kW | Useful Life | Initial Measure Cost | Historical Incentive Amount | UCT Ratio | Measure Description |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 9046 | HVAC Shell | Floor Insulation Above Crawlspace - Heat pump | SF | N/A | Retrofit | 6,359.1 | 1% | 37.9 | -0.044 | 25.0 | $316.20 | $90.00 | 0.00 | R13 floor insulation |
| 9047 | HVAC Shell | ENERGY STAR Door - Heat pump | SF | N/A | Retrofit | 6,321.2 | 2% | 129.9 | 0.046 | 25.0 | $388.00 | $120.00 | 1.10 | Fiberglasss |
| 9048 | HVAC Shell | Smart Window Coverings - Shade/Blind/Controller/Sensor - Heat pump_ET | SF | N/A | Retrofit | 6,321.2 | 16% | 979.8 | 0.471 | 7.0 | $14,875.00 | $1,000.00 | 0.41 | Smart shades |
| 9049 | HVAC Shell | Smart Window Coverings - Film/Transformer - Heat pump_ET | SF | N/A | Retrofit | 6,321.2 | 16% | 979.8 | 0.471 | 7.0 | $8,160.75 | $1,000.00 | 0.41 | Smart films |
| 9050 | HVAC Shell | Radiant Barrier - Electric furnace | SF | N/A | Retrofit | 11,684.8 | 1% | 102.2 | 0.065 | 20.0 | $416.67 | $130.00 | 0.91 | Installation of radiant barrier |
| 9051 | HVAC Shell | Cool Roof - Electric furnace | SF | N/A | Retrofit | 11,684.8 | 0% | -21.1 | 0.079 | 20.0 | $3,876.00 | $1,000.00 | 0.06 | Installation of cool roof |
| 9052 | HVAC Shell | Wall Sheathing - Electric furnace | SF | N/A | Retrofit | 11,684.8 | 16% | 1,837.2 | 0.2 | 20.0 | $2,943.00 | $1,000.00 | 1.31 | R12 polyiso |
| 9053 | HVAC Shell | ENERGY STAR Windows - Electric furnace | SF | N/A | Retrofit | 11,684.8 | 7% | 798.3 | 0.3 | 25.0 | $13,601.25 | $1,000.00 | 0.89 | U=0.30; SHGC=0.40 |
| 9054 | HVAC Shell | Basement Sidewall Insulation - Electric furnace | SF | N/A | Retrofit | 12,616.3 | 7% | 931.6 | 0.031 | 25.0 | $2,720.00 | $1,000.00 | 0.67 | R0 to R13 sidewall insulation |
| 9055 | HVAC Shell | Floor Insulation Above Crawlspace - Electric furnace | SF | N/A | Retrofit | 11,922.5 | 2% | 237.7 | -0.028 | 25.0 | $316.20 | $90.00 | 1.54 | R13 floor insulation |
| 9056 | HVAC Shell | ENERGY STAR Door - Electric furnace | SF | N/A | Retrofit | 11,684.8 | 2% | 227.3 | 0.035 | 25.0 | $388.00 | $120.00 | 1.58 | Fiberglasss |
| 9057 | HVAC Shell | Smart Window Coverings - Shade/Blind/Controller/Sensor - Electric furnace_ET | SF | N/A | Retrofit | 11,684.8 | 16% | 1,811.1 | 0.498 | 7.0 | $14,875.00 | $1,000.00 | 0.62 | Smart shades |
| 9058 | HVAC Shell | Smart Window Coverings - Film/Transformer - Electric furnace_ET | SF | N/A | Retrofit | 11,684.8 | 16% | 1,811.1 | 0.498 | 7.0 | $8,160.75 | $1,000.00 | 0.62 | Smart films |
| 9059 | HVAC Shell | Duct Sealing - Average Sealing - Heat pump | MF | NLI | Retrofit | 3,646.6 | 8% | 300.6 | 0.140 | 20.0 | $200.00 | $175.00 | 1.81 | 15% to 10% leakage |
| 9060 | HVAC Shell | Duct Sealing - Inadequate Sealing - Heat pump | MF | NLI | Retrofit | 3,815.6 | 16% | 624.5 | 0.281 | 20.0 | $350.00 | $300.00 | 2.20 | 20% to 15% leakage |
| 9061 | HVAC Shell | Duct Sealing/Insulation - Poor Sealing - Heat pump | MF | NLI | Retrofit | 4,021.6 | 41% | 1,630.6 | 0.741 | 20.0 | $981.00 | $500.00 | 3.46 | 25% to 15% leakage |
| 9062 | HVAC Shell | Wall Insulation - Heat pump | MF | NLI | Retrofit | 4,066.7 | 22% | 895.7 | 0.261 | 25.0 | $1,159.20 | $450.00 | 2.04 | R0 to R11 wall insulation |
| 9063 | HVAC Shell | Air Sealing Average Sealing - Heat pump | MF | NLI | Retrofit | 3,171.0 | 7% | 207.6 | 0.0 | 15.0 | $309.69 | $200.00 | 0.57 | 10 ACH 50 to 7 ACH 50 |
| 9064 | HVAC Shell | Air Sealing Inadequate Sealing - Heat pump | MF | NLI | Retrofit | 3,580.6 | 11% | 409.6 | 0.1 | 15.0 | $479.52 | $200.00 | 1.35 | 14 ACH 50 to 10 ACH 50 |
| 9065 | HVAC Shell | Air Sealing Poor Sealing - Heat pump | MF | NLI | Retrofit | 4,306.5 | 17% | 725.9 | 0.152 | 15.0 | $479.52 | $200.00 | 2.42 | 20 ACH 50 to 14 ACH 50 |
| 9066 | HVAC Shell | Attic Insulation - Average Insulation - Heat pump | MF | NLI | Retrofit | 3,171.0 | 3% | 102.4 | 0.045 | 25.0 | $1,298.70 | $450.00 | 0.27 | R30 to R60 |
| 9067 | HVAC Shell | Attic Insulation - Inadequate Insulation - Heat pump | MF | NLI | Retrofit | 3,295.1 | 7% | 226.5 | 0.101 | 25.0 | $1,798.20 | $450.00 | 0.60 | R19 to R60 |
| 9068 | HVAC Shell | Attic Insulation - Poor Insulation - Heat pump | MF | NLI | Retrofit | 3,479.2 | 11% | 393.2 | 0.178 | 25.0 | $1,598.40 | $450.00 | 1.04 | R11 to R49 |
| 9069 | HVAC Shell | Duct Sealing - Average Sealing - Electric furnace | MF | NLI | Retrofit | 5,719.1 | 8% | 457.5 | 0.203 | 20.0 | $200.00 | $175.00 | 2.71 | 15% to 10% leakage |
| 9070 | HVAC Shell | Duct Sealing - Inadequate Sealing - Electric furnace | MF | NLI | Retrofit | 5,935.5 | 13% | 799.9 | 0.319 | 20.0 | $350.00 | $300.00 | 2.68 | 20% to 15% leakage |
| 9071 | HVAC Shell | Duct Sealing/Insulation - Poor Sealing - Electric furnace | MF | NLI | Retrofit | 6,195.8 | 33% | 2,072.8 | 0.861 | 20.0 | $981.00 | $500.00 | 4.24 | 25% to 15% leakage |

| Vectren Electric | Residential Measure Assumptions | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Measure # | End-Use | Measure Name | Home Type | Income Type | Replacement Type | Base Annual Electric | % Elec Savings | Per Unit Elec Savings | Per Unit Summer NCP kW | Useful Life | Initial Measure Cost | Historical Incentive Amount | UCT Ratio | Measure Description |
| 9072 | HVAC Shell | Wall Insulation - Electric furnace | MF | NLI | Retrofit | 6,808.6 | 27% | 1,835.5 | 0.274 | 25.0 | $1,159.20 | $450.00 | 3.52 | R0 to R11 wall insulation |
| 9073 | HVAC Shell | Air Sealing Average Sealing - Electric furnace | MF | NLI | Retrofit | 4,973.1 | 11% | 531.4 | 0.025 | 15.0 | $309.69 | $200.00 | 1.38 | 10 ACH 50 to 7 ACH 50 |
| 9074 | HVAC Shell | Air Sealing Inadequate Sealing - Electric furnace | MF | NLI | Retrofit | 5,850.0 | 15% | 876.9 | 0.094 | 15.0 | $479.52 | $200.00 | 2.50 | 14 ACH 50 to 10 ACH 50 |
| 9075 | HVAC Shell | Air Sealing Poor Sealing - Electric furnace | MF | NLI | Retrofit | 7,325.7 | 20% | 1,475.7 | 0.162 | 15.0 | $479.52 | $200.00 | 4.26 | 20 ACH 50 to 14 ACH 50 |
| 9076 | HVAC Shell | Attic Insulation - Average Insulation - Electric furnace | MF | NLI | Retrofit | 4,973.1 | 4% | 200.1 | 0.063 | 25.0 | $1,298.70 | $450.00 | 0.46 | R30 to R60 |
| 9077 | HVAC Shell | Attic Insulation - Inadequate Insulation - Electric furnace | MF | NLI | Retrofit | 5,177.1 | 8% | 404.1 | 0.123 | 25.0 | $1,798.20 | $450.00 | 0.92 | R19 to R60 |
| 9078 | HVAC Shell | Attic Insulation - Poor Insulation - Electric furnace | MF | NLI | Retrofit | 5,506.9 | 13% | 695.7 | 0.205 | 25.0 | $1,598.40 | $450.00 | 1.58 | R11 to R49 |
| 9079 | HVAC Shell | Duct Sealing - Average Sealing - Heat pump | MF | LI | DI | 3,646.6 | 8% | 300.6 | 0.140 | 20.0 | $200.00 | $200.00 | 1.58 | 15% to 10% leakage |
| 9080 | HVAC Shell | Duct Sealing - Inadequate Sealing - Heat pump | MF | LI | DI | 3,815.6 | 16% | 624.5 | 0.281 | 20.0 | $350.00 | $350.00 | 1.89 | 20% to 15% leakage |
| 9081 | HVAC Shell | Duct Sealing/Insulation - Poor Sealing - Heat pump | MF | LI | DI | 4,021.6 | 41% | 1,630.6 | 0.741 | 20.0 | $981.00 | $981.00 | 1.76 | 25% to 15% leakage |
| 9082 | HVAC Shell | Wall Insulation - Heat pump | MF | LI | DI | 4,066.7 | 22% | 895.7 | 0.261 | 25.0 | $1,159.20 | $1,159.20 | 0.79 | R0 to R11 wall insulation |
| 9083 | HVAC Shell | Air Sealing Average Sealing - Heat pump | MF | LI | DI | 3,171.0 | 7% | 207.6 | 0.017 | 15.0 | $309.69 | $309.69 | 0.37 | 10 ACH 50 to 7 ACH 50 |
| 9084 | HVAC Shell | Air Sealing Inadequate Sealing - Heat pump | MF | LI | DI | 3,580.6 | 11% | 409.6 | 0.087 | 15.0 | $479.52 | $479.52 | 0.56 | 14 ACH 50 to 10 ACH 50 |
| 9085 | HVAC Shell | Air Sealing Poor Sealing - Heat pump | MF | LI | DI | 4,306.5 | 17% | 725.9 | 0.152 | 15.0 | $479.52 | $479.52 | 1.01 | 20 ACH 50 to 14 ACH 50 |
| 9086 | HVAC Shell | Attic Insulation - Average Insulation - Heat pump | MF | LI | DI | 3,171.0 | 3% | 102.4 | 0.045 | 25.0 | $1,298.70 | $1,298.70 | 0.09 | R30 to R60 |
| 9087 | HVAC Shell | Attic Insulation - Inadequate Insulation - Heat pump | MF | LI | DI | 3,295.1 | 7% | 226.5 | 0.101 | 25.0 | $1,798.20 | $1,798.20 | 0.15 | R19 to R60 |
| 9088 | HVAC Shell | Attic Insulation - Poor Insulation - Heat pump | MF | LI | DI | 3,479.2 | 11% | 393.2 | 0.178 | 25.0 | $1,598.40 | $1,598.40 | 0.29 | R11 to R49 |
| 9089 | HVAC Shell | Duct Sealing - Average Sealing - Electric furnace | MF | LI | DI | 5,719.1 | 8% | 457.5 | 0.203 | 20.0 | $200.00 | $200.00 | 2.37 | 15% to 10% leakage |
| 9090 | HVAC Shell | Duct Sealing - Inadequate Sealing - Electric furnace | MF | LI | DI | 5,935.5 | 13% | 799.9 | 0.319 | 20.0 | $350.00 | $350.00 | 2.30 | 20% to 15% leakage |
| 9091 | HVAC Shell | Duct Sealing/Insulation - Poor Sealing - Electric furnace | MF | LI | DI | 6,195.8 | 33% | 2,072.8 | 0.861 | 20.0 | $981.00 | $981.00 | 2.16 | 25% to 15% leakage |
| 9092 | HVAC Shell | Wall Insulation - Electric furnace | MF | LI | DI | 6,808.6 | 27% | 1,835.5 | 0.274 | 25.0 | $1,159.20 | $1,159.20 | 1.36 | R0 to R11 wall insulation |
| 9093 | HVAC Shell | Air Sealing Average Sealing - Electric furnace | MF | LI | DI | 4,973.1 | 11% | 531.4 | 0.025 | 15.0 | $309.69 | $309.69 | 0.89 | 10 ACH 50 to 7 ACH 50 |
| 9094 | HVAC Shell | Air Sealing Inadequate Sealing - Electric furnace | MF | LI | DI | 5,850.0 | 15% | 876.9 | 0.094 | 15.0 | $479.52 | $479.52 | 1.04 | 14 ACH 50 to 10 ACH 50 |
| 9095 | HVAC Shell | Air Sealing Poor Sealing - Electric furnace | MF | LI | DI | 7,325.7 | 20% | 1,475.7 | 0.162 | 15.0 | $479.52 | $479.52 | 1.78 | 20 ACH 50 to 14 ACH 50 |
| 9096 | HVAC Shell | Attic Insulation - Average Insulation - Electric furnace | MF | LI | DI | 4,973.1 | 4% | 200.1 | 0.063 | 25.0 | $1,298.70 | $1,298.70 | 0.16 | R30 to R60 |
| 9097 | HVAC Shell | Attic Insulation - Inadequate Insulation - Electric furnace | MF | LI | DI | 5,177.1 | 8% | 404.1 | 0.123 | 25.0 | $1,798.20 | $1,798.20 | 0.23 | R19 to R60 |
| 9098 | HVAC Shell | Attic Insulation - Poor Insulation - Electric furnace | MF | LI | DI | 5,506.9 | 13% | 695.7 | 0.205 | 25.0 | $1,598.40 | $1,598.40 | 0.44 | R11 to R49 |
| 9099 | HVAC Shell | Radiant Barrier - Heat pump | MF | N/A | Retrofit | 3,171.0 | -6% | -202.0 | -0.062 | 20.0 | $429.57 | $130.00 | 0.00 | Installation of radiant barrier |

| Vectren Electric | Residential Measure Assumptions | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Measure # | End-Use | Measure Name | Home Type | Income Type | Replacement Type | Base Annual Electric | % Elec Savings | Per Unit Elec Savings | Per Unit Summer NCP kW | Useful Life | Initial Measure Cost | Historical Incentive Amount | UCT Ratio | Measure Description |
| 9100 | HVAC Shell | Cool Roof - Heat pump | MF | N/A | Retrofit | 3,171.0 | -22% | -698.2 | -0.120 | 20.0 | $3,996.00 | $1,000.00 | 0.00 | Installation of cool roof |
| 9101 | HVAC Shell | Wall Sheathing - Heat pump | MF | N/A | Retrofit | 3,171.0 | 10% | 311.5 | 0.091 | 25.0 | $1,242.00 | $625.00 | 0.50 | R12 polyiso |
| 9102 | HVAC Shell | ENERGY STAR Windows - Heat pump | MF | N/A | Retrofit | 3,171.0 | 8% | 266.8 | 0.162 | 25.0 | $6,743.25 | $1,000.00 | 0.35 | U=0.30; SHGC=0.40 |
| 9103 | HVAC Shell | Basement Sidewall Insulation - Heat pump | MF | N/A | Retrofit | 3,477.9 | 9% | 306.9 | 0.064 | 25.0 | $2,815.20 | $1,000.00 | 0.28 | R0 to R13 sidewall insulation |
| 9104 | HVAC Shell | Floor Insulation Above Crawlspace - Heat pump | MF | N/A | Retrofit | 3,277.2 | 3% | 106.2 | 0.201 | 25.0 | $849.15 | $425.00 | 0.23 | R13 floor insulation |
| 9105 | HVAC Shell | Smart Window Coverings - Shade/Blind/Controller/Sensor - Heat pump_ET | MF | N/A | Retrofit | 3,171.0 | 16% | 491.5 | 0.211 | 7.0 | $8,500.00 | $1,000.00 | 0.22 | Smart shades |
| 9106 | HVAC Shell | Smart Window Coverings - Film/Transformer - Heat pump_ET | MF | N/A | Retrofit | 3,171.0 | 16% | 491.5 | 0.211 | 7.0 | $4,045.95 | $1,000.00 | 0.22 | Smart films |
| 9107 | HVAC Shell | Radiant Barrier - Electric furnace | MF | N/A | Retrofit | 4,973.1 | -6% | -281.8 | -0.073 | 20.0 | $429.57 | $130.00 | 0.00 | Installation of radiant barrier |
| 9108 | HVAC Shell | Cool Roof - Electric furnace | MF | N/A | Retrofit | 4,973.1 | -33% | -1,661.4 | -0.092 | 20.0 | $3,996.00 | $1,000.00 | 0.00 | Installation of cool roof |
| 9109 | HVAC Shell | Wall Sheathing - Electric furnace | MF | N/A | Retrofit | 4,973.1 | 13% | 662.3 | 0.414 | 25.0 | $1,242.00 | $625.00 | 1.44 | R12 polyiso |
| 9110 | HVAC Shell | ENERGY STAR Windows - Electric furnace | MF | N/A | Retrofit | 4,973.1 | 8% | 415.9 | 0.184 | 25.0 | $6,743.25 | $1,000.00 | 0.48 | U=0.30; SHGC=0.40 |
| 9111 | HVAC Shell | Basement Sidewall Insulation - Electric furnace | MF | N/A | Retrofit | 5,634.1 | 12% | 661.0 | 0.069 | 25.0 | $2,815.20 | $1,000.00 | 0.54 | R0 to R13 sidewall insulation |
| 9112 | HVAC Shell | Floor Insulation Above Crawlspace - Electric furnace | MF | N/A | Retrofit | 7,848.5 | 37% | 2,875.4 | -0.304 | 25.0 | $849.15 | $425.00 | 3.86 | R13 floor insulation |
| 9113 | HVAC Shell | Smart Window Coverings - Shade/Blind/Controller/Sensor - Electric furnace_ET | MF | N/A | Retrofit | 4,973.1 | 16% | 770.8 | 0.238 | 7.0 | $8,500.00 | $1,000.00 | 0.30 | Smart shades |
| 9114 | HVAC Shell | Smart Window Coverings - Film/Transformer - Electric furnace_ET | MF | N/A | Retrofit | 4,973.1 | 16% | 770.8 | 0.238 | 7.0 | $4,045.95 | $1,000.00 | 0.30 | Smart films |
| 9115 | HVAC Shell | Duct Sealing - Average Sealing - Gas Heating | SF | NLI | Retrofit | 3,380.5 | 5% | 161.5 | 0.131 | 20.0 | $200.00 | $175.00 | 1.61 | 15% to 10% leakage |
| 9116 | HVAC Shell | Duct Sealing - Inadequate Sealing - Gas Heating | SF | NLI | Retrofit | 3,442.6 | 7% | 229.5 | 0.115 | 20.0 | $350.00 | $300.00 | 1.25 | 20% to 15% leakage |
| 9117 | HVAC Shell | Duct Sealing/Insulation - Poor Sealing - Gas Heating | SF | NLI | Retrofit | 3,501.7 | 15% | 526.8 | 0.297 | 20.0 | $1,442.50 | $1,000.00 | 0.91 | 25% to 15% leakage |
| 9118 | HVAC Shell | Wall Insulation - Gas Heating | SF | NLI | Retrofit | 3,509.2 | 16% | 569.6 | 0.541 | 25.0 | $2,746.80 | $450.00 | 6.29 | R0 to R11 wall insulation |
| 9119 | HVAC Shell | Air Sealing - Average Sealing - Gas Heating | SF | NLI | Retrofit | 2,939.6 | 7% | 206.9 | 0.353 | 15.0 | $624.65 | $100.00 | 7.18 | 10 ACH 50 to 7 ACH 50 |
| 9120 | HVAC Shell | Air Sealing - Inadequate Sealing - Gas Heating | SF | NLI | Retrofit | 3,363.5 | 13% | 423.9 | 0.392 | 15.0 | $967.20 | $100.00 | 10.02 | 14 ACH 50 to 10 ACH 50 |
| 9121 | HVAC Shell | Air Sealing - Poor Sealing - Gas Heating | SF | NLI | Retrofit | 4,030.0 | 17% | 666.6 | 0.558 | 15.0 | $967.20 | $100.00 | 15.38 | 20 ACH 50 to 14 ACH 50 |
| 9122 | HVAC Shell | Attic Insulation - Average Insulation - Gas Heating | SF | NLI | Retrofit | 2,939.6 | 2% | 62.9 | 0.076 | 25.0 | $1,259.70 | $450.00 | 0.48 | R30 to R60 |
| 9123 | HVAC Shell | Attic Insulation - Inadequate Insulation - Gas Heating | SF | NLI | Retrofit | 2,997.7 | 4% | 120.9 | 0.143 | 25.0 | $1,744.20 | $450.00 | 1.00 | R19 to R60 |
| 9124 | HVAC Shell | Attic Insulation - Poor Insulation - Gas Heating | SF | NLI | Retrofit | 3,135.8 | 8% | 241.1 | 0.225 | 25.0 | $1,550.40 | $450.00 | 1.81 | R11 to R49 |
| 9125 | HVAC Shell | Duct Sealing - Average Sealing - Gas Heating | SF | LI | DI | 3,380.5 | 5% | 161.5 | 0.131 | 20.0 | $200.00 | $200.00 | 1.41 | 15% to 10% leakage |
| 9126 | HVAC Shell | Duct Sealing - Inadequate Sealing - Gas Heating | SF | LI | DI | 3,442.6 | 7% | 229.5 | 0.115 | 20.0 | $350.00 | $350.00 | 1.08 | 20% to 15% leakage |

**Vectren Electric** **Residential Measure Assumptions**

| Measure # | End-Use | Measure Name | Home Type | Income Type | Replacement Type | Base Annual Electric | % Elec Savings | Per Unit Elec Savings | Per Unit Summer NCP kW | Useful Life | Initial Measure Cost | Historical Incentive Amount | UCT Ratio | Measure Description |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 9127 | HVAC Shell | Duct Sealing/Insulation - Poor Sealing - Gas Heating | SF | LI | DI | 3,501.7 | 15% | 526.8 | 0.297 | 20.0 | $1,442.50 | $1,442.50 | 0.63 | 25% to 15% leakage |
| 9128 | HVAC Shell | Wall Insulation - Gas Heating | SF | LI | DI | 3,509.2 | 16% | 569.6 | 0.541 | 25.0 | $2,746.80 | $2,746.80 | 1.03 | R0 to R11 wall insulation |
| 9129 | HVAC Shell | Air Sealing - Average Sealing - Gas Heating | SF | LI | DI | 2,939.6 | 7% | 206.9 | 0.353 | 15.0 | $624.65 | $624.65 | 1.15 | 10 ACH 50 to 7 ACH 50 |
| 9130 | HVAC Shell | Air Sealing - Inadequate Sealing - Gas Heating | SF | LI | DI | 3,363.5 | 13% | 423.9 | 0.392 | 15.0 | $967.20 | $967.20 | 1.04 | 14 ACH 50 to 10 ACH 50 |
| 9131 | HVAC Shell | Air Sealing - Poor Sealing - Gas Heating | SF | LI | DI | 4,030.0 | 17% | 666.6 | 0.558 | 15.0 | $967.20 | $967.20 | 1.59 | 20 ACH 50 to 14 ACH 50 |
| 9132 | HVAC Shell | Attic Insulation - Average Insulation - Gas Heating | SF | LI | DI | 2,939.6 | 2% | 62.9 | 0.076 | 25.0 | $1,259.70 | $1,259.70 | 0.17 | R30 to R60 |
| 9133 | HVAC Shell | Attic Insulation - Inadequate Insulation - Gas Heating | SF | LI | DI | 2,997.7 | 4% | 120.9 | 0.143 | 25.0 | $1,744.20 | $1,744.20 | 0.26 | R19 to R60 |
| 9134 | HVAC Shell | Attic Insulation - Poor Insulation - Gas Heating | SF | LI | DI | 3,135.8 | 8% | 241.1 | 0.225 | 25.0 | $1,550.40 | $1,550.40 | 0.52 | R11 to R49 |
| 9135 | HVAC Shell | Wall Sheathing - Gas Heating | SF | N/A | Retrofit | 2,939.6 | 4% | 125.1 | 0.192 | 25.0 | $2,943.00 | $1,000.00 | 0.92 | R12 polyiso |
| 9136 | HVAC Shell | ENERGY STAR Windows - Gas Heating | SF | N/A | Retrofit | 2,939.6 | 8% | 249.6 | 0.535 | 25.0 | $13,601.25 | $1,000.00 | 0.76 | U=0.30; SHGC=0.40 |
| 9137 | HVAC Shell | Basement Sidewall Insulation - Gas Heating | SF | N/A | Retrofit | 2,976.4 | 1% | 36.8 | 0.036 | 25.0 | $2,720.00 | $1,000.00 | 0.48 | R0 to R13 sidewall insulation |
| 9138 | HVAC Shell | Floor Insulation Above Crawlspace - Gas Heating | SF | N/A | Retrofit | 2,908.9 | -1% | -30.7 | -0.036 | 25.0 | $316.20 | $90.00 | 0.73 | R13 floor insulation |
| 9139 | HVAC Shell | ENERGY STAR Door - Gas Heating | SF | N/A | Retrofit | 2,939.6 | 1% | 34.6 | 0.052 | 25.0 | $388.00 | $120.00 | 1.25 | Fiberglasss |
| 9140 | HVAC Shell | Smart Window Coverings - Shade/Blind/Controller/Sensor - Gas Heating_ET | SF | N/A | Retrofit | 2,939.6 | 16% | 455.6 | 0.531 | 7.0 | $14,875.00 | $1,000.00 | 0.53 | Smart shades |
| 9141 | HVAC Shell | Smart Window Coverings - Film/Transformer - Gas Heating_ET | SF | N/A | Retrofit | 2,939.6 | 16% | 455.6 | 0.531 | 7.0 | $8,160.75 | $1,000.00 | 0.53 | Smart films |
| 9142 | HVAC Shell | Duct Sealing - Average Sealing - Gas Heating | MF | NLI | Retrofit | 2,487.5 | 26% | 638.5 | 0.484 | 20.0 | $200.00 | $175.00 | 6.06 | 15% to 10% leakage |
| 9143 | HVAC Shell | Duct Sealing - Inadequate Sealing - Gas Heating | MF | NLI | Retrofit | 2,631.4 | 20% | 532.0 | 0.309 | 20.0 | $350.00 | $300.00 | 2.41 | 20% to 15% leakage |
| 9144 | HVAC Shell | Duct Sealing/Insulation - Poor Sealing - Gas Heating | MF | NLI | Retrofit | 2,796.3 | 48% | 1,342.7 | 0.788 | 20.0 | $981.00 | $500.00 | 3.67 | 25% to 15% leakage |
| 9145 | HVAC Shell | Wall Insulation - Gas Heating | MF | NLI | Retrofit | 2,385.4 | 9% | 222.4 | 0.221 | 25.0 | $1,159.20 | $450.00 | 2.12 | R0 to R11 wall insulation |
| 9146 | HVAC Shell | Air Sealing - Average Sealing - Gas Heating | MF | NLI | Retrofit | 2,163.0 | 9% | 200.4 | 0.183 | 15.0 | $309.69 | $100.00 | 4.26 | 10 ACH 50 to 7 ACH 50 |
| 9147 | HVAC Shell | Air Sealing - Inadequate Sealing - Gas Heating | MF | NLI | Retrofit | 2,390.9 | 10% | 227.9 | 0.162 | 15.0 | $479.52 | $100.00 | 5.01 | 14 ACH 50 to 10 ACH 50 |
| 9148 | HVAC Shell | Air Sealing - Poor Sealing - Gas Heating | MF | NLI | Retrofit | 2,758.6 | 13% | 367.7 | 0.187 | 15.0 | $479.52 | $100.00 | 7.43 | 20 ACH 50 to 14 ACH 50 |
| 9149 | HVAC Shell | Attic Insulation - Average Insulation - Gas Heating | MF | NLI | Retrofit | 2,163.0 | 8% | 172.1 | 0.145 | 25.0 | $1,298.70 | $450.00 | 0.86 | R30 to R60 |
| 9150 | HVAC Shell | Attic Insulation - Inadequate Insulation - Gas Heating | MF | NLI | Retrofit | 2,203.0 | 10% | 212.1 | 0.181 | 25.0 | $1,798.20 | $450.00 | 1.10 | R19 to R60 |
| 9151 | HVAC Shell | Attic Insulation - Poor Insulation - Gas Heating | MF | NLI | Retrofit | 2,290.4 | 13% | 291.6 | 0.245 | 25.0 | $1,598.40 | $450.00 | 1.51 | R11 to R49 |
| 9152 | HVAC Shell | Duct Sealing - Average Sealing - Gas Heating | MF | LI | DI | 2,487.5 | 26% | 638.5 | 0.484 | 20.0 | $200.00 | $200.00 | 5.30 | 15% to 10% leakage |
| 9153 | HVAC Shell | Duct Sealing - Inadequate Sealing - Gas Heating | MF | LI | DI | 2,631.4 | 20% | 532.0 | 0.309 | 20.0 | $350.00 | $350.00 | 2.06 | 20% to 15% leakage |

## Vectren Electric — Residential Measure Assumptions

| Measure # | End-Use | Measure Name | Home Type | Income Type | Replacement Type | Base Annual Electric | % Elec Savings | Per Unit Elec Savings | Per Unit Summer NCP kW | Useful Life | Initial Measure Cost | Historical Incentive Amount | UCT Ratio | Measure Description |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 9154 | HVAC Shell | Duct Sealing/Insulation - Poor Sealing - Gas Heating | MF | LI | DI | 2,796.3 | 48% | 1,342.7 | 0.788 | 20.0 | $981.00 | $981.00 | 1.87 | 25% to 15% leakage |
| 9155 | HVAC Shell | Wall Insulation - Gas Heating | MF | LI | DI | 2,385.4 | 9% | 222.4 | 0.221 | 25.0 | $1,159.20 | $1,159.20 | 0.82 | R0 to R11 wall insulation |
| 9156 | HVAC Shell | Air Sealing - Average Sealing - Gas Heating | MF | LI | DI | 2,163.0 | 9% | 200.4 | 0.183 | 15.0 | $309.69 | $309.69 | 1.38 | 10 ACH 50 to 7 ACH 50 |
| 9157 | HVAC Shell | Air Sealing - Inadequate Sealing - Gas Heating | MF | LI | DI | 2,390.9 | 10% | 227.9 | 0.162 | 15.0 | $479.52 | $479.52 | 1.04 | 14 ACH 50 to 10 ACH 50 |
| 9158 | HVAC Shell | Air Sealing - Poor Sealing - Gas Heating | MF | LI | DI | 2,758.6 | 13% | 367.7 | 0.187 | 15.0 | $479.52 | $479.52 | 1.55 | 20 ACH 50 to 14 ACH 50 |
| 9159 | HVAC Shell | Attic Insulation - Average Insulation - Gas Heating | MF | LI | DI | 2,163.0 | 8% | 172.1 | 0.145 | 25.0 | $1,298.70 | $1,298.70 | 0.30 | R30 to R60 |
| 9160 | HVAC Shell | Attic Insulation - Inadequate Insulation - Gas Heating | MF | LI | DI | 2,203.0 | 10% | 212.1 | 0.181 | 25.0 | $1,798.20 | $1,798.20 | 0.28 | R19 to R60 |
| 9161 | HVAC Shell | Attic Insulation - Poor Insulation - Gas Heating | MF | LI | DI | 2,290.4 | 13% | 291.6 | 0.245 | 25.0 | $1,598.40 | $1,598.40 | 0.43 | R11 to R49 |
| 9162 | HVAC Shell | Wall Sheathing - Gas Heating | MF | N/A | Retrofit | 2,163.0 | 9% | 203.7 | 0.190 | 25.0 | $1,242.00 | $625.00 | 0.96 | R12 polyiso |
| 9163 | HVAC Shell | ENERGY STAR Windows - Gas Heating | MF | N/A | Retrofit | 2,163.0 | 13% | 286.7 | 0.281 | 25.0 | $6,743.25 | $1,000.00 | 0.64 | U=0.30; SHGC=0.40 |
| 9164 | HVAC Shell | Basement Sidewall Insulation - Gas Heating | MF | N/A | Retrofit | 2,293.7 | 2% | 43.4 | -0.002 | 25.0 | $2,815.20 | $1,000.00 | 0.26 | R0 to R13 sidewall insulation |
| 9165 | HVAC Shell | Floor Insulation Above Crawlspace - Gas Heating | MF | N/A | Retrofit | 2,157.6 | -1% | -27.1 | -0.019 | 25.0 | $849.15 | $425.00 | 0.02 | R13 floor insulation |
| 9166 | HVAC Shell | Smart Window Coverings - Shade/Blind/Controller/Sensor - Gas Heating_ET | MF | N/A | Retrofit | 2,163.0 | 16% | 335.3 | 0.258 | 7.0 | $8,500.00 | $1,000.00 | 0.28 | Smart shades |
| 9167 | HVAC Shell | Smart Window Coverings - Film/Transformer - Gas Heating_ET | MF | N/A | Retrofit | 2,163.0 | 16% | 335.3 | 0.258 | 7.0 | $4,045.95 | $1,000.00 | 0.28 | Smart films |
| 10001 | Water Heating | Water Heater Wrap | SF | N/A | Retrofit | 3,536.2 | 2% | 80.4 | 0.009 | 5.0 | $20.00 | $20.00 | 0.98 | Add WH Wrap to reduce standby losses (Electric Only) |
| 10002 | Water Heating | Water Heater Temperature Setback | SF | NLI | Retrofit | 733.6 | 11% | 81.5 | 0.009 | 15.0 | $6.50 | $6.50 | 8.11 | WH Temp Setback from 135 to 120 |
| 10003 | Water Heating | Water Heater Timer | SF | NLI | Retrofit | 3,536.2 | 9% | 318.0 | 0.036 | 15.0 | $60.00 | $30.00 | 6.85 | Install Timer to turn off at night or other periods (Electric Only) |
| 10004 | Water Heating | Pipe Wrap | SF | NLI | Retrofit | 3,536.2 | 3% | 106.1 | 0.012 | 15.0 | $1.72 | $1.72 | 39.87 | Adding Pipe Wrap to Uninsulated Pipes |
| 10005 | Water Heating | Heat Pump Water Heater | SF | N/A | MO | 3,536.2 | 67% | 2,368.0 | 0.935 | 10.0 | $1,000.00 | $300.00 | 3.59 | Heat Pump Water Heater |
| 10006 | Water Heating | Solar Water Heater with Electric Backup | SF | N/A | MO | 3,536.2 | 50% | 1,777.0 | 0.702 | 10.0 | $9,506.00 | $2,850.00 | 0.26 | Solar WH (EF=1.8) |
| 10007 | Water Heating | Smart Water Heater - Tank Controls and Sensors_ET | SF | N/A | Retrofit | 3,536.2 | 15% | 530.0 | 0.209 | 10.0 | $120.00 | $60.00 | 4.26 | Smart WH Controls |
| 10008 | Water Heating | Bathroom Aerator 1.0 gpm | SF | NLI | Retrofit | 49.8 | 47% | 23.6 | 2.153 | 10.0 | $0.52 | $0.52 | 20.53 | 1.0 GPM Bathroom FA |
| 10009 | Water Heating | Kitchen Flip Aerator 1.5 gpm | SF | NLI | Retrofit | 396.6 | 39% | 152.8 | 2.114 | 10.0 | $1.34 | $1.34 | 43.53 | 1.5 GPM Kitchen FA |
| 10010 | Water Heating | Low Flow Showerhead 1.5 gpm | SF | NLI | Retrofit | 611.2 | 43% | 262.6 | 6.429 | 10.0 | $3.32 | $3.32 | 31.13 | 1.5 GPM Low Flow Showerhead |
| 10011 | Water Heating | Thermostatic Restrictor Shower Valve | SF | N/A | Retrofit | 611.2 | 11% | 69.7 | 2.302 | 10.0 | $30.00 | $15.00 | 1.93 | Thermostatic Restrictor Shower Valve (on base flow device) |
| 10012 | Water Heating | Shower Timer | SF | N/A | Retrofit | 611.2 | 9% | 53.6 | 0.321 | 2.0 | $5.00 | $5.00 | 1.28 | Shower Timer limit time to 5 mins (per shower) |
| 10013 | Water Heating | Drain water Heat Recovery | SF | N/A | Retrofit | 3,536.2 | 25% | 884.0 | 0.101 | 20.0 | $742.00 | $225.00 | 3.14 | Drainpipe heat exchanger |
| 10014 | Water Heating | Desuperheater | SF | N/A | Retrofit | 3,536.2 | 44% | 1,556.0 | 0.178 | 25.0 | $620.00 | $185.00 | 7.69 | Install Desuperheater (Paid with GSHP) |
| 10015 | Water Heating | Bathroom Aerator 1.0 gpm | SF | LI | DI | 49.8 | 47% | 23.6 | 2.153 | 10.0 | $0.52 | $0.52 | 20.53 | 1.0 GPM Bathroom FA |
| 10016 | Water Heating | Kitchen Flip Aerator 1.5 gpm | SF | LI | DI | 396.6 | 39% | 152.8 | 2.114 | 10.0 | $1.34 | $1.34 | 43.53 | 1.5 GPM Kitchen FA |

| Vectren Electric | Residential Measure Assumptions | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Measure # | End-Use | Measure Name | Home Type | Income Type | Replacement Type | Base Annual Electric | % Elec Savings | Per Unit Elec Savings | Per Unit Summer NCP kW | Useful Life | Initial Measure Cost | Historical Incentive Amount | UCT Ratio | Measure Description |
| 10017 | Water Heating | Low Flow Showerhead 1.5 gpm | SF | LI | DI | 611.2 | 43% | 262.6 | 6.429 | 10.0 | $3.32 | $3.32 | 31.13 | 1.5 GPM Low Flow Showerhead |
| 10018 | Water Heating | Pipe Wrap | SF | LI | DI | 3,536.2 | 3% | 106.1 | 0.012 | 15.0 | $1.72 | $1.72 | 39.87 | Adding Pipe Wrap to Uninsulated Pipes |
| 10019 | Water Heating | Water Heater Temperature Setback | SF | LI | DI | 733.6 | 11% | 81.5 | 0.009 | 15.0 | $6.50 | $6.50 | 8.11 | WH Temp Setback from 135 to 120 |
| 10020 | Water Heating | Water Heater Temperature Setback | SF | N/A | NC | 733.6 | 11% | 81.5 | 0.009 | 15.0 | $6.50 | $6.50 | 8.11 | WH Temp Setback from 135 to 120 |
| 10021 | Water Heating | Water Heater Timer | SF | N/A | NC | 3,536.2 | 9% | 318.0 | 0.036 | 15.0 | $60.00 | $30.00 | 6.85 | Install Timer to turn off at night or other periods (Electric Only) |
| 10022 | Water Heating | Pipe Wrap | SF | N/A | NC | 3,536.2 | 3% | 106.1 | 0.012 | 15.0 | $1.72 | $1.72 | 39.87 | Adding Pipe Wrap to Uninsulated Pipes |
| 10023 | Water Heating | Heat Pump Water Heater | SF | N/A | NC | 3,536.2 | 67% | 2,368.0 | 0.935 | 10.0 | $1,000.00 | $300.00 | 3.59 | Heat Pump Water Heater |
| 10024 | Water Heating | Solar Water Heater with Electric Backup | SF | N/A | NC | 3,536.2 | 50% | 1,777.0 | 0.702 | 10.0 | $9,506.00 | $2,850.00 | 0.26 | Solar WH (EF=1.8) |
| 10025 | Water Heating | Smart Water Heater - Tank Controls and Sensors_ET | SF | N/A | NC | 3,536.2 | 15% | 530.0 | 0.209 | 10.0 | $120.00 | $60.00 | 4.26 | Smart WH Controls |
| 10026 | Water Heating | Bathroom Aerator 1.0 gpm | SF | N/A | NC | 49.8 | 47% | 23.6 | 2.153 | 10.0 | $0.52 | $0.52 | 20.53 | 1.0 GPM Bathroom FA |
| 10027 | Water Heating | Kitchen Flip Aerator 1.5 gpm | SF | N/A | NC | 396.6 | 39% | 152.8 | 2.114 | 10.0 | $1.34 | $1.34 | 43.53 | 1.5 GPM Kitchen FA |
| 10028 | Water Heating | Low Flow Showerhead 1.5 gpm | SF | N/A | NC | 611.2 | 43% | 262.6 | 6.429 | 10.0 | $3.32 | $3.32 | 31.13 | 1.5 GPM Low Flow Showerhead |
| 10029 | Water Heating | Thermostatic Restrictor Shower Valve | SF | N/A | NC | 611.2 | 11% | 69.7 | 2.302 | 10.0 | $30.00 | $15.00 | 1.93 | Thermostatic Restrictor Shower Valve (on base flow device) |
| 10030 | Water Heating | Shower Timer | SF | N/A | NC | 611.2 | 9% | 53.6 | 0.321 | 2.0 | $5.00 | $5.00 | 1.28 | Shower Timer limit time to 5 mins (per shower) |
| 10031 | Water Heating | Drain water Heat Recovery | SF | N/A | NC | 3,536.2 | 25% | 884.0 | 0.101 | 20.0 | $742.00 | $225.00 | 3.14 | Drainpipe heat exchanger |
| 10032 | Water Heating | Desuperheater | SF | N/A | NC | 3,536.2 | 44% | 1,556.0 | 0.178 | 25.0 | $620.00 | $185.00 | 7.69 | Install Desuperheater (Paid with GSHP) |
| 10033 | Water Heating | Water Heater Wrap | MF | N/A | Retrofit | 2,662.9 | 2% | 60.5 | 0.007 | 5.0 | $20.00 | $20.00 | 0.74 | Add WH Wrap to reduce standby losses (Electric Only) |
| 10034 | Water Heating | Water Heater Temperature Setback | MF | NLI | Retrofit | 733.6 | 11% | 81.5 | 0.009 | 15.0 | $6.50 | $6.50 | 8.11 | WH Temp Setback from 135 to 120 |
| 10035 | Water Heating | Water Heater Timer | MF | NLI | Retrofit | 2,662.9 | 9% | 240.0 | 0.027 | 15.0 | $60.00 | $30.00 | 5.17 | Install Timer to turn off at night or other periods (Electric Only) |
| 10036 | Water Heating | Pipe Wrap | MF | NLI | Retrofit | 2,662.9 | 3% | 79.9 | 0.009 | 15.0 | $1.72 | $1.72 | 30.03 | Adding Pipe Wrap to Uninsulated Pipes |
| 10037 | Water Heating | Heat Pump Water Heater | MF | N/A | MO | 2,662.9 | 58% | 1,544.0 | 0.610 | 10.0 | $1,000.00 | $300.00 | 2.27 | Heat Pump Water Heater |
| 10038 | Water Heating | Smart Water Heater - Tank Controls and Sensors_ET | MF | N/A | Retrofit | 2,662.9 | 15% | 399.0 | 0.158 | 10.0 | $120.00 | $60.00 | 3.21 | Smart WH Controls |
| 10039 | Water Heating | Bathroom Aerator 1.0 gpm | MF | NLI | Retrofit | 57.2 | 47% | 27.1 | 2.153 | 10.0 | $0.52 | $0.52 | 22.77 | 1.0 GPM Bathroom FA |
| 10040 | Water Heating | Kitchen Flip Aerator 1.5 gpm | MF | NLI | Retrofit | 274.9 | 39% | 105.9 | 2.114 | 10.0 | $1.34 | $1.34 | 31.94 | 1.5 GPM Kitchen FA |
| 10041 | Water Heating | Low Flow Showerhead 1.5 gpm | MF | NLI | Retrofit | 649.6 | 43% | 279.1 | 6.429 | 10.0 | $1.34 | $1.34 | 81.22 | 1.5 GPM Low Flow Showerhead |
| 10042 | Water Heating | Thermostatic Restrictor Shower Valve | MF | N/A | Retrofit | 649.6 | 11% | 74.1 | 2.446 | 10.0 | $30.00 | $15.00 | 2.05 | Thermostatic Restrictor Shower Valve (on base flow device) |
| 10043 | Water Heating | Shower Timer | MF | N/A | Retrofit | 649.6 | 9% | 56.9 | 0.321 | 2.0 | $5.00 | $5.00 | 1.33 | Shower Timer limit time to 5 mins (per shower) |
| 10044 | Water Heating | Drain water Heat Recovery | MF | N/A | Retrofit | 2,662.9 | 25% | 666.0 | 0.076 | 20.0 | $742.00 | $225.00 | 2.36 | Drainpipe heat exchanger |
| 10045 | Water Heating | Desuperheater | MF | N/A | Retrofit | 2,662.9 | 44% | 1,172.0 | 0.134 | 25.0 | $620.00 | $185.00 | 5.80 | Install Desuperheater (Paid with GSHP) |
| 10046 | Water Heating | Bathroom Aerator 1.0 gpm | MF | LI | DI | 57.2 | 47% | 27.1 | 2.153 | 10.0 | $0.52 | $0.52 | 22.77 | 1.0 GPM Bathroom FA |
| 10047 | Water Heating | Kitchen Flip Aerator 1.5 gpm | MF | LI | DI | 274.9 | 39% | 105.9 | 2.114 | 10.0 | $1.34 | $1.34 | 31.94 | 1.5 GPM Kitchen FA |
| 10048 | Water Heating | Low Flow Showerhead 1.5 gpm | MF | LI | DI | 649.6 | 43% | 279.1 | 6.429 | 10.0 | $1.34 | $1.34 | 81.22 | 1.5 GPM Low Flow Showerhead |
| 10049 | Water Heating | Pipe Wrap | MF | LI | DI | 2,662.9 | 3% | 79.9 | 0.009 | 15.0 | $1.72 | $1.72 | 30.03 | Adding Pipe Wrap to Uninsulated Pipes |
| 10050 | Water Heating | Water Heater Temperature Setback | MF | LI | DI | 733.6 | 11% | 81.5 | 0.009 | 15.0 | $6.50 | $6.50 | 8.11 | WH Temp Setback from 135 to 120 |

**Vectren Electric** **Residential Measure Assumptions**

| Measure # | End-Use | Measure Name | Home Type | Income Type | Replacement Type | Base Annual Electric | % Elec Savings | Per Unit Elec Savings | Per Unit Summer NCP kW | Useful Life | Initial Measure Cost | Historical Incentive Amount | UCT Ratio | Measure Description |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 10051 | Water Heating | Water Heater Temperature Setback | MF | N/A | NC | 733.6 | 11% | 81.5 | 0.009 | 15.0 | $6.50 | $6.50 | 8.11 | WH Temp Setback from 135 to 120 |
| 10052 | Water Heating | Water Heater Timer | MF | N/A | NC | 2,662.9 | 9% | 240.0 | 0.027 | 15.0 | $60.00 | $30.00 | 5.17 | Install Timer to turn off at night or other periods (Electric Only) |
| 10053 | Water Heating | Pipe Wrap | MF | N/A | NC | 2,662.9 | 3% | 79.9 | 0.009 | 15.0 | $1.72 | $1.72 | 30.03 | Adding Pipe Wrap to Uninsulated Pipes |
| 10054 | Water Heating | Heat Pump Water Heater | MF | N/A | NC | 2,662.9 | 58% | 1,544.0 | 0.610 | 10.0 | $1,000.00 | $300.00 | 2.27 | Heat Pump Water Heater |
| 10055 | Water Heating | Smart Water Heater - Tank Controls and Sensors_ET | MF | N/A | NC | 2,662.9 | 15% | 399.0 | 0.158 | 10.0 | $120.00 | $60.00 | 3.21 | Smart WH Controls |
| 10056 | Water Heating | Bathroom Aerator 1.0 gpm | MF | N/A | NC | 57.2 | 47% | 27.1 | 2.153 | 10.0 | $0.52 | $0.52 | 22.77 | 1.0 GPM Bathroom FA |
| 10057 | Water Heating | Kitchen Flip Aerator 1.5 gpm | MF | N/A | NC | 274.9 | 39% | 105.9 | 2.114 | 10.0 | $1.34 | $1.34 | 31.94 | 1.5 GPM Kitchen FA |
| 10058 | Water Heating | Low Flow Showerhead 1.5 gpm | MF | N/A | NC | 649.6 | 43% | 279.1 | 6.429 | 10.0 | $1.34 | $1.34 | 81.22 | 1.5 GPM Low Flow Showerhead |
| 10059 | Water Heating | Thermostatic Restrictor Shower Valve | MF | N/A | NC | 649.6 | 11% | 74.1 | 2.446 | 10.0 | $30.00 | $15.00 | 2.05 | Thermostatic Restrictor Shower Valve (on base flow device) |
| 10060 | Water Heating | Shower Timer | MF | N/A | NC | 649.6 | 9% | 56.9 | 0.321 | 2.0 | $5.00 | $5.00 | 1.33 | Shower Timer limit time to 5 mins (per shower) |
| 10061 | Water Heating | Drain water Heat Recovery | MF | N/A | NC | 2,662.9 | 25% | 666.0 | 0.076 | 20.0 | $742.00 | $225.00 | 2.36 | Drainpipe heat exchanger |
| 10062 | Water Heating | Desuperheater | MF | N/A | NC | 2,662.9 | 44% | 1,172.0 | 0.134 | 25.0 | $620.00 | $185.00 | 5.80 | Install Desuperheater (Paid with GSHP) |

**Key Acronyms**

| | |
|---|---|
| DI: | Direct-install |
| LI: | Low-income |
| MF: | Multifamily |
| MO: | Market opportunity |
| NC: | New Construction |
| NLI: | Non-low-income |
| SF: | Single-family |

# APPENDIX C *DSM Market Potential Study Commercial Measure Detail*

| Vectren Electric | | Commercial Measure Assumptions | | | | | | |
|---|---|---|---|---|---|---|---|---|
| Measure # | End-Use | Measure Name | % Elec Savings | Per Unit Elec Savings | Per Unit NCP kW | Useful Life | Initial Measure Cost | UCT Ratio |
| 1 | Interior Lighting | Compact Fluorescent - 2019 | 67.8% | 198.8 | 0.039 | 3.0 | $1.20 | 64.96 |
| 2 | Interior Lighting | LED Exit Sign | 91.3% | 206.8 | 0.021 | 16.0 | $30.00 | 10.52 |
| 3 | Interior Lighting | High Performance T8 (vs RWT8) 4ft | 19% | 50 | 0.011 | 15 | $18.00 | 4.98 |
| 4 | Interior Lighting | Wall Mounted Occupancy Sensor | 24.0% | 335.3 | 0.000 | 8.0 | $51.00 | 4.41 |
| 5 | Interior Lighting | Fixture Mounted Occupancy Sensor | 24% | 198 | 0.000 | 8 | $91.83 | 1.45 |
| 6 | Interior Lighting | Remote Mounted Occupancy Sensor | 24% | 568 | 0.000 | 8 | $101.00 | 3.78 |
| 7 | Interior Lighting | High Bay LED vs (Metal Halide 250W) | 35% | 476 | 0.104 | 15 | $200.00 | 5.65 |
| 8 | Interior Lighting | High Bay LED vs (Metal Halide 400W) | 53% | 1,492 | 0.326 | 15 | $250.00 | 14.15 |
| 9 | Interior Lighting | High performance T5 (replacing T8) | 44% | 461 | 0.101 | 15 | $100.00 | 8.20 |
| 10 | Interior Lighting | CFL Hard Wired Fixture - 2019 | 69% | 199 | 0.044 | 12 | $37.50 | 7.94 |
| 11 | Interior Lighting | CFL High Wattage 31-115 - 2019 | 55% | 383 | 0.084 | 3 | $21.00 | 7.46 |
| 12 | Interior Lighting | CFL High Wattage 150-199 -2019 | 58% | 1,088 | 0.238 | 3 | $57.00 | 7.80 |
| 13 | Interior Lighting | Low Bay LED (vs T8HO) | 42% | 306 | 0.067 | 15 | $331.00 | 1.64 |
| 14 | Interior Lighting | High Bay LED (vs T8HO) | 35% | 472 | 0.103 | 15 | $482.00 | 1.74 |
| 15 | Interior Lighting | LED Screw-In Bulb | 51% | 149 | 0.027 | 15 | $1.20 | 207.76 |
| 16 | Interior Lighting | LED Downlight Fixtures | 68% | 168 | 0.037 | 15 | $27.00 | 11.07 |
| 17 | Interior Lighting | LED Linear Replacement Lamps | 37% | 99 | 0.022 | 15 | $25.00 | 7.04 |
| 18 | Interior Lighting | LED Troffer | 38% | 106 | 0.023 | 15 | $62.00 | 3.03 |
| 19 | Interior Lighting | Light Tube | 10% | 250 | 0.104 | 10 | $500.00 | 0.95 |
| 20 | Interior Lighting | Central Lighting Controls | 10% | 4,077 | 1.000 | 8 | $103.00 | 43.51 |
| 21 | Interior Lighting | Lighting Power Density Reduction (NC) | 10% | 4,077 | 1.000 | 15 | $220.00 | 45.78 |
| 22 | Interior Lighting | Switching Controls for Multi-Level Lighting | 30% | 12,232 | 3.000 | 8 | $274.00 | 49.07 |
| 23 | Interior Lighting | Smart Advanced Lighting Controls | 47% | 2 | 0.001 | 10 | $1.51 | 2.63 |
| 24 | Interior Lighting | Smart Web-based lighting Mgmt System | 35% | 3 | 0.001 | 10 | $1.15 | 5.41 |
| 25 | Exterior Lighting | Outdoor LED (< 250W MH) | 65% | 495 | 0.101 | 15 | $238.50 | 3.01 |
| 26 | Exterior Lighting | Outdoor LED (> 250W MH) | 54% | 983 | 0.201 | 15 | $592.00 | 2.41 |
| 27 | Space Cooling - Unitary / Split | Split System, <65,000 Btu/hr (CEE Tier 1) | 13% | 143 | 0.123 | 15 | $63.00 | 8.91 |
| 28 | Space Cooling - Unitary / Split | Split System, <65,000 Btu/hr (CEE Tier 2) | 19% | 201 | 0.173 | 15 | $127.00 | 6.22 |
| 29 | Space Cooling - Unitary / Split | Single Package System <65,000 Btu/hr (CEE Tier 1) | 7% | 66 | 0.057 | 15 | $63.00 | 4.14 |
| 30 | Space Cooling - Unitary / Split | Single Package System <65,000 Btu/hr (CEE Tier2) | 13% | 124 | 0.107 | 15 | $127.00 | 3.85 |
| 31 | Space Cooling - Unitary / Split | <135,000 Btu/hr (CEE Tier 1) (2019- 2022) | 8% | 86 | 0.074 | 15 | $63.00 | 5.37 |
| 32 | Space Cooling - Unitary / Split | <135,000 Btu/hr (CEE Tier 2) (2019-2022) | 13% | 140 | 0.121 | 15 | $127.00 | 4.35 |
| 33 | Space Cooling - Unitary / Split | <135,000 Btu/hr (CEE Advanced Tier) (2023+) | 18% | 169 | 0.146 | 15 | $127.00 | 5.24 |
| 34 | Space Cooling - Unitary / Split | <240,000 Btu/hr (CEE Tier 1) (2019 - 2022) | 6% | 69 | 0.060 | 15 | $63.00 | 4.31 |
| 35 | Space Cooling - Unitary / Split | <240,000 Btu/hr (CEE Tier 2) (2019 - 2022) | 13% | 144 | 0.125 | 15 | $127.00 | 4.47 |
| 36 | Space Cooling - Unitary / Split | <240,000 Btu/hr (CEE Advanced Tier) (2023+) | 17% | 163 | 0.141 | 15 | $127.00 | 5.06 |
| 37 | Space Cooling - Unitary / Split | <760,000 Btu/hr (CEE Tier 1) (2019 -2022) | 6% | 69 | 0.060 | 15 | $19.00 | 14.37 |
| 38 | Space Cooling - Unitary / Split | <760,000 Btu/hr (CEE Tier 2) (2019 -2022) | 12% | 148 | 0.127 | 15 | $38.00 | 15.30 |
| 39 | Space Cooling - Unitary / Split | <760,000 Btu/hr (CEE Advanced Tier) (2023+) | 9% | 96 | 0.083 | 15 | $38.00 | 9.93 |

| Vectren Electric | | Commercial Measure Assumptions | | | | | | |
|---|---|---|---|---|---|---|---|---|
| Measure # | End-Use | Measure Name | % Elec Savings | Per Unit Elec Savings | Per Unit NCP kW | Useful Life | Initial Measure Cost | UCT Ratio |
| 40 | Space Cooling - Unitary / Split | Tier 1) (2019 -2022) | 3% | 44 | 0.038 | 15 | $19.00 | 9.03 |
| 41 | Space Cooling - Unitary / Split | Tier 2) (2019 -2022) | 9% | 113 | 0.097 | 15 | $38.00 | 11.70 |
| 42 | Space Cooling - Unitary / Split | PTAC, <7,000 Btu/hr | 8% | 106 | 0.078 | 15 | $84.00 | 4.51 |
| 43 | Space Cooling - Unitary / Split | PTAC ≥7,000 Btu/h and ≤15,000 Btu/hr | 11% | 162 | 0.124 | 15 | $84.00 | 7.05 |
| 44 | Space Cooling - Unitary / Split | PTHP, ≥7,000 Btu/hr and ≤15,000 Btu/hr | 11% | 177 | 0.130 | 15 | $84.00 | 7.52 |
| 45 | Space Cooling - Unitary / Split | HVAC Tune-up (2019-2022) | 15% | 164 | 0.000 | 3 | $35.00 | 1.98 |
| 46 | Space Cooling - Unitary / Split | HVAC Tune-up (2023+) | 15% | 150 | 0.000 | 3 | $35.00 | 1.80 |
| 47 | Space Cooling - Unitary / Split | Air Source Heat Pump <65,000 BtuH (CEE Tier 1) | 7% | 66 | 0.057 | 15 | $50.00 | 1.14 |
| 48 | Space Cooling - Unitary / Split | Air Source Heat Pump <65,000 BtuH (CEE Tier 2) | 13% | 124 | 0.107 | 15 | $50.00 | 2.38 |
| 49 | Space Cooling - Unitary / Split | Btu/hr (CEE Tier 1) (2019-2022) | 10% | 117 | 0.101 | 15 | $50.00 | 1.99 |
| 50 | Space Cooling - Unitary / Split | Btu/hr (CEE Tier 1) (2023+) | 10% | 101 | 0.088 | 15 | $50.00 | 2.08 |
| 51 | Space Cooling - Unitary / Split | Btu/hr (CEE Tier 1) (2019 -2022) | 9% | 112 | 0.097 | 15 | $50.00 | 1.94 |
| 52 | Space Cooling - Unitary / Split | Btu/hr (CEE Tier 1) (2023+) | 9% | 97 | 0.083 | 15 | $50.00 | 1.76 |
| 53 | Space Cooling - Unitary / Split | (2019 -2022) | 10% | 133 | 0.115 | 15 | $50.00 | 2.22 |
| 54 | Space Cooling - Unitary / Split | (2023+) | 10% | 113 | 0.098 | 15 | $50.00 | 2.00 |
| 55 | Space Cooling - Unitary / Split | Ground Source Heat Pump <135,000 Btu/hr | 10% | 110 | 0.095 | 15 | $75.00 | 1.57 |
| 56 | Space Cooling - Unitary / Split | Water Source Heat Pump <17,000Btu/hr | 13% | 147 | 0.126 | 15 | $75.00 | 1.90 |
| 57 | Space Cooling - Unitary / Split | <135,000Btu/hr | 7% | 76 | 0.066 | 15 | $75.00 | 1.05 |
| 58 | Space Cooling - Unitary / Split | Advanced Rooftop Controls | 45% | 3,034 | 2.617 | 9 | $187.50 | 57.49 |
| 59 | Space Cooling - Unitary / Split | Commercial/Industrial CO2 Heat Pump | 70% | 351 | 0.000 | 10 | $87.78 | 5.52 |
| 60 | Space Cooling - Unitary / Split | Room A/C | 4% | 16 | 0.037 | 9 | $40.00 | 2.23 |
| 61 | Space Cooling - Unitary / Split | Cool roof | 15% | 89 | 0.045 | 20 | $88.22 | 0.65 |
| 62 | Space Cooling - Unitary / Split | Ceiling Insulation | 8% | 87 | 0.044 | 30 | $58.59 | 2.34 |
| 63 | Space Cooling - Unitary / Split | Wall insulation | 2% | 507 | 0.136 | 30 | $8.32 | 71.55 |
| 64 | Space Cooling - Unitary / Split | Roof Insulation | 8% | 24 | 0.019 | 30 | $11.36 | 4.35 |
| 65 | Space Cooling - Unitary / Split | Destratification Fan | 50% | 8 | -0.007 | 15 | $7.27 | 0.51 |
| 66 | Space Cooling - Unitary / Split | EMS | 10% | 310 | 0.014 | 15 | $0.86 | 194.09 |
| 67 | Space Cooling - Unitary / Split | Duct sealing 15% leakage base | 5% | 19 | 0.013 | 18 | $10.85 | 2.47 |
| 68 | Space Cooling - Unitary / Split | Integrated Building Design | 30% | 2 | 0.000 | 20 | $0.11 | 16.35 |
| 69 | Space Cooling - Unitary / Split | Retrocommissioning | 16% | 1 | 0.000 | 7 | $0.03 | 12.80 |
| 70 | Space Cooling - Unitary / Split | Commissioning | 13% | 1 | 0.000 | 7 | $0.12 | 2.69 |
| 71 | Space Cooling - Unitary / Split | Commercial Window Film | 5% | 209 | 0.050 | 10 | $35.50 | 1.94 |
| 72 | Space Cooling - Unitary / Split | High Performance Glazing | 6% | 2 | 0.070 | 20 | $6.82 | 8.95 |
| 73 | Space Cooling - Unitary / Split | Programable Thermostats | 10% | 945 | 0.000 | 4 | $22.44 | 5.36 |
| 74 | Space Cooling - Unitary / Split | Cooling | 25% | 119 | 0.047 | 8 | $18.89 | 3.19 |
| 75 | Space Cooling - Unitary / Split | Smart Thermostats | 8% | 660 | 0.000 | 10 | $29.75 | 6.50 |
| 76 | Space Cooling - Unitary / Split | Smart Cloud-Based Enery Information System (EIS) | 8% | 89 | 0.000 | 10 | $0.61 | 42.60 |
| 77 | Space Cooling - Chillers | Air Cooled Chiller <150 tons | 13% | 318 | 0.116 | 20 | $127.00 | 8.04 |
| 78 | Space Cooling - Chillers | Air Cooled Chiller ≥150 tons | 13% | 305 | 0.112 | 20 | $127.00 | 7.28 |

| Vectren Electric | | Commercial Measure Assumptions | | | | | | |
|---|---|---|---|---|---|---|---|---|
| Measure # | End-Use | Measure Name | % Elec Savings | Per Unit Elec Savings | Per Unit NCP kW | Useful Life | Initial Measure Cost | UCT Ratio |
| 79 | Space Cooling - Chillers | Water Cooled Screw Chiller <150 ton | 13% | 191 | 0.070 | 20 | $177.68 | 3.46 |
| 80 | Space Cooling - Chillers | Water Cooled Screw Chiller ≥150 tons and < 300 tons | 19% | 273 | 0.100 | 20 | $127.00 | 6.91 |
| 81 | Space Cooling - Chillers | Water Cooled Screw Chiller ≥300 ton | 21% | 300 | 0.110 | 20 | $87.00 | 11.09 |
| 82 | Space Cooling - Chillers | Water Cooled Centrifugal Chiller <150 ton | 20% | 300 | 0.110 | 20 | $166.10 | 5.81 |
| 83 | Space Cooling - Chillers | tons | 27% | 410 | 0.150 | 20 | $122.87 | 10.71 |
| 84 | Space Cooling - Chillers | Water Cooled Centrifugal Chiller ≥300 ton | 25% | 355 | 0.130 | 20 | $92.22 | 12.37 |
| 85 | Space Cooling - Chillers | Air Cooled Chiller Tune-up/Diagnostics | 8% | 187 | 0.000 | 5 | $5.66 | 20.10 |
| 86 | Space Cooling - Chillers | WaterCooled Chiller/Tune-up/Diagnostics | 8% | 119 | 0.000 | 5 | $5.66 | 12.78 |
| 87 | Space Cooling - Chillers | Chilled Water Reset Controls | 25% | 173 | 0.030 | 10 | $681.34 | 0.39 |
| 88 | Space Cooling - Chillers | Cool roof | 15% | 89 | 0.045 | 20 | $88.22 | 0.65 |
| 89 | Space Cooling - Chillers | Ceiling Insulation | 8% | 87 | 0.044 | 30 | $58.59 | 2.34 |
| 90 | Space Cooling - Chillers | Wall insulation | 2% | 507 | 0.136 | 30 | $8.32 | 71.55 |
| 91 | Space Cooling - Chillers | Roof Insulation | 8% | 24 | 0.019 | 30 | $11.36 | 4.35 |
| 92 | Space Cooling - Chillers | Destratification Fan | 50% | 8 | -0.007 | 15 | $7.27 | 0.51 |
| 93 | Space Cooling - Chillers | EMS | 10% | 310 | 0.014 | 15 | $0.86 | 194.09 |
| 94 | Space Cooling - Chillers | Duct sealing 15% leakage base | 5% | 19 | 0.013 | 18 | $10.85 | 2.47 |
| 95 | Space Cooling - Chillers | Integrated Building Design | 30% | 2 | 0.000 | 20 | $0.11 | 16.35 |
| 96 | Space Cooling - Chillers | Retrocommissioning | 16% | 1 | 0.000 | 7 | $0.03 | 12.80 |
| 97 | Space Cooling - Chillers | Commissioning | 13% | 1 | 0.000 | 7 | $0.12 | 2.69 |
| 98 | Space Cooling - Chillers | Commercial Window Film | 5% | 209 | 0.050 | 10 | $35.50 | 1.94 |
| 99 | Space Cooling - Chillers | High Performance Glazing | 6% | 2 | 0.070 | 20 | $6.82 | 8.95 |
| 100 | Space Cooling - Chillers | Programable Thermostats | 10% | 945 | 0.000 | 4 | $22.44 | 5.36 |
| 101 | Space Cooling - Chillers | Smart Thermostats | 8% | 660 | 0.000 | 10 | $29.75 | 6.50 |
| 102 | Space Cooling - Chillers | Smart Cloud-Based Enery Information System (EIS) | 8% | 89 | 0.000 | 10 | $0.61 | 42.60 |
| 103 | Space Heating | PTHP, <7,000 Btu/hr | 8% | 65 | 0.100 | 15 | $84.00 | 1.12 |
| 104 | Space Heating | PTHP, ≥7,000 Btu/hr and ≤15,000 Btu/hr | 11% | 94 | 0.146 | 15 | $84.00 | 1.63 |
| 105 | Space Heating | Tier 1) | 4% | 33 | 0.052 | 15 | $50.00 | 1.14 |
| 106 | Space Heating | Tier 2) | 9% | 84 | 0.130 | 15 | $50.00 | 2.38 |
| 107 | Space Heating | System (CEE Tier 1) | 6% | 57 | 0.088 | 15 | $50.00 | 4.14 |
| 108 | Space Heating | System (CEE Tier 2) | 6% | 57 | 0.088 | 15 | $50.00 | 3.85 |
| 109 | Space Heating | Btu/hr (CEE Tier 1) (2019-2022) | 8% | 57 | 0.089 | 15 | $50.00 | 1.99 |
| 110 | Space Heating | Btu/hr (CEE Tier 1) (2023+) | 6% | 37 | 0.057 | 15 | $50.00 | 2.08 |
| 111 | Space Heating | Btu/hr (CEE Tier 1) (2019 -2022) | 9% | 61 | 0.094 | 15 | $50.00 | 1.94 |
| 112 | Space Heating | Btu/hr (CEE Tier 1) (2023+) | 6% | 39 | 0.061 | 15 | $50.00 | 1.76 |
| 113 | Space Heating | (2019 -2022) | 9% | 61 | 0.094 | 15 | $50.00 | 2.22 |
| 114 | Space Heating | (2023+) | 9% | 61 | 0.094 | 15 | $50.00 | 2.00 |
| 115 | Space Heating | Ground Source Heat Pump <135,000 Btu/hr | 10% | 61 | 0.008 | 15 | $75.00 | 1.57 |
| 116 | Space Heating | Water Source Heat Pump < 135,000Btu/hr | 13% | 68 | 0.009 | 15 | $75.00 | 1.90 |
| 117 | Space Heating | <135,000Btu/hr | 7% | 38 | 0.005 | 15 | $75.00 | 1.05 |

| Vectren Electric | | Commercial Measure Assumptions | | | | | | |
|---|---|---|---|---|---|---|---|---|
| Measure # | End-Use | Measure Name | % Elec Savings | Per Unit Elec Savings | Per Unit NCP kW | Useful Life | Initial Measure Cost | UCT Ratio |
| 118 | Space Heating | Commercial/Industrial CO2 Heat Pump | 70% | 189 | 0.000 | 10 | $47.22 | 5.52 |
| 119 | Space Heating | Cool roof | 15% | 41 | 0.021 | 20 | $88.22 | 0.65 |
| 120 | Space Heating | Ceiling Insulation | 8% | 40 | 0.020 | 30 | $58.59 | 2.34 |
| 121 | Space Heating | Wall insulation | 2% | 236 | 0.063 | 30 | $8.32 | 71.55 |
| 122 | Space Heating | Roof Insulation | 8% | 11 | 0.009 | 30 | $11.36 | 4.35 |
| 123 | Space Heating | Destratification Fan | 50% | 4 | -0.003 | 15 | $7.27 | 0.51 |
| 124 | Space Heating | EMS | 10% | 144 | 0.007 | 15 | $0.86 | 194.09 |
| 125 | Space Heating | Duct sealing 15% leakage base | 5% | 9 | 0.006 | 18 | $10.85 | 2.47 |
| 126 | Space Heating | Integrated Building Design | 30% | 1 | 0.000 | 20 | $0.11 | 16.35 |
| 127 | Space Heating | Retrocommissioning | 16% | 0 | 0.000 | 7 | $0.03 | 12.80 |
| 128 | Space Heating | Commissioning | 13% | 0 | 0.000 | 7 | $0.12 | 2.69 |
| 129 | Space Heating | Commercial Window Film | 5% | 97 | 0.023 | 10 | $35.50 | 1.94 |
| 130 | Space Heating | High Performance Glazing | 6% | 1 | 0.032 | 20 | $6.82 | 8.95 |
| 131 | Space Heating | Programable Thermostats | 10% | 945 | 0.000 | 4 | $22.44 | 5.36 |
| 132 | Space Heating | Cooling | 25% | 119 | 0.047 | 8 | $18.89 | 3.19 |
| 133 | Space Heating | Smart Thermostats | 8% | 660 | 0.000 | 10 | $29.75 | 6.50 |
| 134 | Space Heating | Smart Cloud-Based Enery Information System (EIS) | 8% | 89 | 0.000 | 10 | $0.61 | 42.60 |
| 135 | Ventilation | VFD Supply and Return Fans, < 2 HP | 30% | 2,497 | 0.369 | 15 | $1,330.00 | 2.73 |
| 136 | Ventilation | VFD Supply and Return Fans, <3 to 10 HP | 30% | 6,242 | 0.922 | 15 | $1,622.00 | 5.59 |
| 137 | Ventilation | VFD Supply and Return Fans, 11 to 50 HP | 30% | 37,450 | 5.530 | 15 | $3,059.00 | 17.79 |
| 138 | Ventilation | Enthalpy Economizer | 20% | 117 | 0.000 | 10 | $400.00 | 0.30 |
| 139 | Ventilation | Improved Duct Sealing | 23% | 70 | 0.000 | 18 | $107.91 | 1.43 |
| 140 | Ventilation | Electronically-Commutated Permanent Magnet Motors | 65% | 1,635 | 0.000 | 15 | $3,059.00 | 0.78 |
| 141 | Ventilation | High Volume Low Speed Fans | 50% | 8,379 | 3.067 | 10 | $4,185.00 | 4.03 |
| 142 | Ventilation | VFD Tower Fan | 30% | 829 | 0.265 | 10 | $155.96 | 5.50 |
| 143 | Motors | VFD on Chilled Water Pump Motor, 5 HP | 15% | 28,580 | 0.000 | 15 | $1,330.00 | 31.22 |
| 144 | Motors | VFD on Chilled Water Pump Motor, 7.5 HP | 15% | 42,870 | 0.000 | 15 | $1,622.00 | 38.40 |
| 145 | Motors | VFD on Chilled Water Pump Motor, 20 HP | 15% | 171,480 | 0.000 | 15 | $3,059.00 | 81.44 |
| 146 | Motors | High Performance Elevators | 80% | 12,982 | 1.406 | 25 | $54,690.00 | 0.64 |
| 147 | Motors | Escalators Motor Efficiency Controllers | 30% | 5,414.000 | 0.620 | 20 | $6,900.00 | 1.86 |
| 148 | Other | NEMA Premium Transformer, single-phase | 2% | 0.163 | 0.000 | 30 | $0.24 | 3.16 |
| 149 | Other | NEMA Premium Transformer, three-phase | 2% | 0.244 | 0.000 | 30 | $0.18 | 4.81 |
| 150 | Other | High Efficiency Transformer, single-phase | 2% | 0.393 | 0.000 | 30 | $0.46 | 3.56 |
| 151 | Other | High Efficiency Transformer, three-phase | 2% | 0 | 0.000 | 30 | $0.44 | 5.50 |
| 152 | Water Heating | High Efficiency Storage (tank) | 0% | 9 | 0.000 | 15 | $70.00 | 0.18 |
| 153 | Water Heating | retrofit | 20% | 1,284 | 0.000 | 5 | $92.90 | 7.30 |
| 154 | Water Heating | On Demand (tankless) | 7% | 7,905 | 0.000 | 5 | $1,050.00 | 3.97 |
| 155 | Water Heating | dryer | 38% | 86 | 0.000 | 7 | $19.35 | 3.32 |
| 156 | Water Heating | Electric dryer | 25% | 542 | 0.000 | 7 | $72.00 | 5.62 |

| Vectren Electric | | Commercial Measure Assumptions | | | | | | |
|---|---|---|---|---|---|---|---|---|
| Measure # | End-Use | Measure Name | % Elec Savings | Per Unit Elec Savings | Per Unit NCP kW | Useful Life | Initial Measure Cost | UCT Ratio |
| 157 | Water Heating | Gas Dryer | 33% | 429 | 0.000 | 7 | $66.91 | 4.78 |
| 158 | Water Heating | Electric Dryer | 27% | 884 | 0.000 | 7 | $93.21 | 7.08 |
| 159 | Water Heating | ES Dishwasher, High Temp, Elec Heat, Elec Booster | 30% | 11,358 | 0.000 | 15 | $419.05 | 39.44 |
| 160 | Water Heating | ES Dishwasher, High Temp, Gas Heat, Elec Booster | 26% | 4,862 | 0.000 | 15 | $265.03 | 26.69 |
| 161 | Water Heating | ES Dishwasher, High Temp, Gas Heat, Gas Booster | 15% | 1,699 | 0.000 | 15 | $115.95 | 21.32 |
| 162 | Water Heating | ES Dishwasher, Low Temp, Elec Heat | 33% | 12,783 | 0.000 | 16 | $95.07 | 205.29 |
| 163 | Water Heating | ES Dishwasher, Low Temp, Gas Heat | 5% | 584 | 0.000 | 16 | $8.73 | 102.14 |
| 164 | Water Heating | Tank Insulation | 91% | 468 | 0.000 | 15 | $2.22 | 409.25 |
| 165 | Water Heating | Heat Pump Water Heater | 59% | 2,124 | 0.000 | 10 | $433.00 | 6.77 |
| 166 | Cooking | High Efficiency Combination Oven | 35% | 6,368 | 0.000 | 12 | $100.00 | 77.30 |
| 167 | Cooking | Induction Cooktop | 20% | 784 | 0.000 | 11 | $3,000.00 | 0.39 |
| 168 | Cooking | Electric Energy Star Fryers | 17% | 3,126 | 0.000 | 12 | $275.67 | 13.76 |
| 169 | Cooking | Electric Energy Star Steamers,3-6 pan | 57% | 9,967 | 0.000 | 12 | $3,400.00 | 3.56 |
| 170 | Cooking | Energy Star Convection Ovens | 16% | 1,937 | 0.000 | 12 | $388.00 | 6.06 |
| 171 | Cooking | Energy Star Griddles | 12% | 1,909 | 0.000 | 12 | $860.00 | 2.69 |
| 172 | Cooking | Energy Star Hot Food Holding Cabinet | 53% | 1,730 | 0.000 | 12 | $902.00 | 2.33 |
| 173 | Refrigeration | Glass Door Freezer, <15-49 cu ft, Energy Star | 43% | 3,595 | 0.000 | 12 | $166.00 | 26.26 |
| 174 | Refrigeration | Glass Door Freezer, 50+ cu ft, Energy Star | 45% | 9,804 | 0.000 | 12 | $407.00 | 29.21 |
| 175 | Refrigeration | Solid Door Freezer, <15-49 cu ft, Energy Star | 36% | 1,489 | 0.000 | 12 | $166.00 | 10.88 |
| 176 | Refrigeration | Solid Door Freezer, 50+ cu ft, Energy Star | 46% | 5,322 | 0.000 | 12 | $407.00 | 15.86 |
| 177 | Refrigeration | Glass Door Refrigerator, <15 - 49 cu ft, Energy Star | 36% | 828 | 0.000 | 12 | $164.00 | 6.12 |
| 178 | Refrigeration | Glass Door Refrigerator, 50+ cu ft, Energy Star | 35% | 1,577 | 0.000 | 12 | $249.00 | 7.68 |
| 179 | Refrigeration | Solid Door Refrigerator, <15-49 cu ft, Energy Star | 38% | 635 | 0.000 | 12 | $164.00 | 4.70 |
| 180 | Refrigeration | Solid Door Refrigerator, 50+ cu ft, Energy Star | 48% | 1,675 | 0.000 | 12 | $249.00 | 8.16 |
| 181 | Refrigeration | self contained | 7% | 537 | 0.000 | 1 | $75.00 | 1.04 |
| 182 | Refrigeration | contained | 7% | 1,388 | 0.000 | 1 | $75.00 | 2.68 |
| 183 | Refrigeration | Anti-sweat heater controls on freezers | 55% | 2,557 | 0.000 | 12 | $200.00 | 15.50 |
| 184 | Refrigeration | Anti-sweat heater controls, on refrigerators | 55% | 1,082 | 0.000 | 12 | $200.00 | 6.56 |
| 185 | Refrigeration | Vending Miser, Cold Beverage | 46% | 1,612 | 0.000 | 5 | $215.50 | 3.95 |
| 186 | Refrigeration | Brushless DC Motors (ECM) for freezers and coolers | 44% | 1,064 | 0.000 | 15 | $177.00 | 8.73 |
| 187 | Refrigeration | Humidity Door Heater Controls for freezers and coolers | 55% | 1,820 | 0.000 | 12 | $200.00 | 11.03 |
| 188 | Refrigeration | Refrigerated Case Covers | 9% | 945 | 0.000 | 5 | $252.00 | 1.98 |
| 189 | Refrigeration | Zero Energy Doors for freezers and coolers | 20% | 1,360 | 0.000 | 10 | $290.00 | 6.47 |
| 190 | Refrigeration | Evaporator Coil Defrost Control | 30% | 197 | 0.002 | 10 | $500.00 | 0.56 |
| 191 | Refrigeration | Evaporator Fan Motor Control for freezers and coolers | 36% | 1,524 | 0.000 | 16 | $291.00 | 10.64 |
| 192 | Refrigeration | Ice Machine, Energy Star, Self-Contained | 7% | 263 | 0.000 | 9 | $56.00 | 0.51 |
| 193 | Refrigeration | LED Case Lighting (retrofit) | 45% | 437 | 0.000 | 8 | $250.00 | 0.19 |
| 194 | Refrigeration | Efficient Refrigeration Condenser | 2% | 120 | 0.000 | 15 | $35.00 | 0.50 |
| 195 | Refrigeration | Efficient low-temp compressor | 1% | 875 | 0.000 | 13 | $552.00 | 2.74 |

| Vectren Electric | | Commercial Measure Assumptions | | | | | | |
|---|---|---|---|---|---|---|---|---|
| Measure # | End-Use | Measure Name | % Elec Savings | Per Unit Elec Savings | Per Unit NCP kW | Useful Life | Initial Measure Cost | UCT Ratio |
| 196 | Compressed Air | Automatic Drains | 0% | 2,097 | 0.000 | 5 | $355.00 | 4.15 |
| 197 | Compressed Air | Cycling and High Efficiency Dryers | 35% | 4 | 0.000 | 10 | $6.00 | 0.93 |
| 198 | Compressed Air | Efficient Air Compressors | 18% | 914 | 0.000 | 15 | $250.00 | 5.30 |
| 199 | Compressed Air | Low Pressure Drop-Filters | 3% | 65 | 0.000 | 10 | $22.00 | 4.05 |
| 200 | Compressed Air | Receiver Capacity Addition | 10% | 9,159 | 0.000 | 10 | $2,000.00 | 6.31 |
| 201 | Compressed Air | Engineered Nozzles for blow-off | 71% | 22,230 | 0.000 | 15 | $14.00 | 2304.40 |
| 202 | Compressed Air | Compressed Air Leak Survey and Repair | 50% | 496 | 0.000 | 1 | $6.00 | 11.94 |
| 203 | Office Equipment | Commercial Plug Load - Smart Strip Outlets | 15% | 23 | 0.000 | 8 | $15.00 | 1.32 |
| 204 | Office Equipment | Plug Load  Occupancy Sensor | 15% | 169 | 0.000 | 8 | $70.00 | 2.03 |
| 205 | Office Equipment | Energy Star Compliant Refrigerator | 20% | 120 | 0.000 | 17 | $30.00 | 6.35 |
| 206 | Office Equipment | Energy Star Computers | 43% | 81 | 0.000 | 4 | $5.00 | 9.07 |
| 207 | Office Equipment | Computer Power Management Software | 46% | 161 | 0.000 | 5 | $29.00 | 3.91 |
| 208 | Office Equipment | Energy Star UPS | 11% | 105 | 0.000 | 10 | $1,303.35 | 0.11 |
| 209 | Office Equipment | High Efficiency Hand Dryer | 69% | 965 | 0.000 | 10 | $450.00 | 2.96 |
| 210 | Office Equipment | Electrically Commutated Plug Fans in data centers | 33% | 1,445 | 0.000 | 15 | $718.00 | 3.90 |
| 211 | Office Equipment | High Efficiency CRAC unit | 30% | 162 | 0.000 | 15 | $62.50 | 5.03 |
| 212 | Office Equipment | Computer Room Air Conditioner Economizer | 47% | 358 | 0.000 | 15 | $82.00 | 8.46 |
| 213 | Office Equipment | Computer Room Hot Aisle Cold Aisle Configuration | 13% | 125 | 0.000 | 15 | $156.00 | 1.55 |
| 214 | Office Equipment | Computer Room Air Side Economizer | 47% | 440 | 0.000 | 10 | $25.00 | 24.30 |
| 215 | Office Equipment | VFD for Process Fans -CRAC units | 43% | 2,279 | 0.000 | 15 | $200.00 | 22.07 |
| 216 | Office Equipment | Vending Miser for Non-Refrig Equip | 46% | 343 | 0.000 | 5 | $108.00 | 0.34 |
| 217 | Pools | Heat Pump Pool Heater | 61% | 5,732 | 0.000 | 10 | $4,000.00 | 1.98 |
| 218 | Pools | High efficiency spas/hot tubs | 15% | 375 | 0.000 | 10 | $300.00 | 1.72 |
| 219 | Pools | VFD Retrofit on Pool Circulation Pump | 35% | 1,425 | 0.000 | 12 | $200.00 | 11.52 |
| 220 | Behavioral | Reports) | 3% | 7,852 | 0.896 | 2 | $8.88 | 271.30 |
| 221 | Behavioral | Whole-Building Energy Monitoring | 10% | 2 | 0.000 | 2 | $1.00 | 0.52 |
| 222 | Behavioral | Energy Use Displays | 9% | 23,555 | 2.693 | 1 | $250.00 | 14.60 |

# APPENDIX D *DSM Market Potential Study Industrial Measure Detail*

| Vectren Electric | | Industrial Measure Assumptions | | | | | | |
|---|---|---|---|---|---|---|---|---|
| Measure # | End-Use | Measure Name | % Elec Savings | Per Unit Elec Savings | Per Unit Summer NCP kW | Useful Life | Initial Measure Cost | UCT Ratio |
| 101 | Appliances, Computers, Office Equipment | Energy Star Compliant Single Door Refrigerator | 20.0% | 120.0 | 0.000 | 17.0 | $30.00 | 7.38 |
| 102 | Appliances, Computers, Office Equipment | Energy Star computers | 43.0% | 80.5 | 0.000 | 4.0 | $5.00 | 17.75 |
| 103 | Appliances, Computers, Office Equipment | Energy Efficient "Smart" Power Strip for PC/Monitor/Printer | 15.0% | 23.4 | 0.000 | 8.0 | $15.00 | 1.58 |
| 104 | Appliances, Computers, Office Equipment | PC Network Energy Management Controls replacing no central control | 46.0% | 161.0 | 0.000 | 5.0 | $29.00 | 3.24 |
| 106 | Appliances, Computers, Office Equipment | Energy Star UPS | 10.5% | 104.8 | 0.000 | 10.0 | $1,303.35 | 0.13 |
| 107 | Appliances, Computers, Office Equipment | High Efficiency CRAC Unit | 30.0% | 162.3 | 0.020 | 15.0 | $62.50 | 4.96 |
| 151 | Water Heating | Heat Pump Water Heater | 58.8% | 2,123.7 | 0.000 | 10.0 | $433.00 | 5.08 |
| 152 | Water Heating | Electric Tankless Water Heater | 7.4% | 7,905.0 | 0.000 | 5.0 | $1,050.00 | 3.97 |
| 154 | Water Heating | High Efficiency Storage (tank) | 0.2% | 8.6 | 0.000 | 15.0 | $70.00 | 0.18 |
| 168 | Water Heating | Tank Insulation (electric) | 91.0% | 468.0 | 0.000 | 15.0 | $2.22 | 306.25 |
| 169 | Water Heating | Drain Water Heat Recovery Water Heater | 25.0% | 546.0 | 4.490 | 25.0 | $631.00 | 2.30 |
| 171 | Water Heating | Process Cooling Condenser Heat Recovery | 33.0% | 5,720.0 | 1.205 | 15.0 | $254.00 | 49.23 |
| 301 | Envelope | Integrated Building Design | 40.0% | 2.0 | 0.000 | 15.0 | $0.27 | 9.99 |
| 302 | Envelope | Energy Efficient Windows | 13.9% | 2.0 | 0.022 | 20.0 | $17.04 | 8.95 |
| 302 | Envelope | Energy Efficient Windows | 13.9% | 2.0 | 0.022 | 20.0 | $17.04 | 8.95 |
| 303 | Envelope | Cool Roofing | 15.0% | 51.3 | 0.028 | 20.0 | $332.44 | 0.39 |
| 304 | Envelope | Ceiling Insulation | 8.0% | 65.5 | 0.024 | 20.0 | $47.16 | 1.46 |
| 305 | Envelope | Window Improvements | 0.7% | 85.3 | 0.033 | 15.3 | $286.16 | 0.24 |
| 306 | Envelope | Wall Insulation | 1.7% | 364.8 | 0.076 | 20.0 | $4.57 | 85.75 |
| 307 | Envelope | Roof Insulation | 0.8% | 22.1 | 0.014 | 20.0 | $54.88 | 2.70 |
| 308 | Envelope | Improved Duct Sealing | 1.4% | 37.6 | 0.019 | 18.0 | $107.91 | 1.51 |
| 321 | Ventilation | Economizer | 12.0% | 136.6 | 0.001 | 12.5 | $123.00 | 0.98 |
| 327 | Ventilation | EMS for Manufacturing HVAC Fan | 44.0% | 2,197.0 | 0.250 | 15.0 | $800.00 | 10.16 |
| 328 | Ventilation | VFD supply and return fans, <3 to 10 hp | 30.0% | 6,241.7 | 0.922 | 15.0 | $2,852.00 | 7.57 |
| 329 | Ventilation | VFD supply and return fans, 11 to 50 hp | 30.0% | 37,450.0 | 5.530 | 15.0 | $12,899.00 | 24.08 |
| 332 | Ventilation | High Volume Low Speed Fans | 50.0% | 8,379.0 | 3.067 | 10.0 | $4,197.75 | 3.99 |
| 333 | Ventilation | Engineered CKV Hood | 42.8% | 727.2 | 0.288 | 15.0 | $124.62 | 187.25 |
| 341 | Space Cooling - Chillers | Air-Cooled Chiller, <150 ton | 13.1% | 318.0 | 0.086 | 20.0 | $2,540.00 | 8.04 |
| 343 | Space Cooling - Chillers | Water Side Economizer | 10.0% | 1,047.5 | 0.000 | 15.0 | $50.00 | 7.75 |
| 345 | Space Cooling - Chillers | Water-Cooled Chiller > 300 ton | 25.0% | 355.1 | 0.096 | 20.0 | $92.22 | 11.09 |
| 348 | Space Cooling - Chillers | Water-Cooled Chiller < 150 ton | 20.0% | 300.5 | 0.081 | 20.0 | $166.10 | 5.81 |
| 350 | Space Cooling - Chillers | Chiller Tune Up | 8.0% | 119.1 | 0.032 | 5.0 | $5.66 | 12.78 |
| 362 | HVAC Controls | Programmable Thermostats | 10.0% | 945.3 | 0.000 | 4.0 | $56.09 | 5.36 |
| 363 | HVAC Controls | EMS install | 10.0% | 310.4 | 0.014 | 15.0 | $4.71 | 115.04 |
| 364 | HVAC Controls | EMS Optimization | 0.5% | 358.9 | 0.041 | 20.0 | $37.62 | 0.00 |
| 365 | HVAC Controls | HVAC Occupancy Sensors | 19.0% | 99.3 | 0.076 | 15.0 | $107.58 | 0.00 |
| 367 | HVAC Controls | Zoning | 0.0% | 187.4 | 0.000 | 15.0 | $500.00 | 0.00 |
| 368 | HVAC Controls | Setback with Electric Heat | 10.0% | 3,451.6 | 0.000 | 9.0 | $71.00 | 0.00 |
| 369 | HVAC Controls | EMS Pump Scheduling | 10.0% | 1,524.4 | 0.280 | 15.0 | $1.32 | 0.00 |
| 370 | HVAC Controls | Web Enabled EMS | 10.0% | 670.8 | -0.098 | 15.0 | $19.10 | 0.00 |
| 371 | HVAC Controls | Retrocommissioning | 9.0% | 0.9 | 0.000 | 7.0 | $0.08 | 7.54 |
| 382 | Space Cooling - Unitary and Split AC | DX Packaged Sysytem >65000 Btuh CEE Tier 1 | 18.2% | 86.0 | 0.055 | 15.0 | $63.00 | 5.37 |
| 384 | Space Cooling - Unitary and Split AC | Split System, <65,000 Btu/hr (CEE Tier 1) | 12.3% | 142.6 | 0.091 | 15.0 | $897.32 | 8.91 |
| 385 | Space Cooling - Unitary and Split AC | Ground Source Heat Pump - Cooling | 4.9% | 110.3 | 0.012 | 15.0 | $75.00 | 1.57 |
| 387 | Space Cooling - Unitary and Split AC | Water Loop Heat Pump ( WLHP) - Cooling | 11.5% | 146.5 | 0.094 | 15.0 | $75.00 | 1.90 |
| 391 | Space Cooling - Unitary and Split AC | HVAC Tune-up | 6.8% | 58.6 | 0.079 | 3.0 | $32.40 | 1.48 |
| 401 | Cooking | HE Steamer | 56.6% | 9,966.7 | 0.000 | 12.0 | $3,400.00 | 3.56 |
| 402 | Cooking | HE Combination Oven | 34.8% | 6,397.9 | 0.000 | 12.0 | $100.00 | 77.30 |
| 403 | Cooking | HE Convection Ovens | 16.1% | 1,937.1 | 0.000 | 12.0 | $388.00 | 6.06 |
| 404 | Cooking | HE Holding Cabinet | 52.7% | 1,730.0 | 0.000 | 12.0 | $902.00 | 2.33 |
| 405 | Cooking | HE Fryer | 17.2% | 3,126.0 | 0.000 | 12.0 | $275.67 | 13.76 |
| 406 | Cooking | HE Griddle | 12.1% | 1,909.1 | 0.000 | 12.0 | $860.00 | 2.69 |
| 408 | Cooking | Induction Cooktops | 20.0% | 784.0 | 0.000 | 11.0 | $3,000.00 | 0.29 |
| 506 | Lighting | High performance T5 (replacing T8) | 22.4% | 461.1 | 0.094 | 15.0 | $100.00 | 8.19 |
| 507 | Lighting | Outdoor LED (>250 W MH) | 56.9% | 983.3 | 0.201 | 15.0 | $592.00 | 3.01 |
| 509 | Lighting | LED Exit Sign | 81.8% | 88.6 | 0.012 | 16.0 | $30.00 | 10.52 |
| 512 | Lighting | LED High Bay Lighting | 35.0% | 471.8 | 0.096 | 15.0 | $482.00 | 1.74 |
| 513 | Lighting | LED Low Bay Lighting | 42.5% | 305.0 | 0.062 | 15.0 | $331.00 | 1.64 |
| 514 | Lighting | Light Tube | 10.0% | 250.0 | 0.104 | 10.0 | $500.00 | 0.95 |
| 515 | Lighting | High bay 4 lamp HPT8 vs (Metal halide 250 W) | 50.1% | 677.0 | 0.138 | 15.0 | $200.00 | 4.69 |
| 522 | Lighting | CFL Hard Wired Fixture | 69.0% | 199.0 | 0.041 | 12.0 | $37.50 | 7.94 |
| 523 | Lighting | Compact Fluorescent | 67.8% | 198.8 | 0.036 | 2.5 | $1.20 | 64.96 |
| 524 | Lighting | LED Screw In Bulb | 63.9% | 253.5 | 0.043 | 15.0 | $1.20 | 207.76 |
| 528 | Lighting | LED Downlight | 66.2% | 168.1 | 0.034 | 15.0 | $27.00 | 11.07 |
| 529 | Lighting | LED Troffer | 25.1% | 58.3 | 0.012 | 15.0 | $62.00 | 3.03 |
| 536 | Lighting | LED Linear Replacement Lamps | 26.3% | 61.2 | 0.012 | 15.0 | $25.00 | 7.04 |
| 549 | Lighting | SEM | 2.3% | 36.6 | 0.001 | 1.0 | $1.00 | 4.67 |
| 551 | Lighting Controls | Smart Advanced Lighting Controls | 40.0% | 2.2 | 0.001 | 10.0 | $3.02 | 1.98 |
| 552 | Lighting Controls | Smart Web Based Lighting Controls | 28.5% | 3.5 | 0.001 | 10.0 | $2.30 | 4.05 |
| 557 | Lighting Controls | Wall Occupancy Sensor | 24.0% | 335.0 | 0.068 | 8.0 | $51.00 | 4.41 |
| 559 | Lighting Controls | Central Lighting Control | 10.0% | 4,077.3 | 0.704 | 8.0 | $103.00 | 43.51 |
| 560 | Lighting Controls | Switching Controls for Multilevel Lighting (Non-HID) | 20.0% | 8,154.6 | 1.407 | 8.0 | $274.00 | 49.07 |
| 561 | Lighting Controls | Lighting Power Density - Interior | 10.0% | 4,077.3 | 0.704 | 15.0 | $220.00 | 34.34 |
| 601 | Refrigeration | Vending Miser for Soft Drink Vending Machines | 46.0% | 1,611.8 | 0.000 | 5.0 | $215.50 | 3.95 |
| 602 | Refrigeration | Refrigerated Case Covers | 6.0% | 2,900.0 | 0.331 | 4.0 | $150.00 | 9.53 |
| 603 | Refrigeration | Refrigeration Economizer | 30.0% | 166.7 | -0.001 | 15.0 | $126.76 | 1.18 |
| 606 | Refrigeration | Commercial Ice-makers | 6.8% | 263.1 | 0.041 | 9.0 | $55.00 | 1.22 |
| 607 | Refrigeration | Evaporator Fan Motor Controls on S-P motors | 25.1% | 1,155.0 | 0.119 | 5.0 | $300.00 | 2.23 |
| 608 | Refrigeration | Evaporator Fan Motor Controls on PSC motors | 25.0% | 796.0 | 0.082 | 5.0 | $300.00 | 1.54 |
| 609 | Refrigeration | Evaporator Fan Motor Controls on ECM motors | 35.8% | 1,524.0 | 0.174 | 16.0 | $291.00 | 7.98 |
| 610 | Refrigeration | H.E. Evaporative Fan Motors | 30.0% | 773.2 | 0.088 | 15.0 | $60.00 | 18.59 |
| 611 | Refrigeration | Zero-Energy Doors | 20.0% | 1,800.0 | 0.151 | 10.0 | $290.00 | 6.03 |
| 612 | Refrigeration | Door Heater Controls | 55.0% | 1,082.6 | 0.000 | 12.0 | $200.00 | 11.03 |

| Vectren Electric | | Industrial Measure Assumptions | | | | | | |
|---|---|---|---|---|---|---|---|---|
| Measure # | End-Use | Measure Name | % Elec Savings | Per Unit Elec Savings | Per Unit Summer NCP kW | Useful Life | Initial Measure Cost | UCT Ratio |
| 613 | Refrigeration | Discus and Scroll Compressors | 7.5% | 1,500.0 | 0.220 | 13.0 | $825.00 | 2.58 |
| 614 | Refrigeration | Floating Head Pressure Control | 9.2% | 1,264.0 | 0.000 | 15.0 | $80.00 | 15.46 |
| 619 | Refrigeration | ENERGY STAR Commercial Solid Door Refrigerators | 38.3% | 635.0 | 0.000 | 12.0 | $164.00 | 4.70 |
| 620 | Refrigeration | ENERGY STAR Commercial Solid Door Freezers | 35.8% | 1,489.0 | 0.000 | 12.0 | $166.00 | 10.88 |
| 621 | Refrigeration | ENERGY STAR Commercial Glass Door Refrigerators | 30.2% | 754.0 | 0.086 | 12.0 | $600.00 | 1.54 |
| 622 | Refrigeration | ENERGY STAR Commercial Glass Door Freezers | 33.7% | 3,671.0 | 0.419 | 12.0 | $450.00 | 9.98 |
| 623 | Refrigeration | Strip Curtains | 80.2% | 269.5 | 0.028 | 4.0 | $7.50 | 17.14 |
| 624 | Refrigeration | Efficient Refrigeration Condenser | 1.8% | 120.0 | 0.000 | 15.0 | $35.00 | 1.18 |
| 625 | Refrigeration | Door Gaskets - Cooler and Freezer | 99.7% | 98.0 | 0.011 | 4.0 | $2.25 | 21.36 |
| 626 | Refrigeration | Reach-in Refrigerated display case door retrofit | 43.0% | 1,014.0 | 0.185 | 12.0 | $670.00 | 2.97 |
| 627 | Refrigeration | LED Case Lighting | 45.5% | 437.5 | 0.000 | 8.0 | $250.00 | 1.08 |
| 628 | Refrigeration | ECM case fan motors | 8.8% | 1,064.0 | 0.121 | 15.0 | $177.00 | 8.73 |
| 629 | Refrigeration | Efficient low-temp compressor | 1.1% | 283.5 | 0.048 | 13.0 | $552.00 | 0.77 |
| 630 | Refrigeration | Automatic High Speed Doors - between freezer and cooler | 15.0% | 968.3 | 0.110 | 12.0 | $150.00 | 7.89 |
| 631 | Refrigeration | Refrigerant charging correction | 14.0% | 77.7 | 0.080 | 2.0 | $10.36 | 7.01 |
| 801 | Space Heating | PTHP, 1 ton | 23.2% | 94.3 | 0.108 | 15.0 | $84.00 | 1.28 |
| 803 | Space Heating | Ground Source Heat Pump - Heating | 4.9% | 22.7 | 0.014 | 15.0 | $375.00 | 1.00 |
| 805 | Space Heating | Water Loop Heat Pump (WLHP) - Heating | 11.5% | 67.9 | 0.129 | 15.0 | $75.00 | 1.03 |
| 901 | Other | High Efficiency Transformer, single-phase | 2.5% | 0.4 | 0.000 | 30.0 | $0.46 | 3.53 |
| 902 | Other | NEMA Premium Transformer, single-phase | 2.5% | 0.2 | 0.000 | 30.0 | $0.24 | 2.92 |
| 903 | Other | NEMA Premium Transformer, three-phase | 2.5% | 0.2 | 0.000 | 30.0 | $0.18 | 2.94 |
| 909 | Other | High Efficiency Transformer, three-phase | 2.5% | 0.4 | 0.000 | 30.0 | $0.44 | 5.57 |
| 911 | Other | Parking Garage Exhaust Fan CO Control | 48.0% | 2,413.0 | 0.275 | 15.0 | $1,800.00 | 9.43 |
| 912 | Other | Optimized Snow and Ice Melt Controls | 92.0% | 0.1 | 0.000 | 15.0 | $15.15 | 1.16 |
| 913 | Other | Engine Block Heater Timer | 64.0% | 576.0 | 0.800 | 5.0 | $50.00 | 29.89 |
| 1001 | Machine Drive | Sensors & Controls | 3.0% | 1.0 | 0.000 | 15.0 | $0.01 | 14.66 |
| 1002 | Machine Drive | Compressed Air Outdoor Air Intake | 2.2% | 109.8 | 0.015 | 20.0 | $5.00 | 52.35 |
| 1003 | Machine Drive | Electric Supply System Improvements | 3.0% | 1.0 | 0.000 | 15.0 | $0.01 | 20.44 |
| 1004 | Machine Drive | Advanced Efficient Motors | 2.3% | 1.0 | 0.000 | 20.0 | $0.04 | 5.92 |
| 1005 | Machine Drive | Industrial Motor Management | 1.0% | 1.0 | 0.000 | 5.0 | $0.02 | 10.33 |
| 1006 | Machine Drive | Compressed Air Low Pressure Drop Filters | 1.3% | 64.7 | 0.010 | 10.0 | $22.00 | 1.85 |
| 1007 | Machine Drive | Motor System Optimization (Including ASD) | 19.0% | 1.0 | 0.000 | 15.0 | $0.01 | 21.92 |
| 1008 | Machine Drive | Pump System Efficiency Improvements | 16.4% | 1.0 | 0.000 | 15.0 | $0.01 | 25.62 |
| 1009 | Machine Drive | Fan System Improvements | 6.0% | 1.0 | 0.000 | 15.0 | $0.02 | 8.54 |
| 1010 | Machine Drive | Efficient Air Compressors | 18.0% | 957.6 | 0.130 | 14.0 | $177.78 | 7.15 |
| 1011 | Machine Drive | Compressed Air Pressure Flow Controller | 1.5% | 73.0 | 0.010 | 15.0 | $25.00 | 5.77 |
| 1012 | Machine Drive | VFD for Process Fans | 28.0% | 707.0 | 0.000 | 15.0 | $46.00 | 32.68 |
| 1013 | Machine Drive | VFD for Process Pumps | 29.0% | 1,082.0 | 0.000 | 15.0 | $94.00 | 24.47 |
| 1014 | Machine Drive | High Efficiency Pumps | 7.4% | 201.0 | 0.000 | 15.0 | $31.00 | 22.86 |
| 1015 | Machine Drive | Compressed Air Audits and Leak Repair | 8.0% | 496.1 | 0.069 | 1.0 | $8.00 | 9.74 |
| 1016 | Machine Drive | Compressed Air replacement with Air Blowers | 8.5% | 5,587.7 | 4.180 | 15.0 | $620.00 | 38.08 |
| 1017 | Machine Drive | Compressed Air Automatic Drains | 2.2% | 2,097.0 | 0.332 | 5.0 | $100.00 | 4.41 |
| 1018 | Machine Drive | Compressed Air Storage Tank | 8.5% | 423.0 | 0.059 | 20.0 | $36.00 | 28.02 |
| 1019 | Machine Drive | Compressed Air High Efficiency Dryers | 1.0% | 48.0 | 0.000 | 15.0 | $10.00 | 10.21 |
| 1020 | Machine Drive | Compressed Air Nozzles | 7.5% | 21,142.0 | 6.340 | 20.0 | $76.75 | 14.60 |
| 1026 | Process Cooling & Refrig | Sensors & Controls | 3.0% | 1.0 | 0.000 | 15.0 | $0.01 | 14.66 |
| 1027 | Process Cooling & Refrig | Energy Information System | 1.0% | 1.0 | 0.000 | 15.0 | $0.06 | 3.35 |
| 1028 | Process Cooling & Refrig | Electric Supply System Improvements | 3.0% | 1.0 | 0.000 | 15.0 | $0.01 | 20.44 |
| 1029 | Process Cooling & Refrig | Improved Refrigeration | 10.0% | 1.0 | 0.000 | 15.0 | $0.00 | 62.53 |
| 1031 | Process Heating | Sensors & Controls | 3.0% | 1.0 | 0.000 | 15.0 | $0.01 | 14.66 |
| 1032 | Process Heating | Energy Information System | 1.0% | 1.0 | 0.000 | 15.0 | $0.06 | 3.35 |
| 1033 | Process Heating | Electric Supply System Improvements | 3.0% | 1.0 | 0.000 | 15.0 | $0.01 | 20.44 |
| 1034 | Process Heating | Decrease Oven Exhaust Flow | 60.0% | 399.0 | 0.087 | 20.0 | $1.00 | 43.21 |
| 1041 | Industrial Other | High Efficiency Welders | 12.0% | 761.0 | 0.390 | 20.0 | $200.00 | 15.35 |
| 1042 | Industrial Other | 3 Phase High Eff Battery Charger | 8.0% | 2,595.0 | 0.289 | 20.0 | $872.50 | 6.74 |
| 1043 | Industrial Other | Barrel Insulation - Inj. Molding (plastics) | 18.0% | 1,210.0 | 0.291 | 10.0 | $80.00 | 25.78 |
| 1044 | Industrial Other | Pellet Dryer Insulation (plastics) | 17.0% | 185.0 | 0.100 | 10.0 | $40.00 | 7.71 |
| 1045 | Industrial Other | Injection Molding Machine - efficient (plastics) | 51.0% | 223.0 | 0.050 | 20.0 | $125.00 | 4.93 |
| 1047 | Industrial Other | Dewpoint Sensor Control for Dessicant Plastic Dryer | 8.5% | 565.0 | 0.100 | 15.0 | $150.00 | 1.95 |
| 1051 | Agriculture | Other Industrial -Low-Energy Livestock Waterer | 47.7% | 1,593.0 | 1.000 | 10.0 | $788.00 | 3.12 |
| 1052 | Agriculture | Other Industrial -Dairy Refrigerator Tune-Up | 4.0% | 0.1 | 0.000 | 5.0 | $0.05 | 1.58 |
| 1053 | Agriculture | Greenhouse Environmental Controls | 10.0% | 98.0 | 0.000 | 15.0 | $125.00 | 1.67 |
| 1054 | Agriculture | Scroll Compressor with Heat Exchanger for Dairy Refrigeration | 10.5% | 190.0 | 0.000 | 15.0 | $1,500.00 | 0.27 |
| 1055 | Agriculture | Variable Speed Drive withHeat Exchanger, Milk | 15.0% | 878.0 | 0.000 | 15.0 | $2,725.00 | 0.69 |
| 1056 | Agriculture | Milk Pre-Cooler Heat Exchanger | 50.0% | 1.0 | 0.000 | 15.0 | $0.15 | 14.17 |
| 1057 | Agriculture | Variable Speed Drives for Dairy Vacuum Pumps | 34.8% | 598.0 | 0.000 | 10.0 | $250.00 | 3.69 |
| 1058 | Agriculture | VFD for Process Fans - Agriculture | 23.0% | 520.0 | 0.000 | 15.0 | $46.00 | 24.03 |
| 1059 | Agriculture | VFD for Process Pumps - Agriculture | 43.0% | 290.0 | 0.000 | 15.0 | $46.00 | 13.40 |
| 1060 | Agriculture | VFD for Process Pumps - Irrigation | 43.0% | 195.0 | 0.000 | 10.0 | $46.00 | 6.53 |
| 1061 | Agriculture | Grain Storage Temperature and Moisture Management Controller | 49.0% | 349.0 | 0.000 | 15.0 | $233.00 | 3.18 |
| 1062 | Agriculture | Low Pressure Sprinkler Nozzles | 15.0% | 5.0 | 0.000 | 15.0 | $1.00 | 10.63 |
| 1063 | Agriculture | Fan Thermostat Controller | 53.4% | 1,586.0 | 0.000 | 15.0 | $50.00 | 67.44 |
| 1064 | Agriculture | LED Poultry Lights | 57.4% | 5.8 | 0.001 | 9.0 | $1.53 | 2.67 |
| 1065 | Agriculture | Long Daylighting Dairy | 30.0% | 6.2 | 0.001 | 16.0 | $1.79 | 2.57 |
| 1066 | Agriculture | Evaporator Fan Motor Controls Ag | 35.4% | 537.1 | 0.270 | 20.0 | $30.13 | 5.07 |

# APPENDIX E *DSM Market Potential Study Commercial Opt-Out Results*

This section provides the potential results for technical, economic, MAP and RAP for the commercial sector, with opt-out customers included. Results are broken down by end use. The cost-effectiveness results and budgets for the RAP scenario are also provided.

## E.1 SCOPE OF MEASURES & END USES ANALYZED

There were 222 total electric measures included in the analysis. Table E-1 provides the number of measures by end-use and fuel type (the full list of commercial measures is provided in Appendix C). The measure list was developed based on a review of current Vectren programs, the Indiana TRM, other regional TRMs, and industry documents related to emerging technologies. Data collection activities to characterize measures formed the basis of the assessment of incremental costs, electric energy and demand savings, and measure life.

TABLE E-1 COMMERCIAL ENERGY EFFICIENCY MEASURES – BY FUEL TYPE

| End-Use | Number of Unique Measures |
|---|---|
| Space Heating | 32 |
| Cooling | 76 |
| Ventilation | 8 |
| Water Heating | 14 |
| Lighting | 26 |
| Cooking | 7 |
| Refrigeration | 23 |
| Office Equipment | 14 |
| Behavioral | 3 |
| Other | 19 |

## E.2 COMMERCIAL ELECTRIC POTENTIAL

Figure E-1 provides the technical, economic, MAP and RAP results for the 6-year, 10-year, and 20-year timeframes. The 6-year technical potential is 22.2% of forecasted sales, and the economic potential is 20.0% of forecasted sales. The 6-year MAP is 14.8% and the RAP is 6.3%.

FIGURE E-1 COMMERCIAL ELECTRIC ENERGY CUMULATIVE ANNUAL POTENTIAL (AS A % OF COMMERCIAL SALES)

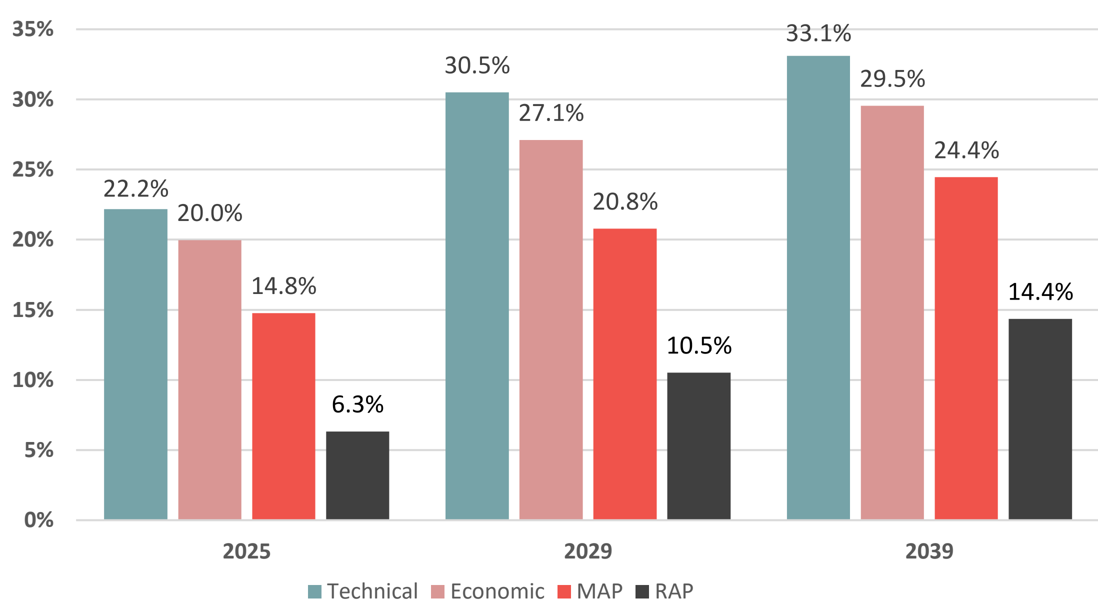


Table E-2 provides cumulative annual technical, economic, MAP and RAP energy savings, in total MWh and as a percentage of the sector-level sales forecast. The RAP reaches 6.3% after six years.

TABLE E-2 COMMERCIAL CUMULATIVE ANNUAL ENERGY EFFICIENCY POTENTIAL SUMMARY

| | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 |
|---|---|---|---|---|---|---|
| **MWh** | | | | | | |
| **Technical** | 50,170 | 101,739 | 156,928 | 213,761 | 267,250 | 316,621 |
| **Economic** | 46,545 | 93,832 | 143,992 | 195,103 | 242,328 | 285,256 |
| **MAP** | 29,659 | 62,928 | 99,777 | 138,516 | 176,072 | 210,908 |
| **RAP** | 11,578 | 24,685 | 39,512 | 55,740 | 72,884 | 90,391 |
| **Forecasted Sales** | 1,390,224 | 1,392,929 | 1,400,166 | 1,408,787 | 1,421,633 | 1,428,202 |
| | | | | | | |
| **Technical** | 3.6% | 7.3% | 11.2% | 15.2% | 18.8% | 22.2% |
| **Economic** | 3.3% | 6.7% | 10.3% | 13.8% | 17.0% | 20.0% |
| **MAP** | 2.1% | 4.5% | 7.1% | 9.8% | 12.4% | 14.8% |
| **RAP** | 0.8% | 1.8% | 2.8% | 4.0% | 5.1% | 6.3% |

Table E-3 provides the incremental annual technical, economic, MAP and RAP energy savings, in total MWh and as a percentage of the sector-level sales forecast. The incremental RAP ranges from 0.8% to 1.4% per year over the next six years.

TABLE E-3 COMMERCIAL INCREMENTAL ANNUAL ENERGY EFFICIENCY POTENTIAL SUMMARY

| | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 |
|---|---|---|---|---|---|---|
| **MWh** | | | | | | |
| **Technical** | 50,170 | 54,751 | 59,038 | 61,705 | 61,577 | 62,517 |
| **Economic** | 46,545 | 50,469 | 53,966 | 55,928 | 55,202 | 55,716 |
| **MAP** | 29,659 | 34,334 | 38,719 | 41,744 | 42,354 | 43,062 |
| **RAP** | 11,578 | 13,618 | 15,630 | 17,541 | 18,846 | 20,006 |
| **Forecasted Sales** | 1,390,224 | 1,392,929 | 1,400,166 | 1,408,787 | 1,421,633 | 1,428,202 |
| | | | | | | |
| **Technical** | 3.6% | 3.9% | 4.2% | 4.4% | 4.3% | 4.4% |
| **Economic** | 3.3% | 3.6% | 3.9% | 4.0% | 3.9% | 3.9% |
| **MAP** | 2.1% | 2.5% | 2.8% | 3.0% | 3.0% | 3.0% |
| **RAP** | 0.8% | 1.0% | 1.1% | 1.2% | 1.3% | 1.4% |

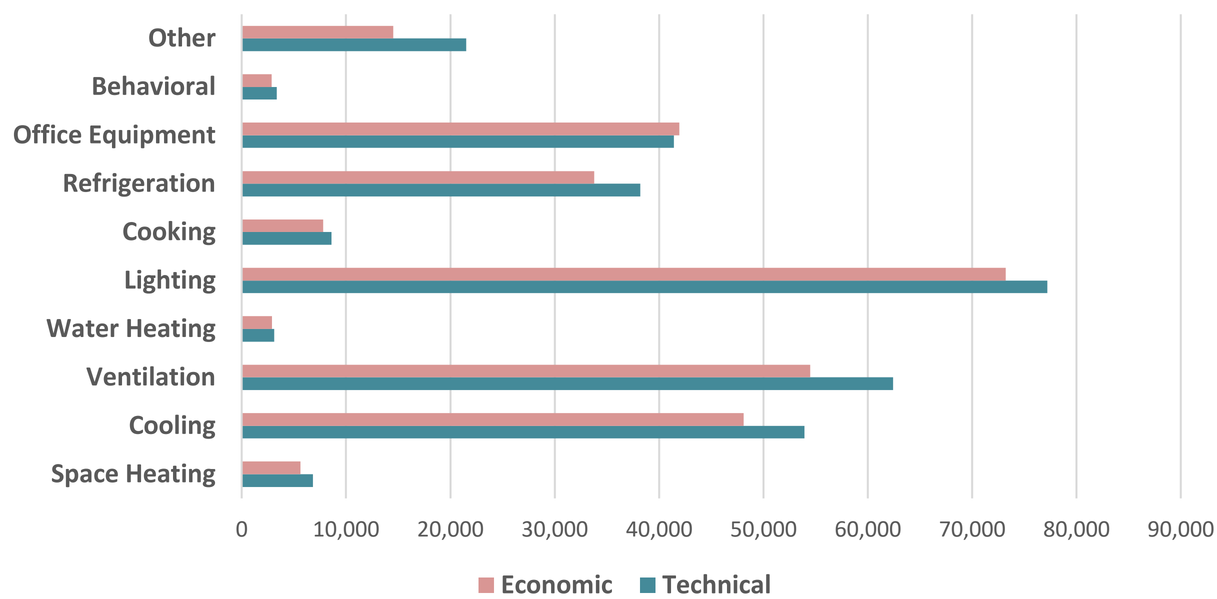
***Technical & Economic Potential***

Table E-4 provides cumulative annual technical and economic potential results from 2020-2025. Figure E-2 shows a comparison of the technical and economic potential (6-year) by end use. Lighting, Ventilation, and Cooling are the leading stand-alone end uses among technical and economic potential.

TABLE E-4 TECHNICAL & ECONOMIC COMMERCIAL ELECTRIC POTENTIAL

| | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 |
|---|---|---|---|---|---|---|
| **Energy (MWh)** | | | | | | |
| **Technical** | 50,170 | 101,739 | 156,928 | 213,761 | 267,250 | 316,621 |
| **Economic** | 46,545 | 93,832 | 143,992 | 195,103 | 242,328 | 285,256 |
| **Peak Demand (MW)** | | | | | | |
| **Technical** | 7 | 13 | 20 | 28 | 34 | 40 |
| **Economic** | 5 | 10 | 16 | 21 | 27 | 32 |

**FIGURE E-2 6-YEAR TECHNICAL AND ECONOMIC COMMERCIAL ELECTRIC POTENTIAL – BY END-USE**




### *Maximum Achievable Potential*

Figure E-3 illustrates the cumulative annual MAP results by end use across the 2020-2025 timeframe. Like technical and economic potential, Lighting, Ventilation, and Cooling are the leading end uses. Refrigeration and Office Equipment also have significant maximum achievable potential.

**FIGURE E-3 COMMERCIAL ELECTRIC ENERGY (CUMULATIVE ANNUAL GWH) MAP POTENTIAL BY END-USE**

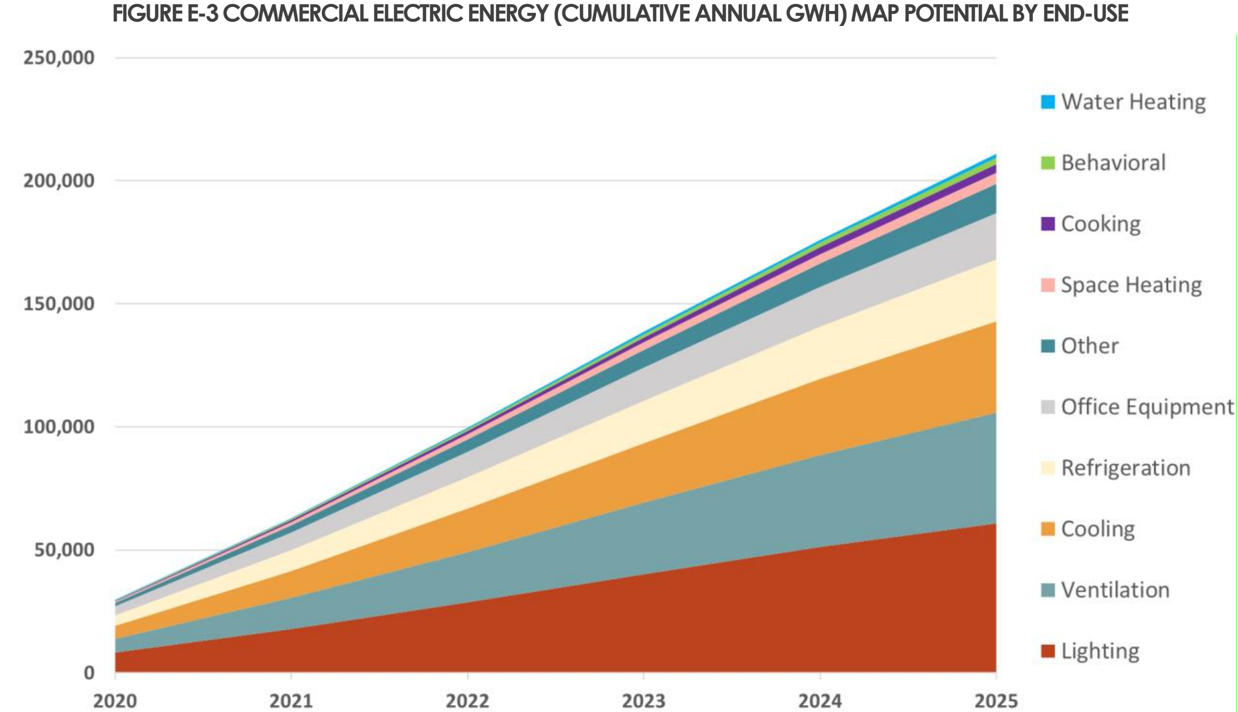



Table E-5 provides the incremental and cumulative annual MAP across the 2020-2025 timeframe. The incremental MAP ranges from 2.1% to 3.0% of forecasted sales across the six-year timeframe. Cumulative annual MAP rises to 14.8% by 2025.

TABLE E-5 COMMERCIAL ELECTRIC MAP BY END-USE

| End Use | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 |
|---|---|---|---|---|---|---|
| **Incremental Annual MWh** | | | | | | |
| **Space Heating** | 632 | 738 | 812 | 825 | 779 | 690 |
| **Cooling** | 5,164 | 5,873 | 6,459 | 7,175 | 7,250 | 6,886 |
| **Ventilation** | 5,703 | 6,840 | 7,891 | 8,528 | 8,447 | 7,669 |
| **Water Heating** | 156 | 204 | 254 | 300 | 336 | 374 |
| **Lighting** | 8,277 | 9,662 | 10,844 | 11,386 | 10,957 | 9,665 |
| **Cooking** | 323 | 431 | 548 | 663 | 770 | 863 |
| **Refrigeration** | 4,216 | 4,939 | 5,477 | 5,745 | 5,754 | 6,593 |
| **Office Equipment** | 3,624 | 3,446 | 3,308 | 3,275 | 3,394 | 5,201 |
| **Behavioral** | 226 | 297 | 600 | 761 | 1,176 | 1,437 |
| **Other** | 1,336 | 1,903 | 2,525 | 3,086 | 3,491 | 3,684 |
| **Total** | 29,659 | 34,334 | 38,719 | 41,744 | 42,354 | 43,062 |
| **% of Forecasted Sales** | 2.1% | 2.5% | 2.8% | 3.0% | 3.0% | 3.0% |
| **Incremental Annual MW** | | | | | | |
| **Total** | 2.4 | 2.9 | 3.3 | 3.5 | 3.5 | 3.3 |
| **% of Forecasted Demand** | 0.7% | 0.9% | 1.0% | 1.0% | 1.0% | 1.0% |
| **Cumulative Annual MWh** | | | | | | |
| **Space Heating** | 632 | 1,371 | 2,183 | 3,008 | 3,787 | 4,477 |
| **Cooling** | 5,164 | 11,037 | 17,496 | 24,217 | 30,902 | 37,118 |
| **Ventilation** | 5,703 | 12,543 | 20,434 | 28,962 | 37,409 | 45,078 |
| **Water Heating** | 156 | 361 | 615 | 914 | 1,250 | 1,608 |
| **Lighting** | 8,277 | 17,939 | 28,784 | 40,169 | 51,127 | 60,791 |
| **Cooking** | 323 | 755 | 1,302 | 1,965 | 2,735 | 3,598 |
| **Refrigeration** | 4,216 | 8,357 | 12,760 | 17,138 | 21,249 | 24,958 |
| **Office Equipment** | 3,624 | 7,070 | 10,378 | 13,653 | 16,245 | 19,000 |
| **Behavioral** | 226 | 509 | 866 | 1,307 | 1,855 | 2,498 |
| **Other** | 1,336 | 2,986 | 4,960 | 7,183 | 9,513 | 11,783 |
| **Total** | 29,659 | 62,928 | 99,777 | 138,516 | 176,072 | 210,908 |
| **% of Forecasted Sales** | 2.1% | 4.5% | 7.1% | 9.8% | 12.4% | 14.8% |
| **Cumulative Annual MW** | | | | | | |
| **Total** | 2.4 | 5.2 | 8.4 | 11.8 | 15.1 | 18.2 |
| **% of Forecasted Demand** | 0.7% | 1.6% | 2.5% | 3.5% | 4.5% | 5.4% |

### *Realistic Achievable Potential*

Figure E-4 illustrates the cumulative annual RAP results by end use across the 2020-2025 timeframe. Like maximum achievable potential, Lighting, Ventilation, and Cooling are the leading end uses. Refrigeration and Office Equipment also have significant realistic achievable potential.

FIGURE E-4 COMMERCIAL ELECTRIC ENERGY (CUMULATIVE ANNUAL GWH) RAP POTENTIAL BY END-USE

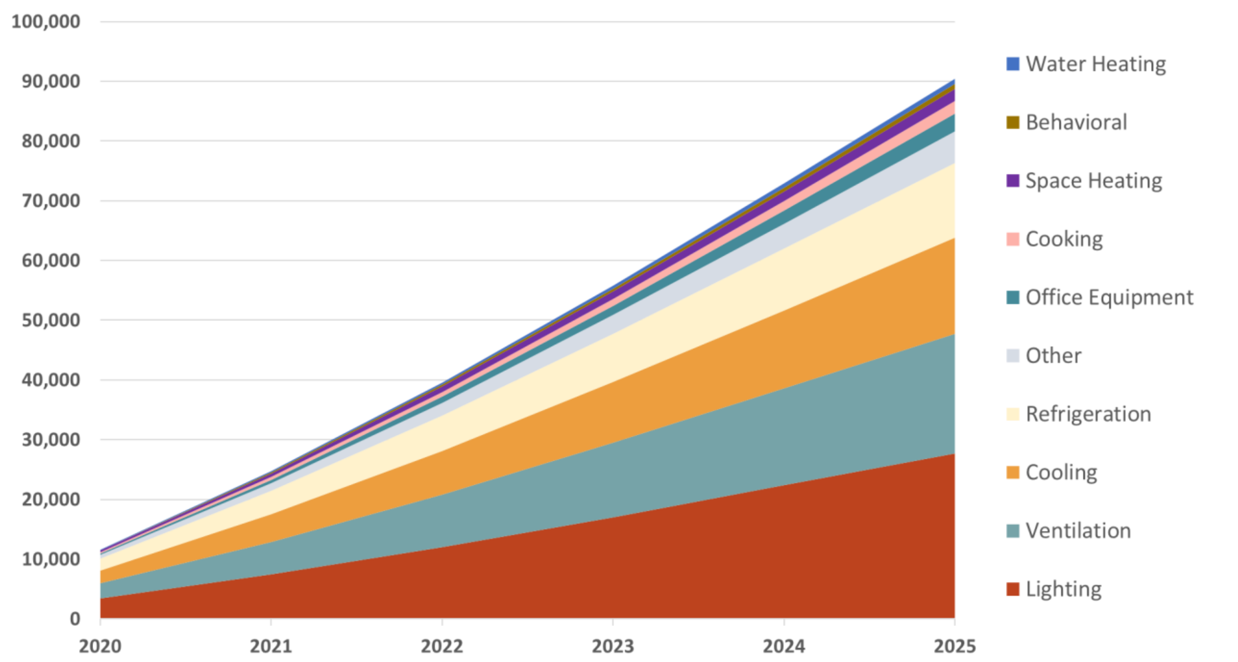



Table E-6 provides the incremental and cumulative annual RAP across the 2020-2025 timeframe. The incremental RAP ranges from 0.8% to 1.4% of forecasted sales across the six-year timeframe. Cumulative annual RAP rises to 6.3% by 2025.

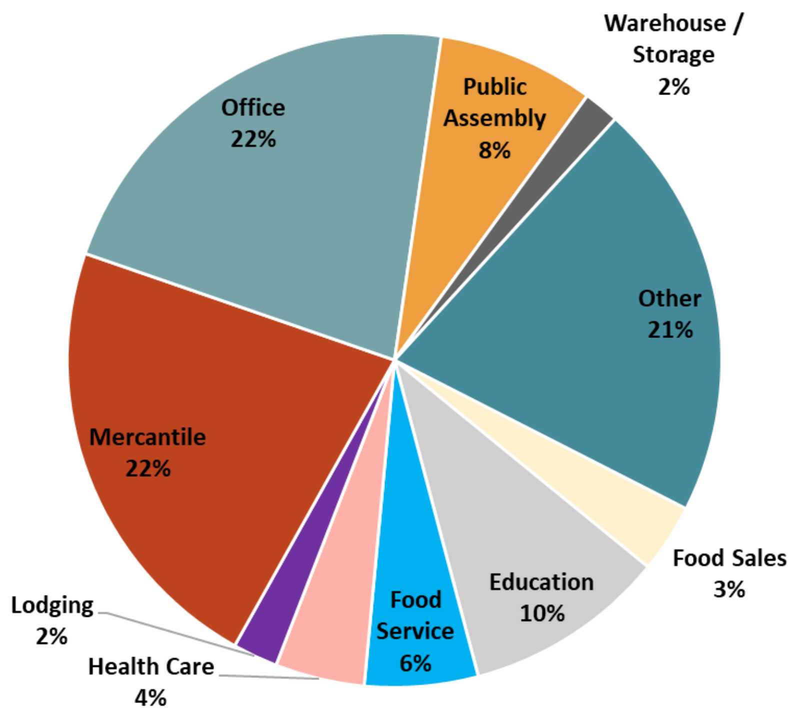
TABLE E-6 COMMERCIAL ELECTRIC RAP BY END-USE

| End Use | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 |
|---|---|---|---|---|---|---|
| **Incremental Annual MWh** | | | | | | |
| **Space Heating** | 267 | 302 | 331 | 346 | 350 | 344 |
| **Cooling** | 2,200 | 2,443 | 2,678 | 3,082 | 3,210 | 3,235 |
| **Ventilation** | 2,515 | 2,947 | 3,325 | 3,641 | 3,805 | 3,817 |
| **Water Heating** | 86 | 108 | 131 | 153 | 174 | 200 |
| **Lighting** | 3,401 | 4,020 | 4,582 | 5,032 | 5,306 | 5,337 |
| **Cooking** | 218 | 273 | 330 | 389 | 447 | 503 |
| **Refrigeration** | 1,985 | 2,301 | 2,591 | 2,824 | 3,010 | 3,585 |
| **Office Equipment** | 253 | 322 | 418 | 531 | 655 | 805 |
| **Behavioral** | 64 | 90 | 190 | 256 | 397 | 513 |
| **Other** | 588 | 813 | 1,054 | 1,287 | 1,491 | 1,668 |
| **Total** | 11,578 | 13,618 | 15,630 | 17,541 | 18,846 | 20,006 |
| **% of Forecasted Sales** | 0.8% | 1.0% | 1.1% | 1.2% | 1.3% | 1.4% |
| **Incremental Annual MW** | | | | | | |
| **Total** | 1.0 | 1.2 | 1.4 | 1.5 | 1.6 | 1.6 |
| **% of Forecasted Demand** | 0.3% | 0.4% | 0.4% | 0.4% | 0.5% | 0.5% |
| **Cumulative Annual MWh** | | | | | | |
| **Space Heating** | 267 | 570 | 901 | 1,247 | 1,597 | 1,941 |
| **Cooling** | 2,200 | 4,643 | 7,321 | 10,165 | 13,103 | 16,042 |
| **Ventilation** | 2,515 | 5,463 | 8,787 | 12,428 | 16,234 | 20,050 |
| **Water Heating** | 86 | 194 | 325 | 478 | 652 | 844 |

| End Use | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 |
|---|---|---|---|---|---|---|
| Lighting | 3,401 | 7,421 | 12,003 | 17,035 | 22,341 | 27,677 |
| Cooking | 218 | 491 | 822 | 1,211 | 1,657 | 2,160 |
| Refrigeration | 1,985 | 3,873 | 5,932 | 8,097 | 10,316 | 12,533 |
| Office Equipment | 253 | 574 | 992 | 1,524 | 2,179 | 2,983 |
| Behavioral | 64 | 150 | 270 | 429 | 626 | 871 |
| Other | 588 | 1,306 | 2,158 | 3,127 | 4,180 | 5,290 |
| Total | 11,578 | 24,685 | 39,512 | 55,740 | 72,884 | 90,391 |
| % of Forecasted Sales | 0.8% | 1.8% | 2.8% | 4.0% | 5.1% | 6.3% |
| **Cumulative Annual MW** | | | | | | |
| Total | 1.0 | 2.2 | 3.5 | 4.9 | 6.5 | 8.0 |
| % of Forecasted Demand | 0.3% | 0.6% | 1.0% | 1.5% | 1.9% | 2.4% |

Figure E-5 illustrates a market segmentation of the RAP in the commercial sector by 2025. Mercantile, Office, and Education are the leading building types.

FIGURE E-5 2025 COMMERCIAL ELECTRIC ENERGY (CUMULATIVE ANNUAL) RAP POTENTIAL BY MARKET SEGMENT




***RAP Benefits & Costs***

Table E-7 provides the net present value benefits and cost, as calculated using the UCT, across the 2020-2025 timeframe for the RAP scenario. Cooling and Water Heating are the most cost-effective end-uses, and Lighting also provides significant NPV benefits.

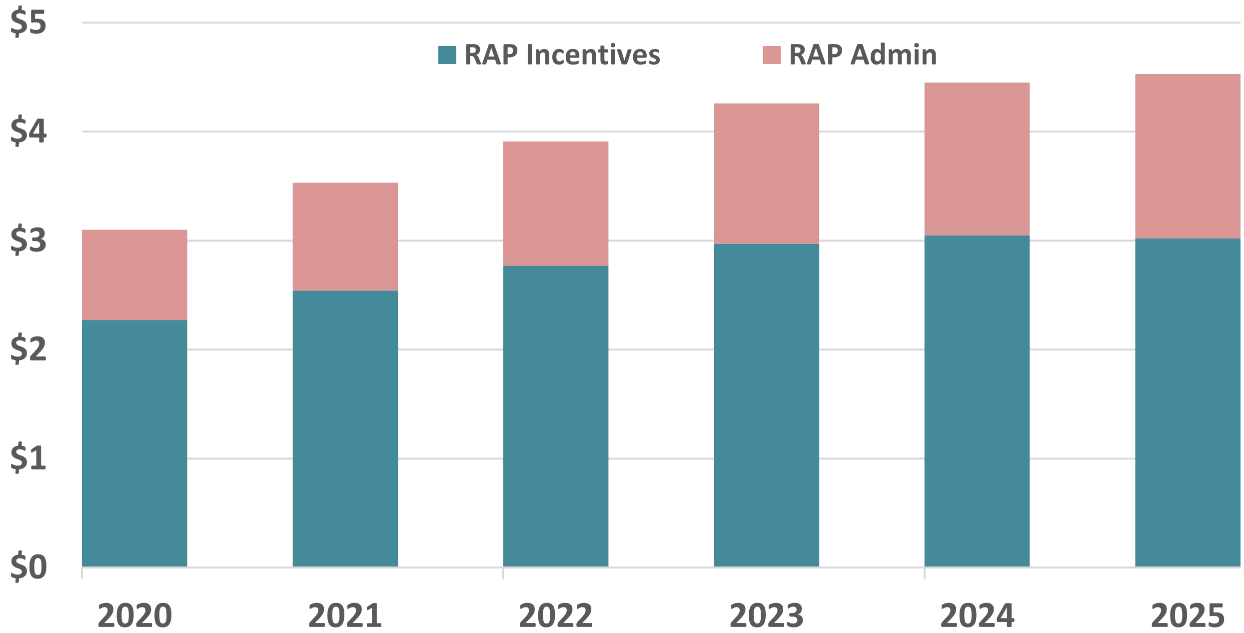
TABLE E-7 COMMERCIAL NPV BENEFITS & COSTS RAP BY END-USE ($ IN MILLIONS)

| End Use | NPV Benefits | NPV Costs | UCT Ratio |
|---|---|---|---|
| Space Heating | $0.63 | $1.76 | 0.36 |
| Cooling | $25.49 | $7.83 | 3.25 |
| Ventilation | $7.94 | $5.05 | 1.57 |
| Water Heating | $0.21 | $0.08 | 2.60 |

| End Use | NPV Benefits | NPV Costs | UCT Ratio |
|---|---|---|---|
| **Lighting** | $10.75 | $5.99 | 1.79 |
| **Cooking** | $0.69 | $0.34 | 2.06 |
| **Refrigeration** | $3.45 | $2.83 | 1.22 |
| **Office Equipment** | $0.72 | $0.29 | 2.47 |
| **Behavioral** | $0.10 | $0.08 | 1.33 |
| **Other** | $1.95 | $0.62 | 3.14 |
| **Total** | $51.9 | $24.9 | 2.09 |

Figure E-6 provides the budget for the RAP scenario. The budget is broken into incentive and admin budgets for each year of the 2020-2025 timeframe. The incentives rise from $2.3 million to $2.1 million, and overall budgets rise from $3.1 million to $4.5 million by 2025.

FIGURE E-6 ANNUAL BUDGETS FOR COMMERCIAL RAP ($ IN MILLIONS)



# APPENDIX F *DSM Market Potential Study Industrial Opt-Out Results*

This section provides the potential results for technical, economic, MAP and RAP for the industrial sector, with opt-out customers included. Results are broken down by end use. The cost-effectiveness results and budgets for the RAP scenario are also provided.

## F.1 SCOPE OF MEASURES & END USES ANALYZED

There were 165 total unique electric measures included in the analysis. Table F-1 provides number of measures by end-use (the full list of industrial measures is provided in Appendix D). The measure list was developed based on a review of current Vectren programs, the Indiana TRM, other regional TRMs, and industry documents related to emerging technologies. Data collection activities to characterize measures formed the basis of the assessment of incremental costs, electric energy and demand savings, and measure life.

**TABLE F-1 INDUSTRIAL ENERGY EFFICIENCY MEASURES – BY FUEL TYPE**

| End-Use | Number of Unique Measures |
|---|---|
| Computers & Office Equipment | 6 |
| Water Heating | 6 |
| Ventilation | 7 |
| Space Cooling | 22 |
| Space Heating | 16 |
| Cooking | 7 |
| Refrigeration | 25 |
| Lighting | 20 |
| Other | 7 |
| Machine Drive | 21 |
| Process Heating and Cooling | 12 |
| Agriculture | 16 |

## F.2 INDUSTRIAL ELECTRIC POTENTIAL

Figure F-1 provides the technical, economic, MAP and RAP results for the 6-year, 10-year, and 20-year timeframes. The 6-year technical potential is 18.9% of forecasted sales, and the economic potential is 18.0% of forecasted sales. The 6-year MAP is 13.2% and the RAP is 6.4%.

FIGURE F-1 INDUSTRIAL ELECTRIC ENERGY CUMULATIVE ANNUAL POTENTIAL (AS A % OF INDUSTRIAL SALES)

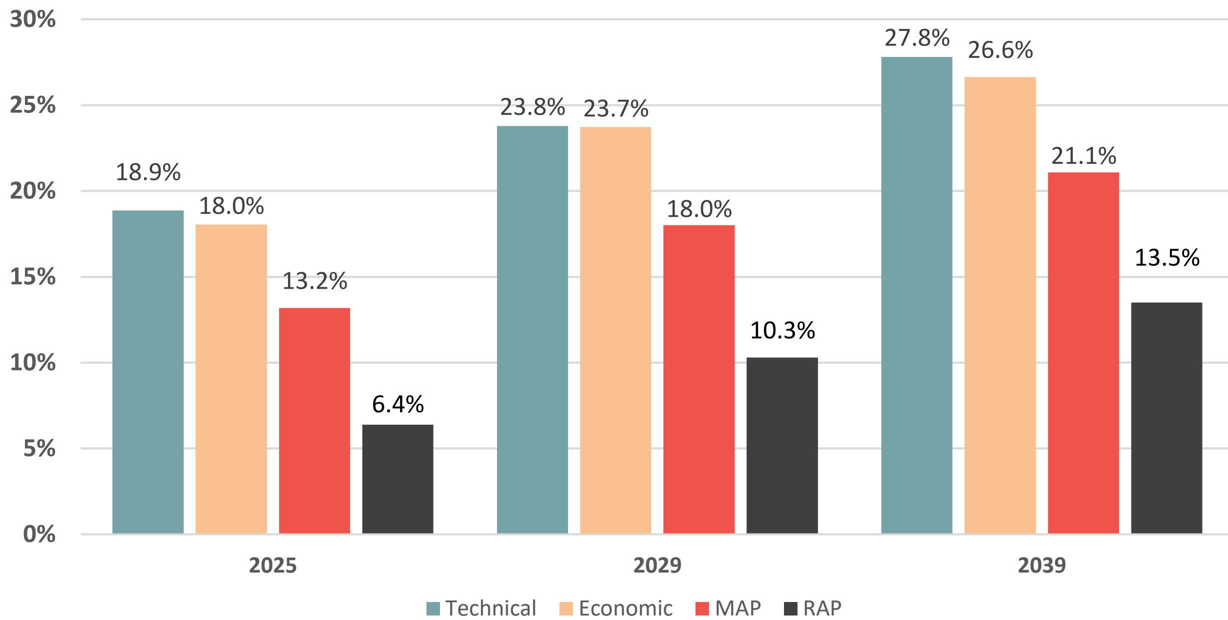



Table F-2 provides cumulative annual technical, economic, MAP and RAP energy savings, in total MWh and as a percentage of the sector-level sales forecast. The RAP reaches 6.4% after six years.

TABLE F-2 INDUSTRIAL CUMULATIVE ANNUAL ENERGY EFFICIENCY POTENTIAL SUMMARY

| | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 |
|---|---|---|---|---|---|---|
| **MWh** | | | | | | |
| **Technical** | 66,750 | 142,458 | 224,968 | 309,520 | 383,043 | 447,367 |
| **Economic** | 63,335 | 135,371 | 214,263 | 295,502 | 366,107 | 427,911 |
| **MAP** | 41,085 | 90,213 | 146,167 | 205,384 | 261,922 | 312,473 |
| **RAP** | 19,324 | 41,785 | 67,208 | 94,837 | 123,025 | 151,326 |
| **Forecasted Sales** | 2,329,890 | 2,336,776 | 2,345,264 | 2,354,201 | 2,362,591 | 2,371,200 |
| **Energy Savings (as % of Forecast)** | | | | | | |
| **Technical** | 2.9% | 6.1% | 9.6% | 13.1% | 16.2% | 18.9% |
| **Economic** | 2.7% | 5.8% | 9.1% | 12.6% | 15.5% | 18.0% |
| **MAP** | 1.8% | 3.9% | 6.2% | 8.7% | 11.1% | 13.2% |
| **RAP** | 0.8% | 1.8% | 2.9% | 4.0% | 5.2% | 6.4% |

Table F-3 provides the incremental annual technical, economic, MAP and RAP energy savings, in total MWh and as a percentage of the sector-level sales forecast. The incremental RAP ranges from 0.8% to 1.6% per year over the next six years.

TABLE F-3 INDUSTRIAL INCREMENTAL ANNUAL ENERGY EFFICIENCY POTENTIAL SUMMARY

| | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 |
|---|---|---|---|---|---|---|
| **MWh** | | | | | | |
| **Technical** | 66,750 | 78,664 | 89,185 | 95,702 | 97,760 | 95,516 |
| **Economic** | 63,335 | 74,992 | 85,566 | 92,390 | 94,842 | 92,995 |
| **MAP** | 41,085 | 51,432 | 61,105 | 67,856 | 71,118 | 70,784 |
| **RAP** | 19,324 | 23,576 | 27,883 | 31,695 | 35,218 | 38,149 |
| **Forecasted Sales** | 2,329,890 | 2,336,776 | 2,345,264 | 2,354,201 | 2,362,591 | 2,371,200 |
| **Energy Savings (as % of Forecast)** | | | | | | |
| **Technical** | 2.9% | 3.4% | 3.8% | 4.1% | 4.1% | 4.0% |

| | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 |
|---|---|---|---|---|---|---|
| **MWh** | | | | | | |
| **Economic** | 2.7% | 3.2% | 3.6% | 3.9% | 4.0% | 3.9% |
| **MAP** | 1.8% | 2.2% | 2.6% | 2.9% | 3.0% | 3.0% |
| **RAP** | 0.8% | 1.0% | 1.2% | 1.3% | 1.5% | 1.6% |

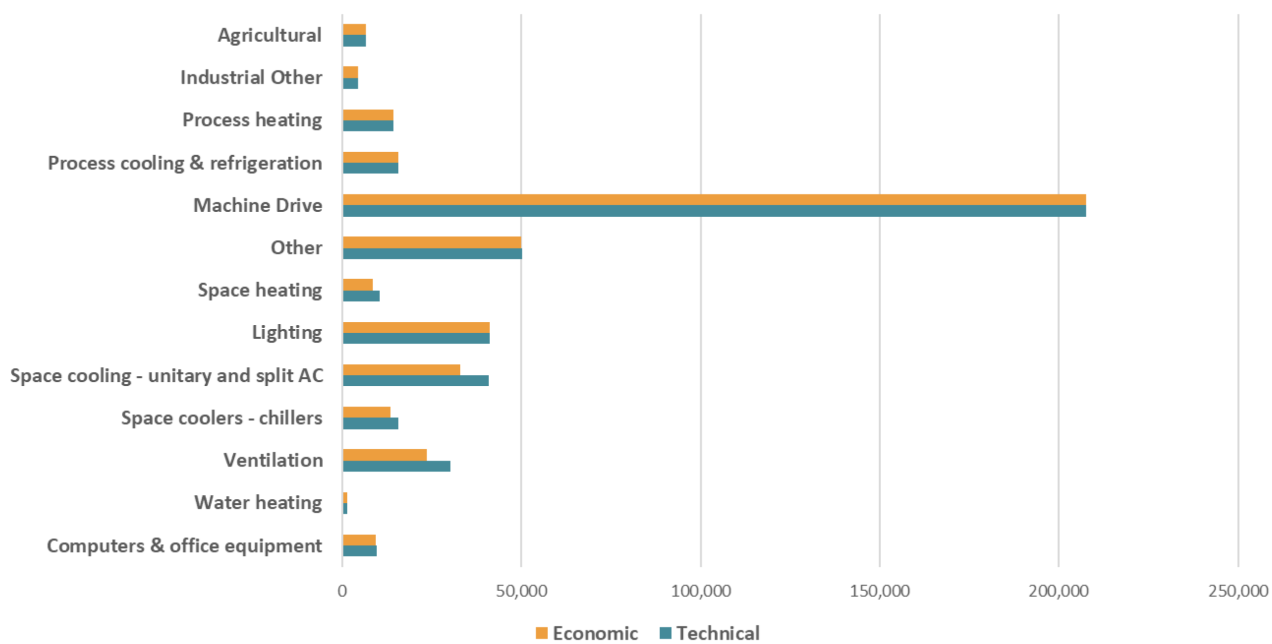
***Technical & Economic Potential***

Table F-4 provides cumulative annual technical and economic potential results from 2020-2025. Figure F-2 shows a comparison of the technical and economic potential (6-year) by end use. Machine drive, Lighting, and Space Cooling – unitary and split AC are the leading stand-alone end uses among technical and economic potential.

TABLE F-4 TECHNICAL AND ECONOMIC INDUSTRIAL ELECTRIC POTENTIAL

| | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 |
|---|---|---|---|---|---|---|
| **Energy (MWh)** | | | | | | |
| **Technical** | 66,750 | 142,458 | 224,968 | 309,520 | 383,043 | 447,367 |
| **Economic** | 63,335 | 135,371 | 214,263 | 295,502 | 366,107 | 427,911 |
| **Peak Demand (MW)** | | | | | | |
| **Technical** | 12 | 25 | 40 | 54 | 67 | 78 |
| **Economic** | 11 | 24 | 38 | 52 | 64 | 74 |

FIGURE F-2 YEAR TECHNICAL AND ECONOMIC INDUSTRIAL ELECTRIC POTENTIAL – BY END-USE




***Maximum Achievable Potential***

Figure F-3 illustrates the cumulative annual MAP results by end use across the 2020-2025 timeframe. Like technical and economic potential, Machine Drive, Lighting, and Space Cooling – unitary and split AC are the leading end uses. Ventilation and Space coolers – chillers also have significant maximum achievable potential.

FIGURE F-3 INDUSTRIAL ELECTRIC ENERGY (CUMULATIVE ANNUAL GWH) MAP POTENTIAL BY END-USE

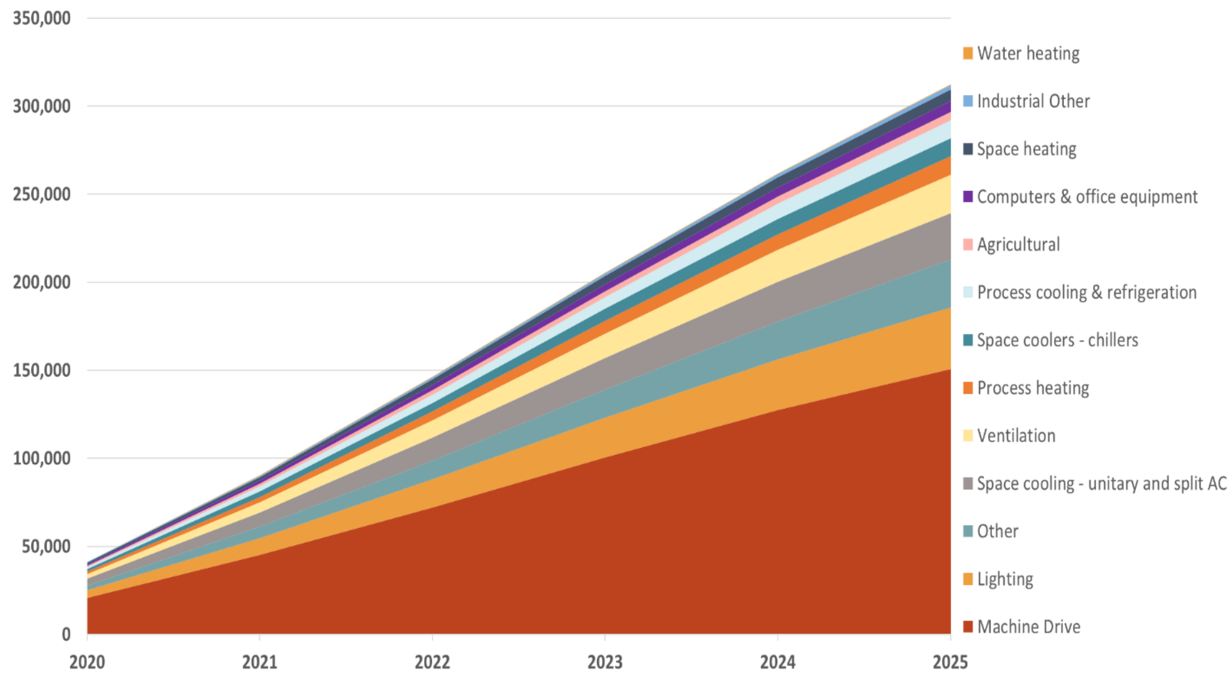



Table F-5 provides the incremental and cumulative annual MAP across the 2020-2025 timeframe. The incremental MAP ranges from 1.8% to 3.0% of forecasted sales across the six-year timeframe. Cumulative annual MAP rises to 13.1% by 2025.

TABLE F-5 INDUSTRIAL ELECTRIC MAP BY END-USE

| End Use | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 |
|---|---|---|---|---|---|---|
| **Incremental Annual MWh** | | | | | | |
| **Computers & office equipment** | 747 | 960 | 1,161 | 1,323 | 1,438 | 1,690 |
| **Water heating** | 89 | 92 | 98 | 109 | 123 | 134 |
| **Ventilation** | 2,728 | 3,394 | 3,978 | 4,236 | 4,083 | 3,582 |
| **Space coolers - chillers** | 1,410 | 1,685 | 1,908 | 1,991 | 2,042 | 1,872 |
| **Space cooling - unitary and split AC** | 3,688 | 4,383 | 4,974 | 5,221 | 5,393 | 4,904 |
| **Lighting** | 4,373 | 5,445 | 6,488 | 7,215 | 7,379 | 6,985 |
| **Space heating** | 921 | 1,103 | 1,260 | 1,327 | 1,381 | 1,264 |
| **Other** | 2,729 | 3,547 | 4,438 | 5,333 | 6,285 | 7,279 |
| **Machine Drive** | 20,695 | 25,930 | 30,767 | 34,161 | 35,486 | 35,311 |
| **Process cooling & refrigeration** | 1,307 | 1,812 | 2,312 | 2,747 | 3,082 | 3,314 |
| **Process heating** | 1,324 | 1,836 | 2,373 | 2,818 | 3,105 | 3,227 |
| **Industrial Other** | 392 | 433 | 460 | 483 | 509 | 537 |
| **Agricultural** | 683 | 810 | 890 | 891 | 812 | 684 |
| **Total** | 41,085 | 51,432 | 61,105 | 67,856 | 71,118 | 70,784 |
| **% of Forecasted Sales** | 1.8% | 2.2% | 2.6% | 2.9% | 3.0% | 3.0% |
| **Incremental Annual MW** | | | | | | |
| **Total** | 7 | 9 | 11 | 12 | 12 | 12 |
| **% of Forecasted Demand** | 1.8% | 2.2% | 2.6% | 2.9% | 3.0% | 3.0% |

| End Use | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 |
|---|---|---|---|---|---|---|
| **Cumulative Annual MWh** | | | | | | |
| **Computers & office equipment** | 747 | 1,707 | 2,868 | 4,191 | 5,122 | 5,950 |
| **Water heating** | 89 | 181 | 279 | 389 | 512 | 643 |
| **Ventilation** | 2,728 | 6,101 | 10,030 | 14,185 | 18,147 | 21,568 |
| **Space coolers - chillers** | 1,410 | 3,088 | 4,981 | 6,947 | 8,828 | 10,343 |
| **Space cooling - unitary and split AC** | 3,688 | 8,010 | 12,845 | 17,811 | 22,452 | 26,423 |
| **Lighting** | 4,373 | 9,662 | 15,802 | 22,429 | 28,941 | 34,762 |
| **Space heating** | 921 | 2,010 | 3,237 | 4,509 | 5,711 | 6,752 |
| **Other** | 2,729 | 6,276 | 10,711 | 16,038 | 21,434 | 27,268 |
| **Machine Drive** | 20,695 | 45,027 | 72,224 | 100,437 | 127,306 | 150,868 |
| **Process cooling & refrigeration** | 1,307 | 2,901 | 4,725 | 6,648 | 8,513 | 10,194 |
| **Process heating** | 1,324 | 2,960 | 4,887 | 6,952 | 8,944 | 10,679 |
| **Industrial Other** | 392 | 798 | 1,196 | 1,574 | 1,928 | 2,258 |
| **Agricultural** | 683 | 1,493 | 2,382 | 3,273 | 4,084 | 4,765 |
| **Total** | 41,085 | 90,213 | 146,167 | 205,384 | 261,922 | 312,473 |
| **% of Forecasted Sales** | 1.8% | 3.9% | 6.2% | 8.7% | 11.1% | 13.2% |
| **Cumulative Annual MW** | | | | | | |
| **Total** | 7 | 16 | 26 | 36 | 46 | 54 |
| **% of Forecasted Demand** | 1.8% | 3.9% | 6.3% | 8.8% | 11.1% | 13.1% |

***Realistic Achievable Potential***

Figure F-4 illustrates the cumulative annual RAP results by end use across the 2020-2025 timeframe. Like maximum achievable potential, Machine Drive, Lighting, and Space Cooling – unitary and split AC are the leading end uses. Ventilation and Space coolers – chillers also have significant maximum achievable potential.

FIGURE F-4 INDUSTRIAL ELECTRIC ENERGY (CUMULATIVE ANNUAL GWH) RAP POTENTIAL BY END-USE

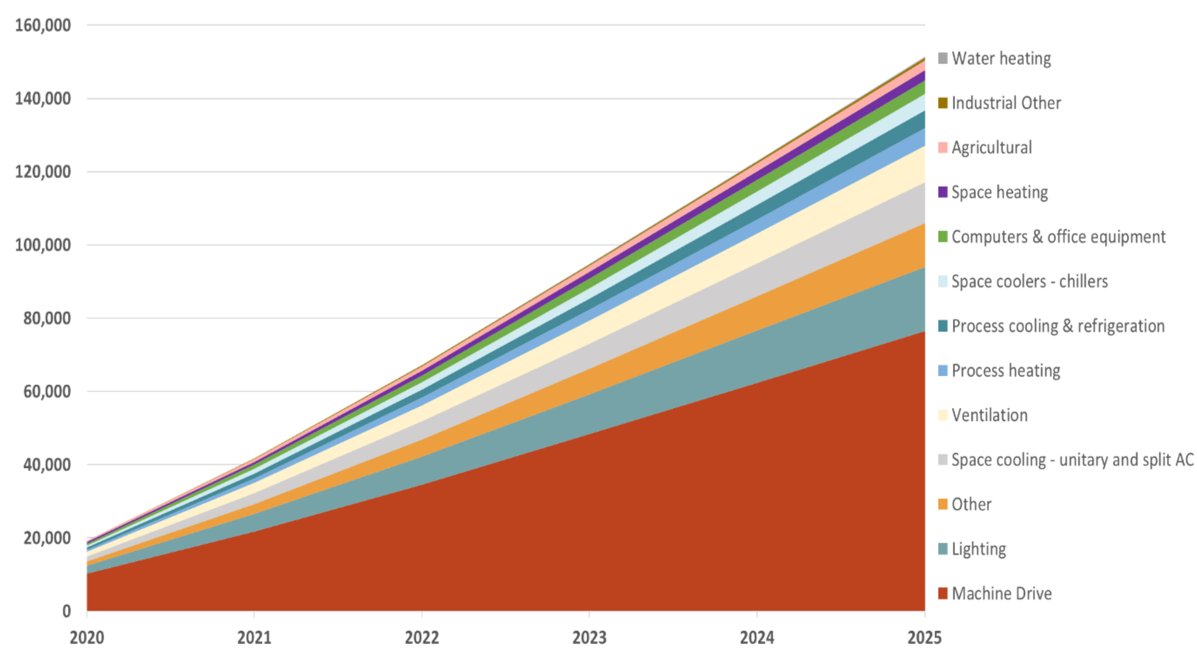


Table F-6 provides the incremental and cumulative annual RAP across the 2020-2025 timeframe. The incremental RAP ranges from 0.8% to 1.6% of forecasted sales across the six-year timeframe. Cumulative annual RAP rises to 6.4% by 2025.

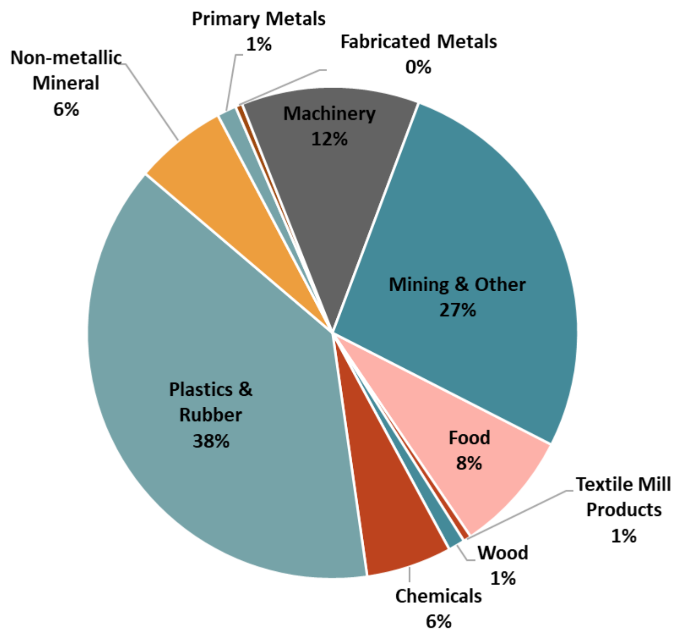
**TABLE F-6 INDUSTRIAL ELECTRIC RAP BY END-USE**

| End Use | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 |
|---|---|---|---|---|---|---|
| **Incremental Annual MWh** | | | | | | |
| **Computers & office equipment** | 512 | 616 | 716 | 810 | 894 | 1,062 |
| **Water heating** | 20 | 27 | 35 | 45 | 55 | 64 |
| **Ventilation** | 1,246 | 1,488 | 1,713 | 1,858 | 1,935 | 1,938 |
| **Space coolers - chillers** | 564 | 675 | 777 | 850 | 952 | 980 |
| **Space cooling - unitary and split AC** | 1,385 | 1,664 | 1,924 | 2,100 | 2,379 | 2,440 |
| **Lighting** | 2,156 | 2,621 | 3,073 | 3,450 | 3,738 | 3,895 |
| **Space heating** | 352 | 424 | 492 | 540 | 613 | 630 |
| **Other** | 1,204 | 1,547 | 1,939 | 2,351 | 2,780 | 3,281 |
| **Machine Drive** | 10,213 | 12,370 | 14,581 | 16,581 | 18,298 | 19,856 |
| **Process cooling & refrigeration** | 625 | 823 | 1,031 | 1,250 | 1,473 | 1,689 |
| **Process heating** | 589 | 796 | 1,019 | 1,235 | 1,446 | 1,643 |
| **Industrial Other** | 97 | 121 | 149 | 179 | 212 | 247 |
| **Agricultural** | 362 | 404 | 431 | 446 | 444 | 424 |
| **Total** | 19,324 | 23,576 | 27,883 | 31,695 | 35,218 | 38,149 |
| **% of Forecasted Sales** | 0.8% | 1.0% | 1.2% | 1.3% | 1.5% | 1.6% |
| **Incremental Annual MW** | | | | | | |
| **Total** | 3 | 4 | 5 | 6 | 6 | 7 |
| **% of Forecasted Demand** | 0.9% | 1.0% | 1.2% | 1.4% | 1.5% | 1.6% |
| **Cumulative Annual MWh** | | | | | | |
| **Computers & office equipment** | 512 | 1,127 | 1,843 | 2,654 | 3,164 | 3,652 |
| **Water heating** | 20 | 47 | 83 | 128 | 182 | 245 |
| **Ventilation** | 1,246 | 2,725 | 4,418 | 6,243 | 8,128 | 9,996 |
| **Space coolers - chillers** | 564 | 1,236 | 2,007 | 2,847 | 3,729 | 4,536 |
| **Space cooling - unitary and split AC** | 1,385 | 3,023 | 4,890 | 6,893 | 8,957 | 11,005 |
| **Lighting** | 2,156 | 4,711 | 7,639 | 10,846 | 14,223 | 17,623 |
| **Space heating** | 352 | 769 | 1,248 | 1,765 | 2,302 | 2,837 |
| **Other** | 1,204 | 2,751 | 4,690 | 7,039 | 9,365 | 11,987 |
| **Machine Drive** | 10,213 | 21,783 | 34,604 | 48,291 | 62,398 | 76,424 |
| **Process cooling & refrigeration** | 625 | 1,348 | 2,156 | 3,032 | 3,950 | 4,876 |
| **Process heating** | 589 | 1,293 | 2,108 | 3,001 | 3,940 | 4,886 |
| **Industrial Other** | 97 | 205 | 326 | 458 | 600 | 750 |
| **Agricultural** | 362 | 766 | 1,197 | 1,642 | 2,086 | 2,509 |
| **Total** | 19,324 | 41,785 | 67,208 | 94,837 | 123,025 | 151,326 |
| **% of Forecasted Sales** | 0.8% | 1.8% | 2.9% | 4.0% | 5.2% | 6.4% |
| **Cumulative Annual MW** | | | | | | |

| End Use | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 |
|---|---|---|---|---|---|---|
| **Total** | 3 | 7 | 12 | 17 | 21 | 26 |
| **% of Forecasted Demand** | 0.9% | 1.8% | 2.9% | 4.1% | 5.2% | 6.4% |

Figure F-5 illustrates a market segmentation of the RAP in the industrial sector by 2025. Plastics & rubber, Mining & Other, and Machinery are the leading market segments.

FIGURE F-5 2025 INDUSTRIAL ELECTRIC ENERGY (CUMULATIVE ANNUAL) RAP POTENTIAL BY MARKET SEGMENT[1]




*RAP Benefits & Costs*

Table F-6**Error! Reference source not found.** provides the net present value benefits and cost, as calculated using the UCT, across the 2020-2025 timeframe for the RAP scenario. Machine Drive is the most cost-effective end-use. Facility HVAC and Facility Lighting also provide significant NPV benefits.

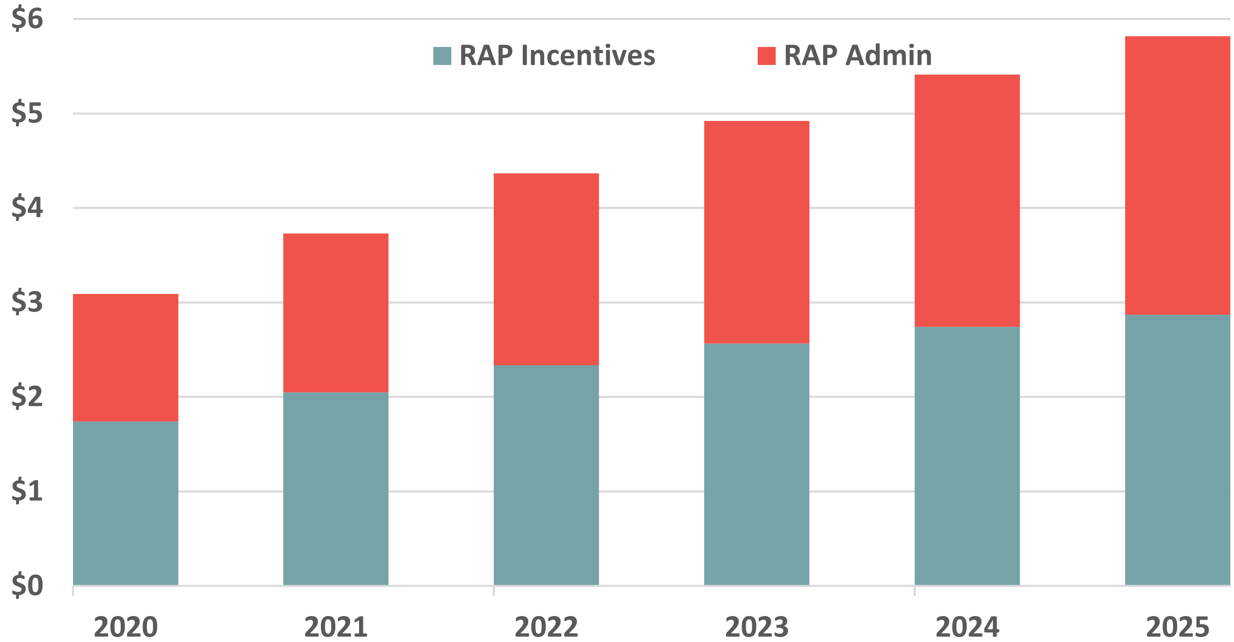
TABLE F-7 INDUSTRIAL NPV BENEFITS AND COSTS RAP BY END-USE ($ IN MILLIONS)

| End Use | NPV Benefits | NPV Costs | UCT Ratio |
|---|---|---|---|
| Machine Drive | $49.7 | $8.4 | 5.90 |
| Facility HVAC | $14.4 | $3.6 | 2.81 |
| Facility Lighting | $11.1 | $6.0 | 2.64 |
| Other Facility Support | $5.4 | $2.2 | 1.53 |
| Process Cooling and Refrigeration | $2.7 | $0.7 | 3.64 |
| Process Heating | $2.0 | $0.5 | 4.59 |
| Other | $6.8 | $2.2 | 3.04 |
| **Total** | 92.1 | 23.5 | 3.91 |

Figure F-6 provides the budget for the RAP scenario. The budget is broken into incentive and admin budgets for each year of the 2020-2025 timeframe. The incentives rise from $1.7 million to $2.9 million, and overall budgets rise from $3.1 million to $5.8 million by 2025.

[1] "Wholesale/Retail" and "Services" industrial types include industrial buildings that devote a minority percentage of floor space to commercial activities like wholesale and retail trade, and construction, healthcare, education and accommodation & food service. Automotive related industries are divided between plastics, rubber, and machinery based on their NAICS codes.

FIGURE F-6 ANNUAL BUDGETS FOR INDUSTRIAL RAP ($ IN MILLIONS)



# APPENDIX G *Demand Response Methodology*

## G.1 DEMAND RESPONSE PROGRAM OPTIONS

Table G-1 provides a brief description of the demand response program options considered and identifies the eligible customer segment for each demand response program that was considered in this study.

**TABLE G-1 DEMAND RESPONSE PROGRAM OPTIONS AND ELIGIBLE MARKETS**

| DR Program Option | Program Description | Eligible Markets |
|---|---|---|
| DLC AC (Switch) | The compressor of the air conditioner is remotely shut off (cycled) by the system operator for periods that may range from 7 ½ to 15 minutes during every 30-minute period (i.e., 25%-50% duty cycle) | Residential and Commercial Customers |
| DLC AC (Smart Thermostat) | The system operator can remotely raise the AC's thermostat set point during peak load conditions, lowering AC load. | Residential and Commercial Customers |
| DLC Pool Pumps | The swimming pool pump is remotely shut off by the system operator for periods normally ranging from 2 to 4 hours. | Residential Customers |
| DLC Water Heaters | The water heater is remotely shut off by the system operator for periods normally ranging from 2 to 8 hours. | Residential and Commercial Customers |
| Critical Peak Pricing with Enabling Technology | A retail rate in which an extra-high price for electricity is provided during a limited number of critical periods (e.g. 100 hours) of the year. Market-based prices are typically provided on a day-ahead basis, or an hour-ahead basis. Includes enabling technology that connects technologies within building. Only for customers with AC. | Residential and Commercial Customers |
| Critical Peak Pricing without Enabling Technology | A retail rate in which an extra-high price for electricity is provided during a limited number of critical periods (e.g. 100 hours) of the year. Market-based prices are typically provided on a day-ahead basis, or an hour-ahead basis. | Residential and Commercial Customers |
| Real Time Pricing | Real Time Pricing reflects the current conditions and is calculated for each hour in the billing period. | Commercial Customers |

| DR Program Option | Program Description | Eligible Markets |
|---|---|---|
| Peak Time Rebate | Instead of charging a higher rate during critical events, participants are paid for load reductions (estimated relative to forecast of what the customer would otherwise have consumed). If customers don't want to participate, they pay the existing rate. | Residential and Commercial Customers |
| Time of Use Rate | A retail rate with different prices for usage during different blocks of time. Daily pricing blocks could include on-peak, mid-peak, and off-peak periods. Pricing is pre-defined, and once established do not vary with actual cost conditions. | Residential and Commercial Customers |

## G.2 DEMAND RESPONSE POTENTIAL ASSESSMENT APPROACH

The analysis for this study was conducted using the GDS DR Model. The GDS DR Model is an Excel spreadsheet tool that allows the user to determine the achievable potential for a demand response program based on the following two basic equations that can be chosen to be the model user.

**TECHNICAL POTENTIAL** • All technically feasible demand reductions are incorporated to provide a measure of the theoretical maximum demand response potential. This assumes 100% of eligible customers will participate in all programs regardless of cost-effectiveness.

**ECONOMIC POTENTIAL** • Economic potential is a subset of technical potential. Only cost-effective demand response program options are included in the economic potential. The cost-effectiveness test applied in this study is the UCT test. Only programs whose net present value of benefits exceed its costs will pass the economic screening.

**ACHIEVABLE POTENTIAL** • The cost-effective demand response potential that can practically be attained in a real-world program delivery scenario, if a certain level of market penetration can be attained are included in this scenario. Achievable potential takes into account real-world barriers to convincing customers to participate in cost-effective demand response programs. Achievable savings potential savings is a subset of economic potential.

If the model user chooses to base the estimated potential demand reduction on a per customer CP load reduction value, then:

$$\textit{Achievable DR Potential} = \textit{Potentially Eligible Customers} \times \textit{Eligible Customer Participation Rate} \times \textit{CP kW Load Reduction Per Participant}$$

The framework for assessing the cost-effectiveness of demand response programs is based on *A Framework for Evaluating the Cost-Effectiveness of Demand Response*, prepared for the National Forum on the National Action

Plan (NAPA) on Demand Response.[1] Additionally, GDS reviewed the May 2017 National Standard Practice Manual published by the National Efficiency Screening Project.[2] GDS utilized this guide to define avoided ancillary services and energy and/or capacity price suppression benefits. Appendix A contains a table from the report summarizing the energy efficiency cost and benefits including in all five major benefit cost tests.

The GDS Demand Response Model determines the estimated savings for each demand response program by performing an extensive review of all benefits and cost associated with each program. GDS developed the model such that the value of future programs could be determined and to help facilitate demand response program planning strategies. The model contains approximately 50 required inputs for each program including: expected life, CP kW load reductions, proposed rebate levels, program related expenses such as vendor service fees, marketing and evaluation cost and on-going O&M expenses. This model and future program planning features can be used to standardize the cost-effectiveness screening process between Vectren departments interested in the deployment of demand response resources.

For this study, the Utility Cost Test (UCT) test was used to determine the cost-effectiveness of each demand response program. Benefits are based on avoided demand, energy (including load shifting), wholesale cost reductions and T&D costs. Costs include incremental program equipment costs (such as control switches or smart thermostats), fixed program capital costs (such as the cost of a central controller), program administrative, marketing, and evaluation costs. Incremental equipment program costs are included for both new and replacement units (such as control switches) to account for units that are replaced at the end of their useful life.

Achievable potential is broken into maximum and realistic achievable potential in this study:

**MAP** represents an estimate of the maximum cost-effective demand response potential that can be achieved over the 20-year study period. For this study, this is defined as customer participation in demand response program options that reflect a "best practices" estimate of what could eventually be achieved. MAP assumes no barriers to effective delivery of programs.

**RAP** represents an estimate of the amount of demand response potential that can be realistically achieved over the 20-year study period. For this study, this is defined as achieving customer participation in demand response program options that reflect a realistic estimate of what could eventually be achieved assuming typical or "average" industry experience. RAP is a discounted MAP, by considering program barriers that limit participation, therefore reducing savings that could be achieved.

This potential study evaluated DR potential for two achievable potential scenarios:

1 ***Utility Incentivized Scenario:*** The utility incentivized scenario assumes that all cost-effective DR programs will be implemented by Vectren and smart thermostats will be paid for and installed by the utility. Since Vectren already has a smart thermostat energy efficiency program, GDS assumed that the customers participating in this program would already have smart thermostats installed and there would be no additional cost to the utility.
2 ***BYOT Scenario:*** The bring your own thermostat (BYOT) scenario also assumes that all cost-effective DR programs will be implemented, but in this scenario smart thermostats will be used purchased and installed by the customer. GDS assumed there would be a one-time $75 credit[3].

---

[1] Study was prepared by Synapse Energy Economics and the Regulatory Assistance Project, February 2013.
[2] National Standard Practice Manual for Assessing Cost-Effectiveness of Energy Efficiency Resources, May 18, 2017, Prepared by The National Efficiency Screening Project
[3] Vectren South 2018 Electric DSM Operating Plan

Demand savings estimates were assumed to be the same for both scenarios, but the costs are different.

## G.3 AVOIDED COSTS & OTHER ECONOMIC ASSUMPTIONS

The avoided costs used to determine utility benefits were provided by Vectren. Avoided electric generation capacity refers to the demand response program benefit resulting from a reduction in the need for new peaking generation capacity. Demand response can also produce energy related benefits. If the demand response option is considered "load shifting", such as direct load control of electric water heating, the consumption of energy is shifted from the control period to the period immediately following the period of control. For this study, GDS assumed that the energy is shifted with no loss of energy. For power suppliers, this shift in the timing of energy use can produce benefits from either the production of energy from lower cost resources or the purchase of energy at a lower rate. If the program is not considered to be "load shifting" the measure is turned off during peak control hours, and the energy is saved altogether. Demand response programs can also potentially delay the construction of new transmission and distribution lines and facilities, which is reflected in avoided T&D costs.

The discount rate used in this study is 7.29%. A peak demand line loss factor of 6.33% and a reserve margin of 8.4 % (for firm load reduction such as direct load control) were also applied to demand reductions at the customer meter. These values were provided by Vectren.

The useful life of a smart thermostat is assumed to be 15 years[4]. Load control switches have a useful life of 15 years[5]. This life was used for all direct load control measures in this study.

The number of control units per participant was assumed to be 1 for all direct load control programs using switches (such as water heaters and air conditioning switches), because load control switches can control up to two units. However, for controllable thermostats, some participants have more than one thermostat. The average number of residential thermostats per single family home was assumed to be 1.72[6].

## G.4 CUSTOMER PARTICIPATION

The assumed level of customer participation for each demand response program option is a key driver of achievable demand response potential estimates. Customer participation rates reflect the total number of eligible customers that are likely to participate in a demand response program. An eligible customer is defined as a customer that is eligible to participate in a demand response program. For DLC programs, eligibility is determined by whether a customer has the end use equipment that will be controlled[7]. The eligible customers for each program is shown in Table G-2 and Table G-3.

**TABLE G-2 ELIGIBLE RESIDENTIAL CUSTOMERS IN EACH DEMAND RESPONSE PROGRAM OPTION**

| DR Program Option | Saturation | Source / Description |
|---|---|---|
| DLC AC (Switch) | 62% of residential customers | Vectren 2016 Electric Baseline Survey - % of residential homes with central AC |
| DLC AC (Thermostat) | 62% of residential customers | Vectren 2016 Electric Baseline Survey - % of residential homes with central AC |

[4] Indiana TRM
[5] Provided by Comverge
[6] EIA RECS table HC6.1

| DR Program Option | Saturation | Source / Description |
|---|---|---|
| DLC Pool Pumps | 6% of residential customers | Vectren 2016 Electric Baseline Survey - % of residential homes with swimming pool pumps |
| DLC Water Heaters | 35% of residential customers | Vectren 2016 Electric Baseline Survey - % of residential homes with electric water heaters |
| Critical Peak Pricing with Enabling Technology | 62% of residential customers | Vectren 2016 Electric Baseline Survey - % of residential homes with central AC |
| Critical Peak Pricing without Enabling Technology | 100% of residential customers | GDS Assumption |
| Peak Time Rebate | 100% of residential customers | GDS Assumption |
| Time of Use | 100% of residential customers | GDS Assumption |

**TABLE G-3 ELIGIBLE NON-RESIDENTIAL CUSTOMERS IN EACH DEMAND RESPONSE PROGRAM OPTION**

| DR Program Option | Saturation | Source / Description |
|---|---|---|
| DLC AC (Switch) | 81.5% of commercial customers | GDS Survey of Vectren C&I Customers - % of C&I customers with central AC |
| DLC AC (Thermostat) | 81.5% of commercial customers | GDS Survey of Vectren C&I Customers - % of C&I customers with central AC |
| DLC Water Heaters | 40% of commercial customers | CBECS 2015 - % of commercial customers in East North Central region with electric water heaters |
| Critical Peak Pricing with Enabling Technology | 81.5% of commercial customers | GDS Survey of Vectren C&I Customers - % of C&I customers with central AC |
| Critical Peak Pricing without Enabling Technology | 100% of commercial customers | GDS Assumption |
| Real Time Pricing | 100% of commercial customers | GDS Assumption |
| Peak Time Rebate | 100% of commercial customers | GDS Assumption |
| Time of Use | 100% of commercial customers | GDS Assumption |

### G.4.1 Existing Demand Response Programs

Vectren and its owner-member cooperatives have offered their Direct Load Control program for many years. This program offers incentives to members who enroll central AC and electric water heaters. However, Vectren plans to transition the DLC AC switch program to be controlled with smart thermostats instead. The DLC water heating and pool pump programs are being phased out. GDS assumed that all DLC programs controlled with switches would be ended by 2023. A cost-effective analysis was still run for these programs, with the assumption that no new switches would be installed and participation would steadily decline until 2023.

### G.4.2 Hierarchy

Double-counting savings from demand response programs that affect the same end uses is a common issue that must be addressed when calculating the demand response savings potential. For example, a direct load control program of air conditioning and a rate program both assume load reduction of the customers' air conditioners. For this reason, it is typically assumed that customers cannot participate in programs that affect the same end uses. This hierarchy where direct load control programs come before rate programs was chosen by Vectren. The order of the rest of the programs is based on savings. Programs with higher savings per customer are ranked as higher in the hierarchy.

**TABLE G-4 DEMAND RESPONSE HIERARCHY**

| DR Program Option | Applicable Sector |
|---|---|
| DLC Programs | Residential, Commercial |
| Critical Peak Pricing with Enabling Technology | Residential, Commercial |
| Critical Peak Pricing without Enabling Technology | Residential, Commercial |
| Real Time Pricing | Commercial |
| Peak Time Rebates | Residential, Commercial |
| Time of Use | Residential, Commercial |

### G.4.3 Participation Rates

The assumed "steady state" participation rates used in this potential study and the sources upon which each assumption is based are shown in Table G-5 for residential and non-residential customers, respectively. The steady state participation rate represents the enrollment rate once the fully achievable participation has been reached. Participation rates are expressed as a percentage of eligible customers. Program participation and impacts (demand reductions) are assumed to begin in 2020. The main sources of participant rates are several studies completed by the Brattle Group. Additional detail about participation rates and sources are shown in Table G-5.

**TABLE G-5 STEADY STATE PARTICIPATION RATES FOR DEMAND RESPONSE PROGRAM OPTIONS**

| DR Program Options | MAP Steady State Participation Rate | RAP Steady State Participation Rate | Source |
|---|---|---|---|
| **RESIDENTIAL** | | | |
| DLC AC (Switch) | 0% (existing program declining to 0 participants) | 0% (existing program declining to 0 participants) | Vectren |
| DLC AC (Thermostat) | 36% | 25% | Demand Response Market Research: Portland General Electric, 2016 to 2035, The Brattle Group, January 2016. (Participation in BYOD programs is estimated to be 5% higher than in DLC programs. |
| DLC Pool Pumps | 0% (existing program declining to 0 participants) | 0% (existing program declining to 0 participants) | Vectren |
| DLC Water Heaters | 0% (existing program declining to 0 participants) | 0% (existing program declining to 0 participants) | Vectren |

| DR Program Options | MAP Steady State Participation Rate | RAP Steady State Participation Rate | Source |
|---|---|---|---|
| Critical Peak Pricing with Enabling Technology | 91% | 22% | Demand Response Market Research: Portland General Electric, 2016 to 2035, The Brattle Group, January 2016. (Opt-Out for MAP, Opt-In for RAP) |
| Critical Peak Pricing without Enabling Technology | 82% | 17% | Demand Response Market Research: Portland General Electric, 2016 to 2035, The Brattle Group, January 2016. (Opt-Out for MAP, Opt-In for RAP) |
| Peak Time Rebate | 93% | 21% | Demand Response Market Research: Portland General Electric, 2016 to 2035, The Brattle Group, January 2016. (Opt-Out for MAP, Opt-In for RAP) |
| Time of Use | 85% | 28% | Demand Response Market Research: Portland General Electric, 2016 to 2035, The Brattle Group, January 2016. (Opt-Out for MAP, Opt-In for RAP) |
| **NON-RESIDENTIAL** | | | |
| DLC AC (Switch) | 0% (existing program declining to 0 participants) | 0% (existing program declining to 0 participants) | Vectren |
| DLC AC (Thermostat) | 19% | 8% | Demand Response Market Research: Portland General Electric, 2016 to 2035, The Brattle Group, January 2016. (Participation in BYOD programs is estimated to be 5% higher than in DLC programs. |
| DLC Water Heaters | 0% (existing program declining to 0 participants) | 0% (existing program declining to 0 participants) | Vectren |
| Critical Peak Pricing with Enabling Technology | 69% | 20% | Demand Response Market Research: Portland General Electric, 2016 to 2035, The Brattle Group, January 2016. (Opt-Out for MAP, Opt-In for RAP) |
| Critical Peak Pricing without Enabling Technology | 63% | 18% | Demand Response Market Research: Portland General Electric, 2016 to 2035, The Brattle Group, January 2016. (Opt-Out for MAP, Opt-In for RAP) |
| Real Time Pricing | 3% | 3% | PACIFICORP DEMAND-SIDE RESOURCE POTENTIAL ASSESSMENT FOR 2015-2034 |

| DR Program Options | MAP Steady State Participation Rate | RAP Steady State Participation Rate | Source |
|---|---|---|---|
| Peak Time Rebate | 71% | 22% | Demand Response Market Research: Portland General Electric, 2016 to 2035, The Brattle Group, January 2016. (Opt-Out for MAP, Opt-In for RAP) |
| Time of Use | 74% | 13% | Demand Response Market Research: Portland General Electric, 2016 to 2035, The Brattle Group, January 2016. (Opt-Out for MAP, Opt-In for RAP) |

Customer participation in new demand response programs is assumed to reach the steady state take rate over a five-year period. The path to steady state customer participation follows an "S-shaped" curve, in which participation growth accelerates over the first half of the five-year period, and then slows over the second half of the period (see Figure G-1). Existing programs have already gone through this ramp-up period, so they were escalated linearly to the final participation rate.

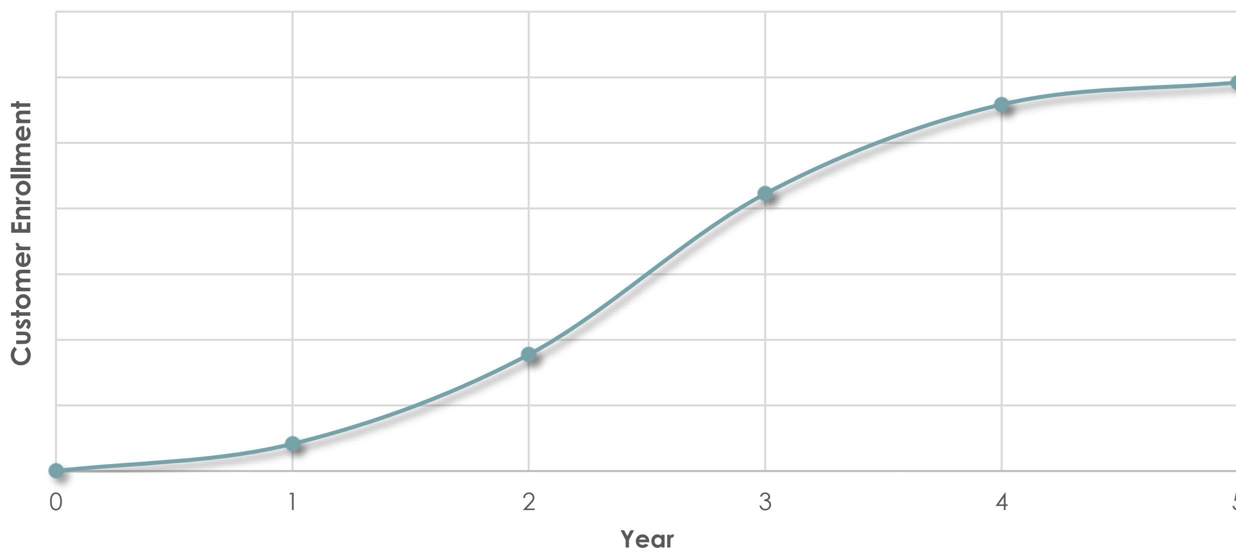



**FIGURE G-1 ILLUSTRATION OF S-SHAPED MARKET ADOPTION CURVE**

## G.5 LOAD REDUCTION ASSUMPTIONS

Table G-6 presents the residential and non-residential per participant CP demand reduction impact assumptions for each demand response program option at the customer meter. Demand reductions were based on load reductions found in Vectren's existing demand response programs, and various secondary data sources including the FERC and other industry reports, including demand response potential studies.

**TABLE G-6 PER PARTICIPANT CP DEMAND REDUCTION ASSUMPTIONS**

| DR Program Options | Per Participant CP Demand Reduction | Source |
|---|---|---|
| **RESIDENTIAL** | | |
| DLC AC (Switch) | 1 kW | 2012 FERC Demand Response Survey Data (Reported realized savings data for 20 utility programs, adjusted to account for peak summer temperature differences using NOAA Normal Max Summer Temperature Data, 1981-2010) |
| DLC AC (Thermostat) | 0.87 kW | 87% of Load Switch Control. Sources: Smart Thermostats: An Alternative to Load Control Switches? Trends and Strategic Options to Consider for Residential Load Control Programs; 2016 Demand Response Potential Study Conducted by GDS for several Michigan utilities (Confidential pilot program report) |
| DLC Pool Pumps | 1.36 kW | Southern California Edison Pool Pump Demand Response Potential Report, 2008. |
| DLC Water Heaters | 0.4 kW Summer | Demand Response Market Research:Portland General Electric, 2016 to 2035, The Brattle Group, January 2016. |
| Critical Peak Pricing with Enabling Technology | 31% of coincident peak load | Demand Response Market Research:Portland General Electric, 2016 to 2035, The Brattle Group, January 2016. |
| Critical Peak Pricing without Enabling Technology | 11.7% of coincident peak load | Demand Response Market Research:Portland General Electric, 2016 to 2035, The Brattle Group, January 2016. |
| Peak Time Rebate | 12.9% of coincident peak load | Demand Response Market Research:Portland General Electric, 2016 to 2035, The Brattle Group, January 2016. |
| Time of Use | 5.2% of coincident peak load | Demand Response Market Research:Portland General Electric, 2016 to 2035, The Brattle Group, January 2016. |
| **NON-RESIDENTIAL** | | |
| DLC AC (Switch) | 1.6 kW | 2012 FERC Demand Response Survey Data (Reported realized savings data for 14 utility programs, adjusted to account for peak summer temperature differences using NOAA Normal Max Summer Temperature Data, 1981-2010) |

| DR Program Options | Per Participant CP Demand Reduction | Source |
|---|---|---|
| DLC AC (Thermostat) | 1.39 kW | 87% of Load Switch Control. Sources: Smart Thermostats: An Alternative to Load Control Switches? Trends and Strategic Options to Consider for Residential Load Control Programs; 2016 Demand Response Potential Study Conducted by GDS for several Michigan utilities (Confidential pilot program report) |
| DLC Water Heaters | 1.2 kW Summer | Demand Response Market Research:Portland General Electric, 2016 to 2035, The Brattle Group, January 2016. |
| Critical Peak Pricing with Enabling Technology | 21.5% of coincident peak load | Dynamic Pricing: Transitioning from Experiments to Full Scale Deployments, Michigan Retreat on Peak Shaving to Reduce Wasted Energy, The Brattle Group, August 06, 2014. |
| Critical Peak Pricing without Enabling Technology | 4.2% of coincident peak load | Demand Response Market Research:Portland General Electric, 2016 to 2035, The Brattle Group, January 2016. (avg of small, med, lrg C&I) |
| Real Time Pricing | 8.4% of coincident peak load | Pacificorp Demand-Side Resource Potential Assessment for 2015-2034 |
| Peak Time Rebate | 0.7% of coincident peak load | Demand Response Market Research:Portland General Electric, 2016 to 2035, The Brattle Group, January 2016. |
| Time of Use | 1.97% of coincident peak load | Demand Response Market Research:Portland General Electric, 2016 to 2035, The Brattle Group, January 2016. (avg of small, med, lrg C&I) |

## G.6 PROGRAM COSTS

One-time program development costs of $40,000[8] were included in the first year of the analysis for new programs. No program development costs are assumed for programs that already exist. It was assumed that there would be a cost of $50[9] per new participant for marketing. Marketing costs are assumed to be 33.3% higher for MAP. There was assumed to be an annual administrative cost of $30,000 per program[10]. All program costs were escalated each year by the general rate of inflation assumed for this study.[11] Table G-7 shows the equipment cost assumptions.

[8] TVA Potential Study Volume III: Demand Response Potential, Global Energy Partners, December 2011; $400,000 split between 10 rate programs
[9] TVA Potential Study Volume III: Demand Response Potential, Global Energy Partners, December 2011
[10] Calculated based on the contract labor and Vectren South Expenses in the 2016 DLC Annual Report. GDS divided this cost by the 6 existing programs and assumed a $30,000 cost per program.
[11] The general rate of inflation used for this study was 1.6%. This was provided by Vectren.

**TABLE G-7 EQUIPMENT COST ASSUMPTIONS**

| Device | Cost | Applicable DR Programs | Source |
|---|---|---|---|
| Two-way communicating load control switch using Wi-Fi | $95 | DLC programs controlled by switches | Comverge |
| Load control switch installation | $200 | All DLC programs controlled by switches | Comverge |
| Smart controllable thermostat (such as Nest or Ecobee) | $249 | DLC AC Thermostat | Nest / Ecobee |

# APPENDIX H *Action Plan Combined Gas & Electric Portfolio Summary*

The following tables provide combined electric and gas portfolio targets for all programs for the years 2020-2025, with individual tables for each year.

## TABLE H-1 2020 COMBINED PORTFOLIO TARGETS

| | Electric | | | | | | | Gas | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Number of Participants | Total kWh Savings | Total kW (Demand) | Admin. | Implementation | Incentives | Total Budget | Number of Participants | Total Therms Savings | Admin. | Implementation | Incentives | Total Budget |
| **Residential** | | | | ELECTRIC | | | | | | | GAS | | |
| Residential Lighting | 239,866 | 8,088,914 | 905.24 | $101,000 | $186,419 | $463,014 | $750,433 | | | | | | |
| Residential Prescriptive | 7,966 | 2,465,148 | 691.22 | $40,400 | $347,608 | $632,065 | $1,020,073 | 15,750 | 1,438,213 | $29,600 | $1,090,398 | $2,456,695 | $3,576,693 |
| Residential New Construction | 86 | 188,624 | 121.46 | $5,050 | $50,000 | $16,775 | $71,825 | 704 | 305,150 | $3,700 | $286,083 | $379,375 | $669,158 |
| Home Energy Assessment | 300 | 519,393 | 55.48 | $5,050 | $240,000 | - | $245,050 | 300 | 20,924 | $3,700 | $55,000 | - | $58,700 |
| Income-Qualified Weatherization | 539 | 778,285 | 443.32 | $20,200 | $1,275,176 | - | $1,295,376 | 513 | 56,971 | $14,800 | $872,202 | - | $887,002 |
| Energy-Efficient Schools | 2,600 | 1,149,200 | 136.50 | $20,200 | $113,589 | - | $133,789 | 2,600 | 38,480 | $22,200 | $28,397 | - | $50,597 |
| Residential Behavioral Savings | 49,000 | 7,049,208 | 1,574.28 | $40,400 | $323,803 | - | $364,203 | 34,778 | 375,933 | $37,000 | $108,182 | - | $145,182 |
| Appliance Recycling | 1,251 | 1,179,811 | 171.20 | $40,400 | $143,657 | $61,000 | $245,057 | | | | | | |
| CVR Residential | - | 1,461,047 | 430 | $30,300 | $218,023 | - | $248,323 | | | | | | |
| Smart Cycle (DLC Change Out) | 1,000 | - | 1,015.00 | $20,200 | $516,000 | $96,000 | $632,200 | | | | | | |
| BYOT (Bring Your Own Thermostat) | 300 | - | 240.00 | $20,200 | $22,280 | $52,280 | $94,760 | | | | | | |
| Food Bank | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Home Energy Management Systems | - | - | - | $10,100 | $70,000 | - | $80,100 | - | - | $11,100 | $130,000 | - | $141,100 |
| Multi-Family Direct Install | | | | | | | | 1,700 | 68,591 | $14,800 | $397,115 | - | $411,915 |
| Targeted Income | | | | | | | | 46 | 15,022 | $29,600 | $74,470 | - | $104,070 |
| Home Energy House Call-Integrated | | | | | | | | 1,122 | 49,144 | $29,600 | $179,527 | - | $209,127 |
| Neighborhood Program-Integrated | | | | | | | | 1,000 | 134,440 | $29,600 | $185,910 | - | $215,510 |
| **Residential Subtotal** | **302,908** | **22,879,629** | **5,783.70** | **$353,500** | **$3,506,555** | **$1,321,134** | **$5,181,189** | **58,513** | **2,502,868** | **$225,700** | **$3,407,285** | **$2,836,070** | **$6,469,055** |
| **Commercial & Industrial** | | | | ELECTRIC | | | | | | | GAS | | |
| Commercial Prescriptive | 42,431 | 14,490,335 | 3,807.71 | $55,550 | $622,327 | $1,370,010 | $2,047,886 | 1,112 | 298,228 | $66,600 | $442,240 | $251,057 | $759,897 |
| Commercial Custom | 196 | 6,107,234 | 740.00 | $60,600 | $344,162 | $491,537 | $896,299 | 71 | 472,810 | $74,000 | $493,803 | $489,600 | $1,057,403 |
| Small Business | 381 | 2,940,932 | 213.00 | $5,050 | $215,618 | $548,167 | $768,835 | 592 | 16,788 | $3,700 | $3,096 | $5,886 | $12,682 |

| | Electric | | | | | | | Gas | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Number of Participants | Total kWh Savings | Total kW (Demand) | Admin. | Implementation | Incentives | Total Budget | Number of Participants | Total Therms Savings | Admin. | Implementation | Incentives | Total Budget |
| CVR Commercial | - | 1,032,656 | 214 | $30,300 | $148,233 | - | $178,533 | | | | | | |
| **Commercial & Industrial Subtotal** | **43,008** | **24,571,158** | **4,974.71** | **$151,500** | **$1,330,340** | **$2,409,714** | **$3,891,554** | **1,775** | **787,826** | **$144,300** | **$939,139** | **$746,543** | **$1,829,982** |
| **Indirect Costs** | **ELECTRIC** | | | | | | | **GAS** | | | | | |
| Contact Center | | | | | | | $63,000 | | | | | | $132,080 |
| Online Audit | | | | | | | $42,911 | | | | | | $200,564 |
| Outreach | | | | | | | $410,000 | | | | | | $534,863 |
| **Portfolio Costs Subtotal** | | | | | | | **$515,911** | | | | | | **$867,508** |
| **Subtotal (Before Evaluation)** | | | | | | | **$9,588,653** | | | | | | **$9,166,544** |
| Evaluation | | | | | | | $490,728 | | | | | | $482,414 |
| **DSM Portfolio Total** | | | | | | | **$10,079,381** | | | | | | **$9,648,958** |
| **Other Costs** | **ELECTRIC** | | | | | | | **GAS** | | | | | |
| Emerging Markets | | | | | | | $ 200,000 | | | | | | $ 200,000 |
| Market Potential Study | | | | | | | - | | | | | | - |
| **Other Costs Subtotal** | | | | | | | **$ 200,000** | | | | | | **$ 200,000** |
| **DSM Portfolio Total including Other Costs** | | | | | | | **$10,279,381** | | | | | | **$9,848,958** |

## TABLE H -2 2021 COMBINED PORTFOLIO TARGETS

| | Electric | | | | | | | Gas | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Number of Participants | Total kWh Savings | Total kW (Demand) | Admin. | Implementation | Incentives | Total Budget | Number of Participants | Total Therms Savings | Admin. | Implementation | Incentives | Total Budget |
| **Residential** | **ELECTRIC** | | | | | | | **GAS** | | | | | |
| Residential Lighting | 262,832 | 8,704,288 | 875.28 | $102,616 | $189,402 | $455,001 | $747,018 | | | | | | |
| Residential Prescriptive | 8,276 | 2,618,629 | 661.70 | $41,046 | $353,169 | $645,510 | $1,039,726 | 16,021 | 1,456,999 | $30,074 | $1,107,845 | $2,491,995 | $3,629,913 |
| Residential New Construction | 77 | 168,932 | 108.81 | $5,131 | $57,249 | $15,025 | $77,405 | 857 | 369,380 | $3,759 | $342,221 | $452,875 | $798,855 |
| Home Energy Assessment | 350 | 605,959 | 64.72 | $5,131 | $258,000 | - | $263,131 | 350 | 24,412 | $3,759 | $55,880 | - | $59,639 |
| Income-Qualified Weatherization | 566 | 823,215 | 467.28 | $20,523 | $1,293,527 | - | $1,314,050 | 538 | 60,190 | $15,037 | $885,268 | - | $900,304 |

| | Electric | | | | | | | Gas | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Number of Participants | Total kWh Savings | Total kW (Demand) | Admin. | Implementation | Incentives | Total Budget | Number of Participants | Total Therms Savings | Admin. | Implementation | Incentives | Total Budget |
| Energy-Efficient Schools | 2,600 | 1,149,200 | 136.50 | $20,523 | $117,253 | - | $137,776 | 2,600 | 38,480 | $22,555 | $29,313 | - | $51,868 |
| Residential Behavioral Savings | 49,000 | 7,049,208 | 1,574.28 | $20,523 | $328,984 | - | $349,507 | 34,778 | 375,933 | $22,555 | $109,913 | - | $132,468 |
| Appliance Recycling | 1,344 | 1,285,473 | 172.83 | $41,046 | $159,415 | $66,625 | $267,086 | | | | | | |
| CVR Residential | - | - | - | $30,785 | $197,378 | - | $228,163 | | | | | | |
| Smart Cycle (DLC Change Out) | 1,000 | 198,000 | 1,015 | $20,523 | $536,000 | $116,000 | $672,523 | | | | | | |
| BYOT (Bring Your Own Thermostat) | 300 | - | 240.00 | $20,523 | $30,280 | $60,280 | $111,083 | | | | | | |
| Food Bank | 6,312 | 1,564,332 | 172.21 | $20,523 | $92,517 | - | $113,041 | 6,312 | 41,628 | $15,037 | $4,626 | - | $19,663 |
| Home Energy Management Systems | 1,000 | 515,000 | 80.00 | $10,262 | $212,900 | - | $223,162 | 1,000 | 54,400 | $11,278 | $194,100 | - | $205,378 |
| Multi-Family Direct Install | | | | | | | | 1,700 | 68,591 | $15,037 | $403,469 | - | $418,506 |
| Targeted Income | | | | | | | | 46 | 15,022 | $30,074 | $75,662 | - | $105,735 |
| Home Energy House Call-Integrated | | | | | | | | 1,122 | 49,144 | $30,074 | $182,399 | - | $212,473 |
| Neighborhood Program-Integrated | | | | | | | | 1,000 | 134,440 | $30,074 | $188,885 | - | $218,959 |
| **Residential Subtotal** | **333,657** | **24,682,235** | **5,568.60** | **$359,156** | **$3,826,074** | **$1,358,441** | **$5,543,671** | **66,324** | **2,688,619** | **$229,311** | **$3,579,580** | **$2,944,870** | **$6,753,761** |
| **Commercial & Industrial** | | | | **ELECTRIC** | | | | | | | **GAS** | | |
| Commercial Prescriptive | 48,449 | 15,981,655 | 4,131.23 | $56,439 | $682,432 | $1,424,756 | $2,163,627 | 1,193 | 315,496 | $67,666 | $487,528 | $266,357 | $821,550 |
| Commercial Custom | 196 | 6,107,234 | 740.00 | $61,570 | $349,669 | $491,537 | $902,775 | 71 | 472,810 | $75,184 | $501,704 | $489,600 | $1,066,488 |
| Small Business | 382 | 2,944,615 | 213.00 | $5,131 | $219,172 | $539,573 | $763,876 | 1,025 | 18,516 | $3,759 | $3,209 | $6,006 | $12,975 |
| CVR Commercial | - | - | - | $30,785 | $133,547 | - | $164,332 | | | | | | |
| **Commercial & Industrial Subtotal** | **49,027** | **25,033,504** | **5,084.23** | **$153,924** | **$1,384,820** | **$2,455,867** | **$3,994,610** | **2,289** | **806,822** | **$146,609** | **$992,441** | **$761,963** | **$1,901,012** |
| **Indirect Costs** | | | | **ELECTRIC** | | | | | | | **GAS** | | |
| Contact Center | | | | | | | $64,008 | | | | | | $134,193 |
| Online Audit | | | | | | | $43,598 | | | | | | $203,774 |
| Outreach | | | | | | | $416,560 | | | | | | $543,421 |

| | Electric | | | | | | | Gas | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Number of Participants | Total kWh Savings | Total kW (Demand) | Admin. | Implementation | Incentives | Total Budget | Number of Participants | Total Therms Savings | Admin. | Implementation | Incentives | Total Budget |
| **Portfolio Costs Subtotal** | | | | | | | **$524,166** | | | | | | **$881,388** |
| **Subtotal (Before Evaluation)** | | | | | | | **$10,062,446** | | | | | | **$9,536,161** |
| Evaluation | | | | | | | $522,653 | | | | | | $507,425 |
| **DSM Portfolio Total** | | | | | | | **$10,585,099** | | | | | | **$10,043,586** |
| **Other Costs** | **ELECTRIC** | | | | | | | **GAS** | | | | | |
| Emerging Markets | | | | | | | 200,000 | | | | | | 200,000 |
| Market Potential Study | | | | | | | 300,000 | | | | | | 300,000 |
| **Other Costs Subtotal** | | | | | | | **500,000** | | | | | | **500,000** |
| **DSM Portfolio Total including Other Costs** | | | | | | | **$11,085,099** | | | | | | **$10,543,586** |

## TABLE H-3 2022 COMBINED PORTFOLIO TARGETS

| | Electric | | | | | | | Gas | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Number of Participants | Total kWh Savings | Total kW (Demand) | Admin. | Implementation | Incentives | Total Budget | Number of Participants | Total Therms Savings | Admin. | Implementation | Incentives | Total Budget |
| **Residential** | **ELECTRIC** | | | | | | | **GAS** | | | | | |
| Residential Lighting | 91,708 | 3,259,915 | 255.83 | $104,258 | $144,380 | $346,846 | $595,484 | | | | | | |
| Residential Prescriptive | 8,303 | 2,722,283 | 737.22 | $41,703 | $358,820 | $680,160 | $1,080,683 | 9,522 | 579,226 | $30,555 | $535,505 | $858,470 | $1,424,530 |
| Residential New Construction | 75 | 164,892 | 106.37 | $5,213 | $53,186 | $14,675 | $73,074 | 1,075 | 462,060 | $3,819 | $424,689 | $561,725 | $990,233 |
| Home Energy Assessment | 420 | 727,151 | 77.67 | $5,213 | $263,225 | - | $268,438 | 420 | 29,294 | $3,819 | $56,774 | - | $60,593 |
| Income-Qualified Weatherization | 594 | 869,076 | 492.09 | $20,852 | $1,312,171 | - | $1,333,023 | 564 | 63,502 | $15,277 | $980,165 | - | $995,443 |
| Energy-Efficient Schools | 2,600 | 670,800 | 93.60 | $20,852 | $92,229 | - | $113,080 | 2,600 | 38,480 | $22,916 | $30,743 | - | $53,659 |
| Residential Behavioral Savings | 49,000 | 7,049,208 | 1,574.28 | $20,852 | $334,248 | - | $355,099 | 34,778 | 375,933 | $22,916 | $111,671 | - | $134,587 |
| Appliance Recycling | 1,425 | 1,360,636 | 184.89 | $41,703 | $171,385 | $70,500 | $283,589 | | | | | | |
| CVR Residential | - | - | - | $31,277 | $190,034 | - | $221,311 | | | | | | |
| Smart Cycle (DLC Change Out) | 1,000 | 198,000 | 1,015 | $20,852 | $556,000 | $136,000 | $712,852 | | | | | | |

| | Electric | | | | | | | Gas | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Number of Participants | Total kWh Savings | Total kW (Demand) | Admin. | Implementation | Incentives | Total Budget | Number of Participants | Total Therms Savings | Admin. | Implementation | Incentives | Total Budget |
| BYOT (Bring Your Own Thermostat) | 300 | - | 240.00 | $20,852 | $38,280 | $68,280 | $127,412 | | | | | | |
| Food Bank | 6,312 | 816,353 | 69.09 | $20,852 | $18,800 | - | $39,651 | 6,312 | 41,628 | $15,278 | $4,700 | - | $19,977 |
| Home Energy Management Systems | 1,000 | 515,000 | 80.00 | $10,426 | $219,900 | - | $230,326 | 1,000 | 54,400 | $11,458 | $187,100 | - | $198,558 |
| Multi-Family Direct Install | | | | | | | | 1,700 | 68,591 | $15,277 | $409,925 | - | $425,202 |
| Targeted Income | | | | | | | | 46 | 15,022 | $30,555 | $76,872 | - | $107,427 |
| Home Energy House Call-Integrated | | | | | | | | 1,122 | 49,144 | $30,555 | $185,318 | - | $215,872 |
| Neighborhood Program-Integrated | | | | | | | | 1,000 | 134,440 | $30,555 | $191,907 | - | $222,462 |
| **Residential Subtotal** | **162,737** | **18,353,314** | **4,926.04** | **$364,902** | **$3,752,658** | **$1,316,461** | **$5,434,021** | **60,139** | **1,911,720** | **$232,980** | **$3,195,369** | **$1,420,195** | **$4,848,544** |
| **Commercial & Industrial** | | | | **ELECTRIC** | | | | | | | **GAS** | | |
| Commercial Prescriptive | 52,971 | 17,154,963 | 4,383.05 | $57,342 | $733,558 | $1,448,274 | $2,239,173 | 1,312 | 338,606 | $68,748 | $541,210 | $286,137 | $896,095 |
| Commercial Custom | 196 | 6,107,234 | 740.00 | $62,555 | $355,263 | $491,537 | $909,355 | 71 | 472,810 | $76,387 | $509,731 | $489,600 | $1,075,718 |
| Small Business | 382 | 2,949,771 | 213.00 | $5,213 | $222,721 | $530,824 | $758,758 | 1,135 | 21,540 | $3,819 | $3,375 | $6,216 | $13,410 |
| CVR Commercial | - | - | - | $31,277 | $128,261 | - | $159,538 | | | | | | |
| **Commercial & Industrial Subtotal** | **53,549** | **26,211,968** | **5,336.05** | **$156,387** | **$1,439,803** | **$2,470,635** | **$4,066,825** | **2,518** | **832,956** | **$148,955** | **$1,054,315** | **$781,953** | **$1,985,223** |
| **Indirect Costs** | | | | **ELECTRIC** | | | | | | | **GAS** | | |
| Contact Center | | | | | | | $65,032 | | | | | | $136,340 |
| Online Audit | | | | | | | $44,295 | | | | | | $207,034 |
| Outreach | | | | | | | $423,225 | | | | | | $552,116 |
| **Portfolio Costs Subtotal** | | | | | | | **$532,552** | | | | | | **$895,490** |
| **Subtotal (Before Evaluation)** | | | | | | | **$10,033,398** | | | | | | **$7,729,257** |
| Evaluation | | | | | | | $518,856 | | | | | | $415,538 |
| **DSM Portfolio Total** | | | | | | | **$10,552,254** | | | | | | **$8,144,795** |
| **Other Costs** | | | | **ELECTRIC** | | | | | | | **GAS** | | |
| Emerging Markets | | | | | | | 200,000 | | | | | | 200,000 |

| | Electric | | | | | | | Gas | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Number of Participants | Total kWh Savings | Total kW (Demand) | Admin. | Implementation | Incentives | Total Budget | Number of Participants | Total Therms Savings | Admin. | Implementation | Incentives | Total Budget |
| Market Potential Study | | | | | | | $ | | | | | | $ |
| **Other Costs Subtotal** | | | | | | | **200,000** | | | | | | **200,000** |
| **DSM Portfolio Total including Other Costs** | | | | | | | **$10,752,254** | | | | | | **$8,344,795** |

## TABLE H -4 2023 COMBINED PORTFOLIO TARGETS

| | Electric | | | | | | | Gas | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Number of Participants | Total kWh Savings | Total kW (Demand) | Admin. | Implementation | Incentives | Total Budget | Number of Participants | Total Therms Savings | Admin. | Implementation | Incentives | Total Budget |
| **Residential** | | | | ELECTRIC | | | | | | GAS | | | |
| Residential Lighting | 12,231 | 807,282 | 19.16 | $105,926 | $32,756 | $78,689 | $217,370 | | | | | | |
| Residential Prescriptive | 8,140 | 2,793,920 | 812.09 | $42,370 | $364,561 | $707,135 | $1,114,066 | 9,565 | 580,541 | $31,044 | $544,073 | $863,520 | $1,438,637 |
| Residential New Construction | 73 | 160,852 | 103.94 | $5,296 | $50,202 | $14,325 | $69,824 | 1,253 | 537,581 | $3,880 | $491,921 | $650,275 | $1,146,077 |
| Home Energy Assessment | 504 | 872,581 | 93.20 | $5,296 | $267,437 | - | $272,733 | 504 | 35,153 | $3,880 | $57,682 | - | $61,563 |
| Income-Qualified Weatherization | 623 | 917,290 | 518.75 | $21,185 | $1,331,114 | - | $1,352,299 | 591 | 66,991 | $15,522 | $1,060,825 | - | $1,076,347 |
| Energy-Efficient Schools | 2,600 | 670,800 | 93.60 | $21,185 | $98,274 | - | $119,460 | 2,600 | 38,480 | $23,283 | $32,758 | - | $56,041 |
| Residential Behavioral Savings | 49,000 | 7,049,208 | 1,574.28 | $21,185 | $339,596 | - | $360,781 | 34,778 | 375,933 | $23,283 | $113,458 | - | $136,741 |
| Appliance Recycling | 1,435 | 1,366,149 | 188.46 | $42,370 | $174,745 | $70,750 | $287,865 | | | | | | |
| CVR Residential | - | 1,461,047 | 430 | $31,778 | $270,252 | - | $302,029 | | | | | | |
| Smart Cycle (DLC Change Out) | 1,000 | 198,000 | 1,015 | $21,185 | $576,000 | $156,000 | $753,185 | | | | | | |
| BYOT (Bring Your Own Thermostat) | 300 | - | 240.00 | $21,185 | $46,280 | $76,280 | $143,745 | | | | | | |
| Food Bank | 3,156 | 649,158 | 46.71 | $21,185 | $9,550 | - | $30,735 | 3,156 | 20,814 | $15,522 | $4,775 | - | $20,297 |
| Home Energy Management Systems | 1,000 | 515,000 | 80.00 | $10,593 | $234,900 | - | $245,493 | 1,000 | 54,400 | $11,641 | $172,100 | - | $183,741 |
| Multi-Family Direct Install | | | | | | | | 1,700 | 68,591 | $15,522 | $416,484 | - | $432,005 |
| Targeted Income | | | | | | | | 46 | 15,022 | $31,044 | $78,102 | - | $109,146 |
| Home Energy House Call-Integrated | | | | | | | | 1,122 | 49,144 | $31,044 | $188,283 | - | $219,326 |

| | Electric | | | | | | | Gas | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Number of Participants | Total kWh Savings | Total kW (Demand) | Admin. | Implementation | Incentives | Total Budget | Number of Participants | Total Therms Savings | Admin. | Implementation | Incentives | Total Budget |
| Neighborhood Program-Integrated | | | | | | | | 1,000 | 134,440 | $31,044 | $194,978 | - | $226,021 |
| **Residential Subtotal** | **80,062** | **17,461,286** | **5,215.19** | **$370,741** | **$3,795,666** | **$1,103,179** | **$5,269,586** | **57,315** | **1,977,090** | **$236,708** | **$3,355,439** | **$1,513,795** | **$5,105,942** |
| **Commercial & Industrial** | | | | **ELECTRIC** | | | | | | | **GAS** | | |
| Commercial Prescriptive | 55,283 | 17,821,076 | 4,524.43 | $58,259 | $769,435 | $1,434,660 | $2,262,354 | 1,479 | 365,992 | $69,848 | $598,626 | $307,777 | $976,251 |
| Commercial Custom | 196 | 6,107,234 | 740.00 | $63,556 | $360,948 | $491,537 | $916,040 | 71 | 472,810 | $77,609 | $517,886 | $489,600 | $1,085,096 |
| Small Business | 382 | 2,952,715 | 213.00 | $5,296 | $226,003 | $521,287 | $752,586 | 1,260 | 24,996 | $3,880 | $3,561 | $6,456 | $13,898 |
| CVR Commercial | - | 1,032,656 | 214 | $31,778 | $184,861 | - | $216,639 | | | | | | |
| **Commercial & Industrial Subtotal** | **55,861** | **27,913,681** | **5,691.43** | **$158,889** | **$1,541,248** | **$2,447,483** | **$4,147,620** | **2,810** | **863,798** | **$151,338** | **$1,120,073** | **$803,833** | **$2,075,244** |
| **Indirect Costs** | | | | **ELECTRIC** | | | | | | | **GAS** | | |
| Contact Center | | | | | | | $66,073 | | | | | | $138,522 |
| Online Audit | | | | | | | $45,004 | | | | | | $210,346 |
| Outreach | | | | | | | $429,997 | | | | | | $560,949 |
| **Portfolio Costs Subtotal** | | | | | | | **$541,073** | | | | | | **$909,818** |
| **Subtotal (Before Evaluation)** | | | | | | | **$9,958,279** | | | | | | **$8,091,004** |
| Evaluation | | | | | | | $512,192 | | | | | | $431,543 |
| **DSM Portfolio Total** | | | | | | | **$10,470,471** | | | | | | **$8,522,547** |
| **Other Costs** | | | | **ELECTRIC** | | | | | | | **GAS** | | |
| Emerging Markets | | | | | | | 200,000 | | | | | | $200,000 |
| Market Potential Study | | | | | | | $ | | | | | | - |
| **Other Costs Subtotal** | | | | | | | **200,000** | | | | | | **$200,000** |
| **DSM Portfolio Total including Other Costs** | | | | | | | **$10,670,471** | | | | | | **$8,722,547** |

## TABLE H-5 2024 COMBINED PORTFOLIO TARGETS

| | Electric | | | | | | | Gas | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Number of Participants | Total kWh Savings | Total kW (Demand) | Admin. | Implementation | Incentives | Total Budget | Number of Participants | Total Therms Savings | Admin. | Implementation | Incentives | Total Budget |
| **Residential** | | | | ELECTRIC | | | | | | GAS | | | |
| Residential Lighting | 14,089 | 977,297 | 19.66 | $107,621 | $38,416 | $92,287 | $238,324 | | | | | | |
| Residential Prescriptive | 7,892 | 2,860,501 | 889.35 | $43,048 | $370,394 | $732,410 | $1,145,852 | 9,584 | 579,541 | $31,540 | $552,778 | $864,995 | $1,449,314 |
| Residential New Construction | 71 | 156,812 | 101.51 | $5,381 | $48,144 | $13,975 | $67,500 | 1,428 | 612,092 | $3,943 | $558,080 | $737,775 | $1,299,797 |
| Home Energy Assessment | 504 | 840,768 | 89.03 | $5,381 | $271,716 | - | $277,097 | 504 | 35,153 | $3,943 | $58,605 | - | $62,548 |
| Income-Qualified Weatherization | 653 | 967,302 | 546.35 | $21,524 | $1,350,360 | - | $1,371,884 | 619 | 70,571 | $15,770 | $1,120,207 | - | $1,135,977 |
| Energy-Efficient Schools | 2,600 | 670,800 | 93.60 | $21,524 | $106,392 | - | $127,916 | 2,600 | 38,480 | $23,655 | $35,464 | - | $59,119 |
| Residential Behavioral Savings | 49,000 | 7,049,208 | 1,574.28 | $21,524 | $345,029 | - | $366,554 | 34,778 | 375,933 | $23,655 | $115,273 | - | $138,929 |
| Appliance Recycling | 1,372 | 1,300,910 | 183.54 | $43,048 | $168,946 | $67,325 | $279,320 | | | | | | |
| CVR Residential | - | - | - | $32,286 | $315,241 | - | $347,528 | | | | | | |
| Smart Cycle (DLC Change Out) | 1,000 | 198,000 | 1,015 | $21,524 | $596,000 | $176,000 | $793,524 | | | | | | |
| BYOT (Bring Your Own Thermostat) | 300 | - | 240.00 | $21,524 | $54,280 | $84,280 | $160,084 | | | | | | |
| Food Bank | 3,156 | 649,158 | 46.71 | $21,524 | $9,703 | - | $31,227 | 3,156 | 20,814 | $15,770 | $4,851 | - | $20,622 |
| Home Energy Management Systems | 1,000 | 515,000 | 80.00 | $10,762 | $245,940 | - | $256,702 | 1,000 | 54,400 | $11,828 | $198,260 | - | $210,088 |
| Multi-Family Direct Install | | | | | | | | 1,700 | 68,591 | $15,770 | $423,147 | - | $438,918 |
| Targeted Income | | | | | | | | 46 | 15,022 | $31,540 | $79,352 | - | $110,892 |
| Home Energy House Call-Integrated | | | | | | | | 1,122 | 49,144 | $31,540 | $191,295 | - | $222,835 |
| Neighborhood Program-Integrated | | | | | | | | 1,000 | 134,440 | $31,540 | $198,097 | - | $229,638 |
| **Residential Subtotal** | **81,637** | **16,185,755** | **4,879.02** | **$376,673** | **$3,920,561** | **$1,166,277** | **$5,463,511** | **57,537** | **2,054,181** | **$240,495** | **$3,535,411** | **$1,602,770** | **$5,378,676** |
| **Commercial & Industrial** | | | | ELECTRIC | | | | | | GAS | | | |
| Commercial Prescriptive | 55,739 | 18,058,503 | 4,572.95 | $59,191 | $791,792 | $1,394,674 | $2,245,657 | 1,712 | 402,215 | $70,966 | $611,299 | $335,962 | $1,018,227 |
| Commercial Custom | 196 | 6,107,234 | 740.00 | $64,572 | $366,723 | $491,537 | $922,832 | 71 | 472,810 | $78,851 | $526,173 | $489,600 | $1,094,624 |
| Small Business | 383 | 2,957,870 | 213.00 | $5,381 | $229,663 | $512,537 | $747,582 | 1,369 | 28,020 | $3,943 | $3,736 | $6,666 | $14,344 |

| | Electric | | | | | | | Gas | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Number of Participants | Total kWh Savings | Total kW (Demand) | Admin. | Implementation | Incentives | Total Budget | Number of Participants | Total Therms Savings | Admin. | Implementation | Incentives | Total Budget |
| CVR Commercial | - | - | - | $32,286 | $216,561 | - | $248,848 | | | | | | |
| **Commercial & Industrial Subtotal** | **56,318** | **27,123,608** | **5,525.95** | **$161,431** | **$1,604,739** | **$2,398,748** | **$4,164,919** | **3,152** | **903,045** | **$153,759** | **$1,141,208** | **$832,228** | **$2,127,195** |
| **Indirect Costs** | **ELECTRIC** | | | | | | | **GAS** | | | | | |
| Contact Center | | | | | | | $67,130 | | | | | | $140,738 |
| Online Audit | | | | | | | $45,724 | | | | | | $213,712 |
| Outreach | | | | | | | $436,877 | | | | | | $569,925 |
| **Portfolio Costs Subtotal** | | | | | | | **$549,730** | | | | | | **$924,375** |
| **Subtotal (Before Evaluation)** | | | | | | | **$10,178,160** | | | | | | **$8,430,246** |
| Evaluation | | | | | | | $520,077 | | | | | | $446,225 |
| **DSM Portfolio Total** | | | | | | | **$10,698,237** | | | | | | **$8,876,471** |
| **Other Costs** | **ELECTRIC** | | | | | | | **GAS** | | | | | |
| Emerging Markets | | | | | | | 200,000 | | | | | | 200,000 |
| Market Potential Study | | | | | | | 300,000 | | | | | | 300,000 |
| **Other Costs Subtotal** | | | | | | | **500,000** | | | | | | **500,000** |
| **DSM Portfolio Total including Other Costs** | | | | | | | **$11,198,237** | | | | | | **$9,376,471** |

## TABLE H -6 2025 COMBINED PORTFOLIO TARGETS

| | Electric | | | | | | | Gas | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Number of Participants | Total kWh Savings | Total kW (Demand) | Admin. | Implementation | Incentives | Total Budget | Number of Participants | Total Therms Savings | Admin. | Implementation | Incentives | Total Budget |
| **Residential** | **ELECTRIC** | | | | | | | **GAS** | | | | | |
| Residential Lighting | 15,913 | 1,146,410 | 274.12 | $109,343 | $44,005 | $105,714 | $259,061 | | | | | | |
| Residential Prescriptive | 8,136 | 2,974,980 | 961.29 | $43,737 | $376,320 | $767,435 | $1,187,492 | 9,591 | 577,456 | $32,045 | $561,623 | $864,845 | $1,458,513 |
| Residential New Construction | 70 | 154,792 | 100.29 | $5,467 | $46,909 | $13,800 | $66,176 | 1,592 | 681,668 | $4,006 | $620,174 | $819,500 | $1,443,680 |
| Home Energy Assessment | 504 | 790,845 | 83.15 | $5,467 | $276,063 | - | $281,530 | 504 | 35,153 | $4,006 | $59,543 | - | $63,549 |

| | Electric | | | | | | | Gas | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Number of Participants | Total kWh Savings | Total kW (Demand) | Admin. | Implementation | Incentives | Total Budget | Number of Participants | Total Therms Savings | Admin. | Implementation | Incentives | Total Budget |
| Income-Qualified Weatherization | 685 | 1,018,544 | 575.34 | $21,869 | $1,369,913 | - | $1,391,782 | 649 | 74,337 | $16,022 | $1,156,992 | - | $1,173,014 |
| Energy-Efficient Schools | 2,600 | 670,800 | 93.60 | $21,869 | $117,023 | - | $138,891 | 2,600 | 38,480 | $24,034 | $39,008 | - | $63,041 |
| Residential Behavioral Savings | 49,000 | 7,049,208 | 1,574.28 | $21,869 | $350,550 | - | $372,418 | 34,778 | 375,933 | $24,034 | $117,118 | - | $141,151 |
| Appliance Recycling | 1,253 | 1,180,913 | 171.99 | $43,737 | $155,651 | $61,050 | $260,438 | | | | | | |
| CVR Residential | - | - | - | $32,803 | $282,073 | - | $314,876 | | | | | | |
| Smart Cycle (DLC Change Out) | 1,000 | 198,000 | 1,015 | $21,869 | $616,000 | $196,000 | $833,869 | | | | | | |
| BYOT (Bring Your Own Thermostat) | 300 | - | 240.00 | $21,869 | $62,280 | $92,280 | $176,429 | | | | | | |
| Food Bank | 3,156 | 649,158 | 46.71 | $21,869 | $9,858 | - | $31,727 | 3,156 | 20,814 | $16,023 | $4,929 | - | $20,952 |
| Home Energy Management Systems | 1,000 | 515,000 | 80.00 | $10,934 | $266,980 | - | $277,914 | 1,000 | 54,400 | $12,017 | $214,420 | - | $226,437 |
| Multi-Family Direct Install | | | | | | | | 1,700 | 68,591 | $16,022 | $429,918 | - | $445,940 |
| Targeted Income | | | | | | | | 46 | 15,022 | $32,045 | $80,621 | - | $112,666 |
| Home Energy House Call-Integrated | | | | | | | | 1,122 | 49,144 | $32,045 | $194,356 | - | $226,401 |
| Neighborhood Program-Integrated | | | | | | | | 1,000 | 134,440 | $32,045 | $201,267 | - | $233,312 |
| **Residential Subtotal** | **83,617** | **16,348,650** | **5,215.76** | **$382,700** | **$3,973,626** | **$1,236,279** | **$5,592,604** | **57,738** | **2,125,438** | **$244,343** | **$3,679,968** | **$1,684,345** | **$5,608,656** |
| **Commercial & Industrial** | | | | **ELECTRIC** | | | | | | | **GAS** | | |
| Commercial Prescriptive | 53,882 | 17,825,085 | 4,513.77 | $60,139 | $797,128 | $1,331,794 | $2,189,060 | 1,964 | 439,398 | $72,101 | $737,459 | $363,357 | $1,172,917 |
| Commercial Custom | 196 | 6,107,234 | 740.00 | $65,606 | $372,590 | $491,537 | $929,733 | 71 | 472,810 | $80,112 | $534,591 | $489,600 | $1,104,304 |
| Small Business | 383 | 2,963,026 | 213.00 | $5,467 | $233,383 | $503,787 | $742,637 | 1,479 | 31,044 | $4,006 | $3,915 | $6,876 | $14,797 |
| CVR Commercial | - | - | - | $32,803 | $193,019 | - | $225,821 | - | - | - | - | - | - |
| **Commercial & Industrial Subtotal** | **54,461** | **26,895,345** | **5,466.77** | **$164,014** | **$1,596,120** | **$2,327,118** | **$4,087,252** | **3,514** | **943,252** | **$156,219** | **$1,275,965** | **$859,833** | **$2,292,017** |
| **Indirect Costs** | | | | **ELECTRIC** | | | | | | | **GAS** | | |
| Contact Center | | | | | | | $68,204 | | | | | | $142,990 |
| Online Audit | | | | | | | $46,456 | | | | | | $217,131 |

| | Electric | | | | | | | Gas | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Number of Participants | Total kWh Savings | Total kW (Demand) | Admin. | Implementation | Incentives | Total Budget | Number of Participants | Total Therms Savings | Admin. | Implementation | Incentives | Total Budget |
| Outreach | | | | | | | $443,867 | | | | | | $579,043 |
| **Portfolio Costs Subtotal** | | | | | | | **$558,526** | | | | | | **$939,165** |
| **Subtotal (Before Evaluation)** | | | | | | | **$10,238,382** | | | | | | **$8,839,838** |
| Evaluation | | | | | | | $520,203 | | | | | | $464,552 |
| **DSM Portfolio Total** | | | | | | | **$10,758,585** | | | | | | **$9,304,390** |
| **Other Costs** | ELECTRIC | | | | | | | GAS | | | | | |
| Emerging Markets | | | | | | | 200,000 | | | | | | 200,000 |
| Market Potential Study | | | | | | | | | | | | | |
| **Other Costs Subtotal** | | | | | | | **200,000** | | | | | | **200,000** |
| **DSM Portfolio Total including Other Costs** | | | | | | | **$10,958,585** | | | | | | **$9,504,390** |

# APPENDIX I *Action Plan Combined Gas & Electric Costs Summary*

The following tables present combined gas and electric costs for all residential programs for the years 2020-2025, with individual tables for each year. This is immediately followed by a table presenting the combined gas and electric costs for all commercial and industrial programs.

TABLE I-1 2020 COMBINED GAS AND ELECTRIC COSTS – RESIDENTIAL

| Residential | Admin. (Electric) | Implementation (Electric) | Incentives (Electric) | Total Budget (Electric) | Admin. (Gas) | Implementation (Gas) | Incentives (Gas) | Total Budget (Gas) |
|---|---|---|---|---|---|---|---|---|
| Residential Lighting | $101,000 | $186,419 | $463,014 | $750,433 | | | | |
| Residential Prescriptive | $40,400 | $347,608 | $632,065 | $1,020,073 | $29,600 | $1,090,398 | $2,456,695 | $3,576,693 |
| Residential New Construction | $5,050 | $50,000 | $16,775 | $71,825 | $3,700 | $286,083 | $379,375 | $669,158 |
| Home Energy Assessment | $5,050 | $240,000 | - | $245,050 | $3,700 | $55,000 | - | $58,700 |
| Income-Qualified Weatherization | $20,200 | $1,275,176 | - | $1,295,376 | $14,800 | $872,202 | - | $887,002 |
| Energy-Efficient Schools | $20,200 | $113,589 | - | $133,789 | $22,200 | $28,397 | - | $50,597 |
| Residential Behavioral Savings | $40,400 | $323,803 | - | $364,203 | $37,000 | $108,182 | - | $145,182 |
| Appliance Recycling | $40,400 | $143,657 | $61,000 | $245,057 | | | | |
| CVR Residential | $30,300 | $218,023 | - | $248,323 | | | | |
| Smart Cycle (DLC Change Out) | $20,200 | $516,000 | $96,000 | $632,200 | | | | |
| BYOT (Bring Your Own Thermostat) | $20,200 | $22,280 | $52,280 | $94,760 | | | | |
| Food Bank | - | - | - | - | - | - | - | - |
| Home Energy Management Systems | $10,100 | $70,000 | - | $80,100 | $11,100 | $130,000 | - | $141,100 |
| Multi-Family Direct Install | | | | | $14,800 | $397,115 | - | $411,915 |
| Targeted Income | | | | | $29,600 | $74,470 | - | $104,070 |
| Home Energy House Call- Integrated | | | | | $29,600 | $179,527 | - | $209,127 |
| Neighborhood Program- Integrated | | | | | $29,600 | $185,910 | - | $215,510 |
| **Residential Subtotal** | **$353,500** | **$3,506,555** | **$1,321,134** | **$5,181,189** | **$225,700** | **$3,407,285** | **$2,836,070** | **$6,469,055** |

TABLE I -2 2020 COMBINED GAS AND ELECTRIC COSTS – COMMERCIAL & INDUSTRIAL

| | Admin. | Implementation | Incentives | Total Budget | Admin. | Implementation | Incentives | Total Budget |
|---|---|---|---|---|---|---|---|---|
| **Commercial & Industrial** | ELECTRIC | | | | GAS | | | |
| Commercial Prescriptive | $55,550 | $622,327 | $1,370,010 | $2,047,886 | $66,600 | $442,240 | $251,057 | $759,897 |
| Commercial Custom | $60,600 | $344,162 | $491,537 | $896,299 | $74,000 | $493,803 | $489,600 | $1,057,403 |
| Small Business | $5,050 | $215,618 | $548,167 | $768,835 | $3,700 | $3,096 | $5,886 | $12,682 |
| CVR Commercial | $30,300 | $148,233 | - | $178,533 | | | | |
| **Commercial & Industrial Subtotal** | **$151,500** | **$1,330,340** | **$2,409,714** | **$3,891,554** | **$144,300** | **$939,139** | **$746,543** | **$1,829,982** |

TABLE I -3 2021 COMBINED GAS AND ELECTRIC COSTS – RESIDENTIAL

| | Admin. | Implementation | Incentives | Total Budget | Admin. | Implementation | Incentives | Total Budget |
|---|---|---|---|---|---|---|---|---|
| **Residential** | ELECTRIC | | | | GAS | | | |
| Residential Lighting | $102,616 | $189,402 | $455,001 | $747,018 | | | | |
| Residential Prescriptive | $41,046 | $353,169 | $645,510 | $1,039,726 | $30,074 | $1,107,845 | $2,491,995 | $3,629,913 |
| Residential New Construction | $5,131 | $57,249 | $15,025 | $77,405 | $3,759 | $342,221 | $452,875 | $798,855 |
| Home Energy Assessment | $5,131 | $258,000 | - | $263,131 | $3,759 | $55,880 | - | $59,639 |
| Income-Qualified Weatherization | $20,523 | $1,293,527 | - | $1,314,050 | $15,037 | $885,268 | - | $900,304 |
| Energy-Efficient Schools | $20,523 | $117,253 | - | $137,776 | $22,555 | $29,313 | - | $51,868 |
| Residential Behavioral Savings | $20,523 | $328,984 | - | $349,507 | $22,555 | $109,913 | - | $132,468 |
| Appliance Recycling | $41,046 | $159,415 | $66,625 | $267,086 | | | | |
| CVR Residential | $30,785 | $197,378 | - | $228,163 | | | | |
| Smart Cycle (DLC Change Out) | $20,523 | $536,000 | $116,000 | $672,523 | | | | |
| BYOT (Bring Your Own Thermostat) | $20,523 | $30,280 | $60,280 | $111,083 | | | | |
| Food Bank | $20,523 | $92,517 | - | $113,041 | $15,037 | $4,626 | - | $19,663 |
| Home Energy Management Systems | $10,262 | $212,900 | - | $223,162 | $11,278 | $194,100 | - | $205,378 |

| | Admin. | Implementation | Incentives | Total Budget | Admin. | Implementation | Incentives | Total Budget |
|---|---|---|---|---|---|---|---|---|
| **Residential** | | ELECTRIC | | | | GAS | | |
| Multi-Family Direct Install | | | | | $15,037 | $403,469 | - | $418,506 |
| Targeted Income | | | | | $30,074 | $75,662 | - | $105,735 |
| Home Energy House Call- Integrated | | | | | $30,074 | $182,399 | - | $212,473 |
| Neighborhood Program- Integrated | | | | | $30,074 | $188,885 | - | $218,959 |
| **Residential Subtotal** | **$359,156** | **$3,826,074** | **$1,358,441** | **$5,543,671** | **$229,311** | **$3,579,580** | **$2,944,870** | **$6,753,761** |

TABLE I -4 2021 COMBINED GAS AND ELECTRIC COSTS – COMMERCIAL & INDUSTRIAL

| | Admin. | Implementation | Incentives | Total Budget | Admin. | Implementation | Incentives | Total Budget |
|---|---|---|---|---|---|---|---|---|
| **Commercial & Industrial** | | ELECTRIC | | | | GAS | | |
| Commercial Prescriptive | $56,439 | $682,432 | $1,424,756 | $2,163,627 | $67,666 | $487,528 | $266,357 | $821,550 |
| Commercial Custom | $61,570 | $349,669 | $491,537 | $902,775 | $75,184 | $501,704 | $489,600 | $1,066,488 |
| Small Business | $5,131 | $219,172 | $539,573 | $763,876 | $3,759 | $3,209 | $6,006 | $12,975 |
| CVR Commercial | $30,785 | $133,547 | - | $164,332 | | | | |
| **Commercial & Industrial Subtotal** | **$153,924** | **$1,384,820** | **$2,455,867** | **$3,994,610** | **$146,609** | **$992,441** | **$761,963** | **$1,901,012** |

TABLE I -5 2022 COMBINED GAS AND ELECTRIC COSTS – RESIDENTIAL

| | Admin. | Implementation | Incentives | Total Budget | Admin. | Implementation | Incentives | Total Budget |
|---|---|---|---|---|---|---|---|---|
| **Residential** | | ELECTRIC | | | | GAS | | |
| Residential Lighting | $104,258 | $144,380 | $346,846 | $595,484 | | | | |
| Residential Prescriptive | $41,703 | $358,820 | $680,160 | $1,080,683 | $30,555 | $535,505 | $858,470 | $1,424,530 |
| Residential New Construction | $5,213 | $53,186 | $14,675 | $73,074 | $3,819 | $424,689 | $561,725 | $990,233 |
| Home Energy Assessment | $5,213 | $263,225 | - | $268,438 | $3,819 | $56,774 | - | $60,593 |
| Income-Qualified Weatherization | $20,852 | $1,312,171 | - | $1,333,023 | $15,277 | $980,165 | - | $995,443 |
| Energy-Efficient Schools | $20,852 | $92,229 | - | $113,080 | $22,916 | $30,743 | - | $53,659 |

| | Admin. | Implementation | Incentives | Total Budget | Admin. | Implementation | Incentives | Total Budget |
|---|---|---|---|---|---|---|---|---|
| **Residential** | | ELECTRIC | | | | GAS | | |
| Residential Behavioral Savings | $20,852 | $334,248 | - | $355,099 | $22,916 | $111,671 | - | $134,587 |
| Appliance Recycling | $41,703 | $171,385 | $70,500 | $283,589 | | | | |
| CVR Residential | $31,277 | $190,034 | - | $221,311 | | | | |
| Smart Cycle (DLC Change Out) | $20,852 | $556,000 | $136,000 | $712,852 | | | | |
| BYOT (Bring Your Own Thermostat) | $20,852 | $38,280 | $68,280 | $127,412 | | | | |
| Food Bank | $20,852 | $18,800 | - | $39,651 | $15,278 | $4,700 | - | $19,977 |
| Home Energy Management Systems | $10,426 | $219,900 | - | $230,326 | $11,458 | $187,100 | - | $198,558 |
| Multi-Family Direct Install | | | | | $15,277 | $409,925 | - | $425,202 |
| Targeted Income | | | | | $30,555 | $76,872 | - | $107,427 |
| Home Energy House Call- Integrated | | | | | $30,555 | $185,318 | - | $215,872 |
| Neighborhood Program- Integrated | | | | | $30,555 | $191,907 | - | $222,462 |
| **Residential Subtotal** | **$364,902** | **$3,752,658** | **$1,316,461** | **$5,434,021** | **$232,980** | **$3,195,369** | **$1,420,195** | **$4,848,544** |

TABLE I -6 2022 COMBINED GAS AND ELECTRIC COSTS – COMMERCIAL & INDUSTRIAL

| | Admin. | Implementation | Incentives | Total Budget | Admin. | Implementation | Incentives | Total Budget |
|---|---|---|---|---|---|---|---|---|
| **Commercial & Industrial** | | ELECTRIC | | | | GAS | | |
| Commercial Prescriptive | $57,342 | $733,558 | $1,448,274 | $2,239,173 | $68,748 | $541,210 | $286,137 | $896,095 |
| Commercial Custom | $62,555 | $355,263 | $491,537 | $909,355 | $76,387 | $509,731 | $489,600 | $1,075,718 |
| Small Business | $5,213 | $222,721 | $530,824 | $758,758 | $3,819 | $3,375 | $6,216 | $13,410 |
| CVR Commercial | $31,277 | $128,261 | - | $159,538 | | | | |
| **Commercial & Industrial Subtotal** | **$156,387** | **$1,439,803** | **$2,470,635** | **$4,066,825** | **$148,955** | **$1,054,315** | **$781,953** | **$1,985,223** |

TABLE I -7 2023 COMBINED GAS AND ELECTRIC COSTS – RESIDENTIAL

| | Admin. | Implementation | Incentives | Total Budget | Admin. | Implementation | Incentives | Total Budget |
|---|---|---|---|---|---|---|---|---|
| **Residential** | ELECTRIC | | | | GAS | | | |
| Residential Lighting | $105,926 | $32,756 | $78,689 | $217,370 | | | | |
| Residential Prescriptive | $42,370 | $364,561 | $707,135 | $1,114,066 | $31,044 | $544,073 | $863,520 | $1,438,637 |
| Residential New Construction | $5,296 | $50,202 | $14,325 | $69,824 | $3,880 | $491,921 | $650,275 | $1,146,077 |
| Home Energy Assessment | $5,296 | $267,437 | - | $272,733 | $3,880 | $57,682 | - | $61,563 |
| Income-Qualified Weatherization | $21,185 | $1,331,114 | - | $1,352,299 | $15,522 | $1,060,825 | - | $1,076,347 |
| Energy-Efficient Schools | $21,185 | $98,274 | - | $119,460 | $23,283 | $32,758 | - | $56,041 |
| Residential Behavioral Savings | $21,185 | $339,596 | - | $360,781 | $23,283 | $113,458 | - | $136,741 |
| Appliance Recycling | $42,370 | $174,745 | $70,750 | $287,865 | | | | |
| CVR Residential | $31,778 | $270,252 | - | $302,029 | | | | |
| Smart Cycle (DLC Change Out) | $21,185 | $576,000 | $156,000 | $753,185 | | | | |
| BYOT (Bring Your Own Thermostat) | $21,185 | $46,280 | $76,280 | $143,745 | | | | |
| Food Bank | $21,185 | $9,550 | - | $30,735 | $15,522 | $4,775 | - | $20,297 |
| Home Energy Management Systems | $10,593 | $234,900 | - | $245,493 | $11,641 | $172,100 | - | $183,741 |
| Multi-Family Direct Install | | | | | $15,522 | $416,484 | - | $432,005 |
| Targeted Income | | | | | $31,044 | $78,102 | - | $109,146 |
| Home Energy House Call- Integrated | | | | | $31,044 | $188,283 | - | $219,326 |
| Neighborhood Program- Integrated | | | | | $31,044 | $194,978 | - | $226,021 |
| **Residential Subtotal** | **$370,741** | **$3,795,666** | **$1,103,179** | **$5,269,586** | **$236,708** | **$3,355,439** | **$1,513,795** | **$5,105,942** |

### TABLE I -8 2023 COMBINED GAS AND ELECTRIC COSTS – COMMERCIAL & INDUSTRIAL

| Commercial & Industrial | Admin. (ELECTRIC) | Implementation (ELECTRIC) | Incentives (ELECTRIC) | Total Budget (ELECTRIC) | Admin. (GAS) | Implementation (GAS) | Incentives (GAS) | Total Budget (GAS) |
|---|---|---|---|---|---|---|---|---|
| Commercial Prescriptive | $58,259 | $769,435 | $1,434,660 | $2,262,354 | $69,848 | $598,626 | $307,777 | $976,251 |
| Commercial Custom | $63,556 | $360,948 | $491,537 | $916,040 | $77,609 | $517,886 | $489,600 | $1,085,096 |
| Small Business | $5,296 | $226,003 | $521,287 | $752,586 | $3,880 | $3,561 | $6,456 | $13,898 |
| CVR Commercial | $31,778 | $184,861 | - | $216,639 | | | | |
| **Commercial & Industrial Subtotal** | **$158,889** | **$1,541,248** | **$2,447,483** | **$4,147,620** | **$151,338** | **$1,120,073** | **$803,833** | **$2,075,244** |

### TABLE I -9 2024 COMBINED GAS AND ELECTRIC COSTS – RESIDENTIAL

| Residential | Admin. (ELECTRIC) | Implementation (ELECTRIC) | Incentives (ELECTRIC) | Total Budget (ELECTRIC) | Admin. (GAS) | Implementation (GAS) | Incentives (GAS) | Total Budget (GAS) |
|---|---|---|---|---|---|---|---|---|
| Residential Lighting | $107,621 | $38,416 | $92,287 | $238,324 | | | | |
| Residential Prescriptive | $43,048 | $370,394 | $732,410 | $1,145,852 | $31,540 | $552,778 | $864,995 | $1,449,314 |
| Residential New Construction | $5,381 | $48,144 | $13,975 | $67,500 | $3,943 | $558,080 | $737,775 | $1,299,797 |
| Home Energy Assessment | $5,381 | $271,716 | - | $277,097 | $3,943 | $58,605 | - | $62,548 |
| Income-Qualified Weatherization | $21,524 | $1,350,360 | - | $1,371,884 | $15,770 | $1,120,207 | - | $1,135,977 |
| Energy-Efficient Schools | $21,524 | $106,392 | - | $127,916 | $23,655 | $35,464 | - | $59,119 |
| Residential Behavioral Savings | $21,524 | $345,029 | - | $366,554 | $23,655 | $115,273 | - | $138,929 |
| Appliance Recycling | $43,048 | $168,946 | $67,325 | $279,320 | | | | |
| CVR Residential | $32,286 | $315,241 | - | $347,528 | | | | |
| Smart Cycle (DLC Change Out) | $21,524 | $596,000 | $176,000 | $793,524 | | | | |
| BYOT (Bring Your Own Thermostat) | $21,524 | $54,280 | $84,280 | $160,084 | | | | |
| Food Bank | $21,524 | $9,703 | - | $31,227 | $15,770 | $4,851 | - | $20,622 |
| Home Energy Management Systems | $10,762 | $245,940 | - | $256,702 | $11,828 | $198,260 | - | $210,088 |
| Multi-Family Direct Install | | | | | $15,770 | $423,147 | - | $438,918 |

| | Admin. | Implementation | Incentives | Total Budget | Admin. | Implementation | Incentives | Total Budget |
|---|---|---|---|---|---|---|---|---|
| **Residential** | ELECTRIC | | | | GAS | | | |
| Targeted Income | | | | | $31,540 | $79,352 | - | $110,892 |
| Home Energy House Call- Integrated | | | | | $31,540 | $191,295 | - | $222,835 |
| Neighborhood Program- Integrated | | | | | $31,540 | $198,097 | - | $229,638 |
| **Residential Subtotal** | **$376,673** | **$3,920,561** | **$1,166,277** | **$5,463,511** | **$240,495** | **$3,535,411** | **$1,602,770** | **$5,378,676** |

### TABLE I -10 2024 COMBINED GAS AND ELECTRIC COSTS – COMMERCIAL & INDUSTRIAL

| | Admin. | Implementation | Incentives | Total Budget | Admin. | Implementation | Incentives | Total Budget |
|---|---|---|---|---|---|---|---|---|
| **Commercial & Industrial** | ELECTRIC | | | | GAS | | | |
| Commercial Prescriptive | $59,191 | $791,792 | $1,394,674 | $2,245,657 | $70,966 | $611,299 | $335,962 | $1,018,227 |
| Commercial Custom | $64,572 | $366,723 | $491,537 | $922,832 | $78,851 | $526,173 | $489,600 | $1,094,624 |
| Small Business | $5,381 | $229,663 | $512,537 | $747,582 | $3,943 | $3,736 | $6,666 | $14,344 |
| CVR Commercial | $32,286 | $216,561 | - | $248,848 | | | | |
| **Commercial & Industrial Subtotal** | **$161,431** | **$1,604,739** | **$2,398,748** | **$4,164,919** | **$153,759** | **$1,141,208** | **$832,228** | **$2,127,195** |

### TABLE I -11 2025 COMBINED GAS AND ELECTRIC COSTS – RESIDENTIAL

| | Admin. | Implementation | Incentives | Total Budget | Admin. | Implementation | Incentives | Total Budget |
|---|---|---|---|---|---|---|---|---|
| **Residential** | ELECTRIC | | | | GAS | | | |
| Residential Lighting | $109,343 | $44,005 | $105,714 | $259,061 | | | | |
| Residential Prescriptive | $43,737 | $376,320 | $767,435 | $1,187,492 | $32,045 | $561,623 | $864,845 | $1,458,513 |
| Residential New Construction | $5,467 | $46,909 | $13,800 | $66,176 | $4,006 | $620,174 | $819,500 | $1,443,680 |
| Home Energy Assessment | $5,467 | $276,063 | - | $281,530 | $4,006 | $59,543 | - | $63,549 |
| Income-Qualified Weatherization | $21,869 | $1,369,913 | - | $1,391,782 | $16,022 | $1,156,992 | - | $1,173,014 |
| Energy-Efficient Schools | $21,869 | $117,023 | - | $138,891 | $24,034 | $39,008 | - | $63,041 |

| | Admin. | Implementation | Incentives | Total Budget | Admin. | Implementation | Incentives | Total Budget |
|---|---|---|---|---|---|---|---|---|
| **Residential** | | ELECTRIC | | | | GAS | | |
| Residential Behavioral Savings | $21,869 | $350,550 | - | $372,418 | $24,034 | $117,118 | - | $141,151 |
| Appliance Recycling | $43,737 | $155,651 | $61,050 | $260,438 | | | | |
| CVR Residential | $32,803 | $282,073 | - | $314,876 | | | | |
| Smart Cycle (DLC Change Out) | $21,869 | $616,000 | $196,000 | $833,869 | | | | |
| BYOT (Bring Your Own Thermostat) | $21,869 | $62,280 | $92,280 | $176,429 | | | | |
| Food Bank | $21,869 | $9,858 | - | $31,727 | $16,023 | $4,929 | - | $20,952 |
| Home Energy Management Systems | $10,934 | $266,980 | - | $277,914 | $12,017 | $214,420 | - | $226,437 |
| Multi-Family Direct Install | | | | | $16,022 | $429,918 | - | $445,940 |
| Targeted Income | | | | | $32,045 | $80,621 | - | $112,666 |
| Home Energy House Call- Integrated | | | | | $32,045 | $194,356 | - | $226,401 |
| Neighborhood Program- Integrated | | | | | $32,045 | $201,267 | - | $233,312 |
| **Residential Subtotal** | **$382,700** | **$3,973,626** | **$1,236,279** | **$5,592,604** | **$244,343** | **$3,679,968** | **$1,684,345** | **$5,608,656** |

TABLE I -12 2025 COMBINED GAS AND ELECTRIC COSTS – COMMERCIAL & INDUSTRIAL

| | Admin. | Implementation | Incentives | Total Budget | Admin. | Implementation | Incentives | Total Budget |
|---|---|---|---|---|---|---|---|---|
| **Commercial & Industrial** | | ELECTRIC | | | | GAS | | |
| Commercial Prescriptive | $60,139 | $797,128 | $1,331,794 | $2,189,060 | $72,101 | $737,459 | $363,357 | $1,172,917 |
| Commercial Custom | $65,606 | $372,590 | $491,537 | $929,733 | $80,112 | $534,591 | $489,600 | $1,104,304 |
| Small Business | $5,467 | $233,383 | $503,787 | $742,637 | $4,006 | $3,915 | $6,876 | $14,797 |
| CVR Commercial | $32,803 | $193,019 | - | $225,821 | | | | |
| **Commercial & Industrial Subtotal** | **$164,014** | **$1,596,120** | **$2,327,118** | **$4,087,252** | **$156,219** | **$1,275,965** | **$859,833** | **$2,292,017** |

# APPENDIX J *Action Plan Market Research*

## RESIDENTIAL SURVEY RESULTS

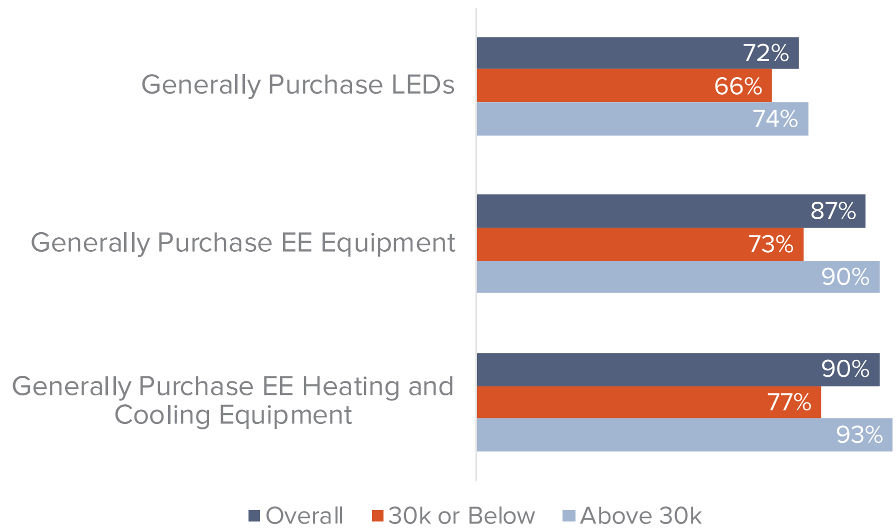
### *Background*

The team completed an online survey of 466 residential customers in Vectren service territory. The survey was completed between June 25 and July 9, 2018. Vectren randomly sampled 4,000 residential customers and sent invitations to complete the survey by email. Customers were offered a$25 incentive upon completion of the survey.

### *Results*

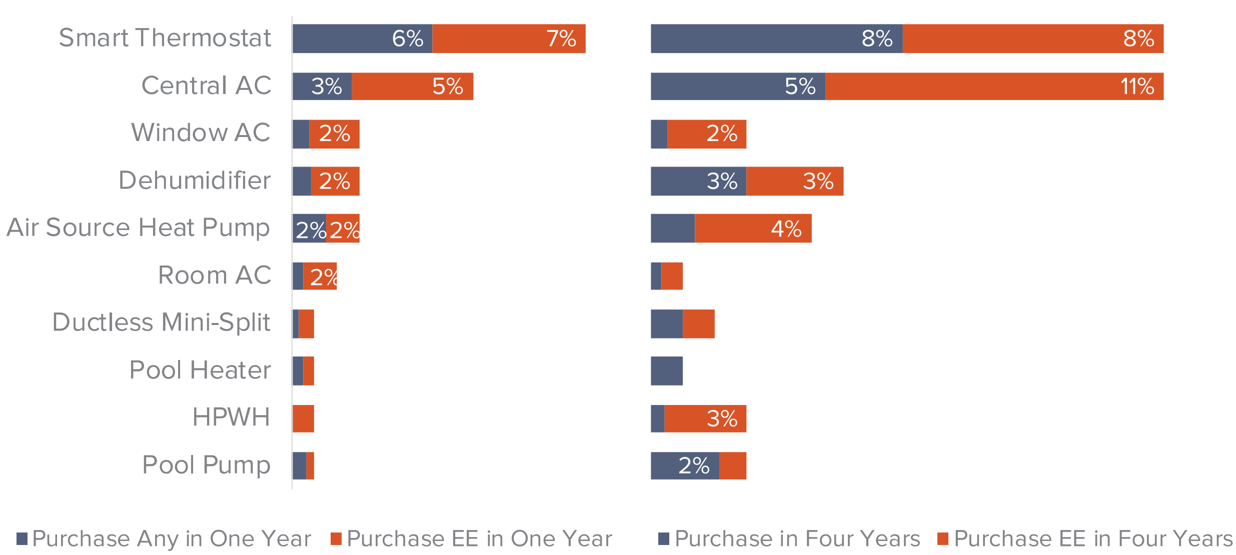
Customers generally reported purchasing energy-efficient equipment (72%, as seen below). As expected, fewer lower income customers (66%) reported purchasing energy-efficient equipment than those making higher incomes (74%).

FIGURE J-1GENERAL PURCHASING BEHAVIOR




Most electric customers did not plan on purchasing any of the equipment discussed in the survey over the next year (76%) or in the next four years (63%). Electric customers most often report planning on purchasing smart thermostats (16%) or central air conditioners (16%) in the next four years.

FIGURE J-2 PLANNED IMPROVEMENTS



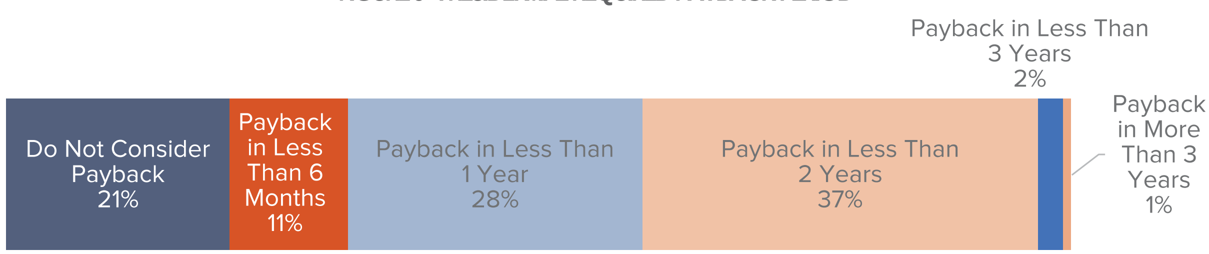
Generally customers reported a lower willingness to pay for weatherization measures and a higher willingness to pay for energy-efficient appliances, as seen in the table below.

FIGURE J-3 WILLINGNESS TO PAY AT VARYING REBATE LEVELS (PERCENT OF INCREMENTAL COST)

| Sector | End-Use / Technology | 25% | 50% | 75% | 100% |
|---|---|---|---|---|---|
| **Average Likelihood** | | | | | |
| Residential | Appliances | 75% | 86% | 91% | 96% |
| Residential | Space Heating | 76% | 84% | 90% | 96% |
| Residential | Weatherization | 61% | 72% | 82% | 93% |
| **Extreme Likelihood** (% the responded "10") | | | | | |
| Residential | Appliances | 31% | 50% | 61% | 85% |
| Residential | Space Heating | 27% | 39% | 53% | 83% |
| Residential | Weatherization | 16% | 20% | 29% | 76% |

Less than one quarter of customers do not consider the payback timeframe of their energy efficiency equipment (21%, as seen below). About three quarters require a payback of two years or less.

FIGURE J-4 RESIDENTIAL REQUIRED PAYBACK PERIOD




## COMMERCIAL & INDUSTRIAL ONSITE VISIT RESULTS

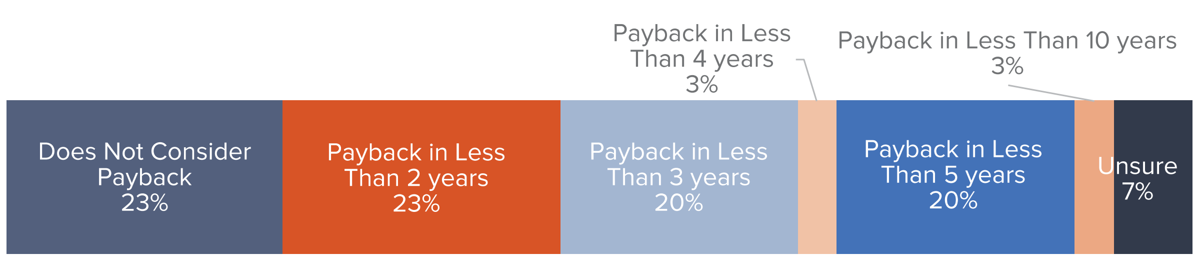
### *Background*

The team completed an audit of 36 commercial and industrial sites in Vectren territory. During these audits, the team asked the company contact questions regarding their energy efficient product purchases and preferences.

### *Results*

Similar to residential customers, about one-quarter of commercial and industrial customers do not consider the payback period of their energy efficiency equipment (23%, as seen below).

FIGURE J-5 COMMERCIAL & INDUSTRIAL REQUIRED PAYBACK PERIOD




Commercial and industrial customers most often reported receiving an incentive as a consideration when purchasing new energy efficient equipment (72%, as seen in the table below). Other regularly reported considerations included lowering monthly electric bills (67%) and increased employee comfort (58%).

TABLE J-6 IMPORTANT CONSIDERATIONS REGARDING ENERGY EFFICIENT EQUIPMENT

| Response | Percent (n=36) |
|---|---|
| Receiving incentive | 72% |
| Lower monthly electric bills | 67% |
| Increased level of employee comfort | 58% |
| Financing options | 50% |
| Improving the image or value of business | 36% |
| Recommendation of sales person, contractor, or consultant | 28% |
| Helping to protect the environment | 8% |
| Other | 3% |

Commercial and industrial customers most often reported that cost was a barrier to purchasing energy-efficient equipment (67%), followed by the performance of the equipment (44%).

TABLE J-7 BARRIERS TO PURCHASING ENERGY EFFICIENT EQUIPMENT

| Response | Percent (n=36) |
|---|---|
| Cost | 67% |
| Performance of the equipment | 44% |
| Lack of product energy savings information | 39% |
| Payback/ROI | 31% |
| Lack of financing options | 17% |
| Availability of equipment | 11% |
| Other | 6% |

Commercial and industrial customers reported a higher willingness to purchase more expensive equipment at most levels of rebate incremental cost than residential customers, as seen in the table below.

TABLE J-8 WILLINGNESS TO PAY AT VARYING REBATE LEVELS (PERCENT OF INCREMENTAL COST)

| Equipment Price | 0% | 25% | 50% | 75% |
|---|---|---|---|---|
| Equipment Priced Below $200 | 6% | 3% | 11% | 77% |
| Equipment Priced Above $1,000 | 6% | 11% | 34% | 97% |

# APPENDIX K *Action Plan Measure Library*

The following table provides a list of all the measures included in the Action Plan program concepts, broken up by year of the program.

TABLE K-1 MEASURE LIBRARY

| Program | Measure | Description | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 |
|---|---|---|---|---|---|---|---|---|
| Residential Lighting | Standard Units | Participation | 159,553 | 180,887 | - | - | - | - |
| Residential Lighting | Standard Units | Total Incentive Budget | $120,861 | $128,882 | - | - | - | - |
| Residential Lighting | Standard Units | Total Gross Incremental Savings (kwh) | 5,143,874 | 5,862,548 | - | - | - | - |
| Residential Lighting | Standard Units | NTG | 0.84 | 0.79 | - | - | - | - |
| Residential Lighting | Standard Units | Incremental Cost | $3.00 | $3.00 | | | | |
| Residential Lighting | Specialty Units | Participation | 64,893 | 73,570 | 81,379 | - | - | - |
| Residential Lighting | Specialty Units | Total Incentive Budget | $259,896 | $275,336 | $281,978 | - | - | - |
| Residential Lighting | Specialty Units | Total Gross Incremental Savings (kwh) | 1,945,811 | 2,209,028 | 2,446,622 | - | - | - |
| Residential Lighting | Specialty Units | NTG | 0.84 | 0.79 | 0.74 | - | - | - |
| Residential Lighting | Specialty Units | Incremental Cost | $4.00 | $4.00 | $4.00 | | | |
| Residential Lighting | LED Fixtures | Participation | 13,700 | 4,935 | 5,169 | 5,351 | 5,489 | 5,593 |
| Residential Lighting | LED Fixtures | Total Incentive Budget | $69,356 | $24,983 | $26,168 | $27,089 | $27,788 | $28,315 |

| Program | Measure | Description | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 |
|---|---|---|---|---|---|---|---|---|
| Residential Lighting | LED Fixtures | Total Gross Incremental Savings (kwh) | 832,872 | 299,999 | 314,224 | 141,855 | 145,513 | 148,270 |
| Residential Lighting | LED Fixtures | NTG | 0.84 | 0.84 | 0.84 | 0.84 | 0.84 | 0.84 |
| Residential Lighting | LED Fixtures | Incremental Cost | $20.00 | $20.00 | $20.00 | $20.00 | $20.00 | $20.00 |
| Residential Lighting | Exterior Lighting Controls | Participation | 1,720 | 3,440 | 5,160 | 6,880 | 8,600 | 10,320 |
| Residential Lighting | Exterior Lighting Controls | Total Incentive Budget | $12,900 | $25,800 | $38,700 | $51,599 | $64,499 | $77,399 |
| Residential Lighting | Exterior Lighting Controls | Total Gross Incremental Savings (kwh) | 166,357 | 332,713 | 499,070 | 665,427 | 831,783 | 998,140 |
| Residential Lighting | Exterior Lighting Controls | NTG | 0.84 | 0.84 | 0.84 | 0.84 | 0.84 | 0.84 |
| Residential Lighting | Exterior Lighting Controls | Incremental Cost | $30.00 | $30.00 | $30.00 | $30.00 | $30.00 | $30.00 |
| Residential Prescriptive | Air Source Heat Pump 16 SEER | Participation | 40 | 47 | 53 | 59 | 64 | 68 |
| Residential Prescriptive | Air Source Heat Pump 16 SEER | Total Incentive Budget | $12,000 | $14,100 | $15,900 | $17,700 | $19,200 | $20,400 |
| Residential Prescriptive | Air Source Heat Pump 16 SEER | Total Gross Incremental Savings (kwh) | 27,760 | 32,618 | 36,782 | 40,946 | 44,416 | 47,192 |
| Residential Prescriptive | Air Source Heat Pump 16 SEER | NTG | 0.52 | 0.52 | 0.52 | 0.52 | 0.52 | 0.52 |
| Residential Prescriptive | Air Source Heat Pump 16 SEER | Incremental Cost | $870.00 | $870.00 | $870.00 | $870.00 | $870.00 | $870.00 |

| Program | Measure | Description | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 |
|---|---|---|---|---|---|---|---|---|
| Residential Prescriptive | Air Source Heat Pump 18 SEER | Participation | 13 | 16 | 18 | 20 | 23 | 25 |
| Residential Prescriptive | Air Source Heat Pump 18 SEER | Total Incentive Budget | $7,800 | $9,600 | $10,800 | $12,000 | $13,800 | $15,000 |
| Residential Prescriptive | Air Source Heat Pump 18 SEER | Total Gross Incremental Savings (kwh) | 16,822 | 20,704 | 23,292 | 25,880 | 29,762 | 32,350 |
| Residential Prescriptive | Air Source Heat Pump 18 SEER | NTG | 0.52 | 0.52 | 0.52 | 0.52 | 0.52 | 0.52 |
| Residential Prescriptive | Air Source Heat Pump 18 SEER | Incremental Cost | $870.00 | $870.00 | $870.00 | $870.00 | $870.00 | $870.00 |
| Residential Prescriptive | Attic Insulation - Elec Heated South (Electric Only) | Participation | 16 | 17 | 13 | 10 | 7 | 5 |
| Residential Prescriptive | Attic Insulation - Elec Heated South (Electric Only) | Total Incentive Budget | $7,200 | $7,650 | $5,850 | $4,500 | $3,150 | $2,250 |
| Residential Prescriptive | Attic Insulation - Elec Heated South (Electric Only) | Total Gross Incremental Savings (kwh) | 12,836 | 13,638 | 10,429 | 8,023 | 5,616 | 4,011 |
| Residential Prescriptive | Attic Insulation - Elec Heated South (Electric Only) | NTG | 0.76 | 0.76 | 0.76 | 0.76 | 0.76 | 0.76 |
| Residential Prescriptive | Attic Insulation - Elec Heated South (Electric Only) | Incremental Cost | $500.00 | $500.00 | $500.00 | $500.00 | $500.00 | $500.00 |
| Residential Prescriptive | Attic Insulation - Gas Heated South (Dual -- Gas & Electric) | Participation | 36 | 8 | 6 | 5 | 4 | 3 |
| Residential Prescriptive | Attic Insulation - Gas Heated South (Dual -- Gas & Electric) | Total Incentive Budget | $10,800 | $2,400 | $1,800 | $1,500 | $1,200 | $900 |

| Program | Measure | Description | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 |
|---|---|---|---|---|---|---|---|---|
| Residential Prescriptive | Attic Insulation - Gas Heated South (Dual -- Gas & Electric) | Total Gross Incremental Savings (kwh) | 8,602 | 1,912 | 1,434 | 1,195 | 956 | 717 |
| Residential Prescriptive | Attic Insulation - Gas Heated South (Dual -- Gas & Electric) | NTG | 0.76 | 0.76 | 0.76 | 0.76 | 0.76 | 0.76 |
| Residential Prescriptive | Attic Insulation - Gas Heated South (Dual -- Gas & Electric) | Incremental Cost | $500.00 | $500.00 | $500.00 | $500.00 | $500.00 | $500.00 |
| Residential Prescriptive | Central Air Conditioner 16 SEER | Participation | 708 | 528 | 632 | 736 | 834 | 923 |
| Residential Prescriptive | Central Air Conditioner 16 SEER | Total Incentive Budget | $141,680 | $105,600 | $126,400 | $147,200 | $166,800 | $184,600 |
| Residential Prescriptive | Central Air Conditioner 16 SEER | Total Gross Incremental Savings (kwh) | 212,326 | 158,255 | 189,427 | 220,598 | 249,971 | 276,647 |
| Residential Prescriptive | Central Air Conditioner 16 SEER | NTG | 0.52 | 0.52 | 0.52 | 0.52 | 0.52 | 0.52 |
| Residential Prescriptive | Central Air Conditioner 16 SEER | Incremental Cost | $400.00 | $400.00 | $400.00 | $400.00 | $400.00 | $400.00 |
| Residential Prescriptive | Central Air Conditioner 18 SEER | Participation | 84 | 62 | 74 | 86 | 98 | 108 |
| Residential Prescriptive | Central Air Conditioner 18 SEER | Total Incentive Budget | $41,800 | $31,000 | $37,000 | $43,000 | $49,000 | $54,000 |
| Residential Prescriptive | Central Air Conditioner 18 SEER | Total Gross Incremental Savings (kwh) | 57,819 | 42,880 | 51,179 | 59,479 | 67,778 | 74,694 |
| Residential Prescriptive | Central Air Conditioner 18 SEER | NTG | 0.52 | 0.52 | 0.52 | 0.52 | 0.52 | 0.52 |

| Program | Measure | Description | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 |
|---|---|---|---|---|---|---|---|---|
| Residential Prescriptive | Central Air Conditioner 18 SEER | Incremental Cost | $800.00 | $800.00 | $800.00 | $800.00 | $800.00 | $800.00 |
| Residential Prescriptive | Dual Fuel Air Source Heat Pump 16 SEER | Participation | 37 | 44 | 51 | 57 | 64 | 70 |
| Residential Prescriptive | Dual Fuel Air Source Heat Pump 16 SEER | Total Incentive Budget | $11,100 | $13,200 | $15,300 | $17,100 | $19,200 | $21,000 |
| Residential Prescriptive | Dual Fuel Air Source Heat Pump 16 SEER | Total Gross Incremental Savings (kwh) | 12,136 | 14,432 | 16,728 | 18,696 | 20,992 | 22,960 |
| Residential Prescriptive | Dual Fuel Air Source Heat Pump 16 SEER | NTG | 0.52 | 0.52 | 0.52 | 0.52 | 0.52 | 0.52 |
| Residential Prescriptive | Dual Fuel Air Source Heat Pump 16 SEER | Incremental Cost | $1,000.00 | $1,000.00 | $1,000.00 | $1,000.00 | $1,000.00 | $1,000.00 |
| Residential Prescriptive | Duct Sealing Electric Heat Pump - South (Electric Only) | Participation | 48 | 79 | 71 | 61 | 50 | 40 |
| Residential Prescriptive | Duct Sealing Electric Heat Pump - South (Electric Only) | Total Incentive Budget | $14,400 | $23,700 | $21,300 | $18,300 | $15,000 | $12,000 |
| Residential Prescriptive | Duct Sealing Electric Heat Pump - South (Electric Only) | Total Gross Incremental Savings (kwh) | 39,792 | 65,491 | 58,859 | 50,569 | 41,450 | 33,160 |
| Residential Prescriptive | Duct Sealing Electric Heat Pump - South (Electric Only) | NTG | 0.76 | 0.76 | 0.76 | 0.76 | 0.76 | 0.76 |
| Residential Prescriptive | Duct Sealing Electric Heat Pump - South (Electric Only) | Incremental Cost | $400.00 | $400.00 | $400.00 | $400.00 | $400.00 | $400.00 |

| Program | Measure | Description | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 |
|---|---|---|---|---|---|---|---|---|
| Residential Prescriptive | Duct Sealing Electric Resistive Furnace - South (Electric Only) | Participation | 38 | 64 | 57 | 49 | 40 | 32 |
| Residential Prescriptive | Duct Sealing Electric Resistive Furnace - South (Electric Only) | Total Incentive Budget | $11,400 | $19,200 | $17,100 | $14,700 | $12,000 | $9,600 |
| Residential Prescriptive | Duct Sealing Electric Resistive Furnace - South (Electric Only) | Total Gross Incremental Savings (kwh) | 51,642 | 86,976 | 77,463 | 66,591 | 54,360 | 43,488 |
| Residential Prescriptive | Duct Sealing Electric Resistive Furnace - South (Electric Only) | NTG | 0.76 | 0.76 | 0.76 | 0.76 | 0.76 | 0.76 |
| Residential Prescriptive | Duct Sealing Electric Resistive Furnace - South (Electric Only) | Incremental Cost | $400.00 | $400.00 | $400.00 | $400.00 | $400.00 | $400.00 |
| Residential Prescriptive | Duct Sealing Gas Heating with A/C - South (Dual -- Gas & Electric) | Participation | 232 | 384 | 346 | 297 | 245 | 196 |
| Residential Prescriptive | Duct Sealing Gas Heating with A/C - South (Dual -- Gas & Electric) | Total Incentive Budget | $34,800 | $57,600 | $51,900 | $44,550 | $36,750 | $29,400 |
| Residential Prescriptive | Duct Sealing Gas Heating with A/C - South (Dual -- Gas & Electric) | Total Gross Incremental Savings (kwh) | 38,365 | 63,500 | 57,216 | 49,113 | 40,514 | 32,411 |
| Residential Prescriptive | Duct Sealing Gas Heating with A/C - South (Dual -- Gas & Electric) | NTG | 0.76 | 0.76 | 0.76 | 0.76 | 0.76 | 0.76 |
| Residential Prescriptive | Duct Sealing Gas Heating with A/C - South (Dual -- Gas & Electric) | Incremental Cost | $200.00 | $200.00 | $200.00 | $200.00 | $200.00 | $200.00 |

| Program | Measure | Description | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 |
|---|---|---|---|---|---|---|---|---|
| Residential Prescriptive | Ductless Heat Pump 17 SEER 9.5 HSPF | Participation | 8 | 9 | 11 | 12 | 13 | 14 |
| Residential Prescriptive | Ductless Heat Pump 17 SEER 9.5 HSPF | Total Incentive Budget | $4,000 | $4,500 | $5,500 | $6,000 | $6,500 | $7,000 |
| Residential Prescriptive | Ductless Heat Pump 17 SEER 9.5 HSPF | Total Gross Incremental Savings (kwh) | 28,998 | 32,623 | 39,872 | 43,497 | 47,122 | 50,747 |
| Residential Prescriptive | Ductless Heat Pump 17 SEER 9.5 HSPF | NTG | 0.52 | 0.52 | 0.52 | 0.52 | 0.52 | 0.52 |
| Residential Prescriptive | Ductless Heat Pump 17 SEER 9.5 HSPF | Incremental Cost | $1,666.67 | $1,666.67 | $1,666.67 | $1,666.67 | $1,666.67 | $1,666.67 |
| Residential Prescriptive | Ductless Heat Pump 19 SEER 9.5 HSPF | Participation | 18 | 21 | 24 | 26 | 29 | 31 |
| Residential Prescriptive | Ductless Heat Pump 19 SEER 9.5 HSPF | Total Incentive Budget | $9,000 | $10,500 | $12,000 | $13,000 | $14,500 | $15,500 |
| Residential Prescriptive | Ductless Heat Pump 19 SEER 9.5 HSPF | Total Gross Incremental Savings (kwh) | 66,147 | 77,172 | 88,196 | 95,546 | 106,571 | 113,920 |
| Residential Prescriptive | Ductless Heat Pump 19 SEER 9.5 HSPF | NTG | 0.52 | 0.52 | 0.52 | 0.52 | 0.52 | 0.52 |
| Residential Prescriptive | Ductless Heat Pump 19 SEER 9.5 HSPF | Incremental Cost | $2,333.33 | $2,333.33 | $2,333.33 | $2,333.33 | $2,333.33 | $2,333.33 |
| Residential Prescriptive | Ductless Heat Pump 21 SEER 10.0 HSPF | Participation | 8 | 9 | 11 | 12 | 13 | 14 |
| Residential Prescriptive | Ductless Heat Pump 21 SEER 10.0 HSPF | Total Incentive Budget | $6,000 | $6,750 | $8,250 | $9,000 | $9,750 | $10,500 |
| Residential Prescriptive | Ductless Heat Pump 21 SEER 10.0 HSPF | Total Gross Incremental Savings (kwh) | 30,158 | 33,927 | 41,467 | 45,237 | 49,006 | 52,776 |

| Program | Measure | Description | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 |
|---|---|---|---|---|---|---|---|---|
| Residential Prescriptive | Ductless Heat Pump 21 SEER 10.0 HSPF | NTG | 0.52 | 0.52 | 0.52 | 0.52 | 0.52 | 0.52 |
| Residential Prescriptive | Ductless Heat Pump 21 SEER 10.0 HSPF | Incremental Cost | $2,833.33 | $2,833.33 | $2,833.33 | $2,833.33 | $2,833.33 | $2,833.33 |
| Residential Prescriptive | Ductless Heat Pump 23 SEER 10.0 HSPF | Participation | 26 | 30 | 34 | 38 | 42 | 45 |
| Residential Prescriptive | Ductless Heat Pump 23 SEER 10.0 HSPF | Total Incentive Budget | $19,500 | $22,500 | $25,500 | $28,500 | $31,500 | $33,750 |
| Residential Prescriptive | Ductless Heat Pump 23 SEER 10.0 HSPF | Total Gross Incremental Savings (kwh) | 94,640 | 109,200 | 123,760 | 138,320 | 152,880 | 163,800 |
| Residential Prescriptive | Ductless Heat Pump 23 SEER 10.0 HSPF | NTG | 0.52 | 0.52 | 0.52 | 0.52 | 0.52 | 0.52 |
| Residential Prescriptive | Ductless Heat Pump 23 SEER 10.0 HSPF | Incremental Cost | $3,333.33 | $3,333.33 | $3,333.33 | $3,333.33 | $3,333.33 | $3,333.33 |
| Residential Prescriptive | Dual Fuel Air Source Heat Pump 18 SEER | Participation | 12 | 16 | 21 | 26 | 32 | 39 |
| Residential Prescriptive | Dual Fuel Air Source Heat Pump 18 SEER | Total Incentive Budget | $6,000 | $8,000 | $10,500 | $13,000 | $16,000 | $19,500 |
| Residential Prescriptive | Dual Fuel Air Source Heat Pump 18 SEER | Total Gross Incremental Savings (kwh) | 10,680 | 14,240 | 18,690 | 23,140 | 28,480 | 34,710 |
| Residential Prescriptive | Dual Fuel Air Source Heat Pump 18 SEER | NTG | 0.52 | 0.52 | 0.52 | 0.52 | 0.52 | 0.52 |
| Residential Prescriptive | Dual Fuel Air Source Heat Pump 18 SEER | Incremental Cost | $1,666.67 | $1,666.67 | $1,666.67 | $1,666.67 | $1,666.67 | $1,666.67 |
| Residential Prescriptive | Heat Pump Water Heater | Participation | 28 | 36 | 45 | 56 | 67 | 78 |

| Program | Measure | Description | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 |
|---|---|---|---|---|---|---|---|---|
| Residential Prescriptive | Heat Pump Water Heater | Total Incentive Budget | $11,200 | $14,400 | $18,000 | $22,400 | $26,800 | $31,200 |
| Residential Prescriptive | Heat Pump Water Heater | Total Gross Incremental Savings (kwh) | 66,304 | 85,248 | 106,560 | 132,608 | 158,656 | 184,704 |
| Residential Prescriptive | Heat Pump Water Heater | NTG | 0.63 | 0.63 | 0.63 | 0.63 | 0.63 | 0.63 |
| Residential Prescriptive | Heat Pump Water Heater | Incremental Cost | $1,000.00 | $1,000.00 | $1,000.00 | $1,000.00 | $1,000.00 | $1,000.00 |
| Residential Prescriptive | Nest On-Line Store South (Electric Only) | Participation | 64 | 64 | 64 | 64 | 64 | 64 |
| Residential Prescriptive | Nest On-Line Store South (Electric Only) | Total Incentive Budget | $4,800 | $4,800 | $4,800 | $4,800 | $4,800 | $4,800 |
| Residential Prescriptive | Nest On-Line Store South (Electric Only) | Total Gross Incremental Savings (kwh) | 58,455 | 58,455 | 58,455 | 58,455 | 58,455 | 58,455 |
| Residential Prescriptive | Nest On-Line Store South (Electric Only) | NTG | 0.55 | 0.55 | 0.55 | 0.55 | 0.55 | 0.55 |
| Residential Prescriptive | Nest On-Line Store South (Electric Only) | Incremental Cost | $39.16 | $39.16 | $39.16 | $39.16 | $39.16 | $39.16 |
| Residential Prescriptive | Nest On-Line Store South (Dual -- Electric) | Participation | 176 | 176 | 176 | 176 | 176 | 176 |
| Residential Prescriptive | Nest On-Line Store South (Dual -- Electric) | Total Incentive Budget | $10,560 | $10,560 | $10,560 | $10,560 | $10,560 | $10,560 |
| Residential Prescriptive | Nest On-Line Store South (Dual -- Electric) | Total Gross Incremental Savings (kwh) | 51,470 | 51,470 | 51,470 | 51,470 | 51,470 | 51,470 |
| Residential Prescriptive | Nest On-Line Store South (Dual -- Electric) | NTG | 0.55 | 0.55 | 0.55 | 0.55 | 0.55 | 0.55 |

| Program | Measure | Description | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 |
|---|---|---|---|---|---|---|---|---|
| Residential Prescriptive | Nest On-Line Store South (Dual -- Electric) | Incremental Cost | $175.00 | $175.00 | $175.00 | $175.00 | $175.00 | $175.00 |
| Residential Prescriptive | Wifi Thermostat - South (Electric) | Participation | 720 | 720 | 720 | 720 | 720 | 720 |
| Residential Prescriptive | Wifi Thermostat - South (Electric) | Total Incentive Budget | $36,000 | $36,000 | $36,000 | $36,000 | $36,000 | $36,000 |
| Residential Prescriptive | Wifi Thermostat - South (Electric) | Total Gross Incremental Savings (kwh) | 291,665 | 291,665 | 291,665 | 291,665 | 291,665 | 291,665 |
| Residential Prescriptive | Wifi Thermostat - South (Electric) | NTG | 0.73 | 0.73 | 0.73 | 0.73 | 0.73 | 0.73 |
| Residential Prescriptive | Wifi Thermostat - South (Electric) | Incremental Cost | $20.64 | $20.64 | $20.64 | $20.64 | $20.64 | $20.64 |
| Residential Prescriptive | Smart Programmable Thermostat - South (Electric) | Participation | 1,478 | 1,478 | 1,478 | 1,478 | 1,478 | 1,478 |
| Residential Prescriptive | Smart Programmable Thermostat - South (Electric) | Total Incentive Budget | $110,850 | $110,850 | $110,850 | $110,850 | $110,850 | $110,850 |
| Residential Prescriptive | Smart Programmable Thermostat - South (Electric) | Total Gross Incremental Savings (kwh) | 729,085 | 729,085 | 729,085 | 729,085 | 729,085 | 729,085 |
| Residential Prescriptive | Smart Programmable Thermostat - South (Electric) | NTG | 0.55 | 0.55 | 0.55 | 0.55 | 0.55 | 0.55 |
| Residential Prescriptive | Smart Programmable Thermostat - South (Electric) | Incremental Cost | $39.16 | $39.16 | $39.16 | $39.16 | $39.16 | $39.16 |

| Program | Measure | Description | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 |
|---|---|---|---|---|---|---|---|---|
| Residential Prescriptive | Variable Speed Pool Pump | Participation | 18 | 28 | 36 | 45 | 56 | 67 |
| Residential Prescriptive | Variable Speed Pool Pump | Total Incentive Budget | $5,400 | $8,400 | $10,800 | $13,500 | $16,800 | $20,100 |
| Residential Prescriptive | Variable Speed Pool Pump | Total Gross Incremental Savings (kwh) | 21,106 | 32,832 | 42,213 | 52,766 | 65,664 | 78,562 |
| Residential Prescriptive | Variable Speed Pool Pump | NTG | 0.63 | 0.63 | 0.63 | 0.63 | 0.63 | 0.63 |
| Residential Prescriptive | Variable Speed Pool Pump | Incremental Cost | $750.00 | $750.00 | $750.00 | $750.00 | $750.00 | $750.00 |
| Residential Prescriptive | Wall Insulation - Elec Heated | Participation | 5 | 5 | 5 | 5 | 5 | 5 |
| Residential Prescriptive | Wall Insulation - Elec Heated | Total Incentive Budget | $2,250 | $2,250 | $2,250 | $2,250 | $2,250 | $2,250 |
| Residential Prescriptive | Wall Insulation - Elec Heated | Total Gross Incremental Savings (kwh) | 4,447 | 4,447 | 4,447 | 4,447 | 4,447 | 4,447 |
| Residential Prescriptive | Wall Insulation - Elec Heated | NTG | 0.76 | 0.76 | 0.76 | 0.76 | 0.76 | 0.76 |
| Residential Prescriptive | Wall Insulation - Elec Heated | Incremental Cost | $500.00 | $500.00 | $500.00 | $500.00 | $500.00 | $500.00 |
| Residential Prescriptive | Wall Insulation - Gas Heated - South (Electric) | Participation | 32 | 32 | 32 | 32 | 32 | 32 |
| Residential Prescriptive | Wall Insulation - Gas Heated - South (Electric) | Total Incentive Budget | $7,200 | $7,200 | $7,200 | $7,200 | $7,200 | $7,200 |
| Residential Prescriptive | Wall Insulation - Gas Heated - South (Electric) | Total Gross Incremental Savings (kwh) | 1,876 | 1,876 | 1,876 | 1,876 | 1,876 | 1,876 |

| Program | Measure | Description | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 |
|---|---|---|---|---|---|---|---|---|
| Residential Prescriptive | Wall Insulation - Gas Heated - South (Electric) | NTG | 0.76 | 0.76 | 0.76 | 0.76 | 0.76 | 0.76 |
| Residential Prescriptive | Wall Insulation - Gas Heated - South (Electric) | Incremental Cost | $500.00 | $500.00 | $500.00 | $500.00 | $500.00 | $500.00 |
| Residential Prescriptive | AC Tune Up | Participation | 3,344 | 3,511 | 3,326 | 2,994 | 2,573 | 2,639 |
| Residential Prescriptive | AC Tune Up | Total Incentive Budget | $83,600 | $87,775 | $83,150 | $74,850 | $64,325 | $65,975 |
| Residential Prescriptive | AC Tune Up | Total Gross Incremental Savings (kwh) | 371,184 | 389,721 | 369,186 | 332,334 | 285,603 | 292,929 |
| Residential Prescriptive | AC Tune Up | NTG | - | - | - | - | - | - |
| Residential Prescriptive | AC Tune Up | Incremental Cost | $64.00 | $64.00 | $64.00 | $64.00 | $64.00 | $64.00 |
| Residential Prescriptive | ASHP Tune Up | Participation | 26 | 71 | 67 | 60 | 52 | 53 |
| Residential Prescriptive | ASHP Tune Up | Total Incentive Budget | $1,300 | $3,550 | $3,350 | $3,000 | $2,600 | $2,650 |
| Residential Prescriptive | ASHP Tune Up | Total Gross Incremental Savings (kwh) | 8,195 | 22,379 | 21,119 | 18,912 | 16,391 | 16,706 |
| Residential Prescriptive | ASHP Tune Up | NTG | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 |
| Residential Prescriptive | ASHP Tune Up | Incremental Cost | $64.00 | $64.00 | $64.00 | $64.00 | $64.00 | $64.00 |
| Residential Prescriptive | Air Purifier | Participation | 100 | 160 | 181 | 200 | 217 | 231 |

| Program | Measure | Description | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 |
|---|---|---|---|---|---|---|---|---|
| Residential Prescriptive | Air Purifier | Total Incentive Budget | $2,500 | $4,000 | $4,525 | $5,000 | $5,425 | $5,775 |
| Residential Prescriptive | Air Purifier | Total Gross Incremental Savings (kwh) | 48,800 | 78,080 | 88,328 | 97,600 | 105,896 | 112,728 |
| Residential Prescriptive | Air Purifier | NTG | 0.52 | 0.52 | 0.52 | 0.52 | 0.52 | 0.52 |
| Residential Prescriptive | Air Purifier | Incremental Cost | $70.00 | $70.00 | $70.00 | $70.00 | $70.00 | $70.00 |
| Residential Prescriptive | ENERGY STAR Dehumidifier | Participation | 368 | 368 | 368 | 368 | 368 | 368 |
| Residential Prescriptive | ENERGY STAR Dehumidifier | Total Incentive Budget | $9,200 | $9,200 | $9,200 | $9,200 | $9,200 | $9,200 |
| Residential Prescriptive | ENERGY STAR Dehumidifier | Total Gross Incremental Savings (kwh) | 70,766 | 70,766 | 70,766 | 70,766 | 70,766 | 70,766 |
| Residential Prescriptive | ENERGY STAR Dehumidifier | NTG | 0.52 | 0.52 | 0.52 | 0.52 | 0.52 | 0.52 |
| Residential Prescriptive | ENERGY STAR Dehumidifier | Incremental Cost | $70.00 | $70.00 | $70.00 | $70.00 | $70.00 | $70.00 |
| Residential Prescriptive | ENERGY STAR Clothes Washer | Participation | 56 | 56 | 70 | 76 | 81 | 84 |
| Residential Prescriptive | ENERGY STAR Clothes Washer | Total Incentive Budget | $1,400 | $1,400 | $1,750 | $1,900 | $2,025 | $2,100 |
| Residential Prescriptive | ENERGY STAR Clothes Washer | Total Gross Incremental Savings (kwh) | 6,272 | 6,272 | 7,840 | 8,512 | 9,072 | 9,408 |
| Residential Prescriptive | ENERGY STAR Clothes Washer | NTG | 0.68 | 0.68 | 0.68 | 0.68 | 0.68 | 0.68 |

| Program | Measure | Description | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 |
|---|---|---|---|---|---|---|---|---|
| Residential Prescriptive | ENERGY STAR Clothes Washer | Incremental Cost | $150.00 | $150.00 | $150.00 | $150.00 | $150.00 | $150.00 |
| Residential Prescriptive | Smart/CEE Tier3 Clothes Washer | Participation | 78 | 78 | 141 | 184 | 238 | 299 |
| Residential Prescriptive | Smart/CEE Tier3 Clothes Washer | Total Incentive Budget | $3,900 | $3,900 | $7,050 | $9,200 | $11,900 | $14,950 |
| Residential Prescriptive | Smart/CEE Tier3 Clothes Washer | Total Gross Incremental Savings (kwh) | 16,302 | 16,302 | 29,469 | 38,456 | 49,742 | 62,491 |
| Residential Prescriptive | Smart/CEE Tier3 Clothes Washer | NTG | 0.68 | 0.68 | 0.68 | 0.68 | 0.68 | 0.68 |
| Residential Prescriptive | Smart/CEE Tier3 Clothes Washer | Incremental Cost | $300.00 | $300.00 | $300.00 | $300.00 | $300.00 | $300.00 |
| Residential Prescriptive | ENERGY STAR Room Air Conditioner | Participation | 121 | 121 | 121 | 121 | 121 | 121 |
| Residential Prescriptive | ENERGY STAR Room Air Conditioner | Total Incentive Budget | $3,025 | $3,025 | $3,025 | $3,025 | $3,025 | $3,025 |
| Residential Prescriptive | ENERGY STAR Room Air Conditioner | Total Gross Incremental Savings (kwh) | 4,979 | 4,979 | 4,979 | 4,979 | 4,979 | 4,979 |
| Residential Prescriptive | ENERGY STAR Room Air Conditioner | NTG | 0.80 | 0.80 | 0.80 | 0.80 | 0.80 | 0.80 |
| Residential Prescriptive | ENERGY STAR Room Air Conditioner | Incremental Cost | $40.00 | $40.00 | $40.00 | $40.00 | $40.00 | $40.00 |
| Residential Prescriptive | Clothes Dryer | Participation | 28 | 38 | 51 | 67 | 86 | 108 |
| Residential Prescriptive | Clothes Dryer | Total Incentive Budget | $1,400 | $1,900 | $2,550 | $3,350 | $4,300 | $5,400 |

| Program | Measure | Description | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 |
|---|---|---|---|---|---|---|---|---|
| Residential Prescriptive | Clothes Dryer | Total Gross Incremental Savings (kwh) | 5,519 | 7,483 | 10,031 | 13,159 | 16,860 | 21,125 |
| Residential Prescriptive | Clothes Dryer | NTG | 0.68 | 0.68 | 0.68 | 0.68 | 0.68 | 0.68 |
| Residential Prescriptive | Clothes Dryer | Incremental Cost | $150.00 | $150.00 | $150.00 | $150.00 | $150.00 | $150.00 |
| Residential New Construction | Gold Star HERS Index Score 63 | Participation | 17 | 15 | 13 | 11 | 9 | 8 |
| Residential New Construction | Gold Star HERS Index Score 63 | Total Incentive Budget | $2,975 | $2,625 | $2,275 | $1,925 | $1,575 | $1,400 |
| Residential New Construction | Gold Star HERS Index Score 63 | Total Gross Incremental Savings (kwh) | 34,340 | 30,300 | 26,260 | 22,220 | 18,180 | 16,160 |
| Residential New Construction | Gold Star HERS Index Score 63 | NTG | 0.50 | 0.50 | 0.50 | 0.50 | 0.50 | 0.50 |
| Residential New Construction | Gold Star HERS Index Score 63 | Incremental Cost | $2,038.73 | $2,038.73 | $2,038.73 | $2,038.73 | $2,038.73 | $2,038.73 |
| Residential New Construction | Platinum Star HERS Index Score 60 | Participation | 69 | 62 | 62 | 62 | 62 | 62 |
| Residential New Construction | Platinum Star HERS Index Score 60 | Total Incentive Budget | $13,800 | $12,400 | $12,400 | $12,400 | $12,400 | $12,400 |
| Residential New Construction | Platinum Star HERS Index Score 60 | Total Gross Incremental Savings (kwh) | 154,284 | 138,632 | 138,632 | 138,632 | 138,632 | 138,632 |
| Residential New Construction | Platinum Star HERS Index Score 60 | NTG | 0.50 | 0.50 | 0.50 | 0.50 | 0.50 | 0.50 |
| Residential New Construction | Platinum Star HERS Index Score 60 | Incremental Cost | $2,428.73 | $2,428.73 | $2,428.73 | $2,428.73 | $2,428.73 | $2,428.73 |

| Program | Measure | Description | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 |
|---|---|---|---|---|---|---|---|---|
| Income Qualified Weatherization | Attic Insulation - Electric Resistance Heated | Participation | 13 | 14 | 15 | 16 | 17 | 18 |
| Income Qualified Weatherization | Attic Insulation - Electric Resistance Heated | Total Incentive Budget | - | - | - | - | - | - |
| Income Qualified Weatherization | Attic Insulation - Electric Resistance Heated | Total Gross Incremental Savings (kwh) | 10,764 | 11,592 | 12,420 | 13,248 | 14,076 | 14,904 |
| Income Qualified Weatherization | Attic Insulation - Electric Resistance Heated | NTG | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 |
| Income Qualified Weatherization | Attic Insulation - Electric Resistance Heated | Incremental Cost | $1,412.60 | $1,412.60 | $1,412.60 | $1,412.60 | $1,412.60 | $1,412.60 |
| Income Qualified Weatherization | Attic Insulation - Gas Heated (Electric) | Participation | 131 | 138 | 145 | 153 | 161 | 170 |
| Income Qualified Weatherization | Attic Insulation - Gas Heated (Electric) | Total Incentive Budget | - | - | - | - | - | - |
| Income Qualified Weatherization | Attic Insulation - Gas Heated (Electric) | Total Gross Incremental Savings (kwh) | 18,209 | 19,182 | 20,155 | 21,267 | 22,379 | 23,630 |
| Income Qualified Weatherization | Attic Insulation - Gas Heated (Electric) | NTG | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 |
| Income Qualified Weatherization | Attic Insulation - Gas Heated (Electric) | Incremental Cost | $706.30 | $706.30 | $706.30 | $706.30 | $706.30 | $706.30 |
| Income Qualified Weatherization | Audit Recommendations - Dual (Electric) | Participation | 340 | 357 | 374 | 392 | 411 | 431 |
| Income Qualified Weatherization | Audit Recommendations - Dual (Electric) | Total Incentive Budget | - | - | - | - | - | - |
| Income Qualified Weatherization | Audit Recommendations - Dual (Electric) | Total Gross Incremental Savings (kwh) | 23,120 | 24,276 | 25,432 | 26,656 | 27,948 | 29,308 |

| Program | Measure | Description | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 |
|---|---|---|---|---|---|---|---|---|
| Income Qualified Weatherization | Audit Recommendations - Dual (Electric) | NTG | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 |
| Income Qualified Weatherization | Audit Recommendations - Dual (Electric) | Incremental Cost | $26.00 | $26.00 | $26.00 | $26.00 | $26.00 | $26.00 |
| Income Qualified Weatherization | Bathroom Aerator 1.0 gpm - Elec DHW | Participation | 112 | 118 | 124 | 131 | 138 | 145 |
| Income Qualified Weatherization | Bathroom Aerator 1.0 gpm - Elec DHW | Total Incentive Budget | - | - | - | - | - | - |
| Income Qualified Weatherization | Bathroom Aerator 1.0 gpm - Elec DHW | Total Gross Incremental Savings (kwh) | 1,344 | 1,416 | 1,488 | 1,572 | 1,656 | 1,740 |
| Income Qualified Weatherization | Bathroom Aerator 1.0 gpm - Elec DHW | NTG | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 |
| Income Qualified Weatherization | Bathroom Aerator 1.0 gpm - Elec DHW | Incremental Cost | $0.52 | $0.52 | $0.52 | $0.52 | $0.52 | $0.52 |
| Income Qualified Weatherization | 9W LED | Participation | 4,021 | 4,223 | 4,435 | 4,657 | 4,890 | 5,135 |
| Income Qualified Weatherization | 9W LED | Total Incentive Budget | - | - | - | - | - | - |
| Income Qualified Weatherization | 9W LED | Total Gross Incremental Savings (kwh) | 128,672 | 135,136 | 141,920 | 149,024 | 156,480 | 164,320 |
| Income Qualified Weatherization | 9W LED | NTG | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 |
| Income Qualified Weatherization | 9W LED | Incremental Cost | $3.21 | $3.21 | $3.21 | $3.21 | $3.21 | $3.21 |
| Income Qualified Weatherization | LED 5W Globe | Participation | 274 | 288 | 303 | 319 | 335 | 352 |

| Program | Measure | Description | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 |
|---|---|---|---|---|---|---|---|---|
| Income Qualified Weatherization | LED 5W Globe | Total Incentive Budget | - | - | - | - | - | - |
| Income Qualified Weatherization | LED 5W Globe | Total Gross Incremental Savings (kwh) | 2,740 | 2,880 | 3,030 | 3,190 | 3,350 | 3,520 |
| Income Qualified Weatherization | LED 5W Globe | NTG | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 |
| Income Qualified Weatherization | LED 5W Globe | Incremental Cost | $8.75 | $8.75 | $8.75 | $8.75 | $8.75 | $8.75 |
| Income Qualified Weatherization | LED R30 Dimmable | Participation | 803 | 844 | 887 | 932 | 979 | 1,028 |
| Income Qualified Weatherization | LED R30 Dimmable | Total Incentive Budget | - | - | - | - | - | - |
| Income Qualified Weatherization | LED R30 Dimmable | Total Gross Incremental Savings (kwh) | 42,559 | 44,732 | 47,011 | 49,396 | 51,887 | 54,484 |
| Income Qualified Weatherization | LED R30 Dimmable | NTG | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 |
| Income Qualified Weatherization | LED R30 Dimmable | Incremental Cost | $11.54 | $11.54 | $11.54 | $11.54 | $11.54 | $11.54 |
| Income Qualified Weatherization | Exterior LED Lamps | Participation | 157 | 165 | 174 | 183 | 193 | 203 |
| Income Qualified Weatherization | Exterior LED Lamps | Total Incentive Budget | - | - | - | - | - | - |
| Income Qualified Weatherization | Exterior LED Lamps | Total Gross Incremental Savings (kwh) | 14,444 | 15,180 | 16,008 | 16,836 | 17,756 | 18,676 |
| Income Qualified Weatherization | Exterior LED Lamps | NTG | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 |

| Program | Measure | Description | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 |
|---|---|---|---|---|---|---|---|---|
| Income Qualified Weatherization | Exterior LED Lamps | Incremental Cost | $7.20 | $7.20 | $7.20 | $7.20 | $7.20 | $7.20 |
| Income Qualified Weatherization | Filter Whistle | Participation | 105 | 111 | 117 | 123 | 130 | 137 |
| Income Qualified Weatherization | Filter Whistle | Total Incentive Budget | - | - | - | - | - | - |
| Income Qualified Weatherization | Filter Whistle | Total Gross Incremental Savings (kwh) | 5,775 | 6,105 | 6,435 | 6,765 | 7,150 | 7,535 |
| Income Qualified Weatherization | Filter Whistle | NTG | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 |
| Income Qualified Weatherization | Filter Whistle | Incremental Cost | $1.64 | $1.64 | $1.64 | $1.64 | $1.64 | $1.64 |
| Income Qualified Weatherization | Kitchen Flip Aerator 1.5 gpm - Elec DHW | Participation | 38 | 40 | 42 | 45 | 48 | 51 |
| Income Qualified Weatherization | Kitchen Flip Aerator 1.5 gpm - Elec DHW | Total Incentive Budget | - | - | - | - | - | - |
| Income Qualified Weatherization | Kitchen Flip Aerator 1.5 gpm - Elec DHW | Total Gross Incremental Savings (kwh) | 4,560 | 4,800 | 5,040 | 5,400 | 5,760 | 6,120 |
| Income Qualified Weatherization | Kitchen Flip Aerator 1.5 gpm - Elec DHW | NTG | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 |
| Income Qualified Weatherization | Kitchen Flip Aerator 1.5 gpm - Elec DHW | Incremental Cost | $1.34 | $1.34 | $1.34 | $1.34 | $1.34 | $1.34 |
| Income Qualified Weatherization | LED Nightlight | Participation | 490 | 515 | 541 | 569 | 598 | 628 |
| Income Qualified Weatherization | LED Nightlight | Total Incentive Budget | - | - | - | - | - | - |

| Program | Measure | Description | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 |
|---|---|---|---|---|---|---|---|---|
| Income Qualified Weatherization | LED Nightlight | Total Gross Incremental Savings (kwh) | 6,860 | 7,210 | 7,574 | 7,966 | 8,372 | 8,792 |
| Income Qualified Weatherization | LED Nightlight | NTG | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 |
| Income Qualified Weatherization | LED Nightlight | Incremental Cost | $2.75 | $2.75 | $2.75 | $2.75 | $2.75 | $2.75 |
| Income Qualified Weatherization | Low Flow Showerhead 1.5 gpm - Elec DHW | Participation | 89 | 94 | 99 | 104 | 110 | 116 |
| Income Qualified Weatherization | Low Flow Showerhead 1.5 gpm - Elec DHW | Total Incentive Budget | - | - | - | - | - | - |
| Income Qualified Weatherization | Low Flow Showerhead 1.5 gpm - Elec DHW | Total Gross Incremental Savings (kwh) | 26,700 | 28,200 | 29,700 | 31,200 | 33,000 | 34,800 |
| Income Qualified Weatherization | Low Flow Showerhead 1.5 gpm - Elec DHW | NTG | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 |
| Income Qualified Weatherization | Low Flow Showerhead 1.5 gpm - Elec DHW | Incremental Cost | $3.32 | $3.32 | $3.32 | $3.32 | $3.32 | $3.32 |
| Income Qualified Weatherization | Pipe Wrap - Elec DHW (per home) | Participation | 23 | 25 | 27 | 29 | 31 | 33 |
| Income Qualified Weatherization | Pipe Wrap - Elec DHW (per home) | Total Incentive Budget | - | - | - | - | - | - |
| Income Qualified Weatherization | Pipe Wrap - Elec DHW (per home) | Total Gross Incremental Savings (kwh) | 3,404 | 3,700 | 3,996 | 4,292 | 4,588 | 4,884 |
| Income Qualified Weatherization | Pipe Wrap - Elec DHW (per home) | NTG | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 |
| Income Qualified Weatherization | Pipe Wrap - Elec DHW (per home) | Incremental Cost | $1.72 | $1.72 | $1.72 | $1.72 | $1.72 | $1.72 |

| Program | Measure | Description | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 |
|---|---|---|---|---|---|---|---|---|
| Income Qualified Weatherization | Refrigerator Replacement | Participation | 35 | 37 | 39 | 41 | 44 | 47 |
| Income Qualified Weatherization | Refrigerator Replacement | Total Incentive Budget | - | - | - | - | - | - |
| Income Qualified Weatherization | Refrigerator Replacement | Total Gross Incremental Savings (kwh) | 15,470 | 16,354 | 17,238 | 18,122 | 19,448 | 20,774 |
| Income Qualified Weatherization | Refrigerator Replacement | NTG | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 |
| Income Qualified Weatherization | Refrigerator Replacement | Incremental Cost | $580.00 | $580.00 | $580.00 | $580.00 | $580.00 | $580.00 |
| Income Qualified Weatherization | Smart Thermostat (Electric) | Participation | 26 | 28 | 30 | 32 | 34 | 36 |
| Income Qualified Weatherization | Smart Thermostat (Electric) | Total Incentive Budget | - | - | - | - | - | - |
| Income Qualified Weatherization | Smart Thermostat (Electric) | Total Gross Incremental Savings (kwh) | 9,620 | 10,360 | 11,100 | 11,840 | 12,580 | 13,320 |
| Income Qualified Weatherization | Smart Thermostat (Electric) | NTG | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 |
| Income Qualified Weatherization | Smart Thermostat (Electric) | Incremental Cost | $77.00 | $77.00 | $77.00 | $77.00 | $77.00 | $77.00 |
| Income Qualified Weatherization | Water Heater Temperature Setback - Elec DHW | Participation | 75 | 79 | 83 | 88 | 93 | 98 |
| Income Qualified Weatherization | Water Heater Temperature Setback - Elec DHW | Total Incentive Budget | - | - | - | - | - | - |

| Program | Measure | Description | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 |
|---|---|---|---|---|---|---|---|---|
| Income Qualified Weatherization | Water Heater Temperature Setback - Elec DHW | Total Gross Incremental Savings (kwh) | 6,450 | 6,794 | 7,138 | 7,568 | 7,998 | 8,428 |
| Income Qualified Weatherization | Water Heater Temperature Setback - Elec DHW | NTG | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 |
| Income Qualified Weatherization | Water Heater Temperature Setback - Elec DHW | Incremental Cost | $6.50 | $6.50 | $6.50 | $6.50 | $6.50 | $6.50 |
| Income Qualified Weatherization | Duct Sealing Gas Heating with A/C | Participation | 316 | 332 | 349 | 367 | 386 | 406 |
| Income Qualified Weatherization | Duct Sealing Gas Heating with A/C | Total Incentive Budget | - | - | - | - | - | - |
| Income Qualified Weatherization | Duct Sealing Gas Heating with A/C | Total Gross Incremental Savings (kwh) | 72,364 | 76,028 | 79,921 | 84,043 | 88,394 | 92,974 |
| Income Qualified Weatherization | Duct Sealing Gas Heating with A/C | NTG | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 |
| Income Qualified Weatherization | Duct Sealing Gas Heating with A/C | Incremental Cost | $225.00 | $225.00 | $225.00 | $225.00 | $225.00 | $225.00 |
| Income Qualified Weatherization | Duct Sealing Electric Heat Pump | Participation | 37 | 39 | 41 | 44 | 47 | 50 |
| Income Qualified Weatherization | Duct Sealing Electric Heat Pump | Total Incentive Budget | - | - | - | - | - | - |
| Income Qualified Weatherization | Duct Sealing Electric Heat Pump | Total Gross Incremental Savings (kwh) | 30,673 | 32,331 | 33,989 | 36,476 | 38,963 | 41,450 |
| Income Qualified Weatherization | Duct Sealing Electric Heat Pump | NTG | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 |

| Program | Measure | Description | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 |
|---|---|---|---|---|---|---|---|---|
| Income Qualified Weatherization | Duct Sealing Electric Heat Pump | Incremental Cost | $450.00 | $450.00 | $450.00 | $450.00 | $450.00 | $450.00 |
| Income Qualified Weatherization | Duct Sealing Electric Resistive Furnace | Participation | 45 | 48 | 51 | 54 | 57 | 60 |
| Income Qualified Weatherization | Duct Sealing Electric Resistive Furnace | Total Incentive Budget | - | - | - | - | - | - |
| Income Qualified Weatherization | Duct Sealing Electric Resistive Furnace | Total Gross Incremental Savings (kwh) | 60,840 | 64,896 | 68,952 | 73,008 | 77,064 | 81,120 |
| Income Qualified Weatherization | Duct Sealing Electric Resistive Furnace | NTG | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 |
| Income Qualified Weatherization | Duct Sealing Electric Resistive Furnace | Incremental Cost | $450.00 | $450.00 | $450.00 | $450.00 | $450.00 | $450.00 |
| Income Qualified Weatherization | Air Sealing Gas Furnace w/ CAC | Participation | 465 | 489 | 514 | 540 | 567 | 596 |
| Income Qualified Weatherization | Air Sealing Gas Furnace w/ CAC | Total Incentive Budget | - | - | - | - | - | - |
| Income Qualified Weatherization | Air Sealing Gas Furnace w/ CAC | Total Gross Incremental Savings (kwh) | 65,100 | 68,460 | 71,960 | 75,600 | 79,380 | 83,440 |
| Income Qualified Weatherization | Air Sealing Gas Furnace w/ CAC | NTG | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 |
| Income Qualified Weatherization | Air Sealing Gas Furnace w/ CAC | Incremental Cost | $100.00 | $100.00 | $100.00 | $100.00 | $100.00 | $100.00 |
| Income Qualified Weatherization | Air Sealing Heat Pump | Participation | 48 | 51 | 54 | 57 | 60 | 63 |
| Income Qualified Weatherization | Air Sealing Heat Pump | Total Incentive Budget | - | - | - | - | - | - |

| Program | Measure | Description | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 |
|---|---|---|---|---|---|---|---|---|
| Income Qualified Weatherization | Air Sealing Heat Pump | Total Gross Incremental Savings (kwh) | 72,048 | 76,551 | 81,054 | 85,557 | 90,060 | 94,563 |
| Income Qualified Weatherization | Air Sealing Heat Pump | NTG | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 |
| Income Qualified Weatherization | Air Sealing Heat Pump | Incremental Cost | $200.00 | $200.00 | $200.00 | $200.00 | $200.00 | $200.00 |
| Income Qualified Weatherization | Air Sealing Electric Furnace w/ CAC | Participation | 32 | 34 | 36 | 38 | 40 | 42 |
| Income Qualified Weatherization | Air Sealing Electric Furnace w/ CAC | Total Incentive Budget | - | - | - | - | - | - |
| Income Qualified Weatherization | Air Sealing Electric Furnace w/ CAC | Total Gross Incremental Savings (kwh) | 150,016 | 159,392 | 168,768 | 178,144 | 187,520 | 196,896 |
| Income Qualified Weatherization | Air Sealing Electric Furnace w/ CAC | NTG | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 |
| Income Qualified Weatherization | Air Sealing Electric Furnace w/ CAC | Incremental Cost | - | - | - | - | - | - |
| Income Qualified Weatherization | Air Source Heat Pump 16 SEER | Participation | 2 | 3 | 4 | 5 | 6 | 7 |
| Income Qualified Weatherization | Air Source Heat Pump 16 SEER | Total Incentive Budget | - | - | - | - | - | - |
| Income Qualified Weatherization | Air Source Heat Pump 16 SEER | Total Gross Incremental Savings (kwh) | 1,582 | 2,373 | 3,164 | 3,955 | 4,746 | 5,537 |
| Income Qualified Weatherization | Air Source Heat Pump 16 SEER | NTG | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 |
| Income Qualified Weatherization | Air Source Heat Pump 16 SEER | Incremental Cost | $5,400.00 | $5,400.00 | $5,400.00 | $5,400.00 | $5,400.00 | $5,400.00 |

| Program | Measure | Description | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 |
|---|---|---|---|---|---|---|---|---|
| Income Qualified Weatherization | Central Air Conditioner 16 SEER | Participation | 19 | 20 | 21 | 23 | 25 | 27 |
| Income Qualified Weatherization | Central Air Conditioner 16 SEER | Total Incentive Budget | - | - | - | - | - | - |
| Income Qualified Weatherization | Central Air Conditioner 16 SEER | Total Gross Incremental Savings (kwh) | 5,700 | 6,000 | 6,300 | 6,900 | 7,500 | 8,100 |
| Income Qualified Weatherization | Central Air Conditioner 16 SEER | NTG | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 |
| Income Qualified Weatherization | Central Air Conditioner 16 SEER | Incremental Cost | $3,500.00 | $3,500.00 | $3,500.00 | $3,500.00 | $3,500.00 | $3,500.00 |
| Income Qualified Weatherization | Wall Insulation - Dual (gas heated) | Participation | 19 | 21 | 23 | 25 | 27 | 29 |
| Income Qualified Weatherization | Wall Insulation - Dual (gas heated) | Total Incentive Budget | - | - | - | - | - | - |
| Income Qualified Weatherization | Wall Insulation - Dual (gas heated) | Total Gross Incremental Savings (kwh) | 1,141 | 1,239 | 1,357 | 1,475 | 1,593 | 1,711 |
| Income Qualified Weatherization | Wall Insulation - Dual (gas heated) | NTG | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 |
| Income Qualified Weatherization | Wall Insulation - Dual (gas heated) | Incremental Cost | $877.00 | $877.00 | $877.00 | $877.00 | $877.00 | $877.00 |
| Income Qualified Weatherization | Water Heater Temperature Setback - Gas DHW | Participation | 55 | 58 | 61 | 65 | 69 | 73 |
| Income Qualified Weatherization | Water Heater Temperature Setback - Gas DHW | Total Incentive Budget | - | - | - | - | - | - |

| Program | Measure | Description | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 |
|---|---|---|---|---|---|---|---|---|
| Income Qualified Weatherization | Water Heater Temperature Setback - Gas DHW | Total Gross Incremental Savings (kwh) | (1,870) | (1,972) | (2,074) | (2,210) | (2,346) | (2,482) |
| Income Qualified Weatherization | Water Heater Temperature Setback - Gas DHW | NTG | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 |
| Income Qualified Weatherization | Water Heater Temperature Setback - Gas DHW | Incremental Cost | - | - | - | - | - | - |
| Income Qualified Weatherization | Mobile Home Audit (Dual) | Participation | 173 | 181 | 190 | 199 | 208 | 218 |
| Income Qualified Weatherization | Mobile Home Audit (Dual) | Total Incentive Budget | - | - | - | - | - | - |
| Income Qualified Weatherization | Mobile Home Audit (Dual) | Total Gross Incremental Savings (kwh) | - | - | - | - | - | - |
| Income Qualified Weatherization | Mobile Home Audit (Dual) | NTG | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 |
| Income Qualified Weatherization | Mobile Home Audit (Dual) | Incremental Cost | $26.00 | $26.00 | $26.00 | $26.00 | $26.00 | $26.00 |
| Income Qualified Weatherization | Mobile Home Audit (Electric) | Participation | 26 | 28 | 30 | 32 | 34 | 36 |
| Income Qualified Weatherization | Mobile Home Audit (Electric) | Total Incentive Budget | - | - | - | - | - | - |
| Income Qualified Weatherization | Mobile Home Audit (Electric) | Total Gross Incremental Savings (kwh) | - | - | - | - | - | - |
| Income Qualified Weatherization | Mobile Home Audit (Electric) | NTG | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 |

| Program | Measure | Description | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 |
|---|---|---|---|---|---|---|---|---|
| Income Qualified Weatherization | Mobile Home Audit (Electric) | Incremental Cost | $106.00 | $106.00 | $106.00 | $106.00 | $106.00 | $106.00 |
| Energy Efficient Schools | 15W LED | Participation | 2,600 | 2,600 | - | - | - | - |
| Energy Efficient Schools | 15W LED | Total Incentive Budget | - | - | - | - | - | - |
| Energy Efficient Schools | 15W LED | Total Gross Incremental Savings (kwh) | 124,800 | 124,800 | - | - | - | - |
| Energy Efficient Schools | 15W LED | NTG | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 |
| Energy Efficient Schools | 15W LED | Incremental Cost | - | - | - | - | - | - |
| Energy Efficient Schools | 11W LED | Participation | 5,200 | 5,200 | - | - | - | - |
| Energy Efficient Schools | 11W LED | Total Incentive Budget | - | - | - | - | - | - |
| Energy Efficient Schools | 11W LED | Total Gross Incremental Savings (kwh) | 353,600 | 353,600 | - | - | - | - |
| Energy Efficient Schools | 11W LED | NTG | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 |
| Energy Efficient Schools | 11W LED | Incremental Cost | - | - | - | - | - | - |
| Energy Efficient Schools | Showerheads | Participation | 2,600 | 2,600 | 2,600 | 2,600 | 2,600 | 2,600 |
| Energy Efficient Schools | Showerheads | Total Incentive Budget | - | - | - | - | - | - |

| Program | Measure | Description | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 |
|---|---|---|---|---|---|---|---|---|
| Energy Efficient Schools | Showerheads | Total Gross Incremental Savings (kwh) | 340,600 | 340,600 | 340,600 | 340,600 | 340,600 | 340,600 |
| Energy Efficient Schools | Showerheads | NTG | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 |
| Energy Efficient Schools | Showerheads | Incremental Cost | - | - | - | - | - | - |
| Energy Efficient Schools | Kitchen Aerators | Participation | 2,600 | 2,600 | 2,600 | 2,600 | 2,600 | 2,600 |
| Energy Efficient Schools | Kitchen Aerators | Total Incentive Budget | - | - | - | - | - | - |
| Energy Efficient Schools | Kitchen Aerators | Total Gross Incremental Savings (kwh) | 145,600 | 145,600 | 145,600 | 145,600 | 145,600 | 145,600 |
| Energy Efficient Schools | Kitchen Aerators | NTG | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 |
| Energy Efficient Schools | Kitchen Aerators | Incremental Cost | - | - | - | - | - | - |
| Energy Efficient Schools | Bathroom Aerators | Participation | 5,200 | 5,200 | 5,200 | 5,200 | 5,200 | 5,200 |
| Energy Efficient Schools | Bathroom Aerators | Total Incentive Budget | - | - | - | - | - | - |
| Energy Efficient Schools | Bathroom Aerators | Total Gross Incremental Savings (kwh) | 114,400 | 114,400 | 114,400 | 114,400 | 114,400 | 114,400 |
| Energy Efficient Schools | Bathroom Aerators | NTG | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 |
| Energy Efficient Schools | Bathroom Aerators | Incremental Cost | - | - | - | - | - | - |

| Program | Measure | Description | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 |
|---|---|---|---|---|---|---|---|---|
| Energy Efficient Schools | Filter Whistle | Participation | 2,600 | 2,600 | 2,600 | 2,600 | 2,600 | 2,600 |
| Energy Efficient Schools | Filter Whistle | Total Incentive Budget | - | - | - | - | - | - |
| Energy Efficient Schools | Filter Whistle | Total Gross Incremental Savings (kwh) | 52,000 | 52,000 | 52,000 | 52,000 | 52,000 | 52,000 |
| Energy Efficient Schools | Filter Whistle | NTG | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 |
| Energy Efficient Schools | Filter Whistle | Incremental Cost | - | - | - | - | - | - |
| Energy Efficient Schools | LED Night Light | Participation | 2,600 | 2,600 | 2,600 | 2,600 | 2,600 | 2,600 |
| Energy Efficient Schools | LED Night Light | Total Incentive Budget | - | - | - | - | - | - |
| Energy Efficient Schools | LED Night Light | Total Gross Incremental Savings (kwh) | 18,200 | 18,200 | 18,200 | 18,200 | 18,200 | 18,200 |
| Energy Efficient Schools | LED Night Light | NTG | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 |
| Energy Efficient Schools | LED Night Light | Incremental Cost | - | - | - | - | - | - |
| Residential Behavior Savings | Residential Behavior | Participation | 35,298 | 35,298 | 35,298 | 35,298 | 35,298 | 35,298 |
| Residential Behavior Savings | Residential Behavior | Total Incentive Budget | - | - | - | - | - | - |
| Residential Behavior Savings | Residential Behavior | Total Gross Incremental Savings (kwh) | 5,600,000 | 5,600,000 | 5,600,000 | 5,600,000 | 5,600,000 | 5,600,000 |

| Program | Measure | Description | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 |
|---|---|---|---|---|---|---|---|---|
| Residential Behavior Savings | Residential Behavior | NTG | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 |
| Residential Behavior Savings | Residential Behavior | Incremental Cost | - | - | - | - | - | - |
| Residential Behavior Savings | Low Income Refill Electric | Participation | 13,702 | 13,702 | 13,702 | 13,702 | 13,702 | 13,702 |
| Residential Behavior Savings | Low Income Refill Electric | Total Incentive Budget | - | - | - | - | - | - |
| Residential Behavior Savings | Low Income Refill Electric | Total Gross Incremental Savings (kwh) | 1,449,208 | 1,449,208 | 1,449,208 | 1,449,208 | 1,449,208 | 1,449,208 |
| Residential Behavior Savings | Low Income Refill Electric | NTG | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 |
| Residential Behavior Savings | Low Income Refill Electric | Incremental Cost | - | - | - | - | - | - |
| Appliance Recycling | Refrigerator Recycling | Participation | 1,028 | 1,142 | 1,206 | 1,206 | 1,142 | 1,028 |
| Appliance Recycling | Refrigerator Recycling | Total Incentive Budget | $51,400 | $57,100 | $60,300 | $60,300 | $57,100 | $51,400 |
| Appliance Recycling | Refrigerator Recycling | Total Gross Incremental Savings (kwh) | 1,013,608 | 1,126,012 | 1,189,116 | 1,189,116 | 1,126,012 | 1,013,608 |
| Appliance Recycling | Refrigerator Recycling | NTG | 0.71 | 0.71 | 0.71 | 0.71 | 0.71 | 0.71 |
| Appliance Recycling | Refrigerator Recycling | Incremental Cost | - | - | - | - | - | - |
| Appliance Recycling | Freezer Recycling | Participation | 161 | 179 | 189 | 189 | 179 | 161 |

| Program | Measure | Description | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 |
|---|---|---|---|---|---|---|---|---|
| Appliance Recycling | Freezer Recycling | Total Incentive Budget | $8,050 | $8,950 | $9,450 | $9,450 | $8,950 | $8,050 |
| Appliance Recycling | Freezer Recycling | Total Gross Incremental Savings (kwh) | 132,020 | 146,780 | 154,980 | 154,980 | 146,780 | 132,020 |
| Appliance Recycling | Freezer Recycling | NTG | 0.71 | 0.71 | 0.71 | 0.71 | 0.71 | 0.71 |
| Appliance Recycling | Freezer Recycling | Incremental Cost | - | - | - | - | - | - |
| Appliance Recycling | Room Air Conditioner Recycling | Participation | 62 | 23 | 30 | 40 | 51 | 64 |
| Appliance Recycling | Room Air Conditioner Recycling | Total Incentive Budget | $1,550 | $575 | $750 | $1,000 | $1,275 | $1,600 |
| Appliance Recycling | Room Air Conditioner Recycling | Total Gross Incremental Savings (kwh) | 34,183 | 12,681 | 16,540 | 22,053 | 28,118 | 35,285 |
| Appliance Recycling | Room Air Conditioner Recycling | NTG | 0.57 | 0.57 | 0.57 | 0.57 | 0.57 | 0.57 |
| Appliance Recycling | Room Air Conditioner Recycling | Incremental Cost | - | - | - | - | - | - |
| Home Energy Assessment | Audit Education - All sites | Participation | 300 | 350 | 420 | 504 | 504 | 504 |
| Home Energy Assessment | Audit Education - All sites | Total Incentive Budget | - | - | - | - | - | - |
| Home Energy Assessment | Audit Education - All sites | Total Gross Incremental Savings (kwh) | 18,364 | 21,424 | 25,709 | 30,851 | 30,851 | 30,851 |
| Home Energy Assessment | Audit Education - All sites | NTG | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 |

| Program | Measure | Description | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 |
|---|---|---|---|---|---|---|---|---|
| Home Energy Assessment | Audit Education - All sites | Incremental Cost | - | - | - | - | - | - |
| Home Energy Assessment | LED 5W Globe | Participation | 600 | 700 | 840 | 1,008 | 1,008 | 806 |
| Home Energy Assessment | LED 5W Globe | Total Incentive Budget | - | - | - | - | - | - |
| Home Energy Assessment | LED 5W Globe | Total Gross Incremental Savings (kwh) | 6,221 | 7,258 | 8,710 | 10,452 | 10,452 | 8,361 |
| Home Energy Assessment | LED 5W Globe | NTG | 0.96 | 0.96 | 0.96 | 0.96 | 0.96 | 0.96 |
| Home Energy Assessment | LED 5W Globe | Incremental Cost | - | - | - | - | - | - |
| Home Energy Assessment | LED 9W Bulb | Participation | 3,000 | 3,500 | 4,200 | 5,040 | 4,032 | 3,024 |
| Home Energy Assessment | LED 9W Bulb | Total Incentive Budget | - | - | - | - | - | - |
| Home Energy Assessment | LED 9W Bulb | Total Gross Incremental Savings (kwh) | 94,680 | 110,460 | 132,552 | 159,062 | 127,250 | 95,437 |
| Home Energy Assessment | LED 9W Bulb | NTG | 0.96 | 0.96 | 0.96 | 0.96 | 0.96 | 0.96 |
| Home Energy Assessment | LED 9W Bulb | Incremental Cost | - | - | - | - | - | - |
| Home Energy Assessment | LED R30 Dimmable | Participation | 900 | 1,050 | 1,260 | 1,512 | 1,512 | 1,210 |
| Home Energy Assessment | LED R30 Dimmable | Total Incentive Budget | - | - | - | - | - | - |

| Program | Measure | Description | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 |
|---|---|---|---|---|---|---|---|---|
| Home Energy Assessment | LED R30 Dimmable | Total Gross Incremental Savings (kwh) | 47,679 | 55,626 | 66,751 | 80,101 | 80,101 | 64,081 |
| Home Energy Assessment | LED R30 Dimmable | NTG | 0.96 | 0.96 | 0.96 | 0.96 | 0.96 | 0.96 |
| Home Energy Assessment | LED R30 Dimmable | Incremental Cost | - | - | - | - | - | - |
| Home Energy Assessment | LED Night Light | Participation | 300 | 350 | 420 | 504 | 504 | 504 |
| Home Energy Assessment | LED Night Light | Total Incentive Budget | - | - | - | - | - | - |
| Home Energy Assessment | LED Night Light | Total Gross Incremental Savings (kwh) | 4,091 | 4,773 | 5,727 | 6,873 | 6,873 | 6,873 |
| Home Energy Assessment | LED Night Light | NTG | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 |
| Home Energy Assessment | LED Night Light | Incremental Cost | - | - | - | - | - | - |
| Home Energy Assessment | Bathroom Aerator | Participation | 600 | 700 | 840 | 1,008 | 1,008 | 1,008 |
| Home Energy Assessment | Bathroom Aerator | Total Incentive Budget | - | - | - | - | - | - |
| Home Energy Assessment | Bathroom Aerator | Total Gross Incremental Savings (kwh) | 5,400 | 6,300 | 7,560 | 9,072 | 9,072 | 9,072 |
| Home Energy Assessment | Bathroom Aerator | NTG | 1.06 | 1.06 | 1.06 | 1.06 | 1.06 | 1.06 |
| Home Energy Assessment | Bathroom Aerator | Incremental Cost | - | - | - | - | - | - |

| Program | Measure | Description | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 |
|---|---|---|---|---|---|---|---|---|
| Home Energy Assessment | Kitchen Aerator | Participation | 300 | 350 | 420 | 504 | 504 | 504 |
| Home Energy Assessment | Kitchen Aerator | Total Incentive Budget | - | - | - | - | - | - |
| Home Energy Assessment | Kitchen Aerator | Total Gross Incremental Savings (kwh) | 34,350 | 40,075 | 48,090 | 57,708 | 57,708 | 57,708 |
| Home Energy Assessment | Kitchen Aerator | NTG | 1.06 | 1.06 | 1.06 | 1.06 | 1.06 | 1.06 |
| Home Energy Assessment | Kitchen Aerator | Incremental Cost | - | - | - | - | - | - |
| Home Energy Assessment | Efficient Showerhead | Participation | 300 | 350 | 420 | 504 | 504 | 504 |
| Home Energy Assessment | Efficient Showerhead | Total Incentive Budget | - | - | - | - | - | - |
| Home Energy Assessment | Efficient Showerhead | Total Gross Incremental Savings (kwh) | 61,707 | 71,992 | 86,390 | 103,668 | 103,668 | 103,668 |
| Home Energy Assessment | Efficient Showerhead | NTG | 1.06 | 1.06 | 1.06 | 1.06 | 1.06 | 1.06 |
| Home Energy Assessment | Efficient Showerhead | Incremental Cost | - | - | - | - | - | - |
| Home Energy Assessment | Filter Whistle | Participation | 300 | 350 | 420 | 504 | 504 | 504 |
| Home Energy Assessment | Filter Whistle | Total Incentive Budget | - | - | - | - | - | - |
| Home Energy Assessment | Filter Whistle | Total Gross Incremental Savings (kwh) | 18,267 | 21,312 | 25,574 | 30,689 | 30,689 | 30,689 |

| Program | Measure | Description | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 |
|---|---|---|---|---|---|---|---|---|
| Home Energy Assessment | Filter Whistle | NTG | 1.15 | 1.15 | 1.15 | 1.15 | 1.15 | 1.15 |
| Home Energy Assessment | Filter Whistle | Incremental Cost | - | - | - | - | - | - |
| Home Energy Assessment | Pipe Wrap (Electric) (per home) | Participation | 300 | 350 | 420 | 504 | 504 | 504 |
| Home Energy Assessment | Pipe Wrap (Electric) (per home) | Total Incentive Budget | - | - | - | - | - | - |
| Home Energy Assessment | Pipe Wrap (Electric) (per home) | Total Gross Incremental Savings (kwh) | 19,620 | 22,890 | 27,468 | 32,962 | 32,962 | 32,962 |
| Home Energy Assessment | Pipe Wrap (Electric) (per home) | NTG | 1.09 | 1.09 | 1.09 | 1.09 | 1.09 | 1.09 |
| Home Energy Assessment | Pipe Wrap (Electric) (per home) | Incremental Cost | - | - | - | - | - | - |
| Home Energy Assessment | Water Heater Temperature Setback | Participation | 300 | 350 | 420 | 504 | 504 | 504 |
| Home Energy Assessment | Water Heater Temperature Setback | Total Incentive Budget | - | - | - | - | - | - |
| Home Energy Assessment | Water Heater Temperature Setback | Total Gross Incremental Savings (kwh) | 25,957 | 30,283 | 36,340 | 43,608 | 43,608 | 43,608 |
| Home Energy Assessment | Water Heater Temperature Setback | NTG | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 |
| Home Energy Assessment | Water Heater Temperature Setback | Incremental Cost | - | - | - | - | - | - |
| Home Energy Assessment | Wi-Fi Thermostat (Dual Fuel) | Participation | 300 | 350 | 420 | 504 | 504 | 504 |

| Program | Measure | Description | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 |
|---|---|---|---|---|---|---|---|---|
| Home Energy Assessment | Wi-Fi Thermostat (Dual Fuel) | Total Incentive Budget | - | - | - | - | - | - |
| Home Energy Assessment | Wi-Fi Thermostat (Dual Fuel) | Total Gross Incremental Savings (kwh) | 59,400 | 69,300 | 83,160 | 99,792 | 99,792 | 99,792 |
| Home Energy Assessment | Wi-Fi Thermostat (Dual Fuel) | NTG | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 |
| Home Energy Assessment | Wi-Fi Thermostat (Dual Fuel) | Incremental Cost | - | - | - | - | - | - |
| Home Energy Assessment | Wi-Fi Thermostat (Electric) | Participation | 300 | 350 | 420 | 504 | 504 | 504 |
| Home Energy Assessment | Wi-Fi Thermostat (Electric) | Total Incentive Budget | - | - | - | - | - | - |
| Home Energy Assessment | Wi-Fi Thermostat (Electric) | Total Gross Incremental Savings (kwh) | 123,657 | 144,267 | 173,120 | 207,744 | 207,744 | 207,744 |
| Home Energy Assessment | Wi-Fi Thermostat (Electric) | NTG | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 |
| Home Energy Assessment | Wi-Fi Thermostat (Electric) | Incremental Cost | - | - | - | - | - | - |
| Home Energy Assessment | Showerstart Device (TSV Valve) | Participation | - | - | - | - | - | - |
| Home Energy Assessment | Showerstart Device (TSV Valve) | Total Incentive Budget | - | - | - | - | - | - |
| Home Energy Assessment | Showerstart Device (TSV Valve) | Total Gross Incremental Savings (kwh) | - | - | - | - | - | - |
| Home Energy Assessment | Showerstart Device (TSV Valve) | NTG | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 |

| Program | Measure | Description | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 |
|---|---|---|---|---|---|---|---|---|
| Home Energy Assessment | Showerstart Device (TSV Valve) | Incremental Cost | - | - | - | - | - | - |
| Home Energy Assessment | Tier 1 Advanced Power Strip | Participation | 300 | 350 | 420 | 504 | 504 | 504 |
| Home Energy Assessment | Tier 1 Advanced Power Strip | Total Incentive Budget | - | - | - | - | - | - |
| Home Energy Assessment | Tier 1 Advanced Power Strip | Total Gross Incremental Savings (kwh) | - | - | - | - | - | - |
| Home Energy Assessment | Tier 1 Advanced Power Strip | NTG | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 |
| Home Energy Assessment | Tier 1 Advanced Power Strip | Incremental Cost | - | - | - | - | - | - |
| Food Bank | 9W LED | Participation | - | 25,248 | - | - | - | - |
| Food Bank | 9W LED | Total Incentive Budget | - | - | - | - | - | - |
| Food Bank | 9W LED | Total Gross Incremental Savings (kwh) | - | 747,979 | - | - | - | - |
| Food Bank | 9W LED | NTG | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 |
| Food Bank | 9W LED | Incremental Cost | - | - | - | - | - | - |
| Food Bank | LED R30 Dimmable | Participation | - | 3,156 | 3,156 | - | - | - |
| Food Bank | LED R30 Dimmable | Total Incentive Budget | - | - | - | - | - | - |

| Program | Measure | Description | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 |
|---|---|---|---|---|---|---|---|---|
| Food Bank | LED R30 Dimmable | Total Gross Incremental Savings (kwh) | - | 167,195 | 167,195 | - | - | - |
| Food Bank | LED R30 Dimmable | NTG | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 |
| Food Bank | LED R30 Dimmable | Incremental Cost | - | - | - | - | - | - |
| Food Bank | Low Flow Showerhead 1.5 gpm - Elec DHW | Participation | - | 3,156 | 3,156 | 3,156 | 3,156 | 3,156 |
| Food Bank | Low Flow Showerhead 1.5 gpm - Elec DHW | Total Incentive Budget | - | - | - | - | - | - |
| Food Bank | Low Flow Showerhead 1.5 gpm - Elec DHW | Total Gross Incremental Savings (kwh) | - | 649,158 | 649,158 | 649,158 | 649,158 | 649,158 |
| Food Bank | Low Flow Showerhead 1.5 gpm - Elec DHW | NTG | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 |
| Food Bank | Low Flow Showerhead 1.5 gpm - Elec DHW | Incremental Cost | - | - | - | - | - | - |
| Bring Your Own Thermostat | BYOT (Bring Your Own Device) | Participation | 300 | 300 | 300 | 300 | 300 | 300 |
| Bring Your Own Thermostat | BYOT (Bring Your Own Device) | Total Incentive Budget | - | - | - | - | - | - |
| Bring Your Own Thermostat | BYOT (Bring Your Own Device) | Total Gross Incremental Savings (kwh) | - | - | - | - | - | - |
| Bring Your Own Thermostat | BYOT (Bring Your Own Device) | NTG | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 |
| Bring Your Own Thermostat | BYOT (Bring Your Own Device) | Incremental Cost | - | - | - | - | - | - |

| Program | Measure | Description | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 |
|---|---|---|---|---|---|---|---|---|
| Smart Cycle | Smart Cycle (DLC Change Out) | Participation | 1,000 | 1,000 | 1,000 | 1,000 | 1,000 | 1,000 |
| Smart Cycle | Smart Cycle (DLC Change Out) | Total Incentive Budget | $96,000 | $116,000 | $136,000 | $156,000 | $176,000 | $196,000 |
| Smart Cycle | Smart Cycle (DLC Change Out) | Total Gross Incremental Savings (kwh) | - | 198,000 | 198,000 | 198,000 | 198,000 | 198,000 |
| Smart Cycle | Smart Cycle (DLC Change Out) | NTG | - | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 |
| Smart Cycle | Smart Cycle (DLC Change Out) | Incremental Cost | - | - | - | - | - | - |
| C&I Prescriptive | Smart Thermostats | Participation | 72 | 91 | 118 | 148 | 177 | 205 |
| C&I Prescriptive | Smart Thermostats | Total Incentive Budget | $1,080 | $1,365 | $1,770 | $2,220 | $2,655 | $3,075 |
| C&I Prescriptive | Smart Thermostats | Total Gross Incremental Savings (kwh) | 34,137 | 43,298 | 56,214 | 70,552 | 84,379 | 97,979 |
| C&I Prescriptive | Smart Thermostats | NTG | 0.80 | 0.80 | 0.80 | 0.80 | 0.80 | 0.80 |
| C&I Prescriptive | Smart Thermostats | Incremental Cost | $39.16 | $39.16 | $39.16 | $39.16 | $39.16 | $39.16 |
| C&I Prescriptive | Refrigerator Strip Curtains | Participation | 18 | 42 | 77 | 122 | 178 | 247 |
| C&I Prescriptive | Refrigerator Strip Curtains | Total Incentive Budget | $54 | $126 | $231 | $366 | $534 | $741 |
| C&I Prescriptive | Refrigerator Strip Curtains | Total Gross Incremental Savings (kwh) | 4,198 | 9,796 | 17,958 | 28,454 | 41,514 | 57,607 |

| Program | Measure | Description | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 |
|---|---|---|---|---|---|---|---|---|
| C&I Prescriptive | Refrigerator Strip Curtains | NTG | 0.80 | 0.80 | 0.80 | 0.80 | 0.80 | 0.80 |
| C&I Prescriptive | Refrigerator Strip Curtains | Incremental Cost | $7.50 | $7.50 | $7.50 | $7.50 | $7.50 | $7.50 |
| C&I Prescriptive | Agriculture - Livestock Waterer | Participation | 1 | 1 | 1 | 1 | 1 | 1 |
| C&I Prescriptive | Agriculture - Livestock Waterer | Total Incentive Budget | $33 | $33 | $33 | $33 | $33 | $33 |
| C&I Prescriptive | Agriculture - Livestock Waterer | Total Gross Incremental Savings (kwh) | 266 | 266 | 266 | 266 | 266 | 266 |
| C&I Prescriptive | Agriculture - Livestock Waterer | NTG | 0.80 | 0.80 | 0.80 | 0.80 | 0.80 | 0.80 |
| C&I Prescriptive | Agriculture - Livestock Waterer | Incremental Cost | $787.50 | $787.50 | $787.50 | $787.50 | $787.50 | $787.50 |
| C&I Prescriptive | Agriculture - Poultry Farm Led Lighting | Participation | 1 | 1 | 1 | 1 | 1 | 1 |
| C&I Prescriptive | Agriculture - Poultry Farm Led Lighting | Total Incentive Budget | $0 | $0 | $0 | $0 | $0 | $0 |
| C&I Prescriptive | Agriculture - Poultry Farm Led Lighting | Total Gross Incremental Savings (kwh) | 292 | 292 | 292 | 292 | 292 | 292 |
| C&I Prescriptive | Agriculture - Poultry Farm Led Lighting | NTG | 0.80 | 0.80 | 0.80 | 0.80 | 0.80 | 0.80 |
| C&I Prescriptive | Agriculture - Poultry Farm Led Lighting | Incremental Cost | $30.00 | $30.00 | $30.00 | $30.00 | $30.00 | $30.00 |
| C&I Prescriptive | Agriculture - VSD Milk Pump | Participation | 1 | 1 | 1 | 1 | 1 | 1 |

| Program | Measure | Description | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 |
|---|---|---|---|---|---|---|---|---|
| C&I Prescriptive | Agriculture - VSD Milk Pump | Total Incentive Budget | $13 | $13 | $13 | $13 | $13 | $13 |
| C&I Prescriptive | Agriculture - VSD Milk Pump | Total Gross Incremental Savings (kwh) | 34 | 34 | 34 | 34 | 34 | 34 |
| C&I Prescriptive | Agriculture - VSD Milk Pump | NTG | 0.80 | 0.80 | 0.80 | 0.80 | 0.80 | 0.80 |
| C&I Prescriptive | Agriculture - VSD Milk Pump | Incremental Cost | $4,000.00 | $4,000.00 | $4,000.00 | $4,000.00 | $4,000.00 | $4,000.00 |
| C&I Prescriptive | Agriculture - High Volume Low Speed Fans | Participation | 1 | 1 | 1 | 1 | 1 | 1 |
| C&I Prescriptive | Agriculture - High Volume Low Speed Fans | Total Incentive Budget | $250 | $250 | $250 | $250 | $250 | $250 |
| C&I Prescriptive | Agriculture - High Volume Low Speed Fans | Total Gross Incremental Savings (kwh) | 8,543 | 8,543 | 8,543 | 8,543 | 8,543 | 8,543 |
| C&I Prescriptive | Agriculture - High Volume Low Speed Fans | NTG | 0.80 | 0.80 | 0.80 | 0.80 | 0.80 | 0.80 |
| C&I Prescriptive | Agriculture - High Volume Low Speed Fans | Incremental Cost | $4,180.00 | $4,180.00 | $4,180.00 | $4,180.00 | $4,180.00 | $4,180.00 |
| C&I Prescriptive | Agriculture - High Speed Fans | Participation | 1 | 1 | 1 | 1 | 1 | 1 |
| C&I Prescriptive | Agriculture - High Speed Fans | Total Incentive Budget | $250 | $250 | $250 | $250 | $250 | $250 |
| C&I Prescriptive | Agriculture - High Speed Fans | Total Gross Incremental Savings (kwh) | 625 | 625 | 625 | 625 | 625 | 625 |
| C&I Prescriptive | Agriculture - High Speed Fans | NTG | 0.80 | 0.80 | 0.80 | 0.80 | 0.80 | 0.80 |

| Program | Measure | Description | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 |
|---|---|---|---|---|---|---|---|---|
| C&I Prescriptive | Agriculture - High Speed Fans | Incremental Cost | $150.00 | $150.00 | $150.00 | $150.00 | $150.00 | $150.00 |
| C&I Prescriptive | Agriculture - Dairy Plate Cooler | Participation | 1 | 1 | 1 | 1 | 1 | 1 |
| C&I Prescriptive | Agriculture - Dairy Plate Cooler | Total Incentive Budget | $17 | $17 | $17 | $17 | $17 | $17 |
| C&I Prescriptive | Agriculture - Dairy Plate Cooler | Total Gross Incremental Savings (kwh) | 76 | 76 | 76 | 76 | 76 | 76 |
| C&I Prescriptive | Agriculture - Dairy Plate Cooler | NTG | 0.80 | 0.80 | 0.80 | 0.80 | 0.80 | 0.80 |
| C&I Prescriptive | Agriculture - Dairy Plate Cooler | Incremental Cost | $16.67 | $16.67 | $16.67 | $16.67 | $16.67 | $16.67 |
| C&I Prescriptive | Agriculture - Heat Mat | Participation | 1 | 1 | 1 | 1 | 1 | 1 |
| C&I Prescriptive | Agriculture - Heat Mat | Total Incentive Budget | $22 | $22 | $22 | $22 | $22 | $22 |
| C&I Prescriptive | Agriculture - Heat Mat | Total Gross Incremental Savings (kwh) | 657 | 657 | 657 | 657 | 657 | 657 |
| C&I Prescriptive | Agriculture - Heat Mat | NTG | 0.80 | 0.80 | 0.80 | 0.80 | 0.80 | 0.80 |
| C&I Prescriptive | Agriculture - Heat Mat | Incremental Cost | $225.00 | $225.00 | $225.00 | $225.00 | $225.00 | $225.00 |
| C&I Prescriptive | Agriculture - Automatic Milker Take Off | Participation | 1 | 1 | 1 | 1 | 1 | 1 |
| C&I Prescriptive | Agriculture - Automatic Milker Take Off | Total Incentive Budget | $2 | $2 | $2 | $2 | $2 | $2 |

| Program | Measure | Description | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 |
|---|---|---|---|---|---|---|---|---|
| C&I Prescriptive | Agriculture - Automatic Milker Take Off | Total Gross Incremental Savings (kwh) | 556 | 556 | 556 | 556 | 556 | 556 |
| C&I Prescriptive | Agriculture - Automatic Milker Take Off | NTG | 0.80 | 0.80 | 0.80 | 0.80 | 0.80 | 0.80 |
| C&I Prescriptive | Agriculture - Automatic Milker Take Off | Incremental Cost | $1.67 | $1.67 | $1.67 | $1.67 | $1.67 | $1.67 |
| C&I Prescriptive | Agriculture - Heat Reclaimer | Participation | 1 | 1 | 1 | 1 | 1 | 1 |
| C&I Prescriptive | Agriculture - Heat Reclaimer | Total Incentive Budget | $2 | $2 | $2 | $2 | $2 | $2 |
| C&I Prescriptive | Agriculture - Heat Reclaimer | Total Gross Incremental Savings (kwh) | 153 | 153 | 153 | 153 | 153 | 153 |
| C&I Prescriptive | Agriculture - Heat Reclaimer | NTG | 0.80 | 0.80 | 0.80 | 0.80 | 0.80 | 0.80 |
| C&I Prescriptive | Agriculture - Heat Reclaimer | Incremental Cost | $1.67 | $1.67 | $1.67 | $1.67 | $1.67 | $1.67 |
| C&I Prescriptive | Air Compressor | Participation | 1 | 1 | 1 | 1 | 1 | 1 |
| C&I Prescriptive | Air Compressor | Total Incentive Budget | $75 | $75 | $75 | $75 | $75 | $75 |
| C&I Prescriptive | Air Compressor | Total Gross Incremental Savings (kwh) | 34,068 | 34,068 | 34,068 | 34,068 | 34,068 | 34,068 |
| C&I Prescriptive | Air Compressor | NTG | 0.80 | 0.80 | 0.80 | 0.80 | 0.80 | 0.80 |
| C&I Prescriptive | Air Compressor | Incremental Cost | $250.00 | $250.00 | $250.00 | $250.00 | $250.00 | $250.00 |

| Program | Measure | Description | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 |
|---|---|---|---|---|---|---|---|---|
| C&I Prescriptive | Air Conditioners | Participation | 125 | 125 | 125 | 125 | 125 | 125 |
| C&I Prescriptive | Air Conditioners | Total Incentive Budget | $34,278 | $34,278 | $34,278 | $34,278 | $34,278 | $34,278 |
| C&I Prescriptive | Air Conditioners | Total Gross Incremental Savings (kwh) | 899,750 | 899,750 | 899,750 | 899,750 | 899,750 | 899,750 |
| C&I Prescriptive | Air Conditioners | NTG | 0.80 | 0.80 | 0.80 | 0.80 | 0.80 | 0.80 |
| C&I Prescriptive | Air Conditioners | Incremental Cost | $100.00 | $100.00 | $100.00 | $100.00 | $100.00 | $100.00 |
| C&I Prescriptive | Anti-Sweat Heater Control | Participation | 290 | 290 | 290 | 290 | 290 | 290 |
| C&I Prescriptive | Anti-Sweat Heater Control | Total Incentive Budget | $19,366 | $19,366 | $19,366 | $19,366 | $19,366 | $19,366 |
| C&I Prescriptive | Anti-Sweat Heater Control | Total Gross Incremental Savings (kwh) | 263,610 | 263,610 | 263,610 | 263,610 | 263,610 | 263,610 |
| C&I Prescriptive | Anti-Sweat Heater Control | NTG | 0.80 | 0.80 | 0.80 | 0.80 | 0.80 | 0.80 |
| C&I Prescriptive | Anti-Sweat Heater Control | Incremental Cost | $200.00 | $200.00 | $200.00 | $200.00 | $200.00 | $200.00 |
| C&I Prescriptive | Barrel Wrap Insulation | Participation | 1 | 1 | 1 | 1 | 1 | 1 |
| C&I Prescriptive | Barrel Wrap Insulation | Total Incentive Budget | $30 | $30 | $30 | $30 | $30 | $30 |
| C&I Prescriptive | Barrel Wrap Insulation | Total Gross Incremental Savings (kwh) | 360 | 360 | 360 | 360 | 360 | 360 |

| Program | Measure | Description | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 |
|---|---|---|---|---|---|---|---|---|
| C&I Prescriptive | Barrel Wrap Insulation | NTG | 0.80 | 0.80 | 0.80 | 0.80 | 0.80 | 0.80 |
| C&I Prescriptive | Barrel Wrap Insulation | Incremental Cost | $30.00 | $30.00 | $30.00 | $30.00 | $30.00 | $30.00 |
| C&I Prescriptive | Chilled Water Reset Control | Participation | 3 | 3 | 3 | 3 | 3 | 3 |
| C&I Prescriptive | Chilled Water Reset Control | Total Incentive Budget | $716 | $716 | $716 | $716 | $716 | $716 |
| C&I Prescriptive | Chilled Water Reset Control | Total Gross Incremental Savings (kwh) | 49,608 | 49,608 | 49,608 | 49,608 | 49,608 | 49,608 |
| C&I Prescriptive | Chilled Water Reset Control | NTG | 0.80 | 0.80 | 0.80 | 0.80 | 0.80 | 0.80 |
| C&I Prescriptive | Chilled Water Reset Control | Incremental Cost | $681.34 | $681.34 | $681.34 | $681.34 | $681.34 | $681.34 |
| C&I Prescriptive | Chiller | Participation | 72 | 72 | 72 | 72 | 72 | 72 |
| C&I Prescriptive | Chiller | Total Incentive Budget | $367,200 | $367,200 | $367,200 | $367,200 | $367,200 | $367,200 |
| C&I Prescriptive | Chiller | Total Gross Incremental Savings (kwh) | 844,776 | 844,776 | 844,776 | 844,776 | 844,776 | 844,776 |
| C&I Prescriptive | Chiller | NTG | 0.80 | 0.80 | 0.80 | 0.80 | 0.80 | 0.80 |
| C&I Prescriptive | Chiller | Incremental Cost | $79.46 | $79.46 | $79.46 | $79.46 | $79.46 | $79.46 |
| C&I Prescriptive | Chiller Tune-Up | Participation | 3 | 3 | 3 | 3 | 3 | 3 |

| Program | Measure | Description | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 |
|---|---|---|---|---|---|---|---|---|
| C&I Prescriptive | Chiller Tune-Up | Total Incentive Budget | $3,816 | $3,816 | $3,816 | $3,816 | $3,816 | $3,816 |
| C&I Prescriptive | Chiller Tune-Up | Total Gross Incremental Savings (kwh) | 29,082 | 29,082 | 29,082 | 29,082 | 29,082 | 29,082 |
| C&I Prescriptive | Chiller Tune-Up | NTG | 0.80 | 0.80 | 0.80 | 0.80 | 0.80 | 0.80 |
| C&I Prescriptive | Chiller Tune-Up | Incremental Cost | $1,272.00 | $1,272.00 | $1,272.00 | $1,272.00 | $1,272.00 | $1,272.00 |
| C&I Prescriptive | Clothes Washer | Participation | 3 | 3 | 3 | 3 | 3 | 3 |
| C&I Prescriptive | Clothes Washer | Total Incentive Budget | $180 | $180 | $180 | $180 | $180 | $180 |
| C&I Prescriptive | Clothes Washer | Total Gross Incremental Savings (kwh) | 1,626 | 1,626 | 1,626 | 1,626 | 1,626 | 1,626 |
| C&I Prescriptive | Clothes Washer | NTG | 0.80 | 0.80 | 0.80 | 0.80 | 0.80 | 0.80 |
| C&I Prescriptive | Clothes Washer | Incremental Cost | $475.33 | $475.33 | $475.33 | $475.33 | $475.33 | $475.33 |
| C&I Prescriptive | Combination Oven | Participation | 3 | 3 | 3 | 3 | 3 | 3 |
| C&I Prescriptive | Combination Oven | Total Incentive Budget | $3,000 | $3,000 | $3,000 | $3,000 | $3,000 | $3,000 |
| C&I Prescriptive | Combination Oven | Total Gross Incremental Savings (kwh) | 55,296 | 55,296 | 55,296 | 55,296 | 55,296 | 55,296 |
| C&I Prescriptive | Combination Oven | NTG | 0.80 | 0.80 | 0.80 | 0.80 | 0.80 | 0.80 |

| Program | Measure | Description | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 |
|---|---|---|---|---|---|---|---|---|
| C&I Prescriptive | Combination Oven | Incremental Cost | $2,125.00 | $2,125.00 | $2,125.00 | $2,125.00 | $2,125.00 | $2,125.00 |
| C&I Prescriptive | Compressed Air Nozzles | Participation | 2 | 2 | 2 | 2 | 2 | 2 |
| C&I Prescriptive | Compressed Air Nozzles | Total Incentive Budget | $13 | $13 | $13 | $13 | $13 | $13 |
| C&I Prescriptive | Compressed Air Nozzles | Total Gross Incremental Savings (kwh) | 1,776 | 1,776 | 1,776 | 1,776 | 1,776 | 1,776 |
| C&I Prescriptive | Compressed Air Nozzles | NTG | 0.80 | 0.80 | 0.80 | 0.80 | 0.80 | 0.80 |
| C&I Prescriptive | Compressed Air Nozzles | Incremental Cost | $14.00 | $14.00 | $14.00 | $14.00 | $14.00 | $14.00 |
| C&I Prescriptive | Convection Oven | Participation | 3 | 3 | 3 | 3 | 3 | 3 |
| C&I Prescriptive | Convection Oven | Total Incentive Budget | $1,050 | $1,050 | $1,050 | $1,050 | $1,050 | $1,050 |
| C&I Prescriptive | Convection Oven | Total Gross Incremental Savings (kwh) | 9,705 | 9,705 | 9,705 | 9,705 | 9,705 | 9,705 |
| C&I Prescriptive | Convection Oven | NTG | 0.80 | 0.80 | 0.80 | 0.80 | 0.80 | 0.80 |
| C&I Prescriptive | Convection Oven | Incremental Cost | $1,113.00 | $1,113.00 | $1,113.00 | $1,113.00 | $1,113.00 | $1,113.00 |
| C&I Prescriptive | Commercial Dishwasher | Participation | 2 | 2 | 2 | 2 | 2 | 2 |
| C&I Prescriptive | Commercial Dishwasher | Total Incentive Budget | $2,325 | $2,325 | $2,325 | $2,325 | $2,325 | $2,325 |

| Program | Measure | Description | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 |
|---|---|---|---|---|---|---|---|---|
| C&I Prescriptive | Commercial Dishwasher | Total Gross Incremental Savings (kwh) | 25,714 | 25,714 | 25,714 | 25,714 | 25,714 | 25,714 |
| C&I Prescriptive | Commercial Dishwasher | NTG | 0.80 | 0.80 | 0.80 | 0.80 | 0.80 | 0.80 |
| C&I Prescriptive | Commercial Dishwasher | Incremental Cost | $616.25 | $616.25 | $616.25 | $616.25 | $616.25 | $616.25 |
| C&I Prescriptive | Exterior LED | Participation | 1,342 | 1,342 | 1,342 | 1,342 | 1,342 | 1,342 |
| C&I Prescriptive | Exterior LED | Total Incentive Budget | $144,225 | $144,225 | $144,225 | $144,225 | $144,225 | $144,225 |
| C&I Prescriptive | Exterior LED | Total Gross Incremental Savings (kwh) | 1,356,762 | 1,356,762 | 1,356,762 | 1,356,762 | 1,356,762 | 1,356,762 |
| C&I Prescriptive | Exterior LED | NTG | 0.80 | 0.80 | 0.80 | 0.80 | 0.80 | 0.80 |
| C&I Prescriptive | Exterior LED | Incremental Cost | $270.24 | $270.24 | $270.24 | $270.24 | $270.24 | $270.24 |
| C&I Prescriptive | Freezer | Participation | 79 | 86 | 93 | 99 | 104 | 109 |
| C&I Prescriptive | Freezer | Total Incentive Budget | $15,800 | $17,200 | $18,600 | $19,800 | $20,800 | $21,800 |
| C&I Prescriptive | Freezer | Total Gross Incremental Savings (kwh) | 240,950 | 262,300 | 283,650 | 301,950 | 317,200 | 332,450 |
| C&I Prescriptive | Freezer | NTG | 0.80 | 0.80 | 0.80 | 0.80 | 0.80 | 0.80 |
| C&I Prescriptive | Freezer | Incremental Cost | $220.25 | $220.25 | $220.25 | $220.25 | $220.25 | $220.25 |

| Program | Measure | Description | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 |
|---|---|---|---|---|---|---|---|---|
| C&I Prescriptive | Fryer | Participation | 1 | 1 | 1 | 1 | 1 | 1 |
| C&I Prescriptive | Fryer | Total Incentive Budget | $80 | $80 | $80 | $80 | $80 | $80 |
| C&I Prescriptive | Fryer | Total Gross Incremental Savings (kwh) | 1,526 | 1,526 | 1,526 | 1,526 | 1,526 | 1,526 |
| C&I Prescriptive | Fryer | NTG | 0.80 | 0.80 | 0.80 | 0.80 | 0.80 | 0.80 |
| C&I Prescriptive | Fryer | Incremental Cost | $500.00 | $500.00 | $500.00 | $500.00 | $500.00 | $500.00 |
| C&I Prescriptive | Griddle | Participation | 3 | 3 | 3 | 3 | 3 | 3 |
| C&I Prescriptive | Griddle | Total Incentive Budget | $1,650 | $1,650 | $1,650 | $1,650 | $1,650 | $1,650 |
| C&I Prescriptive | Griddle | Total Gross Incremental Savings (kwh) | 30,099 | 30,099 | 30,099 | 30,099 | 30,099 | 30,099 |
| C&I Prescriptive | Griddle | NTG | 0.80 | 0.80 | 0.80 | 0.80 | 0.80 | 0.80 |
| C&I Prescriptive | Griddle | Incremental Cost | $2,090.00 | $2,090.00 | $2,090.00 | $2,090.00 | $2,090.00 | $2,090.00 |
| C&I Prescriptive | Heat Pump Water Heater | Participation | 1 | 1 | 1 | 1 | 1 | 1 |
| C&I Prescriptive | Heat Pump Water Heater | Total Incentive Budget | $500 | $500 | $500 | $500 | $500 | $500 |
| C&I Prescriptive | Heat Pump Water Heater | Total Gross Incremental Savings (kwh) | 1,534 | 1,534 | 1,534 | 1,534 | 1,534 | 1,534 |

| Program | Measure | Description | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 |
|---|---|---|---|---|---|---|---|---|
| C&I Prescriptive | Heat Pump Water Heater | NTG | 0.80 | 0.80 | 0.80 | 0.80 | 0.80 | 0.80 |
| C&I Prescriptive | Heat Pump Water Heater | Incremental Cost | $433.00 | $433.00 | $433.00 | $433.00 | $433.00 | $433.00 |
| C&I Prescriptive | Heat Pump | Participation | 135 | 135 | 135 | 135 | 135 | 135 |
| C&I Prescriptive | Heat Pump | Total Incentive Budget | $26,758 | $26,758 | $26,758 | $26,758 | $26,758 | $26,758 |
| C&I Prescriptive | Heat Pump | Total Gross Incremental Savings (kwh) | 166,320 | 166,320 | 166,320 | 166,320 | 166,320 | 166,320 |
| C&I Prescriptive | Heat Pump | NTG | 0.80 | 0.80 | 0.80 | 0.80 | 0.80 | 0.80 |
| C&I Prescriptive | Heat Pump | Incremental Cost | $143.64 | $143.64 | $143.64 | $143.64 | $143.64 | $143.64 |
| C&I Prescriptive | Hot Food Holding Cabinet | Participation | 2 | 2 | 2 | 2 | 2 | 2 |
| C&I Prescriptive | Hot Food Holding Cabinet | Total Incentive Budget | $457 | $457 | $457 | $457 | $457 | $457 |
| C&I Prescriptive | Hot Food Holding Cabinet | Total Gross Incremental Savings (kwh) | 6,584 | 6,584 | 6,584 | 6,584 | 6,584 | 6,584 |
| C&I Prescriptive | Hot Food Holding Cabinet | NTG | 0.80 | 0.80 | 0.80 | 0.80 | 0.80 | 0.80 |
| C&I Prescriptive | Hot Food Holding Cabinet | Incremental Cost | $1,110.00 | $1,110.00 | $1,110.00 | $1,110.00 | $1,110.00 | $1,110.00 |
| C&I Prescriptive | Ice Machine | Participation | 3 | 3 | 3 | 3 | 3 | 3 |

| Program | Measure | Description | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 |
|---|---|---|---|---|---|---|---|---|
| C&I Prescriptive | Ice Machine | Total Incentive Budget | $510 | $510 | $510 | $510 | $510 | $510 |
| C&I Prescriptive | Ice Machine | Total Gross Incremental Savings (kwh) | 2,670 | 2,670 | 2,670 | 2,670 | 2,670 | 2,670 |
| C&I Prescriptive | Ice Machine | NTG | 0.80 | 0.80 | 0.80 | 0.80 | 0.80 | 0.80 |
| C&I Prescriptive | Ice Machine | Incremental Cost | $1,333.60 | $1,333.60 | $1,333.60 | $1,333.60 | $1,333.60 | $1,333.60 |
| C&I Prescriptive | Interior LED - High-Bay (including LED troffer and LED linear tubes) | Participation | 1,293 | 1,475 | 1,597 | 1,643 | 1,627 | 1,536 |
| C&I Prescriptive | Interior LED - High-Bay (including LED troffer and LED linear tubes) | Total Incentive Budget | $87,717 | $93,385 | $93,877 | $89,141 | $80,905 | $69,425 |
| C&I Prescriptive | Interior LED - High-Bay (including LED troffer and LED linear tubes) | Total Gross Incremental Savings (kwh) | 1,466,262 | 1,672,650 | 1,810,998 | 1,863,162 | 1,845,018 | 1,741,824 |
| C&I Prescriptive | Interior LED - High-Bay (including LED troffer and LED linear tubes) | NTG | 0.80 | 0.80 | 0.80 | 0.80 | 0.80 | 0.80 |
| C&I Prescriptive | Interior LED - High-Bay (including LED troffer and LED linear tubes) | Incremental Cost | $113.54 | $113.54 | $113.54 | $113.54 | $113.54 | $113.54 |
| C&I Prescriptive | Interior LED - Low-Bay (including LED troffer and LED linear tubes) | Participation | 37,209 | 42,854 | 47,026 | 49,043 | 49,258 | 47,221 |

| Program | Measure | Description | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 |
|---|---|---|---|---|---|---|---|---|
| C&I Prescriptive | Interior LED - Low-Bay (including LED troffer and LED linear tubes) | Total Incentive Budget | $530,228 | $569,907 | $580,659 | $558,915 | $514,512 | $448,319 |
| C&I Prescriptive | Interior LED - Low-Bay (including LED troffer and LED linear tubes) | Total Gross Incremental Savings (kwh) | 7,367,382 | 8,485,092 | 9,311,148 | 9,710,514 | 9,753,084 | 9,349,758 |
| C&I Prescriptive | Interior LED - Low-Bay (including LED troffer and LED linear tubes) | NTG | 0.80 | 0.80 | 0.80 | 0.80 | 0.80 | 0.80 |
| C&I Prescriptive | Interior LED - Low-Bay (including LED troffer and LED linear tubes) | Incremental Cost | $78.04 | $78.04 | $78.04 | $78.04 | $78.04 | $78.04 |
| C&I Prescriptive | Lighting Control | Participation | 906 | 906 | 906 | 906 | 906 | 906 |
| C&I Prescriptive | Lighting Control | Total Incentive Budget | $16,317 | $16,317 | $16,317 | $16,317 | $16,317 | $16,317 |
| C&I Prescriptive | Lighting Control | Total Gross Incremental Savings (kwh) | 557,190 | 557,190 | 557,190 | 557,190 | 557,190 | 557,190 |
| C&I Prescriptive | Lighting Control | NTG | 0.80 | 0.80 | 0.80 | 0.80 | 0.80 | 0.80 |
| C&I Prescriptive | Lighting Control | Incremental Cost | $98.75 | $98.75 | $98.75 | $98.75 | $98.75 | $98.75 |
| C&I Prescriptive | Lighting Power Density Reduction | Participation | 10 | 10 | 10 | 10 | 10 | 10 |
| C&I Prescriptive | Lighting Power Density Reduction | Total Incentive Budget | $49,958 | $49,958 | $49,958 | $49,958 | $49,958 | $49,958 |
| C&I Prescriptive | Lighting Power Density Reduction | Total Gross Incremental Savings (kwh) | 317,320 | 317,320 | 317,320 | 317,320 | 317,320 | 317,320 |

| Program | Measure | Description | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 |
|---|---|---|---|---|---|---|---|---|
| C&I Prescriptive | Lighting Power Density Reduction | NTG | 0.80 | 0.80 | 0.80 | 0.80 | 0.80 | 0.80 |
| C&I Prescriptive | Lighting Power Density Reduction | Incremental Cost | $4,995.83 | $4,995.83 | $4,995.83 | $4,995.83 | $4,995.83 | $4,995.83 |
| C&I Prescriptive | Low Flow Pre-Rinse Sprayer | Participation | 1 | 1 | 1 | 1 | 1 | 1 |
| C&I Prescriptive | Low Flow Pre-Rinse Sprayer | Total Incentive Budget | $60 | $60 | $60 | $60 | $60 | $60 |
| C&I Prescriptive | Low Flow Pre-Rinse Sprayer | Total Gross Incremental Savings (kwh) | 7,130 | 7,130 | 7,130 | 7,130 | 7,130 | 7,130 |
| C&I Prescriptive | Low Flow Pre-Rinse Sprayer | NTG | 0.80 | 0.80 | 0.80 | 0.80 | 0.80 | 0.80 |
| C&I Prescriptive | Low Flow Pre-Rinse Sprayer | Incremental Cost | $92.90 | $92.90 | $92.90 | $92.90 | $92.90 | $92.90 |
| C&I Prescriptive | Pellet Dryer Duct Insulation | Participation | 1 | 1 | 1 | 1 | 1 | 1 |
| C&I Prescriptive | Pellet Dryer Duct Insulation | Total Incentive Budget | $30 | $30 | $30 | $30 | $30 | $30 |
| C&I Prescriptive | Pellet Dryer Duct Insulation | Total Gross Incremental Savings (kwh) | 198 | 198 | 198 | 198 | 198 | 198 |
| C&I Prescriptive | Pellet Dryer Duct Insulation | NTG | 0.80 | 0.80 | 0.80 | 0.80 | 0.80 | 0.80 |
| C&I Prescriptive | Pellet Dryer Duct Insulation | Incremental Cost | $30.00 | $30.00 | $30.00 | $30.00 | $30.00 | $30.00 |
| C&I Prescriptive | Programmable Thermostat | Participation | 1 | 1 | 1 | 1 | 1 | 1 |

| Program | Measure | Description | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 |
|---|---|---|---|---|---|---|---|---|
| C&I Prescriptive | Programmable Thermostat | Total Incentive Budget | $50 | $50 | $50 | $50 | $50 | $50 |
| C&I Prescriptive | Programmable Thermostat | Total Gross Incremental Savings (kwh) | 649 | 649 | 649 | 649 | 649 | 649 |
| C&I Prescriptive | Programmable Thermostat | NTG | 0.80 | 0.80 | 0.80 | 0.80 | 0.80 | 0.80 |
| C&I Prescriptive | Programmable Thermostat | Incremental Cost | $35.00 | $35.00 | $35.00 | $35.00 | $35.00 | $35.00 |
| C&I Prescriptive | Refrigerated Case Cover | Participation | 1 | 1 | 1 | 1 | 1 | 1 |
| C&I Prescriptive | Refrigerated Case Cover | Total Incentive Budget | $10 | $10 | $10 | $10 | $10 | $10 |
| C&I Prescriptive | Refrigerated Case Cover | Total Gross Incremental Savings (kwh) | 158 | 158 | 158 | 158 | 158 | 158 |
| C&I Prescriptive | Refrigerated Case Cover | NTG | 0.80 | 0.80 | 0.80 | 0.80 | 0.80 | 0.80 |
| C&I Prescriptive | Refrigerated Case Cover | Incremental Cost | $42.00 | $42.00 | $42.00 | $42.00 | $42.00 | $42.00 |
| C&I Prescriptive | Refrigerated LED | Participation | 84 | 111 | 140 | 172 | 204 | 233 |
| C&I Prescriptive | Refrigerated LED | Total Incentive Budget | $2,446 | $3,232 | $4,077 | $5,009 | $5,940 | $6,785 |
| C&I Prescriptive | Refrigerated LED | Total Gross Incremental Savings (kwh) | 25,536 | 33,744 | 42,560 | 52,288 | 62,016 | 70,832 |
| C&I Prescriptive | Refrigerated LED | NTG | 0.80 | 0.80 | 0.80 | 0.80 | 0.80 | 0.80 |

| Program | Measure | Description | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 |
|---|---|---|---|---|---|---|---|---|
| C&I Prescriptive | Refrigerated LED | Incremental Cost | $35.89 | $35.89 | $35.89 | $35.89 | $35.89 | $35.89 |
| C&I Prescriptive | Refrigerator | Participation | 7 | 7 | 7 | 7 | 7 | 7 |
| C&I Prescriptive | Refrigerator | Total Incentive Budget | $419 | $419 | $419 | $419 | $419 | $419 |
| C&I Prescriptive | Refrigerator | Total Gross Incremental Savings (kwh) | 4,284 | 4,284 | 4,284 | 4,284 | 4,284 | 4,284 |
| C&I Prescriptive | Refrigerator | NTG | 0.80 | 0.80 | 0.80 | 0.80 | 0.80 | 0.80 |
| C&I Prescriptive | Refrigerator | Incremental Cost | $180.00 | $180.00 | $180.00 | $180.00 | $180.00 | $180.00 |
| C&I Prescriptive | Steam Cooker | Participation | 1 | 1 | 1 | 1 | 1 | 1 |
| C&I Prescriptive | Steam Cooker | Total Incentive Budget | $200 | $200 | $200 | $200 | $200 | $200 |
| C&I Prescriptive | Steam Cooker | Total Gross Incremental Savings (kwh) | 2,210 | 2,210 | 2,210 | 2,210 | 2,210 | 2,210 |
| C&I Prescriptive | Steam Cooker | NTG | 0.80 | 0.80 | 0.80 | 0.80 | 0.80 | 0.80 |
| C&I Prescriptive | Steam Cooker | Incremental Cost | $3,500.00 | $3,500.00 | $3,500.00 | $3,500.00 | $3,500.00 | $3,500.00 |
| C&I Prescriptive | Vending Machine Control | Participation | 3 | 3 | 3 | 3 | 3 | 3 |
| C&I Prescriptive | Vending Machine Control | Total Incentive Budget | $125 | $125 | $125 | $125 | $125 | $125 |

| Program | Measure | Description | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 |
|---|---|---|---|---|---|---|---|---|
| C&I Prescriptive | Vending Machine Control | Total Gross Incremental Savings (kwh) | 3,162 | 3,162 | 3,162 | 3,162 | 3,162 | 3,162 |
| C&I Prescriptive | Vending Machine Control | NTG | 0.80 | 0.80 | 0.80 | 0.80 | 0.80 | 0.80 |
| C&I Prescriptive | Vending Machine Control | Incremental Cost | $179.67 | $179.67 | $179.67 | $179.67 | $179.67 | $179.67 |
| C&I Prescriptive | VFD-Fan | Participation | 2 | 2 | 3 | 4 | 5 | 6 |
| C&I Prescriptive | VFD-Fan | Total Incentive Budget | $1,725 | $1,725 | $2,588 | $3,450 | $4,313 | $5,175 |
| C&I Prescriptive | VFD-Fan | Total Gross Incremental Savings (kwh) | 48,644 | 48,644 | 72,966 | 97,288 | 121,610 | 145,932 |
| C&I Prescriptive | VFD-Fan | NTG | 0.80 | 0.80 | 0.80 | 0.80 | 0.80 | 0.80 |
| C&I Prescriptive | VFD-Fan | Incremental Cost | $3,638.33 | $3,638.33 | $3,638.33 | $3,638.33 | $3,638.33 | $3,638.33 |
| C&I Prescriptive | VFD-Pump | Participation | 3 | 4 | 5 | 6 | 7 | 9 |
| C&I Prescriptive | VFD-Pump | Total Incentive Budget | $2,475 | $3,300 | $4,125 | $4,950 | $5,775 | $7,425 |
| C&I Prescriptive | VFD-Pump | Total Gross Incremental Savings (kwh) | 164,604 | 219,472 | 274,340 | 329,208 | 384,076 | 493,812 |
| C&I Prescriptive | VFD-Pump | NTG | 0.80 | 0.80 | 0.80 | 0.80 | 0.80 | 0.80 |
| C&I Prescriptive | VFD-Pump | Incremental Cost | $3,059.00 | $3,059.00 | $3,059.00 | $3,059.00 | $3,059.00 | $3,059.00 |

| Program | Measure | Description | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 |
|---|---|---|---|---|---|---|---|---|
| C&I Prescriptive | Wifi-Enabled Thermostat | Participation | 360 | 360 | 360 | 360 | 360 | 360 |
| C&I Prescriptive | Wifi-Enabled Thermostat | Total Incentive Budget | $36,000 | $36,000 | $36,000 | $36,000 | $36,000 | $36,000 |
| C&I Prescriptive | Wifi-Enabled Thermostat | Total Gross Incremental Savings (kwh) | 229,320 | 229,320 | 229,320 | 229,320 | 229,320 | 229,320 |
| C&I Prescriptive | Wifi-Enabled Thermostat | NTG | 0.80 | 0.80 | 0.80 | 0.80 | 0.80 | 0.80 |
| C&I Prescriptive | Wifi-Enabled Thermostat | Incremental Cost | $250.00 | $250.00 | $250.00 | $250.00 | $250.00 | $250.00 |
| C&I Prescriptive | Window Air Conditioner & PTAC | Participation | 10 | 13 | 16 | 19 | 22 | 26 |
| C&I Prescriptive | Window Air Conditioner & PTAC | Total Incentive Budget | $469 | $609 | $750 | $890 | $1,031 | $1,218 |
| C&I Prescriptive | Window Air Conditioner & PTAC | Total Gross Incremental Savings (kwh) | 2,070 | 2,691 | 3,312 | 3,933 | 4,554 | 5,382 |
| C&I Prescriptive | Window Air Conditioner & PTAC | NTG | 0.80 | 0.80 | 0.80 | 0.80 | 0.80 | 0.80 |
| C&I Prescriptive | Window Air Conditioner & PTAC | Incremental Cost | $196.00 | $196.00 | $196.00 | $196.00 | $196.00 | $196.00 |
| C&I Prescriptive | High Efficiency Hand Dryer | Participation | 47 | 63 | 88 | 116 | 144 | 179 |
| C&I Prescriptive | High Efficiency Hand Dryer | Total Incentive Budget | $8,460 | $11,340 | $15,840 | $20,880 | $25,920 | $32,220 |
| C&I Prescriptive | High Efficiency Hand Dryer | Total Gross Incremental Savings (kwh) | 36,132 | 48,432 | 67,651 | 89,176 | 110,701 | 137,608 |

| Program | Measure | Description | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 |
|---|---|---|---|---|---|---|---|---|
| C&I Prescriptive | High Efficiency Hand Dryer | NTG | 0.80 | 0.80 | 0.80 | 0.80 | 0.80 | 0.80 |
| C&I Prescriptive | High Efficiency Hand Dryer | Incremental Cost | $450.00 | $450.00 | $450.00 | $450.00 | $450.00 | $450.00 |
| C&I Prescriptive | Efficient low-temp compressor | Participation | - | 1 | 2 | 3 | 4 | 6 |
| C&I Prescriptive | Efficient low-temp compressor | Total Incentive Budget | - | $221 | $442 | $662 | $883 | $1,325 |
| C&I Prescriptive | Efficient low-temp compressor | Total Gross Incremental Savings (kwh) | - | 678 | 1,356 | 2,033 | 2,711 | 4,067 |
| C&I Prescriptive | Efficient low-temp compressor | NTG | 0.80 | 0.80 | 0.80 | 0.80 | 0.80 | 0.80 |
| C&I Prescriptive | Efficient low-temp compressor | Incremental Cost | $552.00 | $552.00 | $552.00 | $552.00 | $552.00 | $552.00 |
| C&I Prescriptive | Commercial Refrigeration Tune-Up | Participation | 319 | 412 | 511 | 613 | 714 | 810 |
| C&I Prescriptive | Commercial Refrigeration Tune-Up | Total Incentive Budget | $9,570 | $12,360 | $15,330 | $18,390 | $21,420 | $24,300 |
| C&I Prescriptive | Commercial Refrigeration Tune-Up | Total Gross Incremental Savings (kwh) | 186,731 | 241,170 | 299,121 | 358,828 | 417,950 | 474,145 |
| C&I Prescriptive | Commercial Refrigeration Tune-Up | NTG | 0.80 | 0.80 | 0.80 | 0.80 | 0.80 | 0.80 |
| C&I Prescriptive | Commercial Refrigeration Tune-Up | Incremental Cost | $75.00 | $75.00 | $75.00 | $75.00 | $75.00 | $75.00 |
| C&I Prescriptive | Duct sealing | Participation | - | - | - | - | - | - |

| Program | Measure | Description | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 |
|---|---|---|---|---|---|---|---|---|
| C&I Prescriptive | Duct sealing | Total Incentive Budget | - | - | - | - | - | - |
| C&I Prescriptive | Duct sealing | Total Gross Incremental Savings (kwh) | - | - | - | - | - | - |
| C&I Prescriptive | Duct sealing | NTG | - | - | - | - | - | - |
| C&I Prescriptive | Duct sealing | Incremental Cost | - | - | - | - | - | - |
| C&I Custom | C&I Custom | Participation | 35 | 35 | 35 | 35 | 35 | 35 |
| C&I Custom | C&I Custom | Total Incentive Budget | $395,191 | $395,191 | $395,191 | $395,191 | $395,191 | $395,191 |
| C&I Custom | C&I Custom | Total Gross Incremental Savings (kwh) | 4,453,104 | 4,453,104 | 4,453,104 | 4,453,104 | 4,453,104 | 4,453,104 |
| C&I Custom | C&I Custom | NTG | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 |
| C&I Custom | C&I Custom | Incremental Cost | $26,185.00 | $26,185.00 | $26,185.00 | $26,185.00 | $26,185.00 | $26,185.00 |
| C&I Custom | C&I Custom Pilot | Participation | 161 | 161 | 161 | 161 | 161 | 161 |
| C&I Custom | C&I Custom Pilot | Total Incentive Budget | $96,347 | $96,347 | $96,347 | $96,347 | $96,347 | $96,347 |
| C&I Custom | C&I Custom Pilot | Total Gross Incremental Savings (kwh) | 1,654,130 | 1,654,130 | 1,654,130 | 1,654,130 | 1,654,130 | 1,654,130 |
| C&I Custom | C&I Custom Pilot | NTG | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 |

| Program | Measure | Description | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 |
|---|---|---|---|---|---|---|---|---|
| C&I Custom | C&I Custom Pilot | Incremental Cost | - | - | - | - | - | - |
| Small Business | Smart Thermostats | Participation | 18 | 22 | 29 | 37 | 44 | 51 |
| Small Business | Smart Thermostats | Total Incentive Budget | $270 | $330 | $435 | $555 | $660 | $765 |
| Small Business | Smart Thermostats | Total Gross Incremental Savings (kwh) | 13,257 | 16,203 | 21,359 | 27,251 | 32,406 | 37,562 |
| Small Business | Smart Thermostats | NTG | 0.91 | 0.91 | 0.91 | 0.91 | 0.91 | 0.91 |
| Small Business | Smart Thermostats | Incremental Cost | $15.00 | $15.00 | $15.00 | $15.00 | $15.00 | $15.00 |
| Small Business | Anti-Sweat Heater Control | Participation | 6 | 6 | 6 | 6 | 6 | 6 |
| Small Business | Anti-Sweat Heater Control | Total Incentive Budget | $1,020 | $1,020 | $1,020 | $1,020 | $1,020 | $1,020 |
| Small Business | Anti-Sweat Heater Control | Total Gross Incremental Savings (kwh) | 5,454 | 5,454 | 5,454 | 5,454 | 5,454 | 5,454 |
| Small Business | Anti-Sweat Heater Control | NTG | 0.91 | 0.91 | 0.91 | 0.91 | 0.91 | 0.91 |
| Small Business | Anti-Sweat Heater Control | Incremental Cost | $170.00 | $170.00 | $170.00 | $170.00 | $170.00 | $170.00 |
| Small Business | EC Motors | Participation | - | - | - | - | - | - |
| Small Business | EC Motors | Total Incentive Budget | - | - | - | - | - | - |

| Program | Measure | Description | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 |
|---|---|---|---|---|---|---|---|---|
| Small Business | EC Motors | Total Gross Incremental Savings (kwh) | - | - | - | - | - | - |
| Small Business | EC Motors | NTG | 0.91 | 0.91 | 0.91 | 0.91 | 0.91 | 0.91 |
| Small Business | EC Motors | Incremental Cost | $66.76 | $66.76 | $66.76 | $66.76 | $66.76 | $66.76 |
| Small Business | Exterior LED | Participation | 4,263 | 4,263 | 4,263 | 4,263 | 4,263 | 4,263 |
| Small Business | Exterior LED | Total Incentive Budget | $380,302 | $380,302 | $380,302 | $380,302 | $380,302 | $380,302 |
| Small Business | Exterior LED | Total Gross Incremental Savings (kwh) | 1,922,613 | 1,922,613 | 1,922,613 | 1,922,613 | 1,922,613 | 1,922,613 |
| Small Business | Exterior LED | NTG | 0.91 | 0.91 | 0.91 | 0.91 | 0.91 | 0.91 |
| Small Business | Exterior LED | Incremental Cost | $89.21 | $89.21 | $89.21 | $89.21 | $89.21 | $89.21 |
| Small Business | Faucet Aerator | Participation | 3 | 3 | 3 | 3 | 3 | 3 |
| Small Business | Faucet Aerator | Total Incentive Budget | $14 | $14 | $14 | $14 | $14 | $14 |
| Small Business | Faucet Aerator | Total Gross Incremental Savings (kwh) | 1,512 | 1,512 | 1,512 | 1,512 | 1,512 | 1,512 |
| Small Business | Faucet Aerator | NTG | 0.91 | 0.91 | 0.91 | 0.91 | 0.91 | 0.91 |
| Small Business | Faucet Aerator | Incremental Cost | $4.72 | $4.72 | $4.72 | $4.72 | $4.72 | $4.72 |

| Program | Measure | Description | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 |
|---|---|---|---|---|---|---|---|---|
| Small Business | Interior LED | Participation | 3,948 | 3,948 | 3,948 | 3,948 | 3,948 | 3,948 |
| Small Business | Interior LED | Total Incentive Budget | $132,653 | $123,798 | $114,944 | $106,089 | $97,235 | $88,380 |
| Small Business | Interior LED | Total Gross Incremental Savings (kwh) | 852,768 | 852,768 | 852,768 | 852,768 | 852,768 | 852,768 |
| Small Business | Interior LED | NTG | 0.91 | 0.91 | 0.91 | 0.91 | 0.91 | 0.91 |
| Small Business | Interior LED | Incremental Cost | $33.60 | $33.60 | $33.60 | $33.60 | $33.60 | $33.60 |
| Small Business | Lighting Control | Participation | 9 | 9 | 9 | 9 | 9 | 9 |
| Small Business | Lighting Control | Total Incentive Budget | $400 | $400 | $400 | $400 | $400 | $400 |
| Small Business | Lighting Control | Total Gross Incremental Savings (kwh) | 2,115 | 2,115 | 2,115 | 2,115 | 2,115 | 2,115 |
| Small Business | Lighting Control | NTG | 0.91 | 0.91 | 0.91 | 0.91 | 0.91 | 0.91 |
| Small Business | Lighting Control | Incremental Cost | $44.44 | $44.44 | $44.44 | $44.44 | $44.44 | $44.44 |
| Small Business | Low Flow Pre-Rinse Sprayer | Participation | 3 | 3 | 3 | 3 | 3 | 3 |
| Small Business | Low Flow Pre-Rinse Sprayer | Total Incentive Budget | $180 | $180 | $180 | $180 | $180 | $180 |
| Small Business | Low Flow Pre-Rinse Sprayer | Total Gross Incremental Savings (kwh) | 21,390 | 21,390 | 21,390 | 21,390 | 21,390 | 21,390 |

| Program | Measure | Description | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 |
|---|---|---|---|---|---|---|---|---|
| Small Business | Low Flow Pre-Rinse Sprayer | NTG | 0.91 | 0.91 | 0.91 | 0.91 | 0.91 | 0.91 |
| Small Business | Low Flow Pre-Rinse Sprayer | Incremental Cost | $60.00 | $60.00 | $60.00 | $60.00 | $60.00 | $60.00 |
| Small Business | Programmable Thermostat | Participation | 70 | 71 | 71 | 67 | 67 | 67 |
| Small Business | Programmable Thermostat | Total Incentive Budget | $14,047 | $14,248 | $14,248 | $13,445 | $13,445 | $13,445 |
| Small Business | Programmable Thermostat | Total Gross Incremental Savings (kwh) | 51,590 | 52,327 | 52,327 | 49,379 | 49,379 | 49,379 |
| Small Business | Programmable Thermostat | NTG | 0.91 | 0.91 | 0.91 | 0.91 | 0.91 | 0.91 |
| Small Business | Programmable Thermostat | Incremental Cost | $200.67 | $200.67 | $200.67 | $200.67 | $200.67 | $200.67 |
| Small Business | Programmable Thermostat (Gas Heat, Electric Cooling) | Participation | 27 | 27 | 27 | 27 | 27 | 27 |
| Small Business | Programmable Thermostat (Gas Heat, Electric Cooling) | Total Incentive Budget | $4,424 | $4,424 | $4,424 | $4,424 | $4,424 | $4,424 |
| Small Business | Programmable Thermostat (Gas Heat, Electric Cooling) | Total Gross Incremental Savings (kwh) | 19,899 | 19,899 | 19,899 | 19,899 | 19,899 | 19,899 |
| Small Business | Programmable Thermostat (Gas Heat, Electric Cooling) | NTG | 0.91 | 0.91 | 0.91 | 0.91 | 0.91 | 0.91 |
| Small Business | Programmable Thermostat (Gas | Incremental Cost | $163.84 | $163.84 | $163.84 | $163.84 | $163.84 | $163.84 |

| Program | Measure | Description | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 |
|---|---|---|---|---|---|---|---|---|
| | Heat, Electric Cooling) | | | | | | | |
| Small Business | Refrigerated Case Cover | Participation | 30 | 30 | 30 | 30 | 30 | 30 |
| Small Business | Refrigerated Case Cover | Total Incentive Budget | $285 | $285 | $285 | $285 | $285 | $285 |
| Small Business | Refrigerated Case Cover | Total Gross Incremental Savings (kwh) | 1,590 | 1,590 | 1,590 | 1,590 | 1,590 | 1,590 |
| Small Business | Refrigerated Case Cover | NTG | 0.91 | 0.91 | 0.91 | 0.91 | 0.91 | 0.91 |
| Small Business | Refrigerated Case Cover | Incremental Cost | $9.50 | $9.50 | $9.50 | $9.50 | $9.50 | $9.50 |
| Small Business | Refigerated LED | Participation | 12 | 12 | 12 | 12 | 12 | 12 |
| Small Business | Refigerated LED | Total Incentive Budget | $570 | $570 | $570 | $570 | $570 | $570 |
| Small Business | Refigerated LED | Total Gross Incremental Savings (kwh) | 4,908 | 4,908 | 4,908 | 4,908 | 4,908 | 4,908 |
| Small Business | Refigerated LED | NTG | 0.91 | 0.91 | 0.91 | 0.91 | 0.91 | 0.91 |
| Small Business | Refigerated LED | Incremental Cost | $47.50 | $47.50 | $47.50 | $47.50 | $47.50 | $47.50 |
| Small Business | Vending Machine Control | Participation | 6 | 6 | 6 | 6 | 6 | 6 |
| Small Business | Vending Machine Control | Total Incentive Budget | $1,590 | $1,590 | $1,590 | $1,590 | $1,590 | $1,590 |

| Program | Measure | Description | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 |
|---|---|---|---|---|---|---|---|---|
| Small Business | Vending Machine Control | Total Gross Incremental Savings (kwh) | 8,460 | 8,460 | 8,460 | 8,460 | 8,460 | 8,460 |
| Small Business | Vending Machine Control | NTG | 0.91 | 0.91 | 0.91 | 0.91 | 0.91 | 0.91 |
| Small Business | Vending Machine Control | Incremental Cost | $265.00 | $265.00 | $265.00 | $265.00 | $265.00 | $265.00 |
| Small Business | Wifi-Enabled Thermostat | Participation | 6 | 6 | 6 | 6 | 6 | 6 |
| Small Business | Wifi-Enabled Thermostat | Total Incentive Budget | $2,250 | $2,250 | $2,250 | $2,250 | $2,250 | $2,250 |
| Small Business | Wifi-Enabled Thermostat | Total Gross Incremental Savings (kwh) | 4,422 | 4,422 | 4,422 | 4,422 | 4,422 | 4,422 |
| Small Business | Wifi-Enabled Thermostat | NTG | 0.91 | 0.91 | 0.91 | 0.91 | 0.91 | 0.91 |
| Small Business | Wifi-Enabled Thermostat | Incremental Cost | $375.00 | $375.00 | $375.00 | $375.00 | $375.00 | $375.00 |
| Small Business | Wifi-Enabled Thermostat (Gas Heat, Electric Cooling) | Participation | 36 | 36 | 36 | 36 | 36 | 36 |
| Small Business | Wifi-Enabled Thermostat (Gas Heat, Electric Cooling) | Total Incentive Budget | $10,031 | $10,031 | $10,031 | $10,031 | $10,031 | $10,031 |
| Small Business | Wifi-Enabled Thermostat (Gas Heat, Electric Cooling) | Total Gross Incremental Savings (kwh) | 26,532 | 26,532 | 26,532 | 26,532 | 26,532 | 26,532 |
| Small Business | Wifi-Enabled Thermostat (Gas Heat, Electric Cooling) | NTG | 0.91 | 0.91 | 0.91 | 0.91 | 0.91 | 0.91 |

| Program | Measure | Description | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 |
|---|---|---|---|---|---|---|---|---|
| Small Business | Wifi-Enabled Thermostat (Gas Heat, Electric Cooling) | Incremental Cost | $278.65 | $278.65 | $278.65 | $278.65 | $278.65 | $278.65 |
| Small Business | Program the Programmable Thermostat | Participation | 3 | 3 | 3 | 3 | 3 | 3 |
| Small Business | Program the Programmable Thermostat | Total Incentive Budget | $75 | $75 | $75 | $75 | $75 | $75 |
| Small Business | Program the Programmable Thermostat | Total Gross Incremental Savings (kwh) | 2,211 | 2,211 | 2,211 | 2,211 | 2,211 | 2,211 |
| Small Business | Program the Programmable Thermostat | NTG | 0.91 | 0.91 | 0.91 | 0.91 | 0.91 | 0.91 |
| Small Business | Program the Programmable Thermostat | Incremental Cost | $25.00 | $25.00 | $25.00 | $25.00 | $25.00 | $25.00 |
| Small Business | Program the Programmable Thermostat (Gas Heat, Electric Cooling) | Participation | 3 | 3 | 3 | 3 | 3 | 3 |
| Small Business | Program the Programmable Thermostat (Gas Heat, Electric Cooling) | Total Incentive Budget | $56 | $56 | $56 | $56 | $56 | $56 |
| Small Business | Program the Programmable Thermostat (Gas Heat, Electric Cooling) | Total Gross Incremental Savings (kwh) | 2,211 | 2,211 | 2,211 | 2,211 | 2,211 | 2,211 |
| Small Business | Program the Programmable Thermostat (Gas Heat, Electric Cooling) | NTG | 0.91 | 0.91 | 0.91 | 0.91 | 0.91 | 0.91 |

| Program | Measure | Description | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 |
|---|---|---|---|---|---|---|---|---|
| Small Business | Program the Programmable Thermostat (Gas Heat, Electric Cooling) | Incremental Cost | $18.75 | $18.75 | $18.75 | $18.75 | $18.75 | $18.75 |
| Home Energy Management Systems | Home Energy Management System | Participation | - | 1,000 | 1,000 | 1,000 | 1,000 | 1,000 |
| Home Energy Management Systems | Home Energy Management System | Total Incentive Budget | - | - | - | - | - | - |
| Home Energy Management Systems | Home Energy Management System | Total Gross Incremental Savings (kwh) | - | 515,000 | 515,000 | 515,000 | 515,000 | 515,000 |
| Home Energy Management Systems | Home Energy Management System | NTG | - | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 |
| Home Energy Management Systems | Home Energy Management System | Incremental Cost | - | - | - | - | - | - |
| Residential CVR | Residential CVR | Participation | | | | | | |
| Residential CVR | Residential CVR | Total Incentive Budget | - | - | - | - | - | - |
| Residential CVR | Residential CVR | Total Gross Incremental Savings (kwh) | 1,461,047 | - | - | 1,461,047 | - | - |
| Residential CVR | Residential CVR | NTG | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 |
| Residential CVR | Residential CVR | Incremental Cost | - | - | - | - | - | - |

prepared for

# VECTREN ENERGY DELIVERY OF INDIANA

# *2020-2025 Integrated **Electric** DSM Market Potential Study & Action Plan*

*January* 2019

**FINAL REPORT**

*prepared by*

**GDS ASSOCIATES INC**

**EMI CONSULTING**

# Attachment 6.3 All Source RFP

# All-Source Request for Proposals

**Vectren**

**6/12/2019**

# All-Source Request for Proposals

**for**

## Power supply generation facilities, power purchase agreements, and demand resources

**Issued**
**6/12/2019**

**Proposals due**
**7/31/2019**

**prepared by**


**Burns & McDonnell Engineering Company, Inc.**
**Kansas City, Missouri**

# TABLE OF CONTENTS

**Page No.**

# LIST OF TABLES

**Page No.**

# LIST OF FIGURES

**Page No.**

## LIST OF ABBREVIATIONS

| Abbreviation | Term/Phrase/Name |
|---|---|
| Burns & McDonnell | Burns & McDonnell Engineering Company, Inc. |
| CFR | Code of Federal Regulations |
| CO | Carbon Monoxide |
| $CO_2$ | Carbon Dioxide |
| COD | Commercial Operating Date |
| CSP | Curtailment Service Providers |
| DA | Definitive Agreement |
| DIR | Dispatchable Intermittent Resource |
| DR | Demand Resource |
| EFORd | Equivalent Forced Outage Rate Demand |
| EPC | Engineering, Procurement and Construction |
| ERIS | Energy Resource Interconnection Service |
| FERC | Federal Energy Regulatory Commission |
| GDPIPD | Gross Domestic Product Implicit Price Deflator |
| GI | Generation Interconnection |
| GIA | Generator Interconnection Agreement |
| Hg | Mercury |
| ICAP | Installed Capacity |
| IRP | Integrated Resource Plan |
| IURC | Indiana Utility Regulatory Commission |

| | |
|---|---|
| kW | Kilowatt |
| lb | Pound |
| LCOE | Levelized Cost of Energy |
| LCR | Local Clearing Requirement |
| LMR | Load Modifying Resource |
| LRZ | Local Resource Zone |
| LSE | Load Serving Entity |
| MISO | Midcontinent Independent System Operator |
| MMBtu | Million British Thermal Units |
| MW | Megawatt |
| MWh | Megawatt-Hour |
| NDA | Non-Disclosure Agreement |
| $NO_X$ | Nitrogen Oxide |
| NPDES | National Pollutant Discharge Elimination System |
| NRIS | Network Resource Integration Service |
| OEM | Original Equipment Manufacturer |
| OVEC | Ohio Valley Electric Corporation |
| PM | Particulate Matter |
| PPA | Power Purchase Agreements |
| PRM | Planning Reserve Margin |
| RFP | Request for Proposal |
| $SO_2$ | Sulfur Dioxide |

| | |
|---|---|
| UCAP | Unforced Capacity |
| Vectren | Vectren Energy Delivery |
| VOC | Volatile Organize Compounds |

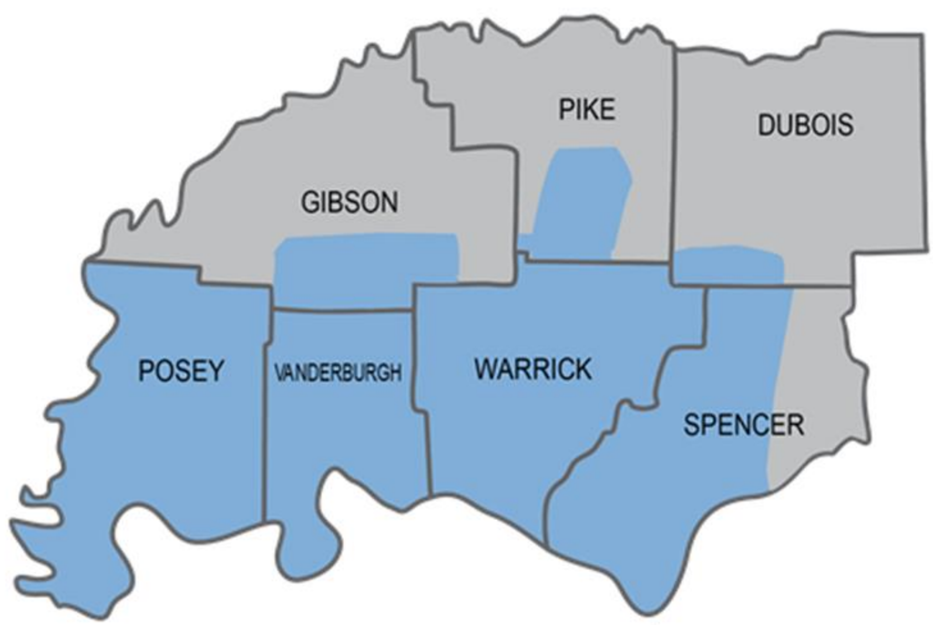
# 1.0 ALL-SOURCE RFP OVERVIEW

## 1.1 Introduction

Southern Indiana Gas and Electric (Vectren) is a subsidiary of CenterPoint Energy, headquartered in Houston, Texas. Vectren provides energy delivery services to 144,000 electric customers located in southwestern Indiana. Vectren also owns and operates electric generation to serve its electric customers and optimizes those assets in the wholesale power market.

Vectren's electric customers are currently served by a mixed portfolio of 1,000 megawatts (MW) of coal-fired generation, up to 225 MW of gas-fired generation and 4 MWs of solar coupled with 1 MW of storage. The portfolio also contains 3 MW from a landfill gas to electric project and purchases from the Ohio Valley Electric Corporation (OVEC) of up to 32 MW, wind purchases of up to 80 MW, and purchases from the Midcontinent Independent System Operator (MISO) power pool as needed to meet Vectren’s load requirements. Furthermore, interruptible load and demand-side management initiatives can reduce load by approximately 60 MW if needed.

**Figure 1-1: Vectren Electric Service Area**




## 1.2 Purpose

Vectren has issued this all-source Request for Proposals (RFP) seeking power supply and demand-side Proposals for capacity and unit-contingent energy to meet the needs of its customers. For asset purchases and power purchase agreements (PPAs) the capacity is preferred to be fully accredited for the 2023/2024

MISO Planning Year (PY). Vectren intends to submit an updated Integrated Resource Plan (2019/2020 IRP) to the Indiana Utility Regulatory Commission (IURC) in 2020 which will evaluate existing resources and identify the preferred resource options to meet capacity and energy requirements. Only resources capable of firm deliverability, further outlined in Section 4.1.1.2, to MISO Local Resource Zone (LRZ) 6 will be considered.

Vectren's resource planning will balance the need for dispatchable capacity with intermittent and demand-side resources to meet customers' needs reliably and cost effectively in an environmentally sustainable manner in both the short and long term. The IRP is designed to provide Vectren customers with a safe, reliable, and affordable power supply.

Vectren prefers Proposals that reflect all of the costs and characteristics of the resource necessary for energy to be financially settled or directly delivered to Vectren's load node (SIGE.SIGW). All potential agreements are subject to IURC approval and are not effective until such approval is final.

**All Proposals must be received by the contact designated in Section 2.1 no later than the Proposal Submittal Due Date shown in Section 2.4. Vectren reserves the right in its sole discretion to modify this schedule for any reason.**

In connection with this RFP, Vectren has retained the services of an independent third-party consultant, Burns & McDonnell, to manage the entire RFP process and work with Vectren to perform the quantitative and qualitative evaluations of all Proposals. However, Vectren will make final decisions (subject to IURC review, as applicable) in Vectren's sole discretion.

All Respondents will directly interface with Burns & McDonnell for all communications including questions, RFP clarification issues, and RFP bid submittal. All correspondence concerning this RFP should be sent via e-mail to VectrenRFP@burnsmcd.com.

Long term resource planning requires addressing risks and uncertainties created by a number of factors including the costs associated with new resources. As part of ongoing resource planning, Vectren has concluded that it is in the best interest of its customers to seek information regarding the potential to acquire, construct or contract for additional capacity that qualifies as a MISO internal resource (i.e. not pseudo-tied into MISO) with physical deliverability utilizing Network Resource Integration Service (NRIS) to MISO LRZ 6. Hereafter within this document, zonal restrictions will be referred to as being within MISO LRZ 6. Within the context of the 2019 IRP process, Vectren is soliciting all-source RFP for supply-side and demand-side capacity resources. The purpose of the RFP is to identify viable resources available to Vectren in the marketplace to meet the needs of its customers. Dependent upon further evaluation of aging resources, and subject to actual IRP results, Vectren may identify a capacity need of approximately 700 MW beginning in the 2023/2024 planning year. Because Vectren is looking at a number of potential resource portfolio combinations in the IRP, it is likely the 2019/2020 IRP will have scenarios that could result in a need less than or greater than 700 MW. Therefore, Respondents are encouraged to offer less than, or more than, 700 MW depending on the resources they have available. Vectren will also consider alternative timelines related to the capacity acquisition to the extent Respondents are able to provide more competitive pricing and/or terms for delivery beginning prior to or after 2023/2024 planning year. Vectren will aggregate data from the RFP responses, which include a delivered price (pending verification), and input such data into its IRP modeling. The RFP bid evaluation and selection process will be based upon the specific resource needs identified through this IRP modeling as well as the bid evaluation criteria. Through this RFP, Vectren seeks to satisfy the identified capacity need through either a single resource or multiple resources including dispatchable generation, load modifying resources (LMRs)/demand resource (DRs), renewables, stand-alone and paired storage, and contractual arrangements.

Vectren is seeking to provide reliable generation supply and demand resources for its customers. This RFP is issued to:

- Acquire a generation facility or facilities described further in Section 4.0, including the following:
    - Existing or planned dispatchable generation facilities that, at a minimum, meet established industry-wide reliability and performance standards or development requirement
        - Planned resources can be but are not required to be in the MISO generator interconnection queue
    - Existing or planned utility scale renewable resources
    - Existing or planned utility scale storage facilities, either stand-alone or paired with renewables
- Procure power purchase contract options for capacity and energy described further in Section 5.0.
- Procure LMRs/DRs that satisfy the criteria described further in Section 6.0.

Accordingly, you are invited to submit a written, binding Proposal in accordance with the requirements described in this RFP. Entities that submit a Proposal are referred to as Respondents.

The milestone dates for this RFP process are presented below. Additional information about milestone dates for the RFP is provided in Section 2.4.

**Table 1-1: RFP Milestone Dates**

| Milestone | Date |
|---|---|
| Issue RFP | Wednesday, June 12, 2019 |
| Notice of Intent w/ Pre-Qualification Documents | Thursday, June 27, 2019 |
| Notification of Pre-Qualification | Wednesday, July 3, 2019 |
| Proposals Due | Wednesday, July 31, 2019 |

# 2.0 INFORMATION AND SCHEDULE

## 2.1 Information Provided to Potential Respondents

This RFP and all of its Appendices are available on the RFP website (http://VectrenRFP.rfpmanager.biz/). Interested parties are expected to be able to download this RFP with its required forms and complete the forms in Microsoft Word, Microsoft Excel[1], and/or PDF format. Respondents should submit properly completed forms by the specified due date to the RFP e-mail address (VectrenRFP@burnsmcd.com). Burns & McDonnell will accept only Proposals that are complete. Proposals that are nonconforming, not complete, or that are mailed, or hand delivered may be deemed ineligible and may not be considered for further evaluation. By submitting a Proposal in response to this RFP, the Respondent certifies that it has not divulged, discussed, or compared any commercial terms of its Proposal with any other party (including any other Respondent and/or prospective Respondent), and has not colluded whatsoever with any other party.

## 2.2 Information on the RFP Website

The information on the RFP website (http://VectrenRFP.rfpmanager.biz/) contains the following:

- This RFP and associated appendices
- Template Information Form Addendum (as described in Section 8.1)
- Form of Notice of Intent
- Form of RFP Non-Disclosure Agreement
- Form of Pre-Qualification Application including Creditworthiness information
- Frequently asked questions and answers about this RFP
- Updates on this RFP process and other relevant information

## 2.3 Questions

An e-mail address (VectrenRFP@burnsmcd.com) has been set up to collect all communications and questions from potential Respondents as well as a website (http://VectrenRFP.rfpmanager.biz/) to download the RFP and provide uniform communications, relevant questions and answers, including updates and other details as may be provided throughout the bidding process. Phone calls and verbal conversations with Respondents regarding this RFP are not permitted before the Proposal Submittal Due Date. All Respondents will directly interface with Burns & McDonnell through the RFP e-mail address for all communications regarding this resource request. Proposals will be opened in private by Burns &

[1] Microsoft Excel format is required for the submission of Appendix D.

McDonnell on a confidential basis, but written questions will not be considered confidential. Individual questions submitted by e-mail to Burns & McDonnell before the submittal due date will be answered and responses sent back via e-mail to the Respondent as soon as practical. Responses to any questions may be placed on the RFP website for the benefit of all Respondents, with any identifying information redacted from the question.

Proposals will be reviewed by Burns & McDonnell for completeness and offers that do not include the information requirements of this RFP may be notified by Burns & McDonnell and allowed five business days to conform. After Proposals are submitted, Burns & McDonnell will review, and both quantitatively and qualitatively evaluate all conforming Proposals. During the evaluation process Respondents may be contacted for additional data or clarifications by Burns & McDonnell. Any Respondents contacted for further clarifications may or may not be invited to begin further negotiations of terms and details of the offers.

## 2.4 Schedule

Vectren has retained Burns & McDonnell to act as an independent third-party consultant to assist with this RFP. All Respondents will directly interface with Burns & McDonnell for all communications including questions, RFP clarification issues, and RFP bid submittal. All correspondence concerning this RFP should be sent via e-mail to VectrenRFP@burnsmcd.com.

The schedule below represents Vectren's expected timeline for conducting this resource solicitation. Vectren reserves the right to modify this schedule as circumstances warrant and/or as Vectren deems appropriate.

**Table 2-1: RFP Schedule**

| Step | Date[2] |
|---|---|
| RFP Issued | Wednesday, June 12, 2019 |
| Notice of Intent, RFP NDA, and Respondent Pre-Qualification Application Due | 5:00 p.m. CDT, Thursday, June 27, 2019 |
| Respondents Notified of Results of Pre-Qualification Application Review | 5:00 p.m. CDT, Wednesday, July 3, 2019 |
| Proposal Submittal Due Date | 5:00 p.m. CDT, Wednesday, July 31, 2019 |
| Initial Proposal Review and Evaluation Period | Wednesday, July 31, 2019 – Wednesday, September 18, 2019 |
| Proposal Evaluation Completion Target and Input to Vectren | 2nd Quarter, 2020 |
| Due Diligence and Negotiations Period | Mid 2020 |
| Definitive agreement(s) Executed (subject to regulatory approvals) with Selected Respondent(s) | Late 2020 |
| Petitions (if required) filed with the IURC, the Federal Energy Regulatory Commission (FERC), or any other required agency/commission | TBD |

[2] Negotiation schedule for smaller projects can be expedited at Vectren's discretion

# 3.0 RFP GENERAL REQUIREMENTS

Proposals must meet the general minimum eligibility requirements described below. Burns & McDonnell will screen all Proposals for compliance with these requirements. Proposals that fail to meet one or more of the general minimum eligibility requirements may be disqualified from further consideration as part of this RFP process. Respondents should refer to the Proposal Checklist in Appendix E for high-level guidance on Proposal requirements.

For a Proposal to be eligible under this RFP, it must offer MISO accredited or accreditable capacity (including Zonal Resource Credits) of no less than 10 MW to MISO LRZ 6[3].

Vectren has a preference for Proposals that provide Vectren with operational control of the asset, regardless of ownership position. Where applicable, proposed generation facilities should have no major operational limitations that reduce the ability to run for extended periods.

## 3.1 Respondent Pre-Qualification

Respondents to this RFP are required to fill out and sign Appendix A: Notice of Intent to Respond, Appendix B: Non-Disclosure Agreement (NDA), and Appendix C: Pre-Qualification Application in its present form.

## 3.2 Multiple Proposals

In the event that multiple Proposals are submitted by the same Respondent, the Respondent must indicate whether the Proposals are to be evaluated independently of one another or if Proposals are to be considered together.

Respondents may submit up to three Proposals at no cost in response to this RFP. Respondents submitting more than three responses will incur a Proposal Evaluation Fee for each additional Proposal submitted. The non-refundable fee for evaluating each additional Proposal is $5,000. This sum will serve to defray evaluation costs. Respondents can find instructions for paying fees for their Proposal(s) on the RFP website (http://VectrenRFP.rfpmanager.biz/). Vectren and Burns & McDonnell will have sole discretion to determine whether a submission is deemed a single Proposal or multiple Proposals.

[3] Load Modifying Resource suppliers must be located entirely within MISO LRZ 6.

## 3.3 Non-Disclosure Agreement

This RFP contains an RFP NDA (Appendix B). Respondents shall submit a signed version to the RFP e-mail address (VectrenRFP@burnsmcd.com) by 5:00 p.m. CDT on June 27, 2019. Respondents may download the form from the RFP website (http://VectrenRFP.rfpmanager.biz/).

## 3.4 Valid Proposal Duration

Proposals must include pricing that is firm and not subject to any revisions during the initial evaluation process. Vectren will receive all associated allowances or credits, if any. Seller agrees to transfer any Financial Transmission Rights or Auction Revenue Rights associated with the asset to the Buyer. Escalation rates shall be fixed or set annually to the Gross Domestic Product Implicit Price Deflator (GDPIPD). The GDPIPD will be reset annually as published by the U.S. Department of Commerce, Bureau of Economic Analysis. Formulaic mechanisms will not be subject to revisions during the evaluation and negotiation process.

All pricing should be provided in Appendix D in terms of US dollars as of the date the term of the contract begins and not subject to a currency exchange rate adjustment. Respondents are strongly encouraged to provide their best pricing with their initial submittal. Vectren is not obligated to provide an opportunity in the evaluation schedule for Respondents to refresh or update their pricing before the final selection(s) are made (if any). Respondents Proposal pricing shall remain valid for 1-year from the Proposal Submittal Due Date.

## 3.5 Acknowledgement of RFP Terms and Conditions

The submission of a Proposal shall constitute Respondent's acknowledgment and acceptance of all the terms, conditions, and requirements of this RFP.

## 3.6 RFP Response Summary Information

All Proposals must include a table of contents and provide concise and complete information on the topics described below, organized as follows:

### 3.6.1 Executive Summary

Please provide a one-page executive summary of the Proposal in the form of a cover letter. Include the facility's location, age or development status and if applicable, MISO generator interconnection project number, size, the primary contact's name, e-mail, and phone number, and an overview of the major features of the Proposal. The Executive Summary must be signed by an officer of the Respondent who is duly authorized to commit the firm to carry out the proposed transaction should Vectren accept the

Proposal (this does not have to be the primary contact). A Table of Contents should be the first page and immediately precede the Executive Summary.

### 3.6.2 General Information

#### 3.6.2.1 Respondent's Information and Experience

Please include information on the Respondent's corporate structure (including identification of any parent companies), the project's financing plan, the Respondent's most recent credit rating, quarterly report containing unaudited consolidated financial statements that is signed and verified by an authorized officer of Respondent attesting to its accuracy, a copy of Respondent's annual report for the prior three years containing audited consolidated financial statements and a summary of Respondent's relevant experience. Please describe any current litigation or environmental fines involving the Respondent within the last five years, including but not limited to, any litigation, settlements of litigation or fines, that could potentially affect the facility or its operation. Please identify all bankruptcy or insolvency proceedings relating to the Respondent in any way. Please describe any litigation related to PPAs or asset purchases similar to the transactions solicited in this RFP that the Respondent or its parent company have been a party to in the last six years. All financial statements, annual reports and other large documents may be referenced via a website address.

Proposals shall include a list of projects with a brief description of Respondent's experience in the areas of development, financing, permitting, ownership, construction, and operation of all utility-scale power generation facilities or LMRs/DRs.

Please provide a list of projects with a brief description of the Engineering, Procurement and Construction (EPC) contractor's experience as it relates to utility-scale power generation.

# 4.0 GENERATION FACILITY PROPOSALS

For generation facility Proposals, Vectren will only consider bids for facilities that have an estimated remaining useful life of five or more years from acquisition date. In all cases, Respondents shall describe the expected useful life of all facilities included in their Proposals.

## 4.1 Content Requirements for Generation Facility Proposals

This section describes Vectren's requirements for the content of any Proposal that is submitted in response to this RFP as an offer to sell a generation facility to Vectren. Proposals that do not include all of the required information may be deemed ineligible and may not be considered for further evaluation. If it appears that certain information has inadvertently been omitted from a Proposal, Burns & McDonnell may, but is not obligated, to contact the Respondent to obtain the missing information, per Section 2.3. If, during the RFP process, there is a material change to the generation facility or the circumstances of the Respondent that could affect the outcome of the RFP evaluation, the Respondent is obligated to inform Burns & McDonnell within five business days. In addition, any winning Respondent must provide such additional information and data as may be requested by Vectren to support regulatory approvals of the generation facility purchase transaction.

Vectren has a preference for projects located near its load. Non-conforming bids by Respondents to sell a generation facility or facilities not meeting the location requirements may be disqualified from consideration on that basis alone.

Vectren will accept Proposals for new or planned generation facilities that will be complete and operational in advance of the expected acquisition date. A project will be defined as complete and commercially operable if, and only if, it includes all facilities necessary to generate and deliver energy into MISO to at least one single point of interconnection within MISO. More detail on the development milestone requirements for planned facilities are included in Section 4.1.7.

If a facility does not have black start capability installed but could be made black start capable, Proposals should indicate the estimated costs to construct and operate and include the estimated construction timeline.

### 4.1.1 Capacity Characteristics

Respondents shall state the nameplate capacity, net summer operating capacity, net winter operating capacity and the awarded unforced capacity (UCAP) of the generation facility for the last five MISO planning years (existing facilities).

Respondents also should provide the expected UCAP for the first five MISO planning years beginning June 1, 2023 based on current MISO rules for the applicable generating technology.

#### 4.1.1.1 Acquisition Date

In preparing their Proposals, Respondents shall assume the acquisition of the facility shall be closed and transfer of title shall occur on or before the start of the 2023/24 Planning Resource Auction window, subject to regulatory approvals. If Respondent is able to offer more competitive pricing and terms for title transferring prior to or after June 1, 2023, Respondent should detail the drivers and the optimal date for title transfer.

#### 4.1.1.2 Capacity Availability and Deliverability

For Proposals to sell an existing generation facility to Vectren, the existing generating facility must be commercially operable, including all facilities and requirements necessary to deliver capacity (Zonal Resource Credits) to MISO LRZ 6. Respondents must identify the specific point(s) of interconnection including the type(s) of transmission service (e.g. NRIS or Energy Resource Interconnection Service (ERIS)). Proposals for facilities without existing firm deliverability to MISO LRZ 6 should include cost estimates and transmission studies associated with securing such deliverability.

The Proposal should also include nodal economic analyses (2023, 2028, and 2033) showing expected unit economic metrics (including congestion impacts on: capacity factor, produced energy, and generation revenue) for the project at the proposed delivery point(s).

Vectren reserves the right to reject any Proposal that does not include the full cost of any known or potential interconnection costs or network upgrades that may be required to provide firm deliverability to MISO LRZ 6 and/or that does not include interconnection, reliability, and/or economic analyses supporting interconnection and transmission requirements. Such materials should include a technical description and estimated costs of network upgrades from studies completed or underway.

### 4.1.2 Technical and Economic Detail

#### 4.1.2.1 Generation Technology

Respondents shall describe the generation technology of the facility, including the make, model, and name of the supplier of all major equipment.

All Proposals to sell a generation facility to Vectren must utilize an existing, proven technology, with demonstrated reliable generation performance that is capable of sustained, predictable operation.

#### 4.1.2.2 Dispatch and Emissions Characteristics

Respondents shall provide the dispatch and emissions characteristics of the generation facility in Appendix D, including, but not limited to:

- Minimum load level
- Maximum load level
- Ramp rates (up and down)
- Number of gas turbines that can be started simultaneously (if applicable)
- Heat rate curve for typical operations, including the minimum load and full load heat rates
    - If applicable, Respondent shall also provide heat rate curves for summer and winter seasons
- Fuel consumption and heat rate during startup, including startup time and the total number of hours annually the facility can be assumed to be in startup mode
- Fuel consumption and heat rate when the facility is being shut down, including how long shutdown takes and the total number of hours annually the facility can be assumed to be in shutdown mode
- An estimation of the total number of hours annually that the facility operates at full load
- Capability decreases as a result of ambient temperature increases
- Supplemental firing capability, including black start capability, and any operating limitations caused by such factors of design
- Pounds/megawatt hour (lb/MWh) emissions rates at relevant dispatch levels (startup, minimum, mid and full loading) and seasons (summer, winter, shoulder) for nitrogen oxides ($NO_X$), sulfur dioxide ($SO_2$), carbon dioxide ($CO_2$), volatile organize compounds (VOC), particulate matter (PM) and carbon monoxide (CO)
- Any other operational limitations that reduce unit availability or reduce a unit's ability to dispatch or regulate

For renewable resources Respondents shall provide expected capacity factors, including 8760 hourly profiles (actual or based on weather data) and the expected useful life of the asset. If applicable, Respondents shall also provide expected annual degradation rates.

Regarding any major current and/or historical operational limitations, Respondents shall provide a description of the root causes of the limitations (e.g. original equipment manufacturer (OEM) design, material condition of the facility, environmental permits, etc.). To the extent that expected performance deviates from observed performance, the Respondent shall provide the basis for the assumption.

#### 4.1.2.3 Revenues and Operating Costs

For existing generation facilities, Respondents shall provide a detailed breakout of the facility's actual annual revenues for each of the past five years. This will include energy, capacity, and ancillary service market revenues, as well as any other revenues the facility earned, including any congestion revenue (positive or negative), as well as uplift revenues. Associated with these revenues, Respondents shall state the estimated annual output in MWh as well as the operation and maintenance costs of the facility on a fixed ($) and variable ($/MWh) basis and provide the actual annual operation and maintenance costs of the facility for each of the past five years in nominal dollars.

Respondents shall provide a detailed breakout of the generation facility's estimated and actual annual fixed costs for the following categories: labor, benefits, materials, and all others for the past five years. Respondents shall provide a breakdown of the number of people employed at the facility, including permanent and contracted employees, and whether those employees are organized under any labor agreement.

If fixed or variable costs for the generation facility are expected to change in the foreseeable future (e.g., following planned upgrades, etc.), the Respondent should provide both the new expected cost(s) and the year(s) in which the costs are expected to change.

Respondents shall also state and describe any property, state, and local taxes and tax abatements associated with the generation facility, including all state and local taxes including property taxes.

New generation facilities also must provide reasonable expectations for all of the above details associated with plant revenues and costs, including market revenues, fixed and variable operations costs, expected upgrades and service timing, and taxes.

### 4.1.3 Operating Considerations

#### 4.1.3.1 Operating Data

For an existing generation facility, Respondents shall provide historical operating data consisting of:

- The commercial operation date (COD) of the facility
- The annual run-time hours (per unit, if applicable)
- The annual operating cycles per year (per unit, if applicable)
- The annual facility capacity and availability factors
- The equivalent forced outage rate demand (EFORd)

The above annual data may be limited to the most recent five years. The EFORd should correspond to the UCAP amounts awarded for the last five Planning Years. Respondents shall provide a breakdown of EFORd by failure mode or North American Electric Reliability Corporation/Generating Availability Data System category. Respondents shall provide a description of the major contributors to the generation facility EFORd. If there are particular costs associated with maintaining the EFORd of a generation facility, those must be provided. Generating facilities considered a Dispatchable Intermittent Resource (DIR) in MISO shall provide historical curtailments over the most recent years. New facilities shall put forth a best effort forecast of curtailments by MISO.

Respondents shall provide details on any current generation facility equipment issues and concerns, including the potential drivers and recommended mitigation procedures for the issues and/or concerns. These may include, but are not limited to, any operation of the turbine, generator, or boiler outside recommended parameters established by OEM, compromised turbine or compressor blades, etc. Respondents shall provide a list of any redundant equipment that is currently bypassed or out of service, and the related reason. Respondents shall also provide historical information on such issues and concerns that have arisen, how they were resolved, and the associated costs for the last ten years of operation, or for the commercial life of the generation facility, whichever is lesser.

Respondents shall provide maintenance history for the lesser of the past ten years of operation or the commercial life of the generation facility consisting of: (i) dates of last full unit inspection and findings based on OEM recommendations; and (ii) outstanding OEM recommendations remaining to be implemented, including the cost and outage duration for any major maintenance requirements expected over the coming ten years. Respondents shall provide the outage reports for major planned and forced outages for each of the past five years.

For new or planned generation facilities, Proposals should include the manufacturer or developer quoted expected performance, as well as historical performance of similar facilities in MISO.

As noted in Section 4.1.5.3, below, Proposals shall disclose if the generation facility or any parts thereof are subject to a service agreement.

#### 4.1.3.2 Operating Plan

Proposals should include a summary of the operating plan for the generation facility. Such plan should include software management system(s) and personnel roles and responsibilities for operating, maintaining, and servicing the facility, including any contractual arrangements currently in place.

Respondent shall provide an overview of key scheduled outage and maintenance plans, as well as plans for procuring and maintaining key spare parts.

For new or planned generation facilities, this should include a summary of the intended operating plan for the facility. The plan should include software management system(s) planned or in use (e.g., SAP, etc.), any third-party roles and responsibilities for operating, maintaining, and servicing the facility, including any contractual arrangements to be executed. Respondent shall provide an overview of key scheduled outage and maintenance plans, as well as plans for procuring and maintaining key spare parts.

#### 4.1.3.3 Fuel Supply

Respondents shall provide a description, including detailed cost information, contract duration, and material contract terms (including whether fuel contracts are take or pay, minimum volume requirements, price reopeners, assignability or termination provisions) of all fuel purchase, storage, and transport agreements related to the generation facility Proposal. Cost of fuel commodities shall be provided separately from the cost of fuel transportation. Respondents also must list any provisions or other considerations that would prohibit or impair the assignment and/or affect the performance obligations of either party under the respective contract(s). Respondents shall describe fuel purchase and transport to the generation facility, as well as any existing or known potential operational restrictions or impediments on such fuel purchase and transportation. Respondents also are required to provide a description of the existing fuel supply (and storage) infrastructure serving the generation facility, including the infrastructure for the delivery of secondary fuel for dual-fuel resources. However, Vectren, through this RFP, is exploring the potential purchase of generation facilities, and it is Vectren's sole discretion whether to assume any contract or contracts associated with the proposed generation facility related to fuel commodities and/or fuel transportation.

Proposals shall describe, to the extent possible, fuel sourcing strategy, including from where their fuel is sourced.

Proposals shall describe the generation facility's ability to access a reliable fuel supply that would support operation for any hour throughout the year, including the plant's on-site fuel storage and dual-fuel capabilities, if applicable. Proposals for gas generators shall indicate whether the facility is dual-fuel capable and Proposals should include an indication of the days of on-site fuel storage available. Gas generators without dual fuel capability shall provide information on the costs required to make the facility dual fuel capable to the extent that such cost estimates are available. Natural gas fired facilities shall have firm gas transportation contracts in place for the amount of gas capacity necessary to fulfill the amount of UCAP being bid. Proposals that do not include firm gas supply may be disqualified.

### 4.1.4 Environmental Considerations

#### 4.1.4.1 Emissions and Waste Disposal Compliance

New and existing resources must be in compliance with all applicable environmental rules and regulations. To the extent applicable, all environmental attributes, including emission reduction credits and/or allowances, related to the power being purchased should be conveyed to Vectren. This includes, but is not limited to, any and all credits in any form (emissions credits, offsets, financial credits, etc.) or baseline emissions associated with both known and unknown pollutants, including but not limited to $SO_2$, $NO_X$, Mercury (Hg), and $CO_2$. Any and all environmental liabilities, including compliance with known and future or unknown regulations or laws will be the sole responsibility of the generation producer or PPA seller.

For Asset Purchase Proposals, the Seller will retain all pre-closing environmental liabilities and obligations as well as all known future environmental liabilities and obligations, in each case associated with the real and personal property transferred with or as part of a Sale of the Plant. This includes both on and off-site liabilities. The Buyer will assume all other post-closing environmental liabilities and obligations. For purposes of facility design, Seller should assume that the unit will be required to meet the proposed New Source Performance Standards for Greenhouse Gases (40 Code of Federal Regulations (CFR) part 60, subpart TTTT).

#### 4.1.4.2 Water Supply

Respondents shall provide a detailed description of the water supply, including but not limited to, contract term, water usage, and cost of water for the generation facility. Respondents shall also provide the status of the facility’s National Pollutant Discharge Elimination System (NPDES) permits, including, but not limited to, permit conditions, permit violations reported over the last five years, the timing of next permit renewal, and any other known concerns.

If applicable, Respondents shall provide a summary of the facility’s water chemistry program, including key systems and suppliers, and its performance in the most recent year.

#### 4.1.4.3 Permits

The generation facility must have all relevant environmental and other permits necessary for operation and maintenance. Facilities without such permits may be disqualified from consideration at Vectren’s sole discretion. Respondents shall provide a description of all permits currently in place for the operation and maintenance of the facility (e.g., Spill Prevention Containment and Control plans, Title IV and Title V permits of the Clean Air Act, Cap and Trade Permits, NPDES permits, Water Withdrawal, and Pollution

Incident Prevention Plan, etc.). Respondents must also state whether there are any provisions that would prohibit the assignment of such permits and/or any consents required for the assignment of such permits.

Respondents shall describe any operating limitations imposed by permitting or environmental compliance that limit plant availability.

Respondents shall provide a description of any identified environmental liabilities (e.g., potential site remediation requirements, etc.) for the facility.

### 4.1.5 Financial Considerations

#### 4.1.5.1 Capital Expenditures

Respondents shall provide historical actual and budgeted capital expenditures for the generation facility. Historical capital expenditures shall be provided for each of the past five years in nominal dollars. Planned and budgeted capital expenditures shall be provided for each of next five years in nominal dollars along with a description of the projects involved. Respondents also shall disclose any known capital expenditure needs outside of the five-year time horizon that are expected to exceed $1 million dollars.

Respondents shall supply a summary list of all spare parts and components currently owned by the facility and their approximate dollar value. Respondents shall also identify any spare parts or components that are currently needed and/or on order as of the date the Proposal is submitted.

#### 4.1.5.2 Acquisition Price

Respondents shall submit an acquisition price consisting of a single fixed payment that is inclusive of all monetary consideration for the generation facility, working inventory, and, if applicable, ancillary facilities and contractual arrangements (e.g., for fuel supply and transportation, maintenance, pollution control bonds, etc.). Respondents must submit their best and final price with their Proposal. Respondents must provide details regarding any liabilities that Vectren might assume as a buyer of a generation facility.

For new or planned generation facilities, the price offered in the Proposal shall include all costs associated with providing a completed generating asset whose full output will be accredited to the MISO LRZ 6. This includes, in particular, but without limitation, costs associated with transmission interconnection, including engineering studies, siting, permitting, acquisition and construction.[4]

[4] If, during the evaluation, Burns & McDonnell or Vectren determines that the Proposal will be unable to achieve firm delivery to MISO LRZ 6, the Proposal will be rejected.

#### 4.1.5.3 Other Contractual Commitments

Respondents shall provide a description, including detailed cost information, of any other contracts that are currently necessary for generation facility operations, including, but not limited to, long-term service agreements, state union labor contracts and/or technical support contracts, agreements related to capacity and/or energy sales from the facility and any capacity offers submitted to any independent system operator/regional transmission organization related to the generation facility that, if accepted, would be binding on Vectren as a result of an acquisition. Respondents must also state whether there are any provisions that would prohibit the assignment and/or affect the performance obligations of either party under the respective contract, including transfer or cancellation fees.

### 4.1.6 Legal Considerations

#### 4.1.6.1 Legal Proceedings, Liabilities & Risks

The Proposal shall include a summary of all material actions, suits, claims or proceedings (threatened or pending) against Respondent, its Guarantor (if applicable) or involving the generation facility or the site as of the Proposal due date, including existing liabilities whether or not publicly disclosed, including but not limited to those related to employment and labor laws, environmental laws, or contractual disputes for the development, construction, maintenance, fueling, or operation of the facility.

#### 4.1.6.2 Material Contingencies

Proposals that have material contingencies, such as for financing, may not be considered.

### 4.1.7 Additional Items Specific to New Facilities

All Proposals for new generation facilities must have a well-defined and credible development plan for Respondent to complete the development, construction, and commissioning of the facility on their proposed development timeline. Respondents submitting Proposals for new or planned facilities should review the Development Risk evaluation metric and be sure to discuss key development milestones in their Proposal.

If available, Respondents shall submit:

1. A copy of an executed MISO Generator Interconnection Agreement
2. A copy of a completed MISO Facilities Study
3. A copy of a completed MISO System Impact Study

4. Nodal economic analyses (2023, 2028, and 2033) showing expected unit economic metrics (including congestion impacts on: capacity factor, produced energy, and generation revenue) for the project at the proposed delivery point(s)

If Respondent cannot provide this information, Respondent must indicate why it cannot be provided and must provide a timeline showing ability to complete key development milestone requirements prior to or after June 1, 2023 including the above referenced items for the MISO generator interconnection queue.

Respondent shall also detail its MISO generator interconnection queue position, if any, and the types and amounts of transmission service requested (e.g. NRIS or ERIS). Respondents submitting Proposals for a new or planned generation facility should also submit a copy of a fully executed EPC contract if available.

Respondents should also provide the following:

- Roles and responsibilities of the companies involved in the design, development, procurement, and construction of the facility. Information about key contributors shall extend to the status of contractual relationship with each key contributor; key contractual assurances, guarantees, warranties or commitments supporting the Proposal, including an executed EPC contract, and any past experience of Respondent working with each key contributor.
- Description of status of major equipment procurement, as well as processes for engineering, procurement, and construction bids and awards.
- Description of the facility site and Respondent’s rights (i.e., whether owned, leased, under option) to such site. Please indicate whether additional land rights are necessary for the development, construction, and/or operation of the facility.
- Discussion of the development schedule and associated risks and risk mitigation plans for that schedule, including whether there are contract commitments from contractors supporting the proposed schedule. The Respondent should be prepared to document and commit to a proposed development schedule, which should include a COD.
- Discussion of the financing arrangements secured by the Respondent, including an overview of the sources of funds, and level of commitment from debt, equity, or other investors.
- Discussion on permitting, including a list of all required permits, permitting status of each, and key risks to securing necessary future permit approvals.
- Description of status in MISO queue process and presentation of documents described above.

- Financial information regarding guarantors and sources of equity funding along with either the Respondent's or guarantors' senior unsecured debt and/or corporate issuer ratings documentation from Moody's and Standard & Poor's showing the name of the rating agency, the type of rating, and the rating of the Respondent or guarantor.

Vectren will not assume any responsibility for the successful development, construction, and/or completion of a proposed facility. Accordingly, development schedule, budget, permits and approval risk will be the sole responsibility of the Respondent.

# 5.0 POWER PURCHASE AGREEMENT PROPOSALS

Vectren will consider meeting some or all of its resource requirements through short, medium and/or long-term PPAs. Vectren will only consider PPAs that have a term of five years or greater.

## 5.1 Name and Location

Respondents shall state the name of the generating facility, the county where the generating facility is located, the owner of the facility, and the commercial pricing node associated with the facility, if applicable. The facility must qualify as MISO internal generation (i.e. not pseudo-tied into MISO) and be qualified to receive Zonal Resource Credits for Zone 6 consistent with MISO’s Module E Planning Resource Auction. Should the facility not be qualified in Zone 6, Respondents shall detail in their Proposals the means by which Zonal Resource Credits will be delivered/fulfilled in Zone 6.

## 5.2 Net Capability of Generating Facility

Respondents proposing a PPA for existing assets shall state the nameplate capacity, net summer operating capacity, net winter operating capacity and the UCAP of the facility for the 2019/2020 MISO planning year. Respondents shall specifically identify any known derates affecting the facility.

Respondents proposing existing assets shall also list the UCAP awarded to the facility, for the MISO Planning Years, 2015, 2016, 2017, 2018, and 2019. Respondents shall provide the projected UCAP for the facility. In the event that the projected UCAP has sizable deviation from historical UCAP, Respondents shall provide a detailed explanation. Respondents proposing facilities in development shall provide the anticipated UCAP after the asset acquisition date.

## 5.3 Generation Technology

Respondents shall describe the generation technology of the facility, including the make of the equipment, model, and name of supplier.

## 5.4 Dispatch and Emissions Characteristics

Respondents shall state/describe the dispatch characteristics of the facility, including, but not limited to, minimum load level, ramp rates (up and down), number of turbines that can be started simultaneously (if applicable), fuel consumption during startup, capability decreases as a result of ambient temperature increases, supplemental firing capability and any operating limitations caused by such factors as design, material condition of the facility, and various permit restrictions. Respondents shall state/describe the emissions profile of the facility, including but not limited to, the lbs/MMBtu at various dispatch profiles as applicable (startup, minimum load, mid, and max output) by season (summer, winter) for applicable emissions: $NO_X$, $SO_2$, $CO_2$, VOC, PM and CO.

Regarding any major operational limitations, Respondents shall provide a description of the root causes of the limitations (e.g., OEM design, material condition of the facility, environmental permits, etc.) Generating facilities considered a DIR in MISO shall provide historical curtailments over the most recent five years. New facilities shall put forth a best effort forecast of curtailments by MISO. Respondents shall also specify how DIR will be addressed (i.e. agreed to MISO offer price, bank of curtailment energy, etc.) within submitted Proposals. Generally, Proposals shall also take into consideration Vectren acting as the MISO Market Participant (responsible for market offers). However, Vectren is willing to consider Proposals where Vectren is not acting as the MISO Market Participant to the extent it is beneficial to Vectren's customers.

## 5.5 Fuel Supply

Respondents must supply a detailed fuel supply plan that fully details how fuel is purchased and transported to the facility as well as any existing or known potential operational restrictions or impediments on such fuel supply. This applies to all fuel types used to operate a facility, including natural gas, coal, fuel oil, biomass, etc. The Respondent is also required to provide a description, including detailed cost information, of all fuel service and purchase agreements applicable to the facility.

Respondents proposing a PPA shall be solely responsible for maintaining a reliable fuel supply that is delivered to the Respondent's proposed generating unit(s) to ensure reliable delivery of firm capacity and energy to Vectren throughout the Delivery Term. Facilities operating on natural gas must have firm natural gas supply agreement(s) capable of meeting 100% of the facility's maximum daily consumption requirements throughout the Delivery Term. The supply agreement(s) should provide all services required to cause natural gas to be delivered to the facility on a firm basis, which may include both timely and intraday supply, transportation, storage, and/or balancing.

## 5.6 Financial Considerations

### 5.6.1 Power Purchase Agreement

Respondents shall submit an annual power purchase price ($ and/or $/MWh as applicable) consisting of a payment that is inclusive of all monetary consideration for the generation facility, working inventory, and, if applicable, ancillary facilities and contractual arrangements (e.g., for fuel supply and transportation, maintenance, pollution control bonds, etc.). Respondents must submit their best and final price with their Proposal. Respondents must provide details regarding any liabilities that Vectren might assume.

For new or planned generation facilities, the price offered in the Proposal shall include all costs associated with providing a completed generating asset whose full output will be accredited to the MISO LRZ 6. This includes, in particular, but without limitation, costs associated with transmission interconnection, including engineering studies, siting, permitting, acquisition and construction.[5]

### 5.6.2 Asset(s) Specific Financial Information

Respondents shall submit audited or unaudited Financial Statements including Balance Sheets, Income Statements and Cash Flow Statements for the proposed asset(s) for the past three years. Respondents shall clearly indicate book value of the asset(s) in the financial information submitted.

### 5.6.3 Other Contractual Commitments

Respondents shall state whether there are other contractual commitments limiting or affecting the operation of the facility. Respondents shall state whether there are any other agreements in place for or claims on output from the facility. Such information should include any obligations that may restrict or compromise Vectren's ability to dispatch the facility.

### 5.6.4 Assets in Development

For PPA supported by proposed assets or assets that have not yet achieved their COD, Respondents must provide the same information requested in Section 4.1.7 for facilities to be developed.

[5] If, during the evaluation, Burns & McDonnell or Vectren determines that the Proposal will be unable to achieve firm delivery to MISO LRZ 6, the Proposal will be rejected.

# 6.0 LOAD MODIFYING RESOURCES/DEMAND RESOURCES

LMRs/DRs are demand-side resources and behind the meter generation not typically modeled or measured as part of MISO's operations but used during capacity shortages to help meet the energy balance. Vectren will consider LMRs/DRs from one or more MISO customers or curtailment service providers (CSP). LMR suppliers must be located entirely within MISO LRZ 6. Proposals for LMRs/DRs are to be for assets that are eligible to participate in MISO LRZ 6 and can meet the additional performance requirements of Vectren as described in Sections 6.1 and 6.3. In addition, for LMRs/DRs located within Indiana, Respondent must identify how the Proposal conforms with any requirements of the local utility and state law in order to offer resources for capacity accreditation within the MISO market under Module E Capacity Tracking.

Proposals for LMRs/DRs may be combined with another power supply Proposal or may be submitted on a standalone basis. Vectren will consider LMR/DR Proposals that have a term of one year or longer, consistent with MISO planning years.

## 6.1 Product Definition

To be eligible for participation in this RFP, the LMR/DR offered by a supplier must:

- Meet LMR/DR Requirements for participation in MISO as a demand-side resource, including any future changes to MISO's requirements for LMRs/DRs for the term of the Proposal
- Meet the additional performance requirements described in Section 6.3
- For capacity accreditation, the Proposal must be sourced from locations entirely within the MISO LRZ 6
- For energy accreditation, the Proposal must be sourced from locations entirely within Vectren's electric service territory
- Be at least 10 MW
- Use an existing, proven technology that has demonstrated reliable demand reduction, which may include use of Behind the Meter Generation (as defined by MISO)
- Reduce load by a predetermined amount when notified by Vectren of a Curtailment Event without further direction or communication by or from Vectren.

## 6.2 Purchase Agreement

If selected, the LMR/DRs supplier and Vectren will negotiate a mutually acceptable agreement to govern any commercial relationship established by the parties. With respect to a Proposal from a CSP, Vectren will not be responsible for making payments to, communicating with, or managing the relationship or performance of any customer within an aggregation, and the CSP shall be solely responsible for the same in all respects. To mitigate risk, Vectren will require the LMR/DR supplier to provide collateral upon execution of a LMR/DR Proposal. Vectren reserves the right to determine the form of that collateral requirement for a winning Proposal.

## 6.3 Curtailment Events: Notification and Performance Requirements

LMRs/DRs must meet notification and performance requirements applicable to a Curtailment Event, as defined and described herein and comply with MISO current and future testing requirements. For purposes of this RFP, a Curtailment Event shall be one in which either Vectren or MISO determines, in its respective sole discretion. MISO may also initiate a Curtailment Event upon its sole determination that a pre-emergency situation exists.

### 6.3.1 Notification, Performance, and Test Requirements

Curtailment Events initiated by MISO: For Curtailment Events initiated by MISO, LMR/DR suppliers shall agree to and be capable of meeting, throughout the entire term of the Proposal, all notification and performance requirements applicable to Capacity Performance demand resources. The supplier shall comply with all MISO Module E Capacity Tracking measurement and verification requirements.

Curtailment Events initiated by Vectren: Suppliers shall also agree to and be capable of meeting the following additional notification and performance requirements applicable to Curtailment Events initiated solely by Vectren:

- Suppliers shall curtail Actual Measured Load to Firm Contract Load within the proposed notification time specified in the Proposal
- Notification of a Curtailment Event initiated solely by Vectren will consist of an electronic message issued by Vectren to a device or devices such as telephone, facsimile, or e-mail, selected and provided by the supplier and approved by Vectren. Two-way information capability shall be incorporated by Vectren and the supplier in order to provide confirmation of receipt of notification messages. Vectren will provide the supplier a notification of when Curtailment Events have ended. Operation, maintenance, and functionality of communication devices for receipt of notifications selected by the supplier shall be the sole responsibility of the supplier, and receipt of notifications set out in this paragraph shall be the sole responsibility of the supplier

- During the entire period of a Curtailment Event initiated by Vectren, the supplier's Actual Measured Load must remain at or below its Firm Contract Load. A supplier's Actual Measured Load shall be determined by integrating the megawatts used over every clock hour (hour-ending).

### 6.3.2 Remedies for Non-Performance

A supplier whose Actual Measured Load exceeds its Firm Contract Load will be subject to performance penalties which may include, but not be limited to, refunding to Vectren monthly payments under the agreement.

A supplier shall be responsible for, and shall indemnify Vectren for, any non-performance penalties, costs, charges, or other amounts assessed by MISO and incurred by Vectren as a result of non-performance attributable to the supplier's LMR/DR, including but not limited to any Capacity Resource Deficiency Charges, Non-Performance Charges, or similar charges or penalties under the MISO agreements. In no event shall the penalties listed above for non-performance during a Curtailment Event be less than the sum of any MISO non-performance penalties, costs, charges, or other amounts incurred by Vectren as a result of non-performance attributable to the supplier's LMR/DR and the Curtailment Event charge.

## 6.4 Proposal Requirements

### 6.4.1 Acquisition Price

Suppliers shall submit an acquisition price consisting of a single fixed amount denominated in units of dollars per megawatt-day ($/MW-day), which is to apply for the term of the Proposal. If a Proposal is accepted, the supplier will be compensated in an amount equal to the monthly Curtailable Load times the Acquisition Price. The Proposal shall include all monetary consideration for the LMR/DR offered. Suppliers must submit their best and final price with their Proposal.

Should Vectren execute an agreement with a Respondent, the contract price between Vectren and the Respondent will be the Acquisition Price submitted in its respective Proposal through this RFP process.

### 6.4.2 Product Description

A Proposal shall include a description of the individual LMR/DR customer(s) and expected load drop values (kW), equipment, and technology that will be deployed and make available any other information required by MISO to meet its registration process, and for CSPs, plans for recruiting, engaging, and maintaining Program Participants.

Proposals should discuss the experience, qualifications, and financial strength of the supplier and other key contributors including the specific number of months the supplier has been providing LMR/DR services in MISO. Responses should indicate whether the supplier has ever been assessed a performance penalty in association with the resource and if so, when any penalties were assessed. For CSPs, Proposals should describe well-defined roles and responsibilities of the supplier and its participants. The supplier should describe successful protocols, if any, they have employed in the MISO LRZ 6 or other MISO zones for dispatching their LMR/DR.

While the product definition requires a load reduction upon notification by Vectren or MISO of a Curtailment Event, there is a preference for resources that can provide a more rapid response and/or ramp up or down in response to specific control signals. Respondents are urged to detail the full, demonstrated capability of the proposed resource in accordance with the evaluation criteria included in Section 7.0.

For planned LMRs/DRs, the supplier must fully describe specific plans detailing what equipment or technology it will deploy and/or utilize to support its operations. For CSPs, Proposals must describe supplier's processes for aggregating participants, how the supplier intends to recruit and engage participants, and/or provide lists of participants. The Proposal also must describe curtailment systems and procedures, budgeting for and structure of dispute resolution, and plans for communicating with participants in connection with a curtailment period.

### 6.4.3 Technical Requirements

Vectren shall acquire all rights, titles, and interests in the LMR/DR including all the potential capacity and energy revenues. Suppliers must agree to cooperate with Vectren in providing information needed to meet all MISO LMR/DR information requirements.

The supplier will assume all responsibilities and liabilities associated with providing LMRs/DRs. Accordingly, Proposals offering LMRs/DRs must include acknowledgment and agreement that the supplier is responsible for the following non-exhaustive list of activities and obligations:

- Managing load reductions, including all notices, communications, controls, equipment, or other processes required
- If the supplier is a CSP, determining the number of participants, in its aggregation, the number of interruptible hours per customer, and the size of each participant's load reduction
- If the supplier is a CSP, paying any participants according to the CSP's agreement with those participants. Such agreements shall be independent of Vectren's agreement with the CSP and

must hold Vectren harmless for any direct or indirect obligations or liability associated with the program

- Paying penalties assessed due to the non-performance of the LMR/DR

The agreement shall reflect that it will be the supplier's responsibility to reimburse Vectren for any penalties, fees, or charges resulting from non-performance of its LMR/DR, including replacement capacity to maintain Vectren's planning reserve margin requirement, and the supplier's obligation to indemnify and hold Vectren harmless against any claim arising from such non-performance. In the case of a supplier who is a CSP, the agreement will additionally set forth CSP's responsibility to reimburse Vectren for any penalties, fees, or charges resulting from non-performance of any CSP participant, and CSP's obligation to indemnify and hold Vectren harmless against any claim arising from such CSP participants' non-performance.

## 6.5 Evaluation Methodology

Burns & McDonnell will identify for recommendation to Vectren the LMR/DR Proposal or portfolio of Proposals that contribute to Vectren's capacity needs consistent with the evaluation methodology outlined in Section 7.0. LMRs/DRs will be evaluated independently of supply-side resources and may include other scoring criteria.

## 6.6 Contract Execution

Vectren does not, by this RFP, obligate itself to purchase any LMR/DR, or to execute an agreement with any Respondent who submits an offer to sell a LMR/DR to Vectren. Vectren may, in its discretion, reject any or all Proposals to sell a LMR/DR to Vectren, as such are described in this RFP.

Selection of a Proposal as a finalist shall not be construed as a commitment by Vectren to execute an agreement. Execution of any agreement is contingent upon Vectren receiving all required regulatory approvals and completion of such due diligence as Vectren in its sole discretion determines is reasonable to confirm the qualifications and performance of a given LMR/DR. During the period between when Burns & McDonnell makes its recommendation(s) to Vectren, and the date of execution of the agreement, Vectren may conduct additional due diligence on the Proposal.

# 7.0 PROPOSAL EVALUATION AND CONTRACT NEGOTIATIONS

## 7.1 Initial Proposal Review

An initial review of the bids will be performed by Burns & McDonnell. Proposals will be reviewed for completeness. Proposals that do not meet the requirements of this RFP may be notified. Respondents may also be contacted for additional data or clarifications by Burns & McDonnell, these communications will be initiated via e-mail (VectrenRFP@burnsmcd.com). Each complete bid will be evaluated by quantitative and qualitative factors. The evaluation criteria outlined in this section are intended to relatively compare each Proposal to analogous submissions and will be the starting guidelines for the evaluation. If needed, the scoring may be adjusted to provide distinction between Proposals. This evaluation, in conjunction with the IRP, will be used to determine which resources are most capable of providing Vectren customers with a safe, reliable, and affordable power supply.

## 7.2 Evaluation Criteria - Generation Facility

Burns & McDonnell will quantitatively and qualitatively evaluate all conforming generation facility Proposals' ability to meet power supply needs. During this evaluation process, Burns & McDonnell may or may not choose to initiate more detailed clarification discussions with one or more Respondents. Discussions with a Respondent shall in no way be construed as commencing contract negotiations. A more detailed quantitative evaluation for select bidders will consider production cost models and nodal analysis.

**Table 7-1: Generation Facility Scoring Criteria Summary**[6]

| | LCOE Evaluation | Energy Settlement Location | Interconnection/ Development Status & LCR | Project Risk Factors |
|---|---|---|---|---|
| Points | 150 | 100 | 90 | 160 |
| % | 30% | 20% | 18% | 32% |

### 7.2.1 Levelized Cost of Energy - 150 Points

The initial evaluation will be primarily based on a comparison of each Proposal's Levelized Cost of Energy (LCOE). A LCOE allows for Proposals within asset classes, which have different sizes, pricing, operating characteristics, ownership structures, etc. to be evaluated and compared to each other on an equivalent economic basis. The LCOE analysis will incorporate all costs associated with an asset purchase or PPA over a 20-year/standardized amount of time. These costs will include the applicable

[6] Vectren reserves the right to add up to 100 points to Proposals located in Southern Indiana, as local resources provide multiple benefits: VAR support, economic development, less future congestion risk, etc.

purchase or PPA cost, fixed costs, and variable operating expenses across standard technology respective operating parameters. The levelized value of these costs over this time period are then divided by the energy produced by the respective Proposal.

Vectren specific assumptions used in this analysis will be in accordance with Vectren's 2019/2020 IRP assumptions, including but not limited to

- Discount rate
- Capital recovery factor
- Escalation
- Commodity forecasts

The LCOE evaluation is a screening level economic evaluation which will determine the cost of energy provided by each Proposal relative to similar technology types. Proposals within an evaluation class with the lowest LCOE will receive full scoring for this metric. Based on variance of costs and number of Proposals in each class, points awarded to higher cost Proposals will be scaled accordingly.

The rules for performing the LCOE analysis will be determined by Burns & McDonnell and Vectren in advance of the receipt and review of any Proposals. However, as part of the process of evaluating Proposals, cases may arise where, in order to adequately project asset costs or to facilitate a comparison between qualified Proposals, the rules related to the LCOE analysis may require review and/or adjustment. To the extent that any additions or adjustments are required, such additions or adjustments will be made solely by Burns & McDonnell. In such cases, any and all rules will be applied consistently across all Respondents.

While performing LCOE analyses of Proposals, Burns & McDonnell may request additional or clarifying information from a given Respondent regarding unit performance, operating costs, or other factors that influence the LCOE calculation for a given resource. This evaluation will also include grid congestion analysis. Requests for additional information may be required to ensure that all qualified Proposals are fairly and consistently evaluated. Consistent with Section 2.3, in such cases, Respondents will be required to respond within five business days of receipt of such request. Burns & McDonnell will not consider unsolicited updates from Respondents related to the cost of any power supply resource.

### 7.2.2 Energy Settlement Location - 100 points

Vectren has a preference for Proposals that include all costs to have energy financially settled or directly delivered to Vectren's load node (SIGE.SIGW). Proposals that meet one of these criteria will receive 100 points, while Proposals failing to meet either criteria will be awarded zero points. Market data from Proposals that include the aforementioned costs will be carried forward into the IRP modeling analysis as described in Section 7.5.

### 7.2.3 Interconnection and Development Status - 60 Points

Existing resources will receive full credit under this evaluation category. Plants that have not achieved commercial operation but that are in the MISO Generation Interconnection (GI) Queue will be awarded points based on the Definitive Planning Phase they are in. Other projects not in the MISO GI Queue must demonstrate development progress. Facilities failing to meet critical development milestones may be disqualified from consideration at Vectren's sole discretion.

Up to 60 points will be will awarded based on the achievement of certain development milestones towards the facility COD. Five milestones have been selected and 12 points will be awarded for each equally. The selected milestones are as follows:

- Executed a MISO Generator Interconnection Agreement
- Completed a MISO Facilities Study
- Completed a MISO System Impact Study
- Achieved site control and completed zoning requirements
- EPC Contract awarded

### 7.2.4 Local Clearing Requirement Risk - 30 Points

The MISO footprint is split into ten LRZs. All load serving entities within MISO are required to obtain capacity which meets their respective Planning Reserve Margin (PRM). A Local Reliability Requirement is also established for each LRZ which is the aggregate of all Load Serving Entity's (LSE's) PRMs. Due to Zonal capacity import/export limitations a portion of each LRZ's Local Reliability Requirement must be served locally, this requirement is the zone's Local Clearing Requirement (LCR). The LCR establishes the amount of Unforced Capacity which is required to be located in each respective LRZ.

Proposals located within LRZ 6 provide additional risk avoidance to Vectren's LCR requirements and will receive 30 points; Proposals located outside of LRZ 6 will receive zero points.

### 7.2.5 Project Risk Factors - 160 Points

Certain risk factors may be unique to a Proposal. Such factors may be significant enough to independently impact the overall ability of the Proposal to meet Vectren's needs.

This category is intended to capture unspecified risk that may be highlighted by a bidder or identified during the Proposal review. The Project Risk Factors Section attempts to identify and score potential risks which may compromise the future performance of the asset[7]. In situations where the level of risk is not accurately represented, scoring may be adjusted. Potential considerations include, but may not be limited to the following:

- Credit and financial plan - Proposals with a long term unsecured credit rating below BBB+ (Baa1 for Moody's) will not be considered in this evaluation. Proposals which have internal financing are preferred and will receive the 20 points for this category[8].
- Development experience - Relevant technology development experience is an important risk factor. Proposals will receive up to 20 points based on the following formula:

$$Points\ awarded = \frac{(nameplate\ MW\ in\ service)}{1{,}500} * 20$$

- Sole ownership vs. partial owner - Due to site and dispatch rights/preferences, a sole ownership Proposal will receive 20 points.
- Proposal ownership structure - Due to a preference for ownership Asset Purchase Proposals will receive 20 points while PPA Proposals will receive zero points.
- Operational control - Proposals which offer Vectren operational control will receive 20 points
- Fuel risk - For applicable Proposals, sites with firm and reliable fuel supply will receive 20 points.
- Delivery date - For each year prior or after 2023, 25% of the 20 possible points will be deducted.
- Site Control - Proposals which have fully achieved site control will receive 20 points

Any such risks shall be disclosed along with a description of the associated measures taken to mitigate the risk. Failure to disclose a reasonably foreseeable risk or risks may be a basis to disqualify a Proposal.

Proposals with no such risks as determined by Burns & McDonnell will receive the full number of points available in this category. Proposals with asset or project-specific risks that are not able to be fully mitigated may receive fewer points depending on Burns & McDonnell's assessment.

## 7.3 Evaluation Criteria - LMR/DR

Burns & McDonnell will quantitatively and qualitatively evaluate all conforming LMR/DR Proposals. During this evaluation process, Burns & McDonnell may or may not choose to initiate more detailed

[7] Vectren reserves the right to add up to 100 points to Proposals located in Southern Indiana, as local resources provide multiple benefits: VAR support, economic development, less future congestion risk, etc.
[8] Vectren reserves the right to re-evaluate credit rating and exclude bidders at its sole discretion.

clarification discussions with one or more Respondents. Discussions with a Respondent shall in no way be construed as commencing contract negotiations. A more detailed quantitative evaluation for select bidders will consider production cost models and nodal analysis.

Vectren will accept Proposals from LMRs/DRs that meet the requirements as established in this RFP and conforms to MISO requirements. These requirements include but are not limited to, the ability to respond to Curtailment Events initiated either by MISO or by Vectren.

LMR/DR proposals will be evaluated across the following criteria:

**Table 7-2: LMR/DR Scoring Criteria Summary**[9]

| | Cost Evaluation | Historical Performance | Response Time | Proposal Risk Factors |
|---|---|---|---|---|
| Points | 200 | 100 | 100 | 100 |
| % | 40% | 20% | 20% | 20% |

### 7.3.1 Cost Evaluation - 200 Points

The cost of each Proposal will be evaluated based on the annual payment per MW for the LMR/DR. The lowest $/MW cost Proposal will receive 200 points for the cost evaluation category. Based on variance of costs and number of Proposals, points awarded to higher cost Proposals will be scaled accordingly.

### 7.3.2 Historical Performance - 100 Points

An end use customer or CSP with a historical performance record of successfully providing demand response services for three or more years without being assessed a non-performance penalty will receive 100 points for this category.

An end use customer or CSP that has provided such services for between one year and three years without being assessed a non-performance penalty will receive 50 points for this category.

An end use customer or CSP that has not provided such services in the past or that has been assessed a non-performance penalty will receive zero points for this category.

[9] Due to benefits other than capacity accreditation, Vectren reserves the right to add up to 100 points to LMR/DR Proposals located within Vectren's electric service territory.

### 7.3.3 Response Time - 100 Points

While the product defines a load reduction response time within a Respondent's Proposal, there is a preference for resources that can provide a more rapid response to specific control signals.

Proposals for LMR/DR that have the ability to follow a real-time signal will be awarded 100 points for the response time category. Proposals for LMR/DR that can achieve the load reduction target within 30 minutes of notification will receive 75 points for this category. Proposals for LMR/DR that can achieve the load reduction target within 60 minutes of notification will receive 50 points for this category. Proposals for LMR/DR that can achieve the load reduction target within 120 minutes of notification will receive 25 points for this category.

### 7.3.4 Proposal Risk Factors - 100 Points

This category is intended to capture unspecified risk that may be highlighted by a LMR/DR Proposal or identified during the Proposal review. The Proposal risk factors category will be used to adjust the overall scoring in cases where there is a material risk identified that may create concerns about the ability of the provider to deliver on their Proposal or that may create a material uncertainty about the cost to Vectren or its customers, significant regulatory uncertainty, or other considerations.

## 7.4 Discussion of Proposals During Evaluation Period

Based on the quantitative and qualitative evaluations and needs identified during the 2019/2020 IRP, Vectren may or may not select candidates for further discussions. Vectren will contact any selected Respondent in writing to confirm interest in commencing contract negotiations. All negotiations will begin with Vectren's standard contract as a starting point. Vectren's commencement of and participation in negotiations shall not be construed as a commitment to execute a contract. If a contract is negotiated, it will not be effective unless and until it is fully executed with the receipt of all required regulatory approvals.

## 7.5 Selection of Highest Scoring Proposal(s) based on IRP Analysis

Where possible, aggregated cost and performance information from the RFP bids, which provide a delivered price (pending verification), will be provided to the IRP team to facilitate certain portfolio modeling[10]. The IRP analysis will provide the RFP team with a preferred portfolio based on these costs. RFP bids will be rank ordered consistent with the evaluation criteria and assets will be selected consistent with the RFP evaluation and the IRP determined need. Consistent with that objective, Vectren may need

[10] Proposals that do not provide an energy settlement contract or physical deliverability to Vectren's load node (SIGE.SIGW) will not be included in the IRP analysis, but may be considered for procurement.

to contract with multiple generating assets. Cost certainty and project implementation are key considerations that will be included in qualitative analysis and that will include the ranking of projects with firm price offers and price caps, projects in the MISO GI queue or with signed Generator Interconnection Agreements (GIAs), recent prior development experience, etc. Vectren will seek to secure resources consistent with the preferred portfolio identified in the 2019/2020 IRP. As such, there is no assurance that the individual, highest-scoring qualified Proposal(s) will be selected.

## 7.6 Contract Execution

Vectren does not, by this RFP, obligate itself to purchase any generation facility or facilities, or to execute the Asset Purchase Agreement or PPA with any Respondent who submits an offer to sell generation capacity and/or energy to Vectren and Vectren may, in its discretion, reject any or all Proposals, as such are described in this RFP.

Selection of a winning Proposal shall not be construed as a commitment by Vectren to execute an agreement. During the period between Burns & McDonnell's delivery of results to Vectren and the date of execution of any agreement, Vectren will conduct additional due diligence on the Proposal which may include, but not be limited to, onsite visits, management interviews, legal and regulatory due diligence, and detailed engineering assessments and facility dispatch modeling.

# 8.0 PROPOSAL SUBMISSION

All Proposal documents must be submitted to the RFP Manager via e-mail to VectrenRFP@burnsmcd.com.

## 8.1 Format and Documentation

All Proposals submitted in response to this RFP must be received by Burns & McDonnell (VectrenRFP@burnsmcd.com) no later than the Proposal Submittal Due Date shown in Section 2.4. Burns & McDonnell and Vectren will not evaluate Proposals as part of this RFP process if submitted after this date and time. Multiple Proposals submitted by the same Respondent must be identified and submitted separately. Financial statements, annual reports, technical specification documents, and other large documents can be sent electronically to the RFP e-mail address. Each Proposal must contain the following:

1. Appendix B: Non-Disclosure Agreement (NDA) in its present form
2. Appendix D: Proposal Data in Excel format

## 8.2 Certification

A Respondent's Proposal must certify that:

1. There are no pending legal or civil actions that would impair the Respondent's ability to perform its obligations under the proposed PPA or Asset Purchase
2. The Respondent has not directly or indirectly induced or solicited any other Respondent to submit a false Proposal
3. The Respondent has not solicited or induced any other person, firm, or corporation to refrain from submitting a Proposal
4. The Respondent has not sought by collusion to obtain any advantage over any other Respondent.

# 9.0 RESERVATION OF RIGHTS

Nothing contained in this RFP shall be construed to require or obligate Vectren to select any Proposals or limit the ability of Vectren to reject all Proposals in its sole and exclusive discretion. Vectren further reserves the right to withdraw and terminate this RFP at any time prior to the Proposal Submittal Due Date, selection of bids or execution of a contract. All final contracts will be contingent on IURC approval.

All Proposals submitted to Vectren pursuant to this RFP shall become the exclusive property of Vectren and may be used for any reasonable purpose by Vectren. Vectren and Burns & McDonnell shall consider materials provided by Respondent in response to this RFP to be confidential only if such materials are clearly designated as Confidential. Respondents should be aware that their Proposal, even if marked Confidential, may be subject to discovery and disclosure in regulatory or judicial proceedings that may or may not be initiated by Vectren. Respondents may be required to justify the requested confidential treatment under the provisions of a protective order issued in such proceedings. If required by an order of an agency or court of competent jurisdiction, Vectren may produce the material in response to such order without prior consultation with the Respondent.

# 10.0 CONFIDENTIALITY OF INFORMATION

All Proposals submitted in response to this RFP become the responsibility of Burns & McDonnell and Vectren upon submittal. Respondents should clearly identify each page of information considered to be confidential or proprietary. Consistent with the RFP NDA (Appendix B), Burns & McDonnell will take reasonable precautions and use reasonable efforts to maintain the confidentiality of all information so identified. Vectren reserves the right to release any Proposals, or portions thereof, to agents, attorneys, or consultants for purposes of Proposal evaluation. Regardless of the confidentiality claimed, however, and regardless of the provisions of this RFP, all such information may be subject to review by, and disclosable by Vectren, to the appropriate state authority, or any other governmental authority or judicial body with jurisdiction relating to these matters, and may also be subject to discovery by other parties subject to fully executed NDAs/confidentiality agreements. Further, because Vectren is conducting this RFP as part of the IRP public advisory process, Vectren will disclose the UCAP MW offered, technology/resource type, average price, general location, proposed ownership structure, and Proposal duration of all Proposals unless a given technology has less than three Respondents in order to inform our stakeholders of the summary results of the RFP. Vectren will also disclose the names of Respondents participating in the RFP.

# 11.0 REGULATORY APPROVALS

Pursuant to the terms of the definitive agreement(s), the Respondent will agree to use its reasonable best efforts, including, if necessary, providing data and testimony, to obtain any and all State, Federal, or other regulatory approvals required for the consummation of the transaction.

Please note in particular that approval by the IURC, MISO and FERC may be required before the transaction can be consummated between the selected Respondent and Vectren. As part of the regulatory process, responses to the RFP may be provided to parties who have executed an NDA/confidentiality agreement, specifically acknowledging that they are neither affiliated with any party responding to the RFP or serving as a conduit for any party responding to the RFP.

# 12.0 CREDIT QUALIFICATION AND COLLATERAL

The credit and commitment of any bid will be a critical part of the bid evaluation process. A Respondent must have a credit rating for its senior unsecured debt of BBB+ or higher for Standard & Poor's (or Baa1 or higher for Moody's). If a Respondent is unrated or does not meet this minimum credit rating requirement, the Respondent may provide credit support from a corporate guarantor that meets the requirement.

As part of a final binding contract, and depending on the structure of the transaction, Vectren will further review the credit of the Respondent and the risk associated with the transaction to determine what, if any, additional credit requirements may be necessary to protect its ability to serve its customers in a reliable manner.

For asset purchases, a Respondent shall have the corresponding obligation to post Definitive Agreement (DA) collateral as determined in accordance with its Proposal if selected for the definitive agreement phase of the RFP. DA Collateral must be posted at the execution of the definitive agreement and will be in force until the transfer of title to Vectren for generating asset Proposals.

For PPAs and LMRs/DRs, winning Respondents may be required to post operating collateral over the term of any PPA or LMR/DR agreement consistent with the terms and conditions of final agreements as negotiated between Vectren and the supplier.

In each case, the collateral must be in the form of either: (a) a letter of credit, (b) cash, or (c) a construction bond. Burns & McDonnell and Vectren reserve the right to require a Respondent to post DA Collateral in an amount that exceeds the amounts listed herein as conditions warrant.

**Table 12-1: Collateral**

| Asset | Collateral Amount |
|---|---|
| Asset Purchase | $50.00/kW (UCAP) at execution of definitive agreement |
| Asset Purchase | $150.00/kW (UCAP) at regulatory approval |
| Power Purchase Agreement | 12-months expected revenues |
| LMR/DR | 12-months expected revenues |

# 13.0 MISCELLANEOUS

## 13.1 Non-Exclusive Nature of RFP

Vectren may procure more or less than the amount of assets solicited in this RFP from one or more Respondent(s). Respondents are advised that any definitive agreement executed by Vectren and any selected Respondent may not be an exclusive contract for the provision of assets. In submitting a Proposal(s), Respondent will be deemed to have acknowledged that Vectren may contract with others for the same or similar deliverables or may otherwise obtain the same or similar deliverables by other means and on different terms.

## 13.2 Information Provided in RFP

The information provided in this RFP, or on the RFP website (http://VectrenRFP.rfpmanager.biz/), has been prepared to assist Respondents in evaluating this RFP. It does not purport to contain all the information that may be relevant to Respondent in satisfying its due diligence efforts. Vectren makes no representation or warranty, express or implied, as to the accuracy, reliability or completeness of the information in this RFP, and shall not be liable for any representation, expressed or implied, in this RFP or any omissions from this RFP, or any information provided to a Respondent by any other source.

## 13.3 Proposal Costs

Vectren shall not reimburse Respondent and Respondent is responsible for any cost incurred in the preparation or submission of a Proposal(s), in negotiations for an agreement, and/or any other activity contemplated by the Proposal(s) submitted in connection with this RFP. The information provided in this RFP, or on Vectren's RFP website, has been prepared to assist Respondents in evaluating this RFP. It does not purport to contain all the information that may be relevant to Respondent in satisfying its due diligence efforts.

## 13.4 Indemnity

Supplementing Respondent's assumption of liability pursuant to this RFP, Respondent shall indemnify, hold harmless and defend Vectren and its parent company, officers, employees and agents, from any and all damages, liabilities, claims, expenses (including reasonable attorneys' fees), losses, judgments, proceedings or investigations incurred by, or asserted against, Vectren or its officers, employees or agents, arising from, or are related to, this RFP, or the execution or performance of one or more definitive agreements.

## 13.5 Hold Harmless

Respondent shall hold Vectren harmless from all damages and costs, including, but not limited, to legal costs in connection with all claims, expenses, losses, proceedings or investigations that arise as a result of this RFP or the award of a Proposal pursuant to the RFP or the execution or performance of a definitive agreement.

## 13.6 Further Assurances

By submitting a Proposal, Respondent agrees, at its expense, to enter into additional agreements, and to provide additional information and documents, in either case as requested by Burns & McDonnell in order to facilitate: (a) the review of a Proposal, (b) the execution of one or more definitive agreements, or (c) the procurement of regulatory approvals required for the effectiveness of one or more definitive agreements.

## 13.7 Licenses and Permits

Respondent shall obtain, at its cost and expense, all licenses and permits that may be required by any governmental body or agency necessary to conduct Respondent's business or to perform hereunder. Respondent's subcontractors, employees, agents and representatives of each in performance hereunder shall comply with all applicable governmental laws, ordinances, rules, regulations, orders and all other governmental requirements.

# APPENDIX A – NOTICE OF INTENT TO RESPOND

# Notice of Intent to Respond

| CONTACT INFORMATION | | | |
|---|---|---|---|
| Company | | | |
| Primary Contact: | | | |
| Name | | | |
| Title | | | |
| Telephone | | | |
| E-mail | | | |
| Mailing Address | | | |
| Signature of Respondent | | Date | |

Due: June 27, 2019

E-mail: VectrenRFP@burnsmcd.com

# APPENDIX B – NON-DISCLOSURE AGREEMENT

# NON-DISCLOSURE AGREEMENT

THIS NON-DISCLOSURE AGREEMENT (Agreement) is entered into as of the __ day of _________, 2019, between Southern Indiana Gas and Electric Company, Inc., Vectren Energy Delivery of Indiana, Inc. (Vectren) having its headquarters and principal place of business in Evansville, Indiana, and [________________________________], a [___________] corporation/llc/partnership (the Company), (collectively, the Parties, and individually, Party).

**R E C I T A L S:**

A. The Parties intend to discuss and evaluate proposals regarding possible energy/capacity transactions that could be entered into between Vectren and the Company, which discussions may include sharing of bid proposal information received from the Company during the competitive bid process administered by Burns & McDonnell on behalf of Vectren (the Transaction).

B. The Parties acknowledge that each Party may make available to the other Party, from time to time, in connection with such discussions, certain Confidential Information, as defined below.

NOW, THEREFORE, in consideration of the premises and the mutual promises and covenants hereinafter set forth, the Parties agree as follows:

1. Non-Disclosure. Subject to Section 4 below, the Party receiving confidential information (the Receiving Party) shall keep strictly confidential and not disclose the following:

(i) all information provided by the disclosing Party (Disclosing Party) or any affiliate, director, officer, employee, agent, advisor, contractor or other representative (individually, Representative, or collectively, Representatives) of the Disclosing Party to the Receiving Party or its Representative(s) in writing, orally or electronically in the course of the Parties' evaluation of the Transaction, whether before or after the date hereof, including, without limitation, any such information

(A) concerning the business, financial condition, operations, products, services, assets and/or liabilities of the Disclosing Party,

(B) relating to technologies, intellectual property or capital, models, concepts, or ideas of the Disclosing Party,

(C) including information from third parties that the Disclosing Party is required under applicable law, contract or other agreement to keep confidential, or

(D) otherwise, clearly identified as confidential or proprietary, including all bid proposal information received by the Receiving Party, during the competitive bid process for intermediate capacity being conducted by Vectren (collectively, the "Confidential Information"); and

(ii) the Disclosing Party's participation in discussions concerning the Transaction, including execution of this Agreement, the Disclosing Party's disclosures of Confidential Information to the Receiving Party or its Representative.

Receiving Party may disclose Confidential Information provided by the Disclosing Party to any Representative of the Receiving Party who needs this Confidential Information to evaluate the Transaction. Receiving Party remains responsible for its Representative(s) compliance with the terms of this Agreement.

2. Use Restriction. The Receiving Party shall not use any Confidential Information of the Disclosing Party for any purpose other than for the Transaction or for regulatory proceedings and RTO/ISO studies and analyses, including for example, an Indiana Utility Regulatory Commission ("IURC") proceeding in which information about the Transaction must be produced by Vectren to satisfy its evidentiary burden. In any such regulatory proceeding, study or analysis, Receiving Party will take care to protect Confidential Information from public disclosure through redacted public filings and other similar measures available to Receiving Party to protect Confidential Information. Receiving Party will advise Disclosing Party as soon as practical, of any such use and the protections in place for the Confidential Information.

3. Exceptions to Confidential Information. Under this Agreement, Confidential Information shall not include information that: (i) is already in Receiving Party's possession at the time of disclosure, as documented by the Receiving Party; (ii) becomes available subsequently to the Receiving Party on a non-confidential basis from a source not known or reasonably suspected by the Receiving Party to be bound by a confidentiality agreement or secrecy obligation owed to the Disclosing Party; (iii) is or becomes generally available to the public other than as a result of a breach of this Agreement by the Receiving Party or its Representative; or (iv) is independently developed by the Receiving Party without use, directly or indirectly, of Confidential Information of the Disclosing Party. If only a portion of the Confidential Information falls under one of the foregoing exceptions, then only that portion shall not be deemed Confidential Information.

4. Required Disclosure. If Receiving Party or its Representative is required, pursuant to any applicable court order, administrative order, statute, regulation or other official order by any government or any agency or department thereof, to disclose Confidential Information, the Receiving Party shall:

(i) provide the Disclosing Party with prompt written notice of any such request or requirement so that the Disclosing Party may seek a protective order or other appropriate remedy or protection and/or waive compliance with the provisions of this Agreement; and

(ii) reasonably cooperate with the Disclosing Party to obtain such protective order or other remedy. If Disclosing Party waives compliance with the relevant provisions of this Agreement or

the Disclosing Party does not receive a protective order or other remedy or protection, the Receiving Party agrees to

(a) provide only that portion of the Confidential Information for which the Disclosing Party has waived compliance with the relevant provisions of this Agreement, or which the Receiving Party is legally required to disclose,

(b) use commercially reasonable efforts to obtain assurances that confidential treatment will be accorded to such information, at Disclosing Party's expense, and

(c) give the Disclosing Party written notice in advance of any disclosure of Confidential Information.

5. Return or Destruction of Confidential Information. Either Party may terminate this Agreement with thirty days written notice. Additionally, at any time for any reason, upon the written request of the Disclosing Party, the Receiving Party and its Representative(s) will promptly:

(i) deliver to the Disclosing Party all original Confidential Information (whether written or electronic) furnished to the Receiving Party by or on behalf of the Disclosing Party, and

(ii) destroy any copies of such Confidential Information (including any extracts there from) if specifically requested by the Disclosing Party, with Receiving Party allowed to retain one archival copy of the Confidential Information in strict confidence for purposes of record retention and compliance or as otherwise required by applicable laws. If the Disclosing Party requests written proof, Receiving Party shall cause a duly authorized officer to certify in writing to the Disclosing Party that the requirements of the preceding sentence have been satisfied in full.

Regardless of the status of discussions regarding the Transaction and any request for return or destruction of Confidential Information, the Receiving Party will continue to be bound by terms of this Agreement.

6. Term. This Agreement is effective as of the date first written, above. It will terminate one (1) year after its effective date unless extended for additional one year terms by agreement of the Parties. If this Agreement is terminated during a term by either Party providing a termination notice pursuant to Section 5 above; the non-disclosure and use restriction obligations for Confidential Information under this Agreement shall survive any termination and remain in effect for the longer of (i) five (5) years, or (ii) such period during which any Confidential Information retains its status as a trade secret or qualifies as confidential under applicable law.

7. Miscellaneous.

(a) The Parties acknowledge and agree that unless and until a definitive agreement with respect to the Transaction has been executed by the Parties, no Party shall be under any legal obligation of any kind whatsoever to the other Party with respect to the Transaction, except as expressly provided in this Agreement.

(b) Receiving Party acknowledges that the Confidential Information is and at all times remains the sole and exclusive property of the Disclosing Party and that the Disclosing Party has the exclusive right, title, and interest to its Confidential Information. No right or license, by implication or otherwise, is granted by the Disclosing Party as a result of disclosure of Confidential Information hereunder. Each Party reserves the right at any time in its sole discretion, for any reason or no reason, to refuse to provide any further access to and to demand the return of the Confidential Information. The Receiving Party agrees that the Disclosing Party and its Representatives (i) makes no warranty as to the accuracy or completeness of the Confidential Information; and (ii) shall have no liability to the Receiving Party or its Representatives resulting from the use of any Confidential Information.

(c) Neither this Agreement nor any right, remedy, obligation or liability arising hereunder shall be assigned by any Party (whether by operation of law or otherwise), and any such assignment shall be null and void, except with the prior written consent of the other Party. Subject to the foregoing, this Agreement shall be binding upon and inure to the benefit of the Parties and their respective successors and permitted assigns. No provision of this Agreement shall create a third-party beneficiary relationship or otherwise confer any benefit, entitlement or right upon any person or entity other than the Parties.

(d) The Parties acknowledge and agree that no failure or delay by a Party in exercising any right or privilege hereunder shall operate as a waiver of that right or privilege. The provisions of this Agreement may be modified or waived only in writing signed by both Parties.

(f) This Agreement shall be governed by and construed in accordance with the laws of the State of Indiana.

(g) This Agreement may be executed in one or more counterparts, each of which shall be deemed an original, but all of which together shall constitute one and the same instrument.

(h) Each Party acknowledges and agrees that money damages would not be a sufficient remedy for any breach of this Agreement by such Party and that the other Party shall be entitled to seek equitable relief, including seeking an injunction and specific performance, as a remedy for any such breach. Such remedies shall not be deemed to be the exclusive remedies for a breach of this

Agreement, but shall be in addition to all other remedies available at law or equity.

(i) This Agreement constitutes the entire agreement between the Parties with respect to the subject matter herein and supersedes and cancels any prior agreements, representations, warranties, or communications, whether oral or written, between the Parties relating to the subject matter herein.

IN WITNESS WHEREOF, each Party hereto has executed this Agreement, or caused this Agreement to be executed on its behalf, all as of the day and year first above written.

Southern Indiana Gas and Electric Company, Inc.,
d/b/a Vectren Energy Delivery of Indiana, Inc.:

By:____________________________________
Name:
Title:

____________<company name>____________

By:____________________________________
Name:
Title:

# APPENDIX C – PRE-QUALIFICATION APPLICATION

# PRE-QUALIFICATION APPLICATION

## *Respondent's Credit-Related Information*

Provide the following data to enable Vectren to assess the financial viability of the Respondent as well as the entity providing the credit support on behalf of the Respondent (if applicable). Include any additional sheets and materials with this Appendix as necessary. As necessary, please specify whether the information provided is for the Respondent, its parent, or the entity providing the credit support on behalf of the Respondent.

Full Legal Name of the Respondent: ______________________________________________________

Dun & Bradstreet No. of Respondent: ______________________________________________________

Type of Organization: (Corporation, Partnership, etc.) ________________________________________

State of Organization: ____________________________________________________________

Respondent's Percent Ownership in Proposal: ______________________________________________

Full Legal Name(s) of Parent Corporation: ________________________________________________

Entity Providing Credit Support on Behalf of Respondent (if applicable): __________________________

Dun & Bradstreet No. of Entity Providing Credit Support: ____________________________________

Address for each entity referenced (provide additional sheets, if necessary): ________________________

______________________________________________________________________________

Type of Relationship: _____________________________________________________________

Current Senior Unsecured Debt Rating from each of S&P and Moody's Rating Agencies (specify the entity these ratings are for): ___________________________________________________________________

OR, if Respondent does not have a current Senior Unsecured Debt Rating, then Tangible Net Worth (total assets minus intangible assets (e.g. goodwill) minus total liabilities):_________________________________________

Bank References & Name of Institution: ________________________________________________

Bank Contact: Name, Title, Address and Phone Number: ______________________________________

______________________________________________________________________________

Pending Legal Disputes, if any (describe): ________________________________________________

__________________________________________________________________________

General description of Respondent's ability to construct, operate and maintain project, to the extent applicable:

______________________________________________________________________________

__________________________________________________________________________

Financial Statements of the Respondent or its Credit Support Provider, where applicable, must include Income Statement, Balance Sheet, Statement of Cash Flows, all notes corresponding to those financial statements and applicable schedules for three most recent fiscal years and financial report for the most recent quarter or year-to-date period. Also if available, please provide copies of the Annual Reports and/or 10K for the three most recent fiscal years and quarterly report (10Q) for the most recent quarter ended, if available. If such reports are available electronically, please provide link.

__________________________________________________________________________

__________________________________________________________________________

# APPENDIX D – PROPOSAL DATA

**SEE ATTACHMENT:**
**APPENDIX D – PROPOSAL DATA.xlsx**

# APPENDIX E – PROPOSAL CHECKLIST

## PROPOSAL CHECKLIST

***Required:***

☐Appendix A – Notice of Intent

☐Appendix B – Non-Disclosure Agreement

☐Appendix C – Pre-Qualification Application

☐Appendix D – Proposal Data

☐Executive Summary

☐MISO Generator Interconnection Agreement

☐MISO Facilities Study

☐MISO System Impact Study

☐Proposal Evaluation Fee (if applicable)

☐EPC Contract (if applicable)

***Other Data:***

☐Nodal economic analyses

☐PSS/E v33 raw or idev file that reflects modeling parameters of the Project at the respective point of interconnection

☐Unit inspection findings and dates and outstanding recommendations yet to be implemented, summary of operating plan, and outage and maintenance plans

☐Water supply description, NPDES permit details, all relevant environmental permits, environmental liabilities, and water chemistry program summary and performance

☐Emissions credits or offsets and baseline emissions of known and unknown pollutants

☐Spare parts list

☐Other contractual commitments

☐Summary of all legal proceedings, claims, actions, or suits against the Respondent, Guarantor, or involving the facility or site

☐Discussion regarding roles and responsibilities of any companies involved, status of major equipment procurement, facility site and Respondent's rights to such site, development schedule and associated risks and risk mitigation plans, and financing arrangements

☐Description of fuel supply, fuel cost information, and fuel contract duration and terms

☐Audited or unaudited financial statements including balance sheets, income statements, and cash flow statements for the proposed asset(s) for the past three years.

***LMR/DR Only:***

☐Description of how Proposal conforms with requirements of local utility and state law in order to offer resources for capacity accreditation within MISO under Module E Capacity Tracking

☐Description of LMR/DR customer(s), load drop values, equipment and technology, plans detailing deployment or utilization to support its operations, LMR/DR supplier and other key contributors, the supplier's process for aggregating and/or plan for recruiting participants, curtailment systems and procedures, and plans for communicating with participants during curtailment periods

☐Acknowledgement and agreement that LMR/DR supplier is responsible for activities and obligations listed in Section 6.4.3

CREATE AMAZING.

Burns & McDonnell World Headquarters
9400 Ward Parkway
Kansas City, MO 64114
O 816-333-9400
F 816-333-3690
www.burnsmcd.com

# Attachment 6.4 1x1 CCGT Study (Redacted)

Confidential

FINAL

# EPC COST - BASIS OF ESTIMATE

A.B. Brown 1x1

B&V PROJECT NO. 400278
B&V FILE NO. 41.0001



PREPARED FORREPARED FOR

VECTREN
A CenterPoint Energy Company

Vectren

31 JANUARY 2020

BLACK & VEATCH

# Table of Contents

# Executive Summary

The following is a basis of estimate summary for the EPC capital cost AACE Class 2 estimate for the A.B. Brown 1X1 Combined Cycle. The cost estimates contained in this report are based on the preliminary design by Black & Veatch, equipment pricing bids from suppliers of power island, and utilizing prior EPC contractor and vendor bid data. Power island equipment includes the combustion turbine(s), steam turbine, and HRSG(s).

The two plant alternatives that were estimated are as follows:

| 1X1 CCPP |
|---|
| GE 7FA.05 Fired |
| GE 7HA.01 Fired |

# 1.0 Estimate Basis

The cost estimate is based on an AACE Class 2 for engineering, equipment and construction costs.

The cost estimate is based upon a lump-sum turnkey EPC approach. Owner will purchase Power Island Equipment and assign to EPC contractor. Under this approach, the EPC contractor would have the responsibility for administration and performance interface of the power island equipment. The EPC structure used for the estimate is based upon the EPC contractor self-performing the work rather than utilizing multiple subcontractors.

The cost estimates are based on competitive bids obtained for power island equipment. Equipment, commodity, and construction services rates were based on EPC contractor and vendor data. Detailed material takeoffs based on the preliminary design of the A.B. Brown combined cycle with reference to similar sized plants that Black & Veatch has designed, constructed, and/or estimated on an EPC basis.

The estimate provided herein is based on preliminary information, and as such is to be considered a non-binding price opinion, and does not represent an offer to sell or a maximum price for the work scope. The estimate assumes moderate level of EPC commercial risk position and does not include specific pricing or schedule impacts for extensive site preparation. Other factors that can impact the price:

- Changes in labor market - A Labor Market Survey may identify craft labor conditions unique to this project that are recommended for further review and evaluation prior to start of construction.
- Final site conditions - Soil boring were secured for the proposed site.
- Noise requirements - Night-time steam blow conditions were assumed.
- Final project schedule.

## 1.1 QUANTITIES

Quantities that form the basis of the estimate were based on the engineering conceptual design and the engineering Bill of Quantities (BOQ) developed. The conceptual design was based on utilizing some of the existing A.B. Brown common system to support the new combined cycle, detailed information from equipment suppliers for new equipment, and specific site conditions. Where details were not available, assumptions were made based on similar sized plants and arrangements.

## 1.2 DIRECT COSTS

EPC bid pricing is segregated into two categories: direct and indirect. The direct project costs associated with the BOQs can then be developed by utilizing the unit costs provided by the EPC bidders.

- Unit manhour rates and wage rates are applied against the 1x1 quantities to develop labor cost.

- Unit material cost are applied against the updated quantities for commodities to develop material cost. Cost for major equipment has been scaled off the equipment cost for the major equipment obtained by the EPCs.
- Subcontract pricing was adjusted based upon the rates developed as part of the EPC bid analysis.

To develop the definitive capital cost estimate an RFI was issued to the major OEM Power Island equipment suppliers to obtain budgetary quotes. The OEM proposals included:

- Combustion Turbine and Generator Package
- Steam Turbine and Generator Package
- Heat Recovery Steam Generator

Bid tabulations were developed to evaluate the bids for completeness, scope, and adherence to the specification. The lowest evaluated bid was selected to use as the basis of the estimate.

## 1.3 CONSTRUCTION MANAGEMENT AND CONSTRUCTION INDIRECTS AND ENGINEERING

Construction Management and Construction Indirects (CMCI) were based on a self-perform (direct-hire) EPC approach instead of a multiple subcontract EPC approach. As a result, the cost for management of the work as well as tools, scaffolding, cranes, warehousing, and laydown to support this work show as a CMCI expense. Under a multiple subcontract approach, these costs would be included in the subcontractor unit rates and appear in the direct cost line items.

Construction management and indirects were estimated based on Black & Veatch's experience with similar plants and scopes of work as well as comparison against the EPC bids. The following costs were developed based upon Black & Veatch's internal metrics and experience then adjusted for schedule and man power loading:

- Project Engineering
- Project Construction Management including Safety, QC, Orientation
- Material Handling
- Mobilization and Demobilization
- Consumables & Small Tools
- Warranty

To obtain competitive bids Black & Veatch, in accordance with IURC code, the estimate includes competitive bids for the following costs:

- Cranes and Construction Equipment
- Scaffolding
- Temporary Facilities

Heavy haul transportation was based on Power Island Equipment delivery to the site and heavy cranes included in the Cranes and Construction Equipment RFQ.

## 1.4 INDIRECTS

Insurances, warranty, performance bonds, and a letter of credit costs are included, based on the EPC bids.

## 1.5 CONTINGENCY

[redacted]

[redacted]

[redacted]

Confidential

FINAL

# HRSG BYPASS STACK ANALYSIS

## A.B. Brown 1x1 F-Class

**B&V PROJECT NO. 400278**
**B&V FILE NO. 41.1201F**



PREPARED FOR

VECTREN
A CenterPoint Energy Company

Vectren

31 JANUARY 2020

BLACK & VEATCH

# Table of Contents



## LIST OF TABLES



## LIST OF FIGURES

# Executive Summary

In developing this report for the new Combined Cycle Power Plant (CCPP), Black & Veatch examined the benefits and drawbacks of adding a flue gas bypass stack between the combustion turbine and the heat recovery steam generator (HRSG). The bypass stack would allow the HRSG to be taken offline while the combustion turbine operates in simple cycle mode and would also allow the combustion turbines to be put into service up to 6 months before the erection and commissioning of the balance-of-plant equipment.

This analysis considered such factors as cost, plant design, environmental permitting, schedule, and operations, and maintenance. One major consideration is whether a selective catalytic reduction (SCR) system would be required to meet US Environmental Protection Agency (USEPA) emissions permitting requirements. The base cost for the installation of an HRSG bypass stack is estimated as [redacted]; the estimated cost with the addition of an SCR system would be [redacted].

The performance of the combined cycle would not be adversely affected by the inclusion of the bypass stack. USEPA standards, however, might limit the number of hours the unit could operate in simple cycle mode. While the addition of a HRSG stack flue gas bypass would provide the benefit of operational flexibility for the power plant, cost and performance impacts typically do not justify including this equipment in the power plant design.

# 1.0 Introduction

HRSG stack flue gas bypass systems provide the benefit of adding operational flexibility to power plant generation. Flue gas bypasses consist of installing a stack between the combustion turbine and HRSG; a diversion damper allows the combustion turbine exhaust to be diverted either to the bypass stack or the HRSG. Having a bypass stack available allows the HRSG to be taken offline or out of service, while the combustion turbine operates in simple cycle mode. The bypass stack would also allow for the combustion turbines to be put into service up to 6 months prior to erection and commissioning of the balance of plant under a typical consecutive construction schedule or longer for phased or delayed construction. The benefits must outweigh the cost in order for a flue gas bypass system to be feasible.

This evaluation of adding a flue gas bypass on each Combustion Turbine will help determine the cost (+/- 30%) and design impact of a flue gas bypass system to the plant design. Environmental permit considerations due to the flue gas bypass addition will also be reviewed. Schedule impacts, operations, and maintenance activities will also be identified and discussed.

# 2.0 Arrangement

On a combined cycle power plant, the flue gas bypass stack would be installed between the combustion turbine and the HRSG. Figure 2-1 shows a typical arrangement of a combustion turbine with a HRSG and a bypass stack. The bypass stack contains a damper that diverts the combustion turbine exhaust either up the bypass stack or to the HRSG. During simple cycle operation, the damper would be positioned to shut off flow to the HRSG and direct flow up the bypass stack. Under combined cycle operation, the damper would be positioned to shut off flow to the bypass stack and allow flow through to the HRSG. The diverter damper is actuated through the operating positions by electronically controlled hydraulic system. Figure 2-2 shows the components of the bypass stack.

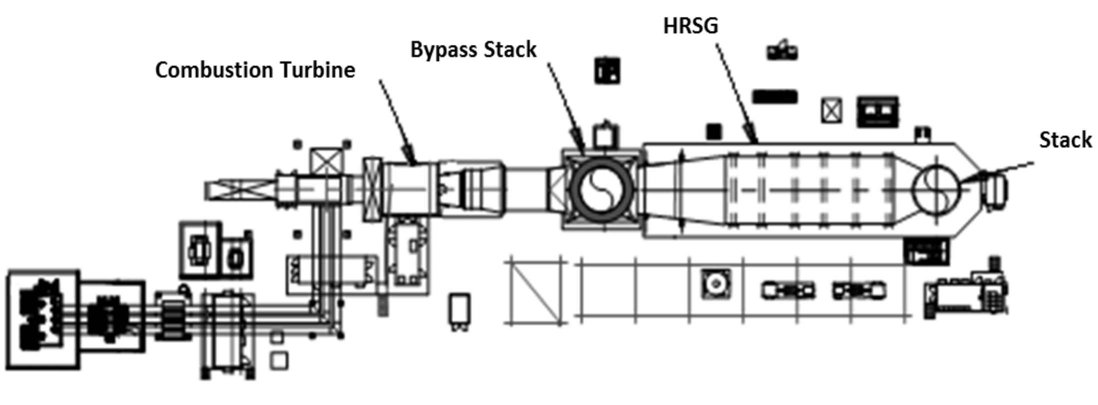



**Figure 2-1 Combined Cycle Layout with Bypass Stack**

| ITEM NO | QTY | DESCRIPTION |
|---|---|---|
| 1 | 1 | INTEGRATED EXPANSION JOINT |
| 2 | 2 | TRANSITION DUCT HALVES |
| 3 | 4 | SILENCER DUCT QUARTER SECTIONS |
| 4 | 4 | SILENCER DUCT FLAT WALL PANELS |
| 5 | 2 | TRANSITION DUCT HALVES |
| 6 | 8 | VERTICAL STACK SEGMENTS |
| 7 | 2 | VERTICAL STACK SEGMENTS |
| 8 | | BOTTOM SILENCER PANELS |
| 9 | | TOP SILENCER PANELS |
| 10 | | SUPPORT STRUCTURE |
| 11 | | LADDERS AND PLATFORMS |
| 12 | | PERSONNEL PROTECTION |
| 13 | 1 | HORIZONTAL TRANSITION |
| 14 | 1 | GUILLOTINE DUCT |
| 15 | 1 | DAMPER |

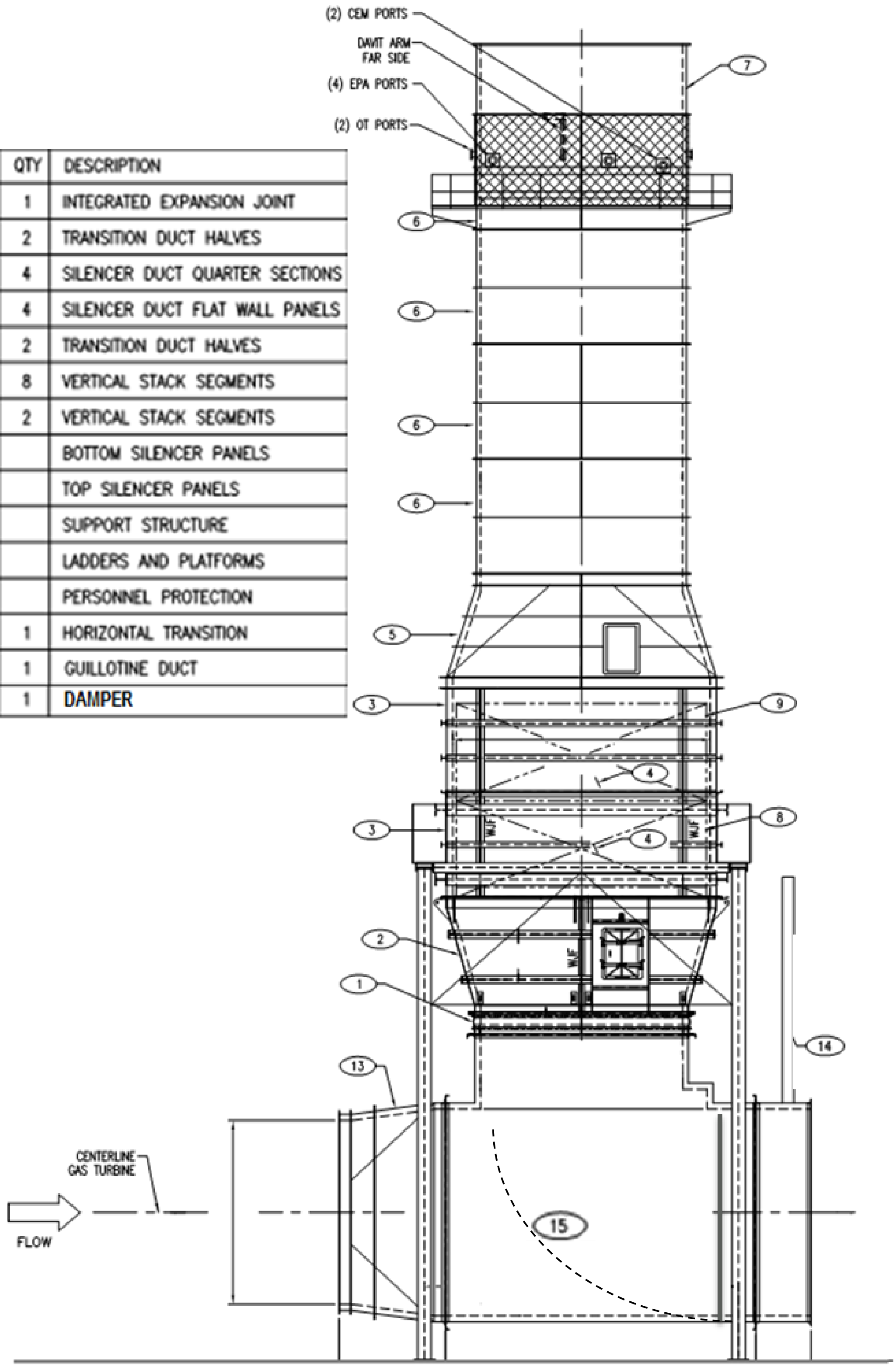



**Figure 2-2 Typical Gas Bypass Stack**

If an SCR were required, a section could be added to the stack upstream of the silencer to house catalyst, tempering air skid, and ammonia injection equipment. While there is not much industry experience with installing SCRs in the vertical sections of combustion turbine bypass stacks, the technical challenges would be similar to those seen in a coal facility where vertical SCRs are common. The SCR would consist of the following components:

- Catalyst
- Tempering air system to lower combustion turbine exhaust gas to an allowable inlet temperature for the catalyst (<800 °F)
- Mixing vanes and flow distribution
- Ammonia distribution manifold and injection grid
- Ammonia vaporization and flow control unit
- Emission monitoring system

Alternatively, the SCR may be horizontal and then the SCR and bypass stack would be placed in parallel with the HRSG. Air emission requirements are discussed in Section 6.0.

# 3.0 Capital Costs

Typical suppliers of HRSG bypass stacks include Braden Manufacturing, Peerless-Aarding, and Clyde Bergmann.

Pricing from recent proposals was reviewed to find a budgetary estimate for a bypass stack with a height of 135 ft with stack silencer and continuous emission monitoring (CEMS) system. Also included were all required dampers, motors, controls, insulation, lighting, support steel and platforming as required.

Table 3-1 is a high level breakdown of the costs associated with the bypass stack.

**Table 3-1 Capital Costs for HRSG Bypass Stack**

| DESCRIPTION | INSTALLED COST / UNIT |
|---|---|
| FOUNDATIONS/CIVIL WORK | [redacted] |
| STACK (including ductwork, damper, supplementary steel, lighting, electrical) | [redacted] |
| CEMS (NOx and CO analyzers, includes electrical and controls) | [redacted] |
| **BYPASS STACK (no SCR)** | [redacted] |
| VERTICAL SCR (includes ammonia injection, $NO_X$ and CO catalyst) | [redacted] |
| **BYPASS STACK (with vertical SCR)** | [redacted] |

# 4.0 Performance Impacts

Installation of a bypass stack allows for the operation of the combustion turbine in simple cycle mode; however, operating in simple cycle mode may have limited operating hours as discussed in Section 6.0, Permitting and Emissions.

[redacted] It would normally be expected that plant output would decrease due to increased exhaust pressure drop due to a reduction in CTG load, which is only partially offset by an increase in STG load resulting from increased CTG exhaust energy. However, the 7F.05 is shaft-limited at this operating condition and the CTG output is not reduced due to the increased exhaust pressure. Instead, the CTG fires harder to maintain its output, resulting in an increase in exhaust flow, thereby increasing steam production and STG output. Other OEM machines may not have this characteristic and net plant output could be expected to decrease due to increased CTG exhaust pressure.

If an SCR is required, a tempering air skid is required to keep the CTG exhaust below 800 °F to prevent damage to the catalyst. The CTG exhaust reaches 800 °F in less than a minute from ignition as the CTG reaches 5% load. The tempering air fan and the ammonia vaporization and flow control system will have an auxiliary load of 1,000 kW.

# 5.0 Maintenance

Maintenance consists of correcting deficiencies noted during inspection. For HRSG bypass stacks without an SCR, the primary maintenance concern is the damper seals, diverter damper bearings, and the dampers hydraulic power unit.

Typical diverter maintenance activities include:

- Shaft seal replacement.
- Housing perimeter seal replacement.
- High temperature bearing repair or replacement.
- Shaft seals are typically designed to last five years.

Recommended spare parts include:

- Spare limit switches.
- Position transmitters.
- Seal-air pressure blower.
- Main drive bearing kit.
- Damper seal sets.
- Expansion joints.

If an SCR is required, additional maintenance is required for the hot air tempering skids, ammonia flow control units, and replacement of $NO_x$ and CO catalysts.

# 6.0 Permitting and Emissions

## 6.1 FEDERAL REGULATIONS POSING CHALLENGES

Officially titled *Standards of Performance for Greenhouse Gas Emissions from New, Modified, and Reconstructed Stationary Sources: Electric Utility Generating Units*, 40 CFR Part 60, Subpart TTTT was finalized by the USEPA on August 3, 2015. In this rulemaking, the USEPA established output-based emissions standards for two subcategories of power plants; electric utility steam generating units (e.g., coal-fired power plants) and stationary combustion turbines. The rule makes no distinction between simple cycle and combined cycle combustion turbines. Rather, it requires combustion turbines to meet certain $CO_2$ emissions standards depending on whether they are classified as baseload or non-baseload units.

The distinction between baseload and non-baseload units is made based upon the number of hours a combustion turbine can operate relative to its design efficiency. If a combustion turbine operates more hours than its net, Lower Heating Value (LHV) design efficiency, then it is considered a baseload unit. Baseload units are required to meet an output-based $CO_2$ emission standard of 1,000 lb/MWh (gross output, 12-operating month basis).

[redacted]

If the plant is restricted in hours less than the percent of net design efficiency hours, the plant is classified as a non-baseload unit with respect to NSPS Subpart TTTT. Natural gas-fired non-baseload units are subject to a heat-input based $CO_2$ emission standard 120 lb/MBtu (HHV, 12-operating month basis). This standard is readily achievable because the $CO_2$ emission rate of natural gas is 117 lb/MBtu.

## 6.2 AIR PERMITTING CHALLENGES

While an emissions netting analysis (wherein any recent unit shutdowns can be used to demonstrate that net emissions increases from the new installation would not exceed major source permitting thresholds) could allow the project to avoid major source permitting requirements there is still a possibility the project could trigger major source permitting. In such a scenario, the air permitting process would be dictated by the Prevention of Significant Deterioration (PSD) regulations which require, among other things, an evaluation of Best Available Control Technology (BACT). Should BACT be required for $NO_X$ emissions, the project's air construction permit could require the use of an SCR.

# 7.0 Conclusions

Having a bypass stack available allows the HRSG to be taken offline or out of service, while the combustion turbine operates in simple cycle mode. In addition, the combustion turbines could be put into service up to 6 months prior to erection and commissioning of the balance of plant under a typical consecutive construction schedule or longer for phased or delayed construction.

While the addition of a HRSG stack flue gas bypass would provide the benefit of operational flexibility for the power plant, cost and performance impacts typically do not justify including this equipment in the power plant design. The total installed cost of the bypass stack for a single 1x1 train is approximately [redacted] without an SCR. A vertical SCR would be considered a first of a kind for this application so no cost is easily achievable without a prior design. It is expected that if an SCR is required due to concerns with emissions the cost would be approximately double [redacted] with an SCR. If a horizontal SCR is required due to emission limits, the SCR would not be feasible as it would be approximately the size of the HRSG. The performance of the combined cycle would not be adversely affected by the inclusion of the bypass stack. The amount of hours where the unit can operate in simple cycle mode with the HRSG bypassed may be limited due to NSPS 40 CFR Part 60, Subpart TTTT.

Confidential

FINAL

# HEAT REJECTION / EXISTING COOLING TOWER ANALYSIS

## A.B. Brown 1x1 F-Class

**B&V PROJECT NO. 400278**
**B&V FILE NO. 41.1202F**



PREPARED FOR

VECTREN
A CenterPoint Energy Company

Vectren

31 JANUARY 2020

BLACK & VEATCH
Building a world of difference.

# Table of Contents



## LIST OF TABLES



## LIST OF FIGURES

# Executive Summary

In developing this report, Black & Veatch focused its attention to the specific areas directed by Vectren by analyzing the design impacts and cost comparison of using one existing cooling tower, circulating water pumps, and circulating water pipe for the new Combined Cycle Power Plant (CCPP). Black & Veatch reviewed multiple existing cooling tower reuse scenarios to evaluate the performance against the design for a new cooling tower. A performance summary for the two most optimal scenarios is provided in Section 2.0.

Black & Veatch evaluated the following three cooling tower alternatives for this study:

- Alternative 1: Reuse Cooling Tower, Circulating Water Pumps, and Existing Piping
- Alternative 2: Reuse Cooling Tower and Circulating Water Pumps with All New Piping
- Alternative 3: All New Cooling Tower, Circulating Water Pumps, and Piping

This report has been summarized in a Cooling Tower Alternatives Comparison Matrix provided in Table ES-1. [redacted] Consequently, it is recommended that Vectren utilize the existing Unit 1 cooling tower, circulating water pumps and piping as the design basis for the new combined cycle power plant.

**Table ES-1 Cooling Tower Alternatives Comparison Matrix**

| ALTERNATIVE | REUSE TOWER, PUMPS, AND PIPING (ALTERNATIVE 1) | REUSE TOWER AND PUMPS WITH ALL NEW PIPING (ALTERNATIVE 2) | NEW TOWER, PUMPS, AND PIPING (ALTERNATIVE 3) |
|---|---|---|---|
| Description | [redacted] | [redacted] | [redacted] |
| Constructability | [redacted] | [redacted] | [redacted] |
| Tower Performance | [redacted] | [redacted] | [redacted] |
| Condenser Adder | [redacted] | [redacted] | [redacted] |
| Tie-In Outage Length | [redacted] | [redacted] | [redacted] |
| Total Installed Cost | [redacted] | [redacted] | [redacted] |
| Operating and Maintenance Cost | [redacted] | [redacted] | [redacted] |
| Circulating Water Pump Auxiliary Load | [redacted] | [redacted] | [redacted] |
| New Major Equipment | [redacted] | [redacted] | [redacted] |
| Advantages | [redacted] | [redacted] | [redacted] |

| ALTERNATIVE | REUSE TOWER, PUMPS, AND PIPING (ALTERNATIVE 1) | REUSE TOWER AND PUMPS WITH ALL NEW PIPING (ALTERNATIVE 2) | NEW TOWER, PUMPS, AND PIPING (ALTERNATIVE 3) |
|---|---|---|---|
| Disadvantages | [redacted]<br>[redacted]<br>[redacted] | [redacted]<br>[redacted]<br>[redacted]<br>[redacted] | [redacted] |

# 1.0 Introduction

The purpose of this study is to analyze the A.B. Brown Unit 1 circulating water system to determine whether all or portions of the existing cooling towers, circulating water pumps, and circulating water piping can be reused for use with a new Combined Cycle Power Plant (CCPP). Black & Veatch has evaluated the performance of the existing cooling towers and circulating water pumps to determine the optimal operating scenarios [redacted] when paired with the new CCPP.

This evaluation of reusing the existing circulating water system components will help determine the [redacted] design impact of this system to the new CCPP design. Schedule impacts, operations, and maintenance activities will also be identified and discussed.

# 2.0 Performance Evaluation

Several operating scenarios were evaluated to determine the best preliminary design basis for reusing the existing cooling towers and circulating water pumps. Upon selection of the final plant design, the preferred number of cooling tower cells in service should be reviewed.

Alternatives 1 and 2 utilize the Unit 1 existing seven cell cooling tower and two circulating water pumps provide a total circulating water flow of 125,000 gallons per minute (gpm).

The existing cooling tower would be larger than the cooling tower for Alternative 3. The design flow rate of the existing cooling tower is larger than the design flow rate would be for the new cooling tower. To accommodate the larger flow rate, the condenser will be larger, and more expensive, but provides better performance. The overall heat rejection system for Alternatives 1 and 2 result in a decrease in steam turbine backpressure and an increase in auxiliary power when compared to the new heat rejection system considered in Alternative 3.

The estimated performance based on nominal 1x1 7F.05 combined cycle performance for the alternatives is shown on Figure 2-1 for unfired heat recovery steam generator (HRSG) operation and Table 2-2 for fired HRSG operation. For reference, Tables 2-1 and 2-2 provide the estimated performance values shown on the graphs.

[redacted]

**Table 2-1 Comparative Unfired Plant Performance for Cooling Tower Alternatives**

| UNFIRED OPERATING CONDITIONS | 1X100% CTG LOAD 8.1F/70% AMBIENT EVAP COOLING OFF DUCT FIRING OFF | 1X100% CTG LOAD 56.8F/48% AMBIENT EVAP COOLING OFF DUCT FIRING OFF | 1X100% CTG LOAD 93.7F/45% AMBIENT EVAP COOLING ON DUCT FIRING OFF |
|---|---|---|---|
| 7 Cell Net Plant Output, kW | [redacted] | [redacted] | [redacted] |
| 7 Cell Net Plant Heat Rate (LHV), Btu/kWh | [redacted] | [redacted] | [redacted] |
| New Tower Net Plant Output, kW | [redacted] | [redacted] | [redacted] |
| New Tower Net Plant Heat Rate (LHV), Btu/kWh | [redacted] | [redacted] | [redacted] |

**Table 2-2 Comparative Fired Plant Performance for Cooling Tower Alternatives**

| FIRED OPERATING CONDITIONS | 1X100% CTG LOAD 8.1F/70% AMBIENT EVAP COOLING OFF DUCT FIRING ON | 1X100% CTG LOAD 56.8F/48% AMBIENT EVAP COOLING OFF DUCT FIRING ON | 1X100% CTG LOAD 93.7F/45% AMBIENT EVAP COOLING ON DUCT FIRING ON |
|---|---|---|---|
| 7 Cell Net Plant Output, kW | [redacted] | [redacted] | [redacted] |
| 7 Cell Net Plant Heat Rate (LHV), Btu/kWh | [redacted] | [redacted] | [redacted] |
| New Tower Net Plant Output, kW | [redacted] | [redacted] | [redacted] |
| New Tower Net Plant Heat Rate (LHV), Btu/kWh | [redacted] | [redacted] | [redacted] |

# 3.0 Existing Equipment

## 3.1 EXISTING COOLING TOWER CONDITION

The Unit 1 cooling tower cells were recently rebuilt from wood to fiberglass as such the condition is assumed satisfactory and no major repairs are required. Three of the seven Unit 2 cooling tower cells were recently rebuilt from wood to fiberglass. To extend the life of the Unit 2 cooling tower the remaining four (4) cells would require rebuilding to fiberglass at a cost of approximately [redacted]. To eliminate the need for this expenditure, the Unit 1 cooling tower will be used for the new CCPP. The existing cooling tower basins for Unit 1 and Unit 2 are lacking an intake structure for an auxiliary cooling water pump. Modifications will be needed to the basin to add the new intake and pump structure.

## 3.2 EXISTING CIRCULATING WATER PUMPS

The existing circulating water pumps have been evaluated for both Alternatives 1 and 2 and it has been determined that they have sufficient capacity to meet the required flow and head for the new CCPP circulating water system. To extend the life of the two pumps and motors a shop overhaul would be required.

Black & Veatch evaluated the use of variable frequency drives (VFDs) on the existing circulating water pumps to modify the pump flow rate for different CCPP operating scenarios. Because the static head component is constant for all operating conditions and accounts for the majority of the circulating water pump head requirement, a VFD would provide minimal performance gains [redacted] per pump.

## 3.3 EXISTING CIRCULATING WATER PIPE

The existing circulating water piping is carbon steel piping with a bitumastic coating. Coatings have been maintained and repaired during normal inspection and repairs throughout the life of the existing A.B. Brown Plant. For this study, it is assumed that the condition of the pipe is satisfactory and no repairs will be required to the piping that is being reused as part of Alternative 1.

# 4.0 Constructability

For each of the cooling tower reuse alternatives there are several items to consider that could impact both the new CCPP and existing A.B. Brown Unit 1 during the installation and commissioning phase of the project.

## 4.1 ALTERNATIVE 1

Alternative 1 reuses a significant amount of existing underground steel piping, which will require continued inspection and maintenance to last the 30 year design life of the new CCPP. The existing piping is assumed to be in satisfactory condition given feedback from Vectren that they have performed scheduled inspections and coatings on the piping as required.

## 4.2 ALTERNATIVE 2

Alternative 2 will require unit outages considerably longer than Alternative 1, up to 2 or 3 months, given that a large section of existing Unit 1 circulating water piping and cooling tower risers are to be replaced in-kind with new steel piping. Once completed, Alternative 2 will result in the existing cooling tower and circulating water pump connected to the new CCPP circulating water system with all new piping, resulting in shutdown of the existing Unit 1 at the time of the tie-in.

## 4.3 ALTERNATIVE 3

Alternative 3 is an all new circulating water system that includes a 6 cell back-to-back mechanical draft counter flow cooling tower, 2x50 percent circulating water pumps, and steel circulating water piping. Because this system is independent of the existing equipment no unit outage will be required and the existing Units 1 and 2 will be able to operate during and after the installation of the new circulating water system. This alternative also results in the least auxiliary load because of minimizing the size of the circulating water pumps for the new CCPP design conditions.

# 5.0 Capital Costs

Table 5-1 is a high-level breakdown of the costs for both reusing the existing cooling towers and installing new cooling towers with a new basin.

**Table 5-1 Estimated Costs for Cooling Tower Alternatives**

| DESCRIPTION | REUSE TOWER, PUMPS, AND PIPING (ALTERNATIVE 1) | REUSE TOWER AND PUMPS WITH ALL NEW PIPING (ALTERNATIVE 2) | NEW TOWER, PUMPS, AND PIPING (ALTERNATIVE 3) |
|---|---|---|---|
| New 6 Cell Cooling Tower with Basin (F&E) | [redacted] | [redacted] | [redacted] |
| Condenser Adder | [redacted] | [redacted] | [redacted] |
| Circulating Water Pumps | [redacted] | [redacted] | [redacted] |
| New Piping and Valves (A/G and U/G) | [redacted] | [redacted] | [redacted] |
| Basin Modifications for Auxiliary Cooling Water Pump | [redacted] | [redacted] | [redacted] |
| Site Work | [redacted] | [redacted] | [redacted] |
| Mechanical Installation (Does not include tower erection) | [redacted] | [redacted] | [redacted] |
| **Total** | [redacted] | [redacted] | [redacted] |
| **Cost Difference** | [redacted] | [redacted] | [redacted] |

# 6.0 Conclusions

Based on the evaluation, the reusing the existing Unit 1 cooling tower, pumps and piping (Alternative 1) is the lowest cost technically acceptable solution and should be used as the design basis for the new combined cycle power plant.

Confidential

FINAL

# FAST START VS. CONVENTIONAL START ANALYSIS

## A.B. Brown 1x1 F-Class

**B&V PROJECT NO. 400278**
**B&V FILE NO. 41.1203F**



PREPARED FOR

VECTREN
A CenterPoint Energy Company

Vectren

31 JANUARY 2020

BLACK & VEATCH
Building a world of difference.

# Table of Contents



## LIST OF TABLES



## LIST OF FIGURES

# 1.0 Introduction

This study evaluates designing a 1x1 GE 7F.05 combined cycle power plant with "fast start" capabilities versus a plant design for "conventional" start. The GE 7F.05 is one of several candidate F-Class combustion turbine offerings.

## 1.1 STARTUP DURATION DEFINITION

Since plant load is affected by ambient conditions, startup durations are typically defined based on achieving a certain operating condition and not a specified operating load. The beginning of the start is typically defined as combustion turbine roll-off or first ignition. Startup is complete when a predefined operating condition is reached.

Startup can be a confusing term as it is used to describe the start from ignition to various ending operating conditions across the industry. These ending operating scenarios can include:

- CTG Full Speed No Load – The point at which the combustion turbine is removed from the static starter and brought to full speed.
- CTG Sync - The point at which the combustion turbine (CTG) is synchronized with the grid.
- Emission Start - Achieving minimum emissions compliance load. This occurs when stack discharge emissions reaching steady state compliance with air quality standards.
- CTG Full Load Start - Combustion turbine at baseload with permitted emissions at the stack.
- Plant Full Load Start - Combustion turbine at baseload and steam turbine bypass valves fully closed. Steam turbine in service.

**For the purpose of this study Fast Start is being defined as a rapid start commencing with ignition until the combustion turbine reaches minimum emission load compliance (MECL). When speaking with others in the industry the ending operating condition should be defined.**

The type of start is also defined by the amount of time the unit has been shutdown. It is typical to assume the shutdown begins at fuel flow shutoff to the combustion turbines during a normal plant shutdown sequence from a steady state baseload condition. Durations as defined by the project are:

- Hot start = Shutdown 8 hours or less
- Warm start = > 8 hours and < 48 hours
- Cold start = Shutdown 48 hours or more

The lead time activities prior to a warm or cold fast startup typically commence with startup of the auxiliary boiler. Depending on the start condition for the auxiliary boiler and the features incorporated to permit its fast start, this activity may need to commence approximately three hours before the actual combustion turbine start condition.

## 1.2 CONVENTIONAL VERSUS FAST START

Conventional combined cycle facility startup durations are constrained by steam cycle equipment limitations, specifically the heat recovery steam generator and steam turbine temperature ramp capabilities. Heat recovery steam generators and steam turbines are designed to operate at very high temperatures and pressures and, therefore, are comprised of very thick metal alloy components (e.g. steam drums, steam turbine rotors). These thick components can suffer from high thermal stress and increased life expenditure if they are subjected to large temperature differentials (e.g., 1,000°F steam across an ambient temperature steam turbine rotor) or rapid temperature ramp rates. HRSG and steam turbine suppliers provide strict temperature ramp rates and temperature differential requirements for their equipment that must be used to define and limit the startup sequence and duration in order to protect the equipment.

HRSGs designed through the middle of the last decade were generally not capable of allowing combustion turbines to start at their maximum capability without incurring significant maintenance impacts. These units required pauses ("holds") at low CTG loads to "heat soak" their heavy-walled components prior to releasing the unit on sustained ramp rates of typically less than 7°F per minute, as measured by the high-pressure (HP) drum steam saturation temperature.

Today's HRSGs can be more robustly designed for the rapid ramp rates of advanced class combustion turbines, which can exceed 50 megawatts (MW) per minute and yield HRSG temperature ramp rates exceeding 30°F per minute.

Though HRSGs are now designed to allow combustion turbines to start at their maximum capability, steam turbines are not. Cold steam turbines require relatively cool steam, typically in the range of 700°F, on first admission to the equipment. During the startup sequence, steam temperatures downstream of the HRSG are primarily controlled through two means working in tandem, CTG exhaust temperature control and desuperheating of the generated steam. CTG exhaust temperature control tunes the CTG to minimize the exhaust temperature into the HRSG during the startup sequence, as a cooler exhaust temperature produces cooler steam. Desuperheaters spray water into the steam headers to reduce, or "attemperate", the steam by reducing the level of superheat above the steam saturation temperature.

Most HRSGs include interstage desuperheaters that are installed between superheater and reheater sections to control the final HRSG exit steam temperatures. As the combustion turbine ramps above very low loads towards the MECL, the CTG exhaust temperature control and HRSG interstage desuperheaters are no longer capable of cooling the steam to the temperatures permitted by a relatively cool steam turbine. The steam turbine becomes a critical constraint on the start time unless the HRSG exit steam temperatures can be further reduced to match the steam turbine steam temperature requirements. In effect, the steam turbine must be 'decoupled' from the combustion turbine so that the combustion turbine start is not constrained by the steam cycle.

The steam turbine can be decoupled and its steam temperature requirements met irrespective of combustion turbine load by adding terminal desuperheaters (i.e., desuperheaters downstream of the HRSG in the high-pressure (HP) and hot reheat steam headers) to cool the HRSG exit steam to the steam turbine requirements.

Decoupling the steam turbine from the CTG/HRSG train allows the combustion turbine to ramp to emissions compliance load levels without hold periods in the firing sequence. A no-holds startup sequence is typically referred to as an uninhibited start.

Figure 1-1 provides a high-level comparison of the typical CTG load path for a 1x1 conventional combined cycle to that of a fast-start combined cycle. Additional details on the performance differences between the two startup types are discussed in Section 4.0.

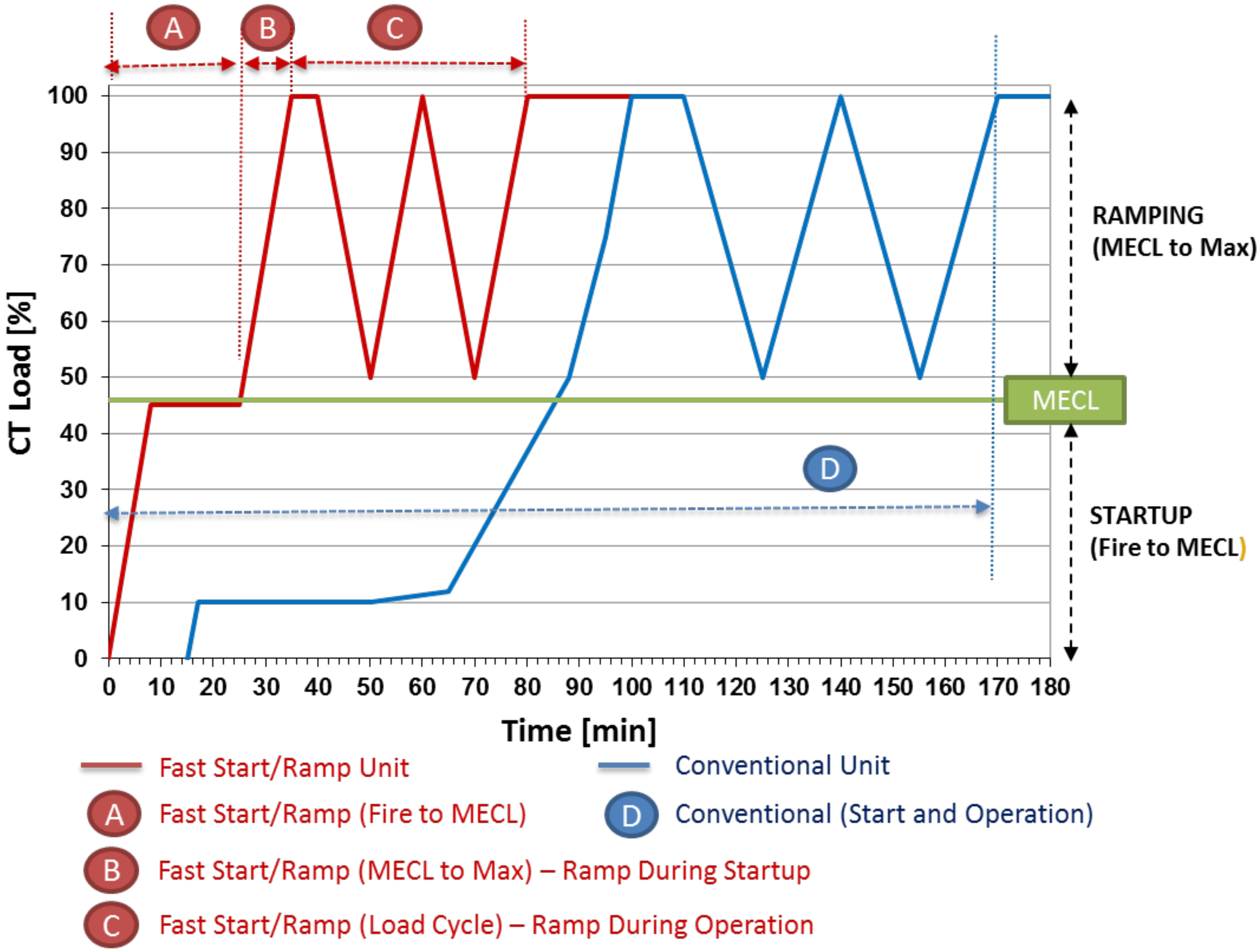



**Figure 1-1 Comparison of Combustion Turbine Loading during Hot Start Event (Excludes Purge)**

# 2.0 Design Features

Capital costs are higher for fast start plants than plants designed for conventional starts. Equipment and balance of plant systems affected by the additional design consideration for fast start are as described below and in Table 2-1. Column A of Table 2-1 lists specific design features and equipment required for fast start operation. Column D of Table 2-1 lists design features of conventional start units. Columns B and C will be discussed in the Fast Start vs. Conventional Unit Ramp Rate Analysis (File No. 400278.41.1204F).

**Table 2-1 Design Features of Combined Cycles Designed for Various Operating Scenarios**

| FEATURES REQUIRED TO MEET OPERATING SCENARIO | A<br>FAST START (FIRE TO MECL) | B<br>FAST RAMP (MECL TO MAX) | C<br>FAST RAMP (LOAD CYCLE) | D<br>CONVENTIONAL (START AND OP) |
|---|---|---|---|---|
| Required Option = ● , Recommended Option = ☐ , Standard Option = ◆ | | | | |
| **Combustion Turbine** | | | | |
| Fast Start Equipped | ● | | | |
| Natural Gas Purge Credits | ● | | | ☐ |
| Service Life Monitoring System | ◆ | ◆ | ◆ | ◆ |
| Advanced Control System | ● | ● | ● | |
| **HRSG** | | | | |
| Advanced Drum Design | ● | ● | | |
| Enhanced Nozzle Connections | ● | ● | | |
| Improved HRSG Materials | ● | ● | | |
| Improved HRSG Geometries | ◆ | ◆ | ◆ | ◆ |
| Service Life Monitoring System | ☐ | ☐ | ☐ | |
| Stack Damper and Insulation | ● | | | ☐ |
| Terminal Attemperators | ● | ● | ● | |
| LP Economizer Recirculation/ Heat Exchanger | ● | ● | | |
| **Steam Turbine** | | | | |
| Optimized Casing Design | ● | ● | | |
| Advanced Control System | ● | ● | ● | |

| FEATURES REQUIRED TO MEET OPERATING SCENARIO | A<br>FAST START<br>(FIRE TO MECL) | B<br>FAST RAMP<br>(MECL TO MAX) | C<br>FAST RAMP<br>(LOAD CYCLE) | D<br>CONVENTIONAL<br>(START AND OP) |
|---|---|---|---|---|
| Service Life Monitoring System | ● | ● | □ | |
| Advanced Stop Valve Design | ● | | | |
| Increased Thermal Clearances | ● | ● | | |
| Advanced Turbine Water Induction Protection | ● | ● | ● | |
| **Emissions Control** | | | | |
| Feed-forward Ammonia Controls | ● | ● | ● | |
| **Auxiliary Steam** | | | | |
| Auxiliary Boiler | ● | | | |
| Condenser and HRSG Sparging | ● | | | |
| **Feedwater System** | | | | |
| Larger Condensate Pump | ● | ● | ● | |
| Larger Feedwater Pump | ● | ● | ● | |
| Higher Stage IP Bleed | ● | ● | ● | |
| **Heat Rejection System** | | | | |
| Surface Condenser – Fast Start Design | ● | | | |
| **Fuel Gas System** | | | | |
| Supplementary Fuel Gas Heating(1) | □ | | | |
| **Water Treatment System** | | | | |
| Condensate Polisher(2) | □ | | | |
| **Auxiliary Electrical System** | | | | |
| Larger Equipment for Higher Loads | ● | ● | ● | |

Notes:

1. Supplementary fuel gas heating as required by combustion turbine supplier.
2. Space should be allotted for future condensate polisher installation, if required.

## 2.1 COMBUSTION TURBINE

Combustion turbines designed for fast-ramping will be equipped with fast start features. These include positive isolation to ensure that purge credits have been maintained per NFPA 85 and that the gas path will not require a purge prior to startup. The control system for fast start of the plant should be fully automated to minimize times between sequential steps and allow for greater consistency during startup.

Both fast start and conventional units are equipped with service life monitoring systems that control unit ramp operations based on predetermined thermal stress limitations. Fast Start units are equipped with advanced control schemes incorporating model based controls (MBC) to optimize startup based on these monitoring systems.

Purge credits established during the shutdown must still be intact. NFPA 85 requires that a fresh air purge of the combustion turbine and HRSG be accomplished prior to start. NFPA 85 requires that at least five volume changes be completed or a minimum purge of 5 minutes prior to ignition. Typical purge durations can range from 5 to 20 minutes. The 2011 edition of NFPA 85 allowed for purge credits to be achieved when the unit is taken off line if the purge is completed and the valving arrangement is shown to positively isolate any fuel from entering the system. The combustion turbine can usually achieve the required purge when coasting down following a loss of ignition.

## 2.2 HRSG

HRSGs designed for fast-start plants can subject HRSG components such as superheaters and reheaters to rapid heating. Large thermal stresses can be produced by the differential expansion of the tubes within the HRSG. HRSG designs in such plants must be capable of accommodating the rapid change in temperature and flow of flue gas generated by load ramping of advanced class combustion turbines.

To reduce thermal capacity of drums many options are used to decrease the drum size and wall thickness including utilizing Benson style drums, utilizing multiple drums, high strength drum materials, and reduced residence time. Self-reinforced nozzles, full penetration nozzles, full penetration welds, and steam sparger systems further improve the ability to accept rapidly changing exhaust gas conditions and steam conditions. Improved materials throughout the high pressure superheater and reheater can be required. Online, real-time monitoring system should be included to evaluate HRSG life consumption.

In order to reduce the thermal capacity of drums, the residence time may also be reduced for fast start units. Fast start units typically have drum storage time around two minutes. Conventional start plants have drum storage time from 3-5 minutes.

Fast start plants are equipped with a stack damper and with an insulated stack up to the stack damper. The stack damper and insulation are critical as they restrict the flow of flue gas out the HRSG stack minimizing heat loss when the unit is offline. While conventional units do not require stack dampers and insulation, it is a recommended practice to minimize heat loss when the unit is offline.

Both fast start and conventional units have improved HRSG geometries compared to those built a decade ago. Improvements in geometries have been to decrease thermal stresses from unit cycling and are part of the HRSG standard design such as coil flexibility to superheater/reheater interconnecting piping and accommodations for tube-to-tube temperature differentials.

## 2.3 STEAM TURBINE

The steam turbine must also be designed for the thermal gradients experienced while ramping during start-up. For fast start machines, the casing design must be optimized to reduce the thermal stress during temperature fluctuations and to accept faster start up and load change gradients. The use of higher grade material may be employed in the high pressure and intermediate casings and valves to reduce component thickness. Main steam stop valves must be designed so that these valves can be opened at a relatively higher pressure. Integral rotor stress monitors can be provided; the rotor stress monitor is typically capable of limiting or reducing the steam turbine load or speed increase and is designed to trip the turbine when the calculated rotor stresses exceed allowable limits.

For machines undergoing a fast ramp, attemperators are often required on the high pressure and hot reheat steam lines. Overspray on these attemperators can lead to water in these steam lines; special attention needs to be provided for turbine water induction prevention for units equipped with terminal attemperators.

## 2.4 EMISSIONS AND AMMONIA FEED

Outlet $NO_x$ from the combustion turbine can vary highly when undergoing fast startup and fast ramp conditions. Conventional units only measure $NO_x$ at the stack; for fast ramping units limiting $NO_x$ measurements to the stack only can lead to over injecting or under injecting ammonia. Higher ammonia slip and potentially greater $SO_2$ conversion in fast-start and fast-ramp units create additional challenges for control of sulfur-bearing deposits in the colder HRSG areas. Low-pressure evaporators and economizers are particularly at risk. For fast ramping plants, addition of feed forward controls to quicken the saturation of the SCR catalyst (if included) is required. Also the HRSG should be equipped with LP economizer recirculation or heating systems to maintain surfaces above $SO_2$ dew points.

## 2.5 AUXILIARY STEAM

Fast start units require an auxiliary boiler to produce steam prior to the startup of the unit. This steam is used for steam line warming, establishing the steam turbine seals, warming up HRSG drums, and condenser sparging to enable uninhibited startup of the unit. The auxiliary boiler may also produce steam when the unit is off line to maintain drum and turbine temperatures.

Conventional units without an auxiliary boiler must use the combustion turbine and HRSG to produce steam to warm the unit and establish seals. During a conventional unit startup, holds are required to complete these warm up periods.

Provisions for fast start of the auxiliary boiler should also be considered which include equipping the auxiliary boiler mud drums with heating coils. Auxiliary boiler heat input, operating hour limits, and emission limits must also be considered.

Note that the auxiliary boiler makes up the majority of the cost to equip a combined cycle with fast start capabilities.

## 2.6 TERMINAL STEAM ATTEMPERATORS

Conventional start plants hold the combustion turbine load during startup as needed to meet the steam turbine startup steam temperature requirements. Fast-start plants decouple the CTG/HRSG startup from the steam turbine startup by using terminal attemperators at the HRSG outlet for meeting steam turbine startup steam temperature requirements, irrespective of CTG/HRSG load. This allows the steam turbine to come on line independently from the CTG and HRSG. As a result, the plant can increase load more quickly.

While the addition of terminal (final stage) steam attemperators on the main steam and hot reheat lines allow for steam turbine temperature matching, they introduce the risk of two phase flow in the steam lines. An adequate run of straight piping downstream of the attemperators, adequate drainage, and robust instrumentation are a must to minimize the risk of condensate carry-over to the steam turbine. Additional controls should be considered to prevent turbine water induction.

## 2.7 FEEDWATER SYSTEM

For fast start plants equipped with terminal attemperators, additional condensate and feedwater pump flow is required to meet the attemperation demands. Inter-stage feedwater used for attemperation may be taken off at a later pump stage to meet the pressure demands of the attemperators which could impact feedwater piping wall thickness.

## 2.8 FUEL GAS SYSTEM

In order to reduce emissions and maintain flame stability, some manufacturers require supplementary fuel gas heating as a part of startup. This heating is in addition to any startup heater used to raise the fuel gas temperature above the dew point.

## 2.9 WATER TREATMENT SYSTEM

Maintaining water chemistry and meeting the water chemistry requirements of the HRSG and steam turbine are a critical part of startup. Blowdown and makeup systems should be sized accordingly to meet expected startup demands. Provisions for the inclusion of a future condensate polisher should be considered should problems arise. Condensate polishers ensure top quality feedwater.

## 2.10 AUTOMATED STARTUP SEQUENCE

Additional controls and automation are required for fast-ramp plants to ensure the matching of steam temperatures and to maintain emission compliance. As a result, more plant instrumentation is required in automated plants to allow the plant control system to monitor system status, minimize times between sequential steps and provide consistent startups.

Also fast-ramp plants should consider the use of service life monitoring systems such as thermal stress indicators on the HRSG and steam turbine. These systems allow control of the unit ramp operations based on predetermined thermal stress limitations.

# 3.0 Capital Costs

Capital costs are higher for fast-start plants than plants designed for conventional starts. Additional costs that must be considered are requirements for a more flexible HRSG (e.g., header returns, tube to header connections, harps per header limits), terminal attemperators and associated systems; more flexible steam piping; improved steam piping drain systems, improved bypass system and controls integration, and requirements for auxiliary steam.

Table 3-1 lists the costs to include the design features listed in Column A of Table 2-1 for a fast start unit. Costs listed in the study are budgetary costs (+/- 30%).

**Table 3-1 Fast Start (Fire to MECL) Operating Scenario Costs**

| FAST START SYSTEM COSTS FOR A 1X1 7F.05 COMBINED CYCLE | |
|---|---|
| Fast Start Options (Required options in Column A excluding Aux Boiler and Stress Monitoring Systems) | [redacted] |
| Auxiliary Boiler | [redacted] |
| Stress Monitoring Systems | [redacted] |
| **Total** | [redacted] |

# 4.0 Performance Impacts

Startup durations are dependent on the ambient conditions, time after shutdown, initial steam turbine rotor temperatures, and the particular OEM equipment/features used in the power train in addition to any margins (if the required start-up times are to be guaranteed). There is a relatively wide range variation, however, for rough indicative values, Table 4-1 provides comparative durations [redacted] All fuel consumption and net generation values are based on combustion turbine ignition through the indicated end point.

**Table 4-1 Estimated Nominal Startup Times (Minutes)**

| START TYPE | CONVENTIONAL START TO MECL | FAST START TO MECL | DIFFERENCE (CONVENTIONAL – FAST) |
|---|---|---|---|
| Hot Start = Shutdown 8 hours or less | [redacted] | [redacted] | [redacted] |
| Warm Start = > 8 hours and < 48 hours | [redacted] | [redacted] | [redacted] |
| Cold Start = Shutdown 48 hours or more | [redacted] | [redacted] | [redacted] |

[redacted]

| [redacted] | [redacted] | [redacted] | [redacted] |
|---|---|---|---|
| [redacted] | [redacted] | [redacted] | [redacted] |
| [redacted] | [redacted] | [redacted] | [redacted] |
| [redacted] | [redacted] | [redacted] | [redacted] |

[redacted]

| [redacted] | [redacted] | [redacted] | [redacted] |
|---|---|---|---|
| [redacted] | [redacted] | [redacted] | [redacted] |
| [redacted] | [redacted] | [redacted] | [redacted] |
| [redacted] | [redacted] | [redacted] | [redacted] |

# 5.0 Startup Emissions

Stack emissions vary widely prior to reaching steady state emissions compliance due to the complexity of starting a combined cycle facility and the plant equipment's ability to operate within threshold limits across a certain operating range. The combustion turbine and the HRSG post-combustion emissions control components (if applicable) are the main equipment governing stack emissions variation.

Combustion turbines are designed with multiple fuel nozzles in each combustor. As combustion turbines start and ramp up to normal operating flow, load, and temperature, the combustion nozzles are sequenced through various combustion operating modes that vary the deflagration type (i.e., diffusion or pre-mixed [i.e., the air and fuel are pre-mixed prior to ignition of the fuel]) and nozzle firing sequences (i.e., which of the multiple nozzles are in service). These startup combustion modes are required so that stable combustion can be maintained in the unit during startup to avoid flame outs. As illustrated in Figure 2-1, in these off-design startup combustion modes, the combustion of the fuel is generally incomplete resulting in higher than normal nitrous oxide ($NO_x$), carbon monoxide (CO), and volatile organic compound (VOC) emissions concentrations. As the turbine reaches a minimum operating load where its normal combustion mode can be stably maintained, combustion becomes more complete and emissions decrease to a level that can be maintained across a wide operating range. The minimum operating load of the combustion turbine in this emissions compliant operating range is called the Minimum Emissions Compliance Load (MECL).

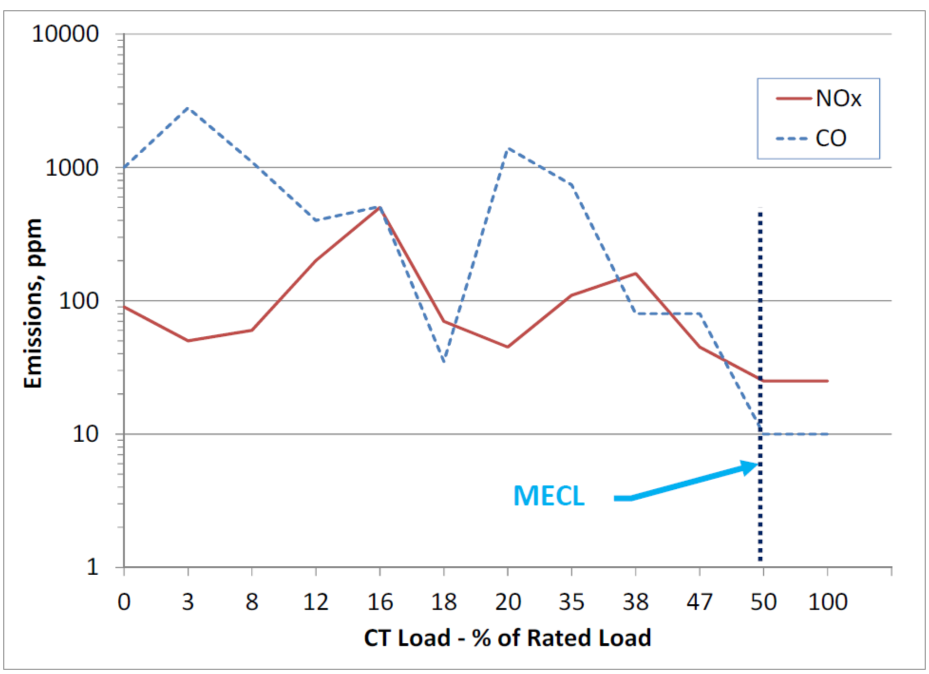



**Figure 5-1 Example Combustion Turbine $NO_x$ and CO Emissions versus Rated Load**

Below MECL, the mass of air pollutant emissions can accumulate quickly and, therefore, these "startup emissions" are of particular interest to regulators. The steady-stated CTG design exhaust emissions for the turbine technologies considered are approximately 15-25 ppmvd @15% O2 for $NO_x$ and 4-10 ppmvd @15% O2 for CO when operating on natural gas. Steady-state VOC emissions are dependent on the site specific natural gas composition.

An emissions netting analysis will be performed for the new combined cycle plant. If a Prevention of Significant Deterioration (PSD) review is required, the emissions standard that must be met is Best Available Control Technology (BACT), an emissions control mandate by the Environmental Protection Agency (EPA). If applicable, combined cycle BACT requirements dictate $NO_x$ and CO emissions shall be no greater than 2 ppm (parts per million) at the HRSG stack discharge over the entire normal operating range. CTG emissions levels are not sufficient for BACT and post-combustion emissions controls components; oxidation catalyst to reduce CO/VOC emissions and a selective catalytic reduction (SCR) system to reduce $NO_x$ emissions, must be installed in the HRSG to further reduce emissions to BACT levels.

Oxidation catalysts and SCR systems are not effective until they are warmed to a minimum threshold temperature and the SCR ammonia injection (utilized with the catalyst to reduce $NO_x$ emissions) is tuned. In general, these post-combustion emissions controls components are designed such that the minimum threshold temperatures are achieved on a startup at or below the combustion turbine MECL. As noted previously, an "emissions" startup sequence is considered complete after the CTG reaches MECL, and in the event of post-combustion emissions control components, they reach their minimum threshold temperatures, and the SCR ammonia injection is tuned such that stack emissions meet the air quality requirements.

Confidential

FINAL

# FAST START VS. CONVENTIONAL UNIT RAMP RATE ANALYSIS

## A.B. Brown 1x1 F-Class

**B&V PROJECT NO. 400278**
**B&V FILE NO. 41.1204F**



PREPARED FOR

VECTREN
A CenterPoint Energy Company

Vectren

31 JANUARY 2020

BLACK & VEATCH
Building a world of difference.

# Table of Contents



## LIST OF TABLES



## LIST OF FIGURES

# 1.0 Introduction

The purpose of this study is to evaluate the differences for conventional and fast ramping options between MECL and full load on unit startup for a 1x1 7F.05 combined cycle. The GE 7F.05 is one of several candidate F-Class combustion turbine offerings.

Since the temperature differential between components is the primary concern of fast ramping between MECL and full load; many of the design features required for fast ramping between MECL and full load are the same as the features required for fast start between combustion turbine ignition to MECL as discussed in the Fast Start vs. Conventional Start Analysis (File No. 400278.41.1203F). Figure 1-1 shows the regions covered under this study noted as Ramping and that covered in the Fast Start vs. Conventional Start Analysis noted as Startup.

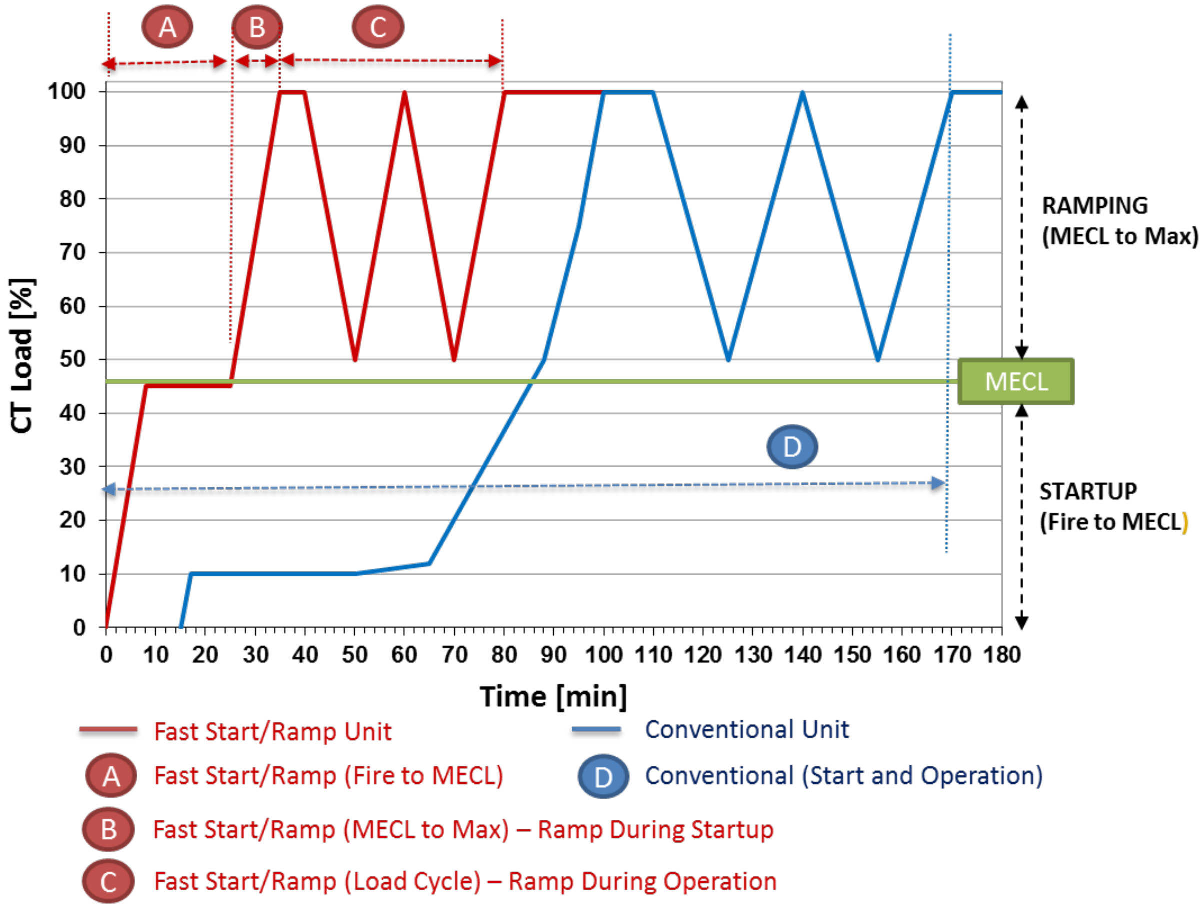



**Figure 1-1 Comparison of Combustion Turbine Loading From MECL to Full Load**

Table 1-1, Column B indicates the design features that would be required for fast ramping and how they differentiate from a conventional unit, Column D, and a fast start unit, Column A. Descriptions for each of the design features can be found in the Fast Start vs. Conventional Start

Analysis and also included in Appendix A. Items included in Column B also encompass those features in Column C which are required for fast ramping during operation.

**Table 1-1 Design Features of Combined Cycles Designed for Various Operating Scenarios**

| FEATURES REQUIRED TO MEET OPERATING SCENARIO | A<br>FAST START<br>(FIRE TO MECL) | B<br>FAST RAMP<br>(MECL TO MAX) | C<br>FAST RAMP<br>(LOAD CYCLE) | D<br>CONVENTIONAL<br>(START AND OP) |
|---|---|---|---|---|
| Required Option = ● , Recommended Option = □ , Standard Option = ◆ | | | | |
| **Combustion Turbine** | | | | |
| Fast Start Equipped | ● | | | |
| Natural Gas Purge Credits | ● | | | □ |
| Service Life Monitoring System | ◆ | ◆ | ◆ | ◆ |
| Advanced Control System | ● | ● | ● | |
| **HRSG** | | | | |
| Advanced Drum Design | ● | ● | | |
| Enhanced Nozzle Connections | ● | ● | | |
| Improved HRSG Materials | ● | ● | | |
| Improved HRSG Geometries | ◆ | ◆ | ◆ | ◆ |
| Service Life Monitoring System | □ | □ | □ | |
| Stack Damper and Insulation | ● | | | □ |
| Terminal Attemperators | ● | ● | ● | |
| LP Economizer Recirculation/Heat Exchanger | ● | ● | | |
| **Steam Turbine** | | | | |
| Optimized Casing Design | ● | ● | | |
| Advanced Control System | ● | ● | ● | |
| Service Life Monitoring System | ● | ● | □ | |
| Advanced Stop Valve Design | ● | | | |
| Increased Thermal Clearances | ● | ● | | |
| Advanced Turbine Water Induction Protection | ● | ● | ● | |
| **Emissions Control** | | | | |
| Feed-forward Ammonia Controls | ● | ● | ● | |

| FEATURES REQUIRED TO MEET OPERATING SCENARIO | A<br>FAST START<br>(FIRE TO MECL) | B<br>FAST RAMP<br>(MECL TO MAX) | C<br>FAST RAMP<br>(LOAD CYCLE) | D<br>CONVENTIONAL<br>(START AND OP) |
|---|---|---|---|---|
| **Auxiliary Steam** | | | | |
| Auxiliary Boiler | ● | | | |
| Condenser and HRSG Sparging | ● | | | |
| **Feedwater System** | | | | |
| Larger Condensate Pump | ● | ● | ● | |
| Larger Feedwater Pump | ● | ● | ● | |
| Higher Stage IP Bleed | ● | ● | ● | |
| **Heat Rejection System** | | | | |
| Surface Condenser – Fast Start Design | ● | | | |
| **Fuel Gas System** | | | | |
| Supplementary Fuel Gas Heating(1) | ☐ | | | |
| **Water Treatment System** | | | | |
| Condensate Polisher(2) | ☐ | | | |
| **Auxiliary Electrical System** | | | | |
| Larger Equipment for Higher Loads | ● | ● | ● | |

Notes:
1. Supplementary fuel gas heating as required by combustion turbine supplier.
2. Space should be allotted for future condensate polisher installation, if required.

# 2.0 Capital Costs

Note that all of the features required for fast ramp are included in Column A of Table 1-1 discussed in the Fast Start vs. Conventional Start Analysis. The costs in Table 2-1 indicate only the costs for Column B of Table 1-1. Costs listed in the study are budgetary costs (+/- 30%).

**Table 2-1 Fast Ramp (MECL to Full Load) Operating Scenario Costs**

| FAST RAMP SYSTEM COSTS FOR A 1X1 7F.05 COMBINED CYCLE | |
|---|---|
| Fast Ramp Options (Required options in Column B excluding Stress Monitoring Systems) | [redacted] |
| Stress Monitoring Systems | [redacted] |
| **Total*** | [redacted] |
| ***NOTE: If a fast start plant is selected, the above costs are not additive to those listed in the Fast Start Study.*** | |

# 3.0 Performance Impacts

Startup and ramping durations are dependent on the ambient conditions, time after shutdown, initial steam turbine rotor temperatures, and the particular OEM equipment/features used in the power train in addition to any margins (if the required start-up times are to be guaranteed). There is a relatively wide range variation, however, for rough indicative values, Table 3-1 provides comparative durations for a GE 7F.05 1x1 combined cycle. [redacted]

**Table 3-1 Estimated Nominal Startup Times (Minutes)**

| START TYPE | CONVENTIONAL START TO MECL | CONVENTIONAL START TO STG FULL LOAD | FAST START TO MECL | FAST START, TO CTG BASELOAD | FAST START, TO CTG BASELOAD WITH STG LOADED |
|---|---|---|---|---|---|
| Hot Start = Shutdown 8 hours or less | Base Conv. | 42 | Base Fast | 7.1 | 54 |
| Warm Start = > 8 hours and < 48 hours | Base Conv. | 37 | Base Fast | 21 | 47 |
| Cold Start = Shutdown 48 hours or more | Base Conv. | 67 | Base Fast | 62 | 98 |

[redacted]

| [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
|---|---|---|---|---|---|
| [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |

[redacted]

| [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
|---|---|---|---|---|---|
| [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |

For a conventional start, each combustion turbine is ramping at a nominal rate from MECL to combustion turbine baseload of 17 MW/min or 7.09%/min, while the combustion turbine ramp rate for fast start is 40 MW/min or about 16.66%/min from MECL to combustion turbine baseload.

After startup and after thermal soaking, the unit will able to achieve fast ramping. For a GE 7F.05, each combustion turbine has the ability to ramp 40 MW/minute. For a 1x1 combined cycle, the ramp rate can be stated to be 40 MW/minute. The steam turbine contribution toward fast ramping is typically not quoted since the steam turbine response is much less predictable than the combustion turbine load response. This is due to a lag in HRSG steam production response due to the CTG load changes. Depending on how the combustion turbine is ramped up and down, the output contribution from the steam turbine would take some time to settle out into a steady state performance level. For conventional units, the combustion turbine ramp rates may be limited by the HRSG and steam turbine limitations. For units equipped with fast ramping, the steam conditions can be conditioned to allow the combustion turbine to ramp independently of the steam turbine.

# 4.0 Emissions

The period for ramping is defined as the period between minimum emissions compliance load and full load. Once the unit has obtained emission compliance, the unit generally stays in compliance for ramping conditions. During a fast ramp the outlet $NO_X$ from the combustion turbine is variable. Conventional units only measure $NO_X$ at the stack; this may lead to short durations of higher $NO_X$ or ammonia slip. For fast ramping units limiting $NO_X$ measurements to the stack only can lead to over injecting or under injecting ammonia. To address this, fast ramping units are equipped with feed-forward $NO_X$ controls which take $NO_X$ measurements at the combustion turbine exhaust as well as the stack to quicken the response to changing combustion turbine exhaust conditions. Both conventional and fast ramping units are designed to operate in compliance with stack emission limits across the averaging period.

# Appendix A. Fast Start and Fast Ramp Design Features

Design features for fast start and fast ramping units are as follows:

## A.1 COMBUSTION TURBINE

Combustion turbines designed for fast-ramping will be equipped with fast start features. These include positive isolation to ensure that purge credits have been maintained per NFPA 85 and that the gas path will not require a purge prior to startup. The control system for fast start of the plant should be fully automated to minimize times between sequential steps and allow for greater consistency during startup.

Both fast start and conventional units are equipped with service life monitoring systems that control unit ramp operations based on predetermined thermal stress limitations. Fast Start units are equipped with advanced control schemes incorporating model based controls (MBC) to optimize startup based on these monitoring systems.

Purge credits established during the shutdown must still be intact. NFPA 85 requires that a fresh air purge of the combustion turbine and HRSG be accomplished prior to start. NFPA 85 requires that at least five volume changes be completed or a minimum purge of 5 minutes prior to ignition. Typical purge durations can range from 5 to 20 minutes. The 2011 edition of NFPA 85 allowed for purge credits to be achieved when the unit is taken off line if the purge is completed and the valving arrangement is shown to positively isolate any fuel from entering the system. The combustion turbine can usually achieve the required purge when coasting down following a loss of ignition.

## A.2 HRSG

HRSGs designed for fast-start plants can subject HRSG components such as superheaters and reheaters to rapid heating. Large thermal stresses can be produced by the differential expansion of the tubes within the HRSG. HRSG designs in such plants must be capable of accommodating the rapid change in temperature and flow of flue gas generated by load ramping of advanced class combustion turbines.

To reduce thermal capacity of drums many options are used to decrease the drum size and wall thickness including utilizing Benson style drums, utilizing multiple drums, high strength drum materials, reduced residence time. Self-reinforced nozzles, full penetration nozzles, full penetration welds, and steam sparger systems further improve the ability to accept rapidly changing exhaust gas conditions and steam conditions. Improved materials throughout the high pressure superheater and reheater can be required. Online, real-time monitoring system should be included to evaluate HRSG life consumption.

In order to reduce the thermal capacity of drums, the residence time may also be reduced for fast start units. Fast start units typically have drum storage time around two minutes. Conventional start plants have drum storage time from 3-5 minutes.

Fast start plants are equipped with a stack damper and with an insulated stack up to the stack damper. The stack damper and insulation are critical as they restrict the flow of flue gas out the HRSG stack minimizing heat loss when the unit is offline. While conventional units do not require stack dampers and insulation, it is a recommended practice to minimize heat loss when the unit is offline.

Both fast start and conventional units have improved HRSG geometries compared to those built a decade ago. Improvements in geometries have been to decrease thermal stresses from unit cycling and are part of the HRSG standard design such as coil flexibility to superheater/reheater interconnecting piping and accommodations for tube-to-tube temperature differentials.

## A.3 STEAM TURBINE

The steam turbine must also be designed for the thermal gradients experienced while ramping during start-up. For fast start machines, the casing design must be optimized to reduce the thermal stress during temperature fluctuations and to accept faster start up and load change gradients. The use of higher grade material may be employed in the high pressure and intermediate casings and valves to reduce component thickness. Main steam stop valves must be designed so that these valves can be opened at a relatively higher pressure. Integral rotor stress monitors can be provided; the rotor stress monitor is typically capable of limiting or reducing the steam turbine load or speed increase and is designed to trip the turbine when the calculated rotor stresses exceed allowable limits.

For machines undergoing a fast ramp, attemperators are often required on the high pressure and hot reheat steam lines. Overspray on these attemperators can lead to water in these steam lines; special attention needs to be provided for turbine water induction prevention for units equipped with terminal attemperators.

## A.4 EMISSIONS AND AMMONIA FEED

Outlet $NO_X$ from the combustion turbine can vary highly when undergoing fast startup and fast ramp conditions. Conventional units only measure $NO_X$ at the stack; for fast ramping units limiting $NO_X$ measurements to the stack only can lead over injecting or under injecting ammonia. Higher ammonia slip and potentially greater SO2 conversion in fast-start and fast-ramp units create additional challenges for control of sulfur-bearing deposits in the colder HRSG areas. Low-pressure evaporators and economizers are particularly at risk. For fast ramping plants, addition of feed forward controls to quicken the saturation of the SCR catalyst (if included) is required. Also the HRSG should be equipped with LP economizer recirculation or heating systems to maintain surfaces above SO2 dew points.

## A.5 AUXILIARY STEAM

Fast start units require an auxiliary boiler to produce steam prior to the startup of the unit. This steam is used for steam line warming, establish the steam turbine seals, warm up HRSG drums, and condenser sparging to enable uninhibited startup of the unit. The auxiliary boiler may also produce steam when the unit is off line to maintain drum and turbine temperatures.

Conventional units without an auxiliary boiler must use the combustion turbine and HRSG to produce steam to warm the unit and establish seals. During a conventional unit startup, holds are required to complete these warm up periods.

Provisions for fast start of the auxiliary boiler should also be considered which include equipping the auxiliary boiler mud drums with heating coils. Auxiliary boiler heat input, operating hour limits, and emission limits must also be considered.

Note that the auxiliary boiler makes up the majority of the cost to equip a combined cycle with fast start capabilities.

## A.6 TERMINAL STEAM ATTEMPERATORS

Conventional start plants hold the combustion turbine load during startup as needed to meet the steam turbine startup steam temperature requirements. Fast-start plants decouple the CTG/HRSG startup from the steam turbine startup by using terminal attemperators at the HRSG outlet for meeting steam turbine startup steam temperature requirements, irrespective of CTG/HRSG load. This allows the steam turbine to come on line independently from the CTG and HRSG. As a result, the plant can increase load more quickly.

While the addition of terminal (final stage) steam attemperators on the main steam and hot reheat lines allow for temperature matching, they introduce the risk of two phase flow in the steam lines. An adequate run of straight piping downstream of the attemperators, adequate drainage, and robust instrumentation are a must to minimize the risk of condensate carry-over to the steam turbine. Additional controls should be considered to prevent turbine water induction.

## A.7 FEEDWATER SYSTEM

For fast start plants equipped with terminal attemperators, additional condensate and feedwater pump flow is required to meet the attemperation demands. Inter-stage feedwater used for attemperation may be taken off at a later pump stage to meet the pressure demands of the attemperators which could impact feedwater piping wall thickness.

## A.8 FUEL GAS SYSTEM

In order to reduce emissions and maintain flame stability, some manufacturers require supplementary fuel gas heating as a part of startup. This heating is in addition to any startup heater used to raise the fuel gas temperature above the dew point.

## A.9 WATER TREATMENT SYSTEM

Maintaining water chemistry and meeting the water chemistry requirements of the HRSG and steam turbine are a critical part of startup. Blowdown and makeup systems should be sized accordingly to meet expected startup demands. Provisions for the inclusion of a future condensate polisher should be considered should problems arise. Condensate polishers ensure top quality feedwater.

## A.10 AUTOMATED STARTUP SEQUENCE

Additional controls and automation are required for fast-ramp plants to ensure the matching of steam temperatures and to maintain emission compliance. As a result, more plant instrumentation is required in automated plants to allow the plant control system to monitor system status, minimize times between sequential steps and provide consistent startups.

Also fast-ramp plants should consider the use of service life monitoring systems such as thermal stress indicators on the HRSG and steam turbine. These systems allow control of the unit ramp operations based on predetermined thermal stress limitations.

Confidential

FINAL

# NUMBER OF COLD, WARM, AND HOT STARTS ANALYSIS

## A.B. Brown 1x1 F-Class

**B&V PROJECT NO. 400278**
**B&V FILE NO. 41.1207F**



PREPARED FOR

Vectren

31 JANUARY 2020

# Table of Contents



## LIST OF TABLES



## LIST OF FIGURES

# 1.0 Introduction

Prior to the early 2000s, combined cycles were predominately designed for base load operation with high focus on highest full load efficiency and lowest capital cost. Due to increases in gas pricing, changing power market production cost structure, and renewable energy generation, many of these plants were forced into intermediate or even daily cycling mode. Many problems associated with the fast changing temperatures in the equipment resulted, such as high thermal stresses, high cyclic fatigue, vibration, flow accelerated corrosion, and water induction.

As a result of these industry issues, today's major equipment suppliers design their equipment to withstand the cumulative wear and damage caused by frequent starts and stops. For modern combined cycle equipment operating as high cycling units, major equipment manufacturers take the following into consideration:

- Base equipment designs consider high cycling
- Service life monitoring equipment is recommended for high cycling units
- Time between service intervals decreases with higher cycling

In addition to the number of starts, the time between the unit shutdown and start also has a significant impact on the equipment. When a unit is shutdown, equipment begins to cool. Upon the next start, the equipment would have to be brought back up to operating temperature putting the equipment through a thermal cycle. The duration between shutdown and startup is usually broken down between different start modes whether the equipment is considered hot, warm, or cold. Equipment manufacturers each have their own definition for hot, warm, and cold starts; however, typical start mode durations are listed in Table 1-1.

**Table 1-1 Start Mode Definitions**

| START TYPE | SHUTDOWN DURATION |
|---|---|
| Hot | < 8 hours |
| Warm | 8-48 hours |
| Cold | > 48 hours |

## 1.1 BASE EQUIPMENT DESIGN

During startup and shutdown, the unit sees large temperature gradients and thermal stresses. Cycling increases concern for thermally induced creep-fatigue damage as a result of rapid heating of the surface of components such as turbine blades, rotors, casings, drums, and other heavy walled components. Creep-fatigue damage can also result from different thermal expansion between thin and thick components or dissimilar metal welds.

To resolve these issues, manufacturers have incorporated the knowledge of these earlier failures into their standard designs. Manufacturers select geometries, materials, thicknesses, and coatings in such a way as to limit the damage of thermal cycling. Geometries and material selection also alleviate other issues such as flow accelerated corrosion, vibration, and water induction. These designs do not alleviate all the issues with thermal factors but allow the equipment to be monitored in such a way to determine its service life.

## 1.2 MAINTENANCE INTERVALS

The design life for the facility is 30 years and the operating equipment will need regular maintenance including hot gas path and major inspections. Figure 1-1 shows the equivalent hours-based and starts-based maintenance intervals for GE and Siemens F-class combustion turbines and the potential impact of maintenance factors on maintenance intervals.

The timing of maintenance intervals are impacted by maintenance factors. Hours based maintenance factors consider fuel type, firing temperature, and water or steam injection used for emissions control or power augmentation. Starts based maintenance factors consider the type of start; whether it is a conventional start, fast start, cold start, warm start; load achieved during each start; and shutdown type such as normal cooldown, rapid cooldown or unit trip. The red lines in Figure 1-1 show how starts or hours based factors could affect the timing of maintenance intervals.

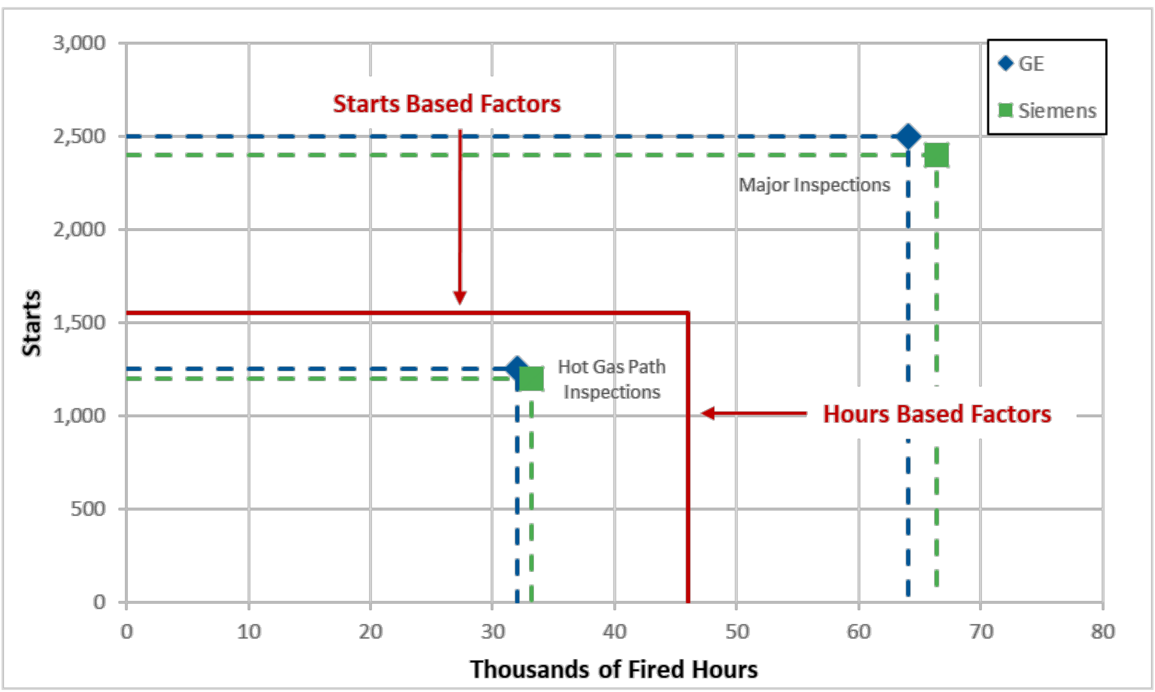



**Figure 1-1 Maintenance Factors Reduce Maintenance Intervals**

Per GE's Heavy-Duty Gas Turbine Operating and Maintenance Considerations (GER-3620N), a GE unit with a baseline maintenance factor would equate to 4,800 operating hours per year (16 hours/start, 6 starts/week, 50 weeks/year) and 300 starts per year. Those 300 starts would consist of 249 hot starts, 39 warm starts, and 12 cold starts. For the design life of 30 years, GE would base their Long Term Service Agreement (LTSA) on 4 maintenance cycles for a GE 7F.05 with a baseline operating profile. The LTSA relates to the serviceable life of the combustion turbine.

Figure 1-2 shows how operating hours and the number of starts per year affect the duration of the LTSA. A 30 year life is based on roughly 333 equivalent starts per year. An operating regime requiring above 333 equivalent starts per year would have service intervals based on equivalent life and start decreasing the life expectancy of the LTSA. For example, 500 equivalent starts per year would be roughly equivalent to a 20 year LTSA life. When operating below 333 equivalent starts per year the figure shows whether hours based operation or number of starts based operation would determine the maintenance intervals for the plant. Since the facility has a 30 year design life, 333 equivalent starts would be the average yearly allowable for the plant. Based on a design basis of 310 starts per year, the breakdown of recommended number of design basis cold, warm, and hot starts would be as shown in Table 1-2.

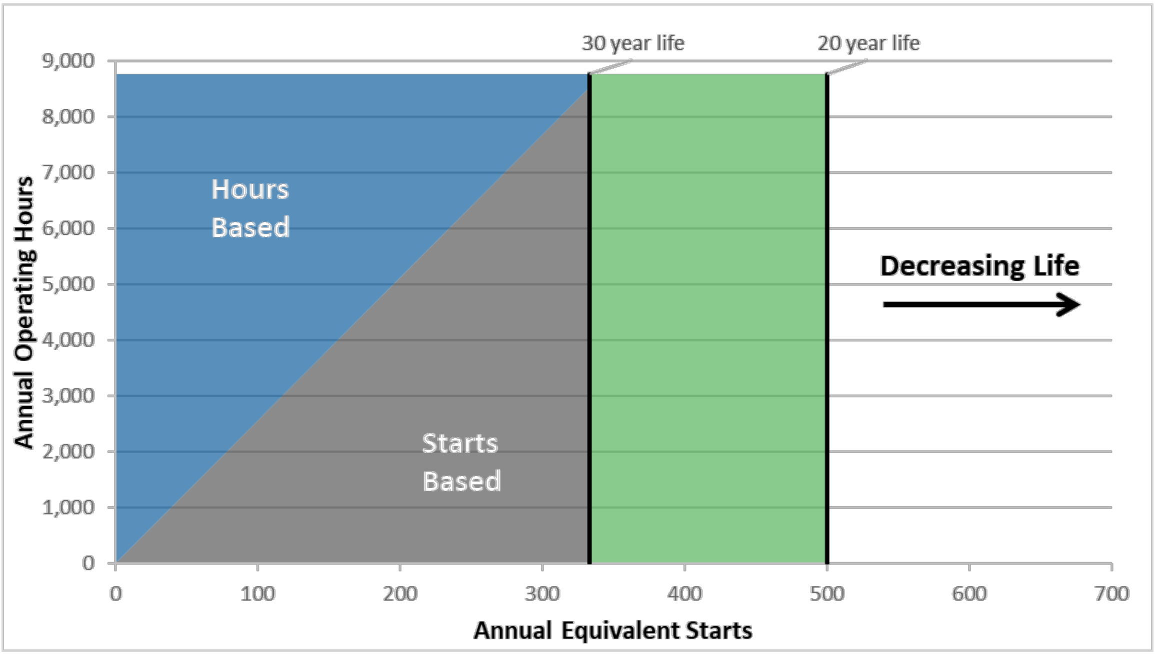



**Figure 1-2 Combustion Turbine LTSA Term vs. Starts and Operating Hours Service Intervals**

**Table 1-2 Operating Conditions Used in Design Basis**

| OPERATING CONDITIONS | DESIGN BASIS |
|---|---|
| Operation | Daily Cycling |
| Yearly Operating Hours | Up to 8,760 |
| Annual Capacity Factor | 45% to 100% |
| Cold Starts Per Year | 10 |
| Warm Starts Per Year | 100 |
| Hot Starts Per Year | 200 |
| Total Starts Per Combustion Turbine | <310 |

## 1.3 SERVICE LIFE MONITORING EQUIPMENT

For plants operating in a regime where the starts based maintenance factors are determining the service intervals, it becomes useful to monitor the equipment to avoid costly outages. Service life monitoring systems perform three functions: instrumentation, evaluation, and determination. The instrumentation and sensor systems record the operating parameters such as localized temperature, pressure, and vibration. Based upon the readings, evaluations can be made such as stresses in critical locations in the turbines and the HRSG. The evaluated data is then combined with the operating history of the system to determine the impact on the remaining service life.

Recommended monitoring systems for high cycling plants include:

- Combustion Turbine Stress Controller
- Steam Turbine Stress Controller
- HRSG Stress Controller
- Condition Monitoring System
- Water Quality Monitoring System

Today's F-class combustion turbines come equipped with control systems that monitor speed, acceleration, temperature, and verify that all sensors are active. These sensors measure performance and monitor the machine's health. These systems also count the operating hours and number of equivalent starts or calculate the equivalent life of each start sequence in order to calculate the next service interval.

The steam turbine stress controller consists of a stress evaluation system that calculates and controls stresses in thick walled components including stop and control valves, HP casing and rotor body, and the IP rotor body. The stress controller monitors and controls ramp rates during start up to calculate the cumulative fatigue of cycling the unit. The stress controller also determines the remaining time to the next service interval.

The HRSG stress controller performs a dynamic analysis of the HRSG to determine fatigue. The stress controller determines risk factors based upon the evaluations, such as the probability of crack initiation. These risk factors are used to plan and indicate HRSG maintenance.

Condition monitoring systems measure critical asset parameters such as vibration, temperature, and speed of rotating equipment including boiler feed pumps, condensate pumps, circulating water pumps, cooling tower fans, and fuel gas compressors. The monitoring systems also evaluate trends, such as vibration amplification, and compare it against set points, historical readings, and known failure patterns.

The water quality monitoring system provides additional water and steam sampling to monitor issues with cycling units. Cycling units result in a large demand on the condenser and, in peak demands, on condensate supply and oxygen controls. Additional controls include online monitoring for condenser tube leaks and condenser air in leakage. It also includes monitoring steam blowdown lines for high level of particulates to indicate any safety issues. Water quality monitoring systems are not as important if the unit includes a condensate polisher.

# 2.0 Service Life Monitoring System Costs

As outlined in Section 1.2, service life monitoring systems are recommended for high cycling plants to help predict and plan maintenance. Table 2-1 provides budgetary cost (+/- 30%) for service life monitoring systems.

**Table 2-1 Service Life Monitoring System Costs**

| SERVICE LIFE MONITORING SYSTEM COSTS | |
|---|---|
| Combustion Turbine Stress Controller | [redacted] |
| Steam Turbine Stress Controller | [redacted] |
| HRSG Stress Controller | [redacted] |
| BOP Condition Monitoring System | [redacted] |
| Water Quality Monitoring System | [redacted] |
| Additional cable and I/O | [redacted] |
| **Total** | [redacted] |

# 3.0 Conclusion

Today's combined cycle equipment is designed for high cycling applications and consider problems associated with the fast changing temperatures in the equipment such as high thermal stresses, high cyclic fatigue, vibration, flow accelerated corrosion, and water induction. The design life of the equipment is 30 years with major overhauls of the combustion turbines occurring every 7.5 to 8 years. The time duration between major overhauls is based upon maintenance factors associated with hours of operation and the number of starts.

While the number of operating hours is not expected to shorten the time between maintenance cycles, the number of starts could decrease the operational life. In order to maintain the 7.5 to 8 years between major overhauls, the combustion turbine should have an equivalent number of annual starts less than 333. To avoid decreasing the life of the LTSA, the typical combined cycle design including balance of plant equipment should not exceed 333 starts per year. The breakdown of the recommended number of design cold, warm, and hot starts would be as shown in Table 3-1.

**Table 3-1 Design Cold, Warm, and Hot Starts**

| OPERATING CONDITIONS | |
|---|---|
| Operation | [redacted] |
| Yearly Operating Hours | [redacted] |
| Annual Capacity Factor | [redacted] |
| Cold Starts Per Year | [redacted] |
| Warm Starts Per Year | [redacted] |
| Hot Starts Per Year | [redacted] |
| Total Starts Per Combustion Turbine | [redacted] |

If the plant is expected to be a high cycling unit with a maintenance cycle that would be determined based upon the number of starts rather than the number of hours operated per year, Vectren should consider additional service life monitoring systems to assist in predictive maintenance, as shown in Table 3-2. While these systems do not prevent maintenance, they allow the operator to better understand how the operation of the unit is impacting the service life of the equipment.

**Table 3-2 Service Life Monitoring Systems**

| SERVICE LIFE MONITORING SYSTEM COSTS | |
|---|---|
| Combustion Turbine Stress Controller | [redacted] |
| Steam Turbine Stress Controller | [redacted] |
| HRSG Stress Controller | [redacted] |
| BOP Condition Monitoring System | [redacted] |
| Water Quality Monitoring System (not required with a condensate polishing system) | [redacted] |
| Additional cable and I/O | [redacted] |
| **Total** | [redacted] |

FINAL

# AUXILIARY BOILER ANALYSIS

## A.B. Brown 1x1 F-Class

**B&V PROJECT NO. 400278**
**B&V FILE NO. 41.1209F**



PREPARED FOR

VECTREN
A CenterPoint Energy Company

Vectren

31 JANUARY 2020

BLACK & VEATCH

# Table of Contents



## LIST OF TABLES

# Executive Summary

In developing this report, Black & Veatch reviewed the requirements for the auxiliary steam system for the new Combined Cycle Power Plant (CCPP). Black & Veatch reviewed multiple pre-start, start-up and shutdown scenarios to determine the required sizing and operation of the auxiliary steam boiler.

The auxiliary steam system users have been summarized in the Auxiliary Steam Demands provided in Table 2-1. The users were estimated based on previous projects using the 7F.05 gas turbines. Based on the maximum co-incident steam demand of the 7F.05 configuration it is recommended that Vectren utilize an auxiliary boiler designed for [redacted] lb/hr and an outlet pressure of [redacted].

# 1.0 Introduction

The purpose of this study is to determine the specific requirements for the Auxiliary boiler to be installed with the new Combined Cycle Power Plant (CCPP). These Fast start units require an auxiliary boiler to produce steam prior to the startup of the unit. This auxiliary steam is used for steam line warming, establish the steam turbine seals, warm up HRSG drums, and condenser sparging to enable quicker startup of the unit. The auxiliary boiler may also produce steam when the unit is off line to maintain drum and turbine temperatures. Black & Veatch has previously performed the "Fast Start vs Conventional Start Analysis" which demonstrates the need for an auxiliary boiler for a unit with fast start capability.

This evaluation will help determine the design impact of this system to the new CCPP design. Auxiliary system users, auxiliary boiler sizing and operation will also be identified and discussed.

# 2.0 Auxiliary Boiler Sizing and Outlet Pressure

The auxiliary steam system provides steam to various users during plant startup and shutdown at multiple operating conditions. Several operating scenarios were evaluated to determine the best preliminary design basis for sizing the auxiliary boiler. Upon selection of the final plant design, the selected size of auxiliary boiler should be reviewed.

## 2.1 COINCIDENT STEAM DEMANDS

The maximum co-incident auxiliary boiler steam demand occurs during startup when supplying maximum steam turbine sealing, fuel heating, maximum condenser sparing steam, and maximum combustion turbine inlet air heating as shown in Table 2-1.

**Table 2-1 Coincident Auxiliary Steam Demands**

| AUXILIARY STEAM USERS | 1X1 7F.05 |
|---|---|
| ST Gland Sealing | [redacted] |
| Startup Steam to Fuel Gas Heater | [redacted] |
| Condenser Hotwell Sparging | [redacted] |
| Combustion Turbine Inlet Air Heating | [redacted] |
| **Total Coincident Boiler Steam Flow Required** | [redacted] |

## 2.2 NON-COINCIDENT STEAM DEMANDS

During unit pre-start, there are two activities that require auxiliary steam flow, but are not co-incident with the other users. These non-coincident activities occur during HRSG pre-warming and HRSG HP pressure holding. The non-coincident auxiliary steam demands are listed in Table 2-2.

**Table 2-2 Non-Coincident Auxiliary Steam Demands During Pre-Start Activities**

| AUXILIARY STEAM USERS | 1X1 7F.05 |
|---|---|
| HRSG Warming | [redacted] |
| HRSG Pressure Holding | [redacted] |

## 2.3 DESCRIPTION OF USERS

- The turbine seals require steam from the auxiliary system to provide sealing until the steam turbine increases load and becomes self-sealing. When the steam turbine exceeds the point of self-sealing, the flow from the auxiliary system will decrease to near zero.
- A startup steam to fuel gas heater is used to raise the fuel gas to the CT manufacturers specified minimum fuel temperature via a steam to water heat exchanger.
- Condenser hotwell sparging is used to heat the condensate in the condenser to normal operating temperatures prior to starting the units.
- The gas turbine inlet air heating system uses auxiliary steam to provide heat via coils in the CT inlet air structure to minimize the possibility for ice formation in the CT compressor section.
- The HRSG HP warming flow increases the metal temperature of the steam drums and the tubes, allowing for faster startup capability.
- The HRSG HP pressure holding maintains the HP evaporator at a minimum of 275 psig to maintain drum and tube temperatures for faster startup capability.

## 2.4 BOILER OUTLET CONDITIONS

The delivery steam pressure of the auxiliary boiler is typically 300 psig at saturation temperature to facilitate HP evaporator pressure holding of approximately 275 psig. Electric superheaters will be used to provide superheated steam to the turbine seals. Delivering saturated steam will reduce the heat input to the auxiliary boiler which is limited due to air permits.

# 3.0 Auxiliary Boiler Operation

## 3.1 PRE-START CONDITION

The auxiliary steam system should be pressurized, heated and drained up to the steam seal feed valve during pre-start activities. The operating conditions of the auxiliary boiler and system must be verified prior to initiating a unit startup. During cold pre-start activities, the steam for turbine sealing, condenser sparging steam and HP evaporator warming is supplied by the auxiliary boiler. During hot start activities, the steam demand for the HP evaporator warming steam is replaced by the steam demand for HP evaporator pressure holding. Following an HRSG outage or cold restart, the HRSG HP warming flow is set to a maximum flowrate to accelerate warming.

## 3.2 INITIAL STARTUP AND SHUTDOWN

During initial startup the auxiliary steam for the turbine sealing, CT air inlet heating, fuel gas heating and condenser sparging is provided from an auxiliary boiler. As the plant cycle steam from the HRSG IP drum becomes available it allows the auxiliary boiler to be shut down or unloaded to idle as plant operations allow. During normal operation the HRSG IP drum provides all required auxiliary steam flow for the plant.

During plant shutdown or trip, it is expected that there is enough residual energy in the HRSG to provide auxiliary steam until the steam turbine exhaust vacuum is broken or the auxiliary boiler can be brought online to provide sealing steam. The auxiliary boiler must remain in a ready condition at all times during combined cycle operation. During overnight plant shutdowns the aux boiler can remain in operation to provide sealing steam, condenser sparging steam and allow rapid starting in the morning.

# 4.0 Conclusions

The purpose of this evaluation was to determine the specific requirements for the auxiliary boiler for the new Combined Cycle Power Plant (CCPP). Black & Veatch reviewed pre-start, start-up and shut down scenarios to determine the required sizing and operation of the auxiliary boiler.

This report has shown:

- Auxiliary steam users and the estimated demand.
- Non-coincident auxiliary steam users and the estimated demand
- Black & Veatch's recommendation for steam requirements listed in Table 2-1 for various plant configurations.

Confidential

FINAL

# EXISTING FIRE WATER SYSTEM REVIEW

A.B. Brown 1x1 F-Class

**B&V PROJECT NO. 400278**
**B&V FILE NO. 42.1212F**



PREPARED FOR

Vectren

31 JANUARY 2020

# Table of Contents

# Executive Summary

In developing this report for the new Combined Cycle Power Plant (CCPP), Black & Veatch reviewed the piping and instrumentation diagrams (P&IDs) for the existing fire protection and service water systems.

The existing system includes existing pumps and a 75,000 gallon raw water storage tank. The raw water storage tank is sized to provide 51,000 gallons of surge capacity devoted to fire water use. To meet the new fire water system design requirements, a third diesel motor fire pump should be added to the system and the pump arrangement modified to a 3x50 percent configuration with two pumps driven by a diesel motor and the other driven by an electric motor. This configuration allows for a fire water demand up to 3,000 gpm. The existing pressure maintenance pump, which is rated for approximately 1 percent for the main pumps flow and same discharge pressure, should remain.

# 1.0 Existing Equipment

Based on the existing site Fire Protection and Service Water Systems P&ID (F-1024) there are 2x100 percent fire pumps (one electric driven and one diesel driven) that are rated for 1,500 gpm @ 300 FT TDH each. The fire water pumps normally take suction from existing Ranney Well pumps of adequate capacity and the Raw Water Storage Tank (75,000 gallons) via a 12" nominal diameter suction header. The Raw Water Storage Tank is sized to provide 51,000 gallons of surge capacity devoted to fire water use. The fire protection water supply system is also cross tied to the River Water pumps. The existing site has a 10" underground fire water loop. This pipe is assumed to be ductile iron.

Per NFPA 850, the existing water source is large enough to be considered a reliable water source. The multiple pumps installed provide reliability such that a single failure or maintenance event will not impair the ability of the system to responds to a fire event. If a single pump were to be out of service, the remaining pumps will still have sufficient capacity to supply water to the existing water users as well as the maximum fire water demand of 2,500 gpm.

# 2.0 Design Basis and Clarifications

- A search of the NFPA codes on the Indiana State website did not include NFPA 850. However, for the purposes of this assessment and the design of the new power plant, Black & Veatch has referenced NFPA 850 – 2015.
- There is a discrepancy between some of the code years referenced on the Indiana State website and from the IBC or IFC. Our basis is the most current version when this occurs.
- It is not clear from the P&ID what the material used for the existing underground fire water supply mains. Our basis is currently ductile iron material; please clarify if different.
- Please clarify who the Authority Having Jurisdiction (AHJ) is for the A.B. Brown Site. We have identified the state fire marshal below.

  Indiana State Fire Marshal
  Stephen Cox
  317-232-2222
  http://www.in.gov/dhs/2445.htm

# 3.0 New Plant Fire Protection Requirements

The new plant's required fire water system supply flow is based on a worst case fire scenario, plus a hose allowance (500 gpm), and any adjacent systems in the immediate area of a potential fire area; as defined in NFPA 850, Section 6.2. The largest system demand is expected to be the Steam Turbine Building/Enclosure at 1,800 gpm in combination with the turbine generator bearings closed head sprinkler system with directional nozzles with a demand of approximately 200 gpm. This total demand will require a main fire pump rated at 2,500 gpm. The velocity limits at this flow require either a 10" DI or 12" HDPE DR 11 pipe.

To meet the new fire water system design requirements a third diesel motor fire pump (1,500 gpm @ 300ft) should be added to the system modifying the pump arrangement to 3x50 percent configuration with two pumps driven by a diesel motor and the other driven by an electric motor. This configuration allows for a fire water demand up to 3,000 gpm. The existing pressure maintenance pump which is rated for approximately 1 percent for the main pumps flow and same discharge pressure should remain. There are no elevated areas for the new or existing plant areas that require booster pumps to obtain adequate pressure for hose stations so a standard pressure rating of 300 ft-H2O at the rated point is expected to be sufficient.

Per NFPA 850 the multiple Ranney Well pumps installed will provide a reliable source of water such that a single failure or maintenance event will not impair the ability of the system to responds to a fire event. In a single pump out of service case the two remaining Ranney Well pumps can provide up to 4,000 gpm. The preliminary water mass balance for other uses states the normal use from non-fire protection demands is approximately 150 gpm. This allows the fire water demand of 2,500 gpm to be met along with the other non-fire protection water users.

The existing 10" fire protection underground system can be reused with new 12" HDPE used for any new underground headers and around the cooling tower. Hydrants will be located as per NFPA 850 and the local code requirements.

# 4.0 List of Applicable Codes and Standards

| | | |
|---|---|---|
| 675 IAC 13-2.6 | Indiana Building Code, 2014 Edition (IBC, 2012 Edition, 1st printing) ANSI A117.1-2009 | Effective 12/1/14 |
| 675 IAC 22-2.5 | Indiana Fire Code, 2014 Edition (IFC 2012 Edition, 1st printing) | Effective 12/1/14 |

**NFPA Standards**

| NFPA # | Description | Effective Date | IAC Cite |
|---|---|---|---|
| 10-2010 | Portable Fire Extinguishers | December 15, 2012 | 675 IAC 28-1-2 |
| 11-2005 | Low Expansion Foam and Combined Systems | September 22, 2006 | 675 IAC 28-1-3 |
| 12-2005 | Carbon Dioxide Extinguishing Systems | September 22, 2006 | 675 IAC 28-1-4 |
| 13-2010 | Installation of Sprinkler Systems | September 26, 2012 | 675 IAC 28-1-5 |
| 14-2000 | Installation of Standpipe and Hose Systems | December 13, 2001 | 675 IAC 13-1-9 Repealed 3/21/14 |
| 15-2001 | Water Spray Fixed Systems | September 22, 2006 | 675 IAC 28-1-8 |
| 20-1999 | Installation of Centrifugal Fire Pumps | December 13, 2001 Amended 12/26/02 | 675 IAC 13-1-10 |
| 25-2011 | Inspection, Testing and Maintenance of Water Based Fire Protection Systems | May 12, 2013 | 675 IAC 28-1-12 |
| 37-2002 | Installation and Use of Stationary Combustion Engines and Gas Turbines | September 22, 2006 | 675 IAC 28-1-15 |
| 70-2008 | National Electrical Code | August 26, 2009 | 675 IAC 17-1.8 |
| 72-2010 | National Fire Alarm Code | March 23, 2014 | 675 IAC 28-1-28 |
| 2001-2004 | Clean Agent Fire Extinguishing Systems | September 22, 2006 | 675 IAC 28-1-40 |

# 5.0 Conclusions

The purpose of this evaluation was to review the existing fire water system. Black & Veatch reviewed P&IDs for both the existing fire protection and service water systems.

This report has shown:

- The raw water storage tank is sized to provide 51,000 gallons of surge capacity devoted to fire water use.
- The existing pressure maintenance pump is sufficient.
- The existing 10 inch fire protection underground system can be reused with new 12 inch HDPE used for any new underground headers and around the cooling tower.
- Black & Veatch's recommendation is to add a third diesel motor fire pump and modify the pump arrangement to a 3x50 percent configuration.

Confidential

FINAL

# NOISE REGULATION REVIEW

## A.B. Brown 1x1 F-Class

B&V PROJECT NO. 400278
B&V FILE NO. 41.1213F



PREPARED FOR

VECTREN
A CenterPoint Energy Company

Vectren

31 JANUARY 2020

BLACK & VEATCH

# Table of Contents

# Executive Summary

Black & Veatch reviewed the noise regulations that might apply to the new Combined Cycle Power Plant (CCPP).

Indiana, Posey County, and Marrs Township have no far field noise regulation or ordinances. Far field noise requirements are generally referenced to the site boundary, property line, or other boundary limit. Occupational Safety and Health Administration (OSHA) standards will apply to near field noise emissions. Near field noise requirements are measured along the equipment envelope. During off-normal and intermittent operation such as startup, shutdown, and upset conditions, the equipment sound pressure level shall not exceed a maximum of 115 dBA at all locations along the equipment envelope, including platform areas, that are normally accessible by personnel.

Near field noise mitigation requirements will be required of equipment. Since there were no extant noise regulations specific to this site, no far field noise mitigation is required.

# 1.0 Results of Noise Regulation Review

Noise requirements fall into two categories: far field or near field. These categories are based upon the distance from the emitter to the receptor. Far field noise requirements are generally referenced to the site boundary, property line, or other boundary limit. Near field noise requirements are measured along the equipment envelope. The envelope is defined as the perimeter line that completely encompasses the equipment package a distance of 3 feet from the face of the equipment.

## 1.1 FAR FIELD NOISE REQUIREMENTS

There are no extant noise regulations or ordinances for Indiana, Posey County, or Marrs Township. The expectation would be that the general environmental sound levels in the surrounding area would not be substantially different from the sound levels with the two coal units in operation, assuming the coal units will be decommissioned after the new unit is operational.

## 1.2 NEAR FIELD NOISE REQUIREMENTS

Near field noise requirements are limited by OSHA requirements. The near-field noise emissions for each equipment component furnished under these specifications shall not exceed a spatially-averaged free-field A-weighted sound pressure level of 85 dBA (referenced to 20 micropascals) measured along the equipment envelope at a height of 5 feet above floor/ground level and any personnel platform during normal operation.

During off-normal and intermittent operation such as start-up, shut-down, and upset conditions the equipment sound pressure level shall not exceed a maximum of 115 dBA at all locations along the equipment envelope, including platform areas, that are normally accessible by personnel.

# 2.0 Conclusions

Near field noise mitigation requirements will be required of equipment. Since there were no extant noise regulations specific to this site, no far field noise mitigation is required.

The attached V100 supplemental, contains the noise abatement requirements to be included with the procurement specifications. Since there were no extant noise regulations specific to this site, the V100 supplemental was developed using the near field requirements which are the typical OSHA limits.

Confidential

FINAL

# CONDENSATE POLISHER EVALUATION SUMMARY

## A.B. Brown 1x1 F-Class

**B&V PROJECT NO. 400278**
**B&V FILE NO. 41.1214F**



**PREPARED FOR**

VECTREN
A CenterPoint Energy Company

Vectren

31 JANUARY 2020

BLACK & VEATCH

# Table of Contents

# Executive Summary

This report provides a summary of Black & Veatch's evaluation of including a condensate polisher system in the conceptual design of the new A.B. Brown Combined Cycle. This summary of the evaluation will show that:

- Five selection criteria for Pre-Coat Condensate Polishers are present in the conceptual design. General industry practice to consider polishing is three or more.

| PRE-COAT POLISHER CRITERIA | A.B. BROWN COMBINED CYCLE PLANT |
|---|---|
| Steam Cation Conductivity ≤0.2uS/cm | **Yes – 0.2uS/cm Allowed*** |
| Graywater Cooling | No – River Water |
| Air Cooled Condenser | No – Wet Surface Condenser |
| All-Volatile Treatment – Oxidizing Treatment (AVT-O) Cycle Chemistry | **Yes – All-Volatile Treatment-Oxidizing with Phosphate (no oxygen scavenger)** |
| HP/Main Stream Pressure >2,400 psig | **Yes – HP/Main Steam >2,500 psig** |
| Cycling with Short Start-up Time | **Yes – Cycling Units with Rapid start** |
| LP Steam Conductivity Limit? | No |
| Suspended Solids (TSS) process contamination possible? | **Yes – River water contains levels of TSS** |
| * GE Steam Purity for Industrial Turbine (Table 4 in document GEK 98965) | |

- [redacted]

| PARAMETERS | 1X1 7F.05 (FIRED) |
|---|---|
| Condensate Design Flow, gpm | [redacted] |
| Estimated Equipment Costs ($450 per gpm) | [redacted] |
| Estimated Total Installed Capital Cost (Equipment Costs + $2.28M installation) | [redacted] |

Based on the selection criteria identified in the summary report, Black & Veatch's recommendation is to include provisions for a future pre-coat type condensate polisher system in the conceptual design for the project. This includes, but not necessarily limited to, [redacted] allowance in condensate pump sizing, space allocation, spare electrical capacity and connections, and condensate discharge by pass piping connections.

# 1.0 Introduction

## 1.1 GENERAL FACILITY OVERVIEW

Vectren (Company) is planning the construction of a combined cycle plant at its existing A.B. Brown Station (ABB) in Evansville, Indiana. This combined cycle configuration will utilize a heat recovery steam generators (HRSG), combustion turbine generator and steam turbine generator to output 440 MW.

Condensate polishing is the process of purifying condensate before returning it to a boiler. Feedwater (condensate and boiler feed) contain various impurities. Corrosion products from the steam cycle, mostly iron, travel through the cycle and can concentrate in the boiler. Impurities in feedwater can affect HRSG performance and can be transported from the HRSG to the steam turbine, causing damage to piping and turbine components from pitting, corrosion, or scaling. They can inhibit heat transfer, cause hot spots and eventual failure of the boiler tubes. Additionally, they can carryover with the steam and degrade the steam purity to the level that it no longer meets the steam turbine suppliers steam purity guarantee requirements.

The water quality required for feedwater is defined by the HRSG manufacturers and is dependent on the unit cycling, chemistry program, and operating pressure of the plant. High pressure (1500 psi or greater) drum boilers have stringent feed water quality requirements in order to meet the steam turbine suppliers steam purity guarantee. Drum boilers meet theses water quality requirements by blowdown to eliminate impurities from the cycle and making up with fresh demineralized water. Condensate polishing provides a means to minimize blowdown and better ensure boiler water quality requirements.

In addition to improving condensate/feed water quality, condensate polishers can decrease unit startup time by minimizing chemistry related delays, minimize impacts of condenser leaks, and reduce frequency of boiler chemical cleaning. Consequently, condensate polishers are a worthy consideration in most high pressure steam cycle units, especially cycling units designed with rapid start.

## 1.2 EVALUATION OBJECTIVE

The purpose of this study is to:

- Identify the selection criteria for condensate polishing and determine if/which criterion is applicable to the project.
- Evaluate the capital costs associated with condensate polishing.

The following evaluation reports should be viewed in conjunction with this document:

- 41.1207F – Number of Cold, Warm and Hot Starts Analysis
- 41.1203F – Fast Start vs. Conventional Start Analysis
- 41.1217F – Demin Water Analysis Evaluation.

# 2.0 Condensate Polishing

## 2.1 SELECTION CRITERIA

Figure 1 below is a flow chart used to confirm whether or not condensate polishing is necessary in the power plant design basis. The primary and secondary factors shown in Figure 1 are used to identify, if necessary, which type of condensate polisher is to be used based on the parameters of the unit; Deep Bed type or Pre-coat type polishers.

**Figure 1 –Condensate Polisher Selection Flow Chart**

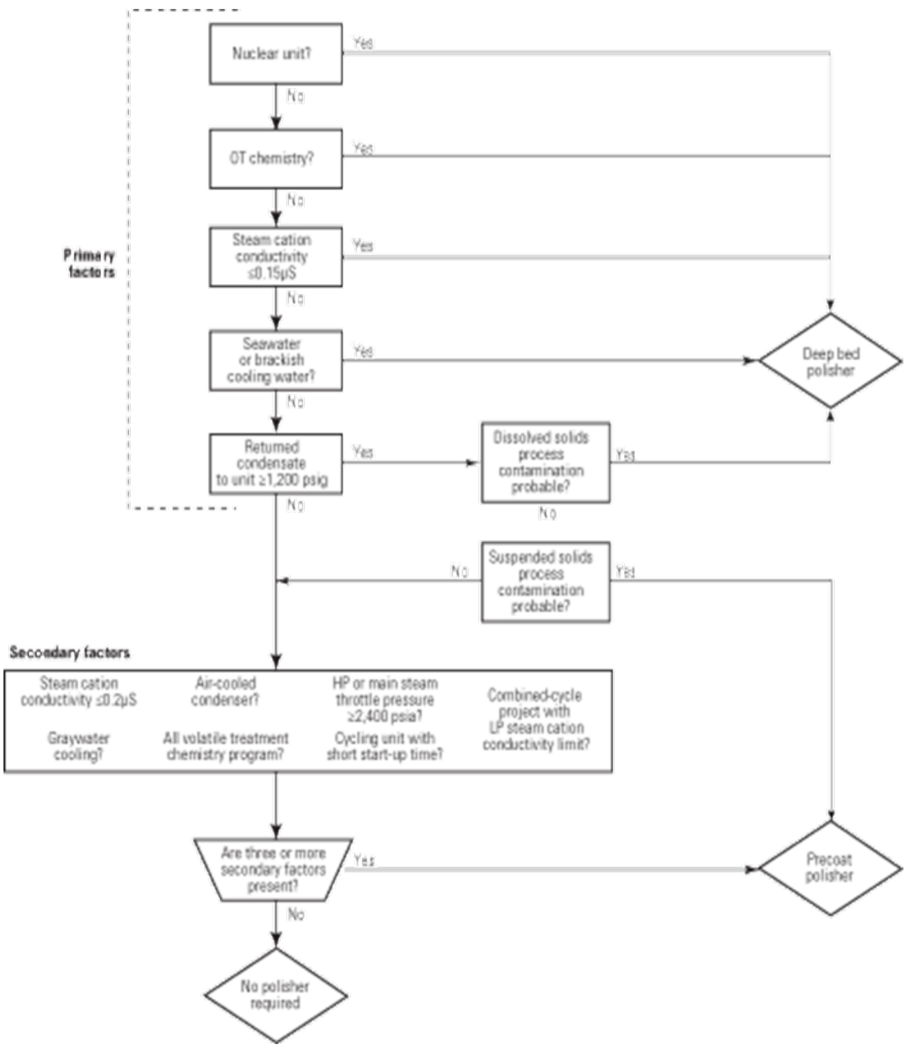



Table 1 reviews the criteria for deep bed type polishers listed and indicates if these factors apply to the project. If one or more of the selection criteria, or factors, apply to ABB, then deep bed condensate polishing should be considered.

### Table 1 – Deep Bed Condensate Polisher Selection Criteria

| DEEP BED POLISHER CRITERIA | A.B. BROWN COMBINED CYCLE PLANT |
|---|---|
| Nuclear Plant | No – Fossil Fuel |
| Oxygenated Treatment (OT) Cycle Chemistry | No – All-Volatile Treatment-Oxidizing with Phosphate |
| Steam Cation Conductivity <0.15uS/cm | No – 0.2uS/cm Allowed* |
| Seawater or Brackish Cooling Water | No – Surface Water, Well Water |
| Returned Condensate to unit >1200 psig | No - 400 psig |
| * GE Steam Purity for Industrial Turbine (Table 4 in document GEK 98965) | |

Based on the design parameters of the plant as shown in Table 1, deep bed condensate polishing would not be considered.

Table 2 reviews the criteria for pre-coat type polishers listed and indicates if these factors apply to the project. General industry practice is if three or more factors apply to ABB, pre-coat polishers should be strongly considered.

### Table 2 – Pre-Coat Condensate Polisher Selection Criteria

| PRE-COAT POLISHER CRITERIA | A.B. BROWN COMBINED CYCLE PLANT |
|---|---|
| Steam Cation Conductivity ≤0.2uS/cm | Yes – 0.2uS/cm Allowed* |
| Graywater Cooling | No – River Water |
| Air Cooled Condenser | No – Wet Surface Condenser |
| All-Volatile Treatment – Oxidizing Treatment (AVT-O) Cycle Chemistry | Yes – All-Volatile Treatment-Oxidizing with Phosphate (no oxygen scavenger) |
| HP/Main Stream Pressure >2,400 psig | Yes – HP/Main Steam >2,500 psig |
| Cycling with Short Start-up Time | Yes – Cycling Units with Rapid start |
| LP Steam Conductivity Limit | No |
| Suspended Solids (TSS) Process Contamination Possible | Yes – River water contains levels of TSS |
| * GE Steam Purity for Industrial Turbine (Table 4 in document GEK 98965) | |

As shown in Table 2, five factors are present in the current design of the project. As a result, pre-coat polishers or design provisions to include future polishers should be considered. The next sections review the benefits of the pre-coat polisher design.

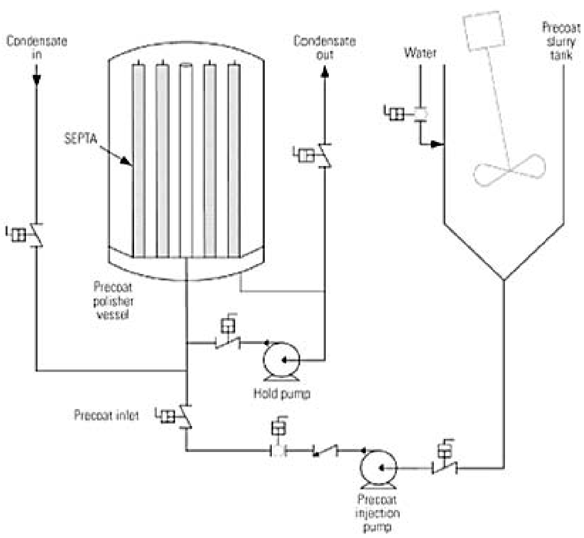
## 2.2 PRE-COAT TYPE CONDENSATE POLISHING

### 2.2.1 Overview

Pre-coat polisher is a vessel containing media-retaining filter elements. A powdered media is placed on the elements and the condensate is passed through the media coated filter element and returned to the condensate flow. Figure 2 shows a diagram of a Pre-coat polisher system.

These filter elements, combined with the ion exchanging media (powder coating), has the capability of simultaneous removal of total dissolved solids (TDS) and total suspended solids (TSS). Pre-coat polishers in particular, perform the dual purpose of straining the TSS particulates (iron oxides produced in the condensate system) and removing dissolved solids. Air in-leakage causes corrosion from oxygen pitting and to a lesser degree acidic attack from CO2. Not only does the oxygen damage the carbon steel surfaces but the iron oxides from this corrosion process, both soluble (TDS) and insoluble (TSS), will be transported into the heat recovery steam generator (HRSG) and will deposit on tube surfaces. Over time these deposits reduce unit efficiency, create an environment for under deposit corrosion (boiler tube failures) and necessitate the need for more frequent chemical cleanings.

**Figure 2 – Pre-Coat Polisher Diagram**




The condensate polisher improves condensate/feed water quality during steady state operations by minimizing the impacts of condenser leaks by the removal of dissolved solids and improves unit startup time by minimizing chemistry related delays by the removal of suspended solids.

### 2.2.2 Operational Impacts

Dissolved gases can enter the cycle as impurities in the makeup water as well as through air in-leakage to the condenser which is under vacuum. Dissolved gases, particularly uncontrolled oxygen and carbon dioxide, can cause corrosion in the cycle and are generally removed in the condenser and deaerator. However, carbon dioxide can accumulate in the condensate/feed water/boiler train because of its pH equilibrium chemistry and can only be effectively removed with condensate polishing. Particularly during startup and shutdown the condensate/feedwater cycle can and will be exposed to carbon dioxide and oxygen. Their corrosive effects on the carbon steel condensate/feedwater piping can be mitigated with the proper chemistry and blowdown over time, but a polishing unit greatly improves the amount of time necessary to reach optimal cycle chemistry.

If left untreated or detected, these impacts will lead to any number of issues including boiler tube failures, damage to the steam turbine and condenser tube failures.

A condensate polisher is warranted for combined-cycle plants where the steam turbine cation conductivity limit is $\leq$ 0.2 μS/cm, and especially cycling units designed with rapid start. The cation conductivity of the condensate/feedwater stream can typically reach 0.5 to 0.6 μS/cm due to carbon dioxide absorption in the water. The GE steam turbine cation conductivity requirement for A.B. Brown is <0.2 μS/cm.

Without a condensate polisher, and in the event of a major feedwater chemistry excursion, typically a plant will either dump the "out-of-spec" water and re-fill the system with "in-spec" water or operate the feedwater system without generating steam until the boiler feedwater chemical treatment system brings the water back into spec. Worst case scenario for ABB is dumping the approximate +100,000 gallons of water from the cycle (one HRSG and condenser).

Utilizing condensate polishing can reduce the average cycle blowdown during both startup and normal operation to approximately 0.5%-1%. For the ABB project, this blowdown reduction can save up to 1,000,000 gallons of demineralized water each year. This is based on the estimated number of starts per year and capacity factor found in 41.1207F – Number of Cold, Warm and Hot Starts Analysis. Condensate polishing can also potentially reduce the number of boiler chemical cleans over the 30 year expected life of the plant.

# 3.0 Risk AND Cost Analysis

## 3.1 RISK ANALYSIS

As stated in Section 3.0, there are several risks associated with operating a combined cycle plant with three or more of the selection factors present in the design. The risk of operating with poor steam/water quality can lead to boiler tube failures, condenser tube failures, and damage to the steam turbine. Table 3 below provides a high level risk analysis of not utilizing a condensate polisher unit.

**Table 3 – Risk Analysis Without Condensate Polishing**

| RISK | SEVERITY | OCCURANCE | DETECTION | LENGTH OF OUTAGE | OVERALL RISK FACTOR |
|---|---|---|---|---|---|
| Boiler Tube Failure | High | Medium | High | Medium | High |
| Steam Turbine Damage | High | Low | Low | High | Medium |
| Condenser Tube Failure | Medium | Medium | Medium | Medium | Medium |
| Overall risk factors are indications of estimated number of failure occurrences per year: High = 1 occurrences/yr; Medium = 0.33 occurrences/yr; Low = 0.11 occurrences/yr | | | | | |

The overall risk factor provides an indication of estimated number of failure occurrences per year. A high overall risk will generally indicate one occurrence per year, while the occurrences per year drop to 33 percent and 11 percent for medium and low factors, respectively.

Utilizing a condensate polisher and a good chemical conditioning program can potentially drop the overall risk factor to the next lower tier for each type of failure.

## 3.2 COST ANALYSIS

A budgetary cost for a full 2x100% pre-coat condensate polishing system (with pre-coating skid, slurry pumps, air receiver, and resin/precoat recovery tank) is approximately [redacted]. An estimated [redacted] for installation, project management, and risk and contingency is used to estimate the total installed cost.

### Table 4 – Cost Evaluation - Condensate Polishing

| PARAMETERS | 1X1 7F.05 (FIRED) |
|---|---|
| Condensate Design Flow, gpm | [redacted] |
| Estimated Equipment Costs [redacted] | [redacted] |
| Estimated Total Installed Capital Cost [redacted] | [redacted] |

A temporary/mobile rental condensate polisher could be considered. [redacted]

# 4.0 Conclusions

## 4.1 SUMMARY OF CONCLUSIONS

This evaluation report has shown that:

- Five selection factors for Pre-coat condensate polishers are present in the current design of the project. General industry practice to consider polishing is three or more.
- Cycling with rapid startup and <0.2 µS/cm steam cation conductivity, are the two key selection factors that are a part of this project.
- Pre-coat condensate polishers have the capability of simultaneous removal of both TDS and TSS. TSS process contamination is a possibility with any cooling water tube leak utilizing river water makeup.
- The condensate polisher, in combination with a sound cycle chemistry scheme, protects all equipment components in the steam/feedwater cycle.

Based on the selection criteria identified in the summary report, Black & Veatch's recommendation is to include provisions for a future pre-coat type condensate polisher system in the conceptual design for the project. This includes, but not necessarily limited to, [redacted] allowance in condensate pump sizing, space allocation, spare electrical capacity and connections, and condensate discharge by pass piping connections.

Confidential

FINAL

# AUXILIARY COOLING WATER SYSTEM ANALYSIS

A.B. Brown 1x1 F-Class

**B&V PROJECT NO. 400278**
**B&V FILE NO. 41.1215F**



PREPARED FOR

Vectren

31 JANUARY 2020

# Table of Contents



## LIST OF TABLES

# Executive Summary

In developing this report for the new Combined Cycle Power Plant (CCPP), Black & Veatch reviewed different design scenarios for the auxiliary cooling water system. It was determined that the design used for the auxiliary cooling water system on the existing units would not be practical for the CCPP. Three alternative designs were investigated:

- Alternative 1--Auxiliary cooling from makeup and circulating water.
- Alternative 2--Circulating water to cool the closed cycle cooling water equipment.
- Alternative 3--Circulating water to cool closed cycle cooling water equipment and hydrogen and lube oil coolers.

The performance, plant area required, reliability and maintenance, and cost of both shell and tube and plate and frame heat exchangers were considered in conjunction with the three alternatives for the auxiliary cooling water system. [redacted]

# 1.0 Introduction

Equipment throughout the plant is cooled by water. The source of this cooling water is through a closed loop system Closed Cycle Cooling Water (CCCW) or directly from an auxiliary cooling water source. This report looks at the sources for water for equipment cooling.

The existing plant cooling system is cooled by the raw water system. The raw water system consists of three (3) 3,300 gpm river water pumps which provide cooling water for the coal units closed cooling heat exchangers. The discharge from these existing heat exchangers is then routed to the cooling towers for makeup. The heat duty of the existing closed cycle cooling water system is minimized as the circulating water system directly provides cooling water flow to the generator hydrogen coolers and lube oil coolers.

In developing this report, Black & Veatch reviewed different design scenarios for the auxiliary cooling system for the new Combined Cycle Power Plant (CCPP). It was determined that the design used for the auxiliary cooling water system on the existing units would not be practical for the CCPP. Three alternative designs were investigated.

- The first alternative uses a combination of water from the cooling tower makeup to the cooling towers and circulating water to cool closed cycle cooling water equipment. Turbine hydrogen and lube oil coolers would be cooled directly from the cooling tower makeup.
- The second alternative uses circulating water to cool the closed cycle cooling water equipment. The closed cycle cooling water equipment provides cooling water to all equipment including the turbine hydrogen and lube oil coolers.
- The third alternative uses circulating water to cool the closed cycle cooling water equipment and the turbine hydrogen and lube oil coolers. This scenario differs from the second alternative as circulating water is used to directly cool the hydrogen and lube oil coolers.

This evaluation will evaluate the different alternatives looking at the system performance and cooling capability of the different cooling configurations.

# 2.0 System Performance – Cooling Capability

Table 2-1 provides a table listing the pros and cons of the different auxiliary cooling water arrangements

**Table 2-1 System Performance Capability**

| ARRANGEMENT | PROS | CONS |
|---|---|---|
| Aux Cooling Water from Raw Water Makeup | - | Not Practical for CCPP |
| Alternative 1 - Circulating water cools CCCW equipment. Aux Cooling Water cools Turbine Lube Oil and Hydrogen Cooling. | Cooler auxiliary cooling water temps.<br>Smaller circulating water pumps.<br>Smaller CCCW system. | Long, large diameter stainless pipe runs to generators.<br>Warmer makeup to cooling tower.<br>Specialized OEM heat exchangers. |
| Alternative 2 - Circulating water cools CCCW. CCCW cools all equipment. | Standard OEM heat exchangers.<br>Typical CCPP design.<br>Minimizes piping costs. | Warmer circulating water temps.<br>Larger circ water pumps. |
| Alternative 3 - Circulating water cools CCCW equipment. Circulating water cools Turbine Lube Oil and Hydrogen Cooling. | Cooler auxiliary cooling water temps.<br>Smaller circulating water pumps.<br>Smaller CCCW system. | Long, large diameter stainless pipe runs to generators.<br>Warmer makeup to cooling tower.<br>Specialized OEM heat exchangers. |

## 2.1 ALL AUXILIARY COOLING FROM RAW WATER MAKEUP

The existing raw water makeup pumps consist of three (3) pumps each having a rated a flow capability of 3,300 gpm at 176 ft of head. To maintain a N+1 sparing philosophy, two pumps would be operating and one pump would be in standby providing a cooling water flow of 6,600 gpm since pressure drop to the new cooling tower is expected to be similar to that the existing system.

If the raw water system provides all of the cooling water for the combined cycle, the temperature rise across the heat exchangers would result in an elevated summer make up temperature to the cooling tower not considered acceptable with the cooling tower fill. To limit the temperature rise across the heat exchanger, it is recommended to use the circulating water system instead of the river water for a minimum of the cooling the generator hydrogen coolers and lube oil coolers.

## 2.2 ALTERNATIVE 1 – AUX COOLING FROM MAKEUP AND CIRC WATER

For Alternative 1, most auxiliary cooling water would be supplied from the river water make up to cool the closed cycle cooling water system while the generator hydrogen coolers and lube oil coolers would be cooled from the circulating water system directly. This scenario would result in a temperature rise for the makeup water system to match the hot water returning from the cooling tower. The temperature rise to the generator hydrogen coolers and lube oil coolers would be designed to match the circulating water temperature rise across the condenser; additional flow to the circulating water system to cool the steam turbine and combustion turbine generator hydrogen coolers and lube oil coolers would be about 3,600 gpm.

Due to the corrosive nature of the circulating water system stainless steel pipe would be required for the piping runs to the generator hydrogen coolers and lube oil coolers. The design for the combustion turbine generator hydrogen coolers and lube oil coolers would need to be coordinated with OEMs. The surface area of these coolers would be approximately twice the size of the standard design to limit the pressure drop across the heat exchanger as needed to match the pressure drop across the condenser as to not adversely impact the circulating water system design. The advantage to supplying cooling water directly from circulating water is that auxiliary cooling water to the generator hydrogen and lube oil coolers is 10°F cooler than if supplied from the closed cycle cooling water system.

## 2.3 ALTERNATIVE 2 – CIRC WATER COOLS CCCW

A typical design for combined cycle plants is to supply the auxiliary cooling water from the circulating water system. Under this design, circulating water would be supplied to the closed cycle cooling water system. The design of the closed cycle cooling water heat exchangers would limit the temperature rise of the circulating water to match the temperature rise of the circulating water across the condenser; the auxiliary cooling water flow would be sized as required to reject the heat of the closed cycle cooling water system. The cold water temperature of the CCCW would have a design temperature of 105°F; this is standard for equipment provided on combined cycle power plants. Circulating water flow to supply auxiliary cooling water system would be about 5,700gpm.

## 2.4 ALTERNATIVE 3 – CIRC WATER COOLS CCCW AND HYDROGEN AND LUBE OIL COOLERS

If the 105°F cooling water is a concern for the generator hydrogen and lube oil coolers and hydrogen coolers, they could be cooled directly from the circulating water system. The design for the combustion turbine generator hydrogen coolers and lube oil coolers would need to be coordinated with OEMs. The surface area of these coolers would be approximately twice the size of the standard design to limit the pressure drop across the heat exchanger as needed to match the pressure drop across the condenser as to not adversely impact the circulating water system design. Circulating water flow to supply auxiliary cooling water system would be about 2,000 gpm.

# 3.0 Conclusions

Since the existing raw water pumps that provide makeup to the cooling tower do not have sufficient flow to meet the requirements of the new combined cycle, a new cooling water arrangement utilizing circulating water is recommended. Since the turbine manufacturers design their heat exchangers including turbine lube oil and hydrogen coolers for cooling water up to 105°F and the CCCW system is designed to meet this condition under the extreme hot summer day, Alternative 2 with all equipment cooling water coming from the CCCW system as it is the lowest cost and allows the use of standard OEM equipment.

Confidential

FINAL

# DEMIN WATER USAGE ANALYSIS

## A.B. Brown 1x1 F-Class

**B&V PROJECT NO. 400278**
**B&V FILE NO. 41.1217F**



PREPARED FOR

VECTREN
A CenterPoint Energy Company

Vectren

31 JANUARY 2020

BLACK & VEATCH

# Table of Contents



## LIST OF TABLES

# Executive Summary

In developing this report, Black & Veatch reviewed the requirements for demineralized water for the new Combined Cycle Power Plant (CCPP). Black & Veatch reviewed multiple pre-start, start-up and steady state scenarios to determine the required sizing and operation of the demineralized water system. Demineralized water storage capacity was evaluated in parallel with system operation. Black & Veatch evaluated water usage based on 1x1 7F.05 gas turbines for this analysis.

The demineralized water system users have been summarized in the steady state demands provided in Table 2-1. Plant pre-start demands have been summarized in Table 2-2 and plant startup demands have been summarized in Table 2-3. For all scenarios, the difference between water demand and existing system capacity is compared. Based on the demineralized water requirements for the multiple scenarios, it is recommended that Vectren utilize an additional water treatment system with a water capacity of [redacted] gpm per Table 3-1. No additional demineralized water storage capacity is required.

# 1.0 Introduction

The purpose of this study is to determine the specific requirements for demineralized water with the new Combined Cycle Power Plant (CCPP). Based on steady state operation, the existing cycle makeup treatment system can meet water demand. However, during startup and steady state operation with the evaporative cooler in operation, water demand exceeds the existing system capacity. The following tables detail differences in water demand for each configuration and condition.

# 2.0 Demineralized Water System Operation Demands

The demineralized water system provides water to various users during plant startup and shutdown at multiple operating conditions. Several operating scenarios were evaluated to determine the maximum water usage for the demineralized water system. Plant pre-start activities, plant startup, and plant steady state operation was evaluated for maximum demineralized water demand. The existing demin water treatment system capacity is [redacted] gpm. Demineralized water storage will need to be sufficient to hold three (3) days storage of the CCPP steady state demineralized water demand without evaporative cooling water makeup. Demin water demands excluded in this steady state operation are evaporative cooler makeup for the CCPP, CT#3 water injection and existing Unit 3 and 4 steam cycle demands.

## 2.1 STEADY STATE AND NON-STEADY STATE DEMANDS

The steady state demineralized water demand occurs during operation when supplying makeup water for CCPP blowdown and sampling losses. Non-steady state demineralized water demands occurs during operation when supplying makeup water for steady state CCPP users plus evaporative cooler operation, existing unit operation and CT#3 water injection operation. Demineralized water demands are shown in Table 2-1. Steady state operation assumes 2% blowdown per the water mass balances. Steady state flows are based on Hot Day Case (93.7F) heat balance. Due to the infrequent operation of existing units and CT#3, storage volume recommendations will account for the excursion in steady state demand for demineralized water.

**Table 2-1 Demineralized Water Demands**

| DEMIN WATER USERS | 1X1 7F.05 |
|---|---|
| **STEADY STATE DEMANDS** | |
| 2% blowdown (gpm) | [redacted] |
| Sample Analytics (gpm) | [redacted] |
| Demand w/o Evaporative Cooler Makeup (gpm) | [redacted] |
| **NON-STEADY STATE DEMANDS** | |
| Existing Unit 3 steam cycle demands (gpm) | [redacted] |
| Evaporative Cooler Makeup on RO Permeate (gpm) | [redacted] |
| Demand w/ Evaporative Cooler Makeup @ 6 COC (gpm) | [redacted] |
| CT #3 Water Injection | [redacted] |
| Instantaneous Demand for Steady State Operation with CT#3 water injection (1) | [redacted] |
| [redacted] | |

## 2.2 PRE-START DEMANDS

During unit pre-start, the auxiliary boiler is used to warm the HRSG and steam turbine seals. The assumption of 2% blowdown on the auxiliary boiler during this operation is included. During this operation, it is assumed all water is non recoverable. The pre-start usage demands are listed in Table 2-2.

**Table 2-2 Demineralized Water Demands during Pre-Start Activities**

| PRESTART USAGE | 1X1 7F.05 |
|---|---|
| Aux Boiler Makeup (gpm) HRSG warming | [redacted] |
| Difference (gpm) - Existing | [redacted] |
| Difference (gpm) - Proposed new | [redacted] |

## 2.3 STARTUP DEMANDS

During unit startup, demineralized water usage is at the maximum. HRSG is warm and the condenser sparging and gland steam flows are recovered in the condenser. Steam drains are open until superheat targets are met. 5% blowdown is utilized for startup. The demineralized water demands are listed in Table 2-3.

**Table 2-3 Demineralized Water Demands During Startup Activities**

| STARTUP DEMAND | 1X1 7F.05 |
|---|---|
| Aux Boiler Makeup Fast Start (gpm) | [redacted] |
| Steam Drains to HRSG Blowdown Tank (gpm) | [redacted] |
| Blowdown (gpm) | [redacted] |
| Total Instantaneous Startup Demand (gpm) | [redacted] |
| Difference (gpm) | [redacted] |
| Difference (gpm) - Proposed new | [redacted] |
| Hot start lost capacity (gallons) (1) | [redacted] |
| Warm start lost capacity (gallons) (1) | [redacted] |
| Cold start lost capacity (gallons) (1) | [redacted] |
| Time to replace lost capacity during normal op (Hot Start), min | [redacted] |
| Time to replace lost capacity during normal op (Warm Start), min | [redacted] |
| Time to replace lost capacity during normal op (Cold Start), min | [redacted] |
| [redacted] | |

# 3.0 Demineralized System

## 3.1 WATER REPLENISHMENT

The demineralized water system provides minimal margin for replenishment from startup of the combined cycle. For a typical combined cycle plant, the rule of thumb for storage is 3 days of steady state demand capacity. This relates to a 3 day outage on the demin supply. Table 3-1 details the time to replenish demineralized water capacity.

**Table 3-1 Demineralized Water Volumes and Treatment Capacities**

| DEMINERALIZED WATER SYSTEM | 1X1 7F.05 |
|---|---|
| **STORAGE CAPACITY** | |
| Existing Demin storage (gallons) | [redacted] |
| 3 day Demin storage capacity required @ steady state demand | [redacted] |
| Storage Surplus (+) / Storage Deficient (-) during a 3 day outage. | [redacted] |
| Recommended Additional Demin Storage (gallons) (1) | [redacted] |
| **STEADY STATE TREATMENT DEMAND** | |
| Current Demin Water Treatment Capacity (gpm) | [redacted] |
| CCPP Steady State Demand (gpm) | [redacted] |
| Treatment Surplus (+) / Deficient (-) (gpm) | [redacted] |
| **NON-STEADY STATE TREATMENT DEMAND** | |
| Current Demin Water Treatment Capacity (gpm) | [redacted] |
| CCPP Non- Steady State Demand (gpm) | [redacted] |
| Treatment Surplus (+) / Deficient (-) (gpm) | [redacted] |
| **PEAK TREATMENT DEMAND** | |
| Current Demin Water Treatment Capacity (gpm) | [redacted] |
| CCPP Peak (CT#3 + Non- Steady State) Demand (gpm) | [redacted] |
| Treatment Surplus (+) / Deficient (-) (gpm) | [redacted] |
| **PROPOSED ADDITIONAL DEMINERALIZED WATER TREATMENT CAPACITY (GPM)** | [redacted] |
| Treatment Surplus (+) / Deficient (-) (gpm) | [redacted] |
| Recover 3 day outage volume, Steady state after (HOURS) | [redacted] |
| Recover 3 day outage volume, Non-Steady state after (HOURS) | [redacted] |
| [redacted] | |

[redacted]

Based on Black & Veatch's evaluation, the existing demineralized water storage capacity can provide sufficient storage of demineralized water based on the design parameters. Furthermore, a new demineralized water treatment system sized to supplement [redacted] gpm (coupled with the existing [redacted] gpm system) would be sufficient to meet various operating demands of the facility as well as replenish demineralized water volume within the design parameters.

# 4.0 Conclusions

Based on the evaluation Black & Veatch can conclude:

- The existing demineralized water storage capacity provides adequate storage of demineralized water based on the design parameters.
- A new demineralized water treatment system sized to supplement [redacted] (coupled with the existing [redacted] system) would be sufficient to meet various operating demands of the facility as well as replenish demineralized water volume within the design parameters.

Confidential

FINAL

# BLACK START ANALYSIS

## A.B. Brown 1x1 F-Class

**B&V PROJECT NO. 400278**
**B&V FILE NO. 41.1221F**



PREPARED FOR

VECTREN
A CenterPoint Energy Company

Vectren

31 JANUARY 2020

BLACK & VEATCH

# Table of Contents



## LIST OF TABLES



## LIST OF FIGURES

# Executive Summary

In developing this report for the new Combined Cycle Power Plant (CCPP), Black & Veatch examined the capability of using the existing combustion turbine generator (CTG) peaking Unit 3 at A.B. Brown as a means of black starting CTG 5 of the new CCPP

Unit 3 is a GE 7EA turbine capable of operating with either natural gas or distillate fuel oil as the fuel source. Two scenarios were modeled for this evaluation:

- Starting of the largest medium voltage induction motor with all necessary auxiliary electric loads in operation.
- Static starting of CTG 5 with all necessary auxiliary electric loads in operation.

For analysis modeling purposes, the aggregate auxiliary electrical load necessary to start a combustion turbine were based on the preliminary conceptual design of the new CCPP. In addition, the excitation system was assumed to be capable of providing the necessary reactive power required by the simulated scenarios while maintaining 100 percent system voltage at a frequency of 60 Hz at the generator terminals.

Within the boundaries of this evaluation, the Unit 3 generator at A.B. Brown appears to be capable of black starting one combustion turbine of the new CCPP. Further analysis would be required to verify that generator control and system protection would permit synchronization of the Unit 5 generator to the Unit 3 generator to shift auxiliary electrical loads from the Unit 3 generator to the Unit 5 generator.

# 1.0 Introduction

The purpose of this evaluation is to examine the capability of the existing combustion turbine generator peaking Unit 3 at A.B. Brown to be utilized as a black starting means for the new combined cycle power plant (CCPP). Unit 3 is a GE 7EA turbine capable of operating with either natural gas or distillate fuel oil as the fuel source. The unit has a dedicated diesel generator and starting motor necessary to start. Unit 3 is utilized as a black starting means for existing A.B. Brown coal-fired Units 1 and 2.

Electrical power system analysis software ETAP was utilized to model and evaluate Unit 3 to verify the capability of black starting CTG 5 of the new CCPP. Figure 1-1 provides the one line diagram that was modeled in ETAP. Two scenarios were modeled for this evaluation, starting of the largest medium voltage induction motor with all necessary auxiliary electric loads in operation, and static starting of CTG 5 with all necessary auxiliary electric loads in operation.

[redacted]

[redacted]

# 2.0 Assumptions

In order to simulate the scenarios included in this evaluation, reasonable assumptions were made in order to model and simulate the black start capability. The assumptions are defined as follows.

## 2.1 LOAD LIST

It is necessary to determine the aggregate auxiliary electrical load that is necessary to start a combustion turbine of the new CCPP. Table 2-1 provides the load list of all loads considered to be in operation to support the black start. Except ACWP, BFP, CWP, CCWP & CP (major loads), all other loads were modeled as a lump load. For lump load motor power factor of 85% has been considered. A 20 percent margin was added to the lump loads of Table 2-1 for modeling purposes. The loads of Table 2-1 are based on the conceptual design of the new CCPP and are preliminary. All cooling tower fans and CWP have been modeled to show to feed from 6.9kV BUS A & existing 4.16kV BUS 1B respectively.

**Table 2-1 Operating Loads during CCPP Starting**

| BLACK START ANALYSIS LOAD LIST | | | |
|---|---|---|---|
| LOAD | LOAD TYPE | LOAD RATING | LOAD UNITS |
| [redacted] | [redacted] | [redacted] | [redacted] |
| [redacted] | [redacted] | [redacted] | [redacted] |
| [redacted] | [redacted] | [redacted] | [redacted] |
| [redacted] | [redacted] | [redacted] | [redacted] |
| [redacted] | [redacted] | [redacted] | [redacted] |
| [redacted] | [redacted] | [redacted] | [redacted] |
| [redacted] | [redacted] | [redacted] | [redacted] |
| [redacted] | [redacted] | [redacted] | [redacted] |
| [redacted] | [redacted] | [redacted] | [redacted] |
| [redacted] | [redacted] | [redacted] | [redacted] |
| [redacted] | [redacted] | [redacted] | [redacted] |
| [redacted] | [redacted] | [redacted] | [redacted] |
| [redacted] | [redacted] | [redacted] | [redacted] |
| [redacted] | [redacted] | [redacted] | [redacted] |
| [redacted] | [redacted] | [redacted] | [redacted] |

| BLACK START ANALYSIS LOAD LIST | | | |
|---|---|---|---|
| LOAD | LOAD TYPE | LOAD RATING | LOAD UNITS |
| [redacted] | [redacted] | [redacted] | [redacted] |
| [redacted] | [redacted] | [redacted] | [redacted] |
| [redacted] | [redacted] | [redacted] | [redacted] |
| [redacted] | [redacted] | [redacted] | [redacted] |
| [redacted] | [redacted] | [redacted] | [redacted] |
| [redacted] | [redacted] | [redacted] | [redacted] |
| [redacted] | [redacted] | [redacted] | [redacted] |
| [redacted] | [redacted] | [redacted] | [redacted] |
| [redacted] | [redacted] | [redacted] | [redacted] |
| [redacted] | [redacted] | [redacted] | [redacted] |
| [redacted] | [redacted] | [redacted] | [redacted] |
| [redacted] | [redacted] | [redacted] | [redacted] |
| [redacted] | [redacted] | [redacted] | [redacted] |
| [redacted] | [redacted] | [redacted] | [redacted] |
| [redacted] | [redacted] | [redacted] | [redacted] |
| [redacted] | [redacted] | [redacted] | [redacted] |
| [redacted] | [redacted] | [redacted] | [redacted] |
| [redacted] | [redacted] | [redacted] | [redacted] |
| [redacted] | [redacted] | [redacted] | [redacted] |
| [redacted] | [redacted] | [redacted] | [redacted] |
| [redacted] | [redacted] | [redacted] | [redacted] |
| [redacted] | [redacted] | [redacted] | [redacted] |
| [redacted] | [redacted] | [redacted] | [redacted] |
| [redacted] | [redacted] | [redacted] | [redacted] |
| [redacted] | [redacted] | [redacted] | [redacted] |
| [redacted] | [redacted] | [redacted] | [redacted] |
| [redacted] | [redacted] | [redacted] | [redacted] |
| [redacted] | [redacted] | [redacted] | [redacted] |

| BLACK START ANALYSIS LOAD LIST | | | |
|---|---|---|---|
| LOAD | LOAD TYPE | LOAD RATING | LOAD UNITS |
| [redacted] | [redacted] | [redacted] | [redacted] |
| [redacted] | [redacted] | [redacted] | [redacted] |
| [redacted] | [redacted] | [redacted] | [redacted] |
| [redacted] | [redacted] | [redacted] | [redacted] |

## 2.2 UNIT 3 EXCITATION SYSTEM

This study does not include analysis of the excitation model or transfer function for Unit 3. Therefore, the excitation system is fixed in the ETAP simulation. Additional modeling of the excitation system and transfer function would be necessary in order to more accurately simulate the response to the reactive power demands imposed when black starting one combustion turbine generator of the new CCCP, however, the excitation system is assumed to be capable of providing the necessary reactive power required by the simulated scenarios while maintaining 100 percent system voltage at a frequency of 60 Hz at the generator terminals, as long as the real and reactive demands on the Unit 3 generator do not exceed the limits of the reactive capability curve.

## 2.3 PROTECTION, CONTROL AND SYNCHRONIZATION

It is recommended during the detailed design phase that the turbine control system of the new CCPP is designed to be capable of allowing the new combustion turbine generator to synchronize with Unit 3 and that existing and new protection schemes are designed to permit synchronization. It also recommended during the detailed design phase that the control system of the existing Unit 3 combustion turbine generator is verified or modified as necessary to permit load sharing of the auxiliary electrical demands of the new CCPP. No investigation into the existing Unit 3 control system or switchyard protection schemes has been performed in support of this black start capability evaluation.

# 3.0 Static Motor Starting of Largest Motor

The starting of a large motor can have a brief, but significant, impact on the auxiliary electrical system. When voltage is applied to the terminals of an at rest motor, the motor will draw locked-rotor current (LRA), which decays toward full-load amps (FLA) as the motor approaches running speed. This is the result of the motor torque overcoming the combined inertia of the motor and the connected load. For an induction motor, a typical value of LRA is approximately 650 percent of FLA.

In the scenario of the black start, motor starting can result in voltage and frequency sags at the generator output, which will have a corresponding impact on the capability of the motor to start and to the existing loads in operation. The ability of the generator to accommodate starting of large motors is dependent upon the generator capacity, the response of the excitation system, the rotating inertia of the generator and the characteristics of the motor at starting. Should a sag in voltage during motor starting result in the motor's inability to develop the torque necessary to accelerate to full speed, the motor could stall. It is necessary to analyze the worst-case motor starting scenario for the purpose of determining the black start capability of the Unit 3 generator.

As a worst-case scenario, static motor starting of the Boiler Feed Pump, the largest medium voltage motor, was analyzed for 1x1 F class case with all other loads necessary for a black start in operation, with the exception of the Unit 5 generator static starting system. Static motor starting models the motor by locked-rotor impedance during acceleration, simulating the worst impact to loads in operation at the time of motor starting. The properties of the modeled Boiler Feed Pump is 6100 HP, 6.6 kV, 452 FLA, 0.93 power factor, 94 percent efficiency and 6.5 pu LRA. Figure 3-1 provides the bus voltage, as a percent of nominal, at each bus during starting of the Boiler Feed Pump. The Watt and VAR demand from the Unit 3 generator and the starting motor are also displayed.

The maximum demand from the Unit 3 generator during starting of the Boiler Feed Pump is 8.2 MW and 30.04MVAR. This is well within the capability curve of the Unit 3 generator, considering a 0.85 lagging power factor and 15 degrees Celsius inlet air temperature, as depicted in Figure 3-2. The worst-case motor terminal voltage during starting of the Boiler Feed Pump is 80.54 percent of nominal system voltage. It is typical to specify medium voltage motors rated to start at 80 percent of nameplate voltage. It is also typical to specify motor nameplate voltage below nominal system voltage. In the case of a nominal 6.9 kV system, the corresponding motor nameplate is 6.6 kV, consistent with ANSI C84.1. The result of the static motor starting analysis for the Boiler Feed Pump indicates that the momentary sag in voltage at the motor terminals is not prohibitive to the starting of the motor. The worst-case bus voltage for the BUS & MCC A (6.9kV) is 78.17 percent during starting of the Boiler Feed Pump for F Class. This will not result in drop out of motor contactors since the nominal bus voltage is above 70%. All other medium voltage motors connected to BUS & MCC A (6.9kV) were considered to be running in this scenario. The bus voltage of MCC A1 recovers to 99.96 percent of nominal system voltage once the Boiler Feed Pump has accelerated to rated speed.

UAT impedance have been modeled with 6.5%for this study. The short circuit current level will be well below 40kA for 6.9kV SWGR and MCC A. UAT primary tap position has been set at -2.5% in order to achieve motor terminal voltage of higher than 80%. There is a possibility of further reducing UAT 5 impedance and motor locked rotor amperes to improve starting motor terminal voltage if necessary. A 3-3/C-500kcmil conductor has been considered to feed the BFP during this study.

[redacted]

[redacted]

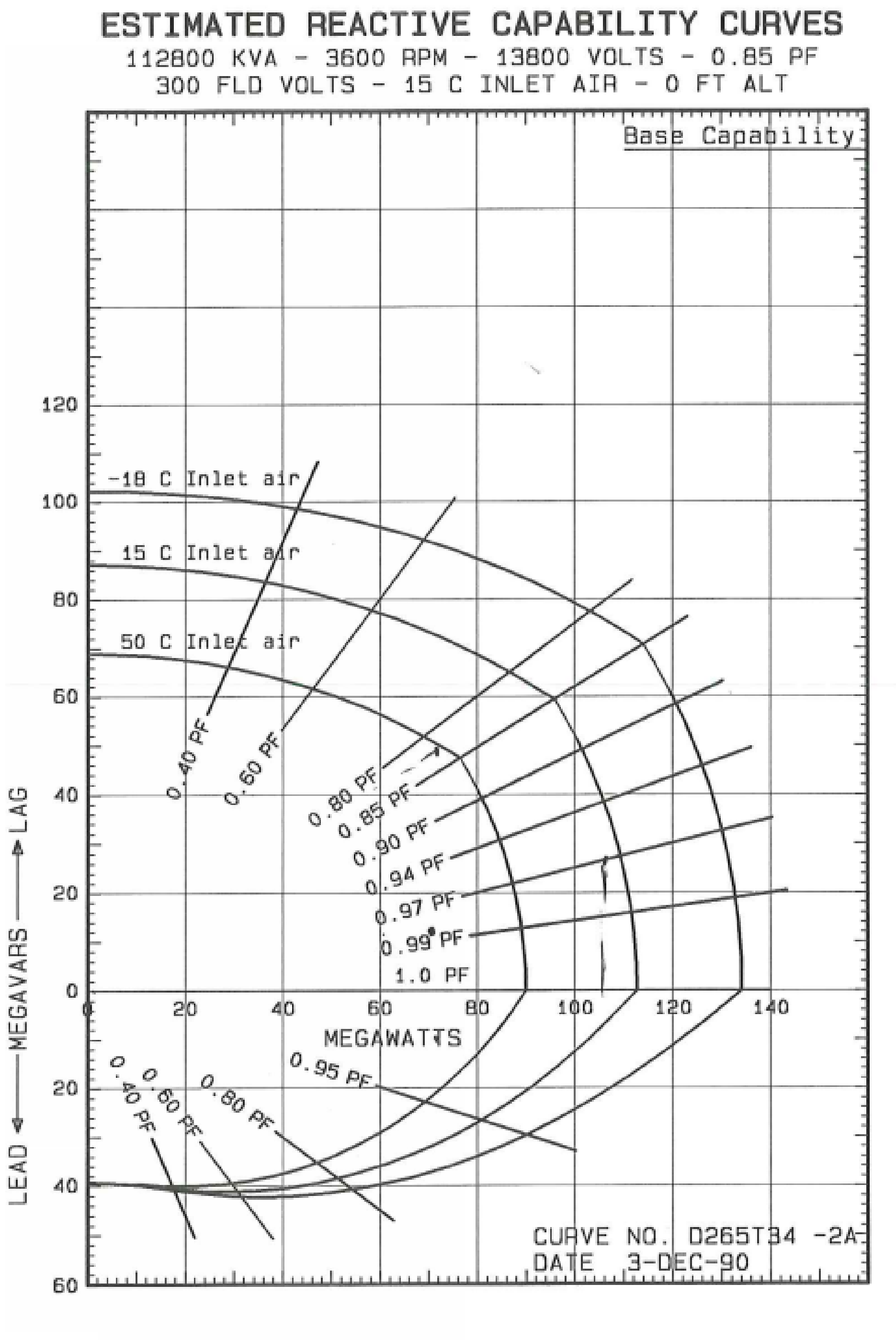



**Figure 3-2 Unit 3 Generator Reactive Capability Curve**

# 4.0 CTG 5 Static Starting Load Flow

A load flow model was analyzed during the static starting of the Unit 5 combustion turbine generator. This scenario considered all loads necessary for black starting to be in operation at the time the static starting system was energized. The maximum demand from the Unit 3 generator during static starting of Unit 5 CTG is as 10.55 MW and 5.81 MVAR. This is well within the capability curve of the Unit 3 generator, considering a 0.85 lagging power factor and 15 degrees Celsius inlet air temperature, as depicted in Figure 3-2.

The bus voltage during operation of the static starting system on 6.9 kV BUS A & 4.16kV BUS 1B will be 99.96 and 98.83 percent of nominal system voltage. This is well within the normal operating 'voltage range A' as per ANSI C84.1 and not considered to be a prohibitive impact to operation during black start. Additionally, the static starting system operates for a short duration until the combustion turbine reaches approximately 90 percent of rated speed, at which point it is self-sustaining and the static starting system is removed from operation and the turbine control system receives control of the turbine. This duration is approximately 30 minutes or less, dependent upon starting conditions with respect to the purging of combustible gases from the hot gas path prior to ignition.

[redacted]

[redacted]

# 5.0 Conclusions

The analyses performed in support of the black starting capabilities of the existing Unit 3 generator at A.B. Brown indicate that the generator has sufficient capacity to provide the required real and reactive power necessary to start the largest medium voltage motor as well as operate the static starting system of the new CCPP. The starting of the Boiler Feed Pump was simulated as a worst-case scenario, with all other loads necessary to support a black start in operation with the exception of the static starting system. Motor terminal voltage and bus voltages were maintained within reasonable limits for the scenario of a black start. Power requirements to support Boiler Feed Pump starting and the static starting system operation were within the capability curve of the Unit 3 generator. Both analyses assume that the Unit 3 generator excitation system is capable of responding appropriately to meet the reactive power needs, and further analysis with the excitation system modeled is necessary to confirm this response. Additionally, further analysis would be required to verify generator control and system protection would permit synchronization of the Unit 5 generator to the Unit 3 generator in order to shift auxiliary electrical loads from the Unit 3 generator to the Unit 5 generator. Within the boundaries of this evaluation, the Unit 3 generator at A.B. Brown appears to be capable of black starting the combustion turbine of the new CCPP.

Confidential

FINAL

# SWITCHYARD EVALUATION AND SEQUENCE

## A.B. Brown 1x1 F-Class

**B&V PROJECT NO. 400278**
**B&V FILE NO. 41.1222F**



PREPARED FOR

VECTREN
A CenterPoint Energy Company

Vectren

31 JANUARY 2020

BLACK & VEATCH

# Table of Contents



## LIST OF TABLES

# Executive Summary

In developing this report, Black & Veatch evaluated the suitability of the existing A.B. Brown 138 kV switchyard for interconnection of a new combustion turbine generator (CTG) and steam turbine generator (STG) operating as a 1x1 Combined Cycle Power Plant (CCPP). This evaluation was performed with existing Unit 2 remaining in operation. Black & Veatch considered preliminary heat balance data for a GE 7FA.05 CCPP as a conservative approach to this evaluation. Switchyard connections and connection sequence were also evaluated.

The continuous current loading of the 3000 Ampere (A) main buses 1 and 2 as well as the 2000 A interpass conductors are not exceeded for the switchyard configurations evaluated. The loading evaluation does not identify any major bus work necessary to independently connect the generators associated with the 1x1 CCPP.

As a result of the available fault current contribution at the existing 138 kV switchyard exceeding 40 kiloampere (kA), with new generation and Unit 2 in service, circuit breakers with a symmetrical interrupting rating 40 kA require replacement. Of the existing 20 circuit breakers in the 138 kV switchyard, 13 are rated 40 kA. [redacted] Therefore, it is recommended to replace all existing circuit breakers in the 138 kV switchyard with 63 kA symmetrical withstand and interrupting rating.

[redacted]

# 1.0 Introduction

The A.B. Brown 1x1 CCPP is a multi-shaft arrangement, with the combustion turbine (CT) and steam turbine (ST) individually coupled to dedicated generators rated to convert maximum turbine capabilities to electric power. The multi-shaft arrangement differs from a single shaft arrangement, with respect to electrical equipment, in that independent generators coupled to each turbine will transmit electric power via dedicated isolated phase bus duct (IPBD) to dedicated generator step-up transformers (GSU). Each GSU is sized to permit maximum real electric power to be transmitted to the electric power grid, with minimal losses, and to permit reactive electric power to be delivered to and absorbed from the electric power grid. Each turbine generator will also provide source power to 100 percent redundant unit auxiliary transformers (UAT). The high voltage side of each GSU will be independently connected to the existing 138 kV switchyard. Interconnection of the CTG and STG to the existing 138 kV switchyard requires consideration of fault current availability and system load flow relative to existing equipment ratings. Black & Veatch considered preliminary heat balance data for a GE 7FA.05 CCPP as a conservative approach for this evaluation. Configurations of a 1x1 CCPP comprised of turbine classes with lower gross megawatt (MW) output will result in additional margin with respect to switchyard loading and fault current. Each of the new generators were modelled with independent connections to the existing 138 kV switchyard, with Unit 2 remaining in operation.

The method of connection for each generator in a given configuration to the existing 138 kV switchyard is based upon the electrical ratings of the switchyard components, switchyard expansion capability, and operation of existing units. The existing 138 kV switchyard is a breaker and a half configuration with two main buses, rated 3000 A continuous. [redacted] 13 of the 20 existing circuit breakers in the 138 kV switchyard are rated to interrupt 40 kA.

# 2.0 Switchyard Evaluation

## 2.1 LOAD FLOW

The interpass connections between Bus 1 and Bus 2 are rated 2,000 A, therefore a single connection to the switchyard is acceptable when the kilowatts (kW) transmitted remain below 430,000 kW at a power factor equal to 0.9. For a single connection above 430,000 kW and less than 645,000 kW, upgrades are required to the entire 138 kV switchyard, such as circuit breaker and disconnect switch replacement with 3000 A continuous rating. Generation exceeding 645,000 kW at a single connection point is not practical at a voltage level of 138 kV as equipment rated above 3000 A continuous is typically not available.

The maximum CTG and STG gross output based on the preliminary fired GE 7FA.05 1x1 considered for this evaluation are 233,750 kW and 243,950 kW and correspond to approximately 974 A and 840 A, respectively. Detailed load flow modelling of the 138 kV switchyard with case permutations of outgoing transmission lines in and out of service is necessary in order to verify the suitability of the 138 kV switchyard to accommodate the connection of two CTGs and identify any overload cases. Initial analysis indicates that the 138 kV switchyard is generally suitable to accommodate independent connection of the new 1x1 CTG and STG while Unit 2 remains in operation.

The maximum current flow in the main and interpass busses for each analyzed case are represented in Table 2-1.

**Table 2-1 Max Load in Main and Interpass Buses - 2026 Summer Peak**

| 138 kV Switchyard Loading 1x1 and Unit 2 | | | | |
|---|---|---|---|---|
| Case | Current in 3kA Main Bus (A) | Percent Loading (%) | Current in 2kA Interpass (A) | Percent Loading (%) |
| All In Service | 689.7 | 22.99 | 605.1 | 30.26 |
| Bus 1 Outage | 1936.5 | 64.55 | 994.3 | 49.72 |
| Bus 1 and Line Z95 Outage | 2219.7 | 73.99 | 1166.5 | 58.33 |
| Bus 1 and Line Z96 Outage | 2072.2 | 69.07 | 1078.8 | 53.94 |
| Bus 1 and Line Z94 Outage | 2401.8 | 80.06 | 1136.8 | 56.84 |
| Bus 1 and Line Z73 Outage | 1996.3 | 66.54 | 1031.3 | 51.57 |
| Bus 1 and Line Z98 Outage | 1657.9 | 55.26 | 1082 | 54.10 |
| Bus 1 and Line Z99 Outage | 1748.1 | 58.27 | 1294 | 64.70 |
| Bus 1 and Line Z93 Outage | 1744.4 | 58.15 | 1162.9 | 58.15 |
| Bus 1 and Line to Culley Outage | 1936.5 | 64.55 | 994.3 | 49.72 |
| Bus 1 and Francisco to Gibson Outage | 2254.6 | 75.15 | 1188.4 | 59.42 |
| Bus 1 and AB Brown – BREC Reid Outage | 2072 | 69.07 | 1539 | 76.95 |
| Bus 2 Outage | 1935.6 | 64.52 | 1049 | 52.45 |

| 138 kV Switchyard Loading 1x1 and Unit 2 | | | | |
|---|---|---|---|---|
| Case | Current in 3kA Main Bus (A) | Percent Loading (%) | Current in 2kA Interpass (A) | Percent Loading (%) |
| Bus 2 and Line Z95 Outage | 2219 | 73.97 | 1167 | 58.35 |
| Bus 2 and Line Z96 Outage | 2071.2 | 69.04 | 1079 | 53.95 |
| Bus 2 and Line Z94 Outage | 2401.2 | 80.04 | 1137.2 | 56.86 |
| Bus 2 and Line Z73 Outage | 1995.3 | 66.51 | 1051.5 | 52.58 |
| Bus 2 and Line Z98 Outage | 1656.8 | 55.23 | 1082.3 | 54.12 |
| Bus 2 and Line Z99 Outage | 1747.6 | 58.25 | 1293.5 | 64.68 |
| Bus 2 and Line Z93 Outage | 1742.8 | 58.09 | 1161.9 | 58.10 |
| Bus 2 and Line to Culley Outage | 1935.6 | 64.52 | 1049 | 52.45 |
| Bus 2 and Francisco to Gibson Outage | 2253.7 | 75.12 | 1209.7 | 60.49 |
| Bus 2 and AB Brown – BREC Reid Outage | 2071.2 | 69.04 | 1539.7 | 76.99 |

## 2.2 FAULT CAPABILITY

13 of the 20 circuit breakers in the existing 138 kV switchyard are rated to withstand and interrupt 40 kA symmetrical fault current. The interrupting capability of the 13 40 kA rated circuit breakers is marginal for three phase faults and exceeded for single phase to ground faults for this evaluated case. Due to the available fault current contribution it is recommended to replace these existing circuit breakers with circuit breakers having sufficient margin beyond maximum fault current contribution. The remaining seven existing circuit breakers are oil filled and are considered to be near the end of service life. It is recommended to replace all of the existing 138 kV switchyard circuit breakers with breakers rated 63 kA symmetrical interrupting duty. This will ensure fault interrupting capability exceeds maximum available fault contribution.

The results of the fault study are included in Table 2-2.

**Table 2-2 138 kV Switchyard Fault Currents**

| Fault Current Availability 1x1 and Unit 2 | | |
|---|---|---|
| Fault type | Fault Component | Value |
| 3-phase fault | Fault Current (A) | 39304 |
| | Phase Angle (°) | -87 |
| | Calculated X/R | 19.07 |
| 1-phase fault | Fault Current (A) | 45908.6 |
| | Phase Angle (°) | -87 |
| | Calculated X/R | 19.17 |

# 3.0 Switchyard Connection Sequence

[redacted]

- [redacted]
- [redacted]
- [redacted]
- [redacted]

[redacted]

[redacted]

[redacted]

[redacted]

# 4.0 Conclusions

The withstand and interrupting rating of 40 kA for thirteen of the twenty existing 138 kV switchyard breakers is exceeded for the fault conditions evaluated, therefore circuit breaker replacement is necessary. The remaining seven switchyard circuit breakers are oil-filled breakers and near the end of their service life. It is recommended to replace all existing circuit breakers in the 138 kV switchyard with 63 kA symmetrical withstand and interrupting rating.

The evaluated load flow of the existing 138 kV switchyard permits independent connection of the CTG and STG of the new 1x1 CCPP considering a fired GE 7FA.05 and associated preliminary heat balance gross output. In general, the existing switchyard is capable of a single point of interconnection for 430,000 kW and below. This evaluation did not identify any major bus or interpass modifications for the existing 138 kV switchyard to accommodate the new CCPP and operation of Unit 2.

Connections to the existing switchyard have been planned to permit the construction and commissioning schedule of the new CCPP, while maintaining the existing A.B. Brown Unit 1 connection as late as practical into construction of the new CCPP.

# Appendix A. Switchyard Connection Sequence

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

# Appendix B. Construction Schedule

[redacted]

Confidential

FINAL

# AUXILIARY ELECTRIC SYSTEM MEDIUM VOLTAGE LEVEL COMPARISON

## A.B. Brown 1x1 F-Class

**B&V PROJECT NO. 195523**
**B&V FILE NO. 41.1223F**



PREPARED FOR

VECTREN
A CenterPoint Energy Company

Vectren

19 FEBRUARY 2020

BLACK & VEATCH

# Table of Contents



## LIST OF TABLES

# Executive Summary

This evaluation provides a summary comparison of nominal 6.9 kV and 4.16 kV auxiliary electric systems for the conceptual design (CPCN project) of the new A.B. Brown Combined Cycle Power Plant (CCPP). The medium voltage switchgear and motor controllers distribute power to large motor loads, ranging from greater than 250 HP up to several thousand HP, as well as to secondary unit substation (SUS) transformers, which derive 480V to be distributed to the low voltage system components and electrical loads.

Both nominal system voltages of 4.16 kV and 6.9 kV are commonly utilized within power generation and supported by most transformer and motor manufacturers.

**Table ES-1 Advantages of 4.16kV and 6.9kV Medium Voltage Systems**

| MEDIUM VOLTAGE | 4.16 KV | 6.9 KV |
|---|---|---|
| Lower Running Current/Starting Current | | X |
| Smaller Conductor Size | | X |
| Less Heating in Below Grade Cable Ductbank | | X |
| Reduction of Bus Short Circuit Rating | | X |
| Overvoltage Withstand | X | |
| Conductor Cost Savings | | X |
| UAT Cost Savings | | [redacted] |
| Switchgear Cost Savings | | [redacted] |
| Motor Cost Saving | Equal | Equal |

# 1.0 Auxiliary Electric System Cabling Design Considerations

The cross-sectional area (CSA) of a current-carrying copper conductor is largely dependent upon the continuous current required for rated operation of the electrical load. A larger continuous current necessitates are larger CSA in order to ensure the thermal limitations of the cable insulation and the equipment terminals are not exceeded. An electrical load with a nominal system voltage rating of 6.9 kV will result in an approximate 40% reduction of running current than that of an electrical load with the same power rating, in kVA or HP, and a nominal system voltage rating of 4.16 kV.

For power cables installed in below grade duct bank, a de-rating study must be performed in order to ensure that the implications of the concrete-encased, below grade cable duct on the current-carrying capability of the conductors are properly applied during conductor sizing. The aggregate of thermal impact of the continuous current flowing through the conductors within the duct bank, depth of duct bank, and soil thermal resistivity determine the de-rating of the conductor ampacity. The ampacity of a current-carrying conductor in below grade duct bank is reduced compared to the ampacity of the same conductor in above grade raceway or free air.

It is typical in a CCPP that the electrical loads, particularly medium voltage, are not installed within proximity of the electrical distribution equipment from which the load is sourced. Voltage drop calculations must be performed in order to ensure that the voltage at the load terminals does not fall below the equipment minimum operating voltage. Voltage drop is directly proportional to current, cable length and cable impedance.

# 2.0 Medium Voltage Motor Starting System Impact

The starting of a large motor can have a significant, albeit brief, impact on the auxiliary electrical system. When voltage is applied to the terminals of an at rest motor, the motor will draw locked-rotor current (LRA), which decays toward full-load amps (FLA) as the motor approaches running speed. This is the result of the motor torque overcoming the combined inertia of the motor and the connected load. For an induction motor, a typical value of LRA is approximately 650% of FLA.

As voltage drop is directly proportional to current, the voltage drop at motor starting due to LRA must be analyzed in order to ensure the motor will start. It is typical to specify medium voltage motors capable of starting at 80% of rated voltage as a means of mitigating this concern.

The starting current of a motor can also have an adverse impact on equipment already in operation at the time of motor starting. Voltage sag resulting from the LRA of the starting motor can result in contactor drop-out in certain circumstances. Methods of avoiding adverse impact of large motor starting to the auxiliary electrical system include on-load tap changers (OLTC) integral to the unit auxiliary transformers for bus voltage regulation, dedicated variable frequency drives (VFD) or soft-starters for the motors of concern. The approximate 40% reduction of FLA and LRA resulting from a 6.9 kV compared to 4.16 kV provides for improved results relative to motor starting.

# 3.0 Short Circuit Contribution During a System Fault

During a system fault, a motor in operation will contribute current to the fault, in attempt to stabilize the decaying system voltage, as a result of the rotating magnetic field that exists in the rotor at the inception of the fault. Analyses of the auxiliary electric system during a faulted condition must be performed in order to ensure that the bus bracing of the electrical distribution equipment is appropriate relative to fault levels. The reduction of FLA of a higher system voltage correlates to reduced short circuit contribution during in a fault condition. Black & Veatch analyses of system faults utilizing Electrical Transient and Analysis Program (ETAP) indicate that motor short circuit contribution can be reduced by up to 50% by increasing the system voltage from 4.16 kV to 6.9 kV.

The reduction of bus short circuit rating of electrical distribution equipment corresponds to a reduction in capital expenditure for 6.9 kV compared to 4.16 kV.

# 4.0 Cost Impact of Equipment Voltage Rating

Manufacturers of switching assemblies offer various equipment voltage ratings above typical industry nominal system voltages. Metal-clad switchgear voltage ratings of 5 kV and 7.2 kV are common and correspond to nominal system voltages of 4.16 kV and 6.9 kV, respectively. Confirmation from switching assembly manufacturers indicates that bus and breaker continuous current and interrupting ratings, as well as bus bracing and short circuit rating, are the primary cost drivers. The cost difference of a line-up of metal-clad switchgear with the same continuous current rating, interrupting capability and bus bracing, but different system voltage ratings, is negligible.

Black & Veatch has received similar confirmation from motor suppliers, with respect to the negligible cost difference between 6.6 kV and 4.0 kV rated motors.

# 5.0 System Loading

The preliminary electrical load list associated with the 2x1 (F and H Class) configuration of the A.B. Brown CCPP conceptual design indicates a total plant running load of approximately 30 MVA. At 6.9 kV, this corresponds to approximately 2500 A of running current in combined cycle operation. The preliminary UAT required to support this auxiliary load is a two-winding transformer with a maximum forced-air cooled rating of 36 MVA. With 100% redundancy, two (2) two-winding UATs correspond to one (1) double-ended (main-tie-main) lineup of 3000A, 6.9 kV switchgear.

With the total plant running MVA, at a system voltage of 4.16 kV, the corresponding running current is approximately 4200 A. Typical switchgear manufacturers offer maximum continuous current ratings of 4000 A, which is achieved using 3000 A rated, fan cooled main circuit breakers. The condition of fan cooling required to achieve this rating is not recommended as it introduces an additional point of failure to the auxiliary electric system.

A system voltage of 4.16 kV would necessitate two (2) three-winding UATs and two (2) double-ended lineups of switchgear in order to adequately source the plant auxiliary load requirements for combined cycle operation. A budgetary cost estimate of [redacted] per UAT and [redacted] of additional metal-clad switchgear would be necessary in order to accommodate auxiliary loads at 4.16 kV system voltage.

# 6.0 Overvoltage Withstand

Equipment manufacturers specify maximum voltage ratings above the nominal system voltage rating. An industry typical maximum voltage rating for a 4.16 kV nominal system voltage is 5.0 kV, providing approximately 20% headroom in an overvoltage condition. Industry typical maximum voltage rating for a 6.9 kV system voltage is 7.2 kV, though some manufacturers are now offering equipment with maximum system voltage rating of up to 7.65 kV. A maximum voltage rating of 7.2 kV provides approximately 4.3% headroom in an overvoltage condition before exceeding the maximum voltage rating. Dependent upon the generator output voltage and the UAT tap, it is possible to exceed this maximum voltage rating with a 6.9 kV system. However, this is not a normal operating condition and could be mitigated with appropriate protective relaying.

# 7.0 Conclusions

This evaluation report has shown that:

- The design of insulated conductors is directly impacted by the medium voltage system level.
- Disturbances to the auxiliary electric system as well as motor starting concerns are mitigated by an elevated system voltage.
- Short circuit contribution from medium voltage motors is reduced by an elevated system voltage, which can correspond to a reduction in the short circuit bus rating of electrical distribution equipment.
- The cost associated with an elevated system voltage to plant equipment such as switching assemblies and motor windings is considered negligible.
- The preliminary plant auxiliary loading required for combined cycle operation of the 2x1 configuration is supported by two-winding UATs and one (1) double-ended lineup of medium voltage switchgear at a system voltage of 6.9 kV. A system voltage of 4.16 kV would necessitate three-winding UATs and two (2) double-ended lineups of medium voltage switchgear.
- 4.16 kV system voltage provides more headroom for an overvoltage condition than that of a 6.9 kV system, for industry typical maximum voltage ratings. However, this condition can be mitigated with protective relaying.

Total cost savings for using 6.9 kV medium voltage system in lieu of a 4.16 kV medium voltage system is approximately [redacted].

Confidential

FINAL

# EPC COST - BASIS OF ESTIMATE

## A.B. Brown 1x1

**B&V PROJECT NO. 400278**
**B&V FILE NO. 41.0001**



PREPARED FORREPARED FOR

VECTREN
A CenterPoint Energy Company

Vectren

31 JANUARY 2020

BLACK & VEATCH

# Table of Contents

# Executive Summary

The following is a basis of estimate summary for the EPC capital cost AACE Class 2 estimate for the A.B. Brown 1X1 Combined Cycle. The cost estimates contained in this report are based on the preliminary design by Black & Veatch, equipment pricing bids from suppliers of power island, and utilizing prior EPC contractor and vendor bid data. Power island equipment includes the combustion turbine(s), steam turbine, and HRSG(s).

The two plant alternatives that were estimated are as follows:

| 1X1 CCPP |
|---|
| GE 7FA.05 Fired |
| GE 7HA.01 Fired |

# 1.0 Estimate Basis

The cost estimate is based on an AACE Class 2 for engineering, equipment and construction costs.

The cost estimate is based upon a lump-sum turnkey EPC approach. Owner will purchase Power Island Equipment and assign to EPC contractor. Under this approach, the EPC contractor would have the responsibility for administration and performance interface of the power island equipment. The EPC structure used for the estimate is based upon the EPC contractor self-performing the work rather than utilizing multiple subcontractors.

The cost estimates are based on competitive bids obtained for power island equipment. Equipment, commodity, and construction services rates were based on EPC contractor and vendor data. Detailed material takeoffs based on the preliminary design of the A.B. Brown combined cycle with reference to similar sized plants that Black & Veatch has designed, constructed, and/or estimated on an EPC basis.

The estimate provided herein is based on preliminary information, and as such is to be considered a non-binding price opinion, and does not represent an offer to sell or a maximum price for the work scope. The estimate assumes moderate level of EPC commercial risk position and does not include specific pricing or schedule impacts for extensive site preparation. Other factors that can impact the price:

- Changes in labor market - A Labor Market Survey may identify craft labor conditions unique to this project that are recommended for further review and evaluation prior to start of construction.
- Final site conditions - Soil boring were secured for the proposed site.
- Noise requirements - Night-time steam blow conditions were assumed.
- Final project schedule.

## 1.1 QUANTITIES

Quantities that form the basis of the estimate were based on the engineering conceptual design and the engineering Bill of Quantities (BOQ) developed. The conceptual design was based on utilizing some of the existing A.B. Brown common system to support the new combined cycle, detailed information from equipment suppliers for new equipment, and specific site conditions. Where details were not available, assumptions were made based on similar sized plants and arrangements.

## 1.2 DIRECT COSTS

EPC bid pricing is segregated into two categories: direct and indirect. The direct project costs associated with the BOQs can then be developed by utilizing the unit costs provided by the EPC bidders.

- Unit manhour rates and wage rates are applied against the 1x1 quantities to develop labor cost.

- Unit material cost are applied against the updated quantities for commodities to develop material cost. Cost for major equipment has been scaled off the equipment cost for the major equipment obtained by the EPCs.
- Subcontract pricing was adjusted based upon the rates developed as part of the EPC bid analysis.

To develop the definitive capital cost estimate an RFI was issued to the major OEM Power Island equipment suppliers to obtain budgetary quotes. The OEM proposals included:

- Combustion Turbine and Generator Package
- Steam Turbine and Generator Package
- Heat Recovery Steam Generator

Bid tabulations were developed to evaluate the bids for completeness, scope, and adherence to the specification. The lowest evaluated bid was selected to use as the basis of the estimate.

## 1.3 CONSTRUCTION MANAGEMENT AND CONSTRUCTION INDIRECTS AND ENGINEERING

Construction Management and Construction Indirects (CMCI) were based on a self-perform (direct-hire) EPC approach instead of a multiple subcontract EPC approach. As a result, the cost for management of the work as well as tools, scaffolding, cranes, warehousing, and laydown to support this work show as a CMCI expense. Under a multiple subcontract approach, these costs would be included in the subcontractor unit rates and appear in the direct cost line items.

Construction management and indirects were estimated based on Black & Veatch's experience with similar plants and scopes of work as well as comparison against the EPC bids. The following costs were developed based upon Black & Veatch's internal metrics and experience then adjusted for schedule and man power loading:

- Project Engineering
- Project Construction Management including Safety, QC, Orientation
- Material Handling
- Mobilization and Demobilization
- Consumables & Small Tools
- Warranty

To obtain competitive bids Black & Veatch, in accordance with IURC code, the estimate includes competitive bids for the following costs:

- Cranes and Construction Equipment
- Scaffolding
- Temporary Facilities

Heavy haul transportation was based on Power Island Equipment delivery to the site and heavy cranes included in the Cranes and Construction Equipment RFQ.

## 1.4 INDIRECTS

Insurances, warranty, performance bonds, and a letter of credit costs are included, based on the EPC bids.

## 1.5 CONTINGENCY

[redacted]

[redacted]

[redacted]

FINAL

# HRSG BYPASS STACK ANALYSIS

## A.B. Brown 1x1 H-Class

**B&V PROJECT NO. 400278**
**B&V FILE NO. 41.1201H**



PREPARED FOR

VECTREN
A CenterPoint Energy Company

Vectren

31 JANUARY 2020

BLACK & VEATCH

# Table of Contents



## LIST OF TABLES



## LIST OF FIGURES

# Executive Summary

In developing this report for the new Combined Cycle Power Plant (CCPP), Black & Veatch examined the benefits and drawbacks of adding a flue gas bypass stack between the combustion turbine and the heat recovery steam generator (HRSG). The bypass stack would allow the HRSG to be taken offline while the combustion turbine operates in simple cycle mode and would also allow the combustion turbines to be put into service up to 6 months before the erection and commissioning of the balance-of-plant equipment.

This analysis considered such factors as cost, plant design, environmental permitting, schedule, and operations, and maintenance. One major consideration is whether a selective catalytic reduction (SCR) system would be required to meet US Environmental Protection Agency (USEPA) emissions permitting requirements. The base cost for the installation of an HRSG bypass stack is estimated as [redacted]; the estimated cost with the addition of an SCR system would be [redacted].

The performance of the combined cycle would not be adversely affected by the inclusion of the bypass stack. USEPA standards, however, might limit the number of hours the unit could operate in simple cycle mode. While the addition of a HRSG stack flue gas bypass would provide the benefit of operational flexibility for the power plant, cost and performance impacts typically do not justify including this equipment in the power plant design.

# 1.0 Introduction

HRSG stack flue gas bypass systems provide the benefit of adding operational flexibility to power plant generation. Flue gas bypasses consist of installing a stack between the combustion turbine and HRSG; a diversion damper allows the combustion turbine exhaust to be diverted either to the bypass stack or the HRSG. Having a bypass stack available allows the HRSG to be taken offline or out of service, while the combustion turbine operates in simple cycle mode. The bypass stack would also allow for the combustion turbines to be put into service up to 6 months prior to erection and commissioning of the balance of plant under a typical consecutive construction schedule or longer for phased or delayed construction. The benefits must outweigh the cost in order for a flue gas bypass system to be feasible.

This evaluation of adding a flue gas bypass on each Combustion Turbine will help determine the cost (+/- 30%) and design impact of a flue gas bypass system to the plant design. Environmental permit considerations due to the flue gas bypass addition will also be reviewed. Schedule impacts, operations, and maintenance activities will also be identified and discussed.

# 2.0 Arrangement

On a combined cycle power plant, the flue gas bypass stack would be installed between the combustion turbine and the HRSG. Figure 2-1 shows a typical arrangement of a combustion turbine with a HRSG and a bypass stack. The bypass stack contains a damper that diverts the combustion turbine exhaust either up the bypass stack or to the HRSG. During simple cycle operation, the damper would be positioned to shut off flow to the HRSG and direct flow up the bypass stack. Under combined cycle operation, the damper would be positioned to shut off flow to the bypass stack and allow flow through to the HRSG. The diverter damper is actuated through the operating positions by an electronically controlled hydraulic system. Figure 2-2 shows the components of the bypass stack. Site specific requirements may result in modifications to the arrangement. For example, if air quality controls such as a selective catalytic reduction (SCR) system were required.

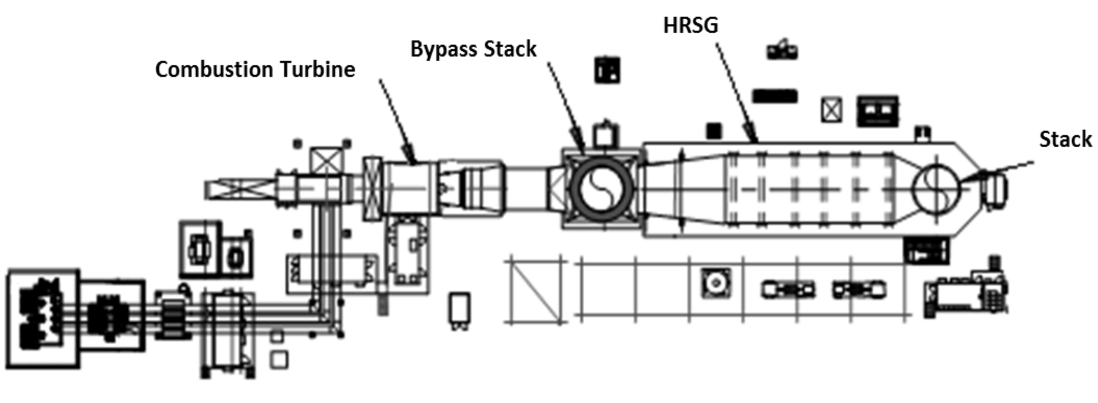



**Figure 2-1 Combined Cycle Layout with Bypass Stack**

| ITEM NO | QTY | DESCRIPTION |
|---|---|---|
| 1 | 1 | INTEGRATED EXPANSION JOINT |
| 2 | 2 | TRANSITION DUCT HALVES |
| 3 | 4 | SILENCER DUCT QUARTER SECTIONS |
| 4 | 4 | SILENCER DUCT FLAT WALL PANELS |
| 5 | 2 | TRANSITION DUCT HALVES |
| 6 | 8 | VERTICAL STACK SEGMENTS |
| 7 | 2 | VERTICAL STACK SEGMENTS |
| 8 | | BOTTOM SILENCER PANELS |
| 9 | | TOP SILENCER PANELS |
| 10 | | SUPPORT STRUCTURE |
| 11 | | LADDERS AND PLATFORMS |
| 12 | | PERSONNEL PROTECTION |
| 13 | 1 | HORIZONTAL TRANSITION |
| 14 | 1 | GUILLOTINE DUCT |
| 15 | 1 | DAMPER |

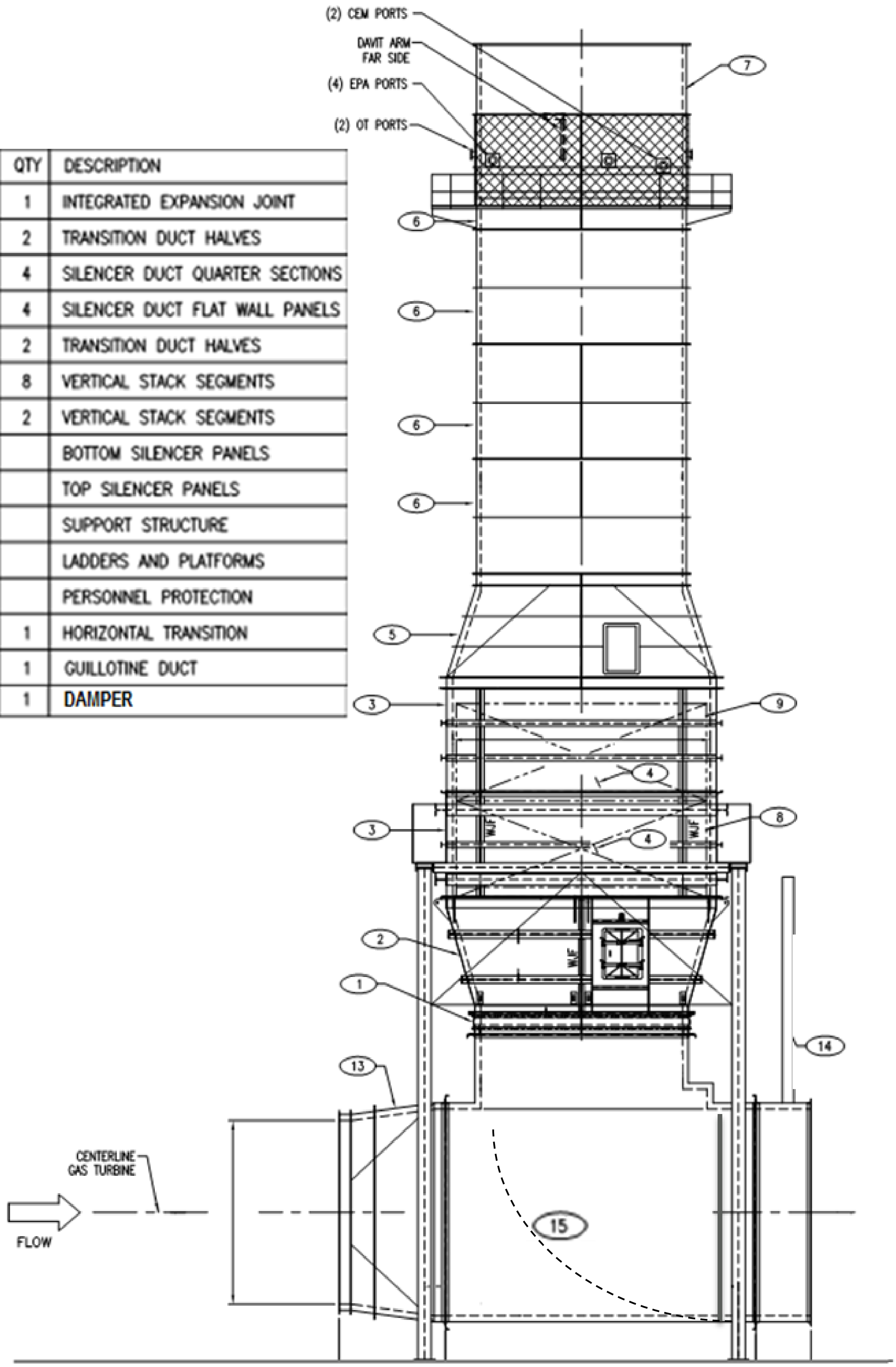



**Figure 2-2 Typical Gas Bypass Stack**

If an SCR were required, a section could be added to the stack upstream of the silencer to house catalyst, tempering air skid, and ammonia injection equipment. While there is not much industry experience with installing SCRs in the vertical sections of combustion turbine bypass stacks, the technical challenges would be similar to those seen in a coal facility where vertical SCRs are common. The SCR would consist of the following components:

- Catalyst
- Tempering air system to lower combustion turbine exhaust gas to an allowable inlet temperature for the catalyst (<800 °F)
- Mixing vanes and flow distribution
- Ammonia distribution manifold and injection grid
- Ammonia vaporization and flow control unit
- Emission monitoring system

Alternatively, the SCR may be horizontal and then the SCR and bypass stack would be placed in parallel with the HRSG. Air emission requirements are discussed in Section 6.0.

# 3.0 Capital Costs

Typical suppliers of HRSG bypass stacks include Braden Manufacturing, Peerless-Aarding, and Clyde Bergmann.

Pricing from recent proposals was reviewed to find a budgetary estimate for a bypass stack with a height of 135 ft with stack silencer and continuous emission monitoring (CEMS) system. Also included were all required dampers, motors, controls, insulation, lighting, support steel and platforming as required.

Table 3-1 is a high level breakdown of the installed costs associated with the bypass stack.

**Table 3-1 Capital Costs for HRSG Bypass Stack**

| DESCRIPTION | INSTALLED COST / UNIT |
|---|---|
| FOUNDATIONS/CIVIL WORK | [redacted] |
| STACK (including ductwork, damper, supplementary steel, lighting, electrical) | [redacted] |
| CEMS (NOx and CO analyzers, includes electrical and controls) | [redacted] |
| **BYPASS STACK (no SCR)** | [redacted] |
| VERTICAL SCR (includes ammonia injection, $NO_X$ and CO catalyst) | [redacted] |
| **BYPASS STACK (with vertical SCR)** | [redacted] |

# 4.0 Performance Impacts

Installation of a bypass stack allows for the operation of the combustion turbine in simple cycle mode; however, operating in simple cycle mode may have limited operating hours as discussed in Section 6.0, Permitting and Emissions.

[redacted]

If an SCR is required, a tempering air skid is required to keep the CTG exhaust below 800 °F to prevent damage to the catalyst. The CTG exhaust reaches 800 °F in less than a minute from ignition as the CTG reaches 5% load. The tempering air fan and the ammonia vaporization and flow control system will have an approximate auxiliary load of 1,000 kW.

# 5.0 Maintenance

Maintenance consists of correcting deficiencies noted during inspection. For HRSG bypass stacks without an SCR, the primary maintenance concern is the damper seals, diverter damper bearings, and the dampers hydraulic power unit.

Typical diverter maintenance activities include:

- Shaft seal replacement.
- Housing perimeter seal replacement.
- High temperature bearing repair or replacement.
- Shaft seals are typically designed to last five years.

Recommended spare parts include:

- Spare limit switches.
- Position transmitters.
- Seal-air pressure blower.
- Main drive bearing kit.
- Damper seal sets.
- Expansion joints.

If an SCR is required, additional maintenance is required for the hot air tempering skids, ammonia flow control units, and replacement of $NO_x$ and CO catalysts.

# 6.0 Permitting and Emissions

## 6.1 FEDERAL REGULATIONS POSING CHALLENGES

Officially titled *Standards of Performance for Greenhouse Gas Emissions from New, Modified, and Reconstructed Stationary Sources: Electric Utility Generating Units*, 40 CFR Part 60, Subpart TTTT was finalized by the USEPA on August 3, 2015. In this rulemaking, the USEPA established output-based emissions standards for two subcategories of power plants; electric utility steam generating units (e.g., coal-fired power plants) and stationary combustion turbines. The rule makes no distinction between simple cycle and combined cycle combustion turbines. Rather, it requires combustion turbines to meet certain $CO_2$ emissions standards depending on whether they are classified as baseload or non-baseload units.

The distinction between baseload and non-baseload units is made based upon the number of hours a combustion turbine can operate relative to its design efficiency. If a combustion turbine operates more hours than its net, Lower Heating Value (LHV) design efficiency, then it is considered a baseload unit. Baseload units are required to meet an output-based $CO_2$ emission standard of 1,000 lb/MWh (gross output, 12-operating month basis).

[redacted]

[redacted]

If the plant is restricted in hours less than the percent of net design efficiency hours, the plant is classified as a non-baseload unit with respect to NSPS Subpart TTTT. Natural gas-fired non-baseload units are subject to a heat-input based $CO_2$ emission standard 120 lb/MBtu (HHV, 12-operating month basis). This standard is readily achievable because the $CO_2$ emission rate of natural gas is 117 lb/MBtu.

## 6.2 AIR PERMITTING CHALLENGES

While an emissions netting analysis (wherein any recent unit shutdowns can be used to demonstrate that net emissions increases from the new installation would not exceed major source permitting thresholds) could allow the project to avoid major source permitting requirements there is still a possibility the project could trigger major source permitting. In such a scenario, the air permitting process would be dictated by the Prevention of Significant Deterioration (PSD) regulations which require, among other things, an evaluation of Best Available Control Technology (BACT). Should BACT be required for $NO_X$ emissions, the project's air construction permit could require the use of an SCR.

# 7.0 Conclusions

Having a bypass stack available allows the HRSG to be taken offline or out of service, while the combustion turbine operates in simple cycle mode. In addition, the combustion turbines could be put into service up to 6 months prior to erection and commissioning of the balance of plant under a typical consecutive construction schedule or longer for phased or delayed construction.

While the addition of a HRSG stack flue gas bypass would provide the benefit of operational flexibility for the power plant, cost and performance impacts typically do not justify including this equipment in the power plant design. The total installed cost of the bypass stack fora 1x1 CTG train is approximately [redacted] without an SCR. A vertical SCR would be considered a first of a kind for this application so no cost is easily achievable without a prior design. It is expected that if an SCR is required due to concerns with emissions the cost would be approximately double [redacted] with an SCR. If a horizontal SCR is required due to emission limits, the SCR would not be feasible as it would be approximately the size of the HRSG. The performance of the combined cycle would not be adversely affected by the inclusion of the bypass stack. The amount of hours where the unit can operate in simple cycle mode with the HRSG bypassed may be limited due to NSPS 40 CFR Part 60, Subpart TTTT.

Confidential

FINAL

# HEAT REJECTION / EXISTING COOLING TOWER ANALYSIS

## A.B. Brown 1x1 H-Class

**B&V PROJECT NO. 400278**
**B&V FILE NO. 41.1202H**



PREPARED FOR

VECTREN
A CenterPoint Energy Company

Vectren

31 JANUARY 2020

BLACK & VEATCH
Building a world of difference.

# Table of Contents



## LIST OF TABLES



## LIST OF FIGURES

# Executive Summary

In developing this report, Black & Veatch focused its attention to the specific areas directed by Vectren by analyzing the design impacts and cost comparison of using one existing cooling tower, circulating water pumps, and circulating water pipe for the new Combined Cycle Power Plant (CCPP). Black & Veatch reviewed multiple existing cooling tower reuse scenarios to evaluate the performance against the design for a new cooling tower. A performance summary for the two most optimal scenarios is provided in Section 2.0.

Black & Veatch evaluated the following three cooling tower alternatives for this study:

- Alternative 1: Reuse Cooling Tower, Circulating Water Pumps, and Existing Piping
- Alternative 2: Reuse Cooling Tower and Circulating Water Pumps with All New Piping
- Alternative 3: All New Cooling Tower, Circulating Water Pumps, and Piping

This report has been summarized in a Cooling Tower Alternatives Comparison Matrix provided in Table ES-1. [redacted] Consequently, it is recommended that Vectren utilize the existing Unit 1 cooling tower, circulating water pumps and piping as the design basis for the new combined cycle power plant.

**Table ES-1 Cooling Tower Alternatives Comparison Matrix**

| ALTERNATIVE | REUSE TOWER, PUMPS, AND PIPING (ALTERNATIVE 1) | REUSE TOWER AND PUMPS WITH ALL NEW PIPING (ALTERNATIVE 2) | NEW TOWER, PUMPS, AND PIPING (ALTERNATIVE 3) |
|---|---|---|---|
| Description | [redacted] | [redacted] | [redacted] |
| Constructability | [redacted] | [redacted] | [redacted] |
| Tower Performance | [redacted] | [redacted] | [redacted] |
| Condenser Adder | [redacted] | [redacted] | [redacted] |
| Tie-In Outage Length | [redacted] | [redacted] | [redacted] |
| Total Installed Cost | [redacted] | [redacted] | [redacted] |
| Operating and Maintenance Cost | [redacted] | [redacted] | [redacted] |
| Circulating Water Pump Auxiliary Load | [redacted] | [redacted] | [redacted] |
| New Major Equipment | [redacted] | [redacted] | [redacted] |
| Advantages | [redacted] | [redacted] | [redacted] |

| ALTERNATIVE | REUSE TOWER, PUMPS, AND PIPING (ALTERNATIVE 1) | REUSE TOWER AND PUMPS WITH ALL NEW PIPING (ALTERNATIVE 2) | NEW TOWER, PUMPS, AND PIPING (ALTERNATIVE 3) |
|---|---|---|---|
| Disadvantages | [redacted] | [redacted] | [redacted] |

# 1.0 Introduction

The purpose of this study is to analyze the A.B. Brown Unit 1 circulating water system to determine whether all or portions of the existing cooling towers, circulating water pumps, and circulating water piping can be reused for use with a new Combined Cycle Power Plant (CCPP). Black & Veatch has evaluated the performance of the existing cooling towers and circulating water pumps to determine the optimal operating scenarios [redacted] when paired with the new CCPP.

This evaluation of reusing the existing circulating water system components will help determine the [redacted] design impact of this system to the new CCPP design. Schedule impacts, operations, and maintenance activities will also be identified and discussed.

# 2.0 Performance Evaluation

Several operating scenarios were evaluated to determine the best preliminary design basis for reusing the existing cooling towers and circulating water pumps. Upon selection of the final plant design, the preferred number of cooling tower cells in service should be reviewed.

Alternatives 1 and 2 utilize the Unit 1 existing seven cell cooling tower and two circulating water pumps provide a total circulating water flow of 125,000 gallons per minute (gpm).

The existing cooling tower would be larger than the cooling tower for Alternative 3. The design flow rate of the existing cooling tower is larger than the design flow rate would be for the new cooling tower. To accommodate the larger flow rate, the condenser will be larger, and more expensive, but provides better performance. The overall heat rejection system for Alternatives 1 and 2 result in a decrease in steam turbine backpressure and an increase in auxiliary power when compared to the new heat rejection system considered in Alternative 3.

The estimated performance based on nominal 1x1 7HA.01 combined cycle performance for the alternatives is shown on Figure 2-1 for unfired heat recovery steam generator (HRSG) operation and Table 2-2 for fired HRSG operation.  For reference, Tables 2-1 and 2-2 provide the estimated performance values shown on the graphs.

[redacted]

### Table 2-1 Comparative Unfired Plant Performance for Cooling Tower Alternatives

| UNFIRED OPERATING CONDITIONS | 1X100% CTG LOAD 8.1F/70% AMBIENT EVAP COOLING OFF DUCT FIRING OFF | 1X100% CTG LOAD 56.8F/48% AMBIENT EVAP COOLING OFF DUCT FIRING OFF | 1X100% CTG LOAD 93.7F/45% AMBIENT EVAP COOLING ON DUCT FIRING OFF |
|---|---|---|---|
| 7 Cell Net Plant Output, kW | [redacted] | [redacted] | [redacted] |
| 7 Cell Net Plant Heat Rate (LHV), Btu/kWh | [redacted] | [redacted] | [redacted] |
| New Tower Net Plant Output, kW | [redacted] | [redacted] | [redacted] |
| New Tower Net Plant Heat Rate (LHV), Btu/kWh | [redacted] | [redacted] | [redacted] |

### Table 2-2 Comparative Fired Plant Performance for Cooling Tower Alternatives

| FIRED OPERATING CONDITIONS | 1X100% CTG LOAD 8.1F/70% AMBIENT EVAP COOLING OFF DUCT FIRING ON | 1X100% CTG LOAD 56.8F/48% AMBIENT EVAP COOLING OFF DUCT FIRING ON | 1X100% CTG LOAD 93.7F/45% AMBIENT EVAP COOLING ON DUCT FIRING ON |
|---|---|---|---|
| 7 Cell Net Plant Output, kW | [redacted] | [redacted] | [redacted] |
| 7 Cell Net Plant Heat Rate (LHV), Btu/kWh | [redacted] | [redacted] | [redacted] |
| New Tower Net Plant Output, kW | [redacted] | [redacted] | [redacted] |
| New Tower Net Plant Heat Rate (LHV), Btu/kWh | [redacted] | [redacted] | [redacted] |

# 3.0 Existing Equipment

## 3.1 EXISTING COOLING TOWER CONDITION

The Unit 1 cooling tower cells were recently rebuilt from wood to fiberglass as such the condition is assumed satisfactory and no major repairs are required. Three of the seven Unit 2 cooling tower cells were recently rebuilt from wood to fiberglass. To extend the life of the Unit 2 cooling tower the remaining four (4) cells would require rebuilding to fiberglass at a cost of approximately [redacted]. To eliminate the need for this expenditure, the Unit 1 cooling tower will be used for the new CCPP. The existing cooling tower basins for Unit 1 and Unit 2 are lacking an intake structure for an auxiliary cooling water pump. Modifications will be needed to the basin to add the new intake and pump structure.

## 3.2 EXISTING CIRCULATING WATER PUMPS

The existing circulating water pumps have been evaluated for both Alternatives 1 and 2 and it has been determined that they have sufficient capacity to meet the required flow and head for the new CCPP circulating water system. To extend the life of the two pumps and motors a shop overhaul would be required.

Black & Veatch evaluated the use of variable frequency drives (VFDs) on the existing circulating water pumps to modify the pump flow rate for different CCPP operating scenarios. Because the static head component is constant for all operating conditions and accounts for the majority of the circulating water pump head requirement, a VFD would provide minimal performance gains [redacted] per pump.

## 3.3 EXISTING CIRCULATING WATER PIPE

The existing circulating water piping is carbon steel piping with a bitumastic coating. Coatings have been maintained and repaired during normal inspection and repairs throughout the life of the existing A.B. Brown Plant. For this study, it is assumed that the condition of the pipe is satisfactory and no repairs will be required to the piping that is being reused as part of Alternative 1.

# 4.0 Constructability

For each of the cooling tower reuse alternatives there are several items to consider that could impact both the new CCPP and existing A.B. Brown Unit 1 during the installation and commissioning phase of the project.

## 4.1 ALTERNATIVE 1

Alternative 1 reuses a significant amount of existing underground steel piping, which will require continued inspection and maintenance to last the 30 year design life of the new CCPP. The existing piping is assumed to be in satisfactory condition given feedback from Vectren that they have performed scheduled inspections and coatings on the piping as required.

## 4.2 ALTERNATIVE 2

Alternative 2 will require unit outages considerably longer than Alternative 1, up to 2 or 3 months, given that a large section of existing Unit 1 circulating water piping and cooling tower risers are to be replaced in-kind with new steel piping. Once completed, Alternative 2 will result in the existing cooling tower and circulating water pump connected to the new CCPP circulating water system with all new piping, resulting in shutdown of the existing Unit 1 at the time of the tie-in.

## 4.3 ALTERNATIVE 3

Alternative 3 is an all new circulating water system that includes a 6 cell back-to-back mechanical draft counter flow cooling tower, 2x50 percent circulating water pumps, and steel circulating water piping. Because this system is independent of the existing equipment no unit outage will be required and the existing Units 1 and 2 will be able to operate during and after the installation of the new circulating water system. This alternative also results in the least auxiliary load because of minimizing the size of the circulating water pumps for the new CCPP design conditions.

# 5.0 Capital Costs

Table 5-1 is a high-level breakdown of the costs for both reusing the existing cooling towers and installing new cooling towers with a new basin.

**Table 5-1 Estimated Costs for Cooling Tower Alternatives**

| Description | Reuse tower, Pumps, and Piping (Alternative 1) | Reuse tower and Pumps wIth ALL new piping (Alternative 2) | New tower, pumps, and piping (Alternative 3) |
|---|---|---|---|
| New 6 Cell Cooling Tower with Basin (F&E) | [redacted] | [redacted] | [redacted] |
| Condenser Adder | [redacted] | [redacted] | [redacted] |
| Circulating Water Pumps | [redacted] | [redacted] | [redacted] |
| New Piping and Valves (A/G and U/G) | [redacted] | [redacted] | [redacted] |
| Basin Modifications for Auxiliary Cooling Water Pump | [redacted] | [redacted] | [redacted] |
| Site Work | [redacted] | [redacted] | [redacted] |
| Mechanical Installation (Does not include tower erection) | [redacted] | [redacted] | [redacted] |
| **Total** | [redacted] | [redacted] | [redacted] |
| **Cost Difference** | [redacted] | [redacted] | [redacted] |

# 6.0 Conclusions

Based on the evaluation, reusing the existing Unit 1 cooling tower, pumps and piping (Alternative 1) is the lowest cost technically acceptable solution and should be used as the design basis for the new combined cycle power plant.

Confidential

FINAL

# FAST START VS. CONVENTIONAL START ANALYSIS

## A.B. Brown 1x1 H-Class

B&V PROJECT NO. 400278
B&V FILE NO. 41.1203H



PREPARED FOR

VECTREN
A CenterPoint Energy Company

Vectren

31 JANUARY 2020

BLACK & VEATCH
Building a world of difference.

# Table of Contents



## LIST OF TABLES



## LIST OF FIGURES

# 1.0 Introduction

This study evaluates designing a 1x1 GE 7HA.01 combined cycle power plant with “fast start” capabilities versus a plant design for “conventional” start. The GE 7HA.01 is one of several candidate H-Class combustion turbine offerings.

## 1.1 STARTUP DURATION DEFINITION

Since plant load is affected by ambient conditions, startup durations are typically defined based on achieving a certain operating condition and not a specified operating load. The beginning of the start is typically defined as combustion turbine roll-off or first ignition. Startup is complete when a predefined operating condition is reached.

Startup can be a confusing term as it is used to describe the start from ignition to various ending operating conditions across the industry. These ending operating scenarios can include:

- CTG Full Speed No Load – The point at which the combustion turbine is removed from the static starter and brought to full speed.
- CTG Sync - The point at which the combustion turbine (CTG) is synchronized with the grid.
- Emission Start - Achieving minimum emissions compliance load. This occurs when stack discharge emissions reaching steady state compliance with air quality standards.
- CTG Full Load Start - Combustion turbine at baseload with permitted emissions at the stack.
- Plant Full Load Start - Combustion turbine at baseload and steam turbine bypass valves fully closed. Steam turbine in service.

**For the purpose of this study Fast Start is being defined as a rapid start commencing with ignition until the combustion turbine reaches minimum emission load compliance (MECL). When speaking with others in the industry the ending operating condition should be defined.**

The type of start is also defined by the amount of time the unit has been shutdown. It is typical to assume the shutdown begins at fuel flow shutoff to the combustion turbines during a normal plant shutdown sequence from a steady state baseload condition. Durations as defined by the project are:

- Hot start = Shutdown 8 hours or less
- Warm start = > 8 hours and < 48 hours
- Cold start = Shutdown 48 hours or more

The lead time activities prior to a warm or cold fast startup typically commence with startup of the auxiliary boiler. Depending on the start condition for the auxiliary boiler and the features incorporated to permit its fast start, this activity may need to commence approximately three hours before the actual combustion turbine start condition.

## 1.2 CONVENTIONAL VERSUS FAST START

Conventional combined cycle facility startup durations are constrained by steam cycle equipment limitations, specifically the heat recovery steam generator and steam turbine temperature ramp capabilities. Heat recovery steam generators and steam turbines are designed to operate at very high temperatures and pressures and, therefore, are comprised of very thick metal alloy components (e.g. steam drums, steam turbine rotors). These thick components can suffer from high thermal stress and increased life expenditure if they are subjected to large temperature differentials (e.g., 1,000°F steam across an ambient temperature steam turbine rotor) or rapid temperature ramp rates. HRSG and steam turbine suppliers provide strict temperature ramp rates and temperature differential requirements for their equipment that must be used to define and limit the startup sequence and duration in order to protect the equipment.

HRSGs designed through the middle of the last decade were generally not capable of allowing combustion turbines to start at their maximum capability without incurring significant maintenance impacts. These units required pauses ("holds") at low CTG loads to "heat soak" their heavy-walled components prior to releasing the unit on sustained ramp rates of typically less than 7°F per minute, as measured by the high-pressure (HP) drum steam saturation temperature.

Today's HRSGs can be more robustly designed for the rapid ramp rates of advanced class combustion turbines, which can exceed 50 megawatts (MW) per minute and yield HRSG temperature ramp rates exceeding 30°F per minute.

Though HRSGs are now designed to allow combustion turbines to start at their maximum capability, steam turbines are not. Cold steam turbines require relatively cool steam, typically in the range of 700°F, on first admission to the equipment. During the startup sequence, steam temperatures downstream of the HRSG are primarily controlled through two means working in tandem, CTG exhaust temperature control and desuperheating of the generated steam. CTG exhaust temperature control tunes the CTG to minimize the exhaust temperature into the HRSG during the startup sequence, as a cooler exhaust temperature produces cooler steam. Desuperheaters spray water into the steam headers to reduce, or "attemperate", the steam by reducing the level of superheat above the steam saturation temperature.

Most HRSGs include interstage desuperheaters that are installed between superheater and reheater sections to control the final HRSG exit steam temperatures. As the combustion turbine ramps above very low loads towards the MECL, the CTG exhaust temperature control and HRSG interstage desuperheaters are no longer capable of cooling the steam to the temperatures permitted by a relatively cool steam turbine. The steam turbine becomes a critical constraint on the start time unless the HRSG exit steam temperatures can be further reduced to match the steam turbine steam temperature requirements. In effect, the steam turbine must be 'decoupled' from the combustion turbine so that the combustion turbine start is not constrained by the steam cycle.

The steam turbine can be decoupled and its steam temperature requirements met irrespective of combustion turbine load by adding terminal desuperheaters (i.e., desuperheaters downstream of the HRSG in the high-pressure (HP) and hot reheat steam headers) to cool the HRSG exit steam to the steam turbine requirements.

Decoupling the steam turbine from the CTG/HRSG train allows the combustion turbine to ramp to emissions compliance load levels without hold periods in the firing sequence. A no-holds startup sequence is typically referred to as an uninhibited start.

Figure 1-1 provides a high-level comparison of the typical CTG load path for a 1x1 conventional combined cycle to that of a fast-start combined cycle. Additional details on the performance differences between the two startup types are discussed in Section 4.0.

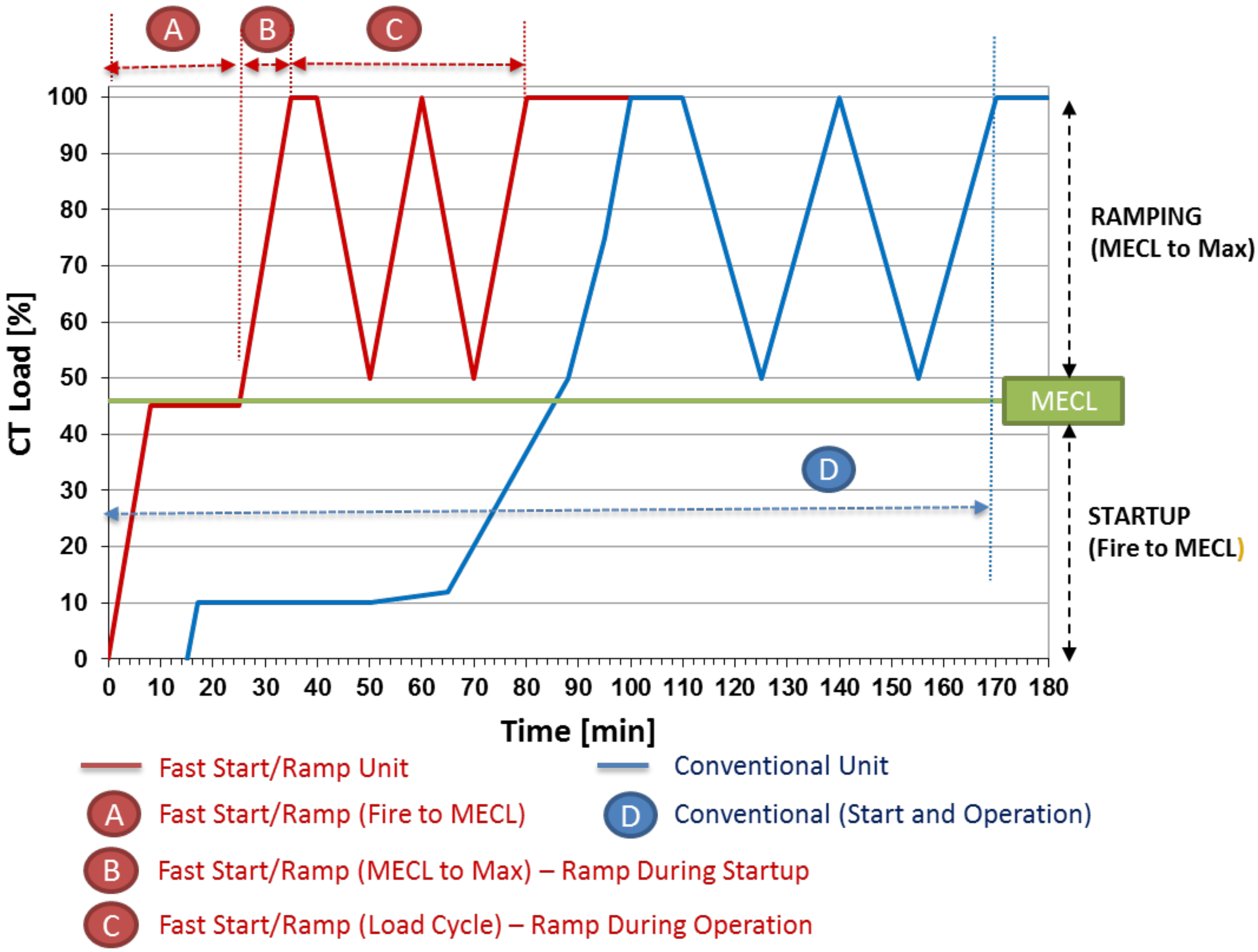



**Figure 1-1 Comparison of Combustion Turbine Loading during Hot Start Event (Excludes Purge)**

# 2.0 Design Features

Capital costs are higher for fast start plants than plants designed for conventional starts. Equipment and balance of plant systems affected by the additional design consideration for fast start are as described below and in Table 2-1. Column A of Table 2-1 lists specific design features and equipment required for fast start operation. Column D of Table 2-1 lists design features of conventional start units. Columns B and C will be discussed in the Fast Start vs. Conventional Unit Ramp Rate Analysis (File No. 400278.41.1204H).

**Table 2-1 Design Features of Combined Cycles Designed for Various Operating Scenarios**

| FEATURES REQUIRED TO MEET OPERATING SCENARIO | A<br>FAST START (FIRE TO MECL) | B<br>FAST RAMP (MECL TO MAX) | C<br>FAST RAMP (LOAD CYCLE) | D<br>CONVENTIONAL (START AND OP) |
|---|---|---|---|---|
| Required Option = ●, Recommended Option = ☐, Standard Option = ◆ | | | | |
| **Combustion Turbine** | | | | |
| Fast Start Equipped | ● | | | |
| Natural Gas Purge Credits | ● | | | ☐ |
| Service Life Monitoring System | ◆ | ◆ | ◆ | ◆ |
| Advanced Control System | ● | ● | ● | |
| **HRSG** | | | | |
| Advanced Drum Design | ● | ● | | |
| Enhanced Nozzle Connections | ● | ● | | |
| Improved HRSG Materials | ● | ● | | |
| Improved HRSG Geometries | ◆ | ◆ | ◆ | ◆ |
| Service Life Monitoring System | ☐ | ☐ | ☐ | |
| Stack Damper and Insulation | ● | | | ☐ |
| Terminal Attemperators | ● | ● | ● | |
| LP Economizer Recirculation/ Heat Exchanger | ● | ● | | |
| **Steam Turbine** | | | | |
| Optimized Casing Design | ● | ● | | |
| Advanced Control System | ● | ● | ● | |
| Service Life Monitoring System | ● | ● | ☐ | |

| FEATURES REQUIRED TO MEET OPERATING SCENARIO | A<br>FAST START (FIRE TO MECL) | B<br>FAST RAMP (MECL TO MAX) | C<br>FAST RAMP (LOAD CYCLE) | D<br>CONVENTIONAL (START AND OP) |
|---|---|---|---|---|
| Advanced Stop Valve Design | ● | | | |
| Increased Thermal Clearances | ● | ● | | |
| Advanced Turbine Water Induction Protection | ● | ● | ● | |
| **Emissions Control** | | | | |
| Feed-forward Ammonia Controls | ● | ● | ● | |
| **Auxiliary Steam** | | | | |
| Auxiliary Boiler | ● | | | |
| Condenser and HRSG Sparging | ● | | | |
| **Feedwater System** | | | | |
| Larger Condensate Pump | ● | ● | ● | |
| Larger Feedwater Pump | ● | ● | ● | |
| Higher Stage IP Bleed | ● | ● | ● | |
| **Heat Rejection System** | | | | |
| Surface Condenser – Fast Start Design | ● | | | |
| **Fuel Gas System** | | | | |
| Supplementary Fuel Gas Heating(1) | □ | | | |
| **Water Treatment System** | | | | |
| Condensate Polisher(2) | □ | | | |
| **Auxiliary Electrical System** | | | | |
| Larger Equipment for Higher Loads | ● | ● | ● | |

Notes:
1. Supplementary fuel gas heating as required by combustion turbine supplier.
2. Space should be allotted for future condensate polisher installation, if required.

## 2.1 COMBUSTION TURBINE

Combustion turbines designed for fast-ramping will be equipped with fast start features. These include positive isolation to ensure that purge credits have been maintained per NFPA 85 and that the gas path will not require a purge prior to startup. The control system for fast start of the plant should be fully automated to minimize times between sequential steps and allow for greater consistency during startup.

Both fast start and conventional units are equipped with service life monitoring systems that control unit ramp operations based on predetermined thermal stress limitations. Fast Start units are equipped with advanced control schemes incorporating model based controls (MBC) to optimize startup based on these monitoring systems.

Purge credits established during the shutdown must still be intact. NFPA 85 requires that a fresh air purge of the combustion turbine and HRSG be accomplished prior to start. NFPA 85 requires that at least five volume changes be completed or a minimum purge of 5 minutes prior to ignition. Typical purge durations can range from 5 to 20 minutes. The 2011 edition of NFPA 85 allowed for purge credits to be achieved when the unit is taken off line if the purge is completed and the valving arrangement is shown to positively isolate any fuel from entering the system. The combustion turbine can usually achieve the required purge when coasting down following a loss of ignition.

## 2.2 HRSG

HRSGs designed for fast-start plants can subject HRSG components such as superheaters and reheaters to rapid heating. Large thermal stresses can be produced by the differential expansion of the tubes within the HRSG. HRSG designs in such plants must be capable of accommodating the rapid change in temperature and flow of flue gas generated by load ramping of advanced class combustion turbines.

To reduce thermal capacity of drums many options are used to decrease the drum size and wall thickness including utilizing Benson style drums, utilizing multiple drums, high strength drum materials, and reduced residence time. Self-reinforced nozzles, full penetration nozzles, full penetration welds, and steam sparger systems further improve the ability to accept rapidly changing exhaust gas conditions and steam conditions. Improved materials throughout the high pressure superheater and reheater can be required. Online, real-time monitoring system should be included to evaluate HRSG life consumption.

In order to reduce the thermal capacity of drums, the residence time may also be reduced for fast start units. Fast start units typically have drum storage time around two minutes. Conventional start plants have drum storage time from 3-5 minutes.

Fast start plants are equipped with a stack damper and with an insulated stack up to the stack damper. The stack damper and insulation are critical as they restrict the flow of flue gas out the HRSG stack minimizing heat loss when the unit is offline. While conventional units do not require stack dampers and insulation, it is a recommended practice to minimize heat loss when the unit is offline.

Both fast start and conventional units have improved HRSG geometries compared to those built a decade ago. Improvements in geometries have been to decrease thermal stresses from unit cycling and are part of the HRSG standard design such as coil flexibility to superheater/reheater interconnecting piping and accommodations for tube-to-tube temperature differentials.

## 2.3 STEAM TURBINE

The steam turbine must also be designed for the thermal gradients experienced while ramping during start-up. For fast start machines, the casing design must be optimized to reduce the thermal stress during temperature fluctuations and to accept faster start up and load change gradients. The use of higher grade material may be employed in the high pressure and intermediate casings and valves to reduce component thickness. Main steam stop valves must be designed so that these valves can be opened at a relatively higher pressure. Integral rotor stress monitors can be provided; the rotor stress monitor is typically capable of limiting or reducing the steam turbine load or speed increase and is designed to trip the turbine when the calculated rotor stresses exceed allowable limits.

For machines undergoing a fast ramp, attemperators are often required on the high pressure and hot reheat steam lines. Overspray on these attemperators can lead to water in these steam lines; special attention needs to be provided for turbine water induction prevention for units equipped with terminal attemperators.

## 2.4 EMISSIONS AND AMMONIA FEED

Outlet $NO_x$ from the combustion turbine can vary highly when undergoing fast startup and fast ramp conditions. Conventional units only measure $NO_x$ at the stack; for fast ramping units limiting $NO_x$ measurements to the stack only can lead to over injecting or under injecting ammonia. Higher ammonia slip and potentially greater $SO_2$ conversion in fast-start and fast-ramp units create additional challenges for control of sulfur-bearing deposits in the colder HRSG areas. Low-pressure evaporators and economizers are particularly at risk. For fast ramping plants, addition of feed forward controls to quicken the saturation of the SCR catalyst (if included) is required. Also the HRSG should be equipped with LP economizer recirculation or heating systems to maintain surfaces above $SO_2$ dew points.

## 2.5 AUXILIARY STEAM

Fast start units require an auxiliary boiler to produce steam prior to the startup of the unit. This steam is used for steam line warming, establishing the steam turbine seals, warming up HRSG drums, and condenser sparging to enable uninhibited startup of the unit. The auxiliary boiler may also produce steam when the unit is off line to maintain drum and turbine temperatures.

Conventional units without an auxiliary boiler must use the combustion turbine and HRSG to produce steam to warm the unit and establish seals. During a conventional unit startup, holds are required to complete these warm up periods.

Provisions for fast start of the auxiliary boiler should also be considered which include equipping the auxiliary boiler mud drums with heating coils. Auxiliary boiler heat input, operating hour limits, and emission limits must also be considered.

Note that the auxiliary boiler makes up the majority of the cost to equip a combined cycle with fast start capabilities.

## 2.6 TERMINAL STEAM ATTEMPERATORS

Conventional start plants hold the combustion turbine load during startup as needed to meet the steam turbine startup steam temperature requirements. Fast-start plants decouple the CTG/HRSG startup from the steam turbine startup by using terminal attemperators at the HRSG outlet for meeting steam turbine startup steam temperature requirements, irrespective of CTG/HRSG load. This allows the steam turbine to come on line independently from the CTG and HRSG. As a result, the plant can increase load more quickly.

While the addition of terminal (final stage) steam attemperators on the main steam and hot reheat lines allow for steam turbine temperature matching, they introduce the risk of two phase flow in the steam lines. An adequate run of straight piping downstream of the attemperators, adequate drainage, and robust instrumentation are a must to minimize the risk of condensate carry-over to the steam turbine. Additional controls should be considered to prevent turbine water induction.

## 2.7 FEEDWATER SYSTEM

For fast start plants equipped with terminal attemperators, additional condensate and feedwater pump flow is required to meet the attemperation demands. Inter-stage feedwater used for attemperation may be taken off at a later pump stage to meet the pressure demands of the attemperators which could impact feedwater piping wall thickness.

## 2.8 FUEL GAS SYSTEM

In order to reduce emissions and maintain flame stability, some manufacturers require supplementary fuel gas heating as a part of startup. This heating is in addition to any startup heater used to raise the fuel gas temperature above the dew point.

## 2.9 WATER TREATMENT SYSTEM

Maintaining water chemistry and meeting the water chemistry requirements of the HRSG and steam turbine are a critical part of startup. Blowdown and makeup systems should be sized accordingly to meet expected startup demands. Provisions for the inclusion of a future condensate polisher should be considered should problems arise. Condensate polishers ensure top quality feedwater.

## 2.10 AUTOMATED STARTUP SEQUENCE

Additional controls and automation are required for fast-ramp plants to ensure the matching of steam temperatures and to maintain emission compliance. As a result, more plant instrumentation is required in automated plants to allow the plant control system to monitor system status, minimize times between sequential steps and provide consistent startups.

Also fast-ramp plants should consider the use of service life monitoring systems such as thermal stress indicators on the HRSG and steam turbine. These systems allow control of the unit ramp operations based on predetermined thermal stress limitations.

# 3.0 Capital Costs

Capital costs are higher for fast-start plants than plants designed for conventional starts. Additional costs that must be considered are requirements for a more flexible HRSG (e.g., header returns, tube to header connections, harps per header limits), terminal attemperators and associated systems; more flexible steam piping; improved steam piping drain systems, improved bypass system and controls integration, and requirements for auxiliary steam.

Table 3-1 lists the costs to include the design features listed in Column A of Table 2-1 for a fast start unit. Costs listed in the study are budgetary costs (+/- 30%).

**Table 3-1 Fast Start (Fire to MECL) Operating Scenario Costs**

| FAST START SYSTEM COSTS FOR A 1X1 7HA.01 COMBINED CYCLE | |
|---|---|
| Fast Start Options (Required options in Column A excluding Aux Boiler and Stress Monitoring Systems) | [redacted] |
| Auxiliary Boiler | [redacted] |
| Stress Monitoring Systems | [redacted] |
| **Total** | [redacted] |

# 4.0 Performance Impacts

Startup durations are dependent on the ambient conditions, time after shutdown, initial steam turbine rotor temperatures, and the particular OEM equipment/features used in the power train in addition to any margins (if the required start-up times are to be guaranteed). There is a relatively wide range variation, however, for rough indicative values, Table 4-1 provides comparative durations, [redacted] All fuel consumption and net generation values are based on combustion turbine ignition through the indicated end point.

**Table 4-1 Estimated Nominal Startup Times (Minutes)**

| START TYPE | CONVENTIONAL START TO MECL | FAST START TO MECL | DIFFERENCE (CONVENTIONAL – FAST) |
|---|---|---|---|
| Hot Start = Shutdown 8 hours or less | [redacted] | [redacted] | [redacted] |
| Warm Start = > 8 hours and < 48 hours | [redacted] | [redacted] | [redacted] |
| Cold Start = Shutdown 48 hours or more | [redacted] | [redacted] | [redacted] |

[redacted]

| [redacted] | [redacted] | [redacted] | [redacted] |
|---|---|---|---|
| [redacted] | [redacted] | [redacted] | [redacted] |
| [redacted] | [redacted] | [redacted] | [redacted] |
| [redacted] | [redacted] | [redacted] | [redacted] |

[redacted]

| [redacted] | [redacted] | [redacted] | [redacted] |
|---|---|---|---|
| [redacted] | [redacted] | [redacted] | [redacted] |
| [redacted] | [redacted] | [redacted] | [redacted] |
| [redacted] | [redacted] | [redacted] | [redacted] |

# 5.0 Startup Emissions

Stack emissions vary widely prior to reaching steady state emissions compliance due to the complexity of starting a combined cycle facility and the plant equipment's ability to operate within threshold limits across a certain operating range. The combustion turbine and the HRSG post-combustion emissions control components (if applicable) are the main equipment governing stack emissions variation.

Combustion turbines are designed with multiple fuel nozzles in each combustor. As combustion turbines start and ramp up to normal operating flow, load, and temperature, the combustion nozzles are sequenced through various combustion operating modes that vary the deflagration type (i.e., diffusion or pre-mixed [i.e., the air and fuel are pre-mixed prior to ignition of the fuel]) and nozzle firing sequences (i.e., which of the multiple nozzles are in service). These startup combustion modes are required so that stable combustion can be maintained in the unit during startup to avoid flame outs. As illustrated in Figure 2-1, in these off-design startup combustion modes, the combustion of the fuel is generally incomplete resulting in higher than normal nitrous oxide ($NO_x$), carbon monoxide (CO), and volatile organic compound (VOC) emissions concentrations. As the turbine reaches a minimum operating load where its normal combustion mode can be stably maintained, combustion becomes more complete and emissions decrease to a level that can be maintained across a wide operating range. The minimum operating load of the combustion turbine in this emissions compliant operating range is called the Minimum Emissions Compliance Load (MECL).

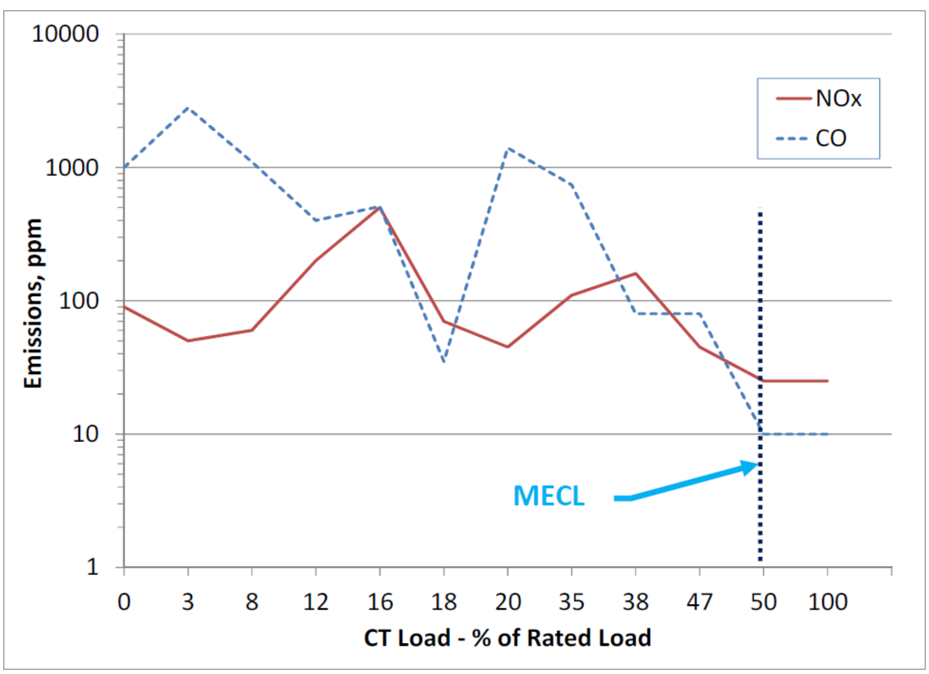



**Figure 5-1 Example Combustion Turbine $NO_x$ and CO Emissions versus Rated Load**

Below MECL, the mass of air pollutant emissions can accumulate quickly and, therefore, these "startup emissions" are of particular interest to regulators. The steady-stated CTG design exhaust emissions for the turbine technologies considered are approximately 15-25 ppmvd @15% O2 for $NO_x$ and 4-10 ppmvd @15% O2 for CO when operating on natural gas. Steady-state VOC emissions are dependent on the site specific natural gas composition.

An emissions netting analysis will be performed for the new combined cycle plant. If a Prevention of Significant Deterioration (PSD) review is required, the emissions standard that must be met is Best Available Control Technology (BACT), an emissions control mandate by the Environmental Protection Agency (EPA). If applicable, combined cycle BACT requirements dictate $NO_x$ and CO emissions shall be no greater than 2 ppm (parts per million) at the HRSG stack discharge over the entire normal operating range. CTG emissions levels are not sufficient for BACT and post-combustion emissions controls components; oxidation catalyst to reduce CO/VOC emissions and a selective catalytic reduction (SCR) system to reduce $NO_x$ emissions, must be installed in the HRSG to further reduce emissions to BACT levels.

Oxidation catalysts and SCR systems are not effective until they are warmed to a minimum threshold temperature and the SCR ammonia injection (utilized with the catalyst to reduce $NO_x$ emissions) is tuned. In general, these post-combustion emissions controls components are designed such that the minimum threshold temperatures are achieved on a startup at or below the combustion turbine MECL. As noted previously, an "emissions" startup sequence is considered complete after the CTG reaches MECL, and in the event of post-combustion emissions control components, they reach their minimum threshold temperatures, and the SCR ammonia injection is tuned such that stack emissions meet the air quality requirements.

Confidential

FINAL

# FAST START VS. CONVENTIONAL UNIT RAMP RATE ANALYSIS

## A.B. Brown 1x1 H-Class

**B&V PROJECT NO. 400278**
**B&V FILE NO. 41.1204H**



PREPARED FOR

VECTREN
A CenterPoint Energy Company

Vectren

31 JANUARY 2020

BLACK & VEATCH
Building a world of difference.

# Table of Contents



## LIST OF TABLES



## LIST OF FIGURES

# 1.0 Introduction

The purpose of this study is to evaluate the differences for conventional and fast ramping options between MECL and full load on unit startup for a 1x1 7HA.01 combined cycle. The GE 7HA.01 is one of several candidate H-Class combustion turbine offerings.

Since the temperature differential between components is the primary concern of fast ramping between MECL and full load; many of the design features required for fast ramping between MECL and full load are the same as the features required for fast start between combustion turbine ignition to MECL as discussed in the Fast Start vs. Conventional Start Analysis (File No. 400278.41.1203H). Figure 1-1 shows the regions covered under this study noted as Ramping and that covered in the Fast Start vs. Conventional Start Analysis noted as Startup.

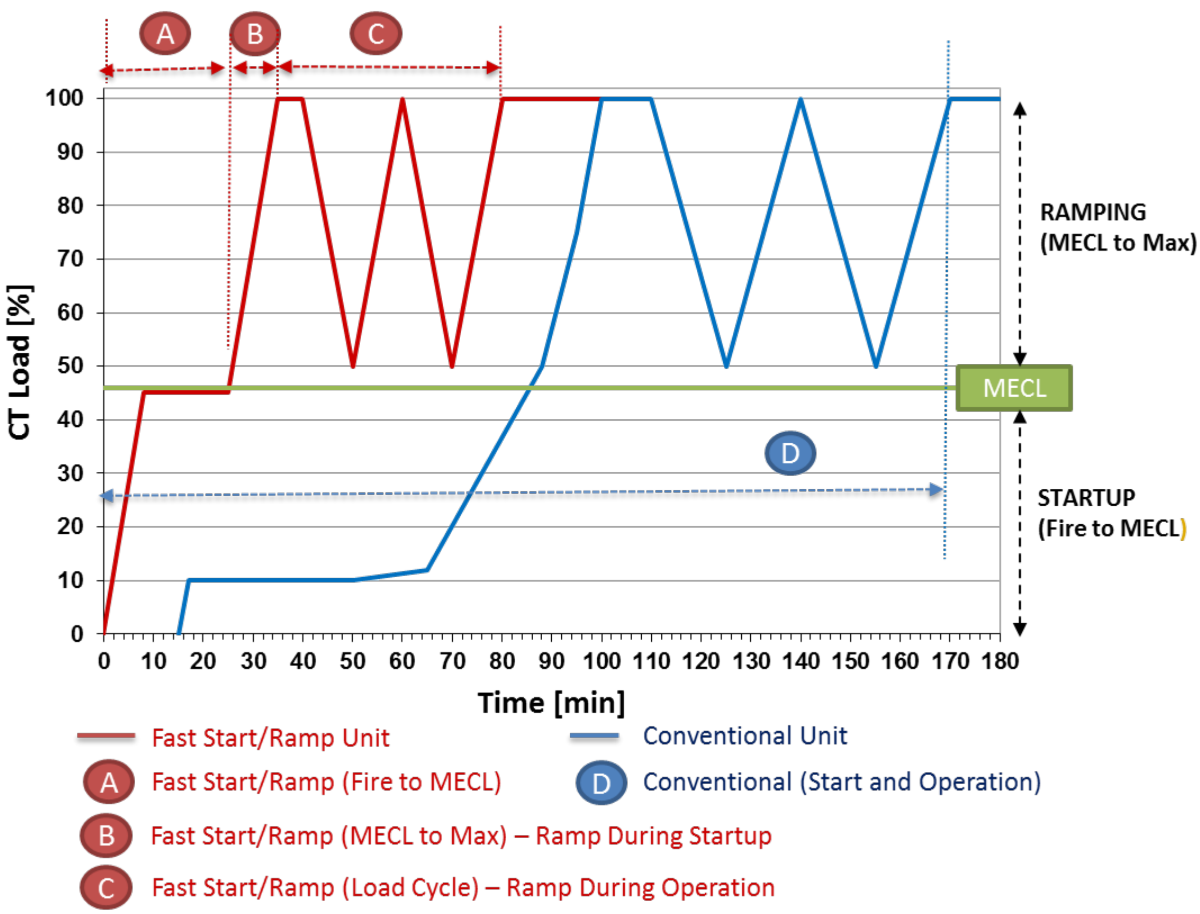



**Figure 1-1 Comparison of Combustion Turbine Loading From MECL to Full Load**

Table 1-1, Column B indicates the design features that would be required for fast ramping and how they differentiate from a conventional unit, Column D, and a fast start unit, Column A. Descriptions for each of the design features can be found in the Fast Start vs. Conventional Start

Analysis and also included in Appendix A. Items included in Column B also encompass those features in Column C which are required for fast ramping during operation.

**Table 1-1 Design Features of Combined Cycles Designed for Various Operating Scenarios**

| FEATURES REQUIRED TO MEET OPERATING SCENARIO | A<br>FAST START<br>(FIRE TO MECL) | B<br>FAST RAMP<br>(MECL TO MAX) | C<br>FAST RAMP<br>(LOAD CYCLE) | D<br>CONVENTIONAL<br>(START AND OP) |
|---|---|---|---|---|
| Required Option = ● , Recommended Option = □ , Standard Option = ◆ | | | | |
| **Combustion Turbine** | | | | |
| Fast Start Equipped | ● | | | |
| Natural Gas Purge Credits | ● | | | □ |
| Service Life Monitoring System | ◆ | ◆ | ◆ | ◆ |
| Advanced Control System | ● | ● | ● | |
| **HRSG** | | | | |
| Advanced Drum Design | ● | ● | | |
| Enhanced Nozzle Connections | ● | ● | | |
| Improved HRSG Materials | ● | ● | | |
| Improved HRSG Geometries | ◆ | ◆ | ◆ | ◆ |
| Service Life Monitoring System | □ | □ | □ | |
| Stack Damper and Insulation | ● | | | □ |
| Terminal Attemperators | ● | ● | ● | |
| LP Economizer Recirculation/Heat Exchanger | ● | ● | | |
| **Steam Turbine** | | | | |
| Optimized Casing Design | ● | ● | | |
| Advanced Control System | ● | ● | ● | |
| Service Life Monitoring System | ● | ● | □ | |
| Advanced Stop Valve Design | ● | | | |
| Increased Thermal Clearances | ● | ● | | |
| Advanced Turbine Water Induction Protection | ● | ● | ● | |
| **Emissions Control** | | | | |
| Feed-forward Ammonia Controls | ● | ● | ● | |

| FEATURES REQUIRED TO MEET OPERATING SCENARIO | A<br>FAST START<br>(FIRE TO MECL) | B<br>FAST RAMP<br>(MECL TO MAX) | C<br>FAST RAMP<br>(LOAD CYCLE) | D<br>CONVENTIONAL<br>(START AND OP) |
|---|---|---|---|---|
| **Auxiliary Steam** | | | | |
| Auxiliary Boiler | ● | | | |
| Condenser and HRSG Sparging | ● | | | |
| **Feedwater System** | | | | |
| Larger Condensate Pump | ● | ● | ● | |
| Larger Feedwater Pump | ● | ● | ● | |
| Higher Stage IP Bleed | ● | ● | ● | |
| **Heat Rejection System** | | | | |
| Surface Condenser – Fast Start Design | ● | | | |
| **Fuel Gas System** | | | | |
| Supplementary Fuel Gas Heating(1) | □ | | | |
| **Water Treatment System** | | | | |
| Condensate Polisher(2) | □ | | | |
| **Auxiliary Electrical System** | | | | |
| Larger Equipment for Higher Loads | ● | ● | ● | |

Notes:

1. Supplementary fuel gas heating as required by combustion turbine supplier.
2. Space should be allotted for future condensate polisher installation, if required.

# 2.0 Capital Costs

Note that all of the features required for fast ramp are included in Column A of Table 1-1 discussed in the Fast Start vs. Conventional Start Analysis. The costs in Table 2-1 indicate only the costs for Column B of Table 1-1. Costs listed in the study are budgetary costs (+/- 30%).

**Table 2-1 Fast Ramp (MECL to Full Load) Operating Scenario Costs**

| FAST RAMP SYSTEM COSTS FOR A 1X1 7HA.01 COMBINED CYCLE | |
|---|---|
| Fast Ramp Options (Required options in Column B excluding Stress Monitoring Systems) | [redacted] |
| Stress Monitoring Systems | [redacted] |
| **Total*** | [redacted] |
| ***NOTE: If a fast start plant is selected the above costs are not additive to those listed in the Fast Start Study.*** | |

# 3.0 Performance Impacts

Startup and ramping durations are dependent on the ambient conditions, time after shutdown, initial steam turbine rotor temperatures, and the particular OEM equipment/features used in the power train in addition to any margins (if the required start-up times are to be guaranteed). There is a relatively wide range variation, however, for rough indicative values, Table 3-1 provides comparative durations for a GE 7HA.01 1x1 combined cycle. [redacted]

**Table 3-1 Estimated Nominal Startup Times (Minutes)**

| START TYPE | CONVENTIONAL START TO MECL | CONVENTIONAL START TO STG FULL LOAD | FAST START TO MECL | FAST START, TO CTG BASELOAD | FAST START, TO CTG BASELOAD WITH STG LOADED |
|---|---|---|---|---|---|
| Hot Start = Shutdown 8 hours or less | Base Conv. | 42 | Base Fast | 7.1 | 54 |
| Warm Start = > 8 hours and < 48 hours | Base Conv. | 34 | Base Fast | 26 | 52 |
| Cold Start = Shutdown 48 hours or more | Base Conv. | 67 | Base Fast | 67 | 103 |

[redacted]

| [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
|---|---|---|---|---|---|
| [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |

[redacted]

| [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
|---|---|---|---|---|---|
| [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |

For a conventional start, each combustion turbine is ramping at a nominal rate from MECL to combustion turbine baseload of 20.7 MW/min or 7.09%/min, while the combustion turbine ramp rate for fast start is 50 MW/min or about 17.1%/min from MECL to combustion turbine baseload.

After startup and after thermal soaking, the unit will able to achieve fast ramping. For a GE 7HA.01, each combustion turbine has the ability to ramp 50 MW/minute. For a 1x1 combined cycle, the ramp rate can be stated to be 50 MW/minute. The steam turbine contribution toward fast ramping is typically not quoted since the steam turbine response is much less predictable than the combustion turbine load response. This is due to a lag in HRSG steam production response due to the CTG load changes. Depending on how the combustion turbine is ramped up and down, the output contribution from the steam turbine would take some time to settle out into a steady state performance level. For conventional units, the combustion turbine ramp rates may be limited by the HRSG and steam turbine limitations. For units equipped with fast ramping, the steam conditions can be conditioned to allow the combustion turbine to ramp independently of the steam turbine.

# 4.0 Emissions

The period for ramping is defined as the period between minimum emissions compliance load and full load. Once the unit has obtained emission compliance, the unit generally stays in compliance for ramping conditions. During a fast ramp the outlet $NO_X$ from the combustion turbine is variable. Conventional units only measure $NO_X$ at the stack; this may lead to short durations of higher $NO_X$ or ammonia slip. For fast ramping units limiting $NO_X$ measurements to the stack only can lead to over injecting or under injecting ammonia. To address this, fast ramping units are equipped with feed-forward $NO_X$ controls which take $NO_X$ measurements at the combustion turbine exhaust as well as the stack to quicken the response to changing combustion turbine exhaust conditions. Both conventional and fast ramping units are designed to operate in compliance with stack emission limits across the averaging period.

# Appendix A. Fast Start and Fast Ramp Design Features

Design features for fast start and fast ramping units are as follows:

## A.1 COMBUSTION TURBINE

Combustion turbines designed for fast-ramping will be equipped with fast start features. These include positive isolation to ensure that purge credits have been maintained per NFPA 85 and that the gas path will not require a purge prior to startup. The control system for fast start of the plant should be fully automated to minimize times between sequential steps and allow for greater consistency during startup.

Both fast start and conventional units are equipped with service life monitoring systems that control unit ramp operations based on predetermined thermal stress limitations. Fast Start units are equipped with advanced control schemes incorporating model based controls (MBC) to optimize startup based on these monitoring systems.

Purge credits established during the shutdown must still be intact. NFPA 85 requires that a fresh air purge of the combustion turbine and HRSG be accomplished prior to start. NFPA 85 requires that at least five volume changes be completed or a minimum purge of 5 minutes prior to ignition. Typical purge durations can range from 5 to 20 minutes. The 2011 edition of NFPA 85 allowed for purge credits to be achieved when the unit is taken off line if the purge is completed and the valving arrangement is shown to positively isolate any fuel from entering the system. The combustion turbine can usually achieve the required purge when coasting down following a loss of ignition.

## A.2 HRSG

HRSGs designed for fast-start plants can subject HRSG components such as superheaters and reheaters to rapid heating. Large thermal stresses can be produced by the differential expansion of the tubes within the HRSG. HRSG designs in such plants must be capable of accommodating the rapid change in temperature and flow of flue gas generated by load ramping of advanced class combustion turbines.

To reduce thermal capacity of drums many options are used to decrease the drum size and wall thickness including utilizing Benson style drums, utilizing multiple drums, high strength drum materials, reduced residence time. Self-reinforced nozzles, full penetration nozzles, full penetration welds, and steam sparger systems further improve the ability to accept rapidly changing exhaust gas conditions and steam conditions. Improved materials throughout the high pressure superheater and reheater can be required. Online, real-time monitoring system should be included to evaluate HRSG life consumption.

In order to reduce the thermal capacity of drums, the residence time may also be reduced for fast start units. Fast start units typically have drum storage time around two minutes. Conventional start plants have drum storage time from 3-5 minutes.

Fast start plants are equipped with a stack damper and with an insulated stack up to the stack damper. The stack damper and insulation are critical as they restrict the flow of flue gas out the HRSG stack minimizing heat loss when the unit is offline. While conventional units do not require stack dampers and insulation, it is a recommended practice to minimize heat loss when the unit is offline.

Both fast start and conventional units have improved HRSG geometries compared to those built a decade ago. Improvements in geometries have been to decrease thermal stresses from unit cycling and are part of the HRSG standard design such as coil flexibility to superheater/reheater interconnecting piping and accommodations for tube-to-tube temperature differentials.

## A.3 STEAM TURBINE

The steam turbine must also be designed for the thermal gradients experienced while ramping during start-up. For fast start machines, the casing design must be optimized to reduce the thermal stress during temperature fluctuations and to accept faster start up and load change gradients. The use of higher grade material may be employed in the high pressure and intermediate casings and valves to reduce component thickness. Main steam stop valves must be designed so that these valves can be opened at a relatively higher pressure. Integral rotor stress monitors can be provided; the rotor stress monitor is typically capable of limiting or reducing the steam turbine load or speed increase and is designed to trip the turbine when the calculated rotor stresses exceed allowable limits.

For machines undergoing a fast ramp, attemperators are often required on the high pressure and hot reheat steam lines. Overspray on these attemperators can lead to water in these steam lines; special attention needs to be provided for turbine water induction prevention for units equipped with terminal attemperators.

## A.4 EMISSIONS AND AMMONIA FEED

Outlet $NO_X$ from the combustion turbine can vary highly when undergoing fast startup and fast ramp conditions. Conventional units only measure $NO_X$ at the stack; for fast ramping units limiting $NO_X$ measurements to the stack only can lead over injecting or under injecting ammonia. Higher ammonia slip and potentially greater SO2 conversion in fast-start and fast-ramp units create additional challenges for control of sulfur-bearing deposits in the colder HRSG areas. Low-pressure evaporators and economizers are particularly at risk. For fast ramping plants, addition of feed forward controls to quicken the saturation of the SCR catalyst (if included) is required. Also the HRSG should be equipped with LP economizer recirculation or heating systems to maintain surfaces above SO2 dew points.

## A.5 AUXILIARY STEAM

Fast start units require an auxiliary boiler to produce steam prior to the startup of the unit. This steam is used for steam line warming, establish the steam turbine seals, warm up HRSG drums, and condenser sparging to enable uninhibited startup of the unit. The auxiliary boiler may also produce steam when the unit is off line to maintain drum and turbine temperatures.

Conventional units without an auxiliary boiler must use the combustion turbine and HRSG to produce steam to warm the unit and establish seals. During a conventional unit startup, holds are required to complete these warm up periods.

Provisions for fast start of the auxiliary boiler should also be considered which include equipping the auxiliary boiler mud drums with heating coils. Auxiliary boiler heat input, operating hour limits, and emission limits must also be considered.

Note that the auxiliary boiler makes up the majority of the cost to equip a combined cycle with fast start capabilities.

## A.6 TERMINAL STEAM ATTEMPERATORS

Conventional start plants hold the combustion turbine load during startup as needed to meet the steam turbine startup steam temperature requirements. Fast-start plants decouple the CTG/HRSG startup from the steam turbine startup by using terminal attemperators at the HRSG outlet for meeting steam turbine startup steam temperature requirements, irrespective of CTG/HRSG load. This allows the steam turbine to come on line independently from the CTG and HRSG. As a result, the plant can increase load more quickly.

While the addition of terminal (final stage) steam attemperators on the main steam and hot reheat lines allow for temperature matching, they introduce the risk of two phase flow in the steam lines. An adequate run of straight piping downstream of the attemperators, adequate drainage, and robust instrumentation are a must to minimize the risk of condensate carry-over to the steam turbine. Additional controls should be considered to prevent turbine water induction.

## A.7 FEEDWATER SYSTEM

For fast start plants equipped with terminal attemperators, additional condensate and feedwater pump flow is required to meet the attemperation demands. Inter-stage feedwater used for attemperation may be taken off at a later pump stage to meet the pressure demands of the attemperators which could impact feedwater piping wall thickness.

## A.8 FUEL GAS SYSTEM

In order to reduce emissions and maintain flame stability, some manufacturers require supplementary fuel gas heating as a part of startup. This heating is in addition to any startup heater used to raise the fuel gas temperature above the dew point.

## A.9 WATER TREATMENT SYSTEM

Maintaining water chemistry and meeting the water chemistry requirements of the HRSG and steam turbine are a critical part of startup. Blowdown and makeup systems should be sized accordingly to meet expected startup demands. Provisions for the inclusion of a future condensate polisher should be considered should problems arise. Condensate polishers ensure top quality feedwater.

## A.10 AUTOMATED STARTUP SEQUENCE

Additional controls and automation are required for fast-ramp plants to ensure the matching of steam temperatures and to maintain emission compliance. As a result, more plant instrumentation is required in automated plants to allow the plant control system to monitor system status, minimize times between sequential steps and provide consistent startups.

Also fast-ramp plants should consider the use of service life monitoring systems such as thermal stress indicators on the HRSG and steam turbine. These systems allow control of the unit ramp operations based on predetermined thermal stress limitations.

Confidential

**FINAL**

# NUMBER OF COLD, WARM, AND HOT STARTS ANALYSIS

A.B. Brown 1x1 H-Class

**B&V PROJECT NO. 400278**
**B&V FILE NO. 41.1207H**



**PREPARED FOR**

VECTREN
A CenterPoint Energy Company

Vectren

31 JANUARY 2020

BLACK & VEATCH
Building a world of difference.

# Table of Contents



## LIST OF TABLES



## LIST OF FIGURES

# 1.0 Introduction

Prior to the early 2000s, combined cycles were predominately designed for base load operation with high focus on highest full load efficiency and lowest capital cost. Due to increases in gas pricing, changing power market production cost structure, and renewable energy generation, many of these plants were forced into intermediate or even daily cycling mode. Many problems associated with the fast changing temperatures in the equipment resulted, such as high thermal stresses, high cyclic fatigue, vibration, flow accelerated corrosion, and water induction.

As a result of these industry issues, today's major equipment suppliers design their equipment to withstand the cumulative wear and damage caused by frequent starts and stops. For modern combined cycle equipment operating as high cycling units, major equipment manufacturers take the following into consideration:

- Base equipment designs consider high cycling
- Service life monitoring equipment is recommended for high cycling units
- Time between service intervals decreases with higher cycling

In addition to the number of starts, the time between the unit shutdown and start also has a significant impact on the equipment. When a unit is shutdown, equipment begins to cool. Upon the next start, the equipment would have to be brought back up to operating temperature putting the equipment through a thermal cycle. The duration between shutdown and startup is usually broken down between different start modes whether the equipment is considered hot, warm, or cold. Equipment manufacturers each have their own definition for hot, warm, and cold starts; however, typical start mode durations are listed in Table 1-1.

**Table 1-1 Start Mode Definitions**

| START TYPE | SHUTDOWN DURATION |
|---|---|
| Hot | < 8 hours |
| Warm | 8-48 hours |
| Cold | > 48 hours |

## 1.1 BASE EQUIPMENT DESIGN

During startup and shutdown, the unit sees large temperature gradients and thermal stresses. Cycling increases concern for thermally induced creep-fatigue damage as a result of rapid heating of the surface of components such as turbine blades, rotors, casings, drums, and other heavy walled components. Creep-fatigue damage can also result from different thermal expansion between thin and thick components or dissimilar metal welds.

To resolve these issues, manufacturers have incorporated the knowledge of these earlier failures into their standard designs. Manufacturers select geometries, materials, thicknesses, and coatings in such a way as to limit the damage of thermal cycling. Geometries and material selection also alleviate other issues such as flow accelerated corrosion, vibration, and water induction. These designs do not alleviate all the issues with thermal factors but allow the equipment to be monitored in such a way to determine its service life.

## 1.2 MAINTENANCE INTERVALS

The design life for the facility is 30 years and the operating equipment will need regular maintenance including hot gas path and major inspections.**Error! Reference source not found.Error! Reference source not found.** Figure 1-1 shows the equivalent hours-based and starts-based maintenance intervals for GE and Siemens H-class combustion turbines and the potential impact of maintenance factors on maintenance intervals.

The timing of maintenance intervals are impacted by maintenance factors. Hours based maintenance factors consider fuel type, firing temperature, and water or steam injection used for emissions control or power augmentation. Starts based maintenance factors consider the type of start; whether it is a conventional start, fast start, cold start, warm start; load achieved during each start; and shutdown type such as normal cooldown, rapid cooldown or unit trip. The red lines in Figure 1-1 show how starts or hours based factors could affect the timing of maintenance intervals.

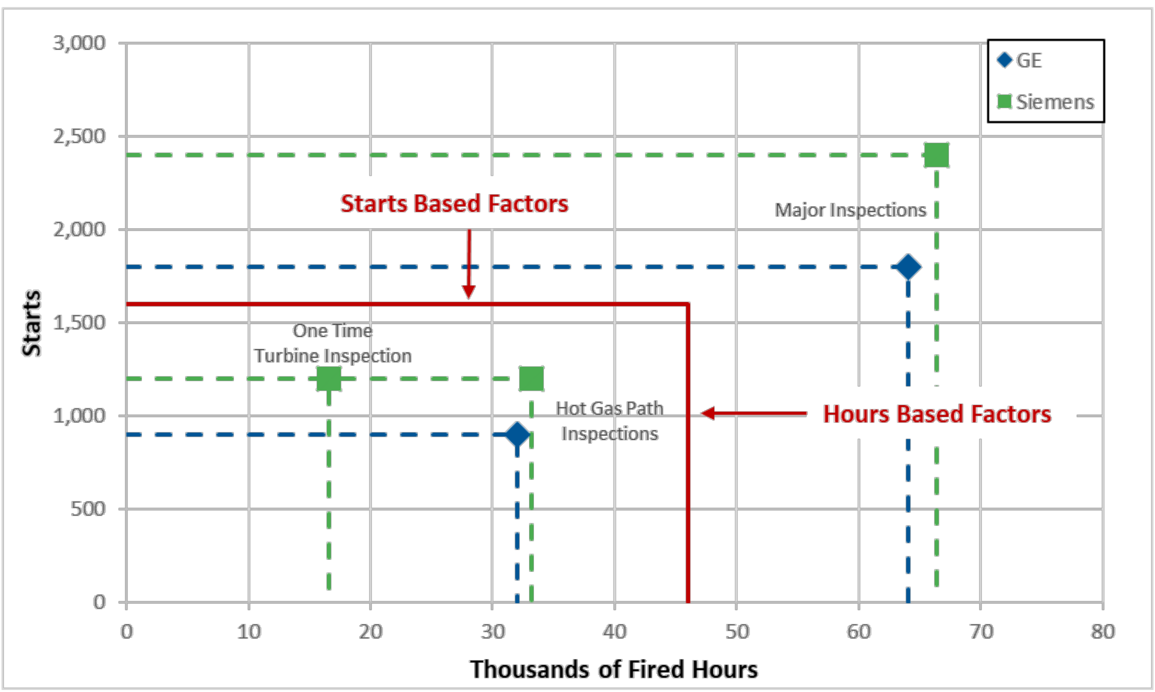



**Figure 1-1 Maintenance Factors Reduce Maintenance Intervals**

Per GE's Heavy-Duty Gas Turbine Operating and Maintenance Considerations (GER-3620N), a GE unit with a baseline maintenance factor would equate to 4,800 operating hours per year (16 hours/start, 6 starts/week, 50 weeks/year) and 300 starts per year. Those 300 starts would consist of 249 hot starts, 39 warm starts, and 12 cold starts. For the design life of 30 years, GE would base their Long Term Service Agreement (LTSA) on 5 maintenance cycles for a GE 7HA.01 with a baseline operating profile. The LTSA relates to the serviceable life of the combustion turbine.

**Error! Reference source not found.**Figure 1-2 shows how operating hours and the number of starts per year affect the duration of the LTSA. A 30 year life is based on roughly 300 equivalent starts per year. An operating regime requiring above about 300 equivalent starts per year would have service intervals based on equivalent life and start decreasing the life expectancy of the LTSA. For example, 450 equivalent starts per year would be roughly equivalent to a 20 year LTSA life. When operating below 300 equivalent starts per year the figure shows whether hours based operation or number of starts based operation would determine the maintenance intervals for the plant. Since the facility has a 30 year design life, 300 equivalent starts would be the average yearly allowable for the plant. Based on a design basis of 310 starts per year, the breakdown of calculated and recommended number of design basis cold, warm, and hot starts would be as shown in Table 1-2.

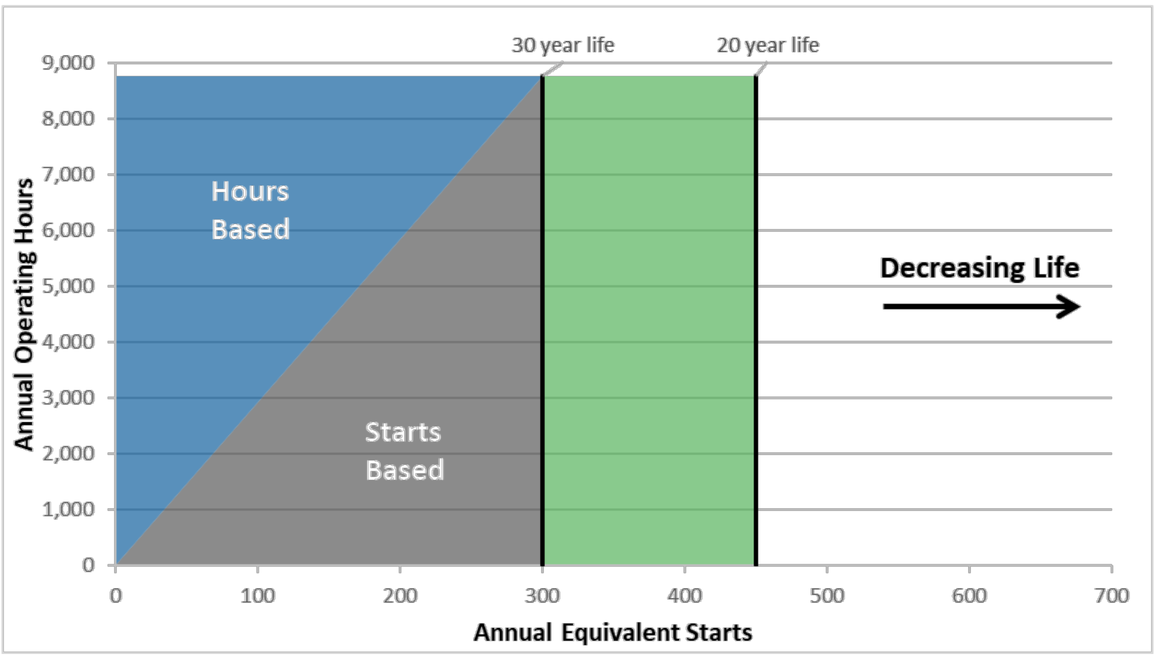



**Figure 1-2 Combustion Turbine LTSA Term vs. Starts and Operating Hours Service Intervals**

**Table 1-2 Operating Conditions Used in Design Basis**

| OPERATING CONDITIONS | DESIGN BASIS |
|---|---|
| Operation | Daily Cycling |
| Yearly Operating Hours | Up to 8,760 |
| Annual Capacity Factor | 45% to 100% |
| Cold Starts Per Year | 10 |
| Warm Starts Per Year | 100 |
| Hot Starts Per Year | 200 |
| Total Starts Per Combustion Turbine | <310 |

## 1.3 SERVICE LIFE MONITORING EQUIPMENT

For plants operating in a regime where the starts based maintenance factors are determining the service intervals, it becomes useful to monitor the equipment to avoid costly outages. Service life monitoring systems perform three functions: instrumentation, evaluation, and determination. The instrumentation and sensor systems record the operating parameters such as localized temperature, pressure, and vibration. Based upon the readings, evaluations can be made such as stresses in critical locations in the turbines and the HRSG. The evaluated data is then combined with the operating history of the system to determine the impact on the remaining service life.

Recommended monitoring systems for high cycling plants include:

- Combustion Turbine Stress Controller
- Steam Turbine Stress Controller
- HRSG Stress Controller
- Condition Monitoring System
- Water Quality Monitoring System

Today's H-class combustion turbines come equipped with control systems that monitor speed, acceleration, temperature, and verify that all sensors are active. These sensors measure performance and monitor the machine's health. These systems also count the operating hours and number of equivalent starts or calculate the equivalent life of each start sequence in order to calculate the next service interval.

The steam turbine stress controller consists of a stress evaluation system that calculates and controls stresses in thick walled components including stop and control valves, HP casing and rotor body, and the IP rotor body. The stress controller monitors and controls ramp rates during start up to calculate the cumulative fatigue of cycling the unit. The stress controller also determines the remaining time to the next service interval.

The HRSG stress controller performs a dynamic analysis of the HRSG to determine fatigue. The stress controller determines risk factors based upon the evaluations, such as the probability of crack initiation. These risk factors are used to plan and indicate HRSG maintenance.

Condition monitoring systems measure critical asset parameters such as vibration, temperature, and speed of rotating equipment including boiler feed pumps, condensate pumps, circulating water pumps, cooling tower fans, and fuel gas compressors. The monitoring systems also evaluate trends, such as vibration amplification, and compare it against set points, historical readings, and known failure patterns.

The water quality monitoring system provides additional water and steam sampling to monitor issues with cycling units. Cycling units result in a large demand on the condenser and, in peak demands, on condensate supply and oxygen controls. Additional controls include online monitoring for condenser tube leaks and condenser air in leakage. It also includes monitoring steam blowdown lines for high level of particulates to indicate any safety issues. Water quality monitoring systems are not as important if the unit includes a condensate polisher.

# 2.0 Service Life Monitoring System Costs

As outlined in Section 1.2, service life monitoring systems are recommended for high cycling plants to help predict and plan maintenance. Table 2-1 provides budgetary cost (+/- 30%) for service life monitoring systems.

**Table 2-1 Service Life Monitoring System Costs**

| SERVICE LIFE MONITORING SYSTEM COSTS | |
|---|---|
| Combustion Turbine Stress Controller | [redacted] |
| Steam Turbine Stress Controller | [redacted] |
| HRSG Stress Controller | [redacted] |
| BOP Condition Monitoring System | [redacted] |
| Water Quality Monitoring System | [redacted] |
| Additional cable and I/O | [redacted] |
| **Total** | [redacted] |

# 3.0 Conclusion

Today's combined cycle equipment is designed for high cycling applications and consider problems associated with the fast changing temperatures in the equipment such as high thermal stresses, high cyclic fatigue, vibration, flow accelerated corrosion, and water induction. The design life of the equipment is 30 years with major overhauls of the combustion turbines occurring every 6 years. The time duration between major overhauls is based upon maintenance factors associated with hours of operation and the number of starts.

While the number of operating hours is not expected to shorten the time between maintenance cycles, the number of starts could decrease the operational life. In order to maintain the 6 years between major overhauls, the combustion turbine should have an equivalent number of annual starts less than 310. To avoid decreasing the life of the LTSA, the typical combined cycle design including balance of plant equipment should not exceed 310 starts per year. The breakdown of the recommended number of design cold, warm, and hot starts would be as shown in Table 3-1.

**Table 3-1 Design Cold, Warm, and Hot Starts**

| OPERATING CONDITIONS | |
|---|---|
| Operation | [redacted] |
| Yearly Operating Hours | [redacted] |
| Annual Capacity Factor | [redacted] |
| Cold Starts Per Year | [redacted] |
| Warm Starts Per Year | [redacted] |
| Hot Starts Per Year | [redacted] |
| Total Starts Per Combustion Turbine | [redacted] |

If the plant is expected to be a high cycling unit with a maintenance cycle that would be determined based upon the number of starts rather than the number of hours operated per year, Vectren should consider additional service life monitoring systems to assist in predictive maintenance, as shown in Table 3-2. While these systems do not prevent maintenance, they allow the operator to better understand how the operation of the unit is impacting the service life of the equipment.

### Table 3-2 Service Life Monitoring Systems

| SERVICE LIFE MONITORING SYSTEM COSTS | |
|---|---|
| Combustion Turbine Stress Controller | [redacted] |
| Steam Turbine Stress Controller | [redacted] |
| HRSG Stress Controller | [redacted] |
| BOP Condition Monitoring System | [redacted] |
| Water Quality Monitoring System (not required with a condensate polishing system) | [redacted] |
| Additional cable and I/O | [redacted] |
| **Total** | [redacted] |

Confidential

FINAL

# AUXILIARY BOILER ANALYSIS

## A.B. Brown 1x1 H-Class

**B&V PROJECT NO. 400278**
**B&V FILE NO. 41.1209H**



**PREPARED FOR**

VECTREN
A CenterPoint Energy Company

Vectren

31 JANUARY 2020

BLACK & VEATCH

# Table of Contents



## LIST OF TABLES

# Executive Summary

In developing this report, Black & Veatch reviewed the requirements for the auxiliary steam system for the new Combined Cycle Power Plant (CCPP). Black & Veatch reviewed multiple pre-start, start-up and shutdown scenarios to determine the required sizing and operation of the auxiliary steam boiler.

The auxiliary steam system users have been summarized in the Auxiliary Steam Demands provided in Table 2-1. The users were estimated based on previous projects using the 7HA.01 gas turbines. Based on the maximum co-incident steam demand of the 7HA.01 configuration it is recommended that Vectren utilize an auxiliary boiler designed for [redacted] lb/hr and an outlet pressure of [redacted].

# 1.0 Introduction

The purpose of this study is to determine the specific requirements for the Auxiliary boiler to be installed with the new Combined Cycle Power Plant (CCPP). These Fast start units require an auxiliary boiler to produce steam prior to the startup of the unit. This auxiliary steam is used for steam line warming, establish the steam turbine seals, warm up HRSG drums, and condenser sparging to enable quicker startup of the unit. The auxiliary boiler may also produce steam when the unit is off line to maintain drum and turbine temperatures. Black & Veatch has previously performed the "Fast Start vs Conventional Start Analysis" which demonstrates the need for an auxiliary boiler for a unit with fast start capability.

This evaluation will help determine the design impact of this system to the new CCPP design. Auxiliary system users, auxiliary boiler sizing and operation will also be identified and discussed.

# 2.0 Auxiliary Boiler Sizing and Outlet Pressure

The auxiliary steam system provides steam to various users during plant startup and shutdown at multiple operating conditions. Several operating scenarios were evaluated to determine the best preliminary design basis for sizing the auxiliary boiler. Upon selection of the final plant design, the selected size of auxiliary boiler should be reviewed.

## 2.1 COINCIDENT STEAM DEMANDS

The maximum co-incident auxiliary boiler steam demand occurs during startup when supplying maximum steam turbine sealing, fuel heating, maximum condenser sparing steam, and maximum combustion turbine inlet air heating as shown in Table 2-1.

**Table 2-1 Coincident Auxiliary Steam Demands**

| AUXILIARY STEAM USERS | 1X1 HA.01 |
|---|---|
| ST Gland Sealing | [redacted] |
| Startup Steam to Fuel Gas Heater | [redacted] |
| Condenser Hotwell Sparging | [redacted] |
| Combustion Turbine Inlet Air Heating | [redacted] |
| **Total Coincident Boiler Steam Flow Required** | [redacted] |

## 2.2 NON-COINCIDENT STEAM DEMANDS

During unit pre-start, there are two activities that require auxiliary steam flow, but are not co-incident with the other users. These non-coincident activities occur during HRSG pre-warming and HRSG HP pressure holding. The non-coincident auxiliary steam demands are listed in Table 2-2.

**Table 2-2 Non-Coincident Auxiliary Steam Demands During Pre-Start Activities**

| AUXILIARY STEAM USERS | 1X1 7HA.01 |
|---|---|
| HRSG Warming | [redacted] |
| HRSG Pressure Holding | [redacted] |

## 2.3 DESCRIPTION OF USERS

- The turbine seals require steam from the auxiliary system to provide sealing until the steam turbine increases load and becomes self-sealing. When the steam turbine exceeds the point of self-sealing, the flow from the auxiliary system will decrease to near zero.
- A startup steam to fuel gas heater is used to raise the fuel gas to the CT manufacturers specified minimum fuel temperature via a steam to water heat exchanger.
- Condenser hotwell sparging is used to heat the condensate in the condenser to normal operating temperatures prior to starting the units.
- The gas turbine inlet air heating system uses auxiliary steam to provide heat via coils in the CT inlet air structure to minimize the possibility for ice formation in the CT compressor section.
- The HRSG HP warming flow increases the metal temperature of the steam drums and the tubes, allowing for faster startup capability.
- The HRSG HP pressure holding maintains the HP evaporator at a minimum of 275 psig to maintain drum and tube temperatures for faster startup capability.

## 2.4 BOILER OUTLET CONDITIONS

The delivery steam pressure of the auxiliary boiler is typically 300 psig at saturation temperature to facilitate HP evaporator pressure holding of approximately 275 psig. Electric superheaters will be used to provide superheated steam to the turbine seals. Delivering saturated steam will reduce the heat input to the auxiliary boiler which is limited due to air permits.

# 3.0 Auxiliary Boiler Operation

## 3.1 PRE-START CONDITION

The auxiliary steam system should be pressurized, heated and drained up to the steam seal feed valve during pre-start activities. The operating conditions of the auxiliary boiler and system must be verified prior to initiating a unit startup. During cold pre-start activities, the steam for turbine sealing, condenser sparging steam and HP evaporator warming is supplied by the auxiliary boiler. During hot start activities, the steam demand for the HP evaporator warming steam is replaced by the steam demand for HP evaporator pressure holding. Following an HRSG outage or cold restart, the HRSG HP warming flow is set to a maximum flowrate to accelerate warming.

## 3.2 INITIAL STARTUP AND SHUTDOWN

During initial startup the auxiliary steam for the turbine sealing, CT air inlet heating, fuel gas heating and condenser sparging is provided from an auxiliary boiler. As the plant cycle steam from the HRSG IP drum becomes available it allows the auxiliary boiler to be shut down or unloaded to idle as plant operations allow. During normal operation the HRSG IP drum provides all required auxiliary steam flow for the plant.

During plant shutdown or trip, it is expected that there is enough residual energy in the HRSG to provide auxiliary steam until the steam turbine exhaust vacuum is broken or the auxiliary boiler can be brought online to provide sealing steam. The auxiliary boiler must remain in a ready condition at all times during combined cycle operation. During overnight plant shutdowns the aux boiler can remain in operation to provide sealing steam, condenser sparging steam and allow rapid starting in the morning.

# 4.0 Conclusions

The purpose of this evaluation was to determine the specific requirements for the auxiliary boiler for the new Combined Cycle Power Plant (CCPP). Black & Veatch reviewed pre-start, start-up and shut down scenarios to determine the required sizing and operation of the auxiliary boiler.

This report has shown:

- Auxiliary steam users and the estimated demand.
- Non-coincident auxiliary steam users and the estimated demand
- Black & Veatch's recommendation for steam requirements listed in Table 2-1 for various plant configurations.

FINAL

# EXISTING FIRE WATER SYSTEM REVIEW

A.B. Brown 1x1 H-Class

**B&V PROJECT NO. 400278**
**B&V FILE NO. 42.1212H**



**PREPARED FOR**

VECTREN
A CenterPoint Energy Company

Vectren

31 JANUARY 2020

BLACK & VEATCH

# Table of Contents

# Executive Summary

In developing this report for the new Combined Cycle Power Plant (CCPP), Black & Veatch reviewed the piping and instrumentation diagrams (P&IDs) for the existing fire protection and service water systems.

The existing system includes existing pumps and a 75,000 gallon raw water storage tank. The raw water storage tank is sized to provide 51,000 gallons of surge capacity devoted to fire water use. To meet the new fire water system design requirements, a third diesel motor fire pump should be added to the system and the pump arrangement modified to a 3x50 percent configuration with two pumps driven by a diesel motor and the other driven by an electric motor. This configuration allows for a fire water demand up to 3,000 gpm. The existing pressure maintenance pump, which is rated for approximately 1 percent for the main pumps flow and same discharge pressure, should remain.

# 1.0 Existing Equipment

Based on the existing site Fire Protection and Service Water Systems P&ID (F-1024) there are 2x100 percent fire pumps (one electric driven and one diesel driven) that are rated for 1,500 gpm @ 300 FT TDH each. The fire water pumps normally take suction from existing Ranney Well pumps of adequate capacity and the Raw Water Storage Tank (75,000 gallons) via a 12" nominal diameter suction header. The fire protection water supply system is also cross tied to the River Water pumps. The Raw Water Storage Tank is sized to provide 51,000 gallons of surge capacity devoted to fire water use. The existing site has a 10" underground fire water loop. This pipe is assumed to be ductile iron.

Per NFPA 850, the existing water source is large enough to be considered a reliable water source. The multiple pumps installed provide reliability such that a single failure or maintenance event will not impair the ability of the system to responds to a fire event. If a single pump were to be out of service, the remaining pumps will still have sufficient capacity to supply water to the existing water users as well as the maximum fire water demand of 2,500 gpm.

# 2.0 Design Basis and Clarifications

- A search of the NFPA codes on the Indiana State website did not include NFPA 850. However, for the purposes of this assessment and the design of the new power plant, Black & Veatch has referenced NFPA 850 – 2015.
- There is a discrepancy between some of the code years referenced on the Indiana State website and from the IBC or IFC. Our basis is the most current version when this occurs.
- It is not clear from the P&ID what the material used for the existing underground fire water supply mains. Our basis is currently ductile iron material; please clarify if different.
- Please clarify who the Authority Having Jurisdiction (AHJ) is for the A.B. Brown Site. We have identified the state fire marshal below.

  Indiana State Fire Marshal<br>
  Stephen Cox<br>
  317-232-2222<br>
  http://www.in.gov/dhs/2445.htm

# 3.0 New Plant Fire Protection Requirements

The new plant's required fire water system supply flow is based on a worst case fire scenario, plus a hose allowance (500 gpm), and any adjacent systems in the immediate area of a potential fire area; as defined in NFPA 850, Section 6.2. The largest system demand is expected to be the Steam Turbine Building/Enclosure at 1,800 gpm in combination with the turbine generator bearings closed head sprinkler system with directional nozzles with a demand of approximately 200 gpm. This total demand will require a main fire pump rated at 2,500 gpm. The velocity limits at this flow require either a 10" DI or 12" HDPE DR 11 pipe.

To meet the new fire water system design requirements a third diesel motor fire pump (1,500 gpm @ 300ft) should be added to the system modifying the pump arrangement to 3x50 percent configuration with two pumps driven by a diesel motor and the other driven by an electric motor. This configuration allows for a fire water demand up to 3,000 gpm. The existing pressure maintenance pump which is rated for approximately 1 percent for the main pumps flow and same discharge pressure should remain. There are no elevated areas for the new or existing plant areas that require booster pumps to obtain adequate pressure for hose stations so a standard pressure rating of 300 ft-H2O at the rated point is expected to be sufficient.

Per NFPA 850 the multiple Ranney Well pumps installed will provide a reliable source of water such that a single failure or maintenance event will not impair the ability of the system to responds to a fire event. In a single pump out of service case the two remaining Ranney Well pumps can provide up to 4,000 gpm. The preliminary water mass balance for other uses states the normal use from non-fire protection demands is approximately 150 gpm. This allows the fire water demand of 2,500 gpm to be met along with the other non-fire protection water users.

The existing 10" fire protection underground system can be reused with new 12" HDPE used for any new underground headers and around the cooling tower. Hydrants will be located as per NFPA 850 and the local code requirements.

# 4.0 List of Applicable Codes and Standards

| | | |
|---|---|---|
| 675 IAC 13-2.6 | Indiana Building Code, 2014 Edition (IBC, 2012 Edition, 1st printing) ANSI A117.1-2009 | Effective 12/1/14 |
| 675 IAC 22-2.5 | Indiana Fire Code, 2014 Edition (IFC 2012 Edition, 1st printing) | Effective 12/1/14 |

**NFPA Standards**

| NFPA # | Description | Effective Date | IAC Cite |
|---|---|---|---|
| 10-2010 | Portable Fire Extinguishers | December 15, 2012 | 675 IAC 28-1-2 |
| 11-2005 | Low Expansion Foam and Combined Systems | September 22, 2006 | 675 IAC 28-1-3 |
| 12-2005 | Carbon Dioxide Extinguishing Systems | September 22, 2006 | 675 IAC 28-1-4 |
| 13-2010 | Installation of Sprinkler Systems | September 26, 2012 | 675 IAC 28-1-5 |
| 14-2000 | Installation of Standpipe and Hose Systems | December 13, 2001 | 675 IAC 13-1-9 Repealed 3/21/14 |
| 15-2001 | Water Spray Fixed Systems | September 22, 2006 | 675 IAC 28-1-8 |
| 20-1999 | Installation of Centrifugal Fire Pumps | December 13, 2001 Amended 12/26/02 | 675 IAC 13-1-10 |
| 25-2011 | Inspection, Testing and Maintenance of Water Based Fire Protection Systems | May 12, 2013 | 675 IAC 28-1-12 |
| 37-2002 | Installation and Use of Stationary Combustion Engines and Gas Turbines | September 22, 2006 | 675 IAC 28-1-15 |
| 70-2008 | National Electrical Code | August 26, 2009 | 675 IAC 17-1.8 |
| 72-2010 | National Fire Alarm Code | March 23, 2014 | 675 IAC 28-1-28 |
| 2001-2004 | Clean Agent Fire Extinguishing Systems | September 22, 2006 | 675 IAC 28-1-40 |

# 5.0 Conclusions

The purpose of this evaluation was to review the existing fire water system. Black & Veatch reviewed P&IDs for both the existing fire protection and service water systems.

This report has shown:

- The raw water storage tank is sized to provide 51,000 gallons of surge capacity devoted to fire water use.
- The existing pressure maintenance pump is sufficient.
- The existing 10 inch fire protection underground system can be reused with new 12 inch HDPE used for any new underground headers and around the cooling tower.
- Black & Veatch's recommendation is to add a third diesel motor fire pump and modify the pump arrangement to a 3x50 percent configuration.

Confidential

FINAL

# NOISE REGULATION REVIEW

## A.B. Brown 1x1 H-Class

B&V PROJECT NO. 400278
B&V FILE NO. 41.1213H



PREPARED FOR

VECTREN
A CenterPoint Energy Company

Vectren

31 JANUARY 2020

BLACK & VEATCH

# Table of Contents

# Executive Summary

Black & Veatch reviewed the noise regulations that might apply to the new Combined Cycle Power Plant (CCPP).

Indiana, Posey County, and Marrs Township have no far field noise regulation or ordinances. Far field noise requirements are generally referenced to the site boundary, property line, or other boundary limit. Occupational Safety and Health Administration (OSHA) standards will apply to near field noise emissions. Near field noise requirements are measured along the equipment envelope. During off-normal and intermittent operation such as startup, shutdown, and upset conditions, the equipment sound pressure level shall not exceed a maximum of 115 dBA at all locations along the equipment envelope, including platform areas, that are normally accessible by personnel.

Near field noise mitigation requirements will be required of equipment. Since there were no extant noise regulations specific to this site, no far field noise mitigation is required.

# 1.0 Results of Noise Regulation Review

Noise requirements fall into two categories: far field or near field. These categories are based upon the distance from the emitter to the receptor. Far field noise requirements are generally referenced to the site boundary, property line, or other boundary limit. Near field noise requirements are measured along the equipment envelope. The envelope is defined as the perimeter line that completely encompasses the equipment package a distance of 3 feet from the face of the equipment.

## 1.1 FAR FIELD NOISE REQUIREMENTS

There are no extant noise regulations or ordinances for Indiana, Posey County, or Marrs Township. The expectation would be that the general environmental sound levels in the surrounding area would not be substantially different from the sound levels with the two coal units in operation, assuming the coal units will be decommissioned after the new unit is operational.

## 1.2 NEAR FIELD NOISE REQUIREMENTS

Near field noise requirements are limited by OSHA requirements. The near-field noise emissions for each equipment component furnished under these specifications shall not exceed a spatially-averaged free-field A-weighted sound pressure level of 85 dBA (referenced to 20 micropascals) measured along the equipment envelope at a height of 5 feet above floor/ground level and any personnel platform during normal operation.

During off-normal and intermittent operation such as start-up, shut-down, and upset conditions the equipment sound pressure level shall not exceed a maximum of 115 dBA at all locations along the equipment envelope, including platform areas, that are normally accessible by personnel.

# 2.0 Conclusions

Near field noise mitigation requirements will be required of equipment. Since there were no extant noise regulations specific to this site, no far field noise mitigation is required.

The attached V100 supplemental, contains the noise abatement requirements to be included with the procurement specifications. Since there were no extant noise regulations specific to this site, the V100 supplemental was developed using the near field requirements which are the typical OSHA limits.

Confidential

FINAL

# CONDENSATE POLISHER EVALUATION SUMMARY

## A.B. Brown 1x1 H-Class

**B&V PROJECT NO. 400278**
**B&V FILE NO. 41.1214H**



PREPARED FOR

VECTREN
A CenterPoint Energy Company

Vectren

31 JANUARY 2020

BLACK & VEATCH

# Table of Contents

# Executive Summary

This report provides a summary of Black & Veatch's evaluation of including a condensate polisher system in the conceptual design of the new A.B. Brown Combined Cycle. This summary of the evaluation will show that:

- Five selection criteria for Pre-Coat Condensate Polishers are present in the conceptual design. General industry practice to consider polishing is three or more.

| PRE-COAT POLISHER CRITERIA | A.B. BROWN COMBINED CYCLE PLANT |
|---|---|
| Steam Cation Conductivity ≤0.2uS/cm | **Yes – 0.2uS/cm Allowed*** |
| Graywater Cooling | No – River Water |
| Air Cooled Condenser | No – Wet Surface Condenser |
| All-Volatile Treatment – Oxidizing Treatment (AVT-O) Cycle Chemistry | **Yes – All-Volatile Treatment-Oxidizing with Phosphate (no oxygen scavenger)** |
| HP/Main Stream Pressure >2,400 psig | **Yes – HP/Main Steam >2,500 psig** |
| Cycling with Short Start-up Time | **Yes – Cycling Units with Rapid start** |
| LP Steam Conductivity Limit? | No |
| Suspended Solids (TSS) process contamination possible? | **Yes – River water contains levels of TSS** |
| * GE Steam Purity for Industrial Turbine (Table 4 in document GEK 98965) | |

- [redacted]

| PARAMETERS | 1X1 7HA.01 (FIRED) |
|---|---|
| Condensate Design Flow, gpm | [redacted] |
| Estimated Equipment Costs ($450 per gpm) | [redacted] |
| Total Installed Capital Cost (Equipment Costs + $2.52M installation) | [redacted] |

Based on the selection criteria identified in the summary report, Black & Veatch's recommendation is to include provisions for a future pre-coat type condensate polisher system in the conceptual design for the project. This includes, but not necessarily limited to, [redacted] allowance in condensate pump sizing, space allocation, spare electrical capacity and connections, and condensate discharge by pass piping connections.

# 1.0 Introduction

## 1.1 GENERAL FACILITY OVERVIEW

Vectren (Company) is planning the construction of a combined cycle plant at its existing A.B. Brown Station (ABB) in Evansville, Indiana. This combined cycle configuration will utilize heat recovery steam generators (HRSG), combustion turbine generators and a single steam turbine generator to output 1,050 MW.

Condensate polishing is the process of purifying condensate before returning it to a boiler. Feedwater (condensate and boiler feed) contain various impurities. Corrosion products from the steam cycle, mostly iron, travel through the cycle and can concentrate in the boiler. Impurities in feedwater can affect HRSG performance and can be transported from the HRSG to the steam turbine, causing damage to piping and turbine components from pitting, corrosion, or scaling. They can inhibit heat transfer, cause hot spots and eventual failure of the boiler tubes. Additionally, they can carryover with the steam and degrade the steam purity to the level that it no longer meets the steam turbine suppliers steam purity guarantee requirements.

The water quality required for feedwater is defined by the HRSG manufacturers and is dependent on the unit cycling, chemistry program, and operating pressure of the plant. High pressure (1500 psi or greater) drum boilers have stringent feed water quality requirements in order to meet the steam turbine suppliers steam purity guarantee. Drum boilers meet theses water quality requirements by blowdown to eliminate impurities from the cycle and making up with fresh demineralized water. Condensate polishing provides a means to minimize blowdown and better ensure boiler water quality requirements.

In addition to improving condensate/feed water quality, condensate polishers can decrease unit startup time by minimizing chemistry related delays, minimize impacts of condenser leaks, and reduce frequency of boiler chemical cleaning. Consequently, condensate polishers are a worthy consideration in most high pressure steam cycle units, especially cycling units designed with rapid start.

## 1.2 EVALUATION OBJECTIVE

The purpose of this study is to:

- Identify the selection criteria for condensate polishing and determine if/which criterion is applicable to the project.
- Evaluate the capital costs associated with condensate polishing.

The following evaluation reports should be viewed in conjunction with this document:

- 41.1207H – Number of Cold, Warm and Hot Starts Analysis
- 41.1203H – Fast Start vs. Conventional Start Analysis
- 41.1217H – Demin Water Analysis Evaluation.

# 2.0 Condensate Polishing

## 2.1 SELECTION CRITERIA

Figure 1 below is a flow chart used to confirm whether or not condensate polishing is necessary in the power plant design basis. The primary and secondary factors shown in Figure 1 are used to identify, if necessary, which type of condensate polisher is to be used based on the parameters of the unit; Deep Bed type or Pre-coat type polishers.

**Figure 1 –Condensate Polisher Selection Flow Chart**

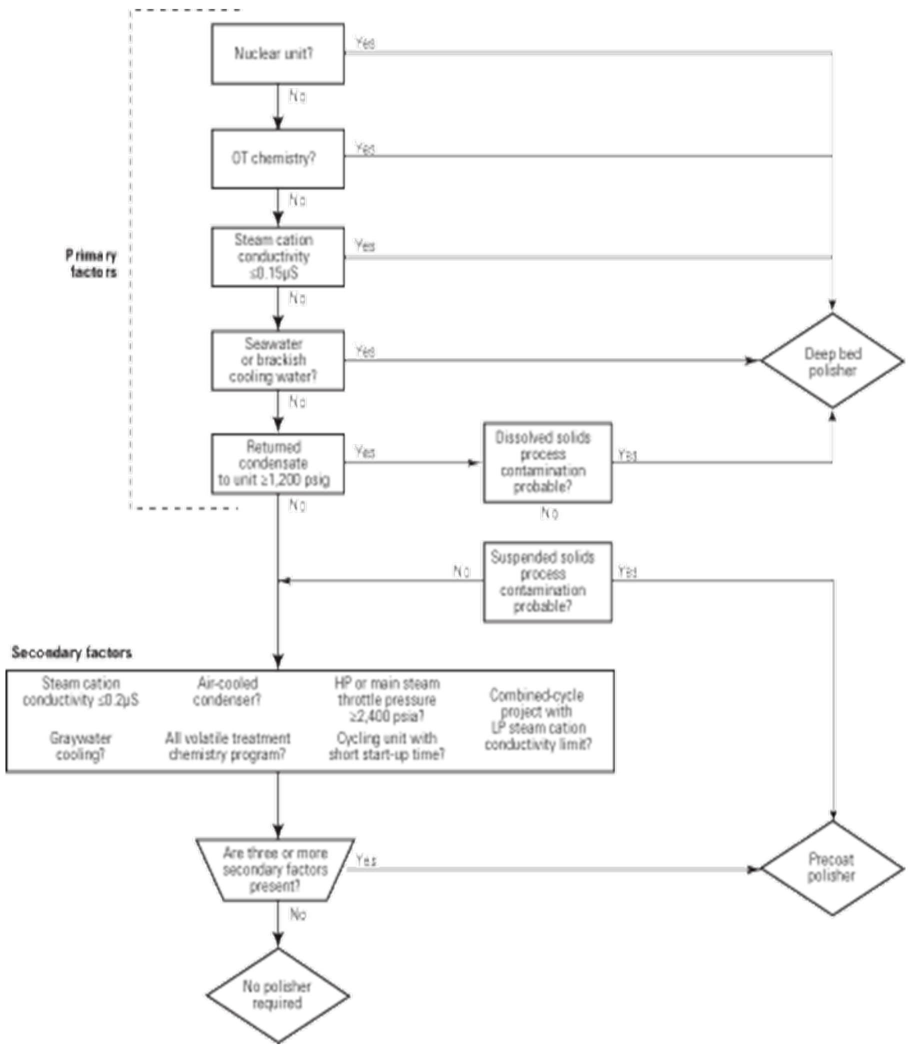



Table 1 reviews the criteria for deep bed type polishers listed and indicates if these factors apply to the project. If one or more of the selection criteria, or factors, apply to ABB, then deep bed condensate polishing should be considered.

### Table 1 – Deep Bed Condensate Polisher Selection Criteria

| DEEP BED POLISHER CRITERIA | A.B. BROWN COMBINED CYCLE PLANT |
|---|---|
| Nuclear Plant | No – Fossil Fuel |
| Oxygenated Treatment (OT) Cycle Chemistry | No – All-Volatile Treatment-Oxidizing with Phosphate |
| Steam Cation Conductivity <0.15uS/cm | No – 0.2uS/cm Allowed* |
| Seawater or Brackish Cooling Water | No – Surface Water, Well Water |
| Returned Condensate to unit >1200 psig | No - 400 psig |
| * GE Steam Purity for Industrial Turbine (Table 4 in document GEK 98965) | |

Based on the design parameters of the plant as shown in Table 1, deep bed condensate polishing would not be considered.

Table 2 reviews the criteria for pre-coat type polishers listed and indicates if these factors apply to the project. General industry practice is if three or more factors apply to ABB, pre-coat polishers should be strongly considered.

### Table 2 – Pre-Coat Condensate Polisher Selection Criteria

| PRE-COAT POLISHER CRITERIA | A.B. BROWN COMBINED CYCLE PLANT |
|---|---|
| Steam Cation Conductivity ≤0.2uS/cm | Yes – 0.2uS/cm Allowed* |
| Graywater Cooling | No – River Water |
| Air Cooled Condenser | No – Wet Surface Condenser |
| All-Volatile Treatment – Oxidizing Treatment (AVT-O) Cycle Chemistry | Yes – All-Volatile Treatment-Oxidizing with Phosphate (no oxygen scavenger) |
| HP/Main Stream Pressure >2,400 psig | Yes – HP/Main Steam >2,500 psig |
| Cycling with Short Start-up Time | Yes – Cycling Units with Rapid start |
| LP Steam Conductivity Limit | No |
| Suspended Solids (TSS) Process Contamination Possible | Yes – River water contains levels of TSS |
| * GE Steam Purity for Industrial Turbine (Table 4 in document GEK 98965) | |

As shown in Table 2, five factors are present in the current design of the project. As a result, pre-coat polishers or design provisions to include future polishers should be considered. The next sections review the benefits of the pre-coat polisher design.

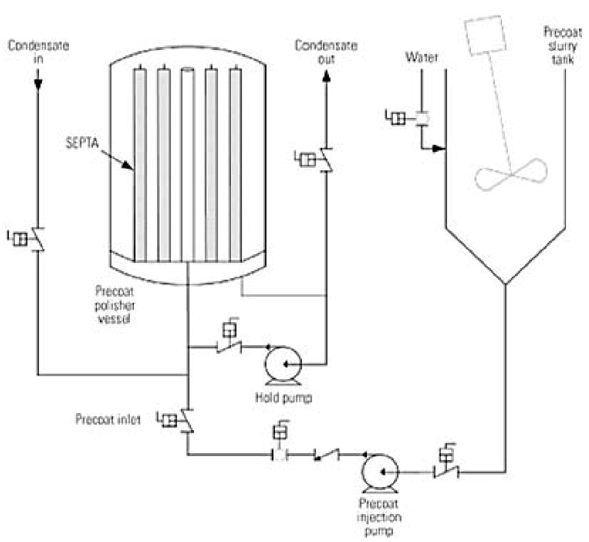
## 2.2 PRE-COAT TYPE CONDENSATE POLISHING

### 2.2.1 Overview

Pre-coat polisher is a vessel containing media-retaining filter elements. A powdered media is placed on the elements and the condensate is passed through the media coated filter element and returned to the condensate flow. Figure 2 shows a diagram of a Pre-coat polisher system.

These filter elements, combined with the ion exchanging media (powder coating), has the capability of simultaneous removal of total dissolved solids (TDS) and total suspended solids (TSS). Pre-coat polishers in particular, perform the dual purpose of straining the TSS particulates (iron oxides produced in the condensate system) and removing dissolved solids. Air in-leakage causes corrosion from oxygen pitting and to a lesser degree acidic attack from CO2. Not only does the oxygen damage the carbon steel surfaces but the iron oxides from this corrosion process, both soluble (TDS) and insoluble (TSS), will be transported into the heat recovery steam generator (HRSG) and will deposit on tube surfaces. Over time these deposits reduce unit efficiency, create an environment for under deposit corrosion (boiler tube failures) and necessitate the need for more frequent chemical cleanings.

**Figure 2 – Pre-Coat Polisher Diagram**




The condensate polisher improves condensate/feed water quality during steady state operations by minimizing the impacts of condenser leaks by the removal of dissolved solids and improves unit startup time by minimizing chemistry related delays by the removal of suspended solids.

### 2.2.2 Operational Impacts

Dissolved gases can enter the cycle as impurities in the makeup water as well as through air in-leakage to the condenser which is under vacuum. Dissolved gases, particularly uncontrolled oxygen and carbon dioxide, can cause corrosion in the cycle and are generally removed in the condenser and deaerator. However, carbon dioxide can accumulate in the condensate/feed water/boiler train because of its pH equilibrium chemistry and can only be effectively removed with condensate polishing. Particularly during startup and shutdown the condensate/feedwater cycle can and will be exposed to carbon dioxide and oxygen. Their corrosive effects on the carbon steel condensate/feedwater piping can be mitigated with the proper chemistry and blowdown over time, but a polishing unit greatly improves the amount of time necessary to reach optimal cycle chemistry.

If left untreated or detected, these impacts will lead to any number of issues including boiler tube failures, damage to the steam turbine and condenser tube failures.

A condensate polisher is warranted for combined-cycle plants where the steam turbine cation conductivity limit is $\leq$ 0.2 µS/cm, and especially cycling units designed with rapid start. The cation conductivity of the condensate/feedwater stream can typically reach 0.5 to 0.6 µS/cm due to carbon dioxide absorption in the water. The GE steam turbine cation conductivity requirement for A.B. Brown is <0.2 µS/cm.

Without a condensate polisher, and in the event of a major feedwater chemistry excursion, typically a plant will either dump the "out-of-spec" water and re-fill the system with "in-spec" water or operate the feedwater system without generating steam until the boiler feedwater chemical treatment system brings the water back into spec.  Worst case scenario for ABB is dumping the approximate +100,000 gallons of water from the cycle (one HRSG's and condenser).

Utilizing condensate polishing can reduce the average cycle blowdown during both startup and normal operation to approximately 0.5%-1%.  For the ABB project, this blowdown reduction can save up to 1,000,000 gallons of demineralized water each year.  This is based on the estimated number of starts per year and capacity factor found in 41.1207F – Number of Cold, Warm and Hot Starts Analysis.  Condensate polishing can also potentially reduce the number of boiler chemical cleans over the 30 year expected life of the plant.

# 3.0 Risk AND Cost Analysis

## 3.1 RISK ANALYSIS

As stated in Section 3.0, there are several risks associated with operating a combined cycle plant with three or more of the selection factors present in the design. The risk of operating with poor steam/water quality can lead to boiler tube failures, condenser tube failures, and damage to the steam turbine. Table 3 below provides a high level risk analysis of not utilizing a condensate polisher unit.

**Table 3 – Risk Analysis Without Condensate Polishing**

| RISK | SEVERITY | OCCURANCE | DETECTION | LENGTH OF OUTAGE | OVERALL RISK FACTOR |
|---|---|---|---|---|---|
| Boiler Tube Failure | High | Medium | High | Medium | High |
| Steam Turbine Damage | High | Low | Low | High | Medium |
| Condenser Tube Failure | Medium | Medium | Medium | Medium | Medium |
| Overall risk factors are indications of estimated number of failure occurrences per year:<br>High = 1 occurrences/yr; Medium = 0.33 occurrences/yr; Low = 0.11 occurrences/yr | | | | | |

The overall risk factor provides an indication of estimated number of failure occurrences per year. A high overall risk will generally indicate one occurrence per year, while the occurrences per year drop to 33 percent and 11 percent for medium and low factors, respectively.

Utilizing a condensate polisher and a good chemical conditioning program can potentially drop the overall risk factor to the next lower tier for each type of failure.

## 3.2 COST ANALYSIS

A budgetary cost for a full 2x100% pre-coat condensate polishing system (with pre-coating skid, slurry pumps, air receiver, and resin/precoat recovery tank) is approximately [redacted]. An estimated [redacted] for installation, project management, and risk and contingency is used to determine the total installed cost.

### Table 4 – Cost Evaluation - Condensate Polishing

| PARAMETERS | 1X1 7HA.01 (FIRED) |
|---|---|
| Condensate Design Flow, gpm | [redacted] |
| Estimated Equipment Costs [redacted] | [redacted] |
| Total Installed Capital Cost [redacted] | [redacted] |

A temporary/mobile rental condensate polisher could be considered. [redacted]

# 4.0 Conclusions

## 4.1 SUMMARY OF CONCLUSIONS

This evaluation report has shown that:

- Five selection factors for Pre-coat condensate polishers are present in the current design of the project. General industry practice to consider polishing is three or more.
- Cycling with rapid startup and <0.2 µS/cm steam cation conductivity, are the two key selection factors that are a part of this project.
- Pre-coat condensate polishers have the capability of simultaneous removal of both TDS and TSS. TSS process contamination is a possibility with any cooling water tube leak utilizing river water makeup.
- The condensate polisher, in combination with a sound cycle chemistry scheme, protects all equipment components in the steam/feedwater cycle.

Based on the selection criteria identified in the summary report, Black & Veatch's recommendation is to include provisions for a future pre-coat type condensate polisher system in the conceptual design for the project. This includes, but not necessarily limited to, [redacted] allowance in condensate pump sizing, space allocation, spare electrical capacity and connections, and condensate discharge by pass piping connections.

Confidential

FINAL

# AUXILIARY COOLING WATER SYSTEM ANALYSIS

## A.B. Brown 1x1 H-Class

**B&V PROJECT NO. 400278**
**B&V FILE NO. 41.1215H**



**PREPARED FOR**

Vectren

31 JANUARY 2020

# Table of Contents



## LIST OF TABLES

# Executive Summary

In developing this report for the new Combined Cycle Power Plant (CCPP), Black & Veatch reviewed different design scenarios for the auxiliary cooling water system. It was determined that the design used for the auxiliary cooling water system on the existing units would not be practical for the CCPP. Three alternative designs were investigated:

- Alternative 1--Auxiliary cooling from makeup and circulating water.
- Alternative 2--Circulating water to cool the closed cycle cooling water equipment.
- Alternative 3--Circulating water to cool closed cycle cooling water equipment and hydrogen and lube oil coolers.

The performance, plant area required, reliability and maintenance, and cost of both shell and tube and plate and frame heat exchangers were considered in conjunction with the three alternatives for the auxiliary cooling water system. [redacted]

# 1.0 Introduction

Equipment throughout the plant is cooled by water. The source of this cooling water is through a closed loop system Closed Cycle Cooling Water (CCCW) or directly from an auxiliary cooling water source. This report looks at the sources for water for equipment cooling.

The existing plant cooling system is cooled by the raw water system. The raw water system consists of three (3) 3,300 gpm river water pumps which provide cooling water for the coal units closed cooling heat exchangers. The discharge from these existing heat exchangers is then routed to the cooling towers for makeup. The heat duty of the existing closed cycle cooling water system is minimized as the circulating water system directly provides cooling water flow to the generator hydrogen coolers and lube oil coolers.

In developing this report, Black & Veatch reviewed different design scenarios for the auxiliary cooling system for the new Combined Cycle Power Plant (CCPP). It was determined that the design used for the auxiliary cooling water system on the existing units would not be practical for the CCPP. Three alternative designs were investigated.

- The first alternative uses a combination of water from the cooling tower makeup to the cooling towers and circulating water to cool closed cycle cooling water equipment. Turbine hydrogen and lube oil coolers would be cooled directly from the cooling tower makeup.
- The second alternative uses circulating water to cool the closed cycle cooling water equipment. The closed cycle cooling water equipment provides cooling water to all equipment including the turbine hydrogen and lube oil coolers.
- The third alternative uses circulating water to cool the closed cycle cooling water equipment and the turbine hydrogen and lube oil coolers. This scenario differs from the second alternative as circulating water is used to directly cool the hydrogen and lube oil coolers.

This evaluation will evaluate the different alternatives looking at the system performance and cooling capability of the different cooling configurations.

# 2.0 System Performance – Cooling Capability

Table 2-1 provides a table listing the pros and cons of the different auxiliary cooling water arrangements

**Table 2-1 System Performance Capability**

| ARRANGEMENT | PROS | CONS |
|---|---|---|
| Aux Cooling Water from Raw Water Makeup | - | Not Practical for CCPP |
| Alternative 1 - Circulating water cools CCCW equipment. Aux Cooling Water cools Turbine Lube Oil and Hydrogen Cooling. | Cooler auxiliary cooling water temps.<br>Smaller circulating water pumps.<br>Smaller CCCW system. | Long, large diameter stainless pipe runs to generators.<br>Warmer makeup to cooling tower.<br>Specialized OEM heat exchangers. |
| Alternative 2 - Circulating water cools CCCW. CCCW cools all equipment. | Standard OEM heat exchangers.<br>Typical CCPP design.<br>Minimizes piping costs. | Warmer circulating water temps.<br>Larger circ water pumps. |
| Alternative 3 - Circulating water cools CCCW equipment. Circulating water cools Turbine Lube Oil and Hydrogen Cooling. | Cooler auxiliary cooling water temps.<br>Smaller circulating water pumps.<br>Smaller CCCW system. | Long, large diameter stainless pipe runs to generators.<br>Warmer makeup to cooling tower.<br>Specialized OEM heat exchangers. |

## 2.1 ALL AUXILIARY COOLING FROM RAW WATER MAKEUP

The existing raw water makeup pumps consist of three (3) pumps each having a rated a flow capability of 3,300 gpm at 176 ft of head. To maintain a N+1 sparing philosophy, two pumps would be operating and one pump would be in standby providing a cooling water flow of 6,600 gpm since pressure drop to the new cooling tower is expected to be similar to that the existing system.

If the raw water system provides all of the cooling water for the combined cycle, the temperature rise across the heat exchangers would result in an elevated summer make up temperature to the cooling tower not considered acceptable with the cooling tower fill. To limit the temperature rise across the heat exchanger, it is recommended to use the circulating water system instead of the river water for a minimum of the cooling the generator hydrogen coolers and lube oil coolers.

## 2.2 ALTERNATIVE 1 – AUX COOLING FROM MAKEUP AND CIRC WATER

For Alternative 1, most auxiliary cooling water would be supplied from the river water make up to cool the closed cycle cooling water system while the generator hydrogen coolers and lube oil coolers would be cooled from the circulating water system directly. This scenario would result in a temperature rise for the makeup water system to match the hot water returning from the cooling tower. The temperature rise to the generator hydrogen coolers and lube oil coolers would be designed to match the circulating water temperature rise across the condenser; additional flow to the circulating water system to cool the steam turbine and combustion turbine generator hydrogen coolers and lube oil coolers would be about 3,800 gpm.

Due to the corrosive nature of the circulating water system stainless steel pipe would be required for the piping runs to the generator hydrogen coolers and lube oil coolers. The design for the combustion turbine generator hydrogen coolers and lube oil coolers would need to be coordinated with OEMs. The surface area of these coolers would be approximately twice the size of the standard design to limit the pressure drop across the heat exchanger as needed to match the pressure drop across the condenser as to not adversely impact the circulating water system design. The advantage to supplying cooling water directly from circulating water is that auxiliary cooling water to the generator hydrogen and lube oil coolers is 10°F cooler than if supplied from the closed cycle cooling water system.

## 2.3 ALTERNATIVE 2 – CIRC WATER COOLS CCCW

A typical design for combined cycle plants is to supply the auxiliary cooling water from the circulating water system. Under this design, circulating water would be supplied to the closed cycle cooling water system. The design of the closed cycle cooling water heat exchangers would limit the temperature rise of the circulating water to match the temperature rise of the circulating water across the condenser; the auxiliary cooling water flow would be sized as required to reject the heat of the closed cycle cooling water system. The cold water temperature of the CCCW would have a design temperature of 105°F; this is standard for equipment provided on combined cycle power plants. Circulating water flow to supply auxiliary cooling water system would be about 6,0 00gpm.

## 2.4 ALTERNATIVE 3 – CIRC WATER COOLS CCCW AND HYDROGEN AND LUBE OIL COOLERS

If the 105°F cooling water is a concern for the generator hydrogen and lube oil coolers and hydrogen coolers, they could be cooled directly from the circulating water system. The design for the combustion turbine generator hydrogen coolers and lube oil coolers would need to be coordinated with OEMs. The surface area of these coolers would be approximately twice the size of the standard design to limit the pressure drop across the heat exchanger as needed to match the pressure drop across the condenser as to not adversely impact the circulating water system design. Circulating water flow to supply auxiliary cooling water system would be about 2,000 gpm.

# 3.0 Conclusions

Since the existing raw water pumps that provide makeup to the cooling tower do not have sufficient flow to meet the requirements of the new combined cycle, a new cooling water arrangement utilizing circulating water is recommended. Since the turbine manufacturers design their heat exchangers including turbine lube oil and hydrogen coolers for cooling water up to 105°F and the CCCW system is designed to meet this condition under the extreme hot summer day, Alternative 2 with all equipment cooling water coming from the CCCW system as it is the lowest cost and allows the use of standard OEM equipment.

Confidential

**FINAL**

# DEMIN WATER USAGE ANALYSIS

## A.B. Brown 1x1 H-Class

**B&V PROJECT NO. 400278**
**B&V FILE NO. 41.1217H**



**PREPARED FOR**

VECTREN
A CenterPoint Energy Company

Vectren

31 JANUARY 2020

BLACK & VEATCH

# Table of Contents



## LIST OF TABLES

# Executive Summary

In developing this report, Black & Veatch reviewed the requirements for demineralized water for the new Combined Cycle Power Plant (CCPP). Black & Veatch reviewed multiple pre-start, start-up and steady state scenarios to determine the required sizing and operation of the demineralized water system. Demineralized water storage capacity was evaluated in parallel with system operation. Black & Veatch evaluated water usage based on 1x1 7HA.01 gas turbines for this analysis:

The demineralized water system users have been summarized in the steady state demands provided in Table 2-1. Plant pre-start demands have been summarized in Table 2-2 and plant startup demands have been summarized in Table 2-3. For all scenarios, the difference between water demand and existing system capacity is compared. Based on the demineralized water requirements for the multiple scenarios, it is recommended that Vectren utilize an additional water treatment system with a water capacity of [redacted] gpm per Table 3-1. No additional demineralized water storage capacity is required.

# 1.0 Introduction

The purpose of this study is to determine the specific requirements for demineralized water with the new Combined Cycle Power Plant (CCPP). Based on steady state operation, the existing cycle makeup treatment system can meet water demand. However, during startup and steady state operation with the evaporative cooler in operation, water demand exceeds the existing system capacity. The following tables detail differences in water demand for each configuration and condition.

# 2.0 Demineralized Water System Operation Demands

The demineralized water system provides water to various users during plant startup and shutdown at multiple operating conditions. Several operating scenarios were evaluated to determine the maximum water usage for the demineralized water system. Plant pre-start activities, plant startup, and plant steady state operation was evaluated for maximum demineralized water demand. The existing demin water treatment system capacity is [redacted] gpm. Demineralized water storage will need to be sufficient to hold three (3) days storage of the CCPP steady state demineralized water demand without evaporative cooling water makeup. Demin water demands excluded in this steady state operation are evaporative cooler makeup for the CCPP, CT#3 water injection and existing Unit 3 and 4 steam cycle demands.

## 2.1 STEADY STATE AND NON-STEADY STATE DEMANDS

The steady state demineralized water demand occurs during operation when supplying makeup water for CCPP blowdown and sampling losses. Non-steady state demineralized water demands occur during operation when supplying makeup water for steady state CCPP users plus evaporative cooler operation, existing unit operation and CT#3 water injection operation. Demineralized water demands are shown in Table 2-1. Steady state operation assumes 2% blowdown per the water mass balances. Steady state flows are based on Hot Day Case (93.7F) heat balance. Due to the infrequent operation of existing units and CT#3, storage volume recommendations will account for the excursion in steady state demand for demineralized water.

**Table 2-1 Demineralized Water Demands**

| DEMIN WATER USERS | 1X1 7HA.01 |
|---|---|
| **STEADY STATE DEMANDS** | |
| 2% blowdown (gpm) | [redacted] |
| Sample Analytics (gpm) | [redacted] |
| Demand w/o Evaporative Cooler Makeup (gpm) | [redacted] |
| **NON-STEADY STATE DEMANDS** | |
| Existing Unit 3 steam cycle demands (gpm) | [redacted] |
| Evaporative Cooler Makeup on RO Permeate (gpm) | [redacted] |
| Demand w/ Evaporative Cooler Makeup @ 6 COC (gpm) | [redacted] |
| CT #3 Water Injection | [redacted] |
| Instantaneous Demand for Steady State Operation with CT#3 water injection (1) | [redacted] |
| [redacted] | |

## 2.2 PRE-START DEMANDS

During unit pre-start, the auxiliary boiler is used to warm the HRSG and steam turbine seals. The assumption of 2% blowdown on the auxiliary boiler during this operation is included. During this operation, it is assumed all water is non recoverable. The pre-start usage demands are listed in Table 2-2.

**Table 2-2 Demineralized Water Demands during Pre-Start Activities**

| PRESTART USAGE | 1X1 7HA.01 |
|---|---|
| Aux Boiler Makeup (gpm) HRSG warming | [redacted] |
| Difference (gpm) - Existing | [redacted] |
| Difference (gpm) - Proposed new | [redacted] |

## 2.3 STARTUP DEMANDS

During unit startup, demineralized water usage is at the maximum. HRSG is warm and the condenser sparging and gland steam flows are recovered in the condenser. Steam drains are open until superheat targets are met. 5% blowdown is utilized for startup. The demineralized water demands are listed in Table 2-3.

**Table 2-3 Demineralized Water Demands During Startup Activities**

| STARTUP DEMAND | 1X1 7HA.01 |
|---|---|
| Aux Boiler Makeup Fast Start (gpm) | [redacted] |
| Steam Drains to HRSG Blowdown Tank (gpm) | [redacted] |
| Blowdown (gpm) | [redacted] |
| Total Instantaneous Startup Demand (gpm) | [redacted] |
| Difference (gpm) | [redacted] |
| Difference (gpm) - Proposed new | [redacted] |
| Hot start lost capacity (gallons) (1) | [redacted] |
| Warm start lost capacity (gallons) (1) | [redacted] |
| Cold start lost capacity (gallons) (1) | [redacted] |
| Time to replace lost capacity during normal op (Hot Start), min | [redacted] |
| Time to replace lost capacity during normal op (Warm Start), min | [redacted] |
| Time to replace lost capacity during normal op (Cold Start), min | [redacted] |
| [redacted] | |

# 3.0 Demineralized System

## 3.1 WATER REPLENISHMENT

The demineralized water system provides minimal margin for replenishment from startup of the combined cycle. For a typical combined cycle plant, the rule of thumb for storage is 3 days of steady state demand capacity. This relates to a 3 day outage on the demin supply. Table 3-1 details the time to replenish demineralized water capacity.

**Table 3-1 Demineralized Water Volumes and Treatment Capacities**

| DEMINERALIZED WATER SYSTEM | 1X1 HA.01 |
|---|---|
| **STORAGE CAPACITY** | |
| Existing Demin storage (gallons) | [redacted] |
| 3 day Demin storage capacity required @ steady state demand | [redacted] |
| Storage Surplus (+) / Storage Deficient (-) during a 3 day outage. | [redacted] |
| Recommended Additional Demin Storage (gallons) (1) | [redacted] |
| **STEADY STATE TREATMENT DEMAND** | |
| Current Demin Water Treatment Capacity (gpm) | [redacted] |
| CCPP Steady State Demand (gpm) | [redacted] |
| Treatment Surplus (+) / Deficient (-) (gpm) | [redacted] |
| **NON-STEADY STATE TREATMENT DEMAND** | |
| Current Demin Water Treatment Capacity (gpm) | [redacted] |
| CCPP Non- Steady State Demand (gpm) | [redacted] |
| Treatment Surplus (+) / Deficient (-) (gpm) | [redacted] |
| **PEAK TREATMENT DEMAND** | |
| Current Demin Water Treatment Capacity (gpm) | [redacted] |
| CCPP Peak (CT#3 + Non- Steady State) Demand (gpm) | [redacted] |
| Treatment Surplus (+) / Deficient (-) (gpm) | [redacted] |
| **PROPOSED ADDITIONAL DEMINERALIZED WATER TREATMENT CAPACITY (GPM)** | [redacted] |
| Treatment Surplus (+) / Deficient (-) (gpm) | [redacted] |
| Recover 3 day outage volume, Steady state after (HOURS) | [redacted] |
| Recover 3 day outage volume, Non-Steady state after (HOURS) | [redacted] |
| [redacted] | |

[redacted]

Based on Black & Veatch's evaluation, the existing demineralized water storage capacity can provide sufficient storage of demineralized water based on the design parameters. Furthermore, a new demineralized water treatment system sized to supplement [redacted] gpm (coupled with the existing [redacted] gpm system) would be sufficient to meet various operating demands of the facility as well as replenish demineralized water volume within the design parameters.

# 4.0 Conclusions

Based on the evaluation Black & Veatch can conclude:

- The existing demineralized water storage capacity provides adequate storage of demineralized water based on the design parameters.
- A new demineralized water treatment system sized to supplement [redacted] (coupled with the existing [redacted] system) would be sufficient to meet various operating demands of the facility as well as replenish demineralized water volume within the design parameters.

Confidential

FINAL

# BLACK START ANALYSIS

## A.B. Brown 1x1 H-Class

**B&V PROJECT NO. 400278**
**B&V FILE NO. 41.1221H**



**PREPARED FOR**

VECTREN
A CenterPoint Energy Company

Vectren

31 JANUARY 2020

BLACK & VEATCH

# Table of Contents



## LIST OF TABLES



## LIST OF FIGURES

# Executive Summary

In developing this report for the new Combined Cycle Power Plant (CCPP), Black & Veatch examined the capability of using the existing combustion turbine generator (CTG) peaking Unit 3 at A.B. Brown as a means of black starting CTG 5 of the new CCPP

Unit 3 is a GE 7EA turbine capable of operating with either natural gas or distillate fuel oil as the fuel source. Two scenarios were modeled for this evaluation:

- Starting of the largest medium voltage induction motor with all necessary auxiliary electric loads in operation.
- Static starting of CTG 5 with all necessary auxiliary electric loads in operation.

For analysis modeling purposes, the aggregate auxiliary electrical load necessary to start a combustion turbine were based on the preliminary conceptual design of the new CCPP. In addition, the excitation system was assumed to be capable of providing the necessary reactive power required by the simulated scenarios while maintaining 100 percent system voltage at a frequency of 60 Hz at the generator terminals.

Within the boundaries of this evaluation, the Unit 3 generator at A.B. Brown appears to be capable of black starting one combustion turbine of the new CCPP. Further analysis would be required to verify that generator control and system protection would permit synchronization of the Unit 5 generator to the Unit 3 generator to shift auxiliary electrical loads from the Unit 3 generator to the Unit 5 generator.

# 1.0 Introduction

The purpose of this evaluation is to examine the capability of the existing combustion turbine generator peaking Unit 3 at A.B. Brown to be utilized as a black starting means for the new combined cycle power plant (CCPP). Unit 3 is a GE 7EA turbine capable of operating with either natural gas or distillate fuel oil as the fuel source. The unit has a dedicated diesel generator and starting motor necessary to start. Unit 3 is utilized as a black starting means for existing A.B. Brown coal-fired Units 1 and 2.

Electrical power system analysis software ETAP was utilized to model and evaluate Unit 3 to verify the capability of black starting CTG 5 of the new CCPP. Figure 1-1 provides the one line diagram that was modeled in ETAP. Two scenarios were modeled for this evaluation, starting of the largest medium voltage induction motor with all necessary auxiliary electric loads in operation, and static starting of CTG 5 with all necessary auxiliary electric loads in operation.

[redacted]

[redacted]

# 2.0 Assumptions

In order to simulate the scenarios included in this evaluation, reasonable assumptions were made in order to model and simulate the black start capability. The assumptions are defined as follows.

## 2.1 LOAD LIST

It is necessary to determine the aggregate auxiliary electrical load that is necessary to start a combustion turbine of the new CCPP. Table 2-1 provides the load list of all loads considered to be in operation to support the black start. Except ACWP, BFP, CWP, CCWP & CP (major loads), all other loads were modeled as a lump load. For lump load motor power factor of 85% has been considered. A 20 percent margin was added to the lump loads of Table 2-1 for modeling purposes. The loads of Table 2-1 are based on the conceptual design of the new CCPP and are preliminary. All cooling tower fans and CWP have been modeled to show to feed from 6.9kV BUS A & existing 4.16kV BUS 1B respectively.

**Table 2-1 Operating Loads during CCPP Starting**

| BLACK START ANALYSIS LOAD LIST | | | |
|---|---|---|---|
| LOAD | LOAD TYPE | LOAD RATING | LOAD UNITS |
| [redacted] | [redacted] | [redacted] | [redacted] |
| [redacted] | [redacted] | [redacted] | [redacted] |
| [redacted] | [redacted] | [redacted] | [redacted] |
| [redacted] | [redacted] | [redacted] | [redacted] |
| [redacted] | [redacted] | [redacted] | [redacted] |
| [redacted] | [redacted] | [redacted] | [redacted] |
| [redacted] | [redacted] | [redacted] | [redacted] |
| [redacted] | [redacted] | [redacted] | [redacted] |
| [redacted] | [redacted] | [redacted] | [redacted] |
| [redacted] | [redacted] | [redacted] | [redacted] |
| [redacted] | [redacted] | [redacted] | [redacted] |
| [redacted] | [redacted] | [redacted] | [redacted] |
| [redacted] | [redacted] | [redacted] | [redacted] |
| [redacted] | [redacted] | [redacted] | [redacted] |
| [redacted] | [redacted] | [redacted] | [redacted] |

| BLACK START ANALYSIS LOAD LIST | | | |
|---|---|---|---|
| LOAD | LOAD TYPE | LOAD RATING | LOAD UNITS |
| [redacted] | [redacted] | [redacted] | [redacted] |
| [redacted] | [redacted] | [redacted] | [redacted] |
| [redacted] | [redacted] | [redacted] | [redacted] |
| [redacted] | [redacted] | [redacted] | [redacted] |
| [redacted] | [redacted] | [redacted] | [redacted] |
| [redacted] | [redacted] | [redacted] | [redacted] |
| [redacted] | [redacted] | [redacted] | [redacted] |
| [redacted] | [redacted] | [redacted] | [redacted] |
| [redacted] | [redacted] | [redacted] | [redacted] |
| [redacted] | [redacted] | [redacted] | [redacted] |
| [redacted] | [redacted] | [redacted] | [redacted] |
| [redacted] | [redacted] | [redacted] | [redacted] |
| [redacted] | [redacted] | [redacted] | [redacted] |
| [redacted] | [redacted] | [redacted] | [redacted] |
| [redacted] | [redacted] | [redacted] | [redacted] |
| [redacted] | [redacted] | [redacted] | [redacted] |
| [redacted] | [redacted] | [redacted] | [redacted] |
| [redacted] | [redacted] | [redacted] | [redacted] |
| [redacted] | [redacted] | [redacted] | [redacted] |
| [redacted] | [redacted] | [redacted] | [redacted] |
| [redacted] | [redacted] | [redacted] | [redacted] |
| [redacted] | [redacted] | [redacted] | [redacted] |
| [redacted] | [redacted] | [redacted] | [redacted] |
| [redacted] | [redacted] | [redacted] | [redacted] |
| [redacted] | [redacted] | [redacted] | [redacted] |
| [redacted] | [redacted] | [redacted] | [redacted] |
| [redacted] | [redacted] | [redacted] | [redacted] |
| [redacted] | [redacted] | [redacted] | [redacted] |

| BLACK START ANALYSIS LOAD LIST | | | |
|---|---|---|---|
| LOAD | LOAD TYPE | LOAD RATING | LOAD UNITS |
| [redacted] | [redacted] | [redacted] | [redacted] |
| [redacted] | [redacted] | [redacted] | [redacted] |
| [redacted] | [redacted] | [redacted] | [redacted] |
| [redacted] | [redacted] | [redacted] | [redacted] |
| [redacted] | [redacted] | [redacted] | [redacted] |

## 2.2 UNIT 3 EXCITATION SYSTEM

This study does not include analysis of the excitation model or transfer function for Unit 3. Therefore, the excitation system is fixed in the ETAP simulation. Additional modeling of the excitation system and transfer function would be necessary in order to more accurately simulate the response to the reactive power demands imposed when black starting one combustion turbine generator of the new CCCP, however, the excitation system is assumed to be capable of providing the necessary reactive power required by the simulated scenarios while maintaining 100 percent system voltage at a frequency of 60 Hz at the generator terminals, as long as the real and reactive demands on the Unit 3 generator do not exceed the limits of the reactive capability curve.

## 2.3 PROTECTION, CONTROL AND SYNCHRONIZATION

It is recommended during the detailed design phase that the turbine control system of the new CCPP is designed to be capable of allowing the new combustion turbine generator to synchronize with Unit 3 and that existing and new protection schemes are designed to permit synchronization. It also recommended during the detailed design phase that the control system of the existing Unit 3 combustion turbine generator is verified or modified as necessary to permit load sharing of the auxiliary electrical demands of the new CCPP. No investigation into the existing Unit 3 control system or switchyard protection schemes has been performed in support of this black start capability evaluation.

# 3.0 Static Motor Starting of Largest Motor

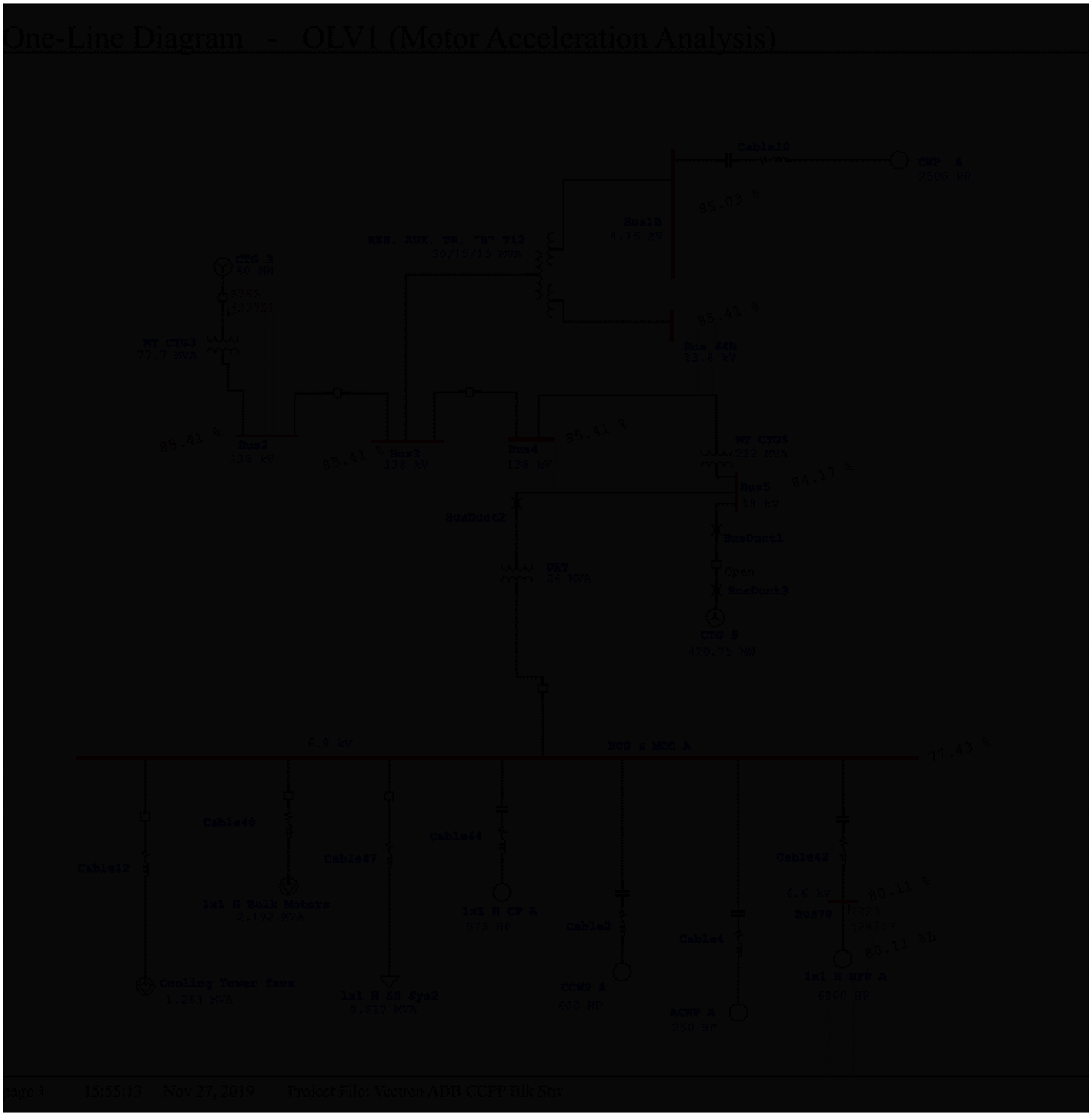
The starting of a large motor can have a brief, but significant, impact on the auxiliary electrical system. When voltage is applied to the terminals of an at rest motor, the motor will draw locked-rotor current (LRA), which decays toward full-load amps (FLA) as the motor approaches running speed. This is the result of the motor torque overcoming the combined inertia of the motor and the connected load. For an induction motor, a typical value of LRA is approximately 650 percent of FLA.

In the scenario of the black start, motor starting can result in voltage and frequency sags at the generator output, which will have a corresponding impact on the capability of the motor to start and to the existing loads in operation. The ability of the generator to accommodate starting of large motors is dependent upon the generator capacity, the response of the excitation system, the rotating inertia of the generator and the characteristics of the motor at starting. Should a sag in voltage during motor starting result in the motor's inability to develop the torque necessary to accelerate to full speed, the motor could stall. It is necessary to analyze the worst-case motor starting scenario for the purpose of determining the black start capability of the Unit 3 generator.

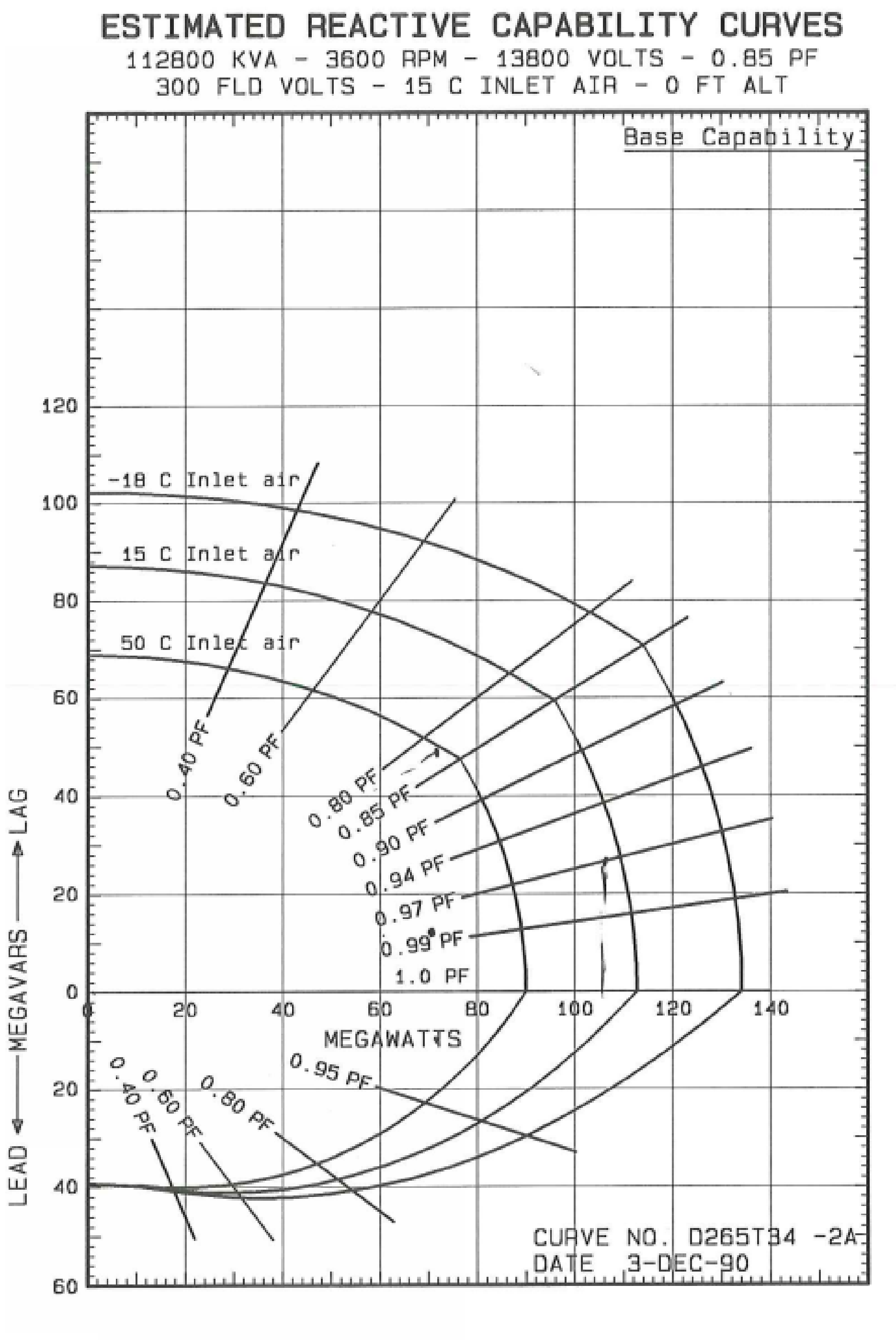
As a worst-case scenario, static motor starting of the Boiler Feed Pump, the largest medium voltage motor, was analyzed with all other loads necessary for a black start in operation, with the exception of the Unit 5 generator static starting system. Static motor starting models the motor by locked-rotor impedance during acceleration, simulating the worst impact to loads in operation at the time of motor starting. The properties of the modeled Boiler Feed Pump is 6900 HP, 6.6 kV, 510 FLA, 0.93 power factor, 94 percent efficiency and 6.5 pu LRA.
Figure 3-1 provides the bus voltage, as a percent of nominal, at each bus during starting of the Boiler Feed Pump. The Watt and VAR demand from the Unit 3 generator and the starting motor are also displayed.

The maximum demand from the Unit 3 generator during starting of the Boiler Feed Pump is 8.58 MW and 33.75MVAR. This is well within the capability curve of the Unit 3 generator, considering a 0.85 lagging power factor and 15 degrees Celsius inlet air temperature, as depicted in Figure 3-2. The worst-case motor terminal voltage during starting of the Boiler Feed Pump is 80.11 percent of nominal system voltage. It is typical to specify medium voltage motors rated to start at 80 percent of nameplate voltage. It is also typical to specify motor nameplate voltage below nominal system voltage. In the case of a nominal 6.9 kV system, the corresponding motor nameplate is 6.6 kV, consistent with ANSI C84.1. The result of the static motor starting analysis for the Boiler Feed Pump indicates that the momentary sag in voltage at the motor terminals is not prohibitive to the starting of the motor. The worst-case bus voltage for the BUS & MCC A is 77.43 percent during starting of the Boiler Feed Pump. This will not result in drop out of motor contactors since the nominal bus voltage is above 70%. All other medium voltage motors connected to BUS & MCC A (6.9kV) were considered to be running in this scenario. The bus voltage of BUS & MCC A recovers to 99.92 percent of nominal system voltage once the Boiler Feed Pump has accelerated to rated speed.

UAT impedance have been modeled with 6.5% for this study. The short circuit current level will be well below 40kA for 6.9kV SWGR and MCC A. UAT primary tap position has been set at -2.5% in order to achieve motor terminal voltage of higher than 80%. There is a possibility of further reducing UAT 5 impedance and motor locked rotor amperes to improve starting motor terminal voltage if necessary. A 3-3/C-500kcmil conductor has been considered to feed the BFP during this study.



[redacted]




## Figure 3-2 Unit 3 Generator Reactive Capability Curve

# 4.0 CTG 5 Static Starting Load Flow

A load flow model was analyzed during the static starting of the Unit 5 combustion turbine generator. This scenario considered all loads necessary for black starting to be in operation at the time the static starting system was energized. The maximum demand from the Unit 3 generator during static starting of Unit 5 CTG is 11.39 MW and 6.57 MVAR. This is well within the capability curve of the Unit 3 generator, considering a 0.85 lagging power factor and 15 degrees Celsius inlet air temperature, as depicted in Figure 3-2.

The worst-case bus voltage during operation of the static starting system on 6.9 kV BUS and 4.16kV BUS 1B will be 99.92 & 98.72 percent of nominal system voltage. This is well within the normal operating 'voltage range A' as per ANSI C84.1 and not considered to be a prohibitive impact to operation during black start. Additionally, the static starting system operates for a short duration until the combustion turbine reaches approximately 90 percent of rated speed, at which point it is self-sustaining and the static starting system is removed from operation and the turbine control system receives control of the turbine. This duration is approximately 30 minutes or less, dependent upon starting conditions with respect to the purging of combustible gases from the hot gas path prior to ignition.

[redacted]

[redacted]

# 5.0 Conclusions

The analyses performed in support of the black starting capabilities of the existing Unit 3 generator at A.B. Brown indicate that the generator has sufficient capacity to provide the required real and reactive power necessary to start the largest medium voltage motor as well as operate the static starting system of the new CCPP. The starting of the Boiler Feed Pump was simulated as a worst-case scenario, with all other loads necessary to support a black start in operation with the exception of the static starting system. Motor terminal voltage and bus voltages were maintained within reasonable limits for the scenario of a black start. Power requirements to support Boiler Feed Pump starting and the static starting system operation were within the capability curve of the Unit 3 generator. Both analyses assume that the Unit 3 generator excitation system is capable of responding appropriately to meet the reactive power needs, and further analysis with the excitation system modeled is necessary to confirm this response. Additionally, further analysis would be required to verify generator control and system protection would permit synchronization of the Unit 5 generator to the Unit 3 generator in order to shift auxiliary electrical loads from the Unit 3 generator to the Unit 5 generator. Within the boundaries of this evaluation, the Unit 3 generator at A.B. Brown appears to be capable of black starting the combustion turbine of the new CCPP.

Confidential

FINAL

# SWITCHYARD EVALUATION AND SEQUENCE

## A.B. Brown 1x1 H-Class

B&V PROJECT NO. 400278
B&V FILE NO. 41.1222H



PREPARED FOR

VECTREN
A CenterPoint Energy Company

Vectren

31 JANUARY 2020

BLACK & VEATCH

# Table of Contents



## LIST OF TABLES

# Executive Summary

In developing this report, Black & Veatch evaluated the suitability of the existing A.B. Brown 138 kV switchyard for interconnection of a new combustion turbine generator (CTG) and steam turbine generator (STG) operating as a 1x1 Combined Cycle Power Plant (CCPP). This evaluation was performed with existing Unit 2 remaining in operation. Black & Veatch considered preliminary heat balance data for a GE 7HA.01 CCPP as a conservative approach to this evaluation. Switchyard connections and connection sequence were also evaluated.

The continuous current loading of the 3000 Ampere (A) main buses 1 and 2 as well as the 2000 A interpass conductors are not exceeded for the switchyard configurations evaluated. The loading evaluation does not identify any major bus work necessary to independently connect the generators associated with the 1x1 CCPP.

As a result of the available fault current contribution at the existing 138 kV switchyard exceeding 40 kiloampere (kA), with new generation and Unit 2 in service, circuit breakers with a symmetrical interrupting rating 40 kA require replacement. Of the existing 20 circuit breakers in the 138 kV switchyard, 13 are rated 40 kA. [redacted] Therefore, it is recommended to replace all existing circuit breakers in the 138 kV switchyard with 63 kA symmetrical withstand and interrupting rating.

[redacted]

# 1.0 Introduction

The A.B. Brown 1x1 CCPP is a multi-shaft arrangement, with the combustion turbine (CT) and steam turbine (ST) individually coupled to dedicated generators rated to convert maximum turbine capabilities to electric power. The multi-shaft arrangement differs from a single shaft arrangement, with respect to electrical equipment, in that independent generators coupled to each turbine will transmit electric power via dedicated isolated phase bus duct (IPBD) to dedicated generator step-up transformers (GSU). Each GSU is sized to permit maximum real electric power to be transmitted to the electric power grid, with minimal losses, and to permit reactive electric power to be delivered to and absorbed from the electric power grid. Each turbine generator will also provide source power to 100 percent redundant unit auxiliary transformers (UAT). The high voltage side of each GSU will be independently connected to the existing 138 kV switchyard. Interconnection of the CTG and STG to the existing 138 kV switchyard requires consideration of fault current availability and system load flow relative to existing equipment ratings. Black & Veatch considered preliminary heat balance data for a GE 7HA.01 CCPP as a conservative approach for this evaluation. Configurations of a 1x1 CCPP comprised of turbine classes with lower gross megawatt (MW) output will result in additional margin with respect to switchyard loading and fault current. Each of the new generators were modelled with independent connections to the existing 138 kV switchyard, with Unit 2 remaining in operation.

The method of connection for each generator in a given configuration to the existing 138 kV switchyard is based upon the electrical ratings of the switchyard components, switchyard expansion capability, and operation of existing units. The existing 138 kV switchyard is a breaker and a half configuration with two main buses, rated 3000 A continuous [redacted] 13 of the 20 existing circuit breakers in the 138 kV switchyard are rated to interrupt 40 kA.

# 2.0 Switchyard Evaluation

## 2.1 LOAD FLOW

The interpass connections between Bus 1 and Bus 2 are rated 2,000 A, therefore a single connection to the switchyard is acceptable when the kilowatts (kW) transmitted remain below 430,000 kW at a power factor equal to 0.9. For a single connection above 430,000 kW and less than 645,000 kW, upgrades are required to the entire 138 kV switchyard, such as circuit breaker and disconnect switch replacement with 3000 A continuous rating. Generation exceeding 645,000 kW at a single connection point is not practical at a voltage level of 138 kV as equipment rated above 3000 A continuous is typically not available.

The maximum CTG and STG gross output based on the preliminary fired GE 7HA.01 1x1 considered for this evaluation are 331,500 kW and 243,950 kW and correspond to approximately 1201 A and 884 A, respectively. Detailed load flow modelling of the 138 kV switchyard with case permutations of outgoing transmission lines in and out of service is necessary in order to verify the suitability of the 138 kV switchyard to accommodate the connection of two CTGs and identify any overload cases. Initial analysis indicates that the 138 kV switchyard is generally suitable to accommodate independent connection of the new 1x1 CTG and STG while Unit 2 remains in operation.

The maximum current flow in the main and interpass busses for each analyzed case are represented in Table 2-1.

**Table 2-1 Max Load in Main and Interpass Buses - 2026 Summer Peak**

| Case | Current in 3kA Main Bus (A) | Percent Loading (%) | Current in 2kA Interpass (A) | Percent Loading (%) |
|---|---|---|---|---|
| All In Service | 1119 | 37.30 | 633.2 | 31.66 |
| Bus 1 Outage | 2017.4 | 67.25 | 1044.5 | 52.23 |
| Bus 1 and Line Z95 Outage | 2320.1 | 77.34 | 1228.5 | 61.43 |
| Bus 1 and Line Z96 Outage | 2169.9 | 72.33 | 1139.3 | 56.97 |
| Bus 1 and Line Z94 Outage | 2490.6 | 83.02 | 1189.5 | 59.48 |
| Bus 1 and Line Z73 Outage | 2125.4 | 70.85 | 1111.4 | 55.57 |
| Bus 1 and Line Z98 Outage | 1735.3 | 57.84 | 1133.4 | 56.67 |
| Bus 1 and Line Z99 Outage | 1820 | 60.67 | 1358.7 | 67.94 |
| Bus 1 and Line Z93 Outage | 1816.1 | 60.54 | 1204.3 | 60.22 |
| Bus 1 and Line to Culley Outage | 2017.4 | 67.25 | 1044.5 | 52.23 |
| Bus 1 and Francisco to Gibson Outage | 2333.9 | 77.80 | 1327.1 | 66.36 |
| Bus 1 and AB Brown – BREC Reid Outage | 2154.8 | 71.83 | 1668.4 | 83.42 |
| Bus 2 Outage | 2016.5 | 67.22 | 1200.47 | 60.02 |

| Case | Current in 3kA Main Bus (A) | Percent Loading (%) | Current in 2kA Interpass (A) | Percent Loading (%) |
|---|---|---|---|---|
| Bus 2 and Line Z95 Outage | 2319.2 | 77.31 | 1229 | 61.45 |
| Bus 2 and Line Z96 Outage | 2168.8 | 72.29 | 1199.9 | 60.00 |
| Bus 2 and Line Z94 Outage | 2489.9 | 83.00 | 1199.5 | 59.98 |
| Bus 2 and Line Z73 Outage | 2124.4 | 70.81 | 1196 | 59.80 |
| Bus 2 and Line Z98 Outage | 1734.1 | 57.80 | 1199.6 | 59.98 |
| Bus 2 and Line Z99 Outage | 1819.4 | 60.65 | 1358.2 | 67.91 |
| Bus 2 and Line Z93 Outage | 1814.4 | 60.48 | 1203.3 | 60.17 |
| Bus 2 and Line to Culley Outage | 2016.5 | 67.22 | 1200.7 | 60.04 |
| Bus 2 and Francisco to Gibson Outage | 2332.9 | 77.76 | 1237.9 | 61.90 |
| Bus 2 and AB Brown – BREC Reid Outage | 2153.90 | 71.80 | 1199.5 | 59.98 |

## 2.2 FAULT CAPABILITY

13 of the 20 circuit breakers in the existing 138 kV switchyard are rated to withstand and interrupt 40 kA symmetrical fault current. The interrupting capability of the 13 40 kA rated circuit breakers is marginal for three phase faults and exceeded for single phase to ground faults for this evaluated case. Due to the available fault current contribution it is recommended to replace these existing circuit breakers with circuit breakers having sufficient margin beyond maximum fault current contribution. The remaining seven existing circuit breakers are oil filled and are considered to be near the end of service life. It is recommended to replace all of the existing 138 kV switchyard circuit breakers with breakers rated 63 kA symmetrical interrupting duty. This will ensure fault interrupting capability exceeds maximum available fault contribution.

The results of the fault study are included in Table 2-2.

**Table 2-2 138 kV Switchyard Fault Currents**

| Fault Current Availability 1x1 and Unit 2 | | |
|---|---|---|
| Fault type | Fault Component | Value |
| 3-phase fault | Fault Current (A) | 38881.2 |
| | Phase Angle (°) | -87 |
| | Calculated X/R | 18.96 |
| 1-phase fault | Fault Current (A) | 46287,2 |
| | Phase Angle (°) | -87 |
| | Calculated X/R | 19.24 |

# 3.0 Switchyard Connection Sequence

[redacted]

- [redacted]
- [redacted]
- [redacted]
- [redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

# 4.0 Conclusions

The withstand and interrupting rating of 40 kA for thirteen of the twenty existing 138 kV switchyard breakers is exceeded for the fault conditions evaluated, therefore circuit breaker replacement is necessary. The remaining seven switchyard circuit breakers are oil-filled breakers and near the end of their service life. It is recommended to replace all existing circuit breakers in the 138 kV switchyard with 63 kA symmetrical withstand and interrupting rating.

The evaluated load flow of the existing 138 kV switchyard permits independent connection of the CTG and STG of the new 1x1 CCPP considering a fired GE 7HA.01 and associated preliminary heat balance gross output. In general, the existing switchyard is capable of a single point of interconnection for 430,000 kW and below. This evaluation did not identify any major bus or interpass modifications for the existing 138 kV switchyard to accommodate the new CCPP and operation of Unit 2.

Connections to the existing switchyard have been planned to permit the construction and commissioning schedule of the new CCPP, while maintaining the existing A.B. Brown Unit 1 connection as late as practical into construction of the new CCPP.

# Appendix A. Switchyard Connection Sequence

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

# Appendix B. Construction Schedule

[redacted]

Confidential

FINAL

# AUXILIARY ELECTRIC SYSTEM MEDIUM VOLTAGE LEVEL COMPARISON

## A.B. Brown 1x1 H-Class

B&V PROJECT NO. 195523
B&V FILE NO. 41.1223H



PREPARED FOR

VECTREN
A CenterPoint Energy Company

Vectren

19 FEBRUARY 2020

BLACK & VEATCH

# Table of Contents



## LIST OF TABLES

# Executive Summary

This evaluation provides a summary comparison of nominal 6.9 kV and 4.16 kV auxiliary electric systems for the conceptual design (CPCN project) of the new A.B. Brown Combined Cycle Power Plant (CCPP). The medium voltage switchgear and motor controllers distribute power to large motor loads, ranging from greater than 250 HP up to several thousand HP, as well as to secondary unit substation (SUS) transformers, which derive 480V to be distributed to the low voltage system components and electrical loads.

Both nominal system voltages of 4.16 kV and 6.9 kV are commonly utilized within power generation and supported by most transformer and motor manufacturers.

**Table ES-1 Advantages of 4.16kV and 6.9kV Medium Voltage Systems**

| MEDIUM VOLTAGE | 4.16 KV | 6.9 KV |
|---|---|---|
| Lower Running Current/Starting Current | | X |
| Smaller Conductor Size | | X |
| Less Heating in Below Grade Cable Ductbank | | X |
| Reduction of Bus Short Circuit Rating | | X |
| Overvoltage Withstand | X | |
| Conductor Cost Savings | | X |
| UAT Cost Savings | | [redacted] |
| Switchgear Cost Savings | | [redacted] |
| Motor Cost Saving | Equal | Equal |

# 1.0 Auxiliary Electric System Cabling Design Considerations

The cross-sectional area (CSA) of a current-carrying copper conductor is largely dependent upon the continuous current required for rated operation of the electrical load. A larger continuous current necessitates are larger CSA in order to ensure the thermal limitations of the cable insulation and the equipment terminals are not exceeded. An electrical load with a nominal system voltage rating of 6.9 kV will result in an approximate 40% reduction of running current than that of an electrical load with the same power rating, in kVA or HP, and a nominal system voltage rating of 4.16 kV.

For power cables installed in below grade duct bank, a de-rating study must be performed in order to ensure that the implications of the concrete-encased, below grade cable duct on the current-carrying capability of the conductors are properly applied during conductor sizing. The aggregate of thermal impact of the continuous current flowing through the conductors within the duct bank, depth of duct bank, and soil thermal resistivity determine the de-rating of the conductor ampacity. The ampacity of a current-carrying conductor in below grade duct bank is reduced compared to the ampacity of the same conductor in above grade raceway or free air.

It is typical in a CCPP that the electrical loads, particularly medium voltage, are not installed within proximity of the electrical distribution equipment from which the load is sourced. Voltage drop calculations must be performed in order to ensure that the voltage at the load terminals does not fall below the equipment minimum operating voltage. Voltage drop is directly proportional to current, cable length and cable impedance.

# 2.0 Medium Voltage Motor Starting System Impact

The starting of a large motor can have a significant, albeit brief, impact on the auxiliary electrical system. When voltage is applied to the terminals of an at rest motor, the motor will draw locked-rotor current (LRA), which decays toward full-load amps (FLA) as the motor approaches running speed. This is the result of the motor torque overcoming the combined inertia of the motor and the connected load. For an induction motor, a typical value of LRA is approximately 650% of FLA.

As voltage drop is directly proportional to current, the voltage drop at motor starting due to LRA must be analyzed in order to ensure the motor will start. It is typical to specify medium voltage motors capable of starting at 80% of rated voltage as a means of mitigating this concern.

The starting current of a motor can also have an adverse impact on equipment already in operation at the time of motor starting. Voltage sag resulting from the LRA of the starting motor can result in contactor drop-out in certain circumstances. Methods of avoiding adverse impact of large motor starting to the auxiliary electrical system include on-load tap changers (OLTC) integral to the unit auxiliary transformers for bus voltage regulation, dedicated variable frequency drives (VFD) or soft-starters for the motors of concern. The approximate 40% reduction of FLA and LRA resulting from a 6.9 kV compared to 4.16 kV provides for improved results relative to motor starting.

# 3.0 Short Circuit Contribution During a System Fault

During a system fault, a motor in operation will contribute current to the fault, in attempt to stabilize the decaying system voltage, as a result of the rotating magnetic field that exists in the rotor at the inception of the fault. Analyses of the auxiliary electric system during a faulted condition must be performed in order to ensure that the bus bracing of the electrical distribution equipment is appropriate relative to fault levels. The reduction of FLA of a higher system voltage correlates to reduced short circuit contribution during in a fault condition. Black & Veatch analyses of system faults utilizing Electrical Transient and Analysis Program (ETAP) indicate that motor short circuit contribution can be reduced by up to 50% by increasing the system voltage from 4.16 kV to 6.9 kV.

The reduction of bus short circuit rating of electrical distribution equipment corresponds to a reduction in capital expenditure for 6.9 kV compared to 4.16 kV.

# 4.0 Cost Impact of Equipment Voltage Rating

Manufacturers of switching assemblies offer various equipment voltage ratings above typical industry nominal system voltages. Metal-clad switchgear voltage ratings of 5 kV and 7.2 kV are common and correspond to nominal system voltages of 4.16 kV and 6.9 kV, respectively. Confirmation from switching assembly manufacturers indicates that bus and breaker continuous current and interrupting ratings, as well as bus bracing and short circuit rating, are the primary cost drivers. The cost difference of a line-up of metal-clad switchgear with the same continuous current rating, interrupting capability and bus bracing, but different system voltage ratings, is negligible.

Black & Veatch has received similar confirmation from motor suppliers, with respect to the negligible cost difference between 6.6 kV and 4.0 kV rated motors.

# 5.0 System Loading

The preliminary electrical load list associated with the 2x1 (F and H Class) configuration of the A.B. Brown CCPP conceptual design indicates a total plant running load of approximately 30 MVA. At 6.9 kV, this corresponds to approximately 2500 A of running current in combined cycle operation. The preliminary UAT required to support this auxiliary load is a two-winding transformer with a maximum forced-air cooled rating of 36 MVA. With 100% redundancy, two (2) two-winding UATs correspond to one (1) double-ended (main-tie-main) lineup of 3000A, 6.9 kV switchgear.

With the total plant running MVA, at a system voltage of 4.16 kV, the corresponding running current is approximately 4200 A. Typical switchgear manufacturers offer maximum continuous current ratings of 4000 A, which is achieved using 3000 A rated, fan cooled main circuit breakers. The condition of fan cooling required to achieve this rating is not recommended as it introduces an additional point of failure to the auxiliary electric system.

A system voltage of 4.16 kV would necessitate two (2) three-winding UATs and two (2) double-ended lineups of switchgear in order to adequately source the plant auxiliary load requirements for combined cycle operation. A budgetary cost estimate of [redacted] per UAT and [redacted] of additional metal-clad switchgear would be necessary in order to accommodate auxiliary loads at 4.16 kV system voltage.

# 6.0 Overvoltage Withstand

Equipment manufacturers specify maximum voltage ratings above the nominal system voltage rating. An industry typical maximum voltage rating for a 4.16 kV nominal system voltage is 5.0 kV, providing approximately 20% headroom in an overvoltage condition. Industry typical maximum voltage rating for a 6.9 kV system voltage is 7.2 kV, though some manufacturers are now offering equipment with maximum system voltage rating of up to 7.65 kV. A maximum voltage rating of 7.2 kV provides approximately 4.3% headroom in an overvoltage condition before exceeding the maximum voltage rating. Dependent upon the generator output voltage and the UAT tap, it is possible to exceed this maximum voltage rating with a 6.9 kV system. However, this is not a normal operating condition and could be mitigated with appropriate protective relaying.

# 7.0 Conclusions

This evaluation report has shown that:

- The design of insulated conductors is directly impacted by the medium voltage system level.
- Disturbances to the auxiliary electric system as well as motor starting concerns are mitigated by an elevated system voltage.
- Short circuit contribution from medium voltage motors is reduced by an elevated system voltage, which can correspond to a reduction in the short circuit bus rating of electrical distribution equipment.
- The cost associated with an elevated system voltage to plant equipment such as switching assemblies and motor windings is considered negligible.
- The preliminary plant auxiliary loading required for combined cycle operation of the 2x1 configuration is supported by two-winding UATs and one (1) double-ended lineup of medium voltage switchgear at a system voltage of 6.9 kV. A system voltage of 4.16 kV would necessitate three-winding UATs and two (2) double-ended lineups of medium voltage switchgear.
- 4.16 kV system voltage provides more headroom for an overvoltage condition than that of a 6.9 kV system, for industry typical maximum voltage ratings. However, this condition can be mitigated with protective relaying.

Total cost savings for using 6.9 kV medium voltage system in lieu of a 4.16 kV medium voltage system is approximately [redacted].

**Attachment 6.5 Coal to Gas Conversion Study (Redacted)**

FINAL

# VECTREN NATURAL GAS CONVERSION INDEPENDENT ASSESSMENT REPORT

A.B. Brown Units 1, 2

F.B. Culley Unit 2

**BLACK & VEATCH PROJECT NO. 403365**
**BLACK & VEATCH FILE NO. 40.4100**



**PREPARED FOR**

VECTREN
A CenterPoint Energy Company

Vectren

MARCH 17, 2020

BLACK & VEATCH

# Table of Contents

## LIST OF TABLES



## LIST OF FIGURES

# Foreword

For several years, Vectren, a CenterPoint Energy Company, has been updating their integrated resource plan (IRP) to forecast energy demands to ensure reliable service to their customers in the most cost-effective ways. To that end, Vectren has been engaged with several engineering consulting firms to evaluate the use of natural gas, in lieu of coal, for operations at A.B. Brown, Units 1 and 2 and F.B. Culley, Unit 2.

The evaluation covered by this report was undertaken to enable Vectren to assess all concepts and options for natural gas conversion. The following summarizes the steps that have been taken during the course of this Project:

- Burns & McDonnell provide a high level natural gas conversion conceptual design and budgetary cost estimate for A.B. Brown Units 1 & 2 in 2015 and provided an update in 2016.
- Early in 2019 to support the current IRP process, Burns & McDonnell provided an update to this previous study for coal to gas conversion of A.B. Brown Unit 2.
- Black & Veatch further developed the estimate by investigating details surrounding preliminary Prevention of Significant Deterioration (PSD) analysis, potential environmental control technologies, Bill of Quantities (BOQ) level construction estimates, and expected boiler performance.
- Babcock & Wilcox (B&W) provided updates to the Boiler Engineering Study (surface area assessment & expected performance) and budgetary cost estimate for boiler equipment.
- Bowen Engineering performed a site investigation developing BOQ of materials and provided a construction budgetary estimate.
- Black & Veatch reviewed and validated the information provided by B&W and Bowen and developed a Natural Gas Conversion cost estimate consistent with an AACE Class 4 (which has an expected accuracy range of +/- 30%).

Black & Veatch utilized prior assessments from the following firms to validate the project conceptual design and budget level cost estimates for the coal to natural gas conversion:

- Burns & McDonnell – Natural Gas Conversion Conceptual Design and Budgetary Cost Estimate for A.B. Brown, Unit 2.
- Bowen Engineering Corporation – Materials and construction budgetary cost estimate for A.B. Brown, Units 1 and 2; F.B. Culley, Unit 2.
- Babcock & Wilcox – Boiler Engineering Study and Budgetary Cost Estimate for A.B. Brown, Units 1 and 2; F.B. Culley, Unit 2.
- Cormetech, Inc. – Estimated costs for selective catalytic reduction (SCR)/carbon monoxide (CO) catalysts for A.B. Brown, Units 1 and 2; F.B. Culley, Unit 2.
- International Chimney Corporation – Estimated costs for chimney inspection and liner washdowns for A.B. Brown, Units 1 and 2.

# 1.0 Executive Summary

Vectren requested Black & Veatch to review the concept of converting Vectren's A.B. Brown, Unit 1 and 2 and F.B. Culley, Unit 2 from firing coal to firing 100 percent natural gas. Converting to 100 percent natural gas firing involves the replacement of the existing bituminous coal fired burners with natural gas burners; the existing natural gas igniters will not be replaced. The new natural gas burners would lower emissions during startups and during normal operations by providing up to 100 percent of boiler maximum continuous rated (MCR) heat input. The existing flue gas cleaning equipment (scrubbers, baghouse/precipitator) would be removed from service. The natural gas pipeline supply to the A.B. Brown site boundary was excluded from the scope of this assessment.

When converted to natural gas the heat rate impact will be approximately four percent less for A.B. Brown Units 1 and 2 and three percent less for F.B. Culley Unit 2 due to the decreased boiler efficiency. The typical project schedule is 30 months (including 10 months for permitting activities) with a 10-month construction period that includes a 12 week outage for A.B. Brown Unit 1, a 14 week outage for A.B. Brown Unit 2, and a 14 week outage for F.B. Culley Unit 2. Replacement burner/igniter manufacture and delivery time is 13 months from award of a purchase order. A summary of the A.B. Brown Units 1 and 2 and F.B. Culley Unit 2 boiler impacts when converting to natural gas as assessed by Babcock & Wilcox is included in Table 1-1 and Table 1-2.

**Table 1-1 Summary of the A.B. Brown Unit 1 and 2 Boiler Impacts (per Unit Basis)**

| COMPONENT | RESULTS | COMMENTS |
|---|---|---|
| Superheat (SH) and Reheat (RH) Attemperator Flows | SH and RH flow rate less than required for firing coal | Lower amounts of excess air required when firing natural gas as compared to firing coal |
| Air Heater Performance | The air and flue gas temperature profiles around the air heater were found to be acceptable for firing natural gas; flue gas and air flows and temperatures in/out of air heater were at or below original design values | No field data were available that indicated higher than original air heater leakage; therefore, original air heater leakage of 7.4% was assumed in evaluation |
| Boiler Performance | • Main steam outlet temperatures, pressures, and flow rates equal to firing bituminous coal<br>• RH steam outlet temperatures and pressure are slightly less when firing natural gas<br>• Boiler efficiency as low as 84.16% compared to 87.92% when firing bituminous coal (because of moisture in losses due to $H_2$ and $H_2O$ in the natural gas) | Boiler efficiency for coal fired based on original contract performance summary |

| COMPONENT | RESULTS | COMMENTS |
|---|---|---|
| Tube Metal Temperature Evaluation | • Existing tube metal metallurgies in the convection pass tubes do not exhibit any overstress issues; tubes predicted to operate below American Society of Mechanical Engineers (ASME) material code published limits<br>• Header metal temperatures within Babcock & Wilcox standards | No surface modifications or surface removals are required when converting to firing 100% natural gas |
| Forced Draft (FD) Fans | Test block conditions for both units of the existing FD fans exceed the requirements for firing natural gas in capacity and static pressure rise | Flue gas and air flow requirements for firing natural gas are less than the requirements when firing coal, resulting in less static pressure rise |
| Induced Draft (ID) Fans | Test block conditions of the existing ID fans far exceed the requirements in capacity and static pressure rise for firing natural gas | Flue gas and air flow requirements for firing natural gas are less than the requirements when firing coal, resulting in less static pressure rise |

### Table 1-2 Summary of the F.B. Culley Unit 2 Boiler Impacts

| COMPONENT | RESULTS | COMMENTS |
|---|---|---|
| Pressure Parts | • Reduction in primary superheater surface is required in both cases where FGR is required to avoid exceeding the limits of the existing tube metallurgy<br>• Twelve tube rows would be removed | Increased absorption through the convection pass components is due to FGR, which increases flue gas flow rates |
| Boiler Performance | • Main steam outlet temperatures, pressures, and flow rates equal to firing bituminous coal<br>• Superheater spray flows as high as 46% above firing bituminous coal<br>• Boiler efficiency firing natural gas as low as 83.93% compared to 87.02% when firing bituminous coal (due to moisture in losses from $H_2$ and $H_2O$ in the natural gas) | Boiler efficiency of 83.93% is based on primary superheater surface reduction without OFA ports |
| Attemperator Capacities | Attemperator flows firing natural gas increased compared to firing bituminous coal with/without FGR and/or boiler modifications | Existing spray water attemperator nozzle size would have to be modified by increasing the orifice diameter to meet the required flows; flows would be adequate with this modification at all boiler loads |
| Air Heater Performance | The air and gas side profiles were found to be acceptable for 100% natural gas firing | No field data were available to indicate amount of air heater leakage; original design value of 10% was used in the evaluation |

| COMPONENT | RESULTS | COMMENTS |
|---|---|---|
| Tube Metal Temperature Evaluation | • Existing tubes in convection pass tube had no overstress issues; tubes predicted to operate at temperatures below ASME material code published limit<br>• Header metal temperatures within Babcock & Wilcox standards | Publishing design tube metal temperatures or unbalanced steam temperatures are not allowed by Babcock & Wilcox policy; available for review in Babcock & Wilcox's offices |
| Forced Draft (FD) Fans | Test block conditions of the existing fans exceed the requirements for firing natural gas with new burners, with/without OFA ports, with/without primary superheater surface reduction | These results are because the FD fans were originally designed for pressurized firing, which has been converted to balanced draft |
| Induced Draft (ID) Fans | Test block conditions of the existing ID fans far exceed the requirements for firing natural gas with new burners, with/without OFA ports, with/without primary superheater surface reduction | Flue gas and air flow requirements for firing natural gas are less than the requirements when firing coal, resulting in less static pressure rise |

When burning natural gas, flue gas emissions reductions from the boilers for particulate matter (PM), sulfur dioxide ($SO_2$), and mercury (Hg) would be reduced almost directly proportional to the reduction in coal combustion. Boiler flue gas emissions of nitrogen oxides ($NO_X$) and CO while firing natural gas would also be reduced compared to firing coal. Options assessed to reduce $NO_X$ and CO emissions include the design and installation of an overfire air (OFA) system, flue gas recirculation (FGR) system, CO catalyst system, and continued operation of the SCRs (A.B. Brown Units 1 and 2 only). For this assessment, all options have been evaluated and costs estimated; final selection will be dependent on final air permitting.

The Natural Gas Conversion Evaluation is consistent with an AACE Class 4 estimate (which has an expected accuracy range of +/- 30%) based on Black & Veatch's review of the third part reports, deliverables, and the level of effort.  In addition, Black & Veatch provided the preliminary environmental approach and recommendations, including estimated the cost for SCR and CO2 requirements for the units.  These estimates are also consistent with an AACE Class 4 estimate.

# 2.0 Conceptual Design Basis

## 2.1 GENERAL

The project concept is to replace existing coal fired equipment with natural gas burners (natural gas igniters are currently in service) to use natural gas for startup and during normal operations at A.B. Brown, Units 1 and 2 and F.B. Culley, Unit 2. The natural gas burners would be sized so that 100 percent of each of the boilers' MCR heat input at full unit load could be supplied by firing 100 percent natural gas.

The implementation of the 100 percent natural gas firing option requires the replacement of the existing coal fired system (burners, pulverizers, coal and ash handling equipment, etc.) with a new low $NO_X$, natural gas fired burner system (burners, piping, valves, controls, and new burner management system [BMS], as a minimum). A new natural gas supply line from the A.B. Brown and F.B. Culley plant boundary to each of the units is included, along with branches to each of the units.

### 2.1.1 A.B. Brown Unit 1 and 2

A.B. Brown Units 1 and 2 are similar in design and are balanced draft, subcritical boilers, each with a secondary superheater, primary superheater, reheater, and economizer surfaces. Superheater and reheater temperatures are controlled by interstage spray attemperation and excess air/spray attemperation, respectively. The units are each front and rear wall fired with a total of twenty (24) Babcock & Wilcox 4Z low $NO_X$ burners per unit. Each unit is equipped with six Babcock & Wilcox pulverizers and two Ljungstrom regenerative air heaters (refer to Figure 2-1). The gas conversion included a review of the boiler heating surfaces and adequacy of the existing forced draft (FD) fans and primary air (PA) fans. The differences in Unit 1 and Unit 2 are as follows:

- The furnace height of Unit 1 is 122'-0" compared to the furnace height of Unit 2, which is 124'-0."
- Unit 1 has a full furnace division wall; Unit 2 has six water-cooled furnace wing walls.
- Unit 1 was originally designed with flue gas recirculation (FGR), which has been removed from service; Unit 2 was designed to operate without FGR.

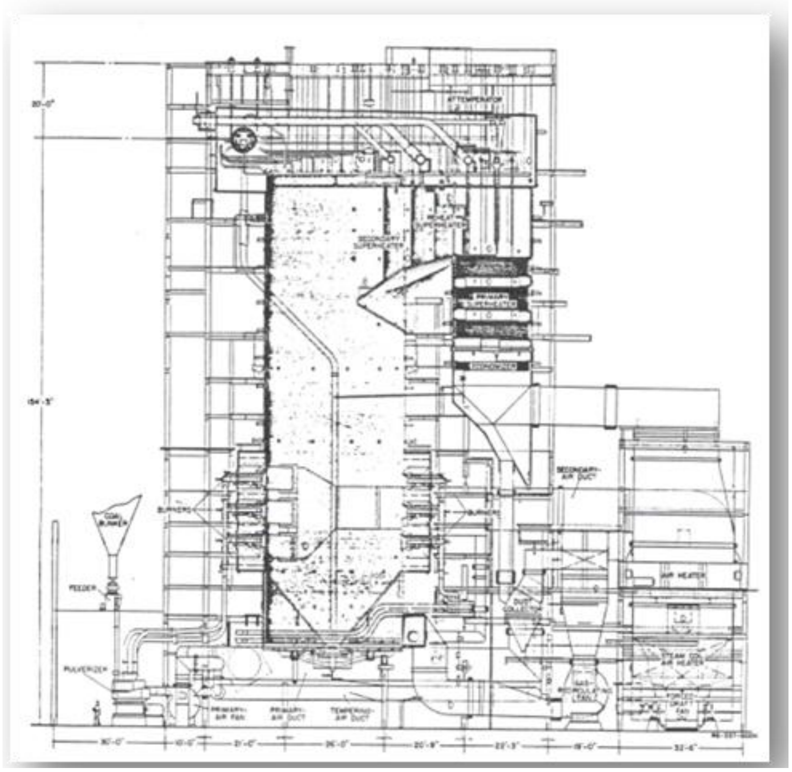


**Figure 2-1 A.B. Brown Units 1 and 2 Typical Boiler Diagram**

**Table 2-1 A.B. Brown Units 1 and 2 Original Design As-Fired Fuel Analyses**

| CONSTITUENT | PERCENT BY WEIGHT |
|---|---|
| Carbon (C) | 64.00 |
| Hydrogen ($H_2$) | 4.44 |
| Nitrogen ($N_2$) | 1.38 |
| Oxygen ($O_2$) | 6.51 |
| Chlorine (Cl) | 0.00 |
| Sulfur (S) | 3.52 |
| Moisture ($H_2O$) | 11.35 |
| Ash | 8.76 |
| **Total** | **100.00** |
| HHV (Btu/lb) | 11,533 |
| HHV - higher heating value; Btu/lb - British thermal unit per pound | |

### 2.1.2 F.B. Culley Unit 2

F.B. Culley Unit 2 is a subcritical El Paso type radiant boiler and was originally a pressurized fired design; it has been converted to a balanced draft design. The primary and secondary superheater and economizer surfaces are arranged in series (refer to Figure 2-2). Steam temperature is controlled via interstage attemperation. The unit is a front wall fired design and consists of 12 pulverized coal burners. F.B. Culley Unit 2 is different from A.B. Brown Units 1 and 2 in that it is not equipped with an SCR system for $NO_X$ control.

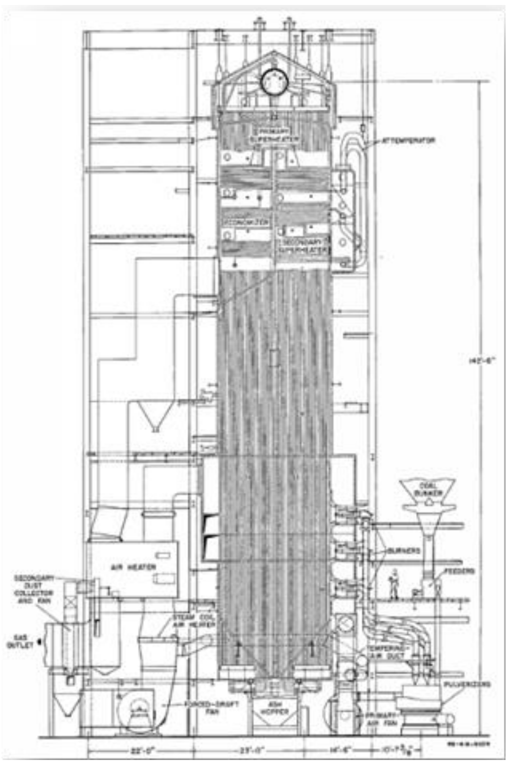



**Figure 2-2 F.B. Culley Unit 2 Typical Boiler Diagram**

**Table 2-2 F.B. Culley Unit 2 Original Design Bituminous Coal Analysis**

| CONSTITUENT | PERCENT BY WEIGHT |
|---|---|
| Carbon (C) | 55.27 |
| Hydrogen ($H_2$) | 3.70 |
| Nitrogen ($N_2$) | 1.05 |
| Oxygen ($O_2$) | 5.68 |
| Chlorine (Cl) | 0.00 |
| Sulfur (S) | 3.30 |
| Moisture ($H_2O$) | 19.00 |
| Ash | 12.00 |
| **Total** | **100.00** |
| HHV (Btu/lb) | 10,000 |

## 2.2 NATURAL GAS SYSTEM CONCEPTUAL DESIGN

For the conversion both A.B. Brown and F.B. Culley will require a new natural gas pipeline source. The natural gas pipeline supply to the A.B. Brown and F.B. Culley site boundaries were excluded from the scope of this assessment.

A conceptual design was developed for a natural gas supply piping, heating, and regulating system from the gas line tap to the boiler OEM's natural gas fuel controls, metering and pressure regulating skid.

Because of the Joule-Thomson effect, the temperature of natural gas can change during a pressure reduction operation, and its final temperature is related to the amount of pressure drop across the pressure regulating valve. Increasing the temperature of the natural gas may be required prior to pressure reduction to overcome the possibility of moisture condensation and freezing following the cooling effect of the pressure reduction operation. Insulation of the natural gas piping is included as required.

Natural gas heating can be accomplished with natural gas fired heaters, electrical resistance heaters, or using steam. For the purposes of this study, natural gas heating was assumed to be upstream of the site gas line connection by the gas supplier.

### 2.2.1 Codes and Standards

The conceptual design is based on meeting applicable national codes. The following are the most significant codes and standards applicable to this conceptual design:

- NFPA 85 will be the governing code used in determining the igniter and burner arrangement and operating principles based on a multiple burner boiler.

- ASME B31.1 Power Piping Code and other ASME codes will be used for mechanical design. It is not anticipated that any ASME Section I components will be affected unless boiler heating surfaces are modified.
- NFPA 497 and the National Electric Code (NFPA 70) will also be used in identifying electrical hazardous area classification issues that must be addressed.

### 2.2.2 A.B. Brown Units 1 and 2 Natural Gas Supply

For the conceptual design, natural gas for the project will be supplied at an assumed pressure at the main gas line connection point on the northwest corner of the site near the existing Unit 2 Cooling Tower at a pressure of approximately 500 psig.

The first stage pressure reduction, metering, and condition station which will reduce the main gas line pressure to around 200 psig will be located at the site gas line connection. From the first stage pressure reduction station a new underground natural gas line will supply the 200 psig natural gas to the southwest corner of Unit 2 where the gas will enter an intermediate regulating station to reduce the pressure to approximately 50 psig required by the boiler OEM. The outlet of the second stage reduction will connect to the Unit 1 and Unit 2 regulating skids provided by boiler OEM, which will further reduce the pressure to a level required for proper operation of the new natural gas burners., Dedicated lines will be routed aboveground to Units 1 and 2 following the second stage regulating stations. At the boilers on Unit 1 and 2, flow control valves and distribution headers will distribute and control the flow of natural gas to the burners located on each level. At each burner, a double block and vent valve arrangement will be furnished. Additional trip, isolation, and header vent valves will be included as part of the boiler OEM's piping internal to the boiler building

The natural gas analysis used in the evaluation was provided by Vectren for A.B. Brown is provided in Table 2-3.

**Table 2-3 A.B. Brown Proximate Analysis for Natural Gas**

| CONSTITUENT | PERCENT BY VOLMUE |
|---|---|
| Nitrogen ($N_2$) | 0.28 |
| Methane ($CH_4$) | 96.31 |
| Ethane ($C_2H_6$) | 1.46 |
| Carbon Dioxide ($CO_2$) | 1.89 |
| Others | 0.06 |
| **Total** | **100.00** |
| HHV (Btu/ft$^3$) | 1,037 |
| Btu/ft$^3$ - British thermal unit per cubic foot | |

### 2.2.3 F.B. Culley Unit 2 Natural Gas Supply

For the conceptual design, natural gas for the project will be supplied at an assumed pressure of approximately 500 psig at the main gas line connection point on the northwest corner of the site near the existing F.B. Culley site gas metering station.

The first stage pressure reduction, metering, and conditioning station which will reduce the main gas line pressure to around 200 psig will be located at the site gas line connection. From the first stage pressure reduction station a new underground natural gas line will supply the 200 psig natural gas to Unit 2 where the gas will enter an intermediate regulating station to reduce the pressure to approximately 50 psig required by the boiler OEM. The outlet of the second stage reduction will connect the regulating skids provided by the boiler OEM, which will further reduce the pressure to a level required for proper operation of the new natural gas burners. Following the second stage regulating stations, flow control valves and distribution headers will distribute and control the flow of natural gas to the burners located on each level. At each burner, a double block and vent valve arrangement will be furnished. Additional trip, isolation, and header vent valves will be included as part of the boiler OEM's piping internal to the boiler building.

The natural gas analysis used in this evaluation was provided by Vectren for F.B. Culley and is shown in Table 2-4.

**Table 2-4 F.B. Culley Proximate Analysis for Natural Gas**

| CONSTITUENT | PERCENT BY VOLUME |
|---|---|
| Nitrogen ($N_2$) | 1.79 |
| Methane ($CH_4$) | 91.88 |
| Ethane ($C_2H_6$) | 5.12 |
| Others | 1.21 |
| **Total** | **100.00** |
| HHV (Btu/ft$^3$) | 1,037 |

## 2.3 BOILER MODIFICATIONS

There is a shift in heat transfer within the boiler from radiant heat when burning coal to more convective heat transfer when burning natural gas when converting a unit from coal firing to natural gas firing. This is due to the natural gas flame having a lower emissivity that results in less radiant heat output. Additionally, there is more heat transfer in the convective pass of the boiler because there is less ash content produced with firing natural gas. Therefore, an assessment of the heat transfer surfaces, typically by the boiler OEM, is required to determine if any boiler heating surface modifications are required to maintain full load output. For this study, Babcock & Wilcox evaluated performance impacts and/or potential modifications to the boiler heating surfaces of converting the coal fired boilers at A.B. Brown Units 1 and 2 and F.B. Culley Unit 2 to firing 100 percent natural gas.

### 2.3.1 A.B. Brown Unit 1 and 2 Boiler Modifications

A review of the heating surfaces was performed to assess the boiler pressure part metals at the boiler operating conditions shown in Table 2-5 using the original coal analysis (refer to Table 2-1) and the natural gas analysis provided by Vectren (refer to Table 2-3).

**Table 2-5 A.B. Brown Units 1 and 2 Boiler Operating Conditions Used in Metals Evaluation**

| BOILER LOAD | MCR | 60% MCR |
|---|---|---|
| Superheater (SH) Steam Flow (lb/h) | 1,850,000 | 1,110,000 |
| Steam Temperature at SH Outlet (°F) | 1,005 | 933 |
| Steam Pressure at SH Outlet (psig) | 1,965 | 1,917 |
| Reheater (RH) Steam Flow (lb/h) w/o attemperator flow | 1,666,500 | 1,000,000 |
| Steam Temperature at RH Outlet (°F) | 992 | 835 |
| Steam Pressure at RH Outlet (psig) | 460 | 261 |
| Feedwater Temperature (°F) | 467 | 417 |
| Excess Air Leaving Economizer (%) | 10 | 18 |

A detailed boiler analysis for converting A.B. Brown Units 1 and 2 to natural gas was performed by Babcock & Wilcock the boiler OEM to determine possible equipment impacts and estimate performance. Table 2-6 provides a summary of Babcock & Wilcox boiler evaluation.

### Table 2-6 Summary of the A.B. Brown Unit 1 and 2 Boiler Evaluation (per Unit Basis)

| COMPONENT | RESULTS | COMMENTS |
|---|---|---|
| Superheat (SH) and Reheat (RH) Attemperator Flows | SH and RH flow rate less than required for firing coal | Lower amounts of excess air required when firing natural gas as compared to firing coal |
| Air Heater Performance | The air and flue gas temperature profiles around the air heater were found to be acceptable for firing natural gas; flue gas and air flows and temperatures in/out of air heater were at or below original design values | No field data were available that indicated higher than original air heater leakage; therefore, original air heater leakage of 7.4% was assumed in evaluation |
| Boiler Performance | • Main steam outlet temperatures, pressures, and flow rates equal to firing bituminous coal<br>• RH steam outlet temperatures and pressure are slightly less when firing natural gas<br>• Boiler efficiency as low as 84.16% compared to 87.92% when firing bituminous coal (because of moisture in losses due to $H_2$ and $H_2O$ in the natural gas) | Boiler efficiency for coal fired based on original contract performance summary |
| Tube Metal Temperature Evaluation | • Existing tube metal metallurgies in the convection pass tubes do not exhibit any overstress issues; tubes predicted to operate below American Society of Mechanical Engineers (ASME) material code published limits<br>• Header metal temperatures within Babcock & Wilcox standards | No surface modifications or surface removals are required when converting to firing 100% natural gas |

### 2.3.2 A.B. Brown Units 1 and 2 Combustion Equipment

For A.B. Brown Unit 1 and 2 two modifications were evaluated to convert the existing twenty-four (24) Babcock & Wilcox DRB-4Z® low $NO_X$ coal fired burners to fire natural gas:[1]

The first option was to modify the existing coal burners by adding a “Super-Spud” to each burner configuration. This modification would allow firing natural gas with the ability to continue to fire coal. Refer to Figure 2-3. The Super-Spud is identified in the figure as “Gas Inlet.”

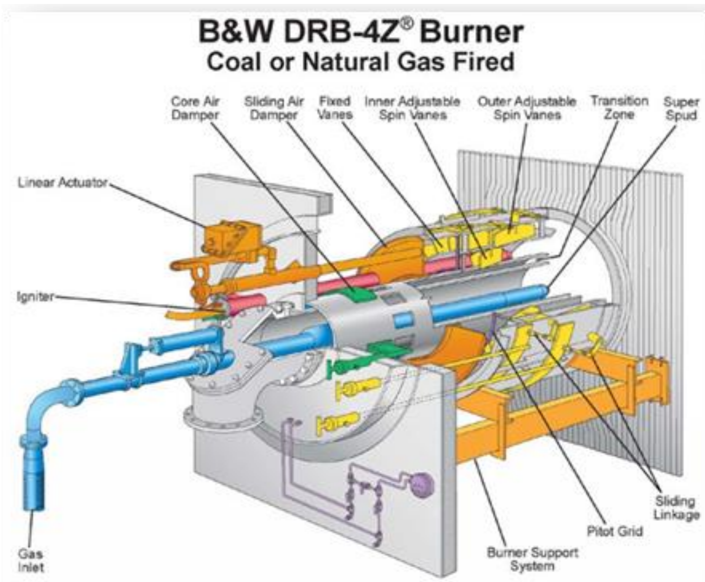



**Figure 2-3 Babcock & Wilcox DRB-4Z® Burner (Coal or Gas Fired)**

[1] Figures 2-3 and 2-4 were retrieved from Babcock & Wilcox’s “Engineering Study for Natural Gas Firing,” Contract 591-1048 (317A), June 13, 2019, Rev. 5.

The second option is to remove the existing coal nozzle and replace it with a hemi-spud cartridge. The modification will basically convert the Babcock & Wilcox 4Z low $NO_X$ burners into a Babcock & Wilcox model XCL-S™ burners (refer to Figure 2-4). The XCL-S burner was developed by Babcock & Wilcox to achieve superior $NO_X$ performance utilizing a burner only.

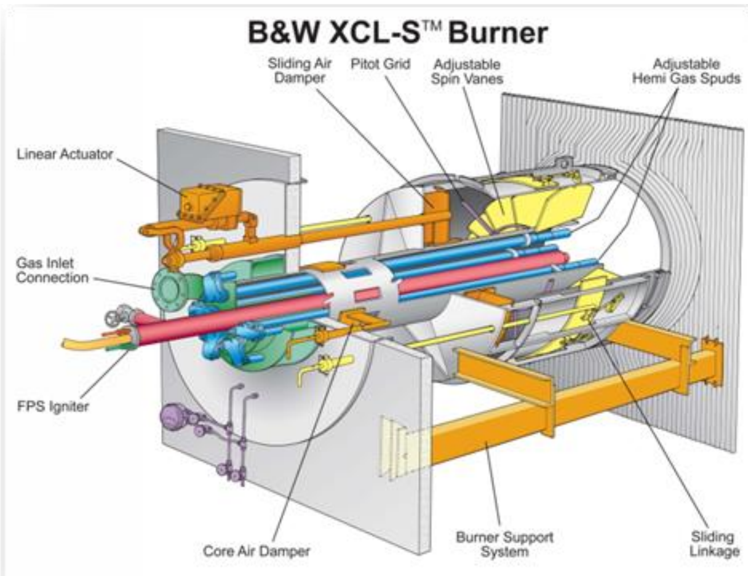



**Figure 2-4** **Babcock & Wilcox XCL-S™ Burner (Natural Gas Fired)**

Additional upgrades to the ignitors and flame scanners are typically required to support the new burner design and control system upgrades.

The existing ignitors will be reused while the flame scanners will be replaced with new UV scanners capable of detecting flames from the new natural gas fuel.

### 2.3.3 F.B. Culley Unit 2 Boiler Modifications

A review of the heating surfaces was performed to assess the boiler pressure part metals at the boiler operating conditions shown in Table 2-7 using the original coal analysis (refer to Table 2-2) and the natural gas analysis provided by Vectren (refer to Table 2-4).

**Table 2-7** **F.B. Culley Unit 2 Boiler Operating Conditions Used in Metals Evaluation**

| BOILER LOAD | MCR | 50% MCR |
|---|---|---|
| Superheater Steam Flow (lb/h) | 840,000 | 420,000 |
| Steam Temperature at SH Outlet (°F) | 955 | 925 |
| Steam Pressure at SH Outlet (psig) | 1,290 | 1,260 |
| Feedwater Temperature (°F) | 425 | 360 |
| Excess Air Leaving Economizer (%) | 10 | 18 |

A detailed boiler analysis for converting F.B. Culley Unit 2 to natural gas was performed by Babcock & Wilcock the boiler OEM to determine possible equipment impacts and estimate performance. Table 2-8 provides a summary of Babcock & Wilcox boiler evaluation.

### Table 2-8 Summary of the F.B. Culley Unit 2 Boiler Evaluation

| COMPONENT | RESULTS | COMMENTS |
|---|---|---|
| Pressure Parts | • Reduction in primary superheater surface is required in both cases where FGR is required to avoid exceeding the limits of the existing tube metallurgy<br>• Twelve tube rows would be removed | Increased absorption through the convection pass components is due to FGR, which increases flue gas flow rates |
| Boiler Performance | • Main steam outlet temperatures, pressures, and flow rates equal to firing bituminous coal<br>• Superheater spray flows as high as 46% above firing bituminous coal<br>• Boiler efficiency firing natural gas as low as 83.93% compared to 87.02% when firing bituminous coal (due to moisture in losses from $H_2$ and $H_2O$ in the natural gas) | Boiler efficiency of 83.93% is based on primary superheater surface reduction without OFA ports |
| Attemperator Capacities | Attemperator flows firing natural gas increased compared to firing bituminous coal with/without FGR and/or boiler modifications | Existing spray water attemperator nozzle size would have to be modified by increasing the orifice diameter to meet the required flows; flows would be adequate with this modification at all boiler loads |
| Air Heater Performance | The air and gas side profiles were found to be acceptable for 100% natural gas firing | No field data were available to indicate amount of air heater leakage; original design value of 10% was used in the evaluation |
| Tube Metal Temperature Evaluation | • Existing tubes in convection pass tube had no overstress issues; tubes predicted to operate at temperatures below ASME material code published limit<br>• Header metal temperatures within Babcock & Wilcox standards | Publishing design tube metal temperatures or unbalanced steam temperatures are not allowed by Babcock & Wilcox policy; available for review in Babcock & Wilcox's offices |

### 2.3.4 F.B. Culley Unit 2 Combustion Equipment

The existing 12 coal fired burners for F.B. Culley Unit 2 will be replaced with new Babcock & Wilcox XCL-S™ burners which can be retrofitted into the existing burner openings in the furnace walls. Some adjustment to the existing burner throat diameter may be required, which will be dependent on the choice of $NO_x$ reduction technologies: burners only, burners plus OFA, FGR, and any combination of these $NO_x$ reduction technologies. Conical ceramic throat inserts for reducing the burner throat diameter may be installed, or refractory may be removed to increase the burner throat diameter. The chosen design will be based on the results of the engineering phase. It should be noted that all the combustion air will have to be supplied via the secondary air ducting system since PA (for pulverized coal transport) will no longer be available

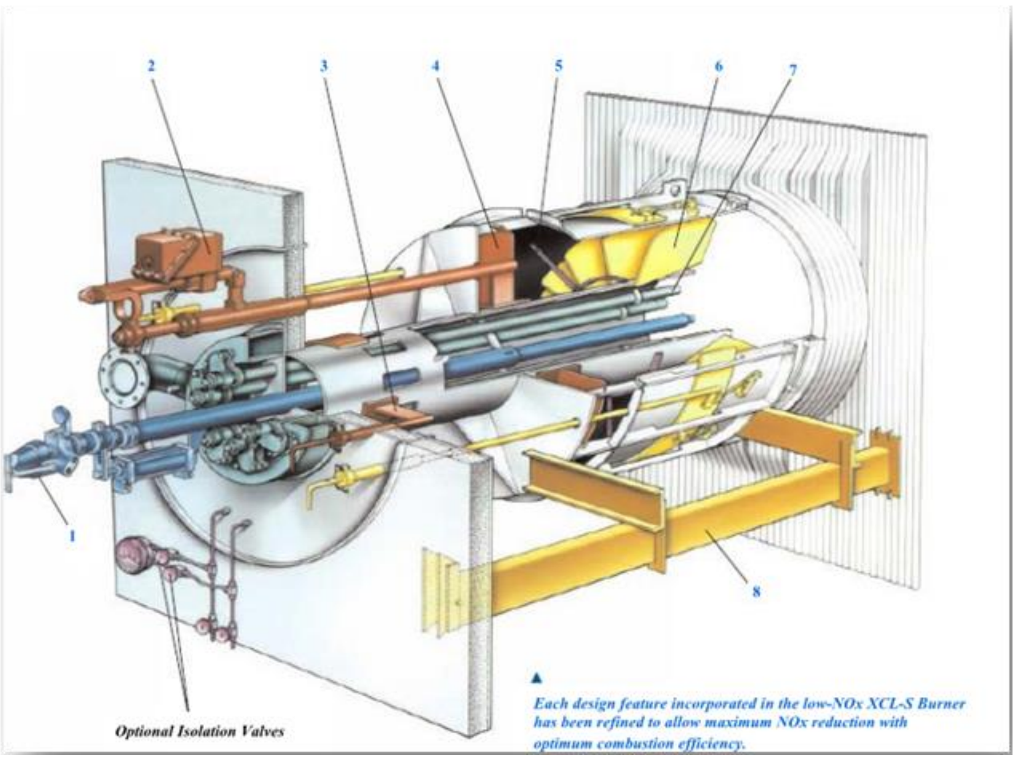



**Figure 2-5 Babcock & Wilcox Low-$NO_X$ XCL-S™ Burner[2]**

The existing ignitors will be replaced with new high energy spark ignitors and the flame scanners will be replaced with new scanners capable of detecting flames from the new natural gas fuel.

[2] Figure 2-5 was retrieved from Babcock & Wilcox's "Engineering Study for Natural Gas Firing," Contract 591-1022 (293H), June 13, 2019, Rev. 2.

## 2.4 COMBUSTION AIR SYSTEM

For natural gas firing, the mills and PA fans can be taken out of service (abandoned in place). The portion of the combustion air traveling to the mills is blocked off such that all combustion air travels to the windbox. These changes are easily accomplished in the combustion air ductwork.

Changes to the windbox size to accommodate the additional combustion air may be required to facilitate installation of FGR and/or OFA based on final design. Typically, no changes are required to the air heaters to accommodate the removal of the PA system. If required, these combustion air system modifications for natural gas firing can easily be reversed for a future return to coal firing, if the plant determines to do so.

### 2.4.1 A.B. Brown Unit 1 and 2 Forced Draft Fan Analysis

The existing forced draft fans on Units 1 and 2 were reviewed for the 100% natural gas firing and determined that no modifications are required to meet the new design conditions as summarized in Table 2-9. The predicated fan performance from the boiler OEM is can be found in Appendix A.

**Table 2-9 A.B. Brown Unit 1 and 2 Fan Evaluation**

| COMPONENT | RESULTS | COMMENTS |
|---|---|---|
| Forced Draft (FD) Fans | Test block conditions for both units of the existing FD fans exceed the requirements for firing natural gas in capacity and static pressure rise | Flue gas and air flow requirements for firing natural gas are less than the requirements when firing coal, resulting in less static pressure rise |

### 2.4.2 F.B. Culley Unit 2 Forced Draft Fan Analysis

The existing forced draft fans on Unit 2 were reviewed for the 100% natural gas firing and determined that no modifications are required to meet the new design conditions as summarized in Table 2-10. The predicated fan performance from the boiler OEM is can be found in Appendix B.

**Table 2-10 F.B. Culley Unit 2 Fan Evaluation**

| COMPONENT | RESULTS | COMMENTS |
|---|---|---|
| Forced Draft (FD) Fans | Test block conditions of the existing fans exceed the requirements for firing natural gas with new burners, with/without OFA ports, with/without primary superheater surface reduction | These results are because the FD fans were originally designed for pressurized firing, which has been converted to balanced draft |

## 2.5 FLUE GAS SYSTEM

Since natural gas firing has no ash and negligible sulfur compared to firing coal, air quality control systems including fabric filters, electrostatic participators, and flue gas desulfurization (FGD) are generally no longer required post conversion. However, it is typical for fabric filters and electrostatic participators to remain in operation for a short period of time following the natural gas conversion to capture residual coal ash remaining in the equipment and ductwork before eventually being decommissioned in place and the internals removed. FGD systems are abandoned or demolished and new flue gas ductwork installed from the FGD inlet to the stack.

### 2.5.1 A.B. Brown Unit 1 and 2 Induced Draft Fan Analysis

The existing induced draft fans on Units 1 and 2 were reviewed for the 100% natural gas firing and determined that no modifications are required to meet the new design conditions as summarized in Table 2-11. The predicated fan performance from the boiler OEM is can be found in Appendix A.

**Table 2-11 A.B. Brown Unit 1 and 2 Fan Evaluation**

| COMPONENT | RESULTS | COMMENTS |
|---|---|---|
| Induced Draft (ID) Fans | Test block conditions of the existing ID fans far exceed the requirements in capacity and static pressure rise for firing natural gas | Flue gas and air flow requirements for firing natural gas are less than the requirements when firing coal, resulting in less static pressure rise |

### 2.5.2 F.B. Culley Unit 2 Induced Draft Fan Analysis

The existing induced draft fans on Unit 2 were reviewed for the 100% natural gas firing and determined that no modifications are required to meet the new design conditions as summarized in Table 2-12. The predicated fan performance from the boiler OEM is can be found in Appendix B.

**Table 2-12 F.B. Culley Unit 2 Fan Evaluation**

| COMPONENT | RESULTS | COMMENTS |
|---|---|---|
| Induced Draft (ID) Fans | Test block conditions of the existing ID fans far exceed the requirements for firing natural gas with new burners, with/without OFA ports, with/without primary superheater surface reduction | Flue gas and air flow requirements for firing natural gas are less than the requirements when firing coal, resulting in less static pressure rise |

## 2.6 CONTROL SYSTEM MODIFICATIONS

The existing BMS and BCS I/O and control processors should be repurposed or replaced along with new control logic and DCS reprogramming to support the new natural gas fired equipment. New instrumentation is required to control the new natural gas supply and burner equipment. Flow transmitters on the natural gas supply to each unit will support boiler fuel input calculations while pressure instrumentation will provide both control and necessary interlocks in accordance with NFPA 85.

## 2.7 FIRE PROTECTION IMPACTS

In general, converting from coal burners to natural gas burner would not require additional fire protection. However, Black & Veatch recommends getting approval from the local Authority Having Jurisdiction (AHJ) during the project design stages.

## 2.8 AUXILIARY ELECTRICAL SYSTEM IMPACTS

No major additions to the existing auxiliary electrical system are needed. Burner block and vent valves will be air operated valves and existing ID and FD fans will remain so that no new major power requirements are foreseen.

All systems associated with coal firing (mills, coal and ash handling equipment, etc.) would be removed from service, resulting in a reduction in auxiliary power. Also removed from service will be the precipitator and the dual alkali scrubber which will further reduce the auxiliary load on the plant.

New natural gas pressure reducing stations will require power for control panels. Each reducing station power supply will be fed by existing plant equipment and will have negligible electrical power consumption.

## 2.9 PLANT WATER SYSTEM IMPACTS

Boiler demineralized water consumption can increase in natural gas conversions if the conversion leads to more cyclical operation. In addition, when the unit is shut down for prolonged periods of time the resulting boiler draining and filling will result in intermittent high demands of demineralized water usage. Wet scrubber technology for the reduction of acid gases from fuel bound nitrogen in the bituminous coal being fired requires a continuous supply of water to make up the continued blowdown system. Water is also utilized for sluicing bottom ash to an ash pond and for the hydroveyor to the barge used for transporting dry fly ash off-site. Water for these systems will no longer be needed with the conversion.

## 2.10 NFPA IMPACTS

### 2.10.1 Hazardous Classification Impacts

NFPA 497 defines hazardous area classifications involving flammable or combustible liquids, combustible gases, or combustible dusts. This classification is necessary for the proper selection and installation of electrical equipment. The National Electric Code (NEC), as defined by NFPA 70, defines the requirements for electrical equipment and associated installation methods within the boundaries of hazardous areas defined by NFPA 497. In many cases, this requires vendors to provide equipment in explosion proof enclosures, the installation of purge air systems, or the use of intrinsically safe barrier systems. Electrical installation methods include the use of raceway systems specifically rated for the hazardous area and the use of seal-offs in raceway that cross the hazardous area boundary.

Assuming that the existing powerhouse meets the definition of being well-ventilated, NFPA 497 requires that 15-foot spheres around each potential leakage point be classified as a Class I Division II hazardous area. Long sections of welded natural gas piping without any flanges, valves, or instruments will not require a hazardous area classification. The fuel gas piping to the burners includes flanged connections, stem packing on the control and shutoff valves, and fittings on instrument connections that represent potential leakage points. As a result, all existing electrical components and raceway within the 15-foot sphere of potential leak points not rated for a Class I Division II environment will require replacement with appropriately rated equipment and materials. Examples include lighting, receptacles, communications equipment, power distribution equipment, control panels, drives, and associated raceway. A detailed hazardous area impact study would need to be performed to identify equipment and materials that need to be upgraded or replaced.

### 2.10.2 NFPA 85 Implosion Control

Although no FD or ID fan modifications are anticipated at this time to enable natural gas firing on any of the units, there may be an increased implosion potential in each boiler due to the firing characteristics of natural gas compared with coal. Natural gas can “flame out” much more quickly than coal, and natural gas does not have residual heat remaining in pulverized fuel pipes like coal. The result is the potential for an immediate drop in boiler temperature, rapidly lowering the internal boiler pressure. To fully evaluate the impacts and required boiler pressure rating due to this operating scenario, a Furnace and Draft System Transient Pressure Analysis study should be completed prior to detailed design. To some extent, the boiler depressurization can be mitigated with controls optimization (damper and fan operation control); this will also need to be evaluated by the study.

## 2.11 EXISTING EMISSION CONTROL EQUIPMENT IMPACTS

When burning natural gas, flue gas emissions reductions from the boilers for PM, SO2, and Hg are reduced almost directly proportional to the reduction in coal combustion. Therefore, the precipitator and related equipment will not be required for firing 100 percent natural gas. The systems, however, will remain in service for a short time after the conversion to 100 percent natural gas to remove any residual ash remaining in the ducting after the conversion. The dual alkali scrubber has numerous maintenance issues and therefore would also be removed from service, demolished, and replaced with ducting from the precipitator outlet to the stack.

The existing SCRs on A.B. Brown Unit 1 and 2 have been considered as part of the $NO_x$ reduction control technologies and continued operation would be confirmed as part of the final netting analysis and permitting strategy (refer to Section 4.0).

# 3.0 Performance Impacts Analysis

Compared to firing coal, firing natural gas will reduce the boiler efficiency which will result in an increase in the net plant heat rate. The main impact on boiler efficiency is due to the hydrogen losses from the higher hydrogen content of the natural gas. Water vapor is a byproduct of combusting hydrogen, which requires additional heat to remove the water vapor. This additional heat is a loss in the flue gas rather than being absorbed in the boiler walls to create steam. Babcock & Wilcox has estimated that the excess air requirements for firing natural gas is 10 percent, compared to 20 percent for firing coal. The lower excess air requirement results in less flue gas flow, which equates to smaller losses for heating the flue gas.

A reduction in auxiliary power requirements will be realized since the pulverizers, motors and electrical equipment associated with the scrubbers, coal handling equipment, will no longer be operated after the conversion.

## 3.1 A.B. BROWN UNITS 1 AND 2 BOILER STEAMING CAPABILITY

Based on an assessment by Babcock & Wilcox, at MCR the main steam temperature leaving the boiler is expected to be the same as with firing coal, however, the hot reheater (HRH) temperature after gas conversion is expected to be less than the HRH temperature from firing coal. A summary of the predicted performance results based on Babcock & Wilcox' evaluation is shown in Table 3-1.

At the 60% MCR flow condition, Table 3-1 shows a more significant reduction in steam temperatures for natural gas operation. Main steam temperature decreases from 1,005 °F to 955 °F and hot reheat temperature decreases from 1,005 °F to 835 °F. Reductions in main steam and reheat steam temperatures will reduce the net turbine heat rate at this operating condition.

In addition, the excess air requirements for firing natural gas are less than the excess requirements for firing coal. This equates to a reduction in the spray water requirements for the main steam and reheater attemperators.

**Table 3-1 A.B Brown Units 1 and 2 Predicted Boiler Steam Conditions**

| LOAD CONDITION | UNITS | MCR | MCR | 60% | 60% |
|---|---|---|---|---|---|
| FUEL | - | 100% COAL | 100% NATURAL GAS | 100% COAL | 100% NATURAL GAS |
| Superheater Exit Steam Flow | kpph | 1,850 | 1,850 | 1,110 | 1,110 |
| CRH Steam Flow | kpph | 1,667 | 1,667 | 1,000 | 1,000 |
| Superheater Exit Steam Pressure | psig | 1,965 | 1,965 | 1,917 | 1,917 |
| Reheater Exit Steam Pressure | psig | 460 | 460 | 261 | 261 |
| Superheater Exit Steam Temperature | F | 1,005 | 1,005 | 1,005 | 955 |
| Reheater Exit Steam Temperature | F | 1,005 | 992 | 1,005 | 835 |

One possible way to reduce the impact to the hot reheat steam temperature is to increase air flow through the boiler with the use of FGR and OFA. These systems are typically considered for NOx control but can also be utilized to improve boiler performance by increasing overall combustion air flow through the boiler. The result is more heat transfer in the convective pass of the boiler improving HRH temperatures. A detailed analysis would need to be performed by the OEM or a third-party boiler model developed to evaluate the potential for improved performance.

### 3.1.1 Steam Turbine Impacts

The increased temperature difference between main steam and hot reheat steam during natural gas firing can have an adverse impact on the steam turbine. Based on the 60% MCR flow conditions for natural gas operation, the temperature difference is estimated to be 120 °F (955 °F – 835 °F). The main steam and hot reheat steam admissions are adjacent to one another in the same turbine shell and thus the initial and reheat temperatures have an important influence on the axial temperature gradient in the turbine shell.

General Electric (GE), the steam turbine OEM, typically provides guidelines on the permissible temperature difference at various operating load points. A review of the A.B. Brown steam turbine operating manual and subsequent discussion with GE indicates that the guideline included by GE for allowable differences between main and reheat steam temperatures is for units with opposed flow HP-IP turbines similar to the A.B. Brown turbines, but with a separate control valve chest. The A.B. Brown turbines however have an integral valve chest (shell mounted). GE has confirmed the provided guideline is also applicable to the A.B. Brown turbines with integral valve chest. The GE provided data indicates the 120°F differential temperature is acceptable at 60% MCR flow. Predicted boiler performance on natural gas operation was not evaluated below 60% MCR flow, therefore this operating condition would need to be assessed to fully understand the possible impacts to the steam turbine at lower loads.

Additional measures to mitigate the reduction in steam temperatures and potentially reducing their temperature difference may include sliding pressure operation at part load (compared to constant main steam pressure at part load), and possible additional measures in the boiler operation. The degree of extension of the constant temperature range for variable pressure operation will vary with a particular steam generator, fuel and other station constraints and would require additional evaluation by Babcock & Wilcox.

Reduced hot reheat steam temperature can result in increased moisture at the low-pressure turbine exhaust. Increased moisture can increase the potential for erosion of the blading of the low-pressure turbine section. The steam turbine OEM should be requested to further evaluate the impact, if any, of this increased exhaust moisture as well as the impact of the changed conditions in the low-pressure turbine section where the onset of condensation will occur (known as the Wilson Line). Initial assessment indicates the exhaust moisture may increase on the order of 3% at the 60% of MCR flow operating conditions.

## 3.2 F.B. CULLEY UNIT 2 BOILER STEAMING CAPABILITY

It is predicted that the main steam output of the units will not be reduced following the conversion. The excess air requirements for firing natural gas are less than the excess requirements for firing coal. This equates to a reduction in the spray water requirements for the main steam attemperators – the orifice diameter in the spray water attemperator nozzle would have to be increased. The main steam temperature and pressure leaving the boiler is expected to be the same as with firing coal. To meet these conditions, a surface reduction in the primary superheater would be required in the case where flue gas recirculation is utilized. A summary of the predicted performance results based on Babcock & Wilcox' evaluation is shown in Table 3-3.

**Table 3-3 F.B. Culley Unit 2 Predicted Boiler Steam Conditions**

| LOAD CONDITION | UNITS | MCR | MCR | 50% | 50% |
|---|---|---|---|---|---|
| **FUEL** | **-** | **100% COAL** | **100% NATURAL GAS** | **100% COAL** | **100% NATURAL GAS** |
| Superheater Exit Steam Flow | kpph | 840 | 840 | 420 | 420 |
| Superheater Exit Steam Pressure | psig | 1,290 | 1,290 | 1,260 | 1,260 |
| Superheater Exit Steam Temperature | F | 955 | 955 | 955 | 955 |

### 3.2.1 Steam Turbine Impacts

As shown in Table 3-3 the superheat steam flow and temperature remain consistent between coal and natural gas fired scenarios. Therefore unlike A.B. Brown Units where they drop off at part load, there is not a concern of potential steam turbine impacts to F.B. Culley Unit 2 when firing natural gas.

# 4.0 NOx and CO Reduction Techniques

Converting the boilers to 100 percent natural gas combustion should significantly decrease the $NO_x$ while increasing CO from the combustion process. Since there is nearly zero fuel-bound nitrogen in natural gas, $NO_x$ production is a direct result of thermal $NO_x$ formation during combustion. In addition, natural gas firing temperatures are typically lower, as less excess air is required to complete combustions compared to coal, reducing the potential for thermal $NO_x$ to form. However, this limited oxygen environment that results in lower $NO_x$ does increase CO from incomplete combustion. It should be noted that even though NOx production is lower for natural gas vs. coal due to less combustion air, the allowable permitting limits for burning natural gas can be much lower than coal. For instance, Unit 1 at A.B. Brown is currently subject to New Source Performance Standard (NSPS) Subpart D, which carries a $NO_X$ limit of 0.70 lb/MBtu for coal-fired units. For natural gas-fired units, the rule prescribes a $NO_X$ limit of 0.20 lb/MBtu. Unit 2 at A.B. Brown is subject to NSPS Subpart Da, which requires that the unit meet a $NO_X$ emission limit of 0.50 lb/MBtu for coal-firing. Following a conversion to natural gas, the unit would be subject to a limit of 0.20 lb/MBtu. F.B. Culley Unit 2 is not subject to any NSPS $NO_X$ limits given its age. Black & Veatch would not anticipate that this would change following a conversion to natural gas assuming that the project is not applicable to major modification permitting requirements.

To control $NO_x$ and CO, additional controls are typically required and for this evaluation included assessment of selective catalytic reduction (SCR), flue gas recirculation (FGR), over-fire air (OFA), and CO Catalyst also referred to as Oxygen catalyst to limit emissions.

Specific reduction techniques considered for A.B. Brown Units 1 and 2 and F.B. Culley Unit 2 are identified in Table 4-1 and Table 4-2. Calculated emission rates for the evaluated emission control technologies are identified in Section 5, Table 5-1.

### Table 4-1 A.B. Brown Unit 1 and 2 Optional Methods for NOx Reduction

| COMPONENT | RESULTS | COMMENTS |
|---|---|---|
| OPTIONAL METHODS FOR $NO_X$ REDUCTION | | |
| Staged Combustion (OFA Ports) | Addition of eight new OFA (aka $NO_X$ ports) in the furnace walls; four in the front wall, four in the rear wall. | Will require windbox and duct work modifications. Since A.B. Brown units are currently equipped with SCR systems OFA may not be required |
| Flue Gas Recirculation (FGR) | Introduction of recirculated flue gas into the combustion air stream upstream of the burner windbox via new FGR fan pulling flue gas from ducting downstream of the air heater. | Mixing device to be added in the combustion air ductwork to adequately distribute the recirculated flue gas into the incoming combustion air. Since A.B. Brown units are currently equipped with SCR systems, FGR may not be required |
| Selective Catalytic Reduction (SCR) | Continued operation of existing SCRs including ammonia storage and feed systems. | Existing SCR catalyst would require analysis to determine if any or all layers require replacement to meet targeted $NO_x$ reduction. |

| | | |
|---|---|---|
| **OPTIONAL METHODS FOR CO REDUCTION** | | |
| CO Catalyst | Addition of a CO (Oxygen) Catalyst to be located in the fourth layer of the existing SCR which is currently unused. | Multiple catalysis technologies are available and include duel SCR and CO catalysis which should be evaluated during detailed design. |

**Table 4-2 F.B. Culley Unit 2 Optional Methods for $NO_x$ Reduction**

| COMPONENT | RESULTS | COMMENTS |
|---|---|---|
| **OPTIONAL METHODS FOR $NO_X$ REDUCTION** | | |
| Staged Combustion (OFA Ports) | Addition of eight new OFA (aka $NO_X$ ports) in the furnace walls; four in the front wall, four in the rear wall, located approximately 8 feet above the top burner row | Will require windbox and duct work modifications |
| FGR | Introduction of recirculated flue gas into the combustion air stream upstream of the burner windbox via new FGR fan pulling flue gas from ducting downstream of the air heater | Mixing device to be added in the combustion air ductwork to adequately distribute the recirculated flue gas into the incoming combustion air |
| **OPTIONAL METHODS FOR CO REDUCTION** | | |
| CO Catalyst | Addition of a new CO (Oxygen) Catalyst in the flue gas ductwork between the economizer outlet and air heater inlet. | Would require extensive modifications to the flue gas ductwork to facilitate installation. |

## 4.1 OVER-FIRE AIR (OFA)

Two-staged combustion is a method of achieving a significant reduction in $NO_x$. Combustion air is directed to the burner zone in quantities (70 percent to 90 percent) that are less than that required to theoretically burn the fuel. The remainder of the combustion air (10 percent to 30 percent) is directed to OFA ports, which are located above the top row of burners. By reducing the excess air in the primary combustion (burner) zone, $NO_x$ formation is stunted due to the limited amount of oxygen in the air. Furthermore, less oxygen means a decrease in the combustion reactions occurring and a decrease in the heat of reaction released, reducing the overall and peak temperatures in the burner zone (first stage). The additional air nozzles also spread the release of heat over a larger area in the furnace. Thermal $NO_x$ formation increases with higher temperatures, so reducing the overall and peak temperatures represses thermal $NO_x$. Any residual unburned material, such as CO that inevitably escapes the main burner zone, is subsequently oxidized as the OFA is added.

The expected $NO_x$ reduction from a given OFA system depends on a number of factors. The stoichiometry in the burner zone decreases as the amount of OFA is increased, and a point is reached where CO emissions reach high levels and become uncontrollable. The point at which this occurs varies, depending on the balance of flows between individual burners. As the OFA amount approaches 10 to 15 percent, the probability for individual burners to be operating under fuel-rich conditions increases so that pockets of very high CO emissions would be formed.

The total estimated furnish and installed cost for an over-fire air system is shown in Table 4-3.

**Table 4-3 Over-Fire Air System Estimated Cost**

| | A.B. BROWN UNIT 1 | A.B. BROWN UNIT 2 | CULLEY, UNIT 2 |
|---|---|---|---|
| Materials and installation[1] | $1,000,000 | $1,000,000 | $975,000 |
| Total furnish and installed cost for OFA system | $1,000,000 | $1,000,000 | $975,000 |

Note:
1. Includes OFA nozzles, ducting modifications, and dampers

## 4.2 FLUE GAS RECIRCULATION

FGR is useful in reducing $NO_x$ when the contribution of fuel nitrogen to the total $NO_x$ formation is a small fraction of the constituents, such as the case with natural gas. Typically, a portion of the flue gas is extracted from the discharge of the economizer (gas side) or discharge of the air heater and introduced into the combustion air flow stream, which lowers the burner peak flame temperatures.

The typical design of an FGR system requires the installation of an FGR fan, ducting, duct supports, and controls. The FGR system utilizes air foils to mix the recirculated flue gas with the combustion air downstream of the FD fan. This ensures that the flue gas and combustion air are thoroughly mixed before reaching the burners.

For retrofit applications, FGR sometimes needs to be provided with OFA ports, because the original burners are not capable of handling the significant increase in mass flow from the recirculated flue gas. The necessary FGR rates can result in throat velocities that exceed the burners' design, which will result in burner instability and potential pulsations while firing.

In general, a significant increase in flue gas recirculation to the burners would produce a large reduction in $NO_x$ emissions. The amount of FGR would be dictated by the emissions levels that are targeted as well as limitations on equipment size and boiler components.

An additional benefit of FGR is that the additional flue gas flow with the combustion air can increase furnace velocities to push heat to the convective heating surfaces, which could increase steam temperatures on coal units that have been converted to gas.

The total estimated furnish and installed cost for a flue gas recirculation system is shown in Table 4-4.

**Table 4-4 Flue Gas Recirculation System Estimated Cost**

| | A.B. BROWN UNIT 1 | A.B. BROWN UNIT 2 | CULLEY, UNIT 2 |
|---|---|---|---|
| Materials and installation[1] | $3,880,000 | $3,880,000 | $1,560,000 |
| Total furnish and installed cost for FGR system | $3,880,000 | $3,880,000 | $1,560,000 |
| Notes: 1. Includes FGR fan/motor, ducting, instrumentation, and installation | | | |

## 4.3 SELECTIVE CATALYTIC REDUCTION

Selective catalytic reduction (SCR) reduces $NO_x$ emissions by introducing ammonia ($NH_3$) into the flue gas upstream of a reaction chamber. Ammonia readily reduces the $NO_x$ molecules into nitrogen and water at temperatures above 1600°F (870°C). The SCR reaction chamber, which is installed between the economizer and air preheater, is at temperatures much less than is optimal for $NH_3$-$NO_x$ reactions, so catalysts are needed to promote the reactions. The reaction chamber contains one or multiple layers of catalyst that are made of metals and/or ceramics contained a highly porous structure.

Poisoning of the catalyst from alkali metals and trace elements (especially arsenic) is a steady process that occurs over the life of the catalyst. As the catalyst becomes deactivated, ammonia slip emissions increase, approaching design values. This means that the catalyst in a SCR system is consumable, requiring periodic replacement at a frequency dependent on the level of catalyst poisoning. For natural gas applications, significantly less catalyst poisoning is expected compared to coal burning facilities.

Since the existing SCR catalyst systems at A.B. Brown Unit 1 and Unit 2 have been in use for several years it was assumed for this study and cost estimate that multiple layers of SCR catalyst would need to be replaced to facilitate continued operation and $NO_x$ reduction through the SCRs. The next step would be for Vectren to have a catalyst OEM assess the condition of the existing catalyst and make a recommendation for replacement or reuse for the natural gas conversion operation.

The total estimated furnish and installed cost for a selective catalytic reduction system is shown in Table 4-5.

**Table 4-5 Selective Catalytic Reduction System Estimated Cost**

| | A.B. BROWN UNIT 1 | A.B. BROWN UNIT 2 | CULLEY, UNIT 2 |
|---|---|---|---|
| Total materials | $1,060,000 | $1,060,000 | N/A |
| Total installation | $1,000,000 | $1,000,000 | N/A |
| Total furnish and installed cost for a SCR system[1] certification | $2,060,000 | $2,060,000 | NA |
| Notes:<br>1. SCR system includes replacement of catalyst, chemical disposal, SCR catalyst replacement, installation. | | | |

## 4.4 OXGYEN CATALYTIC REDUCTION (CO CATALYST)

Catalytic oxidation is a post-combustion method for reduction of CO and VOC emissions. This control process utilizes a platinum/vanadium catalyst that oxidizes CO to CO2 and VOC to CO2 and water. The process is a straight catalytic oxidation/reduction reaction requiring no reagent. Catalytic CO and VOC emissions reduction methods have been proven for use on natural gas and oil fueled combustion turbine sources, but not coal fired boilers. It should be noted that none of the catalyst components are considered toxic.

The primary technical challenge for including an oxidation catalyst on a coal or natural gas fired boiler is the location of the catalyst in a high temperature regime, which would ideally be prior to the economizer as the optimum exhaust gas temperature range for CO and VOC catalyst operation is between 850°F and 1,110°F (1,560°C and 2,012°C). For the purpose of this study the CO catalyst is assumed to be located between the economizer and air heater.

The total estimated cost for a catalytic oxidation system is shown in Table 4-6.

**Table 4-6 Catalytic Oxidation System Estimated Cost**

| | A.B. BROWN UNIT 1 | A.B. BROWN UNIT 2 | CULLEY, UNIT 2 |
|---|---|---|---|
| Total materials | $3,500,000 | $3,500,000 | $2,000,000 |
| Total installation | $1,500,000 | $1,500,000 | $3,000,000 |
| Total furnish and installed cost for CO system[1] | $5,000,000 | $5,000,000 | $5,000,000 |
| Notes:<br>1. Includes CO system materials, | | | |

# 5.0 Emissions Netting

## 5.1 BACKGROUND

Converting A.B. Brown Units 1 and 2 and F.B. Culley Unit 2 to fire natural gas would constitute a modification of an existing air emissions source and would, therefore, require an air construction permit to authorize construction. The first step in any air construction permit application process is to determine the proposed project's applicability to the federal New Source Review (NSR) pre-construction permitting program.

The Federal Clean Air Act (CAA) NSR provisions are implemented for major modifications at existing major sources under two programs: the Prevention of Significant Deterioration (PSD) program outlined in 40 CFR §52.21 for areas in attainment of the National Ambient Air Quality Standards (NAAQS), and the Non-Attainment NSR (NA-NSR) program outlined in 40 CFR §51 and §52 for areas classified as not in attainment of the NAAQS (i.e., non-attainment areas). Currently, both Posey County and Warrick County, Indiana, are designated as either attainment or unclassifiable for all criteria pollutants. Because of this, a determination of whether the proposed natural gas conversions would qualify as a major modification at an existing major source would need to be made in accordance with the procedures outlined in the PSD program. Projects that are subject to PSD permitting are required to undertake extensive analyses as part of the permit application process, including air dispersion modeling and the identification and application of best available control technology (BACT). Additionally, PSD permitting can take as long as 12-18 months. Non-PSD permitting, or minor source permitting, on the other hand does not typically require modeling or BACT and the associated timeline is typically 3-6 months.

For a project to be deemed a major PSD modification under the definition provided in 40 CFR §52.21, the project must result in both a significant emission increase and a significant net emission increase. The process of determining whether a significant emissions increase will result from the construction of a project is commonly referred to as "Step 1" of the PSD applicability test. Because both A.B. Brown and F.B. Culley are existing major sources under the PSD process, the Step 1 evaluation must be conducted on a pollutant-by-pollutant basis by comparing the emissions increase of each pollutant against the PSD significant emissions rates (SERs). If a project's emissions increase of a given pollutant are larger than the pollutant's respective SER, the project is considered to result in a significant emissions increase. Since the proposed natural gas conversions will involve existing emissions units, this Step 1 emissions increase, or project emissions increase (PEI), can be calculated as the difference between either the project actual emissions (PAE) or the potential to emit (PTE) and the baseline actual emissions (BAE). BAE is defined in the federal PSD regulations as the average rate, in tons per year (tpy), at which the emissions unit actually emitted a regulated NSR pollutant during any consecutive 24 month period selected by the owner or operator within the 5 year period immediately preceding when the owner or operator begins actual construction of the project. However, because air construction permit applications are required to be submitted several months prior to the start of construction, agencies will typically accept BAEs based on the 5-year period immediately preceding the submittal of the air construction permit application.

Because the proposed projects entail the conversion of coal fired boilers to natural gas firing, the PAE cannot easily be determined, as no past operation burning natural gas could be used to base a projection on. Therefore, the PTE would likely be used in conjunction with the BAE to determine the PEI of the proposed natural gas conversions in Step 1 of the PSD applicability determination. According to federal and state definitions, the PTE is "the maximum capacity of a source to emit a pollutant under its physical and operational design. Any physical or operational limitation on the capacity of a source to emit an air pollutant, including air pollution control equipment and restrictions on hours of operation or type of/amount of material combusted, stored, or processed, shall be treated as part of its design if the limitation is enforceable […]."

Vectren has determined that any air construction permitting strategy for the proposed natural gas conversions at A.B. Brown and F.B. Culley should try to mitigate the need for PSD. As previously noted, obtaining a PSD permit involves several rigorous requirements including the application of Best Available Control Technology (BACT) and the performance of an air dispersion modeling analysis examining the effects of the project's emissions on the ambient air quality. Thus, the PSD review process typically adds significant time in a project schedule to account for application preparation as well as Indiana Department of Environmental Management (IDEM) and Environmental Protection Agency (EPA) review.

## 5.2 PRELIMINARY PSD APPLICABILITY ANALYSIS

A high-level preliminary emissions analysis was conducted to determine the operational limits (i.e., limits on annual hours of operation) required to keep the Step 1 pollutant-by-pollutant PEI for the natural gas conversion at each facility less than the respective PSD SERs so that PSD permitting would not be required. The analysis examined the added hours of operation that could be achieved utilizing various air quality control technologies.

Assuming all other factors are held equal, because of the cleaner nature of natural gas combustion compared to coal, conversion of the A.B. Brown and F.B. Culley coal fired boilers to natural gas fueled units should result in emissions reductions when comparing the PTE to the BAE for those pollutants that are directly related to fuel makeup (i.e., PM and $SO_2$). On the other hand, for pollutants where emissions are associated with the combustion process (i.e., $NO_X$, CO, and VOC), emissions associated with natural gas combustion can yield emissions increases in the Step 1 PEI calculation. Because of this, the preliminary analysis was limited to examine only $NO_X$, CO, and VOC as the "limiting pollutants."

The $NO_X$, CO, and VOC BAE for A.B. Brown and F.B. Culley utilized a combination of industry standard emission factors from EPA's AP-42 database, continuous emissions monitoring system (CEMS) data, and fuel usage data. The A.B. Brown baseline includes monthly emissions through February 2019 whereas F.B. Culley's BAE was based on data through the end of 2018. The BAE for both A.B. Brown units and the F.B. Culley unit only considered data dating back to January 2015, which is not consistent with the definition above that specifies a lookback period of 5 years. Black & Veatch notes, however, that this approach is consistent with a decision by IDEM that dictated that operational data prior to January 2015 would not be able to be considered, as it was not representative of the current operating characteristics of the A.B. Brown units.

For the PTE calculations, natural gas fired emissions rates that were developed in previous coal to natural gas conversion study were utilized. These emission rates considered varying configurations of three combustion controls designed to reduce $NO_X$ emissions:

- Low $NO_X$ natural gas burners (XCL-S burners).
- OFA.
- FGR.

In addition to combustion controls, Vectren requested that Black & Veatch examine the impacts of catalyst based post-combustion controls for $NO_X$, CO, and VOC. Typical post-combustion catalyst-based controls include SCR to control $NO_X$ emissions and oxidation catalyst (i.e., CO catalyst) to control emissions of CO and VOC. A.B. Brown Units 1 and 2 already employ an SCR to control $NO_X$ emissions, and for the expanded analysis, it was assumed that these systems would be left in service following the natural gas conversion. For F.B. Culley, all additional control scenarios would require newly installed equipment. In addition to a separate catalyst system to control $NO_X$ and CO/VOC, Black & Veatch also analyzed a scenario in which a dual catalyst designed to control both $NO_X$ and CO would be used in addition to SCR to achieve the necessary pollutant controls.

The emissions calculation methodology first entailed calculating the threshold magnitude of $NO_X$, CO, and VOC emissions that could occur without triggering PSD (tpy) by adding the BAE of each unit to the respective SERs (i.e., 40 tpy for $NO_X$ and VOC and 100 tpy for CO). Because the modification at A.B. Brown involves two units, an assumption was made that the threshold emissions increases for the project (the “project” would include the cumulative emissions increases for both unit conversions) would be distributed equally between Unit 1 and Unit 2. The emission rates were then combined with projected heat inputs rates (in million British thermal units per hour [MMBtu/h]) to determine the maximum number of hours that a particular unit could be operated without triggering PSD for at least one of the limiting pollutants. Heat inputs for natural gas-fired operation for all three units were assumed to be identical to heat inputs for coal fired operation.

The analysis examined three different load points: 100 percent load, 60 percent load, and 10 percent load. For each load point, the following air quality control configurations were examined:

- A.B. Brown Units 1 and 2:
  - XCL-S burners only.
  - XCL-S burners and OFA.
  - XCL-S burners, OFA, and FGR.
  - XCL-S burners and FGR.
  - XCL-S burners and CO catalyst.
  - XCL-S burners, existing SCR, and dual catalyst.
  - XCL-S burners, FGR, and CO catalyst.
- F.B. Culley Unit 2:
  - XCL-S burners only.
  - XCL-S burners and OFA.

- XCL-S burners, OFA, and FGR.
- XCL-S burners and FGR.
- XCL-S burners and CO catalyst.
- XCL-S burners, new SCR, and new dual catalyst.
- XCL-S burners, FGR, and CO catalyst.

Preliminary iterations of the analysis examining OFA indicated that the $NO_x$ reduction from OFA is insignificant. As such, the analysis as presented below was refined to only include results from the scenarios that include XCL-S burners, FGR, and post combustion controls. The emission rates that were utilized to calculate the post-conversion PTE's are included in Table 5-1.

**Table 5-1 Natural Gas Fired Emission Rates**

| UNIT | POLLUTANT | XCL-S BURNERS ONLY | XCL-S BURNERS & FGR | XCL-S BURNERS AND CO CATALYST[1] | XCL-S BURNERS, SCR, AND DUAL CATALYST[2] | XCL-S BURNERS, FGR, AND CO CATALYST[1] |
|---|---|---|---|---|---|---|
| A.B. Brown Unit 1 | $NO_X$ | 0.17 | 0.07 | 0.17 | 0.01 | 0.07 |
| | CO | 0.15 | 0.15 | 0.015 | 0.015 | 0.015 |
| | VOC | 0.003 | 0.003 | 0.0017 | 0.0017 | 0.0017 |
| A.B. Brown Unit 2 | $NO_X$ | 0.19 | 0.07 | 0.19 | 0.01 | 0.07 |
| | CO | 0.15 | 0.15 | 0.015 | 0.015 | 0.015 |
| | VOC | 0.003 | 0.003 | 0.0017 | 0.0017 | 0.0017 |
| F.B. Culley Unit 2 | $NO_X$ | 0.16 | 0.07 | 0.16 | 0.01 | 0.07 |
| | CO | 0.15 | 0.15 | 0.015 | 0.015 | 0.015 |
| | VOC | 0.003 | 0.003 | 0.0017 | 0.0017 | 0.0017 |

Notes:
1. $NO_X$ emissions rates for A.B. Brown Units 1 and 2 and F.B. Culley Unit 2 were obtained from Babcock & Wilcox studies on converting the boilers from coal to natural gas. CO and VOC emissions rates are based on engineering estimate. Assumes 90% and 45% removal efficiency in the CO catalyst, respectively.
2. $NO_X$ and CO emissions are based on Cormetech estimates. VOC emissions rates are based on engineering estimate. Assumes 45% removal efficiency in the dual catalyst.

Figures 5-1 through 5-3 illustrate the hours available to each unit while avoiding PSD permitting at 100 percent, 60 percent, and 10 percent load. Finally, in addition to the hours of operation achievable while not triggering PSD, the figures also include the installed cost estimates for each air quality control scenario.

As can be seen in the figures, the most affordable option available that also allows full operational flexibility for all three units is the addition of XCL-S burners and dual catalyst.

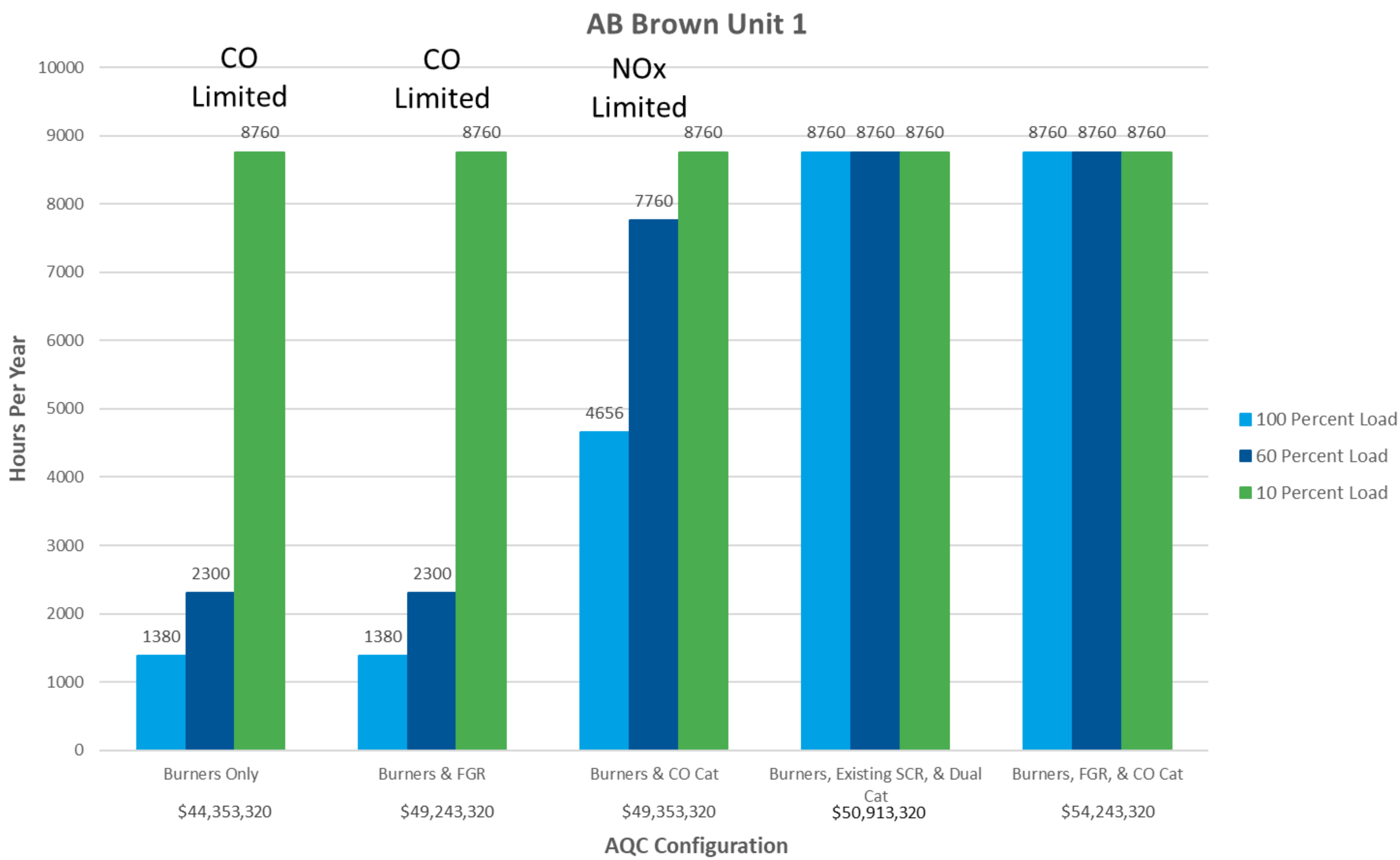



**Figure 5-1 Hours of Operation Achievable without Triggering PSD – A.B. Brown Unit 1**

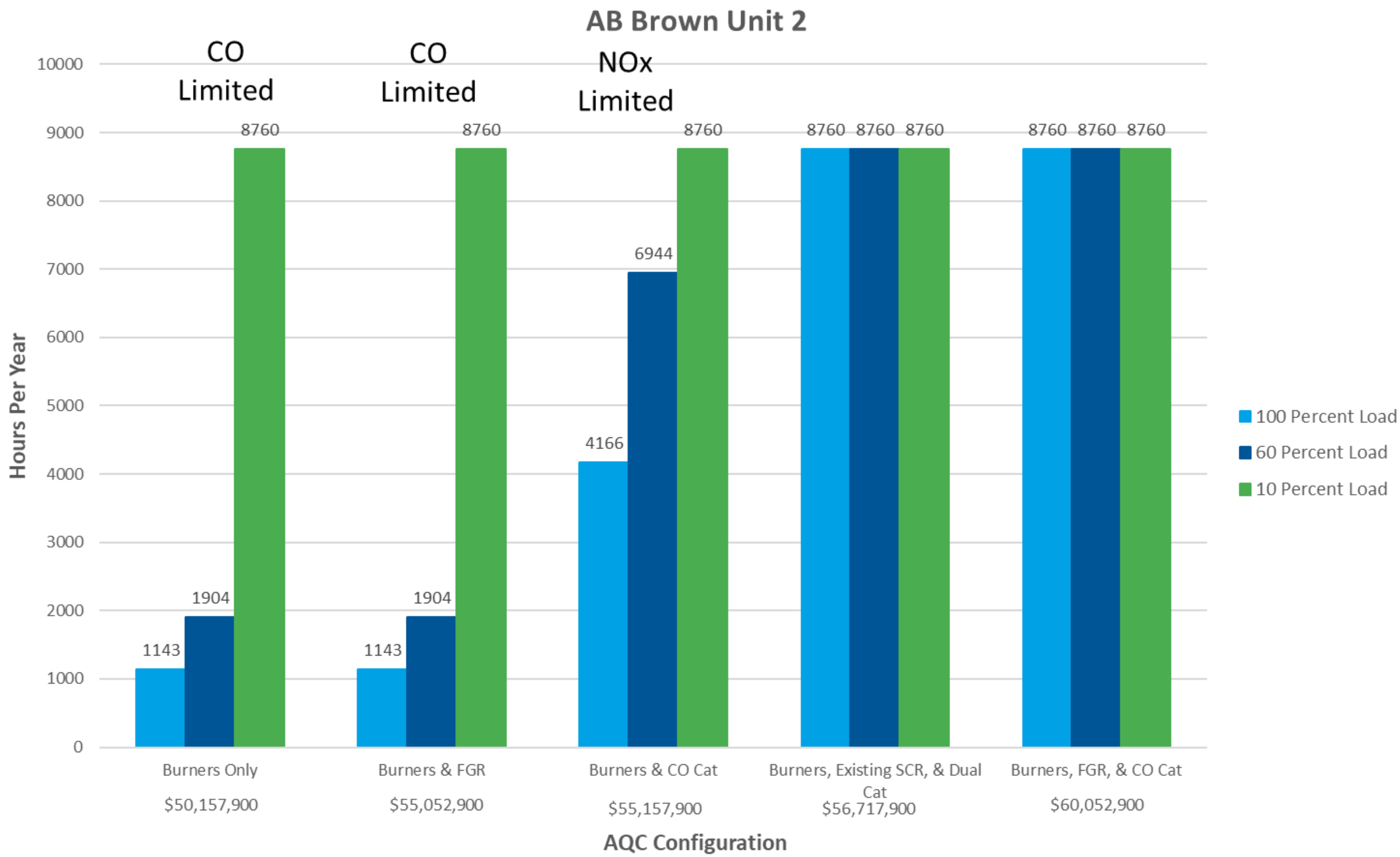



**Figure 5-2 Hours of Operation Achievable without Triggering PSD – A.B. Brown Unit 2**

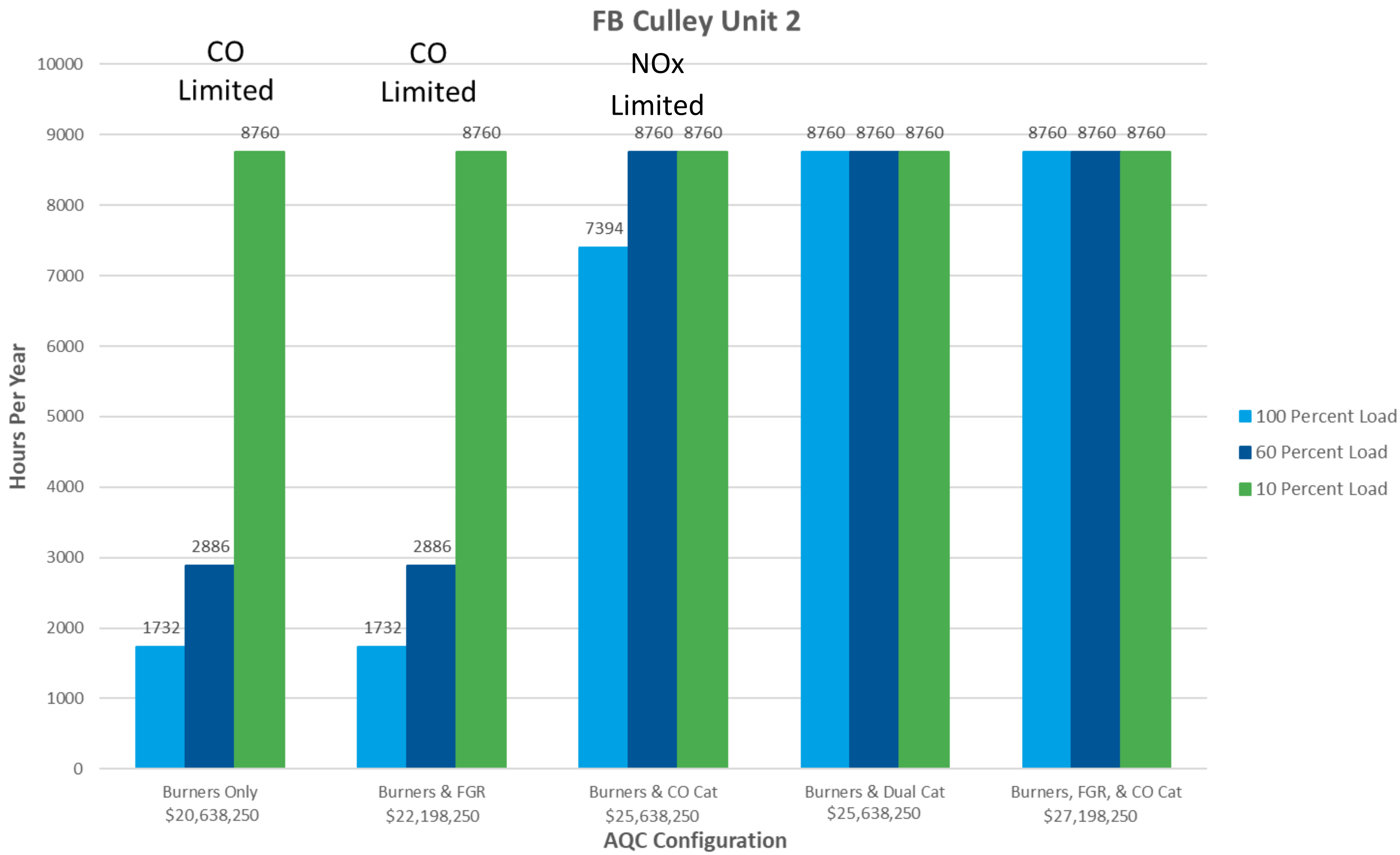



**Figure 5-3 Hours of Operation Achievable without Triggering PSD – F.B. Culley Unit 2**

# 6.0 Estimated Costs

The estimated furnish and installation costs for the conversion were provided from multiple sources and are summarized in Table 6-1.

### Table 6-1 Estimated Project Costs

| | A.B. BROWN UNIT 1 | A.B. BROWN UNIT 2 | CULLEY , UNIT 2 |
|---|---|---|---|
| Materials; burner replacements, ducting metering/regulating station, BOP modifications, etc. | $10,070,000 | $11,419,000 | $8,880,000 |
| Installation; burner replacements, ducting metering/regulating station, BOP modifications, etc. | $8,639,600 | $9,970,000 | $3,660,000 |
| Bowen Gas Line from T10 to Tee | $1,618,000 | $1,618,000 | $685,000 |
| FGD Demo and Bypass Duct | $5,600,000 | $7,798,000 | N/A |
| CO Catalyst Layer (materials) | $3,500,000 | $3,500,000 | $2,000,000 |
| CO Catalyst Layer (installation) | $1,500,000 | $1,500,000 | $3,000,000 |
| SCR Catalyst (materials) (1) | $1,060,000 | $1,060,000 | N/A |
| SCR Catalyst (installation) | $1,000,000 | $1,000,000 | N/A |
| Over Fire Air (materials and installation) (1) | $1,000,000 | $1,000,000 | $975,000 |
| Flue Gas Recirculation System (materials and installation) (1) | $3,880,000 | $3,880,000 | $1,560,000 |
| General Boiler/Plant Modifications | $9,033,360 | $9,185,960 | $3,245,273 |
| Owners Consultant (19%) | $8,911,182 | $9,866,882 | $4,561,002 |
| **Total Project Cost** | **$55,812,142** | **$61,797,842** | **28,566,275** |
| **Annual Maintenance Costs** | **$30,000** | **$30,000** | **$25,000** |

Notes:
1. Optional Scope – Pricing included in Total Project Cost

Abbreviations:
BOP – Balance of Plant
DCS - Distributed Control System
CO – Carbon Monoxide
SCR - Selective Catalytic Reduction

# 7.0 Conclusions

## 7.1 SUMMARY

A.B. Brown Units 1 and 2 and F.B. Culley Unit 2 were evaluated on the basis of converting the units from firing 100 percent bituminous coal to firing 100 percent natural gas. The study included evaluating design changes that are required to make the conversion: new/modified burners, additional natural gas metering/pressure reducing s, balance-of-plant modifications, BMS controls modifications, etc. Additionally, the evaluations discussed plant performance impacts resulting from the coal-to-natural gas conversion and provided estimated costs for the modifications.

Black & Veatch's review concluded the OEM assessed impacts to performance, reduction in boiler efficiency, gross/net output, auxiliary loads, and an increase in net plant heat rate and steam turbine generator heat rate are consistent and reasonable given our experience and assessments of similar sized units.

# Appendix A. Babcock & Wilcox Engineering Study for Natural Gas Firing for A.B. Brown Units 1 and 2

# Engineering Study for Natural Gas Firing

**for**

**Vectren Power Supply**
**AB Brown Station Units 1 & 2**
**Evansville, Indiana**

**Contract 591-1048 (317A)**
**June 13, 2019 - Rev 5**

**THE BABCOCK & WILCOX COMPANY ASSUMES NO LIABILITY WITH RESPECT TO THE USE OF, OR FOR DAMAGES RESULTING FROM THE USE OF, ANY INFORMATION, METHOD OR PROCESS DISCLOSED IN ANY REPORT ISSUED UNDER THIS CONTRACT.**

**THE BABCOCK & WILCOX COMPANY EXPRESSLY EXCLUDES ANY AND ALL WARRANTIES EITHER EXPRESSED OR IMPLIED, WHICH MIGHT ARISE UNDER LAW OR EQUITY OR CUSTOM OF TRADE, INCLUDING WITHOUT LIMITATION, WARRANTIES OF MERCHANTABILITY AND OF FITNESS FOR SPECIFIED OR INTENDED PURPOSE.**

# TABLE OF CONTENTS

## INTRODUCTION

Vectren Power Supply contracted The Babcock and Wilcox Company (B&W), under B&W contract 591-1048 (317A), to evaluate natural gas firing at the AB Brown Station Units 1 and 2, originally supplied by B&W under contract RB-557 and RB-599. The boiler performance model was reviewed at 100% (Maximum Continuous rating) MCR and 60% load when firing 100% natural gas. An analysis of the allowable tube metal stresses was performed for 100% gas firing at 100% MCR and 60% boiler loads in regards to the primary superheater, secondary superheater and reheat superheater.

## BACKGROUND

The AB Brown Units 1 & 2 (RB-557 & RB599) are presently balanced draft (Unit 1 was originally pressure fired and converted to balanced draft operation), subcritical Carolina type radiant boilers, with secondary superheater, primary superheater, reheater and economizer surfaces arranged in series. Superheater steam temperature is controlled by interstage spray attemperation. Reheater steam temperature is controlled by excess air and spray attemperation. The units were originally designed as a front and rear wall, bituminous coal fired units. The original maximum continuous rating for RB-557 and RB-599 is 1,850,000 lbs/hr of main steam at 1005°F and 1965 psig at the superheater outlet with a feedwater temperature of 467°F. The reheat steam flow is 1,666,500 lbs/hr at 1005 F and 485 psig at the reheater outlet. Spray attemperation is used to control superheat and reheat steam temperatures. The units were to be operated at 5% overpressure over the load range.

The units are front and rear wall fired with twenty-four B&W 4Z low $NO_x$ burners, four wide by three high. There are six B&W EL-76 pulverizers for each unit supplying coal to the burners.

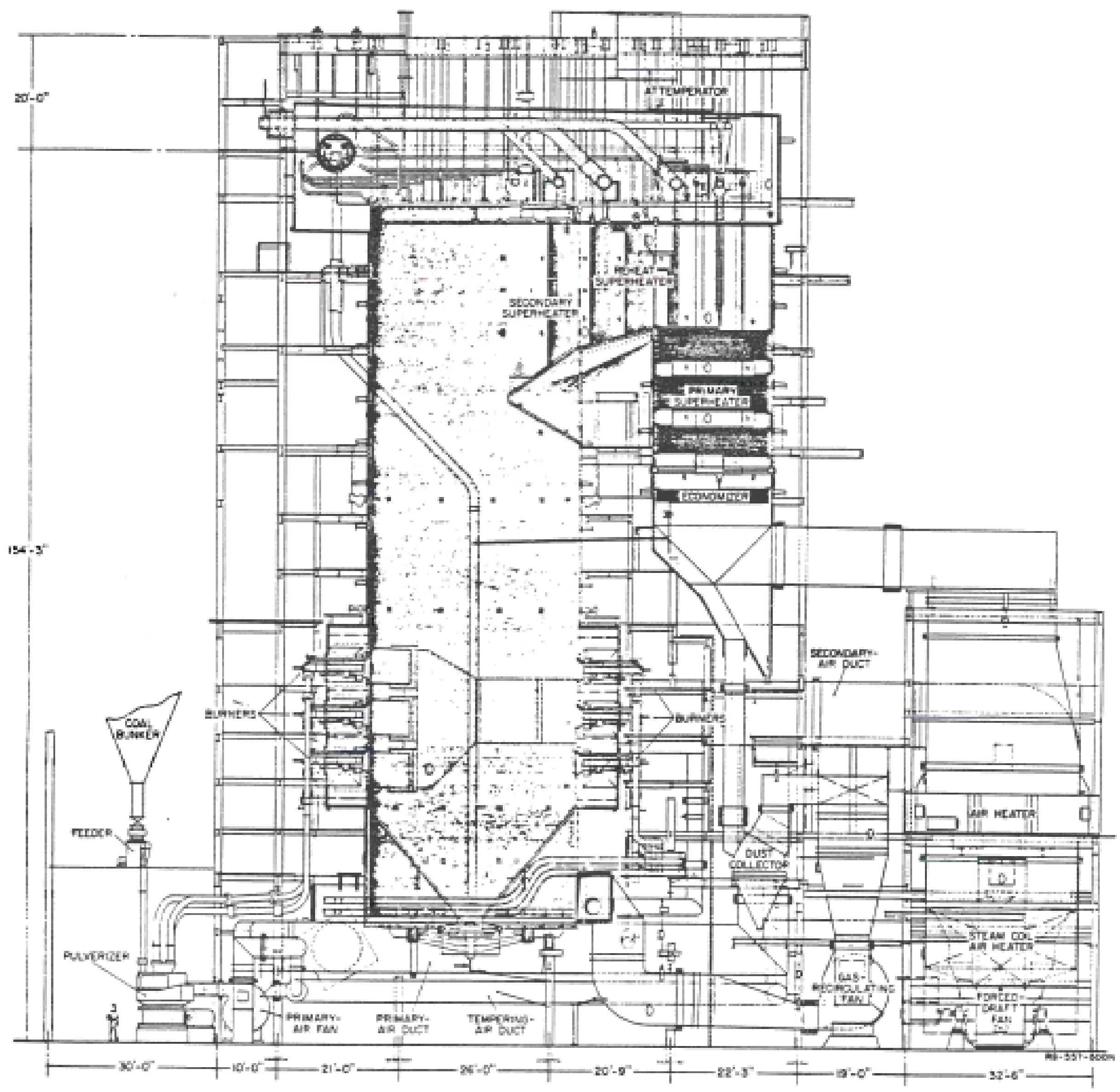
Combustion air is heated through two Ljungstrom regenerative air heaters.

Unit 2 (RB-599) is a semi-duplicate of Unit 1 (RB-557) with the following differences:

- Unit 2 has a furnace height of 124’-0’’ compared to 122’-0” for Unit 1. The vertical burner spacing is 10’-0” for Unit 2 compared to 8’-0” for Unit 1.
- Unit 2 has six water-cooled furnace wing walls. Unit 1 has a full furnace division wall.
- Unit 2 was designed without flue gas recirculation. Unit 1 was originally designed with flue gas recirculation. The flue gas recirculation system on Unit 1 has been removed from service.

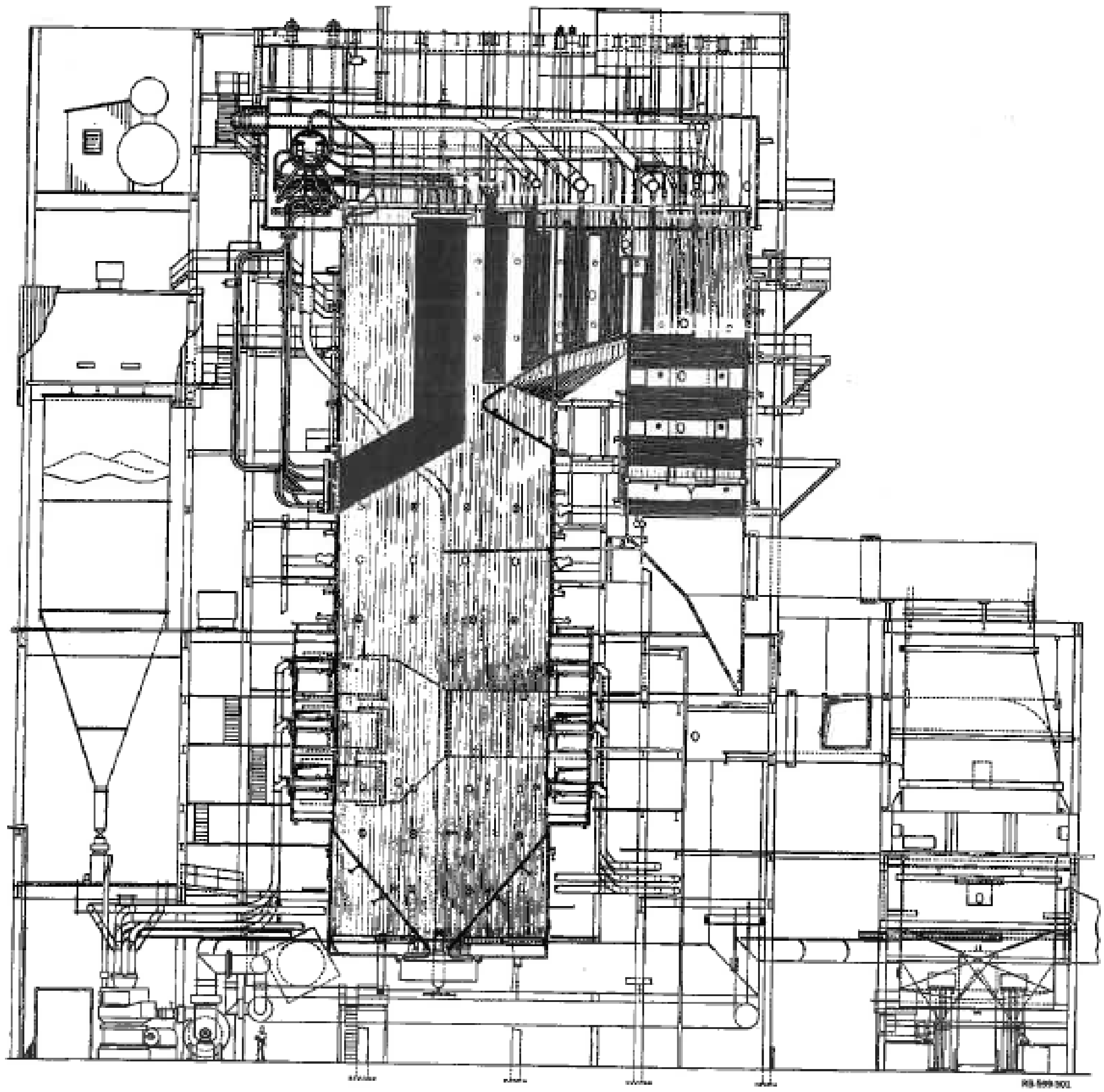
A sectional side view of the boilers is shown in Figures 1a and 1b.

## FIGURE 1a




**Brown Station Unit 1**

**B&W Contract Number RB-557**



**Brown Station Unit 2**

**B&W Contract Number RB-599**

## SCOPE FOR PHASE I

B&W evaluated natural gas firing in the radiant boilers originally supplied by B&W under contract numbers RB-557 and RB-599. Boiler component drawings and original performance summary data were used to develop comprehensive thermal models and boiler pressure part assessments. The predicted performance of the proposed natural gas firing was analyzed at MCR load and 60% load. The tube metallurgy requirements for the primary superheater, secondary superheater, reheater and headers were also developed. In addition to superheater metals analysis, predicted performance of the air preheaters and the attemperator capacities were also evaluated relative to overall performance.

## SCOPE FOR PHASE II

The Phase II engineering scope of supply includes the entire scope of Phase I. In addition, the need surface modifications for firing 100% natural gas were analyzed. The adequacy of the existing forced draft (FD) fans and the induced draft (ID) fans were also assessed.

## BASIS

This boiler pressure part metals assessment requires developing overall unit heat and material balances at the indicated steam flow. The 2015 fuel analyses for coal as supplied by Vectren were found to be very close to original design bituminous coal. Since the 2015 fuel analyses were incomplete, the original design fuel analysis was used. The natural gas analysis was also supplied by Vectren. The original design coal and natural gas fuel analyses are provided in Tables 1 and 2. These were used as a basis for the heat and material balances shown in Table 3.

**Table 1: Original Design As-Fired Fuel Analyses for Bituminous Coal, % by weight**

| **Constituent** | |
|---|---|
| C | 64.00 |
| $H_2$ | 4.44 |
| $N_2$ | 1.38 |
| $O_2$ | 6.51 |
| Cl | 0.00 |
| S | 3.52 |
| $H_2O$ | 11.35 |
| Ash | 8.76 |
| **Total** | **100.00** |
| **HHV (Btu/lb)** | **11533** |

**Table 2: Proximate Analysis for Natural Gas, % by volume**

| Constituent | |
|---|---|
| Nitrogen | 0.28 |
| Methane | 96.31 |
| Ethane | 1.46 |
| $CO_2$ | 1.89 |
| Others | 0.06 |
| **Total** | **100.00** |
| **HHV (Btu/ft$^3$)** | **1,037** |

**Table 3: Boiler Operating Conditions Used in Metals Evaluation**

| Boiler Load | MCR | 60% |
|---|---|---|
| Superheater Steam Flow (lb/hr) | 1,850,000 | 1,110,000 |
| Steam Temperature at SH Outlet (°F) | 1005 | 933 |
| Steam Pressure at SH Outlet (psig) | 1965 | 1917 |
| Reheater Steam Flow (lb/hr) w/o Attemperator Spray | 1,666,500 | 1,000,000 |
| Steam Temperature at RH Outlet (°F) | 992 | 835 |
| Steam Pressure at RH Outlet (psig) | 460 | 261 |
| Feedwater Temperature (°F) | 467 | 417 |
| Excess Air Leaving Econ (%) | 10 | 18 |

## RESULTS

### Boiler Performance

The predicted boiler performance summaries are shown in the Appendix, comparing unit performance firing the original bituminous coal at the original design data, recent field data for each of the units and predicted unit performance firing 100% natural gas.

### Attemperator Capacity

Along with the metals analysis, attemperation capacities were studied. The attemperator spray flows for gas firing are lower than the spray flows for firing coal due to lower amounts of excess air required when firing natural gas. Current attemperator capacities for both units should be satisfactory at all boiler loads. The results are shown in Table 6.

**Table 6: Predicted Attemperator Flows (lbs/hr)**

| Boiler Load | MCR | 60% |
|---|---|---|
| **Bituminous Coal:** | | |
| **SH Spray Flow** | **77,870** | **88,000** |
| **RH Spray Flow** | **19,000** | **0** |
| **Natural Gas** | | |
| **SH Spray Flow** | **53,700** | **0** |
| **RH Spray Flow** | **0** | **0** |

### Air Heater Performance

Air heaters were assessed for natural gas firing. The air and gas side temperature profiles around the air heater were found to be acceptable for the natural gas conversion. Since no field data was provided that would show higher than original air heater leakage or other air heater performance degradation, the predicted air heater performance is based on the original design data with an air heater leakage of 7.4%. Predicted performance is shown on Table 7a and 7b.

**Table 7a: Regenerative Air Heater Predicted Performance at**

| **Unit** | 1 & 2 | 1 | 2 | 1 & 2 |
|---|---|---|---|---|
| **Boiler load** | MCR | 95% | 94% | MCR |
| **Data Basis** | Original Design | 7-14-2015 PI Data | 7-10-2015 PI Data | Predicted Performance* |
| **Fuel** | Bituminous Coal | Bituminous Coal | Bituminous Coal | Natural Gas |
| **Flue Gas Flow Entering Air Heaters, mlb/hr** | 2,570 | 2,584 | 2,422 | 2,234 |
| **Flue Gas Temp Entering Air Heaters, F** | 705 | 650 | 652 | 697 |
| **Flue Gas Temp Leaving Air Heaters w/o Leakage, F** | 304 | 336 | 346 | 303 |
| **Air Flow Leaving Air Heaters, mlb/hr** | 2,307 | 2,323 | 2,174 | 2,056 |
| **Air Temp Entering Air Heaters, F** | 85 | 168 | 138 | 85 |
| **Air Temp Leaving Air Heaters, F** | 566 | 535 | 554 | 567 |

*Based on original design data

**Table 7b: Regenerative Air Heater Predicted Performance**

| Unit | 1 & 2 | 1 & 2 |
|---|---|---|
| **Boiler load** | 60% | 60% |
| **Data Basis** | Original Design | Predicted Performance* |
| **Fuel** | Bituminous Coal | Natural Gas |
| **Flue Gas Flow Entering Air Heaters, mlb/hr** | 2,060 | 1,403 |
| **Flue Gas Temp Entering Air Heaters, F** | 675 | 617 |
| **Flue Gas Temp Leaving Air Heaters w/o Leakage, F** | 283 | 259 |
| **Air Flow Leaving Air Heaters, mlb/hr** | 1,867 | 1,273 |
| **Air Temp Entering Air Heaters, F** | 83 | 83 |
| **Air Temp Leaving Air Heaters, F** | 547 | 520 |

*Based on original design data

**Tube Metal Temperature Evaluation**

B&W uses an ASME Code accepted method to design its tube metallurgies and thicknesses. The method involves applying upsets and unbalances to determine spot and mean tube metal temperatures. The upsets and unbalances include empirical uncertainty in the calculation of furnace exit gas temperature (FEGT), top to bottom gas temperature deviations, side to side gas temperature deviations, steam flow unbalances (a function of tube side pressure drop and component arrangement) and gas flow unbalances. The method applies these upsets and unbalances simultaneously to a single spot in each row of the superheater. Tube row metallurgy and thickness are then determined from the resultant tube spot and mean temperatures, respectively, according to ASME Code material oxidation limits and allowable stresses. B&W policy does not allow the publishing of design tube metal temperatures or unbalanced steam temperatures. However, these values can be reviewed in B&W's offices, if desired.

The remaining life expectancy of the superheaters is dependent on the prior operating history, especially on actual tube operating temperature compared to design temperature. Thus, the assessment of the adequacy of the existing superheaters is not a simple task.

The SSH outlet bank & RSH outlet bank were replaced on unit 1 in the spring of 2012 and on unit 2 in the fall of 2015. The evaluation is based on the design of the present SSH outlet banks & RSH outlet banks which were supplied by B&W.

B&W has determined the operating hoop stress level (based on the current minimum tube wall thickness) at operating pressure. The predicted tube operating temperatures based on B&W's standard design criteria and the resulting ASME Code allowable stress level for the existing material has also been determined. Comparison of the operating hoop stress with the Code allowable stresses results in the percent over the allowable stress. A modest overstress level indicates a modest shortening of remaining life expectancy and, unless otherwise indicated by past maintenance experience, does not warrant tube modification at this time.

If the tube analysis shows significant overstress or shows that tubes are predicted to operate at temperatures above those for which ASME Code stresses are published, then serious consideration should be given to tube upgrades and replacement. Significant overstresses are considered those tube rows that are 20% or greater overstressed. An overstress of 20% or more does not necessarily mean that immediate replacement of the tube row is required, but it identifies which tube rows should be examined for potential problems. Potential problems could be signs of creep, internal exfoliation or swelling.

This study showed that all tubes were predicted to operate at temperatures less than the existing material use limit. In addition, all existing convection pass tubes and component headers had no overstress issues. Therefore, the existing convection pass tube metallurgy is acceptable for natural gas firing.

**Forced Draft Fans**

The existing forced draft fans were analyzed to determine if they meet the requirements of 100% natural gas firing. The Unit 1 FD fans were originally designed to supply the combustion air in a pressure fired boiler operating mode. The boiler has since been converted to balanced draft operation, resulting high static pressure rise margins when firing coal. Unit 2 was originally designed as a balanced draft unit. An adjusted test block static pressure rise and test block capacity for the Unit 2 FD fans was developed from the FD fan curve for 100% natural gas firing. The results show the existing FD fan test block conditions for both Units exceed the requirements in capacity and static pressure rise (including higher natural gas burner pressure drop) for all natural gas firing cases. Predicted fan performance is shown in Table 8A:

**Table 8a: Forced Draft Fan Performance at MCR Load (balanced draft operation)**

| Fuel | FD Fan Test Block Unit 1 | FD Fan Original Net Design Conditions Bituminous Coal Unit 1 | FD Fan Test Block Unit 2 | FD Fan Original Net Design Conditions Bituminous Coal Unit 2 | FD Fan Test Block Adjusted for 100%Natural Gas Unit 2 From Fan Curve | FD Fan Net Conditions 100% Natural Gas Units 1 & 2 |
|---|---|---|---|---|---|---|
| Flow per fan (lb/hr) | 1,417,000 | 1,180,500 | 1,512,000 | 1,260,000 | 1,225,440 | 1,104,100 |
| Static Pressure Rise (in WC) | 37.3 | 29.8 | 19.8 | 15.8 | 25.1 | 20.3 |
| Temperature (F) | 105 | 80 | 105 | 80 | 105 | 80 |

**Induced Draft Fans**

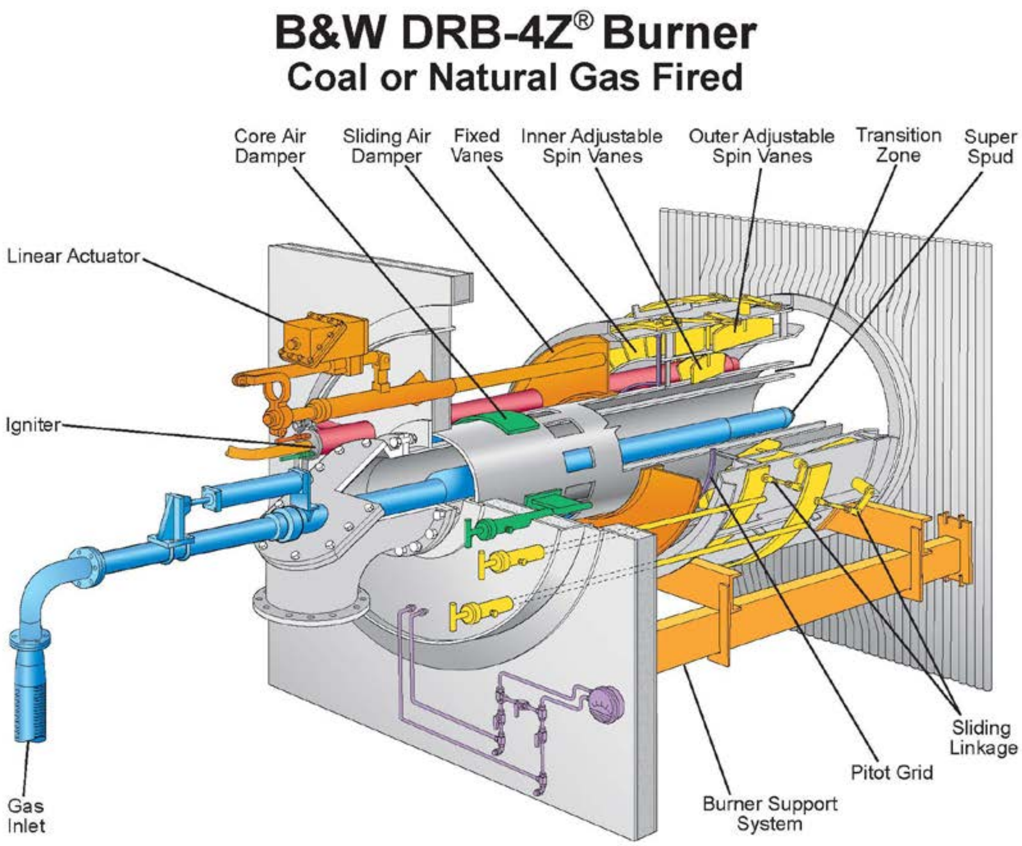
The existing induced draft fans were also analyzed to determine if they meet the requirements of 100% natural gas firing. The results showed the existing ID fans far exceed the requirements in capacity and static pressure rise for all natural gas firing cases. Predicted fan performance is shown in Table 8B:

**Table 8b: Induced Draft Fan Performance at MCR Load (balanced draft operation)**

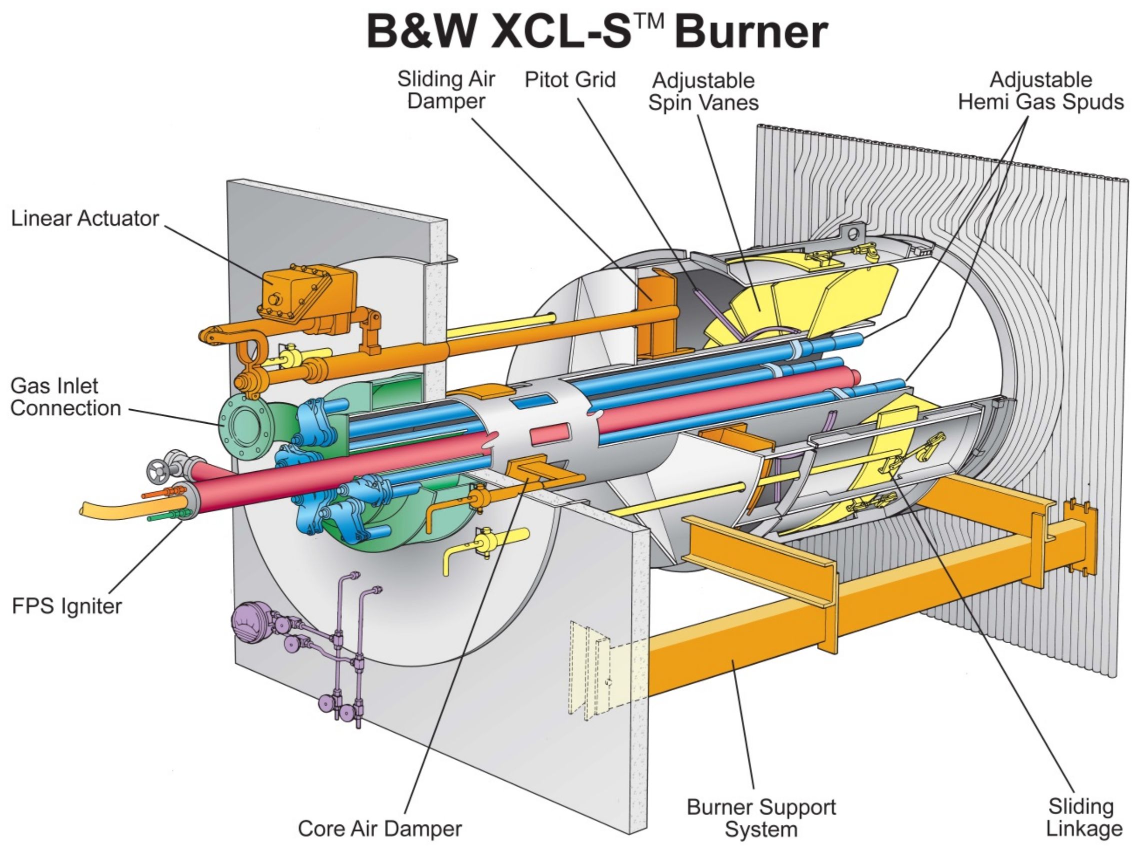
| Fuel | ID Fan Test Block Unit 1 | Bituminous Coal Unit 1 Original ID Fan Design Net Conditions | 100% Natural Gas |
|---|---|---|---|
| Flow per fan (lb/hr) | 1,380,100 | 1,387,610 | 1,199,390 |
| Static Pressure Rise (in WC) | 67.30 | 47.81 | 34.22 |
| Temperature (F) | 330 | 305 | 290 |

### Combustion Equipment

The minimum combustion equipment modifications required to fire natural gas include modifying the twenty-four (24) existing B&W 4Z burners with gas spuds. One option is to add a Super-Spud to each 4Z burner to provide natural gas firing capability to the units. The addition of Super-Spuds will allow the AB Brown units to still fire coal is desired. The figure below shows a 4Z burner with a Super-Spud.




The second option would be to remove the coal nozzle and replace it with a hemi-spud cartridge. This fundamentally converts the 4Z burners to a B&W XCL-S burner as shown in the figure below. B&W XCL-S burner is an advanced low-NOx burner that was developed to achieve superior NOx performance in burner-only applications.




Since the AB Brown units already have SCR's, staged combustion (OFA) or flue gas recirculation (FGR) may not be necessary.

Additional NOx reduction can be achieved with staged combustion and/or flue gas recirculation. For staged combustion, the preferred approach is to locate eight (8) new NOx ports, four on the front wall and four on the rear wall, at an elevation at least eight feet above the top burner row. New NOx ports would require windbox and duct work modifications.

FGR involves the introduction of recirculated flue gas into the combustion air upstream of the burner windbox. A mixing device (such as a slotted air foil in the combustion air duct) is required to adequately distribute the recirculated flue gas in the incoming combustion air.

In addition to the burner modifications, valve racks, gas piping and controls will be needed to supply the natural gas as a main fuel to the modified burners.

## Emissions

Emissions predictions are based on converting the unit to fire natural gas as the main fuel. Full load emission predictions for both units are listed in Table 9.

**Table 9: Predicted Full Load Emissions on Natural Gas**

| | XCL-S Burners only | | XCL-S Burners and OFA | | XCL-S Burners, OFA, and FGR | | XCL-S Burners and FGR | |
|---|---|---|---|---|---|---|---|---|
| | Brown Unit 1 | Brown Unit 2 | Brown Unit 1 | Brown Unit 2 | Brown Unit 1 | Brown Unit 2 | Brown Unit 1 | Brown Unit 2 |
| FGR Rate (&) | N/A | N/A | N/A | N/A | ~16% | ~18% | ~21.5% | ~23.5% |
| $NO_x$ (lb/$10^6$ Btu) | 0.17 | 0.19 | 0.15 | 0.17 | 0.07 | 0.07 | 0.07 | 0.07 |
| CO (ppmvd corrected to 3% $O_2$) | 200 | 200 | 200 | 200 | 200 | 200 | 200 | 200 |
| VOC (lb/$10^6$ Btu) | 0.003 | 0.003 | 0.003 | 0.003 | 0.003 | 0.003 | 0.003 | 0.003 |

- CO is predicted to be less than 200ppm. For 200 ppm (dry vol.) CO @ 3% O2 (dry vol.) firing NG with an Fd factor of 8710, B&W calculates 0.148 lb/mmBTU of CO.

## CONCLUSIONS

As a result of this study, a review of the existing tube metallurgies on the AB Brown Station Units 1 and 2 revealed that all existing convection pass tubes had no overstress issues. In addition, all tubes were predicted to operate at temperatures below their ASME material code published limit. Header metal temperatures were also checked and showed to meet B&W's standards.

Along with the metallurgical analysis, superheater and reheater spray attemperation capacities were studied. The attemperator spray flows for gas firing are lower than the spray flows for firing coal due to lower amounts of excess air required when firing 100% natural gas. Current attemperator capacities for both units should be satisfactory at all boiler loads.

No surface modifications or surface removal are required when firing 100% natural gas.

Air heaters were assessed for 100% natural gas firing. The air and gas side temperature profiles around the air heater were found to be acceptable for firing natural gas based on the original air heater design parameters.

The existing FD and ID fans were found to exceed the performance requirements when firing 100% natural gas.

The predicted boiler performance summaries are shown in the Appendix, comparing unit performance firing the original bituminous coal and predicted unit performance firing natural gas.

## CO-FIRING COAL AND NATURAL GAS

Vectren Power Supply additionally contracted the Babcock and Wilcox Company (B&W), under B&W contract 591-1048 (317A), to evaluate co-firing natural gas and coal in these units.

The predicted boiler performance summaries are shown in the Appendix, comparing unit performance co-firing natural gas and the original bituminous coal at MCR boiler load with the following natural gas inputs:

1. 17% heat input from natural gas through four burners. 83% heat input from coal.
2. 33% heat input from natural gas through eight burners. 67% heat input from coal.
3. 16% heat input (maximum heat input through natural gas ignitors). 84% heat input from coal.

A metallurgical analysis and an analysis of the superheater and reheater spray attemperation capacities were performed for the three conditions above. Current attemperator capacities for both units should be satisfactory at all boiler loads when co-firing natural gas and coal.

This study showed that all tubes were predicted to operate at temperatures less than the existing material use limit. In addition, all existing convection pass tubes and component headers had no overstress issues. Therefore, the existing convection pass tube metallurgy is acceptable for co-firing natural gas and coal.

No surface modifications or surface removal are required when co-firing natural gas and coal.

The air and gas side temperature profiles around the air heater were found to be acceptable for co-firing natural gas and coal based on the original air heater design parameters.

The existing FD and ID fans were found to exceed the performance requirements when co-firing natural gas and coal.

The predicted boiler performance summaries when co-firing natural gas and coal are shown in the Appendix.

### Co-firing Operation

When co-firing the two fuels, the preferred arrangement is to fire natural gas through the burners at the higher elevations on a per mill group, or compartment, basis. The compartmented windboxes on the AB Brown units are advantageous for co-firing the multiple fuels. Airflow control by compartment allows each mill group to obtain its own required amount of air, independent of burner load or fuel. The burners firing natural gas will require more secondary air, since primary airflow is zero, than the coal-firing burners. Managing these separate flow rates can be easily accommodated by the compartment controls. Firing coal at the lower elevations takes advantage of the available residence time in the furnace, maximizing coal burnout and optimizing CO and unburned carbon emissions. If a partial conversion were to become the chosen project path, it would be recommended to convert burners on a per mill group basis following the described firing arrangement, adding gas capability to the top mill groups and continuing downward.

It should be noted that while the AB Brown units are already equipped to operate under the third scenario listed above (16% input ignitors, 84% input from coal), it could come at the expense of emissions. With the ignitor being located in an upper quadrant of the burner and operating at 16% of the rated burner input, not all of the air going through the burner is nearby and readily available for the ignitor fuel. This can create scenarios of inadequate fuel and air mixing, resulting in higher CO emissions, especially from the upper burner elevations. NOx emissions may also increase. The annular zone arrangement of the 4Z burner stages the mixing of the fuel and air. With the ignitor being located in the air sleeve, it circumvents this delayed mixing arrangement, potentially increasing NOx. Emissions predictions are not available for this scenario.

# *APPENDIX A – Preliminary Performance Summaries*

**Table 10a:**

| A. B. Brown Units 1 & 2 - Preliminary Performance Summary | | | | | | |
|---|---|---|---|---|---|---|
| Contract No. | 317A | GBB | Units 1 & 2 | Unit 1 | Unit 2 | Units 1 & 2 |
| Date | 7/31/2015 | Load ID | PC Firing | PC Firing | PC Firing | Natural Gas |
| Revision | 0 | Boiler Arrangement | Existing | Existing | Existing | Existing |
| | | Data Basis | Original Contract | 7-14-2015 PI Data | 7-10-2015 PI Data | Predicted Performance |
| | | | | | | |
| Load Condition | | | MCR | 95% Load | 94% Load | MCR |
| Fuel | | | Bituminous | Bituminous | Bituminous | Natural Gas |
| Steam Leaving SH, mlb/hr | | | 1,850 | 1,814 | 1,736 | 1,850 |
| Superheater Spray Water, mlb/hr | | | 77.86 | 110.32 | 19.10 | 53.70 |
| Cold RH Steam Flow, mlb/hr | | | 1,667 | 1,663 | 1,590 | 1,667 |
| Reheater Spray Water, mlb/hr | | | 18.90 | 60.70 | 16.30 | 0.00 |
| % Excess Air Leaving Economizer | | | 20.0 | 21.9 | 21.1 | 10.0 |
| Flue Gas Recirculation, % | | | None | None | None | None |
| Heat Input, mmBtu/hr | | | 2,549.3 | 2,526.4 | 2,379.8 | 2,614.9 |
| Quantity mlb/hr | Fuel (mcf/hr if gas) | | 221.0 | 219.0 | 207.0 | 2604.5 |
| | Flue Gas Entering Air Heaters | | 2,570 | 2,584 | 2,422 | 2,234 |
| | Total Air To Burners | | 2,307 | 2,323 | 2,174 | 2,056 |
| Pressure, psig | Steam at SH Outlet | | 1965 | 1880 | 1926 | 1965 |
| | Steam at RH Outlet | | 460 | 431 | 424 | 460 |
| Temperature, °F | Steam | Leaving Superheater | 1005 | 1006 | 999 | 1005 |
| | | Leaving Reheater | 1005 | 997 | 985 | 992 |
| | | | | | | |
| | Water | Water Entering Economizer | 467 | 459 | 452 | 467 |
| | | Superheater Spray Water | 380 | 365 | 370 | 380 |
| | Gas | Entering Air Heater | 705 | 650 | 652 | 697 |
| | | Leaving Air Heater (Excl. Leakage) | 304 | 336 | 346 | 303 |
| | Air | Entering Air Heater | 85 | 168 | 138 | 85 |
| | | Leaving Air Heater | 566 | 535 | 554 | 567 |
| Heat Loss Efficiency, % | Dry Gas | | 4.91 | 3.86 | 4.75 | 3.88 |
| | $H_2$ & $H_2O$ in Fuel | | 5.06 | 4.76 | 4.92 | 10.67 |
| | Moisture in Air | | 0.12 | 0.10 | 0.11 | 0.10 |
| | Unburned Combustible | | 0.30 | 0.30 | 0.30 | 0.00 |
| | Radiation | | 0.19 | 0.19 | 0.20 | 0.19 |
| | Unacc. & Mfgs. Margin | | 1.50 | 0.50 | 0.50 | 1.00 |
| | Total Heat Loss | | 12.08 | 9.71 | 10.78 | 15.84 |
| | Gross Efficiency of Unit, % | | 87.92 | 90.29 | 89.22 | 84.16 |
| **B&W Proprietary and Confidential** | | | | | | |

**Table 10a:**

**A. B. Brown Units 1 & 2 - Preliminary Performance Summary**

| | | | | | | |
|---|---|---|---|---|---|---|
| Contract No. | 317A | | GB8 | Unit 1 & 2 | Unit 1 & 2 | | |
| Date | 7/31/2015 | | Load ID | PC Firing | NG Firing | | |
| Revision | 0 | | Boiler Arrangement | Existing | Existing | | |
| | | | Data Basis | Original Contract | Predicted Performance | | |
| | | | | | | | |
| Load Condition | | | | 60% | 60% | | |
| Fuel | | | | Bituminous | Natural Gas | | |
| Steam Leaving SH, mlb/hr | | | | 1,110 | 1,110 | | |
| Superheater Spray Water, mlb/hr | | | | 89 | 0 | | |
| Cold RH Steam Flow, mlb/hr | | | | 1,000 | 1,000 | | |
| Reheater Spray Water, mlb/hr | | | | 0 | 0 | | |
| % Excess Air Leaving Economizer | | | | 52.0 | 18.0 | | |
| Flue gas Recirculation, % | | | | None | None | | |
| Heat Input, mmBtu/hr | | | | 1,638.3 | 1,540.9 | | |
| Quantity mlb/hr | Fuel (mcf/hr if gas) | | | 142.0 | 1486.0 | | |
| | Flue Gas Entering Air Heaters | | | 2,060 | 1,403 | | |
| | Total Air To Burners | | | 1,867 | 1,273 | | |
| Pressure, psig | Steam at SH Outlet | | | 1917 | 1917 | | |
| | Steam at RH Outlet | | | 261 | 261 | | |
| Temperature, °F | Steam | Leaving Superheater | | 1005 | 955 | | |
| | | Leaving Reheater | | 1005 | 835 | | |
| | | | | | | | |
| | Water | Water Entering Economizer | | 417 | 417 | | |
| | | Superheater Spray Water | | 350 | 350 | | |
| | Gas | Entering Air Heater | | 675 | 617 | | |
| | | Leaving Air Heater (Excl. Leakage) | | 283 | 259 | | |
| | Air | Entering Air Heater | | 83 | 83 | | |
| | | Leaving Air Heater | | 547 | 520 | | |
| Heat Loss Efficiency, % | Dry Gas | | | 5.69 | 3.35 | | |
| | $H_2$ & $H_2O$ in Fuel | | | 5.03 | 10.38 | | |
| | Moisture in Air | | | 0.14 | 0.09 | | |
| | Unburned Combustible | | | 0.30 | 0.00 | | |
| | Radiation | | | 0.30 | 0.22 | | |
| | Unacc. & Mfgs. Margin | | | 1.50 | 1.00 | | |
| | Total Heat Loss | | | 12.96 | 15.04 | | |
| | Gross Efficiency of Unit, % | | | 87.04 | 84.96 | | |

**B&W Proprietary and Confidential**

## Table 10c:

**A. B. Brown Unit 1 - Predicted Performance Summary Co-Firing Coal & Natural Gas**

| | | | | | | |
|---|---|---|---|---|---|---|
| Contract No. | 317A | GBB | Unit 1 | Unit 1 | Unit 1 | |
| Date | 8/29/2015 | Load ID | PC & NG Firing | PC & NG Firing | PC & NG Firing | |
| Revision | 0 | Boiler Arrangement | Existing | Existing | Existing | |
| | | Data Basis | Predicted Performance | Predicted Performance | Predicted Performance | |
| | | Natural Gas Firing Method | Through Burners | Through Burners | Through Ignitors | |
| | | Natural Gas Firing % Heat Input | 17 | 33 | 16 | |
| | | Coal Firing % Heat Input | 83 | 67 | 84 | |
| Load Condition | | | MCR | MCR | MCR | |
| Fuel | | | Bit. Coal & Natural Gas | Bit. Coal & Natural Gas | Bit. Coal & Natural Gas | |
| Steam Leaving SH, mlb/hr | | | 1,850 | 1,850 | 1,850 | |
| Superheater Spray Water, mlb/hr | | | 99.50 | 115.17 | 98.48 | |
| Cold RH Steam Flow, mlb/hr | | | 1,667 | 1,667 | 1,667 | |
| Reheater Spray Water, mlb/hr | | | 53.81 | 57.13 | 53.80 | |
| % Excess Air Leaving Economizer | | | 21.1 | 21.1 | 21.1 | |
| Flue Gas Recirculation, % | | | None | None | None | |
| Heat Input Nat. Gas, mmBtu/hr | | | 443.4 | 869.9 | 408.0* | |
| Heat Input Bit. Coal, mmBtu/hr | | | 2164.8 | 1766.1 | 2198.6 | |
| Total Heat Input, mmBtu/hr | | | 2608.2 | 2636.0 | 2606.6 | |
| Quantity mlb/hr | Coal Flow | | 187.7 | 153.2 | 190.6 | |
| | Natural Gas Flow (mcf/hr) | | 441.6 | 866.4 | 406.3 | |
| | Flue Gas Entering Air Heaters | | 2,611 | 2,600 | 2,612 | |
| | Total Air To Burners | | 2,358 | 2,360 | 2,358 | |
| Pressure, psig | Steam at SH Outlet | | 1965 | 1965 | 1965 | |
| | Steam at RH Outlet | | 460 | 460 | 460 | |
| Temperature, °F | Steam | Leaving Superheater | 1005 | 1005 | 1005 | |
| | | Leaving Reheater | 1005 | 1005 | 1005 | |
| | | | | | | |
| | Water | Water Entering Economizer | 467 | 467 | 467 | |
| | | Superheater Spray Water | 365 | 365 | 365 | |
| | Gas | Entering Air Heater | 656 | 658 | 656 | |
| | | Leaving Air Heater (Excl. Leakage) | 338 | 338 | 338 | |
| | Air | Entering Air Heater | 150 | 150 | 150 | |
| | | Leaving Air Heater | 542 | 544 | 542 | |
| Heat Loss Efficiency, % | Dry Gas | | 4.19 | 4.09 | 4.19 | |
| | $H_2$ & $H_2O$ in Fuel | | 5.76 | 6.62 | 5.69 | |
| | Moisture in Air | | 0.10 | 0.10 | 0.10 | |
| | Unburned Combustible | | 0.25 | 0.20 | 0.25 | |
| | Radiation | | 0.19 | 0.19 | 0.19 | |
| | Unacc. & Mfgs. Margin | | 1.42 | 1.42 | 1.42 | |
| | Total Heat Loss | | 11.91 | 12.62 | 11.84 | |
| | Gross Efficiency of Unit, % | | 88.09 | 87.38 | 88.16 | |

**B&W Proprietary and Confidential**

Predicted performance is based on the original contract boiler performance and PI data as supplied by Vectren

*Maximum heat input from ignitors

## Table 10d:

## A. B. Brown Unit 2 - Predicted Performance Summary Co-Firing Coal & Natural Gas

| | | | | | | |
|---|---|---|---|---|---|---|
| Contract No. | 317A | GBB | Unit 2 | Unit 2 | Unit 2 | |
| Date | 8/29/2015 | Load ID | PC & NG Firing | PC & NG Firing | PC & NG Firing | |
| Revision | 0 | Boiler Arrangement | Existing | Existing | Existing | |
| | | Data Basis | Predicted Performance | Predicted Performance | Predicted Performance | |
| | | Natural Gas Firing Method | Through Burners | Through Burners | Through Ignitors | |
| | | Natural Gas Firing % Heat Input | 17 | 33 | 16 | |
| | | Coal Firing % Heat Input | 83 | 67 | 84 | |
| Load Condition | | | MCR | MCR | MCR | |
| Fuel | | | Bit. Coal & Natural Gas | Bit. Coal & Natural Gas | Bit. Coal & Natural Gas | |
| Steam Leaving SH, mlb/hr | | | 1,850 | 1,850 | 1,850 | |
| Superheater Spray Water, mlb/hr | | | 27.38 | 42.94 | 26.70 | |
| Cold RH Steam Flow, mlb/hr | | | 1,667 | 1,667 | 1,667 | |
| Reheater Spray Water, mlb/hr | | | 23.02 | 27.14 | 23.00 | |
| % Excess Air Leaving Economizer | | | 21.9 | 21.9 | 21.9 | |
| Flue Gas Recirculation, % | | | None | None | None | |
| Heat Input Nat. Gas, mmBtu/hr | | | 434.6 | 853.1 | 408.0* | |
| Heat Input Bit. Coal, mmBtu/hr | | | 2121.7 | 1732.0 | 2147.3 | |
| Total Heat Input, mmBtu/hr | | | 2556.3 | 2585.1 | 2555.3 | |
| Quantity mlb/hr | Coal Flow | | 184.0 | 150.2 | 186.0 | |
| | Natural Gas Flow (mcf/hr) | | 432.8 | 849.7 | 406.3 | |
| | Flue Gas Entering Air Heaters | | 2,568 | 2,559 | 2,569 | |
| | Total Air To Burners | | 2,319 | 2,322 | 2,320 | |
| Pressure, psig | Steam at SH Outlet | | 1965 | 1965 | 1965 | |
| | Steam at RH Outlet | | 460 | 460 | 460 | |
| Temperature, °F | Steam | Leaving Superheater | 1005 | 1005 | 1005 | |
| | | Leaving Reheater | 1005 | 1005 | 1005 | |
| | | | | | | |
| | Water | Water Entering Economizer | 467 | 467 | 467 | |
| | | Superheater Spray Water | 380 | 380 | 380 | |
| | Gas | Entering Air Heater | 668 | 670 | 668 | |
| | | Leaving Air Heater (Excl. Leakage) | 352 | 353 | 352 | |
| | Air | Entering Air Heater | 150 | 150 | 150 | |
| | | Leaving Air Heater | 552 | 554 | 552 | |
| Heat Loss Efficiency, % | Dry Gas | | 4.51 | 4.43 | 4.52 | |
| | $H_2$ & $H_2O$ in Fuel | | 5.79 | 6.66 | 5.74 | |
| | Moisture in Air | | 0.11 | 0.11 | 0.11 | |
| | Unburned Combustible | | 0.25 | 0.20 | 0.25 | |
| | Radiation | | 0.19 | 0.19 | 0.19 | |
| | Unacc. & Mfgs. Margin | | 1.42 | 1.42 | 1.42 | |
| | Total Heat Loss | | 12.27 | 13.01 | 12.23 | |
| | Gross Efficiency of Unit, % | | 87.73 | 86.99 | 87.77 | |

**B&W Proprietary and Confidential**

Predicted performance is based on the original contract boiler performance and PI data as supplied by Vectren
*Maximum heat input from ignitors

# *APPENDIX B – NG Conversion Equipment Scope & Budgetary Costs*

## SUPER-SPUD OPTION - Burner Modifications, Scanners, Valve Racks, NG Piping System

### Item 1: B&W 4Z Burners converted to Nat Gas Firing (Quantity: 24)

- Qty 24, Super-Spud Assemblies to replace existing coal nozzles
- Qty 12, Burner Valve Racks
- Burner Front Flex Hose and Hardware
- Burner Front Piping
- Gas Header Piping
- Burner Front Valves & Gauges

### Item 2: Fossil Power Systems (FPS) Flame Scanners

- Qty 24, FPS main UV flame scanners with rigid fiber optic extension
- Qty 1, main flame scanner electronics cabinet
- 1 Lot – Combustion/Cooling air piping from blower skid to burner fronts

### Item 3: Natural Gas Regulating Station and Piping

- Main natural gas regulating station – 50 psig supply pressure
- Natural gas piping from regulating station to the burners
- Natural gas burner front gas piping and valve stations excluding vent piping to above the boiler building roof

## HEMI-SPUD OPTION - Burner Modifications, Scanners, Valve Racks, NG Piping System

### Item 1: B&W 4Z Burners converted to Nat Gas Firing (Quantity: 24)

- Qty 24, Hemispherical Gas Spud Assemblies to replace existing coal nozzles
- Qty 12, Burner Valve Racks
- Burner Front Flex Hose and Hardware
- Burner Front Piping
- Gas Header Piping
- Burner Front Valves & Gauges

### Item 2: Fossil Power Systems (FPS) Flame Scanners

- Qty 24, FPS main UV flame scanners with rigid fiber optic extension
- Qty 1, main flame scanner electronics cabinet
- 1 Lot – Combustion/Cooling air piping from blower skid to burner fronts

**Item 3: Natural Gas Regulating Station and Piping**

- Main natural gas regulating station – 50 psig supply pressure
- Natural gas piping from regulating station to the burners
- Natural gas burner front gas piping and valve stations
- Vent piping from the regulating stations and the burner valve racks to the boiler roof and above the roof is not included

## B&W OVERFIRE AIR (OFA) PORTS OPTION

- Qty 8, Furnace Water Wall Openings
- Windbox Extensions or Individual OFA Windboxes
- Qty 8, Automated Air Flow Control Damper with Rotary Drive - per port
- Boiler Closure Casing
- Temperature Monitoring Thermocouple (port style dependent)

## FLUE GAS RECIRCULATION (FGR) OPTION

- Flue Gas Recirculation Fan and Motor
- FGR Flues
- AH Outlet to FGR Fan Inlet
- FGR Fan Outlet to Secondary Air Mixing Foils
- FGR Flue expansion joints, hangers, bridging steel
- FGR Mixing Foils
- Windbox $O_2$ Monitor
- Burner throat assemblies to accommodate the larger B&W XCL-S burners required for FGR firing.

General Services

- Combustion system tuning services using an economizer outlet sampling grid for measurement of NOx per EPA methods.
- Field Service Engineering outage support for construction, start-up, and post-modification testing.
- Burner System Operator Training consisting of two, one day sessions.
- Training includes project specific training manual for up to 20 participants.
- Brickwork Refractory Insulation & Lagging (BRIL) Specifications and Installation design and materials.
- Contract specific System Requirements Specification, I/O Listing, and Functional Logic Diagrams for all supplied equipment.
- Operating and Maintenance Manuals (10 copies).
- New piping, flue, and duct loading to existing steel
- Delivery F.O.B. Brown Plant, Mt Vernon, IN.

Items not Included

- Hazardous material removal or abatement (i.e., lead paint and asbestos).

- Load analysis of existing structural steel or foundations and any required re-enforcement thereof.
- Hardware or reprograming of existing DCS and/or BMS to support natural gas conversion.
- Gas step down equipment. Equipment scope above assumes incoming gas pressure at B&W's terminal to be 30 to 50psi.

Terminal Points

- Inlet of gas regulating station
- Vent out of any valve rack
- Electrical terminals on provided electrical equipment or instruments
- Electrical terminals in shop provided terminal junction boxes as part of skidded equipment

**Budgetary Material & Installation Pricing (USD 2019)**

| Scope Item | Budgetary | |
|---|---|---|
| | **Material** | **Installation** |
| **Super-Spud Option:** Burner Modifications, Scanners, Valve Racks, NG Piping System | \$2,602,000 | \$3,903,000 |
| **Hemi-Spud Option:** Burner Modifications, Scanners, Valve Racks, NG Piping System | \$2,900,000 | \$4,350,000 |
| **Overfire Air (OFA) Option:** **Wall Openings, Windbox Modifications, Flow Control Dampers, Temperature Monitoring** | \$370,000 | \$555,000 |
| **Flue Gas Recirculation (FGR) Option:** **FGR Fan w/ Motor, Flues, Mixing Foils, $O_2$ Monitoring** | \$850,000 | \$1,275,000 |

**Lead Times**

- Material delivery: 52 - 56 weeks
- Installation outage duration: 8 - 10 weeks

B&W has offered these prices in 2019 US dollars and have not attempted to project escalation for time of performance or delivery.

Please note that these prices are budgetary and is not represent an offer to sell, however, we would welcome the opportunity to provide a formal proposal upon request.

# Appendix B. Babcock & Wilcox Engineering Study for Natural Gas Firing for F.B. Culley Unit 2

# Engineering Study for Natural Gas Firing

## for

## Vectren Power Supply
## Culley Station Unit 2
## Newburgh, Indiana

**Contract 591-1022 (293H)**
**June 13, 2019**
**Rev. 2**

**THE BABCOCK & WILCOX COMPANY ASSUMES NO LIABILITY WITH RESPECT TO THE USE OF, OR FOR DAMAGES RESULTING FROM THE USE OF, ANY INFORMATION, METHOD OR PROCESS DISCLOSED IN ANY REPORT ISSUED UNDER THIS CONTRACT.**

**THE BABCOCK & WILCOX COMPANY EXPRESSLY EXCLUDES ANY AND ALL WARRANTIES EITHER EXPRESSED OR IMPLIED, WHICH MIGHT ARISE UNDER LAW OR EQUITY OR CUSTOM OF TRADE, INCLUDING WITHOUT LIMITATION, WARRANTIES OF MERCHANTABILITY AND OF FITNESS FOR SPECIFIED OR INTENDED PURPOSE.**

# TABLE OF CONTENTS

## INTRODUCTION

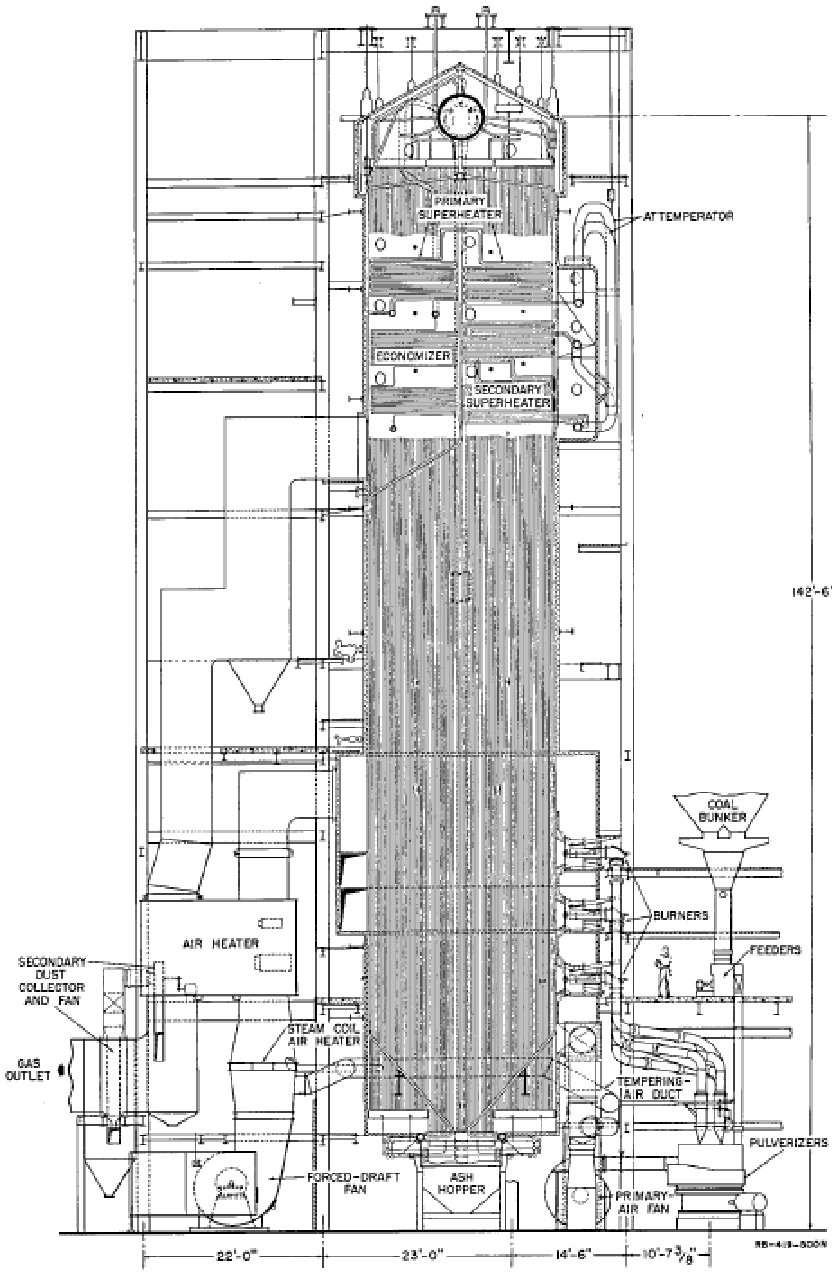
Vectren Power Supply contracted The Babcock and Wilcox Company (B&W), under B&W contract 591-1022 (293H), to evaluate natural gas firing at the Culley Station Unit #2 originally supplied by B&W under contract RB-419. The boiler performance model was reviewed at 100% MCR and 50% load when firing 100% natural gas. An analysis of the allowable tube metal stresses was performed for 100% gas firing at 100% MCR and 50% boiler loads in regards to the primary and secondary superheaters. Modifications to the convection pass components to accommodate natural gas firing were also developed. Also analyzed for adequacy were the forced draft fans, induced draft fans and spray attemperators.

## BACKGROUND

Culley Unit #2 (RB-419) is a balanced draft (originally pressure fired), subcritical El Paso type radiant boiler, with secondary superheater, primary superheater, and economizer surfaces arranged in series. Steam temperature is controlled through interstage attemperation. The unit was originally designed as a front wall, bituminous coal fired unit. The original maximum continuous rating for RB-419 is 840,000 lbs/hr of steam at 955°F and 1290 psig at the superheater outlet with a feedwater temperature of 425°F. The unit was designed to accommodate a peak load (low feedwater temperature condition) for a duration of two (2) hours. The peak load rating is 840,000 lbs/hr of steam at 955°F and 1290 psig at the superheater outlet with a feedwater temperature of 383°F.

A sectional side view of the boilers is shown in Figure 1a.

**FIGURE 1a**




**Culley Station Unit 2**
**B&W Contract Number RB-419**

## SCOPE FOR PHASE I

B&W evaluated natural gas firing in the radiant boiler originally supplied by B&W under contract RB-419. Boiler component drawings and original performance summary data were used to develop comprehensive thermal models and boiler pressure part assessments. The predicted performance of the proposed natural gas firing was analyzed at MCR load and 50% load. The tube metallurgy requirements for the primary superheater, secondary superheater and headers were also developed. In addition to superheater metals analysis, predicted performance of the air preheaters and the attemperator capacities were also evaluated relative to overall performance.

## SCOPE FOR PHASE II

The Phase II engineering scope of supply includes the entire scope of Phase I. In addition, the required surface modifications for firing 100% natural gas were developed. The adequacy of the existing forced draft (FD) fans and the induced draft (ID) fans were also assessed.

## BASIS

This boiler pressure part metals assessment requires developing overall unit heat and material balances at the indicated steam flow. The fuel analysis for the original design bituminous coal and natural gas fuel are provided in Tables 1 and 2. These were used as a basis for the heat and material balances shown in Table 3.

**Table 1: Original Design As-Fired Fuel Analyses for Bituminous Coal, % by weight**

| Constituent | |
|---|---|
| C | 55.27 |
| $H_2$ | 3.70 |
| $N_2$ | 1.05 |
| $O_2$ | 5.68 |
| Cl | 0.00 |
| S | 3.30 |
| $H_2O$ | 19.00 |
| Ash | 12.00 |
| **Total** | **100.00** |
| **HHV (Btu/lb)** | **10,000** |

**Table 2: Proximate Analysis for Natural Gas, % by volume**

| **Constituent** | |
|---|---|
| Nitrogen | 1.79 |
| Methane | 91.88 |
| Ethane | 5.12 |
| Others | 1.21 |
| **Total** | **100.00** |
| **HHV (Btu/ft$^3$)** | **1,037** |

**Table 3: Boiler Operating Conditions Used in Metals Evaluation**

| **Maximum Continuous Rating** | | |
|---|---|---|
| Steam Flow (lb/hr) | 840,000 | 420,000 |
| Steam Temperature at SH Outlet (°F) | 955 | 925 |
| Steam Pressure at SH Outlet (psig) | 1290 | 1260 |
| Feedwater Temperature (°F) | 425 | 360 |
| Excess Air Leaving Econ (%) | 10 | 18 |

## RESULTS

### Boiler Pressure Part Modifications

The boiler pressure part modifications consist of a surface reduction to the primary superheater that would be required with both cases where flue gas recirculation (FGR) is required. FGR increases the flue gas flow rate through the convection pass components thus increasing component absorption. A reduction in the PSH surface is required to avoid exceeding the limits of the existing tube metallurgy. Twelve (12) tube rows would be removed from the PSH inlet bank.

### Boiler Performance

The predicted boiler performance summaries are shown in the Appendix, comparing unit performance firing the original bituminous coal and predicted unit performance firing natural gas with scenarios including PSH heating surface reduction (if required) and FGR requirements as set by flue gas emissions.

### Attemperator Capacity

Along with the metals analysis, attemperation capacities were studied for the boiler operating conditions with and without flue gas recirculation (FGR) and also in regards to surface reductions of the primary superheater (where required). The attemperator spray flows for gas firing are higher than the spray flows for firing 100% coal due to higher flue gas temperatures leaving the furnace and higher component absorption. Required FGR flow rates also raised the total flue gas flow through the convection pass which results in higher convection pass component absorptions. The existing spray water attemperator nozzle size is adequate but would have to be modified by increasing the orifice diameter to meet the required spray flows. With this nozzle modification, capacities should be satisfactory at all boiler loads when firing natural gas. The results are shown in Table 6.

**Table 6: Expected Total Attemperator Flows (lbs/hr)**

| Boiler Load | MCR | 50% |
|---|---|---|
| Bituminous Coal | 54,190 | 1,800 |
| Natural Gas: | | |
| No FGR or boiler modifications | 71,440 | 27,910 |
| 14% FGR with PSH surface reduction | 71,750 | 18,600 |
| 19.5% FGR with PSH surface reduction | 79,280 | 18,600 |

### Air Heater Performance

Air heaters were assessed for natural gas firing. The air and gas side temperature profiles around the air heater were found to be acceptable for the natural gas conversion. Since no field data was provided that would show higher than original air heater leakage or other air heater performance degradation, the predicted air heater performance is based on the original design data with an air heater leakage of 10.0%. Predicted performance is shown on Table 7A & 7 B.

### Table 7A: Regenerative Air Heater Predicted Performance at MCR Load

| **Boiler load** | **MCR** | **MCR** | **MCR** | **MCR** |
|---|---|---|---|---|
| **Fuel** | **Bituminous Coal** | **Natural Gas** | **Natural Gas** | **Natural Gas** |
| **Boiler Modifications** | None | New burners with & without overfire air ports | PSH surface reduction New burners without overfire air ports | PSH Surface Reduction New burners with overfire air ports |
| **Flue Gas Recirculation** | None | None | 19.5% | 14.0% |
| **Flue Gas Flow Entering Air Heaters, mlb/hr** | 1017 | 909 | 918 | 915 |
| **Flue Gas Temp Entering Air Heaters, F** | 752 | 726 | 804 | 796 |
| **Flue Gas Temp Leaving Air Heaters w/o Leakage, F** | 320 | 310 | 334 | 331 |
| **Air Flow Leaving Air Heaters, mlb/hr** | 902 | 846 | 854 | 851 |
| **Air Temp Entering Air Heaters, F** | 100 | 100 | 100 | 100 |
| **Air Temp Leaving Air Heaters, F** | 604 | 598 | 660 | 653 |

**Table 7B: Regenerative Air Heater Predicted Performance at 50 % Load**

| **Boiler load** | **50%** | **50%** | **50%** | **50%** |
|---|---|---|---|---|
| **Fuel** | **Bituminous Coal** | **Natural Gas** | **Natural Gas** | **Natural Gas** |
| **Boiler Modifications** | None | New burners with & without overfire air ports | PSH surface reduction New burners without overfire air ports | PSH Surface Reduction New burners with overfire air ports |
| **Flue Gas Recirculation** | None | None | 19.5 | 14.0 |
| **Flue Gas Flow Entering Air Heaters, mlb/hr** | 541 | 507 | 507 | 507 |
| **Flue Gas Temp Entering Air Heaters, F** | 585 | 581 | 606 | 606 |
| **Flue Gas Temp Leaving Air Heaters w/o Leakage, F** | 264 | 263 | 271 | 270 |
| **Air Flow Leaving Air Heaters, mlb/hr** | 473 | 466 | 466 | 466 |
| **Air Temp Entering Air Heaters, F** | 121 | 121 | 121 | 121 |
| **Air Temp Leaving Air Heaters, F** | 501 | 504 | 526 | 526 |

**Tube Metal Temperature Evaluation**

B&W uses an ASME Code accepted method to design its tube metallurgies and thicknesses. The method involves applying upsets and unbalances to determine spot and mean tube metal temperatures. The upsets and unbalances include empirical uncertainty in the calculation of furnace exit gas temperature (FEGT), top to bottom gas temperature deviations, side to side gas temperature deviations, steam flow unbalances (a function of tube side pressure drop and component arrangement) and gas flow unbalances. The method applies these upsets and unbalances simultaneously to a single spot in each row of the superheater. Tube row metallurgy and thickness are then determined from the resultant tube spot and mean temperatures, respectively, according to ASME Code material oxidation limits and allowable stresses. B&W policy does not allow the publishing of design tube metal temperatures or unbalanced steam temperatures. However, these values can be reviewed in B&W's offices, if desired.

The remaining life expectancy of the superheaters is dependent on the prior operating history, especially on actual tube operating temperature compared to design temperature. Thus, the assessment of the adequacy of the existing superheaters is not a simple task.

B&W has determined the operating hoop stress level (based on the current minimum tube wall thickness) at operating pressure. The predicted tube operating temperatures based on B&W's standard design criteria and the resulting ASME Code allowable stress level for the existing material has also been determined. Comparison of the operating hoop stress with the Code allowable stresses results in the percent over the allowable stress. A modest overstress level indicates a modest shortening of remaining life expectancy and, unless otherwise indicated by past maintenance experience, does not warrant tube modification at this time.

If the tube analysis shows significant overstress or shows that tubes are predicted to operate at temperatures above those for which ASME Code stresses are published, then serious consideration should be given to tube upgrades and replacement. Significant overstresses are considered those tube rows that are 20% or greater overstressed. An overstress of 20% or more does not necessarily mean that immediate replacement of the tube row is required, but it identifies which tube rows should be examined for potential problems. Potential problems could be signs of creep, internal exfoliation or swelling.

This study showed that all tubes were predicted to operate at temperatures less than the existing material use limit for all the boiler operating cases shown in Tables 7A and 7B (with PSH surface reduction if required). In addition, all existing convection pass tubes and component headers had no overstress issues.

Therefore, the existing convection pass tube metallurgy is acceptable for natural gas firing for all cases.

### Forced Draft Fans

The existing forced draft fans were analyzed to determine if they meet the requirements of natural gas firing. The FD fans were originally designed to supply the combustion air in a pressure fired boiler operating mode. The boiler has since been converted to balanced draft operation, resulting high static pressure rise margins when firing coal. The results showed the existing FD fans far exceed the requirements in capacity and static pressure rise (including higher natural gas burner pressure drop) for all natural gas firing cases. Predicted fan performance is shown in Table 8A:

**Table 8A: Forced Draft Fan Performance at MCR Load (balanced draft operation)**

| Fuel | FD Fan Test Block | Bituminous Coal | Natural Gas | Natural Gas | Natural Gas |
|---|---|---|---|---|---|
| **Boiler Modifications** | | None | New burners with & without overfire air ports | PSH surface reduction New burners with overfire air ports | PSH Surface Reduction New burners with overfire air ports |
| **FGR flow (%)** | NA | None | None | 19.5 | 14.0 |
| **Flow per fan (lb/hr)** | 620,000 | 514,500 | 468,510 | 472,960 | 471,790 |
| **Static Pressure Rise (in WC)** | 25.9 | 7.5 | 10.82 | 10.95 | 10.88 |
| **Temperature (F)** | 125 | 100 | 100 | 100 | 100 |

### Induced Draft Fans

The existing induced draft fans were also analyzed to determine if they meet the requirements of natural gas firing. The results showed the existing ID fans far exceed the requirements in capacity and static pressure rise for all natural gas firing cases. Predicted fan performance is shown in Table 8B:

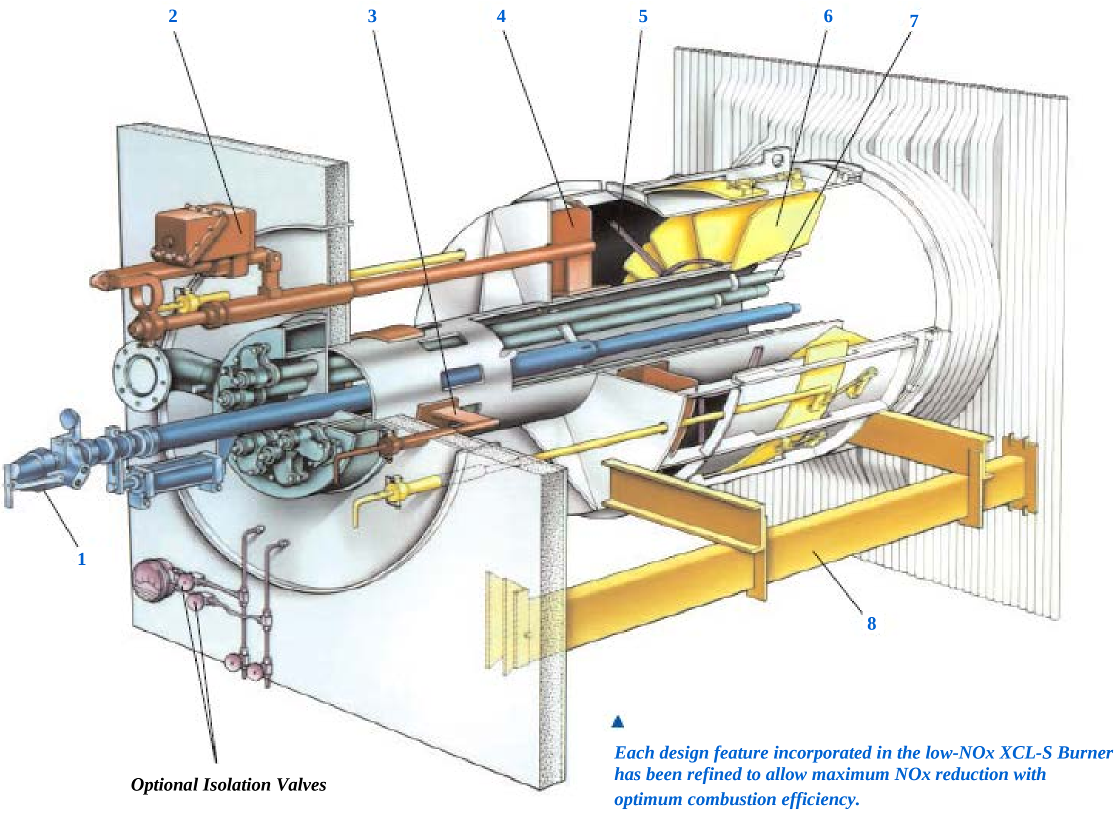
**Table 8B: Induced Draft Fan Performance at MCR Load (balanced draft operation)**

| Fuel | ID Fan Test Block | Bituminous Coal | Natural Gas | Natural Gas | Natural Gas |
|---|---|---|---|---|---|
| **Boiler Modifications** | | None | New burners with & without overfire air ports | PSH surface reduction New burners with overfire air ports | PSH Surface Reduction New burners with overfire air ports |
| **FGR flow (%)** | NA | None | None | 19.5 | 14.0 |
| **Flow per fan (lb/hr)** | 764,900 | 559,350 | 499,450 | 504,900 | 503,250 |
| **Static Pressure Rise (in WC)** | 16.0 | 12.8 | 9.10 | 10.13 | 9.78 |
| **Temperature (F)** | 360 | 301 | 293 | 315 | 308 |

### Combustion Equipment

The minimum combustion equipment modifications required to fire natural gas include replacing the twelve (12) existing PC burners with twelve (12) XCL-S® natural gas burners with natural gas ignitors. The XCL-S burner, shown below in Figure 2, is an advanced low-NOx burner that was developed to achieve superior NOx performance in burner-only applications and in applications using overfire air (OFA) and/or flue gas recirculation (FGR). It is designed as a simple plug-in, with little or no modifications needed to the rest of the boiler.

## Figure 2: Low-NOx XCL-S® Burner




| Components | Features |
|---|---|
| **1** I-Jet oil gun (optional) ) | Produces a finer oil spray, reduces particulate and opacity emissions, minimizes atomizer plugging |
| **2** Linear actuator | Easily adjusts the main air sliding damper position for light-off, full-load and out-of-service cooling |
| **3** Core air damper | Adjusts core air flow to the oil gun or gas spuds for optimizing combustion |
| **4** Sliding air damper | Adjusts the majority of secondary air flow to the outer air zone, independent of swirl, to balance air flow among burners during commissioning |
| **5** Air measurement grid | Ensures an accurate indication of relative air flow with a multi-point impact/suction device |
| **6** Externally adjustable spin vanes | Provide proper mixing of the secondary air and fuel (to the end of the flame) – vane position is optimized and fixed during commissioning |
| **7** Adjustable hemispherical gas spuds | Can be rotated to optimize NOx reduction and are removable while the boiler is in service |
| **8** Burner support system | Supports the burner and allows for differential expansion |

Additional NOx reduction can be achieved with staged combustion and/or flue gas recirculation. For staged combustion, the preferred approach is to locate eight (8) new NOx ports, four on the front wall and four on the rear wall, at an elevation at least eight feet above the top burner row. New NOx ports would require windbox and duct work modifications.

FGR involves the introduction of recirculated flue gas into the combustion air upstream of the burner windbox. A mixing device (such as a slotted air foil in the combustion air duct) is required to adequately distribute the recirculated flue gas in the incoming combustion air.

The new burners can be retrofitted into the existing burner pressure part openings on the furnace front wall. Depending on the choice of NOx reduction technologies (i.e., burners, burners plus OFA, burners plus OFA and FGR, or burners plus FGR) and the results of the associated detailed engineering in a material contract phase, adjustment to the existing throat diameter may be required. This can be accomplished by conical ceramic throat inserts (for a smaller diameter throat) or removal of pin studs and refractory (for a larger diameter throat) while retaining the existing pressure parts.

Note that all of the combustion air flow must now be supplied via the secondary air ducts and windbox since primary/pulverized coal transport air is no longer required.

**Emissions**

Emissions predictions are based on converting the unit to fire natural gas as the main fuel. Full load emission predictions for the various options are listed in Table 9. The values are predicted values with margin which B&W expects to be able to guarantee upon material supply.

**Table 9: Predicted Full Load Emissions on Natural Gas**

| | XCL-S Burners only | XCL-S Burners and OFA | XCL-S Burners, OFA, and FGR | XCL-S Burners and FGR |
|---|---|---|---|---|
| FGR Rate (%) | NA | NA | ~14% | ~19.5% |
| NOx (lb/$10^6$ Btu) | 0.16 | 0.13 | 0.07 | 0.07 |
| CO (ppmvd corrected to 3% $O_2$) | 200 | 200 | 200 | 200 |
| VOC (lb/$10^6$ Btu) | 0.003 | 0.003 | 0.003 | 0.003 |

**CONCLUSIONS**

As a result of this study, when firing natural gas with FGR, the PSH heating surface needs to be reduced to maintain existing tube metallurgy. A complete review of the existing tube metallurgies on Culley Station Unit #2 considering all natural gas firing cases revealed that all existing convection pass tubes had no overstress issues. In addition, all tubes were predicted to operate at temperatures below their ASME material code published limit. Header metal temperatures were also checked and showed to meet B&W's standards.

Along with the metals analysis, existing attemperator capacities were studied for the boiler operating conditions with and without flue gas recirculation (FGR) and also in regards to surface reductions of the primary superheater (where required). Existing attemperator capacities should be satisfactory (with the modification to the nozzle orifice size) at all boiler loads when firing natural gas.

Air heaters were assessed for natural gas firing. The air and gas side temperature profiles around the air heater were found to be acceptable for firing natural gas.

The existing FD and ID fans were found to exceed the performance requirements when firing natural gas.

The predicted boiler performance summaries are shown in the Appendix, comparing unit performance firing the original bituminous coal and predicted unit performance firing natural gas.

It is recommended that the twelve (12) existing PC burners be replaced XCL-S natural gas burners with natural gas ignitors. The addition of NOx ports and/or flue gas recirculation is recommended in order to provide reduced NOx emissions.

# APPENDIX A - Preliminary Performance Summaries

### Table 9.a.

**Vectren Culley Unit 2 - Preliminary Performance Summary**

| | | | | | | |
|---|---|---|---|---|---|---|
| Contract No. | 293H | GBB | | | | |
| Date | 12/16/2013 | Load ID | PC Firing | NG Firing | NG Firing | NG Firing |
| Revision | 0 | Boiler Arrangement | Existing | New Burners with & without Overfire Air Ports | PSH Surface Reduction New Burners without Overfire Air Ports | PSH Surface Reduction New Burners with Overfire Air Ports |
| | | | | | | |
| | | | | | | |
| Load Condition | | | MCR | MCR | MCR | MCR |
| Fuel | | | Bituminous | Natural Gas | Natural Gas | Natural Gas |
| Steam Leaving SH, mlb/hr | | | 840 | 840 | 840 | 840 |
| Superheater Spray Water, mlb/hr | | | 54,190 | 71,440 | 79,281 | 71750 |
| % Excess Air Leaving Economizer | | | 18 | 10 | 10 | 10 |
| Flue Gas Recirculation, % | | | None | None | 19.5 | 14.0 |
| Heat Input, mmBtu/hr | | | 1028.0 | 1077.0 | 1087.2 | 1083.5 |
| Quantity mlb/hr | Fuel (mcf/hr if gas) | | 102.8 | 1038.6 | 1048.4 | 1044.9 |
| | Flue Gas Entering Air Heaters | | 1017 | 909 | 918 | 915 |
| | Total Air To Burners | | 902 | 846 | 854 | 851 |
| Pressure, psig | Steam at SH Outlet | | 1290 | 1290 | 1290 | 1290 |
| | | | | | | |
| Temperature, °F | Steam | Leaving Superheater | 955 | 955 | 955 | 955 |
| | | | | | | |
| | | | | | | |
| | Water | Water Entering Economizer | 425 | 425 | 425 | 425 |
| | | Superheater Spray Water | 225 | 225 | 225 | 225 |
| | Gas | Entering Air Heater | 752 | 726 | 804 | 796 |
| | | Leaving Air Heater (Excl. Leakage) | 320 | 310 | 334 | 331 |
| | Air | Entering Air Heater | 100 | 100 | 100 | 100 |
| | | Leaving Air Heater | 604 | 598 | 660 | 653 |
| Heat Loss Efficiency, % | Dry Gas | | 4.89 | 3.67 | 4.18 | 4.06 |
| | $H_2$ & $H_2O$ in Fuel | | 5.94 | 10.42 | 10.54 | 10.51 |
| | Moisture in Air | | 0.12 | 0.10 | 0.11 | 0.11 |
| | Unburned Combustible | | 0.30 | 0.00 | 0.00 | 0.00 |
| | Radiation | | 0.23 | 0.24 | 0.24 | 0.24 |
| | Unacc. & Mfgs. Margin | | 1.50 | 1.00 | 1.00 | 1.00 |
| | Total Heat Loss | | 12.98 | 15.38 | 16.07 | 15.92 |
| | Gross Efficiency of Unit, % | | 87.02 | 84.58 | 83.93 | 84.08 |

**B&W Proprietary and Confidential**

# APPENDIX A - Preliminary Performance Summaries

## Table 9.b.

**Vectren Culley Unit 2 - Preliminary Performance Summary**

| | | | | | | |
|---|---|---|---|---|---|---|
| Contract No. | 293H | GBB | | | | |
| Date | 1/10/2014 | Load ID | PC Firing | NG Firing | NG Firing | NG Firing |
| Revision | 1 | Boiler Arrangement | Existing | New Burners with & without Overfire Air Ports | PSH Surface Reduction New Burners without Overfire Air Ports | PSH Surface Reduction New Burners with Overfire Air Ports |
| Load Condition | | | 50% | 50% | 50% | 50% |
| Fuel | | | Bituminous | Natural Gas | Natural Gas | Natural Gas |
| Steam Leaving SH, mlb/hr | | | 420 | 420 | 420 | 420 |
| Superheater Spray Water, mlb/hr | | | 2 | 28 | 19 | 18.5 |
| % Excess Air Leaving Economizer | | | 20 | 18 | 18 | 18 |
| Flue gas Recirculation, % | | | None | None | 19.5 | 14.0 |
| Heat Input, mmBtu/hr | | | 539.0 | 561.7 | 561.5 | 561.6 |
| Quantity mlb/hr | Fuel (mcf/hr if gas) | | 53.9 | 541.7 | 541.5 | 541.6 |
| | Flue Gas Entering Air Heaters | | 541 | 507 | 507 | 507 |
| | Total Air To Burners | | 473 | 466 | 466 | 466 |
| Pressure, psig | Steam at SH Outlet | | 1260 | 1260 | 1260 | 1260 |
| Temperature, °F | Steam | Leaving Superheater | 955 | 955 | 955 | 955 |
| | Water | Water Entering Economizer | 360 | 360 | 360 | 360 |
| | | Superheater Spray Water | 225 | 225 | 225 | 225 |
| | Gas | Entering Air Heater | 585 | 581 | 606 | 606 |
| | | Leaving Air Heater (Excl. Leakage) | 264 | 264 | 271 | 270 |
| | Air | Entering Air Heater | 121 | 121 | 121 | 121 |
| | | Leaving Air Heater | 501 | 504 | 528 | 525 |
| Heat Loss Efficiency, % | Dry Gas | | 3.34 | 2.74 | 2.90 | 2.90 |
| | $H_2$ & $H_2O$ in Fuel | | 5.76 | 10.05 | 10.08 | 10.08 |
| | Moisture in Air | | 0.08 | 0.07 | 0.08 | 0.08 |
| | Unburned Combustible | | 0.30 | 0.00 | 0.00 | 0.00 |
| | Radiation | | 0.44 | 0.46 | 0.46 | 0.46 |
| | Unacc. & Mfgs. Margin | | 1.50 | 1.00 | 1.00 | 1.00 |
| | Total Heat Loss | | 11.42 | 14.32 | 14.51 | 14.51 |
| | Gross Efficiency of Unit, % | | 88.58 | 85.68 | 85.49 | 85.49 |

**B&W Proprietary and Confidential**

# APPENDIX B – NG Conversion Equipment Scope & Budgetary Costs

## BASE SCOPE - Natural Gas Burners, Ignitors, Scanners

### Item 1: B&W XCL-S Natural Gas Burners (Quantity: 12)

Each burner to include:

- Externally adjustable secondary air zone spin vanes
- Externally adjustable core zone damper
- Multiple hemispherical gas spuds
- Pitot tube relative air flow measuring device with magnehelic gage
- Provisions to accept ignitor with integral flame detector
- One main flame scanner mount
- Two Type K permanent thermocouples to monitor core zone and burner outer sleeve temperature with two thermocouple heads
- Throat tile ring assembly to reduce the existing burner throat diameter
- Shop insulated cover plate
- Electric Linear Actuator for automated positioning of sliding secondary air damper
- One set of burner support steel with furnace wall and windbox connection hardware

### Item 2: Fossil Power Systems (FPS) Gas Ignitors and Flame Scanners

- Qty 12, FPS gas ignitors with high energy spark ignitors and flame rods
- Qty 3 or 6, pre-assembled valve racks
- Qty 1, combustion/cooling air blower skid
- Qty 12, FPS main flame scanners with rigid fiber optic extension
- Qty 1, main flame scanner electronics cabinet
- 1 Lot – Combustion/Cooling air piping from blower skid to burner fronts

### Item 3: Natural Gas Regulating Station and Piping

- Main natural gas regulating station – 30 psig supply pressure
- Natural gas piping from regulating station to the burners
- Natural gas burner front gas piping and valve stations including vent piping to above the boiler building roof

## OPTION 1 SCOPE - B&W Overfire Air Ports (OFA) – Dual Zone

- Qty 8, Furnace Water wall Openings
- Windbox Extensions or Individual OFA Windboxes
- Qty 8, Automated Air Flow Control Damper with Rotary Drive - per port
- Boiler Closure Casing
- Temperature Monitoring Thermocouple (port style dependent)

## OPTION 2 SCOPE - Flue Gas Recirculation (FGR)

- Flue Gas Recirculation Fan and Motor
- FGR Flues
- AH Outlet to FGR Fan Inlet
- FGR Fan Outlet to Secondary Air Mixing Foils
- FGR Flue expansion joints, hangers, bridging steel
- FGR Mixing Foils
- Windbox $O_2$ Monitor
- Burner throat assemblies to accommodate the larger B&W XCL-S burners required for FGR firing.

General Services

- Combustion system tuning services using an economizer outlet sampling grid for measurement of NOx per EPA methods.
- Performance testing
- Field Service Engineering outage support for construction, start-up, and post-modification testing. Coverage includes one engineer for 30 man-days at 10 hours per day, 6 days per week. In addition, Field Service Engineering to be provided to support system tuning and performance testing for a total of 20 man-days at 10 hours per day, 6 days per week.
- Burner System Operator Training consisting of two, one day sessions.
  - Training includes project specific training manual for up to 20 participants.
- Brickwork Refractory Insulation & Lagging (BRIL) Specifications and Installation design and materials.
- Contract specific System Requirements Specification, I/O Listing, and Functional Logic Diagrams for all supplied equipment.
- Operating and Maintenance Manuals (10 copies).
- New piping, flue, and duct loading to existing steel
- Shop tube butt welds shall be 100% radiographed.
- No weld rings for shop or field welds.
- All tube ends will be prepped, primed, capped and taped.
- All attachments will be shop installed, where possible.
- Shop hydrostatic pressure testing, at 1½ times design pressure, of all fabricated tube assemblies. Loose tubes without tube to tube welds will not be tested. Shop hydrostatic pressure testing will be AI witnessed.
- Pressure part fabrication to be estimated for BWM.
- Delivery F.O.B. Culley Plant, Newburgh, IN.

Items not Included

- Hazardous material removal or abatement (i.e., lead paint and asbestos).
- Load analysis of existing structural steel or foundations and any required re-enforcement thereof.
- Hardware or reprograming of existing DCS and/or BMS to support natural gas conversion.
- Gas step down equipment. Equipment scope above assumes incoming gas pressure at B&W's terminal to be 30 to 50psi.

Terminal Points

- Inlet of gas regulating station
- Interface of new burners to the existing furnace wall
- Field weld at the new wall panel inserts (if any)
- Electrical terminals on provided electrical equipment or instruments
- Electrical terminals in shop provided terminal junction boxes as part of skidded equipment
- FGR duct take off near the existing economizer outlet
- FGR duct tie in at the existing secondary air duct(s)
- OFA duct take off(s) from the existing secondary air duct(s) or windbox

## Budgetary Material & Installation Pricing (USD 2019)

| Scope Item | Budgetary | |
|---|---|---|
| | Material | Installation |
| BASE SCOPE: Burner, Ignitor, Scanner, NG Piping System | $2,900,000 | $4,350,000 |
| OPTION 1 SCOPE: Overfire Air System | $370,000 | $555,000 |
| OPTION 2 SCOPE: Flue Gas Recirculation System | $412,000 | $618,000 |

## Lead Times

- Material delivery: 52 - 56 weeks
- Installation outage duration: 8 - 10 weeks

B&W has offered these prices in 2019 US dollars and have not attempted to project escalation for time of performance or delivery.

Please note that these prices are budgetary and is not represent an offer to sell, however, we would welcome the opportunity to provide a formal proposal upon request.

# Appendix C. Burns & McDonnell A.B. Brown Coal to Gas Conversion, Unit 2

# A.B. Brown Coal to Gas Conversion

**Vectren Energy Delivery**

**AB Brown Unit 2 Coal to Gas Boiler Conversion**
**Project No. 113003**

**Revision 1**
**April 2019**

# A.B. Brown Coal to Gas Conversion

**prepared for**

**Vectren Energy Delivery**
**AB Brown Unit 2 Coal to Gas Boiler Conversion**
**Evansville, Indiana**

**Project No. 113003**

**Revision 1**
**April 2019**

**prepared by**

**Burns & McDonnell Engineering Co.**
**Kansas City, MO**

# TABLE OF CONTENTS

**Page No.**

# LIST OF TABLES

**Page No.**

# 1.0 EXECUTIVE SUMMARY

Vectren Energy Deliveries (Vectren) is studying a coal to gas conversion project (Project) at the A.B. Brown facility. The conversion requires boiler burner modifications and gas infrastructure to fire 100% natural gas and remove coal firing capabilities.

Vectren retained Burns & McDonnell (BMcD) to provide conceptual engineering design to support a feasibility grade cost estimate. This report summarizes the conceptual engineering, performance estimates, and cost estimates for Vectren to evaluate the feasibility of the project.

## 1.1 Purpose

The purpose of this report is to provide the overall scope, schedule, performance, and capital costs to construct the Project based on the assumptions documented herein, and to provide general information to support project screening and evaluations.

## 1.2 Project Configuration Summary

A.B. Brown currently has two pulverized coal fired boilers that burn a local bituminous fuel. Each unit has a net output of approximately 240 MW. The boilers are a Babcock and Wilcox (B&W) wall fired design. The boilers are not equipped with over fire air or flue gas recirculation. Unit 1 is the northern unit which includes Selective Catalytic Reduction (SCR), baghouse, and dual alkali scrubber. Unit 2 is the southern unit which includes Selective Catalytic Reduction (SCR), precipitator, and dual alkali scrubber.

The A.B. Brown boilers were evaluated by B&W to estimate boiler performance and retrofit costs. This study compiles the findings from the B&W report attached in Appendix E with balance of plant (BOP) impacts to develop a total plant evaluation.

This report documents the 100% gas conversion of Unit 2 only. Vectren is evaluating new natural gas offsite infrastructure which is not included in this evaluation. This report assumes a new gas line tap in the existing gas yard. New metering and regulating is added in the gas yard along with a new onsite pipeline from the gas yard to the boiler house. The regulating station in the gas yard lowers the incoming pressure to 200 psig and an intermediate regulating station in the boiler house lowers the pressure further to 50 psig. Additional regulating stations provided by B&W are located at each boiler to lower the pressure further from 50 psig to the burner front pressure. New gas supply piping, vents, and valve stations are included up to the burner fronts. The existing burners will be retrofitted with the B&W Hemi-Spud nozzle to fire 100% natural gas.

For 100% natural gas firing, the SCR and dual alkali scrubber are not necessary. Natural gas emissions are low enough that additional controls shouldn't be necessary, an updated netting analysis should be performed to confirm this. The particulate control will remain in service during startup and initial operation to limit any potential particulate emissions from residual ash in the boiler and ductwork. The dual alkali scrubber will be demolished and replaced with ductwork. The scrubber tower has problems with erosion and leaks and Vectren wanted to remove it as a potential maintenance item.

## 1.3 Performance and Air Emissions Summary

Unit 2 will have an estimated electric generating capacity and heat rate as shown in the table below. The performances are based on adjusting the existing coal performance for the natural gas and co-firing cases.

**Table 1-1: Unit 2 Performance Summary**

| | 100% Coal | 100% Natural Gas |
|---|---|---|
| Net Output, kW | 240,000 | 238,950 |
| Net Heat Rate, Btu/kWhr | 10,650 | 11,175 |
| Gross Output, kW | 260,870 | 255,650 |
| Auxiliary Loads, kW | 20,870 | 16,700 |
| STG Heat Rate, Btu/kWhr | 8,615 | 8,790 |
| Boiler Efficiency, % | 87.9% | 84.2% |

BMcD performed a high-level permitting analysis in 2016 that evaluated the plant while firing 100% natural gas. For two units, this analysis found that while burning 100% natural gas the plant can operate at an approximate 10% capacity factor and not trip PSD. CO was the limiting factor for each case which is based on the 200 ppm estimate from B&W (0.148 lb/MMBtu). The CO emissions while burning natural gas will likely be less than 200 ppm. By only converting a single unit (Unit 2), the capacity factor should increase to almost double. This will be affected by the past operation from 2016 to 2019 though (past actuals vs future potential).

## 1.4 Contracting Approach

The selected contracting strategy for this report is the Multiple Prime Contracts approach with the Owner contracting B&W for the burner modifications and a balance of plant contractor directly.

## 1.5 Schedule

The schedule for this project was developed for a generic start date at month zero (0). The critical path for the project runs through receipt of gas burner equipment, construction, and continuing through startup and commissioning. This schedule assumes Vectren will start preliminary engineering and design while the air permit is being developed and reviewed. The project for 100% gas conversion will likely not trip PSD so air permitting should not be a big risk. The project schedule is shown in Appendix C.

## 1.6 Capital Costs

The capital cost for the gas conversion is presented in Table 1-3 below. The capital cost estimate is an Association for the Advancement of Cost Estimates (AACE) Class IV estimate. Per this classification, the estimate could have a lowest accuracy of -30%/+50% and a highest accuracy of -15%/+20%. Since a site visit was performed and engineering documents were created for estimate takeoffs, this estimate is closer to the highest accuracy range. Due to this, the contingency's below are recommended.

**Table 1-2: Unit 2 Capital Costs**

| | 100% Natural Gas |
|---|---|
| Project Costs w/ B&W Contract, $ | $16,340,000 |
| Owners Costs, $ | $5,485,000 |
| **Total Costs, $** | **$21,825,000** |

The project cost includes direct material and construction costs for the Project as well as indirect costs including engineering, construction management, and other indirects. A project contingency of 5% is applied to the project costs. Owners costs includes owner specific management, operations, legal costs, startup costs, interest during construction, contingency and other owners costs. An owner's project contingency of 10% is included on the total project costs to cover scope definition and estimate accuracy.

# 2.0 INTRODUCTION

## 2.1 Background

Vectren is investigating converting the existing A.B. Brown Unit 2 to burn 100% natural gas. For 100% natural gas conversion, a new natural gas supply will be constructed up to the existing burners which will be retrofitted with gas spuds. The existing emissions controls will be taken out of service except for the particulate control during initial operation.

Vectren retained Burns & McDonnell to provide a feasibility grade cost estimate of the Plant. This report summarizes the conceptual design and presents the project costs to be used by Vectren in evaluating project feasibility.

## 2.2 Study Scope

The scope of work included preparing the following major conceptual design documents:

1. Site Arrangement Drawing
2. Preliminary Process and Instrumentation Diagrams
3. Project Schedule
4. Capital Costs

## 2.3 Objectives

The objectives of this study were to establish the conceptual design for the project, to provide an overall project schedule, and to provide a capital cost estimate to support project screening and evaluations. Vectren can use the information from this report to evaluate the natural gas conversion against other generation options.

## 2.4 Limitations and Qualifications

The costs presented within this report are subject to:

- Design changes for enhanced efficiency/operational flexibility.
- Final negotiation of the Terms and Conditions with the contractors and the major equipment suppliers.
- Final geotechnical report findings.
- Final topographical survey.
- Final determination/negotiation of the project schedule.
- Final selection of the equipment.
- Final permit requirements.
- Changes in federal regulations.

- Full evaluation of existing underground interferences.

# 3.0 PROJECT DEFINITION

## 3.1 Plant Overview

### 3.1.1 Scope of work

The assumptions that formed the basis of the plant conceptual design and cost estimate are summarized in this report. The assumptions were developed through meetings with Vectren and a site visit at A.B. Brown to evaluate how the conversion will impact the existing plant.

### 3.1.2 Key Design Documents

The following preliminary design documents were developed to form the basis of the project preliminary design and are included in the Appendices.

- Appendix A: Site Arrangement
- Appendix B: Process Flow Diagrams
- Appendix C: Project Schedule
- Appendix D: Capital Cost Estimate Summary

## 3.2 General Design Criteria

### 3.2.1 Operating and Control Philosophy

The Plant is expected to be operated as a peaking facility on 100% natural gas. Daily on/off cycling of the plant may be required. Considerations for daily cycling and impacts on existing equipment have not been included in this report.

The plant will be controlled using the existing A.B. Brown control room and distributed control system (DCS). The DCS at A.B. Brown station has recently been upgraded to Emerson Ovation version 3.3.1. Given that this is a modern control system, input/output (I/O) modules can be purchased and added to the system with little impact to the overall control system.

The I/O will change with the conversion from coal to natural gas. In general, a coal-fired station requires more I/O than a gas-fired station, so the gas conversion will be an overall reduction in the DCS I/O. It is assumed that B&W will provide updated instrument lists and I/O lists for the coal to gas conversion that indicate the devices to be removed and new devices that will be added to the control system. This in combination with the balance of plant (BOP) modifications will be used to develop an overall I/O impact. For the purposes of this study, a worse-case scenario was assumed that new DCS cabinets will need to be added to the existing BMS system. During detailed design, the system will be evaluated to determine how the existing system can be best utilized. Most likely, I/O can be relocated and spares can be utilized so that additional hardware is not necessary.

The existing logic will be modified to accommodate the modified gas burners, gas supply equipment, and gas interlocks. The existing master fuel trip (MFT) cabinet will be rewired to accommodate the new configuration. Fuel firing, air flow, and interlock logic will be reviewed and implemented based on the logic diagrams provided by B&W. Additional modifications to the BOP logic will be required to remove systems that are out of service and add logic for gas supply skids. The cost estimate assumes that BMcD will review the proposed logic changes by B&W and develop logic updates for Emerson to program.

The graphics will require evaluation and modification with the coal to gas conversion. During detailed design, BMcD will evaluate the existing graphics compared to the instrument list changes and updated piping configuration provided by B&W to develop graphic update sketches. These sketches will be reviewed with Vectren and then transmitted to Emerson for configuration.

An Emerson Field Service Engineer will be on-site for a portion of the outage to assist BMcD with I/O checkout and resolve any logic or graphic issues. Tuning of the air flow, drum level, furnace draft, throttle pressure control, steam temperature control, and other miscellaneous BOP loops will be required by an Emerson Tuner during startup.

The existing plant operators will be trained for natural gas operation. For the 100% gas firing case, plant operations can be reduced as the gas fired plant will have less equipment operating and require less maintenance.

Plant automation will be designed for secure and safe operation of all equipment. Maintenance support will be supplied by on-site staff as required for routine maintenance activities and may be shared with other Vectren units if such need arises.

### 3.2.2 Plant Design Summary

Design basis of the Plant can be summarized by the key documents accompanying this report as Appendices. Detailed design basis for each discipline as well as system descriptions are presented in this report.

#### 3.2.2.1 Plant Location and Layout

The A.B. Brown plant is located in Mt. Vernon, IN near Evansville, IN. The conversion will have little impact on the existing plant layout. The existing gas yard has adequate space for the new regulating and metering skids. The regulating stations at the boiler will be housed in the southwest corner of the boiler house. Some existing shelving and storage may need to be relocated to allow room for the new regulating stations and valve stations. For the 100% gas conversion, the existing scrubber vessels will be demolished and replaced with ductwork but existing roads and access will not be impacted. The Site Arrangement Drawing is included in Appendix B.

No modifications to existing roads, switchyard, coal yard, or other plant areas are necessary. Existing building and structure modifications are not required.

#### 3.2.2.2 Plant Utilities and Infrastructures

##### 3.2.2.2.1 Fuel Gas Supply

The A.B. Brown plant site currently has existing gas supply utilized as start-up fuel for Units 1 & 2 and as main fuel supply for the GTG units. Plant personnel indicated that an additional gas line would be required for the additional necessary gas quantities for the conversion of Unit 2. A new gas supply line would also require a new revenue quality regulating and metering station. For the purposes of this study, BMcD located the single additional revenue quality regulating and metering station on the west side of the existing gas yard. The cost estimate scope starts at the inlet to the new regulating station and includes the onsite metering and regulation. The offsite supply line is excluded. This regulating station would be the single point of supply for the primary fuel for the converted unit. The new supply line would be fed by an underground line to the southwest corner of the boiler house to an intermediate regulation station to drop the pressure to B&W's required 50 psig. This line will feed B&W's regulating skid, beginning B&W scope of supply. The boiler regulating station would result in reducing the primary fuel pressure from 50 psig to burner supply pressure. The single regulating station located at the gas yard and the boiler supply regulating stations would be designed based upon NFPA 85 code.

##### 3.2.2.2.2 Water Supply & Discharge

The discontinued use of coal after the 100% gas conversion would have considerable impact to water requirements at the A.B. Brown plant site. Both units currently utilize wet scrubber technology for the reduction of acid gases from fuel bound sulfur. This technology requires a continuous water supply to make up the continued blowdown stream. Both A.B. Brown units sluice bottom ash to an ash pond. Fly ash is transported dry to an onsite silo and then conveyed to barge for offsite utilization. The plant will no longer need water for fly ash sluicing or water for the hydroveyor to the barge. Mercury limitations for wastewater discharge (assuming existing coal pile and ponds are closed) will also be mitigated.

#### 3.2.2.3 Buildings and Enclosure

No changes will be made to the existing boiler house building. The gas yard equipment will not be enclosed. The new gas valve stations and regulators for the conversion will be housed in the existing boiler house with no structural modifications necessary. Since the units already use natural gas for startup fuel, additional ventilation (such as louvers or vent fans) should not be required when converting the coal burners to natural gas.

### 3.2.3 Unit Modifications

When a boiler is converted to gas firing, there is no longer a need for primary air to convey coal from the coal mill to the burners. Instead, all of the air supply will be sent through the windbox as secondary air. B&W

estimates a boiler efficiency impact of almost 4 percentage points; however, the excess air requirement will drop from ~20% to ~10%. This change in operating conditions results in lower air supply requirements than when firing coal. B&W reviewed the draft system and confirmed that the induced draft and forced draft fans will be adequate for the boiler conversion.

The A.B. Brown Units have the full scope of air quality control system (AQCS) technologies. Natural gas still produces nitrogen oxides (NOx), but the SCR will not be necessary for 100% natural gas firing as it produces much lower NOx. In the case of full gas conversion, both the particulate matter (PM) control and flue gas desulphurization (FGD) technologies could be fully removed from service but Vectren has elected to keep the PM control in service for initial operation to remove any residual particulate in the system. When operating on 100% natural gas, the boiler and gas path will clean up with time and the particulate systems can be removed from service. Due to the low operating hours and uncertain life of the converted plant, owners typically don't demolish the precipitator internals but the bags can be removed from the baghouse. This study assumes that the particulate control devices will be abandoned in place with no demolition.

#### 3.2.3.1 Boiler Modifications

In order to convert the boiler for 100% gas firing, the existing coal burners will be retrofitted by removing the coal nozzle and replacing it with a hemi-spud cartridge as indicated by B&W in Appendix E. The existing natural gas pilot fuel system and ignitors will be reused. The following components will be supplied for each boiler by the boiler vendor for this modification:

<u>Boiler Front Equipment</u>

- Hemispherical Gas Spud Cartridges to replace existing coal nozzles
- Burner Valve Racks ("double block & bleed")
- Burner Front Flex Hose and Hardware
- Burner Front Piping
- Gas Header Piping
- Main UV flame scanners with rigid fiber optic extension
- Main flame scanner electronics cabinet
- Combustion/Cooling air piping from blower skid to burner fronts

<u>Natural Gas Transport Piping and Regulating</u>

- Main natural gas regulating station located within boiler – 50 psig supply pressure to regulator
- Natural gas piping from regulating station to the burners
- Natural gas burner front gas piping and valve stations excluding vent piping

This previous scope of work is typical of the boiler vendor, but Vectren would still be required to install a regulating and metering station at the gas yard for the new gas supply for the primary gas and an intermediate regulation station to lower pressure further to the 50 psig supply pressure to B&W's regulating skid. For the purposes of this study, BMcD placed the new regulating and metering station on the west end of the gas yard and routed a new gas feed along the same path as the existing igniter gas piping. This routing would run east, south of the existing gas turbines and plant road, before turning northeast into the boiler house. The intermediate regulation skid would be located in the boiler house near the existing valve station.

The boiler vendor's scope starts at the southwest corner of the boiler house. Each boiler would require its own low pressure regulating station to allow for primary fuel gas to be isolatable. The boiler regulating stations may be placed adjacent to the existing igniter gas regulating station. The primary fuel gas piping can follow the similar pipe routing to the existing igniter fuel piping for each respective boiler. BMcD pipe sizing criteria for fuel gas is as follows:

- 2-1/2" – 8" Pipe : < 4000 ft/min Line Velocity
- 10" – 20" Pipe : < 5000 ft/min Line Velocity

This design criteria provides lower velocities, resulting in less noise and pipe vibrations as compared to typical velocities when designed by boiler vendors.  B&W has not confirmed the line velocity assumed for the burner supply piping they are providing.

In addition to the fuel piping, vent pipe will be required per NFPA 85. This vent piping will be required on both the front and rear elevations of the boiler. B&W did not provide any vent piping in their scope. This vent piping is covered in the BOP scope.

The boiler decks at A.B. Brown Unit 2 appear to have sufficient space; however, the coal piping and elbows should be removed for better access the burner fronts for a full gas conversion. Coal piping can be removed from the burner decks, down to the pulverizer top exits. Pulverizers may be abandoned in place and blanked off.

### 3.2.4 Switchyard

No switchyard modifications will be required.

### 3.2.5 Unit 2 Performances

Burning natural gas will be less efficient than burning coal. The main impact on boiler efficiency is from hydrogen losses due to the higher hydrogen content of the natural gas fuel. The byproduct of combusting hydrogen is water vapor, and additional heat is needed to vaporize this water and heat it to the internal boiler temperature. This heat is lost in the flue gas rather than absorbed in the boiler's water walls to create steam.

On the other hand, natural gas is more efficient than coal when it comes to dry gas losses due to less combustion air and excess air. B&W assumed that approximately 10% excess air is needed for proper combustion of natural gas vs. 20% excess air for coal. Less flue gas flow for burning natural gas equates to smaller losses for heating the flue gas.

While the reduced natural gas-fired boiler efficiency reduces net plant output, the reduction in auxiliary power requirements for a gas-fired boiler increases the net plant output accordingly. This study assumes a 20% savings in auxiliary loads for pulverizers, coal handling, soot blowers, etc. that will not be operated on 100% natural gas.

Expected performances for natural gas are shown below along with the existing Unit 2 performances. The boiler efficiency is based on B&W's study. Also based on B&W's boiler evaluation, the STG heat rate will be slightly higher due to lower reheat temperatures.

**Table 3-1: Unit 2 Performance Estimates**

| | 100% Coal | 100% Natural Gas |
|---|---|---|
| Net Output, kW | 240,000 | 238,950 |
| Net Heat Rate, Btu/kWhr | 10,650 | 11,175 |
| Gross Output, kW | 260,870 | 255,650 |
| Auxiliary Loads, kW | 20,870 | 16,700 |
| STG Heat Rate, Btu/kWhr | 8,615 | 8,790 |
| Boiler Efficiency, % | 87.9% | 84.2% |

The 100% natural gas performance will have a lower output and higher heat rate compared to the coal performance based on decreased boiler efficiency, decreased steam turbine gross output and decreased steam turbine heat rate. This is mainly due to the decreased hot reheat temperature while operating on natural gas. The reduction in auxiliary loads could not make up for the reduction in steam turbine performance.

## 3.3 Environmental & Permitting

A high-level permitting analysis was performed in 2016 for the two A.B. Brown units. This evaluation showed that the plant should be able to net out without tripping PSD. By only converting a single unit, the netting analysis and allowed operating hours should improve. An updated netting analysis was not performed for this study.

## 3.4 Project Schedule

### 3.4.1 General

The schedule for this project was developed for a generic start date at month zero (0). This schedule assumes Vectren will start preliminary engineering and design while the air permit is being developed and reviewed. The project for 100% gas conversion should not trip PSD so air permitting should not be a big risk. The project schedule is shown in Appendix C.

### 3.4.2 Major Equipment

The schedule assumes a 12-month lead time for all boiler and burner equipment. B&W provided a lead time of 52-56 weeks.

### 3.4.3 Construction

Major construction activities will include the new onsite gas pipeline and fuel yard work, boiler modifications including mechanical and electrical work, and the scrubber vessel demo and replacement with ductwork. Construction of Unit 2 is estimated at approximately 12 months.

### 3.4.4 Startup

Startup for either the 100% natural gas or co-firing options will be relative short with a duration of approximately 2 months. The unit will be fired and tuned for optimum performance. Since the steam side will not be affected, no steam blows or cleanings will be necessary.

# 4.0 PROJECT COSTS

## 4.1 Project Cost Estimate

The detailed capital cost build-up for the 100% natural gas is included in Appendix D. The capital cost summary is shown below. The project costs exclude escalation and are shown as 2019$. The capital cost estimate is an Association for the Advancement of Cost Estimates (AACE) Class IV estimate. Per this classification, the estimate could have a lowest accuracy of -30%/+50% and a highest accuracy of -15%/+20%. Since a site visit was performed and engineering documents were created for estimate takeoffs, this estimate is closer to the highest accuracy range. Due to this, the contingency's below are recommended. A project contingency of 5% is included to cover pricing accuracy and potential labor productivity. An owner contingency of 10% is included to cover the accuracy of the estimate for the scope defined in this report. Owner costs are also included to account for all project costs that may be incurred during the project.

**Table 4-1: Unit 2 Capital Costs**

| | **100% Natural Gas** |
|---|---|
| Project Costs w/ B&W Contract, $ | $16,340,000 |
| Owners Costs, $ | $5,485,000 |
| **Total Costs, $** | **$21,825,000** |

## 4.2 Cost Estimate Basis

The purpose of the cost estimate basis is to generally describe the scope of the cost estimate and the methodology for estimating the costs.

### 4.2.1 Contracting Approach

The cost estimate was assembled using multiple prime contract approach. The Owner is responsible for the purchase of all equipment, while each prime contractor is responsible for their subcontracts, and labor. The associated risk for the Owner of using multiple contractors is accounted for in the total project contingency. Costs to administer the contract, participate in OEM's meetings, and review submittals are included under engineering cost.

### 4.2.2 Engineered Equipment

B&W will provide the majority of the major equipment. The B&W supplied scope is outlined in 3.2.3.1 and in Appendix E. B&W provided a supply and installation cost for the burner equipment. BMcD checked the installation estimate using information from previous gas conversion estimates and found that it was a conservative estimate. Based on this, the B&W installation cost was carried in the estimate even though B&W may or may not perform that work when the project is executed. The BOP contractor will provide the gas yard regulating and metering. All BOP equipment and materials were based on in house pricing from recent projects. The productivity factors for the equipment installation were derived from Burns & McDonnell past project information for union labor in the project area.

### 4.2.3 Civil

Civil scope for this project is very limited. Scope includes excavation and backfill for the onsite natural gas pipeline and finishing work around the gas yard and scrubber vessel areas. No new roads or grading are required.

### 4.2.4 Concrete

The gas yard metering and regulation is assumed to be field erected. Some foundation work is included for the scrubber vessel replacement where foundations could not be reused. The valve stations and metering in the boiler house will be mounted to the existing floor slab. This scope also includes estimated quantities for the structural excavation and backfill required for foundation construction. For reinforcing steel, a density of rebar per unit of concrete was provided by engineering for estimating purposes. The production rates and material prices were developed from Burns & McDonnell previous project estimates for construction in the project area.

### 4.2.5 Structural Steel

Miscellaneous steel such as pipe rack, grating, handrail, etc. are included for structure access that is not otherwise provided as part of the equipment contracts. Structural steel is also estimated to replace the existing scrubber vessels with ductwork. The existing structural steel around the absorbers was assumed to be corroded and was replaced with new steel where necessary. The production rates and material prices were developed from Burns & McDonnell previous project estimates for construction in the project area.

### 4.2.6 Piping

The BOP piping scope of work includes mostly below grade gas supply piping from the gas yard to the boiler house and vent piping. B&W is providing materials and installation of all the burner supply piping. The piping scope covers purchase of pipe, fittings, flanges, valves, specials, bolt-up kits, supports and pre-fabricated pipe. The piping scope of work does include applicable non-destructive evaluation (NDE) and pressure testing. The piping scope of work includes allowances for underground interferences.

The piping estimate was based on a take-off from the general arrangement with P&IDs. Using these quantities, costs for bulk material, valves, pipe fabrication was based on Burns & McDonnell recent project pricing. The production rates developed from Burns & McDonnell previous project estimates for construction in the project area.

### 4.2.7 Electrical

The auxiliary power requirements for burning natural gas are generally lower than that required for burning coal. Abandonment of the pulverizers will free up considerable load from the aux power system. Power will be required for the new flame scanners, valves, and blowers, but it is assumed that the existing power distribution can accommodate these additional minor loads. New control wiring has been included from the burner devices to the existing burner junction boxes. New marshalling control wiring has also been included from the burner junction boxes back to the DCS. Wiring has been included to the low pressure and high pressure regulating skids. The existing cable tray around the boiler has adequate space to accommodate the new cable. The production rates and material prices were developed from Burns & McDonnell previous project estimates for construction in the project area.

### 4.2.8 Instrumentation & Controls

The majority of instrumentation for this project is either skid-mounted or included in the B&W installation estimate. The skid-mounted regulating skids and valve stations are specified such that all instrumentation is installed and wired to a junction box. Some instrumentation will be installed separately for the field erected gas yard metering and regulation. This results in negligible BOP instrumentation installation work. As described in the General Design Criteria section, the worst case scenario was assumed where new DCS cabinets would be necessary to accommodate the BMS. An internal estimate was developed for this DCS cost that includes both hardware and software modifications.

## 4.3 Indirects

The following methods were used for indirects:

- Cost for construction management and construction indirects were based on a percentage of the project costs based on similar past projects. Costs include construction management staff expenses including travel and living expenses, temporary buildings and utilities, and site maintenance. Additional construction management provided by the contractors is included in the wage rates used in this estimate.

- Cost for engineering was based on a percentage of the project costs based on similar past projects. The engineering estimate includes costs for office and field engineering as well as all per diems, expenses, and general overhead and administrative costs. The engineering estimate also includes costs to review submittals from major equipment OEMs and contract administration tasks such as attending progress meeting, expediting drawing submittals, and reviewing progress report.

- Cost for startup was based on a percentage of the project costs based on similar past projects.

### 4.3.1 Taxes

All taxes are excluded from the estimate.

### 4.3.2 Construction Labor Basis

The estimate was developed on the basis that there will be a sufficient labor pool to draw from the Evansville/Mount Vernon area to support the project. The productivity factors were developed based on Burns & McDonnell project history for labor in the area.

#### 4.3.2.1 Labor Wage Rates & Expenses

Wage rates were taken from the 2019 RSMeans Construction Labor Rates for the Mount Vernon, IN area. The wage rates include wages, fringes, general liability and workers compensation insurance, overtime, per diem, incentives and contractor indirects.

#### 4.3.2.2 Work Hours

The estimate assumes a 5-day, 50-hour week to incentivize labor. The shifts are based on a 50 hour work week with 25% of hours of overtime per day at one and a half times base wage rate for overtime pay.

#### 4.3.2.3 Labor Per Diem

Craft per diem included in the craft wage rates.

### 4.3.3 Escalation

Escalation was excluded from the project costs.

### 4.3.4 Contingency

A project contingency was included to cover typical final accuracy of pricing, commodity estimates, and accuracy of the defined project scope. Typically the level of contingency is set by the amount of scope definition provided, the amount of engineering and estimating conducted by the OE and Vectren prior to providing cost certainty on the project price, and the amount of risk born by the prime contractors (performance, schedule, scope, payment, etc.). This contingency is NOT intended to cover changes in the general project scope (i.e. addition of buildings, addition of redundant equipment, addition of systems, etc.) NOR major shifts in market conditions that could result in significant increases in contractor margins, major shortages of qualified labor, significant increases in escalation, or major changes in the cost of money (interest rate on loans). A 5% contingency was included as a typical allowance for this indirect cost.

### 4.3.5 Owner Costs

Vectren's costs were included in the cost estimate. Burns & McDonnell referenced past projects to develop typical owner costs. Costs were included for the following items:

- Project development
- Vectren's project management
- Vectren's legal counsel
- Permitting and license fees
- Permanent plant operating spare parts
- Startup testing fuels and consumables
- Operator training
- Builder's risk insurance
- Interest during construction (10.2% of project costs provide by Vectren)

Owner's contingency takes into account the level of project scoping and engineering completed during the feasibility design phase to support this cost estimate. 10% contingency on the Total Project Cost and Owner Cost was used at this stage. As the scope and estimating accuracy for this project is refined in subsequent phases the amount of contingency carried will shrink.

# 5.0 CONCLUSIONS AND RECOMMENDATIONS

## 5.1 Conclusions

Burns & McDonnell recommends Vectren evaluate the project economics based on the cost and performances presented in this report. If the Plant economics are favorable as a future generation project, then Burns & McDonnell recommends Vectren proceed with a more detailed study to develop budget level pricing and finalize all design and cost considerations.

# APPENDIX A – SITE ARRANGEMENT

## BUILDING NO. DESCRIPTION

| | |
|---|---|
| 1 | UNIT NO. 1 T-G BUILDING & BOILER BUILDING |
| 2 | UNIT NO. 2 T-G BUILDING & BOILER BUILDING |
| 3 | ADMINISTRATION BUILDING |
| 4 | MAINTENANCE SHOP & STOREROOM |
| 5 | FIRE PUMP & SERVICE WATER PUMP BUILDING |
| 6 | CHLORINE BUILDING |
| 7 | HYDROGEN/CARBON DIOXIDE BUILDING |
| 8 | SUBSTATION CONTROL BUILDING |
| 9 | UNIT NO. 1 FGD SYSTEM FILTER BUILDING |
| 10 | BLACK START GENERATOR BUILDING |
| 11 | UNIT NO. 2 FGD SYSTEM RECIRC. PUMP HOUSE BUILDING |
| 12 | UNIT NO. 2 FGD SYSTEM FILTER BUILDING |
| 13 | UNIT NO. 1 FGD SYSTEM NORTH ABSORBER RECIRC. PUMP HOUSE |
| 14 | UNIT NO. 1 FGD SYSTEM SOUTH ABSORBER RECIRC. PUMP HOUSE |
| 15 | COAL HANDLING SWITCHGEAR BUILDING |
| 16 | COAL HANDLING OFFICE & MAINTENANCE SHOP |
| 17 | SLAKING SYSTEM PUMP ENCLOSURE |
| 18 | LIQUID PRODUCT TANK FARM |
| 19 | GAS TURBINE (UNIT NO. 3) |
| 20 | GUARD HOUSE |
| 21 | ASH POND INTAKE STRUCTURE & RECIRC. PUMPS |
| 22 | FIRE PROTECTION VALVE HOUSES (3 TOTAL) |
| 23 | COAL CONVEYOR TRANSFER HOUSE (PERSONAL PROPERTY) |
| 24 | SHEEP SHED |
| 25 | UNIT NO. 1 STACK |
| 26 | UNIT NO. 2 STACK |
| 27 | TRUCK SCALE BLDG. |
| 28 | FGD HAUL ROAD OVERPASS |
| 29 | CONSTRUCTION SERVICES (OLD S.I.M.I. BUILDING) |
| 30 | COAL TRESTLE |
| 31 | UNIT NO. 1 COOLING TOWER LOAD CENTER |
| 32 | UNIT NO. 2 COOLING TOWER LOAD CENTER |
| 33 | GAS TURBINE (UNIT NO. 4) |
| 34 | OIL/WATER SEPARATOR |
| 35 | FGD LANDFILL RUNOFF CO2 TANK |
| 36 | SOUTH SIDE RUNOFF POND INTAKE STRUCTURE & PUMPS |
| 37 | UNIT NO. 1 SCR |
| 38 | UNIT NO. 2 SCR |
| 39 | AQUEOUS AMMONIA STORAGE TANKS |
| 40 | UNIT NO. 2 SOOTBLOWING AIR COMPRESSOR BUILDING |
| 41 | UNIT NO. 1 FABRIC FILTER |
| 42 | UNIT NO. 1 SERVICE AIR COMPRESSOR BUILDING |
| 43 | UNIT NO. 1 SOOTBLOWING AIR COMPRESSOR BUILDING |
| 44 | COOLING TOWER SULFURIC ACID SYSTEM BUILDING |
| 45 | TRANSFORMER PAD |
| 46 | UNIT NO. 1 BLEACH BROMIDE BUILDING |
| 47 | UNIT NO. 2 BLEACH BROMIDE BUILDING |
| 48 | DRY FLY ASH AIR COMPRESSOR BUILDING |
| 49 | COAL TUNNEL |
| 50 | UNIT NO. 2 PRECIPITATOR |
| 51 | UNIT NO. 1 THICKENER TANK |
| 52 | UNIT NO. 2 THICKENER TANK |
| 53 | TRAINING TRAILER |
| 54 | LANDFILL & FGD SYSTEMS WASTEWATER CHEMICAL BUILDING |
| 55 | ASH POND WASTEWATER CHEMICAL BUILDING |

NOTE: FOR CONTROL MONUMENT GPS DATA, SEE DRAWING G-1012.


NOTES:
1. FOR COMPLETE GAS CONVERSION OPTION, SCRUBBER VESSELS SHALL BE DEMOLISHED.

**FOR REFERENCE ONLY**

**PRELIMINARY - NOT FOR CONSTRUCTION**

| no. | date | by | ckd | description |
|---|---|---|---|---|
| A | 09/08/15 | ACR | ZDL | FOR OWNER REVIEW |

SCALE IN FEET: 0 100' 200'

BURNS & McDONNELL
9400 WARD PARKWAY
KANSAS CITY, MO 64114
816-333-9400

designed: A. ROOT
detailed: M. ATHERTON

VECTREN
POSEY COUNTY, INDIANA

A. B. BROWN POWER STATION
SITE ARRANGEMENT
PLAN

project: 85648
contract:
drawing: SKM-1001
rev.: A
sheet 1 of 1 sheets
file 85648-SKM-1001.dwg



Z:\CLIENTS\ENR\VECTREN\86548_COALTOGASCONV\DESIGN\MECH\86548-SKM-1001.DWG 9/8/2015 9:41 AM MATHERTON


| no. | date | by | ckd | description |
|---|---|---|---|---|
| A | 09/08/15 | ACR | ZDL | FOR OWNER REVIEW |

BURNS & McDONNELL
9400 WARD PARKWAY
KANSAS CITY, MO 64114
816-333-9400

designed: A. ROOT
detailed: M. ATHERTON

VECTREN
POSEY COUNTY, INDIANA

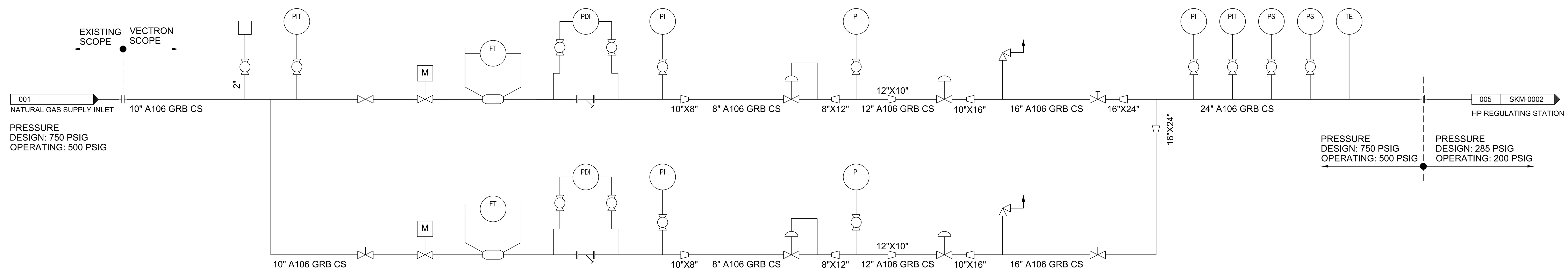
A. B. BROWN POWER STATION
GENERAL ARRANGEMENT
PLAN

project: 85648
contract:
drawing: SKM-1002
rev.: A
sheet 1 of 1 sheets
file 85648-SKM-1002.dwg



Z:\CLIENTS\ENR\VECTREN\86548_COALTOGASCONV\DESIGN\MECH\86548-SKM-1002.DWG 9/8/2015 8:43 AM MATHERTON

# APPENDIX B – PROCESS FLOW DIAGRAMS




**FOR REFERENCE ONLY**

**PRELIMINARY - NOT FOR CONSTRUCTION**

| no. | date | by | ckd | description |
|---|---|---|---|---|
| B | 02/18/16 | ACR | ZDL | REVISED PER B & W REPORT |
| A | 10/29/15 | ACR | ZDL | FOR OWNER REVIEW |

BURNS McDONNELL
9400 WARD PARKWAY
KANSAS CITY, MO 64114
816-333-9400

designed: A. ROOT
detailed: S. CHURCHILL

VECTREN

POSEY COUNTY, INDIANA

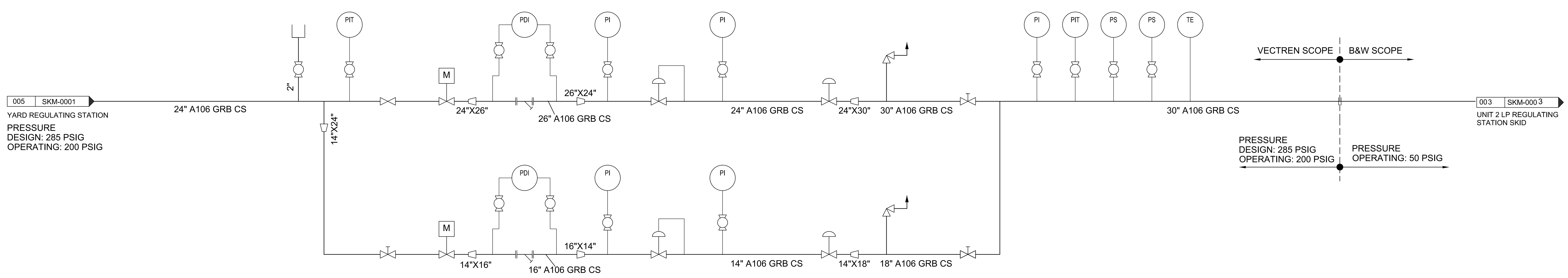
VECTREN COAL TO GAS
YARD REGULATING STATION SKID
A. B. BROWN

| project | contract |
|---|---|
| 86548 | - |

drawing: SKM-0001 — rev. B
sheet 1 of 1 sheets
file 86548-SKM-0001.dwg



Z:\CLIENTS\ENR\VECTREN\86548_COALTOGASCONV\DESIGN\MECH\86548-SKM-0001.DWG 2/15/2016 10:39 AM SACHURCHILL




**FOR REFERENCE ONLY**

**PRELIMINARY - NOT FOR CONSTRUCTION**

| no. | date | by | ckd | description |
|---|---|---|---|---|
| B | 02/18/16 | ACR | ZDL | REVISED PER B & W REPORT |
| A | 10/29/15 | ACR | ZDL | FOR OWNER REVIEW |

BURNS & McDONNELL
9400 WARD PARKWAY
KANSAS CITY, MO 64114
816-333-9400

designed: A. ROOT
detailed: S. CHURCHILL

VECTREN

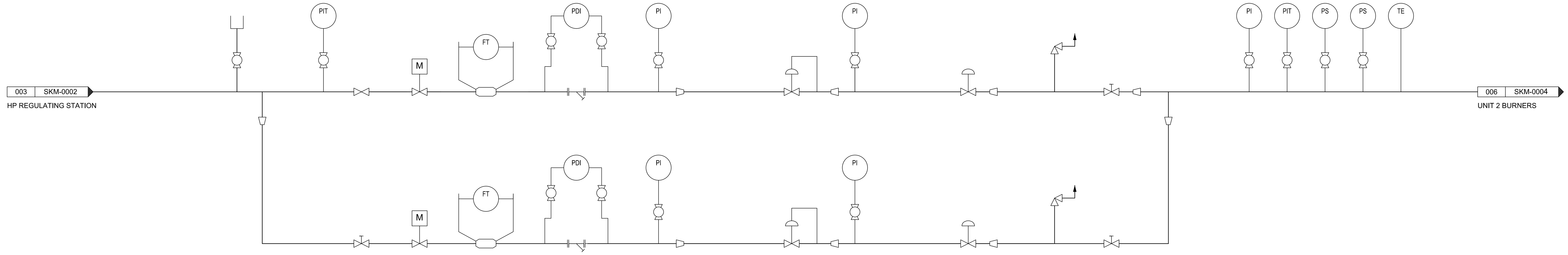
POSEY COUNTY, INDIANA

VECTREN COAL TO GAS
HP REGULATING STATION
A. B. BROWN

project: 86548
contract: -
drawing: SKM-0002 –
rev.: B
sheet 1 of 1 sheets
file 86548-SMK-0002



Z:\CLIENTS\ENR\VECTREN\86548_COALTOGASCONV\DESIGN\MECH\86548-SKM-0002.DWG 2/16/2016 8:29 AM SACHURCHILL




NOTE:

MATERIALS AND DESIGN PROVIDED BY B&W.

**FOR REFERENCE ONLY**

**PRELIMINARY - NOT FOR CONSTRUCTION**

| no. | date | by | ckd | description |
|---|---|---|---|---|
| B | 02/18/16 | ACR | ZDL | REVISED PER B & W REPORT |
| A | 10/29/15 | ACR | ZDL | FOR OWNER REVIEW |

BURNS McDONNELL

9400 WARD PARKWAY
KANSAS CITY, MO 64114
816-333-9400

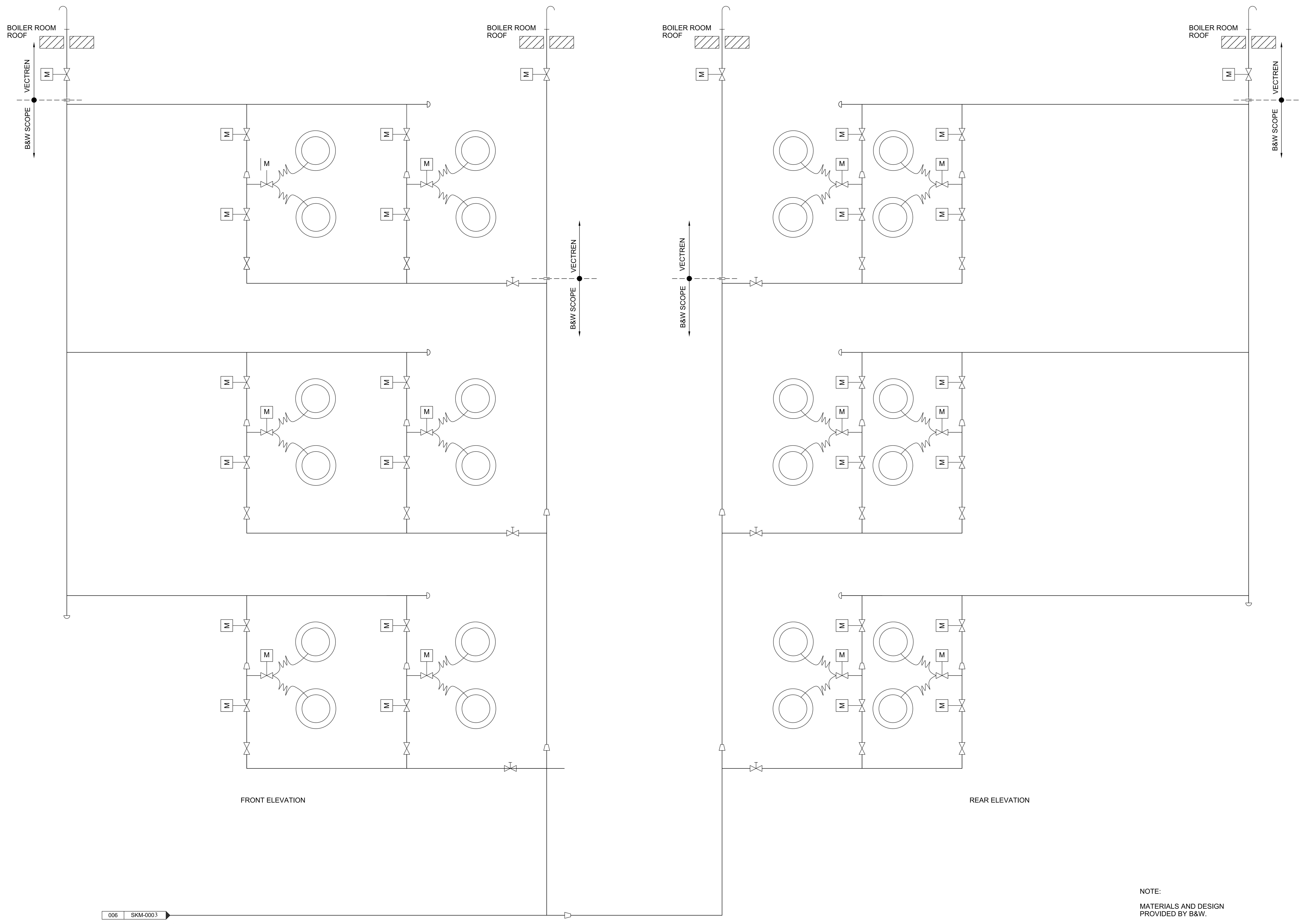
designed: A. ROOT
detailed: S. CHURCHILL

VECTREN

POSEY COUNTY, INDIANA

VECTREN COAL TO GAS
UNIT 2 REGULATING STATION SKID
A. B. BROWN

project: 86548
contract: -
drawing: SKM-0003 -
rev.: B
sheet 1 of 1 sheets
file 86548-SKM-0004.dwg




NOTE:

MATERIALS AND DESIGN PROVIDED BY B&W.

**FOR REFERENCE ONLY**

**PRELIMINARY - NOT FOR CONSTRUCTION**

| no. | date | by | ckd | description |
|---|---|---|---|---|
| B | 02/18/16 | ACR | ZDL | REVISED PER B & W REPORT |
| A | 10/29/15 | ACR | ZDL | FOR OWNER REVIEW |

BURNS & McDONNELL

9400 WARD PARKWAY
KANSAS CITY, MO 64114
816-333-9400

designed: A. ROOT
detailed: S. CHURCHILL

VECTREN

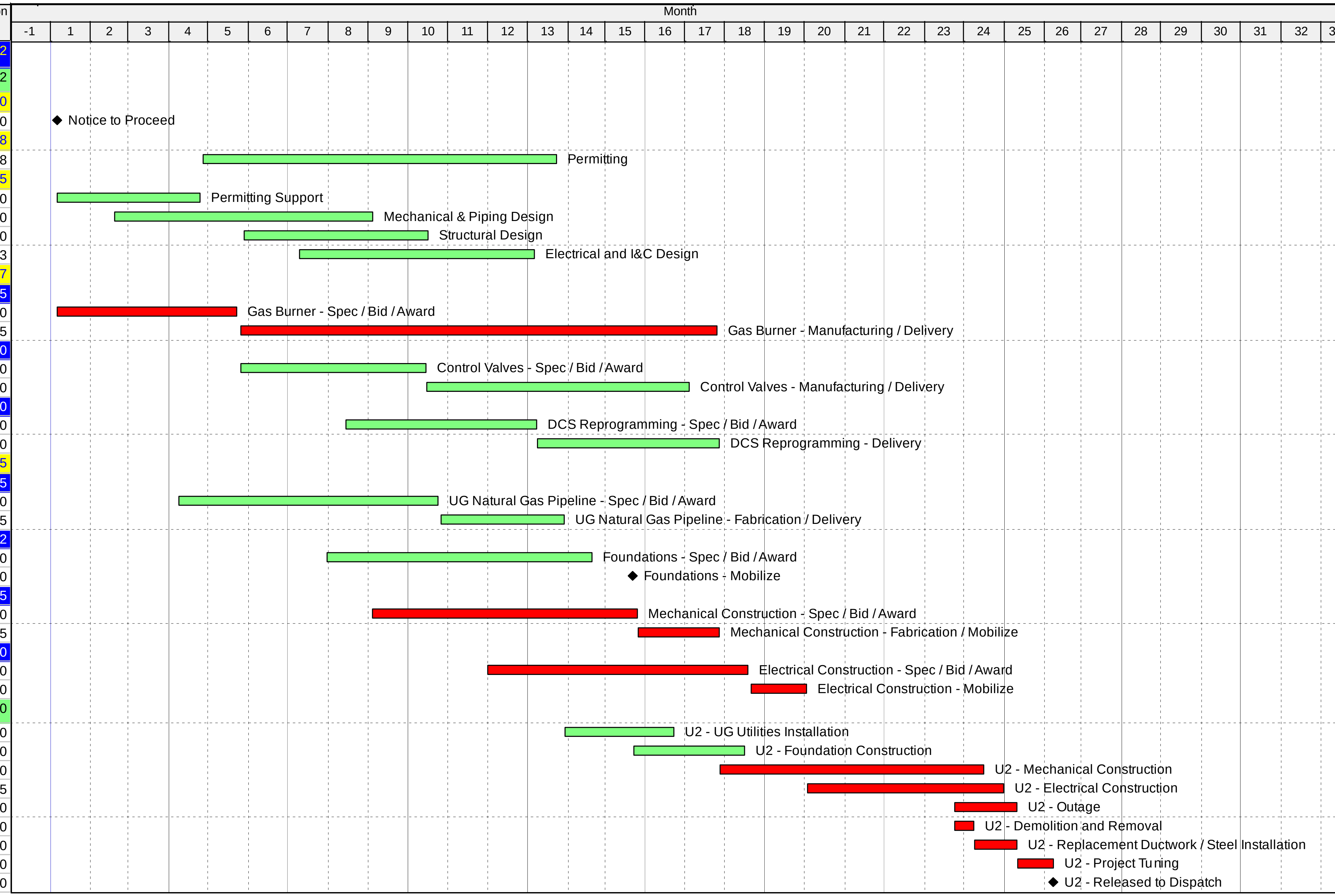
POSEY COUNTY, INDIANA

VECTREN COAL TO GAS
UNIT 2 BOILER
A. B. BROWN

project: 86548
contract: -
drawing: SKM-0004
rev.: B
sheet 1 of 1 sheets
file 86548-SKM-0006.dwg

# APPENDIX C – PROJECT SCHEDULE

| Activity ID | Activity Name | Duration |
|---|---|---|
| **Vectren A B Brown Coal to Gas Conversion** | | 532 |
| **Vectren Gas Conversion Engineering Unit 2** | | 402 |
| **Milestones** | | 0 |
| A1000 | Notice to Proceed | 0 |
| **Permitting** | | 188 |
| A1010 | Permitting | 188 |
| **Engineering** | | 255 |
| A1020 | Permitting Support | 80 |
| A1030 | Mechanical & Piping Design | 140 |
| A1040 | Structural Design | 100 |
| A1050 | Electrical and I&C Design | 123 |
| **Procurement** | | 357 |
| **Gas Burner** | | 355 |
| A1060 | Gas Burner - Spec / Bid / Award | 100 |
| A1070 | Gas Burner - Manufacturing / Delivery | 255 |
| **Control Valves** | | 240 |
| A1080 | Control Valves - Spec / Bid / Award | 100 |
| A1090 | Control Valves - Manufacturing / Delivery | 140 |
| **DCS Reprogramming** | | 200 |
| A1100 | DCS Reprogramming - Spec / Bid / Award | 100 |
| A1110 | DCS Reprogramming - Delivery | 100 |
| **Construction Contracts** | | 335 |
| **UG Natural Gas Pipeline** | | 205 |
| A1120 | UG Natural Gas Pipeline - Spec / Bid / Award | 140 |
| A1130 | UG Natural Gas Pipeline - Fabrication / Delivery | 65 |
| **Foundations** | | 162 |
| A1140 | Foundations - Spec / Bid / Award | 140 |
| A1150 | Foundations - Mobilize | 0 |
| **Mechanical Construction** | | 185 |
| A1180 | Mechanical Construction - Spec / Bid / Award | 140 |
| A1190 | Mechanical Construction - Fabrication / Mobilize | 45 |
| **Electrical Construction** | | 170 |
| A1160 | Electrical Construction - Spec / Bid / Award | 140 |
| A1170 | Electrical Construction - Mobilize | 30 |
| **Vectren Gas Conversion Construction & Startup Unit 2** | | 260 |
| A1200 | U2 - UG Utilities Installation | 60 |
| A1210 | U2 - Foundation Construction | 60 |
| A1220 | U2 - Mechanical Construction | 140 |
| A1230 | U2 - Electrical Construction | 105 |
| A1240 | U2 - Outage | 30 |
| A1250 | U2 - Demolition and Removal | 10 |
| A1260 | U2 - Replacement Ductwork / Steel Installation | 20 |
| A1270 | U2 - Project Tuning | 20 |
| A1280 | U2 - Released to Dispatch | 0 |




Remaining Work
Critical Remaining Work
Milestone

BURNS McDONNELL

**Vectren - A. B. Brown**
**Coal to Gas Conversion Project**


| Date | Revision | Checked | Approved |
|---|---|---|---|
| 23-Jan-19 | Gas Conversion Proposal | Y Ko | |

# APPENDIX D – CAPITAL COST ESTIMATE SUMMARY

**CAPITAL COST ESTIMATE**
**VECTREN**
**AB BROWN**
**UNIT 2 ONLY NATURAL GAS CONVERSION**
**MT. VERNON, IN**
**BMcD #113003**

| Acct | Area / Discipline | Direct MHRS | Labor Cost | Material Cost | Engr Equip/ Subcontract Cost | Const. Equipment Cost | Total Cost |
|---|---|---|---|---|---|---|---|
| 01 | Engineered Equipment | 960 | $120,000 | | $7,180,000 | | $7,300,000 |
| 02 | Civil | 769 | $70,000 | | $50,000 | $10,000 | $130,000 |
| 03 | Deep Foundations | | | | | | |
| 04 | Concrete | 1,820 | $190,000 | $40,000 | $30,000 | $10,000 | $270,000 |
| 05 | Structural Steel | 13,028 | $1,580,000 | $980,000 | | $280,000 | $2,840,000 |
| 06 | Architectural | | | | | | |
| 07 | Piping | 4,191 | $550,000 | $310,000 | $20,000 | $30,000 | $910,000 |
| 08 | Electrical | 5,407 | $680,000 | $100,000 | | $40,000 | $820,000 |
| 09 | Instrument & Control | | | | $270,000 | | $270,000 |
| 10 | Insulation | | | | $530,000 | | $530,000 |
| 11 | Coatings | | | | $20,000 | | $20,000 |
| | **Total Direct Cost** | **26,175** | **$3,190,000** | **$1,430,000** | **$8,100,000** | **$370,000** | **$13,090,000** |

| Rev. | Revision Date |
|---|---|
| 0 | 08/27/15 |
| 1 | 02/12/16 |
| 2 | 07/17/18 |
| 3 | 02/01/19 |

| Item | Cost | Revenue | Amount |
|---|---|---|---|
| Construction Mgmt & Indirects | | | $780,000 |
| Engineering | | | $990,000 |
| Start-Up | | | $290,000 |
| Commercial | | | $250,000 |
| Escalation (From 2016-Jan2019) | | | $160,000 |
| **Total Indirect Cost** | | | **$2,470,000** |
| **Total Direct and Indirect Costs** | | | **$15,560,000** |
| | Cost | Revenue | |
| Project Contingency | 5% | 5% | $780,000 |
| **Total Project Cost** | | | **$16,340,000** |
| Owner's Project Development | | | $250,000 |
| Owner's Operational Personnel Prior to COD | | | Existing |
| Owner's Engineer | | | N/A |
| Owner's Project Management | | | $300,000 |
| Owner's Legal Costs | | | $200,000 |
| Owner's Start-up Engineering | | | $75,000 |
| Temporary Utilities | | | $110,000 |
| Operator Training | | | $50,000 |
| Permitting and Licensing Fees | | | $100,000 |
| Switchyard | | | Existing |
| Political Concessions & Area Development Fees | | | N/A |
| Startup/Testing (Fuel & Consumables) | | | |
| Startup Fuel (@$4/MMBtu) | | | $1,570,000 |
| Startup Variable O&M (@$1.30/MWhr | | | $40,000 |
| Startup Power (@$45/MWhr) | | | $20,000 |
| Test Power Sales (@$-30/MWhr) | | | -$1,010,000 |
| Initial Fuel Inventory | | | N/A |
| Site Security | | | Existing |
| Operating Spare Parts | | | $70,000 |
| Permanent Plant Equipment and Furnishings | | | Existing |
| Builders Risk Insurance (0.45% of Construction Costs) | | | $60,000 |
| Interest During Construction (10.2% Proj Cost) | | | $1,670,000 |
| Owner Contingency | | 10% | $1,980,000 |
| **Total Owner Costs** | | | **$5,485,000** |
| **Total Project Cost Incl. Owner Costs** | | | **$21,825,000** |

BURNS McDONNELL V 3.5

# APPENDIX E – B&W BOILER STUDY

# Engineering Study for Natural Gas Firing

**for**

**Vectren Power Supply**
**AB Brown Station Unit 2**
**Evansville, Indiana**

**Contract 591-1048 (317A)**
**April 1, 2019 - Rev. 4**

**THE BABCOCK & WILCOX COMPANY ASSUMES NO LIABILITY WITH RESPECT TO THE USE OF, OR FOR DAMAGES RESULTING FROM THE USE OF, ANY INFORMATION, METHOD OR PROCESS DISCLOSED IN ANY REPORT ISSUED UNDER THIS CONTRACT.**

**THE BABCOCK & WILCOX COMPANY EXPRESSLY EXCLUDES ANY AND ALL WARRANTIES EITHER EXPRESSED OR IMPLIED, WHICH MIGHT ARISE UNDER LAW OR EQUITY OR CUSTOM OF TRADE, INCLUDING WITHOUT LIMITATION, WARRANTIES OF MERCHANTABILITY AND OF FITNESS FOR SPECIFIED OR INTENDED PURPOSE.**

# TABLE OF CONTENTS

## INTRODUCTION

Vectren Power Supply contracted the Babcock and Wilcox Company (B&W), under B&W contract 591-1048 (317A), to evaluate natural gas firing at the AB Brown Station Unit 2, originally supplied by B&W under contract RB-599. The boiler performance model was reviewed at 100% (Maximum Continuous rating) MCR and 60% load when firing 100% natural gas. An analysis of the allowable tube metal stresses was performed for 100% gas firing at 100% MCR and 60% boiler loads in regards to the primary superheater, secondary superheater and reheat superheater.

## BACKGROUND

The AB Brown Unit 2 (RB599) is presently balanced draft, subcritical Carolina type radiant boiler, with secondary superheater, primary superheater, reheater and economizer surfaces arranged in series. Superheater steam temperature is controlled by interstage spray attemperation. Reheater steam temperature is controlled by excess air and spray attemperation. The unit was originally designed as a front and rear wall, bituminous coal fired units. The original maximum continuous rating for RB-599 is 1,850,000 lbs/hr of main steam at 1005°F and 1965 psig at the superheater outlet with a feedwater temperature of 467°F. The reheat steam flow is 1,666,500 lbs/hr at 1005 F and 485 psig at the reheater outlet. Spray attemperation is used to control superheat and reheat steam temperatures. The unit was to be operated at 5% overpressure over the load range.

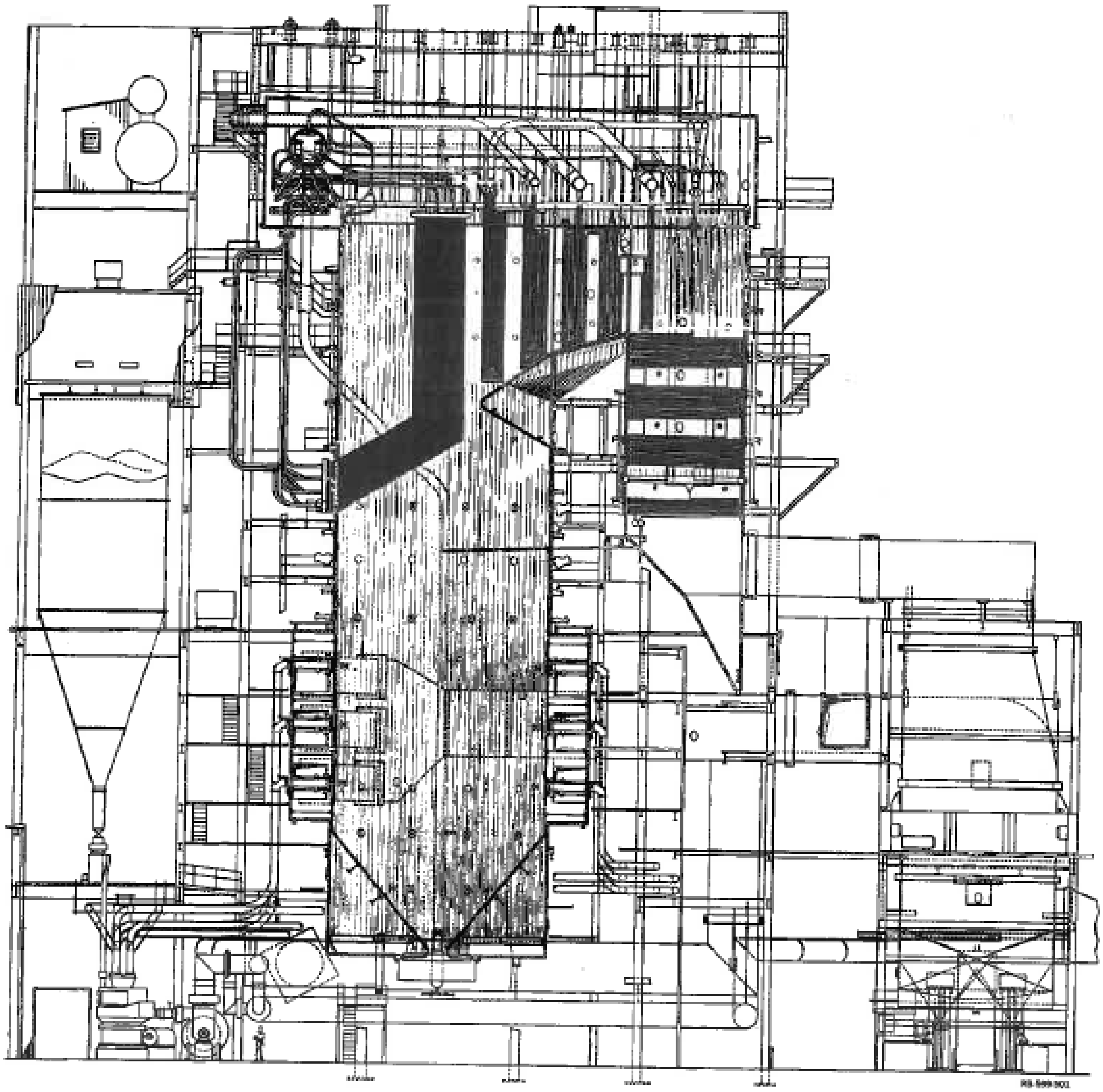
The unit is front and rear wall fired with twenty-four B&W 4Z low $NO_x$ burners, four wide by three high. There are six B&W EL-76 pulverizers supplying coal to the burners.

Combustion air is heated through two Ljungstrom regenerative air heaters.

- Unit 2 has a furnace height of 124'-0''. The vertical burner spacing is 10'-0" for Unit 2.
- Unit 2 has six water-cooled furnace wing walls.
- Unit 2 was designed without flue gas recirculation.

A sectional side view of the boilers is shown in Figures 1.

**FIGURE 1**



**Brown Station Unit 2**

**B&W Contract Number RB-599**

## SCOPE FOR PHASE I

B&W evaluated natural gas firing in the radiant boilers originally supplied by B&W under contract number RB-599. Boiler component drawings and original performance summary data were used to develop comprehensive thermal models and boiler pressure part assessments. The predicted performance of the proposed natural gas firing was analyzed at MCR load and 60% load. The tube metallurgy requirements for the primary superheater, secondary superheater, reheater and headers were also developed. In addition to superheater metals analysis, predicted performance of the air preheaters and the attemperator capacities were also evaluated relative to overall performance.

## SCOPE FOR PHASE II

The Phase II engineering scope of supply includes the entire scope of Phase I. In addition, the need surface modifications for firing 100% natural gas were analyzed. The adequacy of the existing forced draft (FD) fans and the induced draft (ID) fans were also assessed.

## BASIS

This boiler pressure part metals assessment requires developing overall unit heat and material balances at the indicated steam flow. The 2015 fuel analyses for coal as supplied by Vectren were found to be very close to original design bituminous coal. Since the 2015 fuel analyses were incomplete, the original design fuel analysis was used. The natural gas analysis was also supplied by Vectren. The original design coal and natural gas fuel analyses are provided in Tables 2. These were used as a basis for the heat and material balances shown in Table 3.

**Table 1: Original Design As-Fired Fuel Analyses for Bituminous Coal, % by weight**

| **Constituent** | |
|---|---|
| C | 64.00 |
| $H_2$ | 4.44 |
| $N_2$ | 1.38 |
| $O_2$ | 6.51 |
| Cl | 0.00 |
| S | 3.52 |
| $H_2O$ | 11.35 |
| Ash | 8.76 |
| **Total** | **100.00** |
| **HHV (Btu/lb)** | **11533** |

**Table 2: Proximate Analysis for Natural Gas, % by volume**

| **Constituent** | |
|---|---|
| Nitrogen | 0.28 |
| Methane | 96.31 |
| Ethane | 1.46 |
| $CO_2$ | 1.89 |
| Others | 0.06 |
| **Total** | **100.00** |
| **HHV (Btu/ft$^3$)** | **1,037** |

**Table 3: Boiler Operating Conditions Used in Metals Evaluation**

| Boiler Load | MCR | 60% |
|---|---|---|
| Superheater Steam Flow (lb/hr) | 1,850,000 | 1,110,000 |
| Steam Temperature at SH Outlet (°F) | 1005 | 933 |
| Steam Pressure at SH Outlet (psig) | 1965 | 1917 |
| Reheater Steam Flow (lb/hr) w/o Attemperator Spray | 1,666,500 | 1,000,000 |
| Steam Temperature at RH Outlet (°F) | 992 | 835 |
| Steam Pressure at RH Outlet (psig) | 460 | 261 |
| Feedwater Temperature (°F) | 467 | 417 |
| Excess Air Leaving Econ (%) | 10 | 18 |

## RESULTS

### Boiler Performance

The predicted boiler performance summaries are shown in the Appendix, comparing unit performance firing the original bituminous coal at the original design data, recent field data for each of the unit and predicted unit performance firing 100% natural gas.

### Attemperator Capacity

Along with the metals analysis, attemperation capacities were studied. The attemperator spray flows for gas firing are lower than the spray flows for firing coal due to lower amounts of excess air required when firing natural gas. Current attemperator capacities for unit should be satisfactory at all boiler loads. The results are shown in Table 6.

**Table 6: Predicted Attemperator Flows (lbs/hr)**

| Boiler Load | MCR | 60% |
|---|---|---|
| Bituminous Coal: | | |
| SH Spray Flow | 77,870 | 88,000 |
| RH Spray Flow | 19,000 | 0 |
| Natural Gas | | |
| SH Spray Flow | 53,700 | 0 |
| RH Spray Flow | 0 | 0 |

### Air Heater Performance

Air heaters were assessed for natural gas firing. The air and gas side temperature profiles around the air heater were found to be acceptable for the natural gas conversion. Since no field data was provided that would show higher than original air heater leakage or other air heater performance degradation, the predicted air heater performance is based on the original design data with an air heater leakage of 7.4%. Predicted performance is shown on Table 7a and 7b.

**Table 7a: Regenerative Air Heater Predicted Performance at**

| Unit | 2 | 2 | 2 |
|---|---|---|---|
| Boiler load | MCR | 94% | MCR |
| Data Basis | Original Design | 7-10-2015 PI Data | Predicted Performance* |
| Fuel | Bituminous Coal | Bituminous Coal | Natural Gas |
| Flue Gas Flow Entering Air Heaters, mlb/hr | 2,570 | 2,422 | 2,234 |
| Flue Gas Temp Entering Air Heaters, F | 705 | 652 | 697 |
| Flue Gas Temp Leaving Air Heaters w/o Leakage, F | 304 | 346 | 303 |
| Air Flow Leaving Air Heaters, mlb/hr | 2,307 | 2,174 | 2,056 |
| Air Temp Entering Air Heaters, F | 85 | 138 | 85 |
| Air Temp Leaving Air Heaters, F | 566 | 554 | 567 |

*Based on original design data

**Table 7b: Regenerative Air Heater Predicted Performance**

| **Unit** | 2 | 2 |
|---|---|---|
| **Boiler load** | 60% | 60% |
| **Data Basis** | Original Design | Predicted Performance* |
| **Fuel** | Bituminous Coal | Natural Gas |
| **Flue Gas Flow Entering Air Heaters, mlb/hr** | 2,060 | 1,403 |
| **Flue Gas Temp Entering Air Heaters, F** | 675 | 617 |
| **Flue Gas Temp Leaving Air Heaters w/o Leakage, F** | 283 | 259 |
| **Air Flow Leaving Air Heaters, mlb/hr** | 1,867 | 1,273 |
| **Air Temp Entering Air Heaters, F** | 83 | 83 |
| **Air Temp Leaving Air Heaters, F** | 547 | 520 |

*Based on original design data

**Tube Metal Temperature Evaluation**

B&W uses an ASME Code accepted method to design its tube metallurgies and thicknesses. The method involves applying upsets and unbalances to determine spot and mean tube metal temperatures. The upsets and unbalances include empirical uncertainty in the calculation of furnace exit gas temperature (FEGT), top to bottom gas temperature deviations, side to side gas temperature deviations, steam flow unbalances (a function of tube side pressure drop and component arrangement) and gas flow unbalances. The method applies these upsets and unbalances simultaneously to a single spot in each row of the superheater. Tube row metallurgy and thickness are then determined from the resultant tube spot and mean temperatures, respectively, according to ASME Code material oxidation limits and allowable stresses. B&W policy does not allow the publishing of design tube metal temperatures or unbalanced steam temperatures. However, these values can be reviewed in B&W's offices, if desired.

The remaining life expectancy of the superheaters is dependent on the prior operating history, especially on actual tube operating temperature compared to design temperature. Thus, the assessment of the adequacy of the existing superheaters is not a simple task.

The SSH outlet bank & RSH outlet bank were replaced on unit 2 in the fall of 2015. The evaluation is based on the design of the present SSH outlet banks & RSH outlet banks which were supplied by B&W.

B&W has determined the operating hoop stress level (based on the current minimum tube wall thickness) at operating pressure. The predicted tube operating temperatures based on B&W's standard design criteria and the resulting ASME Code allowable stress level for the existing material has also been determined. Comparison of the operating hoop stress with the Code allowable stresses results in the percent over the allowable stress. A modest overstress level indicates a modest shortening of remaining life expectancy and, unless otherwise indicated by past maintenance experience, does not warrant tube modification at this time.

If the tube analysis shows significant overstress or shows that tubes are predicted to operate at temperatures above those for which ASME Code stresses are published, then serious consideration should be given to tube upgrades and replacement. Significant overstresses are considered those tube rows that are 20% or greater overstressed. An overstress of 20% or more does not necessarily mean that immediate replacement of the tube row is required, but it identifies which tube rows should be examined for potential problems. Potential problems could be signs of creep, internal exfoliation or swelling.

This study showed that all tubes were predicted to operate at temperatures less than the existing material use limit. In addition, all existing convection pass tubes and component headers had no overstress issues. Therefore, the existing convection pass tube metallurgy is acceptable for natural gas firing.

**Forced Draft Fans**

The existing forced draft fans were analyzed to determine if they meet the requirements of 100% natural gas firing. Unit 2 was originally designed as a balanced draft unit. An adjusted test block static pressure rise and test block capacity for the Unit 2 FD fans was developed from the FD fan curve for 100% natural gas firing. The results show the existing FD fan test block conditions for Unit exceed the requirements in capacity and static pressure rise (including higher natural gas burner pressure drop) for all natural gas firing cases. Predicted fan performance is shown in Table 8A:

**Table 8a: Forced Draft Fan Performance at MCR Load (balanced draft operation)**

| Fuel | FD Fan Test Block Unit 2 | FD Fan Original Net Design Conditions Bituminous Coal Unit 2 | FD Fan Test Block Adjusted for 100%Natural Gas Unit 2 From Fan Curve | FD Fan Net Conditions 100% Natural Gas Unit 2 |
|---|---|---|---|---|
| Flow per fan (lb/hr) | 1,512,000 | 1,260,000 | 1,225,440 | 1,104,100 |
| Static Pressure Rise (in WC) | 19.8 | 15.8 | 25.1 | 20.3 |
| Temperature (F) | 105 | 80 | 105 | 80 |

**Induced Draft Fans**

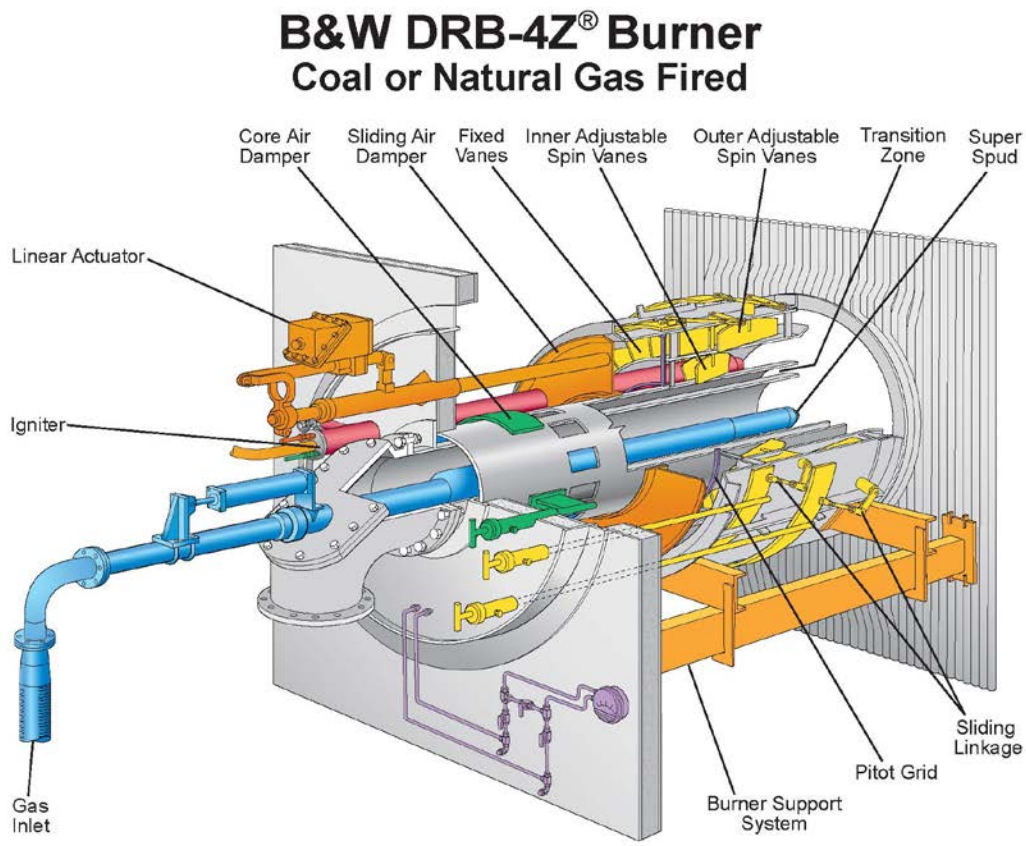
The existing induced draft fans were also analyzed to determine if they meet the requirements of 100% natural gas firing. The results showed the existing ID fans far exceed the requirements in capacity and static pressure rise for all natural gas firing cases. Predicted fan performance is shown in Table 8B:

**Table 8b: Induced Draft Fan Performance at MCR Load (balanced draft operation)**

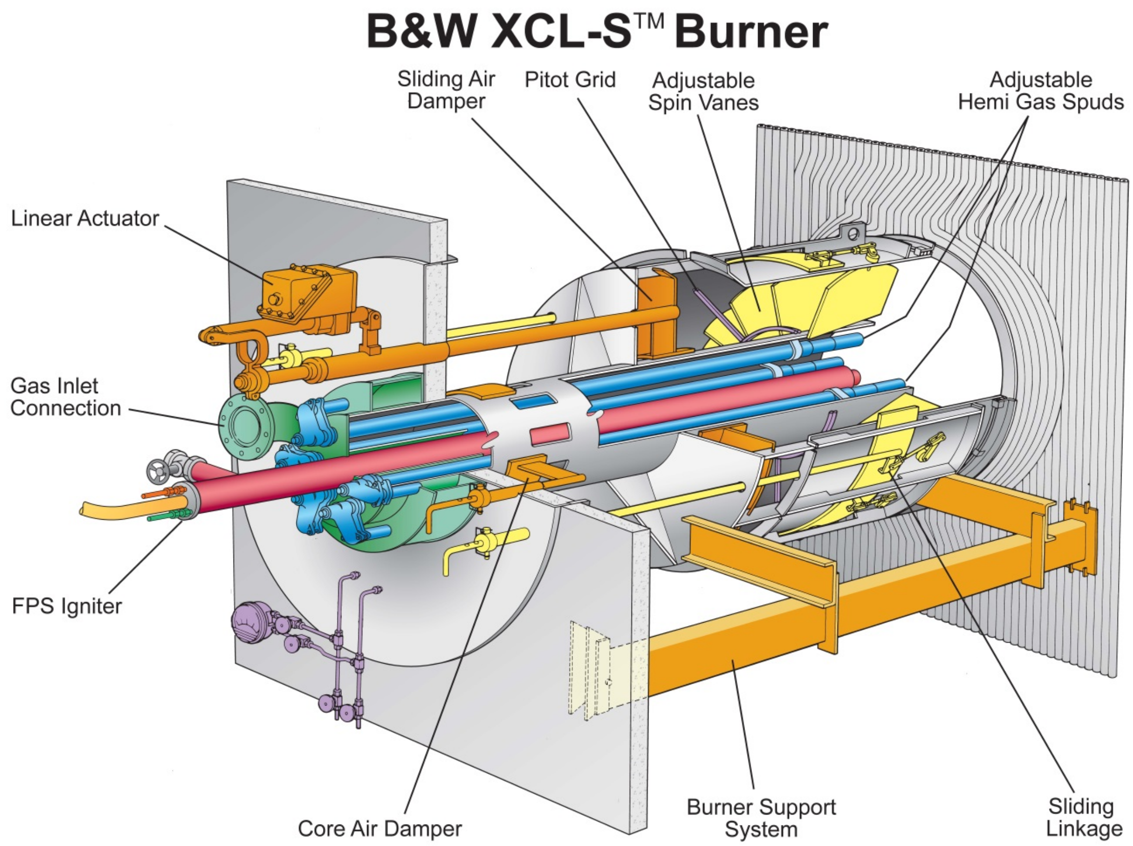
| Fuel | ID Fan Test Block Unit 2 | Bituminous Coal Unit 2 Original ID Fan Design Net Conditions | 100% Natural Gas |
|---|---|---|---|
| Flow per fan (lb/hr) | 1,380,100 | 1,387,610 | 1,199,390 |
| Static Pressure Rise (in WC) | 67.30 | 47.81 | 34.22 |
| Temperature (F) | 330 | 305 | 290 |

**Combustion Equipment**

The minimum combustion equipment modifications required to fire natural gas include modifying the twenty-four (24) existing B&W 4Z burners with gas spuds. One option is to add a Super-Spud to each 4Z burner to provide natural gas firing capability to the units. The addition of Super-Spuds will allow the AB Brown unit to still fire coal is desired. The figure below shows a 4Z burner with a Super-Spud.




The second option would be to remove the coal nozzle and replace it with a hemi-spud cartridge. This fundamentally converts the 4Z burners to a B&W XCL-S burner as shown in the figure below. B&W XCL-S burner is an advanced low-NOx burner that was developed to achieve superior NOx performance in burner-only applications.




Since the AB Brown unit already have SCR's, staged combustion (OFA) or flue gas recirculation (FGR) is not recommended.

In addition to the burner modifications, valve racks, gas piping and controls will be needed to supply the natural gas as a main fuel to the modified burners.

### Emissions

Emissions predictions are based on converting the unit to fire natural gas as the main fuel. Full load emission predictions for unit are listed in Table 9.

| Table 9: Predicted Full Load Emissions on Natural Gas | |
|---|---|
| | AB Brown Unit 2 |
| $NO_x$ (lb/$10^6$ Btu) | 0.19 |

- CO is predicted to be less than 200ppm. For 200 ppm (dry vol.) CO @ 3% O2 (dry vol.) firing NG with an Fd factor of 8710, B&W calculates 0.148 lb/mmBTU of CO.

## CONCLUSIONS

As a result of this study, a review of the existing tube metallurgies on the AB Brown Station Unit 2 revealed that all existing convection pass tubes had no overstress issues. In addition, all tubes were predicted to operate at temperatures below their ASME material code published limit. Header metal temperatures were also checked and showed to meet B&W's standards.

Along with the metallurgical analysis, superheater and reheater spray attemperation capacities were studied. The attemperator spray flows for gas firing are lower than the spray flows for firing coal due to lower amounts of excess air required when firing 100% natural gas. Current attemperator capacities for unit should be satisfactory at all boiler loads.

No surface modifications or surface removal are required when firing 100% natural gas.

Air heaters were assessed for 100% natural gas firing. The air and gas side temperature profiles around the air heater were found to be acceptable for firing natural gas based on the original air heater design parameters.

The existing FD and ID fans were found to exceed the performance requirements when firing 100% natural gas.

The predicted boiler performance summaries are shown in the Appendix, comparing unit performance firing the original bituminous coal and predicted unit performance firing natural gas.

## CO-FIRING COAL AND NATURAL GAS

Vectren Power Supply additionally contracted the Babcock and Wilcox Company (B&W), under B&W contract 591-1048 (317A), to evaluate co-firing natural gas and coal in these units.

The predicted boiler performance summaries are shown in the Appendix, comparing unit performance co-firing natural gas and the original bituminous coal at MCR boiler load with the following natural gas inputs:

1. 17% heat input from natural gas through four burners. 83% heat input from coal.
2. 33% heat input from natural gas through eight burners. 67% heat input from coal.
3. 16% heat input (maximum heat input through natural gas ignitors). 84% heat input from coal.

A metallurgical analysis and an analysis of the superheater and reheater spray attemperation capacities were performed for the three conditions above. Current attemperator capacities for unit should be satisfactory at all boiler loads when co-firing natural gas and coal.

This study showed that all tubes were predicted to operate at temperatures less than the existing material use limit. In addition, all existing convection pass tubes and component headers had no overstress issues. Therefore, the existing convection pass tube metallurgy is acceptable for co-firing natural gas and coal.

No surface modifications or surface removal are required when co-firing natural gas and coal.

The air and gas side temperature profiles around the air heater were found to be acceptable for co-firing natural gas and coal based on the original air heater design parameters.

The existing FD and ID fans were found to exceed the performance requirements when co-firing natural gas and coal.

The predicted boiler performance summaries when co-firing natural gas and coal are shown in the Appendix.

### Co-firing Operation

When co-firing the two fuels, the preferred arrangement is to fire natural gas through the burners at the higher elevations on a per mill group, or compartment, basis. The compartmented windboxes on the AB Brown unit are advantageous for co-firing the multiple fuels. Airflow control by compartment allows each mill group to obtain its own required amount of air, independent of burner load or fuel. The burners firing natural gas will require more secondary air, since primary airflow is zero, than the coal-firing burners. Managing these separate flow rates can be easily accommodated by the compartment controls. Firing coal at the lower elevations takes advantage of the available residence time in the furnace, maximizing coal burnout and optimizing CO and unburned carbon emissions. If a partial conversion were to become the chosen project path, it would be recommended to convert burners on a per mill group basis following the described firing arrangement, adding gas capability to the top mill groups and continuing downward.

It should be noted that while the AB Brown unit is already equipped to operate under the third scenario listed above (16% input ignitors, 84% input from coal), it could come at the expense of emissions. With the ignitor being located in an upper quadrant of the burner and operating at 16% of the rated burner input, not all of the air going through the burner is nearby and readily available for the ignitor fuel. This can create scenarios of inadequate fuel and air mixing, resulting in higher CO emissions, especially from the upper burner elevations. NOx emissions may also increase. The annular zone arrangement of the 4Z burner stages the mixing of the fuel and air. With the ignitor being located in the air sleeve, it circumvents this delayed mixing arrangement, potentially increasing NOx. Emissions predictions are not available for this scenario.

# *APPENDIX A – Preliminary Performance Summaries*

## Table 10a:

**A. B. Brown Unit 2 - Preliminary Performance Summary**

| | | | | | |
|---|---|---|---|---|---|
| Contract No. | 317A | GBB | Unit 2 | Unit 2 | Unit 2 |
| Date | 7/31/2015 | Load ID | PC Firing | PC Firing | Natural Gas |
| Revision | 0 | Boiler Arrangement | Existing | Existing | Existing |
| | | Data Basis | Original Contract | 7-10-2015 PI Data | Predicted Performance |
| | | | | | |
| Load Condition | | | MCR | 94% Load | MCR |
| Fuel | | | Bituminous | Bituminous | Natural Gas |
| Steam Leaving SH, mlb/hr | | | 1,850 | 1,736 | 1,850 |
| Superheater Spray Water, mlb/hr | | | 77.86 | 19.10 | 53.70 |
| Cold RH Steam Flow, mlb/hr | | | 1,667 | 1,590 | 1,667 |
| Reheater Spray Water, mlb/hr | | | 18.90 | 16.30 | 0.00 |
| % Excess Air Leaving Economizer | | | 20.0 | 21.1 | 10.0 |
| Flue Gas Recirculation, % | | | None | None | None |
| Heat Input, mmBtu/hr | | | 2,549.3 | 2,379.8 | 2,614.9 |
| Quantity mlb/hr | Fuel (mcf/hr if gas) | | 221.0 | 207.0 | 2604.5 |
| | Flue Gas Entering Air Heaters | | 2,570 | 2,422 | 2,234 |
| | Total Air To Burners | | 2,307 | 2,174 | 2,056 |
| Pressure, psig | Steam at SH Outlet | | 1965 | 1926 | 1965 |
| | Steam at RH Outlet | | 460 | 424 | 460 |
| Temperature, °F | Steam | Leaving Superheater | 1005 | 999 | 1005 |
| | | Leaving Reheater | 1005 | 985 | 992 |
| | | | | | |
| | Water | Water Entering Economizer | 467 | 452 | 467 |
| | | Superheater Spray Water | 380 | 370 | 380 |
| | Gas | Entering Air Heater | 705 | 652 | 697 |
| | | Leaving Air Heater (Excl. Leakage) | 304 | 346 | 303 |
| | Air | Entering Air Heater | 85 | 138 | 85 |
| | | Leaving Air Heater | 566 | 554 | 567 |
| Heat Loss Efficiency, % | Dry Gas | | 4.91 | 4.75 | 3.88 |
| | $H_2$ & $H_2O$ in Fuel | | 5.06 | 4.92 | 10.67 |
| | Moisture in Air | | 0.12 | 0.11 | 0.10 |
| | Unburned Combustible | | 0.30 | 0.30 | 0.00 |
| | Radiation | | 0.19 | 0.20 | 0.19 |
| | Unacc. & Mfgs. Margin | | 1.50 | 0.50 | 1.00 |
| | Total Heat Loss | | 12.08 | 10.78 | 15.84 |
| | Gross Efficiency of Unit, % | | 87.92 | 89.22 | 84.16 |

**B&W Proprietary and Confidential**

## Table 10b:

**A. B. Brown Unit 2 - Preliminary Performance Summary**

| | | | | | |
|---|---|---|---|---|---|
| Contract No. | 317A | | GBB | Unit 2 | Unit 2 |
| Date | 7/31/2015 | | Load ID | PC Firing | NG Firing |
| Revision | 0 | | Boiler Arrangement | Existing | Existing |
| | | | Data Basis | Original Contract | Predicted Performance |
| | | | | | |
| Load Condition | | | | 60% | 60% |
| Fuel | | | | Bituminous | Natural Gas |
| Steam Leaving SH, mlb/hr | | | | 1,110 | 1,110 |
| Superheater Spray Water, mlb/hr | | | | 89 | 0 |
| Cold RH Steam Flow, mlb/hr | | | | 1,000 | 1,000 |
| Reheater Spray Water, mlb/hr | | | | 0 | 0 |
| % Excess Air Leaving Economizer | | | | 52.0 | 18.0 |
| Flue gas Recirculation, % | | | | None | None |
| Heat Input, mmBtu/hr | | | | 1,638.3 | 1,540.9 |
| Quantity mlb/hr | Fuel (mcf/hr if gas) | | | 142.0 | 1486.0 |
| | Flue Gas Entering Air Heaters | | | 2,060 | 1,403 |
| | Total Air To Burners | | | 1,867 | 1,273 |
| Pressure, psig | Steam at SH Outlet | | | 1917 | 1917 |
| | Steam at RH Outlet | | | 261 | 261 |
| Temperature, °F | Steam | Leaving Superheater | | 1005 | 955 |
| | | Leaving Reheater | | 1005 | 835 |
| | | | | | |
| | Water | Water Entering Economizer | | 417 | 417 |
| | | Superheater Spray Water | | 350 | 350 |
| | Gas | Entering Air Heater | | 675 | 617 |
| | | Leaving Air Heater (Excl. Leakage) | | 283 | 259 |
| | Air | Entering Air Heater | | 83 | 83 |
| | | Leaving Air Heater | | 547 | 520 |
| Heat Loss Efficiency, % | Dry Gas | | | 5.69 | 3.35 |
| | $H_2$ & $H_2O$ in Fuel | | | 5.03 | 10.38 |
| | Moisture in Air | | | 0.14 | 0.09 |
| | Unburned Combustible | | | 0.30 | 0.00 |
| | Radiation | | | 0.30 | 0.22 |
| | Unacc. & Mfgs. Margin | | | 1.50 | 1.00 |
| | Total Heat Loss | | | 12.96 | 15.04 |
| | Gross Efficiency of Unit, % | | | 87.04 | 84.96 |

**B&W Proprietary and Confidential**

## Table 10c:

### A. B. Brown Unit 2 - Predicted Performance Summary Co-Firing Coal & Natural Gas

| | | | | | |
|---|---|---|---|---|---|
| Contract No. | 317A | GBB | Unit 2 | Unit 2 | Unit 2 |
| Date | 8/29/2015 | Load ID | PC & NG Firing | PC & NG Firing | PC & NG Firing |
| Revision | 0 | Boiler Arrangement | Existing | Existing | Existing |
| | | Data Basis | Predicted Performance | Predicted Performance | Predicted Performance |
| | | Natural Gas Firing Method | Through Burners | Through Burners | Through Ignitors |
| | | Natural Gas Firing % Heat Input | 17 | 33 | 16 |
| | | Coal Firing % Heat Input | 83 | 67 | 84 |
| Load Condition | | | MCR | MCR | MCR |
| Fuel | | | Bit. Coal & Natural Gas | Bit. Coal & Natural Gas | Bit. Coal & Natural Gas |
| Steam Leaving SH, mlb/hr | | | 1,850 | 1,850 | 1,850 |
| Superheater Spray Water, mlb/hr | | | 27.38 | 42.94 | 26.70 |
| Cold RH Steam Flow, mlb/hr | | | 1,667 | 1,667 | 1,667 |
| Reheater Spray Water, mlb/hr | | | 23.02 | 27.14 | 23.00 |
| % Excess Air Leaving Economizer | | | 21.9 | 21.9 | 21.9 |
| Flue Gas Recirculation, % | | | None | None | None |
| Heat Input Nat. Gas, mmBtu/hr | | | 434.6 | 853.1 | 408.0* |
| Heat Input Bit. Coal, mmBtu/hr | | | 2121.7 | 1732.0 | 2147.3 |
| Total Heat Input, mmBtu/hr | | | 2556.3 | 2585.1 | 2555.3 |
| Quantity mlb/hr | Coal Flow | | 184.0 | 150.2 | 186.0 |
| | Natural Gas Flow (mcf/hr) | | 432.8 | 849.7 | 406.3 |
| | Flue Gas Entering Air Heaters | | 2,568 | 2,559 | 2,569 |
| | Total Air To Burners | | 2,319 | 2,322 | 2,320 |
| Pressure, psig | Steam at SH Outlet | | 1965 | 1965 | 1965 |
| | Steam at RH Outlet | | 460 | 460 | 460 |
| Temperature, °F | Steam | Leaving Superheater | 1005 | 1005 | 1005 |
| | | Leaving Reheater | 1005 | 1005 | 1005 |
| | | | | | |
| | Water | Water Entering Economizer | 467 | 467 | 467 |
| | | Superheater Spray Water | 380 | 380 | 380 |
| | Gas | Entering Air Heater | 668 | 670 | 668 |
| | | Leaving Air Heater (Excl. Leakage) | 352 | 353 | 352 |
| | Air | Entering Air Heater | 150 | 150 | 150 |
| | | Leaving Air Heater | 552 | 554 | 552 |
| Heat Loss Efficiency, % | Dry Gas | | 4.51 | 4.43 | 4.52 |
| | $H_2$ & $H_2O$ in Fuel | | 5.79 | 6.66 | 5.74 |
| | Moisture in Air | | 0.11 | 0.11 | 0.11 |
| | Unburned Combustible | | 0.25 | 0.20 | 0.25 |
| | Radiation | | 0.19 | 0.19 | 0.19 |
| | Unacc. & Mfgs. Margin | | 1.42 | 1.42 | 1.42 |
| | Total Heat Loss | | 12.27 | 13.01 | 12.23 |
| | Gross Efficiency of Unit, % | | 87.73 | 86.99 | 87.77 |

**B&W Proprietary and Confidential**

Predicted performance is based on the original contract boiler performance and PI data as supplied by Vectren

*Maximum heat input from ignitors

# *APPENDIX B – NG Conversion Equipment Scope & Budgetary Costs*

## SUPER-SPUD OPTION - Burner Modifications, Scanners, Valve Racks, NG Piping System

### Item 1: B&W 4Z Burners converted to Nat Gas Firing (Quantity: 24)

- Qty 24, Super-Spud Assemblies to replace existing coal nozzles
- Qty 12, Burner Valve Racks
- Burner Front Flex Hose and Hardware
- Burner Front Piping
- Gas Header Piping
- Burner Front Valves & Gauges

### Item 2: Fossil Power Systems (FPS) Flame Scanners

- Qty 24, FPS main UV flame scanners with rigid fiber optic extension
- Qty 1, main flame scanner electronics cabinet
- 1 Lot – Combustion/Cooling air piping from blower skid to burner fronts

### Item 3: Natural Gas Regulating Station and Piping

- Main natural gas regulating station – 50 psig supply pressure
- Natural gas piping from regulating station to the burners
- Natural gas burner front gas piping and valve stations excluding vent piping to above the boiler building roof

## HEMI-SPUD OPTION - Burner Modifications, Scanners, Valve Racks, NG Piping System

### Item 1: B&W 4Z Burners converted to Nat Gas Firing (Quantity: 24)

- Qty 24, Hemispherical Gas Spud Assemblies to replace existing coal nozzles
- Qty 12, Burner Valve Racks
- Burner Front Flex Hose and Hardware
- Burner Front Piping
- Gas Header Piping
- Burner Front Valves & Gauges

### Item 2: Fossil Power Systems (FPS) Flame Scanners

- Qty 24, FPS main UV flame scanners with rigid fiber optic extension
- Qty 1, main flame scanner electronics cabinet
- 1 Lot – Combustion/Cooling air piping from blower skid to burner fronts

**Item 3: Natural Gas Regulating Station and Piping**

- Main natural gas regulating station – 50 psig supply pressure
- Natural gas piping from regulating station to the burners
- Natural gas burner front gas piping and valve stations
- Vent piping from the regulating stations and the burner valve racks to the boiler roof and above the roof is not included

General Services

- Combustion system tuning services using an economizer outlet sampling grid for measurement of NOx per EPA methods.
- Field Service Engineering outage support for construction, start-up, and post-modification testing.
- Burner System Operator Training consisting of two, one day sessions.
- Training includes project specific training manual for up to 20 participants.
- Brickwork Refractory Insulation & Lagging (BRIL) Specifications and Installation design and materials.
- Contract specific System Requirements Specification, I/O Listing, and Functional Logic Diagrams for all supplied equipment.
- Operating and Maintenance Manuals (10 copies).
- New piping, flue, and duct loading to existing steel
- Delivery F.O.B. Brown Plant, Mt Vernon, IN.

Items not Included

- Hazardous material removal or abatement (i.e., lead paint and asbestos).
- Load analysis of existing structural steel or foundations and any required re-enforcement thereof.
- Hardware or reprograming of existing DCS and/or BMS to support natural gas conversion.
- Gas step down equipment. Equipment scope above assumes incoming gas pressure at B&W's terminal to be 30 to 50psi.

Terminal Points

- Inlet of gas regulating station
- Vent out of any valve rack
- Electrical terminals on provided electrical equipment or instruments
- Electrical terminals in shop provided terminal junction boxes as part of skidded equipment

## Budgetary Material & Installation Pricing (USD 2015)

| Scope Item | Budgetary | |
|---|---|---|
| | **Material** | **Installation** |
| **Super-Spud Option:** Burner Modifications, Scanners, Valve Racks, NG Piping System | $2,244,000 | $3,379,000 |
| **Hemi-Spud Option:** Burner Modifications, Scanners, Valve Racks, NG Piping System | $2,463,000 | $3,685,000 |

## Lead Times

- Material delivery: 52 - 56 weeks
- Installation duration: 8 - 10 weeks

B&W has offered these prices in 2018 US dollars and have not attempted to project escalation for time of performance or delivery.

Please note that these prices are budgetary and is not represent an offer to sell, however, we would welcome the opportunity to provide a formal proposal upon request.

Burns & McDonnell World Headquarters
9400 Ward Parkway
Kansas City, MO 64114
Phone: 816-333-9400
Fax: 816-333-3690
www.burnsmcd.com

**Burns & McDonnell: Making our clients successful for more than 100 years**

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

# Attachment 6.6 Brown Scrubber Assessment Study

FINAL - REV 1

# A.B. BROWN SCRUBBER ASSESSMENT AND ESTIMATE

B&V PROJECT NO. 400278
B&V FILE NO. 40.0001



PREPARED FOR

Vectren Corporation

11 MARCH 2020

BLACK & VEATCH

# Table of Contents

## LIST OF TABLES



## LIST OF FIGURES

# 1.1 Executive Summary

## 1.2 INTRODUCTION/BACKGROUND

Units 1 and 2 at Vectren's A. B. Brown Power Station are each nominally 265 megawatt (MW) gross, coal-fired electric generating units (EGUs). The units were built in the late 1970s to the mid-1980s. Each of the existing units is outfitted with an originally supplied, dual alkali (DA) wet flue gas desulfurization (FGD) system for the control of acid gases such as sulfur dioxide ($SO_2$).

Vectren has contracted with Black & Veatch Corporation (Black & Veatch) to provide order of magnitude conceptual design cost estimating, technology support, and review and consolidation of third-party conceptual design and cost estimates for the inputs into financial modeling of the current and available air quality control (AQC) scrubber technologies that could be employed at Vectren's A.B. Brown Station, for continued operation of both Unit 1 and Unit 2. Black & Veatch, in addition to other architectural engineering consultants hired by Vectren, has performed technology reviews and assessments to develop construction and ongoing operations and maintenance (O&M) costs of these various technologies.

This document presents AQC technologies evaluated for the A. B. Brown coal fired power plant for evaluation in Vectren's 2019 Integrated Resource Plan (IRP) for continued coal operation of A.B. Brown Units 1 and 2. Black & Veatch served as the lead engineer in the FGD evaluation effort. Black & Veatch, AECOM, and Burns & McDonnell all provided technical data and cost information for individual FGD upgrade options, as requested by Vectren. Those reports served to support the technology and costs presented in this report.

- Burns & McDonnell – A.B. Brown Wet Limestone Forced Oxidation FGD Cost Estimate
- AECOM – Wet FGD Limestone Conversion Study for A.B. Brown Station.

## 1.3 PURPOSE

The purpose in developing this compiled report is to indicate the applicability, reliability, and estimated costs of the AQC technology options that could be utilized at A.B. Brown Station to support continued operation of Unit 1 and Unit 2 on the full range of current coal fuel. The assessment will consider interfaces to the existing equipment and ductwork at the A.B. Brown Units and include evaluation of the reuse and/or removal of the existing auxiliary support equipment (mechanical tanks, pumps, fans, electrical switchgear, etc.).

The technologies evaluated and the responsible lead engineering company performing the work are indicated in Table 1-1.

**Table 1-1 Scrubber Technologies**

| Technology | Lead | Expected Outcome | Water Treatment Impacts | Other Impacts |
|---|---|---|---|---|
| Wet Limestone Forced Oxidation Scrubber | Burns & McDonnell | Feasible | Yes | Lime Injection FGD Gypsum Market |
| Limestone Forced Oxidation (Conversion from DA Scrubber) | AECOM | Not Feasible | Yes | Lime Injection |
| Limestone Inhibited Oxidation (Conversion from DA Scrubber) | AECOM | Not Feasible | Yes | Lime Injection |
| Inhibited Wet Lime Scrubber | Black & Veatch | Feasible | Yes | Lime Injection<br>Powdered Activated Carbon (PAC) Injection |
| Spray Dryer Absorber | Black & Veatch | Not Feasible | No | Not Applicable |
| Circulating Dry Scrubber | Black & Veatch | Feasible | No | PAC Injection |
| Ammonia Scrubber | Black & Veatch | Feasible | Yes | Lime Injection<br>PAC Injection<br>Fertilizer Market |

## 1.4 SUMMARY TABLE OF RESULTS

### 1.3.1 Capital Costs Summary

The technologies were reviewed to determine those that merited further analysis on the basis of their ability to meet emissions criteria for the full range of boiler design fuel. The selected technologies were then evaluated to assess the cost to purchase and operate the control technology. Table 1-2 presents the capital cost estimates. The capital cost presented for the LSFO technology includes cost for wastewater treatment but does not include costs for water treatment or landfill. The capital cost presented for Wet Lime Inhibited Oxidation (WLIO) and Circulating Dry Scrubber (CDS) are for the FGD systems only and do not include the need for or costs for water/wastewater treatment (WWT) or landfill. Waste water treatment costs for the Wet Limestone Forced Oxidation (LSFO) and Ammonia ($NH_3$) FGD system have been included. The LSFO system includes waste water treatment. The $NH_3$ system includes costs for wastewater treatment of water used for the wet ESP. Refer to Appendix A at the end of the report.

**Table 1-2 Capital Cost Estimates**

| (2019 Dollars x 1000) | Wet Lime Inhibited Oxidation Scrubber (WLIO) | Ammonia Scrubber ($NH_3$) | Circulating Dry Scrubber (CDS) | Limestone Forced Oxidation Scrubber (LSFO) |
|---|---|---|---|---|
| Installation Cost (2020 - 2024) | $318,079 | $284,835 | $269,550 | $424,878 |
| Capitalized Cost (2024 - 2039) | $34,313 | $30,727 | $29,078 | $45,834 |

### 1.3.2 20 Year Totals 2020 to 2039

The O&M costs start in 2024 assuming the FGD system installation was completed in 2023. The O&M costs are in 2019 dollars and no escalation has been applied; O&M costs for labor are not included in the estimates below. The O&M costs are total cost for 20 years (from 2020 to 2039) and are rounded to the nearest $1,000. Table 1-3 represents the O&M costs for the FGD systems only and does not include the balance-of-plant O&M costs. Refer to Appendix A at the end of the report.

**Table 1-3 Operations and Maintenance – 20 Year Totals 2020 to 2039**

| (2019 Dollars x 1000) | WLIO | $NH_3$ | CDS | LSFO |
|---|---|---|---|---|
| O&M Schedule Outage | $21,510 | $19,262 | $18,228 | $28,732 |
| O&M – Base Non-Labor | $11,148 | $9,983 | $9,448 | $14,892 |
| Total | $32,659 | $29,245 | $29,078 | $43,624 |

# 2.0 List of Abbreviations

| | |
|---|---|
| acfm | Actual Cubic Foot per Minute |
| AFUDC | Allowance for Funds Used During Construction |
| AQC | Air Quality Control |
| BACT | Best Available Control Technology |
| BPT | Balance-of-Plant Treatment |
| $Ca(OH)_2$ | Calcium Hydroxide |
| CaO | Quicklime |
| $CaSO_3$ | Calcium Sulfite |
| $CaSO_3 \bullet 1/2H_2O$ | Calcium Sulfite Hemihydrate |
| $CaSO_4 \bullet 2H_2O$ | Calcium Sulfate Dihydrate |
| CDS | Circulating Dry Scrubber |
| CEMS | Continuous Emissions Monitoring System |
| DA | Dual Alkali |
| DBA | Dibasic Acid |
| DCS | Distributed Control System |
| DESP | Dry Electrostatic Precipitator |
| ECO | Electrocatalytic Oxidation |
| EPA | Environmental Protection Agency |
| EPC | Engineering, Procurement, and Construction |
| ESP | Electrostatic Precipitator |
| FDA | Flash Dryer Absorber |
| FGD | Flue Gas Desulfurization |
| $H_2SO_4$ | Sulfuric Acid Mist |
| Hg | Mercury |
| ID | Induced Draft |
| IDEM | Indiana Department of Environmental Management |
| IRP | Integrated Resource Plan |
| JET | Jiangnan Environmental Technology, Inc. |
| L/G | Liquid-To-Gas |
| lb/Btu | Pound per British Thermal Unit |
| Lb/h | Pound per Hour |
| LIFAC | Limestone Injection into the Furnace and Activation of Calcium |
| LSFO | Limestone Forced Oxidation |
| LSIO | Limestone Inhibited Oxidation |
| MBtu | Million British Thermal Unit |

| | |
|---|---|
| MW | Megawatt |
| $NH_3$ | Ammonia |
| NIPSCO | Northern Indiana Public Service Company |
| $NO_X$ | Nitrogen Oxides |
| NSR | New Source Review |
| O&M | Operations and Maintenance |
| PAC | Powdered Activated Carbon |
| PGLS | Pre-Ground Limestone |
| PJFF | Pulse Jet Fabric Filter |
| PM | Particulate Matter |
| $PM_{10}$ | Particulate Matter Less than 10 Microns |
| PSD | Prevention of Significant Deterioration |
| SCR | Selective Catalytic Reduction |
| SDA | Spray Dryer Absorber |
| $SO_2$ | Sulfur Dioxide |
| $SO_3$ | Sulfur Trioxide |
| $SO_X$ | Sulfur Oxides |
| TBtu | Trillion British Thermal Units |
| WESP | Wet Electrostatic Precipitator |
| WLIO | Wet Lime Inhibited Oxidation |
| WWT | Wastewater Treatment |

# 3.1 Conceptual Design Basis

## 3.2 ENVIRONMENTAL REGULATIONS

Black & Veatch anticipates that the installation of a new FGD system or major modification of the existing system will be subject to Federal and Indiana Department of Environmental Management (IDEM) air regulations as a modification to an existing major source. An air construction permit would, therefore, need to be obtained to authorize construction. However, Black & Veatch anticipates that the permit could be obtained as a minor modification and would not be subject to Prevention of Significant Deterioration (PSD) review and Best Available Control Technology (BACT) requirements. Black & Veatch notes that confirmation of air permitting applicability of a given technology cannot be accomplished until a New Source Review (NSR) applicability analysis is conducted. Should PSD BACT ultimately be applicable, the results of a BACT analysis could alter the required technology because emissions targets lower than the current emissions limits may be required. An operating change, such as an expected increase in the unit capacity factor, could cause BACT to be applicable. The conceptual design basis used to screen the scrubber technologies must be able to meet, as a minimum, the minor modification to permit (~98 percent removal).

## 3.3 BOILER PERFORMANCE

Characteristics for boiler performance parameters used by Black & Veatch were based on a previous study performed in 2013 for A.B. Brown Unit 1. The same information was utilized for A.B. Brown Unit 2 for this high-level assessment.

### Table 3-1 Combustion Performance

| Parameters | Typical Coal Exhaust Gas Flow (Typical Sulfur) | Maximum Design Exhaust Gas Flow (Maximum Sulfur) | Typical Coal Minimum Exhaust Gas Flow (Typical Sulfur) | Design Maximum Values | Minimum Design Values |
|---|---|---|---|---|---|
| **Unit Characteristics** | | | | | |
| Unit Rating, Gross MW | 268 | 268 | ~115 | 268 | ~115 |
| Unit has an SCR | Yes | Yes | Yes | | |
| Boiler Heat Input, MBtu/h (HHV) | 2,690 | 2,714 | 1,015 | 2,714 | 1,015 |
| Boiler Heat to Steam, MBtu/h | 2,351 | 2,351 | 893 | | |
| Coal Flow Rate, lb/h | 241,000 | 261,000 | 94,000 | 241,000 | 94,000 |
| LOI, % of fly ash | 1.79 | 1.79 | 1.79 | 1.79 | 1.79 |
| Boiler Misc. Heat Losses, % | 1.50 | 1.50 | 1.50 | 1.50 | 1.50 |
| Excess Air at Economizer, % | 3.60 | 3.60 | 6.80 | 6.80 | 3.60 |
| Excess Air, % | 22.81 | 22.82 | 53.21 | | |
| Air Heater Leakage, % | 10.84 | 10.83 | 28.99 | | |
| Fly Ash Portion of Total Ash, % | 85 | 85 | 85 | | |
| Altitude, ft above MSL | 415 | 415 | 415 | 415 | 415 |
| Barometric Pressure, in. Hg Abs | 29.496 | 29.496 | 29.496 | | |
| Ambient Pressure, in. $H_2O$ | 401 | 401 | 401 | 401 | 401 |
| Ambient Temperature, °F | 85 | 85 | 85 | 105 | -23 |
| Relative Humidity, % | 60 | 60 | 60 | | |
| $SO_2$ to $SO_3$ Oxidation Rate by Boiler, percent | 0.8 | 0.8 | 0.8 | | |
| $SO_2$ to $SO_3$ Oxidation Rate by SCR, percent | 0.5 | 0.5 | 0.5 | | |
| Total $SO_2$ to $SO_3$ Oxidation Rate, percent | 1.3 | 1.3 | 1.3 | | |
| **PJFF Inlet Conditions** | | | | | |
| Actual flow, acfm | 1,040,000 | 1,080,000 | 540,000 | | |
| Flue Gas Temperature, °F | 305 | 330 | 285 | 330 | 285 |
| Flue Gas Pressure, in. w.g. | -24.0 | -24.0 | -5.5 | -24.0 | -5.5 |
| ***Flue Gas Composition*** | | | | | |
| $O_2$, % Vol wet basis | 5.29 | 5.29 | 9.92 | | |
| $N_2$,% Vol wet basis | 73.62 | 73.61 | 74.69 | | |
| $CO_2$, % Vol wet basis | 11.98 | 11.84 | 8.32 | | |
| $SO_2$ , % Vol wet basis | 0.27 | 0.43 | 0.19 | | |
| HCl, % Vol wet basis | 0.0013 | 0.0035 | 0.0009 | | |

| Parameters | Typical Coal Exhaust Gas Flow (Typical Sulfur) | Maximum Design Exhaust Gas Flow (Maximum Sulfur) | Typical Coal Minimum Exhaust Gas Flow (Typical Sulfur) | Design Maximum Values | Minimum Design Values |
|---|---|---|---|---|---|
| $H_2O$, % Vol wet basis | 8.83 | 8.83 | 6.88 | | |
| Sulfur Dioxide Concentration, lb/MBtu | 6.72 | 10.54 | 6.92 | | |
| $H_2SO_4$ ppmvd | 22.1 | 34.9 | 15.0 | | |
| $H_2SO_4$, lb/MBtu | 0.076 | 0.120 | 0.079 | | |
| Oxidized Hg, lb/TBtu | 4.75 | 4.75 | 4.35 | 4.80 | |
| Elemental Hg, lb/TBtu | 0.53 | 0.53 | 0.67 | 1.20 | |
| Total Hg, lb/TBtu | 5.28 | 5.28 | 5.02 | 6.00 | |
| Particulate Concentration, lb/MBtu | 7.54 | 12.23 | 7.76 | | |
| Particulate Mass Rate, gr/acf | 2.28 | 3.59 | 1.70 | | |
| **PJFF Outlet/ID Fan Inlet Conditions** | | | | | |
| Actual flow, acfm | 1,340,000 | 1,350,000 | 550,000 | | |
| Actual flow per duct total of two ducts per boiler, acfm | 670,000 | 675,000 | 275,000 | | |
| Flue Gas Temperature, °F | 305 | 330 | 285 | 330 | 285 |
| Flue Gas Pressure, in. w.g. | -32.0 | -32.0 | -13.5 | | |
| **Flue Gas Composition** | | | | | |
| $O_2$, % Vol wet basis | 5.29 | 5.29 | 9.92 | | |
| $N_2$,% Vol wet basis | 73.62 | 73.61 | 74.69 | | |
| $CO_2$, % Vol wet basis | 11.98 | 11.84 | 8.32 | | |
| $SO_2$ , % Vol wet basis | 0.27 | 0.43 | 0.19 | | |
| HCl, % Vol wet basis | 0.0013 | 0.0035 | 0.0009 | | |
| $H_2O$, % Vol wet basis | 8.83 | 8.83 | 6.88 | | |
| $H_2SO_4$ ppmvd | 19.9 | 31.4 | 13.5 | | |
| $H_2SO_4$, lb/MBtu | 0.069 | 0.108 | 0.071 | | |
| Oxidized Hg, lb/TBtu | 4.72 | | 4.80 | 4.80 | |
| Elemental Hg, lb/TBtu | 0.13 | | 0.38 | 1.20 | |
| Total Hg, lb/TBtu | 4.85 | 0.00 | 5.18 | 6.00 | |
| PM (Filterable), lb/MBtu | 0.010 | 0.010 | 0.010 | | |
| Ref: Boiler performance from A.B. Brown Unit 1 Environmental Study 2013 Design Basis – Exhaust Flow Information. | | | | | |

## 3.4 DESIGN COAL

**Table 3-2 Design Coal**

| Parameters | Design Cases - Bituminous<br>Design Coal | Range - Bituminous<br>Minimum | <br>Maximum |
|---|---|---|---|
| **Ultimate Coal Analysis, wet basis** | | | |
| Carbon, % | 62.02 | 50.80 | 75.38 |
| Hydrogen, % | 4.23 | 3.50 | 5.30 |
| Sulfur, % | 3.75 | 0.86 | 5.48 |
| Nitrogen, % | 1.02 | 0.86 | 2.20 |
| Oxygen, % | 6.91 | 5.00 | 11.11 |
| Chlorine, % | 0.04 | 0.01 | 0.17 |
| Ash, % | 9.71 | 7.00 | 14.68 |
| Moisture, % | 12.32 | 2.70 | 16.50 |
| Total, % | 100 | 71 | 131 |
| Higher Heating Value, Btu/lb | 11,143 | 10,400 | 12,493 |
| Ref: A.B. Brown Unit 1 Environmental Study 2013 Design Basis – Fuel Information. Installation Scope. | | | |

# 4.1 Potential Air Quality Control Technologies

The evaluation is being performed to assist Vectren in determining a preliminary selection of the preferred FGD equipment for evaluation in Vectren's 2019 IRP. Black & Veatch has assumed that the installation of a new FGD system will be subject to Federal and IDEM air regulations as a modification to an existing major source, and, therefore, an air construction permit will have to be obtained to authorize construction. However, because of the nature of the project (where the existing air emissions limits are the baseline), it is assumed that the emissions increase as a result of this project, if any, would be less than the PSD significance thresholds. Thus, according to these assumptions, the project would be considered a minor modification and would, therefore, not be subject to PSD BACT requirements. Black & Veatch notes that confirmation of air permitting applicability of a given technology cannot be accomplished until an NSR applicability analysis is conducted. Should PSD BACT ultimately be applicable, the results of a BACT analysis could alter the required technology because emissions targets lower than the current emissions limits may be required. An operating change, such as an expected increase in the unit capacity factor, could result in making BACT applicable.

## 4.2 REVIEW OF POTENTIAL TECHNOLOGIES

This section identifies, summarizes, and evaluates potential $SO_2$ control technologies for feasibility of use at the A.B. Brown Station. The current generation of FGD system design represents improvements and advances to previous generations of FGD systems that were first installed in the United States in the 1970s.

Many of the FGD system vendors offer both semi-dry systems (i.e., CDS or spray dryer absorber [SDA] systems) and wet systems (lime- and limestone-based spray/tray towers absorbers) and will offer whichever best meets the utility's particular requirements on a site-by-site basis. Improvements to the wet FGD technologies have also been realized through better process chemistry and the use of chemical additives such as dibasic acid (DBA). The following subsections identify and describe the potential technologies that were evaluated for use at A.B. Brown Station.

### 4.1.1 Conversion of the Current FGD System to a Limestone-Based Scrubber

Conversion of the existing DA FGD systems to a limestone-based FGD system has been completed on similar type units in industry and was examined in this study. The detailed study of this option was provided in a report completed by AECOM, an engineering firm under separate contract with Vectren. This report is provided as Appendix C at the end of this report. In this report, AECOM presents the option of converting the existing A.B. Brown FGD systems to a limestone-based reagent scrubber using either of two options: limestone inhibited oxidation (LSIO), producing calcium sulfite solids for landfill disposal, or LSFO operations, producing wallboard-quality gypsum that allows for the potential marketing and selling of the byproduct to avoid the landfill costs. AECOM previously converted DA scrubbers at Northern Indiana Public Service Company's (NIPSCO's) Schahfer Station to limestone-based reagent, along with in situ oxidation to produce wallboard-quality gypsum. Both options were assessed with the intention to repurpose and/or reuse as much existing equipment as possible. For this preliminary report, only the use of pre-ground limestone (PGLS) was evaluated. A description of the proposed process configurations, scope of work, capital requirements, and operating cost impacts are presented in the AECOM report. Vectren indicates that additional equipment and construction items that were not included in the AECOM report have been addressed by a local Evansville, Indiana, engineering firm, Three I Design, that has assisted Vectren over the years in the evaluation of the FGD equipment.

### 4.1.2 Wet Limestone Process

Numerous suppliers offer FGD processes using a limestone slurry as the scrubbing agent. A detailed evaluation of this technology option was provided in a report completed by Burns & McDonnell, an engineering firm under separate contract with Vectren. This report is provided in Appendix B at the end of this report. In this report, Burns & McDonnell presents the option of installing new limestone reagent-based scrubbers using LSFO operations to produce wallboard-quality gypsum that can be landfilled or marketed and sold.

The Wet Limestone process utilizes a ball mill to create a limestone slurry which is fed into the absorber reaction tank to maintain the appropriate pH. Recirculation pumps feed limestone slurry from the reaction tank to the spray lances at the top of the absorber tower. The flue gas flows countercurrent to the sprayed slurry where the $SO_2$ reacts and is removed from the flue gas stream. The flue gas continues through a set of mist eliminators before leaving the absorber. The $SO_2$ which reacts with the lime in the system is oxidized to form gypsum. A bleed stream is removed from the absorber reaction tank and sent to the dewatering system where water is removed from the gypsum byproduct.

### 4.1.3 Wet Lime Process

Wet lime FGD is the generic term for processes using slaked lime as the scrubbing reagent in a spray tower FGD module. Wet lime processes are offered by a number of FGD suppliers. The reagent preparation system equipment is the only significant difference between the equipment used in the wet lime and wet limestone systems. The higher reactivity of the lime allows the equipment to be smaller than with a wet limestone scrubber.

Inhibited oxidation producing a calcium sulfite material is used or forced oxidation is used to promote formation of a fully oxidized gypsum byproduct. For this study, an inhibited oxidation process is assumed that produces a material for landfill disposal.

The primary difference in the wet lime and wet limestone processes is the preparation of scrubbing reagent slurry. In wet lime processes, quicklime (CaO) is slaked to produce a calcium hydroxide [Ca $(OH)_2$] slurry.

### 4.1.4 Semi-Dry Lime-Based FGD Systems

Semi-dry FGD processes have been extensively used in the United States, where utilities have installed numerous semi-dry FGD systems on boilers using low sulfur fuels. The semi-dry FGD process uses $Ca(OH)_2$ produced from the lime reagent as either a slurry or as a dry powder added to the flue gas in a reactor designed to provide good flue gas-reagent contact. The $SO_2$ in the flue gas reacts with the calcium in the reagent to produce primarily calcium sulfite hemihydrate ($CaSO_3 \bullet 1/2H_2O$) and a smaller amount of calcium sulfate dihydrate ($CaSO_4 \bullet 2H_2O$) through the following reactions:

$$SO_2 + Ca(OH)_2 \rightarrow CaSO_3 \bullet \tfrac{1}{2}H_2O + \tfrac{1}{2}H_2O$$

$$SO_2 + Ca(OH)_2 + \tfrac{1}{2}O_2 \rightarrow CaSO_4 \bullet 2H_2O$$

Water is also added to the reactor (either as part of the reagent slurry or as a separate stream) to cool and humidify the flue gas, which promotes the reaction and reagent utilization. The amount of water added is typically sufficient to cool the flue gas to within 30° to 40° F of the flue gas adiabatic saturation temperature. Significantly less water is used in these semi-dry FGD processes than in wet FGD processes.

The reaction byproducts and excess reagent are dried by the flue gas and removed from the flue gas by a downstream particulate control device (either fabric filter or dry electrostatic precipitator [DESP]). Fabric filters are preferred for most systems because the additional contact of the flue gas with the particulate on the filter bags provides additional $SO_2$ removal and higher reagent utilization. A portion of the reaction byproducts collected is recycled to the reagent preparation system to increase the utilization of the lime.

Because of the large amount of excess lime present in the FGD byproducts, the byproducts (and fly ash, if present) will experience pozzolanic (cementitious) reactions when wetted. When wetted and compacted, the byproduct makes a fill material with low permeability (low lengthening characteristics) and high bearing strength. However, other than as structural fill, this byproduct has limited commercial value and typically must be disposed of as a waste material.

The semi-dry FGD processes offer benefits in addition to $SO_2$ removal, including the lack of a visible vapor plume and sulfur trioxide ($SO_3$) removal. Because the semi-dry FGD systems do not saturate the flue gas with water, there is no visible plume from the stack under most weather conditions. Environmental concerns with $SO_3$ emissions are also reduced with the semi-dry scrubber. $SO_3$ is formed during combustion and will react with the moisture in the flue gas to form sulfuric acid ($H_2SO_4$) mist in the atmosphere. An increase in $H_2SO_4$ emissions will increase $PM_{10}$ emissions. The gas temperature leaving the reactor is lowered below the sulfuric acid dew point, and significant $SO_3$ removal will be attained as the condensed acid reacts with the alkaline reagent. By removing $SO_3$ in the flue gas, the condensable particulate matter emissions can be reduced. This will reduce the potential for any $SO_3$ plume that may cause opacity in stacks. Similar type $SO_3$ removal is not achievable with a wet scrubber.

The following four variants of semi-dry FGD processes are described further in this analysis:

- Spray Dryer Absorber (SDA).
- Circulating Dry Scrubber (CDS).
- Flash Dryer Absorber (FDA).
- Turbosorp.

#### 4.1.4.1 Spray Dryer Absorber

All current SDA designs use a vertical gas flow absorber. These absorbers are designed for co-current or a combination of co-current and countercurrent gas flow. In co-current applications, gas enters the cylindrical vessel near the top of the absorber and flows downward and outward. In combination-flow absorbers, a gas disperser located near the middle of the absorber directs a fraction of the total flue gas flow upward toward the slurry atomizers.

The atomizer produces an umbrella of atomized reagent slurry through which the flue gas passes. The $SO_2$ in the flue gas is absorbed into the atomized droplets and reacts with the calcium to form calcium sulfite and calcium sulfate. Before the slurry droplet can reach the absorber wall, the water in the droplet evaporates and a dry particulate is formed.

The flue gas, then containing fly ash and FGD byproduct solids, leaves the absorber and is directed to a fabric filter. The fly ash and byproduct solids collected in the fabric filter are pneumatically transferred to a silo for disposal. To improve both reagent utilization and spray solids drying efficiency, a large portion of the collected solids is directed to a recycle system, where it is slurried and re-injected into the spray dryer along with the fresh lime reagent.

SDA installations, primarily located in the western United States, use either lignite or subbituminous coals, such as Powder River Basin, as the boiler fuel and generally have spray dryer systems designed for a maximum fuel sulfur content of less than 2 percent. The semi-dry lime-based FGD system has inherent removal efficiency limitations on higher sulfur fuels with higher $SO_2$ inlet concentration. This limitation varies with flue gas inlet temperature because the amount of slurry that can be injected into the absorber is limited by how close the flue gas temperature can approach its water saturation temperatures.

#### 4.1.4.2 Circulating Dry Scrubber

The CDS FGD, also known as a circulating fluid bed scrubber, process is a semi-dry, hydrated lime-based FGD process that uses a circulating fluid bed contactor. The CDS absorber module is a vertical solid/gas reactor upstream of a particulate control device. The particulate control device is elevated to allow the recycle of the byproduct back to the fluidized bed in the absorber vessel. Water is sprayed into the reactor to reduce the flue gas temperature to the optimum temperature for reaction of $SO_2$ with the reagent. Hydrated lime [$Ca(OH)_2$] and recirculated dry solids from the particulate control device are injected concurrently with the flue gas into the base of the absorber module. One or more venturi should be at the bottom of the absorber module to accelerate the flue gas to maintain the fluidized bed in the absorber. The gas velocity in the reactor is reduced, and a suspended bed of reagent and fly ash is developed. The $SO_2$ in the flue gas reacts with the hydrated lime reagent to form predominantly calcium sulfite ($CaSO_3$).

#### 4.1.4.3 Flash Dryer Absorber

The FDA is a variation of CDS technology. In this system, the fly ash is mixed with lime and water in a mixer/hydrator prior to being injected into the flash dryer. The flue gas is evaporatively cooled and humidified by the water being absorbed onto the dry particulate. Furthermore, $SO_2$ is removed from the flue gas stream by the reaction with the lime or limestone. The dry particulate is then removed in a fabric filter. A portion of the dry particulate from the fabric filter is collected for disposal, while a significant amount is recirculated to the mixer for conditioning and reuse in the absorber to achieve better reagent use and performance.

#### 4.1.4.4 Limestone Injection into Furnace and Reactivation of Calcium

In the early 1980's, Tampella Power Inc. of Finland began the development of a humidification process that would enhance the effectiveness of the furnace-injection FGD process by humidifying the flue gas and installing a solid/gas contact reactor upstream of the particulate control device. This process is referred to by the acronym LIFAC (limestone injection into the furnace and activation of calcium). The two major differences between the LIFAC process and the furnace-injection process are the use of a reactor to enhance reagent contact with the flue gas and the recirculation of a portion of the fly ash and byproduct solids collected in the particulate control device to the reactor.

This process is offered only by Tampella Power or one of its affiliated companies and has been applied to full-scale, coal fired utility boilers in Finland, Russia, Canada, and the United States.

#### 4.1.4.5 Turbosorp

The Turbosorp circulating fluidized bed scrubber is a multi-pollutant control technology that removes $SO_2$, $SO_3$, hydrochloric acid, and mercury (Hg) from flue gas for coal fired applications. Turbosorp was originally developed by Austrian Energy & Environment and is now offered by Andritz and Babcock Power Environmental Inc.

### 4.1.5 Ammonia Scrubber

Anhydrous ammonia is used in the ammonia scrubber as the desulfurization absorbent to capture the $SO_2$, and the byproduct of the process is ammonium sulfate, a known fertilizer material. The only large FGD system of this type in the United States was installed at Dakota Gasification in North Dakota. This site is not a coal burning power plant. At this plant synthetic natural gas is produced by oxidizing lignite coal. The ammonia solution contacts the flue gas in a spray tower type absorber similar to a wet limestone or lime system.

### 4.1.6 Powerspan Electrocatalytic Oxidation Process

The Powerspan Electrocatalytic Oxidation (ECO) process is a multi-pollutant control technology that oxidizes and removes nitrogen oxides ($NO_X$), sulfur oxides ($SO_X$), and Hg from flue gas. The ECO process consists of the following steps:

- Fabric Filter or Electrostatic Precipitator (ESP)--Removes fly ash.
- ECO Reactor--Oxidizes pollutants.
- Absorber Vessel--Removes $SO_2$ and $NO_2$.
- Wet Electrostatic Precipitator (WESP)--Removes acid aerosols, fine PM, and oxidized Hg.

## 4.2 TECHNOLOGY PERFORMANCE EVALUATION CRITERIA ($SO_2$ AND PM)

An analysis was performed to identify the technical feasibility of the control options identified in Section 4.1, considering source-specific factors. A control option that was determined to be technically infeasible was eliminated. “Technically infeasible” in this case was defined as a control option that has not been proven to meet the emissions limits currently required at the plant for the defined range of potential operating conditions.

The performance requirements are as follows:

- 98 percent $SO_2$ removal efficiency for all coals.
- Particulate matter (PM) emissions at or below current baseline emissions.

Technologies are also considered infeasible if performance restrictions preclude the technology from achieving the primary emissions target or secondary emissions targets because of physical, chemical, or engineering issues. Secondary emissions targets would include other air or water emissions limits, such as Hg, not necessarily directly controlled by the technology but for which the technology cannot prevent control of the secondary emissions through other means. After completion of this step, technically infeasible options were then eliminated from the review process.

Control options that are not eliminated are considered technically feasible. A "technically feasible" control option is defined as a control technology that has been installed and operated successfully at a similar type of source of comparable size to the proposed facility under review (i.e., "demonstrated"). If the control option cannot be demonstrated, the analysis considers two key concepts: availability and applicability. "Availability" is defined as technology that can be obtained through commercial channels or is otherwise available within the common sense meaning of the term. A technology that is being offered commercially by vendors or is in licensing and commercial demonstration is deemed an available technology. Technologies that are in development (concept stage/research and patenting) and testing stages (bench-scale/laboratory testing/pilot scale testing) are classified as not available. An "available" technology does not mean that it does not have technical or commercial risks that differ from other available technologies. These risks are identified and evaluated during the analysis and considered in later analysis steps.

## 4.3 ELIMINATED TECHNOLOGIES

In order to eliminate technologies, an evaluation of all the available control technologies identified in Step 1 of the analysis was completed to determine their technical feasibility. A control technology is technically feasible if it has been previously installed and operated successfully at a similar type of source of comparable size, or there is technical agreement that the technology can be applied to the source. Available and applicable are the two terms used to define the technical feasibility of a control technology. Table 4-1 identifies what technologies are considered technically feasible $SO_2$ options for the A. B. Brown application.

### Table 4-1 Summary – Eliminate Technically Infeasible Options

| Technology Alternative | Technically Feasible (Yes/No) Available | Applicable |
|---|---|---|
| Wet FGD | | |
| Limestone Conversion of Existing DA FGD - Forced Oxidation | Yes | No –would not meet expected emissions requirements when operating over the high sulfur range of the coals used at A.B. Brown. |
| Limestone Conversion of Existing DA FGD - Inhibited Oxidation | Yes | No –would not meet expected emissions requirements when operating over the high sulfur range of the coals used at A.B. Brown. |
| Wet Limestone FGD - Forced Oxidation(1) | Yes | Yes |
| Wet Lime FGD - Inhibited Oxidation(1) | Yes | Yes |
| Limestone Injection into the Furnace | Yes | No – would not meet expected emissions requirements when operating over the high sulfur range of the coals used at A.B. Brown. |
| Dry and Semi-Dry Lime FGD | | |
| SDA | Yes | No – SDA has limited $SO_2$ removal efficiency over the project range of fuels, which are higher sulfur contents. |
| CDS or Turbosorp | Yes | Yes – Installations comparable in size are in operation. However, no full-scale operational experience is available in the United States over the high sulfur range of the coals used at A.B. Brown. |
| FDA | Yes | No – FDA has limited $SO_2$ removal efficiency over the high range of sulfur in the fuels. |
| Ammonia Scrubber | Yes | Yes – However, only one US application in operation and current interest limited to one Chinese supplier with no US experience. |
| Powerspan ECO Process | No | No – Only pilot size experience. |

(1) Alternate absorber designs in wet lime or limestone FGD (spray tower, double contact spray tower, trays, etc.) are equal for comparison purposes.

On the basis of the initial selection of candidate technologies to address Vectren's objectives, the control technologies identified in Table 4-2 were selected for further evaluation; the firm responsible for the evaluation is also identified.

**Table 4-2 Selected Technologies**

| Option | Acronym | Data Source |
|---|---|---|
| Wet Lime Inhibited Oxidation | WLIO | Black & Veatch |
| Circulating Dry Scrubber | CDS | Black & Veatch |
| Ammonia | $NH_3$ | Black & Veatch |
| Limestone Forced Oxidation | LSFO | Burns & McDonnell |

## 4.4 POTENTIAL TO MEET FUTURE REGULATIONS

It should be noted that this analysis is focused on meeting current emissions requirements and meeting Vectren's current objectives. It is possible that future environmental regulations will be promulgated that require A.B. Brown to reduce air emissions beyond the current requirements. If this occurs in the future, additional study will be needed to determine what additional modifications and capital expenditures would be needed for each technology.

# 5.1 Limestone Forced Oxidation Scrubber (LSFO)

The LSFO study was completed by Burns & McDonnell and is attached in Appendix B.

## 5.2 DESCRIPTION OF TECHNOLOGY

### 5.1.1 Basic Process Description

Limestone FGD utilizes crushed limestone ($CaCO_3$) ground and mixed with water to be used as a scrubber reagent that is pumped to a scrubber vessel reaction tank and the slurry in the reaction tank is recirculated by large pumps to the spray headers at the top of the spray tower vessel. The spray headers discharge the slurry into the spray towers with flue gas passing through the spray stream in a countercurrent direction and the removes $SO_2$ from the gas stream. Oxidation air blowers are provided to push oxygen to the reaction tank to create a gypsum byproduct.

$$CaCO_3 + SO_2 \rightarrow CaSO_3 + CO_2$$

$$CaSO_3 + \tfrac{1}{2} O_2 + 2H_2O \rightarrow CaSO_4 \bullet 2(H_2O)$$

The gypsum byproduct bleed stream is pumped from the reaction tank through a hydroclone as an initial step to separate solids from liquid. Liquids are returned to the reaction tank and solids are separated and sent to the vacuum filter to further remove liquids before being loaded and shipped to a purchaser or disposed of in a landfill.

For a detailed description of the limestone forced oxidation scrubber technology as provided by Burns & McDonnell, refer to Section 3.2 of the Burns & McDonnell Wet Limestone Forced Oxidation FGD Cost Estimate report included as Appendix B.

### 5.1.2 Flow Diagram

Figure 5-1 is a typical process flow diagram for an LSFO.

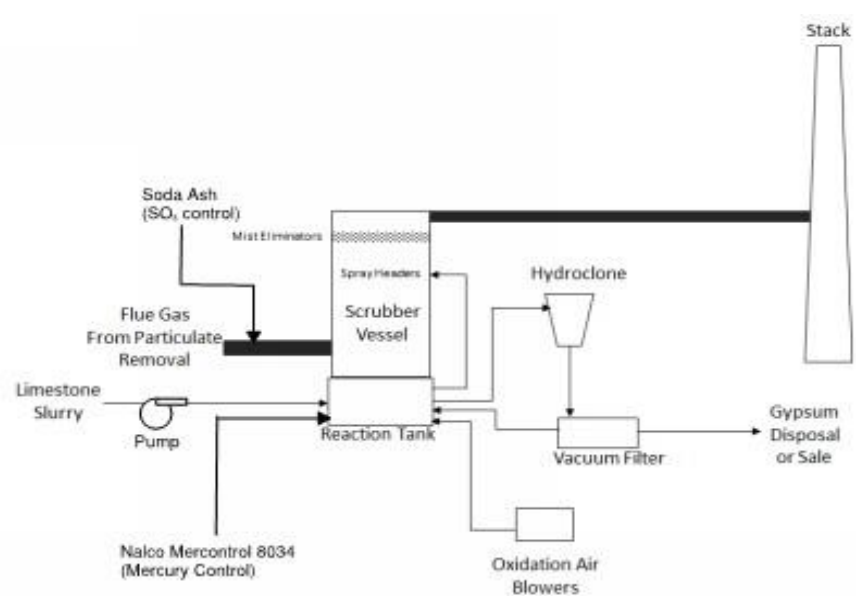



**Figure 5-1 Limestone Forced Oxidation Scrubber**

### 5.1.3 Environmental Controls

The existing particulate control systems (fabric filter on Unit 1 and electrostatic precipitator (ESP) on Unit 2) and ash collection systems remain in service with the fly ash continuing to be available for recycle.

Control of $SO_3$ will be with use of a soda ash injection system (such as AECOM SBS Injection system). The current soda ash injection point is located after the fabric filter on Unit 1 and after the ESP on Unit 2 both locations are upstream of the scrubber vessels.

The LSFO system will use the existing mercury control systems (Nalco Mercontrol 8034) for mercury control. Mercontrol 8034 chemical is injected into the scrubber limestone slurry recirculation piping for mixing and dispersion.

The LSFO scrubber system removes the HCl from the flue gas steam.

**Table 5-1 Environmental Controls LSFO**

| Pollutant | Hg | $SO_3$ | $SO_2$ | PM |
|---|---|---|---|---|
| Control Technologies | LSFO + Nalco Mercontrol 8034 | Existing SBS Injection System | LSFO | Existing PM control: Unit 1 – Fabric Filter Unit 2 - ESP |

## 5.2 ESTIMATING METHODOLOGY

Burns & McDonnell requested budgetary bids from seven FGD system suppliers: Amec Foster Wheeler, Andritz, Babcock & Wilcox, Babcock Power, GE Power, Marsulex and Mitsubishi Hitachi. An average of the budgetary quotes was assumed for the FGD supply cost.

Direct costs were factored based on costs from past FGD projects. Factored costs were used for Indirect costs which include engineering and start-up. Burns & McDonnell developed an estimate of the following balance of plant direct costs:

- Equipment installation.
- Civil and foundation work.
- New chimney for Unit 1.
- Demolition of Unit 1 thickener.
- Concrete.
- Steel.
- Ductwork and insulation.
- Buildings.
- Limestone and gypsum pile canopies.
- Wastewater treatment equipment (falling film evaporator and crystallizer).
- Piping.

- Electrical (new transformers, PCM, switchgear, MCC's and miscellaneous panels).
- Instrumentation and controls.

Refer to Section 3.5 of the Burns & McDonnell report in Appendix B.

## 5.3 ESTIMATE ASSUMPTION

Burns & McDonnell made the following assumptions in preparation of the cost estimate:

- All estimates aide screening-level in nature, do not reflect guaranteed costs, and are not intended for budgetary purposes.
- Assumes contracting philosophy is Engineer, Procure, Construction (EPC) approach.
- All information is preliminary and should not be used foil construction purposes.
- Assumes project engineering starts January 1, 2020 with both scrubbers in operation by January 2024.
- All capital cost and O&M estimates are stated in 2019 US dollars (USD). Escalation is excluded.
- Fuel and power consumed during construction, startup, and/or testing are included.
- Piling is included under heavily loaded foundations.
- All foundations are new; no re-use of existing foundations.
- Adequate water supply is assumed to be available from existing raw water supplies.
- This estimate assumes that the integrity of the tie-in points is sufficient.
- This estimate assumes that there are no significant underground utilities that would have to be re-routed.
- Removal of hazardous materials is not included.
- Emissions estimates are based on a preliminary review of BACT requirements and provide a basis for the assumed air pollution control equipment included in the capital and O&M costs.
- No new induced draft (ID) fans or booster fans ate included in the capital cost estimate. Burns & McDonnell reviewed the fan curves provided by Vectren and determined there was sufficient capacity to handle the pressure drop through the new FGD system.
- This estimate does not include provisions for either Mercury control or $SO_3$ control. Vectren can continue using the existing system for each following conversion to the wet LSFO technology.

Refer to Subsection 3.5.1 of the Burns & McDonnell report in Appendix B.

## 5.4 PROJECT INDIRECT COSTS

Burns & McDonnell included the following indirect costs in the capital cost estimate:

- Performance testing and CEMS/stack emissions testing.
- Pre-operational testing, startup, start-up management and calibration.
- Construction/start-up technical serv ice.
- Engineering.
- Freight.
- Start-up spare parts.

Refer to Section 3.6 of the Burns & McDonnell report in Appendix B.

## 5.5 OWNER COSTS

Burns & McDonnell did not include the following Owner's costs in the estimates:

- Project development.
- Owner's operational personnel.
- Owner's project management.
- Owner's engineering.
- Owner's startup engineering and training.
- Legal fees.
- Permitting/licensing.
- Construction power, temporary utilities, startup consumables.
- Site security.
- Operating spare parts.
- Political concessions.
- Builder's risk insurance.
- Owner's contingency.
- Allowance for funds used during construction (AFUDC).

Refer to Section 3.7 of the Burns & McDonnell report in Appendix B.

## 5.6 COST ESTIMATE EXCLUSIONS

The following costs were excluded from Burns & McDonnell's estimate:

- Escalation.
- Sales tax.
- Property tax and property insurance.
- Utility demand costs.
- Salvage values.

Refer to Section 3.8 of the Burns & McDonnell report in Appendix B.

## 5.7 PRESENTATION OF CAPITAL COSTS

The capital cost of the replacement LSFO system is summarized in Table 5-2. The direct cost includes the cost of the absorber, limestone preparation system, gypsum dewatering system, gypsum canopy for 3 days of gypsum storage, WWT equipment, electrical upgrades, boiler reinforcement, new stack for Unit 1, and installation.

**Table 5-2 LSFO Capital Costs**

| Category | Cost |
|---|---|
| Total Direct Cost | $265,287,000 |
| Indirect Cost | $66,480,000 |
| Contingency | $65,571,000 |
| Engineering, Procurement, and Construction (EPC) Fee | $27,540,000 |
| **Total Project Cost** | **$424,878,000** |

## 5.8 OPERATIONS AND MAINTENANCE COSTS – PRESENT 20 YEAR TOTALS

The O&M costs start in 2024 assuming the LSFO system installation was completed in 2023. The O&M costs are in 2019 dollars and no escalation has been applied; labor costs are not included in the O&M estimates in Table 5-3. The O&M costs are total cost for 20 years (from 2020 to 2039) and are rounded to the nearest $1,000. Table 5-3 represents the O&M costs for the LSFO system only and does not include the balance-of-plant O&M costs.

**Table 5-3 LSFO Operation and Maintenance Costs**

| Category | Cost |
|---|---|
| O&M Schedule Outage | $28,732,000 |
| O&M – Base Non-Labor | $14,892,000 |
| 20 Year Total | $43,624,000 |

## 5.9 WATER/WASTEWATER TREATMENT/WASTEWATER RECYCLE

The cost estimates developed for this FGD technology includes the assumption that the LSFO process will produce a saleable gypsum product. The chloride content is limited in saleable gypsum, therefore a gypsum cake washing process is required. The estimate includes water treatment and wastewater treatment equipment sized and developed for this process only. The LSFO water and wastewater treatment equipment is not sized to handle or treat flow streams from or to support other parts of the project site.

## 5.10 RISKS

*The normal risks associated with procurement of equipment (domestic or internationally sourced), construction of equipment on a large power project, and operations of the plant once completed are not included in this section. Shut down of the AB Brown coal fired units prior to 20 years of operation will economically impact the selection of scrubber technology.*

There are a large number of LSFO systems operating in the United States which have a proven record of achieving the required emissions rates. The limestone reagent required for this system is readily available in the US. The gypsum byproduct will need to be landfilled if a buyer(s) for this material is not found or contracted with to take this material for recycling and re-use.

# 6.1 Wet Lime Inhibited Oxidation Scrubber (WLIO)

## 6.2 DESCRIPTION OF TECHNOLOGY

WLIO is one replacement technology with the capability to achieve the $SO_2$ removal required for A.B. Brown. The technology uses slaked lime in a spray tower scrubber to remove $SO_2$ from the flue gas producing.

### 6.1.1 Basic Process Description

Wet lime FGD is the generic term for processes using slaked lime as the scrubbing reagent in a spray tower FGD module. Wet lime processes are offered by a number of FGD suppliers. The reagent preparation system equipment is the only significant difference between the equipment used in the wet lime and wet limestone systems. However, the higher reactivity of the lime allows the equipment to be smaller than with a wet limestone scrubber.

Inhibited oxidation producing a calcium sulfite material is used or forced oxidation is used to promote formation of a fully oxidized gypsum byproduct. For this study, an inhibited oxidation process is assumed that produces a material for landfill disposal.

The primary difference in the wet lime and wet limestone processes is the preparation of scrubbing reagent slurry. In wet lime processes, CaO is slaked to produce a $Ca(OH)_2$ slurry.

$$CaO + H_2O \rightarrow Ca(OH)_2$$

For a wet lime FGD process, the chemical reactions are as follows:

$$SO_2 + Ca(OH)_2 \rightarrow CaSO_3 \bullet 1\ 1/2\ H_2O + 1/2\ H_2O$$
$$SO_2 + Ca(OH)_2 + 1/2\ O_2 + H_2O \rightarrow CaSO_4 \bullet 2\ H_2O$$

The reactivity of $Ca(OH)_2$ in the lime slurry is significantly greater than that of limestone. Since lime is typically manufactured by calcination of limestone, the cost of lime is significantly greater than that of limestone.

The lime slurry may be prepared in detention, paste, or ball mill slakers. An inventory of prepared slurry is stored in a slurry feed tank, ready for automatic injection into the FGD module's reaction tank as required to maintain the pH of the reaction tank slurry.

Spray towers for wet lime processes are essentially identical to those used in wet limestone FGD processes, except the absorber can be slightly shorter. Slurry from the FGD module reaction tank is sprayed into the flue gas flow stream; the $SO_2$ is absorbed from the flue gas by the lime slurry. The height of the tower and the liquid to gas ratio (L/G) may be lower than for limestone systems because of the reactivity of the lime slurry.

The solubility of $Ca(OH)_2$ in the slurry results in a pH in the reaction tank that is higher than in a wet limestone FGD process. The higher pH limits the natural oxidation of sulfites to sulfates to less than that achieved in a wet limestone process, but an oxidation inhibitor additive is required to keep oxidation levels low enough to prevent potential scaling issues.

### 6.1.2 Flow Diagram

The WLIO system utilizes pebble lime as the reagent, which is slaked producing a 20 percent solids slurry. The slaked lime slurry is fed into a spray tower absorber. The resulting calcium sulfite solids are removed and sent to thickeners and rotary drum filters for dewatering. The byproduct has a high moisture content and must be fixated with fly ash or Portland cement prior to disposal in the landfill. There is no market for the byproduct from a WLIO.

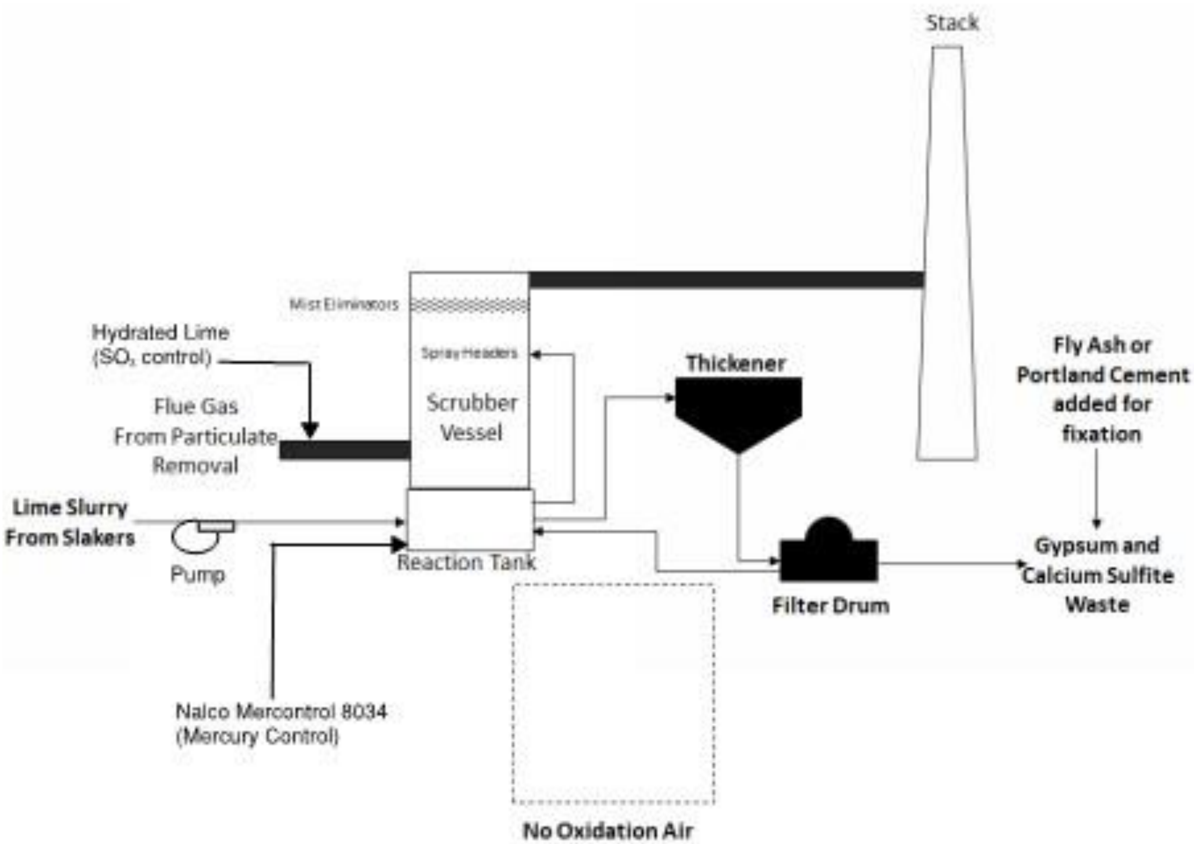



**Figure 6-1 Wet Lime Inhibited Oxidation Scrubber**

### 6.1.3 Environmental Controls

The existing particulate control systems (fabric filter on Unit 1 and electrostatic precipitator (ESP) on Unit 2) and ash collection systems remain in service with the fly ash continuing to be available for recycle.

The WLIO system will use the existing mercury control systems (Nalco Mercontrol 8034) for mercury control. Mercontrol 8034 chemical is injected into the scrubber lime slurry recirculation piping for mixing and dispersion. Mercury is captured in the scrubber slurry as it is circulated through the scrubber vessel.

Hydrated lime is pneumatically injected into the duct (DSI) upstream of the scrubber to control $SO_3$ emissions.

HCl is removed through a combination of hydrated lime injection and the WLIO scrubber system.

**Table 6-1 Environmental Controls WLIO**

| Pollutant | Hg | $SO_3$ | $SO_2$ | PM |
|---|---|---|---|---|
| Control Technologies | WLIO + Nalco Mercontrol 8034 | Hydrated Lime Injection | WLIO | Existing PM control: Unit 1 – Fabric Filter Unit 2 - ESP |

### 6.1.4 Reagent Type, Storage, and Preparation

Pebble lime is utilized as the reagent in a WLIO scrubber. The pebble lime would be shipped to the site by pneumatic truck or railcar and stored in silos. The silos would be designed to store 7 to 14 days of pebble lime on the basis of full load operation. The pebble lime would be fed into a slaker that mixes the pebble lime with water. The exothermic reaction produces a $Ca(OH)_2$ slurry containing about 20 percent solids, which is stored in an agitated slurry tank. Pumps are used to supply the slurry to the absorber based on the demand signal from the control system.

### 6.1.5 Byproduct Type, Storage, and Handling

The byproduct produced by the WLIO system is a combination of calcium sulfite and calcium sulfate. The high pH in the absorber system naturally inhibits oxidation so the resulting byproduct is mostly calcium sulfite. Dewatering of calcium sulfite is difficult so the resulting byproduct will contain 20 to 30 percent free moisture. The byproduct would be mixed with fly ash or Portland cement in a pug mill before being transported via truck to dispose of in a landfill.

### 6.1.6 Description of Basic Equipment in Process

The WLIO system includes the following basic equipment:

- Absorber Module, including spray headers, mist eliminators, and recirculation pumps.
- Reagent Preparation System, including fluidized storage system, feeders, lime slakers, slaked lime slurry storage tanks, and reagent feed pumps.
- Dewatering System, including thickeners and rotary drum filters.
- Byproduct Fixation System, including Portland cement silo and pug mill.

### 6.1.7 Description of Basic Sizing Criteria for Major Equipment

The major equipment was scaled from other projects based on the size of the units (MW), sulfur content of the fuel, and the amount of reagent required to meet the emissions targets.

## 6.2 ESTIMATING METHODOLOGY

Black & Veatch developed order of magnitude estimates for the feasible $SO_2$ control technologies. This section details the basis of these estimates, including scope and assumptions used in the estimate development.

### 6.2.1 Original Equipment Manufacturer Equipment

The capital cost estimate is based on previous EPC bids Black & Veatch received for another project. The costs were adjusted for the size of the units (on a MW basis) and differences in the fuel being burned. The cost was escalated using the Chemical Engineering Plant Cost Index factor to 2019 dollars. To allow for continued operation of the existing units, the location for new FGD equipment installation has been preliminarily selected to be due East of the existing Unit 1 fabric filter. Installation of a new concrete stack for Unit 1 is included in the estimate.

A cost of $18,650,000 was included for the demolition of the existing Unit 1 and Unit 2 scrubbers based on estimated costs for demolition of building and equipment at grade and costs obtained from similar projects for stack demolition. Demolition will occur in two stages to enable continued operation of the units during the construction periods for the new FGD equipment. Demolition includes removal of Unit 1 scrubber equipment, ducts, piping, electrical, and buildings to enable construction of Unit 2 scrubber equipment and reuse of Unit 1 stack for Unit 2 operation. Upon Unit 2 new FGD tie-in and operation, the Unit 2 existing scrubber equipment, ducts, piping, electrical, buildings, sludge handling equipment, and Unit 2 stack will be demolished and removed from the site.

### 6.2.2 Balance-of-Plant Equipment Needed to Make the Estimate Complete

The balance-of-plant modification costs were also based on the recent projects completed by Black & Veatch for WLIO system additions.

The project costs included the following modifications to the balance-of-plant equipment:

- Induced Draft (ID) Fan Upgrades.
- Auxiliary Electrical Equipment.
- Ductwork.
- Structural Steel.
- Foundations.
- Continuous Emissions Monitoring System (CEMS) System.
- Boiler Reinforcement.
- Service Water System.
- Service and Instrument Air Systems.
- Unit 1 Stack Demolition and New Stack Installation.

## 6.3 ESTIMATE ASSUMPTIONS

### 6.3.1 General Assumptions

- No costs associated with existing ash pond were considered.
- Existing soil will have sufficient strength to support the new basins and building.
- No costs were included for existing gravel road repair or new roads.

- A liner was assumed to be needed under the collection basin and settling basins. A liner was not assumed to be needed under new piping.
- No site leveling or raising were included in the estimate.
- The site has sufficient area available to accommodate construction activities including, but not limited to, construction offices (trailers), laydown, and staging.
- No provisions for future expansion of the new WWT equipment were included.
- Equipment sizing was based on two operating units.
- Costs associated with changes to the current FGD wastewater mercury treatment equipment, or any upstream piping or devices from either unit will be made for any options that will reuse the equipment, are included.
- Required instrumentation is included in cost of treatment system.
- Existing excavated dirt is assumed to be suitable for backfill material. No imported fill is included.

### 6.3.2 Direct Cost Assumptions

The following assumptions are included in the base construction cost estimate for direct costs:

- All costs are expressed in 2019 dollars. No escalation was included.
- Direct costs include the costs associated with the purchase of equipment, erection, and all contractor services.
- Construction costs are based on an EPC construction approach.
- Total capital costs are AACE Class 5 ±50 percent for concept screening, and include the costs associated with the purchase of equipment, erection, and all contractor services.
- Separate FGD absorber systems are provided for each unit with some common equipment for both units, including reagent preparation and byproduct handling.

### 6.3.3 Indirect Cost Assumptions

The following indirect costs are included in the base construction cost estimate:

- General indirect costs include all necessary services required for checkouts, testing services, and commissioning.
- Insurance, including builder's risk and general liability.
- Field construction management services, including field management staff, supporting staff personnel, field contract administration, field inspection/quality assurance, and project controls.
- Technical direction and management of startup and testing, cleanup expense for the portion not included in the direct-cost construction contracts, safety and medical services, guards and other security services, insurance premiums, performance bond and liability insurance for equipment and tools.
- Startup/commissioning spare parts.

- Construction contractor contingency costs.
- Construction contractor typical profit margin.
- Reagent usage rates provided for variable O&M component.

The following additional items of cost are not included in the construction estimate. These costs shall be determined by Vectren and included in Vectren's cost estimate:

- Owner's contingency costs.
- Federal, state, and local taxes.
- Major equipment spare parts.
- Land.
- Interest during construction.
- Cost and fees for electrical, gas, and other utility interconnections.
- Project development costs, legal, and community outreach.
- All operating plant vehicles.
- No permitting costs have been included.
- Emissions credits.
- Environmental mitigation.

## 6.4 PROJECT INDIRECT COSTS

The following project indirect costs are included in the capital cost estimate:

- Engineering.
- Construction and field expenses.
- Startup costs.
- Contingencies.
- Freight.
- Performance testing.

## 6.5 OWNER COSTS

The Owner's costs are not included in the capital cost estimate:

- Project development.
- Owner's operational personnel.
- Owner's project management.
- Owner's engineering.
- Owner's startup engineering and training.

- Legal fees.
- Permitting/licensing.
- Construction power, temporary utilities, startup consumables.
- Site security.
- Operating spare parts.
- O&M base non-labor cost for the plant as provided by Vectren.
- O&M base labor cost for the plant as provided by Vectren.
- Political concessions.
- AFUDC.

## 6.6 COST ESTIMATE EXCLUSIONS

In addition to the Owner's costs, the following costs were also excluded from the capital cost estimate:

- Escalation.
- Sales tax.
- Property tax.
- Salvage values.
- Utility demand costs.

## 6.7 PRESENTATION OF CAPITAL COSTS

The capital cost of the replacement WLIO system is summarized in Table 6-2. The direct cost includes the cost of the absorber, reagent preparation system, PAC system, electrical upgrades, ID fan upgrades, boiler reinforcement, silo and pug mill, Unit 1 chimney, and installation. The costs were based on recent projects completed by Black & Veatch.

**Table 6-2 WLIO Capital Costs**

| Category | Cost |
|---|---|
| Total Direct Cost | $318,079,000 |
| Indirect Cost | Included Above |
| Contingency | Included Above |
| EPC Fee | Included Above |
| **Total Project Cost** | **$318,079,000** |

## 6.8 OPERATIONS AND MAINTENANCE COSTS – PRESENT 20 YEAR TOTALS

The O&M costs start in 2024 assuming the WLIO system installation was completed in 2023. The O&M costs are in 2019 dollars and no escalation has been applied. Labor costs are not included in the estimates in Table 6-3. The O&M costs are total cost for 20 years from 2020 to 2039 and are rounded to the nearest $1,000. The O&M costs in Table 6-3 only represent the O&M costs for the WLIO system only and do not include the balance-of-plant O&M costs.

**Table 6-3 WLIO Operation and Maintenance Costs**

| Category | Cost |
|---|---|
| O&M Schedule Outage | $21,510,000 |
| O&M – Base Non-Labor | $11,159,000 |
| 20 Year Total | $32,659,000 |

## 6.9 WATER/WASTEWATER TREATMENT/WASTEWATER RECYCLE

Water and Wastewater treatment system costs for the WLIO system are negligible. Minor water and wastewater treatment system costs have been included with the balance of plant (BOP) costs for upgrade of those systems. Any water used or wastewater created by the WLIO would effectively be managed by mixing with the byproduct and fixating material (either fly ash or Portland Cement) at a pug mill on the discharge of the filter drum to mix these materials. The discharge waste material is then taken to a designated waste disposal area.

## 6.10 RISKS

*The normal risks associated with procurement of equipment (domestic or internationally sourced), construction of equipment on a large power project, and operations of the plant once completed are not included in this section. Shut down of the AB Brown coal fired units prior to 20 years of operation will economically impact the selection of scrubber technology.*

Below is a list of potential risks A.B. Brown may encounter when implementing WLIO technology:

- WLIO scrubbers have the potential to scale which would impact scrubber operation and performance.

# 7.1 Circulating Dry Scrubber (CDS)

## 7.2 DESCRIPTION OF TECHNOLOGY

The CDS FGD, also known as a circulating fluid bed scrubber, process is a semi-dry, lime-based FGD process that uses a circulating fluid bed contactor rather than an SDA. The CDS absorber module shown on Figure 7-1 is a vertical solid/gas reactor between the unit's air heater and its particulate control device. The CDS system consists of an absorber module, particulate control device (fabric filter or ESP), air slides, reagent storage silo, water storage tank, water inject lances, and water pumps. The reagent can be either hydrated lime or pebble lime. If pebble lime is utilized, an on-site hydrator is required to hydrate the pebble lime (CaO) to hydrated lime [$Ca(OH)_2$] prior to injection into the absorber module.

### 7.1.1 Basic Process Description

Water (humidification) is sprayed into the reactor to reduce the flue gas temperature to the optimum temperature for reaction of $SO_2$ with the reagent. Hydrated lime [$Ca(OH)_2$] and recirculated dry solids from the particulate control device are injected concurrently with the flue gas into the base of the reactor just above the water sprays. The gas velocity in the reactor is reduced, and a suspended bed of reagent and fly ash is developed. The $SO_2$, $SO_3$, and HCl in the flue gas reacts with the reagent to form predominantly $CaSO_3$ with some CaCl and $CaSO_4$. Fine particles of byproduct solids, excess reagent, and fly ash are carried out of the reactor and removed by the particulate removal device (either a fabric filter or dry ESP). More than 90 percent of these solids are returned to the reactor to improve reagent utilization and increase the surface area for $SO_2$/reagent contact.

The CDS FGD system produces an extremely high solids load on the particulate removal device as a result of recycling the byproduct/fly ash mixture. Air slides are used to recycle the large amounts of byproduct to the absorber. Air slides are capable of moving large amounts of solids with less energy consumption. The use of air slides require the particulate control device to be elevated to allow the material to flow down to the absorber vessel.

The byproducts from this process are similar to that produced in the lime SDA discussed previously. No dewatering is required, but the wastes must be wetted for control of fugitive dust emissions during transportation and for compaction at the landfill. When wetted, unreacted lime in the wastes should cause a fixation reaction, decreasing waste permeability and increasing unconfined compressive strength.

The process is controlled through three variables: $SO_2$ emissions, reactor exit temperature, and reactor differential pressure. $SO_2$ outlet concentration is monitored, and fresh hydrated lime reagent is introduced at the venturi as required to maintain the desired $SO_2$ removal efficiency. The reactor outlet temperature is maintained between 160° and 180° F, and an approach temperature of 35° to 40° F is maintained by controlling the quantity of water introduced at the venturi. The pressure drop across the reactor is regulated by the rate of return of recycled material to the reactor. One advantage of the CDS system over the SDA system is the addition of water and reagent is separate, allowing the system to inject more reagent to reach higher emissions removal.

These circulating fluid bed $SO_2$ absorber systems have been in operation in Europe since 1980. Since 1987, they have recorded an average of 97 percent $SO_2$ removal rate on a 100 MW lignite fueled plant. The technology has rapidly gained favor with many units as large as 250 to 300 MW on a single absorber. The largest unit operating overseas is 300 MW.

### 7.1.2 Process Flow Diagram

Figure 7-1 is a flow diagram of the CDS system. The CDS system shown below utilizes hydrated lime as it does not include a hydrator system to convert pebble lime to hydrated lime. The CDS system also includes a dedicated water supply system for the humidification of the flue gas, including a water tank and 2 x 100 percent pumps.

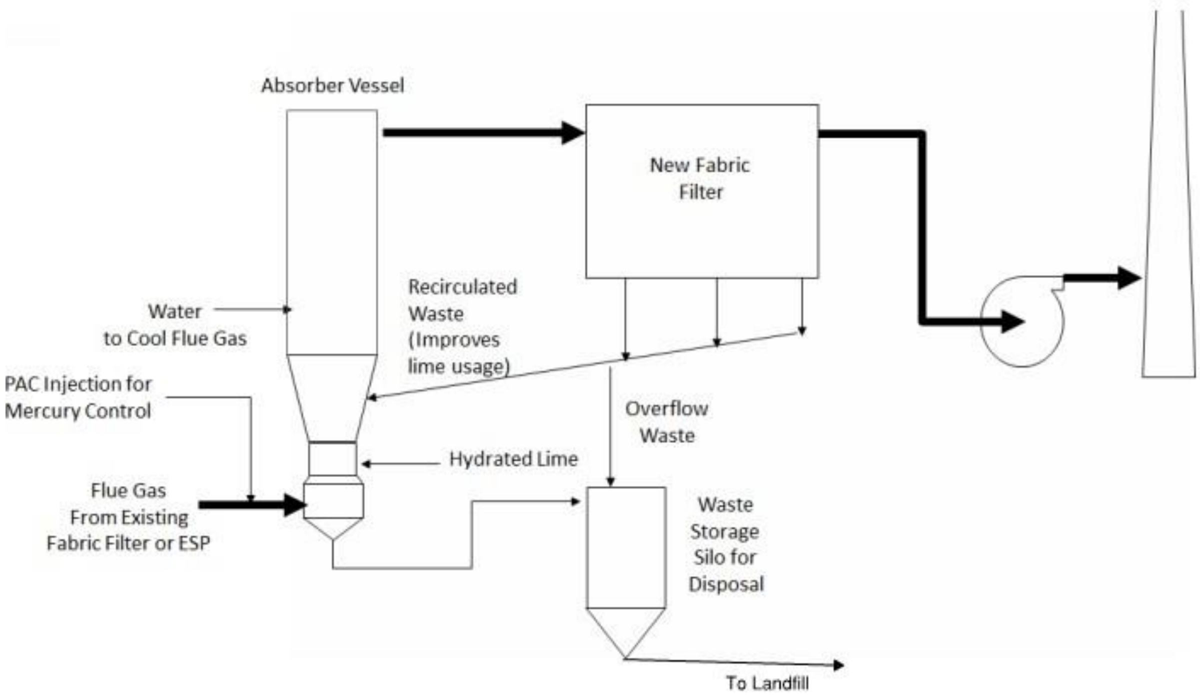



**Figure 7-1 Circulating Dry Scrubber**

### 7.1.3 Environmental Controls

The existing particulate control systems (fabric filter on Unit 1 and electrostatic precipitator (ESP) on Unit 2) and ash collection systems remain in service with the fly ash continuing to be available for recycle.

Powdered activated carbon (PAC) is injected upstream of the CDS vessel to control mercury emissions. The PAC material is circulated in the CDS absorber vessel and collects on the fabric filter media bags.

The hydrated lime reagent in the CDS system removes $SO_3$, HCl, as well as $SO_2$. The fabric filter located downstream of the CDS absorber vessel collects the hydrated lime and ash (including PAC) particulate and returns the majority of the particulate back to be recirculated in the CDS vessel. A portion of this collected particulate is taken and sent to the waste storage silo for safe disposal.

**Table 7-1 Environmental Controls CDS**

| Pollutant | Hg | $SO_3$ | $SO_2$ | PM |
|---|---|---|---|---|
| Control Technologies | Powdered Activated Carbon (PAC) Injection | CDS System | CDS System | Existing PM control:<br>Unit 1 – Fabric Filter<br>Unit 2 – ESP<br>Post CDS - Fabric Filter |

### 7.1.4 Reagent Type, Storage, and Preparation

CDS systems utilize either hydrated lime or pebble lime reagent. Hydrated lime is brought in with pneumatic trucks or railcars and pneumatically conveyed into storage silo(s), which typically have 7 to 14 days of storage.

Pebble lime can also be utilized as the reagent for the CDS. The pebble lime is pneumatically conveyed into a storage silo from a pneumatic truck or railcar. Pebble lime (CaO) must be reacted with water in a hydrator to produce hydrated lime [$Ca(OH)_2$]. The hydrator mixes a stoichiometric amount of water with the pebble lime to produce a hydrated lime product with less than 1 percent free moisture. The hydrated lime product is conveyed to the hydrated lime silo where it is stored for use in the CDS absorber.

### 7.1.5 Byproduct Type, Storage, and Handling

The hydrated lime reagent injected into the CDS module will react with acid gas, including $SO_2$, $SO_3$, and HCl. The resulting byproducts are mostly calcium sulfite ($CaSO_3$) with some calcium sulfate ($CaSO_4$) and calcium chloride (CaCl). The byproducts are mixed with fly ash and activated carbon for mercury removal.

The byproduct is pneumatically conveyed to the byproduct silo where it would be conditioned for dust control before being hauled to the landfill. The byproduct has limited reuse potential but can be used for soil stabilization. In most cases the byproduct is sent to a landfill.

### 7.1.6 Description of Basic Equipment in Process

The CDS system includes the following basic equipment:

- CDS Scrubber Module, including venturi.
- Humidification System, including water tank, pumps, valves, and water injection lances (3 to 4).
- Reagent System, including fluidized storage system, de-aeration bin, weigh belt feeder, rotary valves, and air slide.
- Particulate Collection System, including fabric filter.
- Byproduct Recirculation and Removal System, including air slides and dosing valves.

### 7.1.7 Description of Basic Sizing Criteria for Major Equipment

The major equipment was scaled from other projects based on the size of the units (MW), sulfur content of the fuel, and the amount of reagent required to meet the emissions targets.

## 7.2 ESTIMATING METHODOLOGY

Black & Veatch developed order of magnitude estimates for the feasible $SO_2$ control technologies. This section details the basis of these estimates, including scope and assumptions used in the estimate development.

### 7.2.1 Original Equipment Manufacturer Equipment Estimate

For the CDS System Black & Veatch used actual pricing from recent projects completed in the last 5 years. The project scope was evaluated and modified as needed to compare to the A.B. Brown requirements. The project costs were scaled based on unit size and sulfur removal. The costs were also escalated to 2019 dollars.

### 7.2.2 Balance-of-Plant Equipment Needed to Make the Estimate Complete

The balance-of-plant modification costs were also based on the recent projects completed by Black & Veatch for CDS system additions.

The project costs included modifications to the balance-of-plant equipment:

- ID Fan Upgrades.
- Auxiliary Electrical Equipment.
- Ductwork.
- Structural Steel.
- Foundations.
- CEMS System.
- PAC Injection System.
- Boiler Reinforcement.
- Service Water System.
- Service and Instrument Air Systems.

**PAC Injection**

Activated carbon (PAC) injection was added to the train to control mercury emissions. Hydrated lime is injected in the CDS module, which will control sulfuric acid ($SO_3$) emissions. Additional hydrated lime injection for $SO_3$ control would not be necessary. The PAC will be recirculated in the CDS system and coat the fabric filter bags, allowing for a significant residence time in the flue gas.

**ID Fan**

The existing ID fans do not have the capacity required for the new air quality control train. Due to the added pressure drop of the new fabric filter and CDS module, the ID fans on each unit will need to be replaced. For the purposes of this study, new ID fans have been included in the scope of work.

**Balance-of-Plant Modification**

The scope of work includes modifications to balance-of-plant equipment like distributed control system (DCS), electrical equipment, CEMS, foundations, service and instrument air systems, boiler reinforcement, ductwork, and structural steel, which would be required to support the addition of the new air quality control system.

## 7.3 ESTIMATE ASSUMPTIONS

### 7.3.1 General Assumptions

- No costs associated with existing ash pond were considered.
- Existing soil will have sufficient strength to support the new basins and building.
- No cost was included for existing gravel road repair or new roads.
- A liner was assumed to be needed under the collection basin and settling basins. A liner was not assumed to be needed under new piping.
- No site leveling or raising was included in the estimate.
- The site has sufficient area available to accommodate construction activities including, but not limited to, construction offices (trailers), laydown, and staging.
- No provisions for future expansion of the new WWT equipment were included.
- Equipment sizing was based on two operating units.
- Required instrumentation was included in the cost of the treatment system.
- Existing excavated dirt was assumed to be suitable for backfill material. No imported fill was included.

### 7.3.2 Direct Cost Assumptions

The following assumptions are included in the base construction cost estimate for direct costs:

- All costs are expressed in 2019 dollars. No escalation was included.
- Direct costs include the costs associated with the purchase of equipment, erection, and all contractor services.
- Construction costs were based on an EPC construction approach.
- Total capital costs are AACE Class 5 ±50 percent for concept screening, and include the costs associated with the purchase of equipment, erection, and all contractor services.
- Separate FGD absorber systems were provided for each unit with some common equipment for both units, including reagent preparation, and byproduct handling.

### 7.3.3 Indirect Cost Assumptions

The following indirect costs were included in the base construction cost estimate:

- General indirect costs for checkouts, testing services, and commissioning.
- Insurance, including builder's risk and general liability.
- Field construction management services including field management staff, supporting staff personnel, field contract administration, field inspection/quality assurance, and project controls.
- Technical direction and management of startup and testing, cleanup expense for the portion not included in the direct-cost construction contracts, safety and medical services, guards and other security services, insurance premiums, performance bond, and liability insurance for equipment and tools.
- Startup/commissioning spare parts.
- Construction contractor contingency costs.
- Construction contractor typical profit margin.
- Reagent usage rates provided for variable O&M component.

The following additional items of cost were not included in the construction estimate. These costs shall be determined by Vectren and included in Vectren's cost estimate:

- Owner's contingency costs.
- Federal, state, and local taxes.
- Major equipment spare parts.
- Land.
- Interest during construction.
- Cost and fees for electrical, gas, and other utility interconnections.
- Project development costs, legal, and community outreach.
- All operating plant vehicles.
- No permitting costs have been included.
- Emissions credits.
- Environmental mitigation.

## 7.4 PROJECT INDIRECT COSTS

The following project indirect costs are included in the capital cost estimate:

- Engineering.
- Construction and field expenses.
- Startup costs.

- Contingencies.
- Freight.
- Performance testing.

## 7.5 OWNER COSTS

The Owner's costs are not included in the capital cost estimate:

- Project development.
- Owner's operational personnel.
- Owner's project management.
- Owner's engineering.
- Owner's startup engineering and training.
- Legal fees.
- Permitting/licensing.
- Construction power, temporary utilities, startup consumables.
- Site security.
- Operating spare parts.
- O&M base non-labor cost for the plant as provided by Vectren.
- O&M base labor cost for the plant as provided by Vectren.
- Political concessions.
- AFUDC.

## 7.6 COST ESTIMATE EXCLUSIONS

In addition to the Owner's costs, the following costs were also excluded from the capital cost estimate:

- Escalation.
- Sales tax.
- Property tax.
- Salvage values.
- Utility demand costs.

## 7.7 PRESENTATION OF CAPITAL COSTS

The capital cost of the replacement CDS system is summarized in Table 7-2. The direct cost includes the cost of the absorber, fabric filter, PAC system, electrical upgrades, ID fan upgrades, boiler reinforcement, and installation. The costs were based on recent projects completed by Black & Veatch.

**Table 7-2 CDS Capital Costs**

| Category | Cost |
|---|---|
| Total Direct Cost | $269,550,000 |
| Indirect Cost | Included Above |
| Contingency | Included Above |
| EPC Fee | Included Above |
| **Total Project Cost** | **$269,550,000** |

## 7.8 OPERATIONS AND MAINTENANCE COSTS – PRESENT 20 YEAR TOTALS

The O&M costs start in 2024 assuming the CDS system installation was completed in 2023. The O&M costs are in 2019 dollars and no escalation has been applied; labor costs are not included in the estimates in Table 7-3. The O&M costs are total cost for 20 years (from 2020 to 2039) and are rounded to the nearest $1,000. Table 7-3 represents the O&M costs for the CDS system only and does not include the balance-of-plant O&M costs.

**Table 7-3 CDS Operations and Maintenance Costs**

| Category | Cost |
|---|---|
| O&M Schedule Outage | $18,228,000 |
| O&M – Base Non-Labor | $9,448,000 |
| 20 Year Total | $27,676,000 |

## 7.9 WATER/WASTEWATER TREATMENT/WASTEWATER RECYCLE

Water and Wastewater treatment system costs for the CDS system are negligible. Minor water and wastewater treatment system costs have been included with the balance of plant (BOP) costs for upgrade of those systems. Any water used or wastewater created by the CDS would effectively be used in the CDS as water to cool the flue gas and control flue gas temperature. Solids in the water/wastewater would be removed from the gas stream using the new fabric filter.

## 7.10 RISKS

*The normal risks associated with procurement of equipment (domestic or internationally sourced), construction of equipment on a large power project, and operations of the plant once completed are not included in this section. Shut down of the AB Brown coal fired units prior to 20 years of operation will economically impact the selection of scrubber technology.*

Below is a potential risk A.B. Brown may encounter when implementing CDS scrubber technology.

- Lime Consumption - Large quantities of hydrated lime are required to achieve the removal levels required for these units. The shipping logistics are significant and a delivery interruption could impact unit operation due to material availability to control emissions. The estimated lime consumption would require approximately one pneumatic truck load of pebble lime per hour.

# 8.1 Ammonia ($NH_3$) Scrubber

## 8.2 DESCRIPTION OF TECHNOLOGY

The ammonia ($NH_3$) scrubber technology uses a spray tower absorber with ammonia reagent to remove $SO_2$ from the flue gas. Ammonia combines with $SO_2$ to form ammonium sulfate. The ammonium sulfate is dewatered, crystalized, and dried to form a solid ammonium sulfate byproduct that can be used for fertilizer.

### 8.1.1 Basic Process Description

In the ammonia scrubber, anhydrous ammonia is used as the desulfurization absorbent to capture $SO_2$, and the byproduct of the process is a marketable fertilizer material. The only large FGD system of this type in the United States was installed at Dakota Gasification in North Dakota. At this facility, the ammonia solution contacts the flue gas in a spray tower type absorber similar to a wet limestone or lime system. The ammonia solution absorbs the $SO_2$ to form an ammonium sulfite solution. Air is fed into the absorber to oxidize the ammonium sulfite to an ammonium sulfate solution. The ammonium sulfate solution is concentrated and crystallized into a slurry, which is then transferred to an area where the ammonium sulfate is separated from the solution, and dried. The dried ammonium sulfate can be sold as fertilizer.

Currently one equipment supplier, based in China but with offices in the United States, has expressed interest in the A. B. Brown application. A second potential equipment supplier has indicated that it is currently focusing on industrial applications because of the uncertain operating status of many coal fired power plants. Jiangnan Environmental Technology, Inc. (JET), has completed ammonia scrubbers in China and other overseas countries but has no United States applications to date. The ammonia scrubber technology is similar to the United States application of ammonia scrubbing that currently is in operation in North Dakota; however, JET did not supply the unit in North Dakota.

Dakota Gasification Company's Great Plains Synfuels Plant is the only large U.S. based industrial plant with an ammonia scrubber installed. Emissions limits and the potential for a visible plume produced by the plant were addressed by the addition of a WESP. The plant also has ammonia discharge emissions limits. For the purpose of this study, a WESP has been included in the scope of work to mitigate emissions.

The quality of the ammonium sulfate byproduct produced or purity for the coal analysis specific to this site was not provided.

### 8.1.2 Flow Diagram

Figure 8-1 is a flow diagram of the ammonia scrubber. The typical ammonia scrubber uses anhydrous or aqueous ammonia reagent. The scrubber is a spray tower design using recycle pumps to inject the reagent into the flue gas. A bleed stream is removed from the reaction tank to be dewatered prior to drying the final ammonium sulfate byproduct.

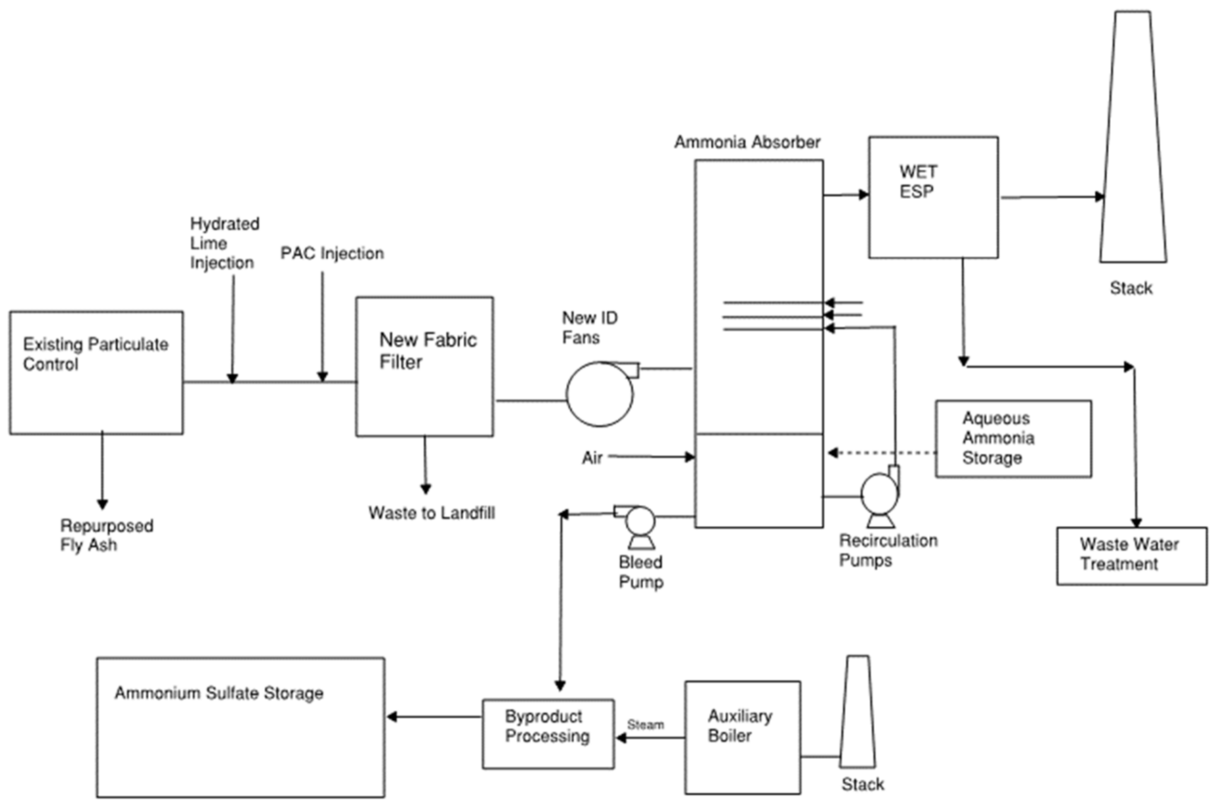



**Figure 8-1 Ammonia Scrubber**

### 8.1.3 Environmental Controls

The existing particulate control systems (fabric filter on Unit 1 and electrostatic precipitator (ESP) on Unit 2) and ash collection systems remain in service with the fly ash continuing to be available for recycle.

A dry sorbent injection system (DSI) system utilizing hydrated lime injection downstream of the existing particulate control system is used to control HCl and $SO_3$ emissions.

Powdered activated carbon (PAC) is injected downstream of the DSI injection to control mercury emissions. A new fabric filter is added to collect the particulate from the PAC and DSI injection. The collected solids from this fabric filter are sent as waste to the landfill.

A wet electrostatic precipitator (ESP) has been included to control ammonia slip and fine particulate emissions.

**Table 8-1 Environmental Controls $NH_3$**

| Pollutant | Hg | $SO_3$ | $SO_2$ | PM |
|---|---|---|---|---|
| Control Technologies | Powdered Activated Carbon (PAC) Injection | Hydrated Lime Injection | Ammonia FGD | Existing PM control:<br>Unit 1 – Fabric Filter<br>Unit 2 – ESP<br>Fabric Filters downstream of DSI and PAC injection<br>WESP downstream of $NH_3$ FGD |

### 8.1.4 Reagent Type, Storage, and Preparation

The reagent is either anhydrous ammonia or aqueous ammonia. Due to concerns regarding the safe storage and handling of anhydrous ammonia Vectren will need to complete a detailed analysis of the risks of storing large quantities of anhydrous ammonia onsite looking at the impact to surrounding communities and public safety.

For the purposes of this study aqueous ammonia was assumed to be utilized at A.B. Brown. The aqueous ammonia would be shipped to the site by a tanker truck or railcar and would be stored in large tanks. Vectren has requested 14 days of storage, which would require about 3,050,000 gallons of storage. The aqueous ammonia would be pumped into the reaction tank based on the demand signal from the process controls.

### 8.1.5 Byproduct Type, Storage, and Handling

The ammonia reagent combines with the $SO_2$ to form ammonium sulfate. The ammonium sulfate solution is pumped via a bleed stream from the recirculation tank. The ammonium sulfate must be dewatered and dried. Once the material is dry, the ammonium sulfate can be packaged and stored or bulk stored and shipped to a fertilizer wholesaler for further processing or blending. Ammonium sulfate is water soluble so it must be stored indoors. No information was provided regarding the purity of the ammonium sulfate, contaminants in the ammonium sulfate, particulate size distribution or whether the product was granular or powder. Processed ammonium sulfate can be sold as a fertilizer for agriculture if a market is available.

### 8.1.6 Description of Basic Equipment in Process

The ammonium scrubber systems can vary from each supplier, however, generally the equipment consists of a spray tower absorber module. Oxidation blowers to help oxidize the byproduct to sulfate. A recirculation tank at or near the bottom of the spray tower stores the recirculation mixture. Recirculation pumps supply the reagent mixture to the spray headers at the top of the absorber so that the reagent is sprayed and falls downward to maximize contact with the up-flow of exhaust gas. A bleed stream from the absorber feeds a small stream of the reagent mixture solution to a liquid and solids separation system.  The byproduct is then further concentrated and crystalized to the ammonium sulfate byproduct. A drying system using steam heat is then used to completely dry the ammonium sulfate crystals.

### 8.1.7 Description of Basic Sizing Criteria for Major Equipment

The auxiliary support equipment required for this technology was scaled from other projects based on the size required, steam heat requirements, and the amount of reagent required to be stored on site to meet the specified days of operation for the emissions targets established.

The ammonia scrubber is to be designed for an inlet SO2 concentration of 6.72 lb/MBtu. The ammonia system is designed to meet an outlet SO2 emission rate of 0.10 lb/MMBtu.

## 8.2 ESTIMATING METHODOLOGY

### 8.2.1 Original Equipment Manufacturer Equipment Estimate

Black & Veatch sent a request for quotation to Marsulex and JET. Marsulex declined to provide a bid; JET provided a budgetary quotation for the ammonia scrubber, including the scrubber modules, recirculation tank with pumps, oxidation air fans, ammonia storage, hydrocyclones, dryers, packing machine, and byproduct storage.

### 8.2.2 Balance-of-Plant Equipment Needed to Make the Estimate Complete

The balance-of-plant modification costs were estimated based on the requirements of the A.B. Brown plant and based on the recent projects completed by Black & Veatch.

The project costs included modifications to the balance-of-plant equipment:

- ID Fan Upgrades.
- Auxiliary Electrical Equipment.
- WESP.
- Auxiliary Boiler.
- Fabric Filters.
- Unit 1 Chimney.
- Ductwork.
- Structural Steel.
- Foundations.
- CEMS System.
- PAC Injection System.
- Boiler Reinforcement.
- Storage Building.
- DCS Upgrade.
- Service and Instrument Air Systems.

### Wet ESP

The Dakota Gasification Company's Great Plains Synfuels Plant is the only large industrial plant with an ammonia scrubber installed in the United States. Emissions limits and concerns for a visible plume produced by the plant were mitigated by the addition of a WESP. A.B. Brown has an ammonia discharge emissions limit to comply with. For the purpose of this study, a WESP has been included in the scope of work to ensure emissions compliance and to eliminate the potential for a visible plume.

### PAC Injection

Activated carbon (PAC) injection was added to the train to control mercury emissions. Hydrated lime will be injected upstream of the PAC injection to control sulfuric acid ($SO_3$) emissions. $SO_3$ impacts the mercury removal performance of the PAC and must be removed from the flue gas prior to the addition of the PAC. New fabric filters have been included to capture the hydrated lime and PAC particulate.

### Fabric Filters

To allow A.B. Brown to continue existing operations, a fabric filter has been added to capture the injected activated carbon and hydrated lime reagents. The fabric filter will be located downstream of the existing particulate control device and upstream of the new ammonia scrubber on each unit. For the purpose of this study, a fabric filter has been included in the scope of work to ensure emissions compliance.

### ID Fan

The existing ID fans do not have the capacity required for the new air quality control train. Due to the added pressure drop of the new fabric filter, ductwork modifications, and WESP, the ID fans on each unit will need to be replaced. For the purposes of this study, new ID fans have been included in the scope of work.

### Auxiliary Boiler

To produce a saleable ammonium sulfate byproduct the bleed stream from the scrubber must be concentrated and dewatered. The resulting dewatered solids must be dried to form a dry granular product suitable for bulk bagging or bulk loading of raw product. Equipment to dewater, dry, and either bag the byproduct or to bulk load equipment into truck or rail containers will be required. A source of steam heat is required to dry the byproduct in preparation for storage and transportation. For the purpose of this study, an auxiliary boiler has been sized and included in the scope of work to provide the required steam to the ammonium sulfate drying system. This will also maintain plant steam supply from the main boiler to the steam turbine to maximize unit output. In addition, Unit 1 and Unit 2 are currently not operated continuously and cannot be depended on to provide a continuous source of steam for heat to the ammonium sulfate drying system.

**Unit 1 Chimney**

In order to minimize outage time, the conceptual design layout developed would include installing the new air quality control system to the east of the existing air quality control system. A new stack would be built east of the new Unit 1 air quality control system. The existing Unit 1 scrubber system would be demolished, allowing for installation of the Unit 2 system. The new Unit 2 scrubber system would reuse the Unit 1 stack. The existing Unit 2 scrubber and Unit 2 stack would be demolished once the new Unit 2 scrubber system had been placed in service.

**Balance-of-Plant Modification**

The scope of work includes modifications and additions to balance-of-plant equipment, like DCS, electrical equipment, CEMS, foundations, service and instrument air systems, piping for water and wastewater systems, storage building, ductwork, and structural steel, which would be required to support the addition of the new air quality control system. Boiler, ductwork, and existing particulate collection equipment will require additional reinforcement to comply with National Fire Protection Association (NFPA) 85 recommendations.

## 8.3 ESTIMATE ASSUMPTIONS

### 8.3.1 General Assumptions

- No costs associated with existing ash pond were considered.
- Existing soil will have sufficient strength to support the new basins and building.
- No cost was included for existing gravel road repair.
- A liner was assumed to be needed under the collection basin and settling basins. A liner was not assumed to be needed under new piping.
- No site leveling or raising was included in the estimate.
- The site has sufficient area available to accommodate construction activities including, but not limited to, construction offices (trailers), laydown, and staging.
- No provisions for future expansion of the new WWT equipment were included.
- Equipment sizing was based on two operating units.
- Changes to the current FGD wastewater mercury treatment equipment or any upstream piping or devices from either unit will be made for any options that will reuse the equipment.
- WWT for the FGD system was provided for those FGD technologies requiring such.
- Required instrumentation was included in cost of treatment system.
- Existing excavated dirt was assumed to be suitable for backfill material. No imported fill was included.

### 8.3.2 Direct Cost Assumptions

The following assumptions are included in the base construction cost estimate for direct costs:

- All costs are expressed in 2019 dollars. No escalation is included.
- Direct costs include the costs associated with the purchase of equipment, erection, and all contractor services.
- Construction costs were based on an EPC construction approach utilizing union craft labor.
- Total capital costs are AACE Class 5 ±50 percent for concept screening, and include the costs associated with the purchase of equipment, erection, and all contractor services.
- Separate FGD absorber systems were provided for each unit with some common equipment for both units, including reagent preparation and byproduct handling.

### 8.3.3 Indirect Cost Assumptions

The following indirect costs are included in the base construction cost estimate:

- General indirect costs include all necessary services required for checkouts, testing services, and commissioning.
- Insurance, including builder's risk and general liability.
- Field construction management services including field management staff, supporting staff personnel, field contract administration, field inspection/quality assurance, and project controls.
- Technical direction and management of startup and testing, cleanup expense for the portion not included in the direct-cost construction contracts, safety and medical services, guards and other security services, insurance premiums, performance bond, and liability insurance for equipment and tools.
- Startup/commissioning spare parts.
- Construction contractor contingency costs.
- Construction contractor typical profit margin.
- Reagent usage rates provided for variable O&M component.

The following additional items of cost are not included in the construction estimate. These costs shall be determined by Vectren and included in Vectren's cost estimate:

- Owner's contingency costs.
- Federal, state, and local taxes except a 25 percent tariff has been placed on the equipment being exported from China.
- Major equipment spare parts.
- Land.
- Interest during construction.

- Cost and fees for electrical, gas, and other utility interconnections.
- Project development costs, legal, and community outreach.
- All operating plant vehicles.
- No permitting costs have been included.
- Emissions credits.
- Environmental mitigation.

## 8.4 PROJECT INDIRECT COSTS

The following project indirect costs are included in the capital cost estimate:

- Engineering.
- Construction and Field Expenses.
- Startup Costs.
- Contingencies.
- Freight.
- Performance Testing.

## 8.5 OWNER COSTS

The Owner's costs are not included in the capital cost estimate:

- Project development.
- Owner's operational personnel.
- Owner's project management.
- Owner's engineering.
- Owner's startup engineering and training.
- Legal fees.
- Permitting/licensing.
- Construction power, temporary utilities, startup consumables.
- Site security.
- Operating spare parts.
- O&M base non-labor cost for the plant as provided by Vectren.
- O&M base labor cost for the plant as provided by Vectren.
- Political concessions.
- AFUDC.

## 8.6 COST ESTIMATE EXCLUSIONS

In addition to the Owner's costs, the following costs were also excluded from the capital cost estimate:

- Escalation.
- Property tax.
- Salvage values.
- Utility demand costs.

## 8.7 PRESENTATION OF CAPITAL COSTS

The capital cost of the replacement CDS system is summarized in Table 8-2. The direct cost includes the cost of the absorber, ammonia storage, byproduct production, storage and bagging, fabric filters, PAC systems, electrical upgrades, Unit 1 chimney, boiler reinforcement, auxiliary boiler, and installation. The costs were based on recent projects completed by Black & Veatch.

**Table 8-2 Ammonia ($NH_3$) Capital Costs**

| Category | Cost |
|---|---|
| Total Direct Cost | $284,835,000 |
| Indirect Cost | Included Above |
| Contingency | Included Above |
| EPC Fee | Included Above |
| **Total Project Cost** | **$284,835,000** |

## 8.8 OPERATIONS AND MAINTENANCE COSTS – PRESENT 20 YEAR TOTALS

The O&M costs start in 2024 assuming the $NH_3$ scrubber system installation was completed in 2023. The O&M costs are in 2019 dollars and no escalation has been applied. Labor costs are not included in the estimates in Table 8-3. The O&M costs are total cost for 20 years (from 2020 to 2039) and are rounded to the nearest $1,000. Table 8-3 represents the O&M costs for the $NH_3$ scrubber system only and does not include the balance-of-plant O&M costs.

**Table 8-3 Ammonia ($NH_3$) Operation and Maintenance Costs**

| Category | Cost |
|---|---|
| O&M Schedule Outage | $19,262,000 |
| O&M – Base Non-Labor | $9,983,000 |
| 20 Year Total | $29,245,000 |

## 8.9 WATER/WASTEWATER TREATMENT/WASTEWATER RECYCLE

Water treatment system costs for the NH3 scrubber system are negligible. Waste water treatment system costs have been included with the NH3 scrubber for treatment of waste water from the wet ESP equipment. Waste water produced from the wet ESP equipment process and intermittent floor drains from equipment washdown is expected. Drains from the cooling water system are considered intermittent and do not result in a continuous flow stream. Use of aqueous ammonia as the reagent will reduce the overall process water requirements, however, the overall water volume decrease has not been confirmed by the manufacturer.

## 8.10 RISKS

*The normal risks associated with procurement of equipment (domestic or internationally sourced), construction of equipment on a large power project, and operations of the plant once completed are not included in this section. Shut down of the AB Brown coal fired units prior to 20 years of operation will economically impact the selection of scrubber technology.*

Below is a list of potential risks A.B. Brown may encounter when implementing ammonia scrubber technology.

- Limited experience is found in the United States as there is only one Ammonia Scrubber System installation in the US which is on an industrial gasification plant in North Dakota that is similar to the scale proposed at AB Brown.
- The supplier providing a proposal for this equipment has not installed any equipment in the United States. This would also appear to be the first project that the supplier would perform work as an EPC Contractor on a construction project in the U.S. The supplier has proposed using U.S. craft labor with Chinese supervision on this project.
- Vectren is a power producer that is dispatched on an irregular basis. The amount of ammonium sulfate that would be produced will vary based on the load they are dispatched at. It will be difficult to enter into a contract to sell the ammonium sulfate when there is no guarantee of the amount of material that can be produced. In the event of a long-term outage, Vectren could be responsible and penalized for not providing the ammonium sulfate material as contracted to a manufacturer or distributor.
- The ammonium sulfate byproduct sales are primarily based on seasonal material usage. This will either require the ability to store a large volume on site or pay to store material at a fertilizer manufacturer's or distributor's facility when the demand for ammonium sulfate is low.
- The seasonal sale price of ammonium sulfate significantly impacts the economics of a power plant needing to operate year-round.
- Ammonium sulfate shipping and handling costs can limit the distribution area.
- Transportation required to remove the ammonium sulfate from the site requires loading of approximately 1.5 transport trucks per hour.
- There are limited disposal options if the ammonium sulfate byproduct cannot be sold (no demand) or is found to be out of specification quality required by the purchaser. Ammonium sulfate is water soluble and will necessitate extensive requirements to stabilize the material and enable it to be landfilled.

- Storage of large quantities of liquid anhydrous ammonia is a safety risk to personnel on the site and to the city of Evansville, Indiana. Vectren can mitigate this by the use of a 19% aqueous ammonia as the reagent, however, the trucks required for transportation and storage volume increase by approximately a factor of five. This requires delivery and unloading of more than two transport trucks of 19 percent aqueous ammonia per hour.
- There is a high variability of anhydrous ammonia and aqueous ammonia supply cost.
- No information was provided regarding the purity of the ammonium sulfate, contaminants in the ammonium sulfate, particulate size distribution or whether the product was granular or powder.
- The ammonium sulfate may require additional processing by a fertilizer manufacturer's or distributor's facility to meet the quality needed for a saleable material to the public or farming community. This would impact sale price received for this material.
- An auxiliary boiler is needed to provide steam for heating to be available on a 24/7 basis for the ammonium sulfate drying process. The emissions from the auxiliary boiler combined with emissions from the ammonia scrubber and ammonium sulfate dryer equipment may require Vectren to perform a PSD analysis.

# Appendix A. 20 Year Capital and O&M Cost Inputs to the IRP

| Ammonia Scrubber (NH3 FGD) | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 | 2036 | 2037 | 2038 | 2039 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| O&M - Labor | | | | | | | | | | | | | | | | | | | | |
| O&M - Scheduled Outage | $ - | $ - | $ - | $ - | $ - | $ - | $ 1,481,658 | $ 1,481,658 | $ - | $ 1,481,658 | $ - | $ 2,963,316 | $ - | $ 2,963,316 | $ 1,481,658 | $ - | $ 2,963,316 | $ 1,481,658 | $ - | $ 2,963,316 |
| O&M - Base Non-Labor | $ - | $ - | $ - | $ - | $ 246,943 | $ 246,943 | $ 634,996 | $ 634,996 | $ 246,943 | $ 634,996 | $ 246,943 | $ 1,269,992 | $ 246,943 | $ 1,269,992 | $ 634,996 | $ 246,943 | $ 1,269,992 | $ 634,996 | $ 246,943 | $ 1,269,992 |
| Total O&M Costs | $ - | $ - | $ - | $ - | $ 246,943 | $ 246,943 | $ 2,116,654 | $ 2,116,654 | $ 246,943 | $ 2,116,654 | $ 246,943 | $ 4,233,308 | $ 246,943 | $ 4,233,308 | $ 2,116,654 | $ 246,943 | $ 4,233,308 | $ 2,116,654 | $ 246,943 | $ 4,233,308 |
| | | | | | | | | | | | | | | | | | | | | |
| Capital - Direct Unit | | | | | $ 458,608 | $ 458,608 | $ 2,116,654 | $ 2,116,654 | $ 458,608 | $ 2,116,654 | $ 458,608 | $ 4,233,308 | $ 458,608 | $ 4,233,308 | $ 2,116,654 | $ 458,608 | $ 4,233,308 | $ 2,116,654 | $ 458,608 | $ 4,233,308 |
| Capital - Construction | $ 79,223,650 | $ 68,296,250 | $ 81,955,500 | $ 43,709,600 | $ 11,650,000 | | | | | | | | | | | | | | | |
| Total Capital Costs | $ 79,223,650 | $ 68,296,250 | $ 81,955,500 | $ 43,709,600 | $ 12,108,608 | $ 458,608 | $ 2,116,654 | $ 2,116,654 | $ 458,608 | $ 2,116,654 | $ 458,608 | $ 4,233,308 | $ 458,608 | $ 4,233,308 | $ 2,116,654 | $ 458,608 | $ 4,233,308 | $ 2,116,654 | $ 458,608 | $ 4,233,308 |
| | | | | | | | | | | | | | | | | | | | | |
| 20 Yr Total | $ 79,223,650 | $ 68,296,250 | $ 81,955,500 | $ 43,709,600 | $ 12,355,551 | $ 705,551 | $ 4,233,308 | $ 4,233,308 | $ 705,551 | $ 4,233,308 | $ 705,551 | $ 8,466,616 | $ 705,551 | $ 8,466,616 | $ 4,233,308 | $ 705,551 | $ 8,466,616 | $ 4,233,308 | $ 705,551 | $ 8,466,616 |

| Limestone Forced Oxidation (LSFO) | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 | 2036 | 2037 | 2038 | 2039 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| O&M - Labor | | | | | | | | | | | | | | | | | | | | |
| O&M - Scheduled Outage | | | | | | | $2,210,135 | $2,210,135 | | $2,210,135 | | $4,420,270 | | $4,420,270 | $2,210,135 | | $4,420,270 | $2,210,135 | | $4,420,270 |
| O&M - Base Non-Labor | | | | | $368,356 | $368,356 | $947,201 | $947,201 | $368,356 | $947,201 | $368,356 | $1,894,402 | $368,356 | $1,894,402 | $947,201 | $368,356 | $1,894,402 | $947,201 | $368,356 | $1,894,402 |
| Total O&M Costs | $0 | $0 | $0 | $0 | $368,356 | $368,356 | $3,157,336 | $3,157,336 | $368,356 | $3,157,336 | $368,356 | $6,314,672 | $368,356 | $6,314,672 | $3,157,336 | $368,356 | $6,314,672 | $3,157,336 | $368,356 | $6,314,672 |
| | | | | | | | | | | | | | | | | | | | | |
| Capital - Direct Unit | | | | | $684,089 | $684,089 | $3,157,336 | $3,157,336 | $684,089 | $3,157,336 | $684,089 | $6,314,672 | $684,089 | $6,314,672 | $3,157,336 | $684,089 | $6,314,672 | $3,157,336 | $684,089 | $6,314,672 |
| Capital - Construction | $42,487,800 | $84,975,600 | $169,951,200 | $127,463,400 | | | | | | | | | | | | | | | | |
| Total Capital Costs | $42,487,800 | $84,975,600 | $169,951,200 | $127,463,400 | $684,089 | $684,089 | $3,157,336 | $3,157,336 | $684,089 | $3,157,336 | $684,089 | $6,314,672 | $684,089 | $6,314,672 | $3,157,336 | $684,089 | $6,314,672 | $3,157,336 | $684,089 | $6,314,672 |
| | | | | | | | | | | | | | | | | | | | | |
| 20 Yr Total | $42,487,800 | $84,975,600 | $169,951,200 | $127,463,400 | $1,052,445 | $1,052,445 | $6,314,672 | $6,314,672 | $1,052,445 | $6,314,672 | $1,052,445 | $12,629,344 | $1,052,445 | $12,629,344 | $6,314,672 | $1,052,445 | $12,629,344 | $6,314,672 | $1,052,445 | $12,629,344 |

| Wet Lime Inhibited Oxidation (WLIO FGD) | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 | 2036 | 2037 | 2038 | 2039 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| O&M - Labor | | | | | | | | | | | | | | | | | | | | |
| O&M - Scheduled Outage | $ - | $ - | $ - | $ - | $ - | $ - | $ 1,654,587 | $ 1,654,587 | $ - | $ 1,654,587 | $ - | $ 3,309,174 | $ - | $ 3,309,174 | $ 1,654,587 | $ - | $ 3,309,174 | $ 1,654,587 | $ - | $ 3,309,174 |
| O&M - Base Non-Labor | $ - | $ - | $ - | $ - | $ 275,764 | $ 275,764 | $ 709,109 | $ 709,109 | $ 275,764 | $ 709,109 | $ 275,764 | $ 1,418,217 | $ 275,764 | $ 1,418,217 | $ 709,109 | $ 275,764 | $ 1,418,217 | $ 709,109 | $ 275,764 | $ 1,418,217 |
| Total O&M Costs | $ - | $ - | $ - | $ - | $ 275,764 | $ 275,764 | $ 2,363,696 | $ 2,363,696 | $ 275,764 | $ 2,363,696 | $ 275,764 | $ 4,727,391 | $ 275,764 | $ 4,727,391 | $ 2,363,696 | $ 275,764 | $ 4,727,391 | $ 2,363,696 | $ 275,764 | $ 4,727,391 |
| | | | | | | | | | | | | | | | | | | | | |
| Capital - Direct Unit | | | | | $ 512,134 | $ 512,134 | $ 2,363,696 | $ 2,363,696 | $ 512,134 | $ 2,363,696 | $ 512,134 | $ 4,727,391 | $ 512,134 | $ 4,727,391 | $ 2,363,696 | $ 512,134 | $ 4,727,391 | $ 2,363,696 | $ 512,134 | $ 4,727,391 |
| Capital - Construction | $ 44,892,339 | $ 74,820,585 | $ 108,832,641 | $ 77,883,435 | $ 11,650,000 | | | | | | | | | | | | | | | |
| Total Capital Costs | $ 44,892,339 | $ 74,820,585 | $ 108,832,641 | $ 77,883,435 | $ 12,162,134 | $ 512,134 | $ 2,363,696 | $ 2,363,696 | $ 512,134 | $ 2,363,696 | $ 512,134 | $ 4,727,391 | $ 512,134 | $ 4,727,391 | $ 2,363,696 | $ 512,134 | $ 4,727,391 | $ 2,363,696 | $ 512,134 | $ 4,727,391 |
| | | | | | | | | | | | | | | | | | | | | |
| 20 Yr Total | $ 44,892,339 | $ 74,820,585 | $ 108,832,641 | $ 77,883,435 | $ 12,437,899 | $ 787,899 | $ 4,727,391 | $ 4,727,391 | $ 787,899 | $ 4,727,391 | $ 787,899 | $ 9,454,782 | $ 787,899 | $ 9,454,782 | $ 4,727,391 | $ 787,899 | $ 9,454,782 | $ 4,727,391 | $ 787,899 | $ 9,454,782 |

| Circulating Dry Scrubber (CDS FGD) | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 | 2036 | 2037 | 2038 | 2039 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| O&M - Labor | | | | | | | | | | | | | | | | | | | | |
| O&M - Scheduled Outage | $ - | $ - | $ - | $ - | $ - | $ - | $ 1,402,148 | $ 1,402,148 | $ - | $ 1,402,148 | $ - | $ 2,804,296 | $ - | $ 2,804,296 | $ 1,402,148 | $ - | $ 2,804,296 | $ 1,402,148 | $ - | $ 2,804,296 |
| O&M - Base Non-Labor | $ - | $ - | $ - | $ - | $ 233,691 | $ 233,691 | $ 600,921 | $ 600,921 | $ 233,691 | $ 600,921 | $ 233,691 | $ 1,201,841 | $ 233,691 | $ 1,201,841 | $ 600,921 | $ 233,691 | $ 1,201,841 | $ 600,921 | $ 233,691 | $ 1,201,841 |
| Total O&M Costs | $ - | $ - | $ - | $ - | $ 233,691 | $ 233,691 | $ 2,003,069 | $ 2,003,069 | $ 233,691 | $ 2,003,069 | $ 233,691 | $ 4,006,138 | $ 233,691 | $ 4,006,138 | $ 2,003,069 | $ 233,691 | $ 4,006,138 | $ 2,003,069 | $ 233,691 | $ 4,006,138 |
| | | | | | | | | | | | | | | | | | | | | |
| Capital - Direct Unit | | | | | $ 433,998 | $ 433,998 | $ 2,003,069 | $ 2,003,069 | $ 433,998 | $ 2,003,069 | $ 433,998 | $ 4,006,138 | $ 433,998 | $ 4,006,138 | $ 2,003,069 | $ 433,998 | $ 4,006,138 | $ 2,003,069 | $ 433,998 | $ 4,006,138 |
| Capital - Construction | $ 63,967,324 | $ 70,059,438 | $ 77,166,904 | $ 46,706,335 | $ 11,650,000 | | | | | | | | | | | | | | | |
| Total Capital Costs | $ 63,967,324 | $ 70,059,438 | $ 77,166,904 | $ 46,706,335 | $ 12,083,998 | $ 433,998 | $ 2,003,069 | $ 2,003,069 | $ 433,998 | $ 2,003,069 | $ 433,998 | $ 4,006,138 | $ 433,998 | $ 4,006,138 | $ 2,003,069 | $ 433,998 | $ 4,006,138 | $ 2,003,069 | $ 433,998 | $ 4,006,138 |
| | | | | | | | | | | | | | | | | | | | | |
| 20 Yr Total | $ 63,967,324 | $ 70,059,438 | $ 77,166,904 | $ 46,706,335 | $ 12,317,690 | $ 667,690 | $ 4,006,138 | $ 4,006,138 | $ 667,690 | $ 4,006,138 | $ 667,690 | $ 8,012,275 | $ 667,690 | $ 8,012,275 | $ 4,006,138 | $ 667,690 | $ 8,012,275 | $ 4,006,138 | $ 667,690 | $ 8,012,275 |

# Appendix B. Limestone Based Wet FGD – Burns & McDonnell

# A.B. Brown Wet Limestone Forced Oxidation FGD Cost Estimate

A CenterPoint Energy Company

**Vectren Energy Delivery**

**Vectren A.B. Brown Wet Limestone Forced Oxidation FGD Cost Estimate**
**Project No. 116946**

**Revision 0**
**3/5/2020**

# A.B. Brown Wet Limestone Forced Oxidation FGD Cost Estimate

prepared for

**Vectren Energy Delivery**
**Vectren A.B. Brown Wet Limestone Forced Oxidation FGD Cost Estimate**
**Evansville, IN**

**Project No. 116946**

**Revision 0**
**3/5/2020**

prepared by

**Burns & McDonnell Engineering Company, Inc.**
**Kansas City, MO**

# TABLE OF CONTENTS

**Page No.**

LIST OF TABLES

**Page No.**

# LIST OF ABBREVIATIONS

| Abbreviation | Term/Phrase/Name |
|---|---|
| ABB | A.B. Brown Generating Station |
| AFUDC | Allowance for funds used during construction |
| BACT | Best Available Control Technology |
| BMcD | Burns & McDonnell Engineering Company, Inc. |
| BOP | Balance of plant |
| FGD | Flue gas desulfurization |
| IRP | Integrated Resource Plan |
| LSFO | Limestone forced-oxidation |
| NAAQS | National Ambient Air Quality Standards |
| O&M | Operation and maintenance |
| PFD | Process flow diagram |
| PM | Particulate matter |
| PSD | Prevention of Significant Deterioration |
| SBS | Sodium bisulfite |
| SCR | Selective catalytic reduction |
| SER | Significant Emission Rate |
| tpy | Tons per year |
| WLSFO | Wet Limestone Forced Oxidation |

# 1.0 EXECUTIVE SUMMARY

Vectren has retained Burns & McDonnell Engineering Company, Inc. (BMcD) to evaluate retrofitting new wet limestone forced oxidation (WLSFO) flue gas desulfurization (FGD) system scrubbers for the two coal units at the A.B. Brown Generating Station (ABB). BMcD was tasked with developing a screening level estimate of the cost to replace the existing scrubbers with new scrubbers that meet current emissions regulations and allow for potential new more restrictive emission limits. This sectional report (the "Report") has been prepared to present results and assumptions of the scrubber replacement cost estimate, as well as a high-level assessment of the environmental permitting impacts of replacing the existing scrubbers.

In 2019, Vectren has retained BMcD to provide an all-inclusive cost estimate in 2019 dollars including all ancillary equipment required for a retrofit of this type.

## 1.1 Replacement Cost Estimate

The FGD technology evaluated by BMcD as a potential replacement for the existing FGD system at A.B. Brown is the wet limestone, forced-oxidation (LSFO) technology. This technology uses limestone ($CaCO_3$) to remove sulfur dioxide ($SO_2$) from the flue gas. In the process, excess oxidation air is added to the absorber reaction tank to create a gypsum ($CaSO_4 \bullet 2H_2O$) byproduct.

The wet LSFO technology is an FGD technology that is commonly used to achieve high $SO_2$ removal rates on coal-fired boilers burning high-sulfur coal. It is available from several suppliers and has a long track record of high $SO_2$ removal rates. The LSFO technology is also reliable with low frequency of outages caused by the scrubber system.

Budgetary quotes for a new wet LSFO FGD system were received in 2017 from seven FGD system suppliers: Amec Foster Wheeler, Andritz, Babcock & Wilcox, Babcock Power, GE Power, Marsulex and Mitsubishi Hitachi were escalated to 2019 dollars, averaged and included in the overall capital cost estimate.

The capital cost estimate for the replacement FGD system is summarized in Table 1-1. The total direct cost listed includes the absorber, limestone preparation equipment, and gypsum dewatering equipment included in the budgetary quotations received from various FGD system suppliers. BMcD developed an estimate of the balance of plant (BOP) costs based on costs from past projects.

**Table 1-1: Capital Cost Estimate Summary (2019 Dollars)**

| Area | Cost |
|---|---|
| Total Direct Cost | $263,808,600 |
| Indirect Cost | $67,095,900 |
| Contingency | $66,178,000 |
| EPC Fee | $27,795,500 |
| Total Project Cost | $424,878,000 |

A high-level environmental evaluation was conducted to determine the potential air permitting requirements applicable to a scrubber replacement project. An important air permitting issue for this scrubber replacement project will be the potential for Prevention of Significant Deterioration (PSD) review. If PSD is triggered for any pollutant, then a Best Available Control Technology (BACT) analysis is required for all new project sources for pollutants that are subject to PSD. In addition, air dispersion modeling is required for PSD pollutants to show compliance with the National Ambient Air Quality Standards (NAAQS) and PSD Increments (Class I and Class II). Based on the preliminary emissions analyses for the scrubber replacement project, a minor source (state) air permit may be required to permit the new installation of the new emission sources required for the wet scrubbers. It is unlikely that a major PSD air permit would be required, therefore no BACT analysis or air dispersion modeling is required by federal requirements. A good assumption for the timeframe to obtain a state air construction permit for the project would be approximately 6 to 9 months.

## 1.2 Limitations and Qualifications

Estimates and projections prepared by BMcD relating to performance, construction costs, and operating and maintenance costs are based on experience, qualifications, and judgment as a professional consultant. BMcD has no control over weather, cost and availability of labor, material and equipment, labor productivity, construction contractor's procedures and methods, unavoidable delays, construction contractor's method of determining prices, economic conditions, government regulations and laws (including interpretation thereof), competitive bidding and market conditions or other factors affecting such estimates or projections. Actual rates, costs, performance, schedules, etc., may vary from the data provided.

# 2.0 INTRODUCTION

## 2.1 Background

The A. B. Brown Generating Station is a four-unit, 650 MW power generating facility located on the northern bank of the Ohio river in Posey County, Indiana, 5 miles southwest of Evansville. Units 1 and 2 are coal-fired each with a nominal capacity of 265 MW, while Units 3 and 4 are gas turbines. Bituminous coal with dry sulfur content around 3.5% is used as the primary fuel for Units 1 and 2. In 1979, Unit 1 initiated operation with a FGD scrubber to help reduce sulfur dioxide emissions. In 1986 Unit 2 was completed also with a FGD scrubber, both of which scrubbers are still in operation. From 2001 to 2005, Vectren installed selective catalytic reduction (SCR) devices on four of the five coal-fired units, to reduce nitrogen oxide emissions. In 2004, Vectren replaced an existing electrostatic precipitator at Unit 1 with a fabric filter. Sodium bisulfite (SBS) solution injection before the SCR was added in 2014 to remove $SO_3$ and enhance mercury removal.

Vectren retained Burns & McDonnell to develop a screening level FEP-1 (±50%) estimate of the cost to replace the existing scrubbers with new WLSFO scrubbers that meet current emissions regulations. For the new scrubbers, Burns & McDonnell performed a high level assessment of the potential environmental permitting impacts of the replacement.

# 3.0 REPLACEMENT COST ESTIMATE

## 3.1 Replacement Selection

BMcD and Vectren agreed that BMcD would estimate the wet LSFO technology as a potential replacement for the current FGD system at A.B. Brown. The wet LSFO technology uses limestone ($CaCO_3$) to remove sulfur dioxide ($SO_2$) from the flue gas. In the process, excess oxidation air is added to the absorber reaction tank to create a gypsum ($CaSO_4 \bullet 2H_2O$) byproduct.

The wet LSFO technology is available from several suppliers and has a long track record of high $SO_2$ removal rates on coal fired boilers burning high-sulfur coal. The LSFO technology is also reliable with low frequency of outages caused by the scrubber system. The gypsum is a byproduct that can be dewatered relatively easily, so it can be handled and disposed of in a dry state. The wet technology also has the benefit of removing mercury in the oxidized form, especially for boilers firing bituminous coal that use selective catalytic reduction (SCR) systems.

It is BMcD's understanding that Vectren is evaluating differences between wet LSFO and other scrubber technologies by conducting similar cost estimate efforts with others on alternative technologies.

## 3.2 Description of Replacement

The wet LSFO technology evaluated in this study consists of two absorber towers (one per unit). This study assumes that a single limestone preparation system and single gypsum dewatering system would be shared by both units. In order to minimize unit outage time, this evaluation assumes that the new absorber for Unit 1 would be built to the north of the unit. A new stack would be constructed for Unit 1. The Unit 1 thickener would be demolished, and the new absorber for Unit 2 would be built in that location. The outlet from the new Unit 2 absorber would then tie into the original Unit 1 stack. A general arrangement drawing of the new absorber layout has been provided in Appendix C.

In order to minimize the amount of absorber bleed, the Unit 1 and 2 absorbers are assumed to be constructed of flake-glass lined carbon steel or Stebbins tile lined, either of which can handle high chloride levels (up to 50,000 mg/L). The quotes originally received for the FGD equipment in 2017 varied on materials of construction with both flake-glass lined carbon steel and Stebbins tile proposed. Both materials are commonly used in FGD retrofit projects, though BMcD understands that Vectren has had issues with flake-glass lining systems failure in the past. Pricing varied as well with neither coating being a clearly higher cost choice; as such the cost estimate provided will accommodate either material choice.

The absorber inlet (interface of wet and dry flue gas) and outlet ducts would be constructed of C276 (Hastelloy) as this environment is very corrosive. Each absorber would include the following:

- Slurry recycle pumps, piping and spray headers
- Mist eliminators and a mist eliminator wash water tank and associated pumps
- Absorber bleed pumps
- Oxidation air blowers and injection lances
- Process water tank
- Piping, valves and instrumentation

The limestone storage and handling system to be shared by the new Unit 1 and 2 FGD systems would consist of a truck unloading system, a limestone bulk storage pile, a reclaim conveyor, and two limestone day bins with weigh feeders. The shared limestone preparation system would consist of two ball mills, a mill product tank, mill product pumps, a ball mill slurry classifier, a limestone slurry storage tank, and limestone feed pumps. A limestone pile canopy is included in the estimate. The canopy will allow for up to 7 days of covered limestone storage.

Each unit would have a dedicated primary dewatering system consisting of a hydroclone, hydroclone underflow tank, and hydroclone underflow pumps. The secondary gypsum dewatering system to be shared by the new Unit 1 and 2 FGD systems would consist of a vacuum filter feed tank, filter feed pumps, two rotary drum-type vacuum filters, a reclaim (filtrate) water tank, and reclaim pumps. A gypsum canopy is included in the estimate. The canopy will allow for up to 3 days of covered gypsum storage.

The estimate is based on producing saleable quality gypsum; typically that limits scrubber chloride concentrations to approximately 20,000 mg/L due to cake washing constraints. If chlorides are held to 20,000 mg/L within the scrubber loop a bleed stream of 55 gallons per minute (gpm) will be required for each Unit. The estimate included wastewater treatment equipment for this purge stream consisting of physical/chemical treatment, falling film evaporator and a crystallizer to comply with the current published version of the Effluent Limitation Guidelines (ELG) which require zero discharge for new FGD waste streams. As there is no discharge of FGD wastewater there is no need for specialized Selenium treatment over and above the thermal system. The wastewater treatment system is sized only for the FGD purge stream, it will not treat flow from general plant drains or leachate collection.

The estimate also includes a FGD outage storage tank. The tank is approximately the same size as the absorber reaction tank and will be constructed of similar materials of construction (Stebbins tile or flake glass lined carbon steel). The tank will allow Vectren to empty the reaction tank during a Unit outage for absorber inspection activities. The FGD bleed pumps will transfer slurry from the absorber to this tank. New transfer pumps are included in the estimate to transfer the slurry back to the FGD vessel once outage activities are complete.

A Process Flow Diagram (PFD) for the replacement FGD system is provided in Appendix B.

## 3.3 Electrical System Evaluation

BMcD evaluated the existing electrical distribution system for AB Brown Units 1 and 2 to determine if upgrades would be required for the additional loads from the new wet LSFO FGD system and its associated ancillary equipment. It was determined that the existing system does not have sufficient capacity for the new auxiliary loads associated with the FGD upgrade. Therefore the estimate includes the following new electrical equipment: two new transformers, new PCM building, new switchgear (4160V and 480V), new MCC's and additional miscellaneous panels.

## 3.4 Conceptual Design Basis

The design basis for the wet LSFO system is shown in Table 4-1. The design coal assumed for this study, based on 2014, 2015 and 2016 coal data provided by Vectren, is provided in Table 4-2.

**Table 3-1: Design Basis**

| Parameter | Unit 1 | Unit 2 |
|---|---|---|
| Gross MW | 265 | 265 |
| Heat Rate (Btu/kWh) | 10,500 | 10,400 |
| Annual Capacity Factor | 70% | 70% |
| Excess Air | 20% | 20% |
| Air Heater Leakage | 5% | 5% |
| Air Heater Outlet Temperature (°F) | 325 | 325 |
| Air Heater Outlet Pressure (in$H_20$) | -8.0 | -8.0 |
| Target $SO_2$ Removal | ≥98% | ≥98% |
| Coal HHV (Btu/lb) | 11,143 | 11,143 |
| Coal sulfur content (%S by weight) | 3.75% | 3.75% |
| Inlet $SO_2$ Loading (lb $SO_2$/mmBtu) | 6.7 | 6.7 |
| Flue Gas at Scrubber Inlet (lb/hr) | 2,898,000 | 2,870,000 |
| Flue Gas at Scrubber Inlet (afcm) | 922,000 | 913,000 |
| PM limit (lb PM/mmBtu) | 0.03 | 0.03 |

**Table 3-2: Design Coal Analysis**

| Proximate Analysis (wt%, as rec'd) | |
|---|---|
| Moisture | 11.8 |
| Volatile Matter | 35.0 |
| Fixed Carbon | 45.0 |
| Ash | 8.1 |
| **Ultimate Analysis (wt%, as rec'd)** | |
| Moisture | 11.8 |
| Carbon | 62.8 |
| Hydrogen | 4.0 |
| Nitrogen | 1.1 |
| Chlorine | 0.1 |
| Sulfur | 3.8 |
| Ash | 8.1 |
| Oxygen | 7.7 |
| **HHV (Btu/lb)** | 11,143 |

## 3.5 Estimating Methodology

Budgetary quotes for a new wet LSFO FGD system were requested from seven FGD system suppliers: Amec Foster Wheeler, Andritz, Babcock & Wilcox, Babcock Power, GE Power, Marsulex and Mitsubishi Hitachi. Many of these quotes included the cost of the limestone preparation and gypsum dewatering equipment. For quotes that did not include this equipment, budgetary quotes on limestone preparation and gypsum dewatering equipment from other projects was added in. An average of the budgetary quotes provided by the system suppliers was assumed for the FGD supply cost.

Direct costs were factored based on costs from past, similar projects. Indirect costs, including engineering and start-up, were also factored based on past, similar projects.

BMcD developed an estimate of the following balance of plant (BOP) direct costs based:

- Equipment installation
- Civil and foundation work
- New chimney for Unit 1
- Demolition of the Unit 1 thickener
- Concrete
- Steel
- Ductwork and insulation
- Buildings (pump houses, limestone preparation enclosure and gypsum dewatering enclosure)

- Limestone and Gypsum pile canopies
- Wastewater Treatment Equipment (falling film evaporator and crystallizer)
- Piping outside of the absorber islands
- Electrical (new transformers, PCM, switchgear, MCC's and miscellaneous panels)
- Instrumentation and controls

### 3.5.1 Estimate Assumptions

The assumptions below govern the overall approach of the cost estimate:

- All estimates are screening-level in nature, do not reflect guaranteed costs, and are not intended for budgetary purposes.
- Assumes contracting philosophy is Engineer, Procure, Construct (EPC) approach.
- All information is preliminary and should not be used for construction purposes.
- Assumes project engineering starts January 1, 2020 with both scrubbers in operation by January 2024.
- All capital cost and O&M estimates are stated in 2019 US dollars (USD). Escalation is excluded.
- Fuel and power consumed during construction, startup, and/or testing are included.
- Piling is included under heavily loaded foundations.
- All foundations are new; no re-use of existing foundations.
- Adequate water supply is assumed to be available from existing raw water supplies.
- This estimate assumes that the integrity of the tie-in points is sufficient.
- This estimate assumes that there are no significant underground utilities that would have to be re-routed.
- Removal of hazardous materials is not included.
- Emissions estimates are based on a preliminary review of BACT requirements and provide a basis for the assumed air pollution control equipment included in the capital and O&M costs.
- No new induced draft (ID) fans or booster fans are included in the capital cost estimate. BMcD reviewed the fan curves provided by Vectren and determined there was sufficient capacity to handle the pressure drop through the new FGD system.
- ABB Unit 2 boiler structural improvements were included as this work would be completed during the scrubber tie-in outage.
- This estimate does not include provisions for either Mercury control or SO3 control. Vectren can continue using the existing system for each following conversion to the wet LSFO technology.

## 3.6 Project Indirect Costs

The following project indirect costs are included in capital cost estimates:

- Performance testing and CEMS/stack emissions testing
- Pre-operational testing, startup, startup management and calibration
- Construction/startup technical service
- Engineering
- Freight
- Startup spare parts

## 3.7 Owner Costs

Allowances for the following Owner's costs are not included in the pricing estimates:

- Project development
- Owner's operational personnel
- Owner's project management
- Owner's engineering
- Owner's startup engineering and training
- Legal fees
- Permitting/licensing
- Construction power, temporary utilities, startup consumables
- Site security
- Operating spare parts
- Political concessions
- Builder's risk insurance
- Owner's Contingency
- Allowance for Funds Used During Construction (AFUDC).

## 3.8 Cost Estimate Exclusions

In addition to Owner's costs noted above, the following costs are also excluded from all estimates:

- Escalation
- Sales tax
- Property tax and property insurance
- Utility demand costs
- Salvage values

### 3.8.1 Capital Costs

The FEP-1 capital cost estimate for the replacement FGD system is summarized in Table 4-3. The total direct cost listed includes the absorber, limestone preparation and gypsum dewatering equipment included in the budgetary quotations received from various FGD system suppliers, as well as BOP Direct Costs including material and installation labor.

**Table 3-3: Capital Cost Estimate Summary (2019 Dollars)**

| Area | Cost |
|---|---|
| Total Direct Cost | $263,808,600 |
| Indirect Cost | $67,095,900 |
| Contingency | $66,178,000 |
| EPC Fee | $27,795,500 |
| Total Project Cost | $424,878,000 |

### 3.8.2 O&M Costs

The scrubber replacement evaluation included a qualitative estimate of the impact of replacing the FGD systems on O&M costs. The major O&M costs associated with FGD systems include reagent, power, waste disposal, and operating and maintenance labor. Auxiliary power loads for the new wet LSFO system are estimated to be 10.2 MW, note this does not include power associated with the existing ID fans. Given that the pressure drop between the existing FGD system and replacement FGD system is not expected to be significantly different the impact on ID fan operations should be minimal.

Both the existing and replacement FGD systems include FGD byproduct dewatering with the use of vacuum filters. Because both systems will handle the dry byproduct in a similar manner, there is not expected to be a significant difference in waste disposal costs. The gypsum cake at 90% solids (saleable quality) generated by the new Unit 1 and 2 FGD systems is estimated to be 0.1 ton/MWhrg.

The number of operators required to operate the replacement FGD system is expected to be similar to that of the existing FGD system. Additional operators and maintenance staff will likely be needed for the wastewater treatment equipment; up to 5 additional full-time equivalents. No significant impact to operating labor cost is expected as a result of replacing the FGD system.

The existing FGD system uses two reagents, lime and soda ash (sodium carbonate, $Na_2CO_3$). The replacement scrubber will use limestone as a reagent. A detailed evaluation of reagent usage and annual costs was not conducted as part of this evaluation, however, limestone is a less expensive commodity. Annual reagent costs are expected to be lower for the replacement FGD system compared to the existing FGD system. The limestone used in the new Unit 1 and 2 FGD systems is estimated to be consumed at 0.06 ton/MWhrg. Maintenance labor and material costs are expected to be lower for the replacement FGD system compared to the existing FGD system.

# 4.0 CONCLUSIONS AND RECOMMENDATIONS

Burns & McDonnell recommends that Vectren consider the information presented in this report when considering the economic viability of a new FGD system. Burns & McDonnell estimates that new scrubbers will cost an order-of-magnitude of $425 million (in 2019 dollars). This includes electrical system upgrades and all BOP considerations.

# APPENDIX A – LIST OF DOCUMENTATION PROVIDED BY VECTREN

1. Capital & O&M Costs
2. Chimney Inspections
3. Coal Data
4. Drawings
    a. General Arrangement
    b. Lime System
    c. SBS Injection System
    d. Scrubber
    e. Soda Ash System
5. Emissions
6. FGD Power and Chemical Usage
7. ID Fan Info
8. Outage Cost Info – 2013
9. Scrubber Condition Reports
10. Scrubber Design Information
11. Service Water Information
12. Site Water Balance

# APPENDIX B – PROCESS FLOW DIAGRAM


| no. | date | by | ckd | description | no. | date | by | ckd | description |
|---|---|---|---|---|---|---|---|---|---|

BURNS McDONNELL

9400 WARD PARKWAY
KANSAS CITY, MO 64114
816-333-9400
FIRM LICENSE NO. xxxxxx

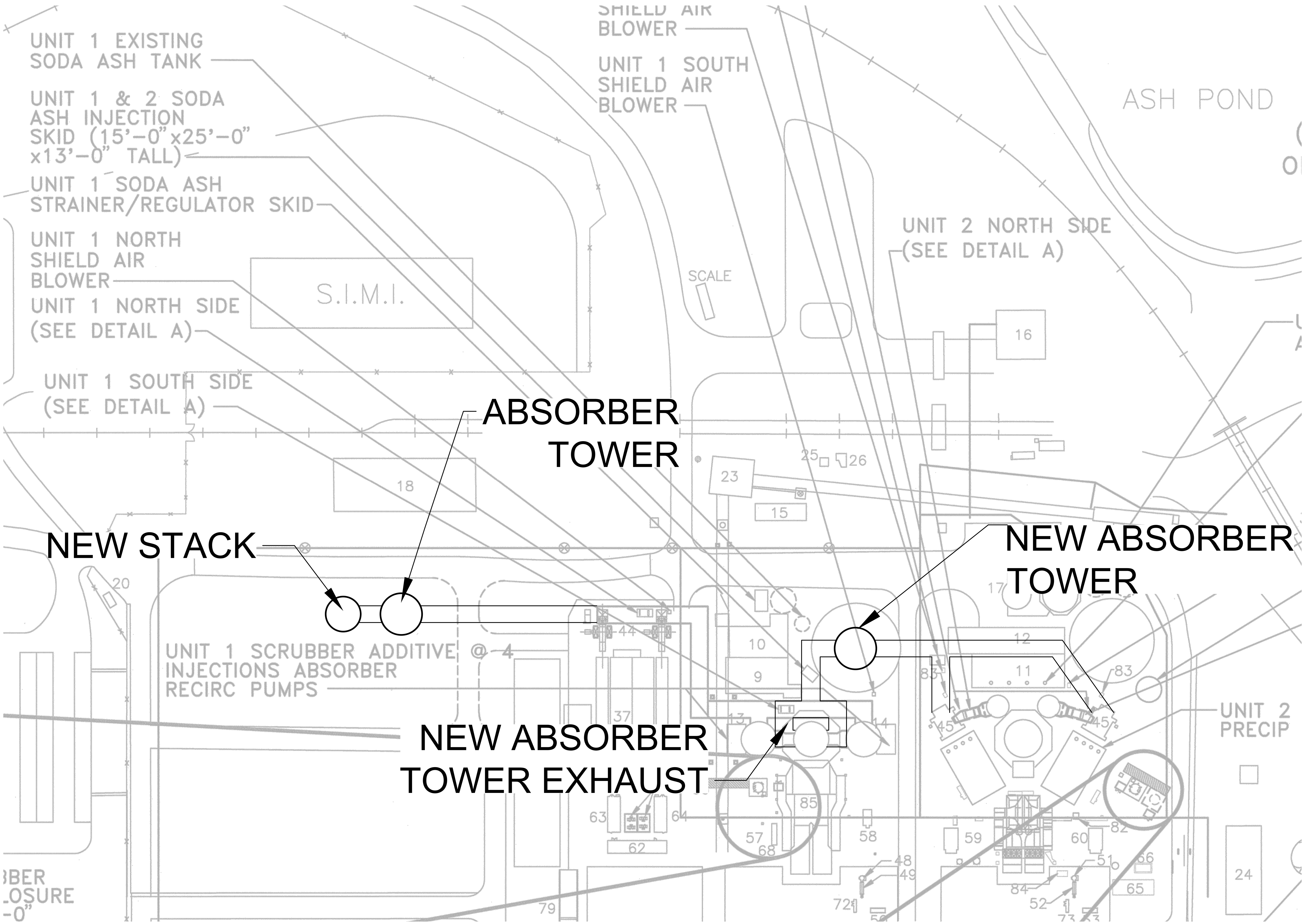
designed: K. BURCHARDT
detailed: R. CHANDLER

VECTREN A.B. BROWN
COUNTY, STATE

PROCESS FLOW DIAGRAM

project: 98818
contract: CONTRACT
drawing: FPD001 – rev. A
sheet 1 of 1 sheets
file PFD001.dwg

## APPENDIX C – SKETCH OF ASSUMED LAYOUT




| no. | date | by | ckd | description |
|---|---|---|---|---|
| A | 5/12/17 | KEB | KEB | ISSUED FOR OWNER REVIEW |

| no. | date | by | ckd | description |
|---|---|---|---|---|

BURNS & McDONNELL
9400 WARD PARKWAY
KANSAS CITY, MO 64114
816-333-9400

designed: K. BURCHARDT
detailed: R. CHANDLER

VECTREN
EVANSVILLE, IL

SKETCH OF ASSUMED LAYOUT

project: 98818
contract:
drawing: SKM001
rev.: A
sheet 1 of 1 sheets
file 98818SKM001.dwg

CREATE AMAZING.

Burns & McDonnell World Headquarters
9400 Ward Parkway
Kansas City, MO 64114
**O** 816-333-9400
**F** 816-333-3690
www.burnsmcd.com

A CenterPoint Energy Company

# A.B. Brown Power Station
# FGD Refurbishment Study
# 10-Year Dual Alkali Scrubber

Revised: May 11, 2020

THREE i DESIGN ENGINEERING + ARCHITECTURE
2425 WEST INDIANA ST EVANSVILLE, IN 47712 P: 812-423-6800 F: 812-423-6814 THREEIDESIGN.COM

# Vectren Power Supply
## A.B. Brown Power Station
## FGD Refurbishment Study
## 10-Year Dual Alkali Scrubber

Prepared by: Three i Design

## Table of Contents

## A. INTRODUCTION

Three I Design (Three I Engineering) has been performing engineering and surveying support work in the A.B. Brown FGD Systems and for the A.B. Brown plant facility since the early 1980's. During the last four decades, we have worked with Vectren engineers, maintenance personnel, production personnel, contractors, and consultants, to upgrade FGD systems and plant systems, improve equipment accessibility, improve equipment handling systems, remediate Vectren safety items, and remediate corrosion damaged systems and structures. A very brief list of FGD system engineering support work is included below.

- Re-design and replace entire lime slaking system
- Re-design and replace lime conveying system
- Design and add ball mill system
- Design and add clarifier tank
- Re-design and replace unit no. 2 north and south absorber inlet ducts
- Re-design and replace unit no. 1 north and south absorber outlet ducts
- Re-design and replace unit no. 1 thickener tank rake drive support bridge
- Reinforce unit no. 2 thickener tank rake drive support bridge
- Re-design and replace unit no. 1 belt filter system
- Re-design and replace unit no. 2 belt filter system
- Re-design and replace unit no. 1 north and south absorber outlet duct support structures
- Reinforce unit no. 2 north and south absorber outlet duct support structures.
- Re-design and replace unit no. 1 rotary filter building and belt filter building siding and roofing systems (and support systems) and reinforce floor support steel and roof support steel
- Re-design and replace unit no. 2 regeneration building siding and roofing systems (and support systems) and reinforce floor support steel and roof support steel
- Re-design and replace unit no. 1 lime mixing tank and foundation
- Re-design and replace unit no. 2 lime mixing tank and foundation
- Re-design and replace unit no. 1 and 2 belt filter building ventilation systems
- Yearly unit no. 1 and unit no. 2 FGD system corrosion remediation projects

Based on experience with the A.B. Brown FGD Systems, Vectren asked Three I Design to help identify and organize the A.B. Brown FGD System Operation, Maintenance, and Remediation needs over the next ten years.

## B. OBJECTIVE

The objective of this study was to identify systems, areas, and items that require regular or ongoing maintenance and/or remediation, based on historical information. This study also included identifying systems, areas, and items that are not continuous or ongoing remediation items but are expected to require maintenance and/or remediation within the next ten years. This study includes developing a ten-year project schedule for the maintenance and/or remediation, for each FGD system.

There are structures that required significant ongoing corrosion remediation work, and these structures were re-assessed in 2019. The 2019 assessment items included the four absorber vessels and the two thickener tanks.

After the work items were assembled into a ten-year project schedule (for each FGD system), budget pricing was developed for each year, as described below.

## C. SCOPE OF WORK FOR FGD REFURBISHMENT STUDY

The following is a brief summary of the process that occurred and the information that was used to develop the budget pricing for Vectren's ten-year FGD plan.

Ten-year Plan - O&M Budget Pricing

The pricing provided was based on historical Vectren O&M information (provided by Vectren), for fiscal years 2011 thru 2018. Based on discussions with Vectren mechanical maintenance and electrical maintenance, the operating and maintenance expenses (2011 thru 2018) should be representative of the O&M expenses during the next ten years excluding overheads, Vectren labor, etc.

Ten-year Plan - Capital Budget Pricing

The pricing provided was based on historical Vectren capital information (provided by Vectren and Vectren's contractors), for fiscal years 2011 thru 2017. The ten-year projected costs are in 2019 dollars and exclude overheads Vectren labor, etc.

For the ten-year capital budget pricing Three I Design identified a list of projects for the first five years (2020 thru 2024). This list includes corrosion remediation items that are part of the most recent Vectren FGD system corrosion review projects (2015 thru 2018), items Vectren has included in their five-year corrosion remediation plan, and corrosion damaged items identified during recent FGD system corrosion review (2019 corrosion review during this project). In addition to corrosion remediation work, the capital project list includes replacing the absorber mist eliminators and adding mist eliminator wash systems in three absorbers (new mist eliminators and a mist eliminator wash system was installed in the Unit No. 2 south absorber at the end of 2015).

For the period 2025 thru 2026 the capital plan remained consistent with the previous 5-year period. During the period 2027-2029, the capital plan includes reductions consistent with an assumed unit retirement for study purpose at the end of 2029.

## D. ESTIMATING METHODOLOGY

### D.1. OEM Equipment Estimates

O&M Budget Pricing

The FGD Refurbishment Study consisted of eight years of Vectren O&M History (2011 thru 2018) and adjusting the historical information relative to current costs (2019 costs). The O&M budget pricing process also included meeting with A.B. Brown mechanical maintenance and electrical maintenance, to identify if current predictive maintenance and preventative maintenance approaches differ than the practices that were in place from 2011 to 2018. Adjustments were made to the budget pricing for 2020 thru 2029 to account for these practices.

Capital Budget Pricing

The FGD Refurbishment Study consisted of taking seven years of capital history (2011 thru 2017) and adjusting the historical information relative to current costs (2019 costs). Most historical information was provided by the contractor who performed the capital projects in the FGD system during this time. For projects performed by other contractors, this information was provided by the Vectren project managers for each project.

The capital budget pricing process also included reviewing the 2015 FGD system structural corrosion review manuals and field reviewing the equipment and structures in the FGD systems, to identify changes in performance, and to develop a list of capital projects for the 2020 to 2029 system life.

The capital budget pricing process also included performing a 2019 FGD system structural corrosion assessment of the absorber vessels and thickener tanks.

Once the FGD system reviews were complete, and the capital project list developed for 2020 thru 2029, this information was provided to Sterling Industrial, LLC a mechanical & electrical contractor familiar with the plant to develop budget pricing. Three I Design continually met with the Sterling Industrial throughout the process and provided additional concept information.

Budget pricing for 2020 thru 2029 was also compared to historical data and the age and condition of the structures and equipment in the FGD system. Changes were made to be consistent with historical data, which is generally an accurate representation of what is required to maintain these systems based on the age and condition of the structures and equipment in the FGD systems.

## D.2. Balance of Plant Equipment Estimates

The descriptions below include references to previous work, previous projects, and previous capital budgets and T&M budget pricing.

The items and work described below are included in the estimates.

All estimates are 2019 dollars.

All estimates exclude overheads, escalation, and Vectren labor.

CCR compliance work was not included in this review.

### Lime Silo

Exterior Walls

A corrosion remediation design package was created and bid in 2015. This work has not been completed at the time of this study and is included in the estimates going forward to avoid more extensive structural corrosion remediation work. An allowance for continual minor corrosion remediation is included each year to maintain the structure.

Roof System & Equipment

The roof system and roof mounted equipment was replaced in 2015. An allowance is included in each year for minor corrosion remediation work to maintain the systems and avoid major corrosion remediation in the future.

Ladders and Landings

The ladders and landings were replaced in 2015. An allowance is included in each year for minor corrosion remediation work to maintain the systems and avoid major corrosion remediation in the future.

Internal Walls

The internal walls were inspected, and minor repairs were made in 2015. An allowance is included in each year for minor corrosion remediation work to maintain the systems and avoid major corrosion remediation in the future.

**Lime Conveyors**

Ongoing Hapman conveyor equipment and conveyor tube maintenance is required, due to abrasion and wear. Regular maintenance costs and conveyor replacement costs are included in the estimate.

**Lime Slaking Tank**

The lime slaking tank has been replaced including the tank, foundations, platforms, and handrail systems in 1999. Regular corrosion remediation work is to be expected going forward due to the corrosive environment.

**Ball Mill**

The ball mill has been replaced including the primary equipment, foundations, platforms, stairs, and handrail systems in 1999 Regular corrosion remediation work is expected going forward due to the corrosive environment.

**Lime Slurry Storage Tank**

The lime slurry storage tank has been replaced including the tank, equipment, foundations, platforms, stairs, and handrail systems in 1996. Regular corrosion remediation work is to be expected going forward due to the corrosive environment.

Corrosion remediation work on the spiral stair to the top of the tank, the landing at the top of the tank, and the stair and the walkway to the belt filter building is included in the estimate.

**Lime Slaking Building**

The lime slaking building has been replaced including the building, framing, roofing, siding, equipment, foundations, doors, roofing, and siding in 1996. Regular corrosion remediation work is to be expected going forward due to the corrosive environment.

**Unit No. 1 North and South Absorbers**

Shell Disc & Donut, Internal Structural Repairs & Flake-glass Coating

Developed scope of work based on historical outage upgrades and repairs. Estimate includes necessary improvements and repairs based on outage schedule going forward.

Anchor Bolts and Anchor Chairs

Extensive corrosion remediation repairs were performed in 2011-2012 on the bottom of the absorbers. Based on the significant ongoing corrosion damage around the base of the absorbers these repairs will need to be performed in the future and this scope is included in the estimate.

Shell Plate

Shell replacement work was performed in 2011-2012. Based on assessment of the large number of external cover plates currently located on the absorbers, this work should be performed in 2020, and in 2025. This scope has been included in the estimate. See Corrosion Review Reports for vessel structural stability associated with external cover plates, and horizontal planes in the vessel shell that are perforated from corrosion damage.

External Stiffeners

Repairs will be needed on the external stiffeners in the next ten years. This scope is included in the estimate. The external shell stiffening work that was performed in 2011-2012 was used to develop this estimate.

Mist Eliminators, Mist Eliminator Supports, & Mist Eliminator Wash Piping

Replacement of the mist eliminators, mist eliminator supports, & mist eliminator wash piping in the north and south absorbers including the dome stiffeners, access opening in dome (and framing), access platform at dome opening, and jib crane for handling mist eliminator equipment, etc. is included in the estimate.

Access Platforms, Walkways, Stairs, and Ladders

Corrosion remediation is an ongoing process on these structures and this process is expected to continue, based on the corrosive environment. This scope is included in the estimate.

Ultrasonic Thickness Testing (Corrosion Remediation)

Vectren hired Three I Design to perform ultrasonic thickness testing, temporary patch plate location work, and corrosion review work on these vessels in 2019. In order to manage risk on these structures, Vectren should continue the current structural shell replacement process of removing damaged shell and installing new shell. This type of repair is outage work and should be performed during every outage, to replace all temporary patch plates with new in-line shell plate. This scope is included in the estimate.

In conjunction with the approach to managing risk, it is recommended that the bottom of each vessel be completely replaced. The original designer of the vessels specified the bottom of these vessels be insulated. Absorber liquid from vessel leaks and leaking expansion joint leaks filled the insulation area and held the corrosive liquid against the outside surface of the vessels. Significant metal loss occurred before Vectren understood how much damage occurred and permanently removed the insulation system.

For budgeting purposes and the replacement schedule, the vessel replacement could occur in three consecutive outages (one third of the vessel, each outage). This approach is included in the estimate.

**Unit No. 1 North and South Absorber Inlet Duct**

The north absorber inlet duct and nozzle has an excessive amount of liquid leaking, and this liquid is causing damage to the base of the absorber and adjacent structures. The north absorber inlet duct and nozzle needs to be repaired or replaced in 2020. This scope had been included in the estimate.

This work should also be performed on the south absorber inlet duct, so this structure doesn't cause damage to the base of the absorber or adjacent structures. This scope has been included in the estimate.

In the past, the outlet duct expansion joints have leaked onto the top of the inlet ducts and saturated the inlet duct insulation and caused significant damage to the insulation, cladding, duct shell, duct stiffeners, and duct supports. Vectren has made modifications in this area including fiberglass cladding on the areas under the expansion joints, however, if this area is saturated with scrubber liquor in the future, the resulting corrosion remediation costs have not been addressed in this ten-year estimate.

**Unit No. 1 North and South Absorber Outlet Duct**

The coated carbon steel elbow on the south absorber outlet duct system was replaced with a stainless steel duct elbow in 2018. This approach is planned and included in the estimate for the north absorber.

Significant corrosion remediation and shell plating work was performed on the north and south absorber outlet ducts and the breech ducts previously. This work is included in each outage estimate for the next ten years.

**<u>Unit No. 1 North and South Absorber Inlet Duct Support Structures</u>**

These structures were repaired within the last two years, but minor corrosion remediation work will be required to maintain them. This scope is included in the estimate. If the duct work is not maintained additional corrosion remediation work on the support structures will be required.

**<u>Unit No. 1 North and South Absorber Outlet Duct Support Structures</u>**

These structures have been replaced within the last two years, so only minimal work should be required to maintain them. This scope is included in the estimate. If the expansion joints are not maintained, additional corrosion remediation work will be required.

**<u>Unit No. 1 North and South Absorber Access Platforms, Stairs, Ladders, etc.</u>**

These structures have been replaced within the last two years, so only minimal work should be required to maintain them. This scope is included in the estimate. If the expansion joints are not maintained, additional corrosion remediation work will be required.

**<u>Unit No. 1 North and South Absorber Recirc. Pump Buildings</u>**

These buildings were replaced in 2013 and these structures are performing relatively well. Minor corrosion remediation work is included in each year, to avoid major corrosion remediation work in the future.

**<u>Unit No. 1 North and South Absorber Recirc. Pumps Concrete Foundations</u>**

There is cracking in the concrete and exposed reinforcing steel on the pump concrete foundations. Pump concrete foundation replacement work is included for all four concrete foundations.

**<u>Unit No. 1 North and South Absorber Bleed Piping</u>**

This 10" diameter piping system is mostly the original FMC fiberglass piping. Most of this piping is outside and exposed to UV rays (outside surfaces) and harsh chemicals on the inside surfaces. Replacement of this piping system is included in the estimate.

**Unit No. 1 North and South Absorber Regeneration Return Piping**

This 14" diameter piping system was replaced in 1997 and 2013. This piping system probably won't need to be completely replaced before 2030 but will require minor corrosion remediation work. This scope is included in the estimate.

**Unit No. 1 North and South Absorber Regeneration Return Valve Access Platform**

Replace access platforms in 2019 or 2020. T&M Budget Pricing was developed in 2018. This scope is included in the estimate.

**Unit No. 1 Alley Pipe Supports**

All Supports in the Unit No. 1 Alley need to be replaced (FMC Corporation drawings 00246-608-1 thru 00246-608-3). The columns will be in new locations, so the columns can be installed before any existing structures are removed (so the existing utilities can be supported from the existing pipe support system and then transferred to the new support system, without excessive false-work). This scope is included in the estimate.

**Unit No. 1 Alley Underground Drain Piping and Manholes**

Vectren has performed ongoing corrosion remediation work on the underground piping and manholes. This work will need to continue, and this scope is included in the estimate.

**Unit No. 1 Thickener Tank**

Thickener Tank Rim

Replace top 2'-6" of rim. This work will be similar to the rim replacement work that was performed in 2008/2009, however, a new rim angle will need to be added to the entire perimeter and the angle will need to continue through the vertical structural tee shell stiffeners. Rim angle to be 4"x4"x3/8". This scope is included in the estimate.

Thickener Tank Vertical Shell Stiffeners

The bottom portion of nearly every vertical structural tee's is missing. Install all new vertical structural tee's on shell. Match the existing member size. The new vertical structural tee's will be placed mid-way between the existing vertical structural tee's. The damaged tee's will be abandoned in place. This scope is included in the estimate.

Thickener Tank Bridge

Entire bridge needs to be sand blasted and painted.  As with previous projects, due to the amount of visual corrosion damage, this process will include a significant amount of structural discovery work/structural repairs.  This scope is included in the estimate.

Thickener Tank Bridge Utility Supports, Rake Canopy, and Handrail System

Entire system needs to be sand blasted and painted.  As with previous projects, due to the amount of visual corrosion damage, include a significant amount of structural discovery work/structural repairs.  This scope is included in the estimate.

Thickener Tank Shell and Floor Plate

Internal corrosion remediation was performed on the thickener tank shell and floor plates in 2010.  This type of work will need to be performed, at least once, during the next ten years.  This scope is included in the estimate.

The outside surface of the thickener tank shell (and all shell stiffeners) should be sand blasted and coated.  This scope is included in the estimate.

Thickener Tank Launder, Regeneration Return Nozzles, and Emergency Overflow

On-going corrosion remediation work is performed on these items and this repair process should continue.  Most of this work requires emptying the tank (or at least lowering the liquid level).  Liquid level adjustments are by Vectren.  This scope is included in the estimate.

Ultrasonic Thickness Testing (Corrosion Remediation)

Vectren hired Three I Design to perform ultrasonic thickness testing, temporary patch plate location work, and corrosion review work on this tank in 2019.  In order to manage risk in this million-gallon capacity tank, it was suggested that the tank be completely replaced.  This remediation is appropriate.  Over the last forty years, Vectren has performed a significant amount of temporary reinforcing and temporary patch plate repairs on this tank (floor cover plates, shell cover plates, corner reinforcement, partial shell replacement, etc.).  The bottom portion of the vertical stiffeners, horizontal stiffening ring, and exterior floor to shell weld are also significantly damaged.

For budgeting purposes and the replacement schedule, the tank replacement is to occur in three consecutive outages (one third of the tank, each outage).  This scope is included in the estimate.

**Unit No. 1 Lime Mixing Tank**

The lime mixing tank was completely replaced in 2013. The lime mixing tank is inspected by Vectren during each outage and the re-designed tank is performing much better than the previous tank. Based on the corrosive environment, the history of this system, and the ten-year period, corrosion damage is expected, and corrosion remediation needed. This scope is included in the estimate.

**Unit No. 1 Soda Ash Tank**

The access platform and perimeter handrail system on top of the tank will need to be replaced within the ten-year time frame. This scope is included in the estimate.

**Unit No. 1 Old Rotary Filter Building**

Structural Steel and Floor Support Steel

Major corrosion remediation work has been performed in this building over the last ten years. The corrosion remediation work over the next ten years should be less than the previous ten years, however, corrosion damage is expected, and corrosion remediation needed each year, to avoid major corrosion remediation work. This scope is included in the estimate.

Trench Drain System

The trench drain that runs north and south adjacent to the vacuum pump is showing significant signs of differential settlement and the old truck bay concrete foundation is cracked and shifted, which has caused a shift and cracking in the block wall that sits on the concrete foundation. This trench drain system should be replaced. The old truck bay concrete foundation and block wall should be repaired. This scope is included in the estimate.

First Floor Stair

Based on the corrosive environment and the history of this system, corrosion damage is expected, and corrosion remediation needed within the ten-year time frame. This scope is included in the estimate.

Second Floor Stair Tower

This abandoned corrosion damaged stair tower should be removed and the utilities attached to the stair tower should be re-supported. This scope is included in the estimate.

Chemical Sump

The grating, grating support steel and handrail system have been repaired numerous times. Based on the corrosive environment, the history of this system, and the ten-year period, corrosion damage is expected, and corrosion remediation needed. This scope is included in the estimate.

Minor ongoing corrosion remediation work has been performed on the piping and pipe supports. Based on the corrosive environment, the history of this system, and the ten-year period, corrosion damage is expected, and corrosion remediation needed. This scope is included in the estimate.

Waste Water Sump

The grating, grating support steel and handrail system have been repaired numerous times. Based on the corrosive environment, the history of this system, and the ten-year period, corrosion damage is expected, and corrosion remediation needed. This scope is included in the estimate.

Minor ongoing corrosion remediation work has been performed on the piping and pipe supports. Based on the corrosive environment, the history of this system, and the ten-year period, corrosion damage is expected, and corrosion remediation needed. This scope is included in the estimate.

## Unit No. 1 Belt Filter Building

South Stair Tower

This stair system was replaced in 2014. Based on the corrosive environment, the history of this system, and the ten-year period, corrosion damage is expected, and corrosion remediation needed. This scope is included in the estimate.

Structural Steel and Floor Support Steel

Major corrosion remediation work has been performed in this building over the last ten years. The corrosion remediation work over the next ten years should be less than the previous ten years, however, the metal deck and concrete were not replaced (this work was postponed). There is a significant amount of corrosion damage in the metal deck. Corrosion remediation will be needed. The south edge beam (at the lime mixing tank) also needs to be reinforced or replaced. Minor corrosion damaged is also expected and corrosion remediation needed. This scope is included in the estimate.

Roof and Roof Support Steel

The roof system was supposed to be replaced, but this work was postponed for several years. This work needs to be performed (replace all roof purlins and reinforce roof support beams). Since this work has been postponed for several years, more extensive corrosion damage is expected, and more extensive corrosion remediation needed. This scope is included in the estimate.

Haul Truck Canopy

Corrosion remediation work was performed on the framing and knee brace for this canopy in 2013. There was also T&M Budget Pricing developed for replacing the purlins and roofing material for the canopy and this work was postponed for several years. This work needs to be performed. The east perimeter/edge beam and the north perimeter/edge beam need to be replaced in a similar manner to the south perimeter/edge beam that was replaced in 2013. This scope is included in the estimate.

**Unit No. 1 Horizontal Belt Filter**

The horizontal belt filter was completely replaced in 2015 and this system appears to be performing relatively well, however, this area is an extremely corrosive area and on-going minor corrosion remediation work should be included (every year), to avoid major corrosion remediation work in the future. This scope is included in the estimate.

**Unit No. 1 Horizontal Belt Filter Drop Chute**

The carbon steel horizontal belt filter drop chute was completely replaced in 2015 with a stainless steel drop chute. This system appears to be performing well, and only occasional minor corrosion remediation is anticipated. This scope is included in the estimate.

**Unit No. 1 Lime Silo Enclosure**

The upper portion of the north and south lime silos has been removed, but the lower portion (columns and cone) were not removed because this area is an enclosure that is still used to protect operating equipment. All wall girts, purlins, and minor support steel need to be replaced with new, and new siding and roofing installed. This scope is included in the estimate.

The main columns and bracing on the lime silos appear to be in relatively good condition and the load on these structures has been greatly reduced, therefore, only minor corrosion remediation is needed. This scope is included in the estimate.

**Unit No. 1 Underflow Piping**

Minor ongoing corrosion remediation work has been performed on the piping and pipe supports. Based on the corrosive environment, the history of this system, and the ten-year period, corrosion damage is expected, and corrosion remediation needed. This scope is included in the estimate.

**Unit No. 1 Underflow Tunnel**

The access platform and stairs into the tunnel need to be replaced. This scope is included in the estimate.

There are numerous areas where the concrete reinforcing steel is exposed and the large areas where the concrete reinforcing steel has dissolved away, completely. The tunnel needs significant corrosion remediation. This scope is included in the estimate.

**Catwalk and Utility Support between Unit 1 and Unit 2**

Major structural remediation work was performed in 2018, however, based on the corrosive environment, the history of this system, and the ten-year period, corrosion damage is expected, and corrosion remediation needed, including complete replacement of the utility supports. This scope is included in the estimate.

**Unit No. 1 & Unit No. 2 Emulsified Sulfur System and Enclosure**

Vectren moved the Unit No. 2 emulsified sulfur pumping system over to the Unit No. 1 emulsified sulfur tank, so this tank provides emulsified sulfur to the Unit No. 1 thickener tank and the Unit No. 2 thickener tank. The structures in this system appear to be performing well. Based on the corrosive environment, the history of this system, and the ten-year period, corrosion damage is expected, and corrosion remediation needed. This scope is included in the estimate.

Minor corrosion remediation is need for the pump enclosure. This scope is included in the estimate.

The Unit No. 1 emulsified sulfur tank agitator support beams and the attachments to the fiberglass tank need to be sand blasted and coated. This scope is included in the estimate.

**Unit No. 1 Switchgear Building**

The roofing system on this building has been repaired several times in the past. The roof needs to be replaced and minor corrosion remediation is needed for the building structure. This scope is included in the estimate.

**Unit No. 2 North and South Absorbers**

Shell Disc & Donut, Internal Structural Repairs & Flake-glass Coating

Corrosion remediation is an ongoing process with a yearly budget. This scope is included in the estimate.

Anchor Bolts and Anchor Chairs

The anchor bolts and anchor chairs on the Unit No. 2 absorbers have not experienced the extensive damage that has occurred on Unit No. 1, based on the corrosive environment, the history of this system, and the ten-year period, corrosion damage is expected, and corrosion remediation needed. This scope is included in the estimate.

Shell Plate

The shell replacement work that was performed in 2012/2013 is expected to be necessary again in the next ten years, due to the corrosive environment and based on the large number of external cover plates currently located on the absorbers. This scope is included in the estimate.

External Stiffeners

The external stiffeners on the Unit No. 2 absorbers have not experienced the extensive damage that has occurred on Unit No. 1, however, based on the corrosive environment, the history of this system, and the ten-year period, corrosion damage is expected, and corrosion remediation needed. This scope is included in the estimate.

Mist Eliminators, Mist Eliminator Supports, & Mist Eliminator Wash Piping

Replace the mist eliminators, mist eliminator supports, & mist eliminator wash piping in the north absorber. Use 2015 Unit No. 2 south absorber mist eliminator replacement pricing (adjust pricing to current year). This work needs to include the absorber dome stiffeners, access opening in dome (and framing), access platform at dome opening, jib crane for handling mist eliminator equipment, etc. This scope is included in the estimate.

Access Platforms, Walkways, Stairs, and Ladders

Corrosion remediation is an ongoing process on these structures and this process is expected to continue, based on the corrosive environment. This scope is included in the estimate.

Ultrasonic Thickness Testing (Corrosion Remediation)

Vectren hired Three I Design to perform ultrasonic thickness testing, temporary patch plate location work, and corrosion review work on these vessels in 2019. In order to manage risk on these structures, Vectren should continue the current structural shell replacement process of removing damaged shell and installing new shell. This type of repair is outage work and should be performed during every outage, to replace all temporary patch plates with new in-line shell plate. This scope is included in the estimate.

**Unit No. 2 North and South Absorber Inlet Duct**

Unit No. 2 north and south absorber inlet duct have both been replaced in the last twenty years, along with ongoing corrosion remediation. This is an extremely corrosive area. Based on the corrosive environment, the history of this system, and the ten-year period, ongoing corrosion damage is expected, and corrosion remediation needed. This scope is included in the estimate.

**Unit No. 2 North and South Absorber Outlet Duct**

The south absorber outlet duct system was replaced in 2015 with a stainless steel. This replacement is expected for the north absorber. This scope is included in the estimate.

If the duct replacement is delayed, additional corrosion remediation work will be required.

**Unit No. 2 North and South Absorber Inlet Duct Support Structures**

These structures have significant corrosion damage and should be replaced. This replacement should include replacing the access platforms and ladders. This scope is included in the estimate.

**Unit No. 2 North and South Absorber Outlet Duct Support Structures**

Major corrosion remediation work was performed in 2016/2017, however, due to the expansion joints in the absorber outlet ducts, and the history of ongoing corrosion damage in this area, similar corrosion remediation is expected in 2025 and minor corrosion remediation in other years, to avoid major corrosion remediation work. This scope is included in the estimate.

**Unit No. 2 North and South Absorber Access Platforms, Stairs, Ladders, etc.**

Ongoing corrosion remediation work has been performed on these structures. Based on the corrosive environment, the history of this system, and the ten-year period, corrosion damage is expected, and corrosion remediation needed. This scope is included in the estimate.

**Unit No. 2 North and South Absorber Recirc. Pump Building**

The siding and roofing were replaced in 2011, but the system was not installed per the manufacturer's installation instructions and panels are not attached properly to the support steel. Some re-work was performed in 2015 when the west wall columns failed, and structure remediation work was performed on the west wall. Ongoing repair work is expected. This scope is included in the estimate.

There are several areas around the trench drains that have differentially settled. Trench drain re-work is expected in the next ten years. This work includes repairing floor areas that have settled (in addition to the areas around the trench drains). This scope is included in the estimate.

**Unit No. 2 North and South Absorber Recirc. Piping**

This piping system is a combination of original 1985 FMC fiberglass piping and fiberglass piping that was installed in 1998. Replacement of this piping system is expected, and this scope is included in the estimate.

**Unit No. 2 North and South Absorber Bleed Piping**

This 10" diameter piping system is mostly the original FMC fiberglass piping. Replacement of this piping system is expected, and this scope is included in the estimate.

**Unit No. 2 North and South Absorber Regeneration Return Piping**

There doesn't appear to be any coating system on the regeneration return piping. based on the number of times the Unit No. 1 regeneration return piping has been replaced, it is expected that this piping system will need to be completely replaced. This scope is included in the estimate.

**Unit No. 2 North and South Absorber Regeneration Return Valve Access Platform**

This platform was replaced in 2006/2007. Based on the amount of corrosion damage in this area, minor ongoing corrosion remediation will be needed on this structure to avoid a complete replacement within ten years. This scope is included in the estimate.

**Unit No. 2 Pipe Supports between Absorbers**

The bottom portions of the utility and pipe supports in this area were replaced a couple years ago, but the steel was never coated. Structural corrosion remediation is required for these supports and then all supports need to be sand blasted and painted. This scope is included in the estimate.

**Unit No. 2 Thickener Tank**

Thickener Tank Rim

Replace top 2'-0" of rim. This work will be similar to the rim replacement work that was performed in 2008/2009 Unit No. 1. This scope is included in the estimate.

Thickener Tank Bridge

Entire Bridge needs to be sand blasted and painted. Based on the corrosive environment, history of corrosion on this structure, corrosion damaged is expected to be discovered after sand blasting, and corrosion remediation needed. This work should include the bridge support columns. This scope is included in the estimate.

Thickener Tank Bridge Utility Supports, Rake Canopy, and Handrail System

Entire system needs to be sand blasted and painted. As with previous projects, due to the amount of visual corrosion damage, include a significant amount of structural discovery work/structural repairs will be needed. This scope is included in the estimate.

Thickener Tank Shell and Floor Plate

Based on the corrosive environment, the history of this system, and the ten-year period, ongoing corrosion damage is expected, and corrosion remediation needed. This scope is included in the estimate.

The outside surface of the thickener tank shell (and all shell stiffeners) needs to be sand blasted and coated. This scope is included in the estimate.

Thickener Tank Launder, Regeneration Return Nozzles, and Emergency Overflow

On-going corrosion remediation work is performed on these items and this repair process should continue. Most of this work requires emptying the tank (or at least lowering the liquid level). Liquid level adjustments are by Vectren. This scope is included in the estimate

Ultrasonic Thickness Testing (Corrosion Remediation)

Vectren hired Three I Design to perform ultrasonic thickness testing, temporary patch plate location work, and corrosion review work on this tank in 2019. In order to manage risk in this million-gallon capacity tank, it was suggested that the tank be completely replaced. This remediation is appropriate. Over the last thirty-five years, Vectren has performed a significant amount of temporary reinforcing and temporary patch plate repairs on this tank (floor cover plates, shell cover plates, partial shell replacement, etc.).

For budgeting purposes and the replacement schedule, the tank replacement is to occur in three consecutive outages (one third of the tank, each outage). This scope is included in the estimate.

**Unit No. 2 Lime Mixing Tank**

Major corrosion remediation was performed on the lime mixing tank in 2017. The lime mixing tank is inspected by Vectren during each outage and the re-designed tank is performing better than the previous tank. However, over a ten-year period, it is safe to assume some corrosion remediation will be needed. The internal roof support steel was also abandoned in place. This steel should be inspected during each outage and any compromised members should be removed. This work will require internal scaffolding. This scope is included in the estimate.

**Unit No. 2 Soda Ash Tank**

The access platform and perimeter handrail system on top of the tank should be replaced within the ten-year time frame. This scope is included in the estimate.

Regular minor corrosion remediation on the spiral stair to the top of the soda ash tank should be performed to avoid major corrosion remediation in the future. This scope is included in the estimate.

**Unit No. 2 Belt Filter Building (Regeneration Building)**

Structural Steel, Roof Support Steel, and Floor Support Steel

Major corrosion remediation work has been performed in this building over the last ten years. The corrosion remediation work over the next ten years should be less than the previous ten years, however, based on the corrosive environment, the history of this system, and the ten-year period, corrosion damage is expected, and corrosion remediation needed. This scope is included in the estimate.

Vectren recently removed many of the masonry block walls in this building and there is corrosion damage on the beams that have been exposed, since the block walls were removed. These beams need to be sand blasted and painted. Based on the history in this building, corrosion damage is expected, and corrosion remediation needed. This scope is included in the estimate.

The coating system for the roof support steel is not performing well. This steel needs to be sand blasted and coated. Based on the history in this building, corrosion damage is expected after sand blasting and corrosion remediation needed, prior to installing the coating system. This scope is included in the estimate.

The coating system on the center support beam in the truck bay (and center support for the filter cake drop chute) is not performing well. This steel needs to be sand blasted and coated. Based on the history in this building, corrosion damage is expected after sand blasting and corrosion remediation needed, prior to installing the coating system. This scope is included in the estimate.

The x-bracing (including connection plates) on the east face of this belt filter building, near the lime mixing tank needs to be completely replaced. This replacement process will be similar to the x-bracing replacement work that has been performed several times in the Unit No. 1 belt filter building. This scope is included in the estimate.

Siding and Roofing Systems

The siding and roofing was replaced in 2011, but the system was not installed per the manufacturer's installation instructions and panels are not attached properly to the support steel. A large area of the west wall failed and was replaced in 2017. Ongoing repair work is expected on these systems. This scope is included in the estimate.

Haul Truck Canopy

Corrosion remediation work was performed on the framing and knee braces for this canopy in 2011, but the east edge beam has corrosion damage, and this beam should be replaced (and all connection plates). This scope is included in the estimate.

Internal Stair (South)

Based on the history in this building, corrosion damage is expected, and corrosion remediation needed. This scope is included in the estimate.

External Stair Tower (North)

Corrosion remediation has been performed several times in the last ten (plus) years, but none of the repairs have been coated. This entire structure needs to be sand blasted and painted, since some of the repairs occurred a long time ago. Based on the history, corrosion damage is expected and sand blasting and corrosion remediation is needed, prior to installing the coating system. This scope is included in the estimate.

**Unit No. 2 Chemical Sump**

Vectren replaced the grating support steel with stainless steel and this system appears to be performing relatively well.

Minor ongoing corrosion remediation work has been performed on the piping and pipe supports. Based on the corrosive environment, the history of this system, and the ten-year period, corrosion damage is expected, and corrosion remediation needed. This scope is included in the estimate.

**Unit No. 2 Wastewater Sump**

The handrail system has been repaired over the years, and it is safe to assume that this ongoing process will continue.

Minor ongoing corrosion remediation work has been performed on the piping and pipe supports. Based on the corrosive environment, the history of this system, and the ten-year period, corrosion damage is expected, and corrosion remediation needed. This scope is included in the estimate.

**Unit No. 2 South Horizontal Belt Filter**

The south horizontal belt filter frame was completely replaced in 2013 (the north horizontal belt filter was removed last year). The coating system on the frame has completely failed. Corrosion remediation on the structural frame will be needed soon. After the major corrosion remediation is complete, minor ongoing corrosion remediation will be needed. This scope is included in the estimate.

**Unit No. 2 Horizontal Belt Filter Drop Chute**

The carbon steel horizontal belt filter drop chute was replaced in 2015 with a stainless steel drop chute. This system appears to be performing well, and only occasional minor corrosion remediation is anticipated. This scope is included in the estimate.

**Unit No. 2 Underflow Piping**

Minor ongoing corrosion remediation work has been performed on the piping and pipe supports. Based on the corrosive environment, the history of this system, and the ten-year period, corrosion damage is expected, and corrosion remediation needed. This scope is included in the estimate.

**Unit No. 2 Clarifier Tank Pipe Rack**

This structure is no longer used for its intended purpose (the 24" diameter and 36" diameter pipes are empty and abandoned in place). The structure is at a reduced structure loading, however, there is significant amount of corrosion damage to the two columns that support this tall structure. This pipe rack should be removed and the SBS compressor utilities routed on a new support system. Any other piping and electrical utilities that are still in use should also be relocated. This process would be similar to the 2016/2017 removal of the Unit No. 2 FMC CEMS building platform and re-supporting the piping and electrical utilities that were attached to the platform columns. This scope is included in the estimate.

**Unit No. 2 Switchgear Room**

See Section on absorber recirc. pump building.

## D.3. List of Major Corrosion Remediation Projects

Unit 1 – 2020

- North and South Absorber Access Platforms, Stairs, Ladders, etc. - Remediation
- Replace North and South Regen. Return Valve Access Platforms
- Replace Alley Pipe Supports
- Alley Underground Drain Piping - Corrosion Remediation
- Alley Drainage Manhole - Corrosion Remediation
- Haul Truck Canopy - Replace Beams, Purlins, and Roof Panels
- Lime Silo Enclosure - Replace Siding System and Roof System
- Underflow Access Platform and Stairs - Corrosion Remediation
- Underflow Tunnel Repair - Concrete & Reinforcing Steel - Corrosion Remediation
- Thickener Tank - Replace Exterior Coating
- Thickener Tank - Corrosion Remediation/Discovery Work
- Thickener Tank Vertical Shell Stiffeners
- Old Rotary Filter Building Trench Repair
- Old Rotary Filter Building Truck Bay Block Wall Repair

Unit 2 – 2020

- Thickener Tank - Replace Exterior Coating System
- Thickener Tank - Corrosion Remediation/Discovery Work
- North Outlet Duct Repairs
- Replace North and South Inlet Duct Support Structures
- North and South Absorber Access Platforms, Stairs and Ladders, Etc. - Remediation
- North and South Recirc. Pump Building Trench Drains and Floor - Remediation
- North and South Absorber Regen. Return Valve Access Platform - Replace Coatings
- Regen. Return. Platform - Discovery Work
- Pipe Supports Between Absorbers - Corrosion Remediation
- Regen. Building Siding and Roofing - Corrosion Remediation
- Belt Filter Building Internal Stairway (South) - Coating
- Belt Filter Building Internal Stairway (South) - Corrosion Remediation/Discovery Work
- Belt Filter Building External Stairway (North) - Coating
- Belt Filter Building External Stairway (North) - Corrosion Remediation/Discovery Work
- Lime Silo Exterior Walls - Corrosion Remediation
- Disc & Donut, Shell, Sump, and Duct Repair
- Thickener Tank Bridge Coating
- Regeneration Building Southeast X Bracing - Replace
- Regeneration Building Grit Pit Area Perimeter Beams - Coating Replacement
- Misc. Piping Replacement
- North and South Absorber Shell Plates

- Replace Top Landing on Lime Slurry Storage Tank
- Lime Slurry Storage Tank Roof Support Steel - Corrosion Remediation
- Clarifier Tank - Dome Top - Corrosion Remediation
- Clarifier Tank - Rake Drive Support Steel and Access Platform - Corrosion Remediation
- Clarifier Tank - Walkway and Stairs - Corrosion Remediation

<u>Unit 1 – 2021</u>

- North and South Inlet Duct at Scrubbers - Replace
- North and South Outlet Duct Repairs - Partial Replacement & Remediation
- North and South Inlet Duct Support Structures - Replace Posts
- Replace North Quench Sprays
- Replace South Quench Sprays
- North and South Absorber Outlet Duct Structures - Remediation
- North Absorber Inlet Expansion Joint Replacement 1-15
- North Absorber Inlet Expansion Joint Replacement 1-23
- North Absorber Inlet Expansion Joint Replacement 1-18B
- South Absorber inlet Expansion Joint Replacement 1-17
- South Absorber Inlet Expansion Joint Replacement 1-18A
- North Absorber Outlet Expansion Joint Replacement
- South Absorber Outlet Expansion Joint Replacement
- Alley Underground Drain Piping - Corrosion Remediation
- Alley Drainage Manhole - Corrosion Remediation
- Thickener Tank Bridge - Corrosion Remediation/Discovery Work
- Thickener Tank Bridge and Utility Supports, Rake Canopy, and Handrail System - Replace Coating
- Soda Ash Tank Install Drains and piping
- Soda Ash Tank Grating (Remove and Install)
- Switch Gear Building - Remediation
- Disc & Donut, Shell, Sump, and Duct Repair
- North and South Absorber Access Platforms, Stairs, ladders, Etc.
- Replace Thickener Tank Rim and Launder - Shop Fabrication
- Replace Thickener Tank Rim and Launder - Exterior and Interior Coating
- Replace Thickener Tank Rim and Launder
- Misc. Piping Replacement
- North and South Absorber Shell plates

<u>Unit 2 – 2021</u>

- North Absorber Inlet Expansion - Replace
- South Absorber Inlet Expansion - Replace
- North Absorber Outlet Expansion (1st one off scrubber) - Replace
- North Absorber Outlet Expansion (At Stack) - Replace
- South Absorber Outlet Expansion (1st one off scrubber) - Replace
- South absorber Outlet Expansion (At Stack) - Replace

- North Outlet Duct Repairs - Remediation
- North and South Inlet Duct Support Structures - Remediation
- North and South Absorber Access Platforms, Stairs and Ladders, etc. - Remediation
- Thickener Tank Rim - Remediation
- Regen Building Siding and Roofing - Remediation
- Clarifier Tank Pipe Rack - Remove & Replace SBS Air Compressor Utilities
- Lime Silo Fill Lines - Replace
- Disc & Donut, Shell, Sump, and Duct Repair
- Misc. Piping Replacement
- North and South Absorber Shell plates
- Replace Walkway From Lime Slurry Storage Tank to Regen. Building
- Clarifier Tank - Shell and Floor - Corrosion Remediation
- Clarifier Tank - Enclosure - Corrosion Remediation
- Clarifier Tank - Tank Floor Support Steel - Corrosion Remediation

<u>Unit 1 – 2022</u>

- North and South Absorber Anchor Bolts and Chairs
- North and South Absorber Shell plates
- North and South Absorber External Stiffeners
- North and South Tower - Replace Flake Glass Liner (Complete Replacement)
- North and South Tower Patching, Vertical Supports And Plates (Drawing 70 thru 74)
- North and South Absorbers Support Post (Drawing 76)
- North and South Absorber Supports (Drawing 77)
- North and South Absorber Alloy Bands and External Stiffening (drawing 78)
- North and South Absorber Repairs to Inlet Duct and Absorber Interface And Internal Awning
- North and South Absorber wall repairs after cleaning
- Replace North Absorber Mist Eliminators
- Replace South Absorber Mist Eliminators
- North Absorber Cone Repair and Reinforcement
- South Absorber Cone Repair and Reinforcement
- North and South Inlet Duct at Scrubbers
- North and South Outlet Duct - Corrosion Remediation
- North and South Inlet Duct Support Structures - Corrosion Remediation
- North and South Absorber Outlet Duct Structures
- North Absorber Outlet Elbow Duct
- Thickener Tank Shell and Floor Plate
- Disc & Donut, Shell, Sump, and Duct Repair
- North and South Absorber Access Platforms, Stairs, Ladders, Etc. - Remediation
- Belt Filter Roof Support Steel - Corrosion Remediation
- Replace Belt Filter Roof System (including purlins and roofing panels)
- Replace Acid Brick Liner in Absorber Sumps

Unit 2 – 2022

- North and South Absorber Access Platforms, Stairs and Ladders, Etc.
- Regen Building Siding and Roofing
- Haul Truck Canopy - Remediation
- Replace Soda Ash Tank Stairway
- Purchase Material for North Absorber Mist Eliminators
- Purchase Material for North Absorber Duct Replacement

Unit 1 – 2023

- Alley Underground Drain Piping - Remediation
- Alley Drainage Manhole - Remediation
- North and South Absorber Access Platforms, Stairs, ladders, Etc.
- Old Rotary Filter Building Coating
- Horizontal Belt Filter Building Coating
- Old Rotary Filter Building - Remediation
- Horizontal Belt Filter Building Coating - Remediation
- Belt Filter Building Floor Replacement
- Soda Ash Tank Access Platform and Perimeter Handrail system

Unit 2 – 2023

- Absorbers Inside Liner Replacement
- North and South Absorber Anchor Bolts and Chairs
- North and South Absorber Shell Plates
- North and South Absorber External Stiffeners
- North Mist Eliminators - Install
- North and South Mist Eliminators Wash Access Platforms and Walkways Corrosion
- North Outlet Duct Replacement - Install
- North and South Inlet Duct Support Structures
- North Quench Spray Piping
- South Quench spray Piping
- North and South Absorber Access Platforms, Stairs and Ladders, Etc.
- North and South Bleed Piping - Replace
- Thickener Tank Shell and Floor Plate Internal Remediation
- Regen Building Siding and Roofing
- South Horizontal Belt Filter - Replace Frame and Main Rollers
- Disc & Donut, Shell, Sump, and Duct Repair
- Replace Absorber Recirc. Piping
- Replace Acid Brick Liner in Absorber Sumps

Unit 1 – 2024

- North and South Inlet Duct at Scrubbers
- North and South Outlet Duct Repairs

- North and South Inlet Duct Support Structures
- North Quench Sprays
- South Quench Sprays
- North and South Absorber Outlet Duct Structures
- North Absorber Inlet Expansion Replacement 1-15
- North Absorber Inlet Expansion Replacement 1-23
- North Absorber Inlet Expansion replacement 1-18B
- South Absorber inlet Expansion Replacement 1-17
- South Absorber Inlet Expansion Replacement 1-18A
- North Absorber Outlet Expansion Replacement
- South Absorber Outlet Expansion Replacement
- Alley Underground Drain Piping - Remediation
- Alley Drainage Manhole - Remediation
- Thickener Tank Bridge Utility Supports, Rake Canopy, and Handrail System Coating
- Disc & Donut, Shell, Sump, and Duct Repair
- North and South Absorber Access Platforms, Stairs, ladders, Etc.
- Lime Mixing Tank - Remediation
- Misc. Piping Replacement
- North and South Absorber Shell plates

<u>Unit 2 – 2024</u>
- North and South Inlet Duct Support Structures
- North and South Absorber Access Platforms, Stairs and Ladders, Etc.
- Regen Building Siding and Roofing
- Replace Thickener Tank Bridge
- Disc & Donut, Shell, Sump, and Duct Repair
- Lime Mixing Tank - Remediation
- Misc. Piping Replacement
- North and South Absorber Shell plates

## <u>E. ESTIMATE ASSUMPTIONS & CLARIFICATIONS</u>

- The project list contains major projects and major tasks.
- Budget pricing for all years is in 2019 dollars.
- The capital projects have not been designed or engineered; therefore, all budget pricing is conceptual only.
- The cost for each outage year includes $1,000,000 for absorber disc and donut repairs and interior shell repairs. This is based on the current Vectren repair approach.
- The cost for the major outage year for unit no. 1 includes $3,500,000 for the north and south absorber mist eliminator and mist eliminator wash system replacement. This is a Vectren planned replacement.
- The cost for the major outage year for unit no. 2 includes $1,700,000 for north absorber mist eliminator and mist eliminator wash system replacement. This is a Vectren planned replacement.
- An engineering cost of 20% for all capital work is included in the budget pricing.
- Costs for planned work were estimated using historical costs from 2011 – 2017 and contractor budget pricing.
- The budget pricing is based on Vectren's current operating practices, maintenance practices, outage approaches, corrosion remediation practices, management practices, etc. If Vectren management, engineering, maintenance, and/or operations, change their practices, the changes may affect the projected costs.
- The budget pricing does <u>not</u> include allowances for changes in EPA requirements, changes in CCR regulations, etc.
- The budget pricing is based on good maintenance and repair practices, which includes quickly repairing all leaks.
- The historical Vectren O&M and capital (2011 thru 2018) was used as reference information for budget pricing data.

## F. RISKS ASSOCIATED WITH OPERATION BEYOND TEN ADDITIONAL YEARS

Unit No. 1 was designed and installed in 1977/1978 and Unit No. 2 was designed and installed in 1983/1984. In 2030, Unit No. 1 will be older than fifty years and Unit No. 2 will be almost fifty years old.

FMC Corporation, who designed the original FGD Systems, didn't identify a service life for the systems or the components. Generally, if no system life is identified, the expected service life would be less than fifty years. Many system components can have a ten to twenty-year service life. In excessively corrosive environments, the expected service life needs to be de-rated, consistent with the corrosion rate.

The FGD system is a very corrosive environment, and even though there has been ongoing repair work and major repair work in numerous areas of the Unit No. 1 and Unit No. 2 FGD systems, the infrastructure is still basically the original FMC Corporation infrastructure.

Operating a system beyond its design service life or anticipated service life results in reduced structural capacity and integrity, increased occurrences of equipment failure, increased Operating and Maintenance Costs, reduced system reliability, reduced system availability, and increased safety risks.

# APPENDIX: COST TABLES

10 Year O&M/CapEx Estimate
9/27/2019

| ABB DA Summary | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| O&M - Labor | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| O&M - Scheduled Outage | $700,000 | $1,000,000 | $700,000 | $700,000 | $1,100,000 | $800,000 | $900,000 | $1,500,000 | $1,200,000 | $1,400,000 | $2,300,000 |
| O&M - Base Non-Labor | $2,900,000 | $3,100,000 | $3,200,000 | $3,400,000 | $3,600,000 | $3,800,000 | $4,100,000 | $4,700,000 | $5,700,000 | $7,000,000 | $7,300,000 |
| Total O&M Costs | $3,600,000 | $4,100,000 | $3,900,000 | $4,100,000 | $4,700,000 | $4,600,000 | $5,000,000 | $6,200,000 | $6,900,000 | $8,400,000 | $9,600,000 |
| | | | | | | | | | | | |
| Capital - Direct Unit | $9,400,000 | $15,500,000 | $18,100,000 | $13,800,000 | $11,900,000 | $8,200,000 | $6,900,000 | $9,200,000 | $7,400,000 | $7,300,000 | $8,300,000 |
| Capital - Construction | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| Total Capital Costs | $9,400,000 | $15,500,000 | $18,100,000 | $13,800,000 | $11,900,000 | $8,200,000 | $6,900,000 | $9,200,000 | $7,400,000 | $7,300,000 | $8,300,000 |
| 20 Yr Total | $13,000,000 | $19,600,000 | $22,000,000 | $17,900,000 | $16,600,000 | $12,800,000 | $11,900,000 | $15,400,000 | $14,300,000 | $15,700,000 | $17,900,000 |

| ABB1 Dual Alkali Re-Furbish | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| O&M - Labor | | | | | | | | | | | |
| O&M - Scheduled Outage | $200,000 | $500,000 | $500,000 | $200,000 | $600,000 | $600,000 | $300,000 | $800,000 | $900,000 | $400,000 | $1,200,000 |
| O&M - Base Non-Labor | $1,500,000 | $1,600,000 | $1,700,000 | $1,800,000 | $1,900,000 | $2,000,000 | $2,200,000 | $2,500,000 | $3,000,000 | $3,700,000 | $3,800,000 |
| Total O&M Costs | $1,700,000 | $2,100,000 | $2,200,000 | $2,000,000 | $2,500,000 | $2,600,000 | $2,500,000 | $3,300,000 | $3,900,000 | $4,100,000 | $5,000,000 |
| | | | | | | | | | | | |
| Capital - Direct Unit | $2,700,000 | $9,200,000 | $15,900,000 | $2,200,000 | $7,200,000 | $4,600,000 | $2,500,000 | $4,800,000 | $5,000,000 | $2,700,000 | $4,800,000 |
| Capital - Construction | | | | | | | | | | | |
| Total Capital Costs | $2,700,000 | $9,200,000 | $15,900,000 | $2,200,000 | $7,200,000 | $4,600,000 | $2,500,000 | $4,800,000 | $5,000,000 | $2,700,000 | $4,800,000 |
| 20 Yr Total | $4,400,000 | $11,300,000 | $18,100,000 | $4,200,000 | $9,700,000 | $7,200,000 | $5,000,000 | $8,100,000 | $8,900,000 | $6,800,000 | $9,800,000 |

| ABB2 Dual Alkali Re-Furbish | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| O&M - Labor | | | | | | | | | | | |
| O&M - Scheduled Outage | $500,000 | $500,000 | $200,000 | $500,000 | $500,000 | $200,000 | $600,000 | $700,000 | $300,000 | $1,000,000 | $1,100,000 |
| O&M - Base Non-Labor | $1,400,000 | $1,500,000 | $1,500,000 | $1,600,000 | $1,700,000 | $1,800,000 | $1,900,000 | $2,200,000 | $2,700,000 | $3,300,000 | $3,500,000 |
| Total O&M Costs | $1,900,000 | $2,000,000 | $1,700,000 | $2,100,000 | $2,200,000 | $2,000,000 | $2,500,000 | $2,900,000 | $3,000,000 | $4,300,000 | $4,600,000 |
| | | | | | | | | | | | |
| Capital - Direct Unit | $6,700,000 | $6,300,000 | $2,200,000 | $11,600,000 | $4,700,000 | $3,600,000 | $4,400,000 | $4,400,000 | $2,400,000 | $4,600,000 | $3,500,000 |
| Capital - Construction | | | | | | | | | | | |
| Total Capital Costs | $6,700,000 | $6,300,000 | $2,200,000 | $11,600,000 | $4,700,000 | $3,600,000 | $4,400,000 | $4,400,000 | $2,400,000 | $4,600,000 | $3,500,000 |
| 20 Yr Total | $8,600,000 | $8,300,000 | $3,900,000 | $13,700,000 | $6,900,000 | $5,600,000 | $6,900,000 | $7,300,000 | $5,400,000 | $8,900,000 | $8,100,000 |

| ABB BPT | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| O&M - Labor | | | | | | | | | | | |
| O&M - Scheduled Outage | | | | | | | | | | | |
| O&M - Base Non-Labor | | | | | | | | | | | |
| Total O&M Costs | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | | | | | | | | | | | |
| Capital - Direct Unit | | | | | | | | | | | $0 |
| Capital - Construction | | | | | | | | | | | |
| Total Capital Costs | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 20 Yr Total | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |

| ABB LF Leachate | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| O&M - Labor | | | | | | | | | | | |
| O&M - Scheduled Outage | | | | | | | | | | | |
| O&M - Base Non-Labor | | | | | | | | | | | |
| Total O&M Costs | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | | | | | | | | | | | |
| Capital - Direct Unit | | | | | | | | | | | |
| Capital - Construction | | | | | | | | | | | |
| Total Capital Costs | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 20 Yr Total | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |

| ABB Selenium | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| O&M - Labor | | | | | | | | | | | |
| O&M - Scheduled Outage | | | | | | | | | | | |
| O&M - Base Non-Labor | | | | | | | | | | | |
| Total O&M Costs | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | | | | | | | | | | | |
| Capital - Direct Unit | | | | | | | | | | | $0 |
| Capital - Construction | | $0 | $0 | $0 | | | | | | | |
| Total Capital Costs | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 20 Yr Total | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |

| ABB DBA | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 |
|---|---|---|---|---|---|---|---|---|---|---|---|

| | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| O&M - Labor | | | | | | | | | | | |
| O&M - Scheduled Outage | | | | | | | | | | | |
| O&M - Base Non-Labor | | | | | | | | | | | |
| Total O&M Costs | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| Capital - Direct Unit | | | | | | | | | | | |
| Capital - Construction | | | | | | | | | | | |
| Total Capital Costs | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 20 Yr Total | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |

| ABB DFA | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| O&M - Labor | | | | | | | | | | | |
| O&M - Scheduled Outage | | | | | | | | | | | |
| O&M - Base Non-Labor | | | | | | | | | | | |
| Total O&M Costs | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| Capital - Direct Unit | | | | | | | | | | | |
| Capital - Construction | | | | | | | | | | | |
| Total Capital Costs | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 20 Yr Total | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |

| ABB By-Products Landfill | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| O&M - Labor | | | | | | | | | | | |
| O&M - Scheduled Outage | | | | | | | | | | | |
| O&M - Base Non-Labor | | | | | | | | | | | |
| Total O&M Costs | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| Capital - Direct Unit | | | | | | | | | | | |
| Capital - Construction | | | | | | | | | | | |
| Total Capital Costs | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 20 Yr Total | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |

**Assumptions**

1 All costs are expressed in 2019 dollars. No Escalation is included.
2 Total Capital costs are +/- 50% and include the costs associated with the purchase of equipment, erection, and all contractor services.
3 Total Capital costs do not include contingency, owners cost, taxes, insurance, spare parts, or construction utility interconnections/consumables.
4 BPT and Selenium treatment is common equipment for both units
5 Leachate and WW Hg Treatment is included in BPT treatment Total Capital Costs
6 O&M Base Non-Labor cost for BPT and Selenium treatment assumed 2% equipment capital costs for maintenance items, consumables and spare parts. Variable O&M costs are not included.
7 Capital Direct cost for BPT and Selenium treatment assumed 4% equipment capital cost for equipment replacement during major outage
8 BPT treatment Total Capital Costs includes all common water treatment infracture.
9 Selenium treatment Total Capital costs includes only biological treatment which requires the BPT treatment system and entire infrastructure upstream for effluent compliance
10 DBA and DFA rates to be established by Vectren

| BPT Reagent Data | | | | |
|---|---|---|---|---|
| Reagent | Unit Pricing | | Usage Rate | |
| Coagulant Feed | 1.4 | $/gal | 15 | gal/MWhr |
| Polymer | 7.5 | $/gal | 5 | gal/MWhr |
| Dewatering Polymer | 7.5 | $/gal | 5 | gal/MWhr |
| Sodium Hypochlorite | 0.95 | $/gal | 2.1 | gal/MWhr |
| Sodium Bisulfite | 2.4 | $/gal | 1.1 | gal/MWhr |
| Organosulfide | 3 | $/gal | 15 | gal/MWhr |

**Landfill Assumptions/Clarifications**
**ADDITIONAL COSTS NOT REFLECTED ABOVE:**
Closure (calendar year 2040) = $6M
Post-Closure (30 years) beginning in 2041 = $0.2M per year.
*Closure costs move up if landfill is no longer used.

A wastewater treatment facility is constructed at the AB Brown Station. Those costs are not included here. Internal treatment cost assumed to be $0.05 per gallon.
No inflation escalator has been included. All estimates are based on 2019 prices.

**ESTIMATES DO NOT INCLUDE:**
Mitigation of wetland areas disturbed by construction.
Project management/supervision by Vectren.
Legal costs associated with zoning.
Purchase of property.
Investigations and/or remediation associated with groundwater impact.
Waste delivery to landfill costs.

# Attachment 6.7 Environmental Compliance Options Study

FINAL

# REVIEW OF ENVIRONMENTAL COMPLIANCE

## A.B. Brown Unit 1 and 2

## F.B. Culley Unit 2

**B&V PROJECT NO. 400278**
**B&V FILE NO. 40.0003**



**PREPARED FOR**

VECTREN
A CenterPoint Energy Company

Vectren

20 MAY 2020

BLACK & VEATCH

# Table of Contents

## LIST OF TABLES

# 1.0 Executive Summary

Southern Indiana Gas and Electric Company d/b/a Vectren Power Supply, Inc. (Company) has contracted with Black & Veatch Corporation (Consultant) to serve as an Owner's Engineer (OE) in the evaluation of coal combustion residuals (CCR) and effluent limit guideline (ELG) regulations for A.B. Brown (ABB) and F.B. Culley (FBC) Power Stations.

On April 17, 2015, the Environmental Protection Agency (EPA) published in the Federal Register the final CCR rule. The CCR rule contains specific requirements that are to be met to continue operation of the CCR unit(s). Failure to meet specific requirements will require operation to cease and closure or retrofit of the CCR unit to begin. For units that are required to close, the CCR rule allows for two options: (1) leave the CCR in place and install a final cover system or (2) remove the CCR and decontaminate the unit.

The EPA finalized an update to the ELG rule on September 30, 2015. The final rule strengthens the technology based ELGs by introducing more stringent discharge restrictions on toxic pollutants. Changes include new standards for flue gas desulfurization (FGD), flue gas mercury control (FGMC), gasification, and landfill leachate waste streams that were previously included under low volume wastes. Additionally, it establishes a zero-discharge standard for fly and bottom ash transport waste streams for both new and existing point sources. The final rule did not include any changes to the previously specified cooling tower blowdown, once-through cooling, or coal pile runoff effluent standards.

On September 18, 2017, the EPA postponed compliance dates in the 2015 rule for best available technology (BAT) effluent limitations and pretreatment standards for existing sources (PSES) for FGD wastewater and bottom ash transport water until new rulemaking could be completed. On May 23, 2019, the EPA released its rulemaking timeline, indicating a new proposed rule would be issued in June 2019, with the final rule issued in August 2020. On November 22, 2019, EPA published the new proposed rule which would revise requirements to FGD wastewater and bottom ash transport water.

The National Pollutant Discharge Elimination System (NPDES) permit issued to A.B. Brown Station in 2017 (effective date of April 1, 2017) by the Indiana Department of Environmental Management (IDEM) was subsequently modified in 2018 and contains new, more strict effluent limitations for copper, chloride, and selenium. Pursuant to the permit, the facility must comply with the final effluent limitations for these constituents by April 1, 2020.

## 1.1 A.B. BROWN STATION

A.B. Brown Station is a two unit, 530 megawatt (MW) coal fired electricity generating power facility, located on the northern bank of the Ohio River, 5 miles southwest of Evansville, Indiana. The station includes Unit 1 with a rated capacity of 265 MW and Unit 2 with a rated capacity of 265 MW. A.B. Brown Station currently utilizes an ash pond for ash handling and settling pond for wastewater treatment, as well as collection of metal cleaning, FGD wash water, other process wastewaters, treated sanitary wastewaters, and storm water.

Closure of the ash pond because of the CCR ruling represents a significant reduction in reuse water, storage, and settling capabilities for A.B. Brown. Of the wastewater streams regulated under the EPA's revised ELG rule, only fly ash transport, bottom ash transport, low volume wastewater, and leachate apply to A.B. Brown. Discharge of ash transport water is no longer permissible and, as such, a new means of transport and storage of CCR materials will be necessary. All wastewater flows into the ash pond will now need to be re-directed, collected, and properly treated prior to discharge.

## 1.2 F.B. CULLEY STATION

F.B. Culley Station is a two unit, 387 MW coal fired electricity generating power facility, located on the northern bank of the Ohio River, southeast of Newburgh, Indiana. The station includes Unit 2 with a rated capacity of 100 MW and Unit 3 with a rated capacity of 287 MW.

As with the A.B. Brown units, the CCR regulations require F.B. Culley to discontinue the use of the Unit 2 and Unit 3 ponds, referred to as east and west, respectively. The elimination of both CCR units represents a significant reduction in storage and settling capabilities for F.B. Culley.

F.B. Culley Unit 3 is planned for a dry bottom ash conversion in 2020 utilizing a submerged chain conveyor. This report discusses the upgrade options for F.B. Culley Unit 2 to also meet CCR and ELG regulations.

## 1.3 OBJECTIVE

The focus of the ELG/CCR Compliance Program is to identify alternative ash handling and water treatment options as well as any water reclamation or elimination options for each regulated discharge stream to bring A.B. Brown and F.B. Culley Stations into future compliance with the updated CCR and ELG regulations.

This report provides the following:

- A review of the updated CCR for both A.B. Brown Units 1 and 2 and F.B. Culley Unit 2.
- ELG regulations and NPDES permit limitations and their impact on A.B. Brown Units 1 and 2, including timing of the respective rules and application.
- An evaluation of bottom ash and fly ash solutions, design concepts, feasibility, and present worth of capital and operating expenses for each option for both A.B. Brown Units 1 and 2 and F.B. Culley Unit 2.
- An evaluation of treatment technology options for A.B. Brown Units 1 and 2 with respect to the updated ELG rulings including design concepts, feasibility, and present worth of capital and operating expenses.

## 1.4 SUMMARY OF RECOMMENDATIONS

The following recommendations are proposed for each unit.

**Table 1-1 Summary of Recommended Technologies – A.B. Brown Station**

| OPTION | TECHNOLOGY DESCRIPTION | CAPITAL COST | O&M COST |
|---|---|---|---|
| ELG Equipment (Table 4-1) | Physical/Chemical and Biological, Collection and Filtration, Location 2 | $43,072,000 | $1,378,000 |
| Bottom Ash | Modified SCC Bottom Ash Handling | $29,927,200 | $1,260,500 |
| Fly Ash | Dry Pneumatic Fly Ash Handling | $22,652,300 | $3,679,300 |

**Table 1-2 Summary of Recommended Technologies – F.B. Culley Station**

| OPTION | TECHNOLOGY DESCRIPTION | CAPITAL COST | O&M COST |
|---|---|---|---|
| Wet-to-Dry Ash Handling | Indoor Dewatering Tanks | $3,868,000 | $300,300 |

# 2.0 Summary of Evaluations

This section summarizes the ELG/CCR Compliance Program ("Projects") for A.B. Brown (ABB) and F.B. Culley (FBC) Stations.

## 2.1 COAL COMBUSTION RESIDUALS RULING

### 2.1.1 Background

On April 17, 2015, the Environmental Protection Agency (EPA) published in the Federal Register the final CCR rule. As expected, the rule regulates CCR as nonhazardous waste under Subtitle D of the Resource Conservation and Recovery Act (RCRA). The rule was published in the Federal Register on April 17, 2015, and it was effective on October 19, 2015.

The CCR rule contains specific requirements that are to be met to continue operation of the CCR unit(s). These requirements include the following:

- Location restrictions.
- Design criteria, including liner design and structural integrity.
- Operating criteria including air criteria, hydrologic and hydraulic capacity requirements, and inspection requirements.
- Groundwater monitoring and corrective action.
- Closure and post-closure care.
- Recordkeeping, notification, and internet posting.

Failure to meet or document the above items generally results in requirements to cease operation and begin closure or retrofit of the CCR unit. For units that are required to close, the CCR rule allows for two options; either to leave the CCR in place and install a final cover system (i.e., close in place) or remove the CCR and decontaminate the unit (i.e., clean closure). Regardless of the selected closure option, in the event of groundwater contamination, closure is not deemed complete until groundwater is no longer exceeding groundwater protection standards

Clean closure requires dewater and excavation of all CCR, removal of the underlying impacted soil, and final backfill with clean soil. This option removes any groundwater contamination risks so any groundwater remediation (if required) is limited to treating the residual contamination. The option also requires only top soil, which eliminates the need for an engineered cap or any post-closure care. The drawbacks are the significant construction costs associated with the dewatering, excavation, and backfill efforts in addition to long construction durations.

Close in place requires dewatering and regrading of the existing surface, backfill efforts, and an engineered cap. This option results in minimal disturbance of the existing CCR, reduced backfill with relatively short construction schedule, and lowered costs. This option does require an engineered cap, typically a geosynthetic layer, and regularly scheduled post-closure care including groundwater monitoring for 30 years. There are more risks involved with this option because the potential for groundwater contamination remains and there is a significant cost for groundwater remediation if groundwater is incised with CCR.

### 2.1.2 Implementation and Enforcement

The rule is self-implementing; therefore, affected facilities must comply with the new regulations irrespective of whether a state adopts the rule. Even if a state promulgates its own rule and incorporates the federal criteria into the state's solid waste management program, the federal rule remains in place as an independent set of federal criteria that must be met (although the EPA states in the preamble that facilities in compliance with an EPA-approved state CCR solid waste management plan that is identical to or more stringent than the federal criteria should be viewed as meeting or exceeding the federal criteria). Because the rule is promulgated under Subtitle D, it does not require regulated facilities to obtain permits, does not require the states to adopt and implement the new rules, and cannot be enforced by the EPA. The rule's only compliance mechanism is for a state or citizen group to bring an RCRA citizen suit in federal district court under RCRA Section 7002 against any facility that is alleged to be in noncompliance with the new requirements.

### 2.1.3 Applicability

The rule applies to new and existing landfills and surface impoundments used to manage CCR generated by coal fired electric utility plants in North American Industry Classification System (NAICS) Industry Code 221112. The rule also applies to inactive surface impoundments (i.e., impoundments not receiving CCR on or after October 19, 2015, but that still contain CCR and liquid) located at power plants producing electricity regardless of fuel type.

## 2.2 EFFLUENT LIMITATION GUIDELINE RULE

### 2.2.1 Background

As authorized by the Clean Water Act (CWA), the National Pollutant Discharge Elimination System (NPDES) permit program controls water pollution by regulating discharge point sources into bodies of water in the United States. Wastewater discharges from Vectren facilities are regulated under the Indiana Department of Environmental Management (IDEM) NPDES program that incorporates the standards set forth in the 40 Code of Federal Regulations (CFR) 423, Steam Electric Power Generating Point Source category.

Guidelines set forth under 40 CFR 423 establish wastewater discharge standards for existing point sources that represent the degree of effluent reduction that can be achieved by application of the best available technology (BAT) that is economically achievable. Guidelines for discharges from new point sources are set forth in new source performance standards (NSPS). In addition, guidelines for existing and new sources that discharge into a publicly owned treatment works (POTW) are established for pretreatment standards for existing sources (PSES) and/or pretreatment standards for new sources (PSNS). These guidelines and standards are to be used by the NPDES permitting authority (IDEM in Indiana) in setting applicable discharge limits for specified effluents in new and renewed NPDES and pretreatment permits for steam electric generation facilities.

In 2015, the EPA released a final rule updating the ELGs in 40 CFR 423. The updated rule strengthened the technology based ELGs by introducing more stringent discharge restrictions on toxic pollutants. Changes included new standards for flue gas desulfurization (FGD), flue gas mercury control (FGMC), gasification, and landfill leachate waste streams that were previously included under low volume wastes. In November 2019, the EPA released a proposed rule to further update the ELGs in 40 CFR 423, which is only applicable to FGD wastewater and bottom ash transport water. The proposed rule would establish BAT effluent limitations for total suspended solids (TSS), mercury (Hg), arsenic (As), selenium (Se), and nitrate/nitrite as nitrogen in FGD wastewater discharges. For bottom ash, the proposal includes a TSS BAT effluent limitation and a not-too-exceed 10 percent volumetric purge limitation. The proposed rule proposes subcategories with separate requirements, including high flow facilities (>4 MGD of FGD wastewater), low utilization boilers (876,000 MWh per year or less), and boilers retiring by 2028.

### 2.2.2 Review of ELG Final Rule

The 2015 ELG rule update was applicable to Vectren facilities that established separate definitions and categories for FGD wastewater and combustion residual leachate, which were previously considered low volume waste sources.

The EPA's rulemaking sets forth technology-based effluent standards for discharges from these new wastewater streams to surface waters and POTW sewer systems. NPDES permitting authorities (IDEM in Indiana) have been incorporating the 2015 ELG standards as applicable into each existing facility's NPDES permit renewals.

The 2015 ELG rule established more stringent BAT effluent limitation guidelines and standards for the various waste streams generated by new and existing steam electric facilities (i.e., FGD wastewater, bottom ash transport water, combustion residual leachate, flue gas mercury control wastewater, fly ash transport water and gasification wastewater). The new proposed rule proposes to amend the more stringent effluent limitations guidelines and pretreatment standards for existing sources in the 2015 rule that apply to FGD wastewater and bottom ash transport water. Where BAT limitations are more stringent than previously established, the new rule proposes that those limitations would not apply until a date determined by the permitting authority (IDEM in Indiana) that is as soon as possible on or after November 1, 2020, but that is no later than December 31, 2023, (for bottom ash transport water) or December 31, 2025 (for FGD wastewater).

The proposal also includes a voluntary incentives program that provides the certainty of more time (until December 31, 2028) for plants to adopt additional process changes and controls that achieve more stringent limitations on mercury, arsenic, selenium, nitrate/nitrite, bromide, and total dissolved solids in FGD wastewater. The optional program provides plants more flexibility, such as additional time, that previous incentives programs.

The technology basis for discharges from existing point sources applicable to the subject Vectren facilities set forth in the proposed 2019 ELG rule are shown in Table 2-1.

**Table 2-1 Technology Basis for BAT/PSES and NSPS/PSNS Effluent Limitation Guidelines**

| WASTE STREAMS | EXISTING BAT AND PSES | NEW NSPS AND PSNS |
|---|---|---|
| Fly Ash Transport Water | Dry Handling | Dry Handling |
| Bottom Ash Transport Water | Dry Handling/Closed Loop<br>Bottom ash transport water on not-too-exceed 10 percent volumetric purge | Dry Handling/Closed Loop<br>Bottom ash transport water on not-too-exceed 10 percent volumetric purge |
| Wet FGD Wastewater | Chemical Precipitation + Biological Treatment<br>Low residence Biological treatment<br>Membranes | Evaporation |
| Combustion Residual Leachate | Gravity Settling Impoundment | Chemical Precipitate |

## 2.3 A.B. BROWN--IMPACT OF CCR REGULATIONS

A.B. Brown Station currently utilizes one ash pond. The pond is designed as a surface impoundment. The pond receives bottom ash and fly ash water and the FGD wash water flows, as well as process wastewater, treated sanitary wastewaters and stormwater.

Future closure of the ash pond represents a significant reduction in reuse water, storage, and settling capabilities for A.B. Brown. In conjunction with the ELG ruling, discharge of ash transport water will no longer be permissible and, as such, a new means of transport and storage of CCR materials will be necessary.

## 2.4 A.B. BROWN--TECHNOLOGY OPTIONS FOR CCR COMPLIANCE

Black & Veatch worked with Vectren to evaluate different cost-effective concepts of bottom ash handling at A.B. Brown Units 1 and 2.

Following the evaluation, Black & Veatch recommended incorporation of a submerged chain conveyor (SCC) underneath the boiler to replace the current sluicing system at A.B. Brown. An SCC uses a submerged drag chain to collect ash and discharge the dewatered ash into a bunker for final dewatering and storage. Subsequently, the ash would be managed for beneficial reuse or disposal. Conversion to SCC may require cooling water depending on final design parameters. The basis for the SCC for the A.B. Brown units is based on the current design, which is in progress for F.B. Culley Unit 3. This design is a United Conveyor Corporation (UCC) submerged flight conveyor (SFC) system. The installed cost to retrofit both A.B. Brown Unit 1 and Unit 2 boilers with SCC equipment has been incorporated into the treatment options in Section 4.0, Table 4-3.

A technology comparison matrix for the bottom ash alternatives described for A.B. Brown Units 1 and 2 is provided in Table 2-2.

**Table 2-2 A.B. Brown Units 1 and 2 Bottom Ash Technology Comparison Matrix**

| ALTERNATIVE | SUBMERGED CHAIN CONVEYOR (ALTERNATIVE 1) | DEWATERING BUNKER (ALTERNATIVE 2) | REMOTE SUBMERGED CHAIN CONVEYOR (ALTERNATIVE 3) |
|---|---|---|---|
| **Description** | Alternative 1 consists of a new submerged chain conveyor under the existing bottom ash hopper and existing grinders. The submerged chain conveyor will be routed out of the Boiler Building, discharging on an exterior pile or waiting truck. | Alternative 2 is a concrete dewatering bunker. The bottom ash is sluiced through piping to a remote bunker location. A concrete bunker is used to separate the larger particles while a settling tank is used to separate the smaller fines. | Alternative 3 provides a remote closed loop system outside of the existing Boiler Building. The existing bottom ash hopper and sluicing pump would deliver the ash to the new remote dewatering containment equipped with a new submerged chain conveyor that would dewater and deliver the ash to a three-sided bunker for truck removal. |
| **Technical Feasibility** | A submerged chain conveyor is often used for removing and dewatering bottom ash from boilers and is a sound technical approach. | The dewatering bunker system is complex with many pumps, piping, and concrete bunkers. | Remote recirculation systems are often used for bottom ash conversions. The technical feasibility is sound but may not be financially viable for small units. |
| **Total Contracted Cost** | $29,927,200 | $36,448,900 | $41,656,700 |
| **Operations and Maintenance Cost** | $1,260,500 | $1,539,400 | $1,463,500 |
| **Estimated Additional Manpower** | 1.8 | 3.6 | 2.4 |
| **Estimated Footprint (sq. ft.)** | 400 | 20,000 | 6,000 |
| **Major Equipment** | • Submerged chain conveyor.<br>• Hydraulic power unit.<br>• Instrumentation and controls.<br>• Quench water overflow tank, pump, and heat exchanger.<br>• Chain wash spray system.<br>• Three-sided concrete bunker.<br>• Motor control center (MCC) to feed new motors and pumps. | • Transfer tank with jet pump.<br>• Water supply tank and sluice transfer pumps.<br>• Dewatering bunker.<br>• Bunker sump pumps.<br>• Settling tank and sludge pumps.<br>• Surge tank and sluice recirculation pumps.<br>• New overhead door on operating floor.<br>• Instrumentation and controls.<br>• MCC to feed new motors and pumps. | • New remote hopper with new submerged chain conveyor.<br>• Hydraulic power unit.<br>• Instrumentation and controls.<br>• Return water pumps and piping.<br>• Chain wash spray system.<br>• Distribution sluice piping.<br>• MCC to feed new motors and pumps. |
| **Advantages** | • Allows for the continued use of existing bottom ash hopper and grinders.<br>• Ash quench water is treated as low volume wastewater. | • Allows for continued use of existing ash hopper.<br>• Minimal outage time for modification of the existing boiler. | • Minimal outage time for modification of the existing boiler. |
| **Disadvantages** | • Requires truck operators throughout the day, but could be reduced if three-sided concrete structure were included.<br>• Requires modification of the existing Boiler Building foundation. | • This alternative has a large amount of footprint needed for the separation tanks and dewatering bunker. Therefore, the only available location is the long distance north of the unit.<br>• Due to this length, excessive piping and larger pumps are involved.<br>• Requires front-end loaders with support crews for bottom ash removal from dewatering bunker.<br>• Ash sluicing water needs to be maintained in a closed loop or treated prior to discharge. | • Requires new foundations for remote equipment.<br>• Requires weather protection for the collection trough.<br>• Requires a three-sided concrete containment structure with weather protection.<br>• Requires freeze protection.<br>• Requires lengthy sluice piping and potential for booster pumps.<br>• Ash sluicing water needs to be maintained in a closed loop or treated prior to discharge. |
| **Reliability** | The reliability of the submerged chain conveyor is proven | The dewatering tanks, bunker, and sluice piping are a proven approach to ash dewatering. | Remote recirculation systems are often used for bottom ash conversions. The technical feasibility is sound but may not be financially viable for small units. |
| **Recommended for Further Review** | Yes | No | No |

### 2.4.1 Existing System and Conceptual Design Basis

The bottom ash system will be designed to receive bottom ash from the existing Units 1 and 2, each rated at 265 MW per pulverized coal fired unit.

The existing ash collection hopper consists of two pyramidal hoppers with two clinker grinders. Jet pumps located at the discharge of the clinker grinders are used to sluice the bottom ash from the bottom ash hopper to the ash storage pond using a single sluice pipe. The existing hopper cooling water overflows from the bottom ash hopper by gravity to an existing plant drain for the alternatives proposed below.

The conceptual design for this study is based on a maximum ash production rate of 3 tons per hour.

### 2.4.2 Bottom Ash Conceptual Design Alternatives

The following conceptual design alternatives were developed for A.B. Brown Units 1 and 2.

#### 2.4.2.1 Submerged Chain Conveyor (Alternative 1)

Alternative 1 consists of a new submerged chain conveyor under the existing bottom ash trough and existing grinders. The submerged chain conveyor will be routed out of the Boiler Building, discharging to a CCR rule-compliant storage area or transport truck.

Refer to Drawing 190507-PFD-4004 for the material flow. Table 4-4 outlines the estimated cost. The major equipment for this alternative includes the following:

- Submerged chain conveyor.
- Hydraulic power unit.
- Programmable logic controller (PLC) control system and instrumentation.
- Motor control center (MCC) to feed new motors.
- Chain wash spray system.

The submerged chain conveyor consists of a water filled lower trough with submerged drag chain flights attached to two chains to move the ash. The inclined conveyor section dewaters the ash and discharges the ash directly into a dump truck. The dump truck can then haul the dewatered ash for beneficial reuse or disposal.

This operation may require two trucks, with one truck located under the discharge point of the conveyor and another truck to haul ash to a storage location. Dump truck operators would be required 7 days per week with full shift coverage on a 24-hour basis to maintain shifts for around-the-clock manpower coverage. A three-sided concrete bunker could be installed outside the plant building to reduce the number of trucks and operators required. In this case, a front-end loader could be used to remove ash from the bunker and load the dump trucks on a single shift per day.

The existing seal troughs have been modified to a dry seal configuration that will eliminate the need for cooling water usage.

Key comparisons for Alternative 1 include the following:

- Disadvantages of the submerged chain conveyor:
  - Requires truck operators throughout the day.
  - Requires a weather structure over the exterior storage pile/truck loading platform.
  - May require front-end loaders.
- Advantages of the submerged chain conveyor:
  - Comparatively minimal new equipment.
  - Continuous removal of ash.

#### 2.4.2.2 Dewatering Bunker (Alternative 2)

Alternative 2 is a dewatering bunker for the dewatering technology. The reason for the selection is the expected lower capital cost with this alternative, as compared to other dewatering alternatives such as a dewatering bin system, dewatering basin system, and remote closed loop systems.

Refer to Drawing 190507-PFD-4005 for the material flow. Table 4-4 outlines the estimated cost. The major equipment for this alternative includes the following:

- Transfer tank with jet pump.
- Water supply tank.
- Sluice transfer pumps.
- Dewatering bunker and sump.
- Bunker sump pumps.
- Settling tank.
- Surge tank.
- Sludge pumps.
- Sluice recirculation pumps.
- PLC control system and instrumentation.
- MCC to feed new motors and pumps.

The difference between a dewatering bunker and a dewatering basin is that a dewatering bunker is used to collect only heavy ash particles (above 1/16 inch) whereas a dewatering basin system with both an ash dewatering basin and a polishing basin is used to capture both the heavy or large ash particles in the ash dewatering basin and the fine particles in the polishing basin. The dewatering bunker is sized for only 1 day of ash storage, so the size of the bunker is small and the capital cost is low. A front-end loader is required to remove ash from the bunker 7 days per week for each day that the unit is at full load and ash is pulled to the bunker. The sump adjacent to the bunker collects the sluice water.

The dewatering bunker system pulls the bottom ash from the bottom ash hoppers and it sluices to the new bottom ash transfer tank using the existing ash sluice pump.

The water from the transfer tank gravity flows to the new water supply tank to supply water to one of two redundant sluice transfer pumps; bottom ash is conveyed from the bottom ash transfer tank to the dewatering bunker. The jet pump at the discharge of the transfer tank removes the ash from the tank. The sluice water flows by gravity from the dewatering bunker to the dewatering bunker sump over the concrete weir located between the bunker and the sump. The bottom ash in the dewatering bunker is segregated from the sump by the concrete weir and a perforated metal screen to keep lumps of ash (over approximately 1/4 to 1/16 inch in size) from entering the sump.

The bunker sump pump is used to pump the sluice water to the settling tank where the fine ash solids are settled in the tank. The sludge is pumped from the settling tank to the storage pile in the bottom ash bunker. The water in the settling tank gravity flows to the surge tank to supply water to the sluice recirculation pumps, recycling the water back to the plant and the existing ash sluice pump.

The bottom ash bunker is sized for 1 day of storage (72 tons). The water level in the dewatering bunker is kept at a constant level and does not require draining to remove the ash from the bunker. A front-end loader removes the ash from the bunker (while there is water in the bunker) and fills dump trucks hauling ash to the intermediate storage location at the plant site. The front-end loader needs to have a wheel axle height higher than the water level in the bunker.

Key comparisons for Alternative 2 include the following:

- Disadvantages of the dewatering bunker:
  - Since this alternative requires pumps, tanks, and concrete structures, a large site area is needed.
  - Numerous pieces of new equipment are required.
  - A lengthy amount of sluice piping is required to deliver the ash to the remote location for the new bunker.
  - Front-end loaders with support crews are required.
  - Ash sluicing water must be 100 percent accounted for and maintained in a closed loop or treated prior to discharge.
- Advantages of the dewatering bunker:
  - Allows for the continued use of existing bottom ash hopper, grinders, and sluice pumps.

#### 2.4.2.3 Remote Submerged Chain Conveyor (Alternative 3)

Alternative 3 provides a remote closed loop system outside of the existing Boiler Building. The existing bottom ash trough and sluicing pump would deliver the ash to the new remote dewatering containment with a new submerged chain conveyor that would dewater and deliver the ash to a three-sided bunker for truck removal.

Refer to Drawing 190507-PFD-4006 for the material flow. Table 4-4 outlines the estimated cost. The major equipment for this alternative includes the following:

- Existing bottom ash trough and existing grinders.
- Existing sluice pumps but may need a booster pump if located a long distance from the Boiler Building.
- New remote hopper with new submerged chain conveyor for dewatering.
- Hydraulic power unit.
- PLC control system and instrumentation.
- MCC to feed new motors and pumps.
- Chain wash spray.
- Return water pumps and piping.

Key comparisons for Alternative 3 include the following:

- Disadvantages of the remote closed loop system:
  - A new foundational support for the remote equipment is required.
  - Weather protection for remote collection trough is required.
  - A weather protection structure may be required to control the ash in the three-sided concrete containment structure.
  - Freeze protection is required for winter operation.
  - More expensive new equipment is required, especially if the remote system is located so far away that a booster pump is required to deliver the wet ash.
  - Ash sluicing water must be 100 percent accounted for and maintained in a closed loop or treated prior to discharge.
- Advantages of the remote closed loop system:
  - No outage time is required for modification of the existing boiler.

### 2.4.3 Fly Ash

A.B. Brown utilizes dry ash handling a majority of the time for beneficial reuse, but resorts to wet fly ash handling when beneficial reuse transport is unavailable. For the dry fly ash system, the low-pressure ash pond water is used to draw a vacuum on various ash hoppers through the hydroveyor and move the fly ash to a filter/separator that is then pressurized and blows the ash to a storage silo near the river for barge loading. For sluicing the wet fly ash, the vacuum portion does not change but the ash is dropped into a combine tube prior to reaching the filter/separators that mixes it with water and moves it to the ash pond for storage when the dry fly ash storage silo is full.

When the ash pond is closed, the source of water for the vacuum will be lost, and the ability to wet the fly ash and move it to the ash pond will be lost. To solve the loss of the vacuum source, a new mechanical exhauster system will be required. Essentially these are vacuum pumps that will use the existing infrastructure to replace the hydroveyor. The ash will still be pulled from the ash collection hoppers to the filter/separator system for pressurized transport to the existing dry fly ash storage silo and new day bin silo. F.B. Culley Station purchased (from UCC), installed, and has been operating mechanical exhausters for several years. The technology and product have proven to be reliable. A.B. Brown has identified the same vendor and equipment to perform a similar function.

Currently the dry fly ash storage silo is located near the river and accepts the pneumatically conveyed ash from the A.B. Brown units as well as trucked ash from F.B. Culley and Warrick. This silo has equipment for pneumatically unloading tank trucks into the silo and a tube conveyor for moving ash to the river for barge loading from the silo. However, it does not have equipment for loading over-the-road trucks for transport of dry fly ash.

New mechanical exhausters and a day bin silo have been identified for installation at the plant site instead of at the river silo area to take advantage of the auxiliaries available for cost reduction. The day bin silo would be a smaller silo with a paddle mixer (pug mill) to wet the ash to control fugitive dust and would be capable of loading into over-the-road trucks. The fly ash handling equipment cost estimate is included in Table 4-4.

## 2.5 A. B. BROWN--IMPACT OF ELG REGULATIONS

The critical aspect of this review is the impact these regulations will have on the wastewater point source discharges at A.B. Brown. Black & Veatch's scope of work for this review was to identify the target areas for specific pollutants that are included in the final ruling and determine which wastewater discharge streams, if any, are affected by the updated ELG regulations.

Of the new wastewater streams regulated under the EPA's revised rule, only fly ash transport, bottom ash transport, low volume wastewater, and leachate apply to A.B. Brown. The EPA and IDEM have determined that the dual alkali scrubber discharge wastewater at A.B. Brown, as it is defined in the 2015 ELG rulemaking, is not subject to the FGD standards in the ELG rule. The EPA established numerical effluent limits that would correspond to the level of treatment that could be achieved based on application of these treatment technologies. While the scrubber wastewater is not subject to ELG standards, the current NPDES permit contains final effluent limitations for copper, selenium, and chloride.

Wastewater at A.B. Brown is considered direct discharge from an existing source. The current ELGs for the steam electric power generating existing sources and their applicability to A.B. Brown are shown in Appendix A.

### 2.5.1 Operation Evaluation

A.B. Brown currently utilizes sluicing systems to transport fly ash and bottom ash to the ash pond for settling. The EPA's final rule on wastewater effluent regulation standards requires zero discharge for fly and bottom ash transport water (refer to Table 2-1). For fly and bottom ash transport, the final ELG rule specifies dry handling or closed-loop systems as the technology basis.

The removal of ash sluice water and closure of the ash pond would comply with the CCR rule requirements. All waste streams currently discharged to the ash pond were sampled to determine water quality. The sampled waste stream data indicate that A.B. Brown is expected to achieve the new direct discharge limits from an existing source imposed by the final rule if the settling capability of the ash pond were to be sufficiently substituted.

## 2.6 A.B. BROWN--TECHNOLOGY OPTIONS FOR ELG/NPDES COMPLIANCE

Based on review of the final ELG, NPDES permit, and capabilities of the existing plant wastewater systems to achieve these standards, Black & Veatch has identified potential modifications to the existing wastewater system as well as additional treatment that could be implemented to comply with wastewater effluent limitations. A summary and breakdown of the conceptual cost estimate can be found in Section 4.0.

### 2.6.1 Ash Pond Elimination

Elimination of the ash pond represents a significant reduction in reuse water, storage, and settling capabilities for A.B. Brown. Ash sluice water and FGD makeup are the major consumers of reuse water and sources of wastewater. The pending ash pond closure and conversion to a closed loop SCC for bottom ash handling represents a large reduction in wastewater generation and storage requirements, which would minimize the size of any downstream treatment equipment. However, the new treatment equipment would still need to be capable of handling approximately 2.5 million gallons per day (mgd) of treated low volume wash water streams from FGD wash water and coal pile runoff.

It is important to note that the FGD wash water is not an FGD wastewater as defined in the ELG rule. The 2015 ELG rule added the following clarifying sentence to the definition of FGD wastewater:

"Wastewater generated from cleaning the FGD scrubber, cleaning FGD solids separation equipment, cleaning FGD solids dewatering equipment, or that is collected in floor drains in the FGD process area is not considered FGD wastewater."

Therefore, the dual alkali scrubber does not discharge FGD wastewater as it is defined in the ELG rule, and the scrubber is not subject to the FGD ELG standards.

While this report focuses on ELG compliance, elimination of the ash pond will impact NPDES permit compliance. Therefore, final effluent limitations for parameters such as copper, chloride and selenium, are being considered in evaluation of treatment options. Treatment options evaluated for compliance with the ELG rule (and NPDES permit) include physical/chemical treatment, settling and dewatering processes, and CCR compliant basins or tanks for reduction of suspended solids.

### 2.6.2 Design Concept

The basic design concept includes treating scrubber wastewater and collecting and re-directing all existing flows that discharge to the ash pond. Collected wastewater would be transferred to the necessary users for reuse demands with the accumulated wastewater.  Water not reused would be filtered and transferred to the existing wastewater mercury treatment system and subsequent lined pond.  The basic design concept would still utilize a significant portion of the existing equipment while providing a physical/chemical/biological system for heavy metals and suspended solids reduction, a basin for collection and flow equalization, a filter system for final suspended solids reduction in the combined basin wastewater, and a sludge dewatering system for solids handling and removal.

Using A.B. Brown's water qualities and a water mass balance provided by Vectren, Black & Veatch developed a proposed water mass balance outlining influent and effluent flows around pieces of equipment impacted by the pending closure.  Black & Veatch's proposed water mass balance is contained in Appendix D.

### 2.6.3 FGD Treatment

#### 2.6.3.1 Physical/Chemical Treatment

Physical/chemical treatment is a process used for heavy metals and total suspended solids (TSS) reduction. On the basis of the effluent limitations identified in the current NPDES permit, the heavy metals of concern are mercury, copper, and selenium. To achieve the desired level of metals removal and TSS reduction, the FGD blowdown would be pumped to a new continuously mixed sulfide reaction tank, followed by a coagulation reaction tank, to allow for chemical addition of organosulfide and coagulant.  An organosulfide would be fed to achieve high removal of heavy metals by converting the soluble metals to an insoluble precipitate.

The reaction tanks are sized to allow sufficient reaction time for the chemical precipitation reactions to occur.  The reaction tanks feed a clarifier where polymer is added to increase the particle size of the insoluble particles and allow settling for solids removal with traditional clarification techniques.  Settled solids from clarification would be directed to dewatering equipment. While the physical/chemical treatment will reduce mercury and copper in the FGD wastewater, additional treatment will be required to reduce selenium.

#### 2.6.3.2 Biological Treatment

Selenium typically exists in one of two forms, selenite ($Se^{+4}$) or selenate ($Se^{+6}$), which are both soluble in water.  Selenite can typically be removed from wastewater through chemical precipitation, where selenate is more soluble, requiring reduction to a less soluble form for removal.  Selenium in FGD wastewater typically exists in both forms and the concentration of each form depends on plant operation and the type of coal being combusted.  Therefore, a biological treatment process is required downstream of the physical/chemical treatment system to reduce selenium.

Anaerobic biological treatment is an industry-proven technology for selenium and is the basis for the ELG limits. Biological treatment involves the growth of naturally occurring microorganisms that act as selenium reducing agents. A food source (nutrient) is oxidized by the microorganisms, which in turn reduces both selenate and selenite and precipitates solid elemental selenium. Biological treatment typically consists of a series of fixed-film biofilters in a controlled, anaerobic environment for the proper reactions and reduction of selenium to occur.

Periodically, biomass and elemental selenium are backwashed from the system. During backwash, treated effluent is used as a counterflow wash to remove entrained solids and gases from the biofilter substrate. Backwash wastewater is allowed to degas and is recycled to the inlet of the secondary pretreatment system where the solids are settled in the clarifier and dewatered with the pretreatment sludge. The treated water is discharged downstream to the collection basin for storage and use within the facility.

#### 2.6.3.3 Sludge Handling

Accumulated sludge from the clarifier is collected in a sludge holding tank. The sludge holding tank is sized to hold 12 hours of sludge accumulation. Two 100 percent capacity filter press feed pumps supply sludge from the holding tank to two 100 percent capacity recessed plate and frame filter presses that dewater the sludge. Sludge conditioning polymer, supplied from a chemical tote, is fed upstream of the filter presses to improve dewatering. Dewatered solids can be deposited in the landfill at A.B. Brown. Removal of solids provides further metals reduction.

### 2.6.4 Collection Basin

A concrete, below grade collection basin will serve the purpose of equalizing wastewater flow rates from the coal pile runoff pond and treated effluent from the new FGD treatment system. The collection basin will provide a reservoir from which to draw reuse water to supply existing high-pressure water recirculation users and makeup water for dry bottom ash system. The collection basin is sized to accommodate 20 minutes of retention time for all flows indicated on the water mass balance. A mixer is included with the collection basin to prevent the settling and accumulation of solids within the collection basin.

Two 100 percent capacity, vertical sump pumps will draw suction from the collection basin to supply existing users of high-pressure ash pond recirculation pumps. New piping from the collection basin will tie into existing high-pressure water piping. Additional piping will be included to direct recirculation water as cooling makeup water for dry bottom ash system from the high-pressure recirculation supply pumps.

While TSS reduction occurs in the upstream FGD treatment system, the combined wastewater in the collection basin will have increased TSS levels because of the contribution from the untreated coal pile runoff pond discharge. To meet the NPDES permit limits for TSS, a new filter system will be installed on the discharge from the collection basin. Two 100 percent capacity discharge pumps controlled based on level in the collection basin will forward wastewater from the collection basin to the filter system for suspended solids removal. Periodically, the filter system is backwashed to remove accumulated solids. The backwash waste stream will be discharged to the sludge handling system further thickening and dewatering prior to disposal. Filtered water is sent to the existing Ash Pond Mercury Treatment System, existing lined settling pond, and finally to Outfall 001.

### 2.6.5 Operations and Maintenance Costs of A.B. Brown NPDES Compliance

Black & Veatch has developed estimated costs for the operations and maintenance (O&M) of the proposed treatment. Costs include consumption of chemical feeds, cost to dispose of solids, power consumption, and staffing costs. The O&M costs are presented in Section 4.0.

## 2.7 F.B. CULLEY--IMPACT OF CCR REGULATIONS

The F.B. Culley facility has two CCR units: the east and west. The west pond is now an inactive surface impoundment undergoing closure. The east pond is an active pond. The elimination of CCR units represents a significant reduction in storage and settling capabilities for F.B. Culley.

## 2.8 F.B. CULLEY--TECHNOLOGY OPTIONS FOR CCR COMPLIANCE

Black & Veatch worked with Vectren to evaluate different cost-effective concepts of bottom ash handling at F.B. Culley Unit 2. These alternatives focus on meeting the ELG regulations by converting the bottom ash system either to a dry system or a closed loop wet system. Each alternative proposed will allow the bottom ash to be dewatered sufficiently and truck transported off-site.

Following the evaluation, Black & Veatch recommended incorporation of a dewatering tank system for F.B. Culley Unit 2. A project is currently in progress to install the SCC at F.B. Culley Unit 3 with installation scheduled for 2020. The installed cost to retrofit the F.B. Culley Unit 2 boiler with dewatering tank equipment has been incorporated into the treatment options in Section 4.0, Table 4-4.

A technology comparison matrix for the bottom ash alternatives described for F.B. Culley Unit 2 is provided in Table 2-3.

**Table 2-3 F.B. Culley Unit 2 Bottom Ash Technology Comparison Matrix**

| ALTERNATIVE | BUCKET ELEVATOR (ALTERNATIVE 1) | INDOOR DEWATERING TANKS (ALTERNATIVE 2) | DRY PNEUMATIC SYSTEM (ALTERNATIVE 3) | REMOTE SUBMERGED CHAIN CONVEYOR (ALTERNATIVE 4) |
|---|---|---|---|---|
| **Description** | Alternative 1 utilizes a new vertical bucket elevator connected under the existing ash trough at the existing grinder discharge. The bucket elevator concept will dewater the material as the ash is raised above the water level. | Alternative 2 delivers the bottom ash from the existing ash trough through the existing pumps to a dewatering tank located on the operating floor near the northeast corner of the Boiler Building. The new dewatering tank will require properly sized filters or screens to separate the water from the bottom ash. The separated water would be recycled back to the existing bottom ash trough. The dewatering tank will discharge bottom ash into a container for a forklift to haul outside of the building. Once outside the Boiler Building, the material can be loaded into trucks for transport off-site. | Alternative 3 is a completely dry system but will require an entirely new dry bottom ash trough and a new exterior dry hopper storage bin. The replacement of the existing bottom ash trough will be a major construction effort requiring a long outage for the unit. There are various options to collect the ash at the bottom of the new trough such as a vacuum conveyor, a vibratory oscillatory conveyor, or a mesh screen drag conveyor. | Alternative 4 provides a remote closed loop system outside of the existing Boiler Building. The existing bottom ash trough and sluicing pump would deliver the ash to the new remote dewatering containment with a new submerged chain conveyor that would dewater and deliver the ash to a three-sided bunker for truck removal. |
| **Technical Feasibility** | This concept utilizes a bucket elevator for dewatering, which is rarely used in the power industry. The design would need thorough investigation to ensure the elevator will handle the fines in the allotted space. As well as assurance that the wet ash would discharge from the bucket effectively. Based on the highly conceptual nature of the design and lack of industry specific equipment available, this option was determined technically not feasible. | This concept of using dewatering tanks has been used in the past. Further design refinement will be required to determine if one or two tanks are necessary to accomplish complete dewatering. | Dry bottom ash troughs are being used in the industry but usually they are intended for larger boilers with more height. Special design will be required to fit the troughs in the shallow height of Unit 2. | Remote recirculation systems are often used for bottom ash conversions. The technical feasibility is sound but may not be financially viable for small units. |
| **Total Contracted Cost** | NA | $3,868,000 | $7,636,600 | $17,059,600 |
| **Operations and Maintenance Cost** | NA | $300,300 | $311,100 | $471,000 |
| **Estimated Manpower** | 0.4 | 0.4 | 0.4 | 0.8 |
| **Est. Footprint (sq. ft.)** | 400 | 1,000 | 2,000 | 6,000 |
| **Major Equipment** | • Vertical bucket elevator.<br>• Hydraulic power unit.<br>• Instrumentation and controls.<br>• Forklift container.<br>• Quench water overflow tank, pumps, separator, and heat exchanger.<br>• MCC to feed new motors and pumps. | • Distribution piping.<br>• Dewatering tank.<br>• Quench water overflow tank, low- and high-pressure pumps, and heat exchanger.<br>• Instrumentation and controls.<br>• Forklift container.<br>• MCC to feed new motors and pumps. | • New dry trough and conveyor.<br>• New grinders.<br>• Pneumatic power unit.<br>• Exterior dry storage tank.<br>• Wet conditioning equipment.<br>• Instrumentation and controls<br>• MCC to feed new motors and pumps. | • Remote submerged chain conveyor.<br>• Hydraulic power unit.<br>• Quench water overflow tank and pump.<br>• Instrumentation and controls.<br>• Recycle water pumps and piping.<br>• Chain wash spray system.<br>• Distribution sluice piping.<br>• MCC to feed new motors and pumps. |
| **Advantages** | • Minimal new equipment.<br>• Utilizes the existing bottom ash trough.<br>• Outage time minimized if foundation modifications can be completed prior to outage. | • Lowest comparative capital costs.<br>• Allows for continued use of existing ash trough, grinders, and jet pumps.<br>• Minimal outage time required. | • Quench water removed from system, but still may require water for a wet conditioner system for loading open top trucks. | • Minimal outage time required for modification of the existing boiler.<br>• Cost prohibitive for a small unit; but may show financial benefit if utilized for multiple units. |
| **Disadvantages** | • Requires a larger pit to be excavated in the existing ground floor of the Boiler Building.<br>• The use of a bucket elevator as a dewatering device is rare and will require additional design refinements and coordination with the equipment supplier.<br>• The ash discharged from the bucket elevator may not be completely dewatered due to the equipment and space constraints. Additional dewatering may be required after the bottom ash prior to truck loading. | • Water from the dewatering tank and forklift container must be recycled in a closed recirculating loop back to the existing bottom ash trough.<br>• The water tank may require special internal screens to dewater sufficiently. Laboratory tests may need to be conducted to ensure this design.<br>• If the dewatering tank is located outside the equipment and piping will require heat trace and insulation for winter operation. | • Requires a lengthy outage period to replace the existing bottom ash trough.<br>• Major modification to boiler requiring expensive new equipment. | • Requires new foundations for remote equipment.<br>• Requires weather protection for the collection trough.<br>• Requires a three-sided concrete containment structure with weather protection.<br>• Requires freeze protection.<br>• Requires lengthy sluice piping.<br>• Ash sluicing water maintained in a closed loop or treated prior to discharge. |
| **Reliability** | The reliability of the bucket elevator is dependent on the ability to properly dewater. Since this is not | The dewatering tanks are a proven approach to bottom ash dewatering. | Dry pneumatic ash handling is a proven approach for large units. | Remote recirculation systems are often used for bottom ash conversions. |

| ALTERNATIVE | BUCKET ELEVATOR (ALTERNATIVE 1) | INDOOR DEWATERING TANKS (ALTERNATIVE 2) | DRY PNEUMATIC SYSTEM (ALTERNATIVE 3) | REMOTE SUBMERGED CHAIN CONVEYOR (ALTERNATIVE 4) |
|---|---|---|---|---|
| | a common use of bucket elevators, the reliability is difficult to predict. | | | |
| **Recommended for Further Review** | No | Yes | No | No |

### 2.8.1 Existing System and Conceptual Design Basis

The bottom ash system will be designed to receive bottom ash from the existing Unit 2, 100 MW pulverized coal fired unit.

The existing ash collection hopper consists of one longitudinal hopper with one clinker grinder mounted at the west end. The hopper is located in the basement area of the Boiler Building while the operating floor is 37 feet above the basement. The east side of the operating floor exits at the grade level, while the west side is over the one story Administration Building. The longitudinal bottom ash hopper has three segments with flat bottoms that are stair-stepped in elevation toward the grinder. Jet pumps located at the discharge of the clinker grinder and jet pump piping located at each step-in elevation are used to sluice the bottom ash from the bottom ash hopper to the bottom ash storage pond. The existing hopper cooling water overflows from the bottom ash hopper by gravity to an existing plant drain.

The conceptual design for this study is based on a maximum ash production rate of 1 ton per hour.

### 2.8.2 Bottom Ash Conceptual Design Alternatives

The following conceptual design alternatives were developed for F.B. Culley Units 2.

#### 2.8.2.1 Bucket Elevator (Alternative 1)

The proposed bucket elevator bottom ash system utilizes a new vertical bucket elevator connected under the existing ash trough at the existing grinder to transport bottom ash away from the existing bottom ash hopper. The bucket elevator will dewater the bottom ash as it lifts it up above the ash flush water level to a waiting container on the basement floor. The existing water level in the ash hopper is approximately 8 feet above the basement floor, while the water level during ash flushing is approximately 2 feet above the basement floor.

The bucket elevator will need at least a 4 foot height above the water level to support adequate dewatering. The elevator requires another 2 feet above this point for the head pulley and drive. Therefore, the total minimum length for the bucket elevator above the basement floor must be 14 feet. There appears to be a number of existing pipes approximately 8 feet above the basement floor in this area that must be rerouted. It is assumed this arrangement is workable and will be refined during final design.

In addition, a sloped transition chute to slide the ash out of the grinder and into the elevator must be provided to properly load the bucket elevator. Therefore, it is estimated that the bottom of the bucket elevator will be a minimum of 5 feet below the basement floor. The existing grinder pit is only 3 feet deep.

After the ash is dewatered, the bucket elevator will discharge into a forklift-sized container. The container could be a large manual wheelbarrow, a customized container for a motorized wheelbarrow, or a container designed for a forklift. This type of container can be moved across the basement floor to the existing exterior door in the southwest corner of the Boiler Building; the bottom ash can then be transported with a dump truck to a new landfill.

Because the new bucket elevator system no longer utilizes the ash quench water in the sluicing operation, it will be required to capture and recycle the quench water in a closed loop back to the bottom ash hopper. The ash quench water recycle system would consist of a quench water overflow tank that is gravity-fed from a new bottom ash hopper overflow connection. This tank would be sized so that it can hold all the ash quench discharged over the duration of the bottom ash removal operation. After the bottom ash flush operation is complete, the flush water would then be pumped back to the hopper via a new quench water recycle pump. However, before the water can enter the hopper it may be necessary to both remove some of the bottom ash fines in a separator and cool the water in a heat exchanger. The need for the quench water system separator and heat exchanger will require additional investigation and potential testing during the next phase.

Drawing 190507-PFD-4000 shows a simplified material flow block diagram for the bucket elevator bottom ash system concept. The major equipment for this alternative includes a vertical bucket elevator, hydraulic power unit, bottom ash container, ash flush water recirculation system, instrument and controls, new MCC, and mobile equipment to move the ash (e.g., forklift, dump truck).

The most critical issue with this alternative is the ability to properly load the bucket elevator in a manner that will not overload the buckets. To prevent possible plugging of the individual buckets, the elevator must operate continuously while the ash trough is evacuated; otherwise, fine material will build up around the tail pulley and overfill the lower section of the elevator with compacted fines.

Other concerns may be the fines that tend to float because the water level in the bucket elevator will be level with the water in the bottom ash trough. The water level is 12 to 14 feet above the bottom of the vertical elevator. If the buckets are traveling at an inappropriate speed, the floating material may spill over the edge of the buckets.

In conclusion, the bucket elevator design is sensitive to the proper sizing of the buckets and the number of dewatering openings, combined with the speed at which the buckets travel. All of these factors must match the actual physical properties of the bottom ash to ensure dewatering over the travel height of the elevator. Based on the highly conceptual nature of the design and lack of industry specific equipment available, this option was determined technically not feasible.

Key comparisons for Alternative 1 include the following:

- Disadvantages of vertical elevator:

    - It requires an excavated large pit of approximately 8 feet by 8 feet by 5 feet in the existing foundation to allow for proper loading of the bottom ash into the bucket elevator. This will require extensive foundation modification.
    - There will be a design balance between elevator speed and material density, possibly requiring laboratory scale testing to finalize the design. Also, an additional pump will be required to remove the flush water in the excavated pit. The new pump may also draw some bottom ash fines. Therefore, a filter/separator may be inserted to assist in removing these fines before the water is recycled.
    - The use of a bucket elevator to dewater bottom ash is rare; it will require buckets with screen material to accomplish dewatering. The lower portion of the elevator will be submerged in water. The number and size of dewatering holes in the buckets must match the properties of the actual ash produced at the plant. If, during the final design phase, it is found that the bucket elevator cannot effectively load the ash, other options within this alternative could be a screw conveyor or drag chain.
    - The bucket elevator may have difficulty starting because of the settlement of ash fines around the tail end pulley. If too much ash collects, it may tend to plug/overload the buckets. To help prevent buildup of fines, the bucket elevator may require startup before the bottom ash is flushed from the boiler.
    - The ash discharged on the operating floor may not be completely dewatered. A watertight collection hopper/container may also require screens to ensure that, by the time the material is dumped into a dump truck, it is sufficiently dry.
- Advantages of vertical elevator:
    - Minimal new equipment is required.
    - The option allows for the continued use of existing bottom ash hoppers.
    - The installation of equipment requires minimal outage time as long as the foundation modification can be complete without an outage.

#### 2.8.2.2 Indoor Dewatering Tanks (Alternative 2)

Alternative 2 delivers the bottom ash from the existing ash trough through the existing pumps to a dewatering tank located on the operating floor near the northeast corner of the Boiler Building. This new dewatering tank will require properly sized filters or screens to separate the water from the bottom ash. The separated water would be recycled back to the existing bottom ash trough. The dewatering tank will discharge into a container for a forklift to haul outside the building. Once outside the Boiler Building, the material can be dumped into a dump truck.

Depending on the actual physical properties of the bottom ash, the forklift container may also require filters or screens to ensure that the material discharged into the dump trucks is dry.

Refer to Drawing 190507-PFD-4001 for the material flow. Table 4-2 outlines the estimated cost. The major equipment for this alternative includes the following:

- Sluice piping.
- Dewatering tank.
- Overflow tank with recirculation pump(s) and heat exchanger.
- PLC control system and instrumentation.
- MCC to feed new motors and pumps.
- Forklift container, along with the use of a forklift and dump truck.

Key comparisons for Alternative 2 include the following:

- Disadvantages of the dewatering tank:
  - Water from the dewatering tank and forklift container must be recycled in a closed recirculating loop back to the existing bottom ash trough. In the event there is a discharge stream it will require the utilization of a zero liquid discharge treatment. One possible ZLD solution would be the utilization of the spray dry evaporator planned for future installation on F.B. Culley Unit 3.
  - If the dewatering tank must be located outside the existing Boiler Building, the dewatering and the water discharge piping must be heat traced for winter operation. The current assumption is that the tank can be located in the turbine deck area.
  - The water tank may require special internal screens to dewater sufficiently. Laboratory tests may need to be conducted to ensure this design.
  - Ash sluicing water must be 100 percent accounted for and maintained in a closed loop or treated prior to discharge.
- Advantages of the dewatering tank:
  - Minimal new equipment is required because the existing sluice pumps will be enough for reuse.
  - Minimal capital costs are required.

Minimal outage will be needed for installation because much of the existing equipment will be reused.

#### 2.8.2.3 Dry Pneumatic System (Alternative 3)

Alternative 3 is a completely dry system but will require an entirely new dry bottom ash trough and a new exterior dry hopper storage bin. The replacement of the existing bottom ash trough would be a major construction effort and would cause a long outage for the unit. There are various options for collecting the ash at the bottom of the new trough such as a vacuum conveyor, a vibratory oscillatory conveyor, or a mesh screen drag conveyor. The exterior storage bin would require new pneumatic equipment to draw the ash out of the Boiler Building to a location north of the plant. This storage bin would require a sizable foundation because the bin would be elevated to allow unloading the material into either an open truck or a pneumatic tanker truck. If an open truck is used, a wet conditioner may be required to prevent fugitive dust.

Refer to Drawing 190507-PFD-4002 for the material flow. Table 4-2 outlines the estimated cost. The major equipment for this alternative includes the following:

- New dry trough and conveyor.
- New grinders.
- Pneumatic power unit.
- Exterior dry storage tank.
- Possible wet conditioning equipment to load open dump trucks.
- PLC control system and instrumentation.
- MCC to feed new motors and pumps.

Key comparisons for Alternative 3 include the following:

- Disadvantages of pneumatic ash removal:
    - A lengthy outage period is required because existing ash hopper must be removed.
    - Additional equipment for a vacuum conveying system is required.
    - A major amount of expensive new equipment is required.
    - If unloaded to an open truck, a wet conditioning system may be required to control dust. This will affect the water balance for the system.
- Advantages of pneumatic ash removal:
    - It does not require water under the boiler but may still require water for a wet conditioner system under the storage bin to properly load open trucks.

#### 2.8.2.4 Remote Submerged Chain Conveyor (Alternative 4)

Alternative 4 provides a remote closed loop system outside the existing Boiler Building. The existing bottom ash trough and sluicing pump would deliver the ash to the new remote dewatering containment with a new submerged chain conveyor that would dewater and deliver the ash to a three-sided bunker for truck removal.

Refer to Drawing 190507-PFD-4003 for the material flow. Table 4-2 outlines the estimated cost. The major equipment for this alternative includes the following:

- Utilizes existing bottom ash trough and existing grinders.
- Utilizes existing slice pumps but may need a booster pump if located a large distance from the Boiler Building.
- New remote hopper with new submerged chain conveyor for dewatering.
- Hydraulic power unit.

- PLC control system and instrumentation.
- MCC to feed new motors and pumps.
- Chain wash spray.
- Return water pumps and piping.

Key comparisons for Alternative 4 include the following:

- Disadvantages of the remote closed loop system:
  - A new foundational support for the remote equipment is required.
  - Weather protection for the collection trough is required.
  - A weather protection structure might be required to control the ash in the three-sided concrete containment structure.
  - Freeze protection for winter operation is required.
  - More expensive new equipment is required, especially if the remote system is located so far away that a booster pump is required to deliver the wet ash.
  - Ash sluicing water must be 100 percent accounted for and maintained in a closed loop or treated prior to discharge.
- Advantages of the remote closed loop system:
  - No outage time required for modification of the existing boiler.
  - May be cost prohibitive for a small unit; but may show financial benefit if utilized for multiple units.

### 2.8.3 Fly Ash

The dry ash handling system is already in service at F.B. Culley using mechanical exhausters. The alternative wet sluicing line will need to be capped and abandoned in place so the capability of sluicing fly ash no longer exists to meet compliance.

# 3.0 Economic Criteria

The economic criteria shown in Table 3-1 was used to develop the cost estimates presented in this report. The present worth discount rate, capital recovery factor, and present worth values listed do not represent Vectren's actual or proposed values. These values represent relative values that have been applied to technology scenarios to determine the most economical alternative. The results of these evaluations are summarized in Section 4.0.

**Table 3-1 A.B. Brown ELG Compliance - Summary of Economic Criteria**

| ECONOMIC INPUTS - ALL UNITS | VALUE | UNITS |
|---|---|---|
| Present Worth Discount Rate | 6.00 | % |
| Economic Life | 20 | years |
| Capital Recovery Factor (Calculated) | 8.72 | % |
| Present Worth Factor (Calculated) | 11.47 | |
| Salary – Full Time O&M Employee | 100,000 | $/year |
| Power Price | 0.098 | $/kWh |
| Plant Capacity – Brown Unit 1 | 65 | % |
| Plant Capacity – Brown Unit 2 | 65 | % |
| Plant Capacity – Culley Unit 2 | 25 | % |
| Balance of Plant Treatment (BPT) Reagent-Coagulant Feed (Ferric Chloride) | 0.12 | $/lb |
| Organosulfide | 1.36 | $/lb |
| BPT Reagent - Flocculant Aid (polymer) | 0.60 | $/lb |
| Filter Press Polymer Costs | 0.60 | $/lb |
| Selenium Reagent - Sulfuric Acid | 0.20 | $/lb |
| Selenium Reagent - Nutrient Feed | 1.98 | $/lb |
| Selenium Reagent - Lime | 0.10 | $/lb |
| On-site Landfill Costs | 24 | $/load |
| On-site Landfill Haul Capacity | 30 | tons/load |
| Off-site Landfill Costs | 990 | $/load |
| Off-site Landfill Haul Capacity | 25 | tons/load |

# 4.0 Conceptual Cost Estimate Cases

Tables 4-1 and 4-2 present the ±50 percent cost estimates for A.B. Brown separated into treatment options for CCR and ELG compliance, respectively. Table 4-3 presents the ±50 percent cost estimate for CCR compliance at F.B. Culley. Table 4-4 presents the ±50 percent fly ash cost estimate for A.B. Brown Units 1 and 2. Each scenario presents the capital cost and O&M costs for its respective treatment technologies.

**Table 4-1 Cost Estimate Summary for ELG Compliance – A.B. Brown Station**

| DESCRIPTION | PHYSICAL/CHEMICAL AND BIOLOGICAL TREATMENT |
|---|---|
| **Direct Cost** | |
| Pumps and Drivers | $163,000 |
| Water Treatment - Physical/Chemical | $7,598,000 |
| Water Treatment - Biological | $6,990,000 |
| Water Treatment - Filtration | $222,000 |
| Mechanical Equipment, Piping and Piping Specials | $1,432,000 |
| Electrical Equipment | $3,502,000 |
| Civil/Structural Works | $3,375,000 |
| **Total Direct Cost (DC)** | **$23,282,000** |
| **Indirect Cost** | |
| Construction Management 20% x DC | $4,657,000 |
| Construction Indirects 15% x DC | $3,492,000 |
| Engineering 15% x DC | $3,492,000 |
| Contingency 20% x DC | $4,657,000 |
| Overhead and Profit 15% x DC | $3,492,000 |
| **Total Indirect Cost Including Material and Labor (IC)** | **$19,790,000** |
| **Total Direct and Indirect Costs = (DC + IC)** | **$43,072,000** |
| **ANNUAL OPERATING COST** | |
| Power | $27,000 |
| Chemical Feed | $906,000 |
| Off-site Landfill Costs | $95,000 |
| Equipment Operator Labor (FTE) | $50,000 |
| Maintenance | $300,000 |
| **Total Direct Annual Costs (DAC)** | **$1,378,000** |

**Table 4-2 Summary of Unit 2 F.B. Culley Bottom Ash Cost Estimate (100 MW; 1 tph Ash Production)**

| DESCRIPTION | BUCKET ELEVATOR | INDOOR DEWATERING TANKS | DRY PNEUMATIC SYSTEM | REMOTE SUBMERGED CHAIN CONVEYOR |
|---|---|---|---|---|
| Alternative | 1 | 2 | 3 | 4 |
| **CAPITAL COST**<br>**Direct Costs** | | | | |
| Weather Structure Remote Structures | NA | NA | NA | $213,400 |
| Weather Structure 3-Sided Conc. Contain | NA | NA | NA | $106,700 |
| New Dry Bottom Ash Trough | NA | NA | $1,067,000 | NA |
| Dewatering Tank Support and Access | NA | $426,800 | NA | NA |
| Emergency Drain Tank for Meeting Plant ZLD Requirement | NA | $400,100 | NA | NA |
| Heat Exchanger | NA | $213,400 | NA | NA |
| New Grinders | NA | NA | $853,600 | NA |
| New Exterior Vacuum System | NA | NA | $533,500 | NA |
| New Wet Conditioning for Dump Truck | NA | NA | $213,400 | NA |
| New Remote Wet Trough w/Submerge Chain Conveyor/Overflow Tank | NA | NA | NA | $4,268,000 |
| Vertical Bucket Elevator w/ Drive Unit | NA | NA | NA | NA |
| **Subtotal: Equipment Costs** | NA | $1,040,300 | $2,667,500 | $4,588,100 |
| Electrical, Instr. and Controls Equipment | NA | $233,700 | $249,700 | $602,900 |
| Mechanical Equipment, Piping and Valves | NA | $266,800 | $298,800 | $1,760,600 |
| Foundations and Civil Works | NA | - | $266,800 | $1,067,000 |
| Miscellaneous Equipment | NA | $277,400 | $106,700 | - |
| Demolition Works | NA | $87,200 | $393,000 | $87,200 |
| Existing BOP System Modifications | NA | $185,400 | $145,300 | $115,600 |

| DESCRIPTION | | BUCKET ELEVATOR | INDOOR DEWATERING TANKS | DRY PNEUMATIC SYSTEM | REMOTE SUBMERGED CHAIN CONVEYOR |
|---|---|---|---|---|---|
| Site Earth Works | | NA | - | - | $1,000,000 |
| **Subtotal: Miscellaneous Costs** | | NA | $1,050,500 | $1,460,300 | $4,633,300 |
| **Total Direct Costs (DC)** | | **NA** | **$2,090,800** | **$4,127,800** | **$9,221,400** |
| **Indirect Costs** | | | | | |
| Construction Management | 20% x DC | NA | $418,200 | $825,600 | $1,844,300 |
| Construction Indirects | 15% x DC | NA | $313,600 | $619,200 | $1,383,200 |
| Engineering | 15% x DC | NA | $313,600 | $619,200 | $1,383,200 |
| Contingency | 20% x DC | NA | $418,200 | $825,600 | $1,844,300 |
| Overhead and Profit | 15% x DC | NA | $313,600 | $619,200 | $1,383,200 |
| **Total Indirect Costs (IC)** | | **NA** | **$1,777,200** | **$3,508,800** | **$7,838,200** |
| **Total Contracted Costs (CC) DC + IC** | | **NA** | **$3,868,000** | **$7,636,600** | **$17.059.600** |
| **ANNUAL OPERATING COST**<br>**Operating Costs** | | | | | |
| Power | | NA | $38,300 | $14,300 | $42,900 |
| Off-site Landfill Costs | | NA | $182,300 | $182,300 | $182,300 |
| Equipment Operator Labor (FTE) | | NA | $42,700 | $42,700 | $85,400 |
| Maintenance | | NA | $37,000 | $71,800 | $160,400 |
| **Total Direct Annual Costs (DAC)** | | **NA** | **$300,300** | **$311,100** | **$471,000** |

**Table 4-3 Summary of Units 1 and 2 A.B. Brown Bottom Ash Cost Estimate (265 MW each; 3 tph Ash Production)**

| DESCRIPTION | SUBMERGED CHAIN CONVEYOR (1) | DEWATERING BUNKER (1) | REMOTE SUBMERGED CHAIN CONVEYOR (1) |
|---|---|---|---|
| Alternative | 1 | 2 | 3 |
| **CAPITAL COST**<br>**Direct Costs** | | | |
| Weather Structure for Remote System | NA | $426,800 | $4,300,000 |
| Weather Structure for 3-Sided Conc. Storage | $406,200 | NA | $406,200 |
| Dewatering Bunker/Sump | NA | $853,600 | NA |
| Settling and Surge Tanks | NA | $2,500,000 | $373,500 |
| Submerged Chain Conveyor | $5,000,000 | NA | NA |
| Bottom Ash Tank w/Jet Pump and Water Supply Tank | NA | $917,600 | NA |
| Sluice, Recirculation and Sump Pumps | NA | $3,128,400 | NA |
| Seal Water Pumps | NA | $640,200 | NA |
| New Remote Wet Trough w/Submerge Chain Conveyor/Overflow Tank | NA | NA | $5,400,000 |
| Mechanical Pump and Piping Modification | NA | $320,100 | $1,600,500 |
| **Subtotal: Equipment Costs** | $5,406,200 | $8,786,700 | $12,080,200 |
| Electrical, Instrumentation and Controls Equipment | $2,942,800 | $1,557,800 | $2,500,000 |
| Mechanical Equipment, Piping and Valves | $3,776,900 | $3,190,300 | $3,000,000 |
| Foundations and Civil Works | $1,941,100 | $3,000,000 | $2,000,000 |
| Miscellaneous Equipment Installation | - | $597,500 | - |
| Demolition Works | $1,454,000 | $440,000 | $440,000 |
| Existing BOP System Modifications | $655,900 | $379,900 | $646,900 |

| DESCRIPTION | | SUBMERGED CHAIN CONVEYOR (1) | DEWATERING BUNKER (1) | REMOTE SUBMERGED CHAIN CONVEYOR (1) |
|---|---|---|---|---|
| Site Earth Works | | - | $1,750,000 | 1,850,000 |
| **Subtotal: Miscellaneous Costs** | | $10,770,700 | $10,915,500 | $10,436,900 |
| **Total Direct Costs (DC)** | | **$16,176,900** | **$19,702,200** | **$22,517,100** |
| **Indirect Costs** | | | | |
| Construction Management | 20% x DC | $3,235,400 | $3,940,400 | $4,503,400 |
| Construction Indirects | 15% x DC | $2,426,500 | $2,955,300 | $3,377,600 |
| Engineering | 15% x DC | $2,426,500 | $2,955,300 | $3,377,600 |
| Contingency | 20% x DC | $3,235,400 | $3,940,400 | $4,503,400 |
| Overhead and Profit | 15% x DC | $2,426,500 | $2,955,300 | $3,377,600 |
| **Total Indirect Costs (IC)** | | **$13,750,300** | **$16,746,700** | **$19,139,600** |
| **Total Contracted Costs (CC)** | **DC + IC** | **$29,927,200** | **$36,448,900** | **$41,656,700** |
| **ANNUAL OPERATING COST**<br>**Operating Costs** | | | | |
| Power | | $22,300 | $89,200 | $126,300 |
| Off-site Landfill Costs | | $946,100 | $946,100 | $946,100 |
| Equipment Operator Labor (FTE) | | $192,100 | $384,100 | $256,100 |
| Maintenance | | $100,000 | $120,000 | $135,000 |
| **Total Direct Annual Costs (DAC)** | | **$1,260,500** | **$1,539,400** | **$1,463,500** |

Note 1: Costs in the Table 4-3 are provided as a total cost for both A.B. Brown Unit 1 and Unit 2.

**Table 4-4 Summary of Units 1 and 2 A.B. Brown Fly Ash Cost Estimate**

| DESCRIPTION | | DILUTE PHASE, VACUUM PNEUMATIC CONVEYING SYSTEM |
|---|---|---|
| **Direct Cost** | | |
| Civil and Structural Costs | | $5,439,300 |
| Mechanical Costs | | $4,328,000 |
| Electrical and Control Costs | | $2,477,100 |
| **Total Direct Cost (DC)** | | **$12,244,400** |
| **Indirect Cost** | | |
| Construction Indirects | 15% x DC | $1,836,700 |
| Engineering | 15% x DC | $1,836,700 |
| Construction Management | 20% x DC | $2,448,900 |
| Contingency | 20% x DC | $2,448,900 |
| Overhead and Profit | 15% x DC | $1,836,700 |
| **Total Indirect Cost Including Material and Labor (IC)** | | **$10,407,900** |
| **Total Contracted Costs (CC)** | **DC + IC** | **$22,652,300** |
| **ANNUAL OPERATING COST**<br>**Operating Costs** | | |
| Power | | $37,200 |
| Offsite Landfill Costs | | $3,574,400 |
| Equipment Operator Labor (FTE) | | $42,700 |
| Maintenance | | $25,000 |
| **Total Direct Annual Costs (DAC)** | | **$3,679,300** |

# 5.0 Conclusions and Recommendations

The analysis covered by this comprehensive report has shown ash pond closure options and alternative ash handling and water treatment options to bring A.B. Brown and F.B. Culley Stations into future compliance with the updated CCR and ELG regulations (NPDES compliance). Flue gas desulfurization wastewater treatment for heavy metals and suspended solids reduction will be required at A.B. Brown.

Recommendations for each station are summarized below with associated cost estimates shown in Tables 5-1 and 5-2.

## 5.1 A.B. BROWN

Based on the evaluations reported in Sections 2.3 through 2.6, Black & Veatch recommends the following:

- **Submerged Chain Conveyor for Bottom Ash Removal**. The modified SCC is technically feasible with less modification to existing equipment and reduced outage time.
- **Mechanical Exhausters for Fly Ash Removal**. The mechanical exhausters match the design at F.B. Culley.
- **Scrubber Treatment and Collection Basin**. The recommended location for the basin and equipment is south of the capital pond. This option avoids expensive impacts to the railway, undergrounds, and is in close proximity to the power block.

## 5.2 F.B. CULLEY

Based on the evaluations reported in Sections 2.7 through 2.8, Black & Veatch recommends the following:

- **Indoor Dewatering Tanks for Bottom Ash Removal.** The indoor dewatering tank is technically feasible and is a proven approach to bottom ash dewatering and ash removal.

**Table 5-1 Summary of Recommended Technologies – A.B. Brown Station**

| OPTION | TECHNOLOGY DESCRIPTION | CAPITAL COST | O&M COST |
|---|---|---|---|
| ELG Equipment (Table 5-2) | Physical/Chemical and Biological, Collection and Filtration, Location 2 | $43,072,000 | $1,378,000 |
| Bottom Ash | Modified SCC Bottom Ash Handling | $29,927,200 | $1,260,500 |
| Fly Ash | Dry Pneumatic Fly Ash Handling | $22,652,300 | $3,679,300 |

**Table 5-2 Summary of Recommended Technologies – F.B. Culley Station**

| OPTION | TECHNOLOGY DESCRIPTION | CAPITAL COST | O&M COST |
|---|---|---|---|
| Wet-to-Dry Ash Handling | Indoor Dewatering Tanks | $3,868,000 | $300,300 |

# Appendix A. Applicable Effluent Guidelines and Standards

| WASTE STREAM/POLLUTANT | EXISTING SOURCE DIRECT DISCHARGE | | APPLICABILITY A.B. BROWN |
|---|---|---|---|
| | BPT[a] | BAT[a] | |
| All Waste Streams | pH: 6-9 S.U.<br>PCBs[b]: Zero Discharge. | PCBs: Zero Discharge. | Yes |
| Low Volume Wastes | TSS: 100 ppm[1] / 30 ppm[2].<br>Oil & Grease: 20 ppm[1] / 15 ppm[2]. | | Yes |
| Flue Gas Desulfurization (FGD) Wastewater | TSS: 100 ppm[1] / 30 ppm[2].<br>Oil & Grease: 20 ppm[1] / 15 ppm[2]. | Arsenic: 11 ppb[1] / 8 ppb[2]. Mercury: 788 ppt[1] / 356 ppt[2].<br>Nitrate/Nitrite as N: 17 ppm[1] / 4.4 ppm[2]. Selenium: 23 ppb[1] / 12 ppb[2]. | No[c] |
| Flue Gas Mercury Control (FGMC) Wastewater | TSS: 100 ppm[1] / 30 ppm[2].<br>Oil & Grease: 20 ppm[1] / 15 ppm[2]. | Zero Discharge. | No |
| Gasification Wastewater | TSS: 100 ppm[1] / 30 ppm[2].<br>Oil & Grease: 20 ppm[1] / 15 ppm[2]. | Arsenic: 4 ppb[1]. Mercury: 1.8 ppt[1] / 1.3 ppt[2]. Selenium: 453 ppb[1] / 227 ppb[2].<br>TDS: 38 ppm[1] / 22 ppm[2]. | No |
| Combustion Residual Leachate | TSS: 100 ppm[1] / 30 ppm[2].<br>Oil & Grease: 20 ppm[1] / 15 ppm[2]. | TSS: 100 ppm[1] / 30 ppm[2].<br>Oil & Grease: 20 ppm[1] / 15 ppm[2]. | No |
| Fly Transport | TSS: 100 ppm[1] / 30 ppm[2].<br>Oil & Grease: 20 ppm[1] / 15 ppm[2]. | Zero Discharge. | Yes |
| Bottom Ash Transport | TSS: 100 ppm[1] / 30 ppm[2].<br>Oil & Grease: 20 ppm[1] / 15 ppm[2]. | Zero Discharge. | Yes |
| Once-Through Cooling | Free Available Chlorine: 0.5 ppm[3] / 0.2 ppm[4]. | Total Residual Chlorine if ≥25 MW: 0.2 ppm[5]. If ≤25 MW: equal to BPT. | No |
| Cooling Tower Blowdown | Free Available Chlorine: 0.5 ppm[3] / 0.2 ppm[4]. | Free Available Chlorine: 0.5 ppm[3] / 0.2 ppm[4]. 126 Priority Pollutants:<br>Zero discharge except: Chromium: 0.2 ppm[3] / 0.2 ppm[4].<br>Zinc: 1.0 ppm[3] / 1.0 ppm[4]. | Yes |
| Coal Pile Runoff | TSS: 50 ppm[5]. | | Yes |
| Chemical Metal Cleaning Wastes | TSS: 100 ppm[1] / 30 ppm[2].<br>Oil & Grease: 20 ppm[1] / 15 ppm[2].<br>Copper, total: 1 ppm[1] / 1 ppm[2].<br>Iron, total: 1 ppm[1] / 1 ppm[2]. | Copper: 1.0 ppm[3] / 1.0 ppm[4].<br>Iron: 1.0 ppm[3] / 1.0 ppm[4]. | Yes |

Source: [40 CFR Part 423]

[1]Maximum concentration for any one day.

[2]Average daily values for 30 consecutive days.

[3]Maximum concentration.

[4]Average concentration.

[5]Instantaneous maximum.

[a]The pH of all discharges, except once-through cooling water, shall be within the range of 6.0 – 9.0. For all effluent guidelines, where two or more waste streams are combined, the total pollutant discharge quantity may not exceed the sum of allowable pollutant quantities for each individual waste stream. BAT, BPT, NSPS allow either mass or concentration-based limitations.

[b]Polychlorinated biphenyl compounds (PCBs) commonly used in transformer fluid.

[c] The EPA has ruled that the type of wet FGD system utilized at ABB, dual alkali scrubber, produces only low volume wastewater.

BPT – Balance of Plant Treatment

BAT – Best Achievable Technology

# Appendix B. List of Assumptions for A.B. Brown

The conceptual cost estimate is provided for alternative treatment options for each stream that discharges into the ash pond to bring A.B. Brown into compliance with ELG regulations. The A.B. Brown site includes existing coal fired plants.

The cost estimate is based on the assumptions in the following sections:

## B.1 GENERAL ASSUMPTIONS

- Ash pond will be closed in place. No costs associated with its closure are included in the estimate.
- All underground pipe will be buried so that the top of pipe is below frost depth. All aboveground pipe will be supported on sleepers.
- Pipe that is running under an existing rail track is assumed to be jack and bored into place.
- Existing buried pipe under 12 inches that will no longer be in service will be capped and abandoned in place. Existing pipe greater or equal to 12 inches will be backfilled. An allowance is also included to remove some large bore piping when in the area of installation of any new piping. No other demolition of any existing structures is included.
- Existing soil will have sufficient strength to support the new basins and building. Cost is added to include a geotechnical survey to confirm this assumption.
- No cost is included for existing gravel road repair or new roads.
- One railroad crossing would be required for Option 2 for new access road.
- A liner was assumed to be needed under collection basin and settling basins. A liner was not assumed to be needed under new piping.
- A new 80 foot by 50 foot metal building with heating, ventilating, and air conditioning (HVAC) is included for new water treatment equipment. A 2 foot thick slab was assumed to be sufficient to support any equipment needed inside the metal building. Piles are not included. There are 2 tons of support steel for miscellaneous equipment inside of the metal building.
- A 2.5 ton jib crane is included for the settling basin.
- No site leveling or raising is included in the estimate.
- The site has sufficient area available to accommodate construction activities including, but not limited to, construction offices (trailers), laydown, and staging.
- Wastewater treatment will include one clarification and sludge handling train. All transfer pumps, sludge pumps and chemical feed pumps will be designed with 2x100 percent redundancy. Wastewater treatment will include programmable logic controller (PLC) control panel, input/output (I/O) cabinets, and motor control center (MCC) all located in the metal building.

- Sludge hauling dumpster is not included in the estimate.
- No provisions for future expansion of the new wastewater treatment equipment are included.
- An emergency generator is not provided.
- Construction power will be provided by Vectren.
- The existing fire protection hydrant loop from the existing facility will be extended as required to serve the new metal building and water treatment areas. It is assumed that existing fire water pressure and volume are sufficient, therefore, no new fire pumps are included.
- Existing auxiliary power system can supply a minimum 100 amperes at 4160 volts.
- A new distributed control system (DCS) remote input/output (RIO) cabinet is located in the new electrical room in the metal building.
- There is fiber-optic connection to plant DCS.
- Add 30 percent for DCS programming engineering, arc flash coordination study.
- Uninterruptible power supply (UPS) feeds are based on typical primary/backup feed to DCS cabinets; other option is local mini-UPS located in Electrical Building. Power provided by available plant UPS.
- Heat trace loads that are nonfreeze protection lines (nonwater) are allowed off 120/208V panel in the power distribution center (PDC) in accordance with previous project work.
- Building will have 20 foot hi-bay ceilings, with potential second floor open grated level.
- All cables fed from plant; not from cooling tower area based on lack of information.
- New collection basin and wastewater treatment equipment sizing is based on two operating units.
- No changes to the current FGD wastewater mercury treatment equipment or any upstream piping or devices from either unit.
- Current coal pile runoff pump capacity is adequate to reach new collection basin based on topography, pump curve, and Black & Veatch flow modeling.
- New collection basin sizing is based on 20 minutes retention time for all flows identified on the Vectren water mass balance (WMB).
- Proposed treatment is based on flows in the A.B. Brown Plant Water Balance, Drawing F-2025.1, and water quality data provided by Vectren.
- Cooling tower blowdown flow rate and water quality assumes the cooling tower operates at six cycles of concentration. Copper content in the cooling tower blowdown is assumed to be reduced to 0.02 ppm after treatment in the existing cooling tower blowdown settling basins. This is consistent with existing plant water quality data.

- Proposed treatment assumes 60 gpm of SCC wastewater total for both units. SCC wastewater quality is assumed to be the same as the quality of the combined collection basin water, except with 1,000 ppm TSS.
- The coal pile runoff pond discharge will improve in quality as a result of the new FGD treatment system. The water quality for the coal pile runoff pond discharge is assumed to be a flow-proportioned blend of non-SCC wastewater (water quality of A.B. Brown's coal pile runoff sample) and the SCC wastewater.
- Proposed physical/chemical treatment assumes 99 percent removal of mercury, removal to 10 ppm TSS in clarifier effluent, and removal to 0.02 ppm copper in clarifier effluent.
- Proposed biological treatment assumes selenium removal to 0.01 ppm in system effluent.
- Proposed dewatering system assumes 99 percent of solids in feed will be removed in filter cake for disposal. Precipitated metals are included in this assumption.
- Treatment vessel will flow by gravity to the existing ash pond wastewater mercury treatment system.
- No electrical equipment or storage building provided at Location No. 3.
- Treatment system is not designed to handle chemical cleaning wastes.
- Required instrumentation is included in cost of treatment system.
- A.B. Brown Station bottom ash handling equipment costs are based on F.B. Culley Unit 3 design and recent proposals from United Conveyor Corporation for submerged chain conveyor.
- New high-pressure and low-pressure recirculation pumps will tie in to existing piping within plant.
- Existing excavated dirt is assumed to be suitable for backfill material. No imported fill is included.

## B.2 DIRECT COST ASSUMPTIONS

The following assumptions are included in the base construction cost estimate for direct costs:

- All costs are expressed in 2019 dollars. No escalation is included.
- Direct costs include the costs associated with the purchase of equipment, erection, and all contractor services.
- Construction costs are based on a turnkey construction approach. Construction is assumed to be performed based on a 50 hour workweek. Local union rates are used that include payroll, payroll taxes, and benefits. The consolidated labor rate used is about $75 per man-hour.

- Total capital costs are ±50 percent and include the costs associated with the purchase of equipment, erection, and all contractor services.
- Construction costs are based on an EPC construction approach.
- Capital direct cost for balance of plant treatment (BPT) assumed 4 percent equipment capital cost for equipment replacement during major outage.
- BPT treatment total capital costs include all common water treatment infrastructure.
- Selenium treatment total capital costs include only biological treatment that requires the BPT treatment system and entire infrastructure upstream for effluent compliance.
- BPT and selenium treatment is common equipment for both units.
- Leachate and WW Hg treatment is included in BPT treatment total capital costs.
- FBC selenium treatment includes all necessary equipment for effluent compliance; physical chemical treatment with biological.

## B.3 INDIRECT COST ASSUMPTIONS

The following assumptions are included in the base construction cost estimate for indirect costs:

- General indirect costs include all necessary services required for checkouts, testing services, and commissioning.
- Insurance including builder's risk and general liability.
- Field construction management services including field management staff, supporting staff personnel, field contract administration, field inspection/quality assurance, and project controls.
- Technical direction and management of startup and testing, cleanup expense for the portion not included in the direct-cost construction contracts, safety and medical services, guards and other security services, insurance premiums, performance bond, and liability insurance for equipment and tools.
- Transportation costs for equipment and materials delivery to the jobsite.
- Startup/commissioning spare parts. Only miscellaneous parts used during the startup process are included. All major equipment long-term spare parts should be included in Vectren's costs.
- Construction contractor contingency costs.
- Construction contractor typical profit margin.
- Total capital costs do not include contingency, owner's cost, taxes, insurance, spare parts, or construction utility interconnections/consumables.

- O&M base non-labor cost for BPT assumed 2 percent equipment capital costs for maintenance items, consumables, and spare parts. Variable O&M costs are not included.

The following additional items of cost are not included in the construction estimate. These costs shall be determined by Vectren and are included in Vectren's cost estimate:

- Owner's contingency costs.
- Federal, state, and local taxes.
- Major equipment spare parts.
- Land.
- Interest during construction.
- Cost and fees for electrical, gas, and other utility interconnections.
- Project development costs, legal, and community outreach.
- All operating plant vehicles.
- No permitting costs have been included.
- Furniture, maintenance and office equipment, supplies, consumables, communications and plant IT systems, and startup fuel.
- Emissions credits.
- Environmental mitigation.

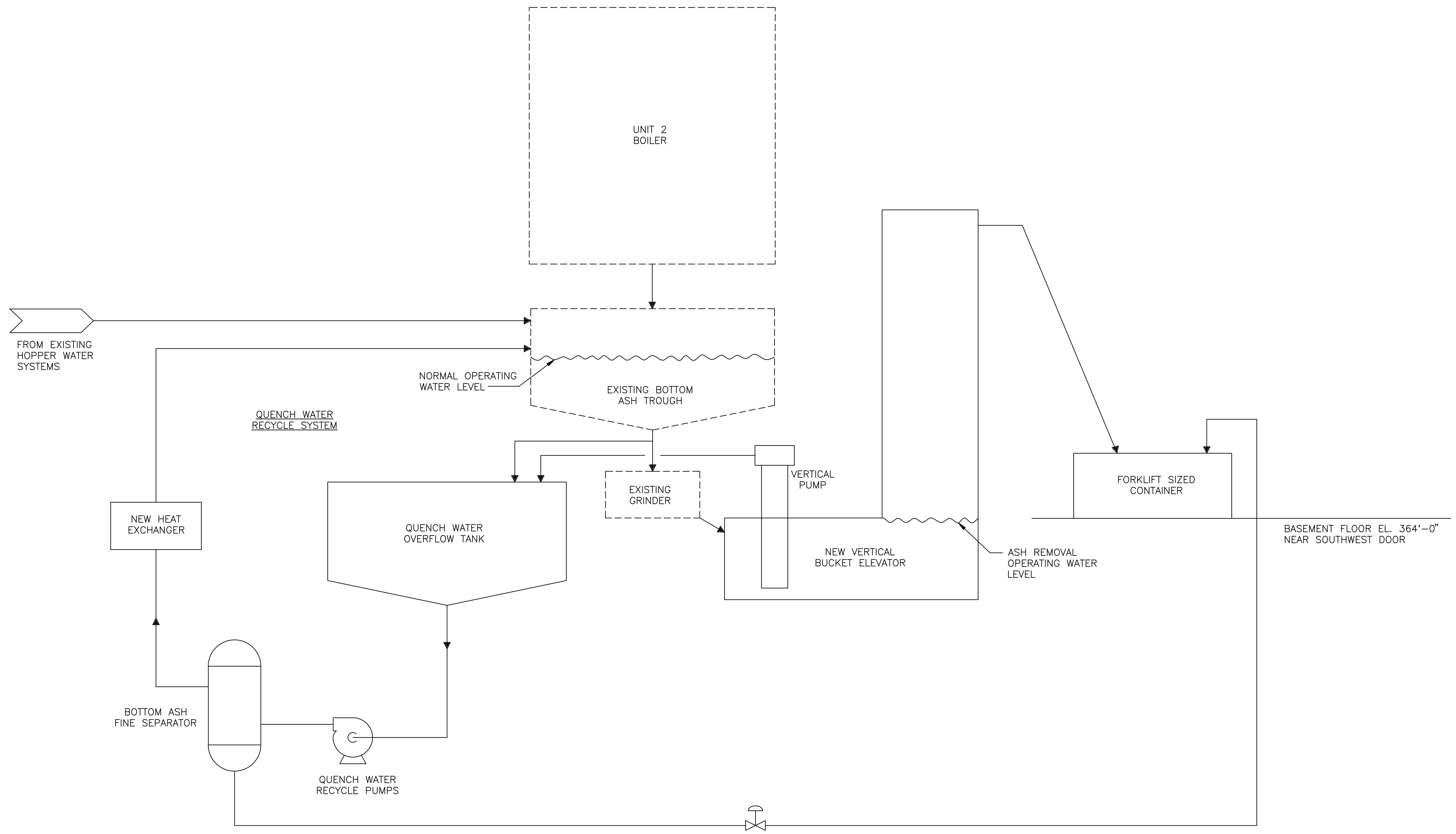
# Appendix C. List of Process Flow Diagrams

## C.1 PROCESS FLOW DIAGRAMS FOR F.B. CULLEY UNIT 2

Bucket Elevator (Alternative No. 1) – 190507-PFD-4000
Indoor Dewatering Tanks (Alternative No. 2) – 190507-PFD-4001
Dry Pneumatic System (Alternative No. 3) – 190507-PFD-4002
Remote Submerged Chain Conveyor (Alternative No. 4) – 190507-PFD-4003

## C.2 PROCESS FLOW DIAGRAMS FOR A.B. BROWN UNITS 1 AND 2

Submerged Chain Conveyor (Alternative No. 1) – 190507-PFD-4004
Dewatering Bunker (Alternative No. 2) – 190507-PFD-4005
Remote Submerged Chain Conveyor (Alternative No. 3) – 190507-PFD-4006




**NOT TO BE USED FOR CONSTRUCTION**

THE DISTRIBUTION AND USE OF THE NATIVE FORMAT CAD FILE OF THIS DRAWING IS UNCONTROLLED. THE USER SHALL VERIFY TRACEABILITY OF THIS DRAWING TO THE LATEST CONTROLLED VERSION.

| NO | DATE | REVISIONS AND RECORD OF ISSUE | DRN | DES | CHK | PDE | APP |
|---|---|---|---|---|---|---|---|
| A | 28/JUL/16 | ISSUED FOR CLIENT REVIEW | DRE | EGC | | LRK | |

BLACK & VEATCH
Building a world of difference®

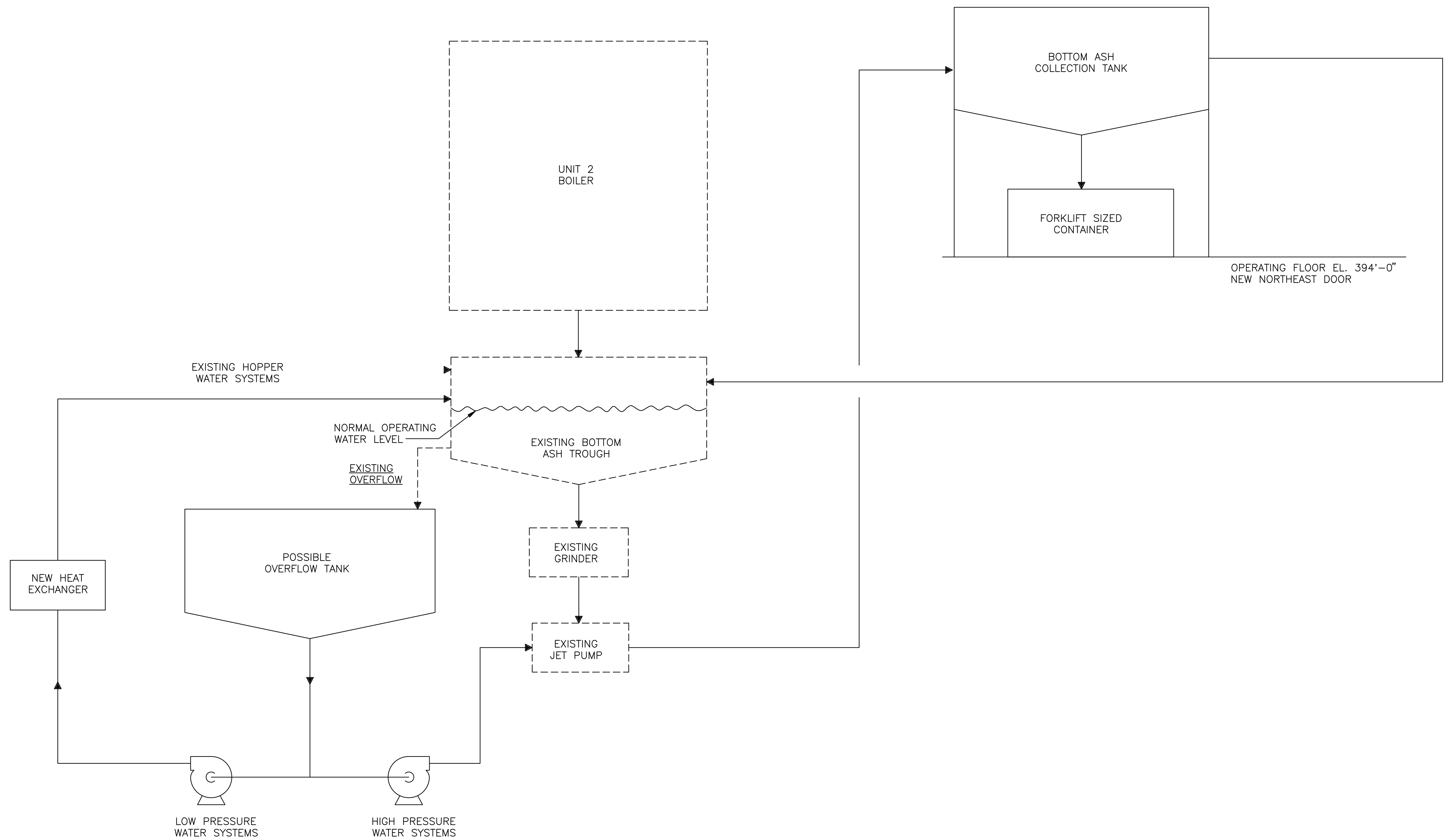
DESIGNER LRK | DRAWN DRE
CHECKED | DATE

VECTREN POWER SUPPLY
CULLEY STATION UNIT 2

ALTERNATIVE 1
VERTICAL BUCKET ELEVATOR FLOW DIAGRAM

PROJECT | DRAWING NUMBER: 190507-PFD-4000 | REV: A
CODE
AREA

ELY65172 D1 1=1 ACAD 18.2s (LMS Tech)
A1ASL028
08/02/16 15:24:16




NOT TO BE USED
FOR CONSTRUCTION

THE DISTRIBUTION AND USE OF THE NATIVE FORMAT CAD FILE OF THIS DRAWING IS UNCONTROLLED. THE USER SHALL VERIFY TRACEABILITY OF THIS DRAWING TO THE LATEST CONTROLLED VERSION.

| NO | DATE | REVISIONS AND RECORD OF ISSUE | DRN | DES | CHK | PDE | APP |
|---|---|---|---|---|---|---|---|
| A | 28/JUL/16 | ISSUED FOR CLIENT REVIEW | DRE | EGC | | LRK | |

BLACK & VEATCH
Building a world of difference®

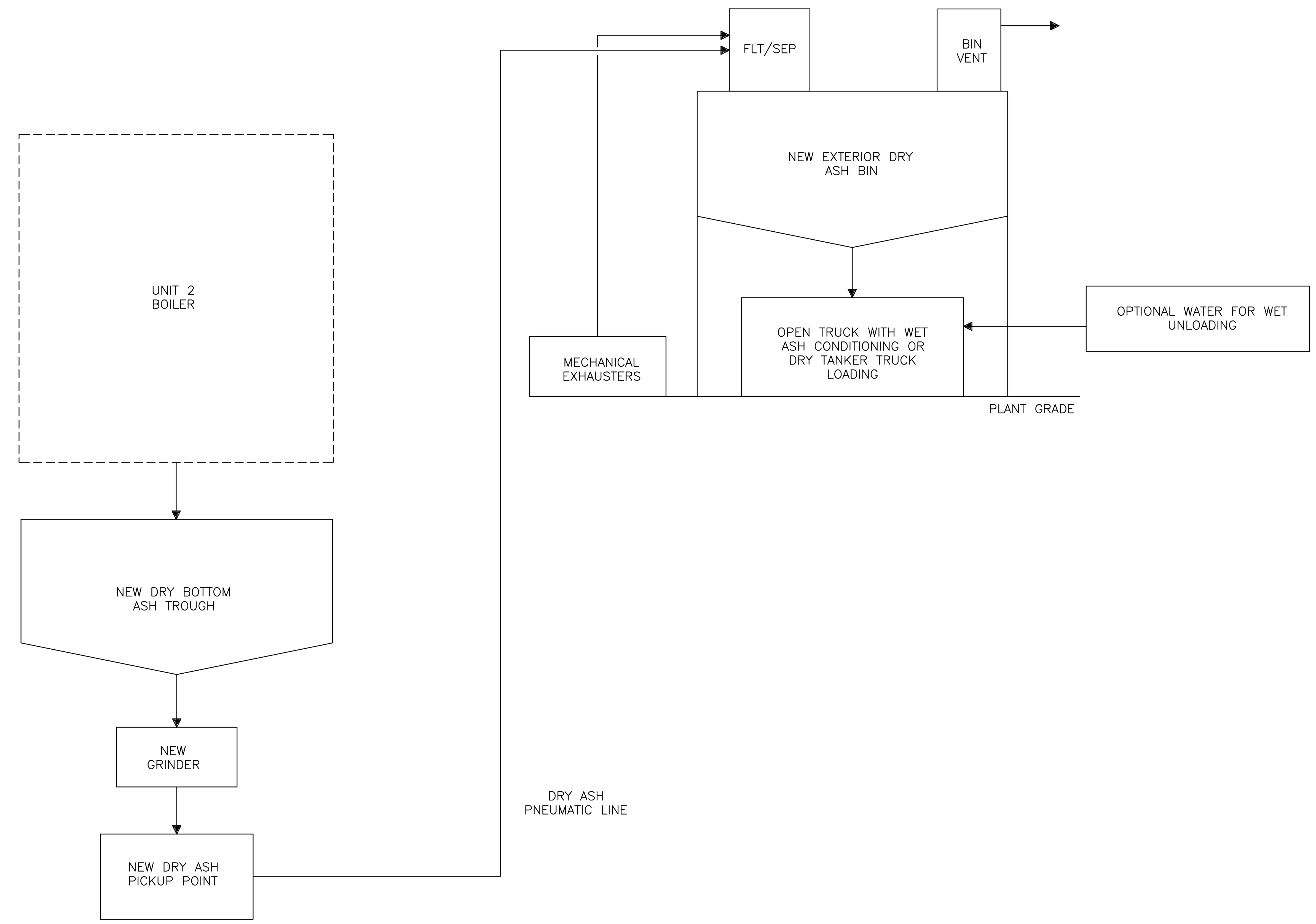
DESIGNER LRK | DRAWN DRE
CHECKED | DATE

VECTREN POWER SUPPLY
CULLEY STATION UNIT 2

ALTERNATIVE 2
INTERIOR DEWATERING TANK FLOW DIAGRAM

PROJECT / DRAWING NUMBER: 190507-PFD-4001
REV: A
CODE
AREA

ELY65172 A1ASL028 08/03/16 08:40:25 D1 1=1 ACAD 18.2s (LMS Tech)




NOT TO BE USED FOR CONSTRUCTION

THE DISTRIBUTION AND USE OF THE NATIVE FORMAT CAD FILE OF THIS DRAWING IS UNCONTROLLED. THE USER SHALL VERIFY TRACEABILITY OF THIS DRAWING TO THE LATEST CONTROLLED VERSION.

| NO | DATE | REVISIONS AND RECORD OF ISSUE | DRN | DES | CHK | PDE | APP |
|---|---|---|---|---|---|---|---|
| A | 28/JUL/16 | ISSUED FOR CLIENT REVIEW | DRE | EGC | | LRK | |

BLACK & VEATCH
Building a world of difference®

DESIGNER LRK | DRAWN DRE | CHECKED | DATE

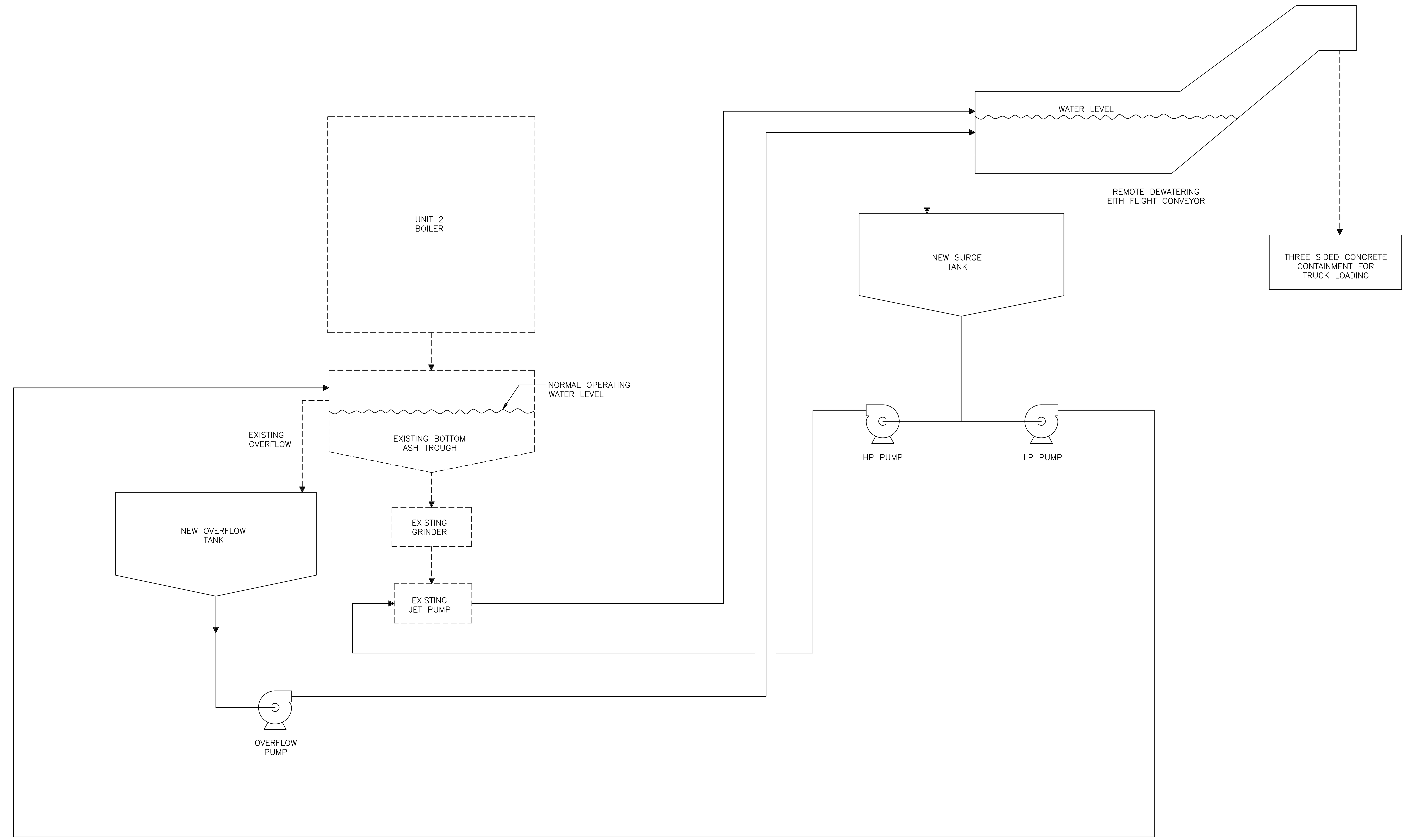
VECTREN POWER SUPPLY
CULLEY STATION UNIT 2

ALTERNATIVE 3
PNEUMATIC ASH REMOVAL FLOW DIAGRAM

PROJECT | DRAWING NUMBER: 190507-PFD-4002 | REV: A

CODE | AREA

ELY65172 A1ASL028 08/03/16 08:21:04 D1 1=1 ACAD 18.2s (LMS Tech)




NOT TO BE USED
FOR CONSTRUCTION

THE DISTRIBUTION AND USE OF THE NATIVE FORMAT CAD FILE OF THIS DRAWING IS UNCONTROLLED. THE USER SHALL VERIFY TRACEABILITY OF THIS DRAWING TO THE LATEST CONTROLLED VERSION.

| NO | DATE | REVISIONS AND RECORD OF ISSUE | DRN | DES | CHK | PDE | APP |
|---|---|---|---|---|---|---|---|
| A | 28/JUL/16 | ISSUED FOR CLIENT REVIEW | DRE | EGC | | LRK | |

BLACK & VEATCH
Building a world of difference®

| | |
|---|---|
| DESIGNER LRK | DRAWN DRE |
| CHECKED | DATE |

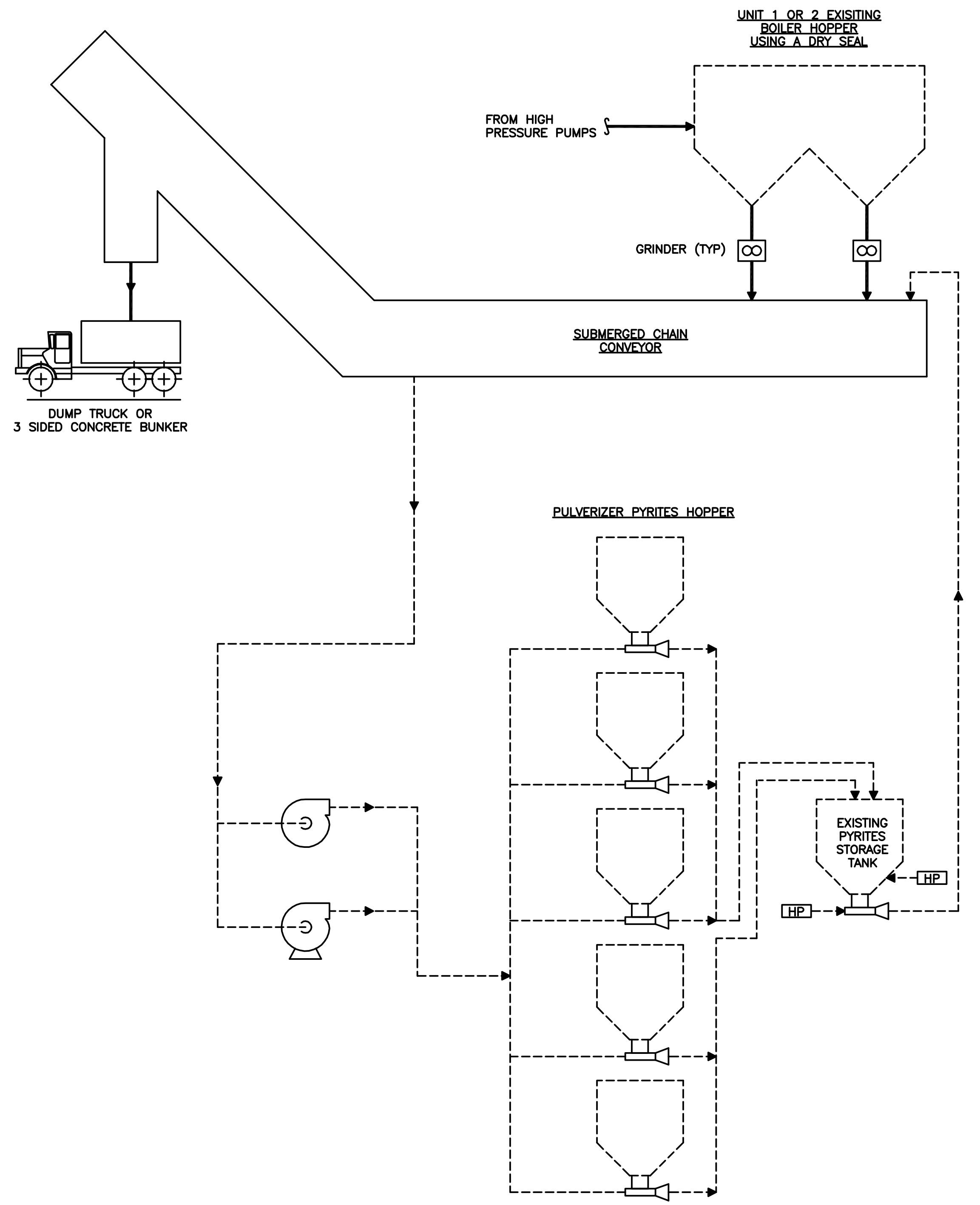
VECTREN POWER SUPPLY
CULLEY STATION UNIT 2

ALTERNATIVE 4
REMOTE DEWATERING FLIGHT CONVEYOR FLOW

| PROJECT | DRAWING NUMBER | REV |
|---|---|---|
| 190507 | PFD-4003 | A |

CODE
AREA

ACAD 18.2s (LMS Tech)
D1 1=1
ELY65172
A1ASL028
08/03/16 08:57:09




NOT TO BE USED FOR CONSTRUCTION

THE DISTRIBUTION AND USE OF THE NATIVE FORMAT CAD FILE OF THIS DRAWING IS UNCONTROLLED. THE USER SHALL VERIFY TRACEABILITY OF THIS DRAWING TO THE LATEST CONTROLLED VERSION.

| NO | DATE | REVISIONS AND RECORD OF ISSUE | DRN | DES | CHK | PDE | APP |
|---|---|---|---|---|---|---|---|
| A | 03/JUL/19 | ISSUED FOR CLIENT REVIEW | JLH | MWE | | KMK | |

BLACK & VEATCH
Building a world of difference.

DESIGNER MWE | DRAWN JLH | CHECKED | DATE

VECTREN POWER SUPPLY
A.B. BROWN STATION (UNIT 1 OR 2)

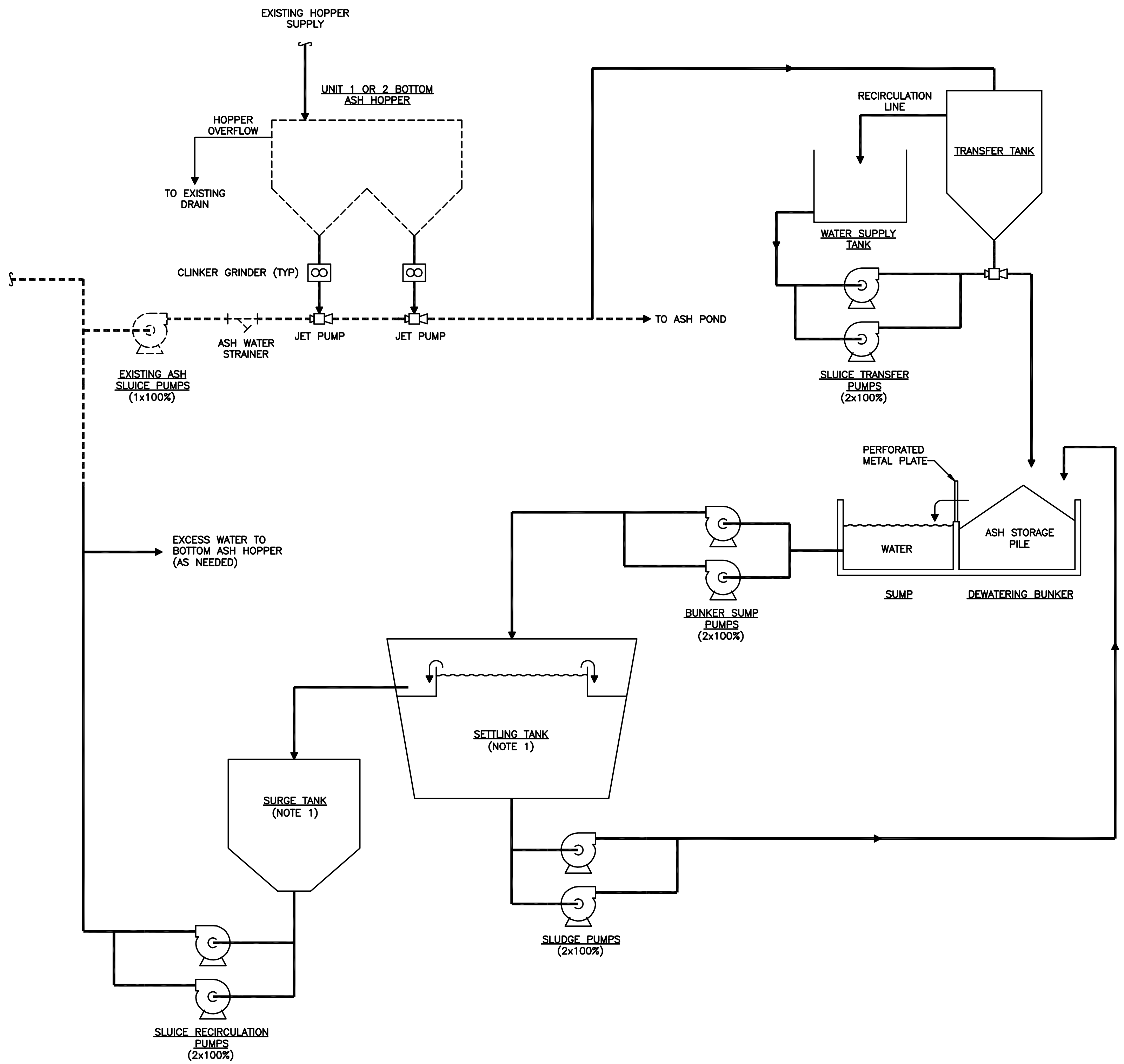
ALTERNATIVE 1
SUBMERGED CHAIN CONVEYOR

PROJECT | DRAWING NUMBER: 190507-PFD-4004 | REV: A
CODE | AREA

ELY65172 A1ASL028 11/14/16 09:48:42 D1 1=1 ACAD 18.2s (LMS Tech)

NOTES:

1. SETTLING TANK & SURGE TANK NEED FURTHER INVESTIGATION.




NOT TO BE USED FOR CONSTRUCTION

THE DISTRIBUTION AND USE OF THE NATIVE FORMAT CAD FILE OF THIS DRAWING IS UNCONTROLLED. THE USER SHALL VERIFY TRACEABILITY OF THIS DRAWING TO THE LATEST CONTROLLED VERSION.

| NO | DATE | REVISIONS AND RECORD OF ISSUE | DRN | DES | CHK | PDE | APP |
|---|---|---|---|---|---|---|---|
| A | 03/JUL/19 | ISSUED FOR CLIENT REVIEW | JLH | MWE | | KMK | |

BLACK & VEATCH Building a world of difference.

| DESIGNER | MWE | DRAWN | JLH |
|---|---|---|---|
| CHECKED | | DATE | |

VECTREN POWER SUPPLY
A.B. BROWN STATION (UNIT 1 OR 2)

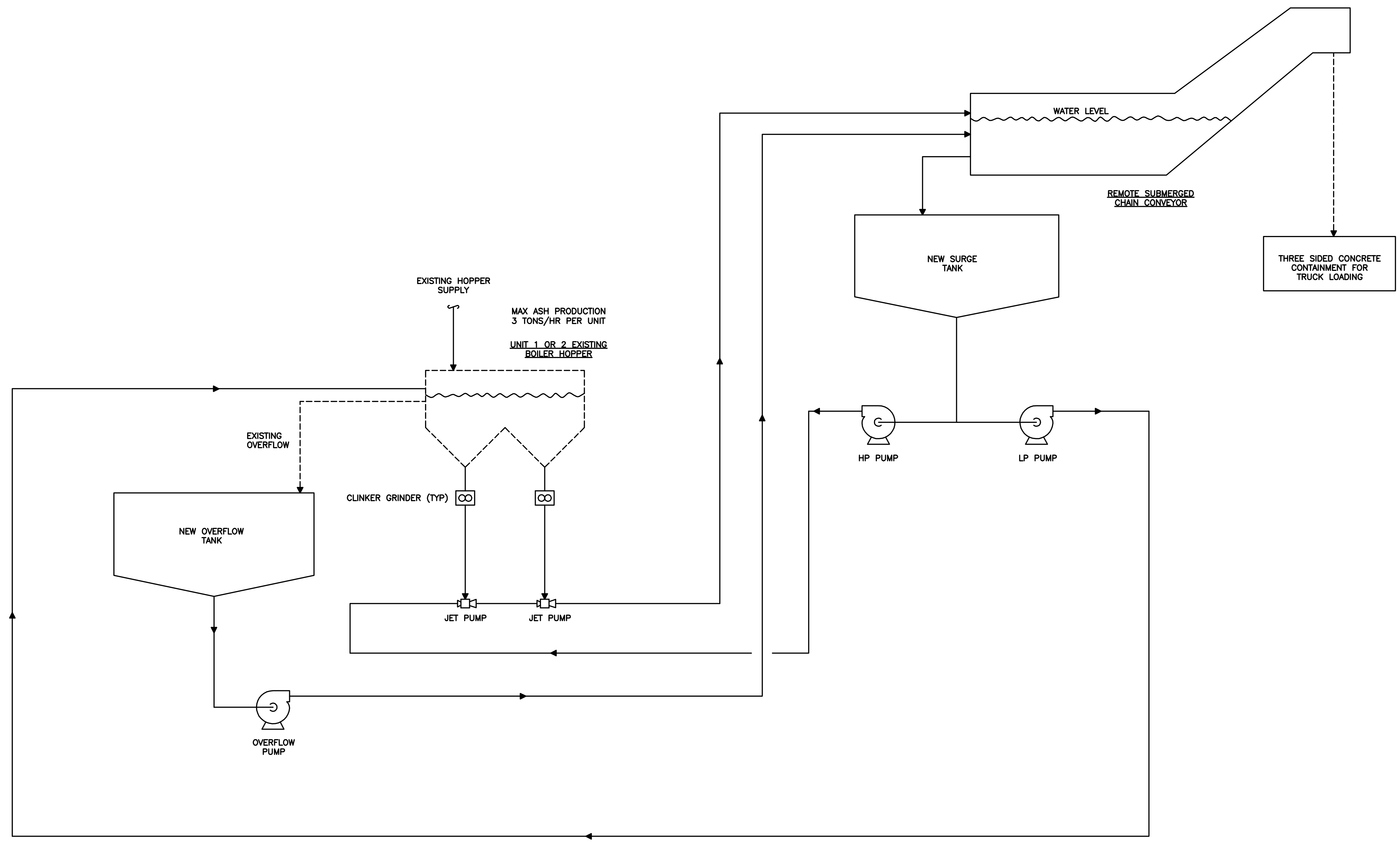
ALTERNATIVE 2
BOTTOM ASH DEWATERING BUNKER

PROJECT: 190507 | DRAWING NUMBER: 190507-PFD-4005 | REV: A

CODE

AREA

ELY65172 A1ASLD2B 08/04/16 10:48:15 D1 1=1 ACAD 18.2s (LMS Tech)




# NOT TO BE USED FOR CONSTRUCTION

THE DISTRIBUTION AND USE OF THE NATIVE FORMAT CAD FILE OF THIS DRAWING IS UNCONTROLLED. THE USER SHALL VERIFY TRACEABILITY OF THIS DRAWING TO THE LATEST CONTROLLED VERSION.

| NO | DATE | REVISIONS AND RECORD OF ISSUE | DRN | DES | CHK | PDE | APP |
|---|---|---|---|---|---|---|---|
| A | 03/JUL/19 | ISSUED FOR CLIENT REVIEW | JLH | MWE | | KMK | |

BLACK & VEATCH
Building a world of difference.

DESIGNER MWE | DRAWN JLH | CHECKED | DATE

VECTREN POWER SUPPLY
A.B. BROWN STATION (UNIT 1 OR UNIT 2)

ALTERNATIVE 3
REMOTE SUBMERGED CHAIN CONVEYOR FLOW

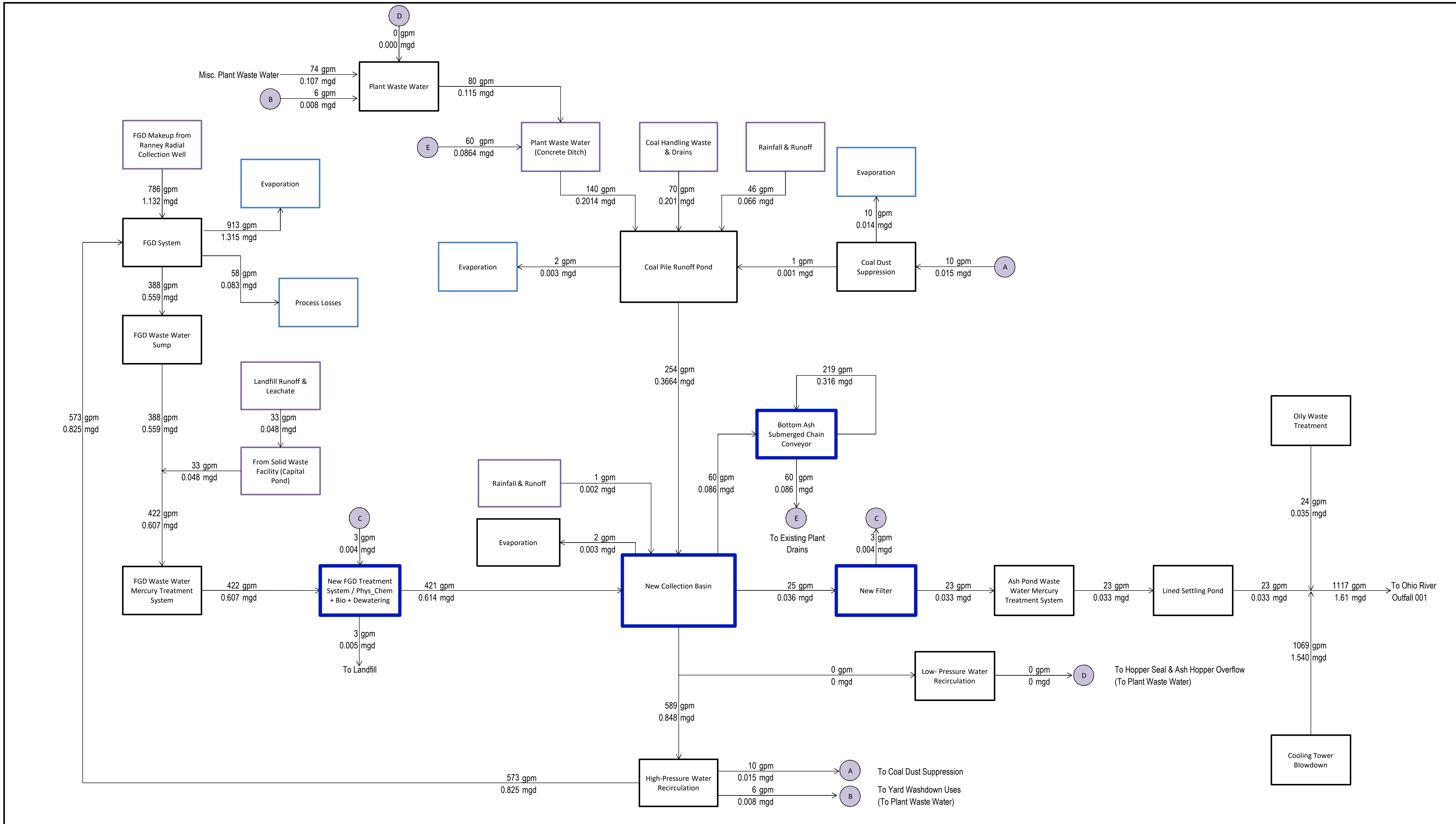
PROJECT | DRAWING NUMBER: 190507-PFD-4006 | REV: A

CODE
AREA

ELV65172 A1ASL028 08/22/16 D1 1=1 16:16:10 ACAD 18.2s (LMS Tech)

# Appendix D. Water Mass Balance Diagram

## D.1 WATER MASS BALANCE DIAGRAM FOR A.B. BROWN




| NO | DATE | REVISIONS AND RECORD OF ISSUE | DRN | ENG |
|---|---|---|---|---|
| A | 2/21/20 | ELG - CCR Compliance Report | VMM | AJF |

BLACK & VEATCH
Building a world of difference.

Eng:
Dwg:
Date: 2/21/2020

Vectren Corp.
A.B. Brown Station
WATER MASS BALANCE - Dual Alkali Scrubber

REV
A

# Attachment 6.8 ACE Rule Heat Rate Study

**FINAL**

# EPA ACE HEAT RATE STUDY

**B&V PROJECT NO. 402338**
**B&V FILE NO. 40.0004**



**PREPARED FOR**

VECTREN
A CenterPoint Energy Company

Vectren

16 JANUARY 2020

BLACK & VEATCH

# Table of Contents

## LIST OF TABLES

## LIST OF FIGURES

# Executive Summary

The Affordable Clean Energy (ACE) rule, finalized by the United States Environmental Protection Agency (EPA) on June 19, 2019, establishes new standards for reducing greenhouse gas (GHG) emissions for coal-fired electric utility generating units (EGUs) based on the "best system of emission reduction" (BSER). First proposed in August 2018, the rule, Docket ID No. EPA-HQ-OAR-2017-0355: FRL-9995-70-OAR, "Repeal of the Clean Power Plan; Emission Guidelines for Greenhouse Gas Emissions from Existing Electric Utility Generating Units; Revisions to Emission Guidelines Implementing Regulations," focuses on measures that can be implemented within the fence line of existing EGU facilities. As such, the EPA concluded that BSER be limited to heat rate improvements (efficiency improvements) for existing coal-fired EGUs. Within ACE, the EPA identified a list of candidate technologies and measures to achieve heat rate improvements (HRI).

In anticipation of the final rule, Vectren requested that Black & Veatch assess these candidate technologies for improvements at four coal fired plants (A.B. Brown Unit 1, A.B. Brown Unit 2, Culley Unit 2, and Culley Unit 3) to meet the goals of the ACE rule. Black & Veatch reviewed the characteristic of the four plants and examined each plant according to several BSER alternatives:

- Steam turbine blade path upgrades.
- Redesign or replacement of the economizer.
- Air heater and duct leakage control.
- Variable frequency drive (VFD) deployment.
- Neural networks.
- Intelligent sootblowing (ISB).
- Various improved operations and maintenance (O&M) practices.

Several factors influenced the recommendations for upgrades at the four plants; these factors are discussed in detail in Section 3.0. A summary of Black & Veatch's assessment and recommendations is as follows:

- The existing steam turbines at A.B. Brown Units 1 and 2 have been upgraded to full dense pack and no significant improvement in heat rate would result in additional upgrades; a turbine blade path upgrade would improve heat rate at F.B. Culley Unit 3 (1.4 to 1.6 percent). Steam turbine blade path upgrades options for F.B. Culley Unit 2 would improve heat rate by 1.3 to 1.5 percent, at a cost of $10.4 million.
- Economizer upgrades are not recommended for A.B. Brown Units 1 and 2 or F.B. Culley Unit 3 at this time; upgrades at F.B. Culley Unit 2 would require significant investment and require further study. A boiler modeling study of the potential benefits of reducing economizer surface area at A.B. Brown Units 1 and 2 or F.B. Culley Unit 3 found that although there was a potential reduction in natural gas use for the gas burners, the net impact upon the units was negative.
- Recommendations were provided for improving unit air heaters at all four units.

- Estimated costs are provided for VFD improvements for the FD and ID Fans at A.B. Brown Units 1 and 2. VFD improvements were studied for the FD fans at F.B. Culley Units 2 and 3 as both units ID fans have already been upgraded with VFDs.
- The deployment of VFDs for circulating water pumps was studied at all four units, but in no instance was it found to be a cost-effective HRI option.
- Estimated costs are provided for neural network deployment at all four units.
- F.B. Culley Unit 2 is the only unit that could benefit from ISB; the other units already use this technology.
- Improved O&M practices include heat rate improvement training, on-site heat rate appraisals, and improved condenser cleanliness strategies; these techniques may result in improvements at all four units.

Overall, many opportunities exist for heat rate improvement at the A.B. Brown and F.B. Culley units in compliance with the EPA-ACE rule. The decision of which heat rate improvements should be pursued must be based upon the long-term plans for the continued operation of the units, and the specific cost/benefit factors for each improvement found in Appendix B.

## Recommendations

The following recommendations have been made for the units, based upon their past performance and current operations, as well as the expected future payback potential.

- For the A.B. Brown 1, A.B. Brown 2, and F.B. Culley 3 units upgrades to the air heaters and repair and remediation of ductwork and air quality control systems leakage appears to have a high value to the plants. In the case of air heater upgrades the improvement in heat transfer will improve the boiler efficiency, and the reduction in air heater leakage will reduce station service by reducing the air and gas main fan flow requirements. Reductions in duct leakage and leakage in air quality control equipment leakage will significantly improve induced draft fan performance and will reduce station service. There will also be the ancillary benefit of improved operations and efficiency of the air quality control equipment for emissions reduction.

  F.B. Culley Unit 2 was found to have a poor cost/benefit ratio for these upgrades due to its very low capacity factor and net generation, as well as its relatively short remaining useful life. F.B. Culley Unit 3 on the other hand was found to have the best potential benefit from air heater and duct leakage improvements from the standpoint of improvement per capital dollar spent.

- Steam turbine and blade path upgrades were analyzed for F.B. Culley Units 2 and 3 (A.B. Brown Units 1 and 2 were judged not to benefit from them sufficiently to warrant further upgrades, due to their relatively recent dense pack refurbishments) but only upgrades respective to F.B. Culley Unit 3 were found to be technically feasible and cost-effective at this time. However, as the New Source Review (NSR) exemption portion of EPA-ACE has been deferred and will be proposed in a separate action at a later date, pursuing steam turbine upgrades at this time should be done under the consideration of the potential for triggering NSR.

- Variable frequency drive deployment was found to be only advantageous for the induced draft fans on A.B. Brown Units 1 and 2. For all other systems and the F.B. Culley units, either VFDs had already been deployed to critical systems, or there was no acceptable cost/benefit to further deployment.
- Deploying a neural network or other boiler optimization system was found to be beneficial for all units except F.B. Culley Unit 2, which again was excluded due to its low capacity factor and output. Even modest improvements in optimization could result in significant improvements to heat rate and overall unit control and emissions.
- Heat rate awareness training was found to be a very good cost/benefit for all the units and could yield significant improvements in operations practices and responses to controllable losses at both plants. Targeted heat rate assessment, while difficult to quantify exactly, is expected based upon Black & Veatch experience to have a very high return on investment, and numerous examples have been provided in the text from past projects.
- The addition of more circulating water temperature measurements leaving the condenser would also improve accuracy of results by better capturing temperature stratification in the return piping.

## Summary of Costs

The following table provides a summary of costs associated with the recommended ACE technologies for each unit. Additional detailed cost estimates for each unit can be found in Appendix B.

**Table ES-1 A.B. Brown Unit 1 Summary of ACE Technology Costs**

| Project Description | Est Capital Cost ($000) | Heat Rate Reduction (%) | Heat Rate Reduction (Btu/kWh) |
|---|---|---|---|
| Air Heater Basket, Seal, and Sector Plate Replacement | 850 | 0.50 | 57.88 |
| Air Heater (Steam Coil) System Repairs | 350 | 0.10 | 11.6 |

| Project Description | Est Capital Cost ($000) | Heat Rate Reduction (%) | Heat Rate Reduction (Btu/kWh) |
|---|---|---|---|
| Circulating Water Pumps | 2,100 | N/A | N/A |
| Induced Draft Fans VFD Deployment | 2,900 | 2.39 | 276.5 |
| Forced Draft Fans VFD Deployment | 2,000 | 0.43 | 50.3 |
| Deployment of A Neural Network for Combustion Control and Boiler Excess Air Reduction. (0.25% to 0.75% Reduction in Excess $O_2$) | 500 | 0.23 to 0.60 | 26.6 to 69.5 |
| Heat Rate Improvement Training | 15 | 0.30 | 34.7 |
| On-Site Heat Rate Appraisals | Variable | Variable | N/A |
| Improved Condenser Cleaning Strategies | N/A | 0.15 | 17.4 |

**Table ES-2 A.B. Brown Unit 2 Summary of ACE Technology Costs**

| Project Description | Est Capital Cost ($000) | Heat Rate Reduction (%) | Heat Rate Reduction (Btu/kWh) |
|---|---|---|---|
| Air Heater Basket, Seal, and Sector Plate Replacement | 850 | 0.50 | 55.0 |
| Air Heater (Steam Coil) System Repairs | 350 | 0.10 | 11.0 |
| Circulating Water Pumps | 2,100 | N/A | N/A |
| Induced Draft Fans VFD Deployment | 2,900 | 1.33 | 146.3 |
| Forced Draft Fans VFD Deployment | 2,000 | 0.26 | 28.6 |
| Deployment of A Neural Network for Combustion Control and Boiler Excess Air Reduction. (0.25% to 0.75% Reduction in Excess $O_2$) | 500 | 0.30 to 0.60 | 25.3 to 66.0 |
| Heat Rate Improvement Training | 15 | 0.30 | 33.0 |
| On-Site Heat Rate Appraisals | Variable | Variable | N/A |
| Improved Condenser Cleaning Strategies | N/A | Negligible | Negligible |

**Table ES-3 F.B. Culley Unit 2 Summary of ACE Technology Costs**

| Project Description | Est Capital Cost ($000) | Heat Rate Reduction (%) | Heat Rate Reduction (Btu/kWh) |
|---|---|---|---|
| Air Heater Basket, Seal, and Sector Plate Replacement | 476 | 0.50 | 63.2 |
| Circulating Water Pumps | 900 | N/A | N/A |
| Forced Draft Fans VFD Deployment | 2,000 | 0.48 | 60.9 |
| Deployment of A Neural Network for Combustion Control and Boiler Excess Air Reduction. (0.25% to 0.75% Reduction in Excess $O_2$) | 500 | 0.26 to 0.62 | 32.9 to 78.4 |
| Boiler Feed Pump VFD Deployment | 600 | 0.6 | 75.8 |
| Synchronized Controlled Sootblowing System Designed to Alleviate Excessive Use of Steam, Air or Water That Have A Negative Effect on Heat Rate. | 350 | 0.10 | 12.64 |
| Heat Rate Improvement Training | 15 | 0.30 | 37.9 |
| On-Site Heat Rate Appraisals | Variable | Variable | N/A |
| Improved Condenser Cleaning Strategies | N/A | 0.42 | 53.1 |

**Table ES-4 F.B. Culley Unit 3 Summary of ACE Technology Costs**

| Project Description | Est Capital Cost ($000) | Heat Rate Reduction (%) | Heat Rate Reduction (Btu/kWh) |
|---|---|---|---|
| HP/IP Upgrades | 19,900 | 1.5 | 158.3 |
| Air Heater Basket, Seal, and Sector Plate Replacement | 750 | 0.50 | 52.8 |
| Air Heater (Steam Coil) System Repairs | 350 | 0.10 | 10.6 |
| Circulating Water Pumps | 2,100 | N/A | N/A |
| Forced Draft Fans VFD Deployment | 2,000 | 0.51 | 54.3 |
| Deployment of A Neural Network for Combustion Control and Boiler Excess Air Reduction. (0.25% to 0.75% Reduction in Excess $O_2$) | 500 | 0.25 to 0.62 | 26.4 to 65.4 |
| Heat Rate Improvement Training | 15 | 0.30 | 31.7 |
| On-Site Heat Rate Appraisals | Variable | Variable | N/A |
| Improved Condenser Cleaning Strategies | N/A | 0.44 | 46.4 |

# 1.0 Introduction

Vectren requested that Black & Veatch support its efforts to analyze a potential response to the United States Environmental Protection Agency (EPA) Docket ID No. EPA-HQ-OAR-2017-0355: FRL-9995-70-OAR, "Repeal of the Clean Power Plan; Emission Guidelines for Greenhouse Gas Emissions from Existing Electric Utility Generating Units; Revisions to Emission Guidelines Implementing Regulations;" known as the Affordable Clean Energy (ACE) rule. Vectren operates the A.B. Brown Unit 1, A.B. Brown Unit 2, F.B. Culley Unit 2, and F.B. Culley Unit 3 coal-fired electric generating units (EGUs) and specifically requested that Black & Veatch develop a high-level assessment report identifying opportunities to improve plant efficiency to meet ACE rule goals.

To meet these goals, Black & Veatch prepared a high-level description of four primary heat rate improvement (HRI) projects that have been proposed by the EPA as the best system of emission reduction (BSER). Estimates of HRI, annual carbon dioxide ($CO_2$) reduction, and a rough order-of-magnitude capital cost estimate were developed for each alternative.

Black & Veatch performed a high-level assessment to consider the technical and economic feasibility of items that have been seen as beneficial in previous ACE studies. Financial benefits would be confirmed by integrated resource plan (IRP) modeling; specific modifications would then be reviewed in a detailed effort to confirm the performance and financial benefits.

## 1.1 AN OVERVIEW OF EPA-ACE

On June 19, 2019, EPA issued the ACE rule, a replacement to the previous presidential administration's Clean Power Plan (CPP) to regulate $CO_2$ emissions from existing coal-fired power plants. ACE regulates EGUs based on the BSER. Unlike the CPP, ACE focuses on only those measures which can be implemented within the fence line of existing EGU facilities. As such, EPA has determined BSER to be limited to heat rate improvement (HRI) measures (efficiency improvements) for existing coal-fired EGUs at the individual unit level. The lower a unit's heat rate, the more efficiently it will convert heat input to electrical output, consuming less fuel per kilowatt-hour (kWh) and emitting lower amounts of $CO_2$. To aid operators and state agencies in determining which measures should be considered when determining BSER, EPA developed a list of 7 HRI candidate technologies. According to EPA, these technologies have been shown to be reliable, efficient, cost-effective, and broadly achievable for a source category across the country. The technologies include:

- Steam turbine blade path upgrades.
- Redesign or replacement of the economizer.
- Air heater and duct leakage control.
- Variable frequency drive (VFD) deployment.
- Neural networks/Intelligent sootblowing (ISB).
- Boiler feed pump upgrade/overhaul
- Various improved operations and maintenance (O&M) practices.

The EPA has responsibility under the CAA to provide a range of reductions and costs associated with each of the candidate technologies. The ranges of expected reductions for each technology are to be used as guidance, but the states will be expected to evaluate each affected unit individually. For reference, EPA's summary of HRI measures and the range of their HRI potential (%) by EGU size is included in Table 1-1. These ranges represent the degree of emission reduction achievable for each technology, however the EPA acknowledges that a specific unit may have the potential for more or less emission reduction based on the unit's specific characteristics. According to the preamble to the final rule, HRI potential will be determined by source-specific factors including, but not limited to, the EGU's past and projected utilization rate, maintenance history, and remaining useful life[1].

**Table 1-1 EPA's Summary of HRI Measures and Range of HRI Potential (%) by EGU Size**

| HRI MEASURE | <200 MW | | 200-500 MW | | >500 MW | |
|---|---|---|---|---|---|---|
| | MIN | MAX | MIN | MAX | MIN | MAX |
| Neural Network/Intelligent Sootblowers | 0.5 | 1.4 | 0.3 | 1.0 | 0.3 | 0.9 |
| Boiler Feed Pumps | 0.2 | 0.5 | 0.2 | 0.5 | 0.2 | 0.5 |
| Air Heater & Duct Leakage Control | 0.1 | 0.4 | 0.1 | 0.4 | 0.1 | 0.4 |
| Variable Frequency Drives | 0.2 | 0.9 | 0.2 | 1.0 | 0.2 | 1.0 |
| Blade Path Upgrade (Steam Turbine) | 0.9 | 2.7 | 1.0 | 2.9 | 1.0 | 2.9 |
| Redesign/Replace Economizer | 0.5 | 0.9 | 0.5 | 1.0 | 0.5 | 1.0 |
| Improved Operating and Maintenance (O&M) Practices | Can range from 0 to >2.0% depending on the unit's historical O&M practices. | | | | | |

Ultimately, it is the EPA's role to determine the possible BSERs and the degree of emission control achievable for each technology, and it is the states' role to create plans establishing unit-specific standards (in a lbm $CO_2$/MWh format) that reflect the application of the BSER. Each state will be required to submit plans (or a State Implementation Plan [SIP]) to the EPA explaining how the state applied the BSER to each source and what other factors were considered when developing the unit-specific standards. In addition to the performance standards, states will also propose compliance deadlines for each EGU, as well as monitoring, recordkeeping and reporting requirements in their plans. These plans will be due to the EPA in three years (July 2022). Upon submittal, the EPA will have 12 months to determine whether or not to approve the plan.

[1] This could have the most significant implications for F.B. Culley Unit 2.

The emission limits and requirements for Vectren's affected EGUs will ultimately be established by IDEM. States are afforded considerable flexibility in determining emission standards for each unit as each state is more familiar with the existing sources within their jurisdictions. States are to use the guidelines EPA provided to evaluate each applicable EGU within its jurisdiction with regards to the utilization of each of the candidate technologies, equipment upgrades, and best O&M practices in establishing a standard of performance for that source. Physical and cost considerations will limit or prevent full implementation of the listed technologies and each state will consider these factors when establishing the standards of performance required. The remaining useful life of the source and other source-specific factors will also be considered by the states when establishing the standards of performance for each unit.

It will be the states' responsibilities to determine how these factors will be taken into consideration when establishing the standards. One approach that states may use is a top-down analysis that examines technical feasibility and cost effectiveness when determining an appropriate standard. Black & Veatch notes that variations of this type of analysis have been used by EPA in multiple regulatory programs to determine appropriate controls (e.g., BACT, RACT, BART, etc.). Such an analysis of the candidate BSER technologies could entail the following steps:

1. Identify all technologies (This step has already been done by the rule);
2. Eliminate technically infeasible options;
3. Rank remaining technologies by effectiveness;
4. Evaluate the most effective controls – entails energy, environmental, and economic impacts – cost effectiveness could entail a consideration of remaining useful life to ultimately determine the cost of a technology on the basis of dollars per lbm $CO_2$/MWh improvement.
5. Select the appropriate technology and set a standard of performance in terms of a lbm $CO_2$/MWh emission rate.

Black & Veatch notes that such an approach could provide state agencies such as IDEM with the defensible approach that they seek to avoid potential legal vulnerabilities while at the same time allowing Vectren to implement the most cost-effective option. Given the lack of specificity in the Rule, IDEM and their stakeholders have been afforded a great deal of latitude in designing the SIP. Therefore, early engagement with IDEM is encouraged in order to influence and assist in their determinations of the appropriate performance standard to include in the SIP for Vectren's affected units.

Numerous lawsuits have already been filed against the ACE rule, however, no stay (delay in rule administration) has been requested to this point. As with many environmental rules, industry sentiment is that the Rule's fate could be determined by the 2020 presidential election. In the meantime, however, Black & Veatch would expect that states will begin to gather information in order to begin designing their SIPs.

## 1.2 EPA'S INTEGRATED PLANNING MODEL

To assess the potential costs and benefits associated with the ACE rule, the EPA used the Integrated Planning Model (IPM) in support of final rulemaking. According to EPA documentation on the latest version of the model (EPA Platform v6, November 2018), "IPM is a multi-regional [...] model of the U.S. electric power sector" that provides "[...] forecasts of least cost capacity expansion, electricity dispatch, and emission control strategies while meeting energy demand, environmental, transmission, dispatch, and reliability constraints." Historically, EPA has used the IPM to forecast power sector behavior and examine the impact of potential air pollution control policies. The EPA has used this model for over two decades to evaluate the economic and emission impacts of potential environmental regulations. Specifically, EPA has used v6 to develop regulatory impact analyses in support of the Cross-State Air Pollution Rule (CSAPR), the greenhouse gas New Source Performance Standard (NSPS) for new, modified, and reconstructed electric utility generating units (NSPS Subpart TTTT), the Mercury and Air Toxics Rule (MATS), the Regional Haze Rule, 316b, and ELG/CCR regulations.

The EPA IPM is quite complex and utilizes numerous inputs to characterize the power sector including:

- Power System Operation
- Generation Resources
- Emission Control Technologies
- $CO_2$ Capture, Transport, and Storage
- Coal Characteristics (i.e., Supply Curves and Transportation Matrix)
- Natural Gas Market Characteristics
- Other Fuel Assumptions
- Financial Assumptions

These inputs are processed in the model in order to arrive at outputs quantifying sector-wide emissions, costs, capacity expansion, retrofit decisions, fuel consumption and prices, and electricity generation and prices. Finally, these outputs can be fed into a post-processor in order to forecast individual boiler-level data, retail electricity price projections, and outputs needed to assess the impacts on air quality via air quality modeling. According to the model documentation, "The model has been tailored to meet the unique environmental considerations important to EPA, while also fully capturing the detailed and complex economic and electric dispatch dynamics of power plants across the country."

The IPM model was not designed to evaluate the technological or economic feasibility of the various BSER technologies for a single ACE-affected unit, but, rather, is intended to be used to holistically evaluate the impacts of EPA rulemakings on the entire power sector. Additionally, the model appears overly complex, such that it could be time-consuming and provide a false sense of accuracy when used to evaluate the technologies as part of an ACE study. As such, it is unlikely that the IPM would/should ever be utilized to evaluate the BSER technologies as a part of a state ACE compliance plan.

## 1.3 POTENTIAL NEW SOURCE REVIEW CHANGES

To accommodate and facilitate the HRI projects associated with the ACE rulemaking, EPA has proposed changes to the New Source Review (NSR) permitting program. Under the current regulations, modifications to stationary sources, such as EGUs, that increase annual emissions of regulated pollutants at or above certain regulatory thresholds are subject to NSR permitting requirements. EPA is now proposing to incorporate a comparison of hourly emissions into the NSR applicability assessment for EGUs. Under this approach, the maximum actual emissions values measured on an hourly basis before the project and the projected hourly emission rate that will occur after the proposed modification would be compared to determine if an emission increase would result. If no *hourly* emissions increase will occur, NSR would not be applicable.

However, if hourly emissions were determined to increase, the emissions analysis must continue per the traditional methodology where an assessment of both project-specific overall emissions increases, and plant-wide net emissions increases on an annual basis would need to be calculated to determine if NSR permitting requirements would apply. Black & Veatch notes that this proposed rule-making is considered particularly vulnerable to legal challenges. Therefore, an evaluation of the potential applicability of NSR to each of the BSER options examined in this report may be prudent in order to provide Vectren a full picture of the costs project timeline associated with the various options. Additionally, EPA has noted in the final rule, that costs associated with permitting NSR applicable projects can be included in the economic evaluation of the various ACE technologies.

# 2.0 Existing Plant Characteristics

This section briefly describes the baseline characteristics of each unit. The average and summary annual performance data for each unit that were used to calculate the potential heat rate benefits of applicable technologies can be found in Section 4.0.

A.B. Brown Units 1 and 2 are "sister units" in that they share many common characteristics. Each unit is a nominal 265-megawatt (MW) gross and 245 MW net unit, featuring a subcritical pulverized coal furnace with reheat steam and designed for bituminous coal from the Illinois Basin. A.B. Brown Unit 1 was commissioned in 1979, and A.B. Brown Unit 2 in 1986. Each unit employs low-nitrogen oxide ($NO_X$) burners and a selective catalytic reduction system (SCR) for $NO_X$ control, and a scrubber for sulfur dioxide ($SO_2$) control. Unit 1 uses a pulse-jet fabric filter baghouse, and Unit 2 uses a cold-side electrostatic precipitator for particulate removal. Heat rejection is provided by mechanical draft cooling towers.

F.B. Culley Unit 2 is a nominal 100 MW gross and 90 MW net unit, featuring a non-reheat subcritical pulverized coal furnace designed for bituminous coal from the Illinois Basin. F.B. Culley Unit 2 was commissioned in 1966. The unit employs low-$NO_X$ burners for $NO_X$ control and a scrubber for $SO_2$ control. The unit uses a cold-side electrostatic precipitator for particulate removal. Cooling water is provided by the Ohio River.

F.B. Culley Unit 3 is a nominal 287 MW gross and 270 MW net unit, featuring a subcritical pulverized coal furnace with reheat steam and designed for bituminous coal from the Illinois Basin. F.B. Culley Unit 3 was commissioned in 1973. The unit employs low-$NO_X$ burners and an SCR system for $NO_X$ control and a scrubber for $SO_2$ control. The unit uses a pulse-jet fabric filter (PJFF) baghouse for particulate removal. Cooling water is provided by the Ohio River.

## 3.1 Description of Heat Rate Improvement Alternatives

This preliminary heat rate project screening was based on a high-level analysis of A.B. Brown Unit 1 and on Black & Veatch's experience with similar projects. The projects depicted herein were selected from HRI projects detailed by the EPA in its ACE rule as BSER projects. A detailed table summarizing the benefits and costs is included in Appendix B.

## 3.2 UNIT STEAM TURBINE BLADE PATH UPGRADES

Black & Veatch reviewed the steam turbine blade path upgrade option for each of the existing plants. The specific steam turbine upgrades are described for each individual plant in the following subsections.

### 3.2.1 A.B. Brown Unit 1 Steam Turbine Blade Path Upgrades

Black & Veatch reviewed steam turbine blade path upgrade. The A.B. Brown Unit 1 steam turbine had a full dense pack upgrade installed in 2012. In 2016, extensive high-pressure/ intermediate-pressure (HP/IP) repairs were made because of a main stop valve bypass failure. Black & Veatch estimates that there would not be any significant improvement with a steam turbine upgrade now, considering the relatively shorter duration since the last steam path upgrade and the potential cost associated with it.

### 3.2.2 A.B. Brown Unit 2 Steam Turbine Blade Path Upgrades

Black & Veatch reviewed the steam turbine blade path upgrade. The A.B. Brown Unit 2 steam turbine had a full dense pack upgrade installed in 2013. Black & Veatch estimates that there would not be any significant improvement with a steam turbine upgrade now, considering the relatively shorter duration since the last steam path upgrade and the potential cost associated with it.

### 3.2.3 F.B. Culley Unit 2 Steam Turbine Blade Path Upgrades

The Culley Unit 2 steam turbine is a GE non-reheat steam turbine with a two-flow low-pressure turbine with 20 inch last stage blades. Black & Veatch performed a review of the steam turbine blade path upgrade. As a result of this investigation, two heat balance model of the Culley Unit 2 steam turbine were developed:

- Base: Best match of the Culley Unit 2 Thermal Kit heat balance 328 HB 706 rating flow (guarantee) +5%. (Valve-Wide-Open, Normal Pressure (VWO-NP) case).
- Upgrade Scenario: The entire steam path HP/LP (High-Pressure and Low-Pressure turbines) are upgraded.

This analysis is based on the incremental improvement in steam turbine efficiency, and the differential performance is more important than the absolute performance. The performance improvements and pricing estimates are based on in house data and past project experience. However, steam turbine manufacturers should be contacted to confirm performance and pricing.

#### 3.1.3.1 Base Case

The Base case model is matched to the original thermal kit heat balance 328 HB 706, which is the rating flow (guarantee) +5%. The condenser pressure was set to 1.5 in HgA to keep the basis consistent across the models for comparison against various upgrade options. This Base model was then used to run four cases: Rating flow + 5%, guarantee load (rated pressure and rated flow, corresponding to thermal kit heat balance 332 HB 827), 80% of guarantee load (rated pressure and reduced flow, corresponding to thermal kit heat balance 332 HB 829), and 60% of guarantee load (rated pressure and reduced flow, corresponding to thermal kit heat balance 332 HB 831).

#### 3.1.3.2 Upgrade Scenario: HP/LP Steam Path Upgrades

In this model, the HP and LP sectional efficiencies were increased from approximately 86.9% and 69.9%, to approximately 87.9% and 71.9% respectively. The advanced age of the Culley Unit 2 steam turbine makes it difficult to estimate exactly how much efficiency could be gained in each section and further analysis should be completed by a steam turbine manufacturer. This model was then used to run four cases: Rating flow + 5%, guarantee load, 80% of guarantee load, and 60% of guarantee load. In each of the cases the boiler steam generation was reduced such that the steam turbine power output matches the value found in the corresponding cases in the original design (STG OEM Thermal Kit).

Tables 3-1 through 3-4 show the results of the turbine modeling conducted by Black & Veatch for this study. For comparison purposes, it was assumed that a boiler efficiency of 88.3% (HHV basis) applies regardless of the magnitude and type of boiler upgrades that may be required. This boiler efficiency is provided by the Vectren data in the Culley Unit 3 snapshot data and was assumed to be the same for Culley Unit 2 for the purposes of this modeling to allow for a comparison between the units.

**Table 3-1 Culley Unit 2 Steam Turbine Modeling Results – Rating Flow + 5%**

| | | ORIGINAL HEAT BALANCE | UPGRADE HP/LP |
|---|---|---|---|
| Boiler Efficiency (HHV)* | % | 88.3 | 88.3 |
| STG Gross Output | kW | 99,765 | 99,766 |
| Gross Turbine Heat Rate | Btu/kWh | 9,012 | 8,881 |
| Gross Turbine Heat Rate Change | Btu/kWh | N/A | -131 |
| Turbine Heat Rate Improvement | % | N/A | 1.5% |
| Boiler Heat Input (HHV) | MBtu/h | 1,018.4 | 1,003.6 |
| Boiler Heat Input (HHV) Change | MBtu/h | N/A | -14.8 |
| Boiler Heat Input (HHV) Improvement | % | N/A | 1.5% |
| Gross Plant Heat Rate (HHV) | Btu/kWh | 10,208 | 10,060 |
| Gross Plant Heat Rate (HHV) Change | Btu/kWh | N/A | -136 |
| Gross Plant Heat Rate (HHV) Improvement | % | N/A | 1.5% |
| *See the explanation above regarding the choice of the boiler efficiency value. | | | |

**Table 3-2 Culley Unit 2 Steam Turbine Modeling Results – Guarantee Load**

| | | ORIGINAL HEAT BALANCE | UPGRADE HP/LP |
|---|---|---|---|
| Boiler Efficiency (HHV)* | % | 88.3 | 88.3 |
| STG Gross Output | kW | 95,500 | 95,501 |
| Gross Turbine Heat Rate | Btu/kWh | 9,002 | 8,870 |
| Gross Turbine Heat Rate Change | Btu/kWh | N/A | -131 |
| Turbine Heat Rate Improvement | % | N/A | 1.5% |
| Boiler Heat Input (HHV) | MBtu/h | 973.8 | 959.6 |
| Boiler Heat Input (HHV) Change | MBtu/h | N/A | -14.2 |
| Boiler Heat Input (HHV) Improvement | % | N/A | 1.5% |
| Gross Plant Heat Rate (HHV) | Btu/kWh | 10,197 | 10,048 |
| Gross Plant Heat Rate (HHV) Change | Btu/kWh | N/A | -136 |
| Gross Plant Heat Rate (HHV) Improvement | % | N/A | 1.5% |
| * See the explanation above regarding the choice of the boiler efficiency value. | | | |

**Table 3-3 Culley Unit 2 Steam Turbine Modeling Results – 80% of Guarantee Load**

| | | ORIGINAL HEAT BALANCE | UPGRADE HP/LP |
|---|---|---|---|
| Boiler Efficiency (HHV)* | % | 88.3 | 88.3 |
| STG Gross Output | kW | 76,239 | 76,239 |
| Gross Turbine Heat Rate | Btu/kWh | 8,977 | 8,856 |
| Gross Turbine Heat Rate Change | Btu/kWh | N/A | -121 |
| Turbine Heat Rate Improvement | % | N/A | 1.4% |
| Boiler Heat Input (HHV) | MBtu/h | 775.3 | 764.8 |
| Boiler Heat Input (HHV) Change | MBtu/h | N/A | -10.5 |
| Boiler Heat Input (HHV) Improvement | % | N/A | 1.4% |
| Gross Plant Heat Rate (HHV) | Btu/kWh | 10,169 | 10,032 |
| Gross Plant Heat Rate (HHV) Change | Btu/kWh | N/A | -138 |
| Gross Plant Heat Rate (HHV) Improvement | % | N/A | 1.4% |
| * See the explanation above regarding the choice of the boiler efficiency value. | | | |

**Table 3-4 Culley Unit 2 Steam Turbine Modeling Results – 60% of Guarantee Load**

| | | ORIGINAL HEAT BALANCE | UPGRADE HP/LP |
|---|---|---|---|
| Boiler Efficiency (HHV)* | % | 88.3 | 88.3 |
| Gross STG Gross Output | kW | 56,672 | 56,672 |
| Gross Turbine Heat Rate | Btu/kWh | 9,133 | 9,020 |
| Turbine Heat Rate Change | Btu/kWh | N/A | -113 |
| Turbine Heat Rate Improvement | % | N/A | 1.2% |
| Boiler Heat Input (HHV) | MBtu/h | 586.3 | 579.0 |
| Boiler Heat Input (HHV) Change | MBtu/h | N/A | -7.3 |
| Boiler Heat Input (HHV) Improvement | % | N/A | 1.2% |
| Gross Plant Heat Rate (HHV) | Btu/kWh | 10,346 | 10,217 |
| Gross Plant Heat Rate (HHV) Change | Btu/kWh | N/A | -129 |
| Gross Plant Heat Rate (HHV) Improvement | % | N/A | 1.2% |
| * See the explanation above regarding the choice of the boiler efficiency value. | | | |

The estimate capital cost and HRI for the turbine upgrade option is as follows:

***Full Steam Path Upgrade***

| | |
|---|---|
| Total Installed Capital Cost: | $10.4 million |
| Heat Rate (efficiency) Improvement: | 1.3-1.5% |

### 3.1.4 F.B. Culley Unit 3 Steam Turbine Blade Path Upgrades

The F.B. Culley Unit 3 steam turbine is a GE reheat steam turbine with a two-flow LP turbine and 26-inch last stage blade length for the LP end. Black & Veatch reviewed the steam turbine blade path upgrade. As a result of this investigation, heat balance cases were developed for the F.B. Culley Unit 3 steam turbine:[2]

- Base Case: Best match of the F.B. Culley Unit 3 thermal kit heat balance 534 HB 894 (guarantee).
- Upgrade Scenario: The entire HP/IP/LP steam path is upgraded.

This analysis is based on the incremental improvement in steam turbine efficiency, and the differential performance is more important than the absolute performance. The performance improvements and pricing estimates are based on in-house data and past project experience and are believed to be achievable. However, steam turbine manufacturers should be contacted to confirm performance and pricing.

#### 3.1.4.1 Base Case

The Base Case model is matched to the thermal kit heat balance 534 HB 894, which is the guarantee case. The condenser pressure was set to 3.5 in. HgA to keep the basis consistent across the models for comparison against various upgrade options. This Base Case model was then used to run three cases: Guarantee load (rated pressure and rated flow, corresponding to thermal kit heat balance 534 HB 894); 80 percent of guarantee load (rated pressure and reduced flow, corresponding to thermal kit heat balance 170X450-21); and 60 percent of guarantee load (rated pressure and reduced flow, corresponding to thermal kit heat balance 170X450-22).

#### 3.1.4.2 Upgrade Scenario: HP/IP/LP Steam Path Upgrades

In this model, the HP, IP, and LP sectional efficiencies were increased from approximately 86.7 percent, 88.2 percent, and 89.3 percent to approximately 90 percent, 90 percent, and 92 percent, respectively[3]. This model was then used to run three cases: Guarantee load; 80 percent of guarantee load; and 60 percent of guarantee load. In each of the cases, the boiler steam generation was reduced so that the steam turbine power output matched the values found in the corresponding cases in the original design (STG OEM thermal kit).

[2] Additional cases could be evaluated which look at the difference between current performance if the blades and turbine are newly overhauled, versus a new upgrade. Another possibility is developing a map of turbine performance over an expected life between major turbine outages and maintenance activities. Those require more detailed studies which mandate input from the STG OEM with a reference upgrade design, which is beyond the scope of this EPA-ACE analysis.

[3] Based upon OEM data.

Tables 3-5 through 3-7 show the results of the turbine modeling conducted by Black & Veatch for this study. For comparison purposes, it was assumed that a boiler efficiency of 88.3 percent (HHV basis) applies regardless of the magnitude and type of boiler upgrades that may be required.

**Table 3-5 F.B. Culley Unit 3 Steam Turbine Modeling Results – Guarantee Load**

| | | ORIGINAL HEAT BALANCE | UPGRADE HP/IP/LP |
|---|---|---|---|
| Boiler Efficiency (HHV)* | % | 88.3 | 88.3 |
| STG Gross Output | kW | 288,360 | 288,367 |
| Gross Turbine Heat Rate | Btu/kWh | 8,219 | 8,085 |
| Gross Turbine Heat Rate Change | Btu/kWh | N/A | -134 |
| Turbine Heat Rate Improvement | % | N/A | 1.6% |
| Boiler Heat Input (HHV) | MBtu/h | 2,684.7 | 2,640.9 |
| Boiler Heat Input (HHV) Change | MBtu/h | N/A | -43.8 |
| Boiler Heat Input (HHV) Improvement | % | N/A | 1.6% |
| Gross Plant Heat Rate (HHV) | Btu/kWh | 9,310 | 9,158 |
| Gross Plant Heat Rate (HHV) Change | Btu/kWh | N/A | -152 |
| Gross Plant Heat Rate (HHV) Improvement | % | N/A | 1.6% |
| *This boiler efficiency takes its basis from the F.B. Culley Unit 3 data snapshot, collected on May 27, 2019. | | | |

**Table 3-6 F.B. Culley Unit 3 Steam Turbine Modeling Results – 80% of Guarantee Load**

| | | ORIGINAL HEAT BALANCE | UPGRADE HP/IP/LP |
|---|---|---|---|
| Boiler Efficiency (HHV)* | % | 88.3 | 88.3 |
| STG Gross Output | kW | 236,806 | 236,817 |
| Gross Turbine Heat Rate | Btu/kWh | 8,254 | 8,129 |
| Gross Turbine Heat Rate Change | Btu/kWh | N/A | -125 |
| Turbine Heat Rate Improvement | % | N/A | 1.5% |
| Boiler Heat Input (HHV) | MBtu/h | 2,214.1 | 2,180.7 |
| Boiler Heat Input (HHV) Change | MBtu/h | N/A | -33.4 |
| Boiler Heat Input (HHV) Improvement | % | N/A | 1.5% |
| Gross Plant Heat Rate (HHV) | Btu/kWh | 9,350 | 9,208 |
| Gross Plant Heat Rate (HHV) Change | Btu/kWh | N/A | -142 |
| Gross Plant Heat Rate (HHV) Improvement | % | N/A | 1.5% |

*This boiler efficiency takes its basis from the F.B. Culley Unit 3 data snapshot, collected on May 27, 2019.

**Table 3-7 F.B. Culley Unit 3 Steam Turbine Modeling Results – 60% of Guarantee Load**

| | | ORIGINAL HEAT BALANCE | UPGRADE HP/IP/LP |
|---|---|---|---|
| Boiler Efficiency (HHV)* | % | 88.3 | 88.3 |
| STG Gross Output | kW | 178,684 | 178,683 |
| Gross Turbine Heat Rate | Btu/kWh | 8,451 | 8,333 |
| Gross Turbine Heat Rate Change | Btu/kWh | N/A | -118 |
| Turbine Heat Rate Improvement | % | N/A | 1.4% |
| Boiler Heat Input (HHV) | MBtu/h | 1,710.6 | 1,686.7 |
| Boiler Heat Input (HHV) Change | MBtu/h | N/A | -23.9 |
| Boiler Heat Input (HHV) Improvement | % | N/A | 1.4% |
| Gross Plant Heat Rate (HHV) | Btu/kWh | 9,573 | 9,440 |
| Gross Plant Heat Rate (HHV) Change | Btu/kWh | N/A | -134 |
| Gross Plant Heat Rate (HHV) Improvement | % | N/A | 1.4% |
| *This boiler efficiency takes its basis from the F.B. Culley Unit 3 data snapshot, collected on May 27, 2019. | | | |

The estimate capital cost and HRI for the turbine upgrade options is as follows:

***Full Steam Path Upgrade***

Total Installed capital cost: $19.9 million

Heat Rate (efficiency) improvement: 1.4-1.6%

## 3.2 UNIT ECONOMIZER REDESIGN OR UPGRADES

### 3.2.1 Economizer Upgrades Under EPA ACE

One of the primary BSER under the EPA ACE is the prospect of upgrades to, or even complete replacement of, the economizer. The overarching goal in economizer upgrades or replacement is to improve heat transfer from the flue gas to add heat to the boiler water/steam circuit and, thus, improve boiler efficiency. According to the performance estimates included in the EPA ACE proposal, redesign or replacement of the economizer should yield a heat rate improvement from 0.5 percent to 0.9 percent for units under 200 MW, and from 0.5 percent to 1.1 percent for units ranging from 200 MW to 500 MW. The EPA specifically states that economizer replacements are often avoided because of concerns over triggering New Source Review (NSR); for this reason, the EPA ACE is intended to provide power plants with the flexibility to make these changes.

However, there are many risks associated with redesign or replacement of the economizer:

- Most commonly, projects that consider increasing economizer tube surface area are ones which consider adding tube passes to either the upstream or the downstream portion of the economizer(s). This is because most economizers have a dense tube packing that disallows addition of tube assemblies across the furnace width. However, in the boiler backpass region, space constraints often limit the ability to add more than 2 or 3 tube passes. Thus, making significant changes to the economizer may not be possible at many units.
- Even the addition of a single pass of tubes requires an extended boiler outage; significant construction preparation and welding/tie-in work are required to add tubes to the economizer. The replacement power cost and lost opportunity/contract cost of this outage can be significant if it is not combined with a previously planned outage (such as, for steam turbine upgrades).
- Replacement of entire economizers is not generally done within the industry because of the large expense involved. When it has been undertaken in recent years, the most common reasons are either to replace a badly eroded economizer, or to replace an economizer with spiral-finned tubes with one with bare tubes to reduce tube fouling (especially after conversions to Powder River Basin coals).
- Changing tube surface area will often change the balance of heat transfer between the radiative and connective sections, as well as the main steam and reheat steam circuitry. This is especially true in the case of units that employ a split backpass design with gas biasing reheat control. Prediction of the complex interactions between the water, main steam, and reheat steam circuits in both the radiative and convective sections typically requires detailed boiler modeling.
- Adding tube surface to an economizer will reduce the flue gas temperature exiting the economizer, which could reduce operations flexibility if an SCR is positioned downstream of the economizer. Reduced flue gas temperatures will increase the minimum load possible with the SCR in service and could require a system such as an economizer gas bypass or in-duct burners to allow for SCR operation with these reduced temperatures. Both of these reparative measures will worsen the plant heat rate, thus negating the benefit of the upgraded economizer.
- Reduced flue gas temperatures entering the air heater will help improve the overall boiler efficiency but can also lead to operations problems should the cold-end average temperature be reduced below the recommended point for the type of fuel that is being burned and its sulfur content. In addition, ammonium bisulfate deposition can be increased in some cases where the flue gas inlet temperature at the air heaters is reduced from normal.
- In some cases, flue gas temperatures could be reduced to the point where other downstream air quality control equipment (such as an electrostatic precipitator or fabric filter baghouse) could be at risk for corrosion damage.

- While it is possible to add an economizer downstream of the SCR system to reduce the impact on the flue gas temperature entering the SCR, such installations are unusual and often require variable water bypass circuitry to maintain good temperature control.

Assessment of the ability of a unit to accommodate changes in the economizer tube surface area typically requires plant modeling of some sort, whether utilizing a combined first-principles and empirical model (such as the Electric Power Research Institute's [EPRI's] Vista program), or even a highly detailed (and expensive) computation fluid dynamics model of the entire boiler circuit and downstream affected equipment. The following section is a high-level overview of economizer upgrades, while the further sections provide more detail through the use of Vista modelling software.

Cost estimation for economizer upgrades is highly variable and depends on the amount of work conducted, the site spacing and access, other boiler or plant modifications that are required, etc. The EPA ACE rule advises in Table 2 that the cost to redesign or replace an economizer can be up to $3.74 million for a 200 MW unit or up to $6.35 million for a 500 MW unit.

### 3.2.2 A.B. Brown Units 1 and 2 Economizer Redesign or Upgrades

Plant personnel report that because of low SCR inlet temperatures, A.B. Brown Units 1 and 2 require natural gas duct burners to be operated to maintain temperatures over the minimum SCR inlet temperature of 625° F. An example of the gas duct burner operation as a function of gross output is shown for Unit 1 on Figure 3-1.

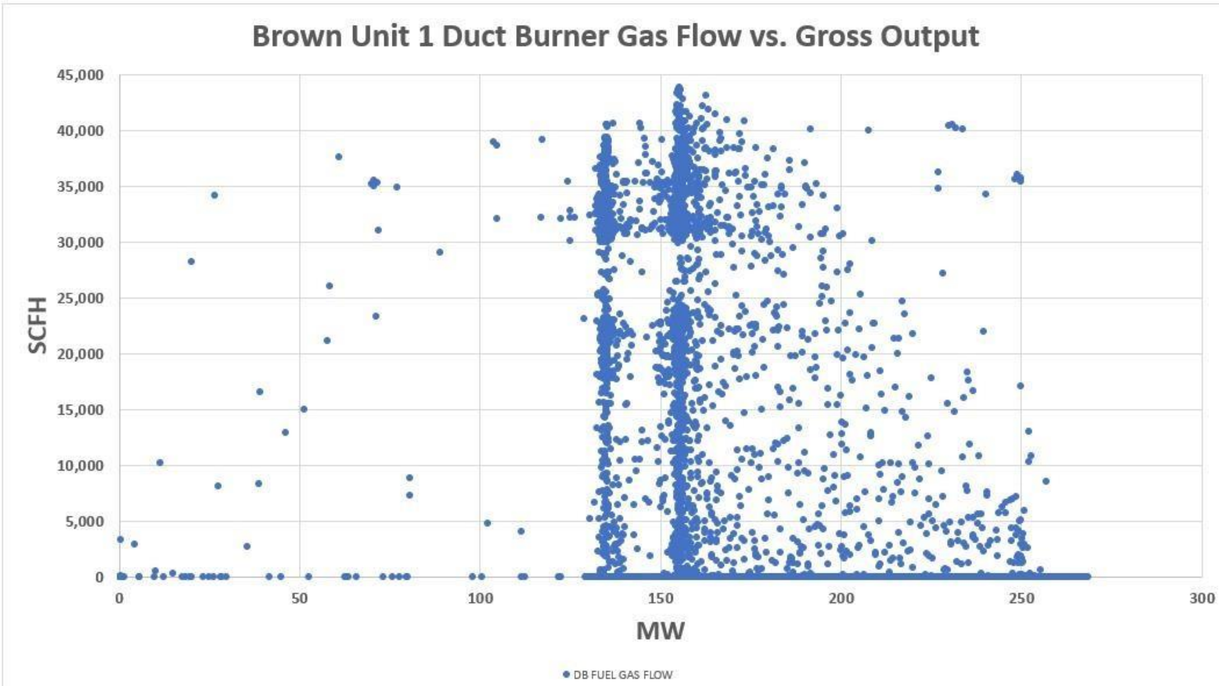



**Figure 3-1 A.B. Brown Unit 1 Economizer Gas Flow vs. Gas Outlet**

Plant personnel stated that the high gas use of the duct burners is a concern from a heat rate standpoint, although, unlike the case of F.B. Culley Unit 3, there was no estimate on the overall annual heat rate impact. Given this situation at A.B. Brown Units 1 and 2, adding economizer tube surface area is not recommended at this time. It is possible that reducing the economizer tube surface area could improve the plant heat rate by reducing the natural gas usage, and a next-phase study could easily determine this by employing coordinated plant modeling with a boiler-SCR-air heater model across the typical operating load ranges of the units.

### 3.2.3 F.B. Culley Unit 2 Economizer Redesign or Upgrades

F.B. Culley Unit 2 has maintained its original economizer design, and as it does not have an SCR system, it does not suffer from the constraint of reduced flue gas temperatures limiting operation. As a result, it is possible that economizer modifications could result in a significant heat rate benefit to the unit, especially as the F.B. Culley Unit 2 economizer gas outlet temperature appears to be high at higher loads (over 700° F at times). Refer to Figure 3-2.

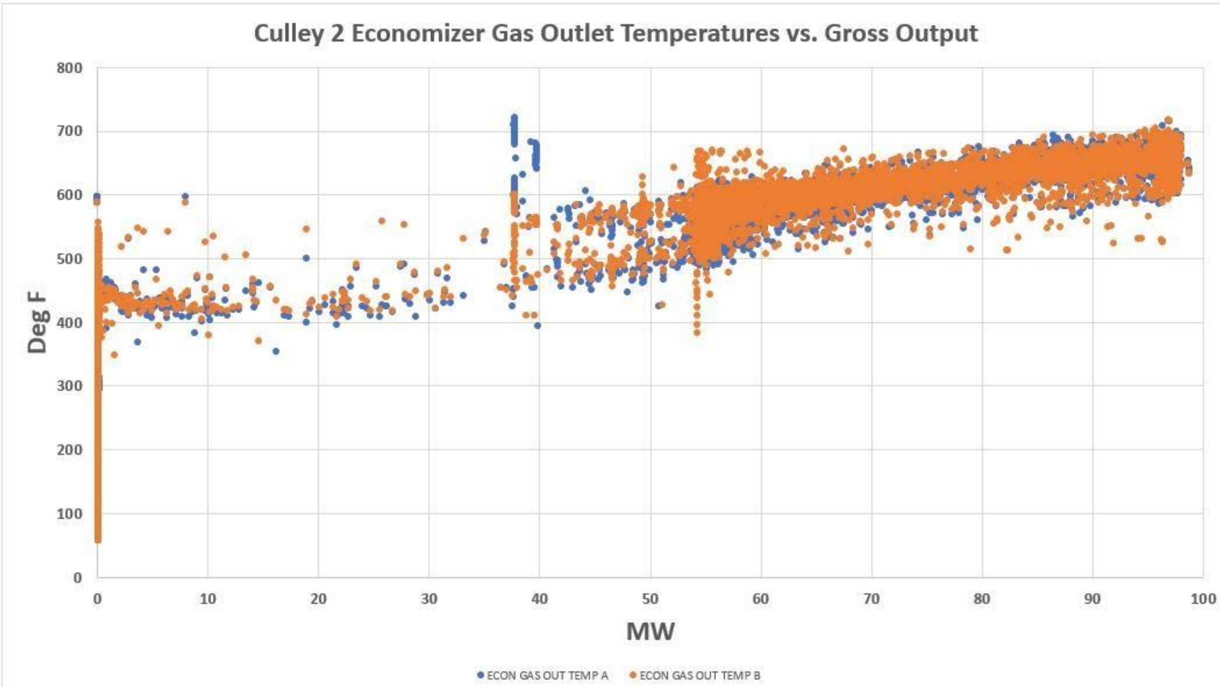



**Figure 3-2 F.B. Culley Unit 2 Economizer Gas Outlet Temperature Versus Gross Output**

The estimated costs and logistics of such a change to the economizers requires significant investigation as a next-phase effort. Assuming no header relocation is needed, and neglecting the loss of contract availability, such a cost is estimated at about $40,000 to 50,000 per British thermal unit per kilowatt-hour (Btu/kWh) for the improvement, or between $2 million to $4 million. For a small, non-reheat unit such as F.B. Culley Unit 2, such an investment may not be warranted at this juncture unless the unit was expected to operate for a significant length of time so that a sufficient payback period could be realized. When the expected future load factor and remaining plant life are taken into account, it is nearly impossible to justify an investment in this area of the plant.

### 3.2.4 F.B. Culley Unit 3 Economizer Redesign or Upgrades

According to plant personnel, the F.B. Culley Unit 3 economizer was replaced in 1994 with a tube configuration that had additional tube surface area relative to the original design. The goal of this upgrade was to reduce flue gas exit temperatures and improve cycle efficiency, and in that respect, it was successful. However, when the SCR system was added in 2003, the lower flue gas temperatures exiting the economizer resulted in the need for natural gas duct burners to maintain the minimum SCR flue gas inlet temperature of 625° F. The economizer was replaced again in 2008 but was not changed to the original design because of concerns about triggering NSR. Refer to Figure 3-3.

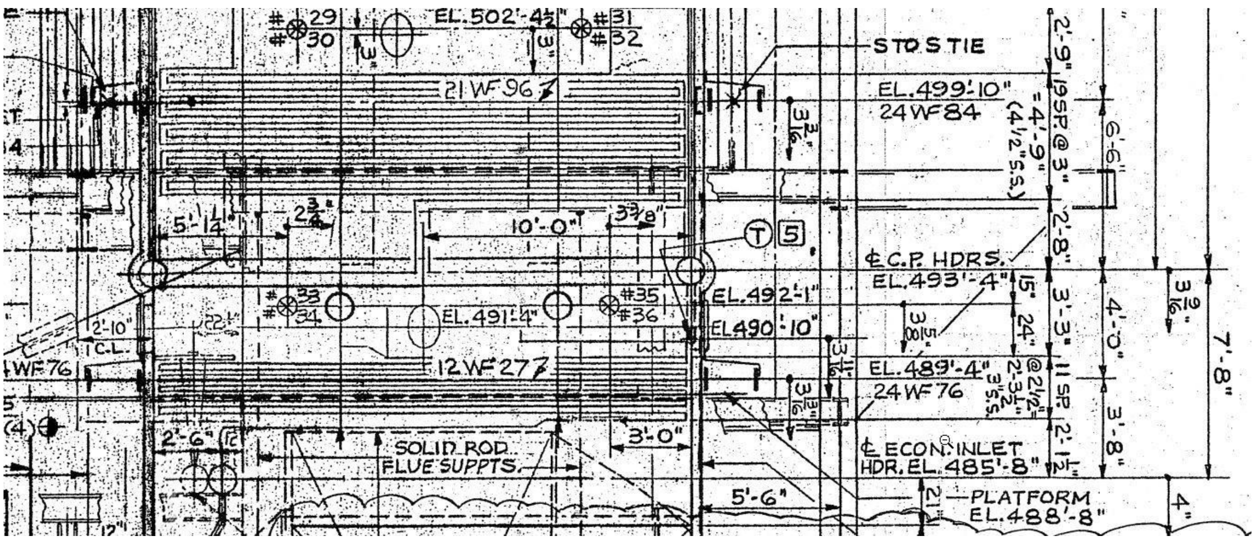



**Figure 3-3 F.B. Culley Unit 3 Original Economizer Design**

F.B. Culley Unit 3 is required to utilize significant amounts of natural gas via in-duct burners upstream of the SCR system to maintain SCR operating temperatures at anything less than 75 to 80 percent of full load. A plot of operational data, comparing the natural gas burner fuel flow rate versus the unit gross output, is shown by Figure 3-4.

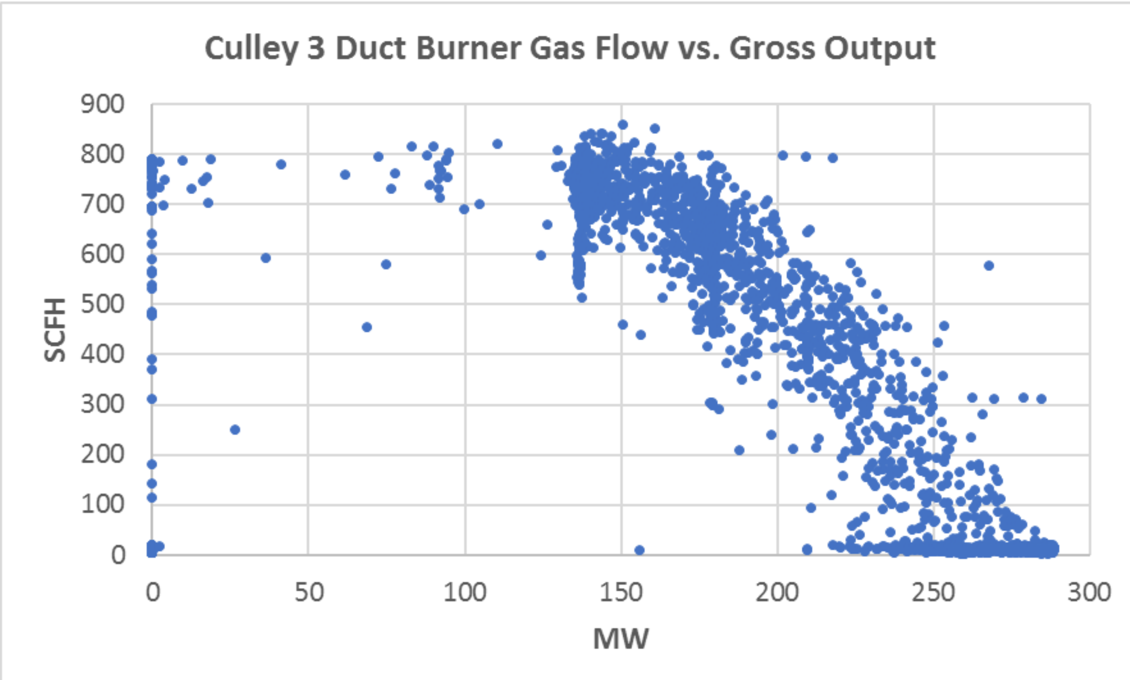



**Figure 3-4 F.B. Culley Unit 3 Duct Burner Gas Flow Versus Gross Output**

Given this situation at F.B. Culley Unit 3, adding economizer tube surface area is not recommended at this time. It is possible that reducing the economizer tube surface area could improve the plant heat rate by reducing the natural gas usage, and a next-phase study could easily determine this by employing coordinated plant modeling with a boiler-SCR-air heater model across the typical operating load ranges of the units. Plant personnel report that natural gas heat input to the duct burners comprised nearly 2 percent of the total heat input to the unit for 2018 and 2019 to date.

### 3.2.5 Economizer Analysis using Vista

Based on the analysis and discussion in the above sections, an analysis of the benefit of reducing natural gas flow to the duct burners by reducing the size of the economizer section was performed for A.B. Brown 1 and F.B. Culley 3. To assess the economizer, Black & Veatch created a base case and then investigated three options: removing 1, 2, and 3 tube passes.

Using data provided by Vectren engineering personnel, an EPRI Vista fuel quality impact model was created for A.B. Brown 1 and F.B. Culley 3. The Vista program contains a detailed linear heat transfer model that has the power to conduct "what if" analyses upon tube banks surface area configurations, and this model was utilized successfully for this study. Several simulations of tube configurations that would decrease the heat transfer area of the economizer were analyzed, and these are detailed in this section. A schematic of the current economizer for A.B. Brown 1 is depicted below (F.B. Culley 3 is depicted in Figure 3-3):

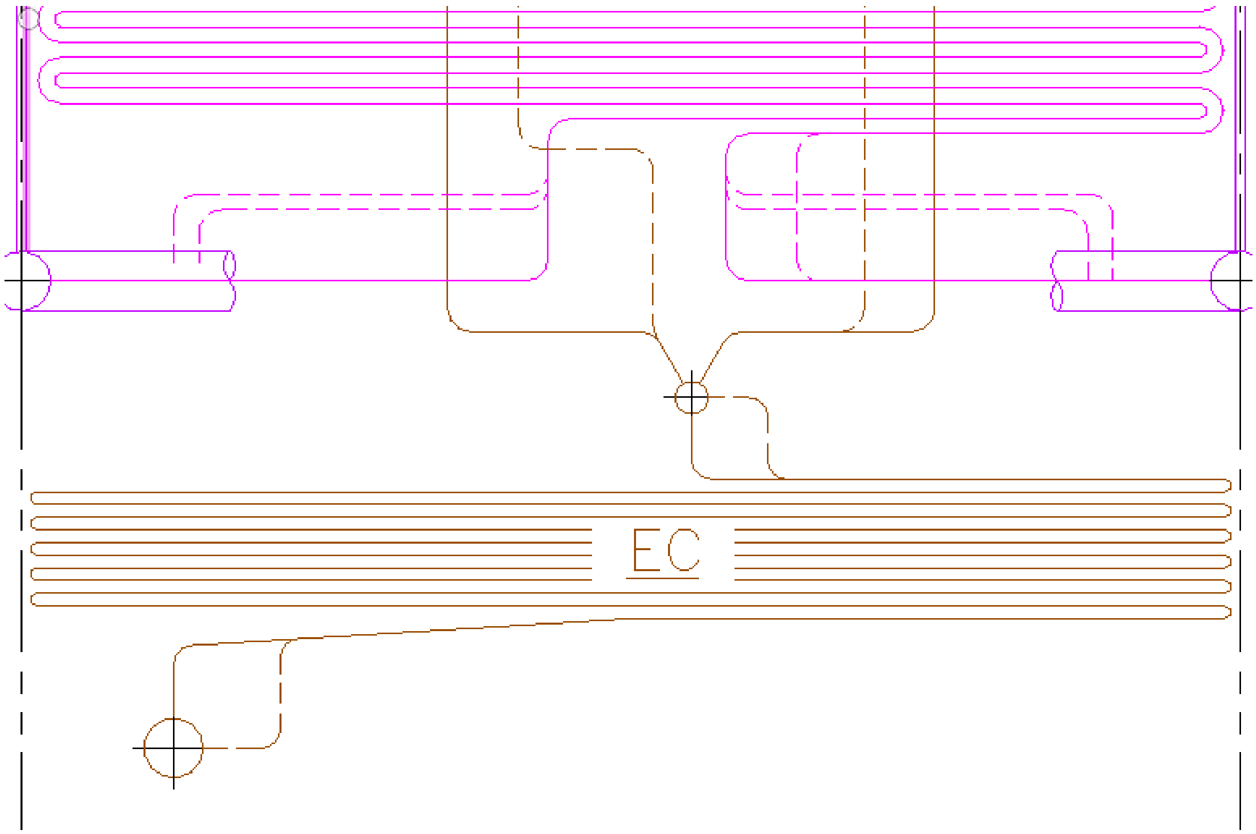



**Figure 3-5 A.B. Brown 1 Economizer**

### 3.2.5.1 A.B. Brown Units 1 and 2 Economizer Analysis Results

After calibrating the Vista model of A.B. Brown 1 to 264 MW gross from data collected on August 9, 2018, the following scenarios were run, with the following results.

- Baseline case – SCR inlet temperature = 651 °F.
- Removing 1 pass to the lower economizer – SCR inlet temperature = 662 °F.
- Removing 2 pass to the lower economizer – SCR inlet temperature = 675 °F.
- Removing 3 passes to the lower economizer – SCR inlet temperature = 690 °F.

The results above were from running the model at full load. The graph below shows the unit load vs. the duct burner natural gas flow.

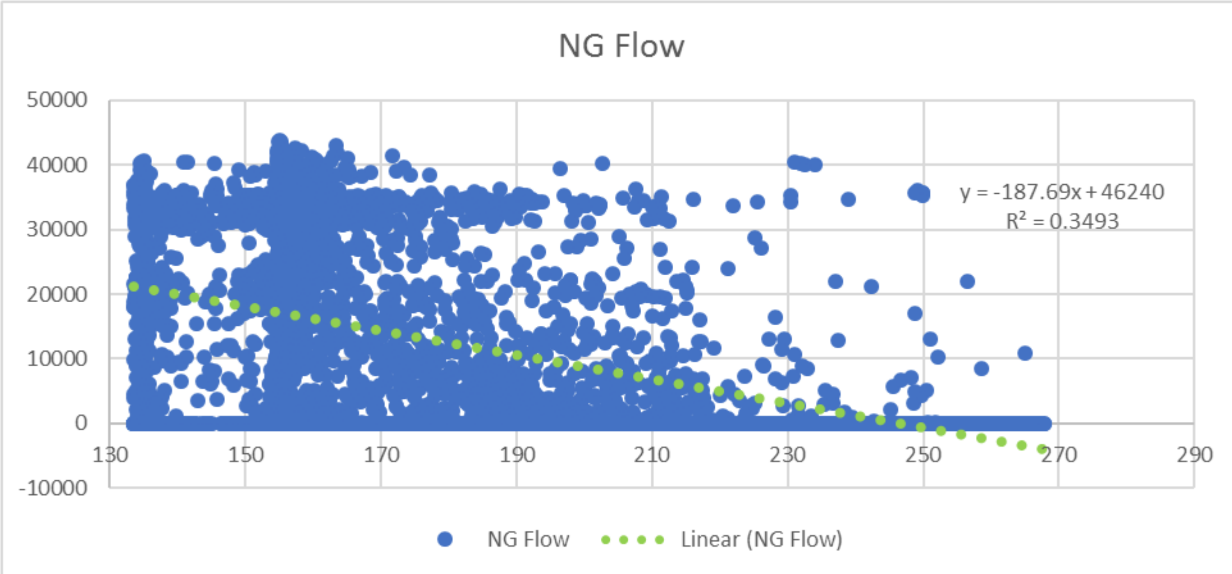



**Figure 3-6 Load vs. Temperature and Flow**

Linear regression was used to determine the natural gas flow; however, the correlation between natural gas flow and load was poor ($R^2$ of 0.35). This may warrant further investigation into the measurement or control methodology of the natural gas flow for the duct burners. Also, A.B. Brown 1 does not have an online measurement for the economizer flue gas outlet temperature. If this temperature was measured and tracked in the data historian, it would significantly improve the analysis of the data.

This reduction in economizer surface area comes at a cost in heat rate. From the analysis a reduction in the economizer surface area produces the following heat rate impacts on an overall basis:

- Baseline case – 0% difference.
- Removing 1 pass to the lower economizer – 0.17 % worsening.
- Removing 2 passes to the lower economizer – 0.36 % worsening.
- Removing 3 passes to the lower economizer – 0.61 % worsening.

This heat rate impact had the following effects on fuel burn rate at full load:

- Removing 1 pass to the lower economizer – 4.23 MMBtu/hr increase.
- Removing 2 passes to the lower economizer – 8.91 MMBtu/hr increase.
- Removing 3 passes to the lower economizer – 15.06 MMBtu/hr increase.

Should a change be made to the economizer tube surface area, the estimated costs and logistics of such a change to the economizers, assuming no header relocation is needed and neglecting the loss of contract availability, are expected to range from $750,000 to $1,400,000 depending upon the amount of modification. Complete replacement of the economizer was not estimated during this effort, nor was any addition to hot reheat surface or any other modifications.

### 3.2.5.2 F.B. Culley Unit 3 Economizer Analysis Results

After calibrating the Vista model of F.B. Culley 3 to 286 MW gross from data collected on May 27, 2019, the following scenarios were run, with the following results.

- Baseline case – SCR inlet temperature = 649 °F.
- Removing 1 pass to the lower economizer – SCR inlet temperature = 656 °F.
- Removing 2 pass to the lower economizer – SCR inlet temperature = 663 °F.
- Removing 3 passes to the lower economizer – SCR inlet temperature = 670 °F.

The results above were from running the model at full load. The graph below shows unit load vs. SCR inlet temperature, economizer gas outlet temperature, and duct burner natural gas flow. The delta-temperature below the minimum acceptable SCR inlet temperature of 625 °F was also plotted.

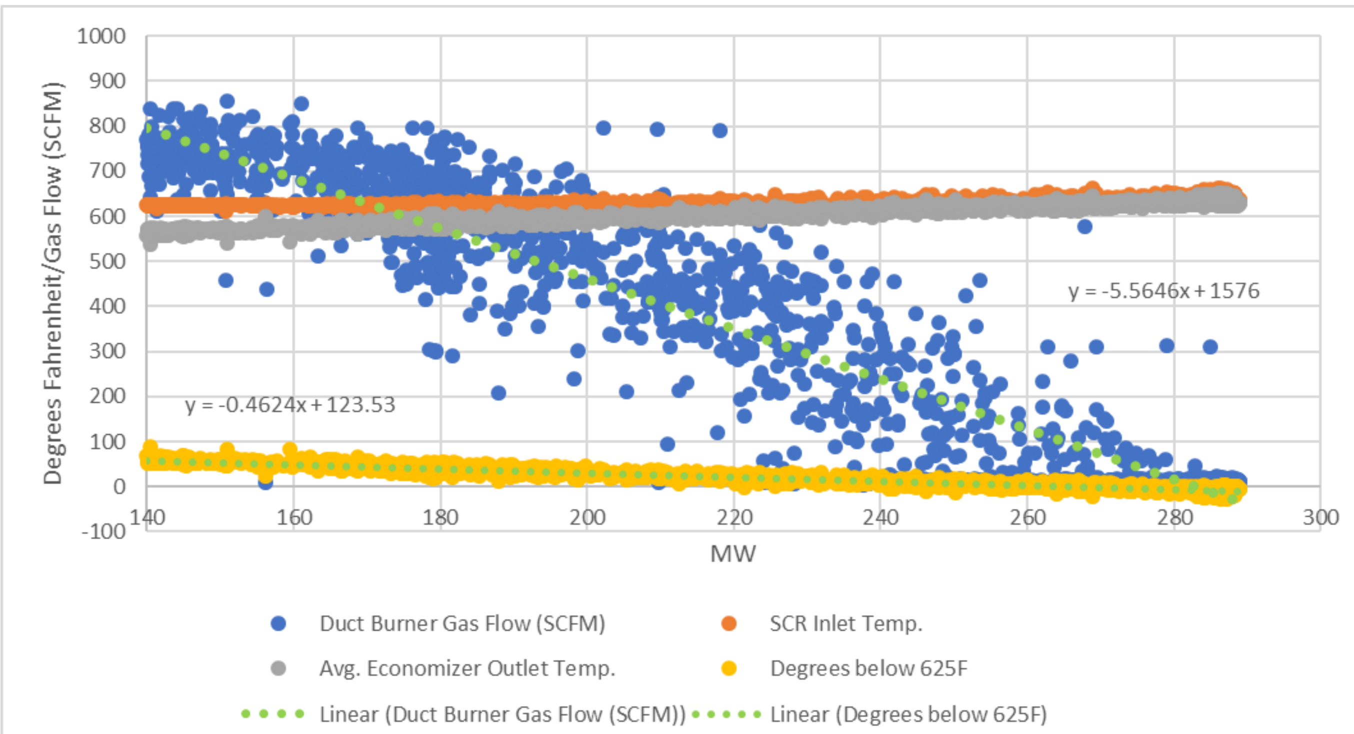



**Figure 3-7 Load vs. Temperature and Flow**

Using linear regression, the temperature difference calculated from Vista was used to determine new loads without using the duct burner and the gas flow savings for each economizer pass reduction"

- Removing 1 pass to the lower economizer – New load without duct burner use - 252MW, Gas Flow savings - 174 SCFM (10.6 MMBtu).

- Removing 2 passes to the lower economizer – New load without duct burner use- 237MW, Gas Flow savings - 257 SCFM (15.7 MMBtu).
- Removing 3 passes to the lower economizer – New load without duct burner use- 222MW, Gas Flow savings - 341 SCFM, (20.8 MMBtu).

This reduction does come at a cost in heat rate. From the analysis a reduction in the economizer surface area produces the following heat rate impacts on an overall basis:

- Baseline case – 0% difference.
- Removing 1 pass to the lower economizer - 0.14% worsening.
- Removing 2 passes to the lower economizer – 0.28% worsening.
- Removing 3 passes to the lower economizer – 0.43% worsening.

This heat rate impact had the following effects on fuel burn rate at full load:

- Removing 1 pass to the lower economizer – 3.22 MMBtu/hr increase.
- Removing 2 passes to the lower economizer – 6.6 MMBtu/hr increase.
- Removing 3 passes to the lower economizer – 10.16 MMBtu/hr increase.

From examining the results listed above, removing a portion of the economizer would results in an energy savings. Given the cost differential of $3.00 per MMBtu for natural gas compared to Vectren's $2.22 per MMBtu for coal, the savings in natural gas flow at full load would be approximately $5.76 per hour for the 1 pass case and $8.30 per hour for the 3-pass case. Assuming that savings would be realized over 70% of the year (8760 hours). This would result in $151k in savings for the first year for the base case and $244k in savings for the first year for the alternate case.

Should a change be made to the economizer tube surface area, the estimated costs and logistics of such a change to the economizers, assuming no header relocation is needed and neglecting the loss of contract availability are expected to range from $750,000 to $1,400,000 depending upon the amount of modification. Complete replacement of the economizer was not estimated during this effort, nor was any addition to hot reheat surface or any other modifications.

## 3.3 AIR HEATER AND LEAKAGE CONTROL UPGRADES

A core opportunity for net plant heat rate (NPHR) improvement is solidifying the operational reliability and process integrity of the combustion air draft system and flue gas draft system. The gas-to-air regenerative air heaters are a critical nexus between these two subsystems. Similarly, balanced draft units are susceptible to the effects of air in-leakage in the flue gas draft system because of the negative (internal) operating pressure of the flue gas ductwork. The following sections outline the NPHR improvement initiatives targeting the existing regenerative air heaters and mitigating the detrimental effects of flue gas draft system duct air in-leakage. The A.B.

Brown Unit 1, A.B. Brown Unit 2, F.B. Culley Unit 2, and F.B. Culley Unit 3 considerations are addressed in the following sections.

### 3.3.1 A.B. Brown Unit 1 Air Heater and Leakage Control Upgrades

The main NPHR benefit of air heater and flue gas ductwork leakage control repairs/upgrades is due to reducing the duty of the unit's combustion air and flue gas induced draft fans, thus reducing the unit's overall auxiliary load.

Excessive air heater and flue gas duct leakage presents additional issues beyond degradation in NPHR, however. Air in-leakage can also result in tempering of flue gas and causing corrosive flue gas acid gasses to condense on air heater cold end baskets and ductwork components. Reduction in air heater and flue gas duct leakage can improve overall equipment life, reduce capital investment for repair and reduce operation and maintenance (O&M) costs caused by flue gas acid gas corrosion. Additionally, the following are some other characteristics of air in-leakage that can negatively impact draft system and air quality control equipment performance:

- Higher velocities from additional mass flow, potentially reducing the life expectancy of pulse jet fabric filter (PJFF) bags.
- Higher pressure drops through combustion air and flue gas draft system equipment.
- Reduced air heater gas outlet temperatures (due to additional leak of cold combustion air mixing with hot flue gas out of air heater), causing flue gas to be closer to acid dew point and increasing the potential for equipment corrosion throughout the flue gas draft system.

The following subsections provide further discussion of air heater and leakage control upgrades. The discussions are based on Black & Veatch prior experience in heat rate assessments and implementation of HRI projects. The typical information and results provided for such projects can be used to assess and further screen the potential benefits. Future efforts would be required to assess the in-service condition of the air heaters and ductwork to determine the definitive benefits of potential improvement projects.

#### 3.3.1.1 Air Heater

As previously noted, air heater leakage rates have the effect of increasing the duty of the combustion air fans and flue gas induced draft fans. Higher pressure combustion air passing through the air heater will leak past air heater seals to the flue gas side (on the cold-side of the air heater for the most part), reduce the temperature of the flue gas, and increase the mass and volumetric flow of the flue gas, which results in a higher flue gas-induced draft fan duty. The combustion air leakage within the air heater also increases the duty of the combustion air fans since additional combustion air needs to be supplied at the outlet of the combustion air fan to account for the combustion air lost across the air heater.

The two air heaters of A.B. Brown Unit 1 are regenerative Ljungström type air heaters with rotating baskets. Radial, axial, and circumferential seals provide sealing between the combustion air and flue gas paths across and around the air heater baskets as they rotate within the air heater casing. Deterioration of seals from typical usage, corrosion, many large temperature swings such as unit trips, or damage of seals that are misaligned or out of adjustment will result in increased air heater leakage rates. The A.B. Brown Unit 1 air heaters are regularly inspected by the OEM, including an assessment of the air heater seals and replacement if required during all planned outages. Prior to the SCR installation, the original design air leakage for the A.B. Brown Unit 1 air heaters was approximately 7 percent to 8 percent. The installation of the SCR units has resulted in a corresponding increase of the full load air-to-gas side differential pressure by several inches of water column (when combustion air and flue gas pressures are compared). Additionally, the hot end sector plates have been replaced for A.B. Brown Unit 1, and the OEM recommendation is to replace the cold-end sectors plates. Air heater leakage is closely monitored for A.B. Brown Unit 1 because of the detrimental effect of oxygen on the dual alkali scrubbers within the air quality control system (AQCS).

According to feedback from Vectren operations personnel, positive contact seals have been attempted for the A.B. Brown Unit 1 air heaters in the past but were removed from service because of failures during operation. The air heaters now utilize the original seal types. More frequent in situ monitoring or installation of permanent probes measuring flue gas oxygen content at the induced draft (ID) fan inlet would allow for more accurate trending of the air in-leakage over time. This information would assist with planned outage maintenance and would provide ancillary benefits such as reducing ID fan power consumption and improved heat rate due to dry gas loss reduction.

In addition to improving air heater leakage, replacing worn air heater baskets with new ones can improve draft system losses and air heater effectiveness. The replacement of the existing air heater baskets with new ones that are more thermally efficient could be beneficial because the average flue gas temperature leaving the unit could be decreased with minimal, if any, impact to pressure drop. As a rule, for every 40° F decrease in air heater gas outlet temperature, a 1.0 percent increase in boiler efficiency can be expected. The reduction in leakage previously discussed is expected to increase the measured average air heater gas outlet temperature. This increase would not be expected to negatively impact boiler efficiency as the air heater no-leak gas outlet temperature would remain the same. Black & Veatch expects that air heater upgrades that could lower the no-leak temperature by 20° F are attainable without an in-depth analysis of the air preheat system and acid gas dew points. This would increase boiler efficiency by about 0.5 percent.

However, if additional efficiency gains are desired, additional analyses of the air preheat system and acid gas dew points with the air heater performance would be required to ensure the average gas temperature does not encroach upon the acid gas dew point at all loads. It is expected that the air heater gas outlet temperature could be lowered by another 10 to 15° F, improving boiler efficiency by another 0.25 percent. To achieve this, upgrades to the air preheat system and air-side and/or gas-side air heater bypasses would likely be required to maintain air heater gas outlet temperatures above the acid dew point at lower loads and during colder times of the year.

It should be noted that internal air heater condition should also be assessed to help in the decision-making process for upgrading or refurbishing air heater components to improve unit NPHR.

An additional area of opportunity for NPHR improvement related to the A.B. Brown Unit 1 air heaters is the potential reduction of the air heater cold-end setpoint temperature for A.B. Brown Unit 1.

According to unit operating data provided by Vectren, A.B. Brown Unit 1 maintains a consistent air heater cold-end temperature near 325 to 330° F (measured at the ID fan inlet for A.B. Brown Unit 1). This temperature target is considered above the recommended setpoint, given the potential acid gas dew point temperature, which is likely below 300° F. The gradual reduction of the air heater cold-end setpoint (e.g., reduction by 5 degrees every few months) would be a zero-cost (i.e., can be implemented via changes to setpoints within the existing control system) means of improving NPHR and not negatively impacting beneficial reuse of the fly ash. Changes to the condition of the draft system could be monitored during the regularly scheduled maintenance outages. While plant personnel report that generally speaking dew point temperatures have not been a problem at the unit, they nonetheless would be concerned about any significant reduction in air heater gas outlet temperature which takes the unit into an unfamiliar operating regime.

Air heater bypasses have been installed on the A.B. Brown Unit 1 draft system. This system provides a backup for the existing air preheating steam coil systems for cold-end temperature control for periods of extreme cold weather or a coil being taken out of service. Upgrades to the steam coil system would allow for fewer uses of the air heater (air-side) bypass during the year and fewer instances of the associated heat rate penalty during the intermittent use of the bypass.

#### 3.3.1.2 Ductwork

The ductwork system can be divided between the combustion air and the boiler flue gas ductwork systems. Excessive leakages in either ductwork system will negatively impact the overall NPHR of the unit and long-term equipment health.

The combustion air ductwork system operates at a pressure greater than atmosphere and will experience combustion air leakages to atmosphere. Excessive combustion air duct leakages will increase the duty of the combustion air fans and result in an increase in the combustion air fan auxiliary load, thus negatively impacting the unit's NPHR.

The flue gas ductwork system will operate at a pressure slightly below atmosphere and will experience air in-leakage. For balanced draft units, the differential in flue gas ductwork internal pressure compared to ambient increases (i.e., becomes more negative) as the flue gas progresses from the furnace, through the draft system, and to the inlet of the ID fans. Excessive air in-leakage to the flue gas ductwork will increase the duty of the flue gas ID fans and result in an increase in the flue gas ID fan auxiliary load, thus negatively impacting the unit's NPHR.

Air in-leakage to the flue gas duct work will also have the result of tempering the flue gas. A reduction in flue gas temperature (overall or localized) below that of the dew point of acid gases of the flue gas will result in acid gasses condensing on ductwork components. Condensed acid gasses will result in corrosion and degradation of ductwork components. Reducing air in-leakage of the ductwork system will also provide a capital and O&M expense benefit by improving equipment life and mitigating O&M issues resulting from ductwork corrosion.

The ductwork inspection activities and the air heater upgrades discussed in the previous section would be expected to be incorporated during the regularly scheduled O&M outages. The A.B. Brown Unit 1 forecast for scheduled maintenance outages is outlined in Table 3-8.

**Table 3-8 A.B. Brown Unit 1 O&M Scheduled Outage Intervals (2020-2039)**

| YEAR | A.B. BROWN UNIT 1 O&M - SCHEDULED OUTAGE |
|---|---|
| 2020 | -- |
| 2021 | 3 weeks |
| 2022 | Major |
| 2023 | -- |
| 2024 | 3 weeks |
| 2025 | 3 weeks |
| 2026 | -- |
| 2027 | 3 weeks |
| 2028 | 3 weeks |
| 2029 | -- |
| 2030 | 3 weeks |
| 2031 | Major |
| 2032 | -- |
| 2033 | 3 weeks |
| 2034 | 3 weeks |
| 2035 | -- |
| 2036 | 3 weeks |
| 2037 | 3 weeks |
| 2038 | -- |
| 2039 | 3 weeks |

To determine the overall cost associated with improving the ductwork leakage rates, field examinations and tests must be carried out to pinpoint ductwork leakage locations. Utilization of a smoke generator (or similar system) to locate and catalog the leaks would be required. Leakage quantities should then be estimated for each leakage source to quantify an impact to fan duty and associated auxiliary load increase. The initial field examination should focus on high impact areas where the differential between the inside duct pressure and atmosphere is greater (i.e., areas closer to the discharge of the combustion air forced draft/primary air [FD/PA]) fans or areas closer to the inlet of the flue gas induced draft fans). In addition, the initial review should focus on expansion joints, expansion joint health, expansion joint sealing gaskets, duct door gaskets, duct gaskets, or potentially failing duct jointing seal welds.

Draft system leakage testing data for A.B. Brown Unit 1 were not available for review or incorporation into this analysis. Therefore, Black & Veatch has not assessed any NPHR impacts regarding reducing flue gas draft system leakage other than that discussed for the air heaters. The following activities can be implemented to improve the existing air heater units and find draft system leakage points. With the availability of additional data, the following estimates could be further refined, and the following heat rate benefits would likely increase.

***Air Heater Basket, Seal, and Sector Plate Replacement***

| | |
|---|---|
| Total Installed Capital Cost: | $850,000 |
| Heat Rate (efficiency) Improvement: | 0.5% (assumes 20 °F air heater gas outlet temperature improvement) |

***Air Preheater (Steam Coil) System Repairs***

| | |
|---|---|
| Total Installed Capital Cost: | $350,000 |
| Heat Rate (efficiency) Improvement: | 0.1% (applicable to intermittent periods when steam coils would be used) |

### 3.3.2 A.B. Brown Unit 2 Air Heater and Leakage Control Upgrades

The main NPHR benefit of air heater and flue gas ductwork leakage control repairs/upgrades results from reducing the duty of the unit's combustion air and flue gas induced draft fans, thus reducing the unit's overall auxiliary load demand.

Excessive air heater and flue gas duct leakage presents additional issues beyond degradation in NPHR, however. Air in-leakage can also result in tempering of flue gas and causing corrosive flue gas acid gasses to condense on air heater cold end baskets and ductwork components, resulting in degradation of equipment materials. Reduction in air heater and flue gas duct leakage can improve overall equipment life, reduce capital investment for repair, and reduce O&M costs caused by flue gas acid gas corrosion. Additionally, the following are some other characteristics of air in-leakage that can negatively impact draft system and air quality control equipment performance:

- Higher velocities from additional mass flow reducing the ability of an electrostatic precipitator to capture ash.
- Higher pressure drops through combustion air and flue gas draft system equipment.
- Reduced air heater gas outlet temperatures (due to additional leak of cold combustion air mixing with hot flue gas out of air heater), causing flue gas to be

closer to acid dew point increasing the potential for equipment corrosion throughout flue gas draft system.

The following subsections provide further discussion of air heater and leakage control upgrades. The discussions are based on Black & Veatch prior experience in heat rate assessments and implementation of heat rate improvement projects. The typical information and results provided for such projects can be used to assess and further screen the potential benefit. Future efforts would be required to assess the in-service condition of the air heaters and ductwork to determine the definitive benefits of potential improvement projects.

#### 3.3.2.1 Air Heater

As previously noted, air heater leakage rates have the effect of increasing the duty of the combustion air fans and flue gas ID fans. Higher pressure combustion air passing through the air heater will leak past air heater seals to the flue gas side (on the cold-side of the air heater for the most part), reducing the temperature of the flue gas, and increasing the mass and volumetric flow of the flue gas, resulting in a higher flue gas ID fan duty. The combustion air leakage within the air heater also increases the duty of the combustion air fans since additional combustion air needs to be supplied at the outlet of the combustion air fan to account for the combustion air lost across the air heater.

The two air heaters of A.B. Brown Unit 2 are regenerative Ljungström type air heaters with rotating baskets. Radial, axial, and circumferential seals provide sealing between the combustion air and flue gas paths across and around the air heater baskets as they rotate within the air heater casing. Deterioration of seals from typical usage, corrosion, many large temperature swings such as unit trips, or damage of seals that are misaligned or out of adjustment will result in increased air heater leakage rates. The A.B. Brown Unit 2 air heaters are regularly inspected by the OEM, including an assessment of the air heater seals and replacement if required during all planned outages. Prior to the SCR installation, the original design air leakage for the A.B. Brown Unit 2 air heaters was approximately 7 to 8 percent. The installation of the SCR units has resulted in a corresponding increase of the full load air-to-gas side differential pressure by several inches of water column (when combustion air and flue gas pressures are compared). Additionally, the hot end sector plates have been replaced for A.B. Brown Unit 2, and the OEM recommendation is to replace the cold-end sectors plates. Air heater leakage is closely monitored for A.B. Brown Unit 2 because of the detrimental effect of oxygen on the dual alkali scrubbers within the AQCS.

According to feedback from Vectren operations personnel, positive contact seals have been attempted for the A.B. Brown Unit 2 air heaters in the past but were removed from service because of failures during operation. The air heaters now utilize the original seal types. More frequent in-situ monitoring or installation of permanent probes measuring flue gas oxygen content at the ID fan inlet would allow for more accurate trending of the air in-leakage trends over time. This information would assist with planned outage maintenance and would provide ancillary benefits such as reducing ID fan power consumption and improved heat rate due to dry gas loss reduction.

In addition to improving air heater leakage, replacing worn air heater baskets with new ones can improve draft system losses and air heater effectiveness. The replacement of the existing air heater baskets with new ones that are more thermally efficient could be beneficial because the average flue gas temperature leaving the unit could be decreased with minimal, if any, impact to pressure drop. As a rule, for every 40° F decrease in air heater gas outlet temperature, a 1.0 percent increase in boiler efficiency can be expected. The reduction in leakage previously discussed is expected to increase the measured average air heater gas outlet temperature. This increase would not be expected to negatively impact boiler efficiency as the air heater no-leak gas outlet temperature would remain the same. Black & Veatch expects that air heater upgrades that could lower the no-leak temperature by 20° F are attainable without an in-depth analysis of the air preheat system and acid gas dew points. This would increase boiler efficiency by about 0.5 percent.

However, if additional efficiency gains are desired, additional analyses of the air preheat system and acid gas dew points with the air heater performance would be required to ensure the average gas temperature does not encroach upon the acid gas dew point at all loads. It is expected that the air heater gas outlet temperature could be lowered by another 10 to 15° F, improving boiler efficiency by another 0.25 percent. Upgrades to the air preheat system and air-side and/or gas-side air heater bypasses are expected to be likely, however, to maintain air heater gas outlet temperatures above the acid dew point at lower loads and during colder times of the year.

It should be noted that internal air heater condition should also be assessed to help in the decision-making process for upgrading or refurbishing air heater components to improve unit NPHR.

An additional area of opportunity for NPHR improvement related to the A.B. Brown Unit 2 air heaters is the potential reduction of the air heater cold-end setpoint temperature for A.B. Brown Unit 2.

According to unit operating data provided by Vectren, A.B. Brown Unit 2 maintains a consistent air heater cold-end temperature near 325 to 330° F (measured at the ID fan inlet for A.B. Brown Unit 2). This temperature target is considered above the recommended setpoint, given the potential acid gas dew point temperature, which is likely below 300° F. The gradual reduction of the air heater cold-end setpoint (e.g., reduction by 5 degrees every few months) would be a zero-cost (i.e., can be implemented via changes to setpoints within the existing control system) means of improving NPHR and not negatively impacting beneficial reuse of the fly ash. Changes to the condition of the draft system could be monitored during the regularly scheduled maintenance outages.

Air heater bypasses have been installed on the A.B. Brown Unit 2 draft system. This system provides a backup for the existing air preheating steam coil systems for cold-end temperature control for periods of extreme cold weather or a coil being taken out of service. Upgrades to the steam coil system would allow for fewer uses of the air heater (air-side) bypass during the year and fewer instances of the associated heat rate penalty during the intermittent use of the bypass.

#### 3.3.2.2 Ductwork

The ductwork system can be divided between the combustion air and the boiler flue gas ductwork systems. Excessive leakages in either ductwork system will negatively impact the overall NPHR of the unit and long-term equipment health.

The combustion air ductwork system operates at a pressure greater than atmosphere and will experience combustion air leakages to atmosphere. Excessive combustion air duct leakages will increase the duty of the combustion air fans and result in an increase in the combustion air fan auxiliary load, thus negatively impacting the unit's NPHR.

The flue gas ductwork system will operate at a pressure slightly below atmosphere and will experience air in-leakage. For balanced draft units, the differential in flue gas ductwork internal pressure compared to ambient increases (i.e., becomes more negative) as the flue gas progresses from the furnace, through the draft system and to the inlet of the ID fans. Excessive air in-leakage to the flue gas ductwork will increase the duty of the flue gas ID fans and result in an increase in the flue gas ID fan auxiliary load, thus negatively impacting the unit's NPHR.

Air in-leakage to the flue gas duct work will also have the result of tempering the flue gas. A reduction in flue gas temperature (overall or localized) below that of the dew point of acid gases of the flue gas will result in acid gasses condensing on ductwork components. Condensed acid gasses will result in corrosion and degradation of ductwork components. Reducing air in-leakage of the ductwork system will also provide a capital and O&M expense benefit by improving equipment life and mitigating O&M issues resulting from ductwork corrosion.

Ductwork inspection activities and the air heater upgrades discussed in the previous section would be expected to be incorporated during the regularly scheduled O&M outages. The A.B. Brown Unit 2 forecast for scheduled maintenance outages is outlined in Table 3-9.

**Table 3-9 A.B. Brown Unit 2 O&M Scheduled Outage Intervals (2020-2039)**

| YEAR | A.B. BROWN UNIT 2 O&M - SCHEDULED OUTAGE |
|---|---|
| 2020 | 3 weeks |
| 2021 | 3 weeks |
| 2022 | -- |
| 2023 | Major |
| 2024 | 3 weeks |
| 2025 | -- |
| 2026 | 3 weeks |
| 2027 | 3 weeks |
| 2028 | -- |
| 2029 | 3 weeks |
| 2030 | 3 weeks |
| 2031 | -- |
| 2032 | 3 weeks |
| 2033 | Major |
| 2034 | -- |
| 2035 | 3 weeks |
| 2036 | Major |
| 2037 | -- |
| 2038 | 3 weeks |
| 2039 | Major |

To determine the overall cost associated with improving the ductwork leakage rates field examinations and tests must be carried out to pinpoint ductwork leakage locations. Utilization of a smoke generator (or similar system) to locate and catalog the leaks would be required. Leakage quantities should then be estimated for each leakage source to quantify an impact to fan duty and associated auxiliary load increase. The initial field examination should focus on high impact areas where the differential between the inside duct pressure and atmosphere is greater (i.e., areas closer to the discharge of the combustion air fans or areas closer to the inlet of the flue gas ID fans). In addition, the initial review should focus on expansion joints, expansion joint health, expansion joint sealing gaskets, duct door gaskets, duct gaskets, or potentially failing duct jointing seal welds.

Draft system leakage testing data for A.B. Brown Unit 2 were not available for review/incorporation into this analysis. Therefore, Black & Veatch has not assessed any NPHR impacts regarding reducing flue gas draft system leakage other than that discussed for the air heaters. The following activities can be implemented to improve the existing air heater units and find draft system leakage points. With the availability of additional data, the following estimates could be further refined, and the following heat rate benefits could likely increase.

***Air Heater Basket, Seal, and Sector Plate Replacement***

| | |
|---|---|
| Total Installed Capital Cost: | $850,000 |
| Heat Rate (efficiency) Improvement: | 0.5% (assumes 20° F air heater gas outlet temperature improvement) |

***Air Preheater (Steam Coil) System Repairs***

| | |
|---|---|
| Total Installed Capital Cost: | $350,000 |
| Heat Rate (efficiency) Improvement: | 0.1% (applicable to intermittent periods when steam coils would be used) |

### 3.3.3 F.B. Culley Unit 2 Air Heater and Leakage Control Upgrades

The main NPHR benefit of air heater and flue gas ductwork leakage control repairs/upgrades is a result of reducing the duty of the unit's combustion air and flue gas induced draft fans, thus reducing the unit's overall auxiliary load demand.

Excessive air heater and flue gas duct leakage presents additional issues beyond degradation in NPHR, however. Air in-leakage can also result in tempering of flue gas, causing corrosive flue gas acid gases to condense on air heater cold end baskets and ductwork components. Reduction in air heater and flue gas duct leakage can improve overall equipment life, reduce capital investment for repair, and reduce O&M costs caused by flue gas acid gas corrosion. Additionally, the following are some other characteristics of air in-leakage that can negatively impact draft system and air quality control equipment performance:

- Higher velocities from additional mass flow, potentially reducing the life expectancy of PJFF bags.
- Higher pressure drops through combustion air and flue gas draft system equipment.
- Reduced air heater gas outlet temperatures (due to additional leak by of cold combustion air mixing with hot flue gas out of air heater), causing flue gas to be closer to acid dew point and increasing the potential for equipment corrosion throughout flue the gas draft system.

The following subsections provide further discussion of air heater and leakage control upgrades. The discussions are based on Black & Veatch prior experience in heat rate assessments and implementation of heat rate improvement projects. The typical information and results provided for such projects can be used to assess and further screen the potential benefit. Future efforts would be required to assess the in-service condition of the air heaters and ductwork to determine the definitive benefits of potential improvement projects.

#### 3.3.3.1 Air Heater

As previously noted, air heater leakage rates have the effect of increasing the duty of the combustion air fans and flue gas ID fans. Higher pressure combustion air passing through the air heater will leak past air heater seals to the flue gas side (on the cold-side of the air heater for the most part), reducing the temperature of the flue gas, and increasing the mass and volumetric flow of the flue gas, resulting in a higher flue gas ID fan duty. The combustion air leakage within the air heater also increases the duty of the combustion air fans since additional combustion air needs to be supplied at the outlet of the combustion air fan to account for the combustion air lost across the air heater.

The F.B. Culley Unit 2 air heater is a regenerative Ljungström type air heater with rotating baskets. Radial, axial, and circumferential seals provide sealing between the combustion air and flue gas paths across and around the air heater baskets as they rotate within the air heater casing. Deterioration of seals from typical usage, corrosion, many large temperature swings such as unit trips, or damage of seals that are misaligned or out of adjustment will result in increased air heater leakage rates. The F.B. Culley Unit 2 air heaters are regularly inspected by the OEM, including an assessment of the air heater seals and replacement if required during all planned outages. More frequent in situ monitoring or installation of permanent probes measuring flue gas oxygen content at the ID fan inlet would allow for more accurate trending of the air in-leakage over time. This information would assist with planned outage maintenance and would provide ancillary benefits such as reducing ID fan power consumption and improved heat rate from a dry gas loss reduction.

In addition to improving air heater leakage, replacing worn air heater baskets with new ones can improve draft system losses and air heater effectiveness. The replacement of the existing air heater baskets with new ones that are more thermally efficient could be beneficial because the average flue gas temperature leaving the unit could be decreased with minimal, if any, impact to pressure drop. As a rule, for every 40° F decrease in air heater gas outlet temperature, a 1.0 percent increase in boiler efficiency can be expected. The reduction in leakage previously discussed is expected to increase the measured average air heater gas outlet temperature. This increase would not be expected to negatively impact boiler efficiency because the air heater no-leak gas outlet temperature would remain the same. Black & Veatch expects that air heater upgrades that could lower the no-leak temperature by 20° F are attainable without an in-depth analysis of the air preheat system and acid gas dew points. This would increase boiler efficiency by about 0.5 percent.

However, if additional efficiency gains are desired, additional analyses of the air preheat system and acid gas dew points with the air heater performance would be required to ensure the average gas temperature does not encroach upon the acid gas dew point at all loads. It is expected that the air heater gas outlet temperature could be lowered by another 10 to 15° F, improving boiler efficiency by another 0.25 percent.

The F.B. Culley Unit 2 air preheater (steam coil) units are reportedly in good condition and operate reliably; because of this, there were no recommendations or perceived improvements to unit performance as a result of additional capital budget spending for the air preheater units.

It should be noted that an internal air heater conditional assessment should also be made to help in the decision-making process for upgrading or refurbishing air heater components to improve unit NPHR.

An additional area of opportunity for NPHR improvement related to the F.B. Culley Unit 2 air heaters is the potential reduction of the air heater cold-end setpoint temperature for F.B. Culley Unit 2.

According to unit operating data provided by Vectren, F.B. Culley Unit 2 maintains a consistent air heater cold-end temperature near 325 to 330°F (measured at the ID fan inlet for F.B. Culley Unit 2). This temperature target is considered above the recommended setpoint, given the potential acid gas dew point temperature, which is likely below 300° F. The gradual reduction of the air heater cold-end setpoint (e.g., reduction by 5 degrees every few months) would be a zero-cost (i.e., can be implemented via changes to setpoints within the existing control system) means of improving NPHR and not negatively impacting beneficial reuse of the fly ash. Changes to the condition of the draft system could be monitored during the regularly scheduled maintenance outages.

#### 3.3.3.2 Ductwork

The ductwork system can be divided between the combustion air and the boiler flue gas ductwork systems. Excessive leakages in either ductwork system will negatively impact the overall NPHR of the unit and long-term equipment health.

The combustion air ductwork system operates at a pressure greater than atmosphere and will experience combustion air leakages to atmosphere. Excessive combustion air duct leakages will increase the duty of the combustion air fans and result in an increase in the combustion air fan auxiliary load, thus negatively impacting the unit's NPHR.

The flue gas ductwork system will operate at a pressure slightly below atmosphere and will experience air in-leakage. For balanced draft units, the differential in flue gas ductwork internal pressure compared to ambient increases (i.e., becomes more negative) as the flue gas progresses from the furnace, through the draft system, and to the inlet of the ID fans. Excessive air in-leakage to the flue gas ductwork will increase the duty of the flue gas ID fans and result in an increase in the flue gas induced draft fan auxiliary load, thus negatively impacting the units NPHR.

Air in-leakage to the flue gas duct work will also have the result of tempering the flue gas. A reduction in flue gas temperature (overall or localized) below that of the dew point of acid gases of the flue gas will result in acid gasses condensing on ductwork components. Condensed acid gasses will result in corrosion and degradation of ductwork components. Reducing air in-leakage of the ductwork system will also provide a capital and O&M expense benefit by improving equipment life and mitigating O&M issues resulting from ductwork corrosion.

Ductwork inspection activities and the air heater upgrades discussed in the previous section would be expected to be incorporated during the regularly scheduled O&M outages. The F.B. Culley Unit 2 forecast for scheduled maintenance outages is outlined in Table 3-10.

**Table 3-10 F.B. Culley Unit 2 O&M Scheduled Outage Intervals (2020-2039)**

| YEAR | F.B. CULLEY UNIT 2 O&M - SCHEDULED OUTAGE |
|---|---|
| 2020 | 3 weeks |
| 2021 | -- |
| 2022 | 3 weeks |
| 2023 | -- |
| 2024 | Major |
| 2025 | -- |
| 2026 | 3 weeks |
| 2027 | -- |
| 2028 | 3 weeks |
| 2029 | -- |
| 2030 | 3 weeks |
| 2031 | -- |
| 2032 | 3 weeks |
| 2033 | -- |
| 2034 | Major |
| 2035 | -- |
| 2036 | 3 weeks |
| 2037 | -- |
| 2038 | 3 weeks |
| 2039 | -- |

To determine the overall cost associated with improving the ductwork leakage rates field examinations and tests must be carried out to pinpoint ductwork leakage locations. Utilization of a smoke generator (or similar system) to locate and catalog the leaks would be required. Leakage quantities should then be estimated for each leakage source to quantify an impact to fan duty and associated auxiliary load increase. The initial field examination should focus on high impact areas where the differential between the inside duct pressure and atmosphere is greater (i.e., areas closer to the discharge of the combustion air fans or areas closer to the inlet of the flue gas ID fans). In addition, the initial review should focus on expansion joints, expansion joint health, expansion joint sealing gaskets, duct door gaskets, duct gaskets, or potentially failing duct jointing seal welds.

Draft system leakage testing data for F.B. Culley Unit 2 were not available for review or incorporation into this analysis. Therefore, Black & Veatch has not assessed any NPHR impacts regarding reducing flue gas draft system leakage other than that discussed for the air heaters. The following activities can be implemented to improve the existing air heater units and find draft system leakage points. With the availability of additional data, the following estimates could be further refined, and the following heat rate benefits would likely increase.

***Air Heater Basket, Seal, and Sector Plate Replacement***

| | |
|---|---|
| Total Installed Capital Cost: | $476,000 |
| Heat Rate (efficiency) Improvement: | 0.5% (assumes 20° F air heater gas outlet temperature improvement) |

### 3.3.4 F.B. Culley Unit 3 Air Heater and Leakage Control Upgrades

The main NPHR benefit of air heater and flue gas ductwork leakage control repairs/upgrades is as a result of reducing the duty of the unit's combustion air and flue gas induced draft fans thus reducing the units overall auxiliary load demand.

Excessive air heater and flue gas duct leakage presents additional issues beyond degradation in NPHR, however. Air in-leakage can also result in tempering of flue gas, causing corrosive flue gas acid gases to condense on air heater cold end baskets and ductwork components. Reduction in air heater and flue gas duct leakage can improve overall equipment life, reduce capital investment for repair, and reduce O&M costs caused by flue gas acid gas corrosion. Additionally, the following are some other characteristics of air in-leakage that can negatively impact draft system and air quality control equipment performance:

- Higher velocities from additional mass flow, potentially reducing the life expectancy of PJFF bags.
- Higher pressure drops through combustion air and flue gas draft system equipment.
- Reduced air heater gas outlet temperatures (due to additional leak-by of cold combustion air mixing with hot flue gas out of air heater), causing flue gas to be closer to acid dew point and increasing the potential for equipment corrosion throughout the flue gas draft system.

The following subsections provide further discussion of air heater and leakage control upgrades. The discussions are based on Black & Veatch prior experience in heat rate assessments and implementation of heat rate improvement projects. The typical information and results provided for such projects can be used to assess and further screen the potential benefit. Future efforts would be required to assess the in-service condition of the air heaters and ductwork to determine the definitive benefits of potential improvement projects.

#### 3.3.4.1 Air Heater

As previously noted, air heater leakage rates have the effect of increasing the duty of the combustion air fans and flue gas ID fans. Higher pressure combustion air passing through the air heater will leak past air heater seals to the flue gas side (on the cold-side of the air heater for the most part), reducing the temperature of the flue gas, and increasing the mass and volumetric flow of the flue gas, resulting in a higher flue gas ID fan duty. The combustion air leakage within the air heater also increases the duty of the combustion air fans since additional combustion air needs to be supplied at the outlet of the combustion air fan to account for the combustion air lost across the air heater.

The two air heaters of F.B. Culley Unit 3 are regenerative Ljungström type air heaters with rotating baskets. Radial, axial, and circumferential seals provide sealing between the combustion air and flue gas paths across and around the air heater baskets as they rotate within the air heater casing. Deterioration of seals from typical usage, corrosion, many large temperature swings such as unit trips, or damage of seals that are misaligned or out of adjustment will result in increased air heater leakage rates. The F.B. Culley Unit 3 air heaters are regularly inspected by the OEM, including an assessment of the air heater seals and replacement if required during all planned outages. Prior to the SCR installation, the original design air leakage for the F.B. Culley Unit 3 air heaters was approximately 7 to 8 percent. The installation of the SCR units has resulted in a corresponding increase of the full load air-to-gas side differential pressure by several inches of water column (when combustion air and flue gas pressures are compared).

Air in-leakage testing (measuring the oxygen content rise in discrete sections of the F.B. Culley Unit 3 draft system) was performed in 2017. This testing indicated a 16 to 17 percent leakage across each of the F.B. Culley Unit 3 air heaters (with the unit at full load). The leakage data across the PJFF and SCR units indicated no significant air infiltration. These data are outlined in Table 3-11 and Figure 3-8.

Table 3-11 F.B. Culley Unit 3 Draft System and Air Heater Air In-Leakage Test Data (July 2017)

| TESTING LOCATION | DESCRIPTION | F.B. CULLEY UNIT 3 DRAFT SYSTEM – WEST SIDE | F.B. CULLEY UNIT 3 DRAFT SYSTEM – EAST SIDE |
|---|---|---|---|
| SCR Inlet | SCR inlet after duct burner; duct burner out of service at during full load test | 4.0 | 3.5 |
| SCR Outlet | SCR outlet/AH inlet duct section | 4.0 | 3.7 |
| AH Outlet | AH outlet/PJFF inlet duct section | 6.4 | 6.3 |
| FF Outlet | PJFF outlet/ID fan inlet(s) duct section | 6.5 | 6.2 |
| Calculated AH Leakage (%) | Calculated from "SCR Out" and "AH Out" data provided above | 16.9 | 17.8 |
| AH - air heater | | | |

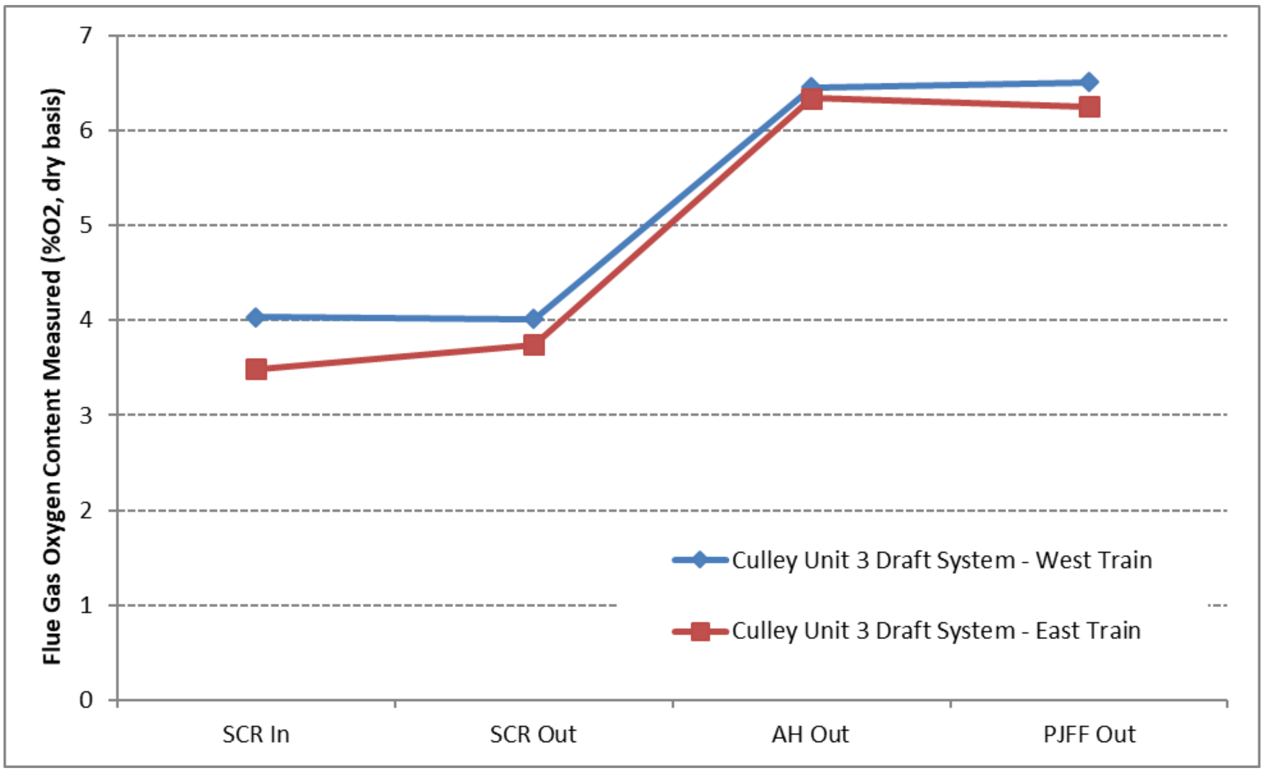



Figure 3-8 F.B. Culley Unit 3 Draft System Air Leakage Test Data (July 2017)

As a result of the air heater leakage test data, all sector plates and seals were replaced at the recommendation of the OEM during the recently completed 2019 planned outage for F.B. Culley Unit 3.

More frequent in situ monitoring or installation of permanent probes measuring flue gas oxygen content at the ID fan inlet would allow for more accurate trending of the air in-leakage over time. This information would assist with planned outage maintenance and would provide ancillary benefits such as reducing ID fan power consumption and improved heat rate due to dry gas loss reduction.

In addition to improving air heater leakage, replacing worn air heater baskets with new ones can improve draft system losses and air heater effectiveness. The replacement of the existing air heater baskets with new ones that are more thermally efficient could be beneficial because the average flue gas temperature leaving the unit could be decreased with minimal, if any, impact to pressure drop. As a rule, for every 40° F decrease in air heater gas outlet temperature, a 1.0 percent increase in boiler efficiency can be expected. The reduction in leakage previously discussed is expected to increase the measured average air heater gas outlet temperature. This increase would not be expected to negatively impact boiler efficiency as the air heater no-leak gas outlet temperature would remain the same. Black & Veatch expects that air heater upgrades that could lower the no-leak temperature by 20° F are attainable without an in-depth analysis of the air preheat system and acid gas dew points. This would increase boiler efficiency by about 0.5 percent.

However, if additional efficiency gains are desired, additional analyses of the air preheat system and acid gas dew points with the air heater performance would be required to ensure the average gas temperature does not encroach upon the acid gas dew point at all loads. It is expected that the air heater gas outlet temperature could be lowered by another 10 to 15° F, improving boiler efficiency by another 0.25 percent. The F.B. Culley Unit 3 air preheater (steam coils) are located in the FD fan room to maintain a minimum air inlet temperature setpoint, controlled by the FD fan outlet temperature. To achieve this, upgrades to the air preheat system and air-side and/or gas-side air heater bypasses would likely be required to maintain air heater gas outlet temperatures above the acid dew point at lower loads and during colder times of the year.

It should be noted that internal air heater condition should also be assessed to help in the decision-making process for upgrading or refurbishing air heater components to improve unit NPHR.

An additional area of opportunity for NPHR improvement related to the F.B. Culley Unit 3 air heaters is the potential reduction of the air heater cold-end setpoint temperature.

According to unit operating data provided by Vectren, F.B. Culley Unit 3 maintains a consistent air heater cold-end temperature near 325 to 330° F (measured at the ID fan inlet for F.B. Culley Unit 3). This temperature target is considered above the recommended setpoint, given the potential acid gas dew point temperature which is likely below 300° F. The gradual reduction of the air heater cold-end setpoint (e.g., reduction by 5 degrees every few months) would be a zero-cost (i.e., can be implemented via changes to set points within the existing control system) means of improving NPHR and not negatively impacting beneficial reuse of the fly ash. Changes to the condition of the draft system could be monitored during the regularly scheduled maintenance outages.

Air heater bypasses have been installed on the F.B. Culley Unit 3 draft system. This system provides a backup for the existing air preheating steam coil systems for cold-end temperature control for periods of extreme cold weather or a coil being taken out of service. Upgrades to the steam coil system would allow for fewer uses of the air heater (air-side) bypass during the year and fewer instances of the associated heat rate penalty during the intermittent use of the bypass.

In October 2018, Ljungström (F.B. Culley Unit 3 air heater OEM, a division of Arvos Group) provided information regarding a proposed air heater upgrade to improve heat rate as part of Vectren's ongoing heat rate improvement initiatives. According to a preliminary review of Ljungström's proposed air heater upgrade options, a 0.4 percent heat rate improvement was estimated. Black & Veatch recommends additional review of the proposed upgrades and potential balance-of-plant impacts (ID fan, ductwork, etc.). The basis of this improvement is relocating the DSI system upstream of the air heater, which would also need to be considered in the project costs.

#### 3.3.4.2 Ductwork

The ductwork system can be divided between the combustion air and the boiler flue gas ductwork systems. Excessive leakages in either ductwork system will negatively impact the overall NPHR of the unit and long-term equipment health.

The combustion air ductwork system operates at a pressure greater than atmosphere and will experience combustion air leakages to atmosphere. Excessive combustion air duct leakages will increase the duty of the combustion air fans and result in an increase in the combustion air fan auxiliary load, thus negatively impacting the unit's NPHR.

The flue gas ductwork system will operate at a pressure slightly below atmosphere and will experience air in-leakage. For balanced draft units, the differential in flue gas ductwork internal pressure compared to ambient increases (i.e., becomes more negative) as the flue gas progresses from the furnace, through the draft system, and to the inlet of the ID fans. Excessive air in-leakage to the flue gas ductwork will increase the duty of the flue gas ID fans and result in an increase in the flue gas induced draft fan auxiliary load, thus negatively impacting the unit's NPHR.

Air in-leakage to the flue gas duct work will also have the result of tempering the flue gas. A reduction in flue gas temperature (overall or localized) below that of the dew point of acid gases of the flue gas will result in acid gasses condensing on ductwork components. Condensed acid gasses will result in corrosion and degradation of ductwork components. Reducing air in-leakage of the ductwork system will also provide a capital and O&M expense benefit by improving equipment life and mitigating O&M issues resulting from ductwork corrosion. Information provided to assess the flue gas duct work leakage is provided in Table 3-11 and Figure 3-8 above.

Ductwork inspection activities and the air heater upgrades discussed in the previous section would be expected to be incorporated during the regularly scheduled O&M outages. The F.B. Culley Unit 3 forecast for scheduled maintenance outages is outlined in Table 3-12.

**Table 3-12 F.B. Culley Unit 3 O&M Scheduled Outage Intervals (2020-2039)**

| YEAR | F.B. CULLEY UNIT 3 O&M - SCHEDULED OUTAGE |
|---|---|
| 2020 | 3 weeks |
| 2021 | -- |
| 2022 | 3 weeks |
| 2023 | 3 weeks |
| 2024 | -- |
| 2025 | 3 weeks |
| 2026 | Major |
| 2027 | -- |
| 2028 | 3 weeks |
| 2029 | 3 weeks |
| 2030 | -- |
| 2031 | 3 weeks |
| 2032 | 3 weeks |
| 2033 | -- |
| 2034 | 3 weeks |
| 2035 | Major |
| 2036 | -- |
| 2037 | 3 weeks |
| 2038 | 3 weeks |
| 2039 | -- |

To determine the overall cost associated with improving the ductwork leakage rates, field examinations and tests must be carried out to pinpoint ductwork leakage locations. Utilization of a smoke generator (or similar system) to locate and catalog the leaks would be required. Leakage quantities should then be estimated for each leakage source to quantify an impact to fan duty and associated auxiliary load increase. The initial field examination should focus on high impact areas where the differential between the inside duct pressure and atmosphere is greater (i.e., areas closer to the discharge of the combustion air fans or areas closer to the inlet of the flue gas ID fans). In addition, the initial review should focus on expansion joints, expansion joint health, expansion joint sealing gaskets, duct door gaskets, duct gaskets, or potentially failing duct jointing seal welds.

Because the age of the previous leakage testing data and the subsequent air heater maintenance performed by Vectren, Black & Veatch has not assessed any NPHR impacts regarding reducing flue gas draft system leakage other than that discussed for the air heaters. The following activities described in this section can be implemented to continue to find draft system leakage points. With the availability of additional data, the following estimates could be further refined, and the following heat rate benefits would likely increase.

***Air Heater Basket, Seal, and Sector Plate Replacement***

| | |
|---|---|
| Total Installed Capital Cost: | $750,000 |
| Heat Rate (efficiency) Improvement: | 0.5% (assumes 20° F air heater gas outlet temperature improvement) |

***Air Preheater (Steam Coil) System Repairs***

| | |
|---|---|
| Total Installed Capital Cost: | $350,000 |
| Heat Rate (efficiency) Improvement: | 0.1% (applicable to intermittent periods when steam coils would be used) |

## 3.4 UNIT VARIABLE FREQUENCY DRIVE UPGRADES

Variable-frequency drives (VFDs) function by controlling electric motor speed by converting incoming constant frequency power to variable frequency, using pulse width modulation. VFD upgrades for main plant electric motors provide many co-benefits, the largest one of which is improved part-load efficiency and performance. The benefit is greatest at low load. The more part load and unit cycling that is done, the greater the benefit.

In addition to the reduced auxiliary power consumption, other benefits that are gained from the installation of VFDs on rotating equipment are as follows:

- Reduced noise levels around the equipment.
- Lower in-rush current during startups.
- Decreased wear on existing auxiliary power equipment.

Disadvantages of the installation of VFDs include the high capital cost plus a minimal amount of increased electrical equipment maintenance associated with the VFD system.

Output power signal quality and reliability of VFD equipment has increased significantly in the last 10 to 15 years. Part of this increased reliability comes from the development of technology to allow the VFD equipment to remain in operation if one or multiple insulated-gate bipolar transistor (IGBT) power cells fail by automatically bypassing the bad cell, or cells, until an outage when repairs can be made. Additionally, output power signals meet Institute of Electrical and Electronics Engineers (IEEE) 519 1992 requirements, eliminating the need for harmonic filters.

VFD installation typically requires about 2 months of total pre-outage work, with a 1-week outage (per device) for the final tie-in. To support installation of the VFDs, the following changes are necessary:

- Replacement of existing rotating equipment coupling with resilient elastomeric block shaft couplings to accommodate the shaft misalignment and absorb the high torque loads during rapid load changes. This means the existing equipment must be de-coupled from the motor and then realigned with the new coupling.
- Upgrades to lube oil system as necessary.
- New VFD enclosure foundations.
- New VFD enclosures and heat exchangers.
- Replace the power supply cables from existing switchgear to the new VFD cabinet. Install new cables from the VFD cabinet to the motor.
- For smaller units, the VFD control enclosure and cabinets will also be smaller with reduced pre-outage time requirements.

A high-level assessment of the technical and economic feasibility of VFD modifications that have been seen as beneficial in previous ACE studies were considered as part of this study. With financial benefits confirmed by integrated resource plan (IRP) modeling, specific modifications can then be reviewed in a detailed effort to confirm the performance and financial benefits of VFD modifications.

### 3.4.1 A.B. Brown Unit 1 Variable Frequency Drive Upgrades

The A.B. Brown Unit 1 rotating equipment evaluated for the possible addition of VFD systems in this study include the boiler feed pumps, circulating water pumps, cooling tower fans, and the large draft fans for handling combustion air and flue gas.

After discussion with Vectren personnel, the best potential application for further VFD upgrades appears to be the ID fans.

#### 3.4.1.1 Boiler Feed Pumps

The A.B. Brown Unit 1 boiler feed pump is a turbine driven feed pump that already provides high efficiency variable speed capability. The installation of a VFD system on the boiler feed pump will therefore not be evaluated further.

#### 3.4.1.2 Circulating Water Pumps

The circulating water system includes two 50 percent capacity vertical turbine circulating water pumps driven by 1,750 horsepower motors. The impellers on the circulating water pumps were replaced with new impellers in 2008. According to the A.B. Brown Unit 1 operating data provided by Vectren, during the period of January 2017 through September of 2018, the unit was off-line at times and operated as high as 100 percent load. Excluding any hours when the unit was off-line or appeared to be ramping up to load, the operating data indicates that the unit operated between 40 percent load and 60 percent load for approximately 52 percent of the time, a significant period where Unit 1 was operating at a relatively significant part load. The operating data also indicate that the unit operated between 60 percent load and 80 percent load for approximately 15 percent of the time and between 80 percent load and 100 percent load for approximately 33 percent of the time. The addition of VFDs on the circulating water pumps would allow variation in pump operating speed and circulating water flow over the operating load ranges experienced during normal operation of the unit. However, variations in pump speed and circulating water flow can have a significant impact on condenser pressure.

Past studies performed by Black & Veatch on similar coal fired plants have shown that condenser pressure has a higher impact on plant heat rate than changes in auxiliary power associated with the circulating water system (i.e., circulating water pumps and cooling tower fans). These studies have shown that, for the majority of time, it is more advantageous to operate the circulating water pumps and cooling tower fans at full capacity to maintain the lowest temperature circulating water to the condenser with the resulting lowest condenser pressure possible. This operating scenario typically provides a better plant heat rate than lowering the auxiliary power requirements with a resulting increase in condenser back pressure.

As an example, for every 0.1 in. Hg increase in condenser pressure for A.B. Brown Unit 1, the turbine generator output is expected to decrease by about 0.3 to 0.8 MW, according to past experience. Decreasing circulating water flow by 5 percent will decrease the circulating water pump auxiliary load by about 0.3 to 0.4 MW, and the condenser pressure is expected to increase by more than 0.2 in. Hg for the vast majority of operating scenarios and unit loads, especially during the warmer months, creating a significant loss in turbine generator output, more so than the gains that would be seen in modulating circulating water pump flow.

For reference, the impact on the circulating water pump power consumption at lower pump speeds and flow rates can be estimated utilizing the pump affinity laws. Table 3-13 summarizes the rated circulating water pump design conditions, as provided in the A.B. Brown Unit 1 documentation, and the reduced operating pump brake horsepower at a 1 percent and a 5 percent reduction in circulating water flow rate per pump. Estimations of pump speed have also been provided if these pumps were to be equipped with VFD systems.

**Table 3-13 Predicted Circulating Water Pump Operating Conditions at Reduced Flows**

| | RATED OPERATING CONDITIONS | 1% REDUCED FLOW OPERATING CONDITIONS | 5% REDUCED FLOW OPERATING CONDITIONS |
|---|---|---|---|
| Flow, gpm | 65,000 | 64,350 | 61,750 |
| Total head, ft | 84 | 82.3 | 75.8 |
| Pump brake horsepower, hp | 1,558 | 1,512 | 1,336 |
| Pump speed, rpm | 514 | 509 | 488 |

gpm – gallons per minute; ft – feet; hp – horsepower; rpm – revolutions per minute
Note: The above operating data is for one of two (2x50%) circulating water pumps.

This is not strictly true for systems with a high static head, and the savings could be somewhat less when the pump speed differences are fully accounted for. Detailed pump modeling should be conducted to improve the accuracy of these predictions as part of a next-phase effort.

The only scenarios that Black & Veatch has assessed where the installation of VFD systems on circulating water pumps has been beneficial is with once-through circulating water systems that use river or lake water that cools during winter months and there is no concern of freezing. Since the heat rejection system on A.B. Brown Unit 1 involves the use of a cooling tower, the installation of VFD systems on the circulating water pumps does not appear to be cost effective.

Lastly, the costs of adding VFDs to large motors is significant. The estimated costs for adding VFDs to the two Unit 1 circulating water pumps is $2,100,000.

#### 3.4.1.3 Cooling Tower Fans

Cycle heat rejection is via a seven-cell mechanical draft cross-flow cooling tower with seven mechanical draft cooling tower fans. Each cooling tower fan is driven by a 200 hp motor equipped with a VFD system to control both de-icing and to control condenser backpressure. As the cooling tower fans are already equipped with VFDs, the fans will not be investigated further.

#### 3.4.1.4 Large Draft Fans

According to available information and operating data, the A.B. Brown Unit 1 ID fan auxiliary power consumption benefit is estimated to be a total of 3.3 MW for both fans at full load and 4.1 MW for both fans at low load on the basis of the density of the inlet air to the fans of 0.0473 pounds per cubic foot (lbm/ft$^3$) at 322° F.

The estimated furnish and erect price for a VFD system for the A.B. Brown Unit 1 ID fans includes the VFD, VFD enclosure, enclosure foundations, fan coupling, new power cabling and any new raceway required, engineering, installation, and contingency. If there is limited available space immediately around the rotating equipment, the installation of VFD systems would not be affected because the VFD equipment can be placed virtually anywhere on the plant site and still provide adequate, clean power to the equipment.

The evaluated impacts of this project are as follows:

***VFD Deployment for ID Fans***

| | |
|---|---|
| Total Installed Capital Cost: | $2,900,000 for both fans |
| Auxiliary Power Reduction: | Full load: 3.3 MW<br>Low Load: 4.1 MW |
| Heat Rate (efficiency) improvement: | Full Load: 1.4%<br>Low Load: 3.0% |

Estimated Additional Annual O&M Cost: $2,000 per unit

The A.B. Brown Unit 1 FD fan auxiliary power consumption benefit is estimated to be a total of 0.85 MW for both fans at full load and 0.7 MW for both fans at low load on the basis of the density of the inlet air to the fans of 0.0726 pounds per cubic foot (lbm/ft$^3$) at 74° F.

The estimated furnish and erect price for a VFD system for the A.B. Brown Unit 1 FD fans includes VFD, VFD enclosure, enclosure foundations, fan coupling, new power cabling and any new raceway required, engineering, installation, and contingency. If there is limited available space immediately around the rotating equipment, the installation of VFD systems would not be affected because the VFD equipment can be placed virtually anywhere on the plant site and still provide adequate, clean power to the equipment.

The evaluated impacts of this project are as follows:

***VFD Deployment for FD Fans***

| | |
|---|---|
| Total Installed Capital Cost: | $2,000,000 for both fans |
| Auxiliary Power Reduction: | Full load: 0.85 MW<br>Part load: 0.7 MW |
| Heat Rate (efficiency) Improvement: | Full Load: 0.37%<br>Low Load: 0.54% |

Estimated Additional Annual O&M Cost: $2,000 per unit

### 3.4.2 A.B. Brown Unit 2 Variable Frequency Drive Upgrades

The A.B. Brown Unit 2 rotating equipment evaluated for the possible addition of VFD systems in this study include the boiler feed pumps, circulating water pumps, cooling tower fans, and the large draft fans for handling combustion air and flue gas.

After discussion with Vectren personnel, the best potential application for further VFD upgrades appears to be the ID fans.

#### 3.4.2.1 Boiler Feed Pumps

The A.B. Brown Unit 2 boiler feed pump is a turbine driven feed pump that already provides high efficiency variable speed capability. The installation of a VFD system on the boiler feed pump will therefore not be evaluated further.

#### 3.4.2.2 Circulating Water Pumps

The circulating water system includes two 50 percent capacity vertical turbine circulating water pumps driven by 1,750 hp motors. The impellers on the circulating water pumps were replaced with new impellers in 2008. According to A.B. Brown Unit 2 operating data provided by Vectren, during the period of January 2017 through September of 2018, the unit was off-line at times and operated as high as 100 percent load. Excluding any hours when the unit was off-line or appeared to be ramping up to load, the operating data indicate that the unit operated between 40 percent load and 60 percent load for approximately 44 percent of the time, a significant period where Unit 2 was operating at a relatively significant part load. The operating data also indicate that the unit operated between 60 percent load and 80 percent load for approximately 19 percent of the time and between 80 percent load and 100 percent load for approximately 37 percent of the time. The addition of VFDs on the circulating water pumps would allow variation in pump operating speed and circulating water flow over the operating load ranges experienced during normal operation of the unit. However, variations in pump speed and circulating water flow can have a significant impact on condenser back pressure.

Past studies performed by Black & Veatch on similar coal fired plants have shown that condenser pressure has a higher impact on plant heat rate than changes in auxiliary power associated with the circulating water system (i.e., circulating water pumps and cooling tower fans). These studies have shown that, for the majority of time, it is more advantageous to operate the circulating water pumps and cooling tower fans at full capacity to maintain the lowest temperature circulating water to the condenser with the resulting lowest condenser pressure possible. This operating scenario by and large provides a better plant heat rate than lowering the auxiliary power requirements with a resulting increase in condenser back pressure.

As an example, for every 0.1 in. Hg increase in condenser pressure for A.B. Brown Unit 2, the turbine generator output is expected to decrease by about 0.3 to 0.8 MW, according to past experience. Decreasing circulating water flow by 5 percent will decrease the circulating water pump auxiliary load by about 0.3 to 0.4 MW, and the condenser pressure is expected to increase by more than 0.2 in. Hg for the vast majority of operating scenarios and unit loads, especially during the warmer months, creating a significant loss in turbine generator output, more so than the gains that would be seen in modulating circulating water pump flow.

For reference, the impact on the circulating water pump power consumption at lower pump speeds and flow rates can be estimated utilizing the pump affinity laws. Table 3-14 summarizes the rated circulating water pump design conditions, as provided in the A.B. Brown Unit 2 documentation, and the reduced operating pump brake horsepower at a 1 percent and a 5 percent reduction in circulating water flow rate per pump. Estimations of pump speed have also been provided if these pumps were to be equipped with VFD systems.

**Table 3-14 Predicted Circulating Water Pump Operating Conditions at Reduced Flows**

| | RATED OPERATING CONDITIONS | 1% REDUCED FLOW OPERATING CONDITIONS | 5% REDUCED FLOW OPERATING CONDITIONS |
|---|---|---|---|
| Flow, gpm | 65,000 | 64,350 | 61,750 |
| Total head, ft | 84 | 82.3 | 75.8 |
| Pump brake horsepower, hp | 1,558 | 1,512 | 1,336 |
| Pump speed, rpm | 514 | 509 | 488 |
| Note: The above operating data is for one of two (2x50%) circulating water pumps. | | | |

This is not strictly true for systems with a high static head, and the savings could be somewhat less when the pump speed differences are fully accounted for. Detailed pump modeling should be conducted to improve the accuracy of these predictions as part of a next-phase effort.

The only scenarios that Black & Veatch has assessed where the installation of VFD systems on circulating water pumps has been beneficial is with once-through circulating water systems that use river or lake water that cools during winter months and there is no concern of freezing. Since the heat rejection system on A.B. Brown Unit 2 involves the use of a cooling tower, the installation of VFD systems on the circulating water pumps does not appear to be cost effective.

Lastly, the costs of adding VFDs to large motors is significant. The estimated costs for adding VFDs to the two Unit 2 circulating water pumps is $2,100,000.

#### 3.4.2.3 Cooling Tower Fans

Cycle heat rejection is via a seven-cell mechanical draft cross-flow cooling tower with seven mechanical draft cooling tower fans. Each cooling tower fan is driven by a 200 hp motor equipped with a VFD system. As the cooling tower fans are already equipped with VFDs, the fans will not be investigated further.

#### 3.4.2.4 Large Draft Fans

According to available information and operating data, the A.B. Brown Unit 2 ID fan auxiliary power consumption benefit is estimated to be a total of 1.7 MW for both fans at full load and 2.3 MW on the basis of the density of the inlet air to the fans of 0.048 lbm/ft$^3$ at 321° F.

The evaluated impacts of this project are as follows:

***VFD Deployment for ID Fans***

| | |
|---|---|
| Total Installed Capital Cost: | \$2,900,000 for both fans |
| Auxiliary Power Reduction: | Full load: 1.7 MW |
| | Part Load: 2.3 MW |
| Heat Rate (efficiency) improvement | Full Load: 0.73% |
| | Low Load: 1.7% |

Estimated Additional Annual O&M Cost: \$2,000 per unit

The estimated furnish and erect price for a variable frequency drive system for the A.B. Brown Unit 2 ID fans includes VFD, VFD enclosure, enclosure foundations, fan coupling, new power cabling and any new raceway required, engineering, installation, and contingency. If there is limited available space immediately around the rotating equipment, the installation of VFD systems would not be affected because the VFD equipment can be placed virtually anywhere on the plant site and still provide adequate, clean power to the equipment.

The Brown Unit 2 FD fan auxiliary power consumption benefit is estimated to be a total of 0.3 MW for both fans at full load and 0.45 MW for both fans at low load on the basis of the density of the inlet air to the fans of 0.0726 pounds per cubic foot (lbm/ft$^3$) at 74° F.

The estimated furnish and erect price for a VFD system for the Brown Unit 2 FD fans includes VFD, VFD enclosure, enclosure foundations, fan coupling, new power cabling and any new raceway required, engineering, installation, and contingency. If there is limited available space immediately around the rotating equipment, the installation of VFD systems would not be affected because the VFD equipment can be placed virtually anywhere on the plant site and still provide adequate, clean power to the equipment.

The evaluated impacts of this project are as follows:

***VFD Deployment for FD Fans***

| | |
|---|---|
| Total Installed Capital Cost: | \$2,000,000 for both fans |
| Auxiliary Power Reduction: | Full load: 0.3 MW |
| | Part load: 0.45 MW |
| Heat Rate (efficiency) improvement | Full Load: 0.13% |
| | Low Load: 0.34% |

Estimated Additional Annual O&M Cost: \$2,000 per unit

### 3.4.3 F.B. Culley Unit 2 Variable Frequency Drive Upgrades

The F.B. Culley Unit 2 rotating equipment evaluated for the possible addition of VFD systems in this study include the boiler feed pumps, circulating water pumps, and the large draft fans for handling combustion air and flue gas.

After discussion with Vectren personnel, the best potential application for further VFD upgrades appears to be the circulating water pumps.

#### 3.4.3.1 Boiler Feed Pumps

F.B. Culley Unit 2 includes one 100 percent capacity motor driven boiler feed pumps. The pump is driven by a 2,500 hp single-speed electric motor, which indicates that this system is amenable to a VFD deployment. The boiler feed pump has a design capacity of 1,980 gpm. Feedwater flow at full load is 1,550 gpm and 960 gpm at low load.

**Table 3-15 Boiler Feed Water Pump Operating Conditions**

| | RATED OPERATING CONDITIONS | FULL LOAD | LOW LOAD | FULL LOAD WITH VFD | LOW LOAD WITH VFD |
|---|---|---|---|---|---|
| Flow, gpm | 1,980 | 1,550 | 960 | 1,550 | 960 |
| Total head, ft | 3,980 | 4,375 | 4,550 | 3,700 | 3,307 |
| Pump brake horsepower, hp | 2,388 | 2,146 | 1,690 | 1,771 | 1,133 |
| Pump speed, rpm | 3,750 | 3,750 | 3,750 | 3,310 | 3,050 |

The evaluated impacts of this project are as follows:

***VFD Deployment for Boiler Feed Pump***

Total Installed Capital Cost: $600,000

Auxiliary Power Reduction: Full load: 0.3 MW
Part load: 0.4 MW

Heat Rate (efficiency) improvement 0.6%

Estimated Additional Annual O&M Cost: $2,000 per unit

#### 3.4.3.2 Circulating Water Pumps

Unit cooling is provided via a once-through circulating water system utilizing river water as the cooling water supply. Circulating water pump installation is two 50 percent capacity vertical turbine wet pit circulating water pumps. The pumps are driven by 450 hp motors. The circulating water pumps take suction directly from the Ohio River. According to F.B. Culley Unit 2 operating data provided by Vectren, during the period of January 2017 through January of 2019, the unit was off-line at times and operated as high as 100 percent load. Excluding any hours when the unit was off-line or appeared to be ramping up to load, the operating data indicate that the unit operated between 40 percent load and 60 percent load for approximately 45 percent of the time, a significant period where Unit 2 was operating at a relatively significant part load. The operating data also indicate that the unit operated between 60 percent load and 80 percent load for approximately 23 percent of the time and between 80 percent load and 100 percent load for approximately 32 percent of the time. The addition of VFDs on the circulating water pumps would allow variation in pump operating speed and circulating water flow over the operating load ranges experienced during normal operation of the unit. However, variations in pump speed and circulating water flow can have a significant impact on condenser back pressure.

Past studies performed by Black & Veatch on similar coal fired plants have shown that condenser back pressure has a higher impact on plant heat rate than changes in auxiliary power associated with the circulating water system (i.e., circulating water pumps and cooling tower fans). However, Black & Veatch has assessed some coal fired plants where the installation of VFD systems on circulating water pumps has been beneficial when unit cooling was provided by once-through circulating water systems using river or lake water. The impact is particularly beneficial during winter months when the water supply is cold and there is no concern of freezing.

For reference, the impact on the circulating water pump power consumption at lower pump speeds and flow rates can be estimated utilizing the pump affinity laws. Table 3-16 summarizes the rated circulating water pump design conditions, as provided in the F.B. Culley Unit 2 documentation, and the reduced operating pump brake horsepower at a 1 percent and a 5 percent reduction in circulating water flow rate per pump. Estimations of pump speed have also been provided if these pumps were to be equipped with VFD systems.

**Table 3-16 Predicted Circulating Water Pump Operating Conditions at Reduced Flows**

| | RATED OPERATING CONDITIONS | 1% REDUCED FLOW OPERATING CONDITIONS | 5% REDUCED FLOW OPERATING CONDITIONS |
|---|---|---|---|
| Flow, gpm | 34,920 | 33,947 | 32,576 |
| Total head, ft | 43.7 | 42.8 | 39.4 |
| Pump brake horsepower, hp | 443 | 430 | 380 |
| Pump speed, rpm | 505 | 500 | 480 |
| Note: The above operating data is for one of two (2x50%) circulating water pumps. | | | |

This is not strictly true for systems with a high static head, and the savings could be somewhat less when the pump speed differences are fully accounted for. Detailed pump modeling should be conducted to improve the accuracy of these predictions as part of a next-phase effort.

Variations in pump speed and circulating water flow can have a significant impact on condenser pressure, particularly when the reduced speed and corresponding decrease in flow result in an increased circulating water temperature to the unit. As an example, for every 0.1 in. Hg increase in condenser pressure for F.B. Culley Unit 2, the turbine generator output is expected to decrease by about 0.1 to 0.5 MW, according to past experience. Decreasing circulating water flow by 5 percent will decrease the circulating water pump auxiliary load by about 0.09 to 0.1 MW, and the condenser pressure is expected to increase by more than 0.2 in. Hg for the vast majority of operating scenarios and unit loads, especially during the warmer months, creating a significant loss in turbine generator output, more so than the gains that would be seen in modulating circulating water pump flow.

However, when unit cooling is provided by once-through circulating water systems using river water, such as the F.B. Culley Unit 2, the water supply can be provided with little day-to-day variation in temperature. This is particularly beneficial during the winter months when the water supply is very cold and any reduction in circulating water pump speed, with the corresponding decrease in flow, can have little effect on the condenser pressure.

Evaluating the impact to condenser pressure and auxiliary load by the addition of VFDs to circulating water pumps on units with once-through cooling is an involved assessment. It is necessary to determine a temperature profile of the river water over at least one annual operating period since the cooling water temperature directly impacts condenser back pressure. Additionally, the circulating water flow rate impacts heat transfer, which also directly impacts condenser back pressure. The assessment basically requires creating condenser back pressure curves as a function of the two different variables but must also consider the river water temperature profile as a function of time. The assessment would then identify the auxiliary power savings on the basis of the operating profile of the VFD speed controlled circulating water pumps. Still another concern is that low water flow velocities can cause silting and drop-out of suspended particles in piping.

The costs of adding VFDs to large motors is significant, but in the case of once-through cooling water systems, the investment can prove beneficial. The estimated costs for adding VFDs to the two Unit 2 circulating water pumps is $900,000.

#### 3.4.3.3 Large Draft Fans

Vectren personnel informed Black & Veatch that F.B. Culley Unit 2 has already installed VFDs on the ID fans, which are typically the motors that can gain the most HRI benefit.

The Culley Unit 2 FD fan auxiliary power consumption benefit is estimated to be a total of 0.3 MW for both fans at full load and 0.3 MW for both fans at low load on the basis of the density of the inlet air to the fans of 0.0727 pounds per cubic foot (lbm/ft$^3$) at 74° F.

The estimated furnish and erect price for a VFD system for the Culley Unit 2 FD fans includes VFD, VFD enclosure, enclosure foundations, fan coupling, new power cabling and any new raceway required, engineering, installation, and contingency. If there is limited available space immediately around the rotating equipment, the installation of VFD systems would not be affected because the VFD equipment can be placed virtually anywhere on the plant site and still provide adequate, clean power to the equipment.

The evaluated impacts of this project are as follows:

***VFD Deployment for FD Fans***

| | |
|---|---|
| Total Installed Capital Cost: | $2,000,000 for both fans |
| Auxiliary Power Reduction: | Full load: 0.3 MW |
| | Low load: 0.3 MW |
| Heat Rate (efficiency) improvement: | Full Load: 0.34% |
| | Low Load: 0.57% |

Estimated Additional Annual O&M Cost: $2,000 per unit

### 3.4.4 F.B. Culley Unit 3 Variable Frequency Drive Upgrades

The F.B. Culley Unit 3 rotating equipment evaluated for the possible addition of VFD systems in this study include the boiler feed pumps, circulating water pumps, and the large draft fans for handling combustion air and flue gas.

After discussion with Vectren personnel, the best potential application for further VFD upgrades appears to be the circulating water pumps.

#### 3.4.4.1 Boiler Feed Pumps

The F.B. Culley Unit 3 boiler feed pump is a turbine driven feed pump that already provides high efficiency variable speed capability. The installation of a VFD system on the boiler feed pump will therefore not be evaluated further.

#### 3.4.4.2 Circulating Water Pumps

Unit cooling is provided via a once-through circulating water system utilizing river water as the cooling water supply. The circulating water system includes two 50 percent capacity vertical turbine circulating water pumps driven by electric motors. The circulating water pumps take suction directly from the Ohio River. According to F.B. Culley Unit 3 operating data provided by Vectren, during the period of January 2017 through June of 2018, the unit was off-line at times and operated as high as 100 percent load. Excluding any hours when the unit was off-line or appeared to be ramping up to load, the operating data indicate that the unit operated between 60 percent load and 80 percent load for approximately 14 percent of the time and between 80 percent load and 100 percent load for approximately 60 percent of the time. The operating data also indicate that the unit operated at less than 60 percent load for approximately 26 percent of the time. The addition of VFDs on the circulating water pumps would allow variation in pump operating speed and circulating water flow over the operating load ranges experienced during normal operation of the unit. However, variations in pump speed and circulating water flow can have a significant impact on condenser back pressure.

Past studies performed by Black & Veatch on similar coal fired plants have shown that condenser back pressure has a higher impact on plant heat rate than changes in auxiliary power associated with the circulating water system (i.e., circulating water pumps and cooling tower fans). However, Black & Veatch has assessed some coal fired plants where the installation of VFD systems on circulating water pumps has been beneficial when unit cooling was provided by once-through circulating water systems using river or lake water. The impact is particularly beneficial during winter months when the water supply is cold and there is no concern of freezing.

For reference, the impact on the circulating water pump power consumption at lower pump speeds and flow rates can be estimated utilizing the pump affinity laws. Table 3-17 summarizes the rated circulating water pump design conditions, as provided in the Culley Unit 3 documentation, and the reduced operating pump brake horsepower at a 1 percent and a 5 percent reduction in circulating water flow rate per pump. Estimations of pump speed have also been provided if these pumps were to be equipped with VFD systems.

**Table 3-17 Predicted Circulating Water Pump Operating Conditions at Reduced Flows**

| | RATED OPERATING CONDITIONS | 1% REDUCED FLOW OPERATING CONDITIONS | 5% REDUCED FLOW OPERATING CONDITIONS |
|---|---|---|---|
| Flow, gpm | 69,000 | 68,310 | 65,550 |
| Total head, ft | 57 | 55.9 | 51.4 |
| Pump brake horsepower, hp | 1170 | 1135 | 1,003 |
| Pump speed, rpm | 300 | 297 | 285 |
| Note: The above operating data is for one of two (2x50%) circulating water pumps. | | | |

Variations in pump speed and circulating water flow can have a significant impact on condenser pressure, particularly when the reduced speed and corresponding decrease in flow result in an increased circulating water temperature to the unit. As an example, for every 0.1 in. Hg increase in condenser pressure for F.B. Culley Unit 3, the turbine generator output is expected to decrease by about 0.4 to 0.9 MW, according to past experience. Decreasing circulating water flow by 5 percent will decrease the circulating water pump auxiliary load by about 0.25 MW, and the condenser pressure is expected to increase by more than 0.2 in Hg for the vast majority of operating scenarios and unit loads, especially during the warmer months. This creates a significant loss in turbine generator output, more so than the gains that would be seen in modulating circulating water pump flow.

However, when unit cooling is provided by once-through circulating water systems using river water, such as the F.B. Culley Unit 3, the water supply can be provided with little day-to-day variation in temperature. This is particularly beneficial during the winter months when the water supply is very cold and any reduction in circulating water pump speed, with the corresponding decrease in flow, can have little effect on the condenser pressure.

Evaluating the impact to condenser pressure and auxiliary load by the addition of VFDs to circulating water pumps on units with once-through cooling is an involved assessment. It is necessary to determine a temperature profile of the river water over at least one annual operating period since the cooling water temperature directly impacts condenser back pressure. Additionally, the circulating water flow rate impacts heat transfer, which also directly impacts condenser back pressure. The assessment basically requires creating condenser back pressure curves as a function of the two different variables but must also consider the river water temperature profile as a function time. The assessment would then identify the auxiliary power savings on the basis of the operating profile of the VFD speed controlled circulating water pumps. Moreover, plant personnel have expressed concerns about silting problems due to low water velocity, which is already a known issue at the plant, where, extended periods of operation at low flows have led to silting in the condenser tubes and associated corrosion.

The costs of adding VFDs to large motors is significant, but in the case of once-through cooling water systems, the investment can prove beneficial. The estimated costs for adding VFDs to the two Unit 3 circulating water pumps is $2,100,000.

#### 3.4.4.3 Large Draft Fans

Vectren personnel informed Black & Veatch that F.B. Culley Unit 3 has already installed VFDs on the ID fans, which are typically the motors that can gain the most HRI benefit at a coal fired power plant.

The only other large rotating equipment identified for this F.B. Culley Unit 3 study that has the potential for significant HRI benefits from a VFD retrofit are the FD fans. The F.B. Culley Unit 3 FD fan auxiliary power consumption benefit is estimated to be a total of 0.6 MW for both fans at full load and 0.9 MW for both fans at low load on the basis of the density of the inlet air to the fans of 0.0727 pounds per cubic foot (lbm/ft$^3$) at 74° F.

The estimated furnish and erect price for a VFD system for the Culley Unit 3 FD fans includes VFD, VFD enclosure, enclosure foundations, fan coupling, new power cabling and any new raceway required, engineering, installation, and contingency. If there is limited available space immediately around the rotating equipment, the installation of VFD systems would not be affected because the VFD equipment can be placed virtually anywhere on the plant site and still provide adequate, clean power to the equipment.

The evaluated impacts of this project are as follows:

***VFD Deployment for FD Fans***

| | |
|---|---|
| Total Installed Capital Cost: | $2,000,000 for both fans |
| Auxiliary Power Reduction: | Full load: 0.6 MW |
| | Low load: 0.9 MW |
| Heat Rate (efficiency) improvement: | Full load: 0.23% |
| | Low Load: 0.69% |

Estimated Additional Annual O&M Cost: $2,000 per unit

## 3.5 BOILER FEED PUMP UPGRADES, REBUILDING, OR REPLACEMENT

The purpose of this project would be to reduce the energy consumed by the boiler feed pumps by exploring whether upgrades or repairs to the pump internal components, or replacement in kind with a new boiler feed pump would be warranted. As steam-driven boiler feed pumps are inherently much more efficient than any electric-driven boiler feed pumps, no analysis of a conversion to VFD use will be assessed on A.B. Brown Units 1 and 2, or Culley Unit 3.

### 3.5.1 A.B. Brown Unit 1 Boiler Feed Pumps

A.B. Brown 1 has one Pacific, 5 stage, Type BFIDS, Size 12" RHBK pump. The pump has a rated capacity of 4,400 gpm at 5,470 feet of head, 5,400 rpm, for 367 °F water. With the current data available, there is no indication that any significant improvement could be made to the overall unit heat rate by upgrading this pump. Discussions with one boiler feed pump retrofit vendor indicated that at best a 1-1.5% drive turbine efficiency could be realized, which would only translate to a very small efficiency improvement on a unit basis.

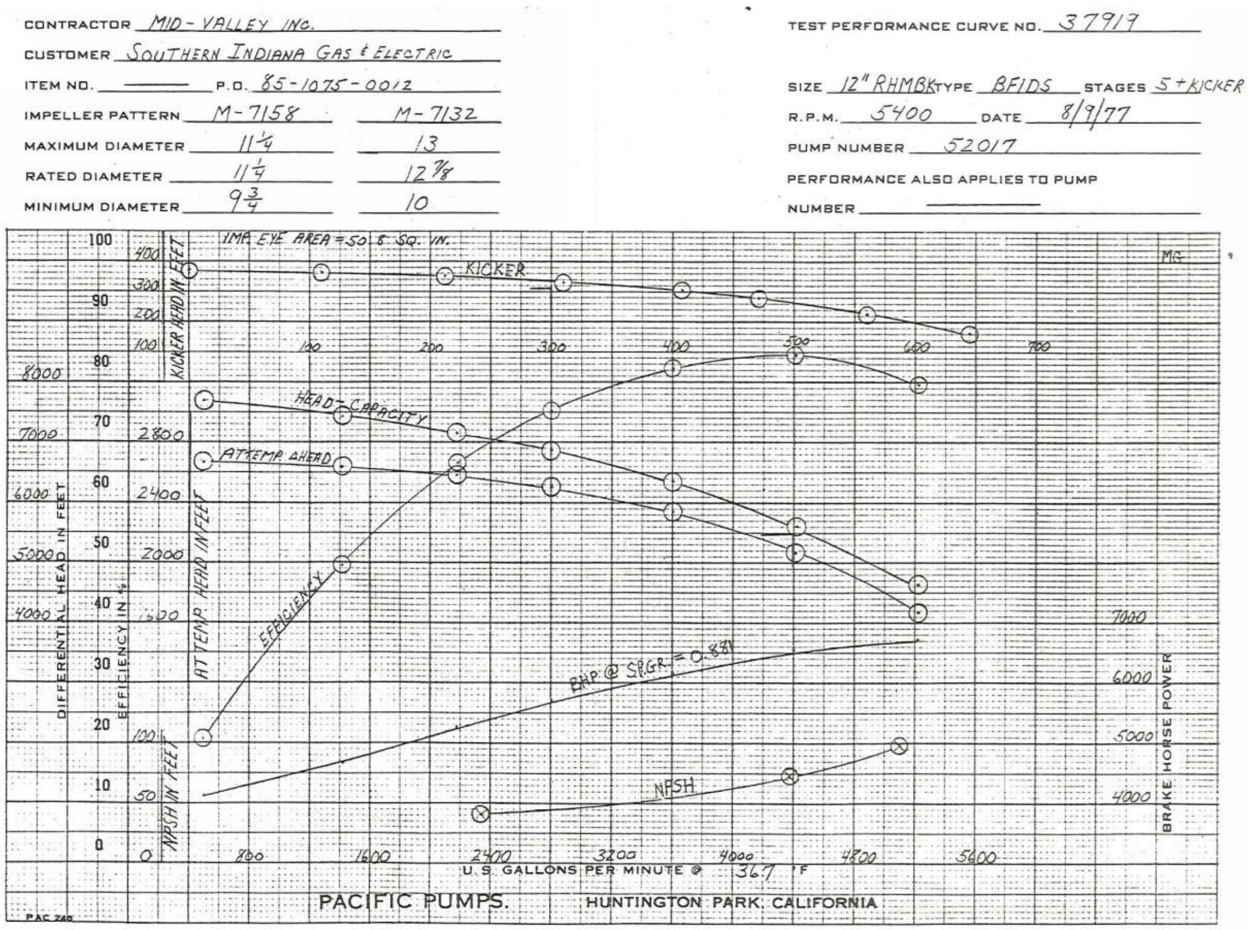



**Figure 3-9 Brown 1, Brown 2, and Culley 3 Boiler Feed Pump Performance Curve**

### 3.5.2 A.B. Brown Unit 2 Boiler Feed Pumps

A.B. Brown 2 has one Pacific, 5 stage, Type BFIDS, Size 12" RHBK pump. The pump has a rated capacity of 4,400 gpm at 5,470 feet of head, 5,400 rpm, for 367 °F water. As in the case of Unit 1, with the current data available, there is no indication that any significant improvement could be made to the overall unit heat rate by upgrading this pump. Discussions with one boiler feed pump retrofit vendor indicated that at best a 1-1.5% drive turbine efficiency could be realized, which would only translate to a very small efficiency improvement on a unit basis.

### 3.5.3 F.B. Culley Unit 2 Boiler Feed Pumps

F.B. Culley 2 has one Byron Jackson, double volute, 7 stage multiplex, Type DVMX, Size 6x8x11B pump. The pump has a rated capacity of 1,980 gpm at 3,980 feet of head, 3,750 rpm, and 220 °F water. The full load operating data set Black & Veatch was provided has the BFP operating with a discharge flow rate of 1,550 gpm and a total developed head of 3,980 ft. The pump curve shows that the pump should have a TDH of 4,380 ft. The actual developed head of the BFP is 9.2% less than that of the design curve. The pump no longer lies on the initial operating curve which suggest that degradation has occurred. Please see the section on VFD deployment for further information on upgrades that are possible for F.B. Culley Unit 2's boiler feed pump.

### 3.5.4 F.B. Culley Unit 3 Boiler Feed Pumps

F.B. Culley 3 has one Pacific, 5 stage, Type BFIDS, Size 12" RHBK pump. The pump has a rated capacity of 4,400 gpm at 5,470 feet of head, 5,400 rpm, for 367 °F water. With the current data available, there is no indication that any significant improvement could be made to the overall unit heat rate by upgrading this pump. Discussions with one boiler feed pump retrofit vendor indicated that at best a 1-1.5% drive turbine efficiency could be realized, which would only translate to a very small efficiency improvement on a unit basis.

## 3.6 UNIT NEURAL NETWORK DEPLOYMENT

The purpose of this project would be to tune the system to allow for the reduction of boiler outlet oxygen concentration without increasing $NO_X$ or carbon monoxide (CO) emissions. Adaptive neural net systems have the greatest effect when controlling air flow and fuel mixtures down to a fine level. The full benefits are realized only if the plant has adequate feedback signals to allow the neural net to sense changes made to the available controls. For instance, individual fuel and air controls at each burner provide tremendous levers for a neural net system; however, the effect of the levers is reduced if the neural net does not receive feedback about the air/fuel mixture through a grid of CO measurements.

### 3.6.1 A.B. Brown Unit 1 Neural Network Deployment

The unit has the ability to bias individual mills as well as compartmented windboxes. Each burner row has an independent windbox with a damper for air control on each end, but there is only manual secondary air adjustment at each individual burner. CO measurement is located at the outlet of the reheat section, but this requires regular maintenance for reliable operation.

Reducing excess oxygen levels in the boiler increases the boiler efficiency by reducing sensible heat losses, although in some cases, unburned carbon losses can be increased (but almost never more than the sensible heat losses are reduced). In addition, reducing excess oxygen levels improves the NPHR by reducing both FD and ID fan flow requirements and can also benefit emissions control systems performance. Still another benefit would be the ability to better control the balance of $O_2$ across the furnace, which is known to be a current concern.

For A.B. Brown Unit 1, the excess oxygen varies roughly from between 2 percent to 4.5 percent at gross output levels above 250 MW, with an average level approximating 3.0 to 3.3 percent. No online correlation of NPHR or boiler efficiency from distributed control system (DCS) system calculations was readily available from which to draw a plant-specific correlation, but from examining the plant air heater temperature data, boiler temperature data, and other factors, it was estimated by utilizing representative plant models within the EPRI Vista fuel quality impact model that reducing the excess oxygen would result in the following improvements to boiler efficiency and heat rate:

- 0.25 percent reduction in excess $O_2$: 0.10 percent gain in boiler efficiency, 0.23 percent improvement in net plant heat rate.
- 0.50 percent reduction in excess $O_2$: 0.21 percent gain in boiler efficiency, 0.43 percent improvement in net plant heat rate.
- 0.75 percent reduction in excess $O_2$: 0.27 percent gain in boiler efficiency, 0.60 percent improvement in net plant heat rate.

Utilization of a specific Vista model of A.B. Brown Unit 1 would result in improved heat rate benefit estimates and should be considered as a next-phase effort. Hypothetically, it would be assumed that a modest reduction in boiler excess oxygen would be possible; therefore, if the unit could lower boiler outlet oxygen concentration by approximately 0.25 percent, then the NPHR improvement would be about 0.23 percent. The effects on NPHR were not linear because they varied as a function of auxiliary power changes, as well as changes in steam temperatures, which were affected by reduced excess $O_2$ levels.

| | |
|---|---|
| Total Installed Capital Cost: | $500,000 |
| Heat Rate (efficiency) Improvement: | 0.23% |

### 3.6.2 A.B. Brown Unit 2 Neural Network Deployment

The unit has the ability to bias individual mills as well as compartmented windboxes. Each burner row has an independent windbox with a damper for air control on each end, but there is only manual secondary air adjustment at each individual burner. There is no valid CO measurement [4]; thus, the unit must be restricted to an arbitrary $O_2$ lower limit to avoid typical low oxygen combustion issues such as slagging and tube wastage.

Reducing excess oxygen levels in the boiler increases the boiler efficiency by reducing sensible heat losses, although in some cases, unburned carbon losses can be increased (but almost never more than the sensible heat losses are reduced). In addition, reducing excess oxygen levels

[4] Lack of a valid CO measurement would significantly hamper the ability of a neural network system to affect positive change in unit operations.

improves the NPHR by reducing both FD and ID fan flow requirements and can also benefit emissions control systems performance.

For A.B. Brown Unit 2, the excess oxygen varies roughly from between 2 percent to 4.5 percent at gross output levels above 250 MW, with an average level approximating 3.1 to 3.3 percent. No online correlation of NPHR or boiler efficiency from DCS system calculations was readily available from which to draw a plant-specific correlation, but from examining the plant air heater temperature data, boiler temperature data, and other factors, it was estimated by utilizing representative plant models within the EPRI Vista fuel quality impact model that reducing the excess oxygen would result in the following improvements to boiler efficiency and heat rate (these are the same as A.B. Brown Unit 1):

- 0.25 percent reduction in excess $O_2$: 0.10 percent gain in boiler efficiency, 0.23 percent improvement in net plant heat rate.
- 0.50 percent reduction in excess $O_2$: 0.21 percent gain in boiler efficiency, 0.43 percent improvement in net plant heat rate.
- 0.75 percent reduction in excess $O_2$: 0.27 percent gain in boiler efficiency, 0.60 percent improvement in net plant heat rate.

Utilization of a specific Vista model of Brown 2 would result in improved heat rate benefit estimates and should be considered as a next-phase effort. Hypothetically, it could be assumed that a modest reduction in boiler excess oxygen would be possible; therefore, if the unit could lower boiler outlet oxygen concentration by approximately 0.25 percent then the NPHR improvement would be about 0.23 percent. The effects on NPHR were not linear because they varied as a function of auxiliary power changes, as well as changes in steam temperatures, which were affected by reduced excess $O_2$ levels.

| | |
|---|---|
| Total Installed Capital Cost: | $500,000 |
| Heat Rate (efficiency) Improvement: | 0.23% |

### 3.6.3 F.B. Culley Unit 2 Neural Network Deployment

The unit has the ability to bias individual mills, and each burner has an air shroud that can be biased; fuel biasing is available at each burner. Also, there is no valid CO measurement; thus, the unit must be restricted to an arbitrary $O_2$ lower limit to avoid typical low oxygen combustion issues such as slagging and tube wastage.

Reducing excess oxygen levels in the boiler increases the boiler efficiency by reducing sensible heat losses, although in some cases, unburned carbon losses can be increased (but almost never more than the sensible heat losses are reduced). In addition, reducing excess oxygen levels improves the NPHR by reducing both FD and ID fan flow requirements and can also benefit emissions control systems performance.

The excess oxygen varies roughly from between 3.5 percent to 5.2 percent at gross output levels above 80 MW, with an average level approximating 4.3 percent. No online correlation of

NPHR or boiler efficiency from DCS system calculations was readily available from which to draw a plant-specific correlation, but from examining the plant air heater temperature data, boiler temperature data, and other factors, it was estimated by utilizing representative plant models within the EPRI Vista fuel quality impact model that reducing the excess oxygen would result in the following improvements to boiler efficiency and heat rate:

- 0.25 percent reduction in excess $O_2$: 0.15 percent gain in boiler efficiency, 0.26 percent improvement in net plant heat rate.
- 0.50 percent reduction in excess $O_2$: 0.29 percent gain in boiler efficiency, 0.47 percent improvement in net plant heat rate.
- 0.75 percent reduction in excess $O_2$: 0.43 percent gain in boiler efficiency, 0.62 percent improvement in net plant heat rate.

Utilization of a specific Vista model of F.B. Culley 2 would result in improved heat rate benefit estimates and should be considered as a next-phase effort. Hypothetically, it could be assumed that a modest reduction in boiler excess oxygen would be possible; therefore, if the unit could lower boiler outlet oxygen concentration by approximately 0.25 percent, then the NPHR improvement would be approximately 0.26 percent. The effects on NPHR were not linear because they varied as a function of auxiliary power changes, as well as changes in steam temperatures, which were affected by reduced excess $O_2$ levels.

| | |
|---|---|
| Total Installed Capital Cost: | $500,000 |
| Heat Rate (efficiency) Improvement: | 0.26% |

### 3.6.4 F.B. Culley Unit 3 Neural Network Deployment

The unit has the ability to bias individual mills, and each burner has an air shroud that can be biased; there is no fuel biasing available at each burner. Also, there is no valid CO measurement[5]; thus, the unit must be restricted to an arbitrary $O_2$ lower limit to avoid typical low oxygen combustion issues such as slagging and tube wastage.

Reducing excess oxygen levels in the boiler increases the boiler efficiency by reducing sensible heat losses, although in some cases, unburned carbon losses can be increased (but almost never more than the sensible heat losses are reduced). In addition, reducing excess oxygen levels improves the NPHR by reducing both FD and ID fan flow requirements and can also benefit emissions control systems performance. Plant personnel have commented that this could also help to control the $O_2$ balance across the furnace, which would yield better combustion control and help reduce slagging.

For F.B. Culley Unit 3, the excess oxygen varies roughly from between 2.5 percent to 4.2 percent at gross output levels above 270 MW, with an average level approximating 3.5 percent. No online correlation of net plant heat rate NPHR or boiler efficiency from DCS system calculations was

[5] Lack of a valid CO measurement would significantly hamper the ability of a neural network system to affect positive change in unit operations.

readily available to draw a plant-specific correlation, but from examining the plant air heater temperature data, boiler temperature data, and other factors, it was estimated by utilizing representative plant models within the EPRI Vista fuel quality impact model that reducing the excess oxygen would result in the following improvements to boiler efficiency and heat rate:

- 0.25 percent reduction in excess $O_2$: 0.13 percent gain in boiler efficiency, 0.25 percent improvement in net plant heat rate.
- 0.50 percent reduction in excess $O_2$: 0.24 percent gain in boiler efficiency, 0.46 percent improvement in net plant heat rate.
- 0.75 percent reduction in excess $O_2$: 0.32 percent gain in boiler efficiency, 0.62 percent improvement in net plant heat rate.

Utilization of a specific Vista model of F.B. Culley 3 would result in improved heat rate benefit estimates and should be considered as a next-phase effort. Hypothetically, it could be assumed that a modest reduction in boiler excess oxygen would be possible; therefore, if the unit could lower boiler outlet oxygen concentration by about 0.25 percent, then the NPHR improvement would be about 0.25 percent. The effects on NPHR were not linear because they varied as a function of auxiliary power changes, as well as changes in steam temperatures, which were affected by reduced excess $O_2$ levels.

| | |
|---|---|
| Total Installed Capital Cost: | $500,000 |
| Heat Rate (efficiency) Improvement: | 0.25% |

## 3.7 UNIT INTELLIGENT SOOTBLOWING DEPLOYMENT

The purpose of this project would be to reduce the required sootblowing flow by installing an integrated intelligent sootblowing (ISB) control system. This system would utilize heat flux sensors, hanger strain gauges, and process data to determine the areas needing to be cleaned. By cleaning only "dirty" areas, sootblowing flow would be reduced and tube life potentially extended.

### 3.7.1 A.B. Brown Unit 1 Intelligent Sootblowing Deployment

An ISB system will not be investigated for this unit because A.B. Brown Unit 1 already has ISB installed.

### 3.7.2 A.B. Brown Unit 2 Intelligent Sootblowing Deployment

An ISB system will not be investigated for this unit because A.B. Brown Unit 2 already has ISB installed.

### 3.7.3 F.B. Culley Unit 2 Intelligent Sootblowing Deployment

The plant uses air as the sootblowing media, but currently, no heat flux sensors or hanger strain gauges are installed. Sootblowing is currently based on operator observation, attemperation, and control operator judgement. In addition to current sootblower O&M, it is estimated that an ISB could reduce sootblowing by approximately 10 percent or greater.

| | |
|---|---|
| Total Installed Capital Cost: | $350,000 |
| Heat Rate (efficiency) Improvement: | 0.10% |

### 3.7.4 F.B. Culley Unit 3 Intelligent Sootblowing Deployment

An ISB system will not be investigated for this unit because F.B. Culley Unit 3 already has ISB installed.

## 3.8 IMPROVED O&M PRACTICES

The purpose of this project would be to improve O&M practices as they pertain to three particular areas of focus: heat rate improvement training, on-site appraisals for identifying additional heat rate improvements, and improved condenser cleaning strategies.

### 3.8.1 Heat Rate Improvement Training

Black & Veatch conducts heat rate awareness training, which covers the fundamentals of determining unit performance, how to use these metrics, and the operating conditions and decisions that impact unit efficiency and heat rate. The course includes numerous real-life case studies identified through years of monitoring and diagnostic work. This on-site course is typically 2.5 days and is primarily geared toward operators and engineers.

| | |
|---|---|
| Total Installed Capital Cost | $15,000/class (could cover multiple units and plants) |
| Heat Rate (efficiency) Improvement: | Unknown, although improved O&M practices at peer coal fired EGUs have claimed to result in net plant heat rate improvements of 0.1 to 0.5 percent in the first year of implementation |

### 3.8.2 On-Site Heat Rate Appraisals

On-site heat rate appraisals, mentioned as a BSER in the EPA ACE proposal, is left open to interpretation; indeed, the EPA was not able to provide suitable guidance for estimated ranges of capital cost or HRI. On-site heat rate appraisals are often conducted via a detailed assessment of controllable losses, especially those that can be reduced or eliminated by low-impact operations changes and equipment repairs and upgrades. This assessment utilizes a combination of a review and analysis of historical operations data, interviews with plant O&M personnel, review of past test and capability reports, a detailed study of the current fuel sources and fuel-related impacts upon the plant, discussions with plant management to understand the plant generation goals and objectives, and a reliability and maintenance history analysis.

Real-world examples of heat rate improvement projects resulting from on-site heat rate appraisals and audits include the following:

- Diagnosis of a cracked feedwater heater partition plate via analysis of online performance data, which resulted in a $12,000 monthly heat rate savings and 0.4 MW capacity improvement.
- Discovery of a failed reheat stop valve by analyzing reheat pressure swings over time, resulting in a $65,000 monthly heat rate improvement and 4 MW capacity improvement.
- An audit of terminal temperature difference (TTD) and drain cooler approach (DCA) temperature trends across a feedwater heater train at one power plant found that the highest-pressure feedwater heater emergency drain valve was leaking, with 50 percent of its flow returning to the condenser, rather than cascading to the next feedwater heater. This failure resulted in a heat rate loss of 53 Btu/kWh (about 0.5 percent and a net capacity loss of 2.5 MW.
- Testing of mill dirty air flows and coal flow balances at one power plant found that by rebalancing the flows on four mills to bring the coal and air flow deviation to within ± 10% (compared to the ± 30 percent it formerly operated at), coal unburned carbon heat losses decreased by 0.5 percent, which directly translated to an HRI of 0.5 percent. Moreover, burner-zone slagging was nearly eliminated by this change, resulting in significantly less use of sootblowing steam in the furnace wall blowers, which resulted in an additional long-term heat rate benefit of 0.1 percent (and a corresponding improvement in furnace wall tube life).
- Long-term analysis of subtle deviations in feedwater heater extraction lines revealed an internal line had failed, resulting in not only a $15,000 heat rate loss, but the potential for an unplanned outage because of debris in the heater.
- An analysis of 19 different truck coals supplied to a power plant found that not only were 7 of the coals unprofitable to burn, burning the worst coal resulted in a heat rate loss of more than 2 percent Moreover, this coal was responsible, in whole or in part, for the majority of the plant de-rates because of high-temperature sodium-based fouling, which cost the unit an additional 1.2 percent in heat rate on an annual basis because of the increased number of starts and stops from fouling-related outages.
- A long-term analysis of plant continuous emissions monitoring system (CEMS) data and motor amperage data found that a malfunctioning VFD controller in the coal handling system was responsible for incorrect blending of two different coals to meet the plant $SO_2$ limit, resulting in not only excess use of low-sulfur coal, but a loss of heat rate equating 0.6 percent on an annual basis.

Heat rate assessment is an ever-moving target, so while there is substantial benefit from a focused heat rate auditing and improvement program, long-term use of some type of performance and O&M monitoring system will provide the best overall heat rate improvement.

### 3.8.3 Improved Condenser Cleanliness Strategies

#### 3.8.3.1 A.B. Brown Unit 1 Improved Condenser Cleaning Strategies

Condenser performance problems can be caused by any combination of many factors: tube sheet fouling, tube fouling, high number of plugged tubes, circulating water flow issues, waterbox priming, air in-leakage, and poor steam cycle isolation to condenser. Generally, plant data can provide clear evidence of condenser performance problems, but the causes may be difficult to discern.

To determine condenser performance, an energy balance was calculated between the boiler and turbine cycle. Gross generation data allowed the calculation of a gross turbine cycle heat rate and condenser heat duty. The condenser design data and industry standard condenser performance calculations were used to determine the actual operating condenser performance and calculate the expected back pressure. This allowed a comparison between actual and expected condenser back pressure. The turbine OEM back pressure correction curve was employed to calculate a heat rate impact for the difference between actual and expected back pressure. For every hour of operation in the remaining data set, the heat rate impact in $/hour was calculated with an assumed fuel cost of $2.50/MBtu, actual generation, and assumed boiler efficiency.

Condenser performance was reviewed over 1.3 years of operating data. The timing covered two summers and one winter. Condenser performance was calculated across load and across seasons. The working data set began with 8,500 hours of data. Nearly 8,000 hours of data (93 percent) were considered good quality and used for analysis. The range of unit load for the data set spanned 120 MW to 270 MW gross load. Low load operation (less than 175 MW gross) comprised 56 percent of the generation while high loads (less than 240 MW gross) accounted for 31 percent operating data.

From summer 2017 to summer 2018, the hourly average heat rate impact for condenser back pressure showed a significant change across the 2018 spring outage. Condenser performance during 2017 showed very poor performance at low loads. The expected back pressure across load for A.B. Brown Unit 1 is shown by the red trace on Figure 3-10. Actual unit back pressure is shown by the blue trace on this figure. Actual back pressure never falls below 3.3 in. HgA when the unit drops load. This yielded a high heat rate impact on average of 84 Btu/kWh, with an associated fuel cost of $37.00/h.

Figure 3-10 shows a “floor” in actual back pressure (blue) around 3.5 in. HgA in 2017. As unit load goes down, the back pressure should follow the red trend.

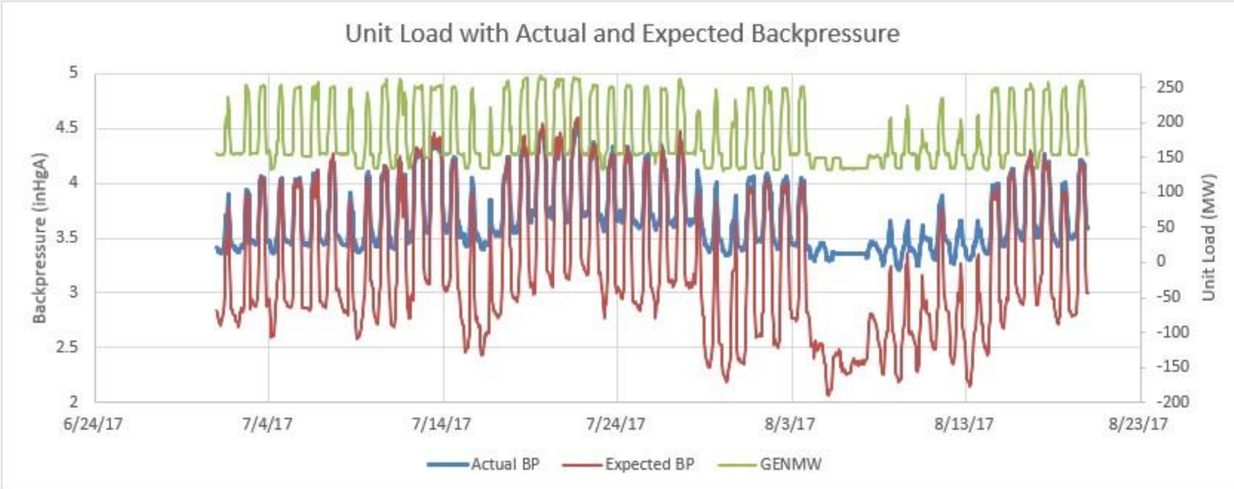



**Figure 3-10 Summer 2017 Backpressure vs Time (the actual is shown in red and blue is expected performance.)**

Figure 3-11 provides the perspective of actual and expected backpressure versus circulating water flow at low load. Back pressure deviations at low load for any unit can be significant.

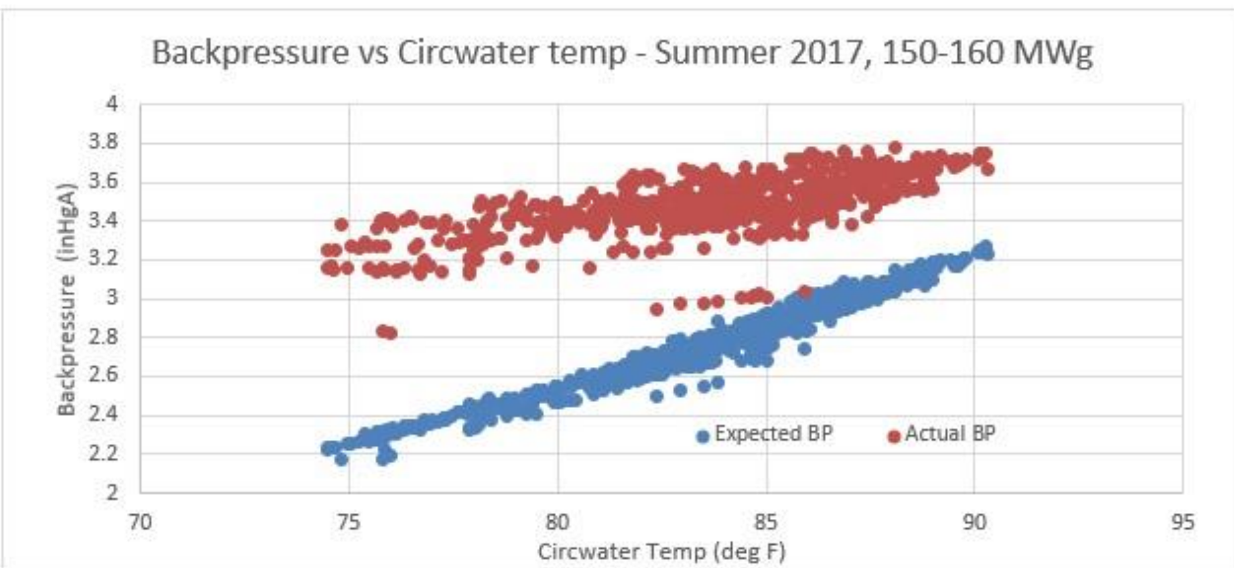



**Figure 3-11 Poor Condenser Performance at Low Load 2017**

When normal operation resumed in May of 2018, condenser performance looked good across load. The average heat rate impact from May to September of 2018 was estimated at 14 Btu/kWh, with a fuel-based heat rate cost of $5.7/h.

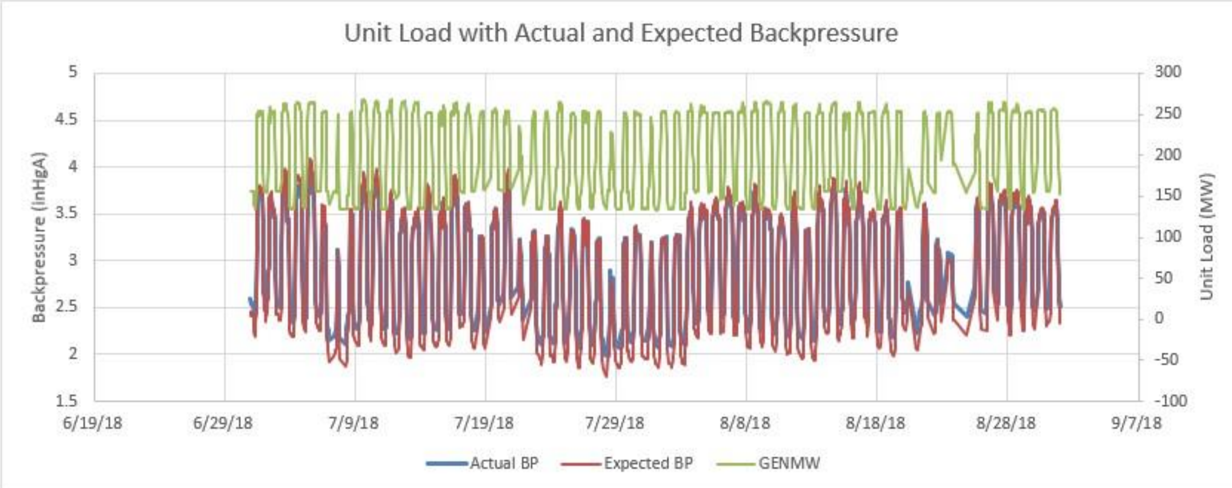



**Figure 3-12 2018 Post Outage Actual and Expected Backpressure Over Time**

On Figure 3-13 and 3-14, this actual back pressure is much closer to expected values in 2018. The remaining heat rate impact after the outage is likely to be due to the remaining gap in condenser performance at low load.

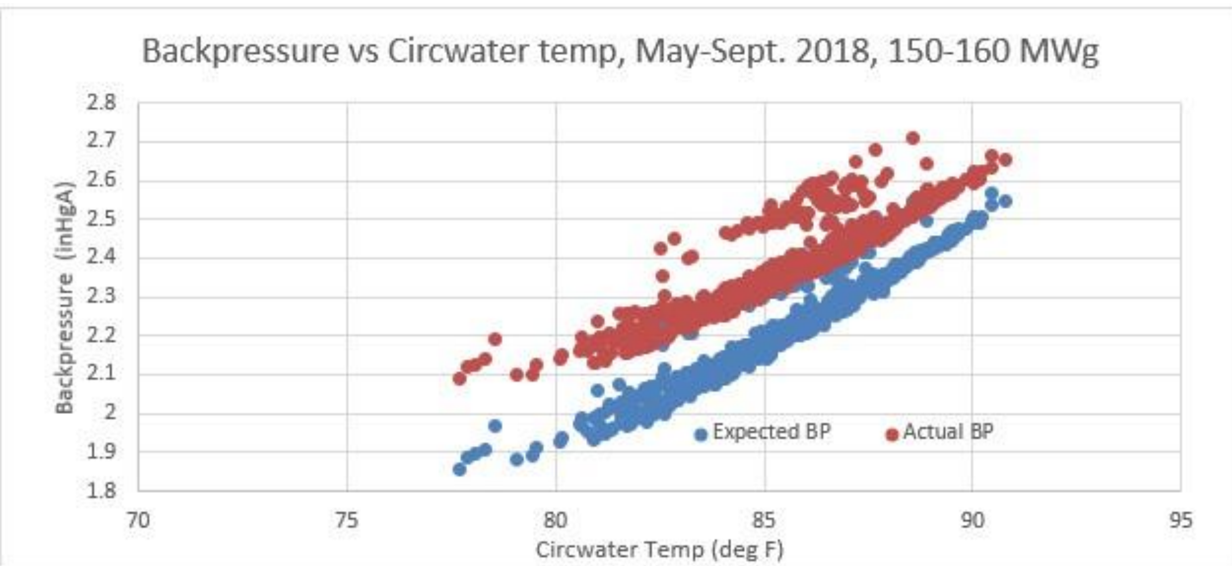



**Figure 3-13 2018 Post Outage Performance at Low Load vs Circulating Water Outlet Temperature**

Another noted change in condenser operation looking at both summers was calculated circulating water flow rate. Through the summer of 2017, average circulating water flow estimates were typically more than 25 percent below the design circulating water flow rate of 124,000 gpm. After the 2018 spring outage, estimated circulating water flow at full unit load was consistently 145,000 gpm, which is well above design. The estimated flow is sensitive to field measured circulating water temperatures and may need closer inspection.

The combination of these changes suggests significant air in-leakage or air removal improvements were made on the steam side, and water condenser cleaning yielded higher circulating water flows. According to plant personnel, they have repaired steam seal piping internal to the condenser neck. This issue has been appearing more regularly, and F.B. Culley 3 has had to perform similar repairs twice in the last two years. Across the span of the 15 months of operating data at full load, condenser performance was generally good, with cleanliness values at or above 70 percent as shown on Figure 3-14. However, because of low load performance problems, a fuel-based cost for 2017 operation is estimated to be $230,000 on an annual basis. Following the spring 2018 outage, the small deviation from expected condenser performance yields an estimated annual fuel cost of $35,000 on an annual basis. On the basis of the outage improvements seen in 2018, regularly scheduled maintenance and trending of performance should be sufficient to maintain good condenser performance.

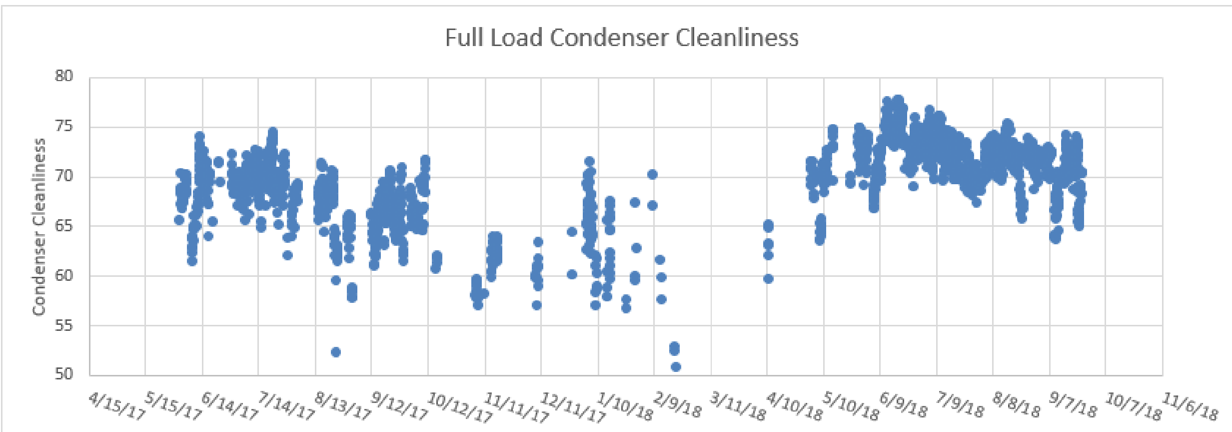



**Figure 3-14 Full Load Cleanliness Results Over Time**

### 3.8.3.2 A.B. Brown Unit 2 Improved Condenser Cleaning Strategies

Condenser performance was reviewed over 1.3 years of operating data. The timing covered two summers and one winter. Condenser performance was calculated across load and across seasons. In the process of reducing bad or suspicious data, 46 percent of the total data was removed. Nearly 6,000 hours of operating data ranging from 148 MW gross to full load was used for analysis.

Calculated results showed good performance for the condenser across load. It is suspected that measured back pressure readings may be biased low by approximately 0.2 to 0.3 in. HgA as actual back pressure consistently trended lower than expected and TTD at full load is unrealistically low (too good) at 3.5 to 5° F. The relationship between actual and expected back pressure versus circulating water temperature at constant load can be seen on Figure 3-15. As a result, condenser cleanliness values at full load consistently run greater than 90 percent and more than 100 percent at lower loads. Calculated circulating water flow rate is stable with estimated flows between

110,000 and 120,000 gpm. This is slightly below the design value of 124,000 gpm. Temperature rise across the condenser at full load runs 22° F versus design values of 20° F.

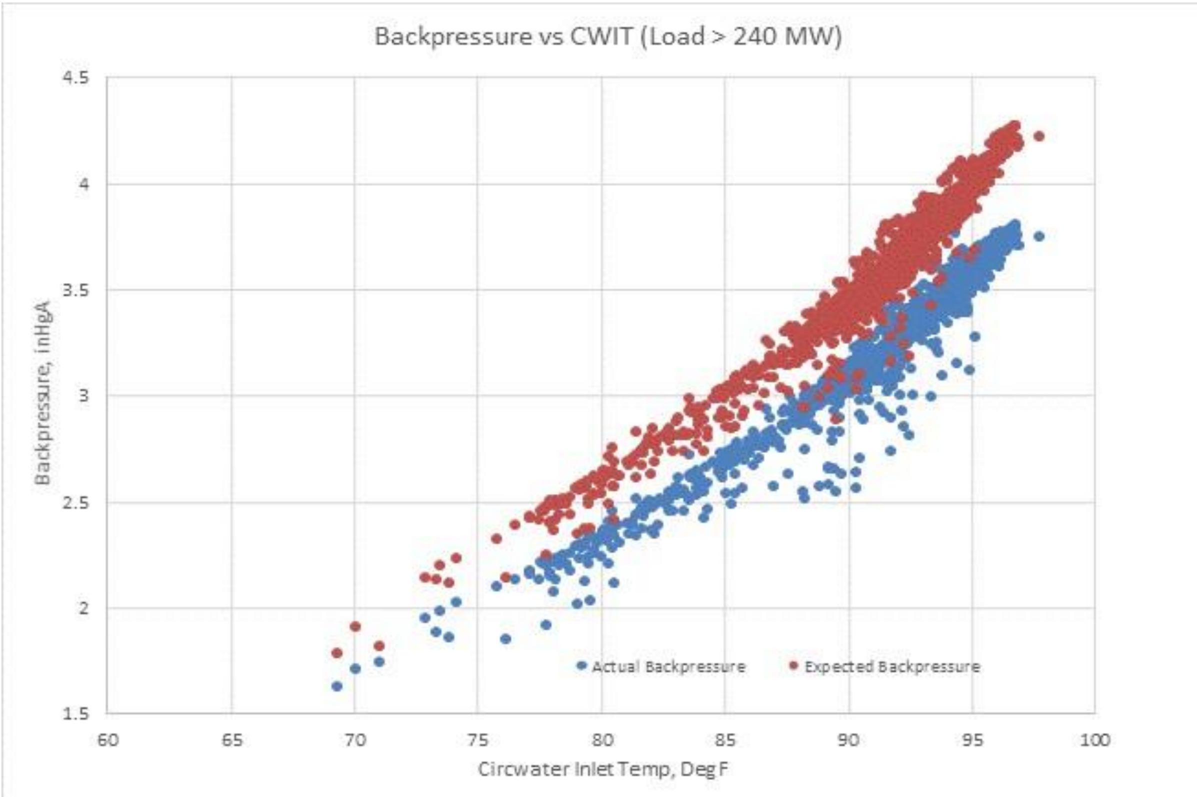



**Figure 3-15 Condenser Back Pressure Versus Circulating Water Temperature at High Load**

Generally, back pressure trended well across load during summer of 2017 and 2018. Separate trends of condenser performance behavior for summer 2017 and summer 2018 are provided on Figure 3-16 and Figure 3-17.

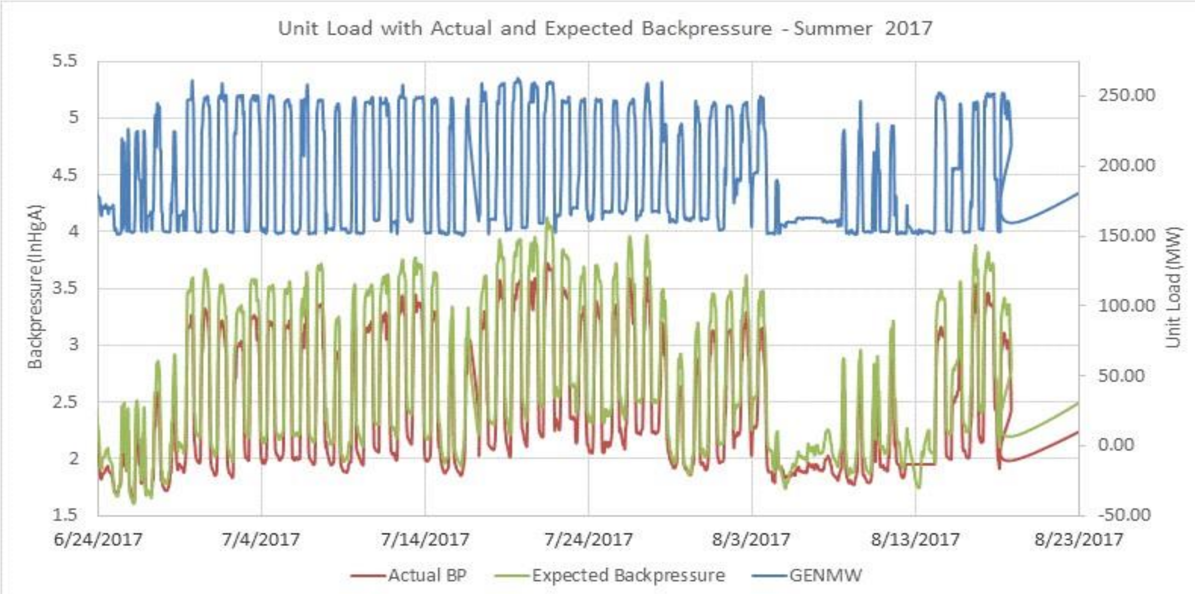



**Figure 3-16** **Condenser Performance Summer 2017 Across Load**

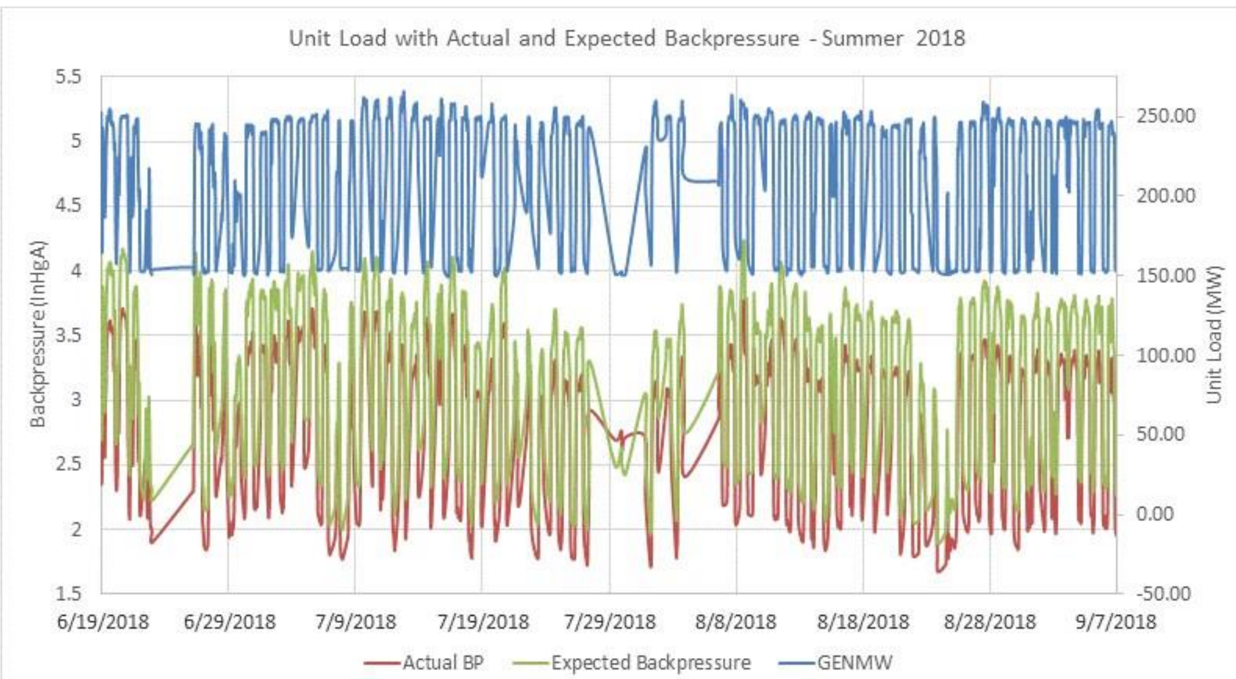



**Figure 3-17** **Condenser Performance Summer 2018 Across Load**

Because the actual back pressure trends better than expected, no heat rate penalty is associated with normal unit operation for the data reviewed. Regularly scheduled maintenance and tracking of performance to highlight changes should be enough to maintain good condenser performance. For improved fidelity and confidence in performance metrics, the measured back pressure indication should be checked for accuracy and proper installation. The addition of more circulating water temperature measurements leaving the condenser would also improve accuracy of results by better capturing temperature stratification in the return piping.

#### 3.8.3.3 F.B. Culley Unit 2 Improved Condenser Cleaning Strategies

For this study, 2 years of plant data were reviewed. Condenser performance was calculated across load and across seasons. Significant data reduction was necessary to eliminate offline or suspect data. This yielded more than 4,800 hours of operating data to characterize operation. In this data set, nearly 60 percent of the operating data were part load operation below 70 MW gross. Just over 30 percent of the data represented loads greater than 90 MW gross.

The hourly average heat rate impact of high condenser back pressure for Unit 2 is $42/h. Assuming the unit operates for 70 percent of a calendar year, this equates to a fuel cost of $257,000 per year. The average cleanliness value for Unit 2 is 28 percent. The highest achieved cleanliness values were in the low 50 percent range. The most significant observation with this analysis is shown on Figure 3-18 and is typical for the unit operation. Back pressure should have a strong load dependency. The Unit 2 back pressure data does not follow the expected pattern. The most likely cause of this behavior is significant air in-leakage or inadequate air removal system performance or limited capacity. Two additional factors are that Unit 2 relies upon steam jet air ejectors for air removal, and there is a suspected large air in-leakage around the turbine that has been present for years and has never been successfully resolved.

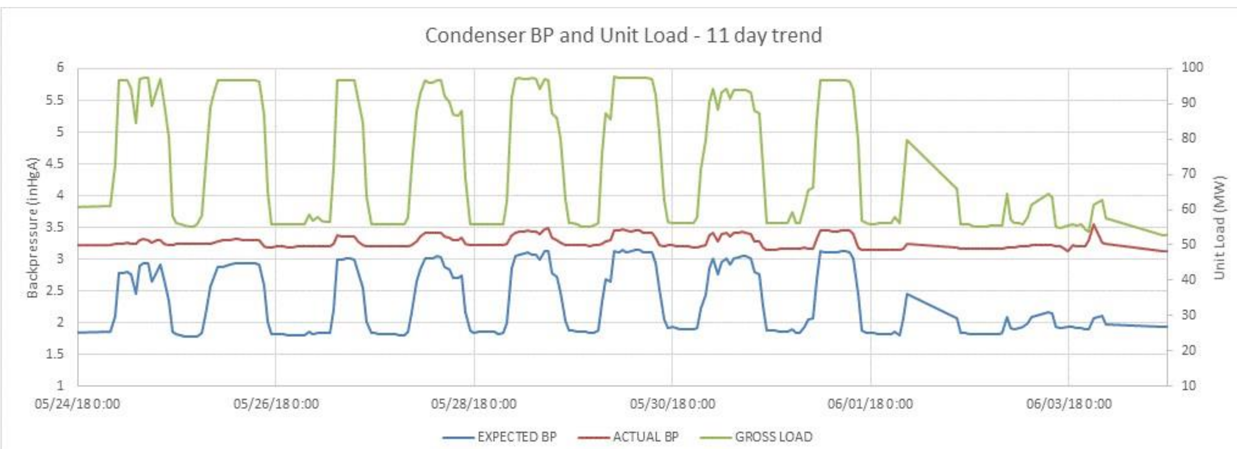



**Figure 3-18 Condenser Back Pressure Versus Time (11 Day Trend)**

The expected back pressure is calculated assuming no condenser tubes are plugged and cleanliness of 70 percent. Circulating water flow rate is calculated based on actual heat duty and circulating water temperature rise. Looking at full load operations across all season, there is a notable gap between actual and expected back pressure. This is shown on Figure 3-19, which illustrates back pressure versus circulating water temperature and versus time in Figure 3-20. The primary driver is expected to be the same issue of steam side air binding inhibiting lower backpressure at low circulating water temperatures.

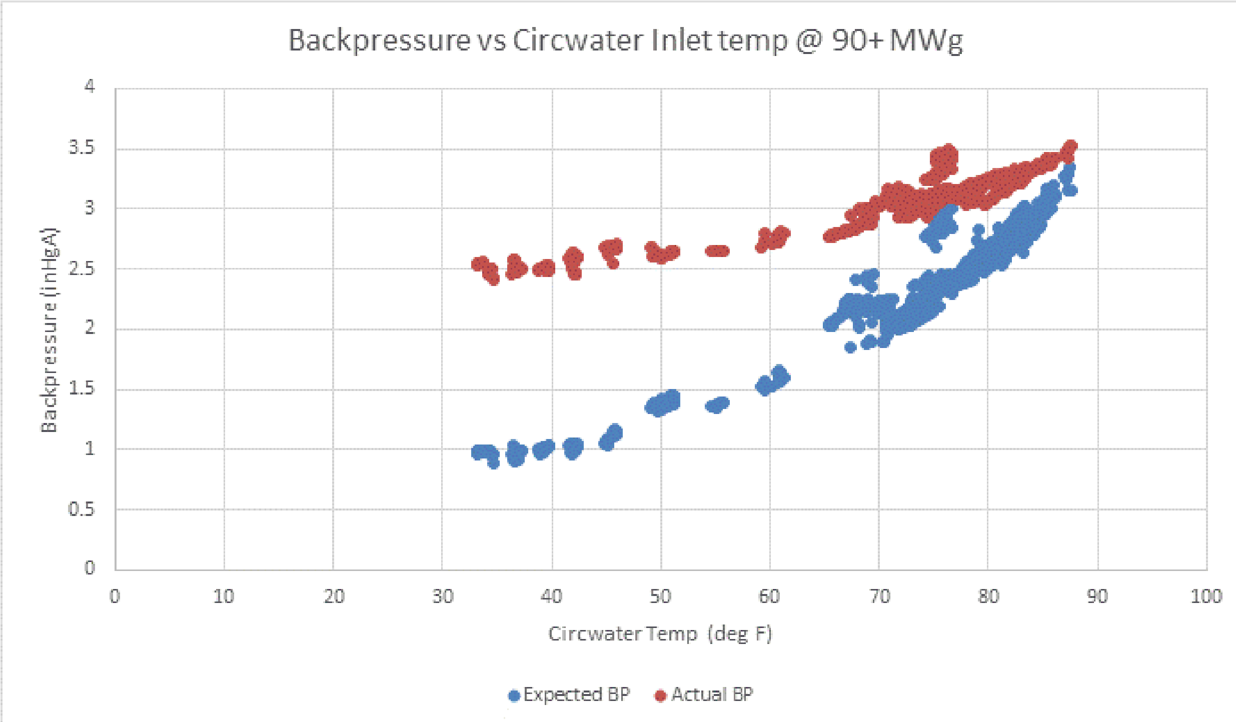



**Figure 3-19 Condenser Back Pressure Versus Circulating Water Temperature**

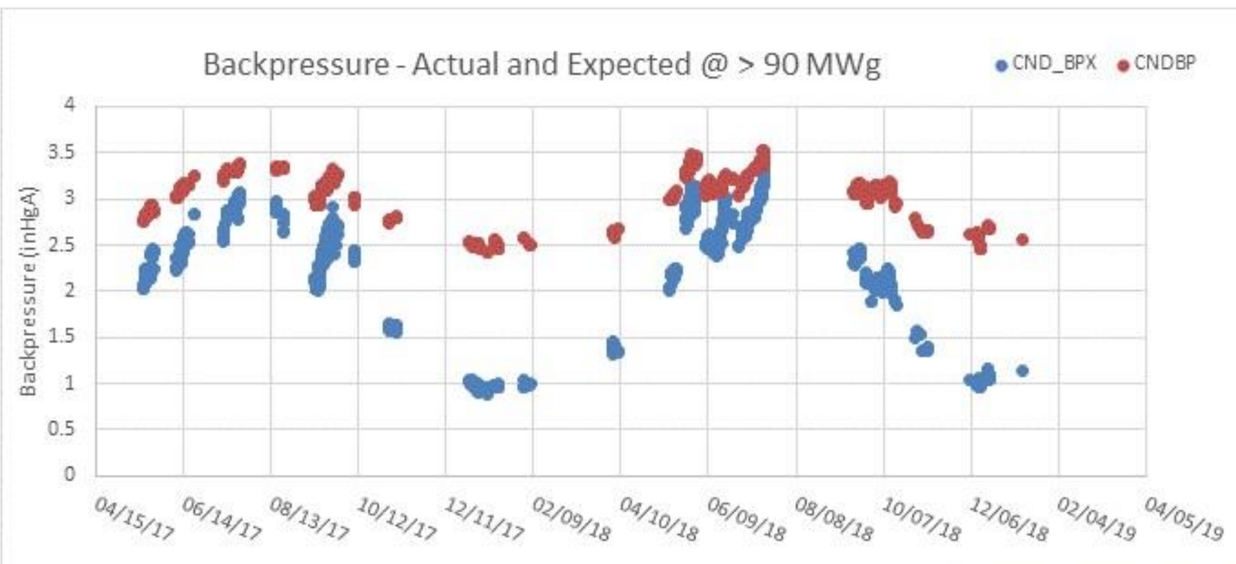



**Figure 3-20 Back Pressure Versus Time (2-year trends)**

### 3.8.3.4 F.B. Culley Unit 3 Improved Condenser Cleaning Strategies

The review of operating data for Unit 3 included 1.8 years of operational data. Data reduction to eliminate offline or suspect data eliminated 20 percent of the data, yielding more than 12,700 hours of data. The load used for analysis ranged from 135 MW gross up to 289 MW gross.

The hourly average heat rate impact of high condenser back pressure across all loads was 42 Btu/kWh and $24.8/h. Based on the data set for this analysis, the unit was in operation 90 percent of the time. Assuming this level of availability on an annual basis, the fuel cost associated with poor condenser performance is conservatively estimated at $196,000 per year. Load derates caused by high back pressure limits are probable for this unit, but highly variable, depending on the turbine design and manufacturer recommendation. Given the emphasis on efficiency opportunity in this report, an estimate for potential load impacts is not considered in this evaluation.

The highest sustained cleanliness value was slightly above 60 percent, with significant decay in performance lasting 9 of the 22 months, as seen on Figure 3-21.

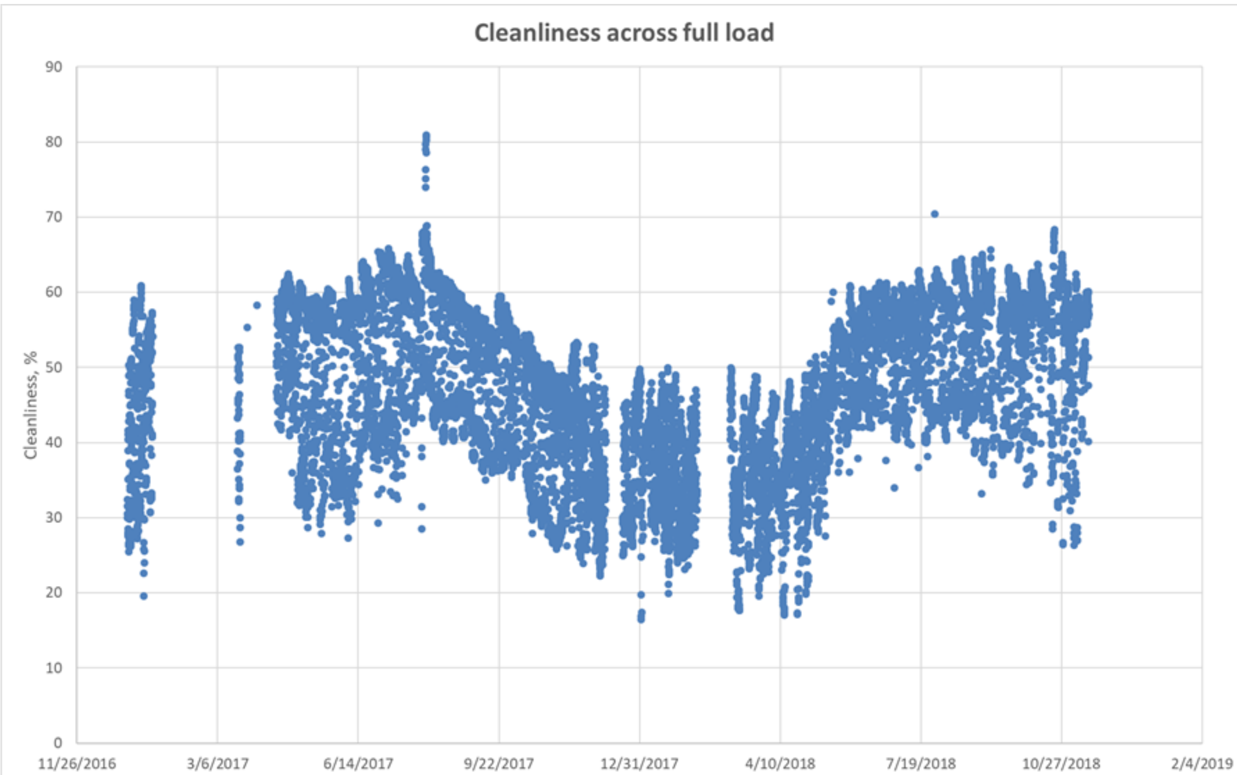



**Figure 3-21 Condenser Cleanliness Across Time and Load**

On closer look at the operating data, the repeated trend of increasing back pressure suggests significant tube sheet and or tube fouling issues on Figure 3-22.

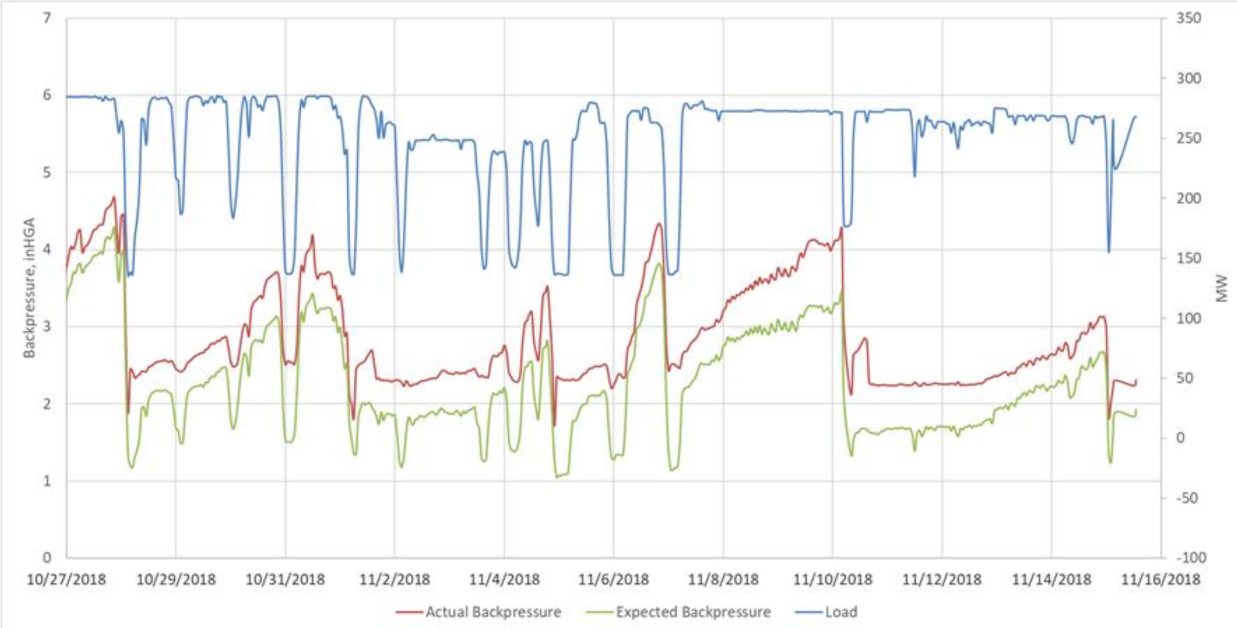



**Figure 3-22 Condenser Performance – 11 Day Trend**

On Figure 3-23 and 3-24, a trend of back pressure versus circulating water inlet temperature at high load shows a mixture of good performance and very poor performance, especially at lower river temperatures.

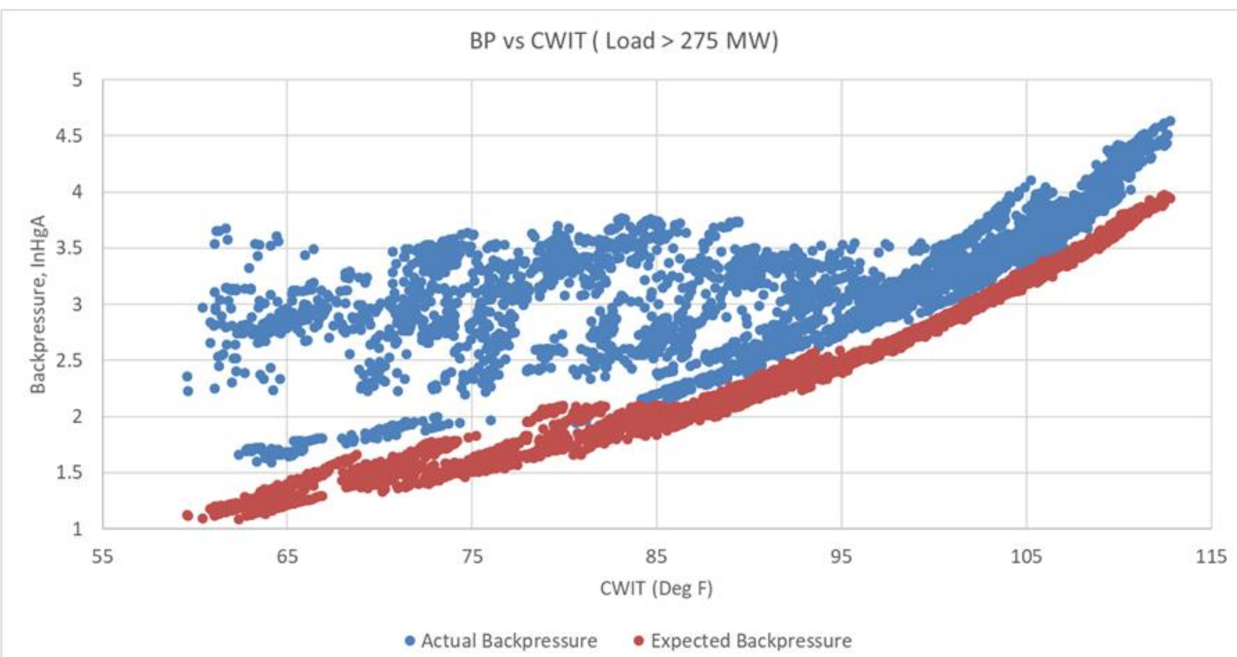



**Figure 3-23 Condenser Back Pressure Versus Circulating Water Inlet Temperature**

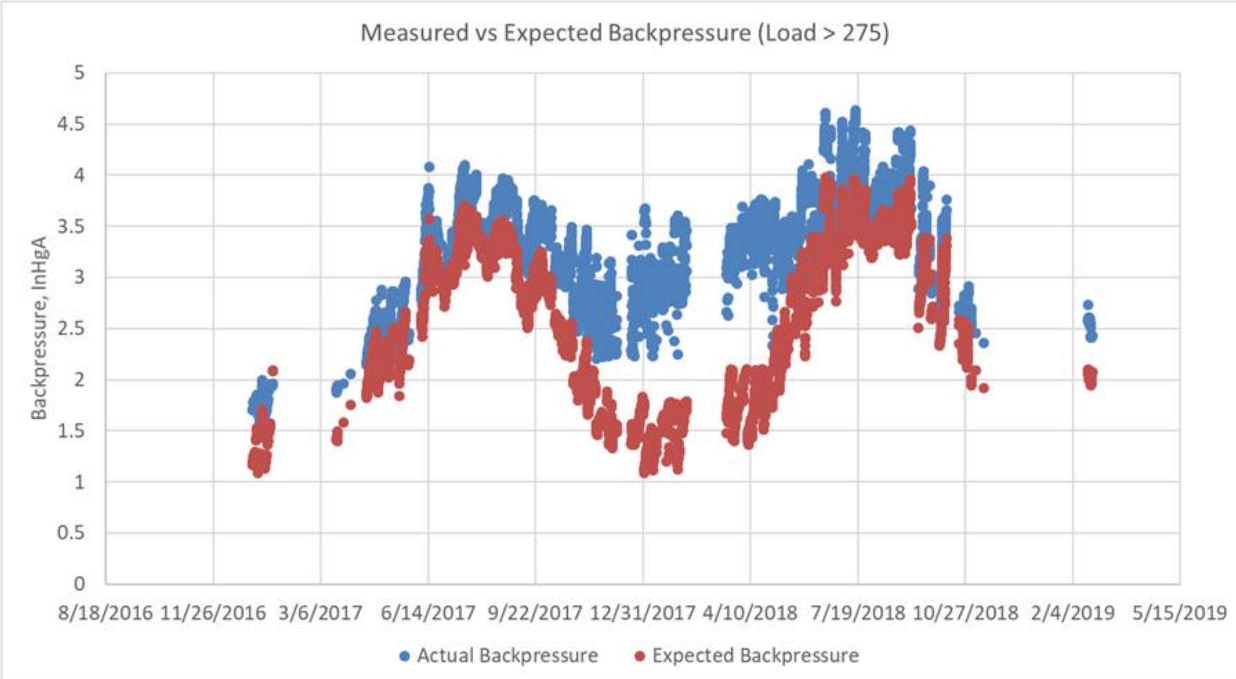



**Figure 3-24 Condenser Back Pressure Versus Time at High Load**

Condenser performance problems are unique to each unit and can be caused by a combination of factors. Considering the high availability, load capacity, and extent of condenser performance issues, this unit could be a candidate for added focus for improvement. If fouling the condenser is the primary concern felt by O&M personnel, payback on capital expenditure to rectify the situation may be too long, given this fuel cost. Adding backwash capability is likely to be cost prohibitive because of proximity of major piping work that would be required close to the turbine foundation. The addition of a debris filtering system would be beneficial and would be required before possible consideration of a ball cleaning system. The combined cost of these two capital improvements would likely be cost prohibitive.

# 4.0 Performance and $CO_2$ Production Estimates

High-level plant performance estimates were used to estimate the average annual $CO_2$ reduction. These performance benefits are summarized in Appendix B, Table B-1, Table B-2, Table B-3, and Table B-4, for A.B. Brown Unit 1, A.B. Brown Unit 2, F.B. Culley Unit 2, and F.B. Culley Unit 3, respectively. It should be noted that some projects will have overlapping performance impacts and benefits, so that the overall net benefit for a series of projects considered together will likely differ from the sum of the individual project benefits listed in each table.

The annual $CO_2$ production estimates shown in Tables 4-1 through 4-4 were based on the following plant performance basis. Net capacity, capacity factor, and the average annual net plant heat rate were provided by average annual values from the most recent full year data (2017) provided by SNL and Ventyx Velocity data.

**Table 4-1 Basis for A.B. Brown Unit 1 $CO_2$ Reduction Estimates**

| GROSS/NET CAPACITY (MW) | NET CAPACITY FACTOR (%) | AVERAGE ANNUAL NET PLANT HEAT RATE (BTU/KWH) | FUEL HEAT INPUT (MBTU/Y) | LB $CO_2$/ MBTU (HHV) | ANNUAL $CO_2$ (TONS/Y) |
|---|---|---|---|---|---|
| 265/248 | 43.7 | 11,575 | 11,427,186 | 205.2 | 1,172,428 |

**Table 4-2 Basis for A.B. Brown Unit 2 $CO_2$ Reduction Estimates**

| GROSS/NET CAPACITY (MW) | NET CAPACITY FACTOR (%) | AVERAGE ANNUAL NET PLANT HEAT RATE (BTU/KWH) | FUEL HEAT INPUT (MBTU/Y) | LB $CO_2$/ MBTU (HHV) | ANNUAL $CO_2$ (TONS/Y) |
|---|---|---|---|---|---|
| 265/248 | 45.7 | 11,007 | 11,554,139 | 205.2 | 1,185,450 |

**Table 4-3 Basis for F.B. Culley Unit 2 $CO_2$ Reduction Estimates**

| GROSS/NET CAPACITY (MW) | NET CAPACITY FACTOR (%) | AVERAGE ANNUAL NET PLANT HEAT RATE (BTU/KWH) | FUEL HEAT INPUT (MBTU/Y) | LB $CO_2$/ MBTU (HHV) | ANNUAL $CO_2$ (TONS/Y) |
|---|---|---|---|---|---|
| 104/90 | 22.2 | 12,639 | 2,395,298 | 205.0 | 245.523 |

**Table 4-4 Basis for F.B. Culley Unit 3 $CO_2$ Reduction Estimates**

| GROSS/NET CAPACITY (MW) | NET CAPACITY FACTOR (%) | AVERAGE ANNUAL NET PLANT HEAT RATE (BTU/KWH) | FUEL HEAT INPUT (MBTU/Y) | LB $CO_2$/ MBTU (HHV) | ANNUAL $CO_2$ (TONS/Y) |
|---|---|---|---|---|---|
| 287/270 | 70.5 | 10,552 | 20,885,900 | 205.1 | 2,141,818 |

Where:

Fuel Heat Input [MBtu/y] =

Net Capacity [MW] * 1,000 kW/MW * Capacity Factor [%] * 8,760 h/y * NPHR [Btu/kWh, HHV]/ (1,000,000 Btu/MBtu)

Annual $CO_2$ Production [tons/y] =

Fuel Heat Input [MBtu/y] * $CO_2$ Production Rate [$CO_2$ emissions, lbm/MBtu of Fuel Burned]/ (2,000 lbm/ ton)

# 5.0 Capital Cost Estimates

High-level capital cost estimates were developed for each alternative and are detailed with each HRI project in Section 3.0. These estimates are summarized in Appendix B, Tables B-1, B-2, B-3, and B-4 and are based on the information available and should be considered preliminary for comparative purposes. The estimates are on an overnight basis (exclusive of escalation). The estimates represent the total capital requirement for each project, assuming a turnkey EPC project execution strategy. Pricing was based on similar project pricing or Black & Veatch's internal database. Black & Veatch has not developed preliminary equipment sizing or layouts to determine the feasibility of adding the proposed equipment or performing the modifications that will be required to support their installation. More detailed evaluations will be required to verify, refine, and confirm the viability of any of the proposed projects that require equipment modification or additional area.

## 6.1 Project Risk Considerations

Factors that influence the ability to maintain power plant efficiency and corresponding $CO_2$ emissions reductions on an annual basis are discussed in this section.

## 6.2 EFFICIENCY DIFFERENCES DUE TO OPERATING PROFILE

Efficiency is significantly affected when plants operate under off-design conditions, particularly part-load operation or with frequent starts. The future operating characteristics of A.B. Brown Unit 1, A.B. Brown Unit 2, F.B. Culley Unit 2, and F.B. Culley Unit 3 can have a significant impact on the ability to achieve the expected efficiency gains and associated reduced $CO_2$ emissions.

### 6.2.1 Operating Load and Load Factor

Plants that operate with a low average output will have lower efficiency than their full-load design efficiency. Load or capacity factor describes the plant output over a period of time relative to the potential maximum; it depends on both running time at a given load and the operating load. Therefore, annual variation in both operating load and load factor can alter the $CO_2$ emissions as well as the benefit of capital projects intended to reduce plant emissions. Variation in the unit load factor can significantly impact the annual $CO_2$ emissions for a given generation rate.

Capital projects that may offer benefit in reducing outage duration or frequency may also see some benefit mitigated. For example, a plant may be able to extend the time between major overhauls and shorten the time required for a major overhaul of the steam turbine because of improved design. However, this could increase the hours the plant may run in a year and could increase the annual $CO_2$ emissions. Plant generation may be limited to avoid exceeding annual $CO_2$ emissions rates, negating some of the potential benefit of the upgrade.

### 6.2.2 Transient Operation

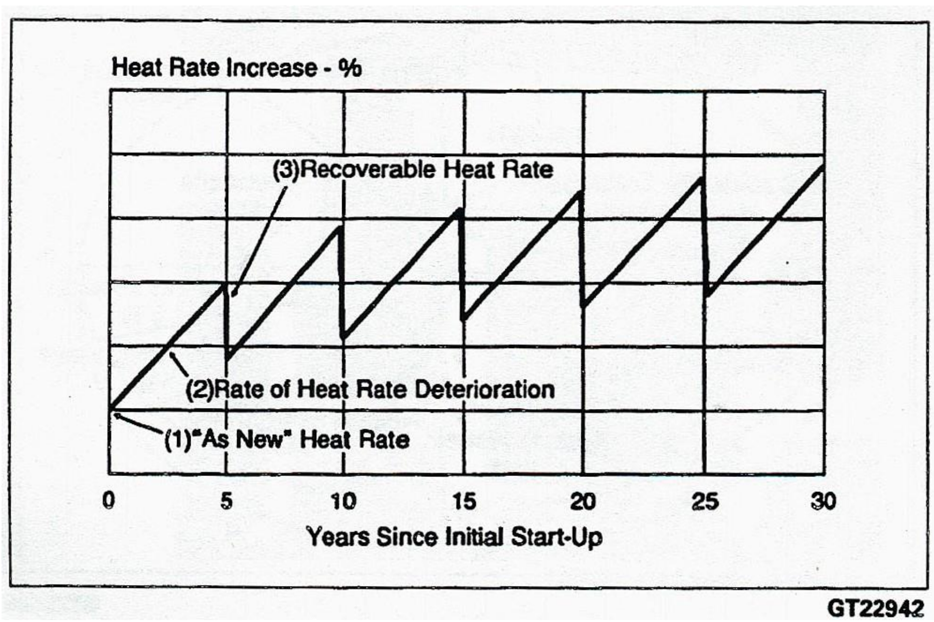
The greater the number of transients from steady state operating conditions that the plant experiences, the greater the impact to annual efficiency. During each of these transients, the plant will not be operating at peak performance. The influence of increasing renewable energy can affect the frequency of transient operation. Operation in frequency response mode, where steam flow and boiler firing fluctuate to regulate system frequency, can lead to more transients. Other situations may require frequent load changes, notably in response to power system constraints or power market pricing.

### 6.2.3 Plant Starts

Frequent shutdowns incur significant off-load energy losses, particularly during subsequent plant startup. Power plants operating in volatile or competitive markets, or operating as marginal providers of power, may be required to shut down frequently. This can also lead to deterioration in equipment condition, which will further affect annual plant efficiency and increase $CO_2$ emissions.

## 6.3 DETERIORATION

Figure 6-1 illustrates the characteristic performance deterioration that the steam turbine can be expected to experience between major overhauls. In addition, the ability of the steam turbine to economically recover from any deterioration in performance during a regularly scheduled maintenance overhaul is also illustrated. Any steam turbine retrofit is expected to experience a similar pattern of increasing deterioration, where increasingly, a portion of this deterioration is not viably recovered, even following a major overhaul. Turbine suppliers recognize the importance of sustained efficiency and work to incorporate features that result in superior sustained efficiency. The degree to which deterioration can be minimized by new designs is in large part dependent on the current design and feasible proven options. The ability of the steam turbine to sustain efficiency is a significant factor in achieving year after year $CO_2$ reduction.




**Source: Steam Turbine Sustained Efficiency, GER-3750C**

**Figure 6-1 Steam Turbine Generator Heat Rate Change Over Time**

Other plant equipment is also expected to see performance deterioration over the operating life after capital projects are implemented. The degree of deterioration and the rate at which it occurs is difficult to predict and presents a risk to the longer-term ability of the plants to sustain their efficiency gains.

## 6.4 PLANT MAINTENANCE

As well as ensuring plant availability, a key requirement of plant maintenance is to maintain peak operating efficiency. Improved maintenance and component replacement and upgrading can reduce energy losses.

Any poorly performing auxiliary equipment or individual components that affect performance will also contribute to the overall deterioration of plant performance over time, compounding the effects of deterioration in major components, such as the steam turbine. While not an intended outcome, plant upgrades can also result in increased maintenance if the expected improvements cannot be not achieved without increased or more complicated plant maintenance. Tables B-1, B-2, B-3, and B-4 (Appendix B) include an order-of-magnitude rating of comparative operating and maintenance cost impact associated with each of the given projects.

## 6.5 FUEL QUALITY IMPACTS

Variation in fuel quality can have a significant impact on the boiler efficiency. Reduced boiler efficiency will increase the required fuel heat input for a given generation which will increase $CO_2$ emissions. Variation in fuel composition can also have an effect on the pounds of $CO_2$ emission/MBtu of fuel burned.

## 6.6 AMBIENT CONDITIONS

Variation in ambient conditions can affect the condenser operating pressure and the resulting steam turbine output. In particular, higher wet bulb temperatures can have a significant impact on plant heat rate. Variation in annual average turbine back pressure because of wet bulb will affect the expected benefits of several of the heat rejection and steam turbine capital improvement projects.

# Appendix A. Abbreviations and Acronyms

| | |
|---|---|
| °F | Degrees Fahrenheit |
| ACE | Affordable Clean Energy (Plan) |
| ADSP | Advanced Design Steam Path |
| AH | Air Heater |
| AQCS | Air Quality Control System |
| BSER | Best System of Emission Reduction |
| Btu | British Thermal Unit |
| CO | Carbon Monoxide |
| $CO_2$ | Carbon Dioxide |
| CPP | Clean Power Plan |
| DCA | Drain Cooler Approach |
| DCS | Distributed Control System |
| EGU | Electric Generating Unit |
| EPA | United States Environmental Protection Agency |
| EPRI | Electric Power Research Institute |
| FD | Forced Draft |
| Ft | Feet |
| GE | General Electric |
| GHG | Greenhouse Gas |
| gpm | Gallons per minute |
| h | Hour |
| HHV | Higher Heating Value |
| hp | Horsepower |
| HP | High Pressure |
| HRI | Heat Rate Improvement |
| ID | Induced Draft |
| IGBT | Insulated-Gate Bipolar Transistor |
| in. HgA | Inches of Mercury – Absolute |
| IP | Intermediate Pressure |
| IRP | Integrated Resource Plan |
| ISB | Intelligent Sootblowing |
| kW | Kilowatt |
| kWh | Kilowatt hour |
| lbm | Pound |
| LP | Low Pressure |
| MBtu | Million British Thermal Units |

| | |
|---|---|
| MW | Megawatt |
| $NO_x$ | Nitrogen Oxide |
| NP | Normal Pressure |
| NPHR | Net Plant Heat Rate |
| NSR | New Source Review |
| OEM | Original Equipment Manufacturer |
| PA | Primary Air |
| PJFF | Pulse Jet Fabric Filter |
| rpm | Revolutions per Minute |
| SLR | Selective Catalytic Reduction |
| $SO_2$ | Sulfur Dioxide |
| STG | Steam Turbine Generator |
| TTD | Terminal Temperature Difference |
| VFD | Variable Frequency Drive |
| VWO | Valve Wide Open |
| y | Year |

# Appendix B. Capital Cost and Performance Estimates

**Table B-1 A.B. Brown Unit 1 Preliminary EPC Capital Cost Estimate (in 2019 Dollars) and First Year Performance Benefits**

| Component | Project Description | Est Capital Cost ($000) | Heat Rate Reduction (%) | Heat Rate Reduction (Btu/kWh) | Total Annual First Year Fuel Reduction (MBtu/y) | First Year Annual $CO_2$ Reduction (Tons/y) | Capital Cost/Annual $CO_2$ Reduction - First Year ($/(Ton/y)) | Average Annual O&M Cost Impact** |
|---|---|---|---|---|---|---|---|---|
| Steam Turbine | HP/IP Upgrades or Full Steam Path Upgrades | Not Recommended | N/A | N/A | N/A | N/A | N/A | N/A |
| Economizer | Redesign or Replacement | Not Recommended | N/A | N/A | N/A | N/A | N/A | N/A |
| Air Heater/Duct Leakage | Air Heater Basket, Seal, and Sector Plate Replacement | 850 | 0.50 | 57.88 | 57,136 | 5,862 | 145.0 | Low |
| Air Heater/Duct Leakage | Air Heater (Steam Coil) System Repairs | 350 | 0.10 | 11.6 | 11,427 | 1,172 | 298.5 | N/A |
| Variable Frequency Drive (VFD) Upgrades | Boiler Feed Pumps | Not Recommended | N/A | N/A | N/A | N/A | N/A | N/A |
| Variable Frequency Drive (VFD) Upgrades | Circulating Water Pumps | 2,100 | N/A | N/A | N/A | N/A | N/A | Low |
| Variable Frequency Drive (VFD) Upgrades | Cooling Tower Fans | Not Recommended | N/A | N/A | N/A | N/A | N/A | N/A |
| Variable Frequency Drive (VFD) Upgrades | Forced Draft Fans | 2,000 | 0.43 | 50.3 | 49,701 | 5,099 | 392.2 | Low/Med |
| Variable Frequency Drive (VFD) Upgrades | Induced Draft Fans | 2,900 | 2.39 | 276.50 | 272,973 | 28,007 | 103.5 | Low |
| Neural Network | Neural network deployment for combustion control and boiler excess air reduction. (0.25% reduction in excess $O_2$) | 500 | 0.23 | 26.6 | 26,283 | 2,697 | 185.4 | Low |
| Neural Network | Neural network deployment for combustion control and boiler excess air reduction. (0.50% reduction in excess $O_2$) | 500 | 0.43 | 49.77 | 49,137 | 5,041 | 99.2 | N/A |

| Component | Project Description | Est Capital Cost ($000) | Heat Rate Reduction (%) | Heat Rate Reduction (Btu/kWh) | Total Annual First Year Fuel Reduction (MBtu/y) | First Year Annual $CO_2$ Reduction (Tons/y) | Capital Cost/Annual $CO_2$ Reduction - First Year ($/(Ton/y)) | Average Annual O&M Cost Impact** |
|---|---|---|---|---|---|---|---|---|
| Neural Network | Neural network deployment for combustion control and boiler excess air reduction. (0.75% reduction in excess $O_2$) | 500.0 | 0.60 | 69.5 | 68,563 | 7,035 | 71.1 | Low |
| Intelligent Soot Blowing (ISB) | Synchronized controlled sootblowing system designed to alleviate excessive use of steam, air or water that have a negative effect on heat rate. | Not Recommended | N/A | N/A | N/A | N/A | N/A | N/A |
| Improved O&M Practices | Heat rate improvement training. | 15 | 0.30 | 34.7 | 34,282 | 3,517 | 4.3 | Low |
| Improved O&M Practices | On-site heat rate appraisals. | Variable | Variable | N/A | N/A | N/A | N/A | Low |
| Improved O&M Practices | Improved Condenser Cleaning Strategies | N/A | 0.15 | 17.4 | 17,141 | 1,759 | N/A | Low |

**Table B-2 A.B. Brown Unit 2 Preliminary EPC Capital Cost Estimate (in 2019 Dollars) and First Year Performance Benefits**

| Component | Project Description | Est Capital Cost ($000) | Heat Rate Reduction (%) | Heat Rate Reduction (Btu/kWh) | Total Annual First Year Fuel Reduction (MBtu/y) | First Year Annual $CO_2$ Reduction (Tons/y) | Capital Cost/Annual $CO_2$ Reduction - First Year ($/(Ton/y)) | Average Annual O&M Cost Impact** |
|---|---|---|---|---|---|---|---|---|
| Steam Turbine | HP/IP Upgrades or Full Steam Path Upgrades | Not Recommended | N/A | N/A | N/A | N/A | N/A | No change |
| Economizer | Redesign or Replacement | Not Recommended | N/A | N/A | N/A | N/A | N/A | N/A |
| Air Heater/Duct Leakage | Air Heater Basket, Seal, and Sector Plate Replacement | 850 | 0.50 | 55.0 | 57,771 | 5,927 | 143.4 | Low |
| Air Heater/Duct Leakage | Air Heater (Steam Coil) System Repairs | 350 | 0.10 | 11.0 | 11,554 | 1,185 | 295.2 | Low |
| Variable Frequency Drive (VFD) Upgrades | Boiler Feed Pumps | Not Recommended | N/A | N/A | N/A | N/A | N/A | Low |
| Variable Frequency Drive (VFD) Upgrades | Circulating Water Pumps | 2,100 | N/A | N/A | N/A | N/A | N/A | N/A |
| Variable Frequency Drive (VFD) Upgrades | Cooling Tower Fans | Not Recommended | N/A | N/A | N/A | N/A | N/A | N/A |
| Variable Frequency Drive (VFD) Upgrades | Forced Draft Fans | 2,000 | 0.26 | 28.6 | 30,015 | 3,080 | 649.4 | N/A |
| Variable Frequency Drive (VFD) Upgrades | Induced Draft Fans | 2,900 | 1.33 | 146.3 | 153,608 | 15,760 | 184.0 | Low |
| Neural Network | Neural network deployment for combustion control and boiler excess air reduction. (0.25% reduction in excess $O_2$) | 500 | 0.23 | 25.3 | 26,575 | 2,727 | 183.4 | Low/Med |
| Neural Network | Neural network deployment for combustion control and boiler excess air reduction. (0.50% reduction in excess $O_2$) | 500 | 0.43 | 47.33 | 49,683 | 5,097 | 98.1 | Low |

| Component | Project Description | Est Capital Cost ($000) | Heat Rate Reduction (%) | Heat Rate Reduction (Btu/kWh) | Total Annual First Year Fuel Reduction (MBtu/y) | First Year Annual $CO_2$ Reduction (Tons/y) | Capital Cost/Annual $CO_2$ Reduction - First Year ($/(Ton/y)) | Average Annual O&M Cost Impact** |
|---|---|---|---|---|---|---|---|---|
| Neural Network | Neural network deployment for combustion control and boiler excess air reduction. (0.75% reduction in excess $O_2$) | 500 | 0.60 | 66.0 | 69,325 | 7,113 | 70.3 | Low |
| Intelligent Soot Blowing (ISB) | Synchronized controlled sootblowing system designed to alleviate excessive use of steam, air or water that have a negative effect on heat rate. | Not Recommended | N/A | N/A | N/A | N/A | N/A | Low |
| Improved O&M Practices | Heat rate improvement training. | 15 | 0.30 | 33.0 | 34,662 | 3,556 | 4.2 | Low |
| Improved O&M Practices | On-site heat rate appraisals. | Variable | Variable | N/A | N/A | N/A | N/A | Low |
| Improved O&M Practices | Improved Condenser Cleaning Strategies | N/A | N/A | N/A | N/A | N/A | N/A | Low |

**Table B-3 F.B. Culley Unit 2 Preliminary EPC Capital Cost Estimate (in 2019 Dollars) and First Year Performance Benefits**

| Component | Project Description | Est Capital Cost ($000) | Heat Rate Reduction (%) | Heat Rate Reduction (Btu/kWh) | Total Annual First Year Fuel Reduction (MBtu/y) | First Year Annual $CO_2$ Reduction (Tons/y) | Capital Cost/Annual $CO_2$ Reduction - First Year ($/(Ton/y)) | Average Annual O&M Cost Impact** |
|---|---|---|---|---|---|---|---|---|
| Steam Turbine | Full steam path upgrades. | 10,400 | 1.4 | 176.9 | 33,534 | 3.44 | 3,025,611 | No change |
| Economizer | Redesign or Replacement | Not Recommended | N/A | N/A | N/A | N/A | N/A | N/A |
| Air Heater/Duct Leakage | Air Heater Basket, Seal, and Sector Plate Replacement | 476 | 0.50 | 63.2 | 11,976 | 1.23 | 387,744 | Low |
| Air Heater/Duct Leakage | Air Heater (Steam Coil) System Repairs | Not Recommended | N/A | N/A | N/A | N/A | N/A | N/A |
| Variable Frequency Drive (VFD) Upgrades | Boiler Feed Pumps | 600 | 0.60 | 75.8 | 14,372 | 1.47 | 407,294 | N/A |
| Variable Frequency Drive (VFD) Upgrades | Circulating Water Pumps | 900 | N/A | N/A | N/A | N/A | N/A | N/A |
| Variable Frequency Drive (VFD) Upgrades | Cooling Tower Fans | Not Recommended | N/A | N/A | N/A | N/A | N/A | N/A |
| Variable Frequency Drive (VFD) Upgrades | Forced Draft Fans | 2,000 | 0.48 | 60.9 | 11,549 | 1.18 | 1,689,525 | N/A |
| Variable Frequency Drive (VFD) Upgrades | Induced Draft Fans | Not Recommended | N/A | N/A | N/A | N/A | N/A | N/A |
| Neural Network | Neural network deployment for combustion control and boiler excess air reduction. (0.25% reduction in excess $O_2$) | 500 | 0.26 | 32.9 | 6,228 | 0.64 | 783,257 | Low/Med |
| Neural Network | Neural network deployment for combustion control and boiler excess air reduction. (0.50% reduction in excess $O_2$) | 500 | 0.47 | 59.40 | 11,258 | 1.15 | 433,291 | Low |

| Component | Project Description | Est Capital Cost ($000) | Heat Rate Reduction (%) | Heat Rate Reduction (Btu/kWh) | Total Annual First Year Fuel Reduction (MBtu/y) | First Year Annual $CO_2$ Reduction (Tons/y) | Capital Cost/Annual $CO_2$ Reduction - First Year ($/(Ton/y)) | Average Annual O&M Cost Impact** |
|---|---|---|---|---|---|---|---|---|
| Neural Network | Neural network deployment for combustion control and boiler excess air reduction. (0.75% reduction in excess $O_2$) | 500 | 0.62 | 78.4 | 14,851 | 1.52 | 328,463 | Low |
| Intelligent Soot Blowing (ISB) | Synchronized controlled sootblowing system designed to alleviate excessive use of steam, air or water that have a negative effect on heat rate. | 350 | 0.10 | 12.64 | 2,395 | 0.25 | 1,425,528 | Low |
| Improved O&M Practices | Heat rate improvement training. | 15 | 0.30 | 37.9 | 7,186 | 0.74 | 20,365 | Low |
| Improved O&M Practices | On-site heat rate appraisals. | Variable | Variable | N/A | N/A | N/A | N/A | N/A |
| Improved O&M Practices | Improved Condenser Cleaning Strategies | N/A | 0.42 | 53.1 | 10,060 | 1.03 | N/A | Low |

**Table B-4 F.B. Culley Unit 3 Preliminary EPC Capital Cost Estimate (in 2019 Dollars) and First Year Performance Benefits**

| Component | Project Description | Est Capital Cost ($000) | Heat Rate Reduction (%) | Heat Rate Reduction (Btu/kWh) | Total Annual First Year Fuel Reduction (MBtu/y) | First Year Annual $CO_2$ Reduction (Tons/y) | Capital Cost/Annual $CO_2$ Reduction - First Year ($/(Ton/y)) | Average Annual O&M Cost Impact** |
|---|---|---|---|---|---|---|---|---|
| Steam Turbine | HP/IP upgrades | 19,900 | 1.5 | 158.3 | 313,289 | 32,127 | 619.4 | No change |
| Economizer | Major redesign with additional tube passes. | Not Recommended | N/A | N/A | N/A | N/A | N/A | N/A |
| Air Heater/Duct Leakage | Air Heater Basket, Seal, and Sector Plate Replacement | 750 | 0.50 | 52.8 | 104,430 | 10,709 | 70.0 | Low |
| Air Heater/Duct Leakage | Air Heater (Steam Coil) System Repairs | 350 | 0.10 | 10.6 | 20,886 | 2,142 | 163 | Low |
| Variable Frequency Drive (VFD) Upgrades | Boiler Feed Pumps | Not Recommended | N/A | N/A | N/A | N/A | N/A | N/A |
| Variable Frequency Drive (VFD) Upgrades | Circulating Water Pumps | 2,100 | N/A | N/A | N/A | N/A | N/A | N/A |
| Variable Frequency Drive (VFD) Upgrades | Cooling Tower Fans | Not Recommended | N/A | N/A | N/A | N/A | N/A | N/A |
| Variable Frequency Drive (VFD) Upgrades | Forced Draft Fans | 2,000 | 0.51 | 54.3 | 107,412 | 11,015 | 181.6 | N/A |
| Variable Frequency Drive (VFD) Upgrades | Induced Draft Fans | Not Recommended | N/A | N/A | N/A | N/A | N/A | N/A |
| Neural Network | Neural network deployment for combustion control and boiler excess air reduction. (0.25% reduction in excess $O_2$) | 500 | 0.25 | 26.4 | 52,215 | 5,355 | 93.4 | Low/Med |
| Neural Network | Neural network deployment for combustion control and boiler excess air reduction. (0.50% reduction in excess $O_2$) | 500 | 0.46 | 48.54 | 96,075 | 9,852 | 50.7 | Low |

| Component | Project Description | Est Capital Cost ($000) | Heat Rate Reduction (%) | Heat Rate Reduction (Btu/kWh) | Total Annual First Year Fuel Reduction (MBtu/y) | First Year Annual $CO_2$ Reduction (Tons/y) | Capital Cost/Annual $CO_2$ Reduction - First Year ($/(Ton/y)) | Average Annual O&M Cost Impact** |
|---|---|---|---|---|---|---|---|---|
| Neural Network | Neural network deployment for combustion control and boiler excess air reduction. (0.75% reduction in excess $O_2$) | 500 | 0.62 | 65.4 | 129,493 | 13,279 | 37.7 | Low |
| Intelligent Soot Blowing (ISB) | Synchronized controlled sootblowing system designed to alleviate excessive use of steam, air or water that have a negative effect on heat rate. | Not Recommended | N/A | N/A | N/A | N/A | N/A | N/A |
| Improved O&M Practices | Heat rate improvement training. | 15 | 0.30 | 31.7 | 62,658 | 6,425 | 2.3 | Low |
| Improved O&M Practices | On-site Heat Rate Appraisals | Variable | Variable | N/A | N/A | N/A | N/A | N/A |
| Improved O&M Practices | Improved Condenser Cleaning Strategies | N/A | 0.44 | 46.4 | 91,898 | 9,424 | #VALUE! | Low |

**Table B-5 Preliminary Fuel and O&M Cost Impacts Expansion, Including Useful Plant Life for all Units (Report – 5 year)**

| Unit | Project Description | In-Service Year | Project Cost ($000's) | Heat Rate Improvement (%) | Heat Rate Improvement (Btu/kWh) | MMBtu Savings | Coal Savings per year ($000's) | Variable O&M Savings per year ($000's) | Natural Gas Savings Per Year ($000's) | Total Savings per year ($000's) | Payback Period (Yrs. from project in-service) | Total Period | Cost per year ($000's) (5-year useful life) | Cost per ton of CO2 ($) (5-year useful Life) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| ABB1 | Air Heater Basket, Seal, and Sector Plate Replacement | 2021 | 850 | 0.5 | 58 | 58,716 | 130.1 | 0 | 0 | 130.1 | 6.5 | 8.5 | 39.9 | 29.00 |
| ABB1 | Air Heater (Steam Coil) System Repairs | 2021 | 350 | 0.1 | 11.6 | 11,768 | 26.1 | 0 | 0 | 26.1 | 13.4 | 15.4 | 43.93310101 | 59.71 |
| ABB1 | Circulating Water Pumps | 2021 | 2,100 | N/A | N/A | N/A | N/A | 0 | 0 | 0.0 | N/A | N/A | 420.0 | N/A |
| ABB1 | Induced Draft Fans | 2021 | 2,900 | 2.2 | 254.65 | 258,330 | 572.2 | -2 | 0 | 570.2 | 5.1 | 7.1 | 9.764152778 | 22.49 |
| ABB1 | Forced Draft Fans | 2021 | 2,000 | 0.5 | 58 | 58,711 | 130.1 | -2 | 0 | 128.1 | 15.6 | 17.6 | 271.9 | 68.23 |
| ABB1 | Neural Network with 0.25% Reduction in Excess $O_2$ | 2021 | 500 | 0.23 | 26.6 | 26,984 | 59.8 | 0 | 0 | 59.8 | 8.4 | 10.4 | 40.22590404 | 37.08 |
| ABB1 | Neural Network with 0.50% Reduction in Excess $O_2$ | 2021 | 500 | 0.4 | 50 | 50,489 | 111.8 | 0 | 0 | 111.8 | 4.5 | 6.5 | -11.8 | 19.84 |
| ABB1 | Neural Network with 0.75% Reduction in Excess $O_2$ | 2021 | 500 | 0.6 | 69.5 | 70,504 | 156.2 | 0 | 0 | 156.2 | 3.2 | 5.2 | -56.17667929 | 14.22 |
| ABB1 | Heat Rate Improvement Training. | 2021 | 15 | 0.3 | 35 | 35,201 | 78.0 | 0 | 0 | 78.0 | 0.2 | 2.2 | -75.0 | 0.85 |
| ABB1 | On-Site Heat Rate Appraisals. | 2021 | Variable | Variable | N/A | N/A | N/A | 0 | 0 | 0.0 | N/A | N/A | N/A | N/A |
| ABB1 | Improved Condenser Cleaner Strategies | 2021 | N/A | 0.2 | 17 | 17,651 | 39.1 | 0 | 0 | 39.1 | N/A | N/A | N/A | N/A |
| ABB1 | Economizer (1 Tube Pass) | 2021 | 750 | -0.17 | -17.5 | -17,753 | -39.3 | 0 | N/A | -39.3 | -19.1 | -17.1 | 189.3 | -75.26 |
| ABB1 | Economizer (2 Tube Pass) | 2021 | 1,075 | -0.4 | -37 | -37,433 | -82.9 | 0 | N/A | -82.9 | -13.0 | -11.0 | 297.9 | -50.94 |
| ABB1 | Economizer (3 Tube Pass) | 2021 | 1,400 | -0.61 | -62.4 | -63,302 | -140.2 | 0 | N/A | -140.2 | -10.0 | -8.0 | 420.2 | -39.15 |
| ABB2 | Air Heater Basket, Seal, and Sector Plate Replacement | 2021 | 850 | 0.5 | 55 | 58,348 | 129.2 | 0 | 0 | 129.2 | 6.6 | 8.6 | 40.8 | 29.00 |

| Unit | Project Description | In-Service Year | Project Cost ($000's) | Heat Rate Improvement (%) | Heat Rate Improvement (Btu/kWh) | MMBtu Savings | Coal Savings per year ($000's) | Variable O&M Savings per year ($000's) | Natural Gas Savings Per Year ($000's) | Total Savings per year ($000's) | Payback Period (Yrs. from project in-service) | Total Period | Cost per year ($000's) (5-year useful life) | Cost per ton of CO2 ($) (5-year useful Life) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| ABB2 | Air Heater (Steam Coil) System Repairs | 2021 | 350 | 0.1 | 11 | 11,670 | 25.8 | 0 | 0 | 25.8 | 13.5 | 15.5 | 44.15010234 | 59.71 |
| ABB2 | Circulating Water Pumps | 2021 | 2,100 | N/A | N/A | N/A | N/A | 0 | 0 | 0.0 | N/A | N/A | 420.0 | N/A |
| ABB2 | Induced Draft Fans | 2021 | 2,900 | 1.2 | 132.084 | 140,125 | 310.4 | 0 | 0 | -2.0 | -1,450.0 | -1448.0 | 582 | 41.22 |
| ABB2 | Forced Draft Fans | 2021 | 2,000 | 0.2 | 22 | 23,354 | 51.7 | 0 | 0 | -2.0 | -1,000.0 | -998.0 | 402.0 | 170.59 |
| ABB2 | Neural Network with 0.25% Reduction in Excess $O_2$ | 2021 | 500 | 3 | 25.3 | 26,840 | 59.5 | 0 | 0 | 59.5 | 8.4 | 10.4 | 40.54523538 | 2.84 |
| ABB2 | Neural Network with 0.50% Reduction in Excess $O_2$ | 2021 | 500 | 0.4 | 47 | 50,211 | 111.2 | 0 | 0 | 111.2 | 4.5 | 6.5 | -11.2 | 19.84 |
| ABB2 | Neural Network with 0.75% Reduction in Excess $O_2$ | 2021 | 500 | 0.6 | 66 | 70,018 | 155.1 | 0 | 0 | 155.1 | 3.2 | 5.2 | -55.09938596 | 14.22 |
| ABB2 | Heat Rate Improvement Training | 2021 | 15 | 0.3 | 33 | 35,009 | 77.5 | 0 | 0 | 77.5 | 0.2 | 2.2 | -74.5 | 0.85 |
| ABB2 | On-Site Heat Rate Appraisals | 2021 | Variable | Variable | N/A | N/A | N/A | 0 | 0 | 0.0 | N/A | N/A | N/A | N/A |
| ABB2 | Improved Condenser Cleaner Strategies | 2021 | N/A | N/A | N/A | N/A | N/A | 0 | 0 | 0.0 | N/A | N/A | N/A | N/A |
| ABB2 | Economizer (1 Tube Pass) | 2021 | 750 | -0.17 | -17.5 | -18,565 | -41.1 | 0 | N/A | -41.1 | -18.2 | -16.2 | 239.3250631 | -100.34 |
| ABB2 | Economizer (2 Tube Pass) | 2021 | 1,075 | -0.4 | -37 | -39,146 | -86.7 | 0 | N/A | -86.7 | -12.4 | -10.4 | 282.9 | -47.39 |
| ABB2 | Economizer (3 Tube Pass) | 2021 | 1,400 | -0.61 | -62.4 | -66,199 | -146.6 | 0 | N/A | -146.6 | -9.5 | -7.5 | 340.2219394 | -27.96 |
| FBC2 | Air Heater Basket, Seal, and Sector Plate Replacement | 2021 | 476 | 0.5 | 63 | 12,782 | 28.3 | 0 | 0 | 28.3 | 16.8 | 18.8 | 66.9 | 16.24 |
| FBC2 | Circulating Water Pumps | 2021 | 900 | N/A | N/A | N/A | N/A | 0 | 0 | 0.0 | N/A | N/A | 180 | N/A |
| FBC2 | Boiler Feed Pump | 2021 | 600 | 0.6 | 76 | 15,337 | 34.0 | -2 | 0 | 32.0 | 18.8 | 20.8 | 88.0 | 17.06 |
| FBC2 | Forced Draft Fans | 2021 | 2,000 | 0.5 | 63.195 | 12,781 | 28.3 | -2 | 0 | 26.3 | 76.0 | 78.0 | 373.6878337 | 68.23 |

| Unit | Project Description | In-Service Year | Project Cost ($000's) | Heat Rate Improvement (%) | Heat Rate Improvement (Btu/kWh) | MMBtu Savings | Coal Savings per year ($000's) | Variable O&M Savings per year ($000's) | Natural Gas Savings Per Year ($000's) | Total Savings per year ($000's) | Payback Period (Yrs. from project in-service) | Total Period | Cost per year ($000's) (5-year useful life) | Cost per ton of CO2 ($) (5-year useful Life) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| FBC2 | Neural Network with 0.25% Reduction in Excess $O_2$ | 2021 | 500 | 0.3 | 33 | 6,654 | 14.7 | 0 | 0 | 14.7 | 33.9 | 35.9 | 85.3 | 32.81 |
| FBC2 | Neural Network with 0.50% Reduction in Excess $O_2$ | 2021 | 500 | 0.47 | 59.4 | 12,014 | 26.6 | 0 | 0 | 26.6 | 18.8 | 20.8 | 73.38804211 | 18.15 |
| FBC2 | Neural Network with 0.75% Reduction in Excess $O_2$ | 2021 | 500 | 0.6 | 78 | 15,856 | 35.1 | 0 | 0 | 35.1 | 14.2 | 16.2 | 64.9 | 13.76 |
| FBC2 | Synchronized Controlled Sootblowing System | 2021 | 350 | 0.1 | 12.64 | 2,556 | 5.7 | 0 | 0 | 5.7 | 61.8 | 63.8 | 64.33711872 | 59.71 |
| FBC2 | Heat Rate Improvement Training | 2021 | 15 | 0.3 | 38 | 7,665 | 17.0 | 0 | 0 | 17.0 | 0.9 | 2.9 | -14.0 | 0.85 |
| FBC2 | On-Site Heat Rate Appraisals | 2021 | Variable | Variable | N/A | N/A | N/A | 0 | 0 | 0.0 | N/A | N/A | N/A | N/A |
| FBC2 | Improved Condenser Cleaner Strategies | 2021 | N/A | 0.4 | 53 | 10,740 | 23.8 | 0 | 0 | 23.8 | N/A | N/A | N/A | N/A |
| FBC3 | HP/IP Upgrades | 2022 | 19,900 | 1.5 | 158.3 | 280,580 | 621.5 | 0 | 0 | 621.5 | 32.0 | 35.0 | 3358.478728 | 226.31 |
| FBC3 | Air Heater Basket, Seal, and Sector Plate Replacement | 2022 | 750 | 0.5 | 53 | 93,586 | 207.3 | 0 | 0 | 207.3 | 3.6 | 6.6 | -57.3 | 25.59 |
| FBC3 | Air Heater (Steam Coil) System Repairs | 2022 | 350 | 0.1 | 10.6 | 18,788 | 41.6 | 0 | 0 | 41.6 | 8.4 | 11.4 | 28.38202472 | 59.71 |
| FBC3 | Circulating Water Pumps | 2022 | 2,100 | N/A | N/A | N/A | N/A | 0 | 0 | 0.0 | N/A | N/A | 420.0 | N/A |
| FBC3 | Forced Draft Fans | 2022 | 2,000 | 0.46 | 48.5392 | 86,034 | 190.6 | -2 | 0 | 188.6 | 10.6 | 13.6 | 211.424224 | 74.17 |
| FBC3 | Neural Network with 0.25% Reduction in Excess $O_2$ | 2022 | 500 | 0.3 | 26 | 46,793 | 103.7 | 0 | 0 | 103.7 | 4.8 | 7.8 | -3.7 | 34.12 |
| FBC3 | Neural Network with 0.50% Reduction in Excess $O_2$ | 2022 | 500 | 0.46 | 48.54 | 86,035 | 190.6 | 0 | 0 | 190.6 | 2.6 | 5.6 | -90.57891699 | 18.54 |

| Unit | Project Description | In-Service Year | Project Cost ($000's) | Heat Rate Improvement (%) | Heat Rate Improvement (Btu/kWh) | MMBtu Savings | Coal Savings per year ($000's) | Variable O&M Savings per year ($000's) | Natural Gas Savings Per Year ($000's) | Total Savings per year ($000's) | Payback Period (Yrs. from project in-service) | Total Period | Cost per year ($000's) (5-year useful life) | Cost per ton of CO2 ($) (5-year useful Life) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| FBC3 | Neural Network with 0.75% Reduction in Excess $O_2$ | 2022 | 500 | 0.6 | 65 | 115,919 | 256.8 | 0 | 0 | 256.8 | 1.9 | 4.9 | -156.8 | 13.76 |
| FBC3 | Heat Rate Improvement Training | 2022 | 15 | 0.3 | 31.7 | 56,187 | 124.5 | 0 | 0 | 124.5 | 0.1 | 3.1 | -121.4613034 | 0.85 |
| FBC3 | On-Site Heat Rate Appraisals | 2022 | Variable | Variable | N/A | N/A | N/A | 0 | 0 | 0.0 | N/A | N/A | N/A | N/A |
| FBC3 | Improved Condenser Cleaner Strategies | 2022 | N/A | 0.44 | 46.4 | 82,242 | 182.2 | 0 | 0 | 182.2 | N/A | N/A | N/A | N/A |
| FBC3 | Economizer (1 Tube Pass) | 2022 | 750 | -0.1 | -14 | -25,169 | -55.8 | 0 | 195.0 | 139.2 | 5.4 | 8.4 | 10.8 | 70.12 |
| FBC3 | Economizer (2 Tube Pass) | 2022 | 1,075 | -0.28 | -29.1 | -51,578 | -114.3 | 0 | 288.8 | 174.6 | 6.2 | 9.2 | 40.4 | 92.79 |
| FBC3 | Economizer (3 Tube Pass) | 2022 | 1,400 | -0.4 | -45 | -79,583 | -176.3 | 0 | 382.6 | 206.3 | 6.8 | 9.8 | 73.7 | 117.78 |

**Table B-6 Preliminary Fuel and O&M Cost Impacts Expansion, Including Useful Plant Life for all Units (Report –10 year)**

| Unit | Project Description | In-Service Year | Project Cost ($000's) | Heat Rate Improvement (%) | Heat Rate Improvement (Btu/kWh) | MMBtu Savings | Coal Savings per year ($000's) | Variable O&M Savings per year ($000's) | Natural Gas Savings Per Year ($000's) | Total Savings per year ($000's) | Payback Period (Yrs. from project in-service) | Total Period | Cost per year ($000's) (10-year useful life) | Cost per ton of CO2 ($) (10-year useful Life) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| ABB1 | Air Heater Basket, Seal, and Sector Plate Replacement | 2021 | 850 | 0.5 | 58 | 58,716 | 130.1 | 0 | 0 | 130.1 | 6.5 | 8.5 | -45.1 | 14.50 |
| ABB1 | Air Heater (Steam Coil) System Repairs | 2021 | 350 | 0.1 | 11.6 | 11,768 | 26.1 | 0 | 0 | 26.1 | 13.4 | 15.4 | 8.9 | 29.85 |
| ABB1 | Circulating Water Pumps | 2021 | 2,100 | N/A | N/A | N/A | N/A | 0 | 0 | 0.0 | N/A | N/A | 210.0 | N/A |
| ABB1 | Induced Draft Fans | 2021 | 2,900 | 2.2 | 254.65 | 258,330 | 572.2 | -2 | 0 | 570.2 | 5.1 | 7.1 | -280.2 | 11.24 |
| ABB1 | Forced Draft Fans | 2021 | 2,000 | 0.5 | 58 | 58,711 | 130.1 | -2 | 0 | 128.1 | 15.6 | 17.6 | 71.9 | 34.12 |
| ABB1 | Neural Network with 0.25% Reduction in Excess $O_2$ | 2021 | 500 | 0.23 | 26.6 | 26,984 | 59.8 | 0 | 0 | 59.8 | 8.4 | 10.4 | -9.8 | 18.54 |
| ABB1 | Neural Network with 0.50% Reduction in Excess $O_2$ | 2021 | 500 | 0.4 | 50 | 50,489 | 111.8 | 0 | 0 | 111.8 | 4.5 | 6.5 | -61.8 | 9.92 |
| ABB1 | Neural Network with 0.75% Reduction in Excess $O_2$ | 2021 | 500 | 0.6 | 69.5 | 70,504 | 156.2 | 0 | 0 | 156.2 | 3.2 | 5.2 | -106.2 | 7.11 |
| ABB1 | Heat Rate Improvement Training. | 2021 | 15 | 0.3 | 35 | 35,201 | 78.0 | 0 | 0 | 78.0 | 0.2 | 2.2 | -76.5 | 0.43 |
| ABB1 | On-Site Heat Rate Appraisals. | 2021 | Variable | Variable | N/A | N/A | N/A | 0 | 0 | 0.0 | N/A | N/A | N/A | N/A |
| ABB1 | Improved Condenser Cleaner Strategies | 2021 | N/A | 0.2 | 17 | 17,651 | 39.1 | 0 | 0 | 39.1 | N/A | N/A | N/A | N/A |
| ABB1 | Economizer (1 Tube Pass) | 2021 | 750 | -0.17 | -17.5 | -17,753 | -39.3 | 0 | N/A | -39.3 | -19.1 | -17.1 | 114.3 | -37.63 |
| ABB1 | Economizer (2 Tube Pass) | 2021 | 1,075 | -0.4 | -37 | -37,433 | -82.9 | 0 | N/A | -82.9 | -13.0 | -11.0 | 190.4 | -25.47 |
| ABB1 | Economizer (3 Tube Pass) | 2021 | 1,400 | -0.61 | -62.4 | -63,302 | -140.2 | 0 | N/A | -140.2 | -10.0 | -8.0 | 280.2 | -19.58 |

| Unit | Project Description | In-Service Year | Project Cost ($000's) | Heat Rate Improvement (%) | Heat Rate Improvement (Btu/kWh) | MMBtu Savings | Coal Savings per year ($000's) | Variable O&M Savings per year ($000's) | Natural Gas Savings Per Year ($000's) | Total Savings per year ($000's) | Payback Period (Yrs. from project in-service) | Total Period | Cost per year ($000's) (10-year useful life) | Cost per ton of CO2 ($) (10-year useful Life) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| ABB2 | Air Heater Basket, Seal, and Sector Plate Replacement | 2021 | 850 | 0.5 | 55 | 58,348 | 129.2 | 0 | 0 | 129.2 | 6.6 | 8.6 | -44.2 | 14.50 |
| ABB2 | Air Heater (Steam Coil) System Repairs | 2021 | 350 | 0.1 | 11 | 11,670 | 25.8 | 0 | 0 | 25.8 | 13.5 | 15.5 | 9.2 | 29.85 |
| ABB2 | Circulating Water Pumps | 2021 | 2,100 | N/A | N/A | N/A | N/A | 0 | 0 | 0.0 | N/A | N/A | 210.0 | N/A |
| ABB2 | Induced Draft Fans | 2021 | 2,900 | 1.2 | 132.084 | 140,125 | 310.4 | 0 | 0 | -2.0 | -1,450.0 | -1448.0 | 292.0 | 20.61 |
| ABB2 | Forced Draft Fans | 2021 | 2,000 | 0.2 | 22 | 23,354 | 51.7 | 0 | 0 | -2.0 | -1,000.0 | -998.0 | 202.0 | 85.29 |
| ABB2 | Neural Network with 0.25% Reduction in Excess $O_2$ | 2021 | 500 | 3 | 25.3 | 26,840 | 59.5 | 0 | 0 | 59.5 | 8.4 | 10.4 | -9.5 | 1.42 |
| ABB2 | Neural Network with 0.50% Reduction in Excess $O_2$ | 2021 | 500 | 0.4 | 47 | 50,211 | 111.2 | 0 | 0 | 111.2 | 4.5 | 6.5 | -61.2 | 9.92 |
| ABB2 | Neural Network with 0.75% Reduction in Excess $O_2$ | 2021 | 500 | 0.6 | 66 | 70,018 | 155.1 | 0 | 0 | 155.1 | 3.2 | 5.2 | -105.1 | 7.11 |
| ABB2 | Heat Rate Improvement Training | 2021 | 15 | 0.3 | 33 | 35,009 | 77.5 | 0 | 0 | 77.5 | 0.2 | 2.2 | -76.0 | 0.43 |
| ABB2 | On-Site Heat Rate Appraisals | 2021 | Variable | Variable | N/A | N/A | N/A | 0 | 0 | 0.0 | N/A | N/A | N/A | N/A |
| ABB2 | Improved Condenser Cleaner Strategies | 2021 | N/A | N/A | N/A | N/A | N/A | 0 | 0 | 0.0 | N/A | N/A | N/A | N/A |
| ABB2 | Economizer (1 Tube Pass) | 2021 | 750 | -0.17 | -17.5 | -18,565 | -41.1 | 0 | N/A | -41.1 | -18.2 | -16.2 | 139.3 | -50.17 |
| ABB2 | Economizer (2 Tube Pass) | 2021 | 1,075 | -0.4 | -37 | -39,146 | -86.7 | 0 | N/A | -86.7 | -12.4 | -10.4 | 182.9 | -23.69 |
| ABB2 | Economizer (3 Tube Pass) | 2021 | 1,400 | -0.61 | -62.4 | -66,199 | -146.6 | 0 | N/A | -146.6 | -9.5 | -7.5 | 240.2 | -13.98 |

| Unit | Project Description | In-Service Year | Project Cost ($000's) | Heat Rate Improvement (%) | Heat Rate Improvement (Btu/kWh) | MMBtu Savings | Coal Savings per year ($000's) | Variable O&M Savings per year ($000's) | Natural Gas Savings Per Year ($000's) | Total Savings per year ($000's) | Payback Period (Yrs. from project in-service) | Total Period | Cost per year ($000's) (10-year useful life) | Cost per ton of CO2 ($) (10-year useful Life) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| FBC2 | Air Heater Basket, Seal, and Sector Plate Replacement | 2021 | 476 | 0.5 | 63 | 12,782 | 28.3 | 0 | 0 | 28.3 | 16.8 | 18.8 | 19.3 | 8.12 |
| FBC2 | Circulating Water Pumps | 2021 | 900 | N/A | N/A | N/A | N/A | 0 | 0 | 0.0 | N/A | N/A | 90.0 | N/A |
| FBC2 | Boiler Feed Pump | 2021 | 600 | 0.6 | 76 | 15,337 | 34.0 | -2 | 0 | 32.0 | 18.8 | 20.8 | 28.0 | 8.53 |
| FBC2 | Forced Draft Fans | 2021 | 2,000 | 0.5 | 63.195 | 12,781 | 28.3 | -2 | 0 | 26.3 | 76.0 | 78.0 | 173.7 | 34.12 |
| FBC2 | Neural Network with 0.25% Reduction in Excess $O_2$ | 2021 | 500 | 0.3 | 33 | 6,654 | 14.7 | 0 | 0 | 14.7 | 33.9 | 35.9 | 35.3 | 16.40 |
| FBC2 | Neural Network with 0.50% Reduction in Excess $O_2$ | 2021 | 500 | 0.47 | 59.4 | 12,014 | 26.6 | 0 | 0 | 26.6 | 18.8 | 20.8 | 23.4 | 9.07 |
| FBC2 | Neural Network with 0.75% Reduction in Excess $O_2$ | 2021 | 500 | 0.6 | 78 | 15,856 | 35.1 | 0 | 0 | 35.1 | 14.2 | 16.2 | 14.9 | 6.88 |
| FBC2 | Synchronized Controlled Sootblowing System | 2021 | 350 | 0.1 | 12.64 | 2,556 | 5.7 | 0 | 0 | 5.7 | 61.8 | 63.8 | 29.3 | 29.85 |
| FBC2 | Heat Rate Improvement Training | 2021 | 15 | 0.3 | 38 | 7,665 | 17.0 | 0 | 0 | 17.0 | 0.9 | 2.9 | -15.5 | 0.43 |
| FBC2 | On-Site Heat Rate Appraisals | 2021 | Variable | Variable | N/A | N/A | N/A | 0 | 0 | 0.0 | N/A | N/A | N/A | N/A |
| FBC2 | Improved Condenser Cleaner Strategies | 2021 | N/A | 0.4 | 53 | 10,740 | 23.8 | 0 | 0 | 23.8 | N/A | N/A | N/A | N/A |
| FBC3 | HP/IP Upgrades | 2022 | 19,900 | 1.5 | 158.3 | 280,580 | 621.5 | 0 | 0 | 621.5 | 32.0 | 35.0 | 1,368.5 | 113.16 |
| FBC3 | Air Heater Basket, Seal, and Sector Plate Replacement | 2022 | 750 | 0.5 | 53 | 93,586 | 207.3 | 0 | 0 | 207.3 | 3.6 | 6.6 | -132.3 | 12.79 |
| FBC3 | Air Heater (Steam Coil) System Repairs | 2022 | 350 | 0.1 | 10.6 | 18,788 | 41.6 | 0 | 0 | 41.6 | 8.4 | 11.4 | -6.6 | 29.85 |

| Unit | Project Description | In-Service Year | Project Cost ($000's) | Heat Rate Improvement (%) | Heat Rate Improvement (Btu/kWh) | MMBtu Savings | Coal Savings per year ($000's) | Variable O&M Savings per year ($000's) | Natural Gas Savings Per Year ($000's) | Total Savings per year ($000's) | Payback Period (Yrs. from project in-service) | Total Period | Cost per year ($000's) (10-year useful life) | Cost per ton of CO2 ($) (10-year useful Life) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| FBC3 | Circulating Water Pumps | 2022 | 2,100 | N/A | N/A | N/A | N/A | 0 | 0 | 0.0 | N/A | N/A | 210.0 | N/A |
| FBC3 | Forced Draft Fans | 2022 | 2,000 | 0.46 | 48.5392 | 86,034 | 190.6 | -2 | 0 | 188.6 | 10.6 | 13.6 | 11.4 | 37.08 |
| FBC3 | Neural Network with 0.25% Reduction in Excess $O_2$ | 2022 | 500 | 0.3 | 26 | 46,793 | 103.7 | 0 | 0 | 103.7 | 4.8 | 7.8 | -53.7 | 17.06 |
| FBC3 | Neural Network with 0.50% Reduction in Excess $O_2$ | 2022 | 500 | 0.46 | 48.54 | 86,035 | 190.6 | 0 | 0 | 190.6 | 2.6 | 5.6 | -140.6 | 9.27 |
| FBC3 | Neural Network with 0.75% Reduction in Excess $O_2$ | 2022 | 500 | 0.6 | 65 | 115,919 | 256.8 | 0 | 0 | 256.8 | 1.9 | 4.9 | -206.8 | 6.88 |
| FBC3 | Heat Rate Improvement Training | 2022 | 15 | 0.3 | 31.7 | 56,187 | 124.5 | 0 | 0 | 124.5 | 0.1 | 3.1 | -123.0 | 0.43 |
| FBC3 | On-Site Heat Rate Appraisals | 2022 | Variable | Variable | N/A | N/A | N/A | 0 | 0 | 0.0 | N/A | N/A | N/A | N/A |
| FBC3 | Improved Condenser Cleaner Strategies | 2022 | N/A | 0.44 | 46.4 | 82,242 | 182.2 | 0 | 0 | 182.2 | N/A | N/A | N/A | N/A |
| FBC3 | Economizer (1 Tube Pass) | 2022 | 750 | -0.1 | -14 | -25,169 | -55.8 | 0 | 195.0 | 139.2 | 5.4 | 8.4 | -64.2 | 35.06 |
| FBC3 | Economizer (2 Tube Pass) | 2022 | 1,075 | -0.28 | -29.1 | -51,578 | -114.3 | 0 | 288.8 | 174.6 | 6.2 | 9.2 | -67.1 | 46.40 |
| FBC3 | Economizer (3 Tube Pass) | 2022 | 1,400 | -0.4 | -45 | -79,583 | -176.3 | 0 | 382.6 | 206.3 | 6.8 | 9.8 | -66.3 | 58.89 |

**Table B-7 Preliminary Fuel and O&M Cost Impacts Expansion, Including Useful Plant Life for all Units (Report –15 year)**

| Unit | Project Description | In-Service Year | Project Cost ($000's) | Heat Rate Improvement (%) | Heat Rate Improvement (Btu/kWh) | MMBtu Savings | Coal Savings per year ($000's) | Variable O&M Savings per year ($000's) | Natural Gas Savings Per Year ($000's) | Total Savings per year ($000's) | Payback Period (Yrs. from project in-service) | Total Period | Cost per year ($000's) (15-year useful life) | Cost per ton of CO2 ($) (15-year useful Life) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| ABB1 | Air Heater Basket, Seal, and Sector Plate Replacement | 2021 | 850 | 0.5 | 58 | 58,716 | 130.1 | 0 | 0 | 130.1 | 6.5 | 8.5 | -73.4 | 9.67 |
| ABB1 | Air Heater (Steam Coil) System Repairs | 2021 | 350 | 0.1 | 11.6 | 11,768 | 26.1 | 0 | 0 | 26.1 | 13.4 | 15.4 | -2.7 | 19.90 |
| ABB1 | Circulating Water Pumps | 2021 | 2,100 | N/A | N/A | N/A | N/A | 0 | 0 | 0.0 | N/A | N/A | 140.0 | N/A |
| ABB1 | Induced Draft Fans | 2021 | 2,900 | 2.2 | 254.65 | 258,330 | 572.2 | -2 | 0 | 570.2 | 5.1 | 7.1 | -376.9 | 7.50 |
| ABB1 | Forced Draft Fans | 2021 | 2,000 | 0.5 | 58 | 58,711 | 130.1 | -2 | 0 | 128.1 | 15.6 | 17.6 | 5.3 | 22.74 |
| ABB1 | Neural Network with 0.25% Reduction in Excess $O_2$ | 2021 | 500 | 0.23 | 26.6 | 26,984 | 59.8 | 0 | 0 | 59.8 | 8.4 | 10.4 | -26.4 | 12.36 |
| ABB1 | Neural Network with 0.50% Reduction in Excess $O_2$ | 2021 | 500 | 0.4 | 50 | 50,489 | 111.8 | 0 | 0 | 111.8 | 4.5 | 6.5 | -78.5 | 6.61 |
| ABB1 | Neural Network with 0.75% Reduction in Excess $O_2$ | 2021 | 500 | 0.6 | 69.5 | 70,504 | 156.2 | 0 | 0 | 156.2 | 3.2 | 5.2 | -122.8 | 4.74 |
| ABB1 | Heat Rate Improvement Training. | 2021 | 15 | 0.3 | 35 | 35,201 | 78.0 | 0 | 0 | 78.0 | 0.2 | 2.2 | -77.0 | 0.28 |
| ABB1 | On-Site Heat Rate Appraisals. | 2021 | Variable | Variable | N/A | N/A | N/A | 0 | 0 | 0.0 | N/A | N/A | N/A | N/A |
| ABB1 | Improved Condenser Cleaner Strategies | 2021 | N/A | 0.2 | 17 | 17,651 | 39.1 | 0 | 0 | 39.1 | N/A | N/A | N/A | N/A |
| ABB1 | Economizer (1 Tube Pass) | 2021 | 750 | -0.17 | -17.5 | -17,753 | -39.3 | 0 | N/A | -39.3 | -19.1 | -17.1 | 89.3 | -25.09 |
| ABB1 | Economizer (2 Tube Pass) | 2021 | 1,075 | -0.4 | -37 | -37,433 | -82.9 | 0 | N/A | -82.9 | -13.0 | -11.0 | 154.6 | -16.98 |
| ABB1 | Economizer (3 Tube Pass) | 2021 | 1,400 | -0.61 | -62.4 | -63,302 | -140.2 | 0 | N/A | -140.2 | -10.0 | -8.0 | 233.6 | -13.05 |

| Unit | Project Description | In-Service Year | Project Cost ($000's) | Heat Rate Improvement (%) | Heat Rate Improvement (Btu/kWh) | MMBtu Savings | Coal Savings per year ($000's) | Variable O&M Savings per year ($000's) | Natural Gas Savings Per Year ($000's) | Total Savings per year ($000's) | Payback Period (Yrs. from project in-service) | Total Period | Cost per year ($000's) (15-year useful life) | Cost per ton of CO2 ($) (15-year useful Life) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| ABB2 | Air Heater Basket, Seal, and Sector Plate Replacement | 2021 | 850 | 0.5 | 55 | 58,348 | 129.2 | 0 | 0 | 129.2 | 6.6 | 8.6 | -72.6 | 9.67 |
| ABB2 | Air Heater (Steam Coil) System Repairs | 2021 | 350 | 0.1 | 11 | 11,670 | 25.8 | 0 | 0 | 25.8 | 13.5 | 15.5 | -2.5 | 19.90 |
| ABB2 | Circulating Water Pumps | 2021 | 2,100 | N/A | N/A | N/A | N/A | 0 | 0 | 0.0 | N/A | N/A | 140.0 | N/A |
| ABB2 | Induced Draft Fans | 2021 | 2,900 | 1.2 | 132.084 | 140,125 | 310.4 | 0 | 0 | -2.0 | -1,450.0 | -1448.0 | 195.3 | 13.74 |
| ABB2 | Forced Draft Fans | 2021 | 2,000 | 0.2 | 22 | 23,354 | 51.7 | 0 | 0 | -2.0 | -1,000.0 | -998.0 | 135.3 | 56.86 |
| ABB2 | Neural Network with 0.25% Reduction in Excess $O_2$ | 2021 | 500 | 3 | 25.3 | 26,840 | 59.5 | 0 | 0 | 59.5 | 8.4 | 10.4 | -26.1 | 0.95 |
| ABB2 | Neural Network with 0.50% Reduction in Excess $O_2$ | 2021 | 500 | 0.4 | 47 | 50,211 | 111.2 | 0 | 0 | 111.2 | 4.5 | 6.5 | -77.9 | 6.61 |
| ABB2 | Neural Network with 0.75% Reduction in Excess $O_2$ | 2021 | 500 | 0.6 | 66 | 70,018 | 155.1 | 0 | 0 | 155.1 | 3.2 | 5.2 | -121.8 | 4.74 |
| ABB2 | Heat Rate Improvement Training | 2021 | 15 | 0.3 | 33 | 35,009 | 77.5 | 0 | 0 | 77.5 | 0.2 | 2.2 | -76.5 | 0.28 |
| ABB2 | On-Site Heat Rate Appraisals | 2021 | Variable | Variable | N/A | N/A | N/A | 0 | 0 | 0.0 | N/A | N/A | N/A | N/A |
| ABB2 | Improved Condenser Cleaner Strategies | 2021 | N/A | N/A | N/A | N/A | N/A | 0 | 0 | 0.0 | N/A | N/A | N/A | N/A |
| ABB2 | Economizer (1 Tube Pass) | 2021 | 750 | -0.17 | -17.5 | -18,565 | -41.1 | 0 | N/A | -41.1 | -18.2 | -16.2 | 106.0 | -33.45 |
| ABB2 | Economizer (2 Tube Pass) | 2021 | 1,075 | -0.4 | -37 | -39,146 | -86.7 | 0 | N/A | -86.7 | -12.4 | -10.4 | 149.6 | -15.80 |
| ABB2 | Economizer (3 Tube Pass) | 2021 | 1,400 | -0.61 | -62.4 | -66,199 | -146.6 | 0 | N/A | -146.6 | -9.5 | -7.5 | 206.9 | -9.32 |

| Unit | Project Description | In-Service Year | Project Cost ($000's) | Heat Rate Improvement (%) | Heat Rate Improvement (Btu/kWh) | MMBtu Savings | Coal Savings per year ($000's) | Variable O&M Savings per year ($000's) | Natural Gas Savings Per Year ($000's) | Total Savings per year ($000's) | Payback Period (Yrs. from project in-service) | Total Period | Cost per year ($000's) (15-year useful life) | Cost per ton of CO2 ($) (15-year useful Life) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| FBC2 | Air Heater Basket, Seal, and Sector Plate Replacement | 2021 | 476 | 0.5 | 63 | 12,782 | 28.3 | 0 | 0 | 28.3 | 16.8 | 18.8 | 3.4 | 5.41 |
| FBC2 | Circulating Water Pumps | 2021 | 900 | N/A | N/A | N/A | N/A | 0 | 0 | 0.0 | N/A | N/A | 60.0 | N/A |
| FBC2 | Boiler Feed Pump | 2021 | 600 | 0.6 | 76 | 15,337 | 34.0 | -2 | 0 | 32.0 | 18.8 | 20.8 | 8.0 | 5.69 |
| FBC2 | Forced Draft Fans | 2021 | 2,000 | 0.5 | 63.195 | 12,781 | 28.3 | -2 | 0 | 26.3 | 76.0 | 78.0 | 107.0 | 22.74 |
| FBC2 | Neural Network with 0.25% Reduction in Excess $O_2$ | 2021 | 500 | 0.3 | 33 | 6,654 | 14.7 | 0 | 0 | 14.7 | 33.9 | 35.9 | 18.6 | 10.94 |
| FBC2 | Neural Network with 0.50% Reduction in Excess $O_2$ | 2021 | 500 | 0.47 | 59.4 | 12,014 | 26.6 | 0 | 0 | 26.6 | 18.8 | 20.8 | 6.7 | 6.05 |
| FBC2 | Neural Network with 0.75% Reduction in Excess $O_2$ | 2021 | 500 | 0.6 | 78 | 15,856 | 35.1 | 0 | 0 | 35.1 | 14.2 | 16.2 | -1.8 | 4.59 |
| FBC2 | Synchronized Controlled Sootblowing System | 2021 | 350 | 0.1 | 12.64 | 2,556 | 5.7 | 0 | 0 | 5.7 | 61.8 | 63.8 | 17.7 | 19.90 |
| FBC2 | Heat Rate Improvement Training | 2021 | 15 | 0.3 | 38 | 7,665 | 17.0 | 0 | 0 | 17.0 | 0.9 | 2.9 | -16.0 | 0.28 |
| FBC2 | On-Site Heat Rate Appraisals | 2021 | Variable | Variable | N/A | N/A | N/A | 0 | 0 | 0.0 | N/A | N/A | N/A | N/A |
| FBC2 | Improved Condenser Cleaner Strategies | 2021 | N/A | 0.4 | 53 | 10,740 | 23.8 | 0 | 0 | 23.8 | N/A | N/A | N/A | N/A |
| FBC3 | HP/IP Upgrades | 2022 | 19,900 | 1.5 | 158.3 | 280,580 | 621.5 | 0 | 0 | 621.5 | 32.0 | 35.0 | 705.1 | 75.44 |
| FBC3 | Air Heater Basket, Seal, and Sector Plate Replacement | 2022 | 750 | 0.5 | 53 | 93,586 | 207.3 | 0 | 0 | 207.3 | 3.6 | 6.6 | -157.3 | 8.53 |
| FBC3 | Air Heater (Steam Coil) System Repairs | 2022 | 350 | 0.1 | 10.6 | 18,788 | 41.6 | 0 | 0 | 41.6 | 8.4 | 11.4 | -18.3 | 19.90 |

| Unit | Project Description | In-Service Year | Project Cost ($000's) | Heat Rate Improvement (%) | Heat Rate Improvement (Btu/kWh) | MMBtu Savings | Coal Savings per year ($000's) | Variable O&M Savings per year ($000's) | Natural Gas Savings Per Year ($000's) | Total Savings per year ($000's) | Payback Period (Yrs. from project in-service) | Total Period | Cost per year ($000's) (15-year useful life) | Cost per ton of CO2 ($) (15-year useful Life) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| FBC3 | Circulating Water Pumps | 2022 | 2,100 | N/A | N/A | N/A | N/A | 0 | 0 | 0.0 | N/A | N/A | 140.0 | N/A |
| FBC3 | Forced Draft Fans | 2022 | 2,000 | 0.46 | 48.5392 | 86,034 | 190.6 | -2 | 0 | 188.6 | 10.6 | 13.6 | -55.2 | 24.72 |
| FBC3 | Neural Network with 0.25% Reduction in Excess $O_2$ | 2022 | 500 | 0.3 | 26 | 46,793 | 103.7 | 0 | 0 | 103.7 | 4.8 | 7.8 | -70.3 | 11.37 |
| FBC3 | Neural Network with 0.50% Reduction in Excess $O_2$ | 2022 | 500 | 0.46 | 48.54 | 86,035 | 190.6 | 0 | 0 | 190.6 | 2.6 | 5.6 | -157.2 | 6.18 |
| FBC3 | Neural Network with 0.75% Reduction in Excess $O_2$ | 2022 | 500 | 0.6 | 65 | 115,919 | 256.8 | 0 | 0 | 256.8 | 1.9 | 4.9 | -223.4 | 4.59 |
| FBC3 | Heat Rate Improvement Training | 2022 | 15 | 0.3 | 31.7 | 56,187 | 124.5 | 0 | 0 | 124.5 | 0.1 | 3.1 | -123.5 | 0.28 |
| FBC3 | On-Site Heat Rate Appraisals | 2022 | Variable | Variable | N/A | N/A | N/A | 0 | 0 | 0.0 | N/A | N/A | N/A | N/A |
| FBC3 | Improved Condenser Cleaner Strategies | 2022 | N/A | 0.44 | 46.4 | 82,242 | 182.2 | 0 | 0 | 182.2 | N/A | N/A | N/A | N/A |
| FBC3 | Economizer (1 Tube Pass) | 2022 | 750 | -0.1 | -14 | -25,169 | -55.8 | 0 | 195.0 | 139.2 | 5.4 | 8.4 | -89.2 | 23.37 |
| FBC3 | Economizer (2 Tube Pass) | 2022 | 1,075 | -0.28 | -29.1 | -51,578 | -114.3 | 0 | 288.8 | 174.6 | 6.2 | 9.2 | -102.9 | 30.93 |
| FBC3 | Economizer (3 Tube Pass) | 2022 | 1,400 | -0.4 | -45 | -79,583 | -176.3 | 0 | 382.6 | 206.3 | 6.8 | 9.8 | -113 | 39.26 |

**Table B-8 Preliminary Fuel and O&M Cost Impacts Expansion, Including Useful Plant Life for all Units (Report –20 year)**

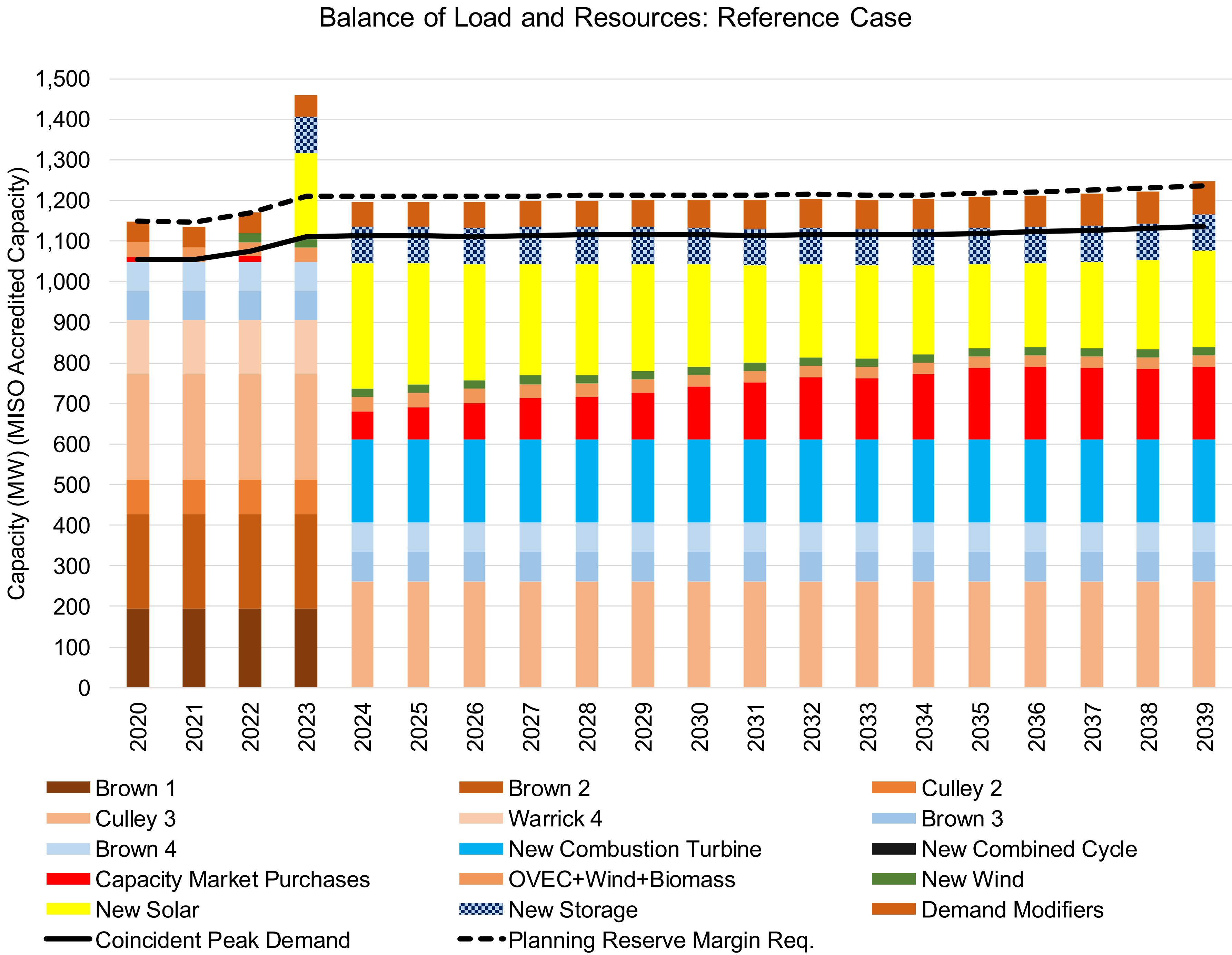
| Unit | Project Description | In-Service Year | Project Cost ($000's) | Heat Rate Improvement (%) | Heat Rate Improvement (Btu/kWh) | MMBtu Savings | Coal Savings per year ($000's) | Variable O&M Savings per year ($000's) | Natural Gas Savings Per Year ($000's) | Total Savings per year ($000's) | Payback Period (Yrs. from project in-service) | Total Period | Cost per year ($000's) (20-year useful life) | Cost per ton of CO2 ($) (20-year useful Life) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| ABB1 | Air Heater Basket, Seal, and Sector Plate Replacement | 2021 | 850 | 0.5 | 58 | 58,716 | 130.1 | 0 | 0 | 130.1 | 6.5 | 8.5 | -73.4 | 9.67 |
| ABB1 | Air Heater (Steam Coil) System Repairs | 2021 | 350 | 0.1 | 11.6 | 11,768 | 26.1 | 0 | 0 | 26.1 | 13.4 | 15.4 | -2.7 | 19.90 |
| ABB1 | Circulating Water Pumps | 2021 | 2,100 | N/A | N/A | N/A | N/A | 0 | 0 | 0.0 | N/A | N/A | 140.0 | N/A |
| ABB1 | Induced Draft Fans | 2021 | 2,900 | 2.2 | 254.65 | 258,330 | 572.2 | -2 | 0 | 570.2 | 5.1 | 7.1 | -376.9 | 7.50 |
| ABB1 | Forced Draft Fans | 2021 | 2,000 | 0.5 | 58 | 58,711 | 130.1 | -2 | 0 | 128.1 | 15.6 | 17.6 | 5.3 | 22.74 |
| ABB1 | Neural Network with 0.25% Reduction in Excess $O_2$ | 2021 | 500 | 0.23 | 26.6 | 26,984 | 59.8 | 0 | 0 | 59.8 | 8.4 | 10.4 | -26.4 | 12.36 |
| ABB1 | Neural Network with 0.50% Reduction in Excess $O_2$ | 2021 | 500 | 0.4 | 50 | 50,489 | 111.8 | 0 | 0 | 111.8 | 4.5 | 6.5 | -78.5 | 6.61 |
| ABB1 | Neural Network with 0.75% Reduction in Excess $O_2$ | 2021 | 500 | 0.6 | 69.5 | 70,504 | 156.2 | 0 | 0 | 156.2 | 3.2 | 5.2 | -122.8 | 4.74 |
| ABB1 | Heat Rate Improvement Training. | 2021 | 15 | 0.3 | 35 | 35,201 | 78.0 | 0 | 0 | 78.0 | 0.2 | 2.2 | -77.0 | 0.28 |
| ABB1 | On-Site Heat Rate Appraisals. | 2021 | Variable | Variable | N/A | N/A | N/A | 0 | 0 | 0.0 | N/A | N/A | N/A | N/A |
| ABB1 | Improved Condenser Cleaner Strategies | 2021 | N/A | 0.2 | 17 | 17,651 | 39.1 | 0 | 0 | 39.1 | N/A | N/A | N/A | N/A |
| ABB1 | Economizer (1 Tube Pass) | 2021 | 750 | -0.17 | -17.5 | -17,753 | -39.3 | 0 | N/A | -39.3 | -19.1 | -17.1 | 76.8 | -18.81 |
| ABB1 | Economizer (2 Tube Pass) | 2021 | 1,075 | -0.4 | -37 | -37,433 | -82.9 | 0 | N/A | -82.9 | -13.0 | -11.0 | 136.7 | -12.73 |
| ABB1 | Economizer (3 Tube Pass) | 2021 | 1,400 | -0.61 | -62.4 | -63,302 | -140.2 | 0 | N/A | -140.2 | -10.0 | -8.0 | 210.2 | -9.79 |
| ABB2 | Air Heater Basket, Seal, and Sector Plate Replacement | 2021 | 850 | 0.5 | 55 | 58,348 | 129.2 | 0 | 0 | 129.2 | 6.6 | 8.6 | -72.6 | 9.67 |

| Unit | Project Description | In-Service Year | Project Cost ($000's) | Heat Rate Improvement (%) | Heat Rate Improvement (Btu/kWh) | MMBtu Savings | Coal Savings per year ($000's) | Variable O&M Savings per year ($000's) | Natural Gas Savings Per Year ($000's) | Total Savings per year ($000's) | Payback Period (Yrs. from project in-service) | Total Period | Cost per year ($000's) (20-year useful life) | Cost per ton of CO2 ($) (20-year useful Life) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| ABB2 | Air Heater (Steam Coil) System Repairs | 2021 | 350 | 0.1 | 11 | 11,670 | 25.8 | 0 | 0 | 25.8 | 13.5 | 15.5 | -2.5 | 19.90 |
| ABB2 | Circulating Water Pumps | 2021 | 2,100 | N/A | N/A | N/A | N/A | 0 | 0 | 0.0 | N/A | N/A | 140.0 | N/A |
| ABB2 | Induced Draft Fans | 2021 | 2,900 | 1.2 | 132.084 | 140,125 | 310.4 | 0 | 0 | -2.0 | -1,450.0 | -1448.0 | 195.3 | 13.74 |
| ABB2 | Forced Draft Fans | 2021 | 2,000 | 0.2 | 22 | 23,354 | 51.7 | 0 | 0 | -2.0 | -1,000.0 | -998.0 | 135.3 | 56.86 |
| ABB2 | Neural Network with 0.25% Reduction in Excess $O_2$ | 2021 | 500 | 3 | 25.3 | 26,840 | 59.5 | 0 | 0 | 59.5 | 8.4 | 10.4 | -26.1 | 0.95 |
| ABB2 | Neural Network with 0.50% Reduction in Excess $O_2$ | 2021 | 500 | 0.4 | 47 | 50,211 | 111.2 | 0 | 0 | 111.2 | 4.5 | 6.5 | -77.9 | 6.61 |
| ABB2 | Neural Network with 0.75% Reduction in Excess $O_2$ | 2021 | 500 | 0.6 | 66 | 70,018 | 155.1 | 0 | 0 | 155.1 | 3.2 | 5.2 | -121.8 | 4.74 |
| ABB2 | Heat Rate Improvement Training | 2021 | 15 | 0.3 | 33 | 35,009 | 77.5 | 0 | 0 | 77.5 | 0.2 | 2.2 | -76.5 | 0.28 |
| ABB2 | On-Site Heat Rate Appraisals | 2021 | Variable | Variable | N/A | N/A | N/A | 0 | 0 | 0.0 | N/A | N/A | N/A | N/A |
| ABB2 | Improved Condenser Cleaner Strategies | 2021 | N/A | N/A | N/A | N/A | N/A | 0 | 0 | 0.0 | N/A | N/A | N/A | N/A |
| ABB2 | Economizer (1 Tube Pass) | 2021 | 750 | -0.17 | -17.5 | -18,565 | -41.1 | 0 | N/A | -41.1 | -18.2 | -16.2 | 106.0 | -33.45 |
| ABB2 | Economizer (2 Tube Pass) | 2021 | 1,075 | -0.4 | -37 | -39,146 | -86.7 | 0 | N/A | -86.7 | -12.4 | -10.4 | 149.6 | -15.80 |
| ABB2 | Economizer (3 Tube Pass) | 2021 | 1,400 | -0.61 | -62.4 | -66,199 | -146.6 | 0 | N/A | -146.6 | -9.5 | -7.5 | 206.9 | -9.32 |
| FBC2 | Air Heater Basket, Seal, and Sector Plate Replacement | 2021 | 476 | 0.5 | 63 | 12,782 | 28.3 | 0 | 0 | 28.3 | 16.8 | 18.8 | 3.4 | 5.41 |
| FBC2 | Circulating Water Pumps | 2021 | 900 | N/A | N/A | N/A | N/A | 0 | 0 | 0.0 | N/A | N/A | 60.0 | N/A |
| FBC2 | Boiler Feed Pump | 2021 | 600 | 0.6 | 76 | 15,337 | 34.0 | -2 | 0 | 32.0 | 18.8 | 20.8 | 8.0 | 5.69 |
| FBC2 | Forced Draft Fans | 2021 | 2,000 | 0.5 | 63.195 | 12,781 | 28.3 | -2 | 0 | 26.3 | 76.0 | 78.0 | 107.0 | 22.74 |

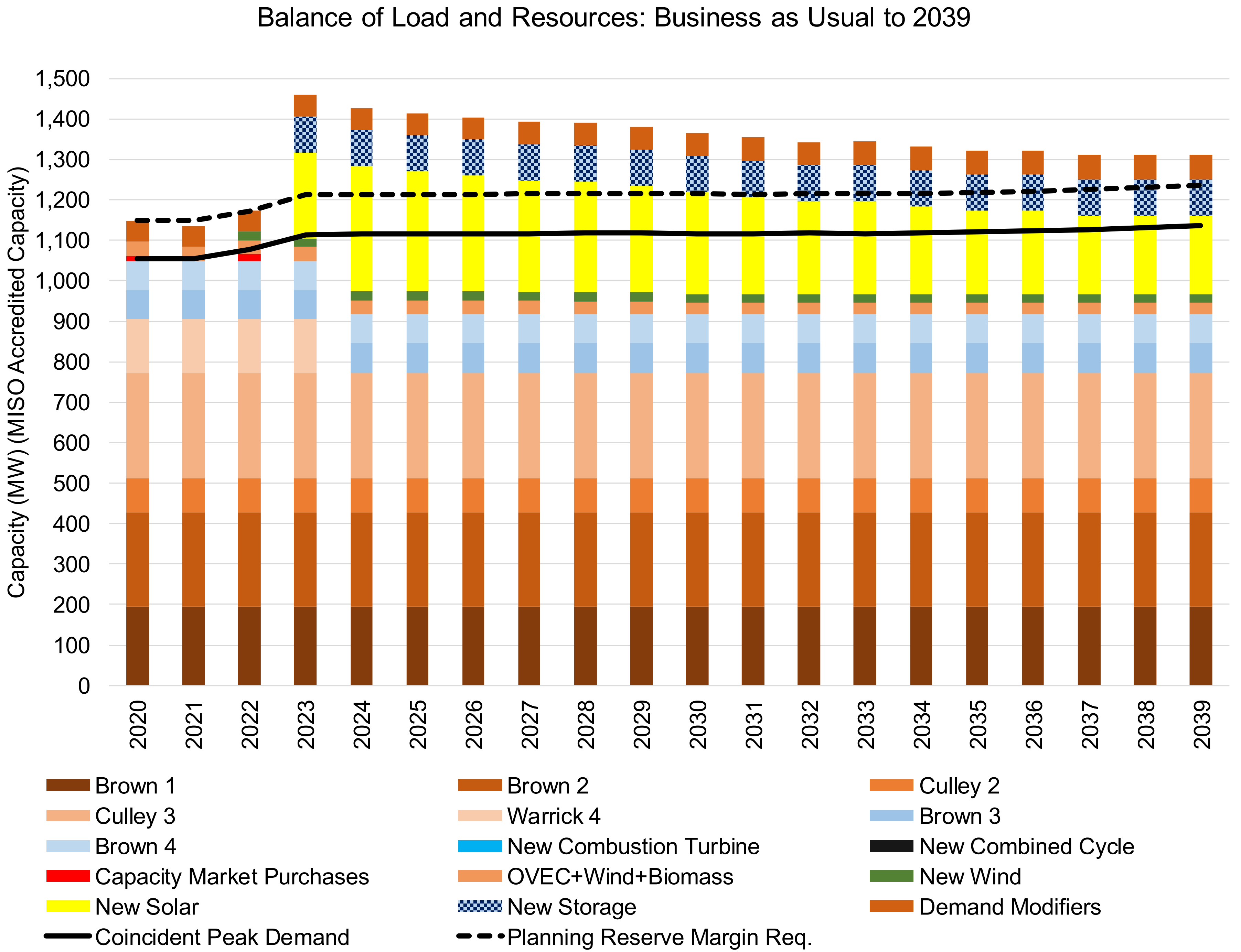
| Unit | Project Description | In-Service Year | Project Cost ($000's) | Heat Rate Improvement (%) | Heat Rate Improvement (Btu/kWh) | MMBtu Savings | Coal Savings per year ($000's) | Variable O&M Savings per year ($000's) | Natural Gas Savings Per Year ($000's) | Total Savings per year ($000's) | Payback Period (Yrs. from project in-service) | Total Period | Cost per year ($000's) (20-year useful life) | Cost per ton of CO2 ($) (20-year useful Life) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| FBC2 | Neural Network with 0.25% Reduction in Excess $O_2$ | 2021 | 500 | 0.3 | 33 | 6,654 | 14.7 | 0 | 0 | 14.7 | 33.9 | 35.9 | 18.6 | 10.94 |
| FBC2 | Neural Network with 0.50% Reduction in Excess $O_2$ | 2021 | 500 | 0.47 | 59.4 | 12,014 | 26.6 | 0 | 0 | 26.6 | 18.8 | 20.8 | 6.7 | 6.05 |
| FBC2 | Neural Network with 0.75% Reduction in Excess $O_2$ | 2021 | 500 | 0.6 | 78 | 15,856 | 35.1 | 0 | 0 | 35.1 | 14.2 | 16.2 | -1.8 | 4.59 |
| FBC2 | Synchronized Controlled Sootblowing System | 2021 | 350 | 0.1 | 12.64 | 2,556 | 5.7 | 0 | 0 | 5.7 | 61.8 | 63.8 | 17.7 | 19.90 |
| FBC2 | Heat Rate Improvement Training | 2021 | 15 | 0.3 | 38 | 7,665 | 17.0 | 0 | 0 | 17.0 | 0.9 | 2.9 | -16.0 | 0.28 |
| FBC2 | On-Site Heat Rate Appraisals | 2021 | Variable | Variable | N/A | N/A | N/A | 0 | 0 | 0.0 | N/A | N/A | N/A | N/A |
| FBC2 | Improved Condenser Cleaner Strategies | 2021 | N/A | 0.4 | 53 | 10,740 | 23.8 | 0 | 0 | 23.8 | N/A | N/A | N/A | N/A |
| FBC3 | HP/IP Upgrades | 2022 | 19,900 | 1.5 | 158.3 | 280,580 | 621.5 | 0 | 0 | 621.5 | 32.0 | 35.0 | 705.1 | 75.44 |
| FBC3 | Air Heater Basket, Seal, and Sector Plate Replacement | 2022 | 750 | 0.5 | 53 | 93,586 | 207.3 | 0 | 0 | 207.3 | 3.6 | 6.6 | -157.3 | 8.53 |
| FBC3 | Air Heater (Steam Coil) System Repairs | 2022 | 350 | 0.1 | 10.6 | 18,788 | 41.6 | 0 | 0 | 41.6 | 8.4 | 11.4 | -18.3 | 19.90 |
| FBC3 | Circulating Water Pumps | 2022 | 2,100 | N/A | N/A | N/A | N/A | 0 | 0 | 0.0 | N/A | N/A | 140.0 | N/A |
| FBC3 | Forced Draft Fans | 2022 | 2,000 | 0.46 | 48.5392 | 86,034 | 190.6 | -2 | 0 | 188.6 | 10.6 | 13.6 | -55.2 | 24.72 |
| FBC3 | Neural Network with 0.25% Reduction in Excess $O_2$ | 2022 | 500 | 0.3 | 26 | 46,793 | 103.7 | 0 | 0 | 103.7 | 4.8 | 7.8 | -70.3 | 11.37 |
| FBC3 | Neural Network with 0.50% Reduction in Excess $O_2$ | 2022 | 500 | 0.46 | 48.54 | 86,035 | 190.6 | 0 | 0 | 190.6 | 2.6 | 5.6 | -157.2 | 6.18 |

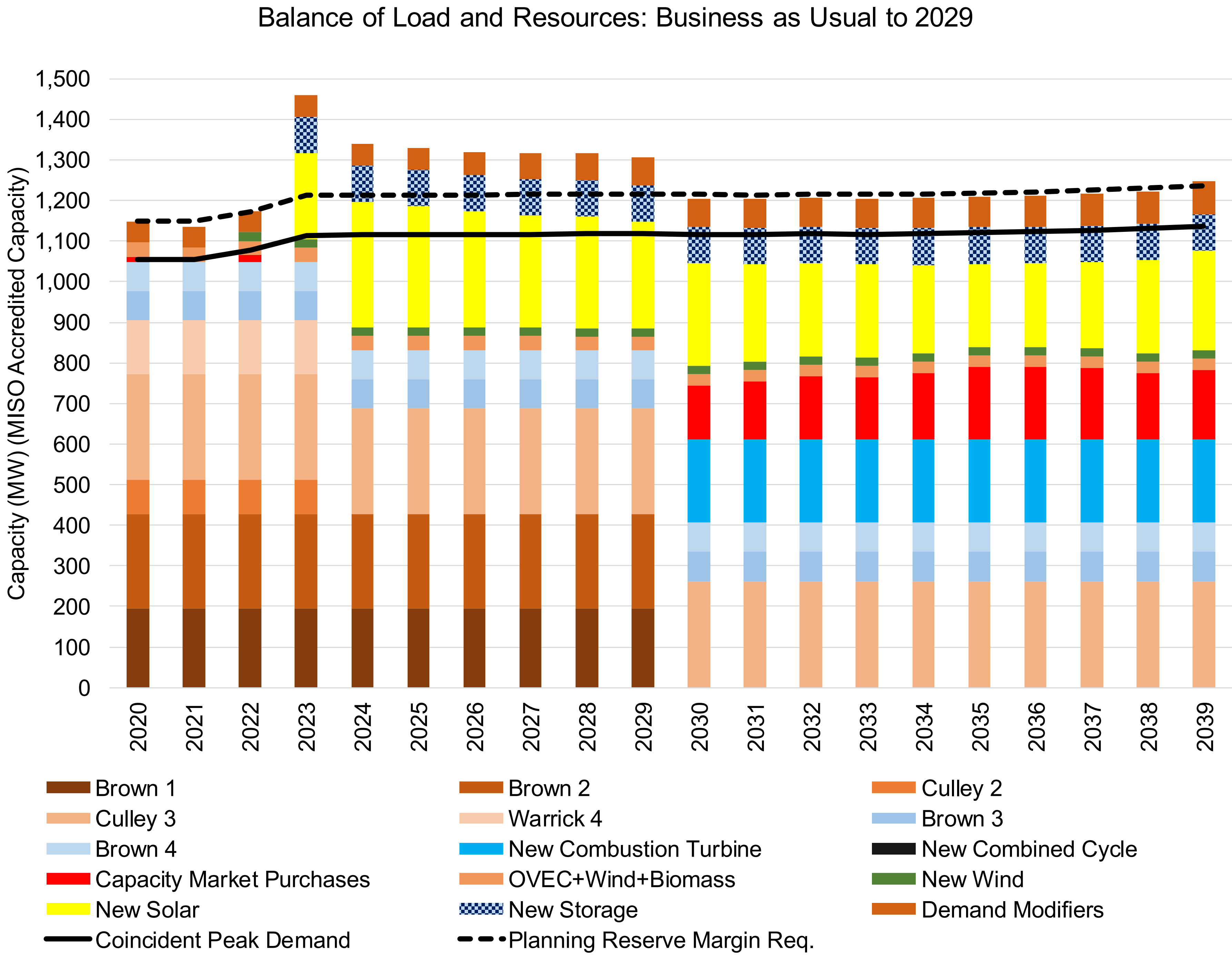
| Unit | Project Description | In-Service Year | Project Cost ($000's) | Heat Rate Improvement (%) | Heat Rate Improvement (Btu/kWh) | MMBtu Savings | Coal Savings per year ($000's) | Variable O&M Savings per year ($000's) | Natural Gas Savings Per Year ($000's) | Total Savings per year ($000's) | Payback Period (Yrs. from project in-service) | Total Period | Cost per year ($000's) (20-year useful life) | Cost per ton of CO2 ($) (20-year useful Life) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| FBC3 | Neural Network with 0.75% Reduction in Excess $O_2$ | 2022 | 500 | 0.6 | 65 | 115,919 | 256.8 | 0 | 0 | 256.8 | 1.9 | 4.9 | -223.4 | 4.59 |
| FBC3 | Heat Rate Improvement Training | 2022 | 15 | 0.3 | 31.7 | 56,187 | 124.5 | 0 | 0 | 124.5 | 0.1 | 3.1 | -123.5 | 0.28 |
| FBC3 | On-Site Heat Rate Appraisals | 2022 | Variable | Variable | N/A | N/A | N/A | 0 | 0 | 0.0 | N/A | N/A | N/A | N/A |
| FBC3 | Improved Condenser Cleaner Strategies | 2022 | N/A | 0.44 | 46.4 | 82,242 | 182.2 | 0 | 0 | 182.2 | N/A | N/A | N/A | N/A |
| FBC3 | Economizer (1 Tube Pass) | 2022 | 750 | -0.1 | -14 | -25,169 | -55.8 | 0 | 195.0 | 139.2 | 5.4 | 8.4 | -101.7 | 17.53 |
| FBC3 | Economizer (2 Tube Pass) | 2022 | 1,075 | -0.28 | -29.1 | -51,578 | -114.3 | 0 | 288.8 | 174.6 | 6.2 | 9.2 | -120.8 | 23.20 |
| FBC3 | Economizer (3 Tube Pass) | 2022 | 1,400 | -0.4 | -45 | -79,583 | -176.3 | 0 | 382.6 | 206.3 | 6.8 | 9.8 | -136.3 | 29.44 |

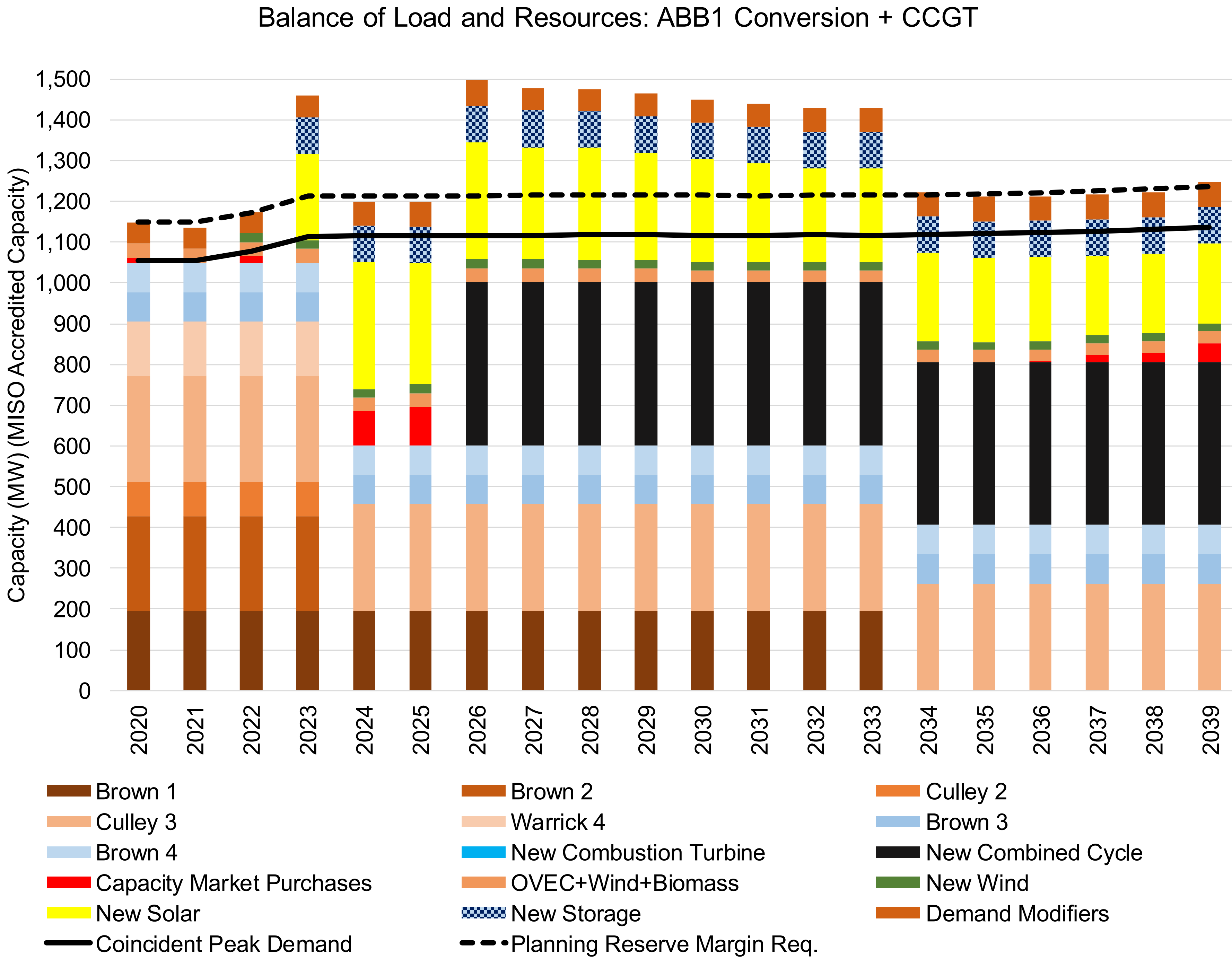
# Attachment 8.1 Balance of Load and Resources



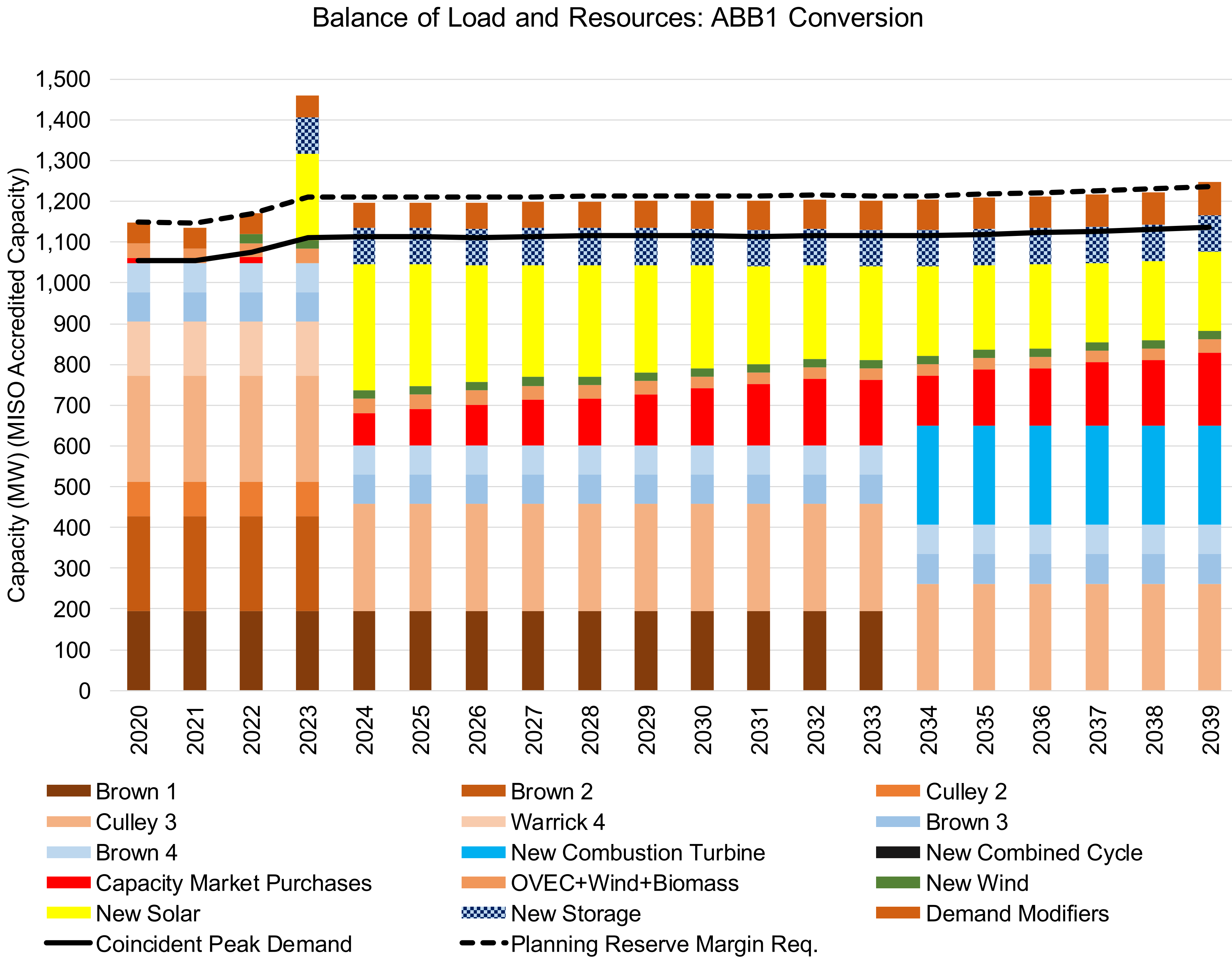
Balance of Load and Resources: Reference Case
Capacity (MW) (MISO Accredited Capacity)
0
100
200
300
400
500
600
700
800
900
1,000
1,100
1,200
1,300
1,400
1,500
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
2032
2033
2034
2035
2036
2037
2038
2039
Brown 1
Brown 2
Culley 2
Culley 3
Warrick 4
Brown 3
Brown 4
New Combustion Turbine
New Combined Cycle
Capacity Market Purchases
OVEC+Wind+Biomass
New Wind
New Solar
New Storage
Demand Modifiers
Coincident Peak Demand
Planning Reserve Margin Req.


Balance of Load and Resources: Business as Usual to 2039
Capacity (MW) (MISO Accredited Capacity)
1,500
1,400
1,300
1,200
1,100
1,000
900
800
700
600
500
400
300
200
100
0
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
2032
2033
2034
2035
2036
2037
2038
2039
Brown 1
Brown 2
Culley 2
Culley 3
Warrick 4
Brown 3
Brown 4
New Combustion Turbine
New Combined Cycle
Capacity Market Purchases
OVEC+Wind+Biomass
New Wind
New Solar
New Storage
Demand Modifiers
Coincident Peak Demand
Planning Reserve Margin Req.

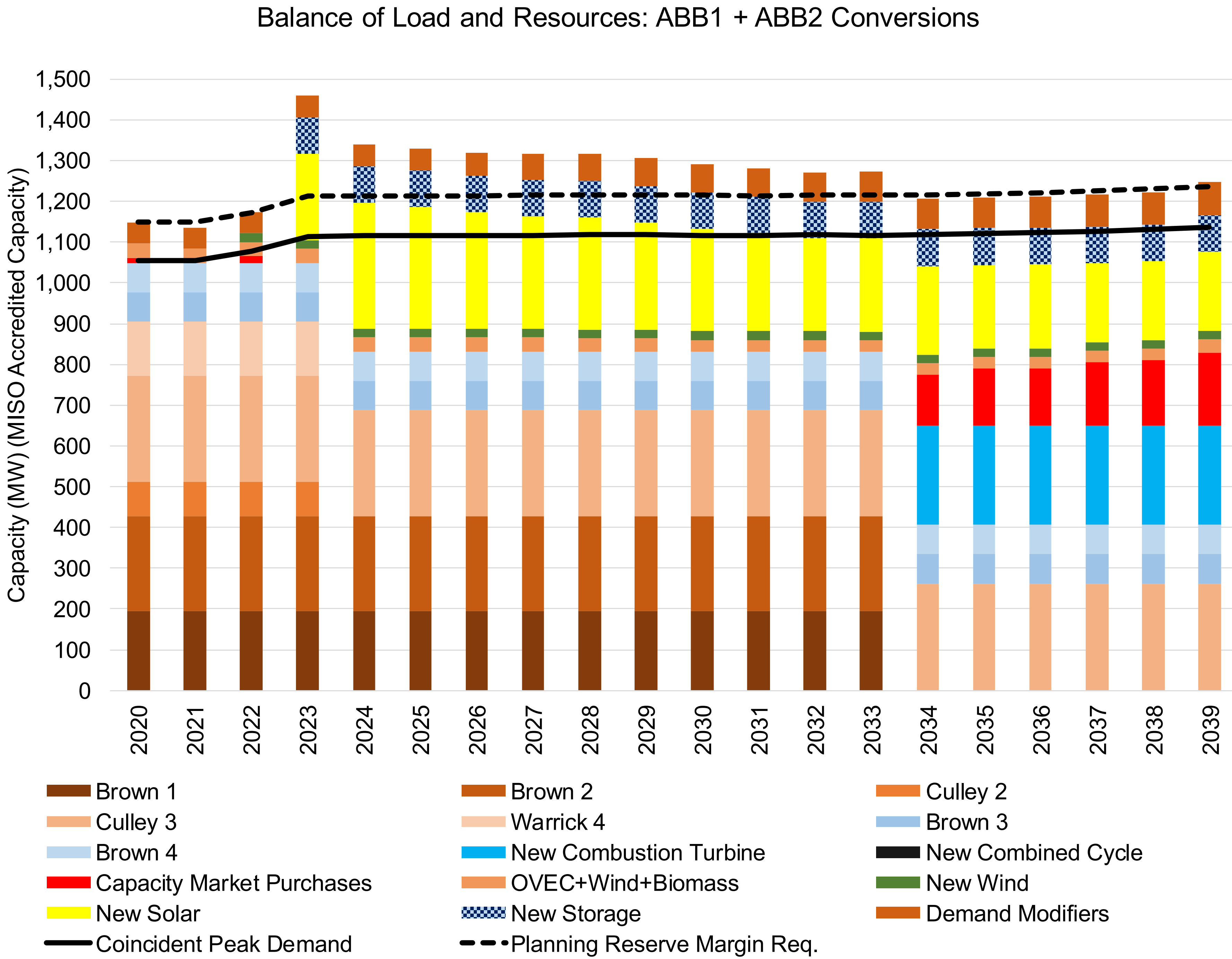

Balance of Load and Resources: Business as Usual to 2029
Capacity (MW) (MISO Accredited Capacity)
1,500
1,400
1,300
1,200
1,100
1,000
900
800
700
600
500
400
300
200
100
0
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
2032
2033
2034
2035
2036
2037
2038
2039
Brown 1
Brown 2
Culley 2
Culley 3
Warrick 4
Brown 3
Brown 4
New Combustion Turbine
New Combined Cycle
Capacity Market Purchases
OVEC+Wind+Biomass
New Wind
New Solar
New Storage
Demand Modifiers
Coincident Peak Demand
Planning Reserve Margin Req.



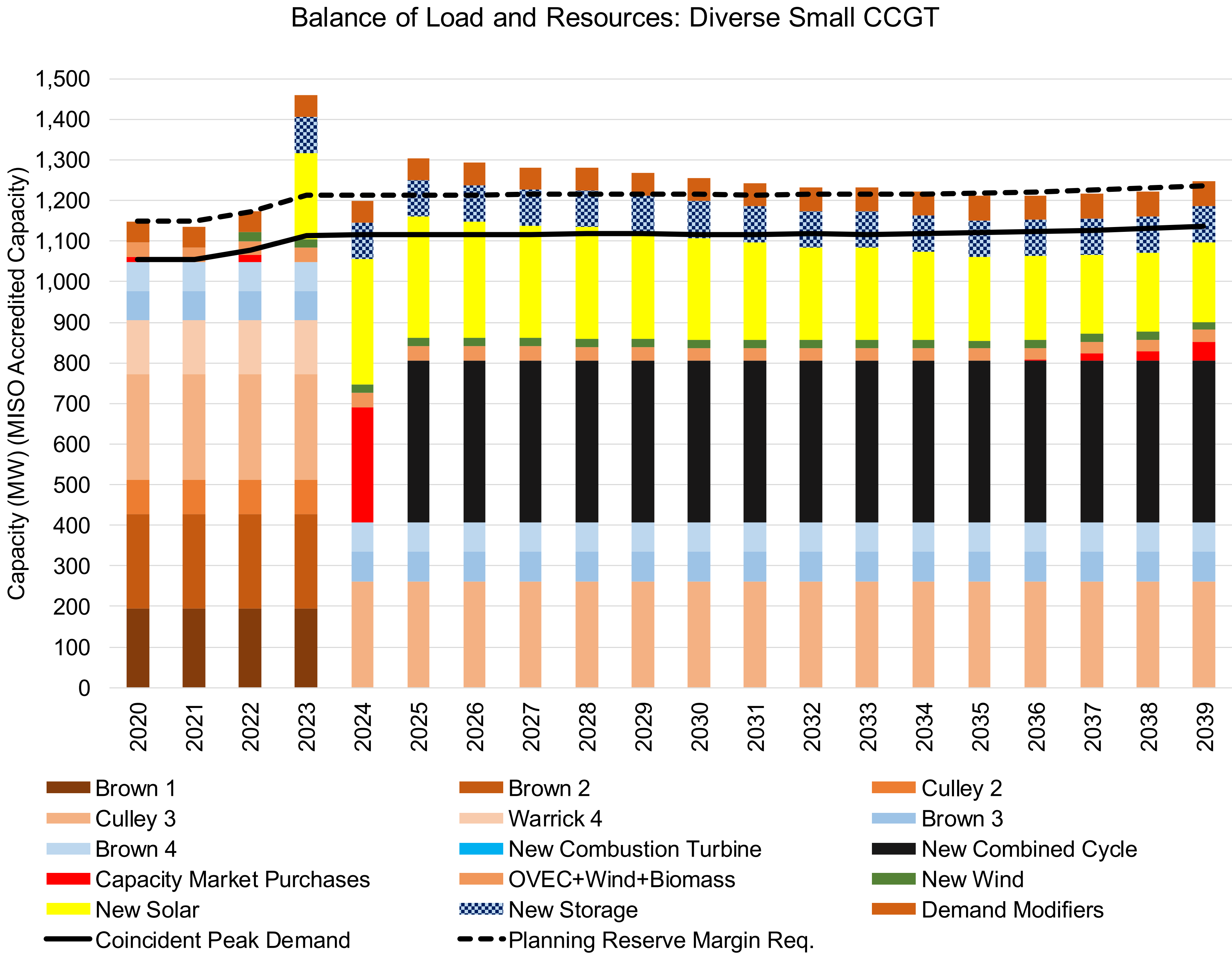
Balance of Load and Resources: ABB1 Conversion + CCGT
Capacity (MW) (MISO Accredited Capacity)
0
100
200
300
400
500
600
700
800
900
1,000
1,100
1,200
1,300
1,400
1,500
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
2032
2033
2034
2035
2036
2037
2038
2039
Brown 1
Brown 2
Culley 2
Culley 3
Warrick 4
Brown 3
Brown 4
New Combustion Turbine
New Combined Cycle
Capacity Market Purchases
OVEC+Wind+Biomass
New Wind
New Solar
New Storage
Demand Modifiers
Coincident Peak Demand
Planning Reserve Margin Req.

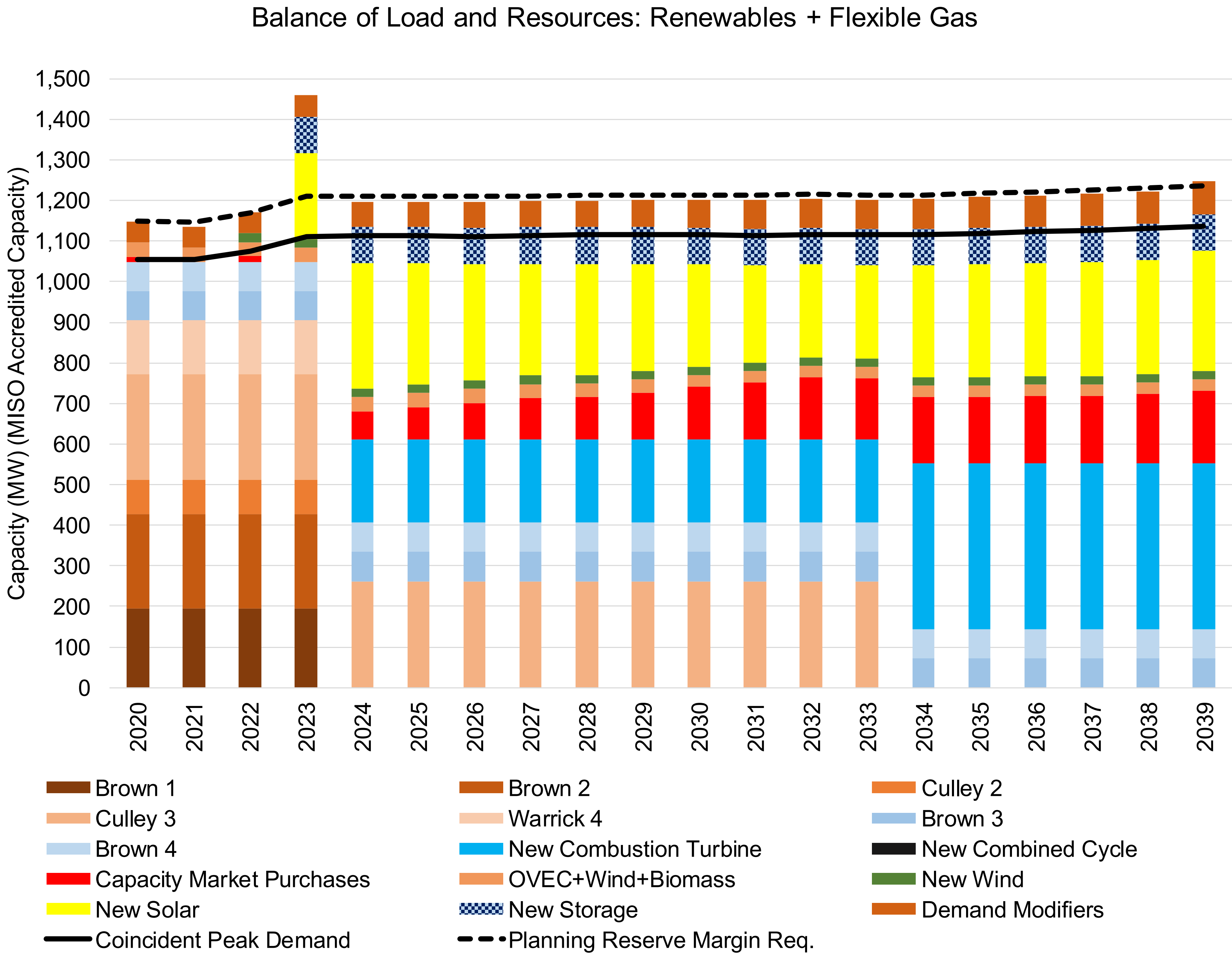


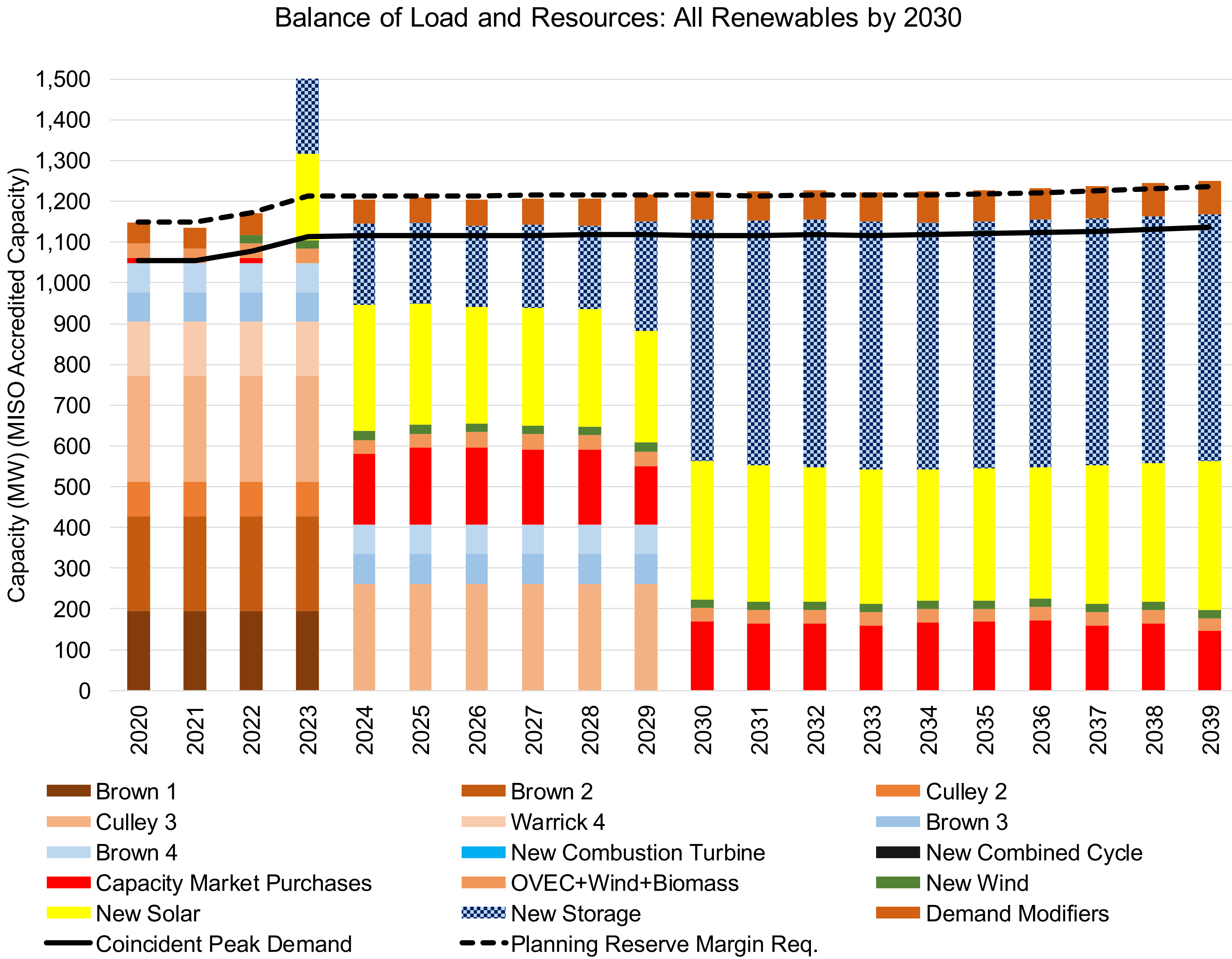
Balance of Load and Resources: ABB1 Conversion
Capacity (MW) (MISO Accredited Capacity)
1,500
1,400
1,300
1,200
1,100
1,000
900
800
700
600
500
400
300
200
100
0
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
2032
2033
2034
2035
2036
2037
2038
2039
Brown 1
Brown 2
Culley 2
Culley 3
Warrick 4
Brown 3
Brown 4
New Combustion Turbine
New Combined Cycle
Capacity Market Purchases
OVEC+Wind+Biomass
New Wind
New Solar
New Storage
Demand Modifiers
Coincident Peak Demand
Planning Reserve Margin Req.

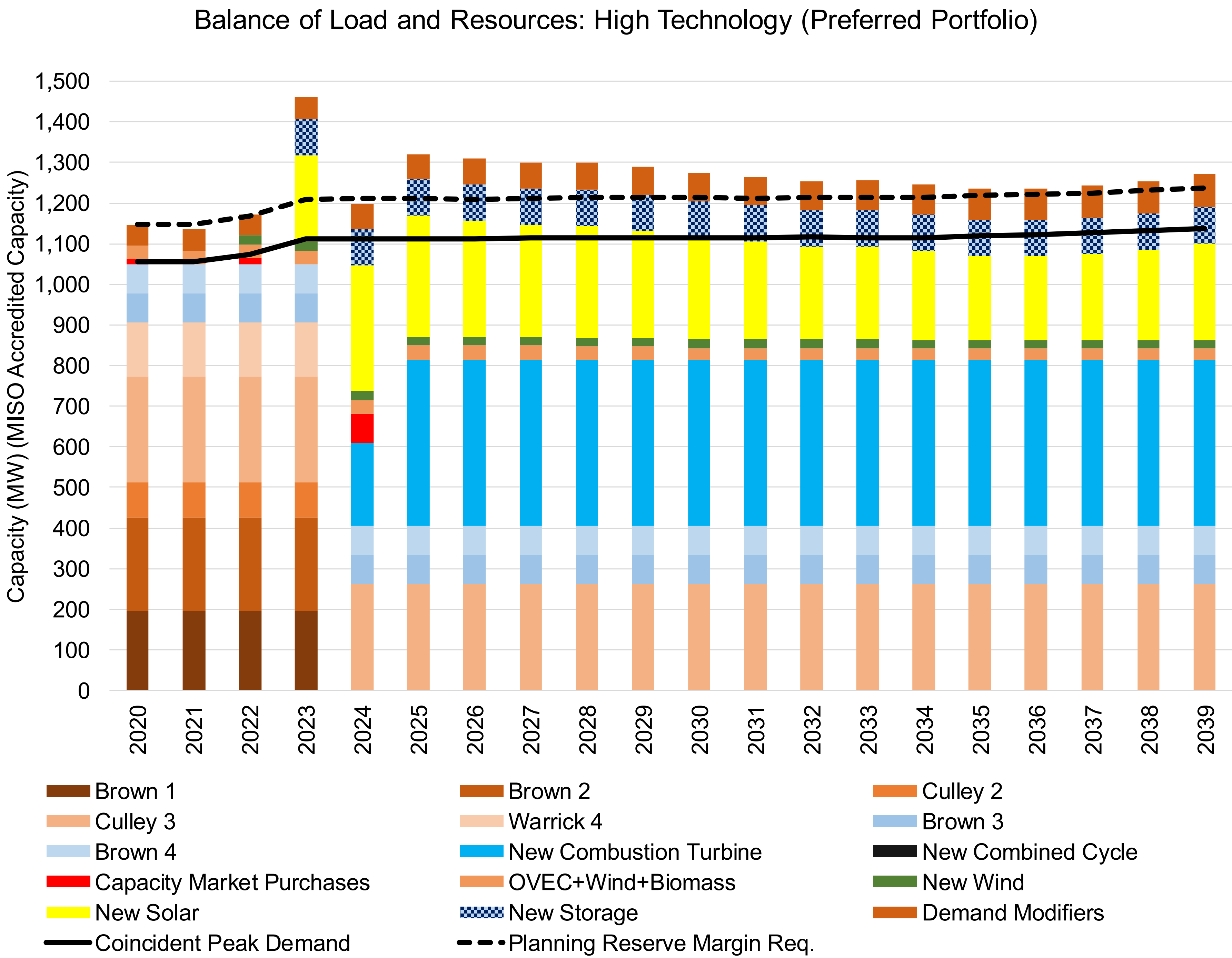


Balance of Load and Resources: ABB1 + ABB2 Conversions
Capacity (MW) (MISO Accredited Capacity)
0
100
200
300
400
500
600
700
800
900
1,000
1,100
1,200
1,300
1,400
1,500
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
2032
2033
2034
2035
2036
2037
2038
2039
Brown 1
Brown 2
Culley 2
Culley 3
Warrick 4
Brown 3
Brown 4
New Combustion Turbine
New Combined Cycle
Capacity Market Purchases
OVEC+Wind+Biomass
New Wind
New Solar
New Storage
Demand Modifiers
Coincident Peak Demand
Planning Reserve Margin Req.


Balance of Load and Resources: Diverse Small CCGT
Capacity (MW) (MISO Accredited Capacity)
1,500
1,400
1,300
1,200
1,100
1,000
900
800
700
600
500
400
300
200
100
0
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
2032
2033
2034
2035
2036
2037
2038
2039
Brown 1
Brown 2
Culley 2
Culley 3
Warrick 4
Brown 3
Brown 4
New Combustion Turbine
New Combined Cycle
Capacity Market Purchases
OVEC+Wind+Biomass
New Wind
New Solar
New Storage
Demand Modifiers
Coincident Peak Demand
Planning Reserve Margin Req.


Balance of Load and Resources: Renewables + Flexible Gas
Capacity (MW) (MISO Accredited Capacity)
1,500
1,400
1,300
1,200
1,100
1,000
900
800
700
600
500
400
300
200
100
0
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
2032
2033
2034
2035
2036
2037
2038
2039
Brown 1
Brown 2
Culley 2
Culley 3
Warrick 4
Brown 3
Brown 4
New Combustion Turbine
New Combined Cycle
Capacity Market Purchases
OVEC+Wind+Biomass
New Wind
New Solar
New Storage
Demand Modifiers
Coincident Peak Demand
Planning Reserve Margin Req.


Balance of Load and Resources: All Renewables by 2030
Capacity (MW) (MISO Accredited Capacity)
1,500
1,400
1,300
1,200
1,100
1,000
900
800
700
600
500
400
300
200
100
0
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
2032
2033
2034
2035
2036
2037
2038
2039
Brown 1
Brown 2
Culley 2
Culley 3
Warrick 4
Brown 3
Brown 4
New Combustion Turbine
New Combined Cycle
Capacity Market Purchases
OVEC+Wind+Biomass
New Wind
New Solar
New Storage
Demand Modifiers
Coincident Peak Demand
Planning Reserve Margin Req.


Balance of Load and Resources: High Technology (Preferred Portfolio)
Capacity (MW) (MISO Accredited Capacity)
1,500
1,400
1,300
1,200
1,100
1,000
900
800
700
600
500
400
300
200
100
0
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
2032
2033
2034
2035
2036
2037
2038
2039
Brown 1
Brown 2
Culley 2
Culley 3
Warrick 4
Brown 3
Brown 4
New Combustion Turbine
New Combined Cycle
Capacity Market Purchases
OVEC+Wind+Biomass
New Wind
New Solar
New Storage
Demand Modifiers
Coincident Peak Demand
Planning Reserve Margin Req.