SOUTHERN INDIANA GAS AND ELECTRIC COMPANY
d/b/a CENTERPOINT ENERGY INDIANA SOUTH
(CENTERPOINT INDIANA SOUTH)

IURC CAUSE NO. 45564

DIRECT TESTIMONY (PUBLIC)
OF
MATTHEW A. RICE
DIRECTOR OF INDIANA ELECTRIC REGULATORY AND RATES

ON

INTEGRATED RESOURCE PLAN, NECESSITY OF THE COMBUSTION TURBINES PROJECT AND RATEMAKING ISSUES

SPONSORING PETITIONER'S EXHIBIT NO. 5 (CONFIDENTIAL)

ATTACHMENTS MAR-1 THROUGH MAR-16

DIRECT TESTIMONY OF MATTHEW A. RICE

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Matthew Rice. My business address is 211 NW Riverside Drive, Evansville, Indiana 47708.

Q. On whose behalf are you submitting this direct testimony?

A. I am submitting testimony on behalf of Southern Indiana Gas and Electric Company d/b/a CenterPoint Energy Indiana South (“Petitioner”, “CenterPoint Indiana South”, or “Company”), which is an indirect subsidiary of CenterPoint Energy, Inc.

Q. What is your role with respect to Petitioner?

A. I am Director of Indiana Electric Regulatory and Rates.

Q. Please describe your educational background.

A. I received a Bachelor of Science degree in Business Administration from the University of Southern Indiana in 1999. I also received a Master of Business Administration from the University of Southern Indiana in 2008.

Q. Please describe your professional experience.

A. Prior to working for CenterPoint Indiana South, I worked as a Market Research Analyst for American General Finance for six years working primarily on customer segmentation, demographic analysis, and site location analysis. In 2007, I joined the Company as a Market Research Analyst, and have held various positions of increasing responsibility, including Senior Analyst, Manager of Market Research, and Director of Research and Energy Technologies. Since 2009, I have been responsible for long-term energy forecasting for the Company’s IRPs, helping to manage the Company’s 2011, 2014, 2016, and 2019/2020 IRPs. I have also managed its IRP stakeholder process since 2014. My duties have included conducting economic analysis, primary and secondary customer research (including surveying, focus groups, segmentation, and demographic analysis), customer satisfaction research, housing market research, and monitored industry research. In February 2019, I became Manager of Resource Planning with responsibility for internal and external generation analysis and reporting. I was named to my current position of Director of Indiana Electric Regulatory and Rates in October 2020.

Q. What are your present duties and responsibilities as Director of Indiana Electric Regulatory and Rates?

A. I am responsible for Petitioner's electric regulatory and rate matters in regulated proceedings before the Indiana Utility Regulatory Commission ("Commission"). I also have responsibility for resource planning and reporting for CenterPoint Indiana South, including the IRP.

Q. Have you previously testified before the Indiana Utility Regulatory Commission ("IURC" or "Commission")?

A. Yes. I testified before the Commission in support of CenterPoint Indiana South's Certificate of Public Convenience and Necessity ("CPCN") in Cause No. 45052, and Petitioner's request for approval of a tariff rate for Excess Distributed Generation in Cause No. 45378. Additionally, I recently provided written testimony in Cause No. 45501, Cause No. 44910-TDSIC-8, Cause No. 44909-CECA 3, and in Cause No. 45052-ECA 2.

II. PURPOSE & SCOPE OF TESTIMONY

Q. What is the purpose of your testimony in this proceeding?

A. My testimony describes the analysis and results of CenterPoint Indiana South's 2019/2020 Integrated Resource Plan ("2019/2020 IRP") process. I summarize and respond to comments made in the draft Director's report issued on April 12, 2021. In addition, I describe and support CenterPoint Indiana South's request for a CPCN to construct two combustion turbines ("CTs") at the A.B. Brown site to replace A.B. Brown coal units 1 and 2 and testify that the proposed generation is consistent with the IRP. I describe how the cost of the A.B. Brown combustion turbines will be recovered in rates. Finally, I describe how customer rates are projected to be impacted by the Generation Transition Plan.

Q. Are you sponsoring any attachments to your direct testimony in this proceeding?

A. Yes. I am sponsoring the following attachments:

- Petitioner's Exhibit No. 5, **Attachment MAR-1**: CenterPoint Indiana South's 2019/2020 Integrated Resource Plan Volume 1 of 2
- Petitioner's Exhibit No. 5, **Attachment MAR-2 (CONFIDENTIAL)**: CenterPoint Indiana South's 2019/2020 Integrated Resource Plan Volume 2 of 2
- Petitioner's Exhibit No. 5, **Attachment MAR-3**: Low End Estimated Net Monthly Rate Impact by Customer Class
- Petitioner's Exhibit No. 5, **Attachment MAR-4**: High End Estimated Net Monthly Rate Impact by Customer Class
- Petitioner's Exhibit No. 5, **Attachment MAR-5**: Low End Estimated Net Monthly Rate Impact by Customer Class – Existing Allocations
- Petitioner's Exhibit No. 5, **Attachment MAR-6**: High End Estimated Net Monthly Rate Impact by Customer Class – Existing Allocations
- Petitioner's Exhibit No. 5, **Attachment MAR-7 (CONFIDENTIAL)**: Posey County Solar Project
- Petitioner's Exhibit No. 5, **Attachment MAR-8 (CONFIDENTIAL)**: Warrick County Solar Project
- Petitioner's Exhibit No. 5, **Attachment MAR-9 (CONFIDENTIAL)**: 335 MW Solar PPA Projects
- Petitioner's Exhibit No. 5, **Attachment MAR-10 (CONFIDENTIAL)**: 200 MW Wind PPA Project
- Petitioner's Exhibit No. 5, **Attachment MAR-11**: 2 Combustion Turbine Project
- Petitioner's Exhibit No. 5, **Attachment MAR-12 (CONFIDENTIAL)**: 130 MW Owned Solar
- Petitioner's Exhibit No. 5, **Attachment MAR-13 (CONFIDENTIAL)**: 150 MW Wind Project
- Petitioner's Exhibit No. 5, **Attachment MAR-14**: BAU 2029 – Continue ABB1 & ABB2 Project
- Petitioner's Exhibit No. 5, **Attachment MAR-15**: Conversion of ABB1 & ABB2 Coal to Gas Project

Q. Were these attachments prepared by you or under your direction?

A. Yes, they were. The Company's 2019/2020 IRP process was managed under my direction or supervision, although it is important to recognize that other Company employees and consultants with specific areas of expertise engaged by the Company were involved in the process of developing the 2019/2020 IRP. In addition to these attachments, I am also sponsoring Petitioner's Exhibit No. 5, Attachment MAR-16, which was prepared by the Commission and is its 2018 Report of the Statewide Analysis of Future Resources for Electricity.

III. CENTERPOINT INDIANA SOUTH'S 2019/2020 IRP PROCESS

Q. Please describe how CenterPoint Indiana South approached the 2019/2020 IRP.

A. The 2019/2020 IRP was CenterPoint Indiana South's most detailed resource planning analysis process. The Company worked with several industry experts to conduct the technical analysis: Itron provided the long-term energy and demand forecast; 1898 and Company, a Burns and McDonnell company ("Burns and McDonnell"), worked with CenterPoint Indiana South to conduct an All-Source Request For Proposals ("All-Source RFP") and provide modeling inputs for various generating resources; Black and Veatch assisted with several studies utilized to evaluate numerous alternatives for existing resources; GDS provided Energy Efficiency modeling inputs; and Siemens PTI, formerly Pace Global Energy Services ("Siemens PTI"), provided scenario development, deterministic modeling, probabilistic modeling, and provided assistance with the risk analysis. A copy of Petitioner's 2019/2020 IRP is attached to my testimony as Petitioner's Exhibit No. 5, Attachments MAR-1 and MAR-2 (CONFIDENTIAL).

Q. What process did Petitioner use in developing the 2019/2020 IRP?

A. Petitioner began the process by reviewing stakeholder comments from the 2016 IRP, including the Director's Report, and by carefully reviewing the Commission Orders issued in connection with Petitioner's requests for CPCNs in Cause Nos. 45052 (F.B. Culley 3 upgrades and Combined Cycle Gas Turbine ("CCGT")) and 45086 (50 MW Troy solar). This feedback was used to formulate twelve continuous improvement commitments that were shared with CenterPoint Indiana South IRP stakeholders in our first public stakeholder meeting on August 15, 2019, and fulfilled on June 30, 2020, with the submission of the 2019/2020 IRP. In the first stakeholder meeting, CenterPoint Indiana South presented the analysis plan and laid out all topics to be discussed with stakeholders for each of CenterPoint Indiana South's public stakeholder meetings. Figure 3.1 "2019/2020 Stakeholder Meetings" on page 108 of the IRP, Petitioner's Exhibit No. 5, Attachment MAR-1, details the topics discussed in each meeting, summarized in Figure 1 below.

Figure 1: 2019/2020 Stakeholder Meetings

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

The general process involved presenting information and gathering feedback from stakeholders on key topics, including but not limited to the following: objectives, scorecard development, forecasts, modeling inputs, scenario development, portfolio development, technical modeling, and results. At the beginning of each stakeholder meeting, CenterPoint Indiana South made a point to follow up with stakeholders on input provided in the prior meeting. Often stakeholder feedback was utilized, but in instances where it was not, CenterPoint Indiana South discussed why it was not used. The planning analysis began with an All-Source RFP, which was conducted simultaneously with the IRP and was utilized as an input into modeling for resource selection/portfolio development. Objectives were presented at the first meeting. Scorecard development also began at this meeting and was refined throughout the process based on stakeholder feedback and evaluation of measures to ensure that each was a good representation of the risk factor it represented. Scenarios (potential future states) then were developed with stakeholder input for use in deterministic modeling. Portfolios (combinations of resource options to meet customer load over the evaluation period) were then developed with stakeholder input. Care was taken to ensure a wide range of scenarios and portfolios were utilized and evaluated within the IRP analysis, respectively. These portfolios then were modeled and evaluated within the deterministic futures and within probabilistic simulation of 200 potential futures (also referred to as stochastic modeling). CenterPoint Indiana South utilized quantitative and qualitative information produced within this analysis to select a preferred portfolio.

Q. Please describe the role of the All-Source RFP within the IRP.

A. Per Commission feedback in Cause No. 45052, CenterPoint Indiana South, with the help of Burns and McDonnell, conducted an All-Source RFP to gather resource availability and pricing information for various resources, particularly emerging resources such as solar, solar + storage, and standalone storage. Results of the All Source RFP were summarized into modeling inputs for the IRP for solar, solar + storage, standalone storage, and wind.

Q. What steps did CenterPoint Indiana South take to ensure that pricing included within modeling was as accurate as possible?

A. Care was taken to help ensure up-to-date and accurate information was included within modeling. For example, only projects that provided a firm price and were either on CenterPoint Indiana South's system or included a delivered price were included within modeling inputs. These were referred to as Tier 1 projects within the IRP.

> Proposals were divided into two tiers, based on factors that could add cost risk to [CenterPoint Indiana South] customers. Tier 1 Proposals were those that included binding pricing and delivery of energy to SIGE.SIGW ([CenterPoint Indiana South's] load node) or were physically located in [CenterPoint Indiana South's] service territory. Tier 2 included the remaining Proposals that were not classified as Tier 1. Tier 2 Proposals generally did not provide a binding bid price and/or were located off [CenterPoint Indiana South's] system, which increases cost risk due to congestion. Despite these risks, several were still analyzed and considered during the RFP evaluation process; however, [CenterPoint Indiana South] wanted, to the extent possible, to include

> bids with more price certainty within the IRP modeling in order to protect customers from price volatility.

Petitioner's Exhibit No. 5, Attachment MAR-1 at 153.

Burns and McDonnell took care to understand the bids and include all relevant costs, including known transmission upgrades. This involved communications between Burns and McDonnell and bidders to clarify information provided within the bid. Relevant data was provided to Burns and McDonnell via a standardized template to help keep information consistent among bids.

Q. Were bids for traditional fossil fuel resources used to create modeling inputs?

A. No, CenterPoint Indiana South received two bids for 100 MW coal PPAs (5 and 10 years), and several bids for mid-sized to large natural gas CCGTs. None were Tier 1 bids and therefore were not modeled. No bids were received for CTs. For new traditional fossil fuel resources, CenterPoint Indiana South relied on a technology assessment from Burns and McDonnell for cost and operational data, found in IRP Vol. 1, Petitioner's Exhibit No. 5, Attachment MAR-1.

Q. Did you receive any Demand Response bids?

A. Yes, CenterPoint Indiana South received only one bid for a demand response resource. It was for 50 MWs over a 6-year duration and covered the years where there was not a capacity need (2021 – 2022). Capacity was modeled as a potential resource within the IRP. The cost of this bid was higher than the capacity price forecast utilized within the IRP.

Q. Was cogeneration considered?

A. Yes. However, we did not receive any Tier 1 bids for cogeneration, so cogeneration was not an option to be selected in the near term. In the long-term, Combined Heat and Power ("CHP") was considered but not selected.

Q. Did you consider joint ownership of any facilities?

A. Yes, we approached other electric utilities in Indiana about jointly owning generation. No partnership opportunities materialized.

Q. Did you conduct a full Levelized Cost of Energy ("LCOE") screening analysis to

exclude technologies from being modeled?

A. No. In the 2016 IRP, an LCOE screening analysis was necessary because of the use of Strategist modeling software, which could not analyze multiple resources options at one time. The screening analysis removed resources that were not cost effective, prior to modeling to improve efficiency. There was no need to conduct a full LCOE analysis in the 2019/2020 IRP, as the Aurora model was able to consider many options at one time. This was responsive to the Commission's findings in Cause No. 45052 that ". . . multiple less expensive alternatives" were screened out. Only two options were excluded prior to modeling: aeroderivative natural gas combustion turbines due to high-pressure gas supply; and reciprocating natural gas engines due to high cost. In addition to multiple existing unit options (continue coal, retire coal, or conversion), the model was able to consider a large number of new options simultaneously, including: hydroelectric, wind, wind plus storage, solar, solar plus storage, lithium-ion battery storage, flow battery storage, energy efficiency, demand response, coal, biomass, landfill gas, combined heat and power, combined cycle gas, and simple cycle gas.

Q. What forecasts did CenterPoint Indiana South use in its 2019/2020 IRP?

A. Multiple forecasts were used as an input to the analysis to first develop a Reference Case. As described in Petitioner's Exhibit No. 5, Attachment MAR-1 Section 2.4.1 of the IRP, pages 89-91, CenterPoint Indiana South relied on several industry experts for key inputs in the IRP analysis. For coal, gas, market capacity price forecasts, and long-term emerging resource costs, a consensus forecast was used. For natural gas and coal, CenterPoint Indiana South created an average price using data from PIRA Energy Group, Wood Mackenzie, Siemens PTI, ABB, and Energy Ventures Analysis ("EVA"). For the MISO Zone 6 capacity value, CenterPoint Indiana South created an average, utilizing Siemens PTI, ABB, and Wood Mackenzie forecasts.[1] The long-term capital price forecast (beyond 2024) for emerging supply side resources was based on the average of National Renewable Energy Laboratory ("NREL"), Burns and McDonnell, and Siemens PTI forecasts. Siemens PTI developed the carbon price forecast. Itron developed the energy and demand forecast. GDS created a price forecast for demand side resources. Siemens PTI utilized both AURORAxmp power dispatch model with Reference Case inputs and

[1] CenterPoint Indiana South did not have access to a capacity forecast from PIRA or EVA.

expectations for the broader market to generate on-peak and off-peak power prices in the MISO region. To create varying inputs for scenarios, CenterPoint Indiana South worked with stakeholders to determine how key inputs would vary by scenario in the short-, mid-, and long-term based on narrative-based futures. This process helped ensure multiple perspectives were captured and used to create a wide range of potential futures. Siemens PTI used probabilistic distributions and adjusted Reference Case forecasts for each scenario in conjunction with stakeholder guidance, where reasonable.

Q. In your opinion, were the forecasts used by CenterPoint Indiana South reasonable?

A. Yes. Following the 2016 IRP, CenterPoint Indiana South was praised in the Director's report for using consensus forecasts where possible to increase transparency for stakeholders and incorporate multiple views from credible sources. CenterPoint Indiana South continued using consensus forecasts to develop the 2019/2020 IRP. Other inputs provided by expert third-party sources were shared and discussed as part of the stakeholder process. Forecasts were also compared with publicly available forecasts, such as the Energy Information Administration's Annual Energy Outlook, for reasonableness.

Q. Did CenterPoint Indiana South consider stakeholder input received at the Company-specific meetings?

A. Yes. CenterPoint Indiana South held three workshops as part of these meetings designed to solicit input from stakeholders that was incorporated into the IRP planning process. The fourth public meeting included a preview of the Preferred Portfolio. CenterPoint Indiana South described how stakeholder input received at the prior stakeholder meeting was utilized in each meeting. Where feedback was not used, CenterPoint Indiana South explained the reasoning. Feedback from stakeholders helped shape the analysis in significant ways, including but not limited to: scorecard development (identification and inclusion of key risks including considering full life cycle of CO_2e), scenario development, expected MISO accreditation of resources, fuel price forecasts, consideration of a wide range of portfolios, and use of an All-Source RFP.

Q. Did you incorporate stakeholder input into the portfolio development process?

A. Yes. CenterPoint Indiana South incorporated stakeholder input prior to and during the

2019/2020 IRP analysis. Continuous improvement of the resource planning analysis was integral to CenterPoint Indiana South's 2019/2020 IRP. CenterPoint Indiana South learned from the last IRP that stakeholders were interested in utilizing least cost optimization to help ensure portfolio cost was as low as possible. In the third public stakeholder meeting held on December 13, 2019, CenterPoint Indiana South discussed each portfolio development strategy and described the relevant stakeholder input used to help develop portfolios. Examples of stakeholder input considered included, but were not limited to: explore options at A.B. Brown, make adjustments to various scenarios, explore conversion options, run A.B. Brown until 2029, run A.B. Brown until 2039, do not run fossil fuel plants beyond 2030, consider smaller CCGT options, and consider flexible gas CTs and renewables.

Q. How did CenterPoint Indiana South develop the portfolios modeled in the 2019/2020 IRP?

A. CenterPoint Indiana South worked with stakeholders to consider and utilize strategies to develop a wide range of portfolios. Five portfolio development strategies were discussed with stakeholders: (i) Status Quo (i.e., continue running existing units), (ii) Scenario-Based (i.e., least cost optimization), (iii) Bridge (i.e., continued use of A.B. Brown assets), (iv) Diverse (i.e., diverse energy with renewables, gas, and coal), and (v) Renewables Focused (i.e., much less to no reliance on fossil fuel resources). Except for the Scenario-Based portfolio development strategy, various resource options were locked in, and deterministic modeling was utilized to select the most economical way to meet the remaining capacity and energy obligations. For example, under the Bridge portfolio development strategy, the Brown units would continue to run with the existing scrubber through 2029, and the model determined the replacement to meet MISO's planning reserve margin requirements and optimized for lowest net present value of revenue requirements ("NPVRR"). The Scenario-Based portfolio options were created for each of the five deterministic scenarios. In this process, existing coal units[2] were evaluated for economic retirement. Ultimately this process produced fifteen distinct portfolios, ranging

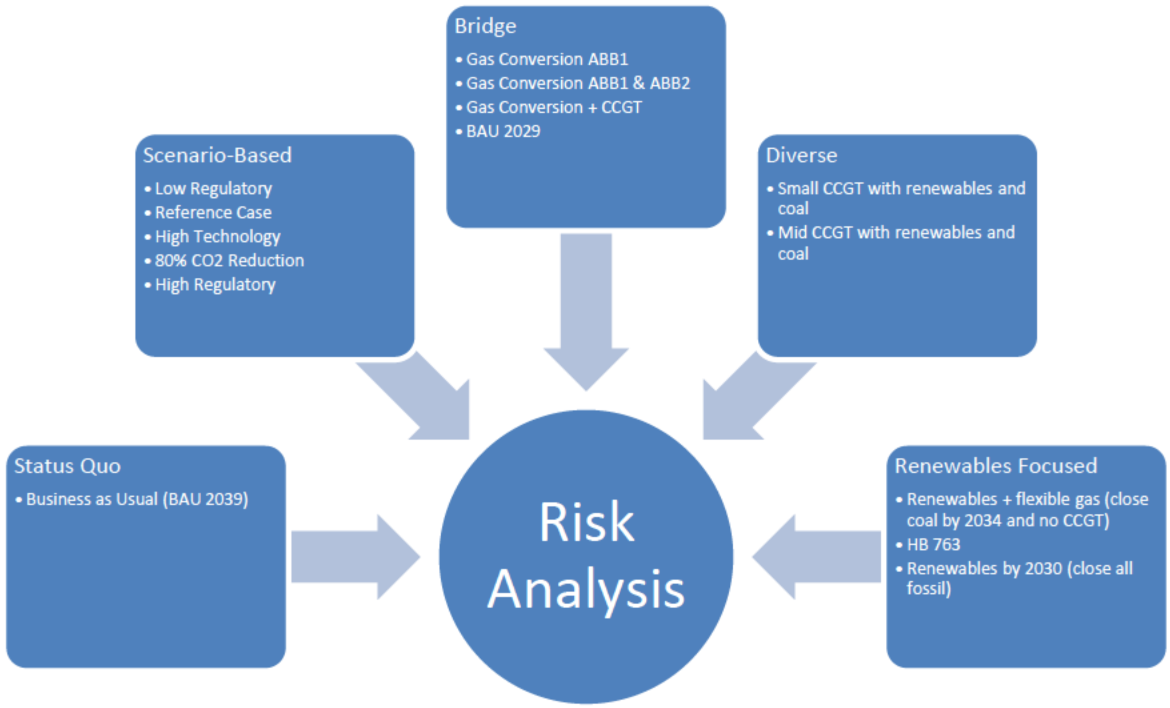
[2] A.B. Brown units 1 & 2, F.B. Culley 2, and Warrick Unit #4. Warrick Unit #4 is a jointly operated plant with Alcoa Power Generating, Inc. ("Alcoa"). The current contract expires at the end of 2023, leaving a 150 MW capacity shortfall currently in all portfolios. CenterPoint Indiana South modeled a potential 3-year extension of the contract; it was not selected based on economics.

from continuing most coal resources through the end of the forecast to an all-renewables portfolio by 2030.

Q. Please summarize the fifteen optimized portfolios that CenterPoint Indiana South examined.

A. Fifteen portfolios were created utilizing the process described above. Figure 2 below is a visual representation of the wide range of portfolios analyzed, bucketed by five portfolio development strategies: Status Quo, Scenario-Based, Bridge, Diverse, and Renewables Focused. A brief description of each strategy follows below. A Status Quo portfolio identified as Business as Usual ("BAU") through 2039 was included as a bookend. This portfolio included continuing to run all coal plants, except for Warrick Unit #4, through 2039. Five Scenario-Based portfolios were created (one per scenario) for the following scenarios: Reference Case, Low Regulatory, High Technology, 80 percent reduction of CO_2 by 2050, and High Regulatory. Each of these potential future states were optimized to produce a least cost portfolio in each future state. Four Bridge portfolios were created to explore options to continue to utilize existing equipment at the A.B. Brown plant. These portfolios included converting one unit to gas, converting two units to gas, converting one unit to gas with the addition of a small CCGT, and continuing to run both units with coal through 2029. Two Diverse energy portfolios were created: one with a small CCGT and the other with a mid-sized CCGT. These portfolios were included to explore options that produce a balanced mix of energy from coal, gas, and renewable resources. Finally, three Renewables Focused portfolios were created. The first was a Renewables Plus Flexible Gas portfolio, which involved closure of all coal units by 2034 and included gas CTs, renewables, and storage. The House Bill 763 portfolio was created with a very high CO_2 price per stakeholder input. The other bookend portfolio was to close all fossil fuel plants by 2030.

Figure 2: Portfolios by Strategy



All portfolios included demand side resources (i.e., Energy Efficiency and Demand Response). It should also be noted that the model selected a significant amount of wind and solar resources in all portfolios (300 MWs of wind and 1,150 MWs of solar before 2025), including the BAU portfolios, in part to replace Warrick Unit #4, but also because these resources lowered the NPVRR due to their production of low cost energy.

Q. Please describe the role of CO_2 in your analysis.

A. One of the biggest risk factors considered in this analysis was CO_2 output. Scenarios, potential future states, were constructed using various regulatory environments including alternate paths for CO_2. The Low Regulatory scenario only included the Affordable Clean Energy (ACE) rule, which required upgrades at coal plants to improve efficiency. The Reference Case assumed ACE would be repealed and replaced with a modest CO_2 tax beginning in 2027. As mentioned in Petitioner's Witness Angila M. Retherford's testimony, ACE has since been vacated in court. The High Technology scenario assumed a low CO_2 tax beginning in 2025. The 80% Reduction of CO_2 by 2050 includes a CO_2 cap and trade price that is consistent with the Paris Accords, designed to achieve an 80% reduction in

CO_2 by 2050 from 2005 levels. Finally, the High Regulatory scenario includes an extremely high CO_2 tax beginning in 2022. Table 1 below shows a visual summary of each scenario.

Table 1: Scenario Summary Table

	CO_2	Gas Reg.	Water Reg.	Economy	Load	Gas Price	Coal Price	Renewables and Storage Cost	EE Cost
Reference Case	ACE Replaced with CO_2 Tax	none	ELG	Base	Base	Base	Base	Base	Base
Low Regulatory	ACE	none	ELG Light*	Higher	Higher	Higher	Base	Base	Base
High Technology	Low CO_2 Tax	none	ELG	Higher	Higher	Lower	Lower	Lower	Lower
80% CO_2 Reduction by 2050	CO_2 Cap	Methane	ELG	Lower	Lower	Base	Lower	Lower	Higher
High Regulatory	High CO_2 Tax w/ Dividend	Fracking Ban	ELG	Base	Base	Highest (+2 SD)	Lower	Lower	Higher

Additionally, CenterPoint Indiana South worked with Siemens to incorporate a CO_2 equivalent measure for lifetime life cycle emissions for the score card. This measure included cradle to grave emissions for each portfolio, including, but not limited to, emissions associated with building the resource, getting it on site, methane leakage from the well head, emissions out of the stack, and decommissioning. Generation was tracked by resource and was multiplied by a CO_2e factor supplied by NREL. In this way, CO_2e was one trade off considered within the scorecard.

CO_2 prices were also utilized within stochastic modeling. Each portfolio was modeled in 200 potential future states to capture the cost of each portfolio and cost risk. A wide range of CO_2 prices were included in the net present value and the 95th percentile net present value[3] of each portfolio. The higher the CO_2 output for a portfolio, the higher the portfolio cost and cost risk.

Q. What were the CO_2 prices used within scenario modeling?

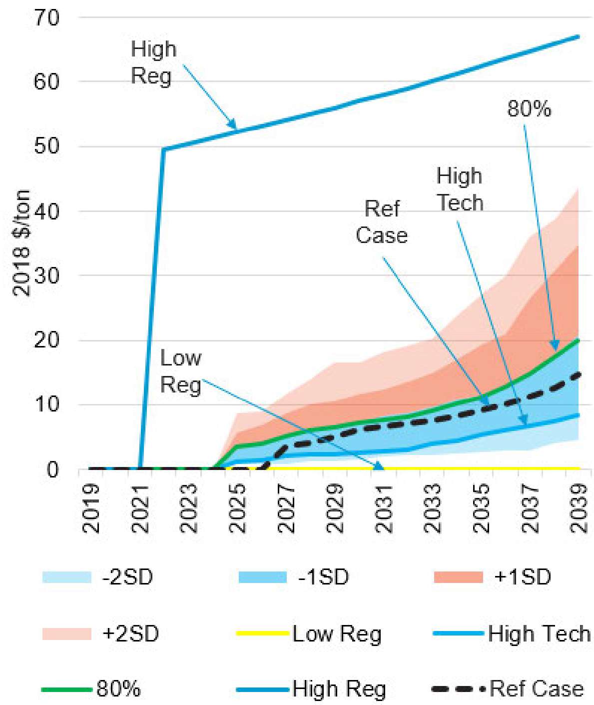
A. CenterPoint Indiana South included a wide range of CO_2 prices within scenario modeling

[3] 95th percentile of NPVRR (million$) across 200 dispatch iterations under varying market conditions. Used to illustrate the upper end cost risk for each portfolio within the IRP scorecard. Simply put, there is a 5% chance costs could go above this level.

to help understand the potential costs of future regulations to customers. The Preferred Portfolio preformed consistently well across multiple potential future states. Figure 3 below shows CO_2 cost modeled within each deterministic scenario.

Figure 3: Scenario CO_2 Costs

	Ref 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	3.57	0	2.06	5.10	54.17
2028	4.08	0	2.28	6.12	55.11
2029	5.10	0	2.38	6.63	56.05
2030	6.12	0	2.68	7.14	56.99
2031	6.63	0	2.94	7.65	57.94
2032	7.14	0	3.17	8.16	58.88
2033	7.65	0	3.89	9.18	60.06
2034	8.16	0	4.49	10.20	61.23
2035	9.18	0	5.46	11.22	62.41
2036	10.20	0	6.01	12.75	63.59
2037	11.22	0	6.85	14.79	64.77
2038	12.75	0	7.52	17.34	65.94
2039	14.79	0	8.50	19.89	67.12

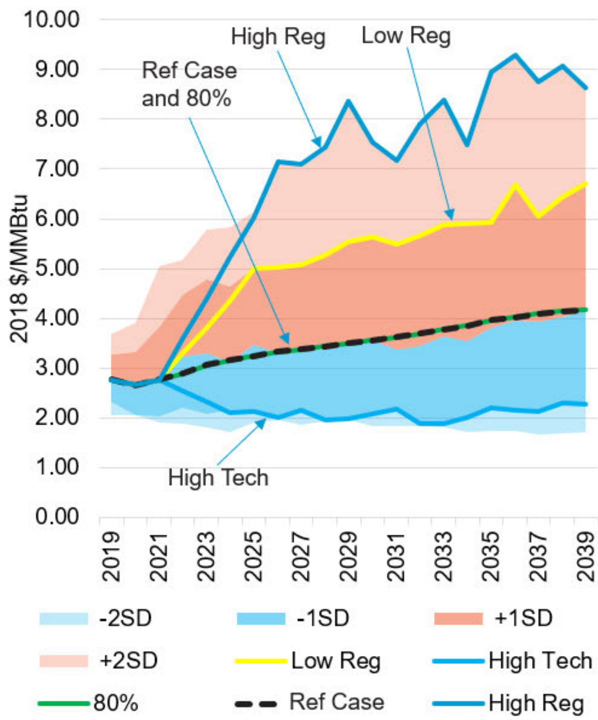


Q. What were the gas prices used within scenario modeling?

A. CenterPoint Indiana South modeled a very wide range of gas prices, including the High Regulatory scenario, which varied gas prices by two standard deviations. This was based on Commission guidance in Cause No. 45052 to fully explore risks of higher gas prices. The High Regulatory scenario assumes a fracking ban that drives supply down and prices dramatically up. Figure 4 below shows the range of gas prices modeled in the 2019/2020 IRP within each deterministic scenario.

Figure 4: Scenario Natural Gas Costs

	Ref 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



Q. What analyses did CenterPoint Indiana South use to determine the Preferred Portfolio?

A. CenterPoint Indiana South worked with Siemens PTI to conduct a multi-facetted risk analysis, which included evaluating portfolios on a quantitative and qualitative basis. After creation of the fifteen portfolios, each portfolio was evaluated utilizing simulated dispatch in the Reference Case. Several portfolios included fatal flaws and were excluded from further consideration. As described in more detail in <u>Petitioner's Exhibit No. 5</u>, Attachment MAR-1 Section 8.2 Evaluation of Portfolio Performance, on page 243 of the IRP, these included the HB 763, Low Regulatory, High Regulatory, 80 percent reduction of CO_2, and the Diverse Energy Mid-sized CCGT portfolio. Reasons for the exclusion of these portfolios included high net sales, high market exposure, high cost, or redundancy. The remaining ten portfolios were then dispatched in each deterministic scenario to determine performance among a wide range of potential future states. Some portfolios performed very consistently in terms of cost across each scenario, including the Reference Case, preferred portfolio, and Renewables Plus Flexible Gas. Others, like the BAU portfolio or the all renewables portfolio had much greater cost variation relative to the Reference Case across each potential future. Next, the remaining ten portfolios were dispatched 200 times under varying market conditions. Information gathered from this modeling was then utilized to populate the balanced scorecard, which was developed with stakeholder input. The balanced scorecard included quantitative measures to help CenterPoint Indiana South understand tradeoffs among competing objectives of the IRP; these included stochastic mean 20-year NPVRR (cost), 95th Percentile Value of NPVRR (cost risk), Percent Reduction of CO_2e (life cycle emissions reduction including CO_2, methane and other emissions on a CO_2 equivalent basis), long-term percentage reliance on the energy market for sales or purchases, and long-term percentage reliance on the capacity market for sales and purchases. Table 2 below shows a summary of these measures.

Table 2: Quantitative IRP Scorecard Objectives and Metrics

Objective	Metric
Affordability	Mean value for the 20-Year Net Present Value of Revenue Requirements (NPVRR) (million$) across 200 dispatch iterations under varying market conditions
Cost Uncertainty Risk Minimization	95th percentile of NPVRR (million$) across 200 dispatch iterations under varying market conditions
Environmental Emissions	Reduction in tons of life-cycle greenhouse gas emissions (CO_2e) 2019-2039
Avoiding Overreliance on Market Risk	Annual Energy Sales and Purchases, divided by Annual Generation, average (%) and Annual Capacity Sales and Purchases, divided by Total Resources, average (%)

Six portfolios (five included continued use of A.B. Brown with coal or conversion options and the remaining CCGT option), which were highest in cost and cost risk, were removed from consideration at this point based on their overall performance on scorecard measures and other qualitative considerations discussed at the last stakeholder meeting on June 15, 2020. Four competitive options remained for further analysis and consideration: (i) the Reference Case, (ii) Renewables Plus Flexible Gas, (iii) Renewables by 2030, and (iv) the High Technology portfolio. Table 3 below provides details regarding each portfolio.

Table 3: Portfolio Detail

Year	Reference Case	Renewables + Flexible Gas	Renewables by 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)

Q. Within scenario-based optimization was any coal unit selected to continue running based on economics?

A. No. Every scenario retired 730 MWs of coal, including the Low Regulatory Scenario which was favorable to coal resources. As shown in Table 1 above, the Low Regulatory Case included no price for CO_2[4], low coal cost (declining and below $1.80 per MMBTu), higher load than the Reference Case, and higher gas prices than the Reference Case.

Q. What were the results of the scorecard process?

A. Of the four remaining portfolios, the High Technology portfolio performed well across all risk factors. Within the IRP, the cost was listed as being within 2.5 percent of the lowest cost portfolio, the Renewables Plus Flexible Gas. The Renewables Plus Flexible Gas portfolio retires F.B. Culley 3 earlier than the High Technology portfolio thereby saving customers money. Both portfolios include about the same level of renewables and a second CT. As discussed in Petitioner's Witness Nelson Bacalao's testimony, this cost gap closes to 1.5 percent due to construction efficiencies that would be lost with building

[4] Minimal costs were included to comply with ACE, which has since been vacated.

the second CT ten years later under the Renewables Plus Flexible Gas option, which is not reflected within the IRP NPVRR. The Preferred Portfolio performed well in terms of cost risk relative to other portfolios. While the percent reduction of CO_2e was less than the renewables flexible gas and all renewables by 2030 portfolios, the Preferred Portfolio was near the middle of all portfolios and overwhelmingly driven by the continued use of F.B. Culley 3. As Witness Retherford explains, due to changes in environmental regulations, the Company is presently evaluating the decision to retire F. B. Culley 3 earlier than 2039. If the decision is made to retire F.B. Culley 3 early, the differences between the Preferred Portfolio and Renewables Plus Flexible Gas in terms of NPVRR and percent reduction of CO_2e are not expected to be material. Of the remaining portfolios, the Preferred Portfolio relied least on energy purchases and was among the best in terms of reliance on energy sales to the market. The Preferred Portfolio was dramatically better, at 0.4 percent, in terms of less long-term reliance on the capacity purchases, while the other three portfolios average reliance ranged from 9.4 to 11.9 percent per year. The Preferred Portfolio relied on capacity sales of 4.6 percent, which was in the middle of all portfolios.

Q. Please describe further why the Preferred Portfolio was selected.

A. The Preferred Portfolio was selected because it was determined to be a very reliable and resilient portfolio that offers a transition to a clean energy future by complementing renewable energy resources with fast start and fast ramping capability. The portfolio is a good mix of traditional and emerging resources and has enough dispatchable capacity to cover CenterPoint Indiana South’s load in the winter when there is drastically less solar output during the winter peak period. This point is illustrated in Petitioner’s Witness Bacalao’s testimony. The Preferred Portfolio is cost effective and expected to save CenterPoint Indiana South’s customers up to $320 million over the IRP’s twenty-year planning period (2020 – 2039) compared to continuing to operate coal units. The Preferred Portfolio provides a physical hedge against high energy and capacity costs. As the future continues to be uncertain, this plan offers a diverse set of resources with multiple off-ramps, designed to hedge against risk of putting too much emphasis on a few large resources. While the flexible gas CTs are available to provide low cost capacity, their projected usage, largely limited to critical times, results in lower CO_2 emissions by 75 percent by 2035 over 2005 levels.

Q. Has modeling been updated since submitting the IRP on June 30, 2020?

A. No. CenterPoint Indiana South considered a wide range of potential future states within the IRP analysis to understand how the portfolios would perform if the future turns out to be different than expected. The result does not rely on a single set of assumptions that can later be invalidated by evolving market conditions. That being said, we have not seen the shifts in key inputs in recent years that would have changed the selection of the Preferred Portfolio. During the IRP, some market data suggested that solar costs may be going up. As described on page 101 of the IRP in Petitioner's Exhibit No. 5, Attachment MAR-1 "[CenterPoint Indiana South] performed a sensitivity in which the cost of solar Power Purchase Agreement ("PPA") resources increase 30 percent, based on more recent market information at the time. The sensitivity demonstrated that even with increased costs, the solar PPA costs remain below the market clearing on-peak price of $42-45/MWh and continue to be selected as economic portfolio additions." Secondly, the period between submitting the IRP and filing this CPCN is only about 1 year. While we have seen impacts due to COVID lock downs, it is too soon to know the long-term effects. While one might argue that load could be lower going forward, that does not negate the need for two combustion turbines. [redacted] It should be noted that the Commission recently found in NIPSCO Cause No. 45462 that the mere passage of time did not invalidate their 2018 IRP. The Commission went on to state that integrated resource plans are performed at a point in time and use modeled scenarios to show how resources perform over a variety of alternative future conditions. CenterPoint Indiana South's IRP sought to understand potential changes that could affect the electric industry[5].

[5] The Commission, in its Order in Cause No. 45462, wrote: "The mere passage of time does not invalidate the 2018 IRP, nor does the fact that NIPSCO chose to submit three Solar Projects that represent its largest proposed investment to date. Inherently, integrated resource plans are performed at a point in time and use modeled scenarios to show how resources perform over a variety of alternative future conditions. This is not a case where NIPSCO performed the 2018 IRP analysis and has failed to respond to changes in the electric industry or the broader market, and now seeks approval of generation additions based on a questionable foundation." *Cause No. 45462* (IURC 5/5/2021), at p. 62

Q. Does the Preferred Portfolio rely heavily on the market for energy or capacity sales and purchases?

A. No. The Commission provided clear guidance in Cause No. 45052 that CenterPoint Indiana South should not ". . . have a one-sided view of market risk." As such, CenterPoint Indiana South included this key risk in the balanced scorecard. Portfolios that relied too heavily on the market for wholesale market sales or capacity sales were considered riskier than those that more closely aligned with retail need. Market energy and capacity sales have the effect of lowering the Net Present Value of Revenue Requirements. Effectively, portfolios that have high market energy and capacity sales are taking a chance at the customers' expense that the projected energy price will remain at or above projected levels. On the other side of the spectrum, portfolios that relied heavily on the market for long-term energy and capacity purchases were also deemed risky. Portfolios with sufficient resources to meet customer retail load and maintain sufficient capacity to meet long-term planning reserve margin requirements shield customers from market price risk. Overall, the Preferred Portfolio performed well on these score card measures.

Q. How did portfolios perform that included A.B. Brown continuation on coal or conversion to natural gas?

A. Five portfolios were created to explore options to continue utilizing existing generation at the A.B. Brown plant: BAU 2039 (continues use of Brown coal units through 2039), Bridge BAU 2029 (continues use of Brown coal units through 2029), Bridge ABB1 Conversion (conversion of 1 Brown unit to gas), Bridge ABB1 + ABB2 Conversion (conversion of both Brown coal units to gas), and Bridge ABB1 + CCGT (conversion of one Brown coal unit to gas with the addition of a mid-sized CCGT at stakeholder request). As shown in Table 4: IRP Scorecard below, these options were among the highest cost and cost risk. Additionally, portfolios that relied on continued coal burn relied the most on Market energy sales. Overall, these portfolios performed poorly compared to the Preferred Portfolio (High Technology), as shown below in Table 4: IRP Scorecard.

Table 4: IRP Scorecard

	Stochastic Mean 20-Year NPVRR	95th Percentile Value of NPVRR	% Reduction of CO2e (2019-2039)	Purchases as a % of Generation	Sales as a % of Generation	Purchases as a % of Peak Demand	Sales as a % of Peak Demand
Reference Case	$2,538	$2,921	58.1%	16.8%	26.8%	9.7%	1.2%
BAU to 2039	$2,914	$3,308	35.2%	12.0%	36.5%	0.1%	11.1%
Bridge BAU 2029	$2,691	$3,094	61.9%	15.2%	31.4%	7.1%	4.3%
Bridge ABB1 Conversion+CCGT	$2,875	$3,269	47.9%	6.6%	31.8%	1.3%	10.1%
Bridge ABB1 Conversion	$2,677	$3,048	61.5%	19.2%	26.4%	1.2%	9.3%
Bridge ABB1+ABB2 Conversion	$2,836	$3,215	61.5%	18.5%	27.6%	4.0%	5.6%
Diverse Small CCGT	$2,681	$3,072	47.9%	6.4%	31.1%	1.7%	3.7%
Renewables Peak Gas	$2,528	$2,927	77.4%	21.5%	27.7%	9.4%	1.2%
Renewables 2030	$2,614	$3,003	79.3%	26.1%	31.9%	11.9%	1.7%
High Technology	$2,592	$2,978	59.8%	16.7%	26.9%	0.4%	4.6%

Q. Have you reviewed the Draft Director's Report for CenterPoint Indiana South's 2019/2020 Integrated Resource Plan, which was published on April 9, 2021?

A. Yes. I have reviewed the report.

Q. Please describe the Director's Report.

A. Following submission of the IRP, Dr. Brad Borum Director of Research, Policy and Planning will submit a critique of the Company's IRP. The Director's Report is a tool that allows for Commission staff to provide direct feedback on the stakeholder process, analysis methodology, compliance with the rule, and clarity of communication materials, including the IRP report. Within the Director's draft report, there is also a synthesis of stakeholder comments that were provided on the Company's IRP with feedback from the Director. CenterPoint Indiana South utilizes this report to drive continuous improvement in our IRP analysis. Feedback from the prior Director's Report addressing CenterPoint Indiana South's 2016 IRP was discussed in the first of four public stakeholder meetings and informed a wide range of improvements in the 2019/2020 IRP.

Q. Please describe the major concerns raised in the 2016 Director's Report.

A. The Director raised four major concerns about the 2016 IRP in that Director's report: 1) CenterPoint Indiana South did not consider a wide range of portfolios; 2) CenterPoint Indiana South did not consider a wide enough range of gas price forecasts; 3) CenterPoint Indiana South did not perform a comprehensive risk analysis; and 4) modeling methodology concerns were raised.

Q. Were these concerns addressed in the 2019/2020 IRP?

A. Yes. The Director did not raise these issues in the 2019/2020 IRP. In fact, he had several positive comments, many of which were in these areas. On page 25 of the draft report, the Director noted that "[CenterPoint Indiana South]'s IRP included significant advances to its processes, analysis, methodology, and software. The Director appreciates the significant changes [CenterPoint Indiana South] has made from its 2016 IRP."[6] The Director also commented on page 21 that the "…Risk and uncertainty analysis and discussion in the IRP are well done."[7] Additionally, it was noted on page 21 of the draft report that "The Director appreciates the wide range of alternative candidate portfolios that were partially optimized. Each was clearly designed to evaluate specific alternative resource strategies. Emphasis was placed on the conversion of one or both Brown units to natural gas and the acquisition of 400-500 MW of natural gas combined cycle capacity. The information from this analysis is helpful . . ."[8]

Q. Were any concerns raised about the 2019/2020 IRP?

A. Yes. The Director emphasized two concerns within the Director's draft report, . both of which I will address here. First, as indicated page 32 of the draft report:

> The Director agrees with the OUCC that the large increase in projected industrial sales in the next few years looks unusual. Utilities often make an adjustment in the first few years of an industrial load forecast to account for large changes that are thought to be missed by an econometric forecast that emphasizes historical trends and relationships. The issue of how to account for large near-term changes in load is not new.[9]

As described in the IRP, CenterPoint Indiana South utilized its internal estimate for large sales in the first 5 years of the forecast and then relied on modest long-term annual growth

[6] Draft Director's Report for CenterPoint Indiana South's 2019/2020 Integrated Resource Plan, April 9, 2021, by Dr. Bradley Borum, Director of Research, Policy and Planning on behalf of the Indiana Utility Regulatory Commission, Page 25.
[7] Draft Director's Report for CenterPoint Indiana South's 2019/2020 Integrated Resource Plan, April 9, 2021, by Dr. Bradley Borum, Director of Research, Policy and Planning on behalf of the Indiana Utility Regulatory Commission, Page 21.
[8] Draft Director's Report for CenterPoint Indiana South's 2019/2020 Integrated Resource Plan, April 9, 2021, by Dr. Bradley Borum, Director of Research, Policy and Planning on behalf of the Indiana Utility Regulatory Commission, Page 21
[9] Draft Director's Report for CenterPoint Indiana South's 2019/2020 Integrated Resource Plan, April 9, 2021, by Dr. Bradley Borum, Director of Research, Policy and Planning on behalf of the Indiana Utility Regulatory Commission, Page 32

estimates thereafter. This process ensures that CenterPoint Indiana South captures large, expected shifts in load, up or down, based on conversations/negotiations with CenterPoint Indiana South's largest active and prospective customers. Estimates from large customers not only feed CenterPoint Indiana South's integrated resource planning but also the company budget and are submitted to MISO. CenterPoint Indiana South only includes projects with the most certainty within the forecast. Large shifts in load must be accounted for outside of econometric modeling. For example, when a large customer recently installed a co-generation facility, there was a drop of about 80 MWs in the year that it was installed. CenterPoint Indiana South included the expected reduction in sales and demand within the forecast. A drop of this magnitude cannot be predicted within econometric modeling, nor is it reflective of potential future drops in large customer sales. Additionally, CenterPoint Indiana South continues to engage in confidential negotiations with potential customers for large load additions, [redacted]. This large load was not included within the IRP forecast. To put it into perspective, the IRP anticipated 510,410 MWh increase in large customer load between 2019 and 2023. [redacted]

The second concern emphasized by the Director was found on page 21 of the Director's draft report; ". . . the Director would have appreciated one optimization run with a minimum of constraints or exogenous choices pre-selected. The Director recognizes the resulting portfolio might be unrealistic because it fails to adequately account for real world limitations but thinks such an exercise is still informative."[10] CenterPoint Indiana South described the limited number of constraints in section 7.2.4 Additional Modeling Considerations on pages 211-212 of Petitioner's Exhibit No. 5, Attachment MAR-1. I will describe the three most significant constraints utilized and the reasoning around each one. Ultimately, constraints help produce a portfolio that is practical, achievable, and in-line

[10] Draft Director's Report for CenterPoint Indiana South's 2019/2020 Integrated Resource Plan, April 9, 2021, by Dr. Bradley Borum, Director of Research, Policy and Planning on behalf of the Indiana Utility Regulatory Commission, Page 21

with the stated objectives of the IRP, including diversity and avoidance of risk. First, as stated on page 211 of Petitioner's Exhibit No. 5, Attachment MAR-1:

> [CenterPoint Indiana South] received approval in 2019 from the Commission to upgrade F.B. Culley 3, [CenterPoint Indiana South's] most efficient coal unit, for continued operations. As such, the unit was modeled with continued operations throughout the planning period. As stated in that case, there is a premium for resilience and diversity with continuing to run the Culley unit. Based on updated reference case modeling in this IRP, that premium is estimated to be about ~0.5% in total NPV for continuing to run the plant through 2034. [CenterPoint Indiana South] has chosen to continue operating this unit for the resiliency that it provides. All other coal units could retire economically within the model beginning December 31, 2023.

Second, CenterPoint Indiana South included a few constraints around renewable resources. CenterPoint Indiana South conducted an All-Source RFP to obtain renewable pricing per previous Commission guidance and received bids for solar and wind resources. CenterPoint Indiana South limited the amount of these resources that could be selected within modeling based on a few considerations. CenterPoint Indiana South did not allow for more of these resources than available projects from the All-Source RFP. Competition for resources is high, and many of the bids that came in were very early in development and speculative. CenterPoint Indiana South did not intend to do self builds for these resources, so it would be impractical to allow the model to select more solar and wind than the market would bear in the early years. Additionally, CenterPoint Indiana South limited the amount of solar resources that could be selected through 2024 to 1,150 MWs (roughly the amount of CenterPoint Indiana South's peak load in the summer). As described on page 248 of Petitioner's Exhibit No. 5, Attachment MAR-1:

> The optimization routine in the Aurora model consistently selected for the maximum amount of solar available in the early years. However, the analysis showed that a constraint was necessary to prevent an overbuild of solar in this early timeframe. This is because the lower peak capacity accreditation for solar during the winter season meant that the winter peak demand was not met with solar that exceeded 1,150 MW. Accordingly, this required a limitation on the availability of solar to this level. The amount of solar in the early years [through 2024] was also limited by practical considerations around logistics and operational feasibility.

Third, CenterPoint Indiana South included a constraint that was described on pages 97-98 of the Petitioner's Exhibit No. 5, Attachment MAR-1.

> Market transactions offer supply flexibility but also exposure to potential market risk to [CenterPoint Indiana South] customers. In addition to the

> supply and demand side resource alternatives, portfolios were able to select market supply options as well. To reduce the risk that comes from exposure to the market, a limit of approximately ~15% of capacity needs, or 180 MW, was defined for annual capacity market purchases (except in a transitional year). This is much more than the 2016 IRP where a 10 MW cap was utilized and is responsive to the Commission Order 45052, which said CenterPoint Indiana South did not fully consider energy or capacity purchases.

Modeling is simply a tool to aide in the decision-making process. While an unconstrained model run may provide some information that is useful for the analysis, it will not provide the answer to the IRP analysis. The constraints utilized within the IRP helped produce a wide range of potentially viable portfolios for use within the analysis. Had these constraints not been put into place, the resulting portfolio would have been screened out before probability modeling. Optimization modeling is time consuming and expensive. Reasonable constraints help make the analysis more efficient. Nevertheless, CenterPoint Indiana South has agreed to an unconstrained modeling run in the next IRP.

IV. THE PREFERRED PORTFOLIO

Q. What are the major components of the Preferred Portfolio?

A. The Preferred Portfolio is very diversified, with significant amounts of solar, solar plus storage, wind, gas, coal, demand response, and energy efficiency. Specifically, it includes energy efficiency at 1.25 percent between 2021-2023 and 0.75 percent[11] thereafter. The portfolio calls for 300 MW of wind resources to come online in 2022. It also calls for 1,150 MWs of new solar and solar plus storage in 2023-2024 to replace coal capacity, including Warrick Unit #4 which Petitioner jointly operates with Alcoa. Additionally, two CTs come online in 2024-2025. In 2039, 50 MW of storage was selected. The illustration below in Figure 5 shows the Preferred Portfolio's mix of installed capacity.

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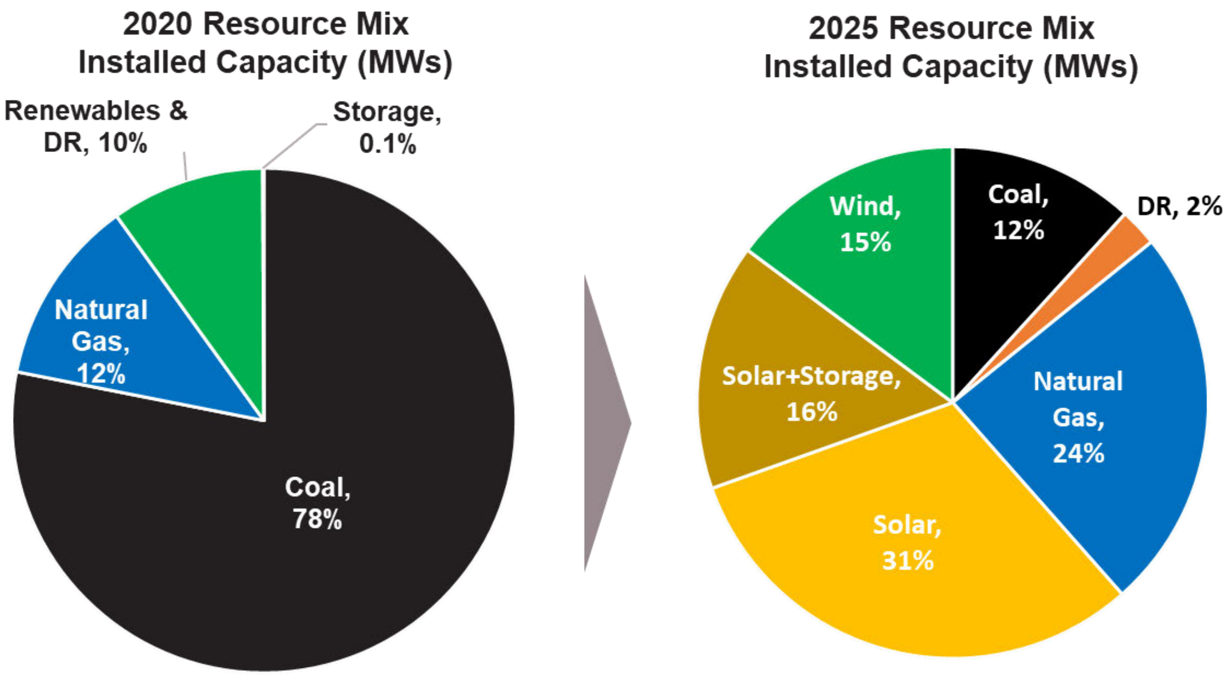
[11] The level of EE for 2024 and beyond will be decided with future IRPs and DSM filings.

Figure 5: Preferred Portfolio Resource Mix



Q. What are the primary benefits of the Preferred Portfolio?

A. The Preferred Portfolio includes a diverse mix of resources. The risk analysis demonstrated that a diversified mix of generation resources minimizes risk to customers if the future differs from the Reference Case scenario. As described in the final stakeholder meeting on June 15, 2020, and the 2019/2020 IRP, the Preferred Portfolio has the following characteristics: reliability, cost effectiveness, flexibility, diversity, risk mitigation, sustainability, and timeliness.

Q. Why did the Preferred Portfolio rank the best in the risk analysis?

A. Benefits of the Preferred Portfolio are spelled out in detail in Section 9 of the IRP (Petitioner's Exhibit No. 5, Attachment MAR-1) and include affordability, cost uncertainty risk mitigation, environmental risk mitigation, market risk mitigation, future flexibility, reliability, operational flexibility, resource diversity, local resources, and economic development for the CenterPoint Indiana South territory and the state of Indiana. As I mentioned earlier, the Preferred Portfolio performed well across multiple risk factors in the balanced scorecard. It avoids long-term reliance on the capacity market or heavy reliance on emerging technology. The fast start and ramping capability of CTs allows for high penetration of low-cost renewable energy resources, which were consistently selected for all portfolios, regardless of potential future events. It also allows CenterPoint Indiana South to incrementally pursue renewable build out with confidence that dispatchable resources will be available when needed, particularly in winter months where multi-day periods of cloud cover and no wind are possible.

Q. What factors support replacing the generation provided by F.B. Culley 2, Warrick Unit #4, and A.B. Brown units 1 & 2?

A. As described in Petitioner's Witness Wayne D. Games' testimony, F.B. Culley 2 is CenterPoint Indiana South's smallest and least efficient coal unit. It does not compete economically in the MISO market and needs costly upgrades to continue operation many years beyond 2023. Even the Indiana Coal Council ("ICC") acknowledged in their recent comments on CenterPoint Indiana South's 2019/2020 IRP, "There is no dispute over whether it should be retired. . . ."[12] Also, CenterPoint Indiana South's contract with Warrick Unit #4 expires on December 31, 2023, and IRP modeling found extension of the contract was not economical. These two units currently provide 240 MW of installed capacity, 206 MW of which counts towards MISO's planning reserve margin ("PRM") requirement for the 2020 – 2021 planning year. While the Petitioner might be able to find economical ways to keep these units running for a year or two longer to help meet its capacity needs, long-term reliance on these units is not the most economical answer for customers.

As described in Petitioner's Exhibit No. 5, Attachment MAR-1 on page 162 of the IRP, A.B. Brown units 1 & 2 utilize dual alkali scrubbers, which present several operational challenges, including: high variable production costs relative to industry standard limestone-based scrubbers, high maintenance costs due to the corrosive dual-alkali process, and challenges in obtaining support and replacement parts for these last of their kind scrubbers. These two units currently provide 500 MW of installed capacity, 466.1 MW of Unforced Capacity ("UCAP") which counts towards MISO's PRM requirement for the 2020 – 2021 planning year.

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[12] ICC comments on CenterPoint Indiana South's 2019/2020 IRP submitted to Director Dr. Bradley Borum on October 28, 2020, bottom of page 6.

Q. What short-term steps does the Preferred Portfolio require CenterPoint Indiana South to take?

A. The Preferred Portfolio calls for CenterPoint Indiana South to pursue renewable projects within the next three years based on the retirement of F.B. Culley 2 and for the expiration of the contract for joint operation of Warrick Unit #4 in December 2023. Adding renewable projects during this time frame has the added benefit of allowing CenterPoint Indiana South customers to take advantage of renewable tax incentives before they expire. Additionally, the plan calls for two combustion turbines equaling approximately 460 MWs of dispatchable installed capacity to replace A.B. Brown units 1 & 2, along with additional renewable wind and solar resources. The Preferred Portfolio also called for capacity purchases to help meet the planning reserve margin requirement during the time in which A.B. Brown units 1 & 2 are retired and the combustion turbines come online.

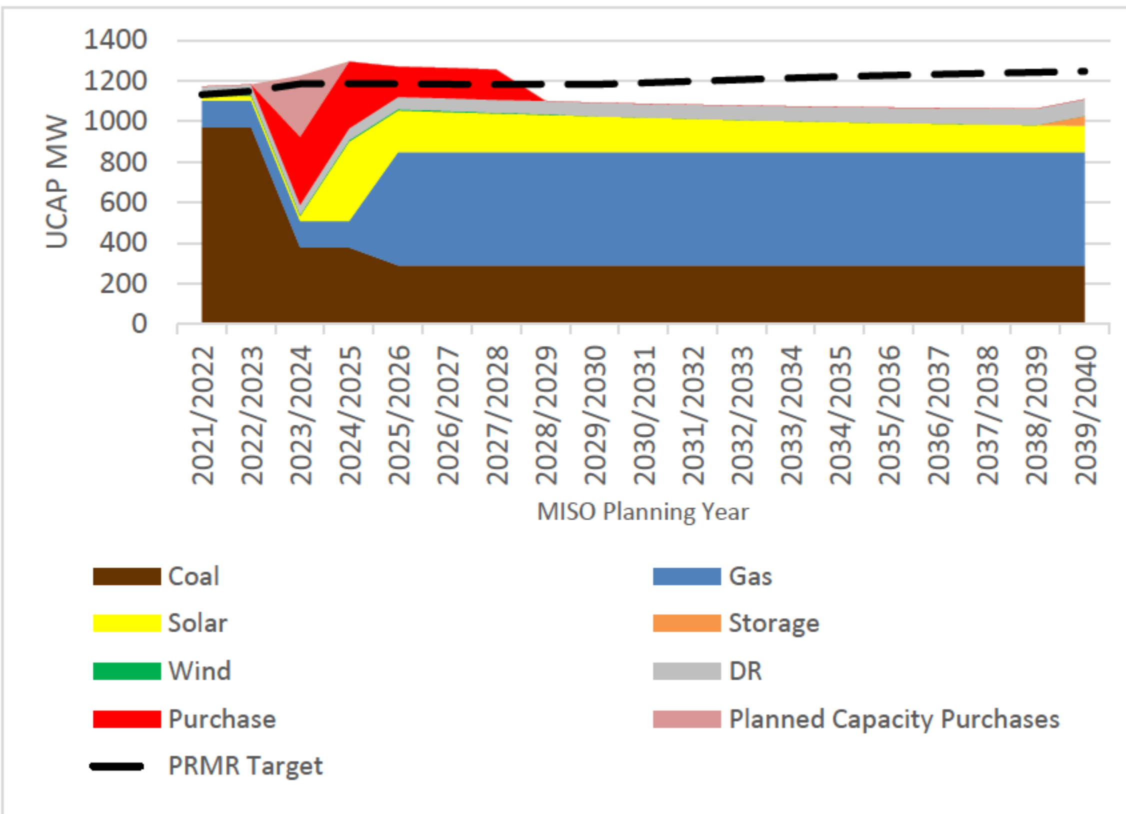
Q. Has CenterPoint Indiana South taken steps to begin implementing the Preferred Portfolio?

A. Yes. Consistent with the short-term action plan in the 2019/2020 IRP, CenterPoint Indiana South selected two projects from the All-Source RFP conducted on June 12, 2019 and filed for these projects in Cause No. 45501. The Posey County Solar Project and Warrick County Solar Project (collectively, the “45501 Solar Projects”) were selected. Definitive agreements have been signed for the projects. Additionally, as discussed in Petitioner’s Witness F. Shane Bradford’s testimony, CenterPoint Indiana South, has begun securing needed capacity through bilateral contracts to ensure CenterPoint Indiana South maintains its PRM requirement while the combustion turbines are constructed. Contingent on approval in this proceeding, CenterPoint Indiana South conducted an RFP for the construction of the CTs and has negotiated a contract to provide firm gas service to the A.B. Brown site to supply the CTs. Finally, CenterPoint Indiana South is in the final stages of evaluating results of a second RFP to secure additional renewable resources identified in the Preferred Portfolio.

Q. Does the Preferred Portfolio offer future flexibility should the future turn out differently than expected?

A. Yes. While the Preferred Portfolio performed consistently well across a wide range of futures, flexibility to pivot is built into the plan. While modeling selected 1,150 MWs of solar and solar plus storage, CenterPoint Indiana South is initially pursuing ~700-800 MWs of a mix of solar ownership and PPAs of varying term lengths from 15-25 years while CenterPoint Indiana South evaluates MISO's future for resource accreditation. Additionally, the Preferred Portfolio included F.B. Culley 3 coal unit through 2039; as Witness Retherford explains, due to a change in regulations, Petitioner is presently evaluating the potential to retire this unit sooner. As described in Witness Bradford's testimony, CenterPoint Indiana South has made capacity purchases to enable the generation transition plan. At the end of these purchases in the 2027/2028 planning year, there is expected to be an additional need that could be filled with additional PPAs, DR, or owned resources. The capacity purchases are illustrated below in Figure 6: Generation Transition Plan.

Figure 6: Generation Transition Plan[13]



[13] Includes Culley 3 through 2039; existing coal, gas, DR and solar resources; 735 MWs of new installed solar capacity, 300 MWs of installed wind capacity, and new 460 MWs of gas CTs. Amount may vary as negotiations continue for resources. Also includes ELCC expectations from the IRP. As more solar penetrates the MISO market, the capacity accreditation is expected to decline.

Finally, the resources included in the Preferred Portfolio are flexible. For instance, should battery prices come down or it make sense to add a large battery to one of our solar fields, this is possible. Also, CenterPoint Indiana South selected GE F-class turbines for the two new combustion turbines. As discussed in Witness Games' testimony, these units can currently burn 30% hydrogen from renewable energy with modifications, thereby lowering the small amount of CO_2 that is expected to be produced from these capacity resources. CenterPoint Indiana South's diverse portfolio is well positioned for the future.

V. COMBUSTION TURBINES PROJECT

Q. Please briefly describe the Combustion Turbines Project.

A. As described in Witness Games' testimony, CenterPoint Indiana South selected F Class CTs through a competitive procurement process. This class of turbines have been in the market for over 30 years and have a proven history of solid and reliable performance. The units are capable of starting in as little as 10 minutes and can ramp 40 MWs per minute, per unit, or 80 MWs per minute. CTs are low cost capacity resources identified in the Preferred Portfolio, supporting intermittent renewable resources in a diverse portfolio.

Q. Have you reviewed the IURC's Statewide Analysis of Future Resources for Electricity ("Statewide Analysis")?

A. Yes. I understand the Statewide Analysis is ongoing and that the most current written version of that analysis is dated 2018. A copy is attached as Petitioner's Exhibit No. 5, Attachment MAR-16.

Q. In your opinion, is the Combustion Turbine Project for which a CPCN is being sought in this proceeding consistent with the Statewide Analysis?

A. Yes. That Analysis cautions that it is not to be construed as an energy plan and it does not predetermine resource decisions. In general, it provides information to various stakeholders. Our proposed Combustion Turbine Project is consistent with the Statewide Analysis, although the data and analysis underlying our proposal has continued to develop since the written Statewide Analysis was completed.

Q. In your opinion, is the Combustion Turbine Project consistent with CenterPoint Indiana South's 2019/2020 IRP?

A. Yes. Two combustion turbines were identified in the Preferred Portfolio to provide low cost capacity to support the low-cost renewable energy resources and help replace 730 MWs of coal generation. The CTs are part of a balanced mix of renewables, gas, coal, and Demand Side Management ("DSM") resources to serve customers, identified in the 2019/2020 IRP.

Q. Does the Combustion Turbines Project fulfill a capacity need identified in CenterPoint Indiana South's 2019/2020 IRP?

A. Yes. The Combustion Turbines Project directly replaces approximately 460 MWs of dispatchable capacity that results from closing A.B. Brown units 1 & 2, which was identified in CenterPoint Indiana South's 2019/2020 IRP. As Petitioner's Witness Retherford describes in her testimony, it is not feasible to continue running A.B. Brown units 1 & 2 until the 2025/2026 planning year (period of time needed to construct the CTs).

Q. What are the benefits of adding combustion turbines generally?

A. The combustion turbines provide several benefits to the Preferred Portfolio. First, they are a part of a diverse mix of resources, which helps to shield customers from risk. Second, combustion turbines compliment renewable resources by providing quick start and fast ramping capability, which is a dramatic improvement over existing coal generation. These attributes, along with the ability to load follow on partially cloudy days supports the build out of solar generation. As solar resources continue to increase in the MISO market, the net peak hour is expected to shift into the evening hours. If needed, CTs may be called upon to help meet this demand as the sun falls behind the horizon; the ability to ramp quickly is important to address the duck curve.[14] Third, combustion turbines provide resilience to the Preferred Portfolio. Dispatchable capacity is needed for long durations when the sun is not shining and the wind is not blowing, particularly in the winter. MISO recently reiterated that the capacity market is moving to a seasonal construct where various resources will receive varying capacity accreditation, depending on the season.

[14] The duck curve is the graphic representation of solar penetration which pushes the net peak load into mid/late evening. Quick ramping resources are needed to meet this phenomenon.

Gas turbines with firm gas service are expected to have a higher accreditation in the winter at ~95%, while solar is expected to receive approximately 5%.[15] CenterPoint Indiana South's Preferred Portfolio will retain enough dispatchable capacity to meet its expected winter load. During the summer, when load increases, capacity accreditation is expected to slightly decrease for gas and increase for solar.

Fourth, the combustion turbines are a physical hedge on the capacity and energy markets. When volatility occurs with high energy prices, CTs are available to shield customers from high cost. Other top portfolios had a long-term reliance on the capacity market, which is risky for CenterPoint Indiana South customers. In addition to being called upon when market energy prices are high, they are also available to be called upon for reliability issues; however, IRP modeling suggests that these units will not run much, which keeps CO_2 output very low. Finally, CTs provide for future flexibility to burn hydrogen in the long-term. As mentioned by Witness Games, the GE units CenterPoint Indiana South selected have the ability to burn 30% hydrogen today with modifications.

Q. Does CenterPoint Indiana South also need to move to a balanced mix of resources in its portfolio in general?

A. In my opinion, yes. CenterPoint Indiana South believes there is value in a balanced portfolio to reduce risk by having a diverse set of resources available to serve customer load (including not only diversity in generation resources but also DSM). The benefits of a balanced energy mix cannot be overstated. One of the simplest and best ways to plan in an uncertain environment is to provide a diverse portfolio, which provides a hedge against unforeseen changes in regulations, technologies, and market.

Q. Did CenterPoint Indiana South consider DSM as a resource in its 2019/2020 IRP?

A. Yes. CenterPoint Indiana South considered DSM as a resource in its 2019/2020 IRP and included DSM in the Preferred Portfolio. CenterPoint Indiana South considers DSM to be part of a balanced utility resource plan.

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[15] MISO, RAN Reliability Requirements + Sub-annual Constructs presentation, RASC, February 3, 2021-updated February 25, 2021, page 22.

Q. In your opinion, are DSM initiatives a viable alternative to completing the CTs identified in the Preferred Portfolio?

A. No. The 2019/2020 IRP demonstrates that DSM will be an important part of CenterPoint Indiana South's resource options in the future. However, the IRP also recognizes that the addition of renewable and gas resources is necessary to meet the needs of the system in the future and to diversify Petitioner's generation portfolio. DSM initiatives may prove to be a viable alternative to future capacity needs. The Preferred Portfolio shows a need for further capacity to meet the forecasted PRM after our short-term actions are complete, and that need would be more if the decision is made to retire F.B. Culley Unit 3 sooner, as being explained by Witness Retherford.

Q. In your opinion, is the addition of the CT Project to CenterPoint Indiana South's generation portfolio in the public convenience and necessity?

A. Yes. The CT Project is consistent with CenterPoint Indiana South's 2019/2020 IRP and is an economic choice to help meet CenterPoint Indiana South's retail electric load 24 hours a day, 365 days a year. The expected capacity attributable to the CT Project is necessary to meet CenterPoint Indiana South's load and adequate reserve margins, particularly in the winter. In addition to providing necessary capacity, the CT Project is a reasonable addition to a portfolio of capacity resources that in the aggregate serve to mitigate risk through diversification. Commission approval of the CT Project and associated relief sought herein is in the public interest and will enhance or maintain the reliability and efficiency of service provided by CenterPoint Indiana South.

Q. Please describe some of the key quantitative and qualitative considerations as to why continuing to run A.B. Brown or converting A.B. Brown is not a good option relative to building two new combustion turbines.

A. As described in the final IRP stakeholder meeting on June 15, 2020, these options are less affordable to customers due to high O&M and on-going capital expenditures to keep the units running. This was evident in the long-term NPVRR for these portfolios as well as near term bill impacts (discussed further below). The NPVRR of converting both A.B. Brown units to gas was $2,836 million, and the NPVRR of running both A.B. Brown units until 2029 was $2,691 million, which was $244 million to $99 million more than replacing the A.B. Brown coal units with two natural gas CTs.

Operationally, these options have a worse heat rate than new combustion turbines, which drives the need to burn more fuel. The heat rate of gas conversion is approximately 11,000 BTU/kwh, and the heat rate for continuing to run A.B. Brown through 2029 is approximately 10,600 BTU/kwh. Both are less efficient than CTs at approximately 9,900 BTU/kwh.

Additionally, there is less operational flexibility when market prices spike suddenly; converted gas units or coal units cannot start and warm up quickly enough to shield customers from potential high costs. As discussed in Witness Games' testimony slow start times (16-24 hrs.) and slow ramp rates (2-6 MW/Min), which does not position us well to support high penetrations of solar that is expected in and around our service territory, regardless of who owns and operates solar plants. The conversion of the A.B. Brown units locks in our inability to respond quickly when needed. As described by Witness Bradford, MISO's recent market reforms and products pay a premium for resources that can be called upon quickly. He also notes that MISO's Independent Market Monitor recently described the need for significant ramping capability to support solar resources. Witness Games noted that coal units are not made to ramp up and down quickly, and this tends to drive more costs as such causes equipment to wear out more quickly than if the units were able to run as designed (base load units). The CTs on the other hand start within 10 minutes and together have the collective ability to ramp 80 MWs per minute.

Finally, this equipment is old and more prone to break down than new combustion turbines. This is partially why on-going O&M capital spend is necessary, but as Witness Games testifies to the A.B. Brown units have corrosion issues due to chemicals needed to run outdated environmental equipment. When these failures occur, they can have an impact on MISO accreditation.

Q. Why is the Preferred Portfolio with two combustion turbines a better option for customers than the Reference Case, which only has one combustion turbine.

A. Two highly dispatchable combustion turbines allow for a high penetration of renewable resources, ensuring reliability and better hedges against the energy and capacity markets. For example, as described in Witness Bradford's testimony, when there is an unexpected constraint on the transmission system, LMPs can spike to high levels. The CTs will have the ability to turn on quickly and shield CenterPoint Indiana South customers from price volatility.

With two combustion turbines, CenterPoint Indiana South has enough dispatchable resources to meet the winter peak. This is important, as MISO continues to move towards a seasonal capacity construct. Solar resources are expected to receive only 5% of their installed capacity using this MISO planning assumption; of the first 735 MWs of solar installed capacity that CenterPoint Indiana South is pursuing, approximately 37 MWs would count towards the anticipated winter planning reserve margin requirement. It is possible that solar could receive zero accreditation in the winter.

Two CTs will help to better ensure reliability when there are multiday periods of cloud cover and no wind. CTs provide affordable capacity and are available to run for long durations when needed. Conversely, energy storage options are higher priced capacity resources than CTs, and they only typically provide enough power for a 4-hour duration. To provide 8 hours' worth of power, the cost nearly doubles. Additionally, Witness Bacalao describes how widespread adoption of storage is expected to decrease storage capacity accreditation in MISO. This risk factor was not considered in the IRP.

Two CTs provide double the ramping capability than one does to better support intermittent solar locally and on the MISO system to meet the evening net peak. Two CTs are able to start within 10 minutes and can ramp at 80 MW/minute versus 40 MW/minute with one CT. They are also load following.

Q. The Renewables Plus Flexible Gas waits to build the second CT in the mid 2030's. Is there an advantage to building two now?

A. Yes. In addition to the benefits mentioned above, there are construction efficiencies in building the units at the same time. As shown in Technical Appendix Attachment 1.2 Vectren Technology Assessment Summary table from <u>Petitioner's Exhibit No. 5</u>, Attachment MAR-2, the second CT is estimated to be approximately $50 million less capital spend than the second CT when built at the same time. Additionally, building two CTs at the same time keeps existing interconnection rights at A.B. Brown, which shields customers from potential transmission upgrade costs in the future should CenterPoint Indiana South have to re-enter the MISO Queue (a two and a half to three-year process).

VI. 21st CENTURY ENERGY POLICY DEVELOPMENT TASK FORCE PILLARS

Q. Have you reviewed the Final Report issued by the 21st Century Energy Policy Development Task Force dated November 19, 2020 (the "Final Report")?

A. Yes. I reviewed the five pillars that the Task Force recommended serve as a lens through which it would review future potential policy decisions.

Q. What are the five pillars?

A. The five pillars are reliability, resilience, stability, affordability, and environmental sustainability. Reliability consists of two fundamental concepts – adequacy and operating reliability. Adequacy is the ability of the electric system to supply the aggregate electric power and energy requirements of electricity consumers at all times, taking into account scheduled and reasonably expected unscheduled outages of system components. Operating reliability is the ability of the electric system to withstand sudden disturbances, such as electric short circuits or unanticipated loss of system components.

Q. In your opinion, is the proposal in this proceeding consistent with those five pillars?

A. Yes. The combustion turbines support the addition of clean renewable energy. This is consistent with the environmental sustainability pillar set forth in the Final Report. The total CO_2 output of the combustion turbines is minimal as these units are there for backup and not expected to run much. Moreover, as further supported by the IRP, this project promotes reliability. The Preferred Portfolio provides adequate, dispatchable capacity to meet MISO's planning reserve margin requirements in the summer and the winter in anticipation of a seasonal capacity requirement. The CTs can also supply power and energy requirements when called on by MISO for reliability or when market prices are sufficiently high, shielding customers from price risk. As Petitioner's Witness Games notes, CenterPoint Indiana South proposes to pair renewable generation with quick start and fast ramping dispatchable natural gas CT generation, which will further enhance the ability of the system to withstand sudden disturbances.

Q. In your opinion, is the Preferred Portfolio resilient and stable?

A. Yes. As to resiliency, the Preferred Portfolio helps to minimize the risk of sustained disruption. As further discussed by Petitioner's Witness Bacalao the IRP resulted in a Preferred Portfolio that significantly, but prudently, diversifies the resource mix for CenterPoint Indiana South's generation portfolio to meet current and future load and reserve margin requirements. Reliability was an important consideration of selecting a holistic portfolio. Solar, wind, natural gas combustion turbine, and coal resources are proven technologies that will help ensure CenterPoint Indiana South can continue to meet PRM requirements. Solar assets are also well suited to provide a stable source of energy in the summer when usage is at its highest. This is balanced with sufficient dispatchable resources to meet winter load. The new combustion turbines will include firm gas service to help ensure adequate gas supply in the winter.

Q. Do you believe the Preferred Portfolio will result in an affordable generation mix?

A. Yes. As demonstrated in the IRP, the Preferred Portfolio was among the most affordable options for customers, regardless of the future we face. As shown in Figure 8-2 on page 244 of the Petitioner's Exhibit No. 5, Attachment MAR-1, also shown below in Table 5, pricing for the Preferred Portfolio was within approximately 1-2% of the Reference Case portfolio in scenarios with varying levels of CO_2 cost, gas costs, coal costs, load, etc. The price of other portfolios evaluated in this analysis swing more depending on the future state. For example, the All Renewables by 2030 or the BAU portfolios are less stable. As discussed later in my testimony, the Preferred Portfolio also minimizes bill impacts in the near term compared to continuing to run the A.B. Brown units through 2029 or conversion to natural gas.

Table 5: Portfolio NPVRR (million $)

	Scenarios				
	Reference	**Low Regulation**	**High Technology**	**80% Reduction of CO_2 by 2050**	**High Regulatory**
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 + 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 + Flex ble 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%
High Technology	102.3%	102.6%	101.3%	102.1%	102.2%

Q. Is the Preferred Portfolio environmentally sustainable?

A. Yes. The Preferred Portfolio 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. Additionally, the Preferred Portfolio 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.

Q. Is the Preferred Portfolio reliable?

A. Yes. CenterPoint Indiana South's balanced portfolio includes a diverse mix of resources with enough dispatchable generation to meet peak demand in the early evening hours during the summer, when the sun goes down, and during winter peak conditions. These resources include F.B. Culley 3 coal, A.B. Brown 3 & 4 gas peaking units, and two new highly dispatchable gas turbines with firm gas service. These units provide fast start (10 minute) and fast ramping capability (40 MW/minute each CT or 80 MW/minute for both CTs), which compliments renewable resources when needed. A reliability assessment was performed as part of the Preferred Portfolio, discussed on pages 195-196 of Petitioner's Exhibit No. 5, Attachment MAR-1. CTs provide sufficient reactive power reserves[16] to minimize potential voltage issues. Finally, CenterPoint Indiana South's transmission system has 750 MWs of import capability, which allows CenterPoint Indiana South to utilize the system to provide power when market prices are low.

VII. COST ISSUES

[16] Real power accomplishes useful work while reactive power supports the voltage that must be controlled for system reliability.

Q. Do the cost estimates for the combustion turbines align with the IRP cost estimates?

A. Yes. The capital costs and expected O&M costs in this filing align with the previous IRP estimates. The following provides more detail.

Q. How do the cost assumptions associated with the combustion turbines modeled in the IRP compare with the cost of the +/- 10% cost estimates described in Witness Games' testimony?

A. The cost estimate for the two CTs in the IRP was approximately $327.8 million in 2024 dollars, which is higher than the cost of two CTs requested in this case at $323 million, as described in Wayne Games' testimony.

Q. Did you model the cost of firm gas service within the IRP?

A. Yes, as described by Witness Paula J. Grizzle, the estimate for firm gas service is approximately $27.3 million per year in 2024 dollars. This was lower than the amount included in IRP modeling at $28.6 million per year in 2024 dollars.

Q. How does the O&M estimate compare to the IRP?

A. IRP O&M estimates were utilized from the Burns and McDonnell Technology Assessment found in IRP Volume 2 attached as <u>Petitioner's Exhibit No. 5</u>, Attachment MAR-1. O&M projections vary by how much the unit is started and operated. Utilizing a comparable amount of starts and run time[17], O&M estimates in Witness Games' testimony are lower than what was modeled within the IRP. For the purposes of rate impact estimates, discussed below, IRP O&M assumptions were utilized.

VIII. <u>RATE ISSUES</u>

Q. Have you estimated the potential bill impact of the combustion turbines?

A. Yes, I provide day one bill impact estimates for the combustion turbines compared to possible alternatives such as conversion of A.B. Brown units 1 & 2 to natural gas or

[17] Conservatively assumes 150 starts per year, per unit with a 10% annual capacity factor. The IRP Reference Case capacity factor was approximately 2% over the forecast period.

running the A.B. Brown units with coal through 2029. Additionally, I provide an estimate for the total day one bill impact for the generation transition.

Q. When will CenterPoint Indiana South begin recovery of the two combustion turbines?

A. Recovery would begin following a decision in the next general rate case, which is required by the end of 2023.

Q. Please describe Petitioner's Exhibit No. 5, Attachments MAR-3 through MAR-15.

A. Petitioner's Exhibit No. 5, **Attachment MAR-3**, Low End Estimated Net Monthly Rate Impact by Customer Class, is a summary table showing the low end of projected bill impacts based on closing F.B. Culley 2, Warrick Unit #4, A.B. Brown 1 & 2 coal units and replacing them with the two CTs proposed in this case, 300 MW Posey Solar, 100 MW Warrick Solar, 335 MWs of solar PPAs, and 200 MWs of owned wind. Additionally, it shows a high-level estimate of the anticipated impact of securitization from the recently enacted Senate Bill 386. The net impact to expected revenue requirements is then allocated by customer class using current Four-Coincident Peak ("4CP") allocations, approved in Cause No. 43354-MCRA 21-S1.

Petitioner's Exhibit No. 5, **Attachment MAR-4**, High End Estimated Net Monthly Rate Impact by Customer Class, includes all projects listed above with the addition of a 130 MW owned solar plant and an additional 150 MWs of wind project. The net impact to expected revenue requirements is then allocated by customer class using current 4CP allocations.

Petitioner's Exhibit No. 5, **Attachment MAR-5**, Low End Estimated Net Monthly Rate Impact by Customer Class – Existing Allocations, shows the net impact by customer class utilizing current 4CP (capacity based) allocations for owned projects and FAC proxy (energy based) allocations for the low end estimate projects listed above in Petitioner's Exhibit No. 5, Attachment MAR-3.

Petitioner's Exhibit No. 5, **Attachment MAR-6**, High End Estimated Net Monthly Rate Impact by Customer Class – Existing Allocations shows the net impact by customer class utilizing current 4CP (capacity based) allocations for owned projects and FAC proxy (energy based) allocations for the high end estimate projects listed above in Petitioner's Exhibit No. 5, Attachment MAR-4.

Confidential Petitioner's Exhibit No. 5, **Attachments MAR-7 (CONFIDENTIAL)** through **MAR-13 (CONFIDENTIAL)** show Project details for each potential resource in the generation transition and the estimated revenue requirement for each.

Petitioner's Exhibit No. 5, **Attachment MAR-14**, BAU 2029 – Continue ABB1 & ABB2 Project, and Petitioner's Exhibit No. 5, **Attachment MAR-15**, Conversion of ABB1 & ABB2 Coal to Gas Project, show the project cost details for these options, including an estimated revenue requirement for these alternatives as a comparison to building 2 CT's.

Q. Please describe the bill impact focusing just on the addition of the combustion turbines without considering any cost reduction offsets.

A. Petitioner's Exhibit No. 5, Attachment MAR-7 (CONFIDENTIAL) shows that the estimated residential year-one bill impact for a residential customer that uses 1,000 kWh per month is approximately $23 per month. This impact focuses simply on adding the two CTs and does not reflect offsets for sales or O&M and fuel savings from exiting the A.B. Brown units one and two.

Q. How does this compare to the bill impact of converting A.B. Brown 1 & 2 to natural gas or continuing to run these units with coal?

A. As described in the IRP, converting one or both A.B. Brown units to natural gas costs customers more in the long run. Conversion also costs customers more on day one. Petitioner's Exhibit No. 5, Attachments MAR-14 and MAR-15 show that the estimated residential year-one bill impact for a residential customer that uses 1,000 kWh per month is approximately $26 per month for conversion and $35 per month for continuing to run with coal through 2029, respectively. This impact for conversion does not reflect offsets for sales or O&M and fuel savings from exiting the A.B. Brown units 1 & 2 in the case of the conversion. In other words, these are the day one impacts that would be comparable to the $23 per month shown in Attachment MAR-7.

Q. You testified that all three of the calculations you have discussed so far do not reflect offsets. Please describe the expected day-one bill impact of implementing the full generation transition plan, including the impact of offsets.

A. The generation transition plan includes closing 730 MWs of coal and replacing with 735-865 MWs of solar, 200-350 MWs of wind, and the two combustion turbines proposed in this case. The plan also calls for securitization of the remaining net book value of the A.B. Brown plant at retirement. The day-one bill impact of the plan is expected to be modest for the generation portion of customer rates, ranging from a $16 million dollars decrease per year to an increase of $27 million dollars per year in the near term and is expected to decrease in the long-term.

Q. Please provide the detail associated with the Bill impact.

A. The tables below show combined savings in millions of dollars for O&M and fuel savings associated with the closure of 730 MWs of coal, removal of A.B. Brown from rate base (securitization), and the sale of Renewable Energy Credit (REC) sales associated with new wind and solar renewable resources to help offset cost to the customer. Impacts are presented in a range based on how successful CenterPoint Indiana South is at procuring renewable resources. The following tables are included in Petitioner's Exhibit No. 5, Attachments MAR-3 and MAR-4.

Table 6: Low End Summary of Generation Transition Impact Annual Savings and Costs in Millions of Dollars[18]

Description	Savings (Millions $)	Cost (Millions $)	Total (Millions $)
Expected O&M and Fuel Savings from C2, W4, ABB 1&2	($143)		
460 MW Combustion Turbine		$79	
300 MW Posey *	($5)	$37	
100 MW Warrick *	($2)	$10	
335 MW Solar PPA *	($6)	$28	
200 MW Wind *	($5)	$36	
Securitization	($68)	$23	
Subtotal	($229)	$213	
Net Cost in millions			($16)

*REC Sale Savings

[18] Estimated rate impact includes Culley 2 through 2023.

Table 7: High End Summary of Generation Transition Impact Annual Savings and Costs in Millions of Dollars[19]

Description	Savings (Millions $)	Cost (Millions $)	Total (Millions $)
Expected O&M and Fuel Savings from C2, W4, ABB 1&2	($143)		
460 MW Combustion Turbine		$79	
300 MW Posey *	($5)	$37	
100 MW Warrick *	($2)	$10	
335 MW Solar PPA *	($6)	$28	
130 MW Solar Owned *	($2)	$18	
200 MW Wind *	($5)	$36	
150 MW Wind *	($4)	$32	
Securitization	($68)	$23	
Subtotal	($236)	$262	
Net Cost in millions			$27

*REC Sale Savings

Q. How will these savings be allocated across customer classes?

A. That will depend on the rate case in 2023 and the associated class cost of service study. However, if bill impacts are spread across customer classes utilizing current 4CP allocations, customers would see the following high-level monthly bill impacts.

Table 8: Summary of Generation Transition Low End Impact Monthly Bills by Class[20]

Day-One Monthly Bill Impact	Customers	4CP Allocations	Monthly Bill Impact 4CP
Residential	132,669	41%	($4)
Small General Service	10,118	2%	($2)
Demand General Service	8,204	28%	($46)
Off Season Service	742	2%	($39)
Large Power	117	26%	($3,100)
High Load Factor	2	1%	($6,100)

[19] Estimated rate impact includes Culley 2 through 2023.
[20] Estimated rate impact includes Culley 2 through 2023.

Table 9: Summary of Generation Transition High End Impact Monthly Bills by Class[21]

Day-One Monthly Bill Impact	Customers	4CP Allocations	Monthly Bill Impact 4CP
Residential	132,669	41%	$7
Small General Service	10,118	2%	$4
Demand General Service	8,204	28%	$76
Off Season Service	742	2%	$65
Large Power	117	26%	$5,100
High Load Factor	2	1%	$10,000

Q. Is it possible that these impacts could look different?

A. Yes. We have done preliminary analysis for securitization, reflected in the table above, with high level estimates for securitization costs, including cost of removal for the A.B. Brown plant, which will require a decommissioning study. The cost for securitization could be higher. But the effects of higher decommissioning would be reflected in other portfolios, because as I understand it, those higher decommissioning costs would be reflected in higher depreciation rates if the A.B. Brown units were retained as coal units or converted to gas. Additionally, CenterPoint Indiana South is including costs associated with owned renewable resources through CECA (allocations are capacity based – 4CP) and PPA renewables though the FAC (energy based). Simply utilizing the current allocation methodology though CECA and the FAC, residential and commercial customers would see a larger decrease, while LP customers could see an increase of approximately 0.6 cents to 1.2 cents per kWh. Finally, I've included an $8 estimate per MWh for REC sales. This is a reasonable estimate, but the REC market could fluctuate up or down in the future. Current practice is to sell RECs on behalf of CenterPoint Indiana South customers. CenterPoint Indiana South could choose to not sell RECs in the future or be utilized in a green energy tariff for customers.

Q. When do you plan to file for securitization for the A.B. Brown Plant?

A. We could file as early as first quarter of 2022. In this filing we will seek authority from the Commission to remove the A.B. Brown plant from rate base, along with decommissioning costs, and costs associated with securing a bond when the proceeds from securitization

[21] Estimated rate impact includes Culley 2 through 2023.

are received. CenterPoint Indiana South will then charge customers for the bond for a set amount of time. The interest rate on the bond will be substantially lower than the weighted average cost of capital in a rate case. Securitization is expected to provide a benefit to all customer classes.

Q. On the subject of costs, is the Company incurring significant costs related to the planning and preparation of this proceeding and request?

A. Yes. As should be well understood, the IRP process has become much more robust over the past several IRPs. The end result is a much better tool to guide resource planning, but it comes at significant cost. And to take the planning from the IRP and further refine for approval of generation is also much more involved than it has been in past years, with the use of outside consultants and studies to explore alternatives.

Q. **How are these costs expected to be recovered?**

A. We are currently carrying these costs on our books and will record them to the cost of owned generating resources, a portion of which will be applied to the new CTs. These costs are included in the estimate of costs of the CTs presented by Witness Games. If for whatever reason the CTs are not ultimately placed in service, we are seeking authority to defer these costs as a regulatory asset at that time to be recovered as described by Witness Kara R. Gostenhofer.

IX. CONCLUSION

Q. Does this conclude your direct testimony?

A. Yes, at the present time.

2019/2020 Integrated Resource Plan

VECTREN
A CenterPoint Energy Company

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IRP Rule Requirements Cross Reference Table

Rule		Section(s)
170 IAC 4-7-2 Integrated Resource Plan Submission Section 2		
(c) On or before the applicable date, a utility subject to subsection (a) or (b) must submit electronically to the director or through an electronic filing system if requested by the director, the following documents:		
(1) The IRP.		2019 IRP submitted on June 30, 2020
(2) A technical appendix containing supporting documentation sufficient to allow an interested party to evaluate the data and assumptions in the IRP. The technical appendix shall include at least the following: (A) The utility's energy and demand forecasts and input data used to develop the forecasts. (B) The characteristics and costs per unit of resources examined in the IRP; (C) Input and output files from capacity planning models, in electronic format. (D) For each portfolio, the electronic files for the calculation of the revenue requirement if not provided as an output file. If a utility does not provide the above information, it shall include a statement in the technical appendix specifying the nature of the information it is omitting and the reason necessitating its omission. The utility may request confidential treatment of the technical appendix under section 2.1 of this rule.		12 Technical Appendix Attachments 1.1-8.3
(3) An IRP summary that communicates core IRP concepts and results to nontechnical audiences in a simplified format using visual elements where appropriate. The IRP summary shall include, but is not limited to, the following: (A) A brief description of the utility's: (i) existing resources; (ii) preferred resource portfolio; (iii) key factors influencing the preferred resource portfolio; (iv) short term action plan; (v) public advisory process; and (vi) additional details requested by the director. (B) A simplified discussion of the utility's resource types and load characteristics.		Executive Summary (non-technical summary document)
The utility shall make the IRP summary readily accessible on its website.		www.vectren.com/irp
170 IAC 4-7-2.6 Public advisory process Sec. 2.6		

(b) The utility shall provide information requested by an interested party relating to the development of the utility's IRP within 15 business days of a written request or as otherwise agreed to by the utility and the interested party. If a utility is unable to provide the requested information within 15 business days or the agreed timeframe, it shall provide a statement to the director and the requestor as to the reason it is unable to provide the requested information.		3.4 Data Requests Summary
(c) The utility shall solicit, consider and timely respond to relevant input relating to the development of the utility's IRP provided by: (1) interested parties; (2) the OUCC; and (3) commission staff.		3 Public Participation Process
(d) The utility retains full responsibility for the content of its IRP.		n/a
(e) The utility shall conduct a public advisory process as follows: (1) Prior to submitting its IRP to the commission, the utility shall hold at least three (3) meetings, a majority of which shall be held in the utility's service territory. The topics discussed in the meetings shall include, but not be limited to, the following:		3.1 Process Description
(A) An introduction to the IRP and public advisory process. (B) The utility's load forecast. (C) Evaluation of existing resources. (D) Evaluation of supply-side and demand-side resource alternatives, including: (i) associated costs; (ii) quantifiable benefits; and (iii) performance attributes. (E) Modeling methods. (F) Modeling inputs. (G) Treatment of risk and uncertainty. (H) Discussion seeking input on its candidate resource portfolios. (I) The utility's scenarios and sensitivities. (J) Discussion of the utility's preferred resource portfolio and the utility's rationale for its selection.		3 Public Participation Process; 12 Technical Appendix Attachment 3.1
(2) The utility may hold additional meetings.		3.1 Process Description
(3) The schedule for meetings shall: (A) be determined by the utility; (B) be consistent with its internal IRP development schedule; and		3 Public Participation Process

(C) provide an opportunity for public participation in a timely manner so that it may affect the outcome of the IRP.		
170 IAC 4-7-4 Integrated resource plan contents Sec. 4		
An IRP must include the following: (1) At least a twenty (20) year future period for predicted or forecasted analyses.		4.6 Base Energy And Demand Forecast
(2) An analysis of historical and forecasted levels of peak demand and energy usage in compliance with section 5(a) of this rule.		11.1.3 Overview of Past Forecasts
(3) At least three (3) alternative forecasts of peak demand and energy usage in compliance with section 5(b) of this rule.		7.3. Alternate Scenarios; Figure 7.8 Vectren Peak Demand Forecast
(4) A description of the utility's existing resources in compliance with section 6(a) of this rule.		6.2 Current Resource Mix
(5) A description of the utility's process for selecting possible alternative future resources for meeting future demand for electric service, including a cost-benefit analysis, if performed.		6 Resource Options; 8 Portfolio Development and Evaluation
(6) A description of the possible alternative future resources for meeting future demand for electric service in compliance with section 6(b) of this rule.		6.3 Potential Future Options Modeling Assumptions; Figure 6-5 Tier 1 Cost Summary
(7) The resource screening analysis and resource summary table required by section 7 of this rule.		Figure 11.35 New Construction Alternatives; Figure 6-5 Tier 1 Cost Summary.
(8) A description of the candidate resource portfolios and the process for developing candidate resource portfolios in compliance with section 8(a) and 8(b) of this rule.		8.1 Portfolio Development
(9) A description of the utility's preferred resource portfolio and the information required by section 8(c) of this rule.		8.2 Evaluation of Portfolio Performance; 9.1 Preferred Portfolio Recommendation
(10) A short term action plan for the next three (3) year period to implement the utility's preferred resource portfolio and its workable strategy, pursuant to section 9 of this rule.		10 Short Term Action Plan
(11) A discussion of the: (A) inputs; (B) methods; and (C) definitions; used by the utility in the IRP.		List of Acronyms/Abbreviations with Definitions; 2 Vectren's IRP Process; 3 Public Participation Process; 4 Customer Energy Needs; 6 Resource Options; 7 Model Inputs and Assumptions; 8 Portfolio Development and Evaluation
(12) Appendices of the data sets and data sources used to establish alternative forecasts in section 5(b) of this		12 Technical Appendix Attachments

rule. If the IRP references a third-party data source, the IRP must include for the relevant data: (A) source title; (B) author; (C) publishing address; (D) date; (E) page number; and (F) an explanation of adjustments made to the data. The data must be submitted within two (2) weeks of submitting the IRP in an editable format, such as a comma separated value or excel spreadsheet file.		
(13) A description of the utility's effort to develop and maintain a database of electricity consumption patterns, disaggregated by: (A) customer class; (B) rate class; (C) NAICS code; (D) DSM program; and (E) end-use. 14) The database in subdivision (13) may be developed using, but not limited to, the following methods: (A) Load research developed by the individual utility. (B) Load research developed in conjunction with another utility. (C) Load research developed by another utility and modified to meet the characteristics of that utility. (D) Engineering estimates. (E) Load data developed by a non-utility source.		6.2.4 Energy Efficiency; 11.1.1 Forecast Inputs; 12 Technical Appendix Attachment 4.1 2019 Long-Term Electric Energy and Demand Forecast Report
(15) A proposed schedule for industrial, commercial and residential customer surveys to obtain data on: (A) end-use penetration; (B) end-use saturation rates; and (C) end-use electricity consumption patterns.		11.1.4 Equipment Efficiencies and Market Share Data
(16) A discussion detailing how information from advanced metering infrastructure and smart grid, where available, will be used to enhance usage data and improve load forecasts, DSM programs and other aspects of planning.		1.3.3.1 Advanced Metering Infrastructure (AMI)
(17) A discussion of the designated contemporary issues designated, if required by section 2.7(e).		1.3.13 Contemporary Issues
(18) A discussion of distributed generation within the service territory and its potential effects on: (A) generation planning;		4.4 Customer Owned Distributed Energy Resources

(B) transmission planning; (C) distribution planning; and (D) load forecasting.		
(19) For models used in the IRP, including optimization and dispatch models, a description of the model's structure and applicability.		4.3 Model Framework; 7.1 Resource Model
(20) A discussion of how the utility's fuel inventory and procurement planning practices have been taken into account and influenced the IRP development.		9.1.7 Fuel Inventory and Procurement Planning
(21) A discussion of how the utility's emission allowance inventory and procurement practices for an air emission have been considered and influenced the IRP development.		11.2.1 Air Emissions
(22) A description of the generation expansion planning criteria. The description must fully explain the basis for the criteria selected.		8.1 Portfolio Development
(23) A discussion of how compliance costs for existing or reasonably anticipated air, land, or water environmental regulations impacting generation assets have been taken into account and influenced the IRP development.		7.2. Reference Case Scenario; 7.3 Alternate Scenarios
(24) A discussion of how the utilities' resource planning objectives, such as: (A) cost effectiveness; (B) rate impacts; (C) risks; and (D) uncertainty; were balanced in selecting its preferred resource portfolio.		8.2 Evaluation of Portfolio Performance; 9.1 Preferred Portfolio Recommendation
(25) A description and analysis of the utility's Reference Case scenario, sometimes referred to a business as usual case or reference case. The Reference Case scenario is the most likely future scenario and must meet the following criteria: (A) Be an extension of the status quo, using the best estimate of forecasted electrical requirements, fuel price projections and an objective analysis of the resources required over the planning horizon to reliably and economically satisfy electrical needs. (B) Include: (i) existing federal environmental laws; (ii) existing state laws, such as renewable energy requirements and energy efficiency laws; and (iii) existing policies, such as tax incentives for renewable resources. (C) Existing laws or policies continuing throughout at least some portion of the planning horizon with		7.2 Reference Case Scenario

a high probability of expiration or repeal must be eliminated or altered when applicable. (D) Not include future resources, laws, or policies unless: (i) a utility subject to section 2.6 of this rule solicits stakeholder input regarding the inclusion and describes the input received; (ii) future resources have obtained the necessary regulatory approvals; and (iii) future laws and policies have a high probability of being enacted. A Reference Case scenario need not align with the utility's preferred resource portfolio.		
(26) A description and analysis of alternative scenarios to the Reference Case scenario, including comparison of the alternative scenarios to the Reference Case scenario.		7.3 Alternate Scenarios
(27) A brief description of the models(s), focusing on the utility's Indiana jurisdictional facilities, of the following components of FERC Form 715: (A) The most current power flow data models, studies and sensitivity analysis. (B) Dynamic simulation on its transmission system, including interconnections, focused on the determination of the performance and stability of its transmission system on various fault conditions. The description must state whether the simulation meets the standards of the North American Electric Reliability Corporation (NERC). (C) Reliability criteria for transmission planning as well as the assessment practice used. This description must include the following: (i) The limits of the utility's transmission use. (ii) The utility's assessment practices developed through experience and study. (iii) Operating restrictions and limitations particular to the utility.		6.4 Transmission Considerations
(28) A list and description of the methods used by the utility in developing the IRP, including the following: (A) For models used in the IRP, the model's structure and reasoning for its use. (B) The utility's effort to develop and improve the methodology and inputs, including for its: (i) load forecast; (ii) forecasted impact from demand-side programs; (iii) cost estimates; and		4.3 Model Framework; 7.1 Resource Model; 6.3.2 DSM, 4.6 Energy and Demand Forecast (Reference Case); 6 Resource Options; 7 Model Inputs and Assumptions; 8.2 Evaluation of Portfolio Performance; 9.1 Preferred Portfolio

(iv) analysis of risk and uncertainty.		
(29) An explanation, with supporting documentation, of the avoided cost calculation for each year in the forecast period, if the avoided cost calculation is used to screen demand-side resources. The avoided cost calculation must reflect timing factors specific to the resource under consideration such as project life and seasonal operation. The avoided cost calculation must include the following: (A) The avoided generating capacity cost adjusted for transmission and distribution losses and the reserve margin requirement. (B) The avoided transmission capacity cost. (C) The avoided distribution capacity cost. (D) The avoided operating cost, including: (i) fuel cost; (ii) plant operation and maintenance costs; (iii) spinning reserve; (iv) emission allowances; (v) environmental compliance costs; and (vi) transmission and distribution operation and maintenance costs.		11.3.5 Avoided Costs
(30) A summary of the utility's most recent public advisory process, including the following: (A) Key issues discussed. (B) How the utility responded to the issues. (C) A description of how stakeholder input was used in developing the IRP.		3 Public Participation Process
(31) A detailed explanation of the assessment of demand-side and supply-side resources considered to meet future customer electricity service needs.		6 Resource Options
170 IAC 4-7-5 Energy and demand forecasts Sec. 5.		
(a) The analysis of historical and forecasted levels of peak demand and energy usage must include the following: (1) Historical load shapes, including the following: (A) Annual load shapes. (B) Seasonal load shapes. (C) Monthly load shapes. (D) Selected weekly load shapes. (E) Selected daily load shapes, which shall include summer and winter peak days and a typical weekday and weekend day.		11.1.3.2 Load Shapes; 12 Technical Appendix Attachments Attachment 4.1 2019 Vectren Long-Term Electric Energy and Demand Forecast Report; Attachment 4.2 Vectren Hourly Load Data
(2) Disaggregation of historical data and forecasts by: (A) customer class; (B) interruptible load; and (C) end-use; where information permits.		11.1.3 Overview of Past Forecasts; 12 Technical Appendix Attachments Attachment 4.1 2019 Vectren Long-Term Electric Energy and Demand Forecast Report

(3) Actual and weather normalized energy and demand levels.		11.1.3 Overview of Past Forecasts
(4) A discussion of methods and processes used to weather normalize.		11.1.3 Overview of Past Forecasts
(5) A minimum twenty (20) year period for peak demand and energy usage forecasts.		4.6 Energy and Demand Forecast (Reference Case)
(6) An evaluation of the performance of peak demand and energy usage for the previous ten (10) years, including the following: (A) Total system. (B) Customer classes or, rate classes, or both. (C) Firm wholesale power sales.		11.1.3 Overview of Past Forecasts
(7) A discussion of how the impact of historical DSM programs is reflected in or otherwise treated in the load forecast.		12 Technical Appendix Attachments 4.1 2019 Vectren Long-Term Electric Energy and Demand Forecast Report
(8) Justification for the selected forecasting methodology.		12 Technical appendix attachments 4.1 2019 Vectren Long-Term Electric Energy and Demand Forecast Report
(9) A discussion of the potential changes under consideration to improve the credibility of the forecasted demand by improving the data quality, tools and analysis.		1.3.3.1 Advanced Metering Infrastructure; 11.1.2 Load Forecast Continuous Improvement
(10) For purposes of subdivisions (1) and (2), a utility may use utility specific data or data such as described in section 4(14) of this rule.		n/a
(b) To establish plausible risk boundaries, the utility shall provide at least three (3) alternative forecasts of peak demand and energy usage including: (1) high; (2) low; and (3) most probable; peak demand and energy use forecasts.		7.3 Alternate Scenarios
(c) In determining the peak demand and energy usage forecast that is deemed by the utility, with stakeholder input, to be most probable, the utility shall consider alternative assumptions such as: (1) Rate of change in population. (2) Economic activity. (3) Fuel prices. (4) Price elasticity. (5) Penetration of new technology. (6) Demographic changes in population. (7) Customer usage. (8) Changes in technology. (9) Behavioral factors affecting customer consumption.		7.3 Alternate Scenarios; 12 Technical Appendix Attachments 4.1 2019 Vectren Long-Term Electric Energy and Demand Forecast Report

(10) State and federal energy policies. (11) State and federal environmental policies.		
170 IAC 4-7-6 Description of available resources		
Sec. 6. (a) In describing its existing electric power resources, the utility must include in its IRP the following information relevant to the twenty (20) year planning period being evaluated: The net and gross dependable generating capacity of the system and each generating unit. The information listed in subdivision (a)(1) through (a)(4) shall be provided for each year of the future planning period.		6.2 Current Resource Mix; 11.4.2 Approximate Net and Gross Dependable Capacity
(2) The expected changes to existing generating capacity, including the following: (A) Retirements. (B) Deratings. (C) Plant life extensions. (D) Repowering. (E) Refurbishment. The information listed in subdivision (a)(1) through (a)(4) shall be provided for each year of the future planning period.		6.2 Current Resource Mix
(3) A fuel price forecast by generating unit. The information listed in subdivision (a)(1) through (a)(4) shall be provided for each year of the future planning period.		12 Technical Appendix Attachments: Confidential Attachment 8.2 Aurora Input Model Files
(4) The significant environmental effects, including: (A) air emissions; (B) solid waste disposal; (C) hazardous waste; and(D) subsequent disposal; and (E) water consumption and discharge; at existing fossil fueled generating units. The information listed in subdivision (a)(1) through (a)(4) shall be provided for each year of the future planning period.		11.2 Environmental Appendix
(5) An analysis of the existing utility transmission system that includes the following: (A) An evaluation of the adequacy to support load growth and expected power transfers. (B) An evaluation of the supply-side resource potential of actions to reduce: (i) transmission losses;		11.8 Transmission Appendix

(ii) congestion; and (iii) energy costs. (C) An evaluation of the potential impact of demand-side resources on the transmission network.		
(6) A discussion of demand-side resources and their estimated impact on the utility's historical and forecasted peak demand and energy. (a)(6) shall be provided for each year of the future planning period.		6.2.4 Energy Efficiency; 6.2.5 Demand Response; 6.3.2 DSM; 11.3 DSM Appendix
The information listed in subdivision (a)(1) through (a)(4) and in subdivision (a)(6) shall be provided for each year of the future planning period.		Included in Sec. 6 (a)(1) through (a)(4) and in subdivision (a)(6)
(b) In describing possible alternative methods of meeting future demand for electric service, a utility must analyze the following resources as alternatives in meeting future electric service requirements: (1) Rate design as a resource in meeting future electric service requirements.		6.3.2.6 Other Innovative Rate Designs
(2) Demand-side resources. For potential demand-side resources, the utility shall include the following: (A) A description of the potential demand-side resource, including its costs, characteristics and parameters. (B) The method by which the costs, characteristics and other parameters of the demand-side resource are determined. (C) The customer class or end-use, or both, affected by the demand-side resource. (D) Estimated annual and lifetime energy (kWh) and demand (kW) savings. (E) The estimated impact of a demand-side resource on the utility's load, generating capacity and transmission and distribution requirements. (F) Whether the program provides an opportunity for all ratepayers to participate, including low-income residential ratepayers.		6.3.2 DSM, 12 Technical Appendix Attachments 6.2 2019 DSM Market Potential Study
(3) Supply-side resources. For potential supply-side resources, the utility shall include the following: (A) Identification and description of the supply-side resource considered, including the following: (i) Size in megawatts. (ii) Utilized technology and fuel type. (iii) Energy profile of nondispatchable resources. (iv) Additional transmission facilities necessitated by the resource.		6 Resource Options; 11.2 Environmental Appendix; 12 Technical Appendix Attachments: Attachment 1.2 Vectren Technology Assessment Summary Table; Confidential Attachment 8.2 Aurora Input Model Files

(B) A discussion of the utility's effort to coordinate planning, construction and operation of the supply-side resource with other utilities to reduce cost. (C) A description of significant environmental effects, including the following: (i) Air emissions. (ii) Solid waste disposal. (iii) Hazardous waste and subsequent disposal. (iv) Water consumption and discharge.		
(4) Transmission facilities as resources. In analyzing transmission resources, the utility shall include the following: (A) The type of the transmission resource, including whether the resource consists of one (1) of the following: (i) New projects. (ii) Upgrades to transmission facilities. (iii) Efficiency improvements. (iv) Smart grid technology. (B) A description of the timing, types of expansion and alternative options considered. (C) The approximate cost of expected expansion and alteration of the transmission network. (D) A description of how the IRP accounts for the value of new or upgraded transmission facilities increasing power transfer capability, thereby increasing the utilization of geographically constrained cost effective resources. (E) A description of how: (i) IRP data and information affect the planning and implementation processes of the RTO of which the utility is a member; and (ii) RTO planning and implementation processes affect the IRP.		6.4 Transmission Considerations
170 IAC 4-7-7 Selection of resources		
Sec. 7. (a) To eliminate nonviable alternatives, a utility shall perform an initial screening of the future resource alternatives listed in section 6(b) of this rule. The utility's screening process and the decision to reject or accept a resource alternative for further analysis must be fully explained and supported in the IRP. The screening analysis must be additionally summarized in a resource summary table.		6.6 Levelized Cost of Energy Resource Screening Analysis
170 IAC 4-7-8 Resource portfolios Sec. 8		

(a) The utility shall develop candidate resource portfolios from existing and future resources identified in sections 6 and 7 of this rule. The utility shall provide a description of its process for developing its candidate resource portfolios, including a description of its optimization modeling, if used. In selecting the candidate resource portfolios, the utility shall at a minimum consider: (1) risk; (2) uncertainty; (3) regional resources; (4) environmental regulations; (5) projections for fuel costs; (6) load growth uncertainty; (7) economic factors; and (8) technological change.		2.5 Portfolio Development; 8 Portfolio Development and Evaluation
(b) With regard to candidate resource portfolios, the IRP must include the following: (1) An analysis of how candidate resource portfolios performed across a wide range of potential future scenarios, including the alternative scenarios required under section 4(25) of this rule. (2) The results of testing and rank ordering of the candidate resource portfolios by key resource planning objectives, including cost effectiveness and risk metrics. (3) The present value of revenue requirement for each candidate resource portfolio in dollars per kilowatt-hour delivered, with the interest rate specified.		8.2 Evaluation of Portfolio Performance; 9.1.2 Affordability; 11.6.8 Affordability Ranking
(c) Considering the analyses of the candidate resource portfolios, a utility shall select a preferred resource portfolio and include in the IRP the following: (1) A description of the utility's preferred resource portfolio. (2) Identification of the standards of reliability. (3) A description of the assumptions expected to have the greatest effect on the preferred resource portfolio. (4) An analysis showing that supply-side resources and demand-side resources have been evaluated on a consistent and comparable basis, including consideration of: (A) safety; (B) reliability; (C) risk and uncertainty; (D) cost effectiveness; and (E) customer rate impacts.		6 Resource Options; 8 Portfolio Development and Evaluation; 9.1 Preferred Portfolio Recommendation

(5) An analysis showing the preferred resource portfolio utilizes supply-side resources and demand-side resources that safely, reliably, efficiently and cost-effectively meets the electric system demand taking cost, risk and uncertainty into consideration.		9 IRP Preferred Portfolio Recommendation
(6) An evaluation of the utility's DSM programs designed to defer or eliminate investment in a transmission or distribution facility, including their impacts on the utility's transmission and distribution system.		N/A
(7) A discussion of the financial impact on the utility of acquiring future resources identified in the utility's preferred resource portfolio including, where appropriate, the following: (A) Operating and capital costs of the preferred resource portfolio. (B) The average cost per kilowatt-hour of the future resources, which must be consistent with the electricity price assumption used to forecast the utility's expected load by customer class in section 5 of this rule. (C) An estimate of the utility's avoided cost for each year of the preferred resource portfolio. (D) The utility's ability to finance the preferred resource portfolio.		9. IRP Preferred Portfolio; 10.2.5 Ability to Finance the Preferred Portfolio, 11.3.5 Avoided Costs, 11.7.1 Affordability Ranking; 12 Technical Appendix Attachments, Confidential Attachment 8.2 Aurora Input Model Files
(8) A description of how the preferred resource portfolio balances cost effectiveness, reliability and portfolio risk and uncertainty, including the following: (A) Quantification, where possible, of assumed risks and uncertainties, including, but not limited to: (i) environmental and other regulatory compliance; (ii) reasonably anticipated future regulations; (iii) public policy; (iv) fuel prices; (v) operating costs; (vi) construction costs; (vii) resource performance; (viii) load requirements; (ix) wholesale electricity and transmission prices; (x) RTO requirements; and (xi) technological progress. (B) An assessment of how robustness of risk considerations factored into the selection of the preferred resource portfolio.		2 Vectren's IRP Process; 5 MISO Market; 7.2 Reference Case Scenario; 7.3 Alternate Scenarios; 8.2 Evaluation of Portfolio Performance; 9 Preferred Portfolio; Confidential Attachment 8.2 Aurora Input Model Files

(9) Utilities shall include a discussion of potential methods under consideration to improve the data quality, tools and analysis as part of the ongoing efforts to improve the credibility and efficiencies of their resource planning process.		10.2 Discussion of Plans for the Next 3 years; 11.1.4 Advanced metering Infrastructure and Continuous Improvement
(10) A workable strategy to quickly and appropriately adapt its preferred resource portfolio to unexpected circumstances, including changes in the following: (A) Demand for electric service. (B) Cost of new supply-side resources or demand-side resources. (C) Regulatory compliance requirements and costs. (D) Wholesale market conditions. (E) Fuel costs. (F) Environmental compliance costs. (G) Technology and associated costs and penetration. (H) Other factors which would cause the forecasted relationship between supply and demand for electric service to be in error.		8.2 Evaluation of Portfolio Performance; 9 Preferred Portfolio
170 IAC 4-7-9 Short term action plan Sec. 9		
(a) A utility shall prepare a short term action plan as part of its IRP and shall cover a three (3) year period beginning with the first year of the IRP submitted pursuant to this rule.		10 Short Term Action Plan
(b) The short-term action plan shall summarize the utility's preferred resource portfolio and its workable strategy, as described in section 8(c)(9) of this rule, where the utility must act or incur expenses during the three (3) year period.		10 Short Term Action Plan
(c) The short term action plan must include, but is not limited to, the following: (1) A description of resources in the preferred resource portfolio included in the short term action plan. The description may include references to other sections of the IRP to avoid duplicate descriptions. The description must include, but is not limited to, the following: (A) The objective of the preferred resource portfolio. (B) The criteria for measuring progress toward the objective.		10 Short Term Action Plan
(2) Identification of goals for implementation of DSM programs that can be developed in accordance with IC 8-1-8.5-10, 170 IAC 4-8-1 *et seq*. and consistent with the utility's longer resource planning objectives.		10.2.2 DSM

(3) The implementation schedule for the preferred resource portfolio.		10.3 Implementation Schedule for the Preferred Resource Portfolio
(4) A budget with an estimated range for the cost to be incurred for each resource or program and expected system impacts.		10.2 Discussion of Plans for the Next 3 Years
(5) A description and explanation of differences between what was stated in the utility's last filed short-term action plan and what actually occurred.		10.1 Differences Between the Last Short Term Action Plan From What Transpired

List of Acronyms/Abbreviations

ABB	Power Consulting Company
ABB	A.B. Brown Generating Station
AC	Alternating Current
ACE	Affordable Clean Energy
AEO	Annual Energy Outlook
AMI	Advanced Metering Infrastructure
ATC	Around the Clock
AUPC	Average Use Per Customer
BAGS	Broadway Avenue Generating Station
BAU	Business as Usual
BES	Bulk Electric System
BEV	Battery Electric Vehicles
BPM	Business Practice Manual
BSER	Best System of Emission Reduction
Btu	British Thermal Unit
BYOT	Bring You Own Thermostat
C&I	Commercial and Industrial
CAC	Citizens Action Coalition
CAGR	Compound Annual Growth Rate
CAPP	Central Appalachian
CCGT	Combined Cycle Gas Turbine
CCR	Coal Combustion Residuals
CDD	Cooling Degree Day
CDS	Circulating Dry Scrubber
CHP	Combined Heat and Power
CNP	CenterPoint Energy
CO_2	Carbon Dioxide
CO_2e	Carbon Dioxide equivalent
Comm	Commercial
CONE	Cost of New Entry
COVID	Corona Virus Disease
CPCN	Certificate of Public Convenience and Necessity
CSA	Coordinated Seasonal Transmission Assessment
CSAPR	Cross State Air Pollution Rule
CT	Combustion Turbine
CVR	Conservation Voltage Reduction
CWIS	Cooling Water Intake Structures
C&I	Commercial and Industrial
DA-LSFO	Dual-Alkali FGD-Forced Oxidation
DA-LSIO	Dual-Alkali FGD-Inhibited Oxidation
DC	Direct Current
DG	Distributed Generation

List of Acronyms/Abbreviations (Cont.)

DGS	Demand General Service
DLC	Direct Load Control
DPP	Definitive Planning Phase
DR	Demand Response
DSI	Dry Sorbent Injection
DSM	Demand Side Management
DSMA	Demand Side Management Adjustment
EE	Energy Efficiency
EEFC	Energy Efficiency Funding Component
EGU	Electric Generation Units
EIA	Energy Information Administration
ELCC	Effective Load Carrying Capability
ELG	Effluent Limitation Guidelines
EM	Equipment Manufactures
EM&V	Evaluation, measurement and Verification
EPA	U.S. Environmental Protection Agency
ESP	Electrostatic Precipitator
EV	Electric Vehicle
EVA	Energy Ventures Analysis, Inc.
FBC	F.B. Culley Generating Station
FBC3	F.B. Culley Unit 3
FDA	Flash Dryer Absorber
FDNS	Fixed Slope Decoupled Newton-Raphson
FERC	Federal Energy Regulatory Commission
FF	Fabric Filter
FGD	Flue Gas Desulfurization
GDP	Gross Domestic Product
GE	General Electric
GHG	Greenhouse Gas
GI	Generator Interconnection
GIA	Generator Interconnection Agreement
GIR	Generator Interconnection Requests
GPS	Global Positioning System
GS	General Service
GT	Gas Turbine
GW	Gigawatt
GWh	Gigawatt Hour
HB	House Bill
H_2SO_4	Sulfuric Acid
HDD	Heating Degree Days
Hg	Mercury
HHV	Higher Heating Value

List of Acronyms/Abbreviations (Cont.)

HLF	High Load Factor
HRSG	Heat Recovery Steam Generator
HVAC	Heating, Ventilation and Air Conditioning
IC	Internal Combustion
ICAP	Installed Capacity
IDEM	Indiana Department of Environmental Management
ILB	Illinois Basin
IMPA	Indiana Municipal Power Agency
Ind	Industrial
IPL	Indianapolis Power and Light Company
IRP	Integrated Resource Plan
ISB	Intelligent Sootblowing
ISO	Independent System Operator
ITC	Investment Tax Credit
IURC	Indiana Utility Regulatory Commission
kV	Kilovolt
kW	Kilowatt
kWh	Kilowatt Hour
lb	Pound
LCOE	Levelized Cost of Energy
LCR	Local Clearing Requirement
LGE/KU	Louisville Gas and Electric/Kentucky Utilities
LIB	Lithium-ion Battery
Li-ion	Lithium-ion
LMP	Local Marginal Pricing
LMR	Load Modifying Resources
LMR	Load Management Receivers
LNG	Liquefied Natural Gas
LOLE	Loss of Load Expectation
LP	Large Power
LRR	Local Reliability Requirement
LRZ	Local Resource Zone
LSE	Load Serving Entity
LSFO	Limestone FGD – Forced Oxidation
LTCE	Long-term Capacity Expansion
MATS	Mercury and Air Toxics Standards
MEEA	Midwest Energy Efficiency Alliance
MEP	Market Efficiency Project
MILP	Mixed Integer Linear Programming
MISO	Midcontinent Independent System Operator
MISO Tariff	Open Access Transmission, Energy and Operating Reserve Markets Tariff

List of Acronyms/Abbreviations (Cont.)

MLA	Municipal Levee Authority
MMBtu	One Million British Thermal Unit
MMWG	Multiregional Modeling Working Group
MPS	Market Potential Study
MSA	Metropolitan Statistical Area
MTEP	MISO Transmission Expansion Plan
MW	Megawatt
MWh	Megawatt Hour
NAAQS	National Ambient Air Quality Standard
NAEMA	North American Energy Markets Association
NAICS	North American Industry Classification System
NAPP	Northern Appalachia
NDA	Non-Disclose Agreement
NERC	North American Electric Reliability Council
NERC MOD	NERC Modeling, Data and Analysis
NH_3	Ammonia Scrubber
NIPSCO	Northern Indiana Public Service Company
NOAA	National Oceanic and Atmospheric Administration
NO_x	Nitrogen Oxide
NOPR	Notice of Proposed Rulemaking
NPDES	National Pollutant Discharge Elimination System
NPV	Net Present Value
NPVRR	Net Present Value Revenue Requirement
NREL	National Renewable Energy Lab
NRIS	Network Resource Integration Service
NTG	Net to Gross
NU	Network Upgrade
NYMEX	New York Mercantile Exchange
O&M	Operation and Maintenance
OMS	Organization of MISO States
ORSANCO	Ohio River Valley Sanitation Commission
OUCC	Office of Utility Consumer Counselor
OVEC	Ohio Valley Electric Corporation
PC	Pulverized Coal
PHEV	Plug-in Hybrid Electric
PIRA	PIRA Energy Group
PJM	Pennsylvania New Jersey Maryland Interconnection LLC
PM	Particulate Matter
PPA	Purchase Power Agreement
PPT	Parts Per Trillion
PRA	Planning Resource Auction

List of Acronyms/Abbreviations (Cont.)

PRB	Powder River Basin
PRM	Planning Reserve Margin
PRMR	Planning Reserve Margin Requirement
PSEG	Public Service Electric and Gas
PTC	Production Tax Credit
PTI PSS/E	Power Technologies Incorporated's Power System Simulator Program for Engineers
PV	Photovoltaic
RAN	Resource Availability and Need
Res	Residential
RF	ReliabilityFirst
RFP	Request for Proposals
RGGI	Regional Greenhouse Gas Initiative
RIIA	Renewable Integration Impact Assessment
RIM	Ratepayer Impact Measure
RS	Rate Schedules
RTO	Regional Transmission Operator
SAE	Statistically Adjusted End-use
SBS	Sodium Based Sorbents
SCGT	Simple Cycle Gas Turbine
SCR	Selective Catalytic Reduction
SD	Standard Deviation
SDA	Spray Dryer Absorber
SEA	Senate Enrolled Act
SERC	Southeast Reliability Corporation
SGS	Small General Service
SIGECO	Southern Indiana Gas and Electric Company
SIP	State Implementation Plan
SO_2	Sulfur Dioxide
SO_3	Sulfur Trioxide
STD Dev	Standard Deviation
TDSIC	Transmission, Distribution and Storage System Improvement Charge
T&D	Transmission and Distribution
TBtu	One Trillion British Thermal Unit
TRC	Total Resource Cost
UC	Utility Cost
UCAP	Unforced Capacity
UCT	Utility Cost Test
ULRC	Urban Living Research Center
UPC	Use Per Customer
V	Volt

List of Acronyms/Abbreviations (Cont.)

VAR	Volt-Amp Reactance
VER	Variable Energy Resources
VFD	Variable Frequency Drive
VOM	Variable Operation and Maintenance
VVC	Vectren Corporation
WLIO	Wet Lime FGD – Inhibited Oxidation
WN	Weather Normalized
WTE	Waste to Energy

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Executive Summary (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.

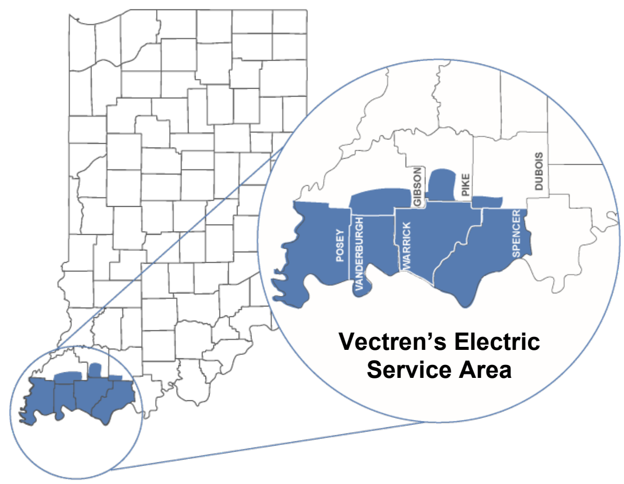
The resource options selected in this plan provide a bridge to the future. For example, CT's allow time for battery storage technology to continue to become more competitive in price and further develop longer duration storage capabilities. Further, should there be a need for new baseload generation 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 (H2S04) 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.

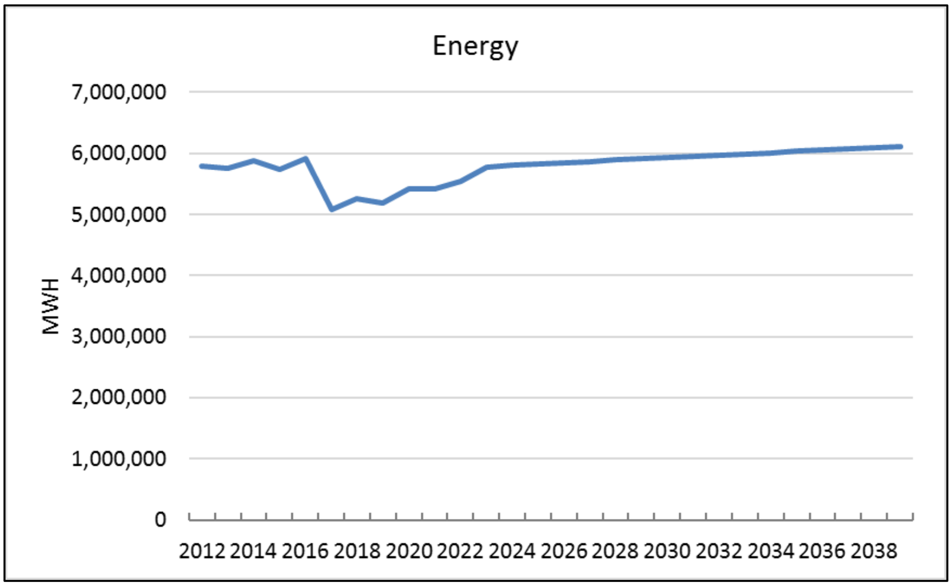
[3] The Blackfoot landfill gas generators are connected at the distribution level.
[4] Oak Hill Solar is connected at the distribution level.
[5] Volkman Rd. Solar is connected at the distribution level.

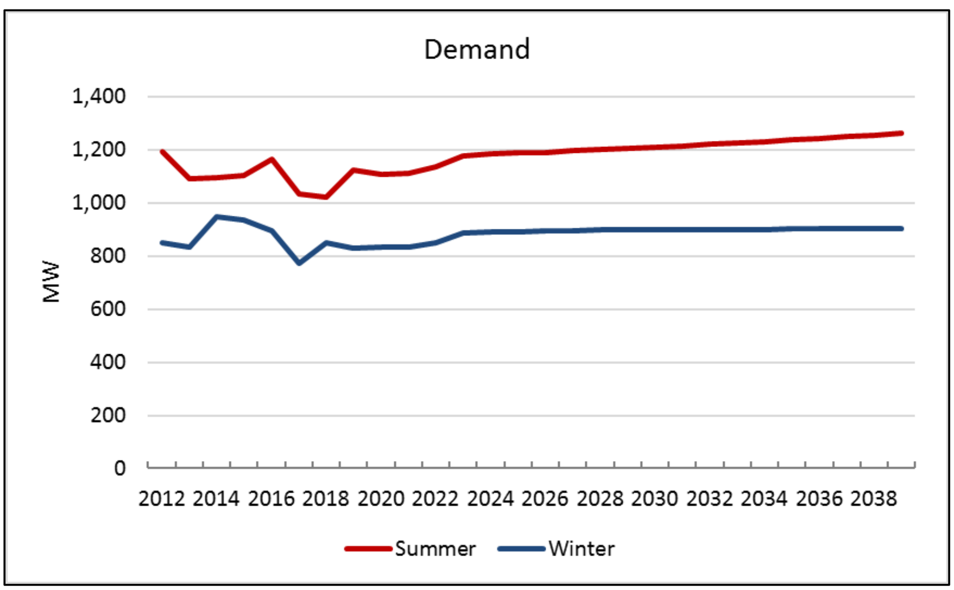
A. Customer Energy Needs

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.

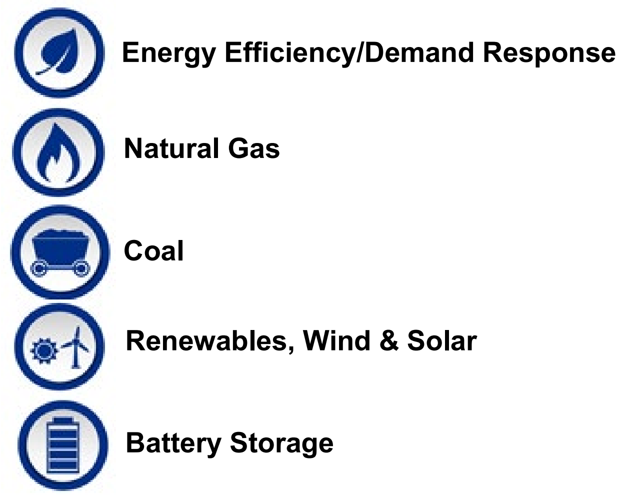
Historically, IRPs have focused on meeting customer demand in the summer, which is typically when reserve margins are at a minimum. As the regional resource mix changes towards intermittent (variable) renewable generation, it is important to ensure that resources are available to meet this demand in 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



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.

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

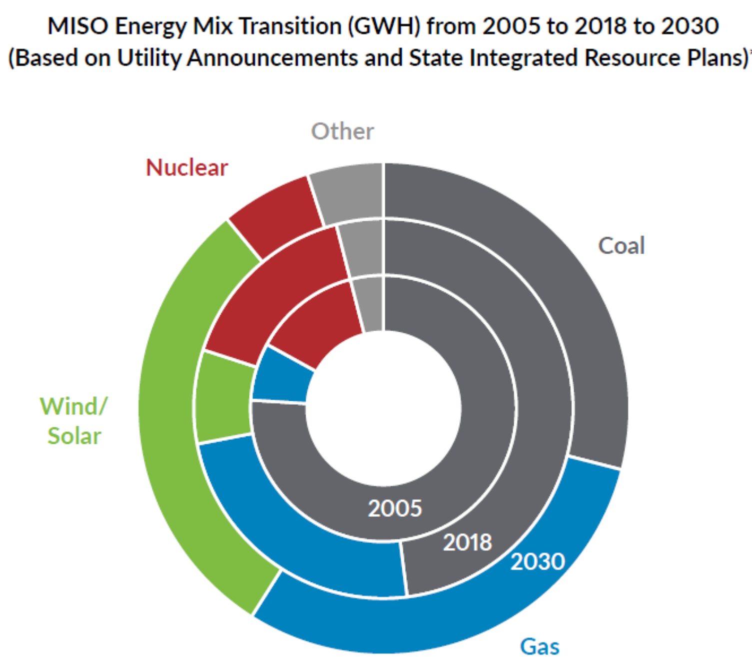


*Chart reflects ratios of generation.

[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.

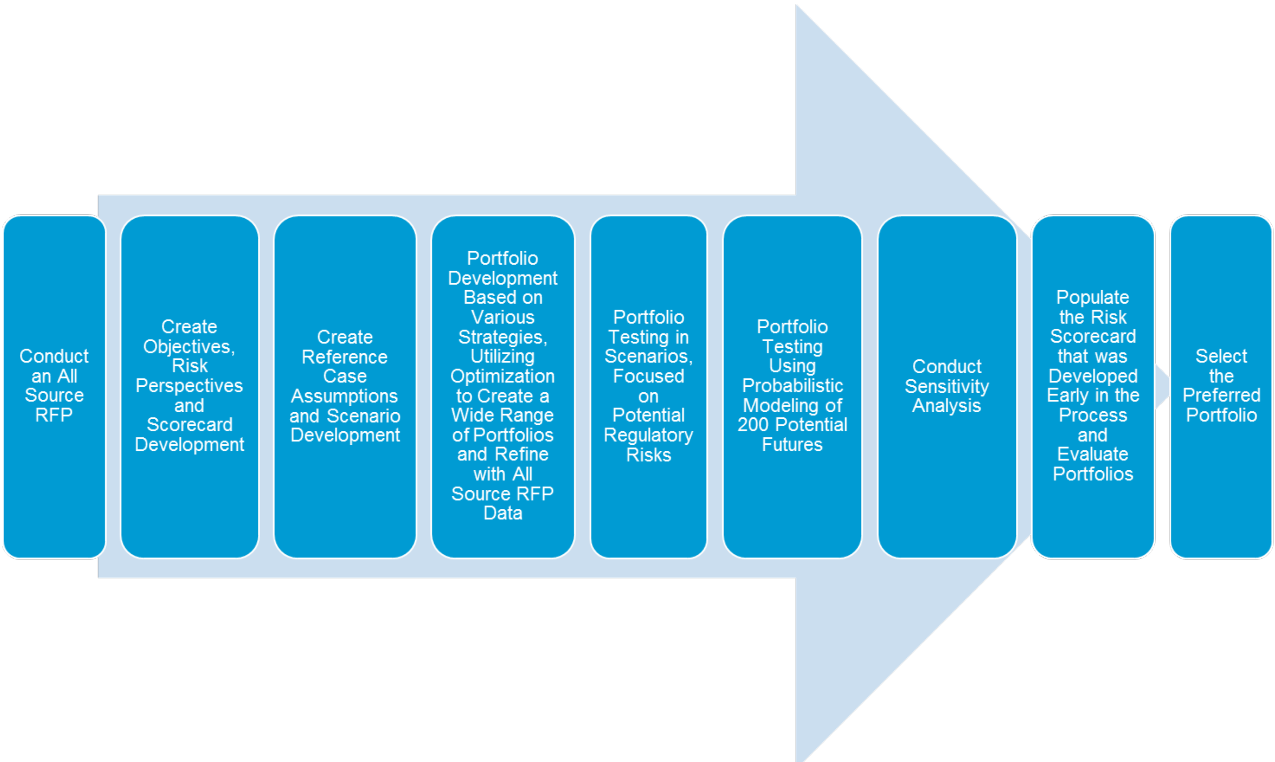
C. Uncertainty/Risk

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 • Objectives and Measures • All-Source RFP • Environmental Update • Draft Reference Case Market Inputs & Scenarios	• RFP Update • Draft Resource Costs • Sales and Demand Forecast • DSM MPS/ Modeling Inputs • Scenario Modeling Inputs • Portfolio Development	• Draft Portfolios • Draft Reference Case Modeling Results • All-Source RFP Results and Final Modeling Inputs • Scenario Testing and Probabilistic Modeling Approach and Assumptions	• Final Reference Case and Scenario Modeling Results • Probabilistic Modeling Results • Risk Analysis Results • 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.

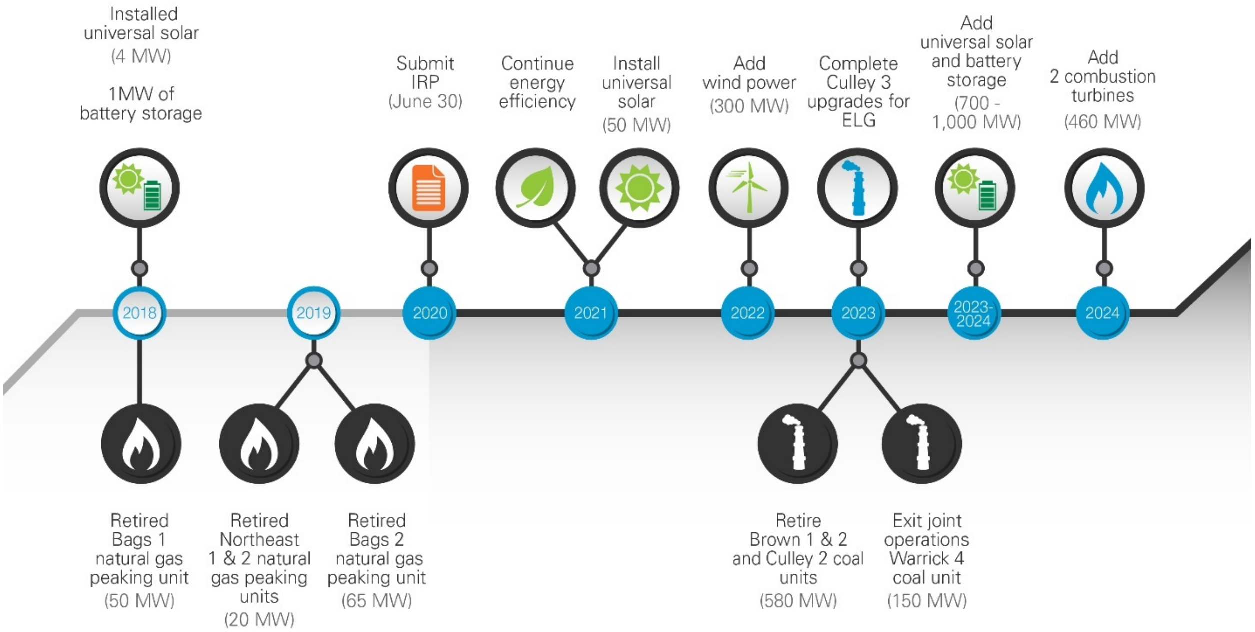
Request	Response
Update the High Regulatory scenario to include a carbon fee and dividend	Included a fee and dividend construct which assumed a balanced impact on the load (the economic drag from a carbon fee is neutralized by the economic stimulus of a dividend)
Lower renewables costs in the High Regulatory 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).

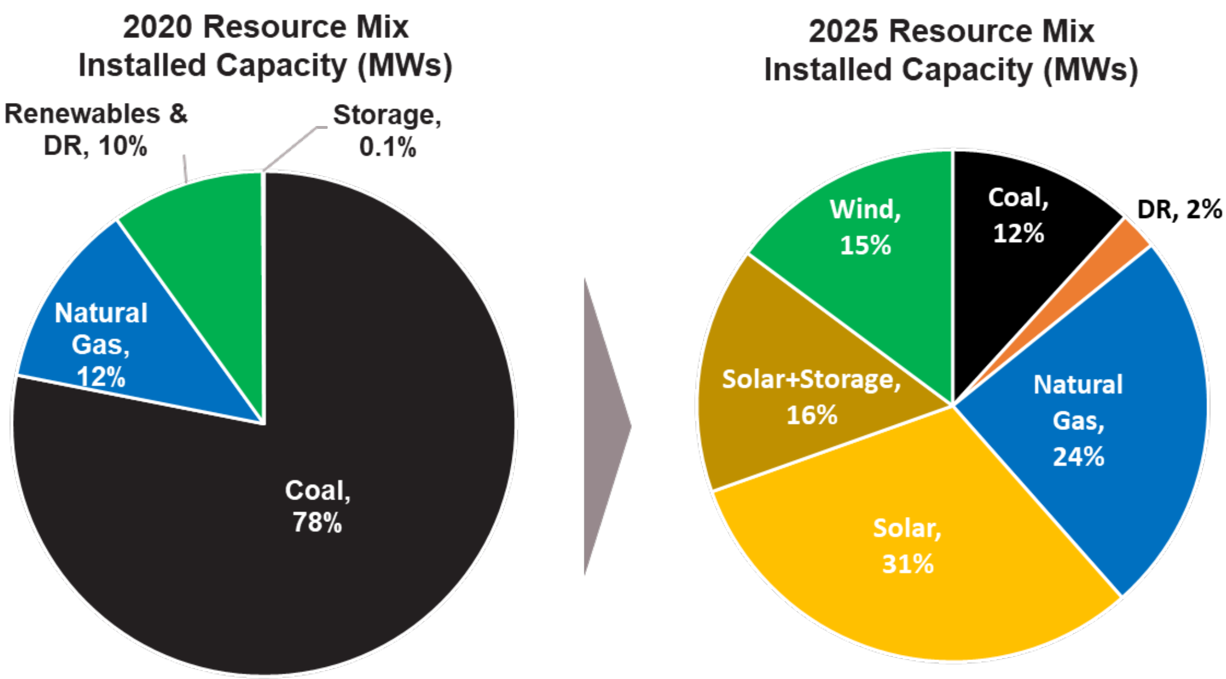


Bags = Broadway Avenue Gas Turbines
ELG = Effluent Limitations Guidelines
MW = Megawatt

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.

SECTION 1
OVERVIEW

1.1 COMPANY BACKGROUND

Vectren is a wholly owned subsidiary of CenterPoint Energy, Inc. On February 1, 2019, CenterPoint Energy, Inc. (NYSE: CNP) and Vectren Corporation (NYSE: VVC) completed a merger. The combined company, which is named CenterPoint Energy and headquartered in Houston, has regulated electric and natural gas utility businesses in eight states that serve more than 7 million metered customers.

Operation of Vectren’s electric transmission and distribution services, including its power generation and wholesale power operations now fall into CenterPoint’s Indiana Electric business. Vectren serves approximately 146,000 customers in Southern Indiana.

1.2 INTEGRATED RESOURCE PLANNING

Vectren takes integrated resource planning very seriously. The IRP is used as a guide for how Vectren will serve existing and future customers over the next 20 years in a reliable and economic manner. The integrated resource plan can be thought of as a compass setting the direction for future generation and Demand Side Management (DSM) options. It is not a turn-by-turn GPS. Future analyses of changing conditions, filings and subsequent approvals from the IURC are needed to chart the specific course.

Vectren is required to submit its Integrated Resource Plan (IRP) to the Indiana Utility Regulatory Commission (IURC) every three years and last submitted it in 2016 with a plan to transition its generation fleet away from a majority reliance on coal. Vectren began this IRP process by gathering feedback from stakeholders on the last IRP, the Final Director’s Report for 2016 Integrated Resource Plans and the Indiana Utility Regulatory Commission’s Order in 45052 (Vectren’s 2018 generation transition filing). Additionally, Vectren worked more closely with IRP stakeholders than ever before to listen, inform and consider updates to the process, as discussed in Chapter 3 Public Participation Process.

The future is uncertain; several factors have helped to set the stage for this analysis. Gas prices remain historically low and are projected to be stable over the long term. Shale gas has revolutionized the industry, driving these low gas prices. This has fueled a surge in gas generation investment, due to its low-cost energy and capacity value that it brings to the grid.

Renewable costs continue to decline and are producing competitively priced energy in the Midwest region, but still require backup for times when the wind is not blowing and the sun is not shining (on a daily and seasonal basis). Based on expectations of increasing penetration of renewables, particularly solar, MISO (Midcontinent Independent System Operator), Vectren's regional transmission operator, continues to evaluate rules and mechanisms that are needed now and in the future to maintain reliability. Vectren continues to monitor developments within MISO; the outcomes of two major studies are important for resource planning. 1) MISO is conducting a Renewable Integration Impact Assessment (RIIA) related to impacts of renewable energy growth in MISO over the long term. This study will assess implications to MISO's transmission needs and ability to effectively dispatch its members' generation fleet. 2) MISO is simultaneously conducting the Resource Availability and Need (RAN) initiative, which looks at more granular planning and accreditation of generation resources to account for a changing generation mix and resulting attributes, both of which are discussed in detail below.

In order to better evaluate renewable, energy storage and energy efficiency resources within the IRP analysis, Vectren chose to move to a more sophisticated IRP modeling tool than was used in the 2016 IRP, the Aurora modeling platform. It provided several benefits: 1) simultaneous evaluation of many resources, 2) evaluation of portfolios on an hourly basis and 3) consistency in modeling, including optimization, simulated dispatch of resources and probabilistic modeling. The output from this model provides quantitative data to help evaluate portfolios within a robust risk analysis, designed to understand performance over a wide range of futures.

1.2.1 IRP Objectives

Vectren's IRP strategy is designed to accommodate the ongoing changes and uncertainties in the competitive and regulated markets. The main objective is to select a preferred portfolio[8] of supply and demand resources to best meet customers' needs for reliable, reasonably priced, environmentally acceptable power over a wide range of future market and regulatory conditions, taking into account risk and uncertainty. Specifically, Vectren's objectives are as follows:

- Safe Reliable Service (a requirement for all portfolios)
- Affordability (reflected in the balanced scorecard)
- Environmental Risk Minimization (reflected in the balanced scorecard)
- Cost Uncertainty Risk Minimization (reflected in the balanced scorecard)
- Avoiding Overreliance on Market Risk for capacity and energy (reflected in the balanced scorecard)
- Future Flexibility (reflected in both offramps and "other considerations")
- Resource Diversity (reflected in "other considerations")
- System Flexibility (operational flexibility to back up renewable resources)

1.2.2 IRP Development

As mentioned above, Vectren incorporated feedback from IRP stakeholders, IURC staff and the Commission in developing the 2019/2020 IRP. Detailed feedback was provided to IRP stakeholders on August 15, 2019, in Vectren's first of four public stakeholder meetings in a presentation titled "2019/2020 IRP Process." This presentation provided the backdrop for several Vectren commitments to improve and strengthen the analysis, most notably with the addition of an All-Source RFP, but also other improvements, including but not limited to the following:

- Additional stakeholder input,
- More consistency in modeling,
- More comprehensive analysis and

[8] A portfolio is a mix of future supply and demand side resources to meet expected future demand for electricity.

- The evaluation of a wider mix of resources, including an exhaustive evaluation of existing resources.

Vectren worked closely with industry experts to develop a comprehensive analysis. Burns and McDonnell, now known as 1828 and Company, managed all aspects of the All-Source RFP. This analysis was utilized to provide current market pricing for resources and an opportunity for Vectren to pursue individual projects to help serve Vectren customers following the conclusion of the IRP. Pace Global, now known as Siemens Energy Business Advisory, worked with Vectren to conduct scenario development, modeling and a comprehensive risk analysis, which included both scenario based and probabilistic modeling.

1.3 CHANGES SINCE THE 2016 IRP

Several developments have occurred since the last IRP was submitted in 2016, which helps to illustrate the dynamic nature of integrated resource planning. The IRP analysis and subsequent write up represent the best available information at a point in time. The following sections discuss some of the major changes that have occurred over the last three years. Vectren realizes that conditions will change, and tis analysis was designed to test portfolios under a wide range of plausible futures.

1.3.1 Generation and Storage Filings

1.3.1.1 Generation Transition Plan

Following the conclusion of the 2016 IRP, Vectren began a generation transition plan to replace the majority of its coal fleet with a highly efficient, large, natural gas plant and a 50 MW universal solar plant. Vectren also proposed to continue operation of its most efficient coal unit by installing certain environmental compliance equipment. This was done through two separate filings in Cause numbers 45052 and 45086.

In April 2019, the IURC granted partial approval of Vectren's Smart Energy Future electric generation transition plan which included approval to retrofit F.B. Culley 3, Vectren's largest, most-efficient 270 MW coal-fired unit and to proceed with construction of a 50 MW universal solar array. The request to construct a 700-850 MW combined cycle natural gas power plant was not approved. The following concerns were raised in opposition to the proposal:

- 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)

Each of these concerns is addressed in detail within this IRP analysis and selection of the preferred portfolio. All will be addressed in detail within this report.

1.3.1.2 Urban Living Research Center (ULRC)

Vectren has partnered with Scannell to develop the Urban Living Research Center (ULRC), a living laboratory facility which will serve as a leading-edge research vehicle for Vectren to better understand and partner with customers. The ULRC is part of a larger, mixed-use, multifamily development called the “Post House” which opened on June 1, 2020. The Post House/ ULRC originated as a partnership in response to the Regional Cities Initiative, which aims to retain and attract talent by enhancing the quality of Indiana communities. The ULRC will include a mix of natural gas and electric, efficient and smart energy-using devices, such as lighting, HVAC, water heating and instrumentation, that will help the Company research new products and services to help customers manage their energy use. The Company was awarded funding from the Department of Energy’s Building Technologies Office to utilize toward the ULRC to advance research in grid-interactive buildings in partnership with Oak Ridge National Laboratory. Based on actual construction of the facility and the available rooftop space, Vectren plans to install rooftop solar. Lithium-ion battery storage in both front- and behind-the-meter configurations was also planned for the facility but was removed from the project due to concerns related to the placement of Lithium-ion batteries indoors in light of evolving safety standards and best practices. Lessons learned and data from this project could help future integrated resource planning efforts.

1.3.1.3 Volkman and Oak Hill Universal Solar and Battery Projects

In 2017, Vectren filed for and received approval to construct two 2-MW universal solar projects that are currently in operation; one near North High School in northern Vanderburgh County and the second near Oak Hill Cemetery near Morgan Ave., which is through a partnership with the City of Evansville. Both sites have been constructed and have been generating power since December 2018. The Volkman Road project also includes battery storage with the ability to discharge one megawatt of power per hour over a four-hour period.

1.3.2 Environmental Rules

1.3.2.1 Rules Update

1.3.2.1.1 Air

In March 2015, USEPA entered into a consent decree to resolve litigation concerning deadlines for completing 1-hour sulfur dioxide (SO2) National Ambient Air Quality Standard (NAAQS) designations. The agreement required USEPA to designate as nonattainment, attainment or unclassifiable, certain areas that included sources that emitted more than 16,000 tons of SO2 in 2012 or emitted more than 2,600 tons of SO2 with an average emission rate greater than 0.45 lbs./MMBtu. USEPA identified five sources in Indiana that exceeded this threshold, including the A. B. Brown plant. In order for Posey County to meet the attainment designation, Vectren had to agree to a lower SO2 emission rate for the A.B. Brown plant. Vectren worked with IDEM and accepted a Commissioner's Order to voluntarily lower the plant's SO2 emission limit, which went into effect April 19, 2016.

EPA finalized the Affordable Clean Energy rule (ACE) repealing and replacing the Clean Power Plan in June 2019. The ACE rule established carbon dioxide (CO_2) emission guidelines for states to use when developing plans to limit CO_2 at coal-fired electric generating units (EGUs) within the state. ACE established heat rate improvement, or efficiency improvement, as the Best System of Emissions Reductions (BSER) for CO_2 from coal-fired Electric Generating Units (EGUs). States were given six candidate technologies to be considered as BSER along with their calculated efficiency improvements and costs to implement and operate. States are to establish unit-specific standards of performance that reflect the emission limitation achievable through application of the BSER technologies with consideration of "the remaining useful life of the source" and other source-specific factors. State Implementation Plans are due July 2022 with compliance planned to begin within 24 months of submission.

In December 2015, Vectren agreed to a modified Consent Decree to resolve alleged air violations at the F. B. Culley and A. B. Brown plants. The negotiated settlement required Vectren to eliminate the scrubber bypass stack for F. B. Culley Unit 2 and install equipment to mitigate SO3 emissions from A. B. Brown Units 1 and 2 and F. B Culley Unit 3. Each unit is required to maintain a H2SO4 emission limit to demonstrate compliance.

The state of Indiana has developed a state implementation plan (SIP) to administer the three trading programs under the Cross-State Air Pollution Rule (CSAPR) and allocate allowances for affected electric generating unit starting in 2021. The SIP was published in the Federal Register on December 17, 2018. The intent of CSAPR is to address power plant emissions that cross state lines and contribute to ozone and fine particle pollution in other states.

1.3.2.1.2 Water

On September 30, 2015, EPA published the final Effluent Limitations Guidelines rule (ELG). The rule sets strict technology-based limits for waste waters generated from fossil fuel fired generating facilities and, will force significant operational and technological changes at coal fired power plants. EPA finalized the rule with a hybrid of the most stringent of the proposed options for fly ash transport water, bottom ash transport waters and FGD waste waters.

While the 2015 final rule includes reference to multiple waste waters, the key elements applicable to Vectren are FGD waste waters and ash transport waters. Specifically, FGD waste waters must meet new limits for arsenic, mercury, selenium and nitrate / nitrite at the end of the wastewater treatment system and prior to mixing with any other process waters. Water used to transport bottom ash or fly ash is prohibited from discharge in any quantity, which effectively forces the installation of dry or closed loop ash handling systems. In September 2017, the ELG Postponement Rule was published. The

Postponement Rule delayed the applicability date for the Bottom Ash Transport Waters from November 1, 2018 to November 1, 2020, but the no later than December 31, 2023 date for completion remained in place.

The A.B. Brown and F.B. Culley NPDES permits were renewed in 2017 and have since been modified as appropriate to allow for the BATW date extension allowed by the ELG Postponement Rule. As required by the ELG Rule and consequently the NPDES permits, FBC has ceased the discharge of FATW and will complete the conversion of bottom ash to a dry system in fall 2020. For FGD waste waters at F.B. Culley, alternate, but more restrictive limits can be voluntarily agreed to which would automatically extend the applicability date to December 31, 2023. Technology to meet the more restrictive limits could include the installation of zero liquid discharge equipment that would eliminate all discharge of FGD wastewater. The A.B. Brown permit was modified following publication of the ELG Postponement Rule. Currently, A.B. Brown is required to stop discharging both Fly Ash Transport Water and Bottom Ash Transport Water by November 2021. An additional ELG reconsideration rule, proposed in 2019, maintained the prohibition on the discharge of fly ash transport water and prohibits the discharge of bottom ash transport water, except in limited, specific circumstances, such as significant storm events.

1.3.2.1.3 Waste

The Coal Combustion Residuals Rule (CCR) was finalized on April 17, 2015. The rule regulates the final disposal of CCRs which include fly ash, bottom ash, boiler slag and flue gas desulfurization solids. The rule is applicable to all new and existing landfills and surface impoundments used to store or dispose of CCRs at a power plant that was generating electricity on the effective date of the rule (October 2015). The rule establishes operating criteria and assessments as well as closure and post closure care standards. The “Phase 1, Part 1” rule was published on July 30, 2018 and became effective on August 28, 2018. This rule delayed the deadline by which facilities must cease the placement of waste in a CCR surface impoundment in cases where the CCR unit fails to meet the aquifer location restriction and in cases where a CCR unit demonstrates an exceedance of a groundwater protection standard. The regulatory deadlines that currently present a scenario that could trigger the closure of Vectren surface impoundments include exceedance of ground water protection standards (triggering closure in October 2020), or failure to demonstrate compliance with location restrictions (triggering closure in October 2020). Environmental groups challenged the final “Phase 1, Part 1” rule in the D.C. Circuit Court. Additionally, in August 2018, the D. C. Circuit Court issued a decision in USWAG v. EPA, finding that the administrative record showed that all unlined impoundments pose a reasonable probability of adverse effects to human health and the environment and must be required to close. EPA filed a motion to remand the Phase 1, Part 1 rule and is currently working on rulemakings to implement the D.C. Circuit’s decision. The “Disposal of Coal Combustion Residuals from Electric Utilities; A Holistic Approach to Closure Part A: Deadline to Initiate Closure” proposed rule provides an option for utilities to submit a demonstration (application) for surface impoundments to remain active beyond the current rule closure dates, however no longer than October 15, 2023.

1.3.2.2 Retrofitting Culley 3 to Comply with ELG

In accordance with the order of the IURC in Cause No. 45052 approving the planned activities necessary to continue to operate Culley 3 in compliance with the ELG and CCR rules, the bottom ash system at F.B. Culley Unit 3 is scheduled to be converted to a dry system in the Fall of 2020. Work is also taking place to convert the FGD system to zero liquid discharge technology. These two technologies will make Culley Unit 3 fully compliant with the Effluent Limitation Guidelines (ELG) rule and the NPDES permit requirements for Culley 3.

1.3.2.3 Closing Coal Ash Ponds

The West Ash Pond at F.B. Culley is currently undergoing closure, with those activities scheduled to be completed by December 2020. The closure design includes the construction of a lined contact storm water pond, which will receive contact storm water from various areas of the plant. The construction of this pond, along with the installation of the dry bottom ash and FGD ZLD technologies will enable the upcoming required closure of the F.B. Culley East Ash Pond.

The A.B. Brown Ash Pond is also facing forced closure soon. Plans are currently underway to prepare for the excavation of all material from the A.B. Brown ash pond, with a majority of the ash being sent for beneficial reuse.

1.3.3 Electric TDSIC

The IURC approved Vectren's seven-year infrastructure improvement plan for the period of 2018-2024 (Cause No. 44910). This plan helps to build/rebuild high–voltage transmission lines, replaces substation transformers, rebuilds electric circuits and includes distribution automation. These improvements will help Vectren to continue to reliably deliver power to its customers now and in the future. Additionally, these improvements, will allow more flexibility in resource planning by improving power flows across Vectren's system, particularly the addition of the East-West transmission line that will connect the F.B. Culley Plant site on the east side of the system with the A.B. Brown plant site on the west side.

1.3.3.1 Advanced Metering Infrastructure (AMI)

In 2017, Vectren began installation of AMI smart meters as a key part of Vectren's grid modernization plan. Vectren has since successfully installed meters across its territory. AMI provides access to much more granular customer load data and will help Vectren to better understand and anticipate changes in an evolving energy landscape. This improvement will have long-term benefits for load research and long-term load forecasting, as well as provide the opportunity to create innovative DSM programs for shaping customer load. Vectren customers have already received many benefits in the near term for billing, quicker service response time and quicker responses to power outages; however, the long-term benefits will take time and have not been fully realized by the compilation of this IRP.

1.3.4 IRP Rule Making Process

Revisions to Integrated Resource Planning were made via RM# 11-07, which began in 2010. Vectren voluntarily followed the draft rule in 2014 and 2016 IRPs, which included a public stakeholder process. In 2019 the rule was finalized and can be found in the IRP Rule Requirements Cross reference table of this document. Major updates to the rule included moving from a two year to three-year cycle and several updates to the stakeholder process, including the number of required stakeholder meetings, which is now three.

1.3.5 DSM Filing

On April 10, 2017, Vectren filed with the Indiana Utility Regulatory Commission (IURC) a Petition seeking approval of Vectren's 2018-2020 Energy Efficiency Plan (2018-2020 Plan or Plan). The Plan included proposed energy efficiency goals; program budgets and costs; and procedures for independent evaluation, measurement and verification (EM&V) of programs included in the Plan. The Plan has an estimated cost of $28.6 million, with $9.5 million in 2018, $9.6 million in 2019 and $9.5 million in 2020. The Plan includes a portfolio of programs designed to achieve 111 million kWh in energy savings and 26,000 KW in demand reduction during the three-year period.

On December 28, 2017, the IURC issued an Order approving Vectren's 2018-2020 Energy Efficiency Plan (2018-2020 EE Plan) pursuant to Section 10. Vectren carried out a lengthy analysis of the DSM resources included in its IRP process. The Commission found that the proposed energy savings goals appear reasonably achievable and consistent with historical savings that has been previously approved. A summary of the savings and budgets are listed in the table below.

Figure 1.1 – 2018-2020 Portfolio Summary of Participation, Impacts, & Budget

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 carryforward costs related to smart thermostats, BYOT and CVR program.

1.3.6 Alcoa Contract

Alcoa and Vectren have jointly owned and operated the 300 MW Warrick 4 unit since 1970. In 2016, Alcoa split into two separate public companies and Alcoa Inc., as owner of the Warrick site, closed the aluminum smelter and greatly reduced load at the Warrick site. Alcoa also issued notice to Vectren that it would terminate and exit the joint operations of Warrick 4. However, Alcoa later reopened the smelter. After filing the 2016 IRP, Vectren worked with Alcoa to extend joint operations of Warrick unit 4 until December 31, 2023. The Warrick power plant consists of four generating units: three 150 Megawatt (MW) industrial units wholly owned by Alcoa and one 300 MW electric generating unit (Warrick 4) that is jointly owned by 50% Alcoa and 50% Vectren. Alcoa's power plant provides most of its 600 MW electric generation, if not all, to meet the electric demand of the Warrick Operations facility with the smelter being most of that demand. Alcoa's interest in continuing to operate the jointly owned Warrick 4 is unclear. As Vectren sought to maintain flexibility in this IRP, the company approached Alcoa to see if there was any potential to continue jointly operating Warrick 4 beyond 2023. Alcoa commented that it would possibly consider jointly operating the unit for an additional three years. While there is no commitment to run past 2023, Vectren included a three-year Warrick 4 extension possibility within the IRP modeling analysis as an option to maintain flexibility. Part of Alcoa's evaluation of the future of Warrick 4 is the potential need to invest in environmental control upgrades to continue operating the unit beyond 2023.

1.3.7 Merger with CenterPoint Energy

On February 1, 2019, CenterPoint announced the successful completion of the merger between Vectren and CenterPoint. The combined company, which is named CenterPoint Energy and headquartered in Houston, has regulated electric and natural gas utility businesses in eight states that serve more than 7 million metered customers. These utilities consist of the following:

- Electric utility business – CenterPoint Energy maintains wires, poles and electric infrastructure serving 2.4 million metered customers in the greater Houston area and 146,000 customers in Indiana. The company also owns and operates approximately 1,200 megawatts of power generation capacity in Indiana. CenterPoint Energy's Texas electric utility business is headquartered in Houston and its Indiana electric utility business is headquartered in Evansville, Ind.
- Natural gas utility business – CenterPoint Energy sells and delivers natural gas to 4.5 million homes and businesses in eight states: Arkansas, Indiana, Louisiana, Minnesota, Mississippi, Ohio, Oklahoma and Texas, including the high-growth areas of Houston and Minneapolis. The company's natural gas utility business is headquartered in Evansville.

1.3.8 FERC Grid Resilience and MISO Initiatives

Grid resilience became a national topic of interest in 2017 when the Department of Energy issued a Notice of Proposed Rulemaking (NOPR) for the Federal Energy Regulatory Commission’s (FERC) consideration. The basis of the NOPR was that due to the large amounts of retiring dispatchable generation, namely nuclear and coal, the nation’s bulk electric system was susceptible to power interruptions during extreme events and that it would be ill-suited to recover from these events. In January of 2018, FERC terminated the NOPR and directed each regional transmission owner (RTO) to evaluate its own resiliency, defined as the ability to withstand and reduce the magnitude and/or duration of disruptive events, which includes the capability to anticipate, absorb, adapt to and/or rapidly recover from such an event. MISO, the RTO that Vectren is a member of, filed comments to FERC stating its grid is resilient due to its robust electric and gas transmission infrastructure and its diverse generator makeup that spans a region from Ontario to the Gulf Coast. Furthermore, MISO stated footprint diversity is a staple of MISO's annual Value Proposition and is the cornerstone that MISO points to that ensures resiliency. MISO also noted several areas in which it would focus efforts to ensure continued resilience, namely through transmission planning, best in class technological tools and engagement with state and local regulators to assist in measurement and planning for local systems that may be vulnerable to high-impact events.

MISO's Resource Availability and Need (RAN) Initiative and its Renewable Integration Impact Assessment (RIIA) are the two current methods in which it is dealing with its evolving grid to help keep the system resilient and reliable. The RAN Initiative is aimed at better accrediting generation units while the RIIA is focused on understanding the impacts of renewable energy growth in MISO over the long term and assessing potential transmission solutions to mitigate them.

1.3.8.1 MISO Resource Availability and Need (RAN)

As a reaction to the increasing frequency, duration and ability for Max-Gen Events to occur within all periods of the year, in 2018 MISO implemented its Resource Availability and Need (RAN) initiative. The goal of this initiative is "ensure the processes in use appropriately assure the conversion of committed capacity resources into sufficient energy every hour of the Planning Year. A dramatically changing landscape has made this conversion process increasingly more uncertain. Therefore, an issue and solution development effort will help MISO and its stakeholders identify and meet the challenges posed by current and future portfolio and technology changes facing the region[9]."

[9] MISO Resource Availability and Need Issue Summary: page 1, January 12, 2018
https://www.misoenergy.org/api/documents/getbymediaId/96780

The RAN initiative has led to market mechanism reform that is currently underway. Such reform has included changes to the ability to interrupt customers enrolled as Load Modifying Resources/Interruptible Load. MISO currently has reform initiatives[10] that are high priority, including:

- Emergency Energy Pricing, which would allow higher cost energy resources to set pricing, thereby increasing energy pricing during emergency events,
- Increasing the Energy Offer Cap from $1,000/MWh to $2,000/MWh, thereby allowing generation to double its maximum offer price and allow prices to reach a higher threshold and
- a Seasonal Planning Resource Auction construct, which could break up the current annual capacity auction into seasons (winter and summer auctions) that would adjust the PRMR and capacity accreditation for resources during these periods. This initiative is in the primary phase of stakeholder vetting, with a possibility of tariff revisions submitted next year and could be in effect as early as the 2022-23 Planning Year.

1.3.8.2 MISO Renewable Integration Impact Assessment (RIIA)

With increased levels of intermittent renewable generation, operating the grid becomes increasingly more complex. To help understand what is needed in the long term to deal with this complexity, in 2017 MISO launched its Renewable Integration Impact Assessment (RIIA) study to find system integration inflection points. In other words, to find out where there may be potential issues as renewable penetration increases from 10%, 20%, 30% or beyond. MISO is focusing on a few key areas: Resource Adequacy, Energy Adequacy and Operating Reliability. As discussed further in this document, the resource adequacy portion of the analysis has already yielded actionable insights into integrated resource planning, which have been incorporated into Vectren's 2019/2020 analysis, particularly the amount of capacity that will likely be accredited to wind and solar resources over time based on penetration rate and expected output under peak

[10] MISO Market Roadmap, February 2019: https://cdn.misoenergy.org/MISO%20Market%20Roadmap194258.pdf

conditions. MISO calls this Effective Load Carrying Capability (ELCC). This study illustrates the need for dispatchable resources that support high renewable penetrations as the peak load, net of renewable generation, pushes farther into the evening after the sun goes down. Flexible, dispatchable resources are needed to meet this need quickly.

1.3.9 2016 IRP Director's Report

Each year, the Director to the IURC electric division issues a critique of IRPs. The 2016 IRP Director's report listed a balance of positive comments, coupled with improvement opportunities for Vectren. The table below shows the improvement opportunities with a brief description of how the comment was addressed within the 2019/2020 IRP:

Figure 1.2 – IRP Improvements Based on 2016 IRP Director's Report

Improvement Opportunities	Addressed
Include lower and higher boundary scenarios to create a wider range of portfolios	A wider range of forecasts were considered for key inputs within scenario development
Model a wide range of portfolios	Vectren modeled 10 portfolios in the risk analysis, utilizing feedback from multiple stakeholders to ensure many potential paths were covered, from continue most coal to all renewables by 2030
Strategist model did not consider enough options simultaneously	Utilized Aurora, which did consider all resources simultaneously
Update risk analysis methodology to be less qualitative and more encompassing of known risks. Clearly define risk analysis methodology	Included known risks within scenario development and the risk analysis, including, but not limited to CO_2 cost, potential methane regulations, possible

Improvement Opportunities	Addressed
	shale gas ban, uneconomic asset risk, etc.
Explore other options for modeling EE cost options and make greater use of a Market Potential Study (MPS) and Clearly define Energy Efficiency Methodology	Worked closely with stakeholders throughout the development process to develop EE modeling inputs using the latest MPS
More consideration given to Warrick unit 4 in scenario development	Warrick unit 4 extension (3 year) was considered within scenario optimizations. Discussions with Alcoa continue

1.3.10 Statewide Energy Policy Analysis

In 2019 the General Assembly created a task force to develop energy policy recommendations, and at this time, that work is ongoing.

The 21st Energy Policy Development Task Force was created by HEA 1278 (2019) to develop recommendations for the General Assembly and the Governor on the following:

1. Outcomes that must be achieved in order to overcome any identified challenges concerning Indiana's electric generation portfolios, along with a timeline for achieving those outcomes.
2. Whether existing state policy and statutes enable state regulators to properly consider the statewide impact of changing electric generation portfolios and, if not, the best approaches to enable state regulators to consider those impacts.
3. How to maintain reliable, resilient and affordable electric service for all electric utility consumers, while encouraging the adoption and deployment of advanced energy technologies.

In order to arrive at its recommendations, the task force will examine existing policies and how shifts in generation portfolios may impact system reliability, grid resiliency and affordability of electric service. The task force will issue its recommendations by December 1, 2020. Any outcomes that require statutory changes will likely be proposed in the 2021 legislative session.

Additionally, HEA 1278 passed in 2019 and required the IURC to conduct a statewide analysis of impacts of transitions in fuel sources and other electric generation resources, as well as the impacts of new and emerging technologies on electric generation and distribution infrastructure, electric generation capacity, system reliability, system resilience and the cost of electric utility service for consumers. IURC staff is working with Laurence Berkeley National Lab, Indiana University and the State Utility Forecasting Group. Results will be available this summer to help inform the 21st Energy Policy Development Taskforce.

Vectren stands ready to act as a resource to members of the 21st Energy Policy Development Task Force as progress is monitored. To this point, task force meetings have served as information-gathering sessions on various topics related to electric generation and delivery. Following the conclusion of the task force's work, Vectren will work collaboratively with policymakers and all stakeholders to help ensure a bright energy future for the State of Indiana.

1.3.11 HB 1414

The Indiana General Assembly passed legislation pertaining to electric generation during the 2020 legislation session. HEA 1414 Electric Generation was signed into law by Governor Holcomb on March 21, 2020 and provides the following:

- A public utility that owns and operates a reliable capacity electric generation resource must operate and maintain the unit using good utility practices and in a manner reasonably intended to support the availability of the unit for dispatch

- The bill sets parameters around a public utility's decision to retire, sell or transfer a reliable capacity resource with a capacity of at least 80 megawatts before May 1, 2021:
  - The utility must first provide written notice of its intent to do so to the IURC
  - The IURC must conduct a public hearing to receive information and issue analysis and conclusions, after which the utility may proceed, if doing so aligns with the preferred portfolio in its most recent IRP
  - If the planned retirement, sale or transfer was not included in the most recent IRP, the utility may not proceed for at least six months from the date of the commission's receipt of the written notice
  - If the utility cites a federal mandate as the basis for the planned retirement, sale, or transfer of the reliable capacity resource, the IURC may consider the status of the mandate in its analysis and conclusions.

Passage of HEA 1414 did not impact the selection of the preferred portfolio. The timing of Vectren's IRP is such that no retirements of electric generating stations could take place before the May 1, 2021 date in the legislation.

1.3.12 COVID-19

COVID-19, the disease caused by the coronavirus, has led to unprecedented changes in the energy industry as it has affected every aspect of life. The energy industry has seen demand drop since March of 2020, on average 6-10%, while commodity prices have decreased at a steep rate. This recent pandemic is still underway as of the writing of this document and the effects and duration are still largely unknown. The scenarios in this IRP account for a range of outcomes and the Low Load scenario is illustrative of the effects from a wholesale market pricing perspective. The following sections are independent of COVID-19 as the studies were performed prior to its onset and constitute resource planning for a 20-year period. The preferred portfolio includes multiple off-ramps, which help mitigate the risk that demand does not grow to pre-Covid-19 levels.

1.3.13 Contemporary Issues

Vectren participates in the Commission's IRP Contemporary Issues Technical Conference held each year. In 2019, the Conference was held on April 15, 2019. The Conference also covered topics such as database management, integration of DERs, incorporation of load shapes into planning, the changing availability and flexibility requirements of MISO Resource Availability and Need (RAN) initiative, long-term utility planning assumptions and procurement decisions, preliminary lessons learned from NIPSCO's all-source RFP, risk analysis and life cycle analysis of greenhouse gas emissions.

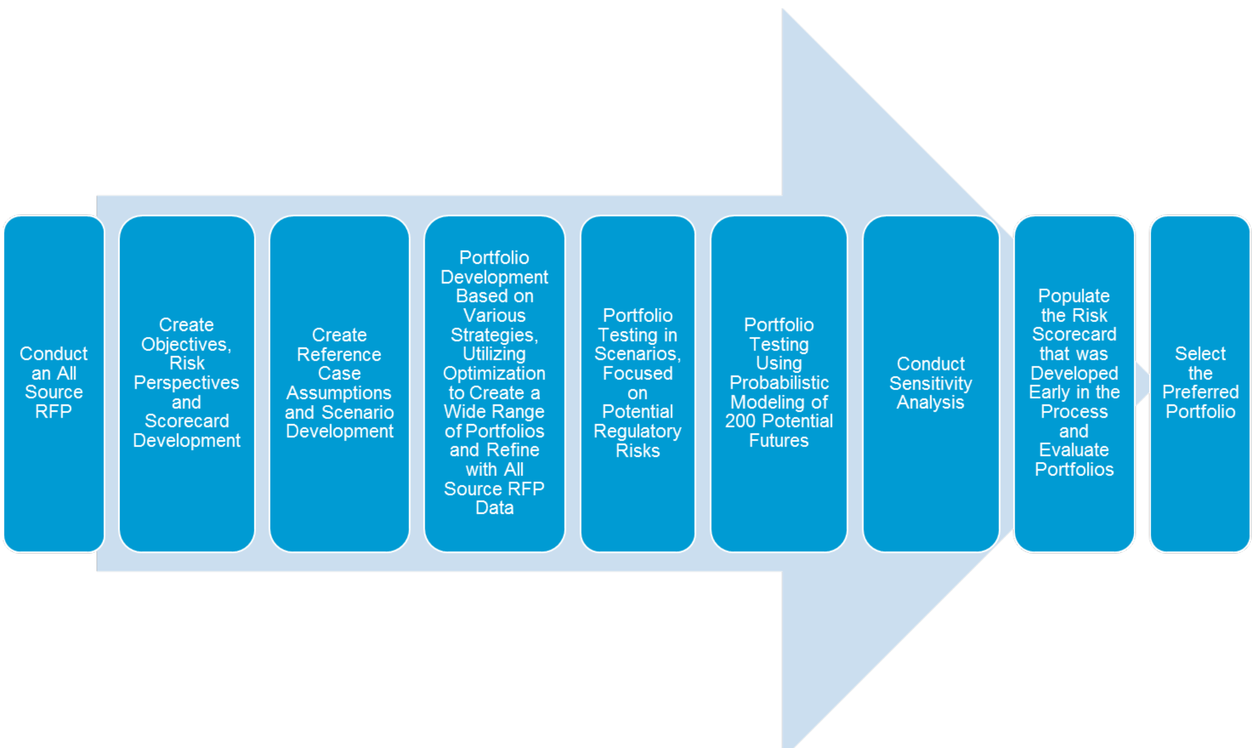
Several of these topics were timely and influential within Vectren's analysis. For example, the MISO RAN discussion, which included and expected focus on resource availability and flexibility to meet daily and variable energy needs, as well as a need for a holistic solution for seasonal resource adequacy. NIPSCO's discussion of All-Source RFP and lessons learned for the IRP was helpful as Vectren conducted its first All-Source RFP for this analysis. Finally, EVA's discussion on the need for Life Cycle Analysis (LCA) of carbon emissions analysis influenced Vectren's decision to include a life cycle greenhouse gas emissions variable within the risk scorecard.

SECTION 2
VECTREN'S IRP PROCESS

2.1 VECTREN'S IRP PROCESS

Vectren's 2019/2020 IRP followed a very structured, comprehensive process over a 14-month period with extensive risk-based analysis and included an All-Source RFP to include market-based pricing with the opportunity to secure available resources following the conclusion of the IRP. This process was designed to ensure that relevant technologies were evaluated and the resulting portfolio combinations were tested in a wide range of future market and regulatory conditions. The process followed is illustrated below.

Figure 2.1 – Vectren IRP Process



The following sections describe each step in the analysis.

2.2 Conduct an All-Source RFP

Vectren issued an 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. Long term resource planning requires addressing risks and uncertainties created by several factors including the costs associated with new resources. As part of ongoing resource planning, Vectren concluded that it was 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. These requirements helped to provide price certainty, transparency and MISO Local Clearing Requirement (LCR) accreditation, that will be discussed in further detail.

Within the context of the 2019/2020 IRP process, Vectren used an All-Source RFP to solicit bids for supply-side and demand-side capacity resources. The purpose of the RFP was 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 prior to the 2019/2020 IRP, there was a potential capacity need of approximately 700 MW of accredited capacity beginning in the 2023/2024 planning year. Vectren sought flexibility when defining potential resource combinations and encouraged RFP respondents to offer available projects with less than, or more than, 700 MW. Vectren also considered alternative timelines related to the capacity acquisition to the extent Respondents were able to provide more competitive pricing and/or terms for delivery beginning prior to or after the 2023/2024 planning year. Vectren used aggregated data from the RFP responses as inputs into the IRP modeling. The RFP Proposal evaluation process was based upon the specific resource needs identified through this IRP modeling as well as the Proposal evaluation criteria. Through this RFP, Vectren sought to satisfy the identified capacity need through either a single resource or multiple resources including dispatchable generation, load modifying resources (LMRs)/demand response (DRs), renewables, stand-alone and paired storage and contractual arrangements.

In connection with this RFP, Vectren 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.

All Respondents were directed to interface with Burns & McDonnell for all communications including questions, RFP clarification issues and RFP Proposal submittal until late in the evaluation process.

Proposals were initially reviewed for completeness by Burns & McDonnell. Respondents were contacted for additional data or clarifications by Burns & McDonnell via a designated Vectren RFP e-mail address, VectrenRFP@burnsmcd.com. Each complete Proposal was evaluated based on the Levelized Cost of Energy (LCOE), energy settlement location, interconnection/development status & local clearing requirement and project risk factors. The evaluation criteria were intended to relatively compare each Proposal to analogous submissions. This evaluation, in conjunction with the IRP, was used to determine which combination of resources are most capable of providing Vectren customers with a safe, reliable and affordable power supply.

2.3 OBJECTIVES, RISK PERSPECTIVES and SCORECARD DEVELOPMENT

Vectren's IRP process is designed to assure a systematic and comprehensive planning analysis to determine the "preferred portfolio" that best meets all its objectives over a wide range of market futures. This process results in a reliable and efficient approach to securing future resources to meet the energy needs for Vectren customers.

In addition, the IRP process complies with environmental regulations and reliability requirements, while reducing its vulnerability to market and regulatory risks, the risk of supply disruptions. In the IRP, Vectren also focused on increasing the diversification of its supply sources. As part of the IRP, Vectren considered maintaining flexibility to respond to market changes. The evaluation considered both existing and new resources, including renewable energy and battery storage options.

Economic modeling is an important part of the IRP process, as it allows Vectren to identify the portfolio of supply-side and demand-side resources on a competitive economic basis.

The resulting least cost portfolios reflect a combination of market, regulatory or technology specified conditions and market input parameters (for example, identify the least cost portfolio consisting of all renewables by 2030 using reference case market forecasts). While cost is an important objective, it is by no means the only objective. Vectren has several important objectives, each of which needs to be considered when evaluating the best portfolio for its stakeholders over time. Moreover, Vectren needs to account for operational and logistical considerations in the construction of alternative portfolios to ensure that they meet minimum reliability or resource adequacy considerations.

Vectren's IRP strategy is designed to accommodate ongoing changes and uncertainties in the market. Vectren's IRP objectives are based on the need for a resource strategy that provides long term value to its customers and communities. Therefore, as objectives are evaluated, tradeoffs must be considered. Specifically, Vectren's IRP objectives are as follows:

- Reliability: As new technologies proliferate and older baseload units retire, it is apparent that there will be increased reliance on intermittent, renewable energy resources. The ability to support local system stability and reliably provide power must be maintained by meeting MISO and NERC standards for reserve margins and resource adequacy.

Quantitative Metrics Directly Considered

- Affordability: Provide all customers with an affordable supply of energy
- Cost Uncertainty Risk Mitigation: Provide a predictable, balanced and diverse mix of energy resources designed to ensure costs do not vary greatly across alternative future market conditions or supply disruptions.
- Environmental Emission Risk Mitigation: Provide environmentally responsible power, leading to a low carbon future.
- Market Risk Minimization: Develop a flexible plan that can adapt to market conditions and regulatory and technological change to minimize risk to Vectren

customers and shareholders. The plan considers several alternative options for existing resources.

Other Considerations

- Future Flexibility: Mitigate the risk that assets in the portfolio may become uneconomic in the future through off ramps and optionality.
- Resource Diversity: Mitigate risk to customers of over-reliance on a single technology by providing a mix resources to minimize the dependence on any one resource type that could become operationally or economically eclipsed.
- System Flexibility: Operationally able to meet the current and future needs of the evolving grid

Reliability is Vectren's priority over all other objectives. While the IRP doesn't directly assess system stability issues, all portfolios must meet minimum reserve margin and resource adequacy requirements set by MISO. These are minimum requirements met in the modeling rather than a metric tracked for each portfolio. Vectren did a reliability assessment for portfolios that made it through the screening process. This is described in Section 6.4.3 Transmission Facilities as a Resource.

The next several objectives are given one or more defined and measurable metrics. By testing candidate portfolios against these metrics, Vectren illustrates tradeoffs among competing IRP objectives. This tool aided in the selection of the preferred portfolio. The last three objectives are more subjective in nature but relevant to the IRP process so are discussed under "other considerations". The following metrics were used to select the preferred portfolio:

Figure 2.2 – Vectren Scorecard for IRP Objectives and Risk Metrics

Objective		Metric
Quantitative and Qualitative (considered outside of scorecard)	Reliability	• Reliability Assessment
Quantitative Scorecard Measure	Affordability	• Mean value for the 20-Year Net Present Value of Revenue Requirements (NPVRR) (million$) across 200 dispatch iterations under varying market conditions
	Cost Uncertainty Risk Minimization	• 95th percentile[11] of NPVRR (million$) across 200 dispatch iterations under varying market conditions
	Environmental Emissions	• Reduction in tons of life-cycle greenhouse gas emissions (CO_2e) 2019-2039
	Avoiding Overreliance on Market Risk	• Annual Energy Sales and Purchases, divided by Annual Generation, average (%) • Annual Capacity Sales and Purchases, divided by Total Resources, average (%)
Qualitative (considered outside of scorecard)	Resource Diversity	• Risk of overreliance on one type of resource
	System Flexibility	• Ability operationally to support the system to maintain stability and reliability
	Future Flexibility	• Risk that assets in a portfolio may become uneconomic

Defined metrics are used to evaluate different portfolios and planning strategies in the IRP process. These metrics provide objective assessments of critical factors of each portfolio under different market scenarios. There are natural trade-offs among these objectives; for example, the portfolio with low expected costs may increase exposure to market risk. The objective of the IRP is to find the right balance of these metrics across a wide variety of future conditions to ensure that the ultimate choice of a portfolio performs well, regardless of the circumstances. Portfolio selection is based on Vectren evaluating all qualitative and quantitative metrics and using well-informed judgement in selecting its preferred portfolio. A further description of each metric is provided below.

2.3.1 Objectives and Risk Perspectives

The IRP objectives were evaluated using the results of the scenario, sensitivity and probabilistic modeling, as well as other qualitative factors.

2.3.2 Scorecard Metrics

The Balanced Scorecard is a broad comparison of candidate portfolio attributes and risks. It was populated with metrics entirely derived from the probabilistic modeling. The probabilistic modeling subjected each portfolio to 200 iterations of the dispatch model under varying market conditions. Vectren then used the resulting performance data and the distributions from the 200 iterations to quantify the metrics that align with each IRP objective. The Balanced Scorecard metrics are the same as the risk metrics described in Figure 2.2.

2.3.2.1 Affordability

For the Affordability objective, the metric used is the mean value for the 20-Year Net Present Value of Revenue Requirements (NPVRR), expressed in millions of dollars. The NPVRR is a measure of all generation related costs (for each asset, the cost of generation – capital, O&M, fuel and related transmission costs to deliver power to Vectren customers, plus the cost of power and capacity purchases etc.) associated with the portfolio of assets over time. These costs are adjusted through a discount rate to ensure future costs are reflected in present year dollars, commonly known as a time value of money adjustment.

In this way, very different portfolios can be compared on a common metric or value over a long-time frame.

2.3.2.2 Cost Uncertainty Risk Mitigation

For the Cost Uncertainty Risk Mitigation objective, the metric used is the 95th percentile of NPVRR, also expressed in millions of dollars. After each portfolio was subjected to 200 dispatch model runs, a distribution is created of the NPVRR portfolio costs. The 95th percentile (approximately two standard deviations above the mean value) is a commonly used benchmark to demonstrate a reasonable upper threshold of cost risk under widely varying market circumstances.

2.3.2.3 Environmental Emission Risk Minimization

For the Environmental Emission Risk Minimization objective, the metric estimated life cycle greenhouse gas emissions of each generation type, measured in tons of carbon dioxide equivalent (CO_2e). The use of life cycle emissions rather than direct generation emissions was a result of feedback from the stakeholder process. Life cycle emissions account for "cradle to grave" emission impacts of generation and offer more consistent comparisons of environmental impact across generation technologies. The lifecycle emissions captures upstream emissions including raw material extraction, power generation facility construction and any upstream emissions associated with fuel extraction and transportation (if applicable). Life cycle emissions were estimated using the National Renewable Energy Laboratory's (NREL's) harmonized life cycle emissions factors for generation technologies considered in the analysis.[12] Life cycle emissions from existing and new resources are derived by multiplying the generation from each fuel type (including coal, gas combustion turbine, gas combined cycle, utility-scale solar and solar distributed generation and onshore wind) by the corresponding specific technology

[12] NREL conducted a systematic review of 2,100 life cycle greenhouse gas emissions studies for electricity generating technologies and screened down the list to about 300 credible references. From these, NREL published the median values which were shared with IRP stakeholders and used to calculate life cycle greenhouse gas emissions for each portfolio.

emission factor. Emission factors for life cycle greenhouse gas emissions are presented in Figure 2.3.

Figure 2.3 – Life Cycle Greenhouse Gas Emission Factors (grams CO_2e/kWh)[13]

	Specific Technology	Market[14]
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

To account for life cycle emissions from energy purchases imported from the market, Vectren used the MISO 2033 Futures energy utilization mix corresponding to the Accelerated Fleet Change mix from the 2019 MISO Transmission Expansion Planning Report (MTEP19)[15]. This estimation provides a figure of 347.4 grams of CO_2e/kWh as shown below in Figure 2.3a.

[13] Source: https://www.nrel.gov/analysis/life-cycle-assessment.html - Values derived from graphs included for each resource type. Note that battery storage was not estimated.
[14] Utilized when specific technology breakouts were not available within the MTEP study
[15] 2019 MISO Transmission Expansion Planning Report (MTEP19)
https://www.misoenergy.org/planning/planning/mtep-2019-/

Figure 2.4 – MTEP19 Accelerated Fleet Change Mix Used to Calculate CO_2e Emissions from Energy Imports

Resource	Given Percentage in MTEP19 Fig. 2.5-2	Normalized Percentage	Grams of CO2e per kWh (NREL)	Pro Rata Grams of CO2e per kWh
Coal	18%	15.7%	1,002	156.8
Nuclear	6%	5.2%	16	0.8
CC/ST Gas	23%	20.0%	481	96.2
CT	16%	13.9%	599	83.3
Wind	30%	26.1%	12	3.1
Utility Solar	10%	8.7%	54	4.7
DG Solar	5%	4.3%	54	2.3
DR	4%	3.5%	0	0.0
Other	3%	2.6%	0	0.0
Battery	0%	0.0%	0	0.0
Total	115%	100.0%		347.4

Outside of the scorecard, Vectren considered direct portfolio emissions reductions for each portfolio compared to a base year (2005) of power generation and resulting CO_2 emissions. The 2005 benchmark year saw 9,634,957 short tons of CO_2 emissions.

2.3.2.4 Market Overreliance Risk Minimization

For the Market Overreliance Risk Minimization objective, there were four metrics. There is the average annual energy sales and the average annual energy purchases, each divided by average annual generation and expressed as a percentage. There is also the average annual capacity sales and the average annual capacity purchases, divided by average total resources and expressed as a percentage.

Other Considerations

2.3.2.5 Uneconomic Asset Risk Mitigation

The recent generation order suggested that the consideration of future generation mix should include the risk that assets in the portfolio would become uneconomic due to technological advance. Vectren anticipated that the greatest risk would be imposed by capital intensive fossil plants as renewable assets became more economic with time.

To try to measure this risk, the probabilistic modeling provided an annual accounting of a plant's going-forward costs and revenues in each of the 200 iterations. In cases where the annual going-forward costs exceed the annual revenues for three consecutive years, the plant was deemed to be uneconomic[16] at that time. In the first year in which the plant was deemed uneconomic, the unamortized cost of the uneconomic asset and any additional losses in subsequent years was measured.

2.3.2.6 Resource Diversity Maximization

Vectren believes that resource diversity helps minimize risk to customers by providing a mix of resources to minimize the dependence on any one resource type that could become operationally or economically eclipsed. Vectren's coal units have served its customers well over the years, but continued pressure on this resource from environmental regulations, increasing use of intermittent renewable resources and low gas prices have resulted in several units having a low dispatch rate. The concentration of coal in Vectren's generation mix has become costly to Vectren customers over time. Additionally, the Indiana Commission reinforced this consideration in a recent Order that Vectren should consider resource diversity and alternatives that provide off ramps that allow Vectren to react to changing circumstances.

While very important, it is hard to create a measure that adequately captures this value. Instead, Vectren sought to develop a number of portfolios that included a wide range of resource types and fuel sources. To ensure this objective has been met, Vectren built portfolios that ensure diverse mixes. One way in which this has been done is that Vectren did not consider a large 2x1 Combined Cycle Gas Turbine (CCGT) in the 2019/2020 IRP. While potentially an economic solution for customers, moving from mostly coal to mostly gas was considered a risk in the long term due to the lack of

[16] 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

flexibility to adjust to future conditions. Additionally, Vectren included an All-Source RFP to fully consider renewable resources within all portfolios.

2.3.2.7 System Flexibility

System flexibility was an important consideration in the 2019/2020 IRP. As intermittent renewable resources continue to grow on the transmission and distribution system, it is important to back these resources up for reliability and resilience. As such, Vectren considered performance of resources with the ability to start and ramp quickly and be available for sustained periods in times when the sun is not shining and the wind is not blowing. Vectren also considers the transmission system and the ability to rely on the market as an important consideration in IRP planning. While Vectren has considerable import capabilities with the addition of the Duff Coleman Market Efficiency transmission Project (MEP) and the upcoming East/West line, this capability is not unlimited and requires needed upgrades to maintain reliability for portfolios that rely less on dispatchable energy resources.

2.4 REFERENCE CASE ASSUMPTIONS AND BOUNDARY SCENARIOS

After selecting the objectives and metrics, the next step in the process was to define the Scenarios for consideration in the selection of alternative portfolios. In this case Vectren selected a Reference Case and four alternative scenarios for two purposes. The first purpose was to select a least cost portfolio for each of the five scenarios and the second was to test final portfolios against each of the market scenarios to determine how well they perform. Below is a brief discussion of each. Greater detail is provided in Section 7 which identifies the key inputs for each scenario.

2.4.1 Reference Case

The Reference Case scenario represents the most likely future conditions. Vectren surveyed and incorporated a wide array of third-party sources to develop its Reference Case assumptions, several of which reflect a current consensus view of key drivers in power and fuel markets. Reference 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 mine and delivered coal prices
- National carbon (CO_2) prices
- Capital costs and associated cost curves for various supply side (generation) and demand side resource options

The long-term energy and demand forecast for the Vectren service territory was developed for Vectren by Itron, a leading forecasting consultant in the U.S. The forecast is based on historical residential, commercial and industrial usage and drivers such as appliance saturation and efficiency projections, electric price, long-term weather trends, customer-owned generation, electric vehicle adoption and several demographic and economic factors.

For natural gas, coal and capacity price, Vectren used a “consensus” Reference Case view of expected prices by averaging forecasts from several sources. This helps to ensure that multiple views are considered and allows Vectren to be transparent with modeling assumptions. For natural gas and coal, 2019 forecasts from PIRA, Wood Mackenzie, Pace Global, ABB, and EVA were averaged. Based on a stakeholder request to include CO_2 in future years, Vectren decided to include a CO_2 price in the Reference case but not in the low regulatory case. The CO_2 forecast was developed by Pace Global. The capacity price forecast was based on MISO Zone 6 forecasts from Wood Mackenzie, Pace Global and ABB.

All-source RFP bids were utilized for resource cost information between 2022 and 2024, where possible. Long term cost curve information was developed utilizing a consensus approach, using Burns and McDonnell, NREL ATB and Pace Global. Burns & McDonnell technology assessment helped fill in the gaps with operational data and for various traditional technologies like gas and coal resources.

Vectren worked with stakeholders and GDS to develop a Market Potential Study (MPS) for demand side resources. This study was used to create demand side inputs to be compared on a consistent and comparable basis with supply side resources.

Pace Global performed the production cost modeling used to create several key components of the IRP. Using the AURORAxmp power model, Pace Global developed an optimized, least-cost portfolio for the Reference Case, which was then run in chronological hourly dispatch mode. The deterministic dispatch run provided power price forecasts for MISO regions, as well as the least cost portfolios created utilizing the Reference Case. These key drivers constitute the Reference Case assumptions. More information on modeling inputs can be found in Section 7.2 Reference Case Scenario.

2.4.2 Alternative Scenarios

It is important to test technologies against a variety of future market conditions, not just the Reference Case. Hence, Vectren, with the support of Pace Global, selected four alternative scenarios (a Low Regulatory, a High Regulatory, an 80% Carbon Reduction and a High Technology) to provide boundary conditions for testing the technologies and developing portfolios that could be subjected to a full risk assessment (with hundreds of scenarios tested later in the process).

Vectren worked with Pace Global and received input from Vectren stakeholders on key inputs such as load forecasts, gas and coal prices, carbon emission prices and technology capital costs. With input from stakeholders, Vectren and Pace Global determined whether gas prices, coal prices, load, technology capital costs, retirements/ builds, carbon emission prices and power prices would move up or down relative to the Reference Case under each of those scenarios. This process was followed to illustrate what might happen under each of these scenarios in a consistent manner with the risk analysis. This wide range of scenarios is bounded on one end by a Low Regulatory future with no CO_2 price. Regulation of CO_2 and other regulations ratcheted up moving towards the outer boundary condition, the High Regulatory future. Below is an illustrative description of each scenario.

- Low Regulatory – The primary carbon regulation is assumed to be the ACE rule. Indiana implements a lenient interpretation of the rule. ELG is partially repealed with bottom ash conversions not required for some smaller units and is delayed for two years (this does not apply to F.B. Culley 3). The limited regulation promotes a stronger economy, higher load and higher natural gas prices relative to the Reference Case. Other drivers still support declining coal demand over the planning horizon and as a result coal prices remain at levels similar to the Reference Case. Similarly, technology costs retain the same outlook as the Reference Case. This case is consistent with the theme that the Indiana Coal Council has consistently requested.

- High Technology – This scenario assumes that technology costs decline faster than in the Reference Case, allowing renewables and battery storage to be more competitive without significant regulation. A low carbon tax is ultimately implemented. The economic outlook is better than in the Reference Case as lower technology costs and lower energy prices offset the impact of the carbon 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 Reference Case. Less demand for coal results in lower coal prices. 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.

- 80% CO_2 Reduction by 2050 – This scenario assumes a carbon regulation mandating an ~80% reduction of CO_2 emissions from 2005 levels by 2050 is implemented. A gradually declining carbon cap drives carbon allowance costs up over time. Load decreases as the costs for energy and backup power increase and as the energy mix transitions. Natural gas prices remain at similar levels to the Reference Case as the impact of methane regulation is offset by lower demand and productivity increases that lower supply costs. Coal demand declines over time. Renewables and battery storage technologies are widely implemented to help meet the mandated CO_2 reductions. Despite this demand, costs are lower than the Reference Case due to subsidies or similar public support to address climate change concerns.

- High Regulatory – The High Regulatory scenario depicts a future of higher regulation resulting in higher costs of energy and some resulting economic slowdown. A high carbon fee set at the social cost of carbon is implemented early in the planning horizon (2022). 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 notably in the long-term as supply dramatically shrinks. Declining demand for coal results in coal prices lower relative to the Reference Case. With the higher costs, innovation occurs as renewables and battery storage are widely implemented to avoid paying high carbon 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.

A summary of the relative outlooks for key market drivers across the scenarios considered is presented in Figure 2.5.

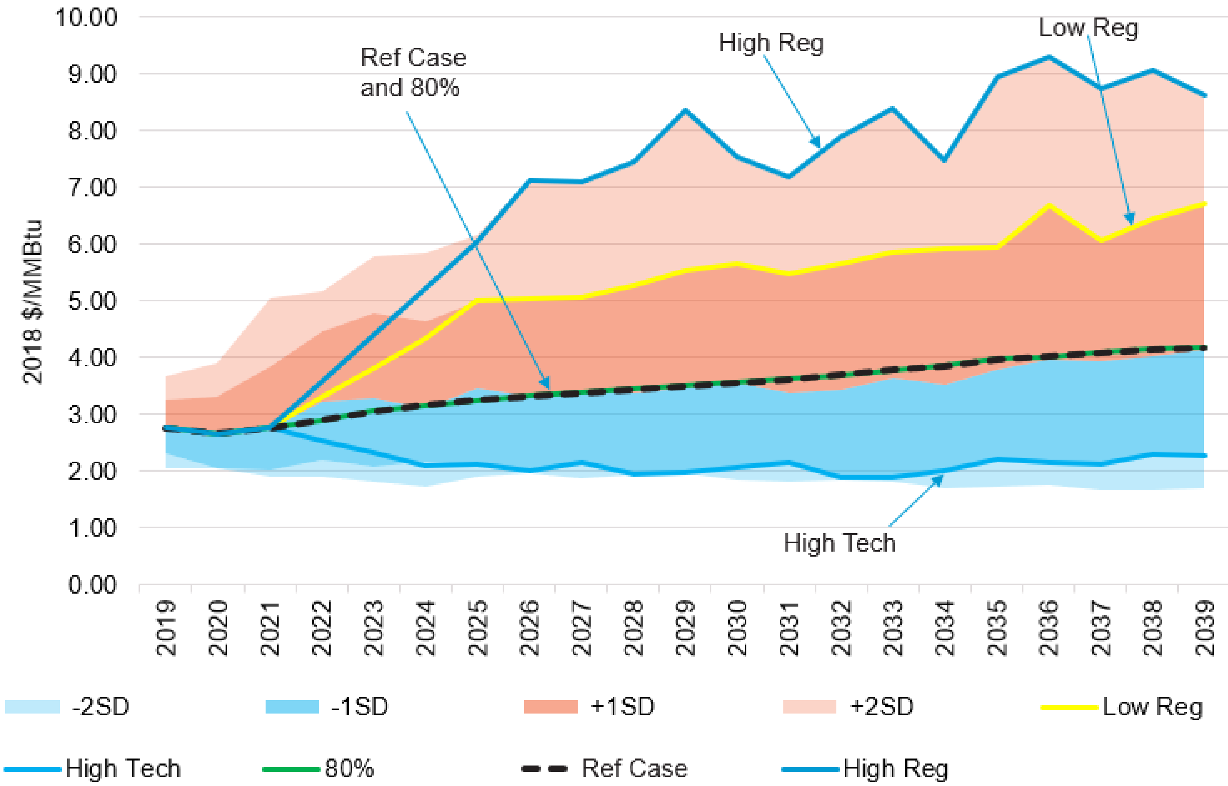
Figure 2.5 – Summary of Directional Relationships of Key Inputs Across Scenarios

	CO_2	Gas Reg.	Water Reg.	Economy	Load	Gas Price	Coal Price	Renewables and Storage Cost	EE Cost
Reference Case	ACE Replaced with CO_2 Tax	none	ELG	Base	Base	Base	Base	Base	Base
Low Regulatory	ACE	none	ELG Light*	Higher	Higher	Higher	Base	Base	Base
High Technology	Low CO_2 Tax	none	ELG	Higher	Higher	Lower	Lower	Lower	Lower
80% CO_2 Reduction by 2050	CO_2 Cap	Methane	ELG	Lower	Lower	Base	Lower	Lower	Higher
High Regulatory	High CO_2 Tax w/ Dividend	Fracking Ban	ELG	Base	Base	Highest (+2 SD)	Lower	Lower	Higher

*No bottom ash conversion required based on size of the unit and delay requirement for 2 years. Does not apply to Culley 3

Using the Reference Case as a consistent starting point, the boundary scenarios were developed. Key variables are assumed to remain the same as the Reference Case in the short-term (2019-2021). In the medium-term (2022-2028), key variables grow or decline to +/-1SD or (+/-2SD) by 2025 (midpoint of medium-term) as shown in the table above. After 2025, the variable stays at +/-1SD (or +/-2SD) into the long-term to 2039. Because this 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 viewed as very wide. The five scenarios were designed to be consistent with the stochastic distributions (200 iterations) developed for the risk analysis, but on a much more limited scale (five scenarios). An illustration of this methodology for natural gas prices is presented in Figure 2.6

Figure 2.6 – Henry Hub Natural Gas Price Scenarios (2018$/MMBtu)



All gas prices begin at $2.77/MMBtu in 2019, dip slightly in 2020 and rise back to $2.76/MMBtu in 2021. After this time, the Reference Case gas prices gradually trend upward to $4.17/MMBtu in 2039. Gas prices in the other scenarios either follow the Reference Case or trend higher or lower, depending on the scenario's coordinated input direction. Gas prices in the High Regulatory scenario are designed to reach the +2 standard deviation level to replicate the price impact of a hydraulic fracturing ban, which would greatly limit domestic production, increase costs and put upward pressure on prices last seen prior to 2008 before the shale boom era began. The High-Tech scenario sees natural gas prices moving downward to -1 standard deviation below the Reference Case.

The convention of +/-1 standard deviation is used to maintain a consistent methodology and result when moving key market drivers up or down in each of the scenarios. It should be noted that the historical price distributions differ among the various market drivers are not necessarily symmetrical (i.e., normally distributed). For example, gas prices are positively skewed because they have no upper boundary and can reach many standard deviations above the historical average, whereas they typically cannot fall below zero (or approximately two standard deviations below the historical average).

Note that the selection of one standard deviation up in every year of the study means that the actual price in any one year may exceed that value 15.8% of the time, but over the entire 20 year planning horizon only about 5-7% of the time the price will exceed the price on the curve. Selecting a 2 standard deviation change, as was done for gas prices, means that only 2.2% of the time the price in any one year will exceed the value selected and over the 20-year planning horizon; the chances of a higher average price is less than 1 percent.

The graphical descriptions of values for each of the key metrics (e.g. load, gas prices, coal prices, technology costs, carbon prices and power prices) are shown in Section 7.3.2.2.

2.5 PORTFOLIO DEVELOPMENT

The portfolio development process was designed to test a wide range of technology options. An exhaustive list of technology options was developed and then refined. The viability of existing resources was considered as well as new resources including demand side measures of varying sizes and timeframes. The wide range of portfolio strategies was informed by stakeholder feedback as well as the All-Source RFP.

A Burns & McDonnell technology assessment defined the list of technologies and provided cost and performance information for resources. Where possible, technology costs from the All-Source RFP bids were utilized. Long-term cost projections were based on consensus estimates from three sources. These long-term cost estimates were averaged with outlooks from Pace Global and NREL to form the consensus technology cost projections over the planning horizon. A total of 30 resource options for power supply were included in the analysis. These included wind with and without storage, solar with and without storage, hydroelectric, landfill gas, several battery storage options, simple cycle and combined cycle natural gas and natural gas fired combined heat and power technologies. Note that Aeroderivative turbines and gas reciprocal engines were excluded based on the cost per KW and high gas pressure needed to run them. Two new coal-fired technologies were included, both of which were assumed to be equipped with carbon capture and storage.

An All-Source RFP was issued at the onset of the IRP process to obtain actual market information for near term indicative pricing for a wide range of technologies. The average delivered cost by resource informed the modeling and portfolio options. This included new builds, power purchase agreements, demand response and other supply options. The results of the All-Source RFP were vetted by Burns & McDonnell and ultimately converted into model inputs.

Long Term Capacity Expansion (LTCE) Assessments

The AURORAxmp power model (Aurora) was used as the central tool in the IRP to develop the 14 candidate portfolios in addition to the Reference Case portfolio. The long-term capacity expansion functionality within Aurora was used to develop least cost optimized portfolios based on the given sets of market input assumptions and portfolio requirements. This includes decisions to build, purchase, or retire plants.

Market transactions offer supply flexibility but also exposure to potential market risk to Vectren customers. In addition to the supply and demand side resource alternatives, portfolios were able to select market supply options as well. To reduce the risk that comes from exposure to the market, a limit of approximately ~15% of capacity needs, or 180 MW, was defined for annual capacity market purchases (except in a transitional year). This is much more than the 2016 IRP where a 10 MW cap was utilized and is responsive to the Commission Order 45052, which said Vectren did not fully consider energy or capacity purchases.

Portfolios were selected in a few different ways.

- Least cost portfolios were developed for the Reference Case and the other market and regulatory scenarios (5 Portfolios)
- Least cost portfolios with some modifications to existing units
- Stakeholder driven least cost portfolios

Portfolios were developed utilizing AURORA's LTCE modeling for the Reference Case and the four alternate scenarios. The model uses hourly chronological dispatch over a 20-year period, which means that outcomes are based on all 8,760 hours each year over a 20-year span. This helped to better evaluate intermittent renewable and storage resources.

In addition, alternative portfolios were developed by Vectren and based on stakeholder input to specifically test alternate resource strategies. These include the following additional 10 resource portfolios:

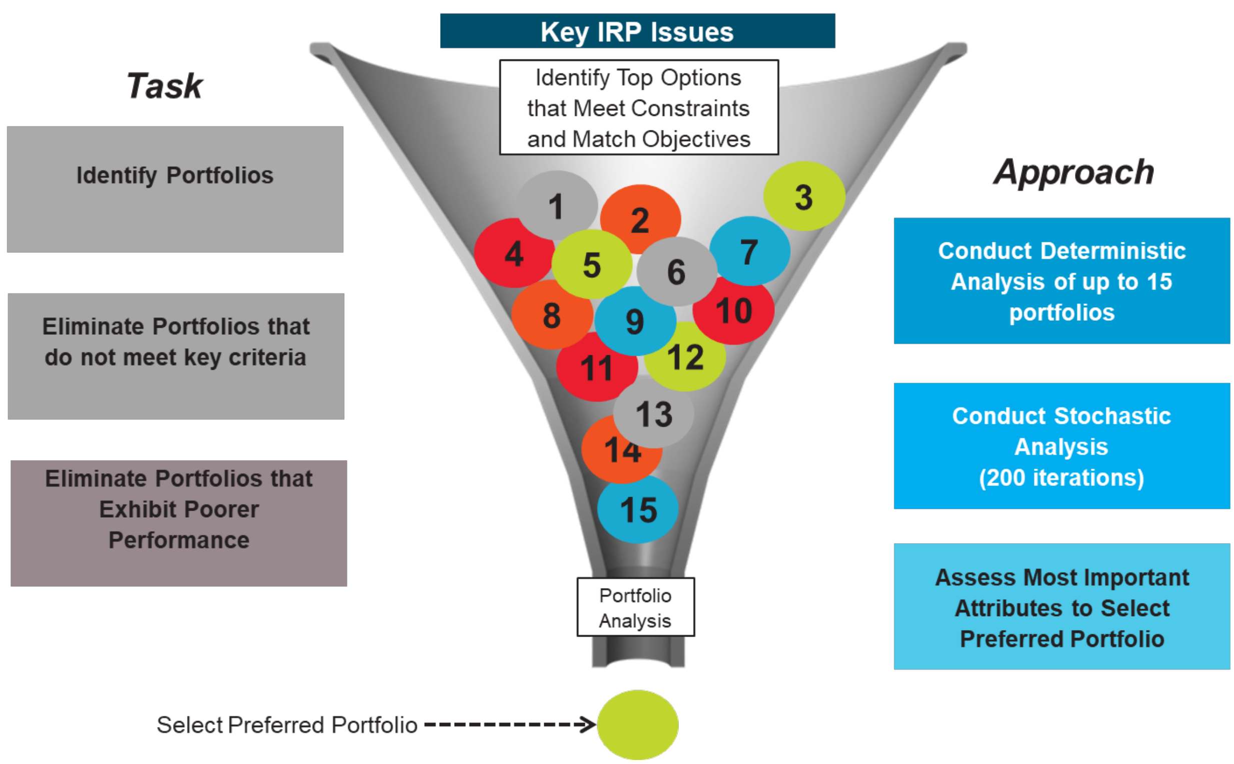
1. Business as usual to 2039 including the continued operation of all existing units (joint operations of Warrick 4 ends by 2024);
2. Bridge with business as usual to 2029, including the continued operation of A.B. Brown units 1 & 2 through 2029;
3. Bridge in which A.B. Brown 1 is converted to natural gas;
4. Bridge in which both A.B. Brown 1 and 2 are converted to natural gas;
5. Bridge in which A.B. Brown 1 is converted to natural gas and a CCGT is added;
6. Diverse energy portfolio including a new small (443 MW) natural gas CCGT;
7. Diverse energy portfolio including a new medium (511 MW) natural gas CCGT;
8. Renewables portfolio utilizing a combination of renewables, storage and peaking natural gas;

9. Renewables portfolio with no fossil technology options allowed in the portfolio by 2030; and
10. Portfolio based on HB 763 CO_2 price, which reaches $200/ton by the end of the study period.

In each of these LTCE assessments, the refinement for each portfolio, whether it be a modification to an existing unit or requiring the addition of a CCGT as a minimum requirement was required as part of a portfolio and then the model selected the remainder of the portfolio on a least cost basis.
Figure 2.7 – Structured Portfolio Selection Process illustrates the portfolio screening process applied in the analysis to select the preferred portfolio.

As described in Section 8, Vectren selected 10 of the 15 least cost portfolios for evaluation in the risk analysis. The selection criteria for eliminating the five portfolios are provided in that section.

Figure 2.7 – Structured Portfolio Selection Process



2.6 PORTFOLIO PERFORMANCE (SCENARIO BASED RISK ASSESSMENT)

The framework of the Indiana law mandating a triennial IRP[17] also requires the creation of alternative future scenarios with unique sets of inputs. Each candidate portfolio must be modeled in a dispatch run using these scenario-based inputs, which can provide a complementary view of portfolio strengths and weaknesses, separate from the probabilistic analysis that serves as the basis for scorecard measures. Four alternative scenarios were created (Low Regulatory, High Technology, 80% Reduction of CO_2 and High Regulatory), each with a unique set of inputs. All 10 candidate portfolios were modeled in a separate dispatch run for each of the four alternative scenarios.

AURORA is run in a market simulation mode holding each of the Vectren portfolios constant but allowing other MISO members to modify its decisions on the basis of the Scenario selected. The results of the scenario-based risk analysis are summarized in Section 8.2.1.

2.7 PORTFOLIO PERFORMANCE (PROBABILISTIC OR STOCHASTIC MODELING RISK ASSESSMENT)

Probabilistic modeling incorporates several market variables and probability distributions into the analysis, allowing for the evaluation of a portfolio's performance over a wide range of market conditions. Quantitative data is extracted from the results and is the foundation for the balanced scorecard and key drivers portion of the risk analysis. Probabilistic modeling begins with the development of 200 sets of future pathways for coal prices, natural gas prices, carbon prices, peak and average load (at the Vectren, MISO Local Resource Zone 6 (LRZ6) and MISO levels) and capital costs for a range of technologies. Each of these stochastic variables is propagated to the end of the study period, typically 1,000 to 3,000 times. A stratified sampling of the runs is taken, which allows the sample set to be reduced to 200 iterations. These 200 iterations of each stochastic variable are

[17] Indiana Code § 8-1-8.5

then loaded as inputs into the dispatch model. These inputs thus allow for the testing of each portfolio's performance across a wide range of market conditions.

Once again, all 10 portfolios were subjected to each of the 200 iterations (scenarios) using AURORA in dispatch mode where the Vectren portfolio is fixed but other MISO members can make decisions under each market scenario.

2.8 SENSITIVITY ANALYSIS

Vectren conducted several sensitivities in order to put brackets around resulting portfolios when one or more variables were adjusted. Sensitivities were also conducted to ensure seasonal Planning Reserve Margin (PRM) targets are met and that the candidate portfolio buildouts are calibrated to the greatest annual constraint, which occurs in the summer peak period.

- Vectren ran sensitivities to compare portfolio buildouts with winter solar/wind peak capacity credit on winter peak demand versus portfolio buildouts with summer solar/wind peak capacity credit on summer peak demand. Portfolios that are overly reliant on solar generation may risk not meeting MISO Planning Reserve Margin Requirements in the winter, as rules continue to evolve.
- Vectren performed sensitivities using a seasonal PRM target and seasonal peak capacity accreditation (solving to monthly peak hour). This sensitivity resulted in a solar peak capacity credit that approached zero as the Vectren system approached 2,000+ MW solar.
- Vectren performed a sensitivity in which the cost of a solar PPA resources increases 30%, based on more recent market information. The sensitivity demonstrated that even with increased costs, the solar PPA costs remain below the market clearing on-peak price of $42-45/MWh and continue to be selected as economic portfolio additions.
- Vectren conducted sensitivities to right-size several portfolios that had more capacity than needed in the early years of the transition from the point of view of the PRM target, but the model selects several early resources to capture the

benefits of the wind Production Tax Credit and solar Investment Tax Credit. Early solar and wind resources help to lower total cost of each portfolio.

- Sensitivities were run on the Reference Case and High Technology portfolios, swapping combustion turbine capacity for storage capacity. Portfolio costs rose as a result, but costs can vary widely depending on whether augmentation (replace dead battery cells) and other costs are fully incorporated into the bid price.
- A sensitivity was run on the Reference Case to assess 1.25% energy efficiency (EE) in the near-term as compared to the selected 0.75% EE in the near-term, which raised portfolio costs by 0.15%. As such, 1.25% was included in all portfolios for the first 3 years.

2.9 BALANCED SCORECARD

The Risk Analysis (based on the probabilistic modeling) of each of the portfolios was developed by Pace Global using the AURORAxmp dispatch model. There were several steps to this process:

- The first step was to develop the input distributions for each of the major market and regulatory drivers, including average and peak load growth and shape, natural gas prices, coal prices, carbon prices and technology capital costs. This was done by considering volatility of each factor in the short-term, medium-term and long-term.
- The second step was to run a probabilistic model (Monte Carlo) which selected 200 possible future states over the 20-year study planning period. This also formed the basis for the scenario inputs development.
- Each candidate portfolio was then run through simulated dispatch for the 200 possible future states using the AURORAxmp production cost model. AURORAxmp dispatches the candidate portfolio for each sampled hour over the

planning horizon. For this risk analysis procedure, AURORAxmp assumes that each Vectren candidate portfolio is constant but allows for builds and retirements to occur throughout the region based on economic criteria. Vectren generation, costs, emissions, revenues, etc. are tracked for each iteration over time.

- Next, values for each metric are tracked across all 200 iterations and presented as a distribution with a mean, standard deviation and other metrics as needed.
- These measures are used as the basis for evaluation in the balanced scorecard.

The results of risk analysis can be found in Section 8 Portfolio Development and Evaluation

2.10 SELECTION OF THE PREFERRED PORTFOLIO

The risk analysis includes scenario modeling, probabilistic modeling, sensitivity and other analyses to inform judgment in the selection of the preferred portfolio. In addition, a key part of selecting the preferred portfolio was based on how well each portfolio met multiple objectives as outlined in Section 2.3, under 200 iterations representing different, but internally consistent and plausible market condition scenarios. The selection process consisted of several comparisons illustrating each candidate portfolio's performance measured against competing objectives. The goal is to create the right balance between satisfying the competing objectives. The preferred portfolio delivered the best balance of performance across all competing metrics when viewed across the full range of 200 iterations, while also maintaining reliability and providing resource diversity/system flexibility. To help illustrate tradeoffs, Vectren used a Balanced Scorecard, as shown below in Figure 2.8 and further discussed in Section 8.

Figure 2.8 – Balanced Scorecard Illustration

Balanced Scorecard		Objective	Affordability	Price Risk Minimization	Environmental Risk Minimization	Market Risk Minimization		Market Risk Minimization	
		Metric	20-Year NPVRR ($million)	95th percentile NPVRR ($million)	Life Cycle GHG Emissions (million tons CO2e reduction 2019-2039)	Energy Market Purchases & Sales (% of generation)		Capacity Market Purchases & Sales (% of peak demand)	
No	Group	Candidate Portfolio							
						Purch	Sale	Purch	Sale
1	Reference	Reference Case							
2	BAU	BAU to 2039							
3		BAU to 2029							
4	Bridge	ABB1 gas conversion							
5		ABB1+ABB2 gas conversions							
6		ABB1 gas conversion + CCGT							
7	Diverse	Diverse Small CCGT							
8	Renewables	Renewables+ Flexible Gas							
9		Renewables 2030							
10	Scenario	High Technology							

The preferred portfolio represents Vectren’s assessment, based on the analysis, of an appropriate balance between all identified objectives (See Figure 2.2) under a wide range of future conditions.

SECTION 3
PUBLIC PARTICIPATION PROCESS

3.1 PUBLIC PARTICIPATION 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 given to improve the process. As a result, significant stakeholder input was directly included in key areas of the IRP, including but not limited to portfolio development, scenario development; scorecard development (metrics and measures), and modeling inputs such as energy efficiency inputs. While improvements have been made, Vectren's objectives for stakeholder engagement remain the same:

- **Listen**: Understand concerns and objectives
- **Inform**: Increase stakeholder understanding of the Integrated Resource Plan process, key assumptions and the challenges facing Vectren and the electric utility industry
- **Consider**: Provide a forum for relevant, timely stakeholder feedback at key points in the Integrated Resource Plan process to inform Vectren's decision making

IRP stakeholders include, but are not limited to, Vectren residential, commercial and industrial customers, regulators, customer advocacy groups, environmental advocacy groups, fuel suppliers and advocacy groups, shareholders and elected officials.

In the first public stakeholder meeting, Vectren publicly made 12 commitments and followed through with all throughout the process:

1. To strive to make every encounter meaningful for stakeholders and for us
2. To provide a data release schedule and provide modeling data ahead of filing for evaluation
3. That the IRP process informs the selection of the preferred portfolio
4. To utilize an All-Source RFP to gather market pricing & availability data
5. To use one model for consistency in optimization, simulated dispatch and probabilistic functions
6. To attempt to model more resources simultaneously

7. To include a balanced, less qualitative risk score card
8. To work with stakeholders on portfolio development
9. To test a wide range of portfolios in scenario modeling and ultimately in the risk analysis
10. To conduct a sensitivity analysis
11. To take an exhaustive look at existing resource options
12. That the IRP will include information presented for multiple audiences (technical and non-technical)

The first three stakeholder meetings began with stakeholder feedback. Vectren would review all requests since the last stakeholder meeting and provide feedback. Often suggestions were incorporated, but in instances where suggestions were not. Vectren made a point to discuss further 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. The final meeting was a preview of the preferred portfolio and a discussion of analysis. Due to COVID, this meeting was held via webinar.

The first three public stakeholder meetings were held at Vectren headquarters in Evansville, IN. Dates and topics covered are listed below:

Figure 3.1 – 2019/2020 Stakeholder Meetings

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

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

3.2 KEY ISSUES DISCUSSED

Throughout the process Vectren engaged stakeholders on all key inputs into the IRP, which helped shape the outcome of the analysis. In the first stakeholder meeting, Vectren presented a draft balanced scorecard which was used to evaluate key tradeoffs among portfolios. Adjustments were made and presented to stakeholders before modeling commenced. Vectren worked closely with stakeholders to develop scenario concepts and helped to refine various scenario inputs. Additionally, stakeholders provided input into portfolio development, which helped to provide a wide range of portfolios, included continuation of the Brown coal units through 2029 or 2039 and an all renewables portfolio by 2030.

3.3 STAKEHOLDER INPUT

During the 2019/2020 IRP, stakeholders provided their input in several ways: 1) verbal feedback through question/answer sessions during public stakeholder meetings; 2) through participation in Vectren stakeholder workshops; 3) via written feedback/requests; 4) telephone conversations; and 5) meetings between stakeholder sessions.

Vectren worked diligently to have an open forum for stakeholders to voice questions/concerns and make suggestions on the IRP analysis. Each Vectren stakeholder meeting was opened by Lynnae Wilson, Chief Business Officer for Indiana Electric. She and other senior management, Vectren subject matter experts and expert consultants actively participated in each meeting to help address stakeholder questions/concerns.

Below is a summary of key feedback during the 2019/2020 IRP that heavily influenced the analysis. For a full list, see the technical appendix Technical Appendix Attachment 3.1 Stakeholder Materials.

Figure 3.2 – Summary of Key Stakeholder Input

Request	Response
Update the High Regulatory scenario to include a carbon fee and dividend	Included a fee and dividend construct which assumed less impact on the economy/load
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 Renewables Energy Laboratory (NREL) Life Cycle

Request	Response
	Greenhouse Gas Emissions (CO_2e) from Electricity Generation by Resource
Include a measure within the risk score card that considers sunk costs	Vectren worked with Pace Global to create an uneconomic asset risk measure. Ultimately, this measure was considered but not included within the scorecard, it did not fulfil the initial intention, to evaluate risk of resources with large initial capital investments
Include a scenario with a carbon dividend modeled after HB 763 with a CO_2 price curve that was approximately $200 by the end of the forecast	Ran a sensitivity to create a portfolio. Ultimately, this was not selected for the risk analysis, as the amount of generation built within modeling vastly exceeded Vectren's need
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 a mid-range CO_2 price curve 8 years into the forecast. The low regulatory scenario did not include a CO_2 price, and remains a boundary condition

3.4 DATA REQUESTS SUMMARY

One of the key data requests made was to provide access to all-source RFP bids. While protecting confidentiality commitments to bidders' competitively sensitive information, Vectren provided two consumer groups (OUCC and CAC) who signed a NDA with electronic read-only access via a locked down SharePoint site. A data key was provided for convenience to show the difference between tier one and tier two bids and many attributes of each bid. Additionally, Vectren received a data request from the CAC on December 9, 2019. Per their request, Vectren provided wind and solar resource shape files, input files utilized in the load forecast for regression modeling along with documentation, probabilistic modeling distributions for natural gas, capital cost, carbon price and peak load and costs associated with the retirement of existing thermal units.

CAC also requested modeling files as a part of their review process, prior to filing the IRP. In order to accommodate this request, Vectren worked with them to provide files to the OUCC and CAC on May 15, 2020 in preparation for the final stakeholder meeting on June 15th. Vectren held a discussion with these stakeholders on May 26th to answer questions and walk them through the file formats. Vectren worked to answer questions leading into and after the final IRP stakeholder meeting.

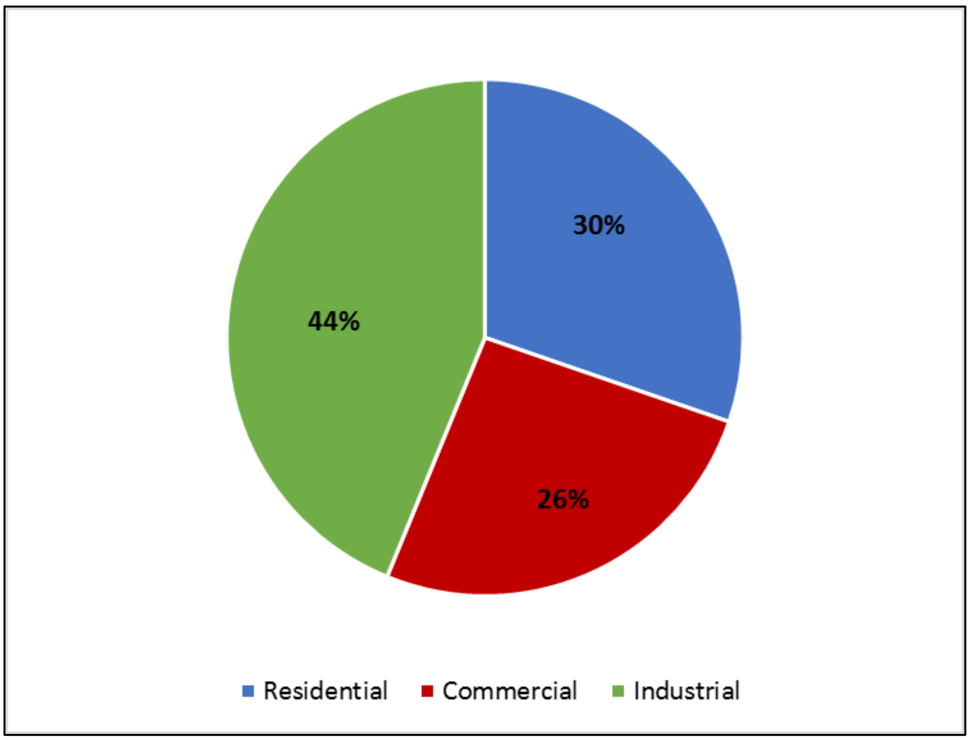
CAC also issued Data Request 2 on 6-5-20, Data Request 3 on 6-10-20 and Data Request 4 on 6-11-20. Vectren provided responses ahead of the required timeframe and before the filing of the IRP.

SECTION 4
CUSTOMER ENERGY NEEDS

4.1 CUSTOMER TYPES

Vectren serves more than 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 energy 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 were 5,308 GWh with non-weather normalized system peak reaching 1,039.2 MW. Figure 4.1 shows 2018 class-level sales distribution.

Figure 4.1 – 2018 Vectren Sales Breakdown



4.2 FORECAST DRIVERS AND DATA SOURCES

The main drivers of the energy and demand forecast include the following: historical energy and demand data, economic and demographic information, weather data, equipment efficiencies and equipment market share data.

Itron used over ten years of historical energy and demand data within the energy and demand forecasts. This data is maintained by Vectren in an internal database and was provided to Itron. Energy data is aggregated by rate class for the purposes of forecasting. There are two major rate classes for residential customers: the standard residential rate and the transitional electric heating rate (rate closed to new premises). Information for these rates is combined for the purposes of forecasting residential average use per customer. Similarly, small commercial (general service) rates are combined to produce the commercial forecast and large customer rates are combined to produce the industrial forecast. The demand forecast utilizes total system demand.

Economics and demographics are drivers of electricity consumption. Historically, there has been a positive relationship between economic performance and electricity consumption. As the economy improves, electricity consumption goes up and vice versa. Economic and demographic information was provided by Moody's Economy.com, which contains both historical results and projected data throughout the IRP forecast period. Examples of economic variables used include, but are not limited to, population, income, output and employment.

Weather is also a driver of electric consumption. Vectren's peak demand is typically in summer when temperatures are hottest. Air conditioning drives summer usage. Normal weather data is obtained from DTN, a provider of National Oceanic and Atmospheric Administration (NOAA) data. Vectren utilizes data over a 20-year period for the sales forecast and a 20-year period for the demand forecast in order to capture recent weather activity.

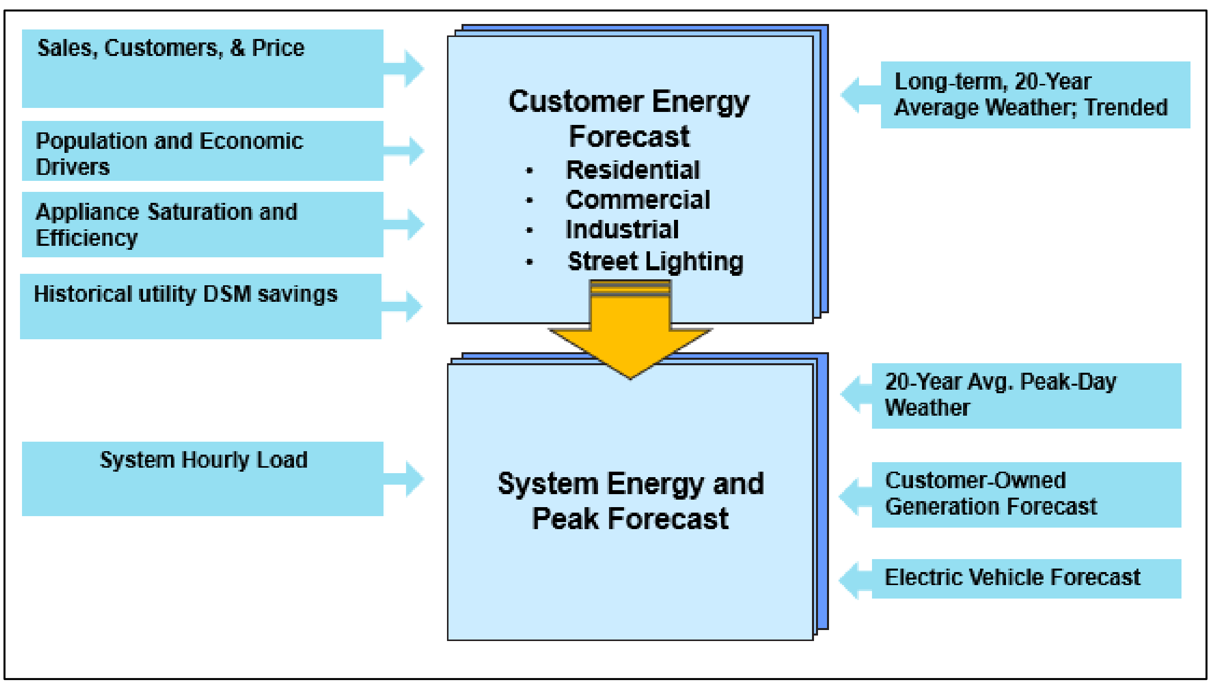
Itron, Inc. provides regional Energy Information Administration (EIA) historic and projected data for equipment efficiencies and market shares. This data captures projected changes in equipment efficiencies based on known codes and standards and market share projections over the forecast period, including but not limited to the following:

electric furnaces, heat pumps, geothermal, central air conditioning, room air conditioning, electric water heaters, refrigeration, dish washers, dryers, etc. Residential market share data was adjusted to Vectren's service territory based on the latest appliance saturation survey data.

4.3 MODEL FRAMEWORK

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 4.2 shows the general framework and model inputs.

Figure 4.2 – 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 ownership 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.

4.4 CUSTOMER OWNED DISTRIBUTED ENERGY RESOURCES

Distributed generation (DG) is an electrical source interconnected to Vectren's transmission or distribution system at the customer's site. The power capacity is typically small when compared to the energy companies' centralized power plants. DG systems allow customers to produce some or all of the electricity they need. By generating a portion or all of the electricity a customer uses, the customer can effectively reduce their electric load. With respect to Vectren's electric service territory, DG will likely take these forms:

Small – 10 kW and under – roof-top photovoltaic (PV) systems, small wind turbine, etc. interconnected at distribution secondary voltage (120/240 V, etc.)

Medium – 10 kW to 10 MW – large scale PV systems, wind turbine(s), micro-turbine(s), etc. interconnected at distribution primary voltage (4 kV or 12 kV)

Large – 10 MW and over – heat recovery steam generator, combustion turbine, etc. interconnected at transmission voltage (69 kV and over)

Most renewable DG systems only produce power when their energy source, such as wind or sunlight, is available. Due to the intermittency of the power supply from DG systems, there will be times when the customer needs to receive electricity from Vectren. Conversely, when a DG system produces more power than the customer's load, excess power can be sent back to Vectren's electric system through a program called net metering. The customer is charged the retail rate for the net power that they consume.

4.4.1 Current DG

As of December 2019, Vectren had approximately 486 residential solar customers and 71 commercial solar customers, with an approximate installed capacity of 10.7 MW. Based on recent solar installation data, the residential average size is 10.5 KW, while the commercial average system size is 78.7 KW. Vectren has incorporated a forecast of customer owned photovoltaic systems into the sales and demand forecast.

Vectren monitors Combined Heat and Power (CHP) developments in its service area and adjusts the load forecast for any known, future customer owned CHP installations. A large CHP system went into service on Vectren's system in 2017.

4.4.2 Solar DG Forecast

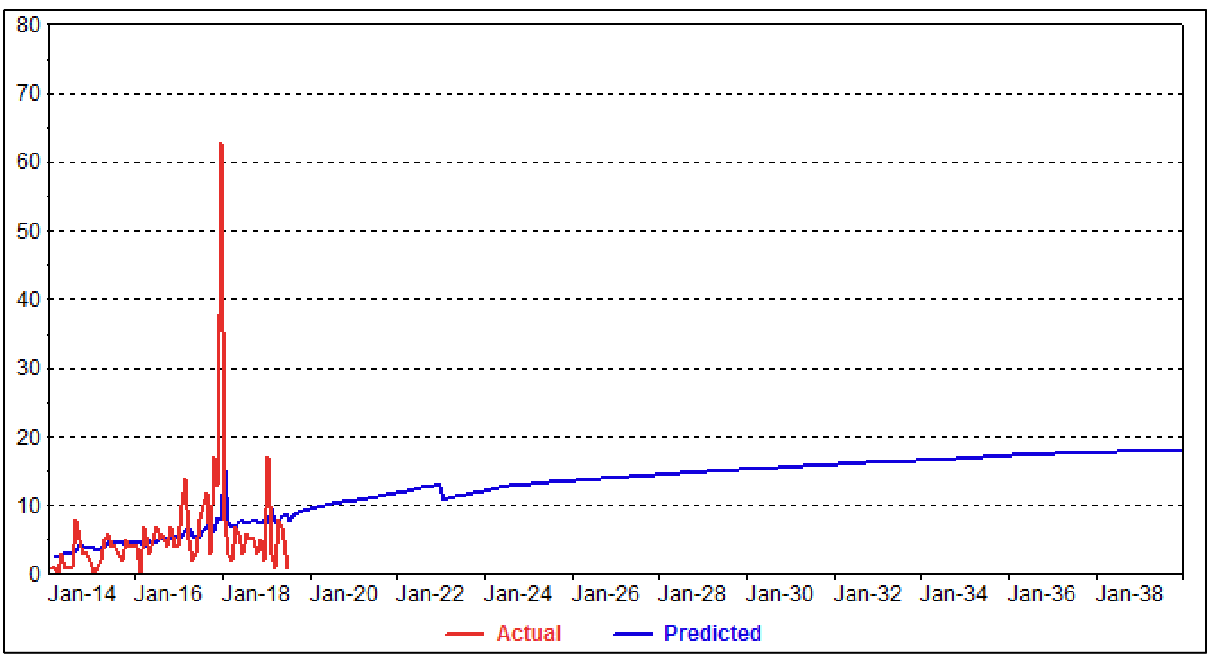
The energy and peak forecasts incorporate the impact of customer-owned photovoltaic systems. System adoption is expected to increase as solar system costs decline.

The primary factor driving system adoption is a customer's return-on-investment. Itron created a simple payback model, which was 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 generated from the system is considered "free." Solar investment payback is calculated as a function of system costs, 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. While current net metering customers will be credited the retail rate, DG installed beyond 2021 will be credited at the wholesale cost plus 25%.

One of the most significant factors driving adoption is declining system costs, which have been declining rapidly over the last several 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, Itron assumed system costs will continue to decline 10% annually through 2024 and an additional 3% annually after 2024. Customer owned solar cost projections are consistent with the U.S. Dept. of Energy's Sun Shot Solar goals and national trends.

The solar adoption model relates monthly residential solar adoptions to simple payback. Figure 4.3 shows the resulting residential solar adoption forecast.

Figure 4.3 – 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. Some challenges to commercial adoption are 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, Itron assumed 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.

As shown in Figure 4.4, installed capacity of solar is expected to increase at a compound annual growth rate of 10.9% with 84.3 MWs by 2039.

Figure 4.4 – Solar Capacity and Generation

Year	Total Generation MWh	Installed Capacity (Aug) MW	Demand Impact MW
2019	20,144	9.3	2.7
2020	23,260	11.8	3.5
2021	26,856	14.6	4.3
2022	30,834	17.6	5.2
2023	34,842	20.7	6.1
2024	38,999	23.8	7.0
2025	43,290	27.1	8.0
2026	47,880	30.6	9.0
2027	52,577	34.2	10.1
2028	57,535	37.9	11.2
2029	62,462	41.7	12.3
2030	67,499	45.6	13.4
2031	72,742	49.6	14.6
2032	78,272	53.6	15.8
2033	83,492	57.7	17.0
2034	89,074	62.0	18.3
2035	94,787	66.3	19.5
2036	100,707	70.6	20.8
2037	106,394	75.1	22.1
2038	112,446	79.7	23.5
2039	118,499	84.3	24.8
CAGR 2020-2039	8.9%	10.9%	10.9%

4.4.3 Potential Effects of Distributed Generation on Transmission and Distribution

Distributed Generation customers currently affect a small amount of load on each respective distribution circuit, which has not caused significant operational issues for Vectren. At higher levels of DG penetration, Vectren would encounter more operational issues and would need to allocate more resources to mitigate these issues. Some examples of potential issues would include:

- **High voltage mitigation** – With a high penetration of DG, distribution feeder voltage profiles could become unacceptably high when light loading periods coincide with high DG output.

- **Protection system modifications** – Traditionally, electric distribution feeders have been designed as unidirectional from the energy company to the customer. Voltage regulation and feeder protection strategies are designed based on this premise. With high DG penetration under light load with high DG output, power flow could reverse from the customer to the energy company.
- **Power quality and harmonics mitigation** – Power quality issues are one of the major impacts of high photovoltaics penetration levels on distribution networks. Power inverters used to interface PV arrays to power grids increase the total harmonic distortion of both voltage and current, which can introduce heating issues in equipment like transformers, conductors, motors, etc.
- **Short term load forecast uncertainty** – At higher levels of DG penetration, short term load forecasting becomes more difficult. DG resources work to offset the customer's load, but their output can be variable depending upon weather conditions. A load forecasting technique would need to be implemented that is more granular and more responsive to short-term weather conditions.
- **Capacitor banks on the distribution feeders** – Capacitor banks are used to improve power factor and maintain acceptable voltages along the lines. These are strategically placed based on load/distance from the normal source (substation). Once additional sources (DG) are added to the circuits, capacitor bank placement will need to be reevaluated.
- **Electric Rates** – Vectren's electric rates are designed to recover the fixed costs of providing service (transmission, distribution, metering, etc.) via energy and (for large customers) demand charges, along with an associated fixed monthly customer facilities charge. The fixed monthly charge does not reflect the full amount of fixed costs that Vectren incurs to provide retail electric service. DG customers (who generate a portion of their own electricity but still rely on the electric grid) avoid paying towards the recovery of the fixed costs of the grid that are recovered through the energy charge, which leads to Vectren's under recovery of the cost of providing service. Over time, as base rates are updated periodically,

recovery of these costs shifts to non-net metering customers, resulting in a subsidy to net metering customers.

- **Transmission Power Flows –** High DG penetration impact power flow on transmission lines. Depending on the concentration and location of these resources, the transmission system may need to be reconfigured, with consideration given to the dependency of the resources on the weather (wind, solar, etc.). High DG penetration may also impact flows on transmission system tie lines to other entities and require additional mitigations, such as installation of reactors or phase shifters to control flows.
- **Generation Reserves** – With the output of DG being weather dependent, the remaining fleet of generators and the electric system must be capable of quickly reacting to the fast and potentially large generation changes on the system, as well as providing generation support during times when DG will not be available (such as nighttime for solar DG). The adoption of Electric Vehicles could also lead to increased load demand in the nighttime hours as they are charging. These issues will need to be evaluated and potentially require mitigations such as storage facilities, quick start generators, etc.
- **Additional Operational Challenges** – High DG penetration causes additional challenges to operate the electric system in a safe and reliable manner due to loss of inertia on the power system by replacing traditional rotating machine generators (high inertia) with inverter-based generators (no/low inertia). These challenges include maintaining spinning and quick start reserves, power system frequency fluctuations and increased system operations (tripping), among others. Each of these issues would need to be evaluated and potentially mitigated to maintain reliable and safe power system operation.

4.5 ELECTRIC VEHICLES

4.5.1 Current EVs

In 2019, Vectren estimated 238 registered electric vehicles were 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. This estimate was based on Indiana BMV registration data for the counties that Vectren serves. Vectren purchases quarterly from the BMV a list of vehicle registrations for the counties that Vectren serves.

4.5.2 EV Forecast

As electric vehicles are gaining more traction in the vehicle market, Vectren decided to include an electric vehicle forecast in the 2019/2020 IRP. As described in the 2019 Long-Term Electric Energy and Demand Forecast Report in the Technical Appendix of this IRP, Itron created an electric vehicle forecast utilizing the Energy Information Administration (EIA) Annual Energy Outlook (AEO) transportation forecast to estimate the number of cars per household over time. This number is multiplied by the forecast of residential customers to create a projected number of vehicles per Vectren household. Itron then applied the EIA AEO projected saturation of battery electric vehicles and plug in hybrid electric vehicles.

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 most of the charging will occur at home in the evening hours. Table 4.5 shows the electric vehicle forecast.

Figure 4.5 – Electric Vehicle Load Forecast

Year	BEV MWh	PHEV MWh	Total EV MWh	Demand Impact MW (Aug)	Demand Impact MW (Jan)
2019	432	305	737	0.1	0.1
2020	1,063	580	1,643	0.2	0.1
2021	2,667	1,110	3,777	0.4	0.3
2022	6,691	2,124	8,815	1.0	0.6
2023	14,769	3,732	18,501	2.1	1.4
2024	19,178	4,503	23,681	2.5	2.2
2025	22,770	5,106	27,876	2.9	2.7
2026	26,320	5,697	32,017	3.3	3.1
2027	29,838	6,275	36,113	3.8	3.5
2028	33,334	6,837	40,171	4.2	3.9
2029	36,869	7,392	44,261	4.6	4.3
2030	40,467	7,933	48,400	5.0	4.8
2031	44,164	8,455	52,619	5.5	5.2
2032	47,920	8,959	56,878	5.9	5.6
2033	51,735	9,438	61,173	6.3	6.1
2034	55,591	9,895	65,486	6.8	6.5
2035	59,461	10,327	69,788	7.2	7.0
2036	63,315	10,741	74,056	7.7	7.4
2037	67,111	11,137	78,248	8.1	7.8
2038	70,863	11,510	82,373	8.5	8.3
2039	74,607	11,872	86,479	8.9	8.7
CAGR 2020-2039	25.1%	17.2%	23.2%	22.7%	25.7%

4.5.3 Potential Effects on Generation, Transmission and Distribution

Electric Vehicles and their associated charging stations currently have a minimal impact on the Vectren electric system and therefore have not caused significant operational issues. As the level of EV charging stations increases, Vectren may encounter multiple operational issues that will need to be evaluated and potentially mitigated. Some examples of potential issues include:

- **Shifting Peak Load** – Increased use of EV will have an impact on the magnitude of daily load demand, as well as the timing of peak loading. If a large concentration of EV charging occurs in the late afternoon and early evening, the daily system peak could be shifted to later in the afternoon or a second (and most likely lesser) peak could occur in the evening.
- **Generation Reserves** – If EV charging largely occurs in the evening or overnight, the electric system would see higher than typical load demand values at times when DG and other solar generation installations would not be available. This would lead to a need for generation support during these hours, such as energy storage facilities, quick start generators, etc.
- **Peak Charging** – If a large portion of EV charging were to occur during peak loading times, the impact of the increased demand could lead to overloaded electrical infrastructure, unless some form of delayed or managed charging is available. These overloaded facilities would need to be upgraded or other system level upgrades would be needed to mitigate the overload conditions.
- **Transmission Planning Concerns** – MISO performs economic studies annually using a range of potential futures. The futures that they are currently evaluating include potential increases in electrification (including EV) at various growth levels. Due to the uncertainty around EV adoption and the differing values being analyzed, uncertainties as to when to complete transmission system upgrades to support a higher level of system peak load due to EV adoption may be introduced. A need for additional planning models and sensitivity analysis would be required to evaluate these uncertainties and determine the appropriate time to perform the needed transmission system upgrades.

- **Dynamic Behavior** – The dynamic behavior of these loads while in a charging state during fault conditions and during re-energization post fault condition is an additional issue that will need to be evaluated. Research is still needed to properly reflect how these types of loads respond from a dynamic behavior perspective and may require additional dynamic modeling for planning studies.

If there is a substantial increase in EV adoption within the next 10 years, it is anticipated that there would be a significant change in the system load profile. As an example, the system peak load hour could shift to later in the day. The load profile and generation expansion implications of the changing load shape suggest that EV adoption and resulting vehicle charging patterns should be monitored in the upcoming years.

4.6 ENERGY AND DEMAND FORECAST (REFERENCE CASE)

For the IRP filing, the long-term energy and demand forecast does not include energy savings from future DSM programs; DSM activity is considered a supply option and not a reduction to demand. Excluding DSM, total energy requirements and peak demand are expected to average 0.6% annual growth over the next 20 years. The table below shows Vectren's energy and demand forecast; the forecast includes the impact of customer owned distributed generation, electric vehicles, trended weather (warmer summers and winters), company owned distributed generation (solar and landfill gas) and customer EE outside of energy company sponsored programs but excludes future energy company sponsored DSM program savings. For more information on Vectren long-term energy and demand forecasts, including load shapes, see Technical Appendix Attachment 4.1 2019 Vectren Long-Term Electric Energy and Demand Forecast Report.

Figure 4.6 – Energy and Demand Forecast[18]

Year	Energy (MWh)		Summer Peak (MW)		Winter Peak (MW)	
2019	5,147,837		1,115		826	
2020	5,374,079	4.4%	1,100	-1.4%	831	0.6%
2021	5,380,877	0.1%	1,102	0.2%	828	-0.3%
2022	5,505,660	2.3%	1,126	2.2%	847	2.3%
2023	5,742,090	4.3%	1,168	3.7%	886	4.6%
2024	5,774,656	0.6%	1,173	0.5%	891	0.5%
2025	5,789,928	0.3%	1,176	0.3%	891	0.1%
2026	5,807,569	0.3%	1,179	0.3%	892	0.1%
2027	5,828,395	0.4%	1,183	0.3%	894	0.2%
2028	5,858,975	0.5%	1,189	0.5%	898	0.4%
2029	5,874,831	0.3%	1,192	0.3%	898	0.1%
2030	5,891,575	0.3%	1,196	0.3%	899	0.1%
2031	5,909,760	0.3%	1,200	0.3%	900	0.1%
2032	5,934,963	0.4%	1,205	0.4%	902	0.3%
2033	5,949,314	0.2%	1,209	0.3%	902	0.0%
2034	5,970,284	0.4%	1,214	0.4%	903	0.1%
2035	5,992,643	0.4%	1,219	0.4%	905	0.2%
2036	6,019,773	0.5%	1,225	0.5%	907	0.3%
2037	6,034,306	0.2%	1,229	0.4%	907	0.0%
2038	6,053,929	0.3%	1,234	0.4%	908	0.1%
2039	6,072,712	0.3%	1,239	0.4%	909	0.1%
CAGR 2020-2039		0.6%		0.6%		0.5%

4.7 DISCUSSION OF BASE LOAD, INTERMEDIATE LOAD and PEAK LOAD

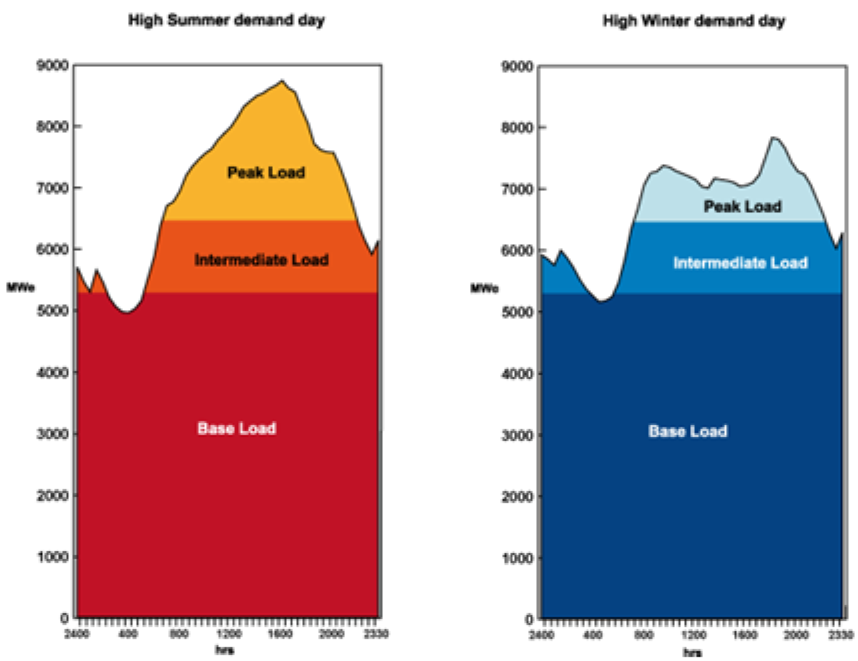
There are three levels of electric load: base load, intermediate load and peak load. Base load is the minimum level of demand on an electrical supply system over 24 hours. Base load is primarily served by power plants which can generate consistent and dependable power. Intermediate load is a medium level of demand. Plants can operate between extremes and generally have output increased in the morning and decreased in the evening. Peak load is the highest level of demand within a 24-hour period. The annual

[18] 2019/2020 IRP energy and demand forecast provided to MISO in Nov. 2019 differed slightly in order to match MISO's requirements which necessitated the following an adjustment. It incorporated the 2016 IRP's preferred level of DSM

peak hour is typically between June and September, when weather is hottest. For modeling purposes, Vectren uses August as the peak summer month and January as the peak winter month. Typically, peak demand is served by units that can be switched on quickly when additional power is needed.

The graphic below shows an illustrative example of summer and winter peak load.

Figure 4.7 – Typical Load Curve Illustrations (Summer and Winter)



This dynamic is evolving as more intermittent renewable resources, particularly solar, come online. MISO nets out energy produced from renewable resources from customer load. This is expected to shift the net peak into the evening hours where dispatchable resources will be needed to serve customer load.

4.8 STAKEHOLDER INPUT – Load Forecast

Vectren discussed the load forecast with stakeholders in the October 10th stakeholder meeting, providing an opportunity to provide input, question and comment on the draft load forecast before finalizing. There was a robust discussion on trended weather projections used in the load forecast. Some stakeholders believed that the trend utilized did not reflect the findings in a recent Purdue University climate study. Vectren reached out to Purdue University and 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 was 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 was well within Vectren's high bound forecast. Vectren did not update its load forecast, based on this analysis. This was discussed in the December 13, 2020 stakeholder meeting.

SECTION 5
The MISO Market

5.1 MISO

Midcontinent Independent System Operator (MISO), is the independent, not-for-profit Regional Transmission Operator (RTO) of which Vectren is a member. MISO oversees power delivery across 15 states and the Canadian province of Manitoba and is the largest energy and operating reserves market in the world. 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 regarding energy and capacity and can rely on neighboring Zones to an extent, largely depending 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.

Figure 5-1 – MISO Local Resource Zones

MISO's two main roles are transmission planning and oversight of its energy, capacity and ancillary service markets. MISO has operational authority to control transmission facilities and coordinate security for its region to ensure reliability. MISO is responsible for dispatch of lowest cost generation units, ensuring the most cost-effective generation meets load needs.

5.2 MISO Planning Reserve Margin Requirement (PRMR)

MISO requires Vectren and its other member electric utilities to maintain a Planning Reserve Margin Requirement (PRMR). The PRMR is the amount of resources MISO requires in order to meet a NERC standard of one loss of load event in ten years and is designed to ensure there is enough power capacity throughout the MISO region to meet customer demands during peak periods, including peak periods where some equipment might fail. To further ensure the NERC standard of one loss of load event in ten years, the PRMR is further detailed by the Local Clearing Requirement (LCR) which mandates how much of a Local Resource Zone's (LRZ) PRMR must be met by generation resources physically located within that LRZ. In recent years the amount of available resources to meet load needs throughout MISO has tightened excess capacity that acts as a reliability safeguard. This trend appears to continue as some baseload units are projected to retire by 2023. As a result, long term dependence on the market for capacity and energy has considerable risk.

The illustration below shows the load on a typical day and load on the peak day with the reserve margin requirement.

Figure 5.2 –Illustration of Load Curve and Planning Reserve Margin

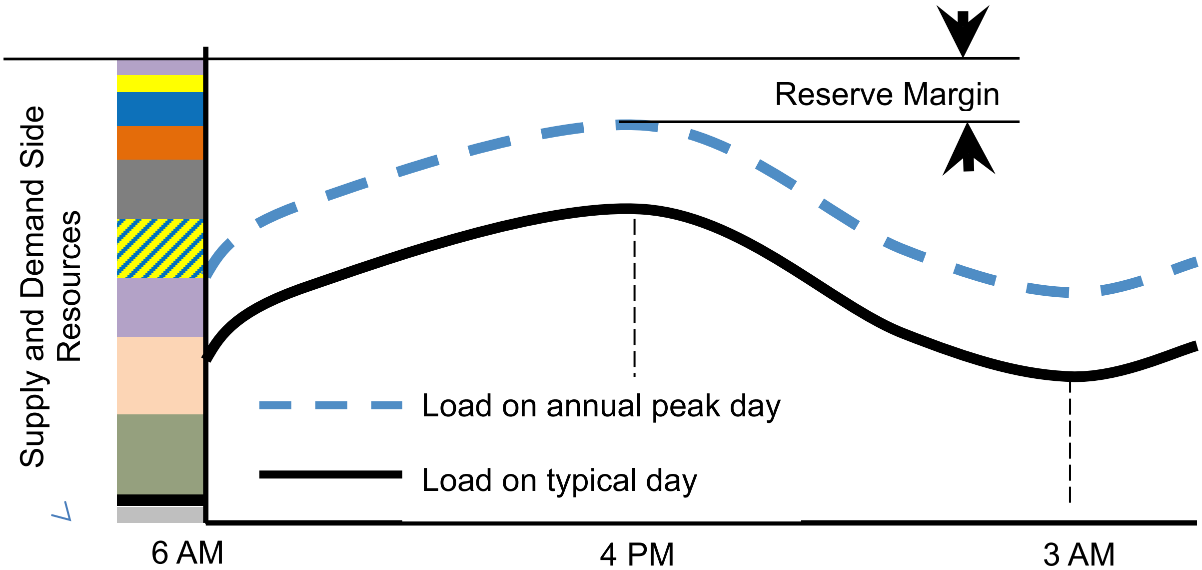


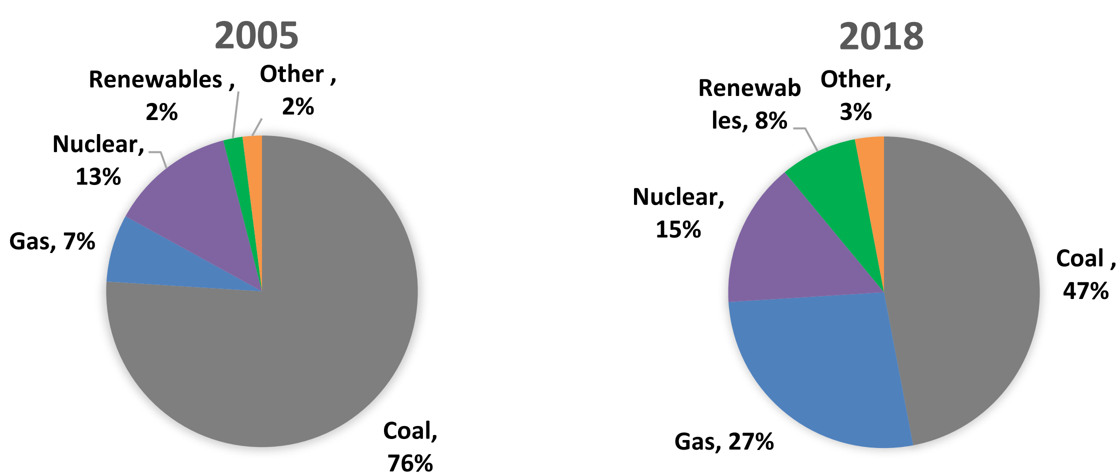
Figure 5.3 –Historic MISO PRMR

Planning Year	MISO PRMR (UCAP)-Required	MISO PRM (UCAP)-Excess Available: Offered/PRMR
2020-21	8.90%	142,082/135,960: 4.50%
2019-20	7.90%	142,082/134,743: 5.45%
2018-19	8.40%	141,781/135,179: 4.88%
2017-18	7.80%	142,146/134,753: 5.49%
2016-17	7.60%	141,524/135,483: 4.46%
2015-16	7.10%	145,861/136,359: 6.97%

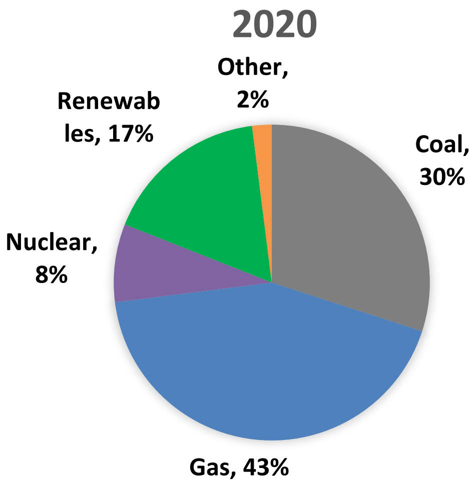
5.3 MISO Resource Mix – Past, Current and Future

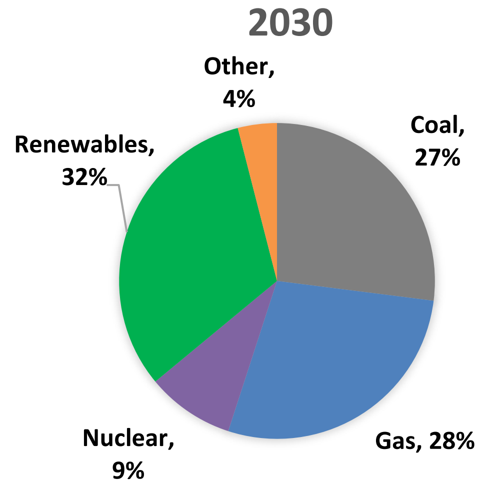
MISO's resource fuel mix has changed drastically since its market inception in 2005. In 2005, coal was the predominant fuel source, with MISO lacking diversity and nuclear as the closest competitor at 13%. In 2018, after the implementation of the Clean Power Plan and various other regulations and due to cost pressure from low gas price and declining renewable energy prices, MISO member companies began retiring aging coal units. As a result, its share of the MISO fuel mix dropped to 47%, with natural gas becoming the second leading fuel source and renewables quadrupling in size. This year natural gas (43%) is the leading fuel source in MISO, followed by coal (30%) and renewables (17%), while nuclear has decreased to only 8%. MISO now projects that by 2030 renewables will be the leading fuel source of MISO capacity at 32%, followed by gas at 28% and coal decreasing to 27%.

Figure 5-4 – MISO Fuel Mix[19]



[19] Sources: 2005 Mix: MISO Evolution of the Grid presentation on 11/07/17 https://ccaps.umn.edu/documents/CPE-Conferences/MIPSYCON-PowerPoints/2017/GenTheEvolutionoftheGridintheMidcontinentIndependentSystemOperator(MISO)Region.pdf
2018 Mix: MISO 2019 MTEP https://cdn.misoenergy.org/MTEP19%20Executive%20Summary%20and%20Report398565.pdf
2020 Mix: MISO Corporate Fact Sheet accessed 03/20 https://www.misoenergy.org/about/media-center/corporate-fact-sheet/
2030 Mix: MISO RASC Presentation 2020 Focus presented on March, 2020
https://cdn.misoenergy.org/20200304%20RASC%20Item%2002%20RAN%20Overview%20(RASC009%20RASC010%20RASC011%20RASC012)432103.pdf





5.4 Dispatchable vs. Intermittent

Dispatchable generation refers to sources of electricity that can be used or dispatched on demand at the request of the power grid operator. Intermittent generation is associated with renewable forms of electricity, mainly solar and wind, that cannot be dispatched at a moment's notice and without storage capabilities only generate electricity as available. Dispatchability of a generation resource allows for planning that is reflected in capacity accreditation, which provides a generator an annual value based on: expected generation output during peak-load conditions, generator characteristics and the past three years of operational performance. Lack of dispatchability creates planning challenges best illustrated through the recent increase in MISO Emergency Max-Gen Events that have occurred throughout the four seasons as the reliance on intermittent resources has increased. An intermittent resource that may be capable of 100% of nameplate generating capacity on a certain day may be reduced to 0% of capacity during another hour of that same day due to a weather pattern. This volatility of intermittent renewable resources has challenged grid planners as these resources have been added to the system. Dispatchable resources that are not on outage remain available as called upon during these severe conditions when intermittent resources do not meet planned output.

MISO has shifted from 96% dispatchable generation (all forms of generation except renewables) in 2005 to approximately 83% currently and is forecasted to be at 60% in

2030. In response to these conditions MISO commenced its Resource Availability and Need (RAN) Initiative and its Renewable Integration Impact Assessment (RIIA) to plan market rule changes to deal with the future resource mix. The RAN Initiative is aimed at better accrediting generation units while the RIIA is focused on understanding the impacts of renewable energy growth in MISO over the long term and assessing potential transmission solutions to mitigate them.

5.5 MISO Maximum-Generation Emergency Events

Maximum-Generation (Max-Gen) Events are the final step in MISO's emergency operating procedure before firm-load shed, otherwise known as blackouts. Max-Gen Events have historically been rare in nature, with MISO experiencing 3 events between 2009 to 2015 and they occurred only during peak load condition summer months. However, since 2016 there have been 10 events, spanning all four weather seasons. In January of 2019, MISO, for the first time in its existence, interrupted energy service to Industrial Customers enrolled as Load Modifying Resources (LMR). Going forward customers enrolled as LMRs must consider the increased possibility of future interruptions. It is likely that some LMRs will end their participation due to the heighted risk.

5.6 MISO Resource Adequacy Reform

As a reaction to the increasing frequency, duration and ability for Max-Gen Events to occur within all periods of the year, MISO implemented its RAN initiative. The goal of this initiative is to "ensure the processes in use appropriately assure the conversion of committed capacity resources into sufficient energy every hour of the Planning Year. A dramatically changing landscape has made this conversion process increasingly more uncertain. Therefore, an issue and solution development effort will help MISO and its stakeholders identify and meet the challenges posed by current and future portfolio and technology changes facing the region."

The RAN initiative has led to market mechanism reform that is currently underway. Such reform has included changes to the ability to interrupt customers enrolled as Load Modifying Resources/Interruptible Load. MISO currently has reform initiatives[20] that are high priority that include Emergency Energy Pricing, which would allow higher cost energy resources to set pricing, thereby increasing energy pricing during emergency events, increasing the Energy Offer Cap from $1,000/MWh to $2,000/MWh, thereby allowing generation to double its maximum offer price and allow prices to reach a higher threshold, instituting a Seasonal Planning Resource Auction construct, which would break up the current annual capacity auction to seasonal auctions that would adjust the PRMR and capacity accreditation for resources during these periods. Vectren considered the potential for winter and summer accreditation.

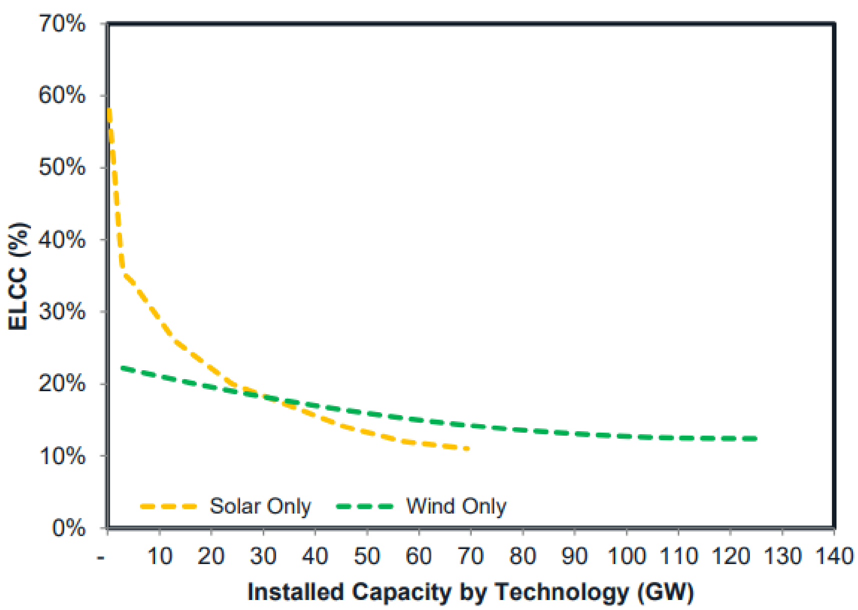
5.7 MISO CAPACITY CREDIT

Each resource option receives varying amounts of capacity credit towards MISO's resource adequacy requirement based on their ability to reliably contribute energy at the peak demand hour. Thermal generation, such as natural gas and coal-fired power plants, can produce an expected level of output when called upon. For this reason, utilities can count nearly the full installed capacity of thermal generation towards their resource adequacy requirement (less their historical outage rate). A new thermal generator can count ~96 MWs out of every 100 MWs of installed capacity towards meeting MISO's summer planning reserve margin requirement. This amount increases in the winter for gas resources due to air density in cold weather conditions. Renewable wind and solar resources are variable sources of power (available when the wind blows or the sun shines), which means they are not always available to meet peak demand. Because neither wind nor solar resources tend to reliably provide their full installed capacity at the peak demand hour, they receive less capacity credit.

[20] MISO 2019 Market Roadmap: https://cdn.misoenergy.org/MISO%20Market%20Roadmap194258.pdf

While renewable wind resources produce a lot of renewable energy over the course of the Planning Year, their capacity accreditation is typically a lot lower than dispatchable generation. MISO calculates the capacity which will be accredited for wind resources by calculating the resources' Effective Load Carrying Capability (ELCC). Wind resources located in MISO Zone 6 received a capacity credit of only 7.8% for MISO's 2019-2020 planning year, meaning for every 100 MWs of installed wind capacity, 7.8 MWs would count towards meeting MISO's planning reserve margin. As part of MISO's RIIA, MISO evaluated the ELCC of wind and solar resources as penetration levels increased. Renewable penetration is expected to increase as shown in Figure 5.4. Renewable penetration increasing results in the net peak load shifting. This shift results in lower renewable energy production coincidence with the net peak load and therefore a lower ELCC accreditation as seen in Figure 5-5.

Figure 5-5 Decreasing solar and wind ELCC as more is installed[21]



[21] Renewable Integration Impact Assessment (RIIA) Assumptions Document Version 6, December 2018, MISO, page 11, https://cdn.misoenergy.org/RIIA%20Assumptions%20Doc_v7429759.pdf

The solar and wind accreditation used in the IRP modeling was calculated using MISO's ELCC accreditation formulas and adjusted based upon the level of renewable penetration expected on MISOs system. As additional renewable resources were included in the model the UCAP accreditation for these resources was revised. Over time, this results in a lower accreditation value as additional resources come online.

While MISO's current methodology for determining resource adequacy only considers the summer peak, they have begun to discuss the inclusion of other seasons. Wind and solar capacity factors and energy coincidence with the net peak load vary seasonally. A Solar PV production chart comparison for the winter and summer is shown in Figure 5-6. It shows solar output has a higher coincident with peak demand in the summer months than winter months, due to not only the lower winter solar production, but also the typical peak demand occurring later in the day. These combined effects result in lower solar winter capacity accreditation. Wind resources typically have higher capacity factors during winter months leading to a higher output during winter peak demand hours. Summer and winter wind production compared to load shape are shown in Figure 5-7 gas resource or other dispatchable generation, benefits from being able to turn on and off as needed with exception to unit outages and therefore have higher capacity accreditation than non-dispatchable intermittent resources. For reference, a typical gas resource seasonal capability difference is shown in Figure 5-8.

Figure 5-6 Average Solar PV energy production summer versus winter

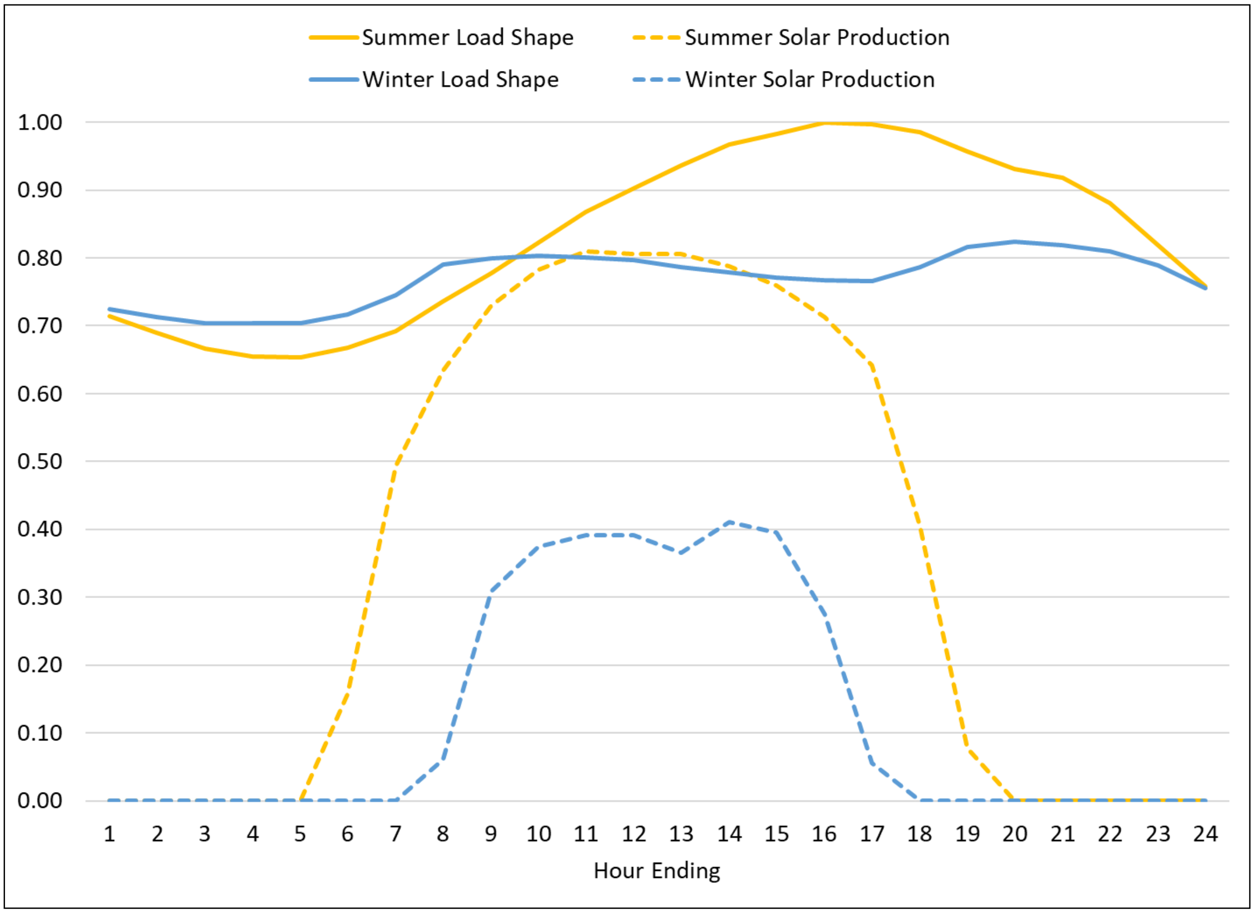


Figure 5-7 Average Wind energy production summer versus winter

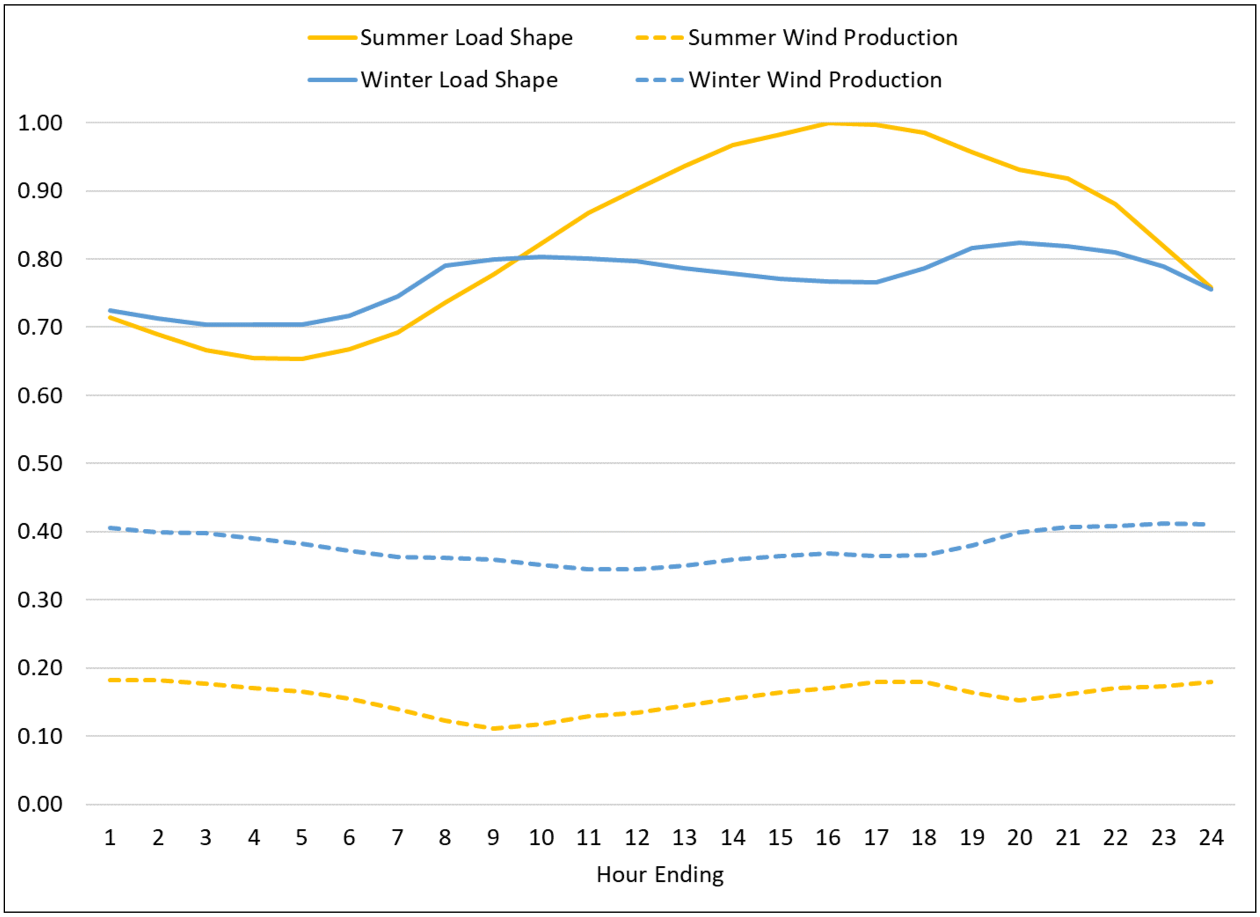
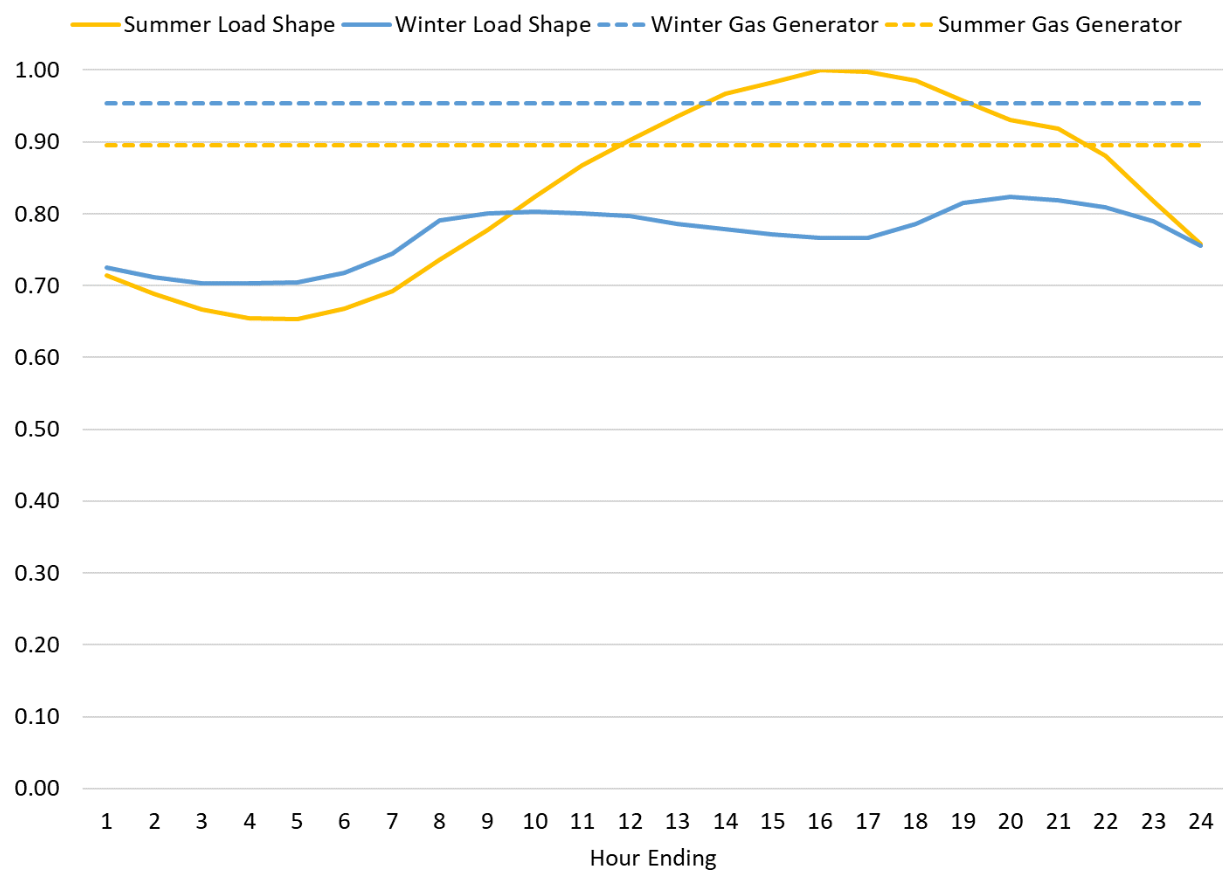


Figure 5-8 Average Gas Resource energy potential summer versus winter



MISO has already implemented seasonal coordinated maintenance schedule reporting. Additionally, MISO currently is considering implementing a seasonal construct to capacity accreditation. Based on recent MISO publications, discussions and input, this likely could be a four-season construct which is planned to be implemented as soon as 2022. Publicly posted feedback from MISO stakeholders and MISO indicated accreditation should vary by season and reflect expected availability of resources in each season. Vectren is a member of MISO and as such cannot ignore nor avoid updates to MISO's accreditation process. Vectren has utilized a conservative summer and winter capacity accreditation construct as part of this IRP as a means of preparing for this implementation.

5.8 MISO Capacity

Historically, the price for capacity in MISO's annual auction has been volatile. The Organization of MISO States (OMS), of which the IURC is a participant and MISO teamed together to better understand future resource needs. Since June of 2014, MISO and the OMS have compiled Resource Adequacy survey responses from MISO members that indicate the need for more supply and demand side resources to meet expected load. This survey has served as the main vehicle in communicating to the MISO stakeholder community the anticipated PRM for upcoming years and is a tool in determining whether additional action is needed.

Since its inaugural survey, MISO has warned that there may be inadequate capacity within the MISO footprint at some future date. OMS-MISO Resource Adequacy survey results have shown projected shortfalls for high certainty resources in the MISO region and Zone 6, which includes most of Indiana and a small portion of Kentucky. Figure 5.9 below illustrates Zone 6's increasing proportion of the entire MISO region shortfall projection and thus increased reliance on neighboring state generation resources. Over the years, the OMS and MISO have updated the methodology to project simply which resources are considered high certainty in hopes of increasing the accuracy of the projection. With these improvements in place since 2017, there is still a projected shortfall. This shortfall is concerning, especially from a zonal standpoint that shows certain zones relying heavily on other zones to meet the overall MISO capacity requirement. The latest OMS survey shows IN Zone 6 as one of the zones most at risk of a shortfall, with a deficit projected to surpass the entire MISO region's deficit. It is worth noting that since 2016 Indiana's Zone 6 has imported capacity to meet its PRMR needs. This means based on current MISO member plans and expectations, Zone 6 is expected to continue importing energy to meet a substantial amount of its needs through the year 2025, the last year of the survey period. This potential long-term reliance on the market makes Zone 6 and Vectren's customers susceptible to volatility in the auction clearing price and the resource adequacy policy and decisions of neighboring Zones. The table below demonstrates that since 2018 the MISO region has cut its projected shortfall in half, while Zone 6’s shortfall has almost doubled.

Figure 5.9 – OMS-MISO Resource Adequacy Survey Results

OMS-MISO Resource Adequacy Survey Results by Year	Zone 6 Resource Adequacy Shortfall, 5-Year Projected	MISO-wide Resource Adequacy Shortfall, 5-Year Projected
2014	No 5-year projection provided	5.8 GW shortfall in 2019
2015	1.1 GW shortfall in 2020	2.3 GW shortfall in 2020
2016	800 MW shortfall in 2021	2.6 GW shortfall in 2021
2017	400 MW shortfall in 2022	No shortfall projected
2018	1.6 GW shortfall in 2023	4.5 GW shortfall in 2023
2019	2.4 GW shortfall in 2024	2.3 GW shortfall in 2024

5.8.1 Capacity Prices

The projected capacity shortfalls can result in volatile capacity prices. MISO’s Planning Resource Auction (PRA) is held annually for each of the load zones within the MISO footprint to ensure sufficient capacity resources. The PRA has yielded a wide fluctuation in capacity pricing for Zone 6 since its inaugural year of 2013, as shown in Figure 5.10 below. These large swings in prices have made it difficult to forecast forward year prices. While the 2020-2021 capacity price was relatively low, neighboring Zone 7, which consists of the lower peninsula of Michigan reached the Cost-of-New-Entry (CONE) rate, which is approximately $257, or ~50 times higher than the $5.00 clearing price. Michigan very narrowly missed cone in the 2019-2020 planning year. Since then, MISO updated market rules to ensure only units that enter the auction will be available at the time of need, the likelihood of price increases intensifies.

Figure 5.10 – MISO Capacity Prices

Planning Year	Highest Clearing price for MISO-region	Clearing Price for Zone 6 (Indiana & Kentucky) per MW/day[22]	Clearing Price for Zone 6 (Indiana & Kentucky) per MW/year	Year-over-Year Price Change
2013-2014	$1.05	$1.05	$383.25	-
2014-2015	$16.75	$16.75	$6,113.75	1495% Increase
2015-2016	$150.00	$3.48	$1,270.20	79% Decrease
2016-2017	$72.00	$72.00	$26,280.00	1969% Increase
2017-2018	$1.50	$1.50	$547.50	98% Decrease
2018-2019	$10.00	$10.00	$3,650.00	567% Increase
2019-2020	$24.30	$2.99	$1,091.35	70% Decrease
2020-2021	$257.53	$5.00	$1,825.00	67% Increase

5.9 MISO Energy Prices

Energy prices in MISO have decreased in the last 18 months and are at all-time lows. The main driver of the price decrease is tied to the marginal generation units that set the energy price. Natural gas and renewables have shifted the marginal generation mix from coal to natural gas. Even prior to COVID-19, Natural gas prices were at historic lows, recently in the $2 range due to increased U.S. and global production and warmer than normal winter weather causing an oversupply, which has lowered the operating costs of natural gas generation. This has lowered the bids of generation in the MISO market and led to lower clearing prices as depicted below:

[22] MW/day is the amount customers are required to pay should they purchase capacity via the MISO Planning Resource Auction. For example, in the 2016-2017 planning year each MW cost $72 per day ($26,280 per MW annually).

Figure 5.11 – MISO Clearing Prices

Indiana Hub/Henry Hub Yearly Averages
2015 - YTD Apr. 2020

Year	Indiana Hub Real Time ATC Average	YoY% Change	Indiana Hub Day Ahead ATC Average	YoY% Change	Henry Hub Average	YoY% Change
YTD 2020	$21.02	-20.39%	$21.60	-19.81%	$1.83	-27.05%
2019	$26.41	-19.95%	$26.98	-18.72%	$2.51	-19.41%
2018	$32.99	12.59%	$33.19	12.97%	$3.12	5.36%
2017	$29.30	4.86%	$29.38	4.50%	$2.96	19.10%
2016	$27.94	-0.27%	$28.11	-1.94%	$2.49	-4.60%
2015	$28.02		$28.67		$2.61	

Over time, it is expected that natural gas prices will increase, but remain low and stable, keeping energy prices low.

5.10 MISO Interconnection of New Resources

Before a new generating facility can connect to the grid, the reliability impacts associated with interconnection must be studied. Issues uncovered during this process can be mitigated through electric transmission Network Upgrades (NU). The addition of upgrades to address system reliability have the potential to increase the costs associated with a new generating facility. Each of the All-Source RFP proposals were analyzed to determine its associated impacts to the transmission system as well as the associated Network Upgrade costs.

The MISO Generator Interconnection (GI) process is a three-phase study cycle that has been conducted twice annually (recent schedule is reduced to once per year) to study the impact and any associated transmission system upgrade costs as a result of new generation connecting to the MISO transmission system. Usually there is a study cycle in the 1st quarter and 3rd quarter of each year. Application and milestone payment requirements based on the size of the unit to be studied are required 45 days prior to the start of the study cycle. These two study cycles are the only two periods in which to enter the GI queue each year. Mid-year and mid-queue requests are not allowed. After all modeling details are finalized the study enters the Definitive Planning Phase (DPP). The DPP is broken into three phases that are restudies based on immaterial changes to generator attributes and the removal of projects that decide not to proceed to the next study phase. Upon completion of the third DPP, MISO and the GI requestor begin the GI Agreement (GIA) process. Upon satisfying all terms of the GIA, the GI requestor will receive a fully executed GIA that enables the generator to connect to the MISO transmission system and depending on the transmission service selected, participate and receive full accreditation in the MISO energy and capacity markets.

MISO estimates the process to take 505 days, start to finish. However, with the record amount of interconnection requests that MISO has seen in the last two years, the process is averaging over 2 and a half years per MISO’s DPP schedule update posted 3/1/2020. As increased renewable development continues in order to qualify for tax incentives before expiration, the number of GI requests is not expected to subside and as a result, the timeline is likely to remain delayed.

GI costs are determined based on the MW impact from each project on identified constrained facilities. As such, cost allocation is assigned to the generator that causes or contributes to a constraint and therefore projects that are studied after prior cycles are more likely to have additional costs identified. More simply stated, the earlier a project gets in the queue, the more likely it is to utilize any available transmission capacity at lowest cost. Conversely, projects that request studying after prior cycles are more likely to be assigned higher costs as a result of prior projects connecting to and exhausting current transmission system topology. For this reason, existing interconnection rights at the Brown site are valuable. MISO allows for an expedited process for new generation with existing interconnection rights; this helps to shield customers from potential upgrade costs should Vectren enter the MISO queue at another site.

SECTION 6
RESOURCE OPTIONS

6.1 ALL SOURCE RFP

The All-Source RFP was conducted according to the schedule outlined in Figure 6-1. More details on the steps included in the RFP timeline are described below.

Figure 6-1 RFP Timeline

Step	Completed/Proposed Date
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 10, 2019
Proposal Submittal Due Date	5:00 p.m. CDT, Friday, August 9, 2019
Initial Proposal Review and Evaluation Period	Friday, August 9, 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

6.1.1 RFP Issued

Burns & McDonnell issued the All-Source RFP on behalf of Vectren on Wednesday, June 12, 2019 (http://vectrenrfp.rfpmanager.biz/default.aspx). Notice was sent to all known IRP stakeholders and posted on www.vectren.com/IRP. The RFP was advertised across multiple media outlets, including Megawatt Daily (~20,000 recipients), North American Energy Markets Association (NAEMA) (150 members) and Midwest Energy Efficiency Alliance (MEEA) Minute (161 members). It was also sent directly via e-mail to participants of Vectren's 2017 RFP, an internal Burns & McDonnell RFP contact list (>450 industry contacts) and Vectren industry contacts. While the RFP included general requirements and communicated that Proposals which do not meet the general requirements may be subject to disqualification, all were included for evaluation. For more details please refer to the submitted Vectren 2019 All-Source RFP in Technical Appendix Attachment 6.3.

6.1.2 Notice of Intent

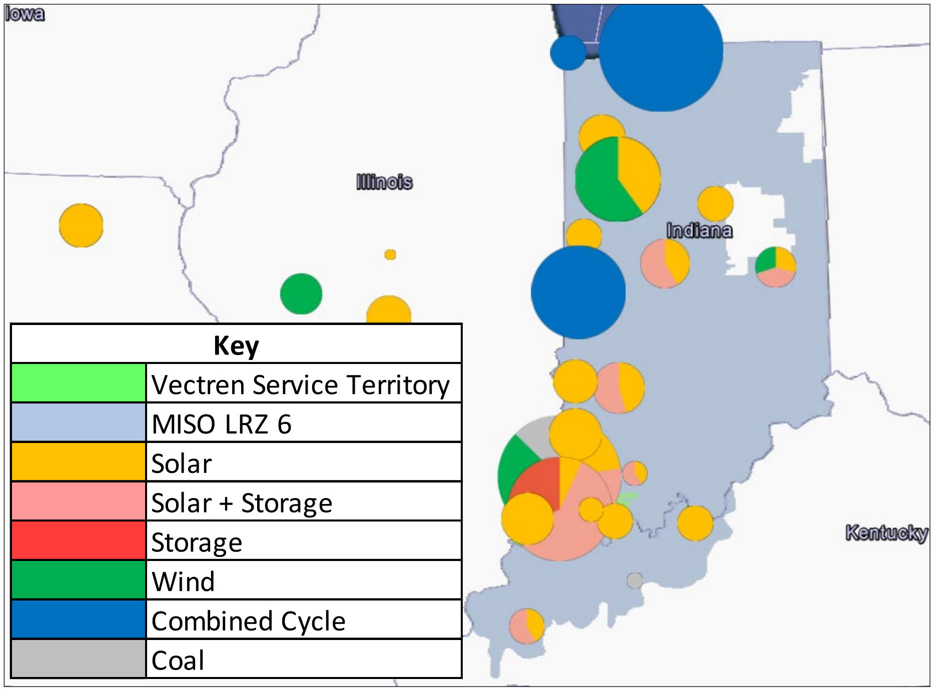
Respondents were given more than two weeks to submit a Notice of Intent to participate in the RFP process, sign the Non-Disclosure Agreement and complete the Pre-Qualification Application. The purpose of the Pre-Qualification Application is to verify that Respondents have adequate experience and financial capability to support their Proposal(s).

6.1.3 Proposal Review

The Proposal Submittal Due Date was Friday, August 9, 2019. After all Proposals had been received, Burns & McDonnell began the Initial Proposal Review. While Proposals were being reviewed, information was clarified with Respondents to confirm Proposals were interpreted as intended.

A total of 110 Proposals were received from 22 Respondents. The Proposals comprised eight battery storage, two coal, seven combined cycle gas, one LMR/DR, 57 solar, 19 solar plus storage, three system energy and 13 wind. Of the 110 Proposals, 91 were in Indiana. The Proposals contained approximately 21 GW of total installed capacity; however, many of the projects were included in multiple proposals. There was approximately 10 GW of unique project installed capacity after accounting for double counting. For example, a single 100 MW wind farm project could be offered as a purchase option or various PPA options. A graphical overview of all Proposals received is shown in Figure 6-2.

Figure 6-2 Map of Proposals Received



6.1.4 MISO Interconnection

The appropriate MISO DPP Generation Interconnection Study Group was identified for each of the respective Proposals. For the Proposals that reside in Study Groups with posted DPP reports, the identified NU and associated costs were used.

For the proposals that reside in Study Groups without posted DPP reports, Burns & McDonnell performed a steady state analysis using the appropriate DPP Study Group cases and auxiliary files. These selections were evaluated against the impact criteria defined in Section 6.1.1.1.8 of MISO's BPM-015 (Business Practices Manual), including the cumulative impact criteria.

Finally, for those selections that have not entered the queue or did not have a DPP Study Group case available, the most recent DPP Study Group case was used for the evaluation. The same impact criteria were applied with the exclusion of the cumulative impact criteria.

Figure 6-3 - RFP Project Definitive Planning Phase (DPP) Study Groups

Number of RFP Projects in DPP Study Group	Study Group	Network Upgrade (NU) Cost From:	Burns and McDonnell Action:
1	DPP-2016-FEB Central	MISO DPP Report	1. Review Reports for total NU Costs; 2. Confirm Generator Interconnection Requests (GIRs) sharing allocations are active.
1	DPP-2016-AUG Central	MISO DPP Report	1. Review Reports for total NU Costs; 2. Confirm GIRs sharing allocations are active.
4	DPP-2017-FEB Central	MISO DPP Report	1. Review Reports for total NU Costs; 2. Confirm GIRs sharing allocations are active.
10	DPP-2017-AUG Central	MISO DPP Report	1. Review Reports for total NU Costs; 2. Confirm GIRs sharing allocations are active.
5	DPP-2018-APR Central	MISO DPP Report	1. Review Reports for total NU Costs; 2. Confirm GIRs sharing allocations are active.
1	DPP-2018-APR West	Project Group Analysis	1. Perform Project Group analysis to determine potential NU costs for ERIS analysis; 2. Allocate costs to GIRs based on full reconductor/replacement cost estimates.
18	DPP-2019-Cycle1 Central	Project Group Analysis	1. Perform Project Group analysis to determine potential NU costs for ERIS analysis; 2. Allocate costs to GIRs based on full reconductor/replacement cost estimates.

For any impacts reported, without any information on the limitation of the facility, Burns & McDonnell assumed a full rebuild scope and cost of the facility. NU costs for the reported impacts were developed using MISO's MTEP transmission cost estimation guide. These NU costs were considered for the evaluation of each proposal. Many Proposals included allowances for NU costs or indicated all NU were included in their Proposal and these nuances were accounted for during the analysis.

6.1.5 Grouping

Proposals were divided into groups based on characteristics such as technology type, ownership structure and contract duration. Aggregated cost and performance information from the RFP Proposals was provided to the IRP team to facilitate portfolio modeling. There are many benefits to modeling the RFP bids in Groups. These benefits include allowing the IRP modeling to help evaluate the technology, size, duration and mix of resources which would be included in the Preferred Portfolio. Given the volume of proposals received as part of the IRP, it may not have been possible and would not have been practical to model each individual project. Moreover, it would be difficult to maintain confidentiality of individual projects. IRP modeling of individual projects does not holistically evaluate all relevant factors, such as locational differences of wholesale market pricing and potential congestion impacts. Using a grouping method allows for IRP inputs to reflect anticipated project costs.

Proposals were divided into two tiers, based on factors that could add cost risk to Vectren customers. Tier 1 Proposals were those that included binding pricing and delivery of energy to SIGE.SIGW (Vectren's load node) or were physically located in Vectren's service territory. Tier 2 included the remaining Proposals that were not classified as Tier 1. Tier 2 Proposals generally did not provide a binding bid price and/or were located off Vectren's system, which increases cost risk due to congestion. Despite these risks, several were still analyzed and considered during the RFP evaluation process; however, Vectren wanted, to the extent possible, to include bids with more price certainty within the IRP modeling in order to protect customers from price volatility.

Seventeen (17) groups were formed. This resulted in data from 49 Tier 1 Proposals being used in IRP analysis. A summary of the Proposal grouping is shown in Figure 6-4. As seen in Figure 6-4, the energy-only Proposals were not put into a group because they did not meet the capacity requirement of the RFP. Due to a high quantity of bids in the group and to provide additional granularity in IRP modeling, groups 15 and 17 were split into high and low-cost groups.

Figure 6-4 Proposal Grouping

Grouping		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**

The costs for Tier 1 Proposals are outlined in Figure 6-5. Costs were not shown for groups that contained only one project to ensure confidentiality.

Figure 6-5 - Tier 1 Cost Summary[23]

	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	1	1	50	50		
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

6.1.6 Evaluation of Proposals

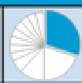
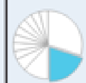
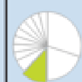
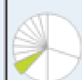
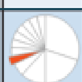
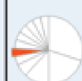
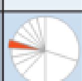
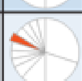
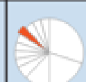
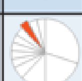
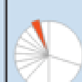
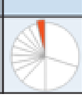
Burns & McDonnell quantitatively and qualitatively evaluated all conforming generation facility Proposals. Proposals were evaluated relative to others within the same grouping

[23] Note that proposals based on one project do not include capacity weighted Average LCOE or Capacity Weighted Purchase Price to maintain confidentiality of the bid.

using the scoring criteria set forth in the RFP. The scoring criteria included four major categories: LCOE, energy settlement location, interconnection/development status and local clearing requirement and project risk factors.

Scoring of the individual RFP Proposals was not part of the IRP process. Scoring criteria has been provided for transparency to respondents and to demonstrate that Vectren is serious about pursuing projects following the completion of the IRP analysis. Vectren does not believe that RFP's should be conducted just to obtain market data. The Proposals were scored to aid in the selection process after the preferred portfolio results were provided from the IRP. The Proposals were scored according to the criteria shown in Figure 6-6.

Figure 6-6 Scoring 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) Completed a MISO Facilities Study (12 points) Completed a MISO System Impact Study (12 points) Achieved site control and completed zoning requirements (12 points) 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.
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.

RFP bids were rank ordered consistent with the evaluation criteria and will be considered based on the RFP evaluation and the IRP determined need. Projects consistent with the

IRP have undergone further due diligence and have led to negotiations with bidders. As such, there is no assurance that the individual, highest-scoring qualified Proposal(s) will be selected. For further discussion of the evaluation criteria and results see Technical Appendix 6.9.

6.1.7 Challenges with Conducting an All-Source RFP within an IRP

While there are advantages to conducting an All-Source RFP as part of the IRP process, there are several challenges that must be considered, particularly the long lead time. Developers prefer certainty on project selection to minimize project development cost risk. Conducting an RFP as an input to the IRP necessitates a long process. Vectren believes that, at a minimum, a year is needed to conduct an IRP analysis. While Vectren asked bidders to keep bids open for a year after bid submittal, this does not mean that developers are able to wait until the process is complete.

As a result, some bids were withdrawn from Vectren’s RFP during the IRP because the projects were acquired by other load serving entities. This delay has hurt the ability to act on proposals before they are acquired. During this IRP, at least one project, was purchased by another utility. Competition for projects in MISO zone 6 is steep with many utilities (NIPSCO, IPL, Hoosier Energy, IMPA and Vectren) currently all vying for announced projects that have more certainty of being developed.

Vectren has also had several attractive local wind and solar projects drop out of the MISO Generation Interconnection queue due to commitments/costs required from interconnection studies and they are no longer available at this time. Often projects are speculative. Developers apply with MISO to develop a project and are put in the MISO queue, as a series of studies is conducted. Each study requires more money from the developer in the form of milestone payments. Early studies put less money at risk for the developer. As interconnection costs for a project are identified the developer must make a choice to stay in the queue or drop out. Without certainty of an off taker, many projects drop. Long lead times increase this risk.

Additionally, some initial cost estimates have proved to be too low. As a project moves along, several issues can arise, including: updated engineering identifying new costs, environmental permitting, local pushback, local permitting, updated interconnection costs, updated risk assessments by the developers, etc.

6.2 CURRENT RESOURCE MIX

Generating units are often categorized as either base load, intermediate, or peaking units. This characterization has more to do with the economic dispatch of the units and how much service time they operate rather than unique design characteristics, outside of intermittent renewables, which do not have variable fuel costs. Base load units generally have the lowest energy costs per kWh and tend to operate most of the time, thereby providing the base of the generating supply stack after intermittent renewables, which operate as available and typically unrelated to market prices and conditions. The supply stack is the variable cost of production of power by each generating unit, stacked from least cost to most cost. In general, units that cost less to run are dispatched before units that cost more. Vectren's larger coal units have historically operated as base load units but with low natural gas prices and the introduction of more renewables into the market, capacity factors have decreased. Vectren's coal units more recently have operated more like intermediate units, particularly in shoulder months during Spring and Fall seasons. Intermediate units may cycle on and off frequently and may sit idle seasonally. Vectren's current peaking units have relatively high energy costs per kWh and are typically only started when energy demand exceeds 24/7 baseload capacity. Currently, Vectren's gas turbines are dispatched during these peak periods to assure reliability. These small peaking units may only run for a few hours and remain idle for long periods of time until called on.

Vectren's current generation mix consists of approximately 1,280 megawatts (MW) of installed capacity. This capacity consists of approximately 1,000 MW of coal-fired generation, 160 MW of gas fired peaking generation, 3 MW of renewable landfill gas generation, 4 MW of solar, Purchase Power Agreements (PPA's totaling 80 MW from wind) and a 1.5% ownership share of Ohio Valley Electric Corporation (OVEC) which equates to approximately 32 MW.

Figure 6.7 below references both Installed Capacity (ICAP) and Unforced Capacity (UCAP). Installed capacity is also referred to as nameplate capacity. This is the maximum output that can be expected from a resource. Unforced capacity is the amount of capacity that can be relied upon to meet peak load. MISO uses UCAP for planning purposes. The UCAP accreditation recognizes that all resources are not equally reliable or, in some cases, capable of achieving their design output. MISO uses a three-year reliability history and a weather normalized capability verification to determine the UCAP accreditation of each unit. Vectren used historical data and MISO's current methodology for thermal units to determine seasonal accreditation values along with the MISO UCAP planning reserve margin requirements (8.9% PRM[24]) in the current IRP. This information was utilized to help ensure that all portfolios met MISO obligations on a seasonal basis.

Figure 6.7 – Vectren Generating Units

Unit	Installed Capacity ICAP (MW)	Summer Unforced Capacity UCAP (MW)	Winter Unforced Capacity UCAP (MW)	Primary Fuel	Year Unit First In-Service
A.B. Brown 1	245	197	235	Coal	1979
A.B. Brown 2	245	232	221	Coal	1986
F.B. Culley 2	90	85	84	Coal	1966
F.B. Culley 3	270	261	263	Coal	1973
Warrick 4	150	133	137	Coal	1970
A.B. Brown 3	80	73	90*	Gas	1991

[24] Planning Year 2020-2021 Load of Load Expectations Report; MISO; https://cdn.misoenergy.org/2020%20LOLE%20Study%20Report397064.pdf; 11/01/2019; page 5

Unit	Installed Capacity ICAP (MW)	Summer Unforced Capacity UCAP (MW)	Winter Unforced Capacity UCAP (MW)	Primary Fuel	Year Unit First In-Service
A.B. Brown 4	80	72	82*	Gas	2002
Blackfoot	3	N/A[25]	N/A[26]	Landfill Gas	2009
Oak Hill Solar	2	N/A[22]	N/A[25]	Sun	2018
Volkman Road Solar	2	N/A[25]	N/A[25]	Sun	2018

*Installed capacity shown at 59°F, winter UCAP shown at 20°F

6.2.1 Coal

The A.B. Brown Generating Station (ABB), located in Mt. Vernon, IN, consists of two coal fired units, each with an installed capacity of 245 MW. ABB Unit 1 began commercial operation in 1979, while ABB Unit 2 became operational in 1986. Over the last three years these units have operated at an average capacity factor of 53%.

Both A.B. Brown units are scrubbed for sulfur dioxide (SO_2) emissions, utilizing a dual-alkali Flue Gas Desulfurization (FGD) process. The FGD systems were included as part of the original unit design and construction. Sulfur trioxide (SO_3) is removed via Sodium Based Sorbents (SBS) injection systems installed on both units in 2015. ABB is also scrubbed for nitrogen oxides (NO_x) with Selective Catalytic Reduction (SCR) systems having been installed on Unit 2 in 2004 and on Unit 1 in 2005. Mercury (Hg) removal is accomplished on both units as a co-benefit of SCR and FGD operations as well as through the addition of organosulfide injection systems installed in 2015. Particulate matter (PM) is captured via an electrostatic precipitator (ESP) on Unit 2. PM control at Unit 1 was upgraded to a fabric filter in 2004. The PM that is captured, also known as fly

[25] The Blackfoot landfill gas generator and 2 MW solar installations are connected at the distribution level and are not part of the transmission connected generation network managed by MISO. Therefore, they are not assigned a MISO UCAP value.

ash, is part of Vectren's beneficial reuse program and is shipped, via barge, to a facility near St. Louis, MO where it is used in the manufacture of cement.

While the A.B. Brown units began commercial operation after the Culley units, the dual-alkali scrubbers on these units present several operational challenges. First, based on historical costs the variable production cost associated with the scrubbers is approximately six times greater than the limestone-based scrubber installed on the Culley units. Also, the dual-alkali process is corrosive which results in high maintenance costs to keep the FGD's and associated equipment operational. And finally, these FGD's are the last dual-alkali scrubbers in operation in the U.S. and are nearing the end of their useful life. This can lead to challenges obtaining operational support and replacement parts when needed.

A.B. Brown Units 1 and 2 burn Illinois basin bituminous coal, which is mined in Knox County, IN and is delivered via rail.

The A.B. Brown plant site also has two natural gas turbine generators which are discussed in Section 6.2.2, Natural Gas.

The F.B. Culley Generating Station (FBC), located near Newburgh, IN, is a two-unit, coal fired facility. FBC Unit 2 has an installed generating capacity of 90 MW and came online in 1966, while FBC Unit 3 has an installed capacity of 270 MW and became operational in 1973. Over the last three years Unit 2 has operated at an annual capacity factor of 23% while Unit 3 was 65%.

FBC is scrubbed for Sulfur Dioxide (SO_2) emissions, utilizing an FGD process which is shared by both units and was retrofitted in 1994. This standard technology is much more cost effective than A.B. Brown's scrubber. The captured SO_2 is converted into synthetic gypsum within the system and, as part of Vectren's beneficial reuse program, is shipped, via barge, to a facility near New Orleans, LA and is shipped via truck to a facility near

Shoals, IN where it is used in the manufacture of drywall. Sulfur trioxide (SO_3) is removed from FBC Unit 3 via a Dry Sorbent Injection (DSI) system installed in 2015. FBC Unit 3 is also scrubbed for NO_x with a Selective Catalytic Reduction (SCR) system that was installed in 2003. NO_x control on FBC Unit 2 is provided by low NO_x burners. Mercury removal is accomplished on both units as a co-benefit of SCR & FGD operation as well as through the addition of organosulfide injection systems installed in 2015. PM is captured via an ESP retrofitted on Unit 2 in 1972. Unit 3 was upgraded to a fabric filter for PM control in 2006. The PM that is captured, also known as fly ash, is part of Vectren's beneficial reuse program and is shipped, via barge, to a facility near St. Louis, MO where it is used in the manufacture of cement.

The F.B. Culley units burn Illinois basin bituminous coal, which is mined in Knox County, IN and delivered via truck. F.B. Culley 3 is Vectren's most efficient coal unit with an industry standard scrubber, which has much lower variable costs than ABB1 and ABB2. As such F.B. Culley 3 is in the process of upgrades to comply with EPAs ELG rule.

Warrick Unit 4 (Warrick) located near Newburgh, IN is a coal fired unit operated and maintained by Alcoa Power Generating Inc. Vectren maintains 50% ownership of Warrick Unit 4. It has an installed capacity of 300 MW which began commercial operation in 1970. Vectren's 50% interest is equal to 150 MW. Over the last three years this unit has operated at a capacity factor of 62%.

Warrick Unit 4 is scrubbed for SO_2 emissions, utilizing a FGD process which was retrofitted in 2009. The captured SO_2 is converted into synthetic gypsum within the system and (as part of Vectren's beneficial reuse program) is shipped via truck to a facility near Shoals, IN where it is used in the manufacture of drywall. SO_3 is removed via a DSI system installed in 2010. Unit 4 is also scrubbed for NO_X with a SCR system which was retrofitted in 2004. Mercury removal is accomplished as a co-benefit of SCR and FGD operation as well as through the addition of organosulfide injection systems installed in 2015. PM is captured via an ESP. The PM that is captured, also known as fly ash, is part of Vectren's beneficial reuse program and is shipped, via barge, to a facility near St. Louis, MO where it is used in the manufacture of cement.

Warrick Unit 4 burns Illinois basin bituminous coal. Vectren purchases coal for its share of Warrick Unit 4, which is mined in Knox County, IN and is delivered by rail.

6.2.2 Natural Gas

The A.B. Brown Generating Station has two natural gas fired Simple Cycle Gas Turbine (SCGT) peaking units. Each has an installed capacity of 80 MW. ABB Unit 3 began commercial operation in 1991, while ABB Unit 4 became operational in 2002. Over the last three years Unit 3 has operated at a capacity factor of 1% with Unit 4 at 2%.

6.2.3 Renewables

The Blackfoot Clean Energy Facility located in Winslow, IN is a base load facility consisting of two Internal Combustion (IC) landfill methane gas fired units. Blackfoot Units 1 & 2 became operational in 2009 and are capable of producing 1.5 MW each. Over the last three years these units have operated at a capacity factor of 42%.

The Oak Hill and Volkman Road universal solar projects in Evansville, IN became operational in 2018 with each location having an installed solar capacity of 2 MW. In addition to the solar capacity the Volkman Road site includes 1 MW of battery storage. These assets are located on the distribution system and are therefore netted out of Vectren load for this analysis. In 2019 the solar installations operated at an average annual capacity factor of 21%. The average annual capacity factor is affected by hours of daylight, cloud cover, temperature, etc. This installation was available over most hours in 2019.

A third solar facility is under development near Troy, IN and will have an installed capacity near 50 MW. It is expected to be operational in early 2021.

6.2.4 Energy Efficiency

Vectren utilizes a portfolio of Demand Side Management (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 Commission and implemented pursuant to various IURC orders over the years.

Since 1992, Vectren 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. A description of the program is included below. While this technology can still be reliably counted on to help lower demand for electricity at times of peak load, 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. Between 2010 and 2018, Vectren's DSM programs reduced demand by approximately 69,000 kW and provided annual incremental gross energy savings of approximately 360,000,000 kWh.

The table below outlines the estimated program penetration on a yearly basis since Vectren programs began in 2010. Gross cumulative savings below, are shown as a percent of eligible retail sales. Note that historical DSM savings are implicitly included in the load forecast as these savings are embedded in the historical sales data.

Figure 6.8 Gross Cumulative Savings

Year	Eligible Retail Sales (GWh)	Gross Cumulative Savings (GWh) *	Gross Cumulative Savings (GW) *	Percent of Sales Achieved (Cumulative)
2010	5,616.87	2.53	.00051	0.04%
2011	5,594.84	19.40	.00331	0.35%
2012	5,464.75	66.95	.01212	1.23%
2013	5,459.11	128.64	.02271	2.36%

Year	Eligible Retail Sales (GWh)	Gross Cumulative Savings (GWh) *	Gross Cumulative Savings (GW) *	Percent of Sales Achieved (Cumulative)
2014**	3,498.69	175.98	.03053	5.03%
2015	3,223.81	202.82	.03552	6.29%
2016	3,256.3	236.40	.04336	7.26%
2017	3,280.7	268.86	.05005	8.20%
2018	3,490.7	309.28	.05759	8.86%

*Gross Cumulative Savings are adjusted for Residential Behavioral, which has a one-year program life therefore not cumulative in nature.

**Statewide DSM programs ended in 2013. The drop in eligible sales is attributed to industrial customers opting-out of DSM programs effective July 1, 2014.

6.2.4.1 2018-2020 Plan Overview

Consistent with the 2016 IRP, the framework for the 2018-2020 EE Plan was modeled at a savings level of 1% of retail sales adjusted for an opt-out rate of 77% of eligible load. Below is a listing of residential and commercial & industrial programs offered in 2018-2020. For full program descriptions including the customer class, end use of each program and participant incentives provided by the programs, please refer to the 2018-2020 EE Plan detail found in the Technical Appendix Attachment 6.2 Vectren Electric 2018-2020 DSM Plan.

Residential Programs

- Residential Lighting
- Home Energy Assessments and Weatherization
- Income Qualified Weatherization
- Appliance Recycling
- Energy Efficient Schools
- Residential Prescriptive
- Residential New Construction
- Residential Behavior Savings
- Residential Smart Thermostat Demand Response (Incentives only)
- Bring Your Own Thermostat (BYOT)

- Food Bank – LED Bulb Distribution
- Conservation Voltage Reduction (CVR) Residential

Commercial & Industrial Programs

- Small Business Direct Install
- Commercial & Industrial Prescriptive
- Commercial & Industrial New Construction
- Commercial & Industrial Custom
- Building Tune-Up
- Multi-Family Retrofit
- Conservation Voltage Reduction - Commercial

The 2018-2020 plan was included an existing resource in the 2019/2020 IRP and has an assumed average measure life of 12 years. The table below shows the amount of net savings included in the IRP as a resource (gross savings can be found in Technical Appendix Attachment 6.2 Vectren Electric 2018-2020 DSM Plan).

Figure 6.9 2018-2020 Energy Efficiency Savings

	2018*		2019**		2020***	
Sector	Net MWh Energy Savings	Net MW Demand Savings	Net MWh Energy Savings	Net MW Demand Savings	Net MWh Energy Savings	Net MW Demand Savings
Residential	19,241	4.0	19,129	4.0	15,821	4.7
Commercial & Industrial	21,602	3.2	16,495	3.4	16,208	1.7
Total	40,843	8.5	35,624	7.4	32,029	6.4

* 2018 Evaluation Results used for 2018
** 2019 Operating Plan used for 2019 savings and Net to Gross (NTG) Factors
*** 2018-2020 Filed Plan used for 2020 Savings and NTG Factors

6.2.5 Demand Response

Vectren's tariff currently includes two active demand response programs: 1) the Direct Load Control and 2) interruptible options for larger customers. Demand response programs allow Vectren to curtail load for reliability purposes. Vectren's tariff also includes a MISO demand response tariff, in which no customers are currently enrolled given the absence of an active demand response program within the MISO market at this time.

6.2.5.1 Current DLC (Summer Cycler)

The DLC program provides remote dispatch control for residential and small commercial air conditioning, electric water heating and pool pumps through radio-controlled load management receivers. Under the program, Vectren compensates customers in exchange for the right to initiate events to reduce air-conditioning and water-heating electric loads during summer peak hours. Vectren can initiate a load control event for several reasons, including: to balance utility system supply and demand, to alleviate transmission or distribution constraints, or to respond to load curtailment requests from MISO.

Vectren manages the program internally and utilizes outside vendors for support services, including equipment installation and maintenance. Prospective goals for the program consist of maintaining load reduction capability and program participation while achieving high customer satisfaction. Vectren also utilizes an outside vendor, The Cadmus Group, to evaluate the DLC program and provide unbiased demand and energy savings estimates.

In 2020 Cadmus predicted that the DLC Program was capable of generating approximately 8.3 MWs of peak demand savings from residential air-conditioning load control and residential water heating load control. This is roughly half of prior predictions, which were used for IRP modeling.

Until recently, DLC switches have been the default choice for residential load control programs. Vectren has had a DLC program since the early 1990’s and as of 2019 had approximately 21,000 residential customers with 27,000 switches participating in the program. However, with the advent of smart thermostats and the myriad of benefits they offer for both EE and DR, Vectren plans to begin replacing DLC switches with smart thermostats.

6.2.5.2 Current Interruptible Load

Vectren makes available a credit for qualified commercial and industrial customers to curtail demand under certain conditions. Vectren included three customers who were participating for a total demand reduction of 35 MW. New MISO testing requirements are currently being put into place to ensure these DR resources are available throughout the year. MISO is proposing interruptible resource accreditation based on the amount of interruptions and available hours to curtail. MISO has already implemented mandatory annual testing for the first time that will require load interruptions to meet the test requirements. Prior to January 31, 2019, Vectren had never been requested by MISO to deploy LMRs, thereby interrupting customer load. Because of these changes that will now require annual interruptions that are likely to increase in occurrence and duration, Vectren expects some, if not all, of its currently enrolled customers to drop out, as frequent interruptions in service can be very costly to industrial customers' operations. Since implemented, one customer (~7MWs) has left the program. While aggressive, Vectren maintained industrial interruptible load at the 35 MWs within the model throughout the analysis period. Given Vectren's mix of industrial customers, it is unlikely that new customers will sign up for this program. As such, Vectren did not allow the model to select additional interruptible DR.

6.2.5.3 Smart Thermostats

Vectren launched its pilot Smart Wi-Fi Thermostat program in 2016, by installing 2,000 smart Wi-Fi enabled thermostats in homes in its service territory. As an alternative to DLC switches, smart thermostats can optimize heating and cooling of a home to reduce energy usage and control load while learning from occupant behavior/preference, adjusting Heating, Ventilation and Air Conditioning ("HVAC") settings. Preliminary evaluation results are showing significantly more load reduction delivered by smart thermostats. The current DLC switch program is a well-established means for Vectren to shed load during peak demand; however, over time, this option is will become obsolete. As such, Vectren has designed a program to change out from switches to smart Wi-Fi thermostats, a strategic option for cost effective load control. The Smart DLC Change-out program will focus on residential single-family homes and apartment dwellers. 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. This change out program is reflected in IRP modeling.

Additionally, Vectren also launched the Bring your Own Thermostat (BYOT) program as a demand response program. The BYOT program is a further expansion of the Residential Smart/Wi-Fi thermostat initiative. The 2018-2020 Plan provides for 240kW demand each year from the BYOT program based on 400 participants each year. BYOT allows customers who have or will purchase their own device from multiple potential vendors to participate in DR and other load curtailing programs managed through the utility. 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. BYOT allows the utility to avoid the costs of hardware, installation and maintenance associated with transitioning to a smart thermostat. 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. Smart thermostat DR programs provide approximately 0.6 kW - 1 kW per thermostat in load reductions during a DR event.

6.3 POTENTIAL FUTURE OPTIONS MODELING ASSUMPTIONS

Vectren utilized the All-Source RFP for modeling inputs through 2024 for wind, solar, solar + storage resources, (Tier 1 bids) as shown in Figure 6.5. The following supply side information was based on a technology assessment from Burns and McDonnell unless otherwise noted and was used to help provide needed information to model other resources where Vectren did not receive a Tier 1 bid and for resources in future years and utilizing the cost curve information in Figure 6.21.

6.3.1 Supply Side

Resources are typically divided into supply side and demand side resources. Supply side simply means resources that produce energy.

6.3.1.1 Coal Technologies

Coal power plants, also known as Pulverized Coal (PC) steam generators, are characterized by pulverizing coal, then burning the coal in a boiler to create heat. The heat from the boiler is then used to turn water into high pressure steam which is used to turn the turbine causing the generator to create electricity.

The power industry typically classifies conventional coal fired power plants as subcritical, supercritical and ultra-supercritical based on the steam operating pressure. Subcritical units operate below the critical point of water, which is 3208 psia and 705°F, supercritical units operate above the critical point of water. Ultra-supercritical units operate at even higher pressures or temperatures in order to increase efficiency. While efficiency is increased, higher grade and thicker materials must be used, which increase costs.

Proposed greenhouse gas (GHG) regulations for new construction will limit CO_2 emissions to 1,100 lbs./MWh, a level which would require carbon capture on PC plants. Carbon capture on PC plants has been demonstrated in the field and as the technologies mature, they will likely become more technically and financially feasible, especially if markets emerge for the captured gases. See Figure 6-10 for further details on the coal technologies evaluated.

Figure 6-10 – Coal Technologies

Coal		
Operating Characteristics and Estimated Costs	**Supercritical Pulverized Coal with Carbon Capture**	**Ultra-Supercritical Pulverized Coal with Carbon Capture**
Base Load Net Output (MW)	506	747
Base Load Net Heat Rate (HHV Btu/kWh)	11,290	10,480
Base Project Costs (2019$/kW)	$6,370	$5,760
Fixed O&M Costs (2019$/kW-year)	$29.10	$29.10

6.3.1.2 Natural Gas Technologies

6.3.1.2.1 Simple Cycle Gas Turbines (Combustion Turbines or CT)

SCGT utilize natural gas to produce power. The gas turbine (Brayton) cycle is one of the most efficient cycles for the conversion of gaseous fuels to mechanical power or electricity. Typically, SCGTs are used for peaking power due to fast load ramp rates, higher heat rates compared to other technologies and relatively low capital costs. See Figure 6-11 for further details on the simple cycle gas turbine technologies evaluated.

To aid in the evaluation of SCGT, technology estimates were developed to represent the natural gas pipeline costs to supply firm gas service to the unit. Estimates were developed for firm gas supply (as opposed to interruptible) because MISO has signaled that while summer peak hours are important all hours of the year matter and a dispatchable resource needs to be available for service when needed by the system. The A.B. Brown site was used for this analysis. It is an existing brownfield site with interconnection rights through MISO. The cost estimates were developed in partnership with a potential service provider, Texas Gas.

Figure 6-11 – Simple Cycle Gas Turbine Technologies

Simple Cycle Gas Turbines					
Operating Characteristics and Estimated Costs	**1xLM 6000 SCGT**	**1xLMS 100 SCGT**	**1xE-Class SCGT**	**1xF-Class SCGT**	**1xG/H-Class SCGT**
Base Load Net Output (MW)	41.6	97.2	84.7	236.6	279.3
Base Load Net Heat Rate (HHV Btu/kWh)	9,280	8,895	11,527	9,928	9,311
Base Project Costs (2019$/kW)	$2,230	$1,660	$1,470	$730	$810
Fixed O&M Costs (2019$/kW-year)[27]	$36.28	$16.04	$21.46	$8.32	$8.02

6.3.1.2.2 Combined Cycle Gas Turbines

Combined Cycle Gas Turbines (CCGT) utilize natural gas to produce power in a gas turbine which can be converted to electric power by a coupled generator and to also use the hot exhaust gases from the gas turbine to produce steam in a Heat Recovery Steam Generator (HRSG). This steam is then used to drive the steam turbine and generator to produce electric power. Using both gas and steam turbine (Brayton and Rankine) cycles in a single plant results in high conversion efficiencies and low emissions. Additionally, natural gas can be fired in the Heat Recovery Steam Generator (HRSG) to produce additional steam and associated output for peaking load, a process commonly referred to as duct firing.

For this assessment, a 1x1 F class and G/H class, as shown in Figure 6-12, were evaluated with General Electric (GE) turbines as representative CCGT technologies. The F class is based on the GE 7F.05 turbine and the G/H class is based on the GE HA.01 turbine. A 1x1 CCGT is configured with one gas turbine and one steam turbine. Vectren did not model a large 2x1 CCGT. See Figure 6-12 for further details on the CCGT technologies evaluated.

[27] The cost for firm gas supply was included in this analysis but isn't included in the Fixed O&M Costs

Figure 6-12 – Combined Cycle Gas Turbine Technologies

Combined Cycle Gas Turbines		
Operating Characteristics and Estimated Costs[28]	**1x1 7F.05 CCGT (ABB)**	**1x1 7HA.01 CCGT (ABB)**
Duct-Firing	Fired	Fired
Base Load (24/7 Power) Net Output (MW)	365	420
Incremental Duct-Fired (Peaking) Net Output (MW)	72	79
Base Load Net Heat Rate (HHV Btu/kWh)	6,460	6,247
Incremental Duct-Fired Heat Rate (HHV Btu/kWh)	8,269	8,221
Base Project Costs (2019$/Fired kW)	$1,153	$1,087
Fixed O&M Costs (2019$/Base Load kW-year)[29]	$13.99	$15.94

6.3.1.3 Renewables Technologies

Four renewable technologies were evaluated in the IRP. Those technologies were wind energy, solar photovoltaic, hydroelectric and waste-to-energy.

6.3.1.3.1 Wind

Wind turbines convert the kinetic energy of wind into mechanical energy. Typically, wind turbines are used to pump water or generate electrical energy which is supplied to the grid. See Figure 6-13 for further details on the variety of wind technologies evaluated. Beyond the RFP bids, the following assumptions were based on the Burns and McDonnell tech assessment.

[28] Combined cycle gas turbines are shown as fired configuration at A.B. Brown site for this table.
Reference the Technology Assessment for additional details on duct-firing
Operational and cost estimates developed by Black & Veatch
[29] The cost for firm gas supply was included in this analysis but isn't included in the Fixed O&M Costs

Figure 6-13 – Wind Renewables

Operating Characteristics and Estimated Costs[30]	Wind (Southern Indiana)	Wind (Northern Indiana)	50 MW Wind (Indiana) & 10 MW / 40 MWh Storage
Base Load Net Output (MW)	200	200	50
Base Project Costs (2019$/kW) / ($/kWh for Storage)	$1,450	$1,450	$1,800 / $650
Fixed O&M Costs (2019$/kW-year)	$40.00	$40.00	$44.14
Variable O&M Costs (2019$/MWh)	Included in FOM	Included in FOM	$14.50 (Storage MWh Only)
Variable O&M Costs (2019$/MWh)	Included in FOM	Included in FOM	$14.50 (Storage MWh Only)
Annual Capacity Factor	28%	38%	

The Production Tax Credit (PTC) is a tax credit per-kilowatt-hour (kWh) for electricity generated by qualified energy resources. The duration of the credit is 10 years after the in-service date for all facilities placed in service after August 8, 2005. The tax credit is $0.015 per kWh in 1993 adjusted by inflation adjustment factor provided by the IRS and rounded to the nearest 0.1 cents. Vectren assumed 2.2% past 2019 IRS values, which was the general inflation used throughout the IRP. The tax credit is phased down by 20 percent per year for wind facilities commencing construction after December 31, 2016. The tax credit reduces from 100 percent for wind facilities commencing construction in 2016 and before, down to 60 percent for wind facilities commencing construction in 2019. See Figure 6-14 below for the percent of production tax credit. For purposes of the IRP, Vectren applied the PTC as if the commence construction was one year prior to the commercial operation date. Modeling assumed a safe harbor assumption of two years PTC extension for generic wind builds.

[30] Based on average of Burns and McDonnell, Pace, and NREL technology assessment information where available.

Figure 6-14 –Production Tax Credit by Year

Commence Construction (Prior to)	Production Tax Credit (%)
2017	100%
2018	80%
2019	60%
2020	40%
2021	60%*
2022	0%
2023	0%

*PTC Extended

6.3.1.3.2 Solar

The conversion of solar radiation to useful energy, in the form of electricity, is a mature concept with extensive commercial experience that is continually developing into a diverse mix of technological designs. Solar conversion technology is generally grouped into solar photovoltaic (PV) technology, which directly converts sunlight to electricity due to the electrical properties of the materials comprising the cell.

Photovoltaic (PV) cells consist of a base material (most commonly silicon), which is manufactured into thin slices and then layered with positively and negatively charged materials. At the junction of these oppositely charged materials, a "depletion" layer forms. When sunlight strikes the cell, the separation of charged particles generates an electric field that forces current to flow from the negative material to the positive material. This flow of current is captured via wiring connected to an electrode array on one side of the cell and an aluminum back-plate on the other. See Figure 6-15 for further details on the solar PV technologies evaluated.

Figure 6-15 – Solar Photovoltaic

Operating Characteristics and Estimated Costs[31]	10 MW Solar PV	50 MW Solar PV	100 MW Solar PV	50 MW Solar PV & 10 MW / 40 MWh Storage
Base Load Net Output (MW)	10	50	100	50
Base Project Costs (2019$/kW)	$1,961	$1,526	$1,414	$1,860
Fixed O&M Costs (2019$/kW-year)	$23.41	$22.91	$18.82	$22.33
Variable O&M Costs (2019$/MWh)	Included in FOM	Included in FOM	Included in FOM	$5.74 (Storage MWh Only)

The Investment Tax Credit (ITC) is a federal tax credit as a percent of basis invested in eligible solar generation. ITC percentage depends on the commencement of construction as shown below in Figure 6-16. For modeling purposes, Vectren assumed commercial operation date and commence construction to be the same year for solar projects. The eligible investment was assumed to be the total invested project costs to build. The ITC was normalized over the book life of the asset, which evenly distributes the tax credit out over the asset book life.

Figure 6-16 – Investment Tax Credit by Year

Commence Construction (Prior to)	Investment Tax Credit (%)
2017	30%
2018	30%
2019	30%
2020	30%
2021	26%
2022	22%
1/1/2022 & beyond	10%

[31] Based on average of Burns and McDonnell, Pace, and NREL technology assessment information where available.

For the purposes of the IRP, all modeled bids received safe harbor for full realization of the ITC. Modeling assumed a safe harbor assumption of two years ITC extension for generic solar builds.

6.3.1.3.2.1 Safe Harboring Methods

There are two options, often referred to as safe harboring methods, that developers can utilize to extend qualifications for the ITC and PTC. First, a project can prove that they have started and maintained construction of the project. Second, a project can purchase five percent of the total project cost. Once these safe harboring methods are initiated the developer has 4 years to complete the project. This allows developers to prolong the usefulness of the ITC and PTC.

6.3.1.3.3 Hydroelectric

Low-head hydroelectric power generation facilities are designed to produce electricity by utilizing water resources with low pressure differences, typically less than 5 feet head but up to 130 feet. This allows the technology to be implemented with a smaller impact to wildlife and environmental surroundings than conventional hydropower. However, power supply is dependent on water supply flow and quality, which are sensitive to adverse environmental conditions like dense vegetation or algae growth, sediment levels and drought. Additionally, low-head hydropower is relatively new and undeveloped, thus resulting in a high capital cost for the relatively small generation output. See Figure 6-17 for further details on the hydroelectric technology evaluated.

Data from a U.S. Army Corps of Engineers report was used to determine the economically feasible output from the Newburgh and John T. Myers dams located locally on the Ohio River. This report showed that when taking economics into consideration both dams had an average potential output near 50 MW which was consistent with tech assessment data used in the analysis. A separate publication from the U.S Army Corps of Engineers showed that the estimated construction cost of the Cannelton facility was very close to the assumptions used in the analysis.

Figure 6-17 – Hydroelectric

Operating Characteristics and Estimated Costs	50 MW Low-head Hydroelectric
Base Load Net Output (MW)	50
Base Project Costs (2019$/kW)	$6,050
Fixed O&M Costs (2019$/kW-year)	$92.40

6.3.1.3.4 Waste-to-Energy

Two waste-to-energy (WTE) technologies were included within the analysis. Waste fuel is combusted directly in the same way fossil fuels are consumed in other combustion technologies. The heat resulting from the burning of waste fuel converts water to steam, which then drives a steam turbine generator to produce electricity. It should be noted that these types of projects are very site specific and hard to have generic assumptions for use in an IRP. The two fuel types evaluated in the IRP were wood and landfill gas, which are represented in Figure 6-18.

Figure 6-18 – Waste to Energy Technologies

Operating Characteristics and Estimated Costs	Bubbling Fluidized Bed	Landfill Gas IC Engine
Base Load Net Output (MW)	50	5
Base Load Net Heat Rate (HHV Btu/kWh)	13,000	10,740
Base Project Costs (2019$/kW)	$5,640	$4,110
Fixed O&M Costs (2019$/kW-year)	$124.00	$111.78

6.3.1.3.5 Congestion Charges

Transmission congestion charges are the final element for consideration when analyzing the true cost of delivered resources and are the most difficult to estimate. Congestion charges are calculated by taking the difference in Locational Marginal Pricing (LMP's) where the energy is injected (source) and where the energy is withdrawn (sink). For Vectren to purchase energy outside of Zone 6 (Indiana) or even off Vectren's system in Indiana, Vectren would be responsible to pay the LMP at the sink and would receive payment from the source. Therefore, any price differential is an added risk and possible added cost to the delivery of energy. MISO does not provide estimates of congestion charges due to the volatility and immense variability that impacts the MISO transmission system and the congestion related charges. When taking into consideration the cost of a resource, the required transmission charges and estimated congestion charges based on historical data, the greater the distance, the greater the potential for higher costs.

Vectren’s modeling accounted for congestion. As previously described, Vectren modeled tier 1 bid information, which included a “delivered price” (all in price from the developer), or projects on Vectren’s system, which minimizes congestion risk. Outside of bid information, projects were generally assumed to be on Vectren’s system. Any resource that is outside of Vectren’s system must include an evaluation of potential congestion charges.

6.3.1.4 Energy Storage

Two types of energy storage technologies were evaluated in the IRP –lithium-ion batteries (typically short-duration) and flow batteries (long-duration). These are shown in Figure 6-19.

Batteries utilize chemical reactions within a battery cell to facilitate electron flow, converting electrical energy to chemical energy when charging and generating an electric current when discharged. Electrochemical technology is continually developing as one of the leading energy storage and load following technologies due to its modularity and ease of installation and operation.

Lithium ion (Li-ion) batteries contain graphite and metal-oxide electrodes and lithium ions dissolved within an organic electrolyte. The movement of lithium ions during cell charge and discharge generates current. Li-ion technology has seen a resurgence of development in recent years due to its high energy density, low self-discharge and cycling tolerance.

Flow batteries utilize an electrode cell stack with externally stored electrolyte material. The flow battery is comprised of positive and negative electrode cell stacks separated by a selectively permeable ion exchange membrane, in which the charge-inducing chemical reaction occurs and liquid electrolyte storage tanks, which hold the stored energy until discharge is required. Various control and pumped circulation systems complete the flow battery system in which the cells can be stacked in series to achieve the desired voltage difference.

Both Li-ion and flow batteries offer a way of storing low-priced, off-peak generation that can be discharged during higher-priced, peak demand hours (wholesale energy market arbitrage). These storage technologies can also function as transmission assets that can assist in maintaining the reliability of the grid, potentially displacing or deferring the need for more traditional transmission upgrades.

Figure 6-19 – Energy Storage Technologies

Operating Characteristics and Estimated Costs[32]	**Lithium Ion 10 MW / 40 MWh**	**Lithium Ion 50 MW / 200 MWh**	**Flow Battery 10 MW / 60 MWh**	**Flow Battery 10 MW / 80 MWh**	**Flow Battery 50 MW / 300 MWh**	**Flow Battery 50 MW / 400 MWh**
Base Load Net Output (MW)	10	50	10	10	50	50
Round-Trip Cycle Efficiency	85%	85%	68%	68%	68%	68%
Base Project Costs (2019$/kW)	$1,972	$1,562	$3,823	$4,305	$3,034	$3,478
Fixed O&M Costs (2019$/kW-year)	$22.36	$18.85	$110.10	$110.10	$35.06	$35.06
Variable O&M Costs (2019$/MWh)	$6.07	$6.07	$1.50	$1.50	$1.50	$1.50

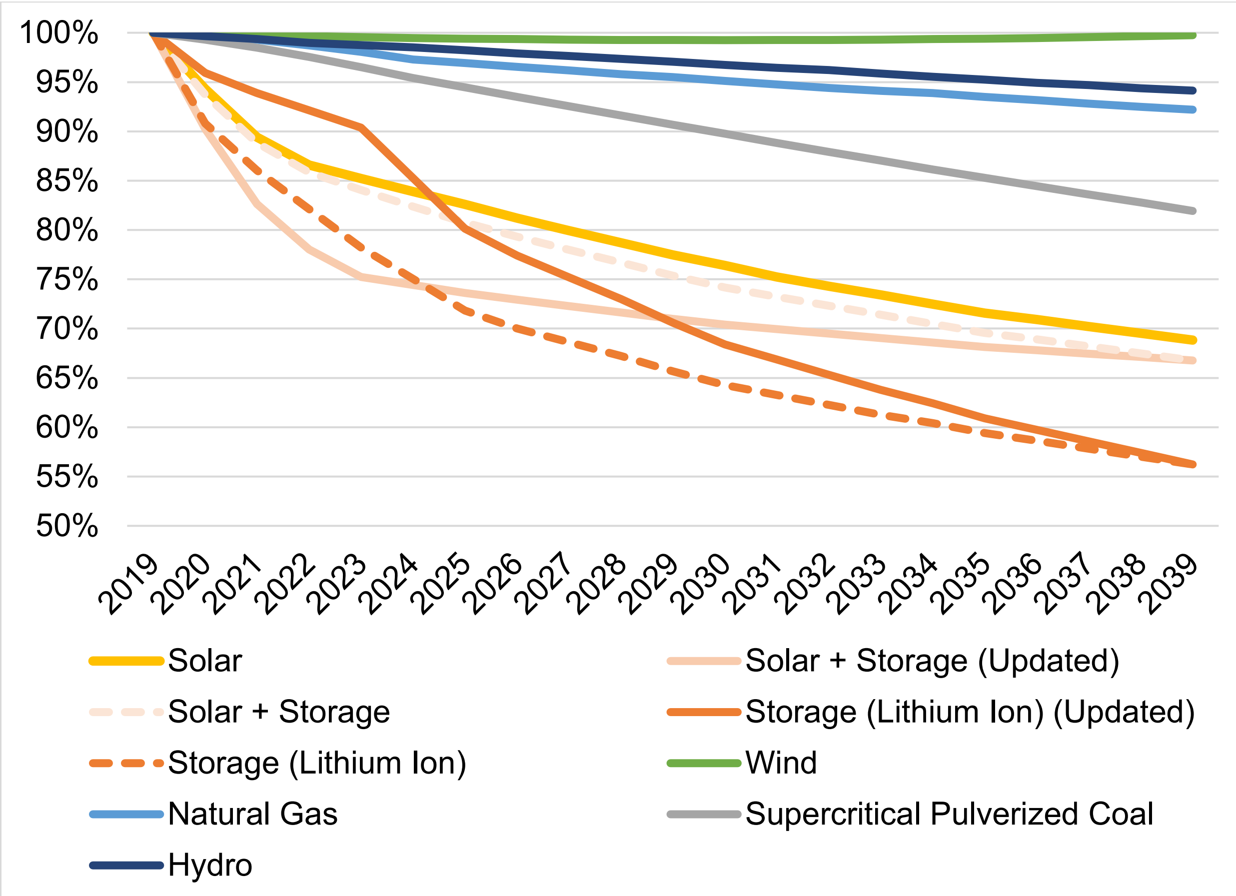
[32] Based on average of Burns and McDonnell, Pace, and NREL technology assessment information where available.

6.3.1.5 Cost Curve Discussion

Forward looking capital cost forecasts were developed and used as part of the 2019/2020 IRP process. Capital cost curves vary based on the generation technology, as shown in Figure 6-21.

Technologies whose capital costs do not decline significantly over the IRP time period such as wind, natural gas, coal and hydro are generally more mature, while technologies such as solar and storage are less mature and are expected to experience larger reductions in capital cost over the IRP time period. In the next 20 years, new technological developments and increasing efficiencies in solar and storage are expected to decrease capital costs by ~30% and ~40%, respectively. Due to uncertainty associated with these less mature technologies, Vectren relied upon multiple third-party sources to develop consensus capital cost forecasts. The capital cost forecast curves were adjusted for solar + storage and storage based on data received as part of the RFP process. Solar bids received in the RFP aligned very closely with the original consensus cost curve forecast (these curves are on top of each other in Figure 6-21, solar + storage bids resulted in lowering the near-term forecast, while the bids received for standalone storage resulted in a slight increase to the near term cost curve forecast. These updates help to align Vectren's forecasts with real market data for these less mature technologies. Figures 7.12-7.14 show modeled values by scenario.

Figure 6-20 - Forward Capital Cost Estimates



6.3.2 DSM

6.3.2.1 Energy Efficiency Background

In developing a resource plan that integrates demand side and supply side resources, it is incumbent for the energy company to provide the integrating process with a set of demand side (DSM) options that can be incorporated into the plan. This process aligns with IURC's Rule 170 IAC 4-7-6(b) which states:

> "An electric utility shall consider alternative methods of meeting future demand for electric service. A utility must consider a demand-side resource, including innovative rate design, as a source of new supply in meeting future electric service

requirements. The utility shall consider a comprehensive array of demand-side measures that provide an opportunity for all ratepayers to participate in DSM, including low-income residential ratepayers."

In addition, this process aligns with Senate Enrolled Act (SEA) 412 which requires that energy efficiency goals be consistent with an electricity supplier's IRP. Taken together, these jointly supportive requirements direct the energy company to study, similar to supply side resources, available DSM options that may be chosen by the IRP analytical process in arriving at a resource plan. In other words, the level of DSM to be pursued by the energy company should be determined through the IRP process.

6.3.2.2 DSM Market Potential Study

The first step in the process is a Market Potential Study (MPS). A key purpose of an energy efficiency MPS is to provide energy efficiency planners, decisionmakers and interested stakeholders with a roadmap to the best opportunities for energy efficiency savings opportunities in the residential, commercial and industrial customer classes. "Energy efficiency potential studies are an effective tool for building the policy case for energy efficiency, evaluating efficiency as an alternative to supply side resources and formulating detailed program design plans. They are typically the first step taken by entities interested in initiating or expanding a portfolio of efficiency programs and serve as the analytic basis for efforts to treat energy efficiency as a high-priority resource equivalent with supply-side options."[33] The results of a potential study pinpoint the energy efficiency measures having the greatest potential for energy savings and identifies the measures that are the most cost effective. Program administrators, regulators and stakeholders can use the results of potential studies to determine the types of programs that should be implemented and how much to invest in energy efficiency as a resource.

[33] "Guide for Conducting Energy Efficiency Potential Studies"; Prepared by Philip Mosenthal and Jeffrey Loiter, Optimal Energy, Inc.; https://www.epa.gov/sites/production/files/2015-08/documents/potential_guide_0.pdf; November 2017; page ES-1

Potential studies also provide useful information on the benefits and costs of energy efficiency measures and programs from various viewpoints: society as a whole, all ratepayers, the program administrator, program participants and utility rates.

Vectren's MPS completed in 2019 was both to inform the IRP and support the development of a DSM Action Plan for Vectren. The study included primary market research and a comprehensive review of current program, historical savings and projected energy savings opportunities to develop estimates of technical, economic and achievable potential. The study collected primary market research on up-to-date C&I data for the Vectren service area for the saturation of energy-using equipment, building characteristics and the percent of energy using equipment that is already high efficiency. Primary market research was also conducted to understand customer willingness to participate in energy efficiency programs at different incentives levels and targeted end-uses.

Technical potential is the maximum energy efficiency available, assuming that cost and market adoption of a technology are not a barrier. Economic potential is the subset of technical potential that is cost effective, meaning the economic benefit outweighs the cost. The economic potential is measured by the total resource cost test, which compares the lifetime energy and capacity benefits to the incremental cost of the energy efficiency measure. While some may contend that the full technical or economic potential should be provided as the level of DSM options available in the IRP process, this ignores the fact that 100% of the customers would have to participate. This is not realistic as historical evidence has shown that not all customers will adopt a given technology for reasons that range from aesthetic preferences, lack of information about energy efficiency measures, lack of access to capital to perceived comfort concerns. Rather, the potential modeled in the IRP should reflect some consideration of achievability.

To that end, 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:

1) **Maximum Achievable Potential** estimates achievable potential on paying incentives equal to 100% of measure incremental costs and aggressive adoption rates.
2) **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.

It is important to also note that the estimates of technical, economic and achievable potential considered in the MPS (and ultimately, in the IRP) exclude potential savings from customers who are eligible and have chosen to actively opt-out of participating in Vectren’s energy efficiency programs. In the Vectren service area, approximately 75% of large C&I customers are eligible to opt-out and nearly 40% of eligible customers have chosen to do so. As a result, only 22% of total large C&I energy (MWh) sales have not presently opted out of funding Vectren’s energy efficiency programs.[34]

6.3.2.3 Energy Efficiency – IRP Reference Case

For the DSM reference case of the IRP analysis, Vectren used the realistic achievable potential identified in the 2019 Market Potential Study as the starting point for developing bundles of energy efficiency to be modeled in .25% increments of eligible sales. However, two additional adjustments to the MPS’ realistic achievable energy efficiency potential were necessary prior to inclusion in the IRP.

[34] These percentages are calculated based on 2019 Vectren large C&I customer data and 2018-2019 billing history.

The first adjustment converted the energy efficiency potential from gross savings to net savings. It is appropriate to model net energy efficiency impacts in order to remove MWh and MW impacts that would have occurred even in the absence of Vectren's programs. Net savings were calculated by applying Vectren's most recent (2017) program evaluation results and NTG ratios to the MPS estimates of gross realistic achievable savings. Due to annual differences in the mix of energy efficiency measures included in the realistic achievable potential, the weighted average NTG ratio adjustment ranged from 0.84 to 0.88 across the 20-year IRP analysis timeframe.

The second adjustment aligned the level of low-income potential identified in the realistic achievable potential with levels achieved historically by Vectren. The MPS assumes Vectren pays the full cost for all possible low-income potential savings, regardless of cost-effectiveness. However, this produces a low-income budget that significantly outpaces historical spending for the low-income sector and would create cross-subsidization concerns across customer segments. As a result of aligning the low-income sector spending in the IRP with recent historical levels, low-income achievable savings were also scaled accordingly.

The model included 2020 savings as a fixed resource as savings are currently approved by the Commission in Cause 44927. A total of 10 bundles were modeled for DSM, including one fixed low-income bundle, one fixed DR bundle (AC DLC as well as Smart Thermostat), one selectable DR BYOT (Bring Your Own Thermostat) and seven selectable energy efficiency bundles each representing 0.25% of annual load excluding opt-out sales.

Figure 6-22 shows the realistic achievable potential (as a % of annual forecast sales) identified in the MPS and the impacts after applying the two adjustments described above.

Figure 6-21 – MPS Realistic Achievable Potential (as a % of annual eligible sales) – Pre- & Post-Adjustments

	2020	2021	2022	2023	2024	2025
MPS Realistic Achievable	1.7%	2.1%	2.0%	2.0%	2.0%	2.0%
Adj#1: Gross to Net	1.4%	1.8%	1.7%	1.8%	1.8%	1.7%
Adj#2: Low Income Alignment	1.2%	1.5%	1.4%	1.5%	1.5%	1.5%

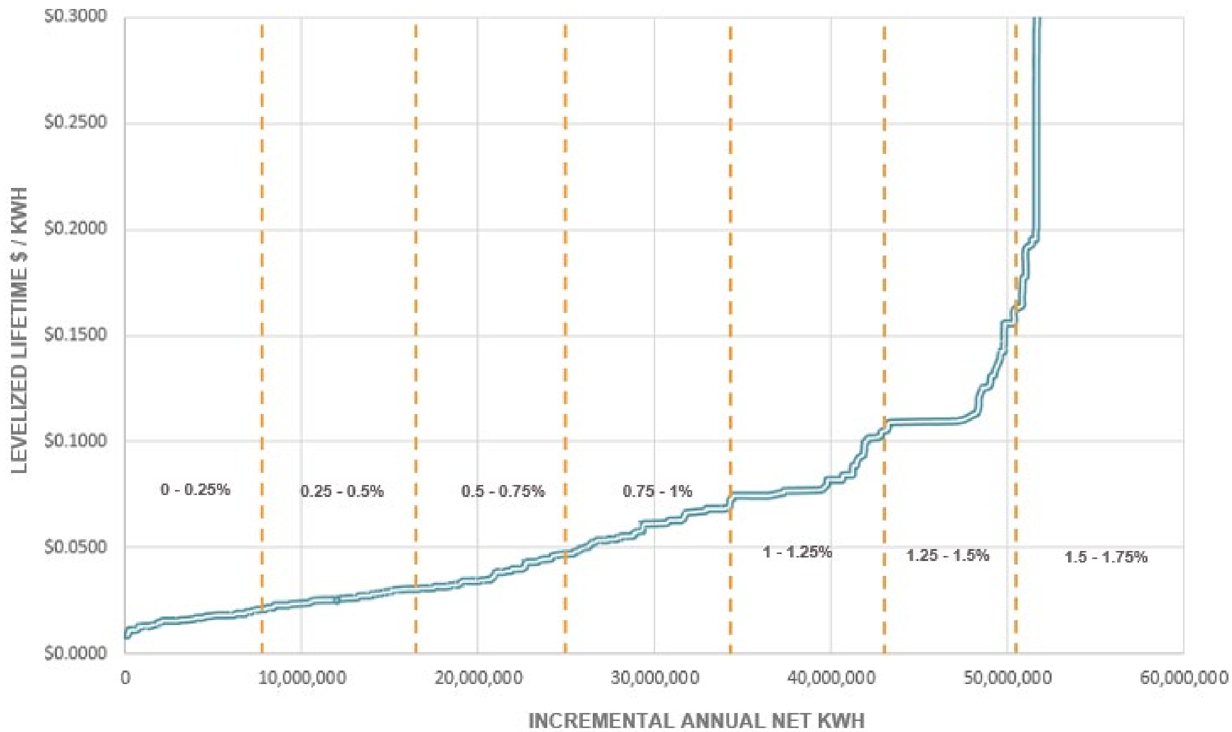
For the Vectren IRP process, energy efficiency is a selectable resource. Once the total energy efficiency savings to be included in the IRP Reference Case were calculated, a cost was assigned to each bundle of energy efficiency so that it can compete and be selected against supply-side resources. Again, the 2019 MPS and the annual supply curves were used to develop costs for each energy efficiency bundle. The costs from the MPS include incentive costs, program delivery costs and other cross-cutting program costs based on reported historical levels. Two modifications to the MPS cost estimates were created to further align the IRP Reference Case with empirical Vectren data. The first adjustment was to reduce incentive costs in the C&I sector from 2020 through 2027. This adjustment served to align modeled costs with Vectren recent historical and 2019 planned costs in the C&I sector. The second adjustment was to change the escalation rate for non-incentive program costs to 2.2% (in lieu of the 1.6% modeled in the MPS) to be consistent with other IRP planning assumptions.[35]

Following these savings and costs adjustments, a supply curve of the remaining electric energy efficiency potential was developed for each year of the MPS. A supply curve of energy efficiency potential is a device for demonstrating the total amount of energy efficiency savings available at specific price points, with the x-axis representing the cumulative annual energy savings available and the y-axis representing the cost of saved energy. The energy efficiency supply curve is useful in that it creates a logical order for pursuing energy efficiency measures based on least cost planning. Energy efficiency measures along the supply curve were then bundled into blocks of approximately 0.25%

[35] Incentive costs were not escalated in the MPS or IRP DSM inputs. Incentives (as a % of measure costs) were held constant in nominal dollars. Any fluctuation in incentives is a result of changes in annual participation.

net energy savings relative to forecast sales. The total number of energy efficiency bundles, each year, is dependent on the realistic achievable potential identified in that year. For example, the realistic achievable potential identified in 2024 allows for 6 complete bundles of 0.25% net efficiency savings and a partial 7th bundle (Figure 6-23).

Figure 6-22 – 2024 Supply Curve for Electric Energy Efficiency



As a final step in the IRP Reference Case energy efficiency bundle development, a single low-income bundle of energy efficiency was created. As noted earlier, this savings bundle is aligned so that total low-income spending in 2020-2039 is consistent with recent historical levels ($1.15 million annually). The cost per lifetime kWh-saved is expected to change over time as the associated mix of low-income measures in the realistic achievable potential changes. Annual savings associated with the LI Bundle range from 889 MWh in the early years of the IRP to a low of 457 MWh as the measure mix converts to higher $/kWh measures over time.

The following table (Figure 6-24) provides the estimated levelized costs, on a cumulative basis, used for each of the energy efficiency bundles included in the IRP Reference Case.

Except for the low-income bundle, no minimum level of energy efficiency impacts was locked in for the IRP optimization modeling for scenario analysis. Empty cells reflect a lack of net achievable potential (based on the MPS results) in that year.

Figure 6-23 – IRP Reference Case Cost of Energy Efficiency; Cost per Net Lifetime kWh[36]

CUM. BIN NET $/kWh	1	2	3	4	5	6	7	LI
2020	$ 0.0163	$ 0.0204	$ 0.0240	$ 0.0299	$ 0.0369			$ 0.1241
2021	$ 0.0154	$ 0.0201	$ 0.0232	$ 0.0268	$ 0.0314	$ 0.0380		$ 0.1448
2022	$ 0.0154	$ 0.0202	$ 0.0245	$ 0.0289	$ 0.0326	$ 0.0394		$ 0.1594
2023	$ 0.0158	$ 0.0206	$ 0.0246	$ 0.0292	$ 0.0342	$ 0.0397		$ 0.1754
2024	$ 0.0162	$ 0.0204	$ 0.0247	$ 0.0302	$ 0.0355	$ 0.0377	$ 0.0412	$ 0.1997
2025	$ 0.0168	$ 0.0217	$ 0.0263	$ 0.0321	$ 0.0375	$ 0.0410	$ 0.0427	$ 0.2134
2026	$ 0.0172	$ 0.0226	$ 0.0278	$ 0.0336	$ 0.0391	$ 0.0426	$ 0.0446	$ 0.2255
2027	$ 0.0179	$ 0.0237	$ 0.0291	$ 0.0357	$ 0.0409	$ 0.0442	$ 0.0462	$ 0.2429
2028	$ 0.0185	$ 0.0250	$ 0.0311	$ 0.0372	$ 0.0426	$ 0.0468	$ 0.0485	$ 0.2469
2029	$ 0.0194	$ 0.0262	$ 0.0330	$ 0.0399	$ 0.0443	$ 0.0499		$ 0.2481
2030	$ 0.0202	$ 0.0283	$ 0.0342	$ 0.0402	$ 0.0457	$ 0.0521		$ 0.2453
2031	$ 0.0210	$ 0.0294	$ 0.0350	$ 0.0423	$ 0.0470	$ 0.0531		$ 0.2517
2032	$ 0.0220	$ 0.0304	$ 0.0388	$ 0.0443	$ 0.0491	$ 0.0557		$ 0.2299
2033	$ 0.0233	$ 0.0317	$ 0.0409	$ 0.0478	$ 0.0505	$ 0.0574		$ 0.2345
2034	$ 0.0241	$ 0.0328	$ 0.0432	$ 0.0497	$ 0.0525	$ 0.0596		$ 0.2038
2035	$ 0.0203	$ 0.0262	$ 0.0323	$ 0.0405	$ 0.0462	$ 0.0480	$ 0.0545	$ 0.2285
2036	$ 0.0206	$ 0.0262	$ 0.0320	$ 0.0405	$ 0.0456	$ 0.0482	$ 0.0547	$ 0.2413
2037	$ 0.0208	$ 0.0264	$ 0.0322	$ 0.0399	$ 0.0457	$ 0.0485	$ 0.0547	$ 0.1969
2038	$ 0.0218	$ 0.0256	$ 0.0324	$ 0.0395	$ 0.0450	$ 0.0499	$ 0.0558	$ 0.2006
2039	$ 0.0231	$ 0.0262	$ 0.0333	$ 0.0398	$ 0.0458	$ 0.0506	$ 0.0564	$ 0.2068

6.3.2.4 Demand Response

Two bundles for demand response savings were included in the IRP Reference Case. The first bundle was included as a fixed adjustment to the total system load, similar to a “must-run” generation unit. This bundle includes demand response savings associated with Vectren’s current demand response capabilities including the historical number of

[36] Savings bundles were based on net savings that were roughly equivalent to 0.25% of annual sales. Projected costs per kWh for each bundle are shown at the gross-level for easier comparison to prior IRP. Projected costs by bundle are cumulative (i.e. the projected cost in Bundle 4 represent the cost to achieve up to 1.0% of forecast sales).

direct load control switches on residential air conditioning units in the Vectren service area. Over the IRP time frame, Vectren anticipates replacing existing direct load control switches with smart thermostats that integrate demand response capabilities (via the Smart Cycle Program). The estimated annual impacts for the fixed bundle of DR is approximately 16 MW in 2020, increasing to 26 MW by 2039.

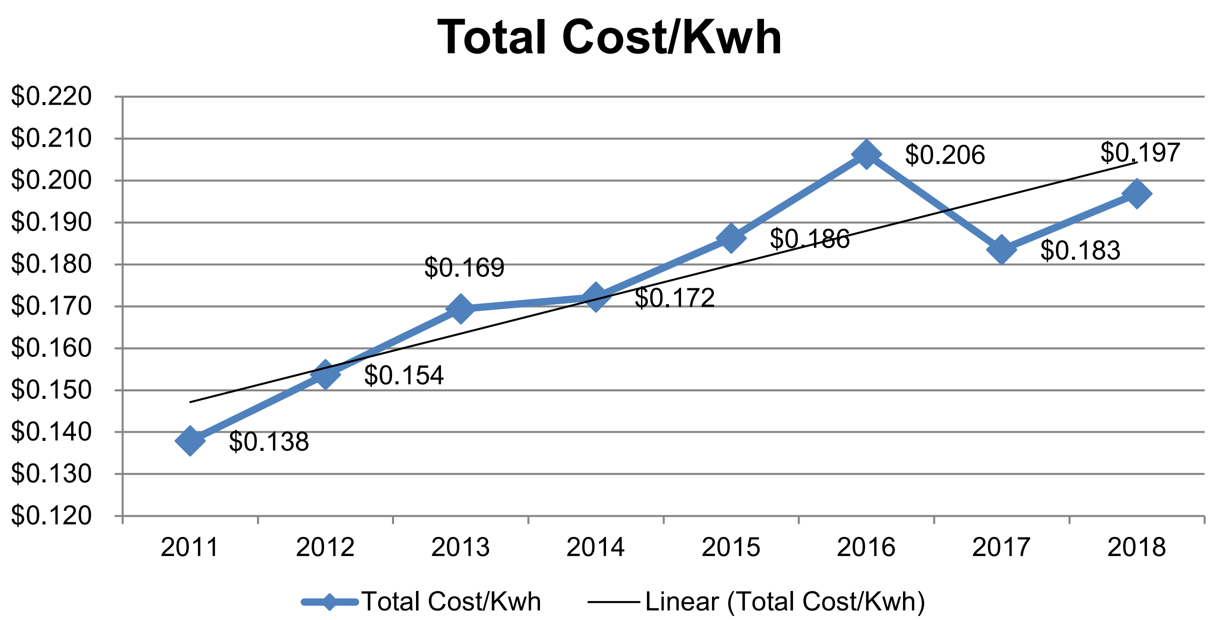
A second bundle, consisting of additional demand response enabled smart thermostats (BYOT Thermostats) above and beyond the current penetration of demand response devices, was included as a selectable resource. This bundle represents an additional 1.6 MW of peak reduction capabilities in 2020 increasing to 10 MW by 2039.

6.3.2.5 DSM Resources – IRP Sensitivities

The previous sections provided the Reference Case projection of DSM resource costs. DSM resource costs are a key component to the integration of DSM into the resource plan. Given the uncertainty around these costs, especially considering a 20-year implementation period, alternate views of the costs should be examined in the context of the scenario analyses. Only time and actual experience with increases in DSM market penetration will provide better guidance on these cost projections.

To that end, high and low DSM resource cost trajectories were developed by leveraging Vectren's 2011-2018 historical DSM spend per first-year kWh saved and calculating one standard deviation from the mean to develop high and low DSM spend scenarios. This approach uses the actual variation in Vectren's energy efficiency resource acquisition costs to define upper and lower bounds on future DSM costs per first-year kWh-saved. The result is an 11.9% increase or reduction in estimated annual DSM costs relative to the IRP Reference Case. Figure 6-25 shows the 2011-2018 average cost per first-year kWh-saved used to determine the IRP sensitivities on DSM costs.

Figure 6-24 – 2011-2018 Vectren Portfolio Cost per 1st-Year kWh Saved



Applying a range of expected costs produces the following high and low tables of projected DSM resource costs.

Figure 6-25 – High Case Cost per kWh: Plus One Standard Deviation

CUM. BIN NET $/kWh	1	2	3	4	5	6	7
2020	$ 0.0182	$ 0.0229	$ 0.0269	$ 0.0335	$ 0.0413		
2021	$ 0.0173	$ 0.0225	$ 0.0259	$ 0.0300	$ 0.0351	$ 0.0426	
2022	$ 0.0172	$ 0.0226	$ 0.0274	$ 0.0323	$ 0.0365	$ 0.0440	
2023	$ 0.0177	$ 0.0230	$ 0.0275	$ 0.0326	$ 0.0383	$ 0.0444	
2024	$ 0.0181	$ 0.0229	$ 0.0277	$ 0.0338	$ 0.0397	$ 0.0421	$ 0.0461
2025	$ 0.0188	$ 0.0242	$ 0.0294	$ 0.0359	$ 0.0419	$ 0.0458	$ 0.0478
2026	$ 0.0192	$ 0.0253	$ 0.0311	$ 0.0376	$ 0.0437	$ 0.0476	$ 0.0499
2027	$ 0.0200	$ 0.0265	$ 0.0325	$ 0.0399	$ 0.0457	$ 0.0495	$ 0.0517
2028	$ 0.0207	$ 0.0280	$ 0.0348	$ 0.0416	$ 0.0477	$ 0.0524	$ 0.0543
2029	$ 0.0217	$ 0.0293	$ 0.0369	$ 0.0446	$ 0.0496	$ 0.0559	
2030	$ 0.0226	$ 0.0317	$ 0.0382	$ 0.0450	$ 0.0511	$ 0.0582	
2031	$ 0.0235	$ 0.0329	$ 0.0391	$ 0.0473	$ 0.0526	$ 0.0594	
2032	$ 0.0246	$ 0.0341	$ 0.0434	$ 0.0496	$ 0.0550	$ 0.0624	
2033	$ 0.0260	$ 0.0355	$ 0.0458	$ 0.0535	$ 0.0565	$ 0.0642	
2034	$ 0.0269	$ 0.0367	$ 0.0483	$ 0.0556	$ 0.0587	$ 0.0667	
2035	$ 0.0227	$ 0.0293	$ 0.0361	$ 0.0453	$ 0.0517	$ 0.0537	$ 0.0610
2036	$ 0.0231	$ 0.0293	$ 0.0358	$ 0.0453	$ 0.0511	$ 0.0539	$ 0.0612

CUM. BIN NET $/kWh	1	2	3	4	5	6	7
2037	$ 0.0233	$ 0.0295	$ 0.0360	$ 0.0446	$ 0.0511	$ 0.0543	$ 0.0612
2038	$ 0.0244	$ 0.0287	$ 0.0363	$ 0.0442	$ 0.0503	$ 0.0558	$ 0.0624
2039	$ 0.0258	$ 0.0293	$ 0.0373	$ 0.0445	$ 0.0513	$ 0.0567	$ 0.0631

Figure 6-26 – Low Case Cost per kWh: Minus One Standard Deviation

CUM. BIN NET $/kWh	1	2	3	4	5	6	7
2020	$ 0.0143	$ 0.0180	$ 0.0212	$ 0.0264	$ 0.0325		
2021	$ 0.0136	$ 0.0177	$ 0.0204	$ 0.0236	$ 0.0276	$ 0.0335	
2022	$ 0.0135	$ 0.0178	$ 0.0216	$ 0.0254	$ 0.0287	$ 0.0347	
2023	$ 0.0139	$ 0.0181	$ 0.0216	$ 0.0257	$ 0.0302	$ 0.0350	
2024	$ 0.0143	$ 0.0180	$ 0.0218	$ 0.0266	$ 0.0313	$ 0.0332	$ 0.0363
2025	$ 0.0148	$ 0.0191	$ 0.0232	$ 0.0282	$ 0.0330	$ 0.0361	$ 0.0377
2026	$ 0.0151	$ 0.0199	$ 0.0245	$ 0.0296	$ 0.0344	$ 0.0375	$ 0.0393
2027	$ 0.0158	$ 0.0209	$ 0.0256	$ 0.0314	$ 0.0360	$ 0.0389	$ 0.0407
2028	$ 0.0163	$ 0.0220	$ 0.0274	$ 0.0328	$ 0.0375	$ 0.0412	$ 0.0427
2029	$ 0.0171	$ 0.0231	$ 0.0291	$ 0.0351	$ 0.0390	$ 0.0440	
2030	$ 0.0178	$ 0.0250	$ 0.0301	$ 0.0354	$ 0.0403	$ 0.0459	
2031	$ 0.0185	$ 0.0259	$ 0.0308	$ 0.0373	$ 0.0414	$ 0.0468	
2032	$ 0.0194	$ 0.0268	$ 0.0342	$ 0.0391	$ 0.0433	$ 0.0491	
2033	$ 0.0205	$ 0.0279	$ 0.0361	$ 0.0421	$ 0.0445	$ 0.0506	
2034	$ 0.0212	$ 0.0289	$ 0.0380	$ 0.0438	$ 0.0462	$ 0.0525	
2035	$ 0.0179	$ 0.0231	$ 0.0284	$ 0.0357	$ 0.0407	$ 0.0423	$ 0.0480
2036	$ 0.0181	$ 0.0231	$ 0.0282	$ 0.0356	$ 0.0402	$ 0.0425	$ 0.0482
2037	$ 0.0183	$ 0.0232	$ 0.0284	$ 0.0351	$ 0.0402	$ 0.0428	$ 0.0482
2038	$ 0.0192	$ 0.0226	$ 0.0286	$ 0.0348	$ 0.0396	$ 0.0439	$ 0.0492
2039	$ 0.0203	$ 0.0231	$ 0.0293	$ 0.0350	$ 0.0404	$ 0.0446	$ 0.0497

No IRP sensitivities for the low-income savings or demand response savings were included in the IRP as these bundles were modeled as fixed load impacts.

6.3.2.5.1 DSM Improvements Based on Stakeholder Feedback

Review of prior comments from stakeholders and robust stakeholder discussion led to several improvements to DSM modeling since the 2016 IRP. The model has been allowed to make multiple decisions over the 20-year period. The model selects DSM for two three-year periods beginning in 2021 and 2024 and then evaluates the remaining years beginning in 2027 as one collective group. This allows the model to select the appropriate level of DSM based on cost-effectiveness differences between the short, mid and long run. Another improvement is the addition of bin specific load shapes which improved accuracy versus utilizing the same average load shape for each bin. Further, DR bundles have been added to the model. The modeled savings were aligned to the latest MPS and conducted price sensitivities mentioned in section “DSM Resources – IRP Sensitivities”. The addition of price sensitivities guides Vectren’s understanding of energy savings potential as costs might vary.

6.3.2.6 Other Innovative Rate Design

Vectren periodically evaluates alternative rate design and its ability to implement new options as the energy marketplace continues to evolve. Proposals that provide variable energy pricing based on how electric prices change throughout the day (Time of Use rates) and other pricing alternatives will be considered now that the required technology upgrades are being finalized, including technology to improve access to multitudes of data provided by installation of AMI. This information was not available for the 2019/2020 IRP.

6.4 TRANSMISSION CONSIDERATIONS

6.4.1 Description of Existing Transmission System

Vectren’s transmission system is comprised of 64 miles of 345 kV lines, 377 miles of 138 kV lines and 570 miles of 69 kV lines. It has interconnections with Duke Energy (345 kV-138 kV-69 kV), Hoosier Energy (161 kV-69 kV), Indianapolis Power and Light Co. (138 kV), Big Rivers Electric Company (138 kV) and LGE/KU (138 kV). Key interconnection points include three 345 kV interconnections to Duke Energy’s system in the area of Duke’s Gibson Generation Station, a 345 kV interconnection to Big Rivers’ Reid EHV Substation, a 138 kV interconnection at IPL’s Petersburg Generation Station and 161 kV and 138 kV interconnections to Hoosier Energy, LGE/KU and Big Rivers at Vectren’s Newtonville Substation.

6.4.2 Discussion on Resources Outside of Area

As mentioned above, Vectren's transmission system interconnects with neighboring systems, which provides wholesale import and export capability. Transmission planning studies indicate the existing transmission system provides a maximum import capability of approximately 750 MWs (or approximately 65% of peak demand). Although Vectren has the capability to offset internal generation with imported capacity, this is not a long-term solution; several factors would influence that capability, including:

- MISO resource adequacy requirements
- Availability of firm capacity
- Transmission path availability
- Operating concerns (post-contingent voltage and line flow)
- Anticipated congestion costs
- Real-time binding constraints

6.4.3 Transmission Facilities as a Resource

As part of this year's IRP, Vectren performed a multitude of transmission planning analysis to study a wide range of potential futures. These included studying the replacement of various levels of coal generation with a Combined Cycle Gas Turbine (CCGT), Combustion Turbines (CTs) and import from the MISO market. Each of these cases also included the addition of various levels of renewable resources, primarily solar and wind. The models utilized were from the latest cycle of the MISO generation interconnection process in order to have the latest modeling data for generation resources in Vectren's area. The renewable resources used for Vectren's analysis were projects already in the MISO queue and existing in the MISO models, while the CCGT and CT's were modeled at Vectren's A.B. Brown power plant for ease of modeling.

The CCGT case was modeled at a similar MW output as the coal generation it was replacing and therefore the results of the transmission planning study analysis showed very few differences from the study case with the system as it is today, or Base Case.

As the level of power imported from the MISO market increased due to the coal generation retirements, network upgrades were identified to increase the Vectren system import capability to suitable levels. These projects included the replacement of three transformers at an estimated total cost of $11 million and were needed for all non-CCGT cases, including the CT cases. In addition to these identified import capability issues, voltage issues also arose due to insufficient reactive power reserves as the level of imported power increased. These issues were minimal in the CT cases due to the reactive capability of the CT's and could be resolved with existing facilities, but the issues became substantial in the all renewables by 2030 portfolio and all import cases and would require additional upgrades of $20-$30 million beyond the $11 million described above. These upgrades for reactive support would need to be studied in more depth to determine the placement of new facilities and to determine the type of devices needed.

6.5 Partnering with Other Utilities

As a part of the 2019/2020 IRP process, Vectren contacted utilities in the region to discuss opportunities to partner together on generation projects to lower costs. Partnership opportunities with other Indiana utilities did not materialize due to a variety of factors including a lack of alignment in timing, needs, or other factors.

SECTION 7
MODEL INPUTS AND ASSUMPTIONS

7.1 RESOURCE MODEL (AURORA)

AURORAxmp was the primary tool for conducting Vectren's analysis. AURORAxmp is an industry standard chronological unit commitment and dispatch model with extensive presence throughout the electric power industry. The model uses a mixed integer linear programming approach (MILP) to capture details of power plant and transmission network operations while observing real world constraints, such as emission reduction targets, transmission and plant operation limitations, renewable energy availability and mandatory portfolio targets.

The model can be run in several modes; two were utilized for this study. The Long-Term Capacity Expansion mode (LTCE), the model was utilized to determine the least cost mix of existing and new generating assets that meets demand (electric load) over time and also meets regulatory and reliability requirements. In dispatch mode, the model was utilized to assess how a portfolio of assets will perform under a fixed set of market conditions.

AURORAxmp is widely used by electric utilities, consulting agencies and other stakeholders to forecast generator performance and economics, develop IRPs, forecast power market prices and assess detailed impact of regulations and market changes affecting the electric power industry. Key inputs to the model include load forecasts, power plant costs and operating characteristics (e.g. heat rates), fuel costs, fixed and variable operating costs, outage rates, emission rates as well as capital costs. The model assesses the potential performance, fixed and variable O&M costs and capital costs of prospective and existing generation technologies and resources and makes resource addition and retirement decisions for economic, system reliability and policy compliance reasons on a utility system, regional and nationwide scale. Outputs of the model include plant generation, gross margin, emissions, power prices, capacity additions, retirements and a variety of other metrics.

Pace Global has used Aurora for well over 15 years as its primary model for asset valuation, power market forecast and IRPs. The model is equipped to determine least cost portfolios and it can analyze portfolio risks by assessing portfolio performance across 200 different future market outlooks. Pace Global has developed a sophisticated stochastic framework to ensure that these future market outlooks reflect both relevant historic uncertainty in key market drivers and cross relationships between different market drivers. Pace Global has also developed modules to simulate the different operating characteristics of ISO/RTO regions across the country. For this reason, it is one of the most comprehensive, reliable and flexible tools in the market for conducting IRPs. Pace Global has successfully conducted numerous IRPs for many utilities across the country. Aurora has gained wide acceptance among electric utility executives, stakeholder groups and regulatory commissions.

In order to perform both the required deterministic (scenario based) and probabilistic (stochastic) modeling, Pace Global developed five scenarios and a set of probability distributions for key market driver variables. These include both forecasts of each variable under the five conditions and probabilistic distributions for demand growth (load), fuel costs (natural gas and coal), environmental compliance costs (carbon) and capital costs. In the sections below is a description of how these forecasts and distributions were developed.

7.2 REFERENCE CASE SCENARIO

Vectren developed a Reference Case forecast of key market drivers that collectively represent the expected or most likely to occur path forward for each input variable. For key assumptions, including natural gas prices, coal prices and capacity prices, a range of views from four vendors were incorporated into a consensus forecast.

The Reference Case scenario is based upon consensus forecasts from several consultants. Hence, it is impossible to describe specifics regarding the assumptions driving each forecast. However, the Reference Case can be described in more general terms based upon consistency in general trends among the individual forecasts that comprise the consensus forecast. Generally, the forecast is characterized by reasonable and balanced levels of growth, best guess forecasts of market conditions, regulatory requirements and technological change. Typically, market participants under Reference Case conditions can adapt and adjust in a timely manner to changing market forces.

Short Term: In the short-term (2020-2021), the Reference Case assumes an overall positive sales growth as Vectren adds general service and large customer growth. Residential customer annual consumption is expected to decline slightly to 2021 before rising again in the medium-term and long-term. Large commercial and industrial (C&I) customers are expected to increase both in numbers and consumption, also with a partial offset of this growth by increasing efficiency. As a result, average energy sales grow at 2.2% for 2019-2021.

Natural gas prices are expected to decline in 2020 compared to 2019, as the oversupply situation from shale gas and associated gas production continues to dominate gas market dynamics. In the short-term, natural gas prices are expected to remain below $2.80/MMBtu.

Meanwhile, coal prices decline in the near-term as domestic markets remain soft. Exports of coal provide a small amount of upward pressure demand, but mine prices are expected to continue to decline in the short-term from the 2019 price of $1.78/MMBtu in the Illinois Coal Basin.

Coal plant retirements were high in 2015 driven by regulation including MATS and again in 2018 for economic reasons. Capacity additions in the form of efficient combined cycle gas turbine plants or fast-ramping simple cycle gas turbines grew rapidly over the past few years as merchant plants and utilities took advantage of low gas prices. The EIA in its AEO 2020 report anticipates a continued pace of capacity additions over the next few years, balanced between gas plants and renewables.[37]

Medium Term: In the medium-term (2022-2028), the Reference Case reflects the assumption that a carbon price will be implemented on the national level and will begin in 2027 at approximately $4/short ton of CO_2 (in real 2018$). CO_2 prices in California and in Northeast states participating in RGGI are expected to harmonize with the broader U.S. market at this time. In this IRP, Vectren is accounting for both direct CO_2 emissions and CO_2-equivalent (CO_2e) emissions for the life cycle of assets.

In the medium-term as in the short-term, energy efficiency standards and energy company sponsored DSM programs mostly offset the growth in energy sales from a growing residential customer base. However, overall load growth continues, driven by new C&I customers locating in the Midwest to take advantage of access to low-cost shale gas.

Natural gas prices at the Henry Hub in the medium-term will continue to be low but will rise over time, with the consensus forecast anticipating prices in the $3.00-$3.50/MMBtu range. Low prices tend to be self-correcting, resulting in restricted production and reduced gas supply. Coupled with LNG export capacity growing through 2023 and increased industrial consumption in many parts of the country, overall demand is expected to rise and gas markets to tighten. This is especially true in the premium Gulf Coast market, where much of the demand is materializing, increasing prices beginning in 2021.

Coal prices in the Illinois Basin are expected to continue to decline gently in the medium-term, as the modest export market is unable to compensate for declining domestic demand. Consensus Illinois Basin prices at the mine are low, averaging $1.60/MMBtu over the study period, with a slight decline over time.

[37] https://www.eia.gov/outlooks/aeo/

Power prices, which are an output of the AURORA model for MISO Zone 6, continue to move upward moderately as natural gas prices increase from the currently low levels. As the customer base continues to grow, energy company operating costs continue to rise. Commodity markets recover in the medium-term, pushing up material costs and consequently capital costs. In addition, as the overall economy continues to improve and the unemployment rate remains near historically low levels, capital costs rise as competitive upward pressure remains on labor costs.

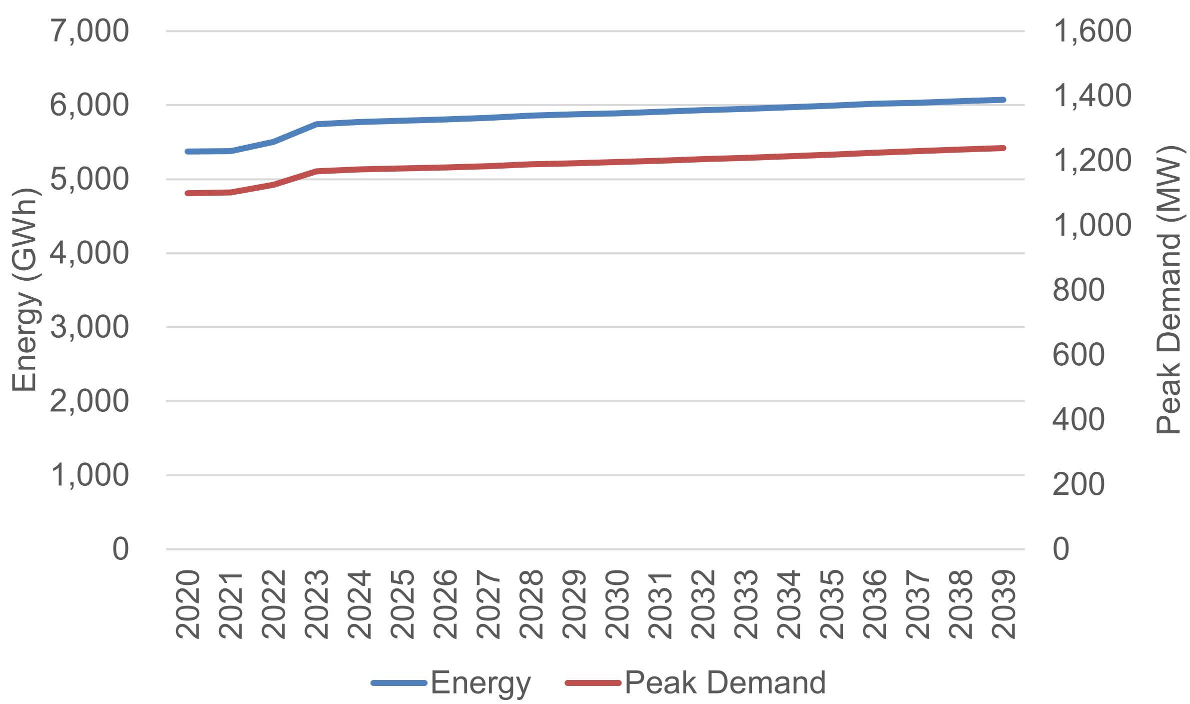
Coal retirements in the Reference Case mean no emissions from retired units, which contribute to lowering total CO_2 (and CO_2e) emissions. Coal plant retirements will continue to be driven by plant-specific going-forward economics, which rise as a national CO_2 price is assumed to begin in 2027. Meanwhile, capacity additions in the medium-term are expected to come from natural gas combined cycle plants as well as solar and wind facilities.

Long Term: In the long-term (2029-2039), the suite of market outcomes and drivers in the Reference Case settles into a pattern of moderate growth based on a well-balanced market. Energy sales grow at a moderate pace (0.6% CAGR for 2020-2039). The consensus forecast for Henry Hub has prices reaching $4/MMBtu by 2036 (in real 2018$), while ILB coal prices at the mine decline to $1.58/MMBtu by 2039 (in real 2018$). Market participants have enough time to adapt and adjust as regulatory compliance costs increase, helping to keep CO_2 prices moderate albeit rising to approximately $15/short ton by 2039 (in real 2018$). Energy demand grows as electric vehicle sales take hold and as residential and commercial customers electrify their energy use, but this is partially offset by continued gains in distributed solar generation, demand side management and energy efficiency measures. Domestic shale gas resources help to keep fuel cost growth to a low level. Capital costs increase at a measured pace as the GDP growth rate averages two percent or more and as higher borrowing costs come from long-term rising interest rates. Capacity additions and retirements continue at a reasonable rate as the fleet of power plants maintains a healthy rate of turnover.

7.2.1 Input Forecasts

The long-term energy and demand forecast for the Vectren service territory was developed for Vectren by Itron. The long-term energy and demand forecast for the MISO market comes from the System Forecasting for Energy Planning section of MISO's website.[38] For more information, please see Section 4 Customer Energy Needs. The forecast is based on a combination of historical usage trends and a bottom-up approach to drivers such as residential and commercial demand, industrial load, appliance saturation, energy efficiency, long-term weather trends, customer-owned generation, electric vehicle adoption and an outlook for economic factors.

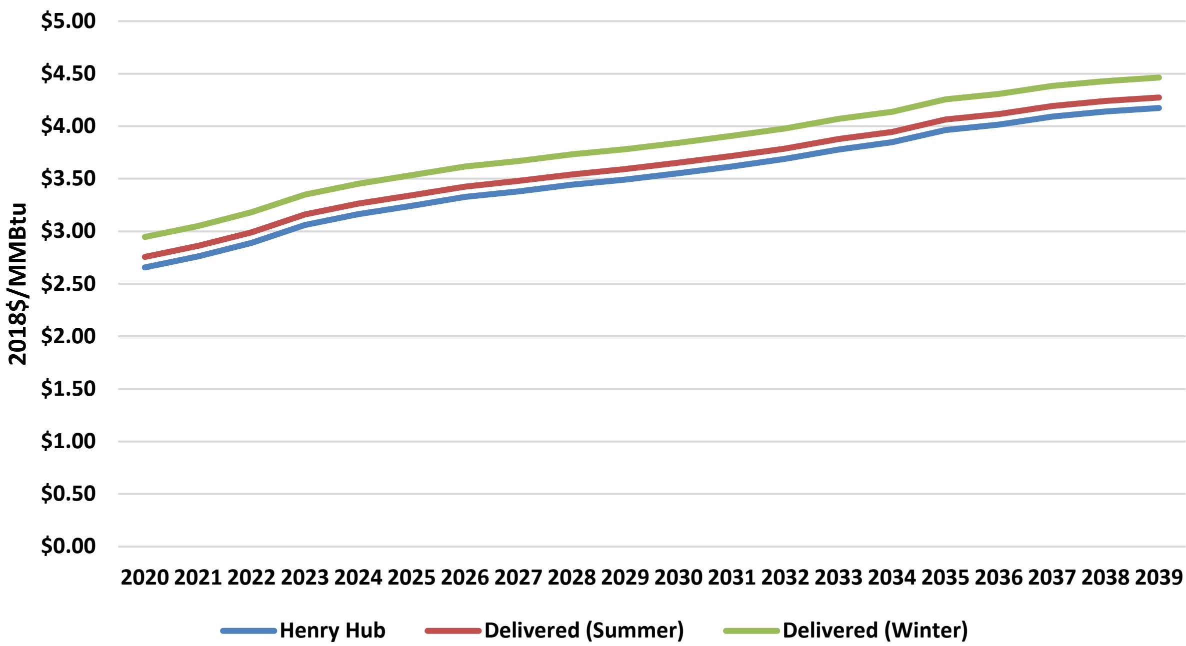
Figure 7.1 – Reference Case Vectren Load Forecast (MWh and MW)



[38] https://www.misoenergy.org/planning/policy-studies/system-forecasting-for-energy-planning/#nt=%2Freport-study-analysistype%3ALoad%20Forecast&t=10&p=0&s=FileName&sd=desc

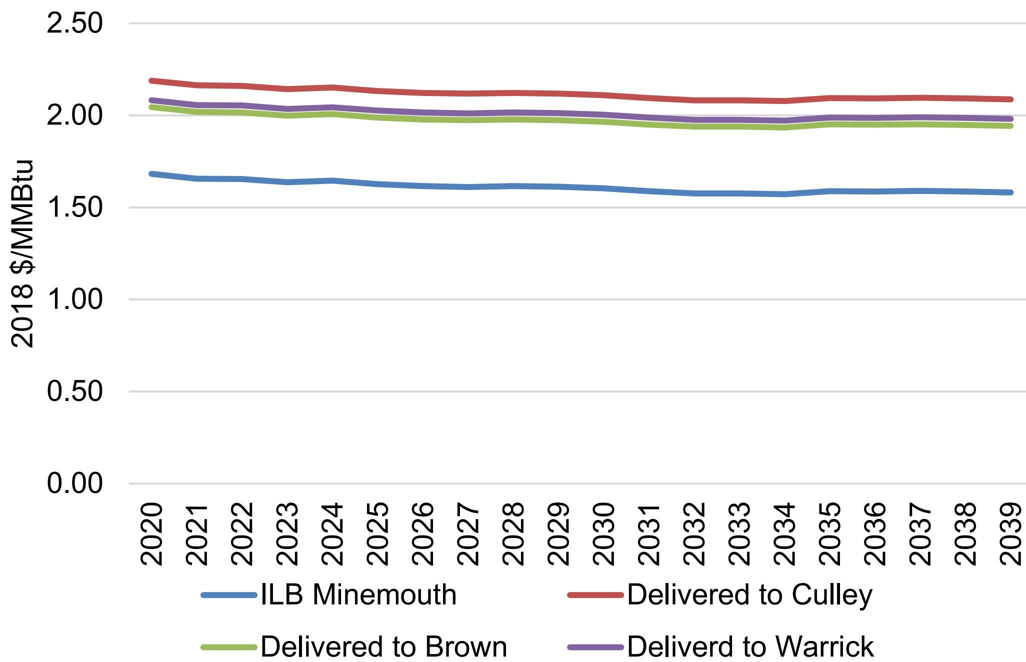
For both natural gas and coal Vectren used a “consensus” Reference Case view of expected prices by averaging forecasts from several sources. For natural gas and coal, forecasts from PIRA, Wood Mackenzie, Pace Global, ABB, & EVA were averaged. For capacity, Vectren used a consensus forecast, using Pace Global, ABB and Wood Mackenzie[39]. This helps to capture views from several experts and allows Vectren to be more transparent in the planning process. Delivered natural gas prices are \$0.10-\$0.29 higher than Henry Hub due to seasonal transportation tariffs.

Figure 7.2 – Reference Case Natural Gas Price Forecast (2018$/MMBtu)



[39] Vectren did not have access to a capacity forecast from PIRA or EVA

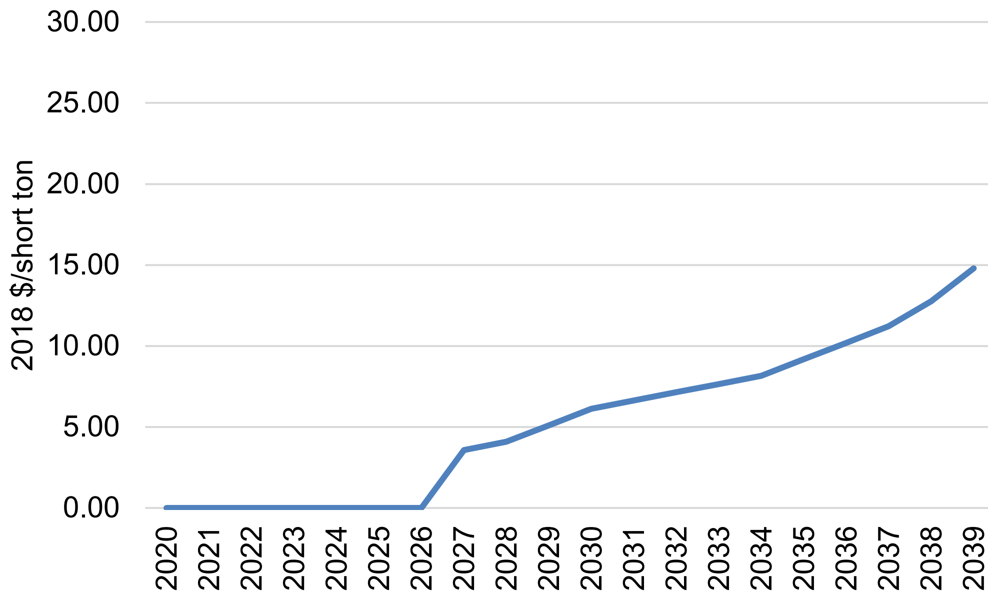
Figure 7.3 – Reference Case Coal Price Forecast (2018$/MMBtu)



No comprehensive national legislation of carbon emissions exists in the United States currently. Efforts to enact federal policy covering carbon emissions from major sources have occurred over the years. This included efforts by the U.S. Congress to pass a national cap-and trade regime, the EPA's regulation of GHG emissions from new and existing power generators which culminated in the current ACE rule, and more recently proposals in the U.S. Congress for carbon taxes and comprehensive clean energy targets.

Action to limit carbon emissions has increased in recent years with states taking the lead in defining low and no-carbon generation requirements. Indiana does not have a state policy limiting or otherwise placing a price on carbon emissions from power generation. However, the potential remains for enactment of such a policy at the national level over the study period. To account for this uncertainty and per stakeholder request, a moderate price on CO_2 emissions from fossil generators is assumed in the Reference Case. This outlook includes a national carbon price to become effective in 2027, covering emissions from electric generating units in the United States. Pace's EBA's CO_2 price projections in the Reference Case are presented in the figure below.

Figure 7.4 – Reference Case CO_2 Price Forecast (2018$/short ton)



Capital costs in the near to midterm (through 2024) were based on Tier 1 bids, as described in Section 6.1.5 Grouping. As described in Section 6, non-renewable capital costs were developed by Burns & McDonnell, while long term solar, wind and battery storage costs were developed using a consensus forecast from Burns & McDonnell, Pace Global and the NREL ATB 2018. Long-term capital costs for storage and solar + storage were adjusted to reflect bid pricing in the near term and then the capital cost indexes were used to adjust prices beyond the bid period. The long-term cost for solar was in line with the consensus forecast and therefore was not adjusted. Forward capital cost estimates can be found in Figure 6-21.

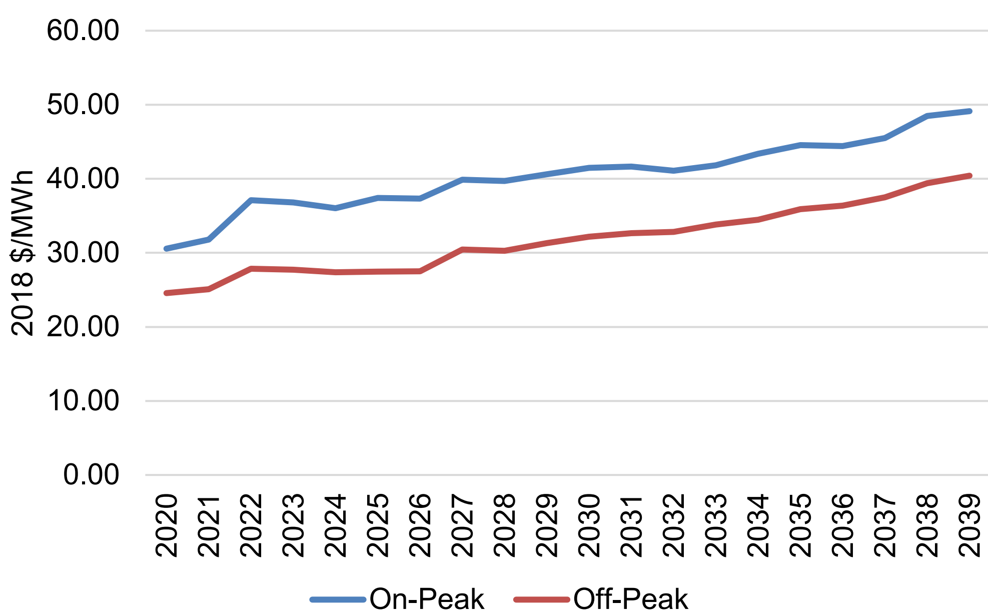
7.2.2 Energy Prices

On- and off-peak (day ahead) power price forecasts were a modeling output developed by Pace Global using the Reference Case assumptions described above, together with

Pace Global' s view of the greater MISO market, in the AURORAxmp power dispatch model.

Vectren's modeling does assume curtailment of resources when more energy is produced than is needed to meet customer load and Vectren's All-Source RFP sought operational control of resources.

Figure 7.5 – Reference Case Power Price Forecast (2018$/MWh)



Levelized DSM costs were developed by utilizing the 2019 MPS and the annual supply curves to develop costs for each energy efficiency bundle, as described in Section 6-32 Energy Efficiency Reference Case.

7.2.3 Environmental Regulations

The current modeling analysis primarily focused on evaluation of alternatives to comply with the CCR, ELG, 316(b) and ACE rule requirements. For CCR and ELG compliance, conversion to dry or closed loop bottom ash handling, wastewater treatment and landfill construction options were evaluated. For 316(b) compliance, based on site-specific considerations, standard mesh and fish friendly screens and fish return systems were assumed. All costs presented below are preliminary screening level estimates used for modeling purposes only. Individual elements of the estimate may go up or down depending on final design specifications and vendor bids.

7.2.3.1 Effluent Limitations Guidelines (ELG)

A. B. Brown: ELG related changes include conversion to dry bottom ash, upgrades to the dry fly ash system, a new landfill that can handle scrubber product and ash and a new system to handle process waters. ($138M)

F. B. Culley: Required plant upgrades include conversion to dry bottom ash, FGD wastewater treatment and access to a landfill that can handle dry ash. ($62M)

For Warrick Unit 4, Vectren modeled its share of the total capital spend.

7.2.3.2 Coal Combustion Residuals (CCR)

For A. B. Brown and F. B. Culley, it was assumed that ash ponds would be closed at the end of their useful life. The timing of the closures are based on forced closure (i.e. exceedance of GWPS and failure of aquifer location restriction) and whether alternative disposal capacity is available. The base cost for the closures does not change regardless of future generation. In order to continue operating coal-fired units, the A.B. Brown facility will potentially need to construct a new CCR rule compliant landfill capacity and a new CCR rule compliant pond, both of which depend on the scrubber technology utilized in the future. Vectren has not historically utilized the ponds at the Warrick power plant for its share of the CCR generated by WPP4 and therefore is not liable for pond closure costs.

7.2.3.3 Affordable Clean Energy (ACE)

As described earlier, In June 2019 EPA finalized the ACE, which replaces the Clean Power Plan from 2015 (a cap and trade program which sought to lower CO_2 emissions from existing power plants by 30% from 2005 levels). Vectren assumed that ACE compliance would begin in 2024.

Figure 7.6 – ACE Cost

Unit	Total ACE Upgrade Cost (2019$)
A.B. Brown 1	$10 Million
A.B. Brown 2	$10 Million
F.B. Culley 2	$26 Million
F.B. Culley 3	$30 Million
Warrick 4	N\A[40]

7.2.3.4 316(b)

EPA issued its final rule regarding Section 316(b) of the Clean Water Act. The rule establishes requirements for cooling water intake structures (CWISs) at existing facilities.

This requirement applies to both F. B. Culley and Warrick. At this time, based on available information for A. B. Brown, IDEM has made a Best Technology Available determination that the existing cooling water intake structures represent best technology available to minimize adverse environmental impact. This determination will be reassessed at the next NPDES permit reissuance. Standard fine mesh and fish friendly screens and fish return systems were estimated to be $21M at F. B. Culley. Warrick is required to install modified travelling screens and a fish handling and return system at Warrick. Vectren is responsible for its share of total capital.

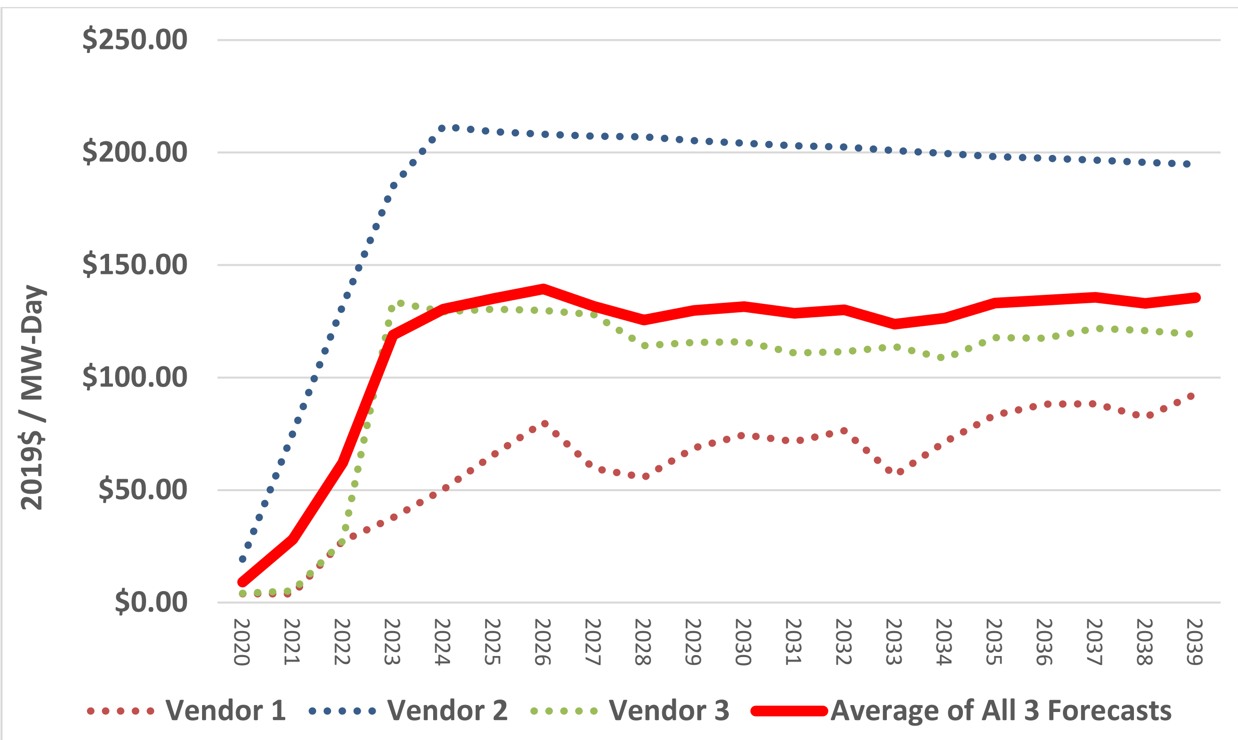
7.2.3.5 Market Capacity Price

The MISO capacity price has been difficult to predict as indicated by the volatile price history shown. This is especially true when analyzing the clearing price for the entire MISO-region. The clearing price in neighboring zones can be drastically different than

[40] In this analysis it is assumed joint operations of Warrick 4 ends in 2023 or 2026; In the 2026 scenario there is a cost of ~$1 million

Zone 6's and becomes an important consideration as Zone 6 imports capacity to meet its planning reserve margin requirement. Nonetheless, it is necessary for analysis purposes to have a capacity market price assumption to be included in the IRP modeling process. For illustrative purposes only, for every $1 per MW-day increase in the auction clearing price, there is an approximate $438,000 ($1 x 1,200 MW x 365 days) annual cost of capacity impact to Vectren customers. Some capacity will be bought or sold nearly every year since load and planning reserve margin requirements vary while most supply side resources, such as generating units, come in large blocks with 30+ year expected lifetimes. Vectren used a consensus forecast, utilizing Pace Global, ABB and Wood Makenzie for Reference Case MISO Indiana capacity prices for modeling purposes.

Figure 7.7 – Capacity Market Value Forecast (2019$/MW-Day)



For reference, MISO has set the Cost of New Entry (CONE) for Zone 6 in the 2020-2021 planning year at $255/MW-Day which sets the maximum offer and clearing price in the annual capacity auction. While the forecast used in this analysis is significantly lower than CONE it is necessary to consider that capacity prices could reach this level making long term reliance on the capacity market a risk that should be avoided. This consideration is even more relevant due to Zone 7, the lower peninsula of Michigan, clearing at CONE during this year's PRA.

It is a combination of the MISO warnings, the widely varying Consultant forecasts and the risks associated with an illiquid market that suggests to Vectren that the best way to mitigate the capacity market risk is through building Combustion Turbines for capacity rather than rely heavily on the market.

7.2.4 Additional Modeling Considerations

Vectren received approval in 2019 from the Commission to upgrade F.B. Culley 3, Vectren's most efficient coal unit, for continued operations. As such, the unit was modeled with continued operations throughout the planning period. As stated in that case, there is a premium for resilience and diversity with continuing to run the Culley unit. Based on updated reference case modeling in this IRP, that premium is estimated to be about ~0.5% in total NPV for continuing to run the plant through 2034. Vectren has chosen to continue operating this unit for the resiliency that it provides. All other coal units could retire economically within the model beginning December 31, 2023.

Modeling also included other fixed considerations. All candidate portfolios were designed to include the first five selectable energy efficiency bins, corresponding to 1.25% of energy efficiency, in the near-term years of 2021-2023. The model also included one fixed low-income bundle and one fixed demand response bundle (an air conditioning direct load control measure to a smart thermostat measure). Vectren's coal units were modeled to dispatch to LRZ6 on the basis of full variable costs (fuel, emissions, VOM) in the years 2019-2023, while dispatching to serve native load on the basis of fuel only in these same years. All coal units (whether selected to continue or not) were modeled to dispatch to full variable costs to LRZ6 and Vectren from 2024 through the end of the forecast period (2039). Long term annual capacity market purchases were limited to ~180 MW.

While a dynamic peak capacity credit (automatically adapting to the penetration level of solar and wind resources in MISO) proved to be challenging to implement in Aurora, Vectren's modeling efforts did include a seasonal, declining peak capacity credit for both solar and wind resources. Summer solar peak capacity credit began at 29% in 2023 (the first year in which new solar resources are available) and declined to 17% by 2039, while winter solar peak capacity credit began at 7% in 2023 and declined to 4% in 2039. Summer wind peak capacity credit began at 7.23% in 2022 (the first year in which new wind resources are available) and declined to 6.62% by 2039, while winter wind peak capacity credit began at 16.1% in 2022 and declined to 14.74% in 2039. Battery storage was modeled with a 95% peak capacity credit. Non-bid solar and Non-bid wind resources were not permitted until 2025 after short-term renewable and storage PPAs were no longer available.

Additional modeling parameters were included to account for logistical, commercial and operational limitations. These included limiting wind energy resources to 400 MW per year, wind plus storage resources to 150 MW per year, solar photovoltaic resources to 500 MW per year, solar plus storage resources to 150 MW per year, lithium-ion battery storage resources to 300 MW per year and flow battery storage to 400 MW per year. Combined cycle gas resources were limited to one unit per year, while simple cycle gas turbine resources were limited to a total of three units. Combined heat and power (CHP), reciprocating engines and aeroderivative gas turbines were excluded as resource options on the basis of lack of a dedicated facility for steam in the case of CHP and for technical considerations (for example, gas pipeline pressure requirements and cost) in the case of aeroderivatives.

7.3 ALTERNATE SCENARIOS

In order to develop several alternative scenarios for its IRP process, Vectren used a construct that allowed for increasing regulatory restrictions across four alternative scenarios. As previously mentioned, there were two purposes for these scenarios. First, each alternative market scenario was used to develop a least cost portfolio. Second, the final list of portfolios was evaluated against each alternative market scenario.

The alternate scenarios were created with increasing order of regulatory restriction included the Low Regulatory scenario, the High Technology scenario, the 80% Reduction in CO_2 scenario and the High Regulatory scenario. Pace Global provided the qualitative descriptions and quantitative inputs for each of these scenarios, which were based on collaboration between Vectren, Pace and stakeholders.

Each of the four alternative scenarios provided a framework of market inputs in which a least cost portfolio solution was developed. Of the four scenario based portfolios that were developed, only the High Technology portfolio was selected for further analysis.

The High Technology portfolio provided a useful boundary condition on the Reference Case, relying on a second combustion turbine unit, 1,146 MW of solar, 300 MW of wind and 176 MW of storage. The other three alternative scenario based portfolios included significantly greater renewable resources in their respective market scenario conditions than needed to serve Vectren customers under reference case conditions. In these three scenarios that were not selected for further analysis, the portfolios selected as least cost assumed large quantities of off-system sales in order to reduce portfolio costs. The high level of sales associated with these portfolios precluded them from further consideration as that was a significant issue raised in several of the portfolios in the 2016 study in the Director's report.

For example, the Low Regulatory portfolio included higher load and higher gas prices than in the Reference Case. However, the portfolio (optimized to those different market conditions) included 2,146 MW of solar, 2,700 MW of wind, 126 MW of battery storage and a relatively heavy reliance on capacity market purchases, in addition to F.B. Culley 3 and one new CT.

The least cost 80% Reduction of CO_2 portfolio included 1,946 MW of solar, 3,050 MW of wind and 392 MW of battery storage. Due to the significant increase in late-term renewables buildout, this portfolio saw annual net energy sales climb from 2,500,000 MWhs in 2033 to over 9,300,000 MWhs by 2039.

The least cost High Regulatory portfolio included 2,956 MW of solar, 3,600 MW of wind and 618 MW of battery storage. Due to the heavy buildout of renewables, this portfolio reached 10,000,000 MWh of annual net energy sales by 2029 and stayed above this level for the remainder of the study period.

7.3.1 Description of Alternate Scenarios

As described in Section 2.4, the second purpose of developing these “boundary” scenarios was to test a relevant range for each of the key market drivers (gas, coal, CO_2, load and capital costs) on how various technologies perform under boundary conditions.

7.3.1.1 Low Regulatory

The Low Regulatory scenario is meant to be a lower boundary scenario in which there is a general laissez-faire attitude toward regulations. In the Low Regulatory scenario, only the ACE rule is included for CO_2 regulation and remains in place throughout the forecast. Indiana implements a lenient interpretation of the rule. ELG is partially repealed with bottom ash conversions not required for some smaller units and is delayed for two years (this does not apply to F.B. Culley 3).

In this scenario, fewer regulations are expected to result in a better economy and higher load. Gas prices are expected to move upward with increased demand, while coal prices continue to remain at Reference Case levels as demand for coal continues to decline nationally due to investor pressure and demand for cleaner alternatives. Technology capitals costs are expected to continue to decline at Reference Case levels.

Energy efficiency costs are expected to net to the Reference Case 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 Reference Case level.

7.3.1.2 High Technology

The High Technology scenario was constructed to be indicative of significant advances in energy storage technology, renewable energy deployment, emissions reduction and CO_2 removal technology, high efficiency gas-fired generation and natural gas extraction productivity. Overall, there are significant developments in technologies that improve energy efficiency, which helps to mitigate the load growth that might otherwise be expected in a high technology scenario with robust economic growth.

The High Technology scenario assumes that technology costs decline faster than in the Reference Case, allowing renewables and battery storage to become more competitive. A relatively low CO_2 tax is implemented in this scenario. The economic outlook is better than in the Reference Case as lower technology costs and lower energy prices offset the impact of the CO_2 tax. The 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 Reference Case. There is less demand for coal, which results in lower prices relative to the Reference Case. In addition, utility-sponsored energy efficiency costs rise early in the forecast but ultimately fall back to below Reference Case 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 increased electric vehicle sales and higher adoption of rooftop distributed solar and battery storage, which trend towards highly efficient electric heat pumps in new homes.

7.3.1.3 80% CO_2 Reduction by 2050

The 80% CO_2 Reduction by 2050 scenario assumes that a carbon cap regulation is implemented, which mandates an 80% reduction of CO_2 by 2050 from 2005 levels. A glide path is then set based on a gradual ratcheting-down of CO_2 emissions and an increasing CO_2 allowance cost.

In this scenario, load decreases as the costs for energy and backup power increase and as the energy mix transitions into areas such as increased electrification. 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 Reference Case. However, there is less demand for coal, which drives prices lower than the Reference Case. Some large and efficient coal plants remain as large fleets can comply with the regulation on a fleet wide basis.

Renewable energy and battery storage technologies are widely implemented to help meet the mandated CO_2 reductions. Despite this demand, costs are lower than the Reference Case due to subsidies or similar public support to address climate change concerns. Market-based solutions are implemented to lower CO_2. Innovation continues to occur but is offset by more codes and standards with no incentives. As a result, energy efficiency costs rise.

7.3.1.4 High Regulatory

The High Regulatory scenario is characterized by a more heavily regulated path. The High Regulatory path is indicative of the following plausible circumstances relative to the Reference Case:

- A much higher cost for compliance with emissions controls, which begins virtually immediately in 2022 at $50/short ton of CO_2;
- More renewable adoption pushed through via mandates;
- Additional regulations on carbon on the horizon after 2030 that are higher than in the Reference Case, including a potential expansion of carbon costs not only at

the upstream level (which is relatively efficient to administer across a few thousand producers) but also on the downstream level (which is much less efficient to administer across millions of consumers, a policy that is adopted to force through more rapid change);

- Greater adoption of distributed generation in the form of solar and combined heat and power; and
- Restrictions on fracking and fugitive methane emissions that limit gas supply growth, drive up gas prices and result in an additional push and economic case for renewable energy.

The social cost of carbon is implemented via a high CO_2 tax early in the scenario. Monthly rebate checks (dividends) help to redistribute the revenues from the tax to American households based on number of people in the household. Furthermore, a fracking ban is imposed, driving up the cost of natural gas to historical levels last seen in the pre-shale boom era (pre-2008) in the long-term as supply dramatically shrinks (quantitatively, the price path is +2 standard deviations above current levels). For coal, a strong decline in demand puts downward pressure on coal prices.

The economic outlook remains at the Reference Case level as any potential benefit of the CO_2 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.

7.3.2 Coordinated Forecasts for Alternate Scenarios

The qualitative description of alternate scenarios described in Section 7.3.1 were next translated into quantitative inputs for use as modeling inputs. The steps in this process were described in Section 2.

- Stochastic distributions were developed for each input variable

- A table was developed that determined whether the variable would be above or below the Reference Case in the short, mid and long term.
- Values in specific years were developed by moving up or down one standard deviation (for gas sometimes two standard deviations) from the mean or reference forecast.
- Smoothing occurred to reach interim year values.

This was done using a probabilistic modeling framework, described below, which allowed the development of higher and lower forecasts, relative to the Reference Case for natural gas prices, CO_2 prices, coal prices, average and peak load for Vectren as well as surrounding markets (MISO, PJM and SERC) and capital costs for renewables, storage and fossil technologies.

7.3.2.1 Stochastic Distributions

In order to perform the probabilistic modeling, also known as stochastic analysis, a set of probability distributions were required for the key market driver variables described above (fuel, emissions, load and capital costs). These probability distributions were developed from a simulation that creates 200 future paths for each stochastic variable. The following sections describe the methodologies for developing these stochastic variables, with additional detail explained in the Technical Appendix 11.6.

7.3.2.1.1 Load Stochastics

To account for electricity demand variability that derives from economic growth, weather, energy efficiency and demand side management measures, Pace Global developed stochastics around the load growth expectations for the Vectren control area and the neighboring ISO zones, including MISO, PJM and SERC. Pace Global' s long-term load forecasting process is a two-step process that captures both the impact of historical load drivers such as economic growth and variability of weather and the possible disruptive impacts of energy efficiency penetration in constructing the average and peak demand outlook. Pace Global benchmarked the projections against MISO-sponsored load forecasting studies that are conducted by independent consultants, institutions and market monitors and then released into the public domain.

7.3.2.1.2 Gas Stochastics

Pace Global developed natural gas price stochastic distributions for the benchmark Henry Hub market point. These stochastic distributions are first based on the consensus Reference Case view of natural gas prices with probability bands developed then based on a combination of historical volatility and mean reversion parameters as well as a forward view of expected volatility. For the period 2019-2022, volatility calculated from the past three years of price data is used. For 2023-2025, volatility calculated from the past five years is used. For 2026-2039, volatility calculated from the past 10 years is used. This allows gas price volatility to be low in the short-term, moderate in the medium-term and higher in the long-term in alignment with observed historical volatility. The 95th percentile probability bands are driven by increased gas demand (e.g., coal retirements) and fracking regulations that raise the cost of producing gas. Prices in the 5th percentile are driven by significant renewable development that keeps gas plant utilization relatively low as well as few to no new environmental regulation around power plant emissions.

7.3.2.1.3 Coal Stochastics

Pace Global developed coal price stochastic distributions for the CAPP, NAPP, ILB and PRB basins. These stochastic distributions are first based on a consensus Reference Case view of coal prices with probability bands developed then based on a combination of historical volatility and mean reversion parameters. It should be noted that most coal contracts in the U.S. are bilateral and only approximately 20% are traded on the NYMEX. The historical data set that is used to calculate the parameters is comprised of the weekly traded data reported in NYMEX.

7.3.2.1.4 Emissions Stochastics

Pace Global developed uncertainty distributions around carbon compliance costs, which were used in Aurora to capture the inherent risk associated with regulatory compliance requirements. The technique to develop carbon costs distributions, unlike the previous variables, is based on projections largely derived from expert judgment, as there are no national historical data sets (only regional markets in California and the Northeast) to estimate the parameters for developing carbon costs distributions.

7.3.2.1.5 Capital Cost Stochastics

Pace Global developed the uncertainty distributions for the cost of new entry units by technology type, which was used in Aurora for determining the economic new builds based on market signals. These technologies included gas peaking units, gas combined cycles, solar, wind and battery storage resources. The methodology of developing the capital cost distributions is a two-step process: (1) a parametric distribution based on a Reference Case view of future all-in capital costs, historical costs and volatilities and a sampling of results to develop probability bands around the Reference Case; and (2) a quantum distribution that captures the additional uncertainty with each technology that factors in learning curve effects, improvements in technology over time and other uncertain events such as leaps in technological innovation.

7.3.2.1.6 Cross-Commodity Stochastics

Pace Global captured the cross-commodity correlations in the stochastic process, which is a separate stochastic process from those for gas, coal and CO_2 prices. The feedback effects are based on statistical relationships between coal and gas switching and the variable cost of coal and gas generators. Pace Global conducted a fundamental analysis to define the relationship between gas and coal dispatch costs and demand. The dispatch costs of gas and coal were calculated from the gas and coal stochastics and CO_2 stochastics, along with generic assumptions for variable operation and maintenance costs. Where the gas-coal dispatch differential changes significantly enough to affect demand, gas demand from the previous year was adjusted to reflect the corresponding change in demand. A gas price delta was then calculated based on the defined gas demand. This gas price delta was then added to the gas stochastic path developed from historic volatility to calculate an integrated set of CO_2 and natural gas stochastic price forecasts.

7.3.2.2 Model Inputs

The following graphs illustrate the key market driver inputs across all the alternate scenarios.

Figure 7.8 – Vectren Peak Load (MW) Alternate Scenarios

	Ref 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

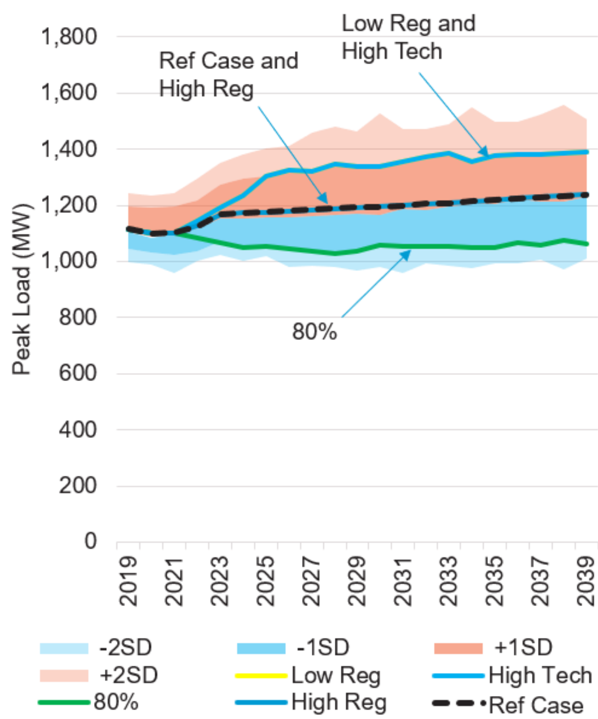


Figure 7.9 – Coal (Illinois Basin) Alternate Scenarios (2018$/MMBtu)

	Ref Case	Low Reg	High Tech	80% Reduction	High Reg
2019	1.78	1.78	1.78	1.78	1.78
2020	1.68	1.68	1.68	1.68	1.68
2021	1.66	1.66	1.66	1.66	1.66
2022	1.65	1.65	1.57	1.57	1.57
2023	1.64	1.64	1.49	1.49	1.49
2024	1.64	1.64	1.41	1.41	1.41
2025	1.63	1.63	1.27	1.27	1.27
2026	1.62	1.62	1.29	1.29	1.29
2027	1.61	1.61	1.25	1.25	1.25
2028	1.62	1.62	1.25	1.25	1.25
2029	1.61	1.61	1.25	1.25	1.25
2030	1.60	1.60	1.25	1.25	1.25
2031	1.59	1.59	1.25	1.25	1.25
2032	1.58	1.58	1.25	1.25	1.25
2033	1.58	1.58	1.25	1.25	1.25
2034	1.57	1.57	1.25	1.25	1.25
2035	1.59	1.59	1.25	1.25	1.25
2036	1.59	1.59	1.25	1.25	1.25
2037	1.59	1.59	1.25	1.25	1.25
2038	1.59	1.59	1.25	1.25	1.25
2039	1.58	1.58	1.25	1.25	1.25

A price floor is set at $1.25/MMBtu

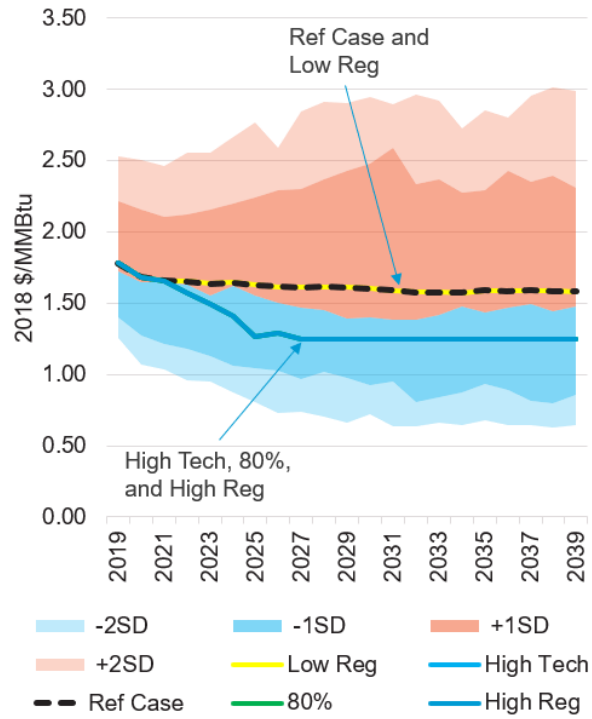


Figure 7.10 – C0₂ Alternate Scenarios (2018$/ton)

	Ref 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	3.57	0	2.06	5.10	54.17
2028	4.08	0	2.28	6.12	55.11
2029	5.10	0	2.38	6.63	56.05
2030	6.12	0	2.68	7.14	56.99
2031	6.63	0	2.94	7.65	57.94
2032	7.14	0	3.17	8.16	58.88
2033	7.65	0	3.89	9.18	60.06
2034	8.16	0	4.49	10.20	61.23
2035	9.18	0	5.46	11.22	62.41
2036	10.20	0	6.01	12.75	63.59
2037	11.22	0	6.85	14.79	64.77
2038	12.75	0	7.52	17.34	65.94
2039	14.79	0	8.50	19.89	67.12

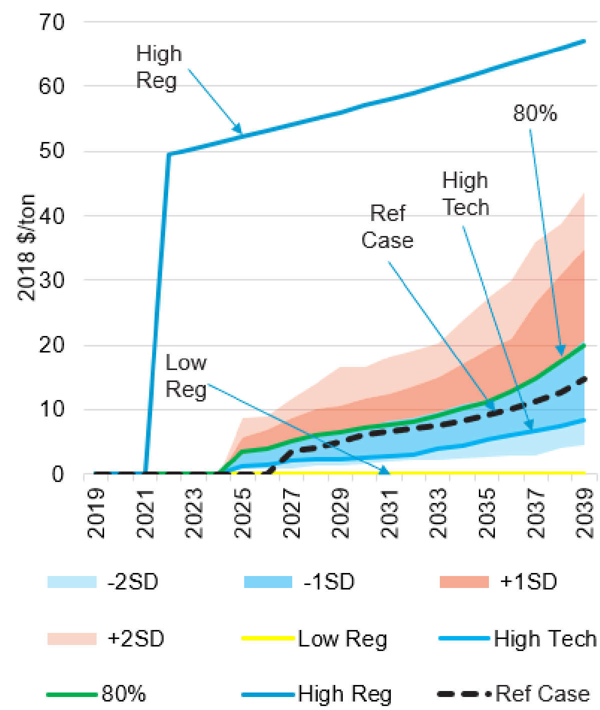


Figure 7.11 – Natural Gas (Henry Hub) Alternate Scenarios (2018$/MMBtu)

	Ref 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

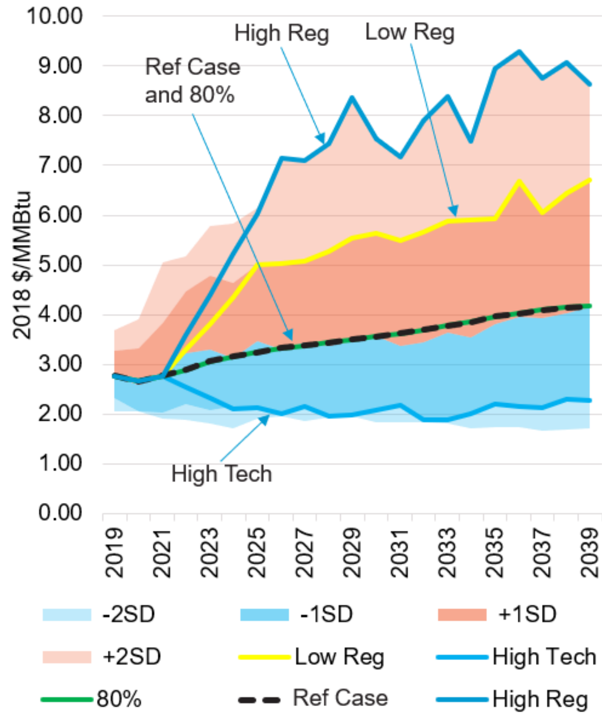


Figure 7.12 – Solar Capital Costs Alternate Scenarios(100 MW) (2018 $/kW)

	Ref Case	Low Reg	High Tech	80% Reduction	High Reg
2019	1,384	1,384	1,255	1,255	1,255
2020	1,305	1,305	1,160	1,160	1,160
2021	1,237	1,237	1,093	1,093	1,093
2022	1,198	1,198	1,043	1,043	1,043
2023	1,179	1,179	1,008	1,008	1,008
2024	1,161	1,161	996	996	996
2025	1,143	1,143	954	954	954
2026	1,124	1,124	956	956	956
2027	1,106	1,106	943	943	943
2028	1,089	1,089	949	949	949
2029	1,072	1,072	921	921	921
2030	1,057	1,057	887	887	887
2031	1,041	1,041	878	878	878
2032	1,028	1,028	871	871	871
2033	1,016	1,016	858	858	858
2034	1,003	1,003	817	817	817
2035	990	990	801	801	801
2036	981	981	790	790	790
2037	972	972	792	792	792
2038	962	962	789	789	789
2039	952	952	800	800	800

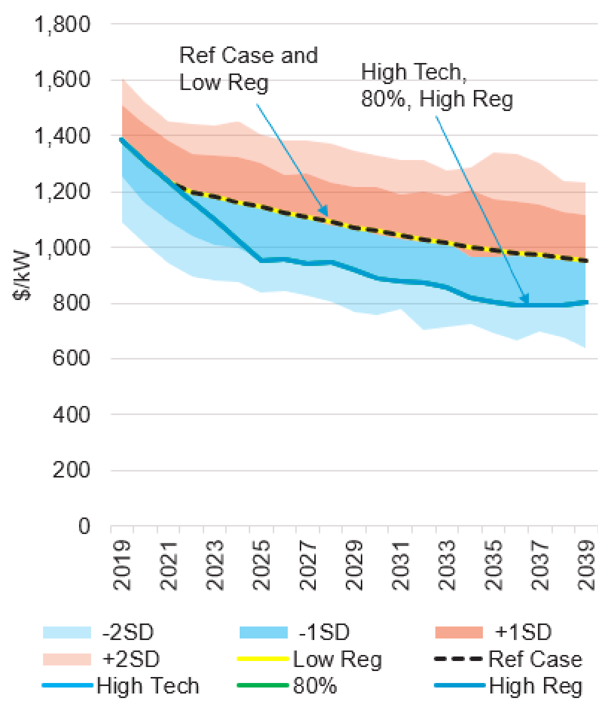


Figure 7.13 – Wind Capital Costs Alternate Scenarios (200 MW) (2018 $/kW)

	Ref 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

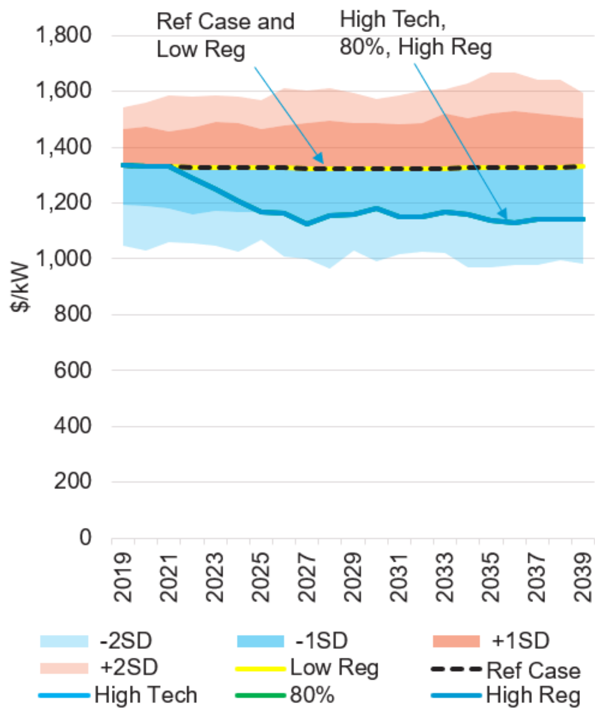
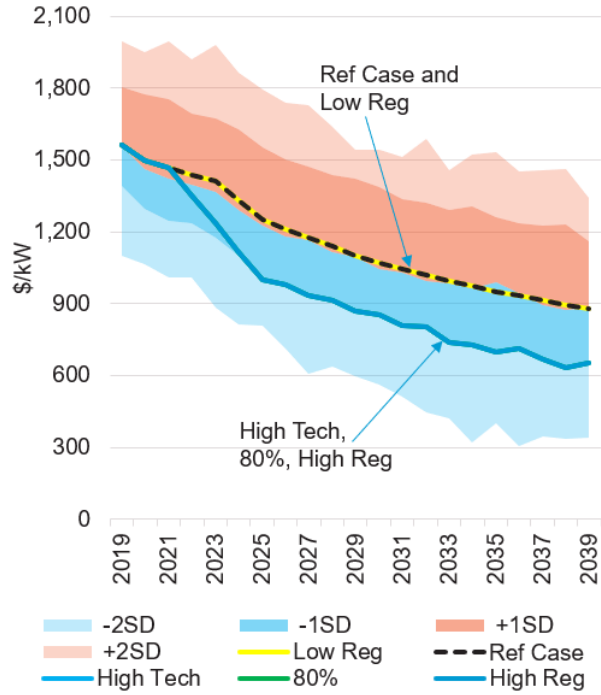


Figure 7.14 – Lithium-Ion 50 MW / 200 MWh Battery Storage Capital Costs Alternate Scenarios (2018$/kW)[41]

	Ref Case	Low Reg	High Tech	80% Reduction	High Reg
2019	1,562	1,562	1,390	1,390	1,390
2020	1,498	1,498	1,299	1,299	1,299
2021	1,467	1,467	1,247	1,247	1,247
2022	1,439	1,439	1,236	1,236	1,236
2023	1,412	1,412	1,178	1,178	1,178
2024	1,332	1,332	1,100	1,100	1,100
2025	1,252	1,252	1,001	1,001	1,001
2026	1,209	1,209	982	982	982
2027	1,175	1,175	936	936	936
2028	1,140	1,140	916	916	916
2029	1,103	1,103	869	869	869
2030	1,068	1,068	852	852	852
2031	1,044	1,044	811	811	811
2032	1,020	1,020	806	806	806
2033	996	996	739	739	739
2034	975	975	727	727	727
2035	951	951	699	699	699
2036	933	933	714	714	714
2037	915	915	669	669	669
2038	897	897	631	631	631
2039	878	878	654	654	654



[41] Note that storage costs were updated since the October 10th stakeholder meeting and are lower

SECTION 8
PORTFOLIO DEVELOPMENT AND EVALUATION

8.1 PORTFOLIO DEVELOPMENT

Vectren developed a wide range of portfolios for scenario modeling in the dispatch module of Aurora and ultimately for the probabilistic modeling portion of this IRP process. Working with external stakeholders and building upon feedback from the IURC Director's Report from the 2016 IRP, Vectren developed 15 "least cost" portfolios for evaluation that included the continuing use of coal plants (status quo) for comparative cost and performance benchmarking purposes, scenario-based portfolios optimized under widely varying market conditions, bridge portfolios designed to take advantage of existing resources during the transition to a generation fleet with many new resources, diversified portfolios with a balanced mix of generation technology types and renewables-focused portfolios designed with directed input from stakeholders. Each least cost portfolio was constructed with the option to include near-term solar, wind and battery storage options, from the All-Source RFP solicitation, while medium-term and long-term resource options were available for selection from a comprehensive technology assessment performed by Burns & McDonnell (with capital costs developed from a consensus view of prices from Burns & McDonnell, Pace Global and NREL for renewable and storage options). These resource portfolios were then selected on a least-cost basis using the LTCE module of the Aurora model. DSM resource options were also available for selection

8.1.1 Portfolio Strategies with Stakeholder Input

Vectren strived to take into consideration the many diverse interests of a broad range of stakeholders. Accordingly, several of the 15 candidate portfolios were developed with direct and indirect input from stakeholders. Three portfolios were designed to be focused on renewables, including a Renewables 2030 portfolio in which all fossil generation is retired at the end of 2029; a Renewables plus Flexible Gas portfolio, that includes closing F.B. Culley 3 by December 31, 2033 and excludes any new gas combined cycle plants; and an HB 763 portfolio modeled after a bill in the U.S. Congress that includes a CO_2 price in 2022 of $15, increasing by $10 per short ton each year (approximately $200 by 2039). Other portfolios, including the Business as Usual and Bridge portfolios, were designed to consider the interests of a separate set of stakeholders.

8.1.2 Least Cost Portfolio Construction

Each of the 15 strategies were utilized to construct portfolios in the Aurora model using a Least Cost Capacity Expansion module in AURORA with a cost minimization objective function. The scenario-based portfolios (Low Regulatory, High Technology, 80% Reduction of CO_2 and High Regulatory) each selected the lowest cost combination of assets assuming their respective market inputs. In Section 7 it is noted that three of those portfolios were eliminated from consideration because they employ greater capacity than needed in the form of renewable resources and rely on extensive off-system sales to reduce costs.

Other portfolios were determined by forcing certain design considerations for specific generating stations, including bridge options that include converting existing coal units into gas peaking units or extending the life of A.B. Brown coal units and then the model selected the least cost portfolio of remaining assets. Vectren also constructed in diverse energy portfolios with two sizes of gas combined cycle technologies and portfolios focused primarily on renewable and battery storage technologies. Utilizing this strategy allowed for a wide range of portfolios that were least cost portfolios using available resources, subject to initial design parameters in each strategy. All portfolios were also designed to include five (5) blocks of near-term (2021-2023) energy efficiency, which is equivalent to approximately 1.25% of eligible retail sales. Each portfolio description below details the optimized amount of EE selected.

8.1.3 Portfolio Descriptions

The following sections describe in detail designed portfolios (including bridge, diverse and renewables-focused portfolios). Figure 8.1 Portfolio Details shows a summary table of the build outs for each of the selected set of portfolios for consideration in the Risk Analysis. Note that the last line of each table shows long-term capacity market exposure under reference case conditions. Also, based on a sensitivity described in Section 8.2.2 near-term energy efficiency of 1.25% included in all portfolios.

Figure 8-1 – Portfolio Details

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)

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)

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)

8.1.3.1 Reference Case

The Reference Case is considered to be the “most likely” case, built with commodity forecasts based on a consensus outlook from industry experts as described in Section 7.2 Reference Case Scenario.

The least cost Reference Case portfolio includes 300 MW of wind resources selected in 2022, approximately 746 MW of solar selected in 2023 and 2024, the selection in 2023 of paired solar+storage resources (400 MW solar; 126 MW storage) and one new 236.6 MW CT selected in 2024, all of which replace A B Brown units 1 and 2, F B Culley 2 and Warrick 4. Approximately 0.75% of energy efficiency blocks are selected in each of the three time periods (near-term 2021-2023, mid-term 2024-2026 and long-term 2027-2039) while the optional demand response bin is selected in the time periods 2024-2026 and 2027-2039. F B Culley 3 operations continue through the forecast period. Any shortfall in capacity is met through capacity market purchases, which average 137.5 MW during the period 2024-2039. Finally, 250 MW of solar is selected in the final three years of the forecast (2037-2039).

8.1.3.2 Status Quo

The BAU to 2039 status quo portfolio was designed, by definition, to provide a business as usual outlook through the forecast period. In this portfolio, each of the four Vectren-owned coal generation units are kept in operation to 2039, subject to various upgrades to keep them in compliance with existing environmental regulatory requirements. The Warrick 4 unit was given the option to extend for an additional three years of operation before exiting the joint agreement, but ultimately was not selected by the optimization routine for continuation based on purely economic considerations. This portfolio provides a useful, status quo benchmark for financial and operational performance to compare against all the other candidate portfolios. Vectren exits Warrick 4 joint operations with Alcoa. This 150 MWs is replaced with renewables. The optimized (least costs) BAU to 2039 portfolio includes 300 MW of wind resources selected in 2022, approximately 746

MW of solar selected in 2023 and 2024 and the selection in 2023 of paired “solar plus storage” resources (400 MW solar; 126 MW storage). Approximately 0.50% of energy efficiency blocks are selected in each of the three time periods (near-term 2021-2023, mid-term 2024-2026 and long-term 2027-2039) while an additional block of EE (0.25%) is selected in the time period 2024-2026. This portfolio is capacity-rich, so no capacity market purchases are required during the period 2024-2039.

8.1.3.3 Four Scenario Based Portfolios

Four scenario-based portfolios (Low Regulatory, High Technology, 80% Reduction of CO_2 and High Regulatory) were developed to evaluate various regulatory constructs, economic and market conditions and technological progress. In general, the scenario-based portfolios move from low to high regulation, with intermediate levels of regulation characterized by the High Technology and 80% Reduction of CO_2 portfolios.

While the Reference Case is considered the most likely future, the alternative scenario-based portfolios were developed to bookend the Reference Case with higher than, lower than, or similar inputs to the Reference Case. The following sections describe the qualitative and quantitative development of the scenario-based portfolios.

8.1.3.3.1 Low Regulatory

The Low Regulatory portfolio (optimized under high load conditions) includes 300 MW of wind resources selected in 2022, approximately 746 MW of solar selected in 2023 and 2024, the selection in 2023 of paired solar+storage resources (400 MW solar; 126 MW storage) and one new 279.3 MW CT is selected in 2024, all of which replace A B Brown units 1 and 2, F B Culley 2 and Warrick 4. An additional 1,000 MW of solar is selected beginning in 2026, while an additional 2,600 MW of wind is selected beginning in 2032. Approximately 1.00% of energy efficiency blocks are selected in each of the three time periods (near-term 2021-2023, mid-term 2024-2026 and long-term 2027-2039), an additional block (0.25%) of energy efficiency is selected in the time period 2024-2026 and the optional demand response bin is selected in the time periods 2024-2026 and 2027-

2039. F B Culley 3 operations continue through the forecast period. Any shortfall in capacity is met through capacity market purchases, which average 18.4 MW during the period 2024-2033. Because the Low Regulatory portfolio was significantly overbuilt relative to the Reference Case load outlook, this optimized portfolio was not selected for further analysis.

8.1.3.3.2 High Technology

The High Technology portfolio includes 300 MW of wind resources selected in 2022, approximately 746 MW of solar selected in 2023 and 2024, the selection in 2023 of paired solar+storage resources (400 MW solar; 126 MW storage) and two new 236.6 MW gas CT is selected in 2024 and 2025, all of which replace A B Brown units 1 and 2, F B Culley 2 and Warrick 4. An additional 50 MW of storage is selected in the final year of the forecast. Approximately 0.75% of energy efficiency blocks are selected in each of the three time periods (near-term 2021-2023, mid-term 2024-2026 and long-term 2027-2039) with the exception of the third block of energy efficiency, which is not selected in the time period 2027-2039. The optional demand response bin is selected in the time periods 2024-2026 and 2027-2039. F B Culley 3 operations continue through the forecast period. The only shortfall in capacity occurs in 2024 and is met through 70.9 MW of capacity market purchases. Because the optimized High Technology portfolio buildout had less reliance on the capacity market than the Reference Case portfolio, it offered a useful comparison of cost and performance. It was selected for further analysis and was eventually selected as the preferred portfolio.

8.1.3.3.3 80% CO_2 Reduction

The 80% Reduction of CO_2 by 2050 portfolio (least cost under reference case load conditions) includes 300 MW of wind resources selected in 2022, approximately 746 MW of solar selected in 2023 and 2024 and the selection in 2023 of paired solar+storage resources (400 MW solar; 126 MW storage), all of which replace A B Brown units 1 and 2, F B Culley 2 and Warrick 4. An additional 800 MW of solar is selected beginning in

2035, an additional 2,750 MW of wind is selected beginning in 2033 and an additional 266 MW of battery storage is selected beginning in 2036. Approximately 0.75% of energy efficiency blocks are selected in each of the three time periods (near-term 2021-2023, mid-term 2024-2026 and long-term 2027-2039) with the exception of the third block of energy efficiency, which is not selected in the time period 2027-2039. The optional demand response bin is selected in the time periods 2024-2026 and 2027-2039. F B Culley 3 operations continue through the forecast period. The only shortfall in capacity occurs in 2024 and is met through 70.9 MW of capacity market purchases. Because the optimized 80% Reduction of CO_2 by 2050 portfolio buildout was significantly overbuilt relative to the Reference Case load outlook, this optimized portfolio was not selected for further analysis.

8.1.3.3.4 High Regulatory

The least cost High Regulatory portfolio includes 300 MW of wind resources selected in 2022, approximately 746 MW of solar selected in 2023 and 2024, approximately 152 MW of storage in 2023 and 2024 and the selection in 2023 of paired solar+storage resources (400 MW solar; 126 MW storage), all of which replace A B Brown units 1 and 2, F B Culley 2 and Warrick 4. An additional 1,810 MW of solar is selected beginning in 2025, an additional 3,300 MW of wind is selected beginning in 2025 and an additional 340 MW of battery storage (which is paired with wind) is selected beginning in 2025. Approximately 1.25% of energy efficiency blocks are selected in the first two time periods (near-term 2021-2023 and mid-term 2024-2026), while 0.50% of energy efficiency is selected in the time period 2027-2039. No optional demand response is selected. F B Culley 3 operations continue through the forecast period. The only shortfall in capacity occurs in 2024 and is met through 165.6 MW of capacity market purchases. Because the optimized High Regulatory portfolio buildout was significantly overbuilt relative to the Reference Case load outlook, this optimized portfolio was not selected for further analysis.

8.1.3.4 Bridges

The following portfolios were designed to serve as bridge portfolios, offering short-term and long-term transition pathways toward a fleet with greater renewable resources while utilizing existing resources.

8.1.3.4.1 Gas Conversion ABB1

This portfolio was designed to include the conversion of the older, less efficient unit at the A B Brown plant from a baseload coal-fired to natural gas peaking, which helps to preserve and repurpose much of the existing asset base. The unit would be converted for operation beginning in 2024 and expected to operate for 10 years before retirement. Conversions utilize some old equipment and require on-going capital investments to keep the units running. Since conversion of a unit offers less flexibility with slow start time (8-24 hrs.) and slow ramp rate (2MW/Min) it does not complement renewables well. The one conversion unit and the near-term (2021-2023) energy efficiency blocks are the only design parameters included in this candidate portfolio. All other resources are selected as part of the least-cost optimization routine in Aurora.

The least cost Gas Conversion ABB1 portfolio includes 300 MW of wind resources selected in 2022, approximately 746 MW of solar selected in 2023 and 2024, the selection in 2023 of paired solar+storage resources (400 MW solar; 126 MW storage), in addition to the conversion in 2024, all of which replace A B Brown units 1 and 2, F B Culley 2 and Warrick 4. One new 279.3 MW CT is selected in 2034 once the conversion unit is retired. Approximately 0.75% of energy efficiency blocks are selected in each of the three time periods (near-term 2021-2023, mid-term 2024-2026 and long-term 2027-2039). The optional demand response bin is selected in the time periods 2024-2026 and 2027-2039. F B Culley 3 operations continue through the forecast period. Any shortfall in capacity is met through capacity market purchases, which average 133.3 MW during the period 2024-2033.

8.1.3.4.2 Gas Conversion ABB1 & ABB2

Similar to the Gas Conversion ABB1 portfolio, this portfolio was designed to include the conversion of both units at the A B Brown plant from baseload coal-fired units to natural gas peaking units. These conversions also help to preserve and repurpose much of the existing asset base at this facility. As described above, gas conversion units do not start or ramp quickly. Both units would be converted for operation beginning in 2024 and expected to operate for 10 years before retirement. The two conversion units and the near-term (2021-2023) energy efficiency blocks are the only design parameters included in this candidate portfolio. All other resources are selected as part of the least-cost optimization routine in Aurora.

The least cost Gas Conversion ABB1 & ABB2 portfolio retired F B Culley 2 and exited joint operations at Warrick 4. and includes 300 MW of wind resources selected in 2022, approximately 746 MW of solar selected in 2023 and 2024, the selection in 2023 of paired solar+storage resources (400 MW solar; 126 MW storage), in addition to the two conversions in 2024, all of which replace A B Brown units 1 and 2, F B Culley 2 and Warrick 4. One new 279.3 MW CT is selected in 2034 once the conversion unit is retired. Approximately 0.50% of energy efficiency blocks are selected in the near-term (2021-2023), while 0.75% is selected in the mid-term (2024-2026) and long-term (2027-2039). The optional demand response bin is selected in the 2027-2039 time period. F B Culley 3 operations continue through the forecast period. Any shortfall in capacity is met through capacity market purchases, which average 150.1 MW during the period 2034-2039.

8.1.3.4.3 Gas Conversion ABB1 + CCGT

This portfolio was designed to include conversion of one unit at the A B Brown plant from a baseload coal-fired unit to a natural gas peaking unit, which helps to preserve and repurpose much of the existing asset base at this facility. It retired A B Brown unit 2, F B Culley 2 and exited joint operations at Warrick 4. In addition, this portfolio includes a small CCGT unit with duct-firing capability (total 442.5 MW) in 2026. The conversion unit is be converted for operation beginning in 2024 and is expected to operate for 10 years before retirement. The conversion and CCGT units are the only design parameters included in this candidate portfolio beyond near term EE. All other resources are selected as part of the least-cost optimization routine in Aurora.

The least cost Gas Conversion ABB1 + CCGT portfolio includes 300 MW of wind resources selected in 2022, approximately 746 MW of solar selected in 2023 and 2024, the selection in 2023 of paired solar+storage resources (400 MW solar; 126 MW storage) and the conversion unit in 2024, all of which replace A B Brown units 1 and 2, F B Culley 2 and Warrick 4. One new 432.6 MW combined cycle unit is designed to begin operations in 2026. Approximately 0.50% of energy efficiency blocks are selected in the near-term (2021-2023), while 0.75% is selected in the mid-term (2024-2026) and long-term (2027-2039). The optional demand response bin is selected in the 2024-2026 time period. F B Culley 3 operations continue through the forecast period. Any shortfall in capacity is met through capacity market purchases, which average 16.4 MW during the period 2024-2039.

8.1.3.4.4 BAU 2029

The BAU 2029 portfolio was designed to bridge half of the study period (2019-2029) using existing baseload coal resources at A B Brown plant. Culley 2 (90 MW) is retired in 2023 and Vectren exits joint operations of Warrick 4 (150 MW) in 2023. The two coal units at A B Brown are extended through 2029 using existing FGD scrubber technology and retired by 2030. This portfolio strategy helps to preserve the existing asset base while providing a transition pathway to a generation fleet with greater renewable resources. The two coal unit extensions through 2029 is the only design parameters included in this candidate portfolio beyond near term EE. All other resources are selected as part of the least-cost optimization routine in Aurora.

The least cost BAU 2029 portfolio includes 300 MW of wind resources selected in 2022, approximately 746 MW of solar selected in 2023 and 2024, the selection in 2023 of paired solar+storage resources (400 MW solar; 126 MW storage) and one new 236.6 MW gas

CT is selected in 2030. The coal unit F B Culley 2 and Warrick 4 are selected for retirement or exit of joint operations beginning in 2024. Approximately 0.50% of energy efficiency blocks are selected in each of the three time periods (near-term 2021-2023, mid-term 2024-2026 and long-term 2027-2039), an additional 0.25% is selected in the time period 2024-2026 and 2027-2039. The optional demand response bin is selected in the time period 2027-2039. F B Culley 3 operations continue through the forecast period. Any shortfall in capacity is met through capacity market purchases, which average 162.4 MW during the period 2030-2039.

8.1.3.5 Diverse

The following portfolios were designed to serve as portfolios that offer a diverse mix of baseload, peaking and intermittent technologies as well as a diversity of fuel sources including coal, natural gas and renewables.

8.1.3.5.1 Small CCGT with Renewables and Coal

The Small CCGT with Renewables and Coal portfolio was designed to provide a diversified mix of generation and fuel technologies, including a small-sized CCGT with duct-firing capability (total 442.5 MW). This portfolio strategy provides a transition pathway to a generation fleet, while maintaining and adding a diverse fuel mix of baseload generation technology. This portfolio retired A B Brown units 1 and 2, F B Culley 2 and exited joint operations at Warrick 4. The CCGT unit and the near-term (2021-2023), keeping Culley 3, and the selection of renewables, storage and DSM options were the only design parameter included in this candidate portfolio beyond near term EE. Also, additional CCGTs or CT’s were not allowed to be selected. All other resources are selected as part of the least-cost optimization routine in Aurora.

The least cost Small CCGT with Renewables and Coal portfolio includes 300 MW of wind resources selected in 2022, approximately 746 MW of solar selected in 2023 and 2024, the selection in 2023 of paired solar+storage resources (400 MW solar; 126 MW storage) and one new small-sized CCGT with duct-firing capability (total 442.5 MW) that begins in

2025. Approximately 0.50% of energy efficiency blocks are selected in each of the three time periods (near-term 2021-2023, mid-term 2024-2026 and long-term 2027-2039), an additional 0.25% is selected in the time periods 2024-2026 and 2027-2039. No optional demand response is selected. F B Culley 3 operations continue through the forecast period. There is a capacity shortfall in 2024 equal to 285.7 MW before the CCGT becomes operations, but thereafter any capacity shortfall is minimal and met through capacity market purchases, which average 21.5 MW during the period 2036-2039.

8.1.3.5.2 Mid CCGT with Renewables and Coal

The Mid CCGT with Renewables and Coal portfolio was designed to provide a diversified mix of generation and fuel technologies, including a medium-sized CCGT with duct-firing capability (total 510.7 MW). This portfolio strategy provides a transition pathway to a generation fleet with greater renewable resources while maintaining and adding a diverse mix of fuels and a diverse mix of baseload, peaking and intermittent generation technologies. This portfolio retired A B Brown units 1 and 2, F B Culley 2 and exited joint operations of Warrick 4. The CCGT unit, keeping Culley 3 and the selection of renewables and storage were the only design parameter included in this candidate portfolio beyond near term EE. Also, additional CCGTs or CT's were not allowed to be selected. All other resources are selected as part of the least-cost optimization routine in Aurora.

The least cost Mid CCGT with Renewables and Coal portfolio includes 300 MW of wind resources selected in 2022, approximately 746 MW of solar selected in 2023 and 2024, the selection in 2023 of paired solar+storage resources (400 MW solar; 126 MW storage) and one new medium-sized CCGT with duct-firing capability (total 510.7 MW) that begins in 2025. Approximately 0.50% of energy efficiency blocks are selected in each of the three time periods (near-term 2021-2023, mid-term 2024-2026 and long-term 2027-2039), an additional 0.25% is selected in the time period 2024-2026. No optional demand response is selected. F B Culley 3 operations continue through the forecast period. There is a capacity shortfall in 2024 equal to 285.7 MW before the CCGT becomes operational, but thereafter any capacity shortfall is minimal and met through capacity market purchases, which occur only in 2039 and equal 3 MW. Because this portfolio did not produce a meaningful distinction with the optimized least cost Small CCGT with Renewables and Coal portfolio other than increased cost, with limited performance benefits, this portfolio was not selected for further analysis.

8.1.3.6 Renewables Focused

The following portfolios were designed to include a primary focus on renewable and battery storage resources, using three strategies: (1) closing all fossil by 2030 and backfilling only with renewables and battery storage resource, (2) closing all coal units by 2034 and backfilling with flexible units (CTs) and renewables and (3) optimizing a renewables-focused portfolio using a very high CO_2 price (modeled after the HB 763 bill introduced before the U.S. Congress) that begins in 2022 at $15 and increases by $10 per short ton each year, reaching ~$200 by 2039. The third portfolio strategy (HB 763) was included for initial analysis based on direct feedback from stakeholders through the public stakeholder process.

8.1.3.6.1 Close All Fossil by 2030

The close All Fossil by 2030 portfolio was designed to transition Vectren's generation fleet to 100% renewables and battery storage beginning in 2030, which requires closing all coal and natural gas peaking units by the end of 2029. This portfolio strategy provides a rapid transition pathway to a generation fleet with 100% renewable and battery storage resources. The requirement that all fossil retire by the end of 2029 was the only design parameter included in this candidate portfolio beyond near term EE. All other resources are selected as part of the least-cost optimization routine in Aurora.

The least cost Close All Fossil by 2030 portfolio includes 300 MW of wind resources selected in 2022, approximately 746 MW of solar selected in 2023 and 2024, the selection in 2023 of paired solar+storage resources (400 MW solar; 126 MW storage) and approximately 152 MW of battery storage are selected in 2023 and 2024, all of which replace A B Brown units 1 and 2, F B Culley 2 and Warrick 4. F B Culley 3 and the two gas peaking units at A B Brown continue operating through 2029 before retiring in 2030. An additional 1,150 MW of solar resources are selected beginning in 2027, while an additional 360 MW of battery storage are selected beginning in 2027. Approximately 1.00% of energy efficiency blocks are selected in each of the three time periods (near-term 2021-2023, mid-term 2024-2026 and long-term 2027-2039) while the optional demand response bin is selected in the time periods 2024-2026 and 2027-2039. Any shortfall in capacity is met through capacity market purchases, which average 169.7 MW during the period 2024-2039.

8.1.3.6.2 Renewables + Flexible Gas (CTs), Close Coal by 2034

The Renewables + Flexible Gas (CTs), Close Coal by 2034 portfolio was designed to transition Vectren's generation fleet to renewables and battery storage while also maintaining the flexibility afforded by gas CTs. This portfolio strategy provides a transition pathway to a generation fleet focused on renewable and battery storage resources while maintaining the resource adequacy provided by flexible gas CTs. The requirement that all coal units retire by the end of 2033 was the only design parameter included in this candidate portfolio beyond near term EE. All other resources are selected as part of the least-cost optimization routine in Aurora.

The least cost Renewables + Flexible Gas (CTs), Close Coal by 2034 portfolio includes 300 MW of wind resources selected in 2022, approximately 746 MW of solar selected in 2023 and 2024 and the selection in 2023 of paired solar+storage resources (400 MW solar; 126 MW storage), all of which replace A B Brown units 1 and 2, F B Culley 2 and Warrick 4. An additional 600 MW of solar resources are selected beginning in 2034. F B Culley 3 operations continue through 2033 before retiring in 2034. Approximately 0.75% of energy efficiency blocks are selected in each of the three time periods (near-term 2021-2023, mid-term 2024-2026 and long-term 2027-2039) while the optional demand response bin is selected in the time periods 2024-2026 and 2027-2039. Any shortfall in capacity is met through capacity market purchases, which average 134.7 MW during the period 2024-2039.

8.1.3.6.3 HB 763

The HB 763 portfolio was designed to incentivize a rapid transition to renewables and battery storage through a very high CO_2 tax (modeled after the HB 763 bill introduced before the U.S. Congress) that begins in 2022 at $15 and increases by $10 per short ton each year, reaching $200 by 2039. This portfolio strategy provides a rapid and aggressive transition pathway to a generation fleet focused on renewable and battery storage resources. The CO_2 price and was the only design parameter included in this candidate portfolio beyond EE. All other resources are selected as part of the least-cost optimization routine in Aurora.

The least cost HB 763 portfolio includes 300 MW of wind resources selected in 2022, approximately 746 MW of solar selected in 2023 and 2024 and the selection in 2023 of paired solar+storage resources (400 MW solar; 126 MW storage), all of which replace A B Brown units 1 and 2, F B Culley 2 and Warrick 4. An additional 1,650 MW of solar resources are selected beginning in 2025 and an additional 3,150 MW of wind resources are selected beginning in 2025. F B Culley 3 operations as well as the two gas peaking units at A B Brown plant continue through the forecast period. Approximately 1.25% of energy efficiency blocks are selected in the near-term (2021-2023), approximately 1.50% of energy efficiency blocks are selected in the medium-term (2024-2026) and approximately 1.00% of energy efficiency blocks are selected in the long-term (2027-2039). No optional demand response is selected. A one-year shortfall in capacity in 2024 is met through capacity market purchases, which equal 164.2 MW. Because the optimized HB 763 portfolio buildout was significantly overbuilt relative to the Reference Case load outlook, because this portfolio was the only portfolio that showed significant amounts of wind and solar curtailments (reaching as high as 11.8% annually and 21.4% annually, respectively) and because this portfolio had very high annual net energy sales, this optimized portfolio was not selected for further analysis.

8.2 EVALUATION OF PORTFOLIO PERFORMANCE

A total of 15 portfolios were developed in this IRP process, as described above. After an initial process in which a least cost portfolio was selected, 10 of the portfolios were selected as candidate portfolios for further analysis.

Five were screened out. These included three scenario-based portfolios (80% Reduction of CO_2 by 2050, High Regulatory and Low Regulatory) and two additional portfolios optimized around a key feature (Diverse Medium CCGT and HB 763). The scenario-based portfolios were optimized using the long-term capacity expansion module of Aurora within the wide-ranging market inputs described in Section 7, then simulated in the chronological hourly dispatch module of Aurora. However, each of three scenario-based portfolios were shown to be heavily reliant on energy market sales to reduce total portfolio costs (43.3%, 229.1% and 62.9% higher than the Reference Case, respectively, for the 80% Reduction by 2050, High Regulatory and Low Regulatory portfolios). In addition, around-the-clock (ATC) market clearing prices were as much as 77.3% higher than the Reference Case (specifically in the High Regulatory portfolio). Similarly, the Diverse Medium CCGT portfolio produced comparable results to the Diverse Small CCGT portfolio but at additional cost with little to no additional benefit. The HB 763 portfolio new unit capital costs were 382% higher than the Reference Case, which sold $5.3 billion in energy market sales in a market with average ATC power prices 55% higher than the Reference Case. In effect, the very high energy market sales in the High Regulatory and HB 763 would create a merchant utility, while the other portfolios were not expected to offer additional insights beyond the 10 candidate portfolios shown in the Balanced Scorecard. Furthermore, the HB 763 portfolio showed relatively high levels of renewable energy curtailments that were not seen in any other portfolio in the deterministic modeling (and very rarely in the subsequent stochastic modeling, for those candidate portfolios that underwent risk analysis). For these reasons, these five scenarios were not selected for further analysis in the stochastic framework.

Each of the remaining candidate portfolios was then subjected to two different forms of a risk analysis. One was scenario-based and one was based on probabilistic modeling (200 iterations), which serves as the basis for the balanced scorecard.

8.2.1 Scenario Risk Analysis

The IRP requires scenario-based modeling be performed as a part of the risk analysis be performed. In the Scenario Based risk analysis, the remaining ten candidate portfolios that were selected for further analysis were each modeled under each of the four scenarios with their respective market inputs. The following provides a summary of the results of this scenario risk analysis. The results of the deterministic scenario-based Risk Analysis are shown in Figures 8-2 – 8.5 below

Figure 8-2 – Portfolio NPVRR (million $)

	Scenarios				
	Reference	**Low Regulation**	**High Technology**	**80% Reduction of CO_2 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 + 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%
High Technology	102.3%	102.6%	101.3%	102.1%	102.2%

Figure 8-3 – Portfolio CO2 Emissions Reductions by 2039 from 2019 Levels (thousand Tons)

	Scenarios				
	Reference	**Low Regulation**	**High Technology**	**80% Reduction of CO_2 by 2050**	**High Regulation**
Reference Case	78.2%	52.0%	87.9%	77.3%	76.4%
Business as Usual to 2039	60.3%	-22.5%	72.6%	54.3%	49.2%
Business as Usual to 2029	74.6%	53.6%	85.9%	74.0%	73.4%
ABB1 Conversion + CCGT	61.5%	40.0%	69.6%	61.8%	62.7%
ABB1 Conversion	74.0%	53.5%	85.6%	73.5%	72.9%
ABB1 + ABB2 Conversions	74.1%	53.5%	85.5%	73.5%	73.0%
Diverse Small CCGT	61.8%	39.8%	69.7%	61.9%	62.7%
Renewables + Flexible Gas	95.2%	90.2%	95.7%	94.9%	91.5%
All Renewables by 2030	95.8%	95.8%	96.0%	95.8%	95.8%
High Technology	77.8%	51.9%	88.2%	77.1%	76.1%

Figure 8-4 – Portfolio Average Market Purchase Amount (thousand MWh) from 2019-2039

	Scenarios				
	Reference	**Low Regulation**	**High Technology**	**80% Reduction of CO_2 by 2050**	**High Regulation**
Reference Case	100.0%	100.0%	100.0%	100.0%	100.0%
Business as Usual to 2039	79.6%	58.1%	97.7%	71.3%	17.1%
Business as Usual to 2029	84.1%	74.5%	90.1%	78.8%	73.5%
ABB1 Conversion + CCGT	38.9%	30.1%	46.0%	42.0%	38.7%
ABB1 Conversion	93.7%	90.9%	103.7%	82.6%	106.1%
ABB1 + ABB2 Conversions	93.2%	89.2%	101.2%	78.1%	104.2%
Diverse Small CCGT	36.2%	26.5%	42.2%	42.2%	35.7%
Renewables + Flexible Gas	108.5%	125.8%	98.9%	106.4%	139.7%
All Renewables by 2030	124.5%	166.1%	134.6%	117.9%	186.1%
High Technology	101.6%	94.0%	89.8%	102.1%	100.9%

Figure 8-5 – Portfolio Average Market Sale Amount (thousand MWh) from 2019-2039

	Scenarios				
	Reference	Low Regulation	High Technology	80% Reduction of CO_2 by 2050	High Regulation
Reference Case	100.0%	100.0%	100.0%	100.0%	100.0%
Business as Usual to 2039	141.9%	170.4%	114.9%	170.5%	222.1%
Business as Usual to 2029	129.8%	138.1%	121.3%	139.5%	140.3%
ABB1 Conversion + CCGT	160.4%	161.3%	139.4%	182.1%	136.0%
ABB1 Conversion	104.2%	102.2%	94.2%	113.2%	98.0%
ABB1 + ABB2 Conversions	107.6%	108.5%	99.9%	130.7%	102.0%
Diverse Small CCGT	160.2%	159.7%	139.1%	170.3%	138.9%
Renewables + Flexible Gas	104.7%	99.8%	108.2%	119.0%	97.3%
All Renewables by 2030	128.4%	116.3%	107.4%	143.9%	107.9%
High Technology	96.3%	99.0%	113.8%	94.0%	96.4%

Four portfolios performed very well across all the alternative scenarios and relative to the remaining six candidate portfolios in terms of low cost, low energy sales and purchases and greater CO_2 emissions reductions. These four portfolios included the Reference Case Renewables + Flexible Gas, All Renewables by 2030 and High Technology portfolios. Each of these portfolios ranked in the top four of 10 portfolios in terms of lowest cost, lowest energy purchases and greatest CO_2 emissions reductions. Similarly, three of these same four portfolios ranked in the top four of 10 portfolios in terms of lowest energy sales (the All Renewables by 2030 portfolio ranked 6th). Accordingly, these four portfolios performed well consistently across the metrics in the Balanced Scorecard[42] and were put forward as final candidates for consideration as the preferred portfolio.

By contrast, the remaining six of 10 portfolios performed relatively less well across these key metrics of portfolio cost, energy sales and purchases and CO_2 emissions reductions. In terms of cost, the BAU to 2039, ABB1 Conversion + CCGT, ABB1 + ABB2 Conversions and BAU to 2029 portfolios were the worst performers, with the notable exception of the two BAU portfolios under Low Regulatory scenario conditions (i.e., no CO_2 price). In terms

[42] Note: The scenario-based risk analysis measured CO_2 emissions reductions rather than CO_2-equivalent emissions reductions.

of CO_2 emissions reductions, the BAU to 2039, ABB1 Conversion + CCGT, Diverse Small CCGT and ABB1 + ABB2 Conversions portfolios showed the worst performance due to increased emissions from coal, CCGT, or coal-to-gas conversion unit operations. Finally, the BAU to 2039, ABB1 Conversion + CCGT, Diverse Small CCGT and ABB1 + ABB2 Conversions portfolios demonstrated the greatest exposure to market risk in terms of energy sales and purchases. The remaining two portfolios with one or both conversion of the A B Brown coal units performed relatively neither well nor poorly in each of these metrics. While the scenario based risk analysis was not the determinative factor for excluding portfolios or promoting them to final consideration, these results did help to inform the final decision-making process. In the end, all but the Reference Case Renewables + Flexible Gas, All Renewables by 2030 and High Technology portfolios were eliminated from final consideration.

8.2.2 Sensitivity Analysis

Several sensitivities were conducted on the candidate portfolios to test and refine the design of the portfolios and whether and how results might change if isolated variables might change. The following section describe these sensitivities and the conclusions drawn from this analysis, as well as any impact on the candidate portfolios.

The All-Source RFP resulted in a number of solar, wind and battery storage resources that were included as near-term resources in the optimization module of the Aurora model. A sensitivity was performed in which solar costs were increased by 30% to determine if this would impact their selection in 2022-2024, the timeframe during which they were offered and allowed to be selected in the model. The sensitivity showed that even with an increase of 30% in cost, the portfolio cost increased by 3.99% but the offerings remained below the market-clearing on-peak locational marginal price for Indiana and thus continued to be selected by the model as beneficial low-cost resources.

A sensitivity was conducted on the near-term (2021-2023) selectable energy efficiency blocks. The optimization module in the Aurora model selected between 0.50% and 1.50%

energy efficiency, based on the modeling inputs and the scenario being optimized. A sensitivity analysis was performed to compare 1.25% of energy efficiency to the 0.75% energy efficiency selected in the Reference Case. The sensitivity showed that increasing the near-term energy efficiency to 1.25% from 0.75% only increased the 20-year portfolio cost (NPVRR) by 0.15%.

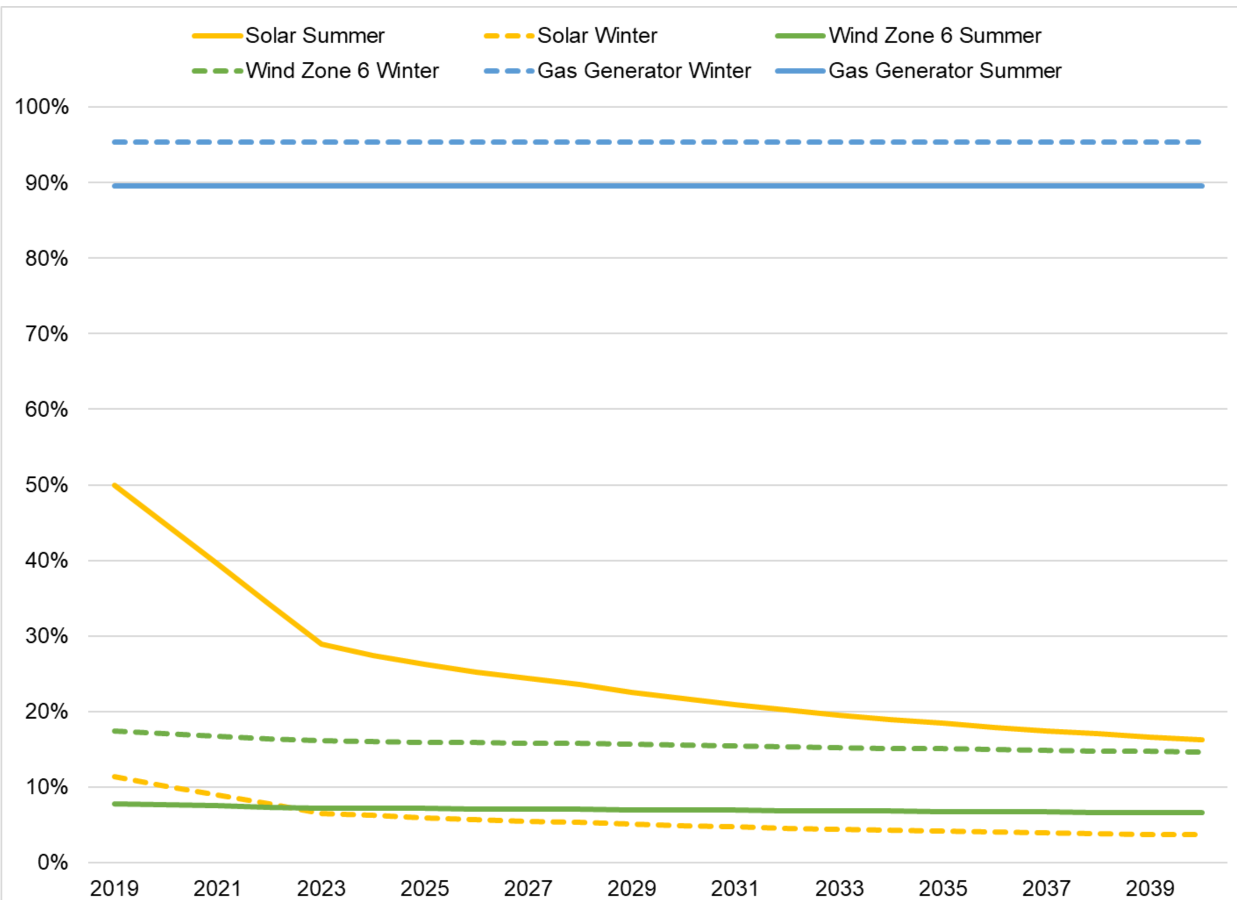
MISO is considering moving to a seasonal planning requirement. Accordingly, a sensitivity was conducted to determine the implications to the Reference Case portfolio of building to a summer peak vs. a winter peak and the resulting impact this would have on seasonal planning reserve margin requirements. Modeling a dynamic seasonal planning reserve margin requirement proved to be challenging and ultimately was not pursued, so the sensitivity focused on comparing a summer peak construct to a winter peak construct. Summer peak load is higher than winter peak load, but this difference in peak load is partially offset by a difference in seasonal unit capacity rating. The optimization routine in the Aurora model consistently selected for the maximum amount of solar available in the early years. However, the analysis showed that a constraint was necessary to prevent an overbuild of solar in this early timeframe. This is because the lower peak capacity accreditation for solar during the winter season meant that the winter peak demand was not met with solar that exceeded 1,150 MW. Accordingly, this required a limitation on the availability of solar to this level. The amount of solar in the early years was also limited by practical considerations around logistics and operational feasibility.

For this sensitivity, Vectren evaluated portfolios utilizing a reasonable summer and winter capacity accreditation construct as part of this IRP as a means of preparing for this implementation. All portfolios were required to meet both summer and winter peaks utilizing winter and summer accreditation. These forecasts were determined using MISO’s ELCC accreditation formulas and MISO MTEP models for estimating renewable penetration levels. Applying similar methodology to MISO’s current accreditation calculations, seasonal resource generation dispatching capabilities were accounted for. While using similar methodology to MISO’s current solar would result in a 0% summer accreditation, Vectren utilized a conservative assumption based on Stakeholder feedback of 11% UCAP accreditation (year 1). 11% was derived by providing some benefit to output at 9 am, which is one of the three non-consecutive highest winter load hours.

Figure 8-6 - Year 1 Seasonal Accreditation

Seasonal Capacity Accreditation	Year 1 (2019)	
	Summer	Winter
Solar	50%	11%
Wind MISO Zone 6	8%	17%
Gas Generator	~90%	~95%

Figure 8-7 - Seasonal UCAP Accreditation Forecast



The sensitivity demonstrated that Vectren should continue to plan for meeting its summer peak as the greater of the two seasonal constraints. When planning for and building to a winter peak, the Vectren system is built to meet the winter peak in all hours but is overbuilt to meet the summer peak in all hours. Based on this sensitivity analysis, each portfolio was designed and built to meet summer peak load and resulting planning reserve margin requirements.

8.2.3 STOCHASTIC (PROBABILISTIC) RISK ASSESSMENT

After selecting the 10 portfolios for further consideration and completion of the deterministic (Scenario based) risk assessment and sensitivities, the remaining step is to conduct the 200 iteration or scenario risk assessment and complete the balanced scorecard, consider “other” relevant factors and select the preferred portfolio given all of that information.

A more comprehensive risk analysis, using 200 iterations or scenarios, was utilized to provide a more comprehensive assessment of how the 10 portfolios performed under a range of conditions. As with any analysis, the risk analysis and the balanced scorecard that is developed from it, does not provide Vectren with an answer, but rather it is intended to provide insights into tradeoffs associated with a variety of portfolios over a range of future conditions.

The relevant information is provided in many of the metrics in the balanced scorecard. The benefit of conducting the stochastic risk assessment is that Vectren can get a clearer picture of the tradeoffs between least cost , the cost uncertainty (measured by the 95th percentile of cost outcomes over the planning horizon), the carbon equivalent profile of the portfolios and the percentage dependence on energy and capacity purchases and sales of the portfolios based on the probabilistic range of potential outcomes. After this comparison there is also a discussion of other factors that must be considered, like diversity, flexibility and optionality to adapt to conditions that might cause uneconomic assets.

A summary of how the ten candidate portfolios performed against each of the above metrics is provided in the table below:

Figure 8-8 - IRP Portfolio Balanced Scorecard Color-Coded Comparison (NPVRR in millions of dollars)

	Stochastic Mean 20-Year NPVRR	95th Percentile Value of NPVRR	% Reduction of CO2e (2019-2039)	Purchases as a % of Generation	Sales as a % of Generation	Purchases as a % of Peak Demand	Sales as a % of Peak Demand
Reference Case	$2,538	$2,921	58.1%	16.8%	26.8%	9.7%	1.2%
BAU to 2039	$2,914	$3,308	35.2%	12.0%	36.5%	0.1%	11.1%
Bridge BAU 2029	$2,691	$3,094	61.9%	15.2%	31.4%	7.1%	4.3%
Bridge ABB1 Conversion+CCGT	$2,875	$3,269	47.9%	6.6%	31.8%	1.3%	10.1%
Bridge ABB1 Conversion	$2,677	$3,048	61.5%	19.2%	26.4%	1.2%	9.3%
Bridge ABB1+ABB2 Conversion	$2,836	$3,215	61.5%	18.5%	27.6%	4.0%	5.6%
Diverse Small CCGT	$2,681	$3,072	47.9%	6.4%	31.1%	1.7%	3.7%
Renewables Peak Gas	$2,528	$2,927	77.4%	21.5%	27.7%	9.4%	1.2%
Renewables 2030	$2,614	$3,003	79.3%	26.1%	31.9%	11.9%	1.7%
High Technology	$2,592	$2,978	59.8%	16.7%	26.9%	0.4%	4.6%

A color-coded comparison (conducted automatically by the spreadsheet) of the balanced scorecard is shown above in Figure 8-8. Green indicates scoring well relative to its peers in a metric and red indicates scoring poorly relative to its peers. The color scheme is purely for illustrative purposes to show where differences between the best performing portfolio and the worst performing for that attribute is displayed.

The Mean of the Net Present Value is clearly one of the most important attributes, as it was the basis on which each of the portfolios were selected in the first place. Under both reference case conditions and also considering the mean of the distribution, the Renewables Peak Gas Portfolio, which retired Culley 3 early, was the lowest cost Portfolio but by less than half of one percent relative to the reference portfolio. Since Culley provides greater reliability, resilience and diversity to the portfolio and the flexibility to retire the plant early, Vectren did not consider this to be a significant difference.

The next two lowest cost portfolios were the Reference portfolio and the High Technology portfolios whose NPVRRs were within two percent of each other. Once again, Vectren did not consider portfolios within two percentage points on both the mean of the distribution and the 95th percentile (representing cost uncertainty risk) to be significant enough to differentiate these two options on the basis of cost.

The Costs and 95th percentile of the Business As Usual Portfolio and two of the Bridge solutions (the Bridge ABB1 and ABB2 and the Bridge ABB1 plus CC) were well above 10 percent higher than the Reference Mean and 95th percentile solutions, so they were eliminated from further consideration on the basis of cost.

SECTION 9
IRP PREFERRED PORTFOLIO

9.1 PREFERRED PORTFOLIO RECOMMENDATION

Based upon several factors, Vectren's preferred portfolio is the High Technology Portfolio.

9.1.1 Description of the Preferred Portfolio

The new and existing supply and demand resources in the preferred portfolio (High Technology) include 300 MW of wind resources selected in 2022, approximately 746 MW of solar selected in 2023 and 2024, the selection in 2023 of paired solar+storage resources (400 MW solar; 126 MW storage[43]) and two new 236.6 MW CT units selected in 2024 and 2025, all of which replace the A B Brown 1 and 2, F B Culley 2 and Warrick 4 coal units when they retire or exit at the end of 2023. An additional 50 MW of storage is selected in the final year of the forecast for reserve margin purposes. Approximately 1.25% of energy efficiency blocks are included in the near-term time period (2021-2023), approximately 0.75% of energy efficiency blocks are selected in the mid-term (2024-2026) and approximately 0.50% of energy efficiency blocks are selected in the long-term (2027-2039). In addition, low Income energy efficiency is included in all periods. The optional demand response bin is selected in the time periods 2024-2026 and 2027-2039, while a Direct Load Control (DLC) program called Summer Cycler is transitioned to Wi-Fi thermostats over time. F B Culley 3 operations continue throughout the forecast period. The only shortfall in capacity occurs in 2024 and is met through 70.9 MW of capacity market purchases.

The preferred portfolio (High Technology) performs well across a range of metrics, both in absolute terms and relative to the other candidate portfolios. The preferred portfolio (High Technology) was within 2.5 percent of the lowest cost portfolio and ranked 2 out of 10 (second best) in the 95th percentile cost risk metric. It did not over-rely on either purchases or sales of energy or capacity.

[43] Modeled as 3-hour battery. Equates to a ~90MWs for 4-hours

Importantly it provides the flexibility and optionality to move quickly to a more renewable future as the reliability of the MISO system adapts to higher levels of renewables across the system. By having the option to retire Culley, Vectren can move when needed to a portfolio more like the Renewable + Flexible Gas portfolio.

Another distinguishing factor in this portfolio is the selection of two CTs. The two CT's provide the following benefits:

- They eliminate the reliance on for capacity in the near term at a time when MISO suggests that there could be shortages
- They provide the capability to convert to a combined cycle if needed for reliability in the future
- They are primarily used for peaking and fast ramping, which provides more room for renewables in the future
- They are relatively inexpensive to build and save customers ~$50M in design and construction costs by building two units at the same time vs. waiting to build the 2^{nd}
- Maintains interconnection rights should units be built at the Brown site, shielding customers from future transmission upgrade costs

The High Technology portfolio provides a number of additional benefits to Vectren customers and other stakeholders, including that it:

- Is among the best performing portfolios across multiple measures on the balanced scorecard
- Is a low cost portfolio (within 2.5% of the lowest cost portfolio and 2.2% of the Reference Case (the latter of which is the more appropriate comparison due to the same assumption that F B Culley 3 is operational through the forecast period)
- Leads to a lower carbon future – Achieves almost 60 percent reduction in life cycle carbon emissions (CO_2e) during the period 2019-2039 and achieves a nearly 75%

reduction in CO_2 (base year 2005) by 2035 with the flexibility to achieve even more if needed

- Brings a significant volume of renewables into the portfolio beginning in 2022. Renewable resources and ongoing energy efficiency account for more than 72% of total installed capacity by 2024 (more than 42% in terms of UCAP)
- Provides dispatchable generation that enhances opportunities for economic development and wholesale sales without overexposure to market risk relative to other candidate portfolios, which lowers customer bills
- Provides fast ramping generation to help manage the intermittency of renewables, including extended periods of complete cloud cover that can reduce solar generation by up to 75%[44]
- Avoids reliance on a single fuel and provides a balanced and diversified mix of renewables, DSM, gas and coal.
- Provides the optionality of converting to a combined cycle unit in the future if market, regulatory, technological and/or economic conditions necessitate
- Reduces dependence on coal-fired generation in a prompt timeframe yet provides the flexibility to adapt to changes in technology in the future
- Takes advantage of tax incentives for new solar power plants and for new wind resources

9.1.2 Affordability

Affordability is a key objective in the balanced scorecard and that is measured as part of the stochastic analysis. The measure for affordability is the 20-year Net Present Value of Revenue Requirements (NPVRR), which comes from the stochastic mean (average) of 200 iterations of a portfolio as it is run in the dispatch model under varying market

[44] NASA, Cloud Cover and Solar Irradiation, (source: https://scool.larc.nasa.gov/lesson_plans/CloudCoverSolarRadiation.pdf) using the formula shown below:

$$P = 990\,(1-0.75F^3) \quad \text{watts/m}^2$$

where F is the fraction of sky cloud cover on a scale from 0.0 (0% no clouds) to 1.0 (100% complete coverage).

conditions. Each iteration provides the total annual cost of each component of total portfolio cost, including fuel costs, emissions costs, variable operations and maintenance costs, fixed operations and maintenance costs, energy export revenues (sales), energy import costs (purchases), capacity market sales revenue and capacity market purchases costs. Each annual cost category is then summed into a total portfolio cost and discounted by Vectren's weighted average cost of capital of 7.71% to arrive at the NPVRR. The lower the NPVRR is for a portfolio, the lower the rates can be in order to recuperate the cost to serve load over the next 20 years. The stochastic methodology allows for a rigorous analytical framework to determine the affordability of a portfolio.

The preferred portfolio (High Technology) was determined to be a cost portfolio across the 10 candidate portfolios, with a 20-year NPVRR of $2,592 million. This NPVRR is only 2.16% higher than the Reference Portfolio, a difference of less than $55 million over 20 years on a net present value basis. The preferred portfolio (High Technology) is 11% less expensive than the Business as Usual to 2039 portfolio (the most expensive portfolio in this objective category), which provides a savings of nearly $322 million over 20 years on a net present value basis.

9.1.3 Cost Uncertainty Risk Minimization

The Cost Uncertainty Minimization objective is measured in a similar way to the Affordability objective, using the 20-year NPVRR values from the stochastic analysis. However, this objective provides a measure of the 95th percentile of the NPVRR to determine an upper boundary (or worst-case perspective) of portfolio costs across the 200 stochastic iterations. The Price Risk Minimization objective can be interpreted as follows: There is a 95% chance that total portfolio costs as measured by the 20-year NPVRR will be at or below this measure. In this way, the risk that total portfolio costs over 20 years can be measured, allowing for the selection of a portfolio that minimizes this risk. This in turn minimizes the risk that rates (prices) will be higher than the expected, where expected rates (costs) come from the Affordability objective.

The preferred portfolio (High Technology) performed well in the Price Risk Minimization category. The 95th percentile of the 20-year NPVRR was determined to be $2,978 million, which is only 1.95% higher ($57 million) as compared to the Reference Portfolio 95th percentile of the 20-year NPVRR. For this same objective, the preferred portfolio (High Technology) was found to be $330 million less than the Business as Usual to 2039 portfolio, which is also the most expensive portfolio in this objective category. Accordingly, the preferred portfolio (High Technology) is shown to have a low level of price risk relative to its own expected NPVRR as well as relative to the least cost portfolio, the most expensive portfolio and all other candidate portfolios.

9.1.4 Environmental Emission Minimization

The Environmental Emission Minimization objective is determined from the stochastic analysis and is measured as the life cycle greenhouse gas emissions reductions during the study period of 2019-2039. Life cycle greenhouse gas emissions are also known as CO_2-equivalent or CO_2e emissions. The development of this measure is described in detail in Section 2.3.2.3 and takes into account the CO_2e emissions associated with the annual MWh of generation over 20 years from each technology type in the candidate portfolio. CO_2e emissions are also calculated for any energy imports from MISO, using a representative future capacity mix by resource that is associated with the 2033 Accelerated Fleet Change mix from MISO's MTEP 2019 document.

The preferred portfolio (High Technology) performed relatively well in the Environmental Risk Minimization objective, reducing annual CO_2e emissions by more than 4 million tons over the 2019-2039 study period (where 2019 CO_2e emissions are more than 6.7 million). This represents a nearly 60% decrease over 20 years and a larger decrease than is shown in the Reference Case, which is determined to have a 58% decrease. Relative to the other candidate portfolios, the preferred portfolio (High Technology) shows a CO_2e emissions reduction figure that is in the middle of the pack, with a smaller reduction than the renewables focused portfolios but a greater reduction than the Business as Usual to 2039 portfolio, which only reduces CO_2e emissions by 35% over the 20 year study period.

However, there is flexibility built into this portfolio to achieve further reductions if coal is no longer needed for reliability and resilience purposes and if the economics of renewables becomes even more compelling.

While not part of the balanced scorecard, the preferred portfolio (High Technology) was found to reduce (actual not life cycle) CO_2 emissions by 74.5% compared to the baseline year of 2005. This represents an annual reduction of nearly 7.2 million tons of CO_2 from the baseline of 9.6 million tons of CO_2. This figure is more than twice the reduction of CO_2 emissions that is shown in the Business as Usual to 2039 portfolio and slightly greater than the Reference Case CO_2 emissions reduction.

9.1.5 Market Risk Minimization

The Market Risk Minimization objective is applicable to both energy market risk and capacity market risk. The greater the energy market purchases that are required by a candidate portfolio, the greater the exposure to the risk that energy prices will be higher than the short-run marginal cost of energy production from the Vectren fleet. Similarly, the greater the capacity market purchases that are required by a candidate portfolio, the greater the exposure to the risk that capacity market purchase prices will be higher than the cost of adding capacity to the Vectren fleet. Conversely, the greater the energy market sales by a candidate portfolio, the greater the exposure to the risk that energy prices will be lower than the short-run marginal cost of energy production from the Vectren fleet. Similarly, the greater the capacity market sales by a candidate portfolio, the greater the exposure to the risk that capacity market purchase prices will be lower than the cost of capacity in the Vectren fleet, meaning the portfolio is overbuilt. In either case, heavy reliance on market sales could lead to inflated valuation of a portfolio.

The preferred portfolio (High Technology) performed relatively well in terms of energy market risk minimization, averaging 16.7% energy purchases as a percentage of generation. This figure is in the middle of the 10 candidate portfolios, slightly less than the Reference Case (16.8%) and much less than the Renewables 2030 portfolio (26.1%) but greater than the Diverse Small CCGT portfolio (6.4%). The preferred portfolio (High Technology) ranked third best in terms of energy sales with a figure of 26.9% as a percentage of generation, only slightly more than the best performing portfolio in this category (the Bridge ABB1 Conversion portfolio at 26.4%) and much less than the Business as Usual to 2039 portfolio at 36.5%. When looking at net energy sales, the preferred portfolio (High Technology) demonstrates a figure of 10.2%, which is within the threshold criteria of 15% that was discussed during a stakeholder meeting. The 15% level is based on a reasonable level of net sales that would not overexpose Vectren to energy market risks, in the estimation of Vectren's market consultants. Accordingly, the preferred portfolio (High Technology) was shown to have a reasonably minimal level of energy market risk, both in terms of its own measure and relative to the measures of other candidate portfolios.

The preferred portfolio (High Technology) performed relatively well in terms of capacity market risk minimization, demonstrating a figure of only 0.4% capacity market purchases as a percentage of peak load. This figure is the second lowest of the 10 candidate portfolios, only slightly more than the Business as Usual to 2039 portfolio with 0.1% capacity market purchases. The selection of two CT's reduces the need for significant levels of capacity purchases throughout the planning horizon, which is important since MISO is still evaluating the issues of reliability and resilience of the grid as renewables become a larger share of the region's portfolio. The preferred portfolio (High Technology) was determined to have capacity market sales of 4.6% as a percentage of peak load, which is in the middle of the 10 candidate portfolios and much less than the 11.1% capacity market sales in the Business as Usual to 2039 portfolio but greater than the Reference Case portfolio with 1.2% capacity market sales. Accordingly, the preferred portfolio (High Technology) was shown to have a reasonably minimal level of capacity market risk, both in terms of its own measure and relative to the measures of other candidate portfolios.

9.1.6 Other Considerations

9.1.6.1 Future Flexibility

The preferred portfolio (High Technology) was originally selected using a least-cost capacity expansion under the market conditions for the High Technology alternative scenario, but was then dispatched under the same Reference Case market conditions in the deterministic analysis and then evaluated using the same range of market conditions as all other candidate portfolios in the stochastic analysis.

These alternative market conditions for the optimization included lower CO_2 costs, higher load, lower fuel prices and lower renewable and EE costs, all relative to the Reference Case. Each of the market conditions are plausible alternatives to the most expected path in the Reference Case. For example, there is not yet a political consensus on whether and how to implement a national tax on carbon, which provides some justification for a lower CO_2 price relative to the Reference Case. The load growth from electric vehicles and the electrification of several sectors (buildings, industry, heavy transport) represent substantially more upside potential than the savings and downside potential that could come from demand side management and energy efficiency, which provides some justification for a higher load outlook. Coal markets experienced a downturn in 2020 due to COVID-19-induced demand reduction, from which (together with many other downward market pressures) it will be difficult to recover in the long-term. Gas prices have come down significantly in the last decade due to technology improvements and an expanding list of reserves from new discoveries, which could continue over the next two decades, while a more aggressive move to renewables could undercut demand for natural gas in the power sector, all of which would put increased downward pressure on gas prices. Finally, an aggressive expansion of renewables relative to the Reference Case could put downward pressure on capital costs, in much the same way that the broad deployment of personal computers led to lower prices due to economies of scale.

The preferred portfolio (High Technology) performed well across the various metrics in the balanced scorecard in both the Reference Case (expected) market conditions and (by definition) the High Technology market conditions, which are only slightly less probable than the Reference Case market conditions (in the estimation of Vectren’s market consultants). It also performed well relative to the other candidate portfolios when dispatched in the 80% Reduction by 2050, High Regulation and Low Regulation alternative market conditions. In all of the scenario-based alternative market conditions as well as the stochastic analysis with 200 iterations of varying market conditions, the preferred portfolio (High Technology) did not show any solar energy curtailments and only showed an expected average value of 0.02% wind energy curtailment in five years during the 2019-2039 study period. Thus, the preferred portfolio (High Technology) demonstrated the flexibility to adapt to a wide range of changing market conditions.

9.1.6.2 Uneconomic Asset Risk

One of the factors that Vectren considered was the potential for assets becoming uneconomic over the planning horizon. This was a concern raised by stakeholders about the 2016 IRP when Vectren recommended building a large combined cycle plant which benefited from a significant reliance on projected energy sales to support its economics. One of the concerns expressed was whether the plant could become uneconomic if renewables and storage were to achieve rapid cost declines such that the combined cycle dispatch would be adversely impacted and thus unable to cover its costs.

An analysis was performed to determine whether this was a significant risk with the mix of assets proposed. A metric was created to assess the risk. An asset was determined to be uneconomic during one of the iterations of the risk analysis if for three years in succession, revenues would not recover costs. The analysis performed determined that the assets most at risk were the assets that were selected to provide capacity to support the renewable resources, mainly the CT’s and storage. The reason is that especially early in the planning horizon, capacity has often been priced below CONE. While MISO has indicated a concern that shortages could well occur in MISO over the next several years, this was not reflected in many of the iterations. Ultimately the value of this metric is questionable. 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.

If Vectren were to mitigate this conclusion it would rely heavily on purchases in the capacity market rather than build CT's and storage. Vectren did not believe this was appropriate in this uncertain environment and chose a path with CT's and storage rather than relying heavily on the capacity market.

9.1.6.3 Reliability

Reliability can be measured in different ways, but one common metric is whether the portfolio experiences any unserved energy. The preferred portfolio (High Technology) was dispatched in the Aurora model using Reference Case inputs as well as the inputs from the four alternative scenarios, each of which had widely varying market assumptions for fuel prices, emissions prices, load and capital costs. In each of these deterministic dispatch runs, the preferred portfolio (High Technology) was not found to have any hours of unserved energy. Accordingly, although Reliability is not an explicit objective in the balanced scorecard, the preferred portfolio (High Technology) was found to provide reliable service in meeting Vectren's expected load requirements over the 20-year study period.

Two highly dispatchable combustion turbines (460 MW) support a high penetration of renewables, ensuring reliability and provide a hedge against both the energy and capacity markets. They help provide customers assurance of reliable service in many ways.

- Thermal resources are still needed to maintain reliable service in multiday periods of cloud cover and no wind
- Two CT's 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 CT's 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 CT's provide fast start (10 min) & more fast ramping capability (80 MW/minute vs 40 MW/minute) to help 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 CT's provide a high degree of flexibility in the future

9.1.6.4 Operational Flexibility

The preferred portfolio (High Technology) includes a significant amount of new variable energy resources (VER) (wind and solar) balanced by 176 MW of battery storage (50 MW of which enters late in the forecast) and two 236.6 MW natural gas peaking units. The battery storage and CT units can help to smooth out the intermittency of the VERs. The fast-ramping requirements of a system increase as the balance shifts toward increased VERs, particularly solar resources. The phenomenon known colloquially as the "duck curve" demonstrates the need for fast-ramping capability, a role that CT's and battery storage perform well, to handle the onset of evening peak demand concurrent with rapidly declining solar output. Given the level of VER in the preferred portfolio (High Technology) (approximately 1,500 MW) together with the fast-ramping capabilities of the CT's and battery storage, this portfolio is expected to meet all operational flexibility requirements.

Natural gas peaking combustion turbines (CT) respond quickly to changing operational requirements, since there is no water to heat on a percentage of capacity per minute basis (as compared to a combined cycle unit). CT's are simple to operate, requiring few staff and resources to run properly and to maintain (typically under a long-term service agreement or LTSA) and often they can be started remotely. CT's can also be black started, offering an additional degree of increased resiliency and operational flexibility.

Given the high volume of intermittent renewable generation in the preferred portfolio Vectren feels it's critical to have an adequate amount of dispatchable generation to meet its obligation to ensure reliable service is provided to Vectren customers throughout the different seasons of the year as well as all 24 hours of the day. Vectren's experience shows that renewable generation can be unpredictable, therefore, a portion of generation should (a) provide a dispatchable (controllable) output (b) be able to start and stop more than once daily and be placed in service quickly and (c) respond to rapid changes in renewable output.

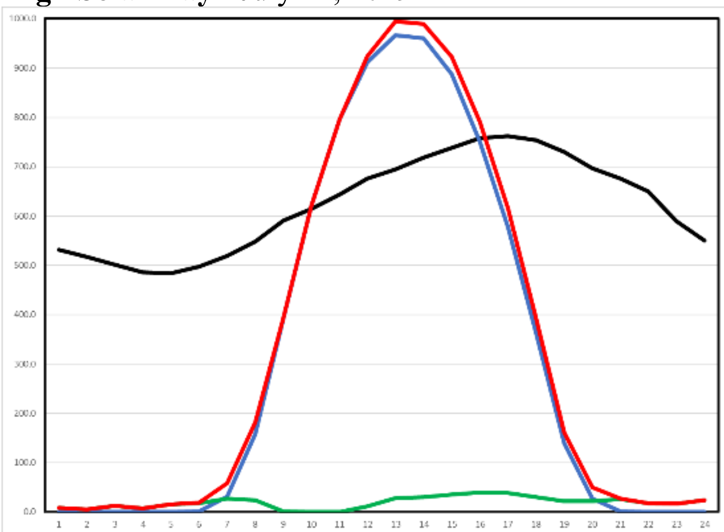
9.1.6.4.1 Vectren Seasonal and Daily Experience with Solar and Wind Production

The figures 9.1-9.4[45] below are actual seasonal days during 2019 and 2020 that show hour by hour customer demand and how 1,000 MW's of solar capacity and 380 MW's of wind capacity would have met customer demand if the solar and wind capacity factors were the same as what was realized from Vectren's current solar fields and wind purchase power agreements. High, typical and low solar production days were chosen for each season to show the large variation in levels that can be experienced daily during each season. Also, note the large drop off in production in the evening hours after the sun goes down. The additional energy required to serve Vectren customer demand would need to be purchased from the market or supplied by Vectren owned dispatchable generation sources. Local generation ensures more reliable energy and capacity with less risk of additional congestion charges associated with importing energy.

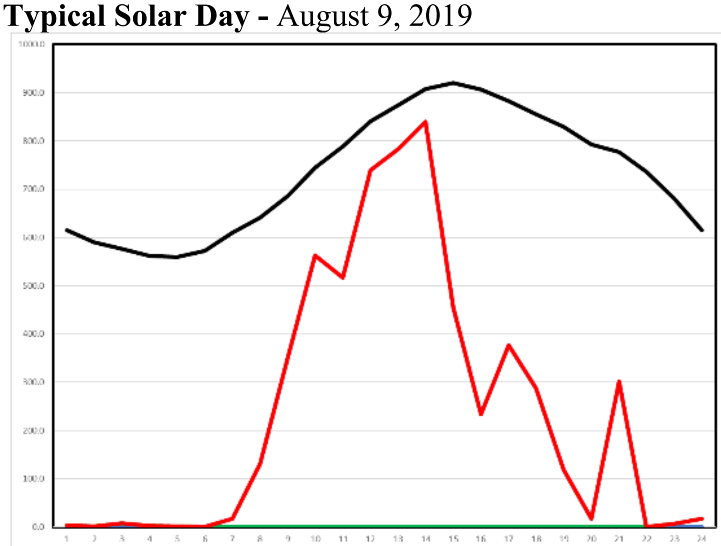
[45] **Black – System Load, Green – Wind, Blue – Solar, Red – Wind + Solar Used 1000 MW solar (scaled up from existing solar), 380MW wind (scaled up from existing 80MW). All data in 1-hour average increments, charts range from 0 to 1,000 MW except on high solar days in December (1,200MW) and March (1,400MW)**

Figure 9-1 - Summer Production and Vectren Demand:

High Solar Day - July 24, 2019



Typical Solar Day - August 9, 2019



Low Solar Day - July 15, 2019

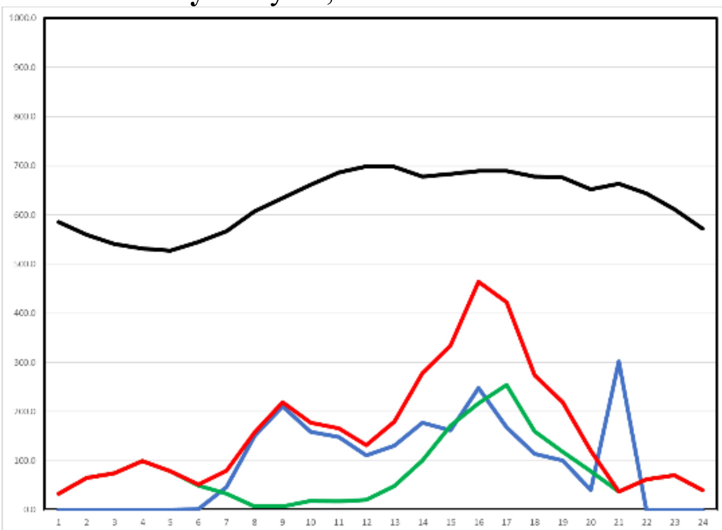
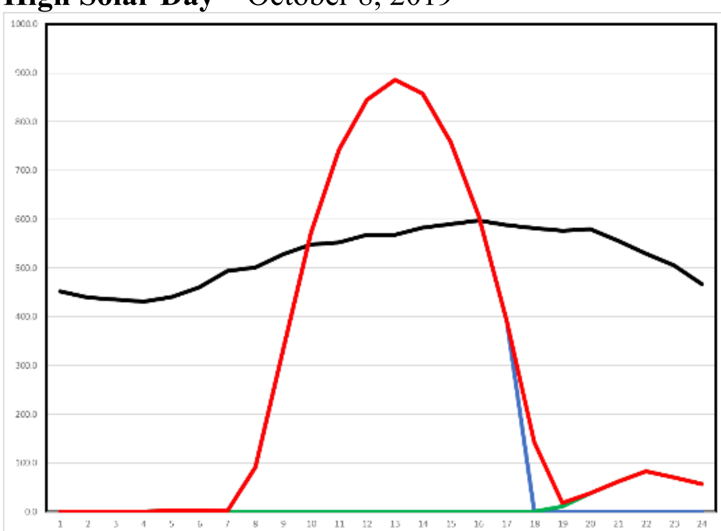
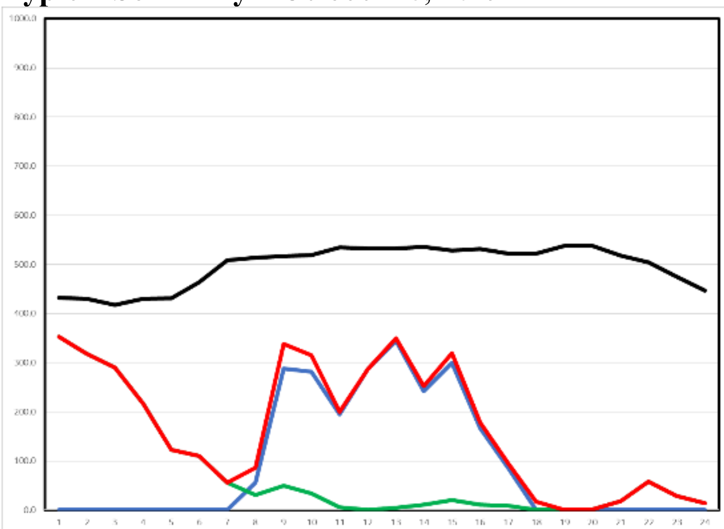


Figure 9-2 – Fall Production and Vectren Demand:

High Solar Day – October 8, 2019



Typical Solar Day – October 18, 2019



Low Solar Day – October 25, 2019

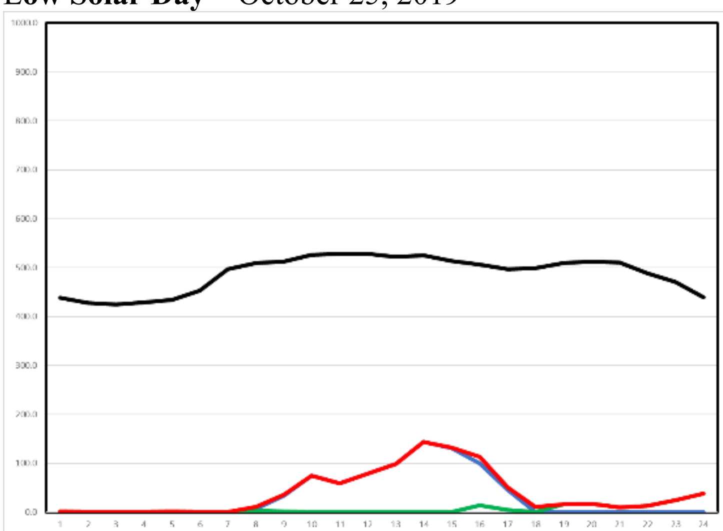
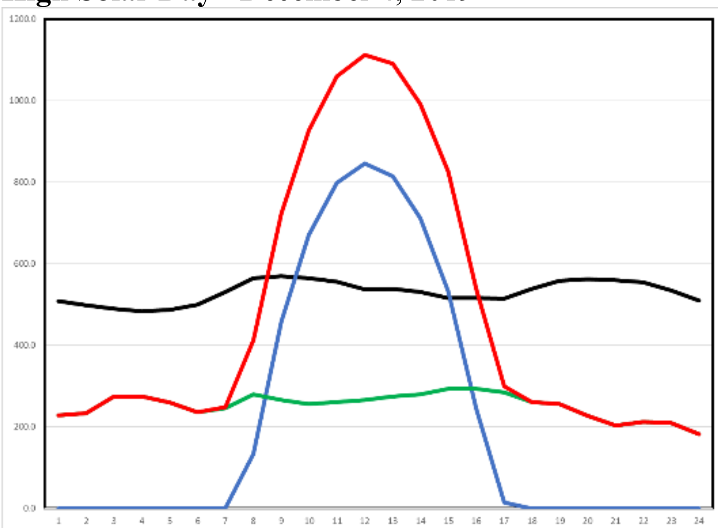
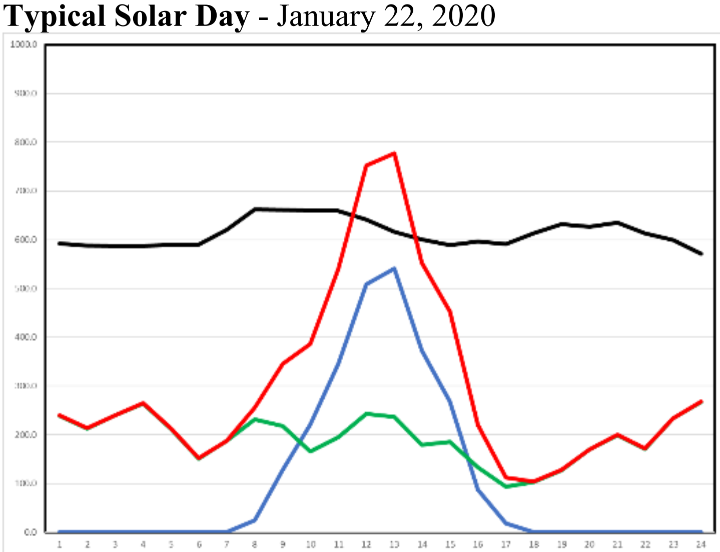


Figure 9-3 - Winter Production and Vectren Demand:

High Solar Day - December 4, 2019



Typical Solar Day - January 22, 2020



Low Solar Day - December 16, 2019

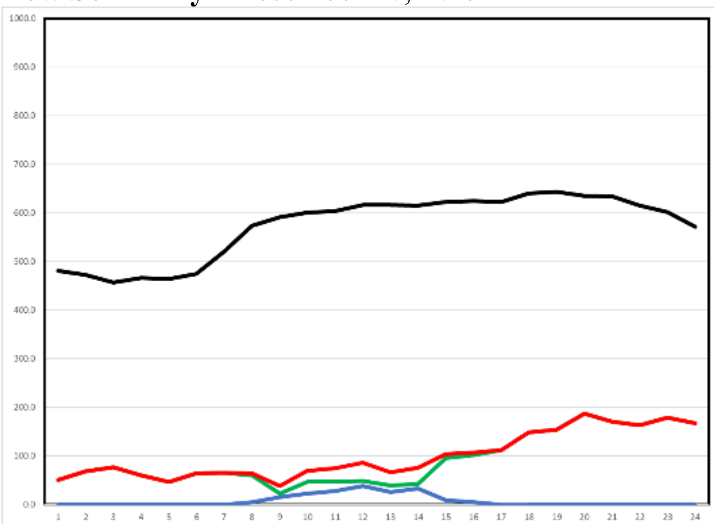
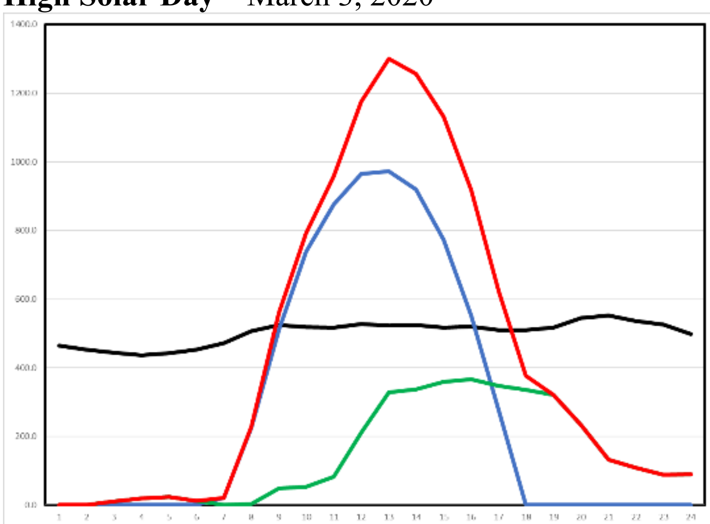
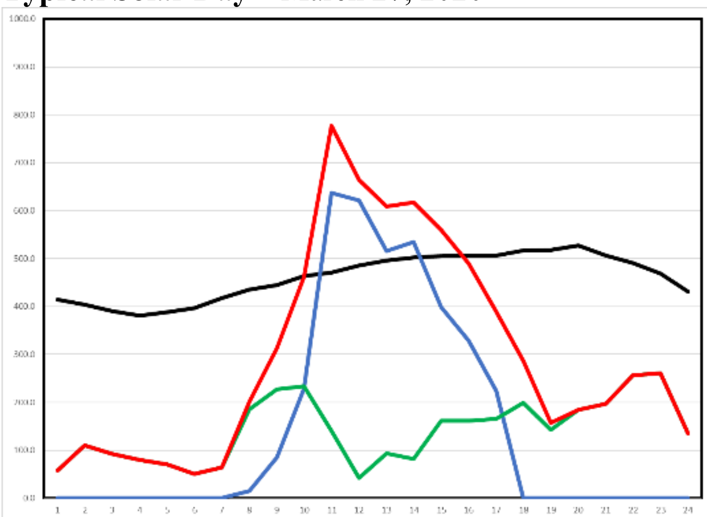


Figure 9-4 - Spring Production and Vectren Demand:

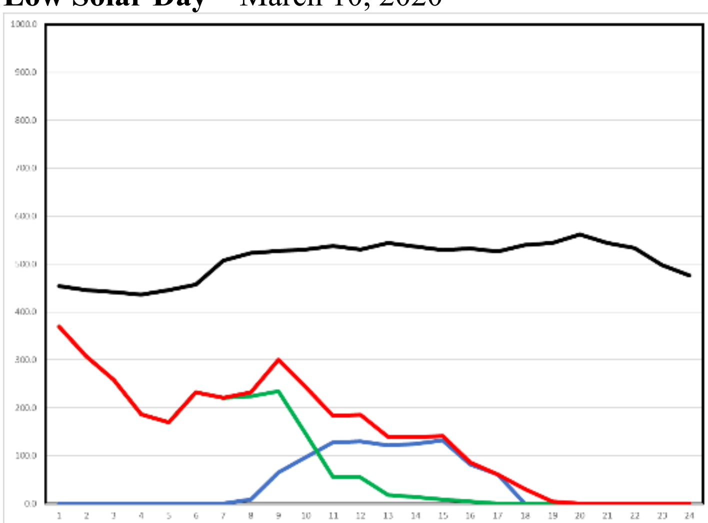
High Solar Day – March 3, 2020



Typical Solar Day – March 27, 2020



Low Solar Day – March 10, 2020



9.1.6.4.2 Vectren Experience with Solar Hourly and Daily Intermittency

The Figures above (9.1-9.4) represent an average hourly output or artificial smoothing of production across each hour of the day. There are days when there are large fluctuations in output over short periods of time due to changes in cloud cover or periodic gusts of wind. The figures below (9.5 and 9.6) show actual variation in output over a twenty-four-hour period and a one-hour period. These rapid fluctuations in output while working to meet constantly changing customer demand require a robust transmission and distribution system to import large amount of power quickly as well as dispatchable resources that can ramp output up and down quickly. It should be noted that as other utilities retire coal resources and install more intermittent generation it will become more important to have locally placed fast reacting dispatchable resources to ensure reliable service is delivered to industrial, commercial and residential customers.

Figure 9-5 – 24 Hour Solar Chart

Sept. 2, 2019 - 12:00 to 13:00

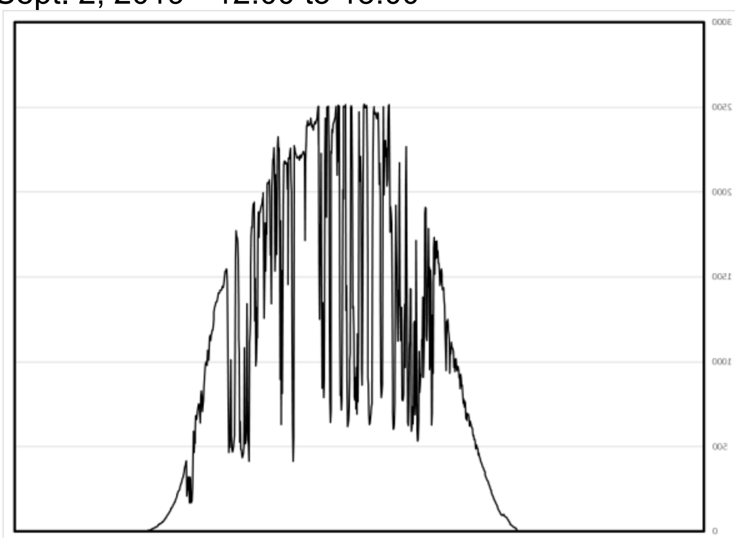
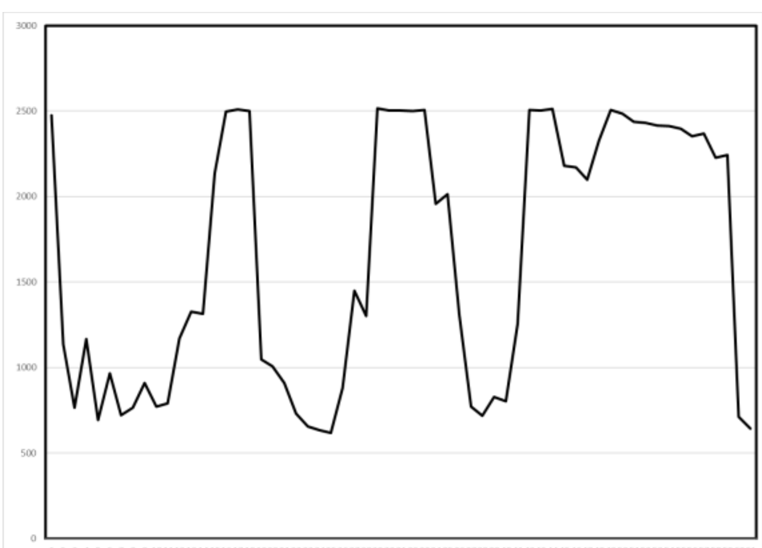


Figure 9-6 – 1-Hour Solar Production – September 2, 2019



Figures 9.5-9.6 aren't representative of every day throughout the year as there will be days when solar and wind production are more consistent; however, Vectren has an obligation to ensure customer demand is met by supplying reliable energy throughout every minute of every day of the year. Local fast start and fast reacting dispatchable resources will still be required to meet customer demand on days like Vectren experienced on September 2, 2019 as well as the evening hours after the sun goes down. Battery storage systems can meet a portion of this need; however, they are limited by discharge times as well as charge/discharge cycles, whereas CT's provide more long duration support.

Each unit will have the ability to start and be synchronized to the grid producing energy in approximately 10 minutes. This is important when relying on a large portfolio of renewable capacity. The CT's may be required to start and provide reliable energy for customers several times throughout the year when renewable energy is operating at reduced capacity due to cloud cover or a lack of wind. It's likely there may be times when the CT's are started and stopped more than one time daily.

Once placed in service, the quick ramping ability of a CT, at approximately 40MW/minute, will help meet customer needs when demand changes or renewable energy supplies quickly dip then return as cloud cover rolls over various solar arrays and wind fluctuates in areas where wind farms are built. Having two new CT's will provide the ability to ramp or adjust output by up to 80MW/minute to help supplement the import capability of the grid. In addition, having two CT's will provide flexibility as only one or both can be started as needed. Due to environmental restrictions, each CT will have a minimum output of approximately 80MW's. With one in service, the output can range from 80-220MW's. With both units in service, the output can range from 160-440MW's providing the operational flexibility to meet the needs of customers.

Of the gas fired generation options explored, the CT's were chosen due to the balance of low capital cost, efficiency and operational flexibility. Given the quantitative objectives in the balanced scorecard that includes; (a) minimizing the cost to the customer, (b) reducing emissions and (c) not relying heavily on the energy or capacity market as well as the qualitative objective such as diversity and properly supporting a large portfolio of renewable resources the CT's were chosen as an important resource in the preferred portfolio.

Lastly, the preferred portfolio with two CT's provides future flexibility to increase capacity and provide lower cost energy to Vectren customers by adding a steam cycle to one or both CT's. A steam cycle could be placed on one or both CT's to create a Combined Cycle Gas Turbine (CCGT) to capture waste heat to be turned into energy. This would lower the cost/MWh by increasing the efficiency of a CT by 30-35%. This could be accomplished if the need arises as a result of load growth due to new industrial customers, if it were determined in a future IRP that Culley Unit 3 should be retired, or the need for more low cost energy arises due to higher than expected market energy prices.

9.1.6.5 Resource Diversity

Resource Diversity is not an explicit objective in the balanced scorecard but is nevertheless an important criterion for a well-balanced portfolio. Resource Diversity allows a portfolio to avoid being dependent on one type of fuel or technology, which can expose the fleet to risks such as an extended cloudy period (reducing solar generation) or a fuel disruption that can come from a force majeure event on a gas pipeline. Resource Diversity also contributes indirectly to the other objectives discussed here, including operational flexibility, future flexibility and reliability. From this point of view, the preferred portfolio (High Technology) is reasonably diverse and well-balanced in terms of resources, with a mix of natural gas CTs, solar and wind resources, battery storage resources and a baseload coal unit.

9.1.6.6 Local Resources

Vectren prefers local resources for both capacity and energy needs. Local resources benefit Vectren customers by reducing cost risk and providing tax base, jobs and grid support for reliability. The All-Source RFP provided many attractive renewable resources in Vanderburgh, Posey, Warrick, Gibson and Spencer Counties, which Vectren is evaluating for procurement.

Local generation also helps to minimize the risks of differences in cost between where power is produced and where it is consumed. When power is produced on system, customers minimize the likelihood of congestion charges, which can occur when delivering power via the transmission system. The chances of incurring these charges increases the further away energy must be delivered. Local generation also reduces the need to construct new high voltage power lines to bring clean renewable power to our area. These transmission projects take years to complete, often require eminent domain and ultimately cost customers money.

Investing in local projects help produce tax base and jobs, which directly benefit the communities Vectren serves. Currently, Vectren generates tax revenues for primarily two counties, Posey and Warrick. The preferred portfolio will provide opportunities for continued investment in these counties with the potential to also provide tax base from generating resources in Vanderburgh, Gibson and Spencer counties. Communities where Vectren customers live can utilize this money to support school systems, police, parks and recreation and other critical support services. Additionally, these projects will continue to be operated by local employees that contribute to the local economy.

Local projects also help keep the system reliable. Vectren's preferred portfolio maintains a good balance between intermittent renewable generation and local, dispatchable generation that provides the system with voltage support and a physical hedge against instances of high market prices. This is particularly important for large, industrial customers that make up nearly half of Vectren load.

9.1.6.7 Transmission/Distribution

The preferred portfolio required the lowest number of transmission system network upgrades of all cases studied, except for the CCGT case. Although the number of network upgrades were lower than other cases, upgrades to the Vectren system import capability were identified. The upgrades identified are the replacement of three transformers for a total estimated cost of $11 million and were also required for the other non-CCGT cases studied.

The reliance on imports from the MISO market into Vectren's area led to voltage concerns for post contingent conditions due to insufficient reactive reserves. CT's provide mitigation to these issues and can be used for reactive (VAR) support in the MISO market. The all imports and all renewables cases studied presented voltage issues that could not be mitigated with existing facilities. These issues would require additional network upgrade projects to add reactive power support and could also potentially lead to the need for Vectren to make Reactive Power Payments to the MISO market to receive off-network support to maintain proper reactive power and voltage levels. These upgrades for reactive support would need to be studied in more depth to determine the placement of new facilities and to determine the type of devices needed. However, initial estimates for needed upgrades are estimated to be between $20 and $30 million to maintain reliability. This amount was not included in the NPVRR of this portfolio.

Studies were performed using the latest MISO generation interconnection system models and all renewable resources studied were assumed to be the projects already in the MISO queue and existing in the model. Additional study will be required on the preferred portfolio once specific renewable projects are identified and sited to determine any further impacts on the Vectren transmission and distribution electric system.

9.1.6.8 Economic Development

The preferred portfolio allows Vectren to provide solutions to assist with manufacturers' renewable and sustainable energy goals. Companies are setting these goals leading to a reduction in fossil fuels consistent with their sustainability strategies. If these companies cannot find a solution with their local utility partners, they may procure energy from other sources or make strategic decisions to relocate manufacturing load.

Renewable energy investments are important steps in facilitating the ability to provide Vectren customers with a portion of their energy requirements via renewable energy. With proper oversight and investment strategy renewable energy can be more efficient and cost-effective for many customers as compared to securing their own sources of energy which requires land and/or capital investments.

The communities in Vectren's service territory will benefit to the extent the addition of renewable energy supports growth among Vectren South's large customers or attracts new customers. The creation of additional jobs in the communities Vectren serves has a ripple effect on the local economy. Moreover, renewable energy projects will create construction jobs in the community and provides additional income for landowners, which also will benefit the local economy. Ultimately, renewable energy projects support the attraction and retention of large customers.

Although Vectren supports cost effective and reliable renewable energy projects, Vectren must maintain strategic planning in the event large industrial customers locate to SW Indiana and require baseload generation for production. Site selectors and large industrial power users are typically sophisticated and fully understand the requirements to apply, receive approval and execute generation buildout. Comprehensive generation planning inclusive of renewable energy and base load assets must be properly balanced to continue economic growth for our region.

For industrial customers to maintain their required voltage level, the Vectren system must be able to supply an adequate amount of reactive power (VARs). Transmission planning studies have shown that this cannot be accomplished without on-network reactive power supplying facilities, such as local synchronous generation. The CT's in the preferred portfolio provide this needed reactive power support. Even when they are not dispatched normally, CT's are able to be started and brought online quickly if needed for Vectren system reliability. CT's also prevent Vectren from entering into Reactive Power Payments through the MISO market, which would impact Vectren customers' bills.

Importantly, the current plan offers flexibility and a hedge assurance, reducing market risk for customers. Specifically, Vectren must remain nimble and dynamic for prospective industrial customers and to be able to adapt to the potential need for CCGT build out. Vectren aggressively pursues manufacturing opportunities which has direct, indirect and induced economic benefits for the region and state of Indiana. Vectren's ability to attract and retain these types of customers is vital to the region's economic wellbeing. Job growth leads to increased earning opportunity for local residents at the same time raising state revenue and tax base. Additionally, large power users assist all Vectren customers with lower utility rates by spreading the fixed cost recovery requirements for the rate base.

In addition, large customers and site selectors understand the comprehensive risks of market rate pricing and the corresponding volatility. The current IRP plan and the opportunity for future baseload generation allows for customers to remain confident in Vectren's ability to provide safe, reliable and cost-effective service. Vectren's generation strategy is an essential service for customers and the region's economic growth capability.

9.1.7 Fuel Inventory and Procurement Planning

It is impossible to perfectly predict price fluctuations in commodity prices such as coal and natural gas. Vectren uses coal contract strategies intended to even out short-term price fluctuations, such as locking in prices for various overlapping time horizons.

Normally these contract renewals are staggered in time in order to even out short-term price fluctuations. Coal suppliers and transportation providers generally require firm commitments on quantities; however, Vectren coal contracts include optionality to adjust tonnage up or down to help manage operational variability which impacts inventory levels. Currently Vectren utilizes non-firm pipeline delivery and gas storage for the existing peaking units. It is planned that the future flexible combustion turbines will utilize firm pipeline supply contracts.

SECTION 10
SHORT TERM ACTION PLAN

10.1 DIFFERENCES BETWEEN THE LAST SHORT-TERM ACTION PLAN FROM WHAT TRANSPIRED

Vectren pursued all the items listed in the 2016 IRP short-term action plan.

10.1.1 Generation Transition

Following the conclusion of the 2016 IRP, Vectren began a generation transition plan to replace the majority of its coal fleet with a highly efficient large natural gas plant and a 50 MW universal solar plant. Vectren also proposed to continue operation of its most efficient coal unit by installing certain environmental compliance equipment. Vectren pursued this plan through two separate filings in Cause numbers 45052 and 45086.

In April 2019, the IURC granted partial approval of Vectren's Smart Energy Future electric generation transition plan which included approval to retrofit F.B. Culley 3, Vectren's largest, most-efficient 270 MW coal-fired unit and to proceed with construction of a 50 MW universal solar array. The request to construct a 700-850 MW combined cycle natural gas power plant was not approved.

10.1.2 DSM

The 2016 IRP did support continued energy efficiency programs designed to save 1% of eligible retail sales. Vectren proposed the 2018-2020 Electric DSM Plan to obtain approval of programs to achieve this level of savings. The Commission approved this plan on December 28, 2017 in Cause No. 44927. Consistent with the 2016 IRP, the framework for the 2018-2020 filed plan was modeled at a savings level of 1% of retail sales adjusted for an opt-out rate of 80% eligible load.

10.1.3 Solar Projects

In 2017, Vectren filed for and received approval to construct two 2-MW universal solar projects that are currently in operation; one near North High School in northern Vanderburgh County and the second near Oak Hill Cemetery near Morgan Ave., which is through a partnership with the City of Evansville. Both sites have been constructed and have been generating power since December of 2018. The Volkman Road project also includes battery storage with the ability to discharge one megawatt of power per hour over a four-hour period.

10.1.4 Environmental Permits for ELG/CCR

The bottom ash system at F.B. Culley Unit 3 is scheduled to be converted to a dry system in the Fall of 2020. Work is also taking place to convert the FGD system to zero liquid discharge technology. These two technologies will make Culley Unit 3 fully compliant with the Effluent Limitation Guidelines (ELG) rule and the NPDES permit requirements for Culley 3.

The West Ash Pond at F.B. Culley is currently undergoing closure, with those activities scheduled to be completed by December 2020. The closure design includes the construction of a lined contact storm water pond, which will receive contact storm water from various areas of the plant. The construction of this pond, along with the installation of the dry bottom ash and FGD ZLD technologies will enable the upcoming required closure of the F.B. Culley East Ash Pond.

The A.B. Brown Ash Pond is also facing forced closure soon. Plans are currently underway to prepare for the excavation of all material from the A.B. Brown ash pond, with a majority of the ash being sent for beneficial reuse.

10.2 DISCUSSION OF PLANS FOR NEXT 3 YEARS

The short-term action plan describes the early steps to pursue the preferred portfolio, consistent with the objectives and risk perspectives listed in Section 2.3. Progress on the items listed below will be tracked and reported on in the next IRP. IRP estimates of each piece of the plan listed below can be found in Confidential Attachment 8.2 Aurora Input Model Files. Individual cost estimates can also be found in Section 6 Resource Options.

10.2.1 Procurement of Supply Side Resources

As described above, the preferred portfolio included 300 MWs of wind, 700-1,000 MWs of solar and two combustion turbines (~460 MWs) to replace approximately 730 MWs of coal fired generation. Vectren will continue to monitor developments with the State of Indiana’s Energy Policy Task Force and the wholesale energy market for potential changes that could alter Vectren’s plan. Regardless of the outcome, Vectren must continue to plan, as some portions are more certain than others.

Vectren plans to close its smallest, most inefficient coal unit, Culley 2 (90 MWs) and Vectren’s contract for joint operations of Warrick unit 4 (150 MWs) expires by the end of 2023. In order to replace this generation, Vectren plans to acquire renewable generation in the next three years in order for Vectren’s customers to benefit from expiring renewables tax incentives and, at a minimum, replace this portion of Vectren’s coal fleet. This equates to approximately 700-1,000 MWs of capacity from solar generation towards the 2023/2024 and the 2024/2025 MISO planning years, partially dependent on expected solar penetration levels within MISO at that time and MISO resource accreditation.

To fill this need, Vectren plans to pursue attractive projects from its 2019 All-Source RFP consistent with the findings in the 2019/2020 IRP. The All Source RFP bids remain open until August 2020 and Vectren is in active discussions with short listed bidders for various renewables projects. Upon completion of expected negotiations Vectren plans to file a CPCN in 2020 so that its customers can receive low-cost solar energy from these projects before tax incentives are reduced. The remainder of Vectren’s renewable need, including wind, solar and storage, could be filled through a second RFP. Affordable pricing will be important.

Vectren’s plan allows for flexibility while awaiting clarity from the outcome of the Energy Policy Task Force and resource accreditation decisions from MISO; however, preliminary planning must begin for the potential replacement of the A.B. Brown coal plants with two combustion turbines most likely as it offers many benefits at the Brown site.

In order to accommodate the need for capacity by the end of 2023 for the 2024/2025 planning season, Vectren will begin design work and obtain updated cost estimates for equipment. Additionally, permits would need to be filed with FERC to bring gas to the Brown site, a continuation of work done in support of the 2016 plan. Vectren currently has approximately 500 MWs of interconnection rights for the Brown units at this brownfield site, which will allow Vectren to bypass the MISO Generation Interconnection Queue. Utilization of the Brown site helps to mitigate risk for Vectren customers, including reliance on the capacity market and risk of future transmission upgrades at different sites or later at the Brown site. A decision on CPCN timing will be made later this year.

10.2.2 DSM

Vectren has filed its 2021-2023 electric demand side management (DSM) plan in June of 2020. The 2021-2023 energy efficiency savings were guided by the 2019/2020 IRP process. Once approved by the Commission, the Vectren Oversight Board, including the Office of Consumers Counselor (OUCC), Citizens Action Coalition (CAC) and Vectren, will oversee the implementation of energy efficiency programs.

10.2.3 Solar Projects

Based on the Commission’s 2019 approval, Vectren is currently constructing a 50 MW universal solar plant, interconnecting at transmission voltage (161kV) and is expected to be in service in the first quarter of 2021.

10.2.4 Culley 3

Based on the Commission’s 2019 approval, Vectren is proceeding with the installation of the F.B. Culley Unit 3 mandated environmental compliance projects. The new pollution control equipment installations are in various stages of engineering and planning with the expected in-service dates meeting the defined timelines.

10.2.5 Ability to Finance the Preferred Portfolio

The Company and its parent corporations expect to have sufficient funds to finance the preferred portfolio, through a combination of internally generated cash flow from operations and external capital markets activity.

10.2.6 Continuous Improvement

Vectren takes continuous improvement seriously and works to ensure that improvement opportunities are evaluated and where appropriate implemented. This is done in several ways. First, Vectren participates in the Director’s report process and listens to critiques of its IRPs from multiple stakeholders. Second, Vectren always conducts post IRP discussions with internal team members, as well as outside consultants to determine what can be done better in the next IRP. Third, Vectren participates in stakeholder meetings of other Indiana utilities and follows stakeholder feedback in those processes. Fourth, Vectren collects information on IRPs through news articles, conferences and Indiana’s annual Contemporary Issues meeting. Finally, improvement opportunities come directly through the stakeholder process with formal and informal meetings, as they did throughout this IRP.

10.3 Implementation Schedule for the Preferred Resource Portfolio

Below is a general timeline for the Preferred Resource Portfolio, subject to change pending outcome of the Energy Policy Task Force.

Figure 10-1 – Implementation Schedule

Year	Quarter	Activity
2020	Q2	File for 2021-2023 DSM Plan File IRP
	Q3	Select Attractive Renewable Projects from All-Source RFP
	Q4	File CPCN for Renewable Projects Second RFP
2021	Q1	File CPCN for Combustion Turbines Results of 2nd RFP in
	Q2	
	Q3	Renewables CPCN Order
	Q4	Begin 2022 IRP Combustion Turbines CPCN Order
2022	Q1	
	Q2	
	Q3	
	Q4	File 2022 IRP

SECTION 11
TECHNICAL APPENDIX

11.1 CUSTOMER ENERGY NEEDS APPENDIX

11.1.1 Forecast Inputs

11.1.1.1 Energy Data

Historical Vectren sales and revenues data were obtained through an internal database. The internal database contains detailed customer information including rate, service, North American Industrial Classification System (NAICS) codes (if applicable), usage and billing records for all customer classes (more than 15 different rate and customer classes). These consumption records were exported out of the database and compiled in a spreadsheet on a monthly basis. The data was then organized by rate code and imported into the load forecasting software.

11.1.1.2 Economic and Demographic Data

Economic and demographic data was provided by Moody's Economy.com for the nation, the state of Indiana and the Evansville Metropolitan Statistical Area (MSA). Moody's Economy.com, a division of Moody's Analytics, is a trusted source for economic data that is commonly utilized by utilities for forecasting electric sales. The monthly data provided to Vectren contains both historical results and projected data throughout the IRP forecast period. This information is input into the load forecasting software and used to project residential, commercial (GS) and industrial (large) sales.

11.1.1.3 Weather Data

Historical and normal HDD and CDD are derived from daily temperature data for the Evansville airport, obtained from DTN, a provider of National Oceanic and Atmospheric Administration (NOAA) data. HDDs are defined as the number of degrees below a base temperature for a given day. CDDs are defined as the number of degrees above s base temperature for a given day. Normal degree-days are calculated by averaging the historical daily HDD and CDD over the last twenty years. Historical weather data is imported into the load forecasting software and is used to normalize the past usage of residential and GS customers. Similarly, the projected normal weather data is used to help forecast the future weather normalized loads of these customers.

In reviewing historical weather data, Itron found a statistically significant positive, but slow, increase in average temperature. This translated into fewer HDD and more CDD over time. Itron's analysis showed HDD are decreasing 0.2% per year while CDD are increasing 0.5% per year. These trends were incorporated into the forecast. Starting normal HDD were allowed to decrease 0.2% over the forecast period while CDD increased 0.5% per year through 2039. Figure 11.1 and Figure 11.2 show historical and forecasted monthly HDD and CDD.

Figure 11.1 – Heating Degree Days

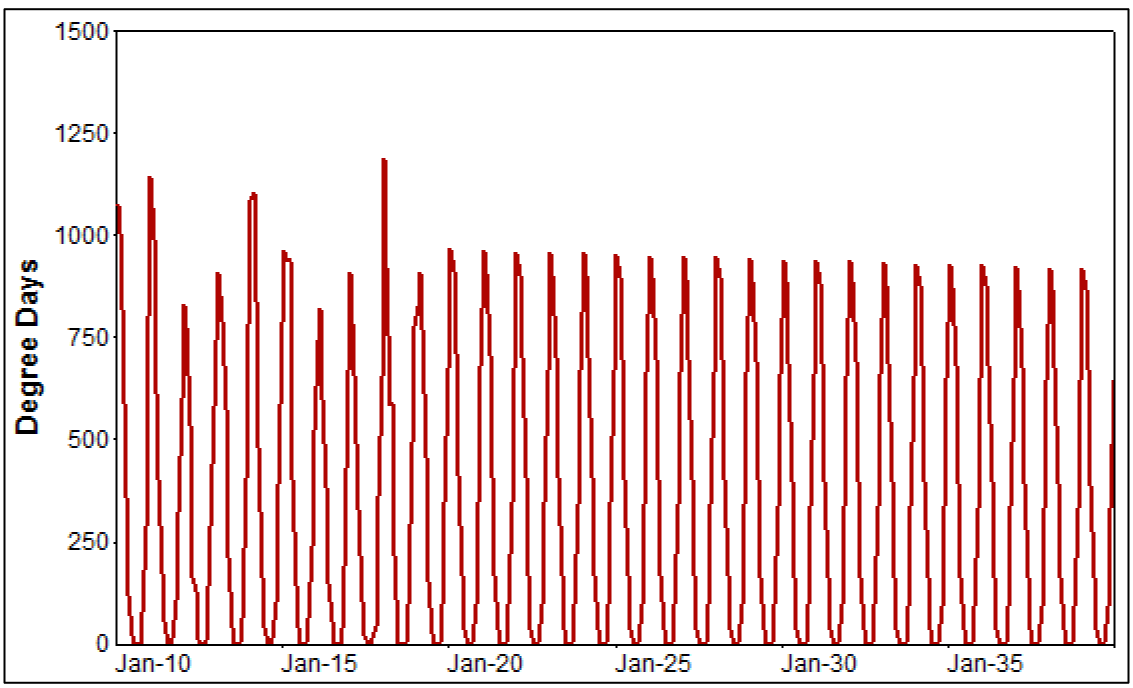
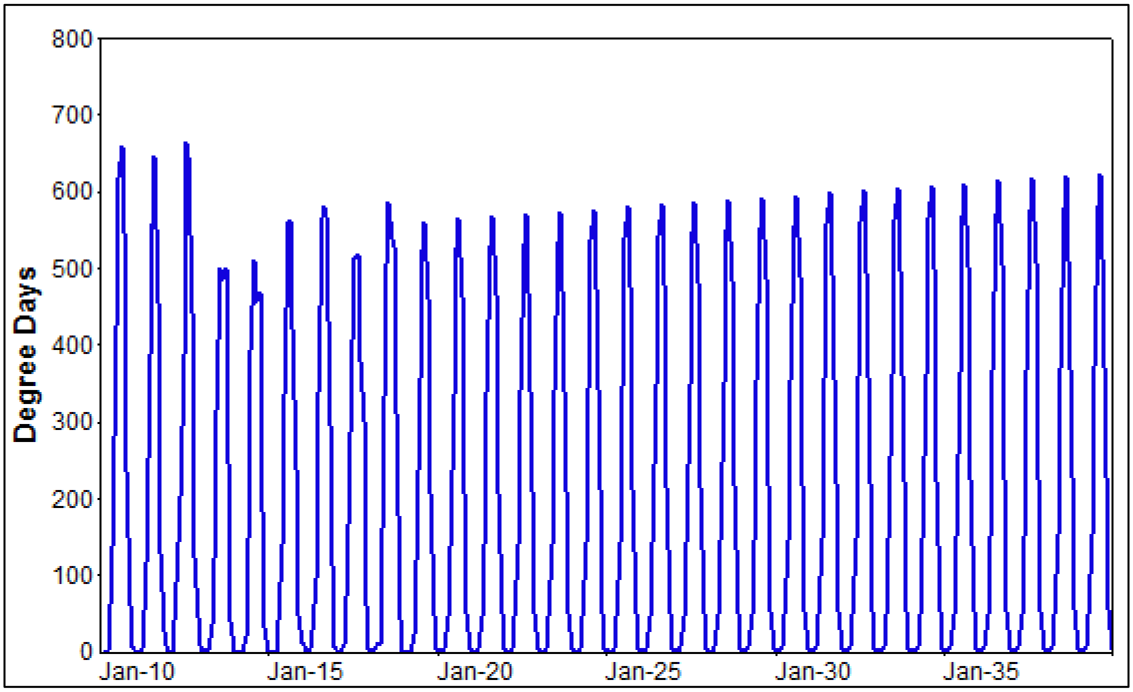


Figure 11.2 – Cooling Degree Days



11.1.1.4 Equipment Efficiencies and Market Shares Data

Itron Inc. provides regional Energy Information Administration (EIA) historic and projected data for equipment efficiencies and market shares. This information is used in the residential average use model and GS sales model. Vectren conducted an Electric Baseline survey in the third quarter of 2016 of Vectren's residential customers. This data was utilized to compare its territory market share data with the regional EIA data. In order to increase the accuracy of the residential average use model, regional equipment market shares were altered to reflect those of Vectren's actual territory. Appliance saturation surveys are conducted every 2-4 years, depending on need.

11.1.2 Load Forecast Continuous Improvement

Itron continues to improve and evolve the SAE (Statistically Adjusted End-Use) modeling framework. In addition to annually updating efficiency and saturations projections with the latest estimates from the EIA (Energy Information Administration) the framework has evolved to include utility specific DSM program activity data. The inclusion of a utility specific DSM variable in the modeling specification greatly improves model fit and enables the model to produce a baseline forecast excluding the impact of future DSM program activity. Additionally, Itron built a framework for the inclusion and use of trended normal weather where historical weather patterns show this to be appropriate.

The Vectren forecast now also takes into account emerging technologies: customer distributed generation and electric vehicles. Customer owned photo-voltaic (PV) adoption is modeled as a function of simple payback. The model explains historic adoption well and provides a framework that considers projected PV installation costs, electric prices and incentives. The adoption of electric vehicles is based on the EIA's forecast of vehicle adoption. The EIA uses a robust transportation model that includes a vehicle manufacturer component and a consumer choice component to estimate the mix of vehicles by powertrain type; gasoline, diesel, electric, plug-in hybrid electric, etc. The model accounts for projected fuel prices, electric prices, the decline in battery costs and federal incentives for electric vehicles.

Additionally, Vectren continually stays up to date with load forecasting topics in a variety of ways. First, Vectren is a member of Itron's Energy Forecasting Group. The Energy Forecasting Group contains a vast network of forecasters from around the country that share ideas and study results on various forecasting topics. Vectren forecasters attend an annual meeting that includes relevant topic discussions along with keynote speakers from the EIA and other energy forecasting professionals. The meeting is an excellent source for end-use forecasting directions and initiatives, as well as a networking opportunity. Vectren forecasters periodically attend continuing education workshops and webinars on various forecasting topics to help improve skills and learn new techniques. Additionally, Vectren discusses forecasts with the State Utility Forecasting Group and other Indiana utilities to better understand their forecasts. Vectren compares Vectren model assumptions and results to these groups to gain a better understanding of how they interpret and use model inputs.

11.1.3 Overview of Past Forecasts

The following tables outline the performance of Vectren's energy and demand forecasts over the last several IRPs by comparing Weather Normalized (WN) sales and demand figurers to IRP forecasts from 2009-2018.

Weather-normalization is performed each month by importing customer count, meter read schedule, billing month sales and daily temperature into Vectren's Electric AUPC Estimation system. Underlying the Electric AUPC Estimation System is a set of MetrixND (Itron's statistical modeling software) average use models. Separate models have been estimated for residential and general service customer classes. These models have been estimated from historical billed sales and customer data and daily system delivery data. On execution, the Use per Customer (UPC) project files read actual weather data from the Access weather database and generate daily use per customer estimates for the revenue classes. The results are exported back to the AUPC system database where the predicted daily use estimates are used to allocate billed monthly sales to the calendar-month period. The models are also executed using normal daily temperatures. Results are written back to the AUPC system database. Weather-normalized sales are then exported from the Electric AUPC Estimation system.

The following tables show the WN[46] and forecasted values for:

- Total Peak Demand
- Total Energy
- Residential Energy
- GS Energy
- Large Energy

[46] Note that large sales are not weather normalized.

Figure 11.3 – Total Peak Demand Requirements (MW), Including Losses and Street Lighting

Year	2007 Total Demand Forecast (MW)	2009 Total Demand Forecast (MW)	2011 Total Demand Forecast (MW)	2014 Total Demand Forecast (MW)	2016 Total Demand Forecast (MW)	WN Total Demand (MW)	2007 % Diff.	2009 % Diff.	2011 % Diff.	2014 % Diff.	2016 % Diff.
2009	1,216					1,069	-13.7%				
2010	1,237	1,153				1,136	-8.9%	-1.5%			
2011	1,252	1,179				1,159	-8.0%	-1.7%			
2012	1,258	1,118	1,156			1,136	-10.7%	1.6%	-1.7%		
2013	1,265	1,115	1,156			1,144	-10.5%	2.6%	-1.0%		
2014	1,272	1,107	1,165			1,133	-12.3%	2.3%	-2.8%		
2015	1,281	1,100	1,164	1,155		1,113	-15.1%	1.1%	-4.6%	-3.8%	
2016	1,290	1,092	1,160	1,156		1,087	-18.7%	-0.5%	-6.7%	-6.3%	
2017	1,299	1,094	1,151	1,113	1,082	1,038	-25.2%	-5.4%	-11.0%	-7.2%	-4.3%
2018	1,308	1,093	1,145	1,109	1,086	1,006	-30.0%	-8.6%	-13.8%	-10.2%	-7.9%
Mean Absolute Error							15.3%	2.8%	5.9%	6.9%	6.1%

Figure 11.4 – Total Energy Requirements (GWh), Including Losses and Street Lighting

Year	2007 Total Energy IRP Forecast (GWh)	2009 Total Energy IRP Forecast (GWh)	2011 Total Energy IRP Forecast (GWh)	2014 Total Energy IRP Forecast (GWh)	2016 Total Energy IRP Forecast (GWh)	WN Total Energy Results (GWh)	2007 % Diff.	2009 % Diff.	2011 % Diff.	2014 % Diff.	2016 % Diff.
2009	6,090					5,365	-13.5%				
2010	6,230	5,306				5,701	-9.3%	6.9%			
2011	6,329	5,460				5,819	-8.8%	6.2%			
2012	6,369	5,456	5,837			5,718	-11.4%	4.6%	-2.1%		
2013	6,422	5,434	5,807			5,743	-11.8%	5.4%	-1.1%		
2014	6,476	5,403	5,803			5,797	-11.7%	6.8%	-0.1%		
2015	6,527	5,365	5,772	5,914		5,773	-13.1%	7.1%	0.0%	-2.4%	
2016	6,580	5,336	5,725	5,936		5,725	-14.9%	6.8%	0.0%	-3.7%	
2017	6,629	5,315	5,657	5,514	5,257	5,073	-30.7%	-4.8%	-11.5%	-8.7%	-3.6%
2018	6,680	5,292	5,590	5,503	5,290	5,139	-30.0%	-3.0%	-8.8%	-7.1%	-2.9%
Mean Absolute Error							15.5%	5.7%	3.4%	5.5%	3.3%

Figure 11.5 – Residential Energy (GWh)

Year	2007 Res. IRP Forecast (GWh)	2009 Res. IRP Forecast (GWh)	2011 Res. IRP Forecast (GWh)	2014 Res. IRP Forecast (GWh)	2016 Res. IRP Forecast (GWh)	WN Res. Results (GWh)	2007 % Diff.	2009 % Diff.	2011 % Diff.	2014 % Diff.	2016 % Diff.
2009	1,595					1,512	-5.5%				
2010	1,620	1,467				1,483	-9.2%	1.1%			
2011	1,645	1,440				1,460	-12.7%	1.3%			
2012	1,663	1,421	1,462			1,437	-15.7%	1.1%	-1.7%		
2013	1,683	1,391	1,419			1,421	-18.4%	2.1%	0.1%		
2014	1,703	1,365	1,399			1,412	-20.6%	3.3%	0.9%		
2015	1,722	1,332	1,371	1,404		1,444	-19.2%	7.8%	5.1%	2.8%	
2016	1,742	1,304	1,340	1,394		1,416	-23.0%	7.9%	5.4%	1.5%	
2017	1,759	1,282	1,305	1,383	1,407	1,398	-25.8%	8.3%	6.7%	1.1%	-0.6%
2018	1,777	1,264	1,271	1,377	1,395	1,375	-29.2%	8.1%	7.6%	-0.2%	-1.5%
Mean Absolute Error							17.9%	4.6%	3.9%	1.4%	1.1%

Figure 11.6 – Commercial (GS) Energy (GWh)

Year	2007 Comm. (GS) IRP Forecast (GWh)	2009 Comm. (GS) IRP Forecast (GWh)	2011 Comm. (GS) IRP Forecast (GWh)	2014 Comm. (GS) IRP Forecast (GWh)	2016 Comm. IRP Forecast (GWh)	WN Comm. (GS) Results (GWh)	2007 % Diff.	2009 % Diff.	2011 % Diff.	2014 % Diff.	2016 % Diff.
2009	1,384					1,319	-4.9%				
2010	1,404	1,275				1,314	-6.8%	3.0%			
2011	1,426	1,284				1,307	-9.1%	1.8%			
2012	1,438	1,296	1,375			1,283	-12.1%	-1.0%	-7.2%		
2013	1,455	1,304	1,383			1,294	-12.4%	-0.7%	-6.9%		
2014	1,472	1,307	1,399			1,312	-12.2%	0.4%	-6.6%		
2015	1,490	1,306	1,402	1,304		1,321	-12.8%	1.1%	-6.2%	1.3%	
2016	1,507	1,306	1,398	1,320		1,281	-17.7%	-1.9%	-9.1%	-3.0%	
2017	1,525	1,309	1,384	1,315	1,315	1,278	-19.3%	-2.4%	-8.3%	-2.9%	-2.9%
2018	1,544	1,311	1,373	1,311	1,324	1,235	-25.0%	-6.1%	-11.1%	-6.1%	-7.2%
Mean Absolute Error							13.2%	2.0%	7.9%	3.3%	5.1%

Figure 11.7 – Industrial (Large) Energy (GWh)

Year	2007 Ind. (Large) IRP Forecast (GWh)	2009 Ind. (Large) IRP Forecast (GWh)	2011 Ind. (Large) IRP Forecast (GWh)	2014 Ind. (Large) IRP Forecast (GWh)	2016 (Large) IRP Forecast (GWh)	WN Ind. (Large) Results (GWh)	2007 % Diff.	2009 % Diff.	2011 % Diff.	2014 % Diff.	2016 % Diff.
2009	2,820					2,251	-25.3%				
2010	2,921	2,281				2,601	-12.3%	12.3%			
2011	2,980	2,445				2,744	-8.6%	10.9%			
2012	2,999	2,449	2,687			2,714	-10.5%	9.8%	1.0%		
2013	3,014	2,449	2,693			2,744	-9.8%	10.7%	1.9%		
2014	3,028	2,446	2,693			2,786	-8.7%	12.2%	3.3%		
2015	3,040	2,445	2,688	2,916		2,722	-11.7%	10.1%	1.2%	-7.1%	
2016	2,718	2,447	2,679	2,932		2,722	0.2%	10.1%	1.6%	-7.7%	
2017	2,730	2,446	2,664	2,546	2,211	2,097	-30.2%	-16.7%	-27.1%	-21.4%	-5.5%
2018	2,742	2,440	2,646	2,547	2,252	2,182	-25.7%	-11.9%	-21.3%	-16.7%	-3.2%
Mean Absolute Error							14.3%	11.6%	8.2%	13.3%	4.3%

11.1.3.1 Actual and Weather Normalized Energy and Demand Levels

Figure 11.8 – Historic Peak Demand

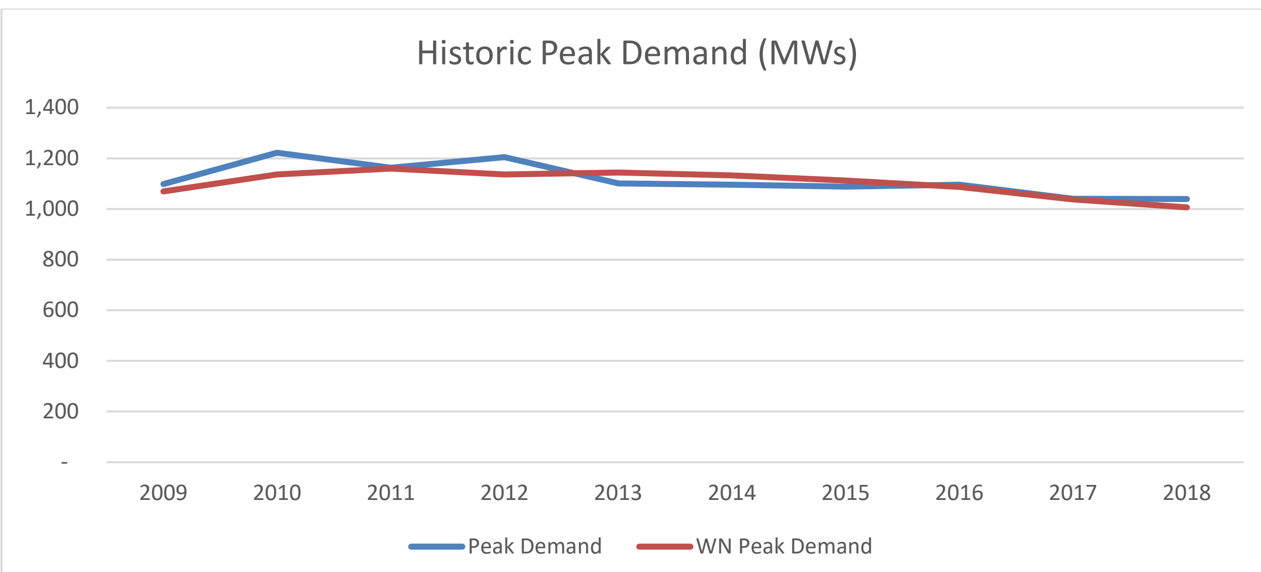
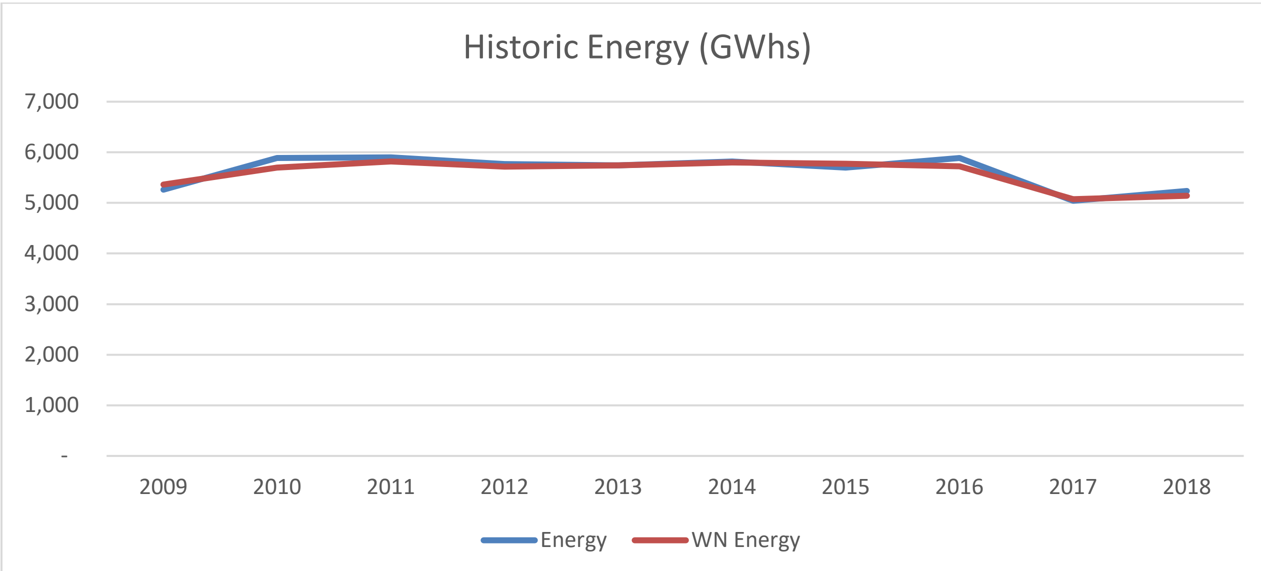


Figure 11.9 – Historic Energy



11.1.3.2 Load Shapes

Figure 11.10 – Historic Annual Load Shape

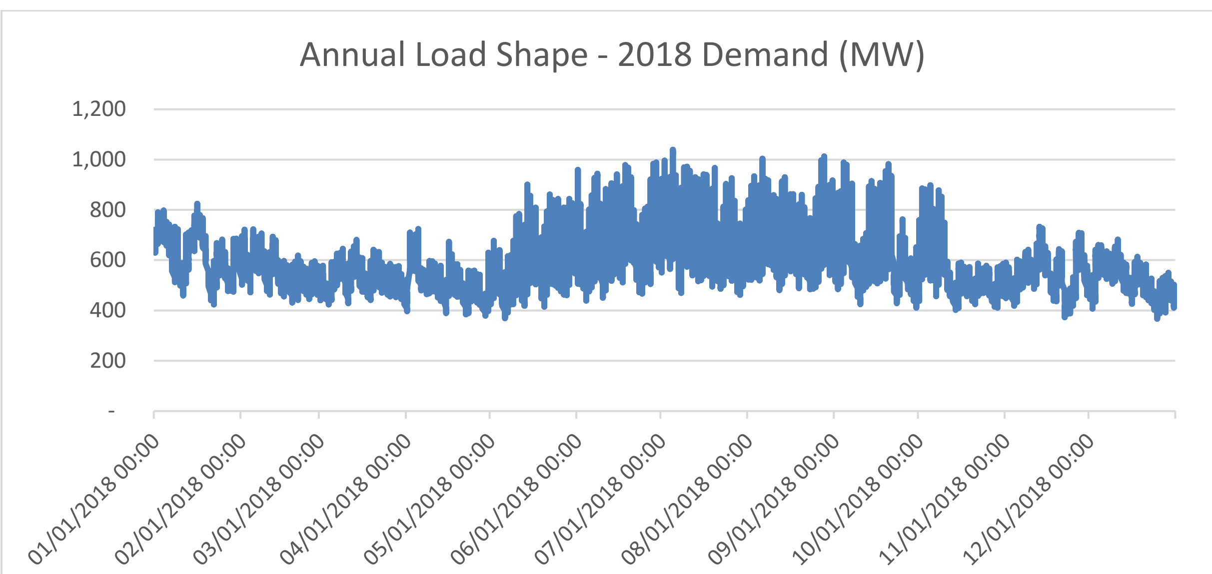


Figure 11.11 – Winter Peak Day

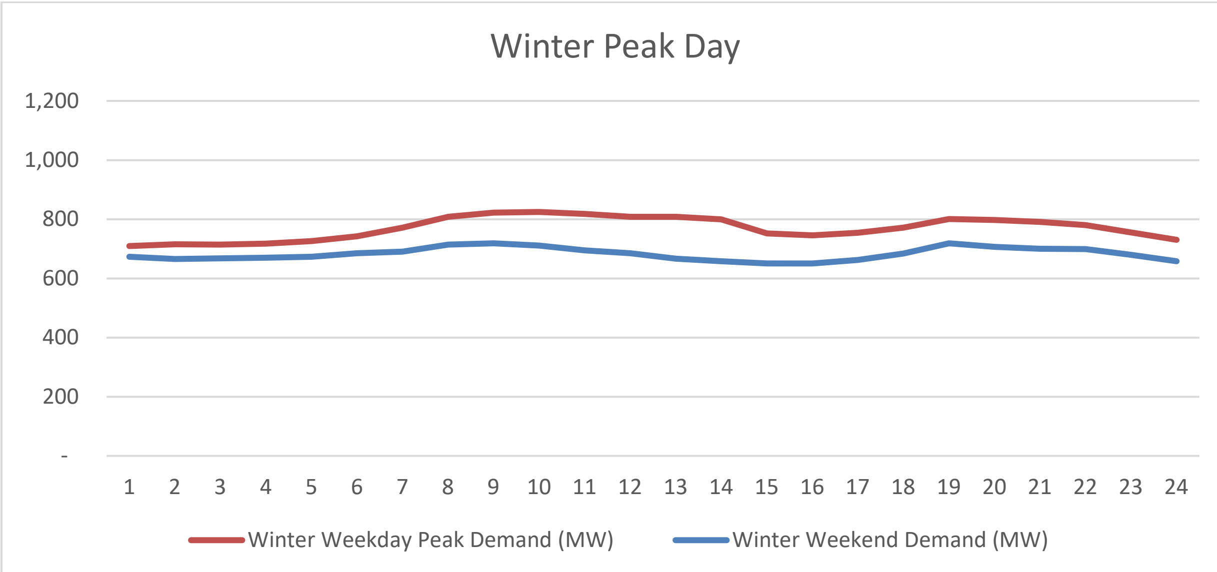


Figure 11.12 – Typical Spring Day

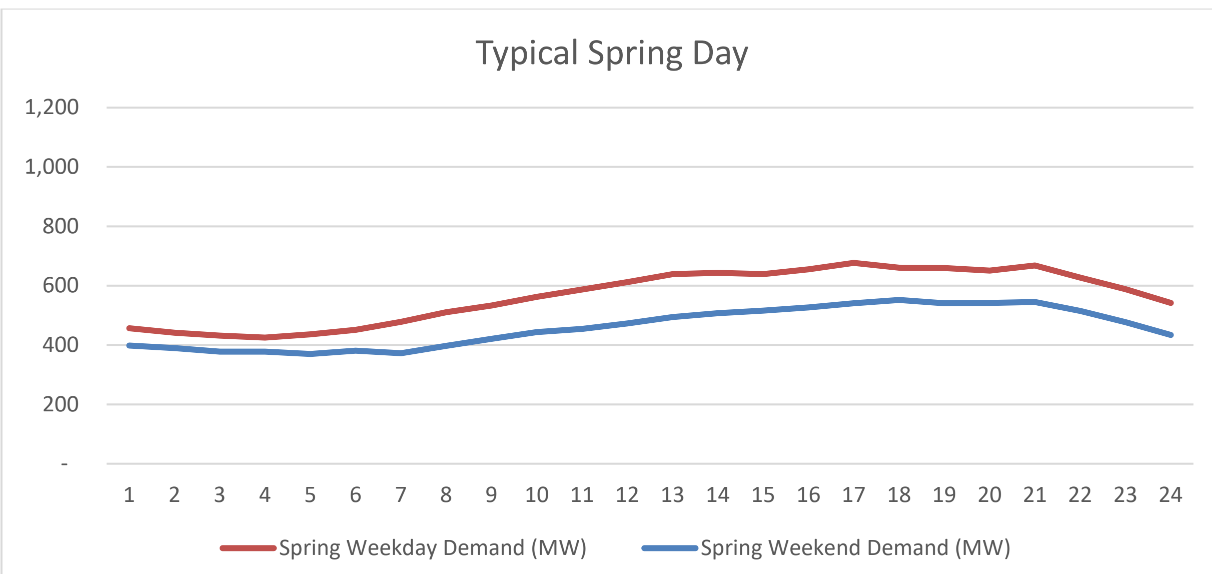


Figure 11.13 – Summer Peak Day

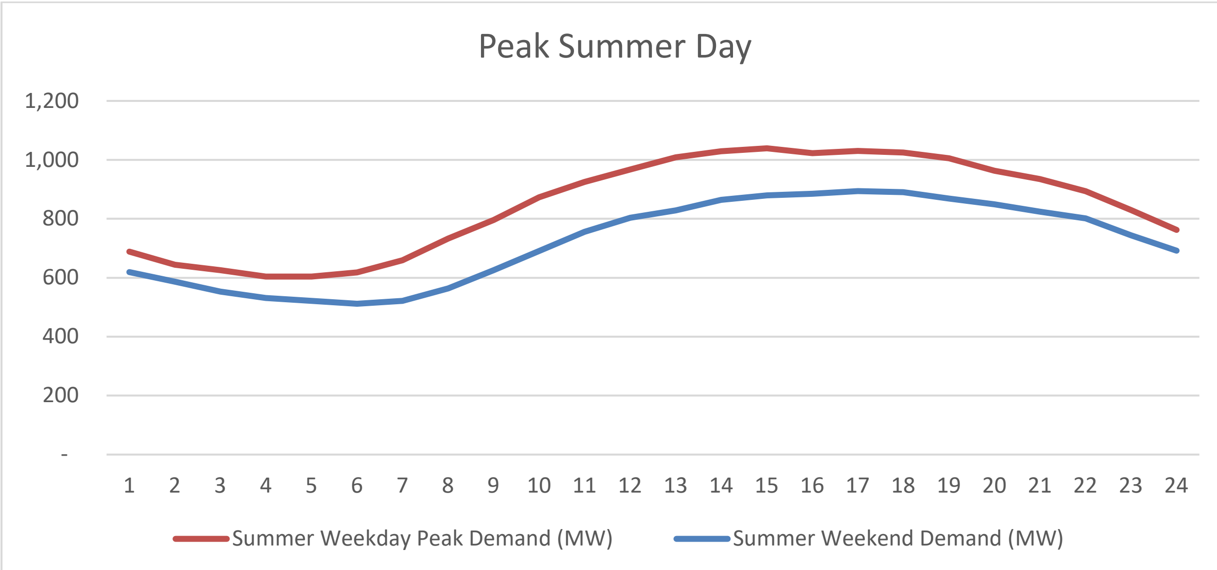


Figure 11.14 – Typical Fall Day

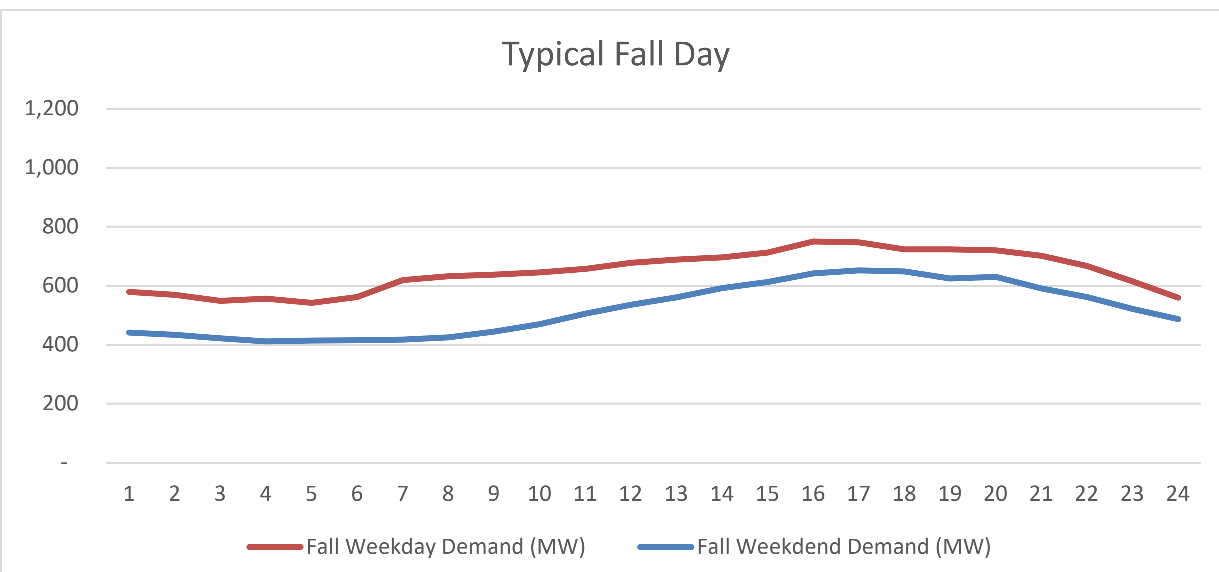


Figure 11.15 – January Load

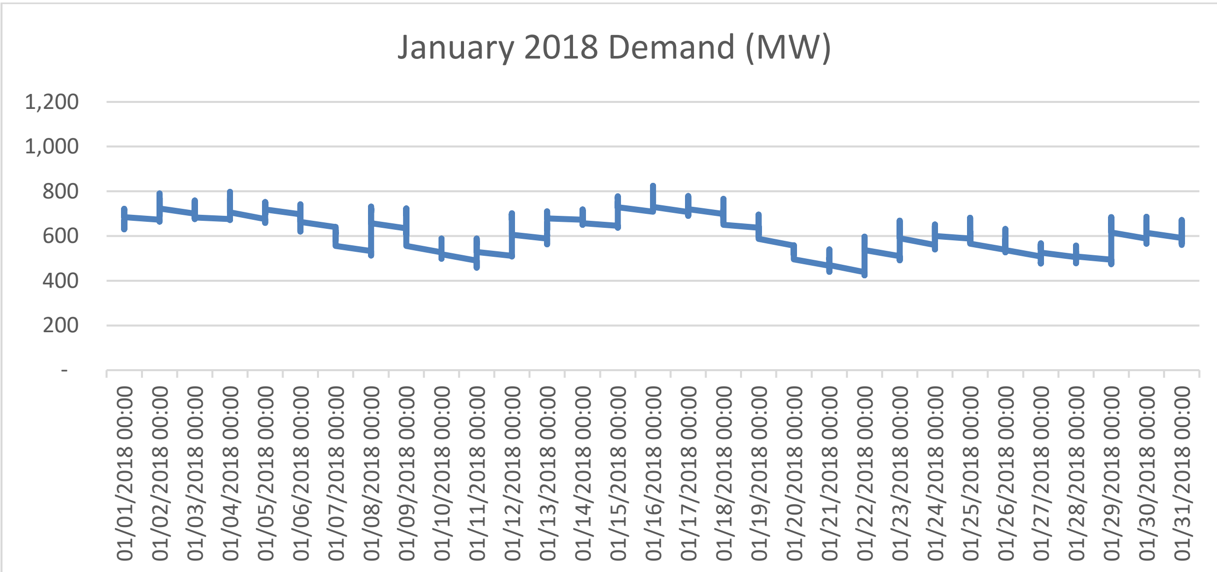


Figure 11.16 – February Load

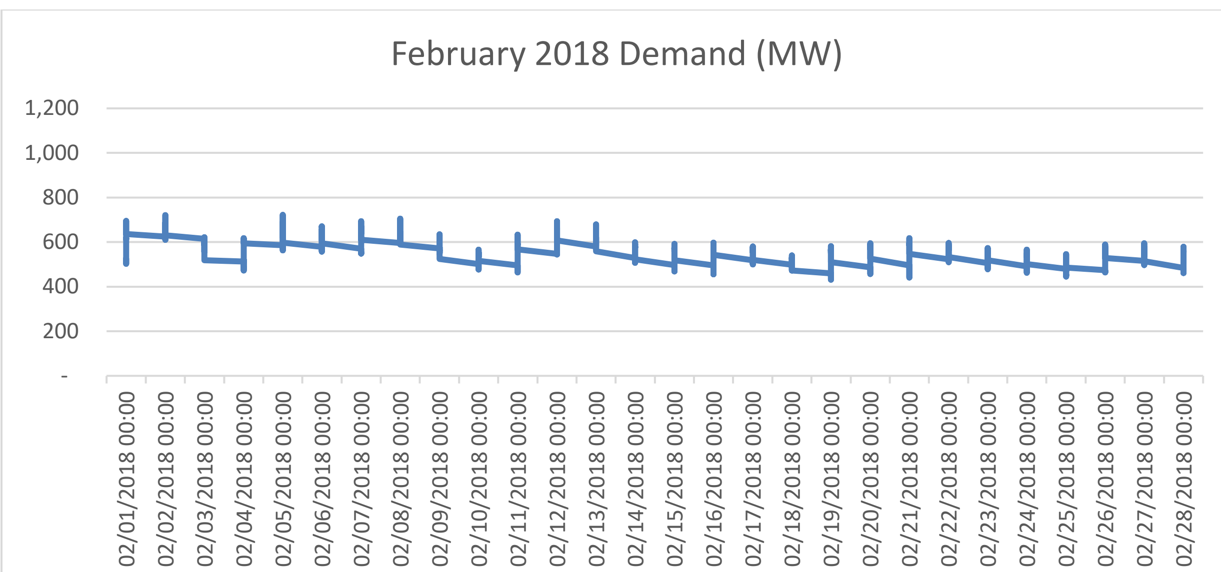


Figure 11.17 – March Load

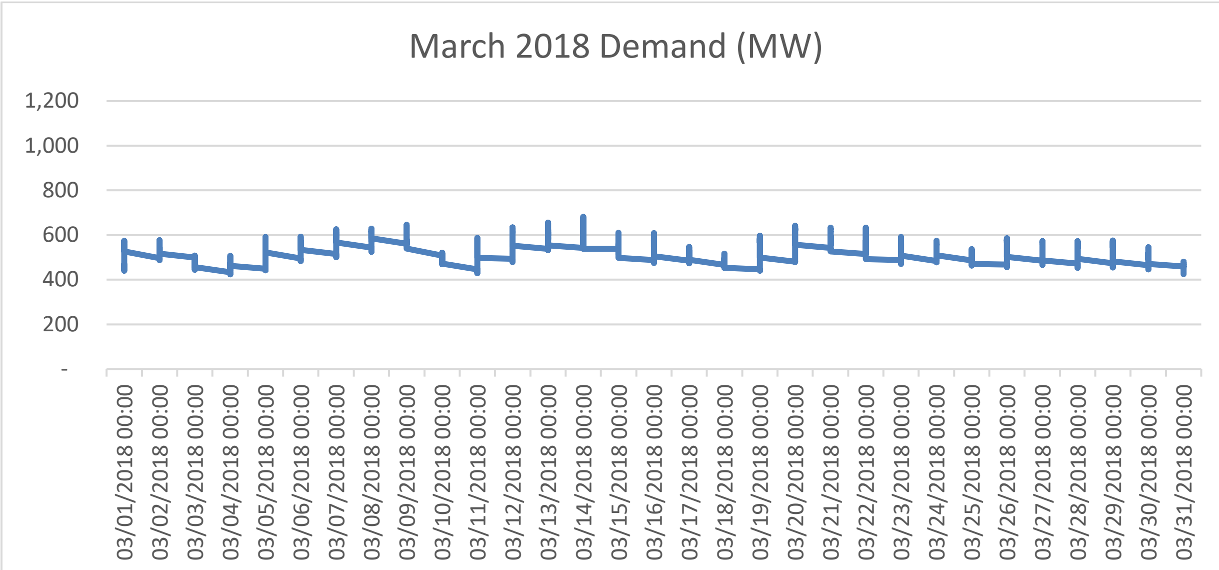


Figure 11.18 – April Load

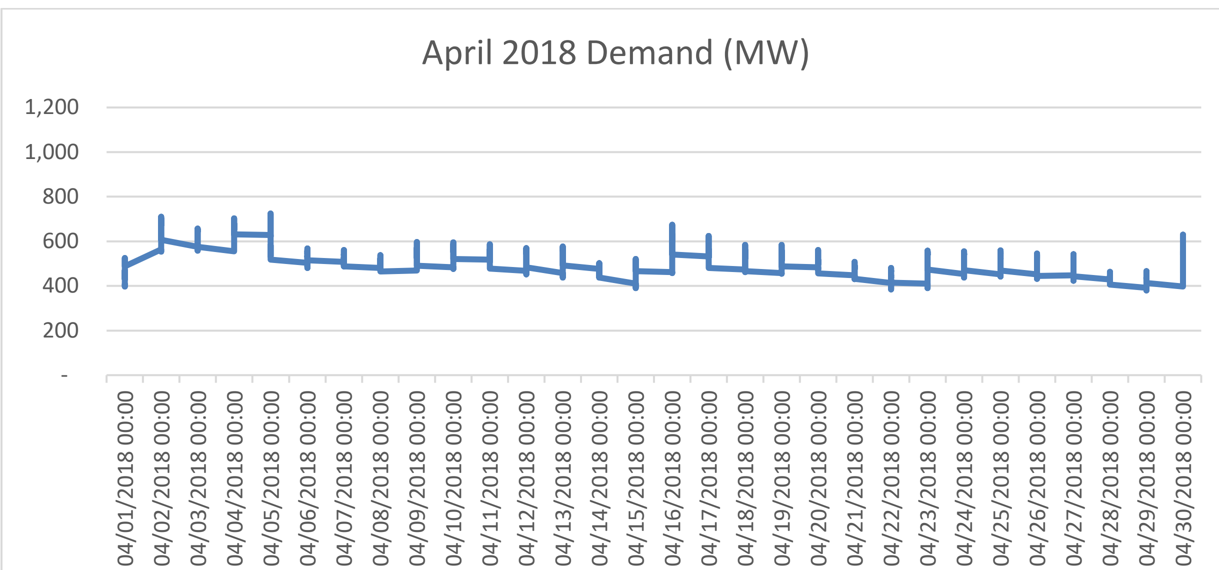


Figure 11.19 – May Load

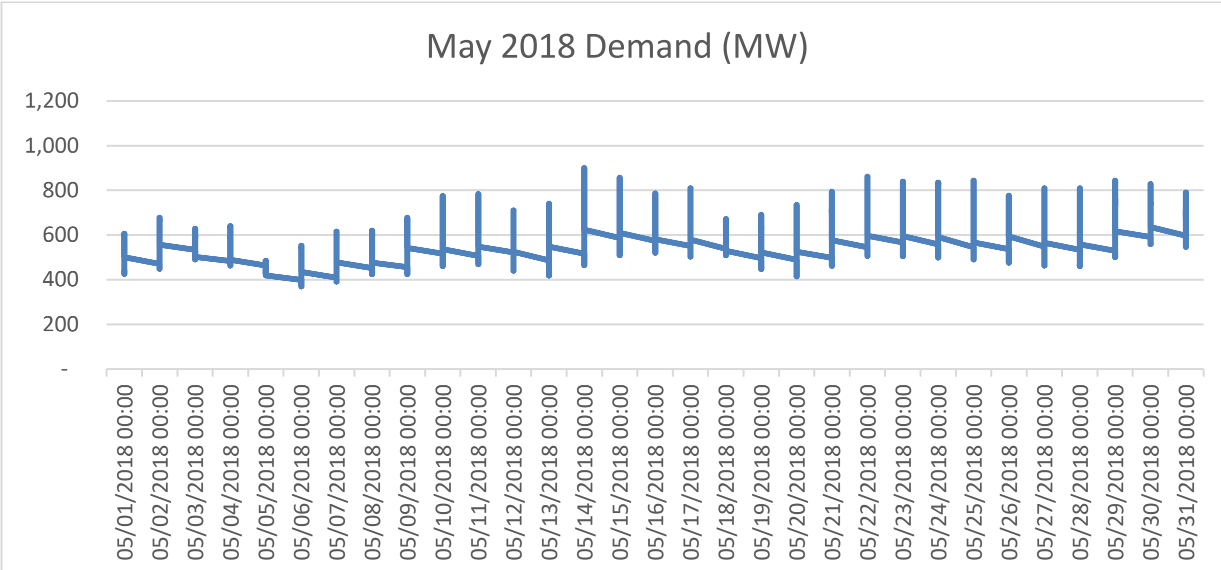


Figure 11.20 – June Load

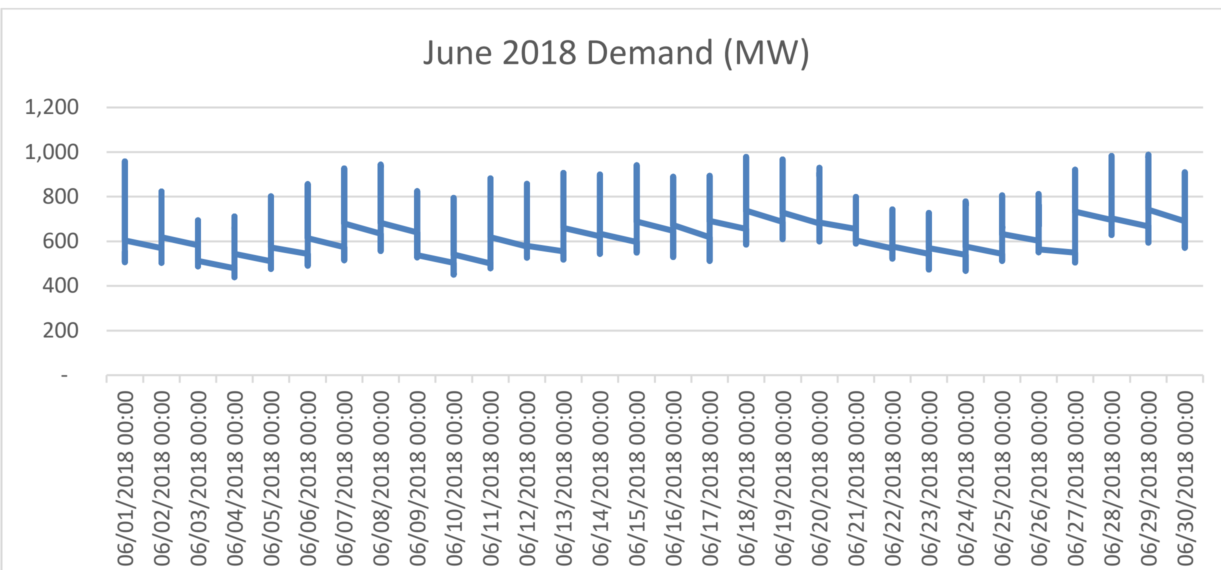


Figure 11.21 – July Load

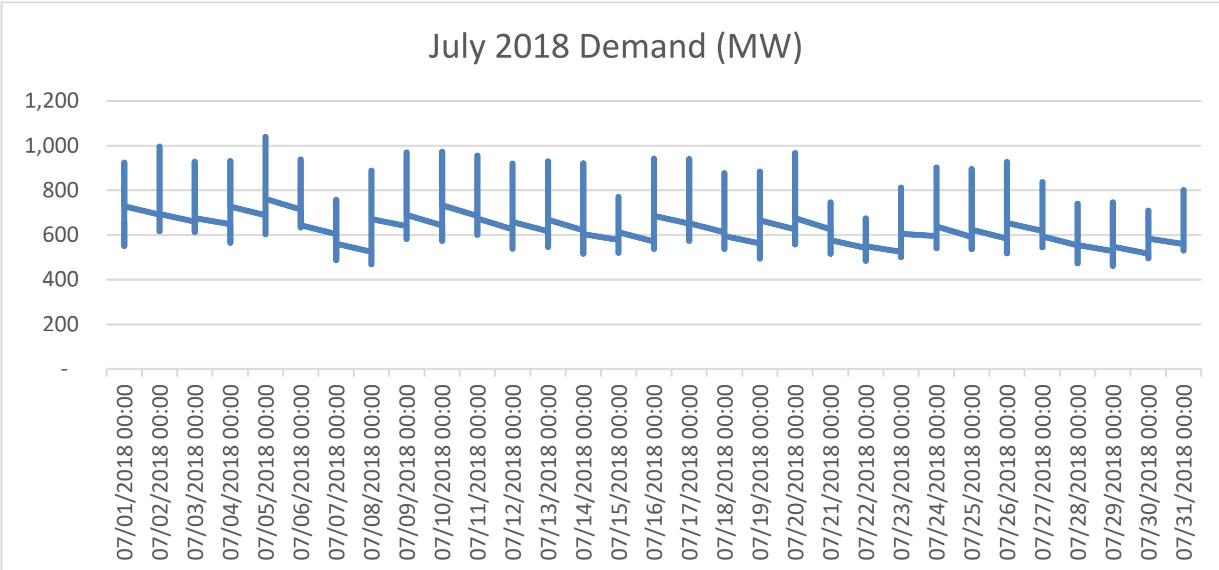


Figure 11.22 – August Load

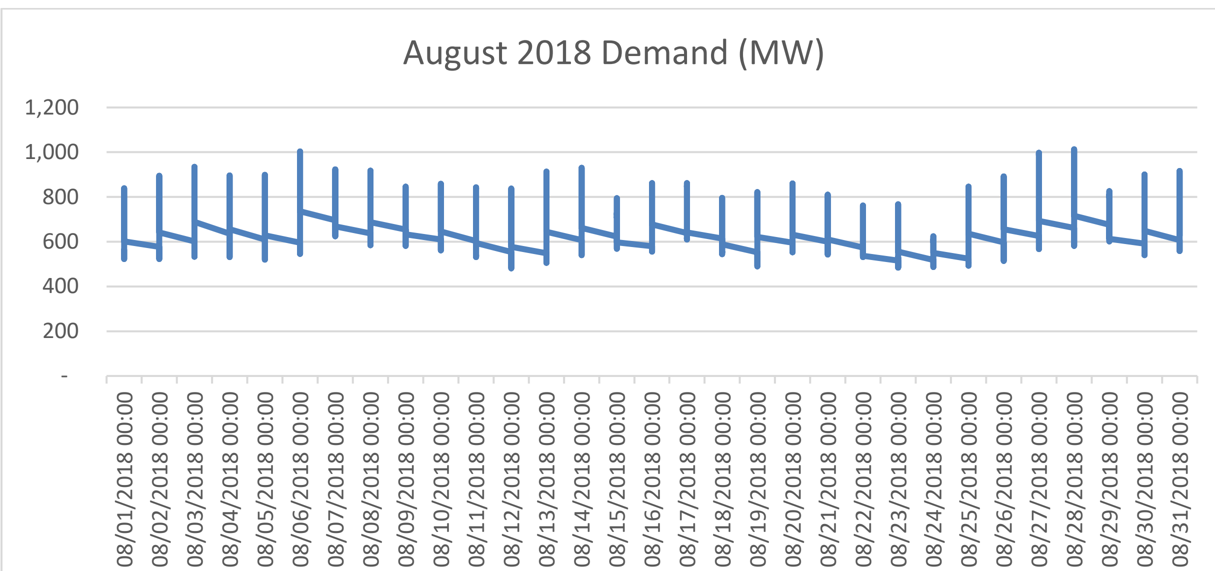


Figure 11.23 – September Load

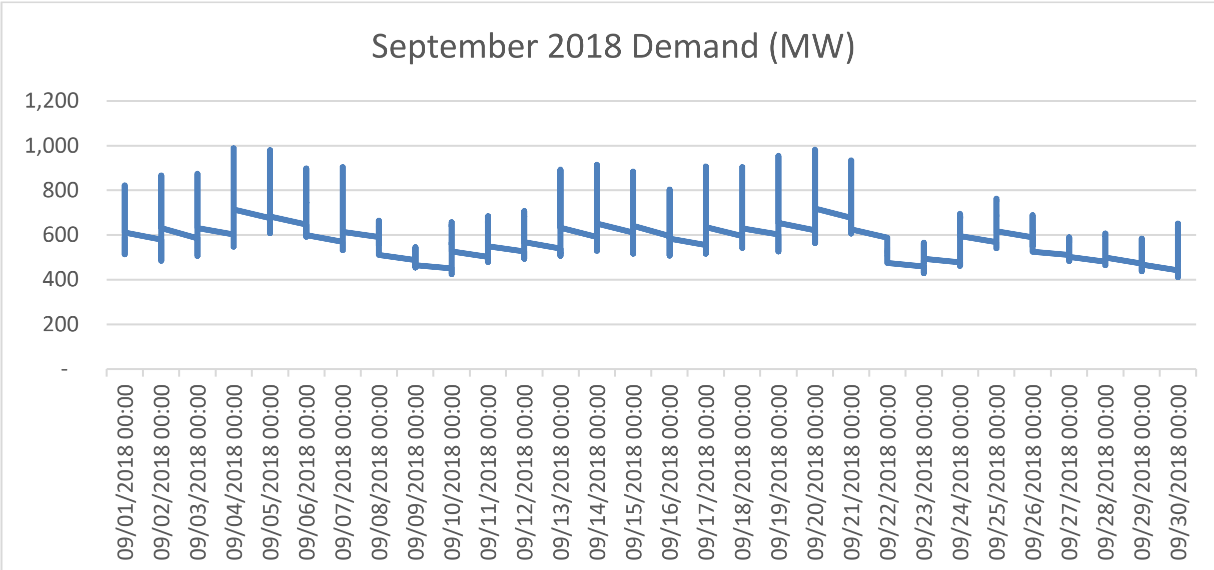


Figure 11.24 – October Load

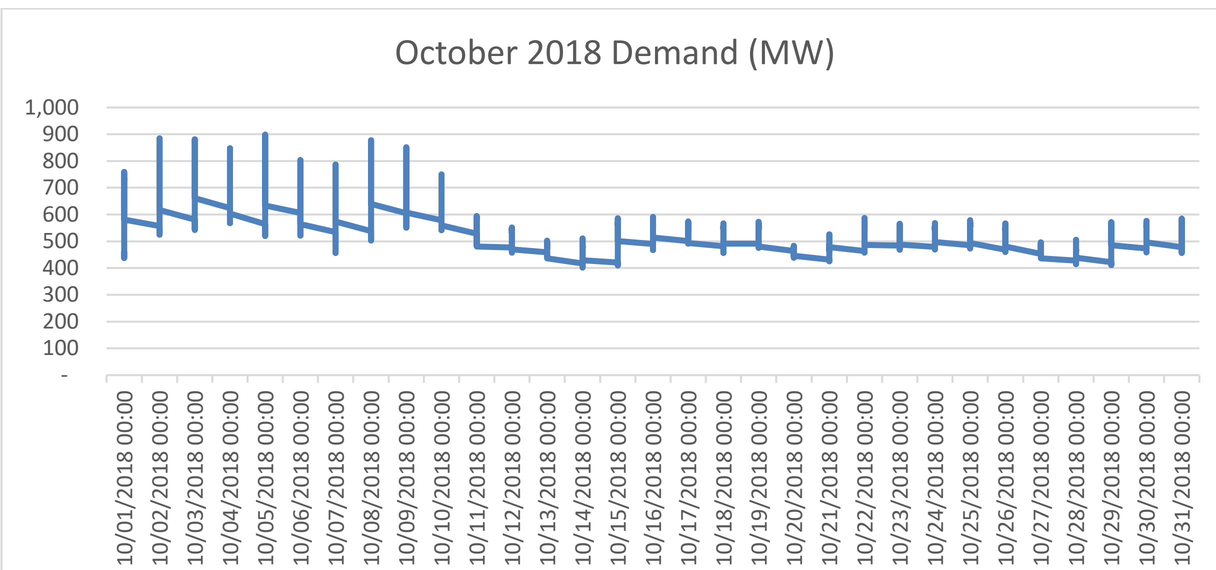


Figure 11.25 – November Load

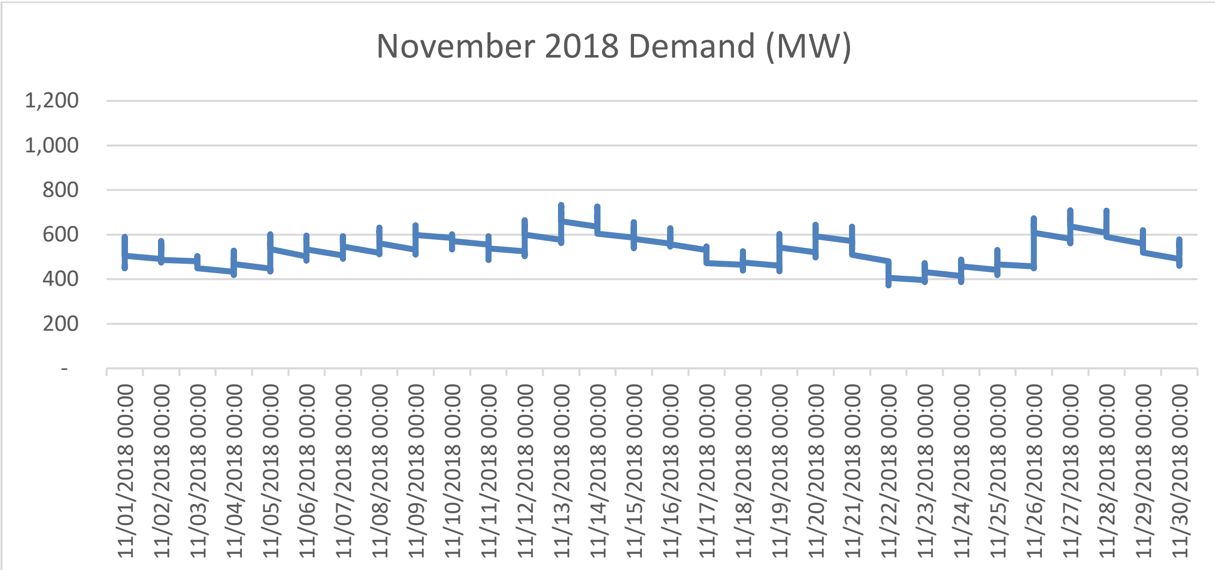
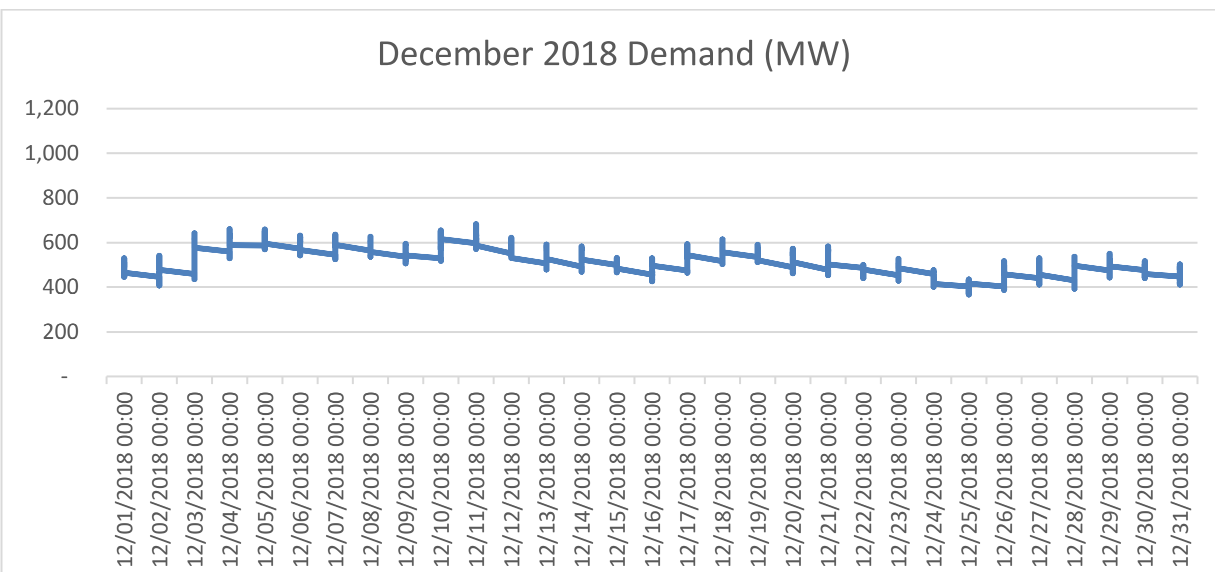


Figure 11.26 – December Load



11.2 ENVIRONMENTAL APPENDIX

11.2.1 Air Emissions

It was assumed that current or future generation resources would not exceed Vectren's allocated SO_2 and NOx emission allowances. Vectren's fleet of existing power generation facilities meet all rules and regulations related to SO_2 and NOx emissions while the cost of emission control equipment for SO_2 and NOx is factored into any new facilities that would be selected as part of a portfolio. Air emissions allowance costs are accounted for within IRP modeling.

Figure 11.27 – Air Pollution Control Devices Installed

	F.B. Culley 2	F.B. Culley 3	Warrick 4	A.B. Brown 1	A.B. Brown 2
Vintage	1966	1973	1970	1979	1986
MW (net)	90	270	150	245	245
NO_X	Low NO_X Burner	SCR	SCR	SCR	SCR
SO_2	FGD	FGD	FGD	FGD	FGD
PM	ESP	FF	ESP	FF	ESP
MATs	Shared w/ U3	Injection	Injection	Injection	Injection
SO_3		Injection	Injection	Injection	injection

Figure 11.28 – CSAPR SO_2 Allowances

SO_2				
	A.B. Brown	F.B. Culley	SIGECO W4	Total
2016	7,894	4,411	2,892	15,197
2017	4,423	3,890	1,620	9,933
2018	4,423	3,890	1,620	9,933
2019	4,423	3,890	1,620	9,933

NOx					
	A.B. Brown	BAGS[47]	F.B. Culley	SIGECO W4	Total
2016	1,214	21	1,060	445	2,740
2017	1,195	21	1,044	437	2,697
2018	1,195	21	1,044		2,698
2019	1,195	21	1,044	437	2,697

47 Retired

Figure 11.29 – CSAPR Seasonal NOx Allowances

	A.B. Brown	BAGS[48]	F.B. Culley	SIGECO W4	Total
2016	1,214	21	1,060	445	2,740
2017	658	6	465	227	1,356
2018	658	6	465	227	1,356
2019	658	6	465	227	1,356

11.2.2 Solid Waste Disposal

Scrubber by-products from A.B. Brown are sent to an on-site landfill permitted by Indiana Department of Environmental Management (IDEM). During the fall of 2009, Vectren finalized construction of a dry fly ash silo and barge loading facility that would allow for the beneficial reuse of Vectren-generated fly ash. Since February 2010, the majority of A.B. Brown fly ash is diverted to the new dry ash handling system and sent for beneficial reuse to a cement processing plant in St. Genevieve, Missouri via a river barge loader and conveyor system. This major sustainability project serves to mitigate negative impacts from the imposition of a more stringent regulatory scheme for ash disposal, as the majority of Vectren's coal combustion materials are now being diverted from the existing ash pond structures and surface coal mine backfill operations and instead transported offsite for recycling into a cement application.

Fly ash from the F.B. Culley facility is similarly transported off-site for beneficial reuse in cement. In May 2009, Culley began trucking fly ash to the St. Genevieve cement plant. Upon completion of the barge loading facility at the A.B. Brown facility in late 2009, F.B. Culley's fly ash is now transported to the A.B. Brown loading facility and shipped to the cement plant via river barge. The F.B. Culley facility sends its bottom ash to the East ash pond via wet sluicing. The pond is approximately 10 acres in size. By the end of 2020, the East pond will no longer receive bottom ash as a result of the conversion to a dry system. The West pond (32 acres) no longer receives bottom ash but has continued to accept coal pile run-off and general storm water from the west side of the plant, including the plant entrance road. By the end of 2020, the West pond will be closed. The closure

[48] Retired

project includes the construction of a new geosynthetic lined contact storm water pond that will receive the coal pile run-off and other storm water that contacts industrial activity. Scrubber by-product generated by the F.B. Culley facility is also used for beneficial reuse and shipped by river barge from F.B. Culley to a wallboard manufacturer. In summary, the majority of Vectren's coal combustion material is no longer handled on site but is being recycled and shipped off-site for beneficial reuse.

11.2.3 Hazardous Waste Disposal

Vectren’s A.B. Brown and F.B. Culley plants are episodic producers of hazardous waste that may include paints, parts washer fluids, or other excess or outdated chemicals. Both facilities are typically classified as Small Quantity Generators. All hazardous waste is disposed of in accordance with Federal and state regulations.

11.2.4 Water Consumption and Discharge

A.B. Brown and F.B. Culley currently discharge process and cooling water to the Ohio River under National Pollutant Discharge Elimination System (NPDES) water discharge permits issued by the Indiana Department of Environmental Management (IDEM). A.B. Brown utilizes cooling towers while F.B. Culley has a once through cooling water system. In fall 2014, both plants installed chemical precipitation water treatment systems to meet Ohio River Valley Sanitation Commission (ORSANCO) regional water quality standards mercury limit of 12 ppt monthly average.

11.3 DSM APPENDIX

11.3.1.1 DSM Planning Process

One of the key objectives of the IRP is to “provide all customers with a reliable supply of energy at the lowest reasonable cost.” The level and costs of DSM to be offered in Vectren’s service territory are important outcomes of the IRP process. The IRP will determine the appropriate level of DSM to include in the preferred resource plan. However, for Vectren, the IRP is not the appropriate tool to determine which specific programs to include in a DSM plan. Instead, every 2-3 years Vectren engages in a multi-step planning process designed to select programs that meet the level of savings established in the preferred resource portfolio. Once the level of DSM to be offered has been established by the IRP and a portfolio of programs to meet the savings levels has been designed, the last step in the planning process is to re-affirm the cost effectiveness of the proposed programs.

11.3.1.2 Cost Benefit Analysis

Utilizing the DSMore cost/benefit model, the measures and programs were analyzed for cost effectiveness. The model includes a full range of economic perspectives typically used in EE and DSM analytics. Inputs into the model include the following: participation rates, incentives paid, energy and demand savings of the measure, life of the measure, avoided costs, implementation costs, administrative costs, incremental costs to the participant of the high efficiency measure and escalation rates and discount rates. Vectren considers the results of each test and ensures that the portfolio passes the Total Resource Cost (TRC) test as it includes the total costs and benefits to both the energy company (program administrator) and the consumer. The outputs include all the California Standard Practice Manual results:

- Participant Cost Test
- Ratepayer Impact Measure Test
- Utility Cost Test (“UCT”)
- Total Resource Cost Test (“TRC”)

The cost effectiveness analysis produces two types of resulting metrics:

- Net Benefits (dollars) = NPV ∑ benefits – NPV ∑ costs
- Benefit Cost Ratio = NPV ∑ benefits ÷ NPV ∑ costs

The Participant Cost Test shows the value of the program from the perspective of the energy company’s customer participating in the program. The test compares the participant's bill savings over the life of the DSM program to the participant's cost of participation.

The Utility Cost Test shows the value of the program to the utility considering only avoided utility supply costs (based on the next unit of generation) in comparison to the utility program costs.

The Ratepayer Impact Measure (RIM) Test shows the impact of a program on all utility customers through impacts on 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 Total Resource Cost (TRC) Test shows the combined perspective of the energy company and the participating customers. This test compares (1) the level of benefits associated with the reduced energy supply costs to (2) the costs incurred by the energy company and by program participants. In completing the tests listed above, Vectren used 6.19% as the weighted average cost of capital, which is the weighted cost of capital that was approved by the IURC on May 29, 2019 in Cause No. 44910.

Figure 5.3.2.8.1 – Vectren Cost Effectiveness Tests Benefits & Costs Summary

Test	Benefits	Costs
Participant Cost Test	• Incentive payments • Annual bill savings • Applicable tax credits	• Incremental technology/equipment costs • Incremental installation costs
Rate Impact Measure Test	• Avoided energy costs • Avoided capacity costs	• All program costs (startup, marketing, labor, evaluation, promotion, etc.) • Utility/Administrator incentive costs • Lost revenue due to reduced energy bills
Utility Cost Test (Program Administrator Cost Test)	• Avoided energy costs • Avoided capacity costs	• All program costs (startup, marketing, labor, evaluation, promotion, etc.) • Utility/Administrator incentive costs
Total Resource Cost Test	• Avoided energy costs • Avoided capacity costs • Applicable participant tax credits	• All program costs (not including incentive costs) • Incremental technology/equipment costs (whether paid by the participant or the utility)

11.3.2 Gross Savings 2018-2020 Plan

Figure 11.30 – 2018-2020 Plan Gross kWh Energy Savings

	2018		**2019**		**2020**	
Sector	Gross kWh Energy Savings	kW Demand Savings	Gross kWh Energy Savings	kW Demand Savings	Gross kWh Energy Savings	kW Demand Savings
Residential	23,302,096	6,417	23,337,912	4,846	19,294,127	5,977
Commercial & Industrial	24,931,097	3,656	20,500,000	4,321	17,053,515	1,773
Total	48,233,193	10,073	43,837,912	9,167	36,347,642	7,750

* 2018 Evaluated Savings used for 2018
** 2019 Operating Plan used for 2019
*** 2020 Filed Plan used for 2020

11.3.3 DSM Programs

Vectren has offered tariff-based DSM resource options to customers for several years. Consistent with a settlement approved in 2007 in Cause No. 43111, the Demand Side Management Adjustment ("DSMA") was created to specifically recover all Vectren's Commission approved DSM costs, including (at that time) a DLC Component. The Commission, in its order in Cause No. 43427, authorized Vectren to include both Core and Core-Plus DSM Program Costs and related incentives in an Energy Efficiency Funding Component ("EEFC") of the DSMA. The EEFC supports the Company's efforts to help customers reduce their consumption of electricity and related impacts on peak demand. It is designed to recover the costs of Commission-approved DSM programs from all customers receiving the benefit of these programs. In Cause Nos. 43427, 43938 and 44318, the Commission approved recovery of the cost of Conservation Programs via the EEFC. This rider is applicable to customers receiving service pursuant to Rate Schedules RS, B, SGS, DGS, MLA, OSS, LP and HLF.

11.3.4 Impacts

The table below demonstrates estimated energy (kWh) and demand (kW) savings per participant for each program.

Figure 11.31 – 2018 Evaluated Electric DSM Program Savings

Program	Residential/ Commercial	Participants *	NTG	Gross kWh	Gross kWh/ Participant	Net kWh	Gross KW	Gross kW/ Participant	Net KW
Residential Lighting	Residential	235,192	58%	8,136,654	35	4,706,664	1,121	0.005	649.0
Residential Prescriptive	Residential	6,900	68%	3,326,588	482	2,277,461	1,667	0.242	1,098.0
Residential New Construction	Residential	145	54%	162,407	1,120	87,700	62	0.428	34.0
Home Energy Assessments	Residential	350	75%	341,133	975	256,938	31	0.089	23.0
Income Qualified Weatherization	Residential	2,043	100%	931,314	456	931,314	100	0.049	100.0
Energy Efficient Schools	Residential	2,401	100%	712,638	297	712,638	76	0.032	76.0
Residential Behavioral Savings	Residential	41,400	100%	7,063,475	171	7,063,475	1,839	0.044	1,838.7
Appliance Recycling	Residential	1,300	67%	1,326,520	1,020	891,359	169	0.130	114.0
BYOT (Bring Your Own Thermostat)	Residential	400	100%				358	0.895	358.0
SmartDLC - Wifi DR/DLC Changeout	Residential	1,043	100%	379,779	364	379,779	866	0.831	866.4
Community Based - LED Lighting	Residential	44,189	100%	921,588	21	921,588	127	0.003	127.0
Evaluated Nonparticipant Spillover	Residential					1,012,564			
Commercial & Industrial Prescriptive	Commercial	37,200	84%	18,605,544	500	15,628,657	2,713	0.073	2,278.7
Commercial & Industrial Custom	Commercial	40	85%	2,512,038	62,801	2,135,232	324	8.100	276.0
Small Business Direct Install	Commercial	138	101%	3,813,515	27,634	3,837,960	619	4.486	623.0
Portfolio Total		372,741	85%	48,233,193	129	40,843,329	10,073	0.027	8,461.8

* Participants are the Verified installations

Figure 11.32 – 2019 Electric DSM Operating Plan Program Savings

Program	Residential/ Commercial	Participants	NTG	Gross kWh	Gross kWh/ Participant	Net kWh	Gross KW	Gross kW/ Participant	Net KW
Residential Lighting	Residential	241,418	72%	8,340,633	35	6,005,256	939	0.004	675.7
Residential Prescriptive	Residential	4,314	53%	2,318,054	537	1,228,569	957	0.222	507.2
Residential New Construction	Residential	171	50%	157,033	918	78,517	90	0.526	45.0
Home Energy Assessments	Residential	400	99%	403,067	1,008	399,036	42	0.105	41.6
Income Qualified Weatherization	Residential	851	100%	546,248	642	546,248	95	0.112	95.0
Energy Efficient Schools	Residential	2,500	100%	962,750	385	962,750	108	0.043	108.0
Residential Behavioral Savings	Residential	41,400	100%	7,370,000	178	7,370,000	961	0.023	961.0
Appliance Recycling	Residential	1,500	53%	1,491,900	995	790,707	198	0.132	104.9
BYOT (Bring Your Own Thermostat)	Residential	400	100%				240	0.600	240.0
SmartDLC - Wifi DR/DLC Changeout	Residential	1,000	100%	198,000	198	198,000	1,015	1.015	1,014.5
Community Based - LED Lighting	Residential	50,496	100%	1,550,227	31	1,550,227	202	0.004	202.0
Commercial & Industrial Prescriptive	Commercial	40,179	75%	13,500,000	336	10,125,000	3,612	0.090	2,709.0
Commercial & Industrial Custom	Commercial	44	96%	3,500,000	79,545	3,360,000	450	10.227	432.0
Small Business Direct Install	Commercial	78	86%	3,500,000	44,872	3,010,000	259	3.321	222.7
Portfolio Total		384,751	81%	43,837,912	114	35,624,309	9,167	0.024	7,358.7

Figure 11.333 – 2020 Electric DSM Filed Plan Program Savings

Program	Residential/ Commercial	Participants	NTG	Gross kWh	Gross kWh/ Participant	Net kWh	Gross KW	Gross kW/ Participant	Net KW
Residential Lighting	Residential	163,416	67%	6,075,005	37	4,070,253	791	0.005	530.0
Residential Prescriptive	Residential	6,595	52%	1,979,280	300	1,029,226	1,910	0.290	993.3
Residential New Construction	Residential	139	50%	187,038	1,346	93,519	118	0.849	59.0
Home Energy Assessments	Residential	1,210	98%	863,991	714	846,711	192	0.159	188.2
Income Qualified Weatherization	Residential	525	100%	1,130,945	2,154	1,130,945	540	1.029	540.2
Energy Efficient Schools	Residential	2,600	100%	645,216	248	645,216	53	0.020	52.8
Residential Behavioral Savings	Residential	35,298	100%	5,600,000	159	5,600,000	1,153	0.033	1,153.0
Appliance Recycling	Residential	920	54%	884,915	962	477,854	117	0.127	63.1
Conservation Voltage Reduction	Residential	5,324	100%	1,461,047	274	1,461,047	263	0.049	263.1
BYOT (Bring Your Own Thermostat)	Residential	400	100%				240	0.600	240.0
SmartDLC - Wifi DR/DLC Changeout	Residential	1,000	100%	466,690	467	466,690	600	0.600	600.0
Community Based - LED Lighting	Residential								
Commercial & Industrial Prescriptive	Commercial	6,856	87%	5,002,621	730	4,352,280	369	0.054	321.0
Commercial & Industrial Custom	Commercial	93	100%	7,002,080	75,291	7,002,080	633	6.806	633.0
Small Business Direct Install	Commercial	131	95%	4,016,159	30,658	3,821,144	585	4.466	556.7
Conservation Voltage Reduction	Commercial	558	100%	1,032,655	1,851	1,032,655	186	0.333	185.9
Portfolio Total		225,065	88%	36,347,642	161	32,029,620	7,750	0.034	6,379.2

11.3.5 Avoided Costs

The avoided power capacity costs are reflective of the estimated replacement capital and fixed operations and maintenance (O&M) cost. For this avoided cost analysis, a 236 MW 1x F-class simple cycle gas turbine was used as the comparison due to the low capital and fixed O&M costs. The operating and capital costs are assumed to escalate with inflation throughout the study period. Transmission and distribution capacity are accounted for within the transmission and distribution avoided cost.

The marginal operating energy costs were based off the modeled Vectren system marginal energy cost from the base optimized scenario under base assumptions. This included emission cost for CO_2 starting in 2027, estimated capital, variable operation and maintenance and fuel costs. The marginal system cost reflects the modeled spinning reserve requirement and adjusted sales forecasts accounting for transmission and distribution losses.

The table below shows avoided costs when energy efficiency is selected through the IRP modeling process. As energy efficiency competes against other supply side resources and is selected, then the cost of a 236 MW 1x F-class simple cycle gas turbine is avoided.

Figure 11.34 – Avoided Costs

Year	Avoided Capital/O&M Cost $/kW*	Transmission & Distribution Avoided Capital Cost $/kW	Total Capacity Avoided Cost $/kW	Natural Gas Forecast $/MMBtu **	CO2 Forecast $/Ton	System Marginal Cost $/MWh***
2020	$148.60	$6.36	**$154.96**	$2.98	$0.00	$28.63
2021	$151.87	$6.43	**$158.30**	$3.16	$0.00	$30.06
2022	$155.21	$6.55	**$161.76**	$3.37	$0.00	$34.99
2023	$158.63	$6.73	**$165.35**	$3.63	$0.00	$35.77
2024	$162.12	$6.71	**$168.82**	$3.83	$0.00	$36.81
2025	$165.68	$6.83	**$172.51**	$4.00	$0.00	$38.82
2026	$169.33	$6.99	**$176.31**	$4.19	$0.00	$39.80
2027	$173.05	$7.15	**$180.20**	$4.35	$4.34	$44.04
2028	$176.86	$7.32	**$184.18**	$4.52	$5.07	$46.36
2029	$180.75	$7.50	**$188.25**	$4.68	$6.48	$48.37
2030	$184.73	$7.63	**$192.36**	$4.87	$7.95	$50.18
2031	$188.79	$7.81	**$196.60**	$5.06	$8.80	$51.76
2032	$192.94	$7.98	**$200.93**	$5.27	$9.68	$52.59
2033	$197.19	$8.16	**$205.35**	$5.51	$10.60	$54.94
2034	$201.53	$8.34	**$209.87**	$5.73	$11.56	$56.60

Year	Avoided Capital/O&M Cost $/kW*	Transmission & Distribution Avoided Capital Cost $/kW	Total Capacity Avoided Cost $/kW	Natural Gas Forecast $/MMBtu **	CO2 Forecast $/Ton	System Marginal Cost $/MWh***
2035	$205.96	$8.52	**$214.48**	$6.02	$13.29	$59.93
2036	$210.49	$8.71	**$219.20**	$6.23	$15.09	$61.52
2037	$215.12	$8.90	**$224.02**	$6.48	$16.97	$64.69
2038	$219.86	$9.10	**$228.95**	$6.70	$19.71	$69.00
2039	$224.69	$9.30	**$233.99**	$6.90	$23.36	$72.04

***Transmission costs derived from switchyard upgrade on brownfield A.B. Brown site**

***Distribution costs derived from average investment per lot**

****Assumes average of winter/summer delivered to S. Indiana**

*****Based on Vectren Reference Case (Around-the-Clock prices shown)**

11.3.6 Estimated Impact on Historical and Forecasted Peak Demand and Energy

11.4 RESOURCE OPTIONS APPENDIX

11.4.1 Existing Resource Studies

11.4.1.1 Existing Brown Scrubber Assessment

Both A.B. Brown units are scrubbed for sulfur dioxide (SO2) emissions, utilizing a dual-alkali flue gas desulfurization (FGD) process. The FGD systems were included as part of the original unit design and construction. A.B. Brown Unit 1 FGD has reached 40 years of service life and Unit 2 FGD has reached 33 years of service life as of 2019. The operating life of these scrubbers has been impacted by a combination of the acidic and caustic dual-alkali conditions, which are both very damaging to structural steel and concrete. Continual maintenance and repairs have been completed throughout the many years of service. Despite these continuous repair and maintenance efforts, many steel elements and foundations exhibit severe corrosion. Structural assessment studies have been completed by a local engineering firm, Three i Design. Major replacements and repairs have been identified to further the existing FGD operation another 10 years to

2029. Three i Design provided costs for upgrading and refurbishing the existing FGD system to extend the life through the 10-year period.

11.4.1.2 Replacement Scrubber Options at Brown

New replacement FGD technologies at A.B. Brown, identified in Table 10-1 have been evaluated for availability and applicability. Technically feasible options that are both available and applicable to A.B. Brown had high level AACE Class 5 installation cost estimates developed.

Table 10-1 Identify Available and Applicable Technologies

Technology Alternative	Technically Feasible (Yes/No)	
	Available	Applicable
Wet FGD		
Limestone Conversion of Existing Dual-Alkali FGD - Forced Oxidation (DA-LSFO)	Yes	No –Existing equipment capacity inadequate for conversion. New technology required to meet emissions criteria.
Limestone Conversion of Existing Dual-Alkali FGD - Inhibited Oxidation (DA-LSIO)	Yes	No –Existing equipment capacity inadequate for conversion. New technology required to meet emissions criteria.
Wet Limestone FGD - Forced Oxidation(1) (LSFO)	Yes	Yes – New installations are capable of meeting performance standards.
Wet Lime FGD - Inhibited Oxidation (1) (WLIO)	Yes	Yes– New installations are capable of meeting performance standards.
Spray Dryer Absorber (SDA)	Yes	No – SDA has limited SO_2 removal efficiency over the project range of fuels, which are higher sulfur contents.
Circulating Dry Scrubber (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.
Flash Dryer Absorber (FDA)	Yes	No – FDA has limited SO_2 removal efficiency over the high range of sulfur in the fuels.

Technology Alternative	Technically Feasible (Yes/No)	
	Available	Applicable
Ammonia Scrubber (NH_3)	Yes	Yes – However, only one small US industrial 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.		

Analysis was inclusive of FGD options necessary to keep the A.B. Brown Units 1 and 2 in compliance with current SO2 emissions limits and maintaining compliance with existing Hg and H2SO4 emissions requirements. Based on these requirements the DA-LSIO and DA-LSFO conversion options will not meet emissions performance criteria. High level capital installation estimates were developed by Black & Veatch for the Wet Lime FGD Inhibited Oxidation (WLIO), Circulating Dry Scrubber (CDS) and Ammonia Scrubber (NH3). Burns & McDonnell developed an estimate for the Wet Limestone FGD Forced Oxidation (LSFO), building on their previous experience with this technology assessment at A.B. Brown. Capital and O&M estimates for these remaining four technologies were evaluated by PACE Global screening using analysis consistent with the IRP evaluation Reference Case. The least cost option was selected and included in the BAU portfolio. Note that there are risks such as byproduct market availability, byproduct disposal requirements and reagent supply availability. These risks were qualitatively assessed independent of the screening analysis.

For the BAU to 2039 portfolio, an analysis of the most economic FGD scrubber option was conducted. Each of the four scrubber technologies was evaluated in the Aurora model with identical model runs except for the difference of the scrubber technology costs and performance metrics. The analysis demonstrated that the DA-LSIO was the least cost FGD scrubber technology among the four options. The DS-LSFO option was shown to increase portfolio costs by 1.51% all other things being equal, the NH3 option was shown to be 1.66% more costly and the CDS option was shown to be 2.95% more costly.

Accordingly, the DA-LSIO option was selected for modeling purposes in the BAU to 2039 portfolio.

11.4.1.3 Coal to Gas Conversion

The conversion of A.B. Brown Unit 1 and 2 existing coal fired boilers to burn natural gas instead of coal was studied. Conceptual design studies were developed by engineering firms and OEM suppliers to determine natural gas conversion MW output, heat rate performance, emissions and balance of plant equipment. Engineering and construction estimates were developed to determine high level AACE Class 4 installation costs. The converted plant is expected to be operated as a peaking facility on 100% natural gas. Daily on/off cycling of the plant may be required. These units were originally designed as base load coal units. The boiler metallurgy and turbine were not designed for cycling operation. The impacts of cycling will require increased maintenance of this equipment compared to previous coal operations. Startup durations remain the same as coal fired operations continuing to limit the response time in a cycling environment. Natural gas conversion of the units reduces boiler efficiency compared to the coal fired design and increase net plant heat rate.

11.4.1.4 ACE Rule Compliance

The Affordable Clean Energy (ACE) rule, finalized by the United States Environmental Protection Agency (EPA) June 19, 2019, establishes new standards for reducing greenhouse gas emissions for coal fired electric utility generating units. ACE details specific heat rate improvement techniques, called Best System of Emission Reduction (BSER), that are meant to be the best technology options or other measures that have been known to reduce plant heat rate.

The specific candidate technology options are as follows:

- 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 Upgrades.
- Equipment & facilities improvements to enhance operations and maintenance (O&M) practices.

The potential alternatives for improvements at the four coal fired units A.B. Brown Units 1 & 2 and F.B. Culley Units 2 & 3 were assessed to meet the goals of the ACE rule. Applicability of candidate technologies for the four existing coal fired units is found in the "ACE Heat Rate Improvement Study" located in technical appendix 6.8. The characteristics of the four plants were reviewed and each plant was examined according to applicable BSER alternatives. Estimates of heat rate improvement, annual carbon dioxide reduction, O&M and a rough order of magnitude capital cost estimate were developed for each applicable alternative.

11.4.2 Approximate Net and Gross Dependable Generating Capacity

Figure 11.35 – Approximate Net and Gross Dependable Generating Capacity

	Gross Dependable Capacity (MW)	Net Dependable Capacity (MW)
A.B. Brown 1	265	245
A.B. Brown 2	265	245
A.B. Brown 3	74	74
A.B. Brown 4	74	74
F.B. Culley 2	100	90
F.B. Culley 3	287	270
Warrick 4	162	150

11.4.3 New Construction Alternatives

Figure 11.36 – New Construction Alternatives

Technology	Fuel	Capacity (kW)
Biomass	Biomass	50,000
Energy Efficiency Bins 1-7 (2021-23)	Energy Efficiency	Varies
Energy Efficiency Bins 1-7 (2024-26)	Energy Efficiency	Varies
Energy Efficiency Bins 1-7 (2027-39)	Energy Efficiency	Varies
Hydroelectric	Hydro	50,000
Landfill Gas	Landfill Gas	4,500
F-Class CT	Natural Gas	236,635
E-Class CT	Natural Gas	84,721
GH-Class CT	Natural Gas	279,319
F-Class CCGT	Natural Gas	442,400
GH-Class CCGT	Natural Gas	510,700
Generic Solar PV	Solar	10,000
Generic Solar PV	Solar	50,000
Generic Solar PV	Solar	100,000
12to15 Year Solar PPA	Solar	112,500
20 Year Solar PPA	Solar	200,000
20 Year Solar PPA	Solar	165,460
25to30 Year Solar PPA	Solar	137,500
Li-Ion Battery Storage (4 hour)	Storage	10,000
Li-Ion Battery Storage (4 hour)	Storage	50,000
Flow Battery Storage (6 hour)	Storage	10,000
Flow Battery Storage (6 hour)	Storage	50,000
Flow Battery Storage (8 hour)	Storage	10,000
Flow Battery Storage (8 hour)	Storage	50,000
Li-Ion Battery Storage (paired with Generic Solar PV) (4 hour)	Storage	10,000
Li-Ion Battery Storage (paired with Generic Wind) (4 hour)	Storage	10,000
Annual MISO Capacity Market Purchase	Capacity	Up to 180,000
Li-Ion Battery Storage PPA (4 hour)	Storage	76,200
Solar PV (paired with Storage) PPA	Solar	133,333
Li-Ion Battery Storage (paired with Solar) PPA (4 hour)	Storage	42,000
Demand Response Bin 1 (2021-23)	Storage	Varies

Technology	Fuel	Capacity (kW)
Demand Response Bin 2 (2024-26)	Storage	Varies
Demand Response Bin 3 (2027-39)	Storage	Varies
Generic Wind	Wind	200,000
Generic Wind	Wind	50,000
12to15 Year Wind PPA	Wind	200,000
20 Year Wind PPA	Wind	300,000

11.5 RISK APPENDIX

Probabilistic modeling incorporates five key market variables and probability distributions into the analysis, allowing for the evaluation of a portfolio's performance over a wide range of future market conditions. Quantitative data are extracted from the results and is the foundation for the balanced scorecard. Probabilistic modeling begins with the development of 200 sets of future pathways for coal prices, natural gas prices, carbon prices, peak and average load (for Vectren, MISO Local Resource Zone 6 and all of MISO) and capital costs for a range of technologies. Each of these stochastic variables is propagated to the end of the study period, typically 1,000 to 3,000 times. A stratified sampling of the runs is taken, which allows the sample set to be reduced to 200 iterations. The 200 iterations of each stochastic variable are then inputted into the Aurora model. This allows for the testing of each candidate portfolio's performance across a wide range of market conditions.

All portfolios were subjected to each of the 200 iterations (scenarios) using the dispatch module in the Aurora model where the Vectren portfolios are fixed but other market participants can make decisions under each market scenario. The entire Eastern Interconnection except FRCC and ISO-NE was run stochastically in each scenario. The risk analysis (based on the probabilistic modeling) of each of the portfolios was developed by Pace Global using the Aurora model. There were several steps to this process:

- The first step was to develop the input distributions for each of the major market and regulatory drivers, including average and peak load growth and shape, natural gas prices, coal prices, carbon prices and technology capital costs. This was done by considering volatility of each factor in the short-term, medium-term and long-term.

- The second step was to run a probabilistic model (Monte Carlo) which selected 200 possible future states over the 20-year study planning period. This also formed the basis for the scenario inputs development.
- Each candidate portfolio was then run through simulated dispatch for the 200 possible future states using the Aurora production cost model. Aurora dispatches the candidate portfolio for each sampled hour over the planning horizon. For this risk analysis procedure, Aurora assumes that each candidate portfolio is constant but allows for builds and retirements to occur throughout the region based on economic criteria. Vectren generation, costs, emissions, revenues, etc. are tracked for each iteration over time.
- Next, values for each metric are tracked across all 200 iterations and presented as a distribution with a mean, standard deviation and other metrics as needed.
- These measures are used as the basis for evaluation in the risk analysis.

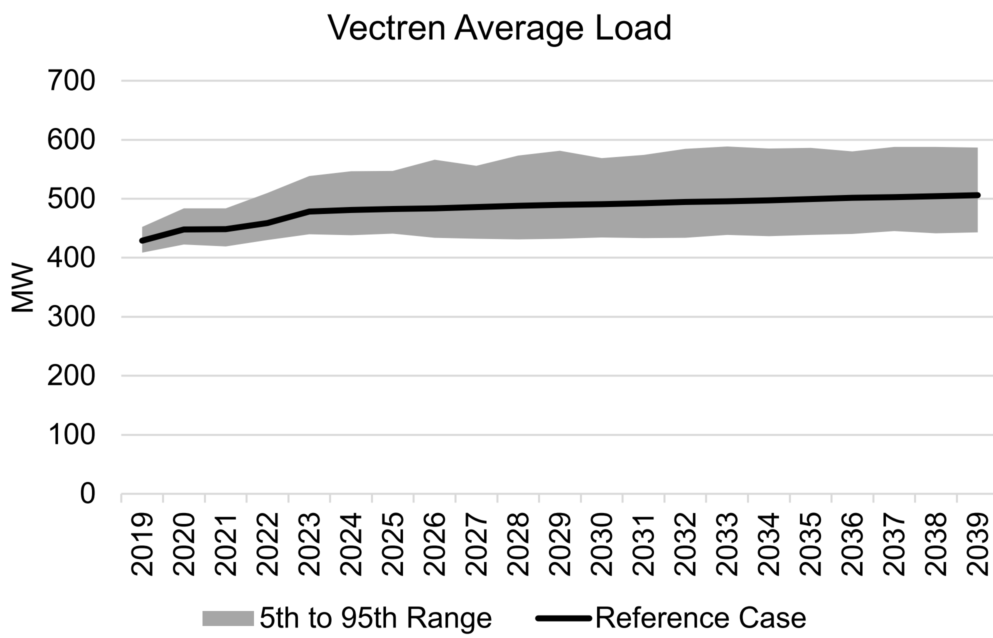
11.6 Stochastic Distributions

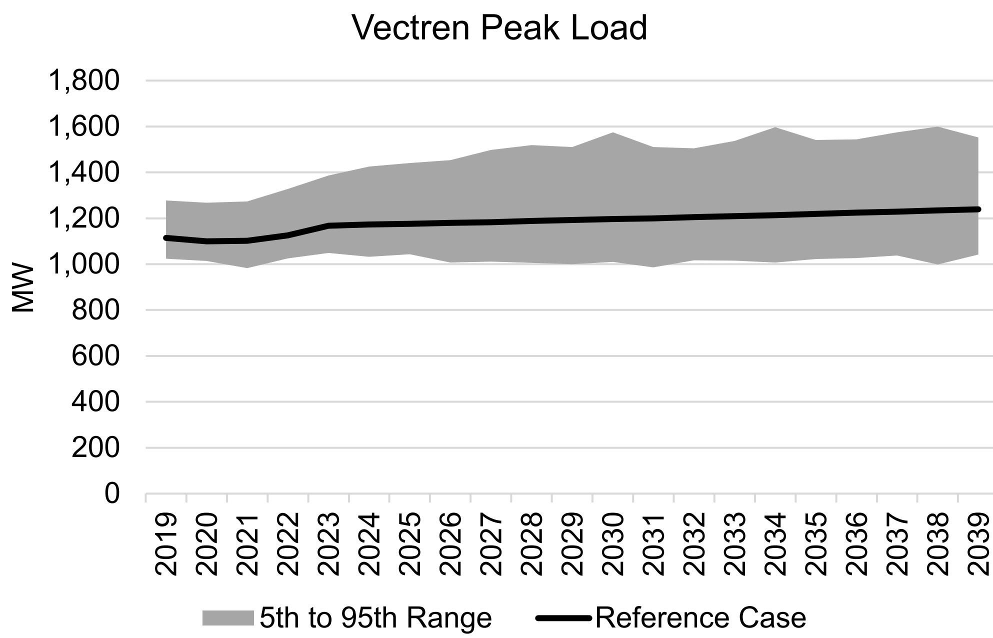
In order to perform the probabilistic modeling (stochastics), a set of probability distributions was required for each of the key market driver variables described above (fuel, emissions, load and capital costs). These probability distributions were developed from a simulation that creates 200 future paths for each stochastic variable. The following sections describe the methodologies for developing these stochastic variables.

11.6.1 Load Stochastics

To account for electricity demand variability that derives from economic growth, weather, energy efficiency and demand side management measures, Pace Global developed stochastics around the average and peak load growth expectations for the Vectren control area and the neighboring ISO zones, including MISO, PJM and utilities not served by an ISO in SERC. Pace Global benchmarked the MISO-wide projections against MISO-sponsored load forecasting studies that are conducted by independent consultants, institutions and market monitors and then released into the public domain. In addition, solar distributed generation (a decrement to Vectren load) and electric vehicles demand (an increment to Vectren load) were developed independently and incorporated into the Vectren load stochastics.

Exhibit 1: Vectren Load Distribution (Megawatts)



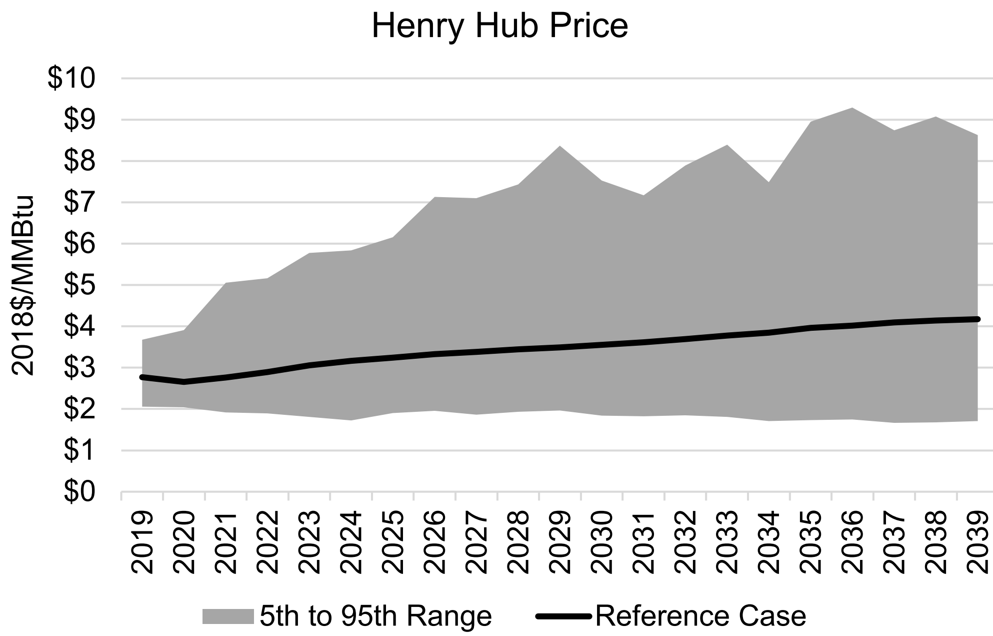


Source: Pace Global

11.6.2 Natural Gas Price Stochastics

Pace Global developed natural gas price stochastic distributions for the benchmark Henry Hub market point. These stochastic distributions are first based on the consensus Reference Case view of natural gas prices with probability bands developed then based on a combination of historical volatility and mean reversion parameters as well as a forward view of expected volatility. For the period 2019-2022, volatility calculated from the past three years of price data is used. For 2023-2025, volatility calculated from the past five years is used. For 2026-2039, volatility calculated from the past 10 years is used. This allows gas price volatility to be low in the short-term, moderate in the medium-term and higher in the long-term in alignment with observed historical volatility. The 95^{th} percentile probability bands are driven by increased gas demand (e.g., coal retirements) and fracking regulations that raise the cost of producing gas. Prices in the 5^{th} percentile are driven by significant renewable development that keeps gas plant utilization relatively low as well as few to no new environmental regulation around power plant emissions.

Exhibit 2: Natural Gas (Henry Hub) Price Distribution (2018$/MMBtu)

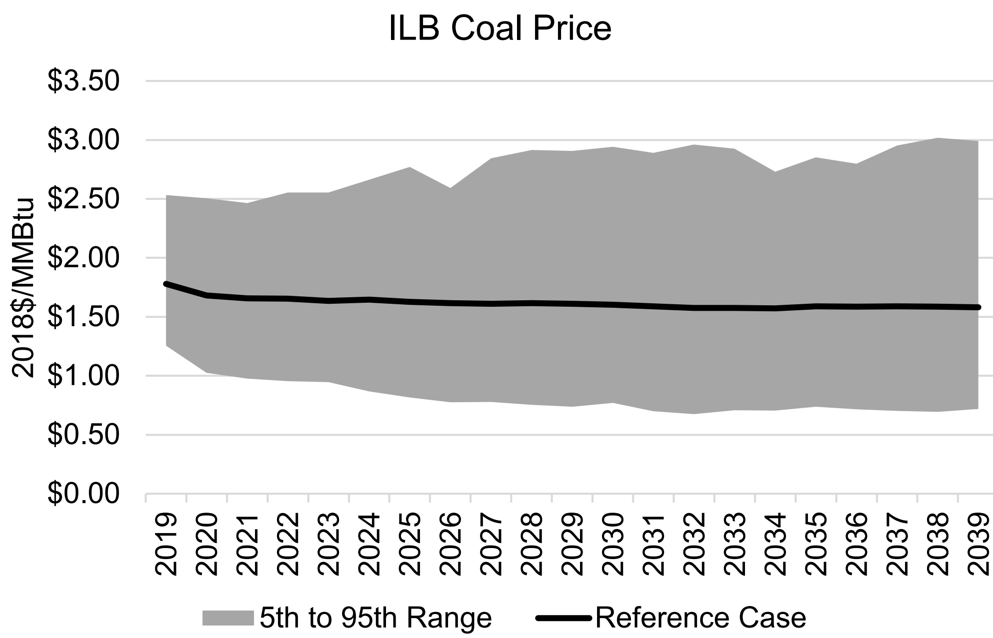


Source: Pace Global

11.6.3 Coal Price Stochastics

Pace Global developed coal price stochastic distributions for the CAPP, NAPP, ILB and PRB basins. These stochastic distributions are first based on the consensus Reference Case view of coal prices with probability bands developed, then based on a combination of historical volatility and mean reversion parameters. It should be noted that most coal contracts in the U.S. are bilateral and only approximately 20% are traded on the New York Mercantile Exchange (NYMEX). The historical data set that is used to calculate the parameters is comprised of the weekly traded data reported in NYMEX.

Exhibit 3: Coal Price Distribution (2018$/MMBtu)

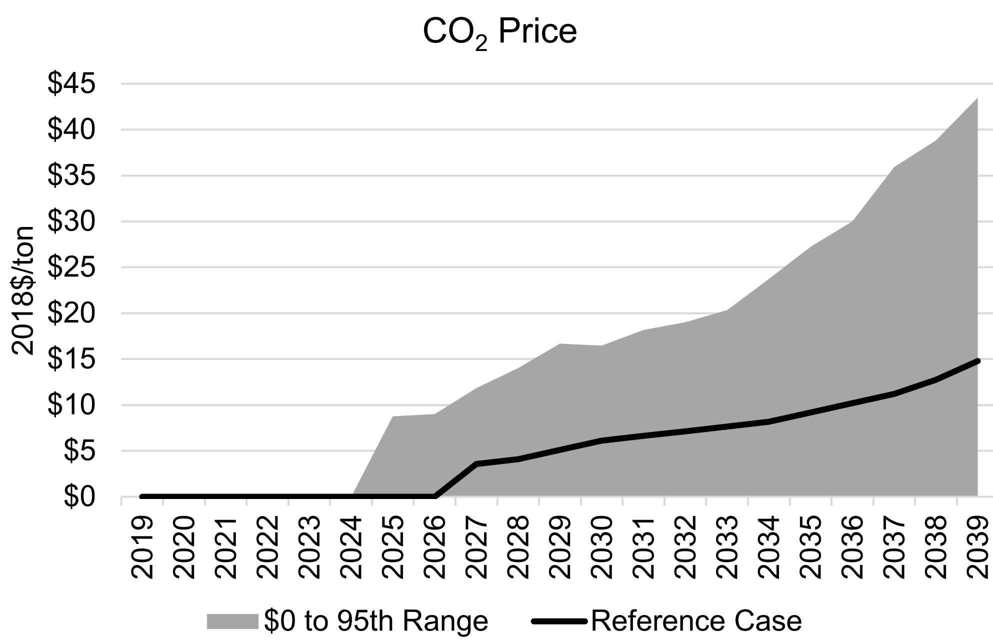


Source: Pace Global

11.6.4 CO_2 Emissions Price Stochastics

Pace Global developed uncertainty distributions around carbon compliance costs, which were used in Aurora to capture the inherent risk associated with regulatory compliance requirements. The technique to develop carbon costs distributions, unlike the previous variables, is based on projections largely derived from expert judgment, as there are no national historical data sets (only regional markets in California and the northeast U.S.) to estimate the parameters for developing carbon costs distributions. The consensus Reference Case CO_2 price outlook reflects a view that some type of legislation will likely occur in the mid-2020s to provide incentives for faster shifts from fossil to renewable generation. Previous studies of a proposed trading mechanism showed prices rising to about $15/ton. The bottom end of the distribution assumes no future regulation. The top end reflects the social cost of a carbon emission program. Two portfolios (HB 763 and High Regulatory) were optimized using CO_2 prices that exceeded the 95th percentile shown below.

Exhibit 4: CO_2 Price Distribution (2018$/ton)



Source: Pace Global

11.6.5 Capital Cost Stochastics

Pace Global developed the uncertainty distributions for the cost of new entry units by technology type, which was used in Aurora for determining the economic new builds based on market signals. These technologies included gas peaking units, gas combined cycles units, solar, wind and battery storage resources. The methodology of developing the capital cost distributions is a two-step process: (1) a parametric distribution based on a consensus Reference Case view of future all-in capital costs, historical costs and volatilities and a sampling of results to develop probability bands around the consensus Reference Case; and (2) a quantum distribution that captures the additional uncertainty with each technology that factors in learning curve effects, improvements in technology over time and other uncertain events such as leaps in technological innovation.

Exhibit 5: Solar Capital Costs Distribution (2018$/kW)

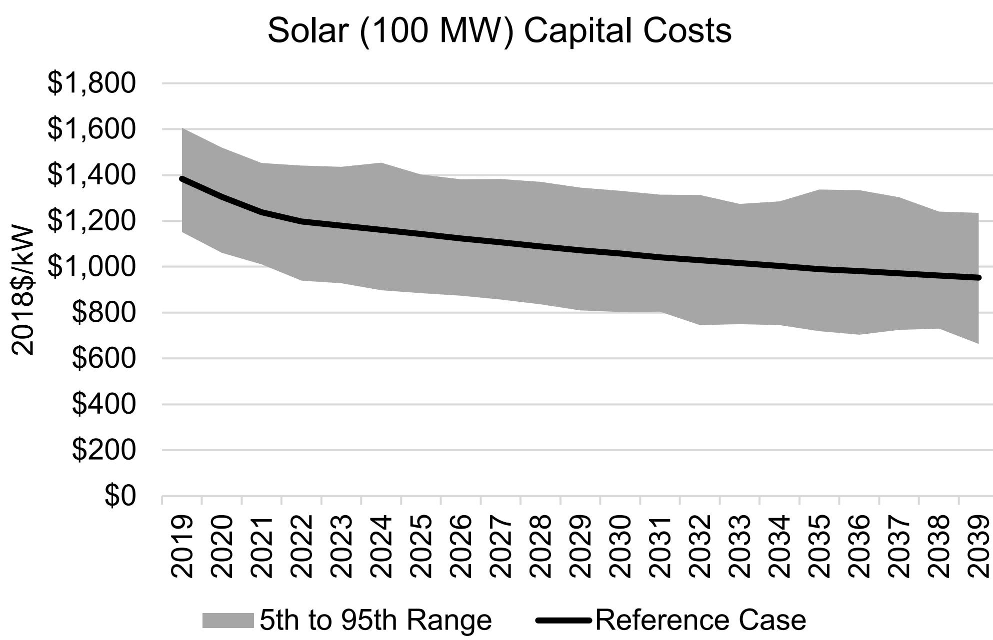
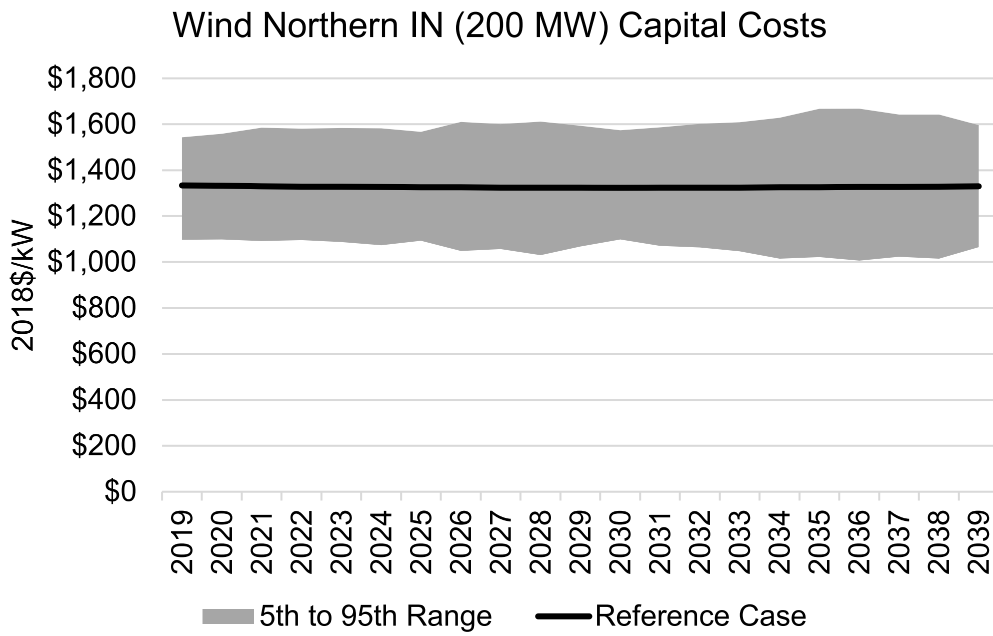


Exhibit 6: Wind Capital Costs Distribution (2018$/kW)



Source: Pace Global

Exhibit 7: Battery Storage Capital Costs Distribution (2018$/kW)

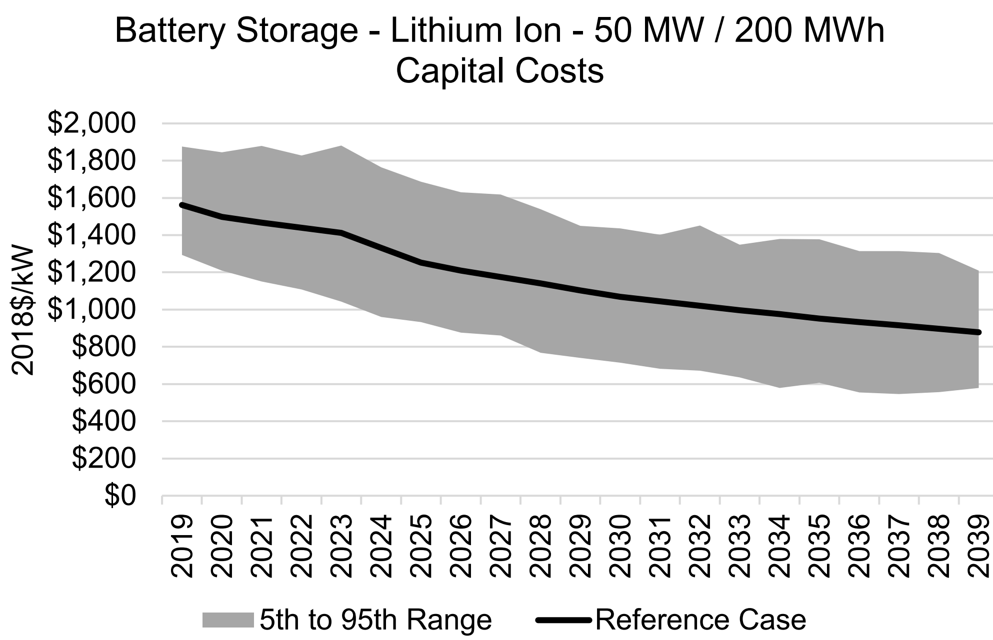
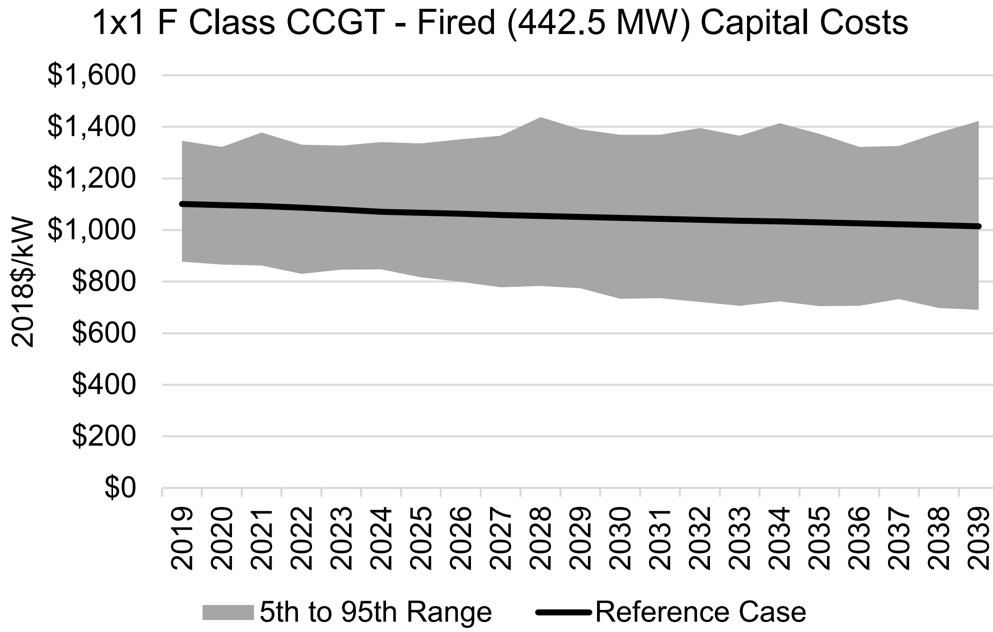
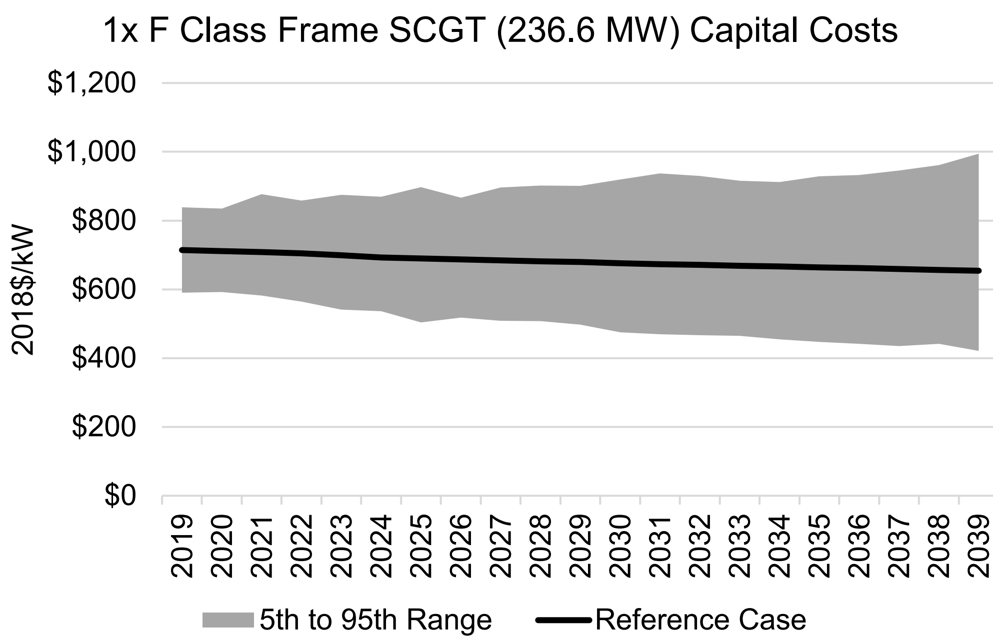


Exhibit 8: Advanced Combined Cycle Capital Costs Distribution (2018$/kW)



Source: Pace Global

Exhibit 9: Advanced Combustion Turbine Capital Costs Distribution (2018$/kW)



Source: Pace Global

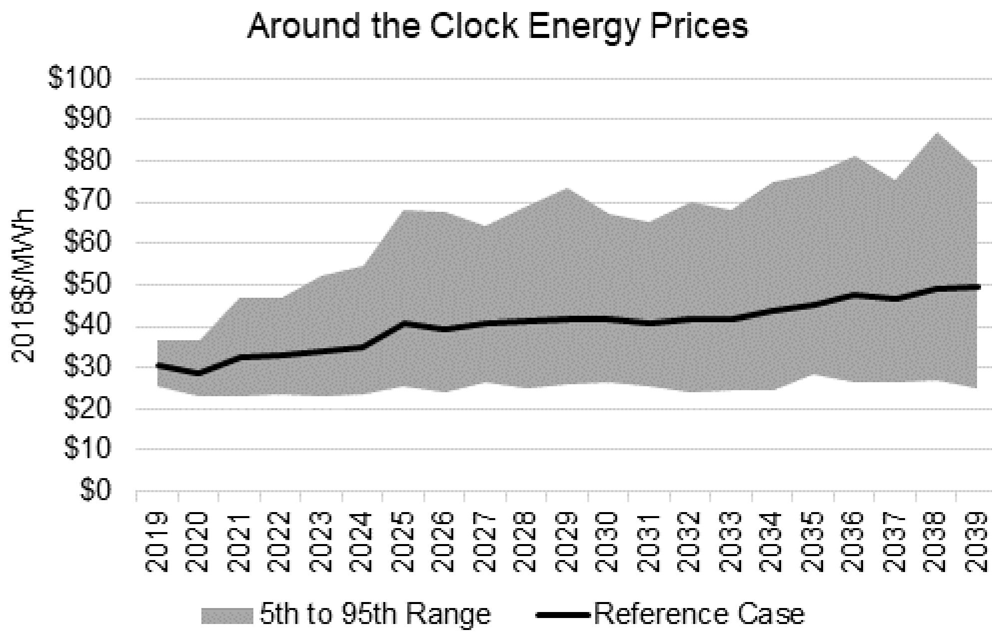
11.6.6 Cross-Commodity Stochastics

Pace Global captured the cross-commodity correlations in the stochastic process, which is a separate stochastic process from those for gas, coal and CO_2 prices. The feedback effects are based on statistical relationships between coal and gas switching and the variable cost of coal and gas generators. Pace Global conducted a fundamental analysis to define the relationship between gas and coal dispatch costs and demand. The dispatch costs of gas and coal were calculated from the gas and coal stochastics and CO_2 stochastics, along with generic assumptions for variable operation and maintenance costs. Where the gas-coal dispatch differential changes significantly enough to affect demand, gas demand from the previous year was adjusted to reflect the corresponding change in demand. A gas price delta was then calculated based on the defined gas demand. This gas price delta was then added to the gas stochastic path developed from historic volatility to calculate an integrated set of CO_2 and natural gas stochastic price forecasts.

11.6.7 Energy Price Distribution

Pace Global produces a stochastic distribution of energy prices as a result of running the input distributions through Aurora (200 times). Aurora not only determines the build decisions for the region but also the resulting prices. The exhibit below displays these prices.

Exhibit 1: Stochastic Inputs – Energy Prices – Market Forecast



11.6.8 Affordability Ranking

Figure 11.37 – Probabilistic 20-Year Mean NPV $ Billion

Portfolio	20 Year NPV[49]	% above lowest cost
Renewables + Flexible Gas	$2,526	99.6%
Reference Case	$2,536	100.0%
High Technology (Preferred Portfolio)	$2,590	102.2%
All Renewables by 2030	$2,613	103.0%
Bridge ABB1 Conversion	$2,675	105.5%
Diverse Small CCGT	$2,680	105.7%
Business as Usual to 2029	$2,689	106.0%
ABB1+ABB2 Conversions	$2,834	111.8%
ABB1 Conversion + CCGT	$2,872	113.3%
Business as Usual to 2039	$2,912	114.8%

[49] The NPV of energy procurement is an indicative component of rates

11.7 TRANSMISSION APPENDIX

11.7.1 Transmission and Distribution Planning Criteria

Vectren continually assesses the performance of its electric transmission and distribution systems to ensure safe and reliable service for its customers. The primary goals of Vectren's planning process can be summarized as follows:

a) Developing a transmission system capable of delivering voltage of constant magnitude, duration and frequency at levels which meet Vectren customers' needs during normal conditions and during a system contingency or set of contingencies;
b) Minimizing thermal loadings on transmission facilities to be within operating limits during normal conditions and to be within emergency limits during contingency conditions;
c) Analyzing the dynamic stability of the transmission system under various contingency conditions;
d) Ensuring the fault current duty imposed on circuit breakers does not exceed the interrupting capability established by the equipment manufacturer;
e) Optimizing the system configuration such that costs (capital and operating) are minimized while maintaining reliability and providing a plan for system upgrades to meet performance requirements;
f) Coordinating transmission planning activities in broader regional evaluations with the Midcontinent Independent System Operator (MISO), ReliabilityFirst (RF) and neighboring transmission owners;
g) Performing an annual assessment of the electric transmission system over a ten-year planning horizon;
h) Performing analysis of reactive power resources to ensure adequate reserves exist and are available to meet system performance criteria;
i) Analyzing the performance of its distribution system to ensure reliability, adequacy to meet future load growth and to address age and condition of existing facilities; and

j) Ensuring compliance with Federal Energy Regulatory Commission (FERC), North American Electric Reliability Corporation (NERC) and RF Reliability Standards for transmission planning.

11.7.2 MISO Regional Transmission Planning

The Midcontinent Independent System Operator (MISO) performs the North American Electric Reliability Corporation (NERC) functional role of Planning Coordinator on behalf of Vectren. In its NERC functional role of Transmission Planner, Vectren supports MISO's regional transmission planning processes.

MISO develops regional transmission models that are used for a variety of near-term and long-term planning studies. On an annual basis, MISO builds models to represent a 10-year planning horizon. The modeling process begins in September and concludes the following August. Vectren is responsible for submitting the required modeling data to MISO pursuant to NERC MOD-032.

Vectren participates in MISO coordinated seasonal transmission assessments (CSAs) for spring, summer, fall and winter peak loads as applicable. MISO's Seasonal Assessments review projected demand and resources for the MISO footprint and assess adequacies and risks for upcoming seasons. The CSAs consider planned and unplanned generation and transmission outages. Vectren also participates in MISO Generator Interconnection and Transmission Service Requests planning processes as required.

Vectren participates in MISO's regional Transmission Expansion Plan (MTEP). The system expansion plans produced through the MTEP process ensure the reliable operation of the transmission system, support achievement of state and federal energy policy requirements and enable a competitive electricity market to benefit all customers. The planning process, in conjunction with an inclusive, transparent stakeholder process, identifies and supports development of transmission infrastructure that is sufficiently robust to meet local and regional reliability standards, enables competition among wholesale capacity and energy suppliers in the MISO markets and allows for competition among transmission developers in the assignment of transmission projects.

MISO approved a 345kV Market Efficiency Project between Vectren's Duff substation and Big Rivers Electric Corporation's Coleman EHV substation during the MTEP 2015 planning cycle. The project is expected to be in-service by the beginning of 2021. Pursuant to FERC Order 1000, MISO solicited competitive bids to construct the 345kV line. Vectren partnered with PSEG in submitting a proposal to MISO to construct the line; however, the project was awarded to Republic Transmission, LLC. Vectren, as the incumbent transmission owner, will be responsible for the Duff substation modifications required for the project. The overall project cost is shared according to MISO's Tariff. The project not only provides regional economic benefits, but also enhances grid reliability in the area of Vectren's Newtonville substation.

11.7.3 Annual Transmission Assessment

Vectren's most recent transmission assessment was completed in 2019. The study used the final Multiregional Modeling Working Group (MMWG) 2018 Series Models, which includes the Vectren full detailed model. The MMWG is responsible for developing a library of solved power flow models and associated dynamics simulation models of the Eastern Interconnection. The models are used by the NERC Regions and their member systems in planning future performance and evaluating current operating conditions of the interconnected bulk electric systems. Siemens PTI PSS/E version 33.11 software was used to conduct the assessment.

Vectren's internal planning procedures direct the specific tasks and methods for conducting this study. The internal procedures also define the ratings methodology used for the existing and proposed facilities. All simulations were performed using Steady State Power Flow models using AC analysis. Models were solved using the Fixed Slope Decoupled Newton-Raphson (FDNS) solution method with stepping transformer tap adjustments, switched shunts enabled, area interchange control enabled for tie lines and loads, DC taps disabled and VAR limits applied automatically. Dynamic simulations were not completed in 2019, as previous dynamic studies were still deemed valid. Dynamic simulations were completed with MTEP-19.

The Vectren Bulk Electrical System (100kV and above) is expected to be stable and perform well over the next 10 years. Normal system conditions do not result in any voltage problems or thermally overloaded facilities. Some facility outage contingencies create thermal overloads and voltage violations. When these violations cannot be effectively mitigated by operational guides, Vectren plans projects to mitigate the violations.

The loss of the two 138kV lines into Toyota substation results in the loss of service to the facility. A new 138kV line from Toyota substation to Scott Township substation is proposed. This line will also provide a second line into Scott Township substation, which is on a radial 138kV line. Scott Township substation provides voltage support for most of the load along the Highway 41 North corridor. This proposed line will also become a parallel path to the Francisco to Elliott 138kV line and increases post-contingent import capability.

The only mentionable extreme contingency is for the complete loss of the A.B. Brown 138kV substation. This substation loss has the potential to cause voltage loss to the Mt. Vernon area and numerous large industrial customers. NERC requirements do not require that Vectren prevent this event. The standards only require that extreme contingencies not cause cascading outage and impair the Bulk Electric System (BES). The electric transmission system outside of Mt. Vernon is not affected; however, an outage of this magnitude would require a notification to NERC.

Several 69kV lines are proposed as alternate feeds to reduce outage times.

- A new 69kV line to be installed between Boonville and Boonville Pioneer Substation (scheduled in-service date of 12/31/2021).

- Extend an existing 69kV line to provide a third source into the Jasper area from Dubois substation (scheduled in-service date of 12/31/2024).

These are not NERC reliability driven projects, but should reduce outage durations to customers caused by transmission outages in these areas and should improve reliability indices and metrics.

Toyota South and Tepe Park are new distribution substations recently installed to meet load growth. The Tepe Park substation project also facilitates 4kV to 12kV conversion projects.

SECTION 12
TECHNICAL APPENDIX ATTACHMENTS

Attachment 8.2 Confidential Aurora Input Model Files

Attachment 8.3 Aurora Output Model Files (submitted via DVD)

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.

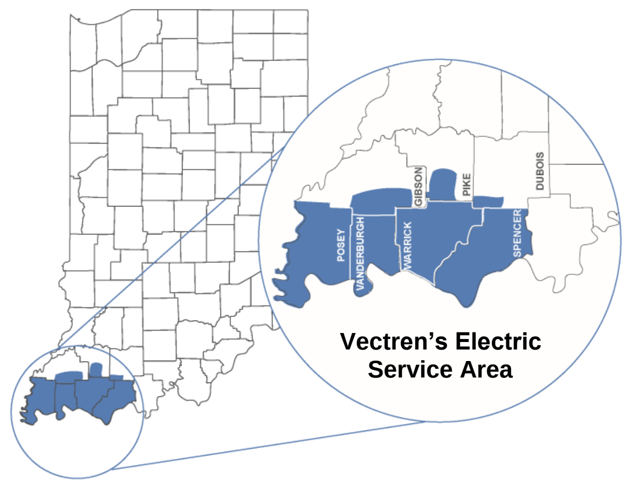
The resource options selected in this plan provide a bridge to the future. For example, CT's allow time for battery storage technology to continue to become more competitive in price and further develop longer duration storage capabilities. Further, should there be a need for new baseload generation 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 (H_2SO_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.

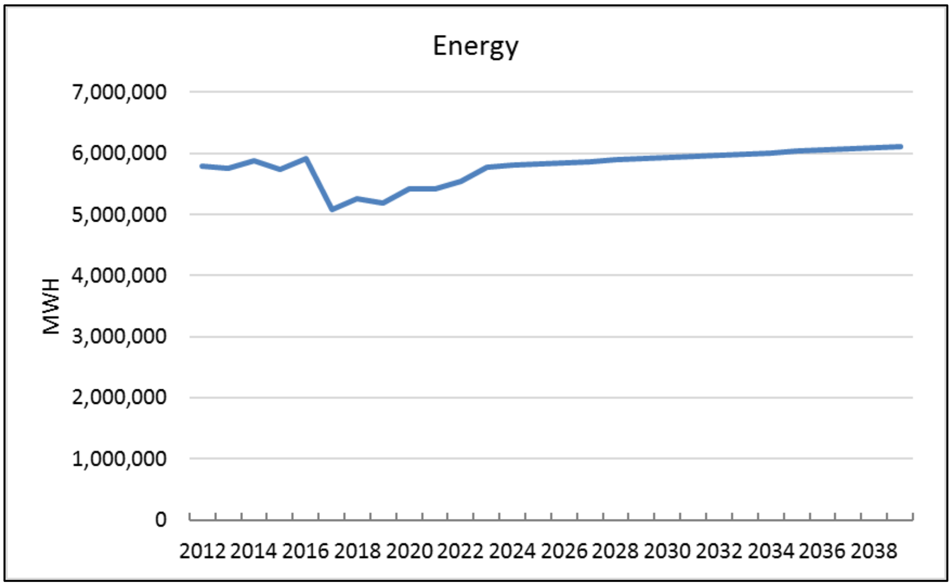
[3] The Blackfoot landfill gas generators are connected at the distribution level.
[4] Oak Hill Solar is connected at the distribution level.
[5] Volkman Rd. Solar is connected at the distribution level.

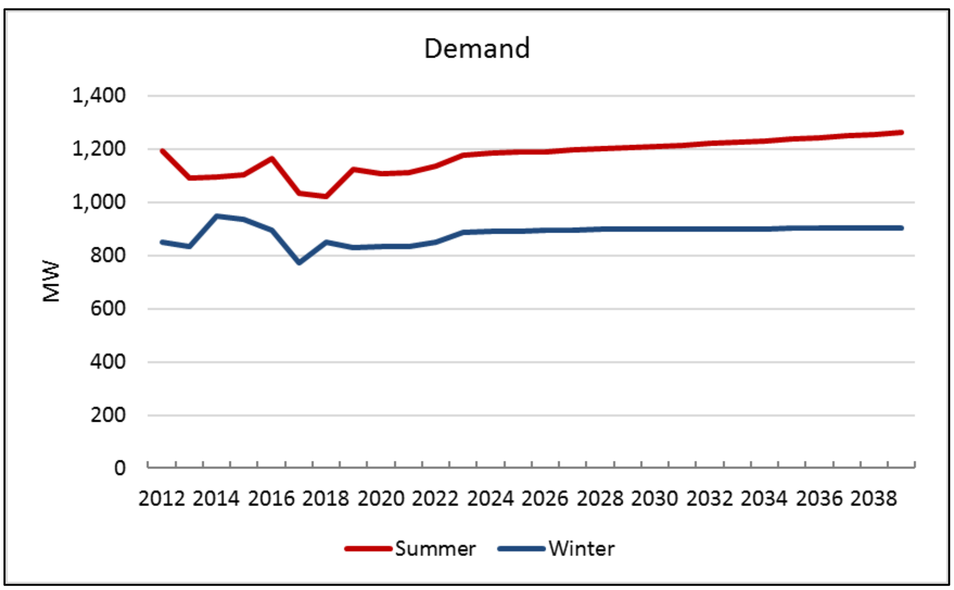
A. Customer Energy Needs

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.

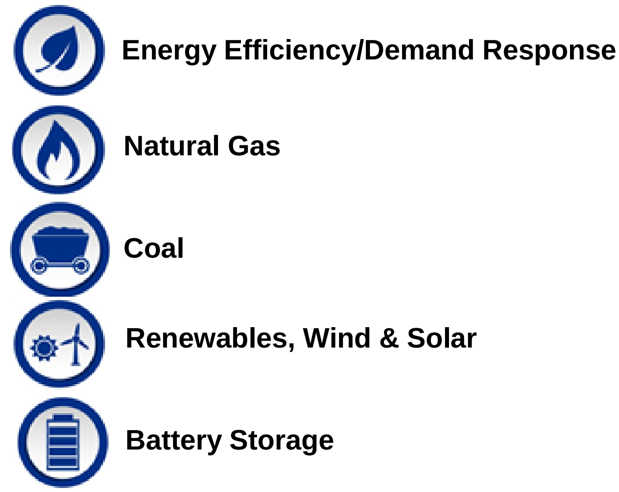
Historically, IRPs have focused on meeting customer demand in the summer, which is typically when reserve margins are at a minimum. As the regional resource mix changes towards intermittent (variable) renewable generation, it is important to ensure that resources are available to meet this demand in 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



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)*

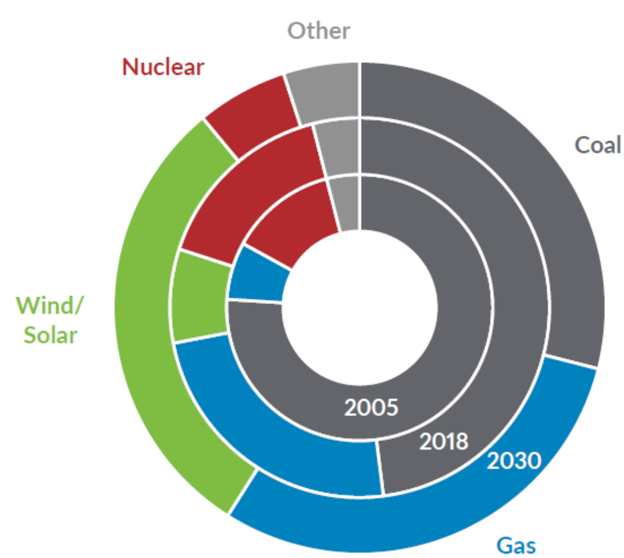


*Chart reflects ratios of generation.

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.

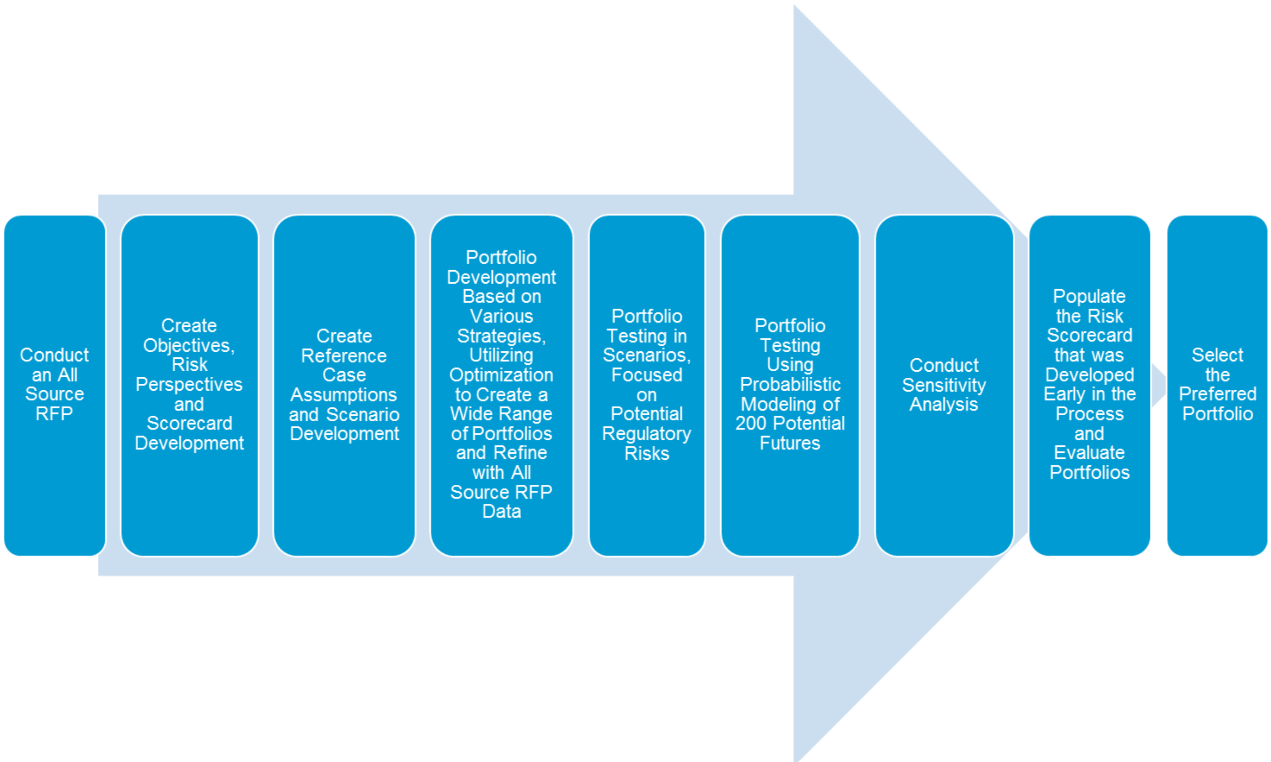
C. Uncertainty/Risk

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

- 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

- 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.

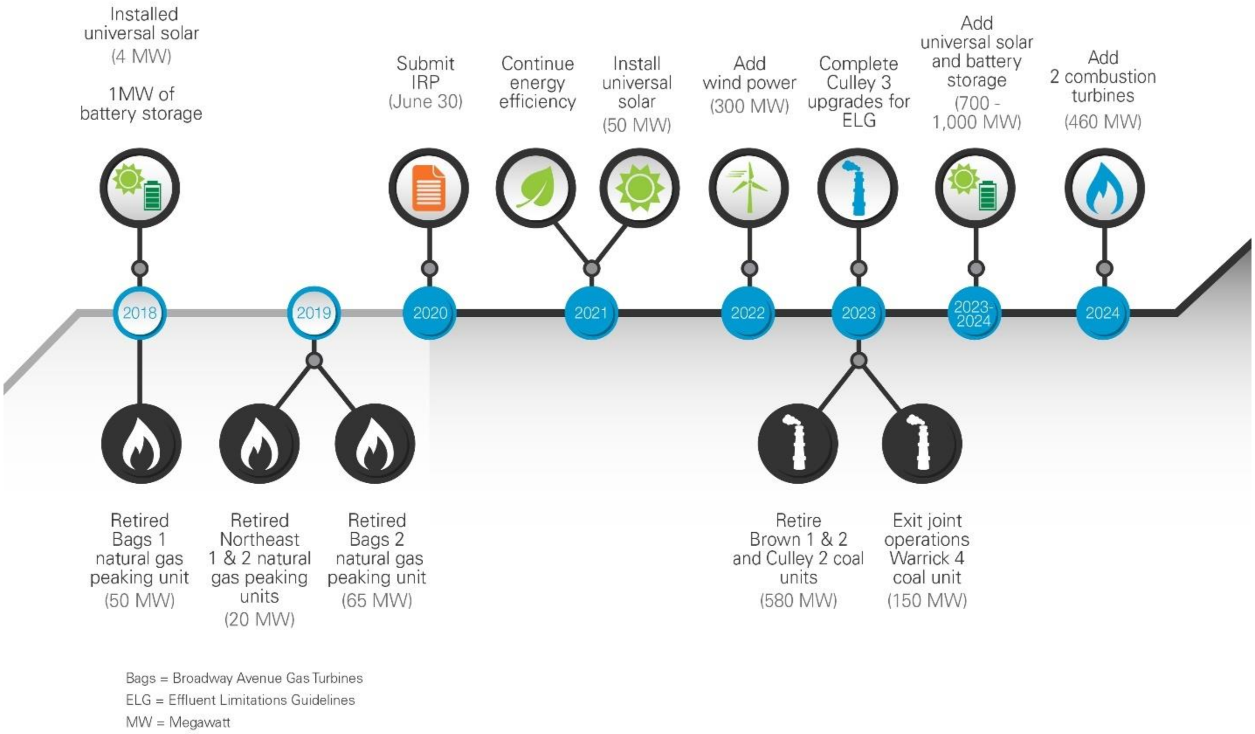
Request	Response
Update the High Regulatory scenario to include a carbon fee and dividend	Included a fee and dividend construct which assumed a balanced impact on the load (the economic drag from a carbon fee is neutralized by the economic stimulus of a dividend)
Lower renewables costs in the High Regulatory 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

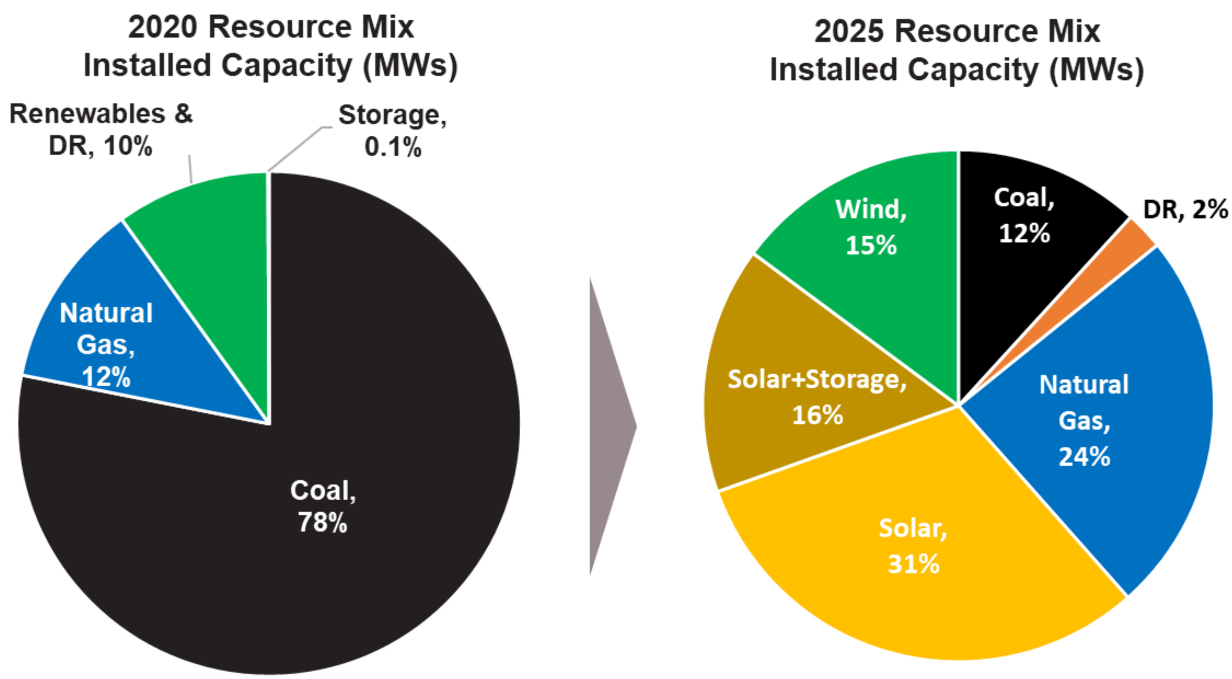
The Preferred Portfolio recommendation is to retire or exit 730 MWs of coal generation and replace with 700-1,000 MWs of solar generation (some connected to battery storage), add 300 MWs of wind backed by dispatchable generation that consists of 2 new Combustion Turbine (CT) gas units and maintaining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

Cause No. 45564

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

Cause No. 45564

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
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
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
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

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
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
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
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
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
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
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
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
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.

Cause No. 45564

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
BASE PLANT DESCRIPTION	Low Head Hydroelectric	Southern IN	Northern IN	North Dakota	Indiana
Nominal Output, MW	50	200	200	200	50 MW Wind & 10 MW / 40 MWh Storage
Number of Turbines	1	58 x 3.45 MW	58 x 3.45 MW	58 x 3.45 MW	15 x 3.45 MW
Capacity Factor (%) (Notes 1,2)	40%	28%	38%	41%	38%
Startup Time (Cold Start)		N/A	N/A	N/A	N/A
Book Life (Years)	40	30	30	30	30
Equivalent Planned Outage Rate (%)	11%	< 5%	< 5%	< 5%	< 5%
Equivalent Forced Outage Rate (%)	< 5%	< 5%	< 5%	< 5%	< 5%
Equivalent Availability Factor (%) (Note 6)	84%	95%	95%	95%	95%
Assumed Land Use (Acres)	N/A	44	44	44	44
Fuel Design	Elevated Water	N/A	N/A	N/A	N/A
Heat Rejection	N/A	N/A	N/A	N/A	N/A
Total System Cycles	N/A	N/A	N/A	N/A	N/A
Interconnection Voltage Assumption	230 kV	230 kV	230 kV	230 kV	230 kV
PV Inverter Loading Ratio (DC/AC)	N/A	N/A	N/A	N/A	N/A
PV Degradation (%/yr) (Note 7)	N/A	N/A	N/A	N/A	N/A
Storage System Initial Overbuild (%)	N/A	N/A	N/A	N/A	18%
Storage System Augmentation (%/yr)	N/A	N/A	N/A	N/A	2.5%
Storage System AC Roundtrip Efficiency (%)	N/A	N/A	N/A	N/A	85%
Technology Rating	Mature	Mature	Mature	Mature	Mature
Permitting & Construction Schedule (Years from FNTP)	7	2.5	2.5	2.5	2.5
ESTIMATED PERFORMANCE					
Base Load Performance @ (Annual Average)					
Net Plant Output, kW	50,000	200,000	200,000	200,000	50,000
Net Plant Heat Rate, Btu/kWh (HHV)	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
ESTIMATED CAPITAL AND O&M COSTS					
Project Capital Costs, 2019 MM$ (w/o Owner's Costs)	**$210**	**$230**	**$230**	**$230**	**$73**
Wind Capital Cost Breakdown					
Engineering	N/A	$1.05	$1.05	$1.05	$0.26
Equipment and Materials	N/A	$160	$160	$160	$40
Turbine Towers	N/A	Incl	Incl	Incl	Incl
Turbine Blades	N/A	Incl	Incl	Incl	Incl
Turbine Hubs	N/A	Incl	Incl	Incl	Incl
Nacelle and nacelle components	N/A	Incl	Incl	Incl	Incl
SCADA Equipment	N/A	Incl	Incl	Incl	Incl
Construction	N/A	$69	$69	$69	$17
Turbine Foundation and Erection	N/A	Incl	Incl	Incl	Incl
BOP Costs	N/A	Incl	Incl	Incl	Incl
Collector Bus	N/A	Incl	Incl	Incl	Incl
Indirects and Fees	N/A	Incl	Incl	Incl	Incl
EPC Contingency	N/A	Incl	Incl	Incl	Incl
PV Capital Cost Breakdown					
Engineering	N/A	N/A	N/A	N/A	N/A
Equipment and Materials	N/A	N/A	N/A	N/A	N/A
Modules	N/A	N/A	N/A	N/A	N/A
Inverters	N/A	N/A	N/A	N/A	N/A
Racking	N/A	N/A	N/A	N/A	N/A
Construction (Note 16)	N/A	N/A	N/A	N/A	N/A
Indirects and Fees	N/A	N/A	N/A	N/A	N/A
EPC Contingency	N/A	N/A	N/A	N/A	N/A
	N/A				
Battery Storage Capital Cost Breakdown					
Batteries	N/A	N/A	N/A	N/A	$8
Inverters	N/A	N/A	N/A	N/A	$1
BOP	N/A	N/A	N/A	N/A	$1
Construction and Indirects	N/A	N/A	N/A	N/A	$6
Owner's Costs, 2019 MM$	**$93**	**$66**	**$66**	**$66**	**$18.9**
Owner's Project Development	Allowance Included	Allowance Included	Allowance Included	Allowance Included	Allowance Included
Owner's Engineer	Allowance Included	Allowance Included	Allowance Included	Allowance Included	Allowance Included
Owner's Project Management	Allowance Included	Allowance Included	Allowance Included	Allowance Included	Allowance Included
Startup / Testing / Warranties	Allowance Included	Allowance Included	Allowance Included	Allowance Included	Allowance Included
Land (Note 11)	Excluded - Assumes Existing Dam	Excluded - Assumes Lease	Excluded - Assumes Lease	Excluded - Assumes Lease	Excluded - Assumes Lease
Transmission Upgrade Costs	Excluded	Excluded	Excluded	Excluded	Excluded
Permitting and Licensing Fees	Included	Included	Included	Included	Included
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
AFUDC (Note 17)	$25.6	$23.2	$23.2	$23.2	$7.4
Builder's Risk Insurance	Allowance Included	Allowance Included	Allowance Included	Allowance Included	Allowance Included
Owner's Contingency	Allowance Included	Allowance Included	Allowance Included	Allowance Included	Allowance Included
Total Project Costs, 2019 MM$	**$303**	**$296**	**$296**	**$296**	**$92**
EPC Cost Per kW, 2019 $/kW (plus $/kWh for Storage)	**$4,200**	**$1,150**	**$1,150**	**$1,150**	**$1460 / $390**
Total Cost Per kW, 2019 $/kW (plus $/kWh for Storage)	**$6,050**	**$1,480**	**$1,480**	**$1,480**	**$1840 / $650**

PROJECT TYPE	Solar Photovoltaic	Solar Photovoltaic	Solar Photovoltaic
BASE PLANT DESCRIPTION	Single Axis Tracking	Single Axis Tracking	Single Axis Tracking
Nominal Output, MW	10	50	100
Number of Turbines	N/A	N/A	N/A
Capacity Factor (%) (Notes 1,2)	24.3%	24.2%	24.2%
Startup Time (Cold Start)	N/A	N/A	N/A
Book Life (Years)	30	30	30
Equivalent Planned Outage Rate (%)	< 1%	< 1%	< 1%
Equivalent Forced Outage Rate (%)	< 1%	< 1%	< 1%
Equivalent Availability Factor (%) (Note 6)	99%	99%	99%
Assumed Land Use (Acres)	80	400	800
Fuel Design	N/A	N/A	N/A
Heat Rejection	N/A	N/A	N/A
Total System Cycles	N/A	N/A	N/A
Interconnection Voltage Assumption	34.5kV	230 kV	230 kV
PV Inverter Loading Ratio (DC/AC)	1.40	1.40	1.40
PV Degradation (%/yr) (Note 7)	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
Storage System Augmentation (%/yr)	N/A	N/A	N/A
Storage System AC Roundtrip Efficiency (%)	N/A	N/A	N/A
Technology Rating	Mature	Mature	Mature
Permitting & Construction Schedule (Years from FNTP)	2	2	2
ESTIMATED PERFORMANCE			
Base Load Performance @ (Annual Average)			
Net Plant Output, kW	10,000	50,000	100,000
Net Plant Heat Rate, Btu/kWh (HHV)	N/A	N/A	N/A
Heat Input, MMBtu/h (HHV)	N/A	N/A	N/A
ESTIMATED CAPITAL AND O&M COSTS			
Project Capital Costs, 2019 MM$ (w/o Owner's Costs)	**$16**	**$73**	**$145.9**
Wind Capital Cost Breakdown			
Engineering	N/A	N/A	N/A
Equipment and Materials	N/A	N/A	N/A
Turbine Towers	N/A	N/A	N/A
Turbine Blades	N/A	N/A	N/A
Turbine Hubs	N/A	N/A	N/A
Nacelle and nacelle components	N/A	N/A	N/A
SCADA Equipment	N/A	N/A	N/A
Construction	N/A	N/A	N/A
Turbine Foundation and Erection	N/A	N/A	N/A
BOP Costs	N/A	N/A	N/A
Collector Bus	N/A	N/A	N/A
Indirects and Fees	N/A	N/A	N/A
EPC Contingency	N/A	N/A	N/A
PV Capital Cost Breakdown			
Engineering	$1.2	$1.2	$1.5
Equipment and Materials			
Modules	$5.2	$25.8	$51.6
Inverters	$0.6	$3.1	$6.2
Racking	$1.7	$8.4	$16.8
Construction (Note 16)	$5.1	$25.7	$51.4
Indirects and Fees	$1.5	$7.1	$14.0
EPC Contingency	$0.5	$2.1	$4.2
Battery Storage Capital Cost Breakdown			
Batteries	N/A	N/A	N/A
Inverters	N/A	N/A	N/A
BOP	N/A	N/A	N/A
Construction and Indirects	N/A	N/A	N/A
Owner's Costs, 2019 MM$	**$9**	**$17**	**$27**
Owner's Project Development	Allowance Included	Allowance Included	Allowance Included
Owner's Engineer	Allowance Included	Allowance Included	Allowance Included
Owner's Project Management	Allowance Included	Allowance Included	Allowance Included
Startup / Testing / Warranties	Allowance Included	Included in EPC	Included in EPC
Land (Note 11)	Excluded - Assumes Lease	Excluded - Assumes Lease	Excluded - Assumes Lease
Transmission Upgrade Costs	Excluded	Excluded	Excluded
Permitting and Licensing Fees	Included in EPC	Included in EPC	Included in EPC
Switchyard / Substation (Notes 8,9,12)	$5.3M Allowance Included	$5.3M Allowance Included	$1.0M Allowance Included
AFUDC (Note 17)	$1.3	$5.9	$11.7
Builder's Risk Insurance	Allowance Included	Allowance Included	Allowance Included
Owner's Contingency	Allowance Included	Allowance Included	Allowance Included
Total Project Costs, 2019 MM$	**$25**	**$90**	**$173**
EPC Cost Per kW, 2019 $/kW (plus $/kWh for Storage)	**$1,580**	**$1,470**	**$1,460**
Total Cost Per kW, 2019 $/kW (plus $/kWh for Storage)	**$2,500**	**$1,810**	**$1,730**

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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.

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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
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% 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

Cause No. 45564

VECTREN 2019 IRP TECHNOLOGY ASSESSMENT
RENEWABLE AND STORAGE TECHNOLOGY ASSESSMENT PROJECT OPTIONS
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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
COAL TECHNOLOGY ASSESSMENT PROJECT OPTIONS
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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
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**
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

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VECTREN PUBLIC STAKEHOLDER MEETING

AUGUST 15, 2019

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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

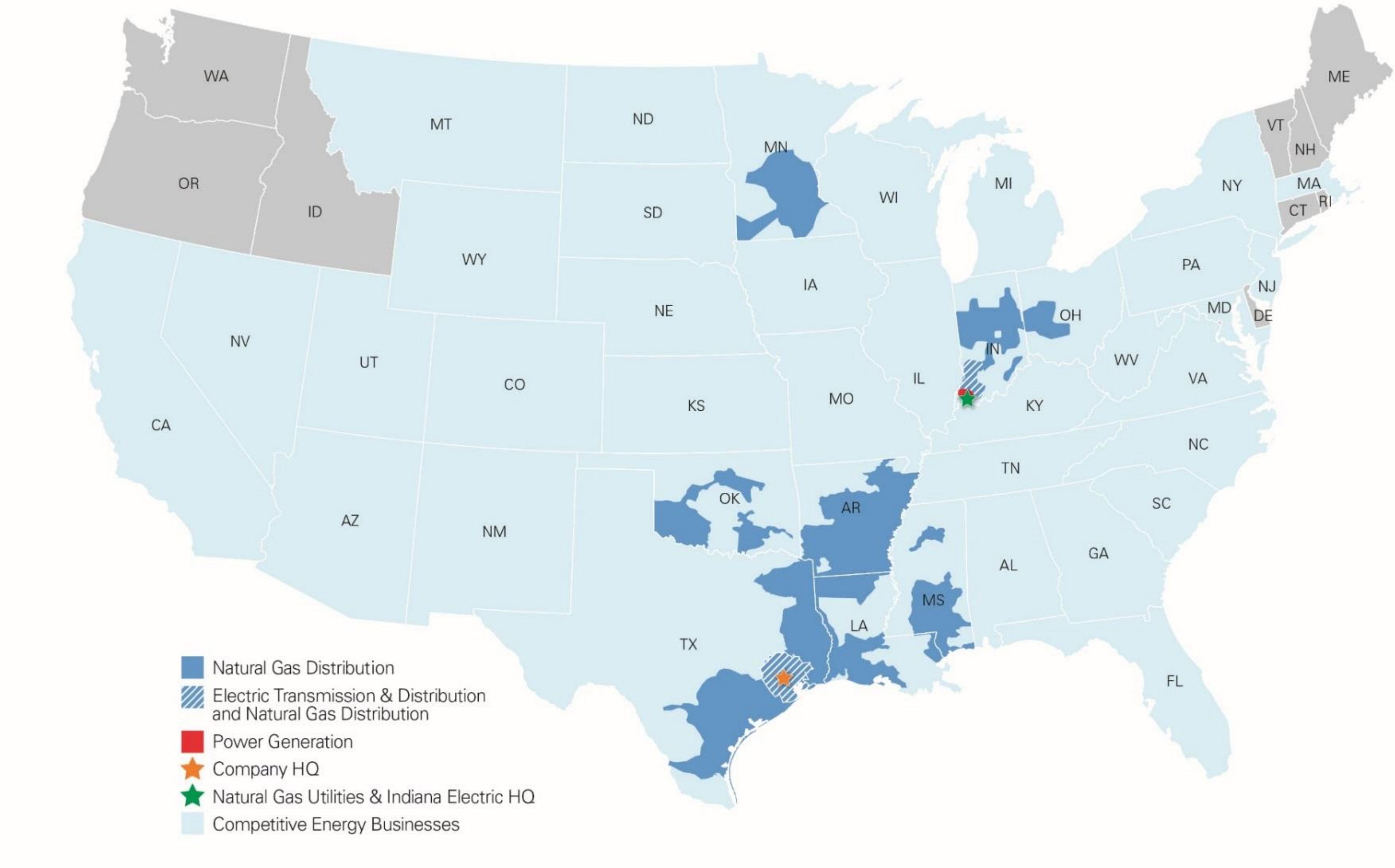
Bad Weather

- 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

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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.

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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

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- 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

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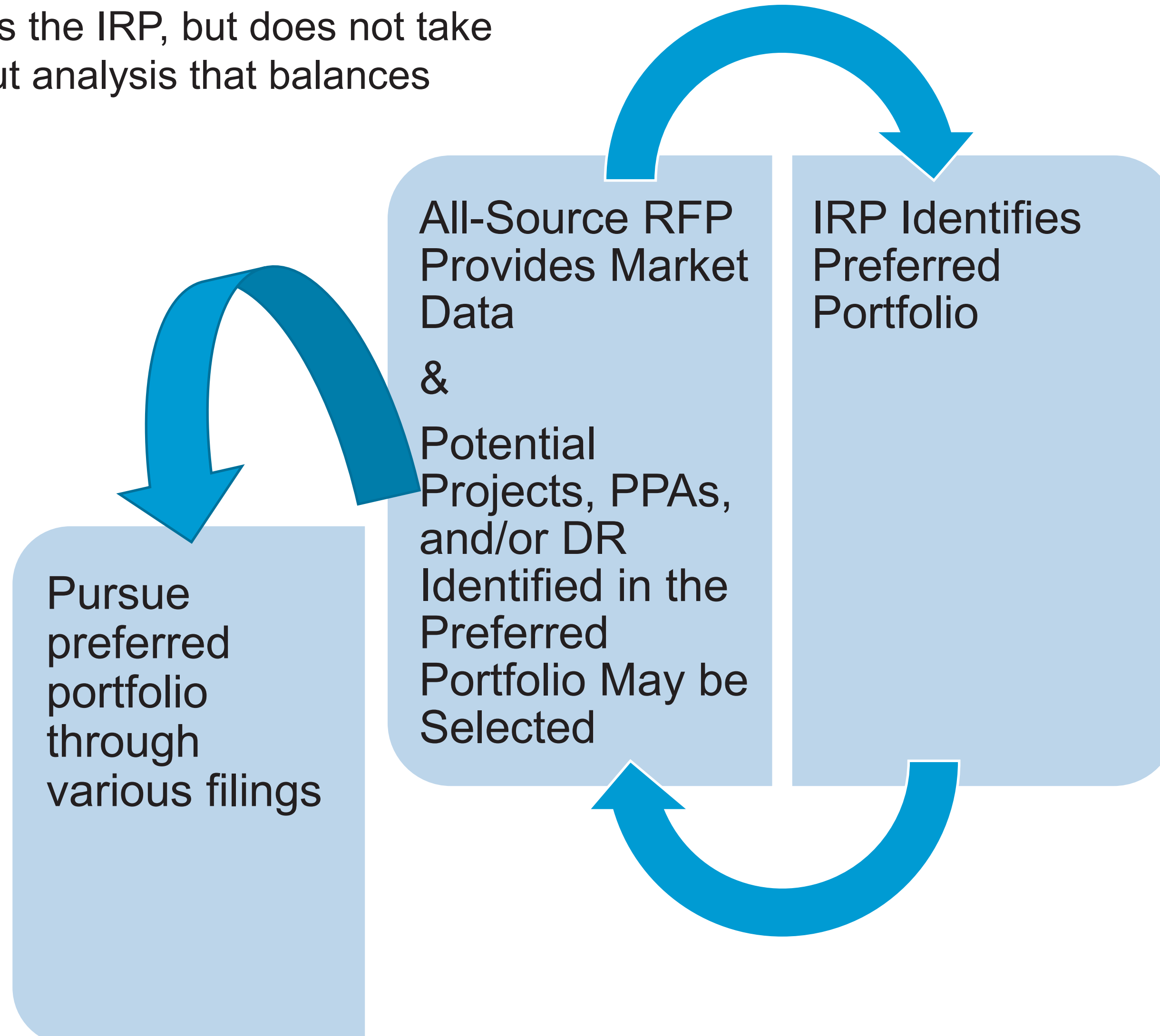
Stakeholder input is provided on a timely basis throughout the process, with meetings held in August, October, December, and March

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

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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

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

FEEDBACK AND DISCUSSION

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OBJECTIVES & MEASURES

GARY VICINUS

MANAGING DIRECTOR FOR UTILITIES, PACE GLOBAL

IRP OBJECTIVES & MEASURES

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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

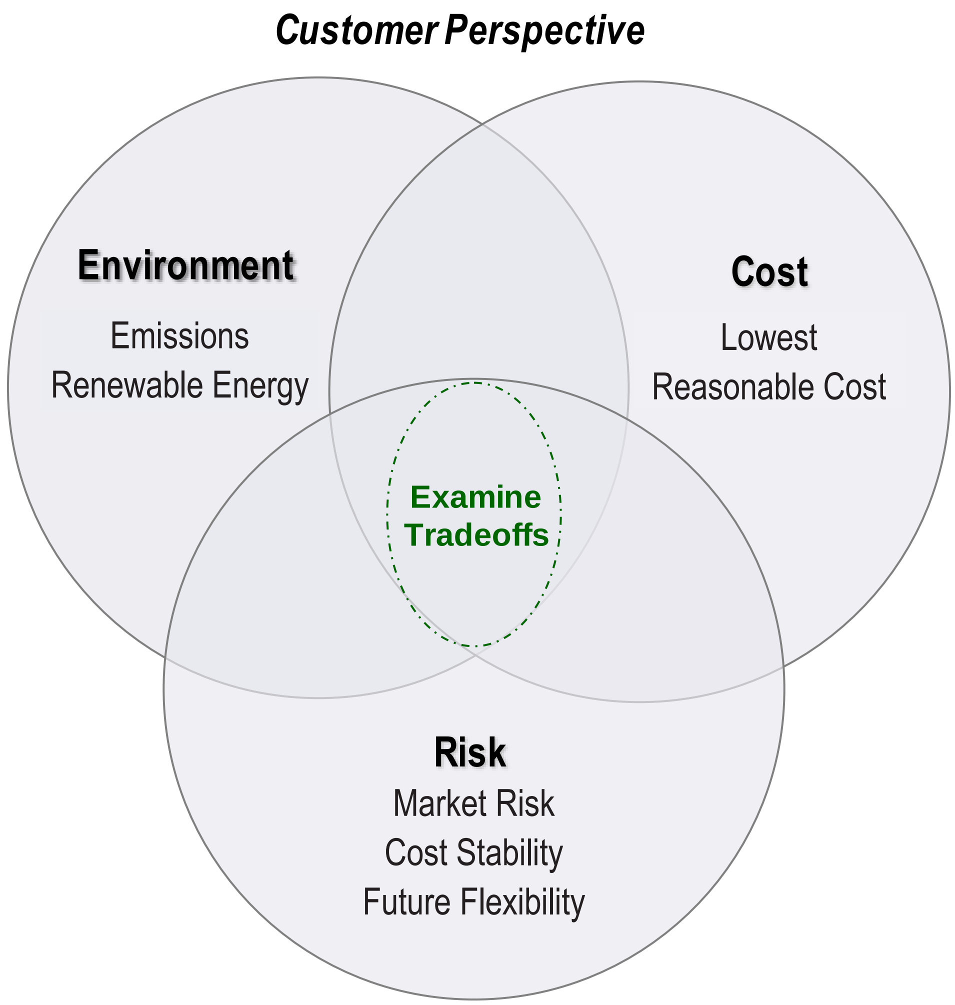
Each objective is important and worthy of balanced consideration in the IRP process, taking into account uncertainty. Some objectives are better captured in portfolio construction than as a portfolio measure

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

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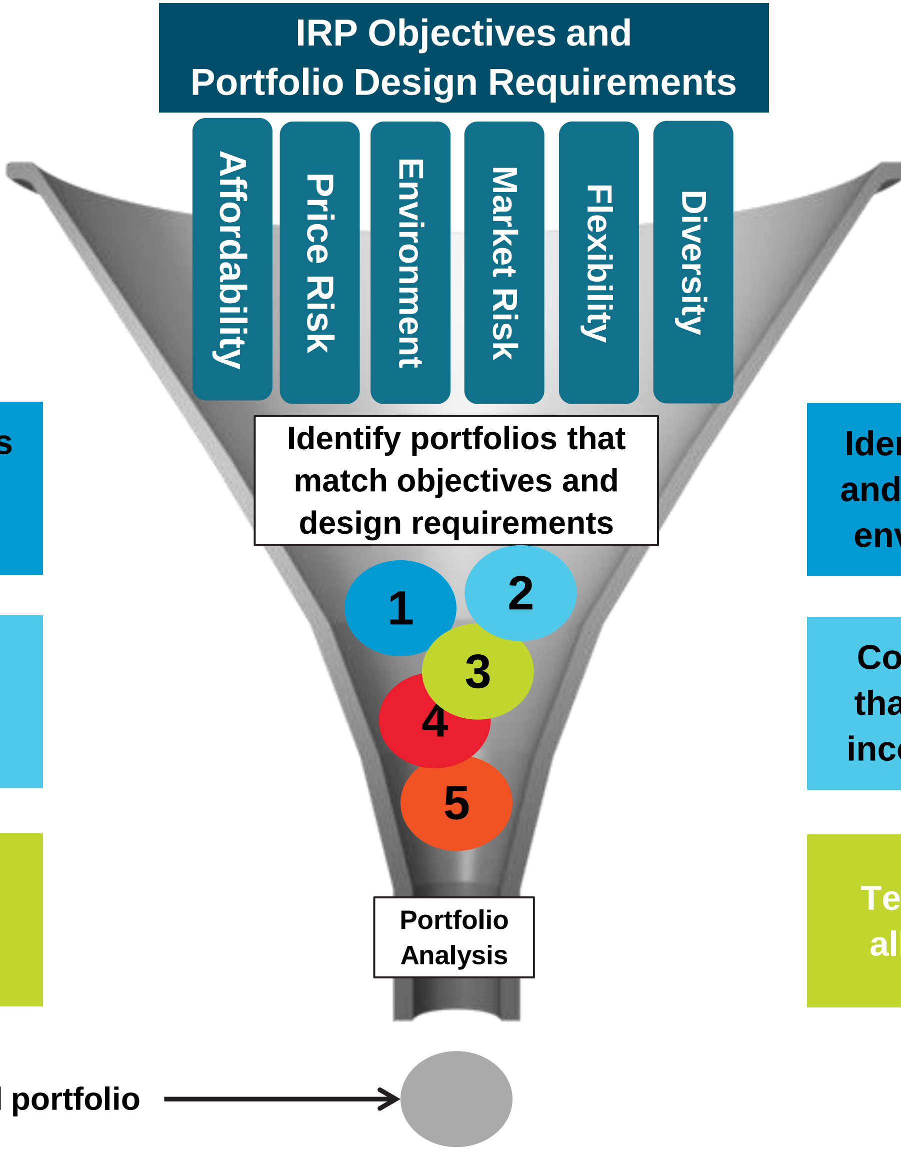
For each resource portfolio, the objectives are tracked and measured to evaluate portfolio performance in the base case, in four alternative scenarios, and across a wide range of possible future market conditions. All measures of portfolio performance are based on probabilistic modeling of 200 futures

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



Task

Screen portfolio options for objectives and design requirements

Combine individual options into integrated portfolios

Perform risk analysis

Approach

Identify design requirements and rank options by cost and environmental performance

Construct portfolio options that meet requirements and incorporate strategy options

Test each portfolio against all objectives & measures

Select preferred portfolio →

FEEDBACK AND DISCUSSION

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ALL-SOURCE RFP UPDATE

MATT LIND,

RESOURCE PLANNING & MARKET ASSESSMENTS BUSINESS LEAD, BURNS AND MCDONNELL

OVERVIEW

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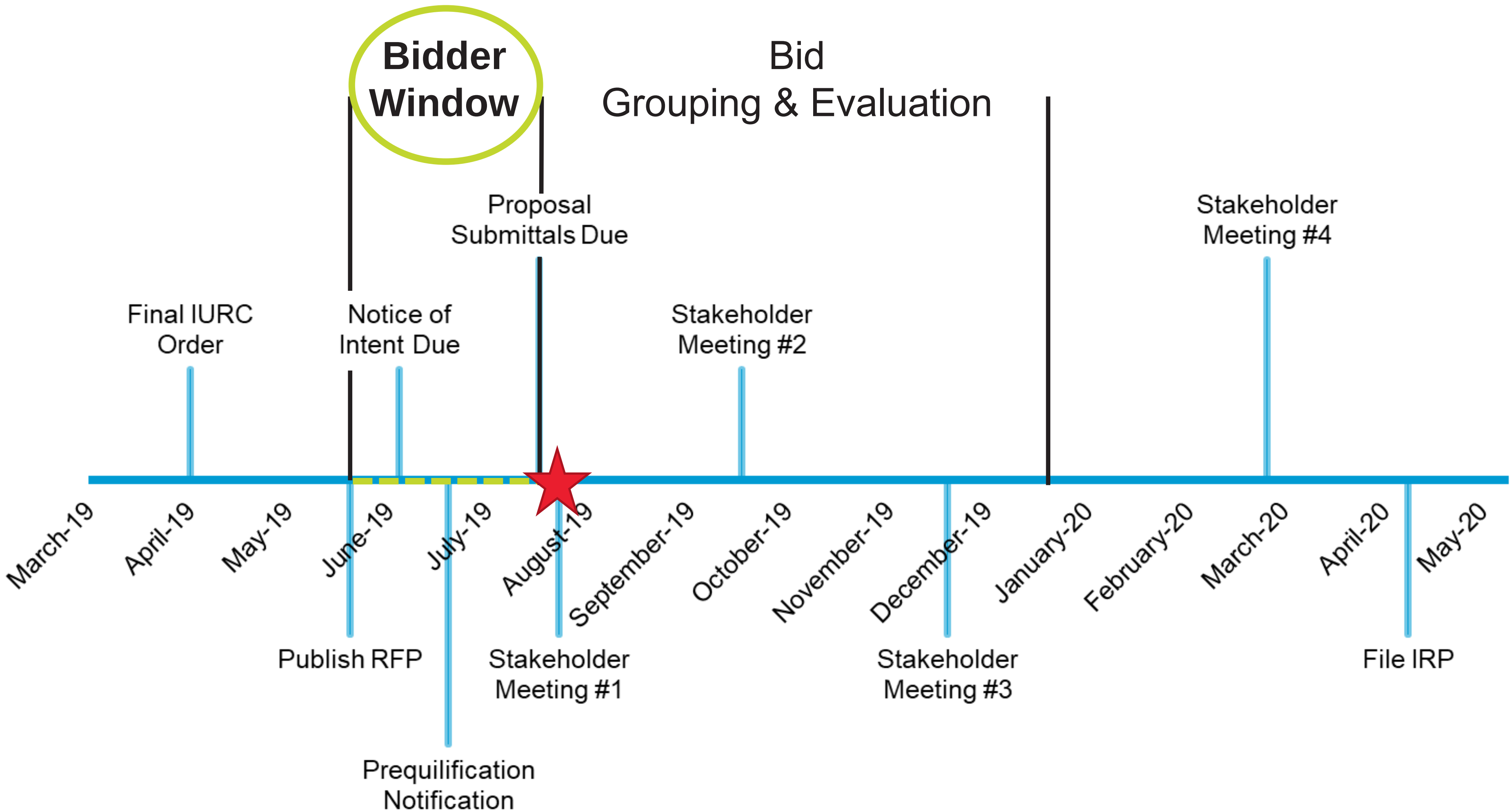
- 2016 IRP:
  - Identified capacity and energy shortfall beginning in 2023
  - Potential need of ~700 MW accredited capacity
- 2019/2020 IRP:
  - Must examine existing resources alongside alternatives
  - Potentially a similar need
- 2019 All-Source RFP:
  - Feed IRP inputs
  - Identify potential cost 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 Thursday, June 27, 2019
Respondents Notified of Results of Pre-Qualification Application Review	5:00 p.m. CDT ~~Wednesday, July 3, 2019~~ Friday, July 12, 2019
Proposal Submittal Due Date	**5:00 p.m. CDT** **~~Wednesday, July 31, 2019~~** **Friday, August 9, 2019**
Initial Proposal Review and Evaluation Period	August - September 2019
Interconnection Evaluation	August - October 2019
Congestion Evaluation	4th Quarter, 2019
Inputs to IRP	4th Quarter, 2019

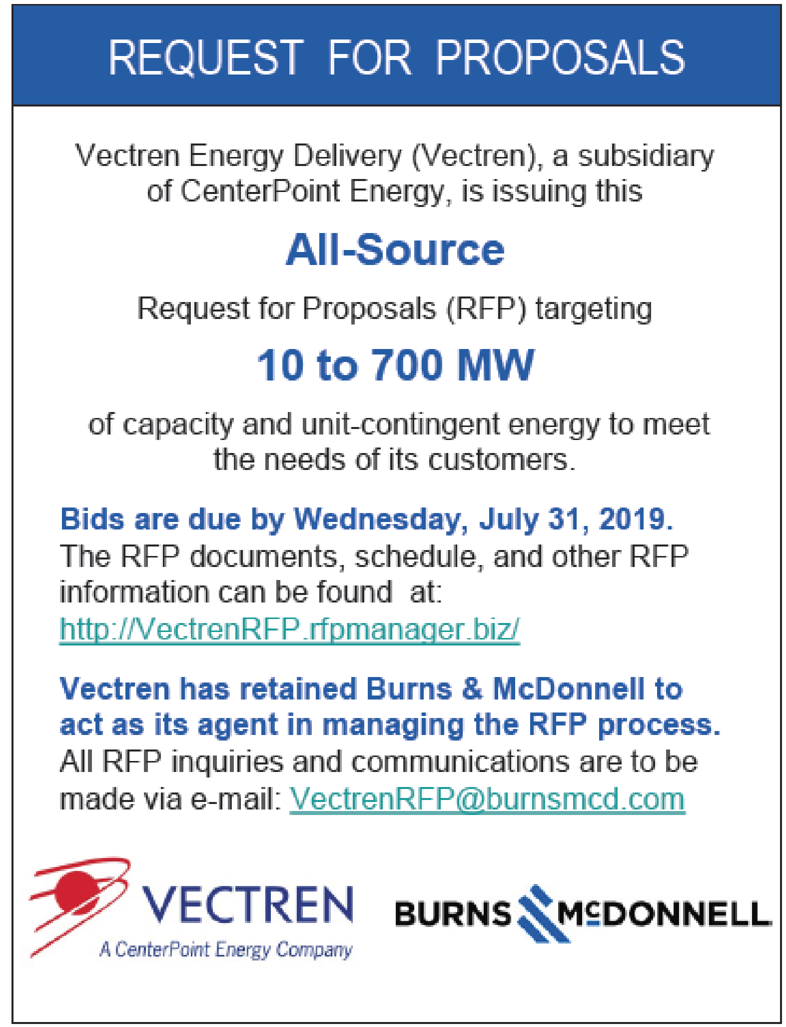
*Negotiation schedule for smaller projects can be expedited at Vectren's discretion

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

- 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

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

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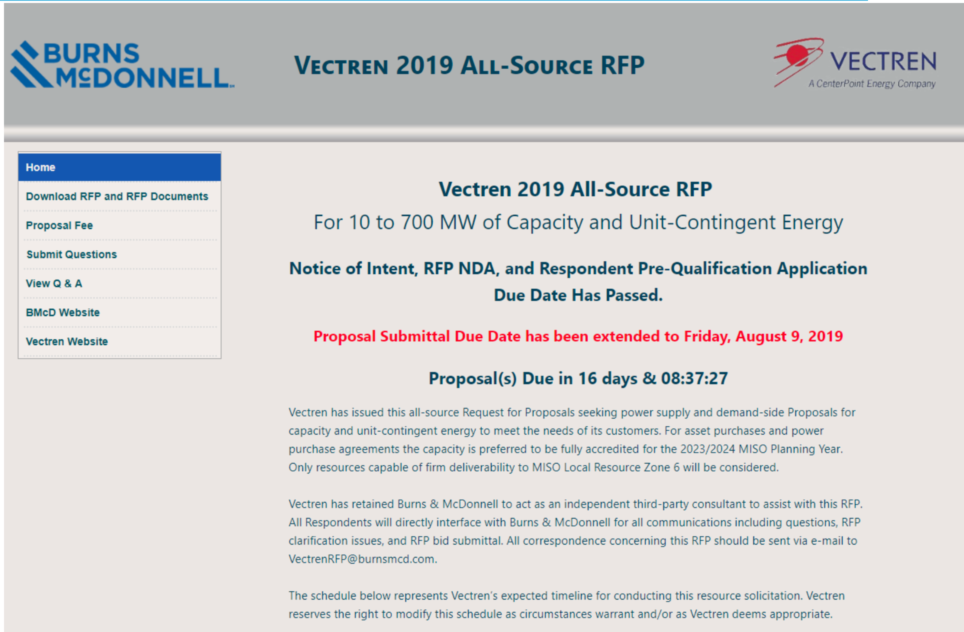
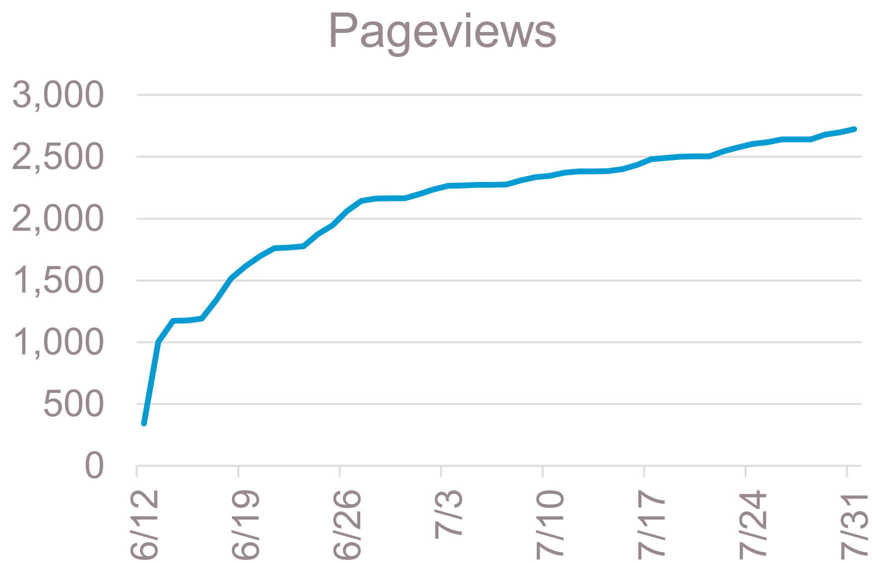
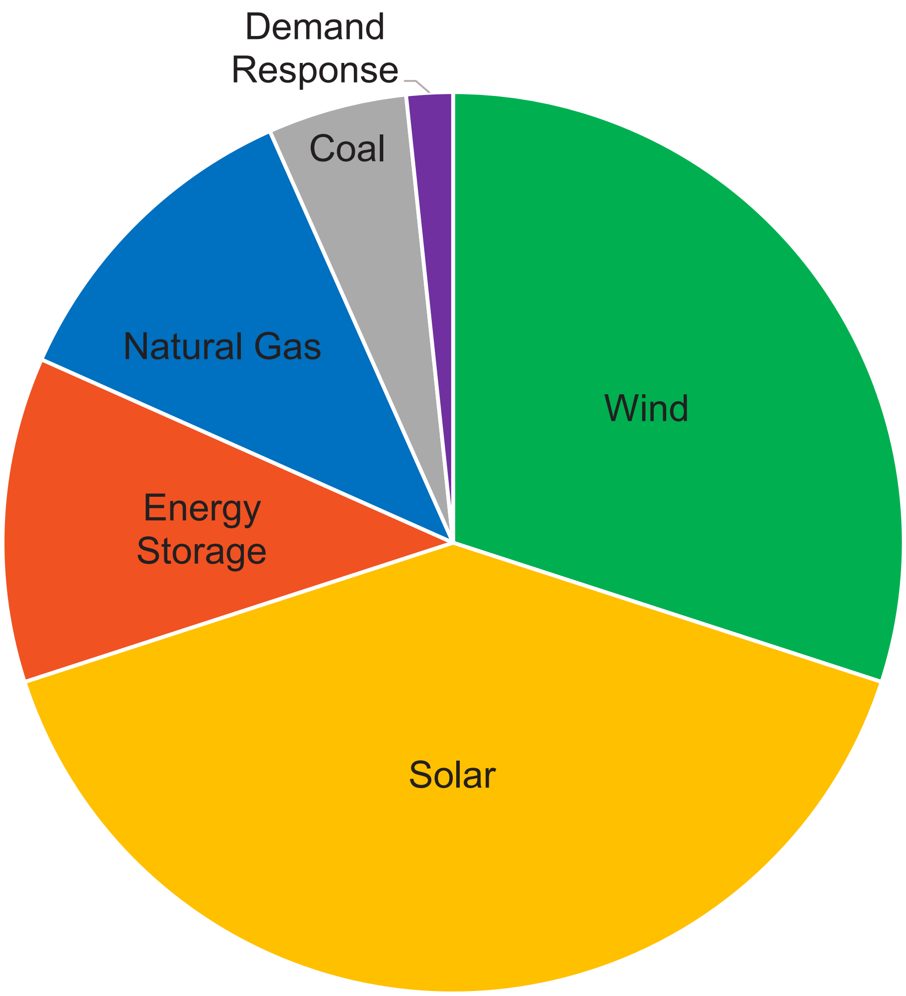
- RFP document downloads
  - 142 unique people
  - 107 companies
- Website visits (June 12th-July 31st)
  - ~800 users
  - ~3,000 pageviews
- Question & Answers posted





ALL-SOURCE RFP PARTICIPATION

- 32 companies submitted Notice of Intent (NOI)



TYPES OF RESOURCES CONSIDERED

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- 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

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- 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

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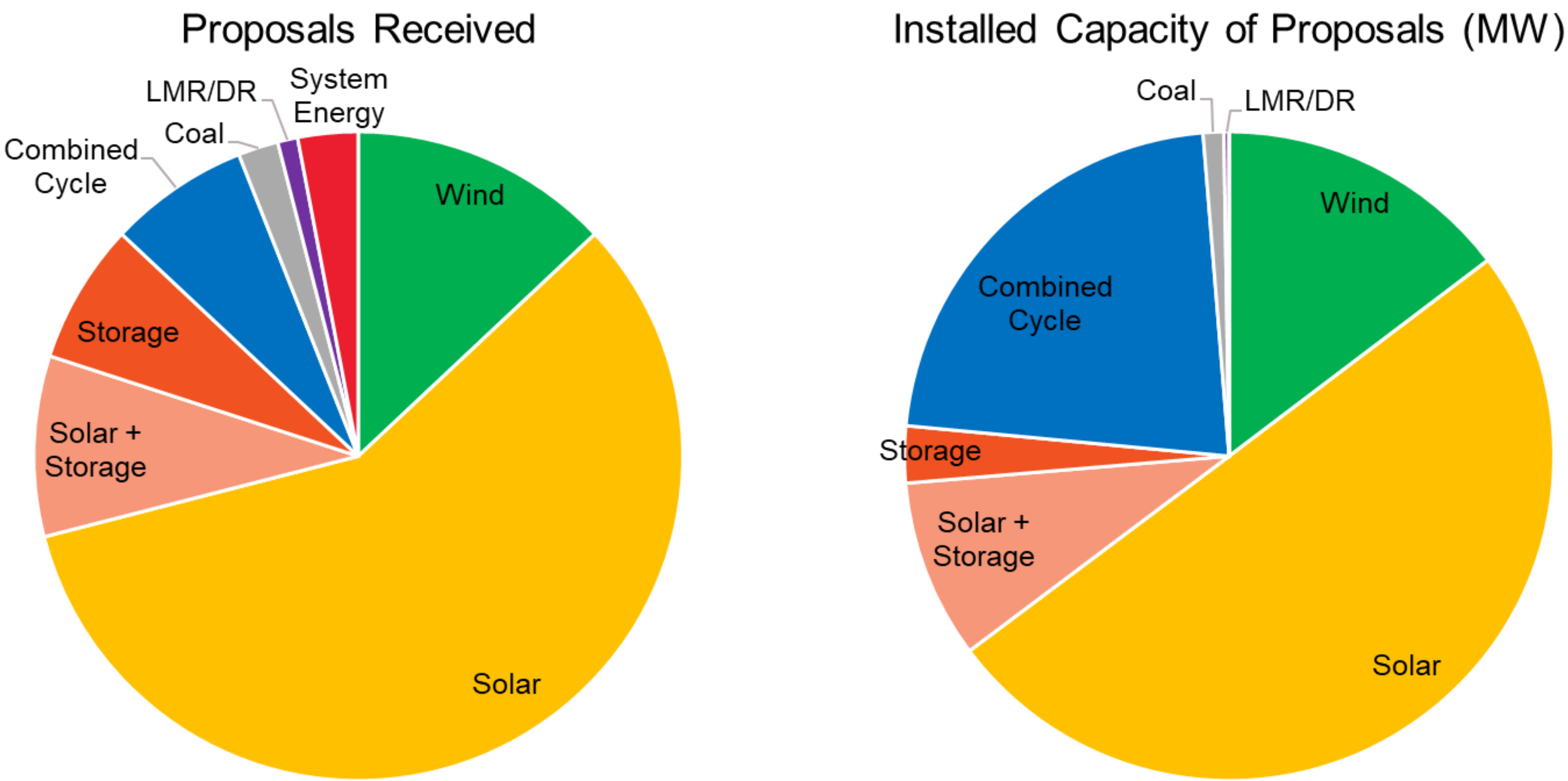
- 100 Proposals from 22 Respondents (4/5 in Indiana, 2/3 are PPA)



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

TIMELINE

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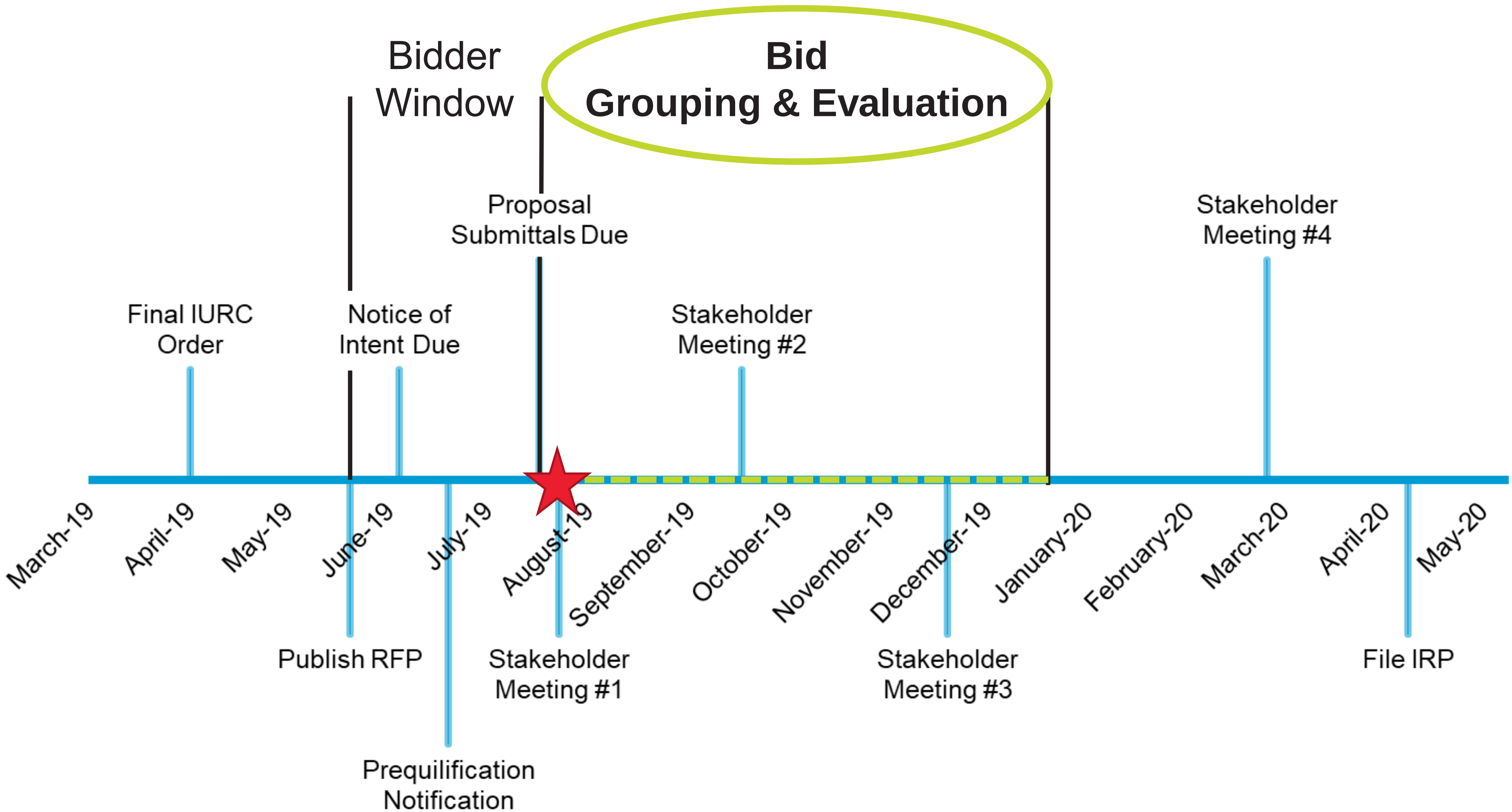

PROPOSAL EVALUATION

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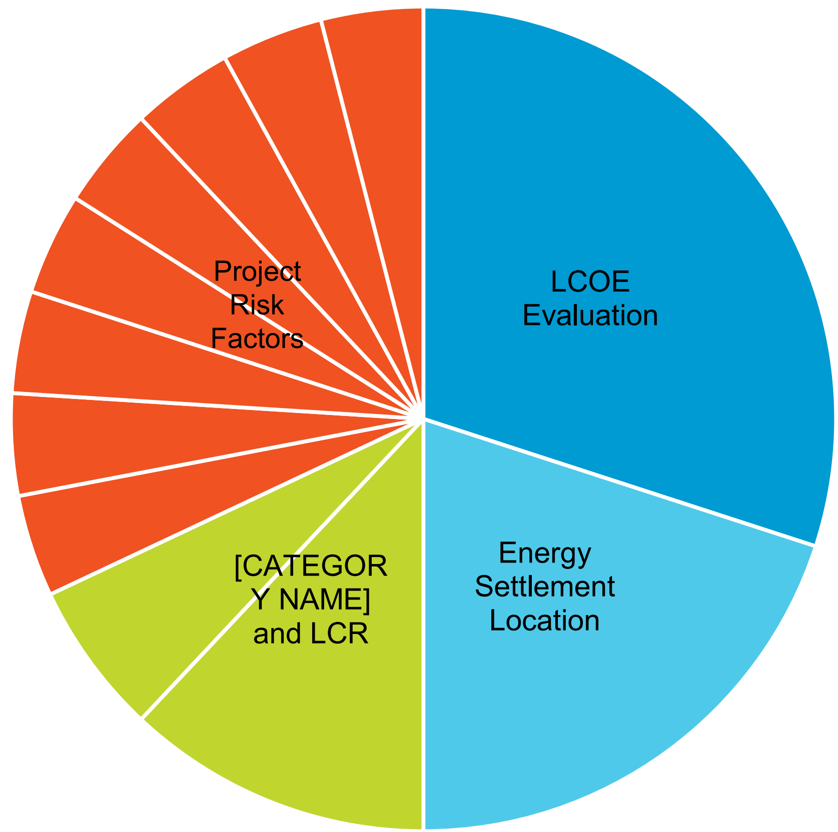
- Proposals will be grouped with similar proposals and scored relative to other bids within the same grouping
  - The preferred resource mix will be identified by the IRP analysis
  - All-Source RFP evaluation will rank order available resources within each grouping

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

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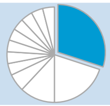
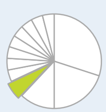
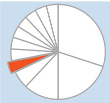
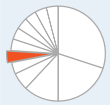
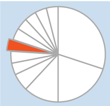
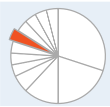
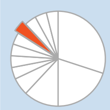
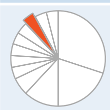
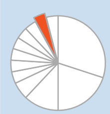
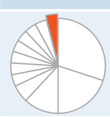
Scoring Criteria Name	Points		Scoring Method	Definition	Importance
LCOE Evaluation	150		Curve	$/MWh calculation within asset class	An LCOE evaluation comparing similar resource groups will help to show which Project(s) may provide lower cost energy to Vectren's customers.
Energy Settlement Location	100		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) Completed a MISO Facilities Study (12 points) Completed a MISO System Impact Study (12 points) Achieved site control and completed zoning requirements (12 points) 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

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

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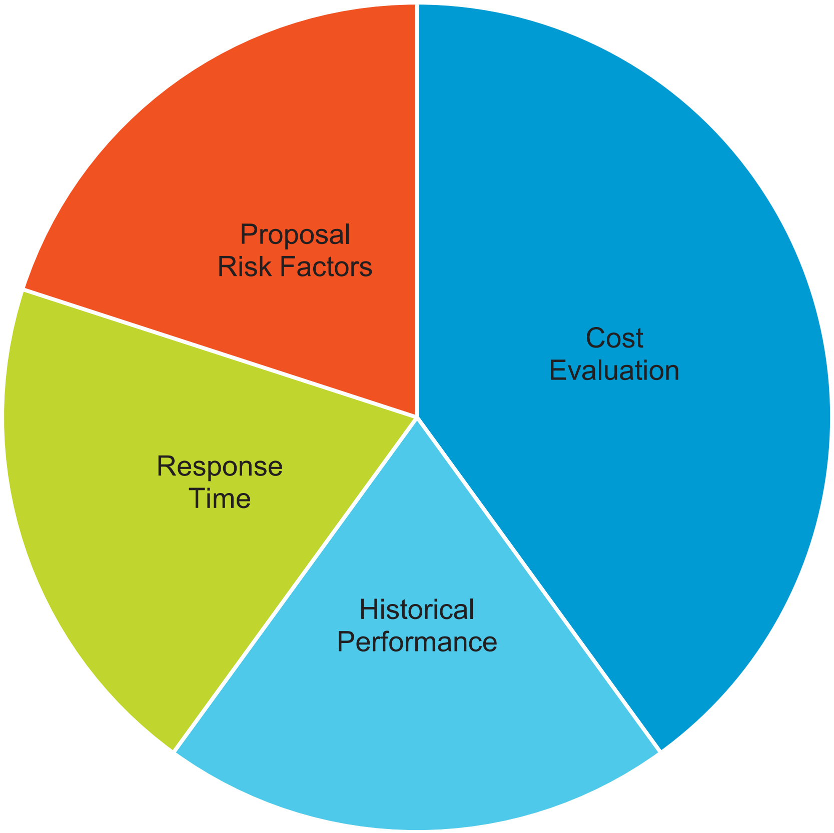
- Proposals will be grouped with similar proposals and scored relative to other bids within the same grouping
  - The preferred resource mix will be identified by the IRP analysis
  - All-Source RFP evaluation will rank order available resources within each grouping

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

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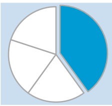
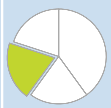
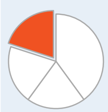
Scoring Criteria Name	Points		Scoring Method	Definition	Importance
Cost Evaluation	200		Curve	$/MW calculation to determine scoring based on rank order	The cost of the Project will have the most impact on Vectren's ability to provide low cost energy to its customers.
Historical Performance	100		Range	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

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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

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- 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

- 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

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- 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

VECTREN
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DRAFT BASE CASE MARKET INPUTS AND SCENARIOS WORKSHOP

GARY VICINUS

MANAGING DIRECTOR FOR UTILITIES, PACE GLOBAL

BASE CASE INPUTS

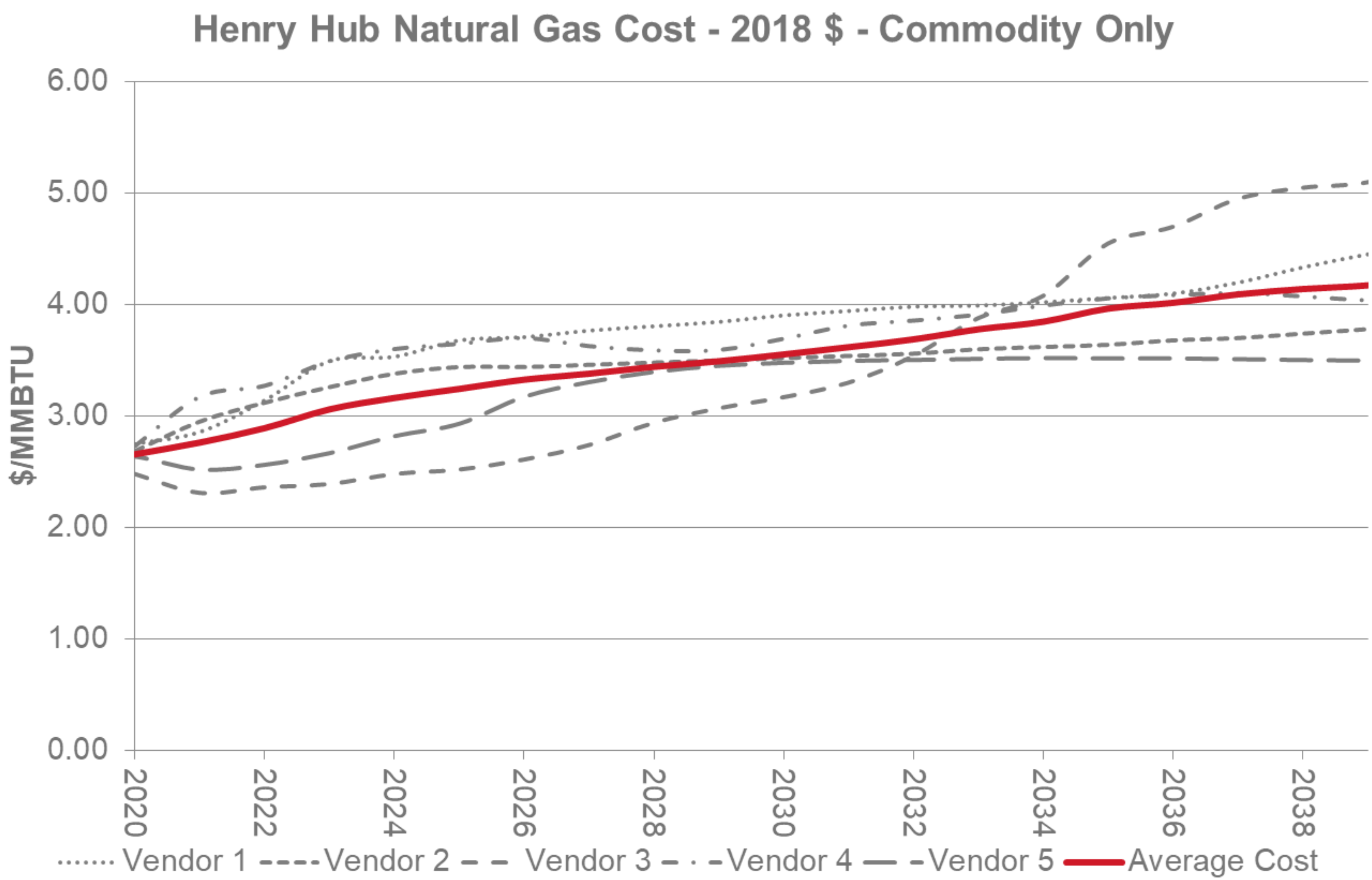
Vectren surveyed and incorporated a wide array of sources in developing its base case assumptions, which reflect a current consensus view of key drivers in power and fuel markets

- 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

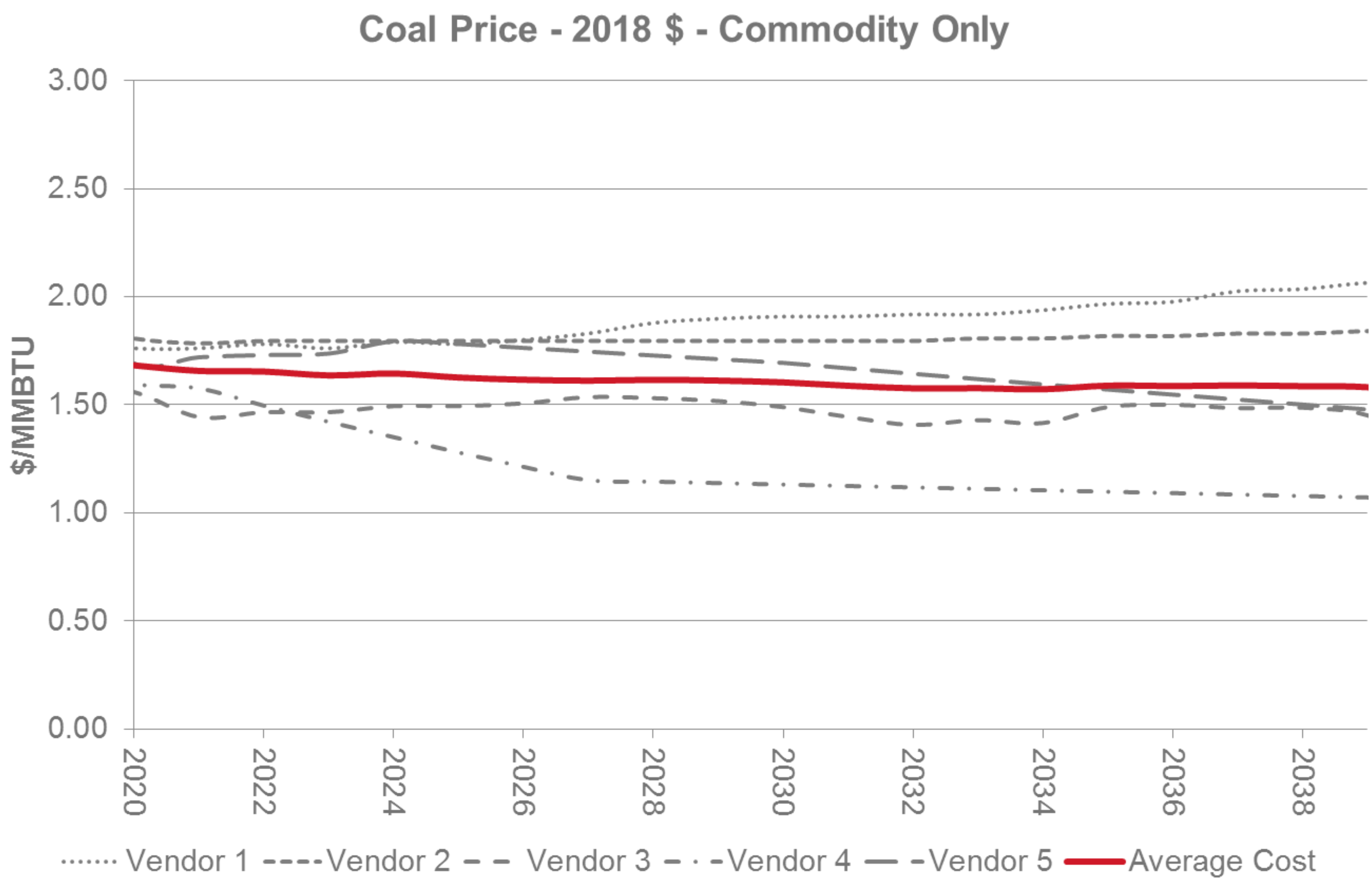
- Vectren uses a consensus base case view, by averaging forecasts from several sources where applicable

BASE CASE CONSENSUS FUEL FORECASTS



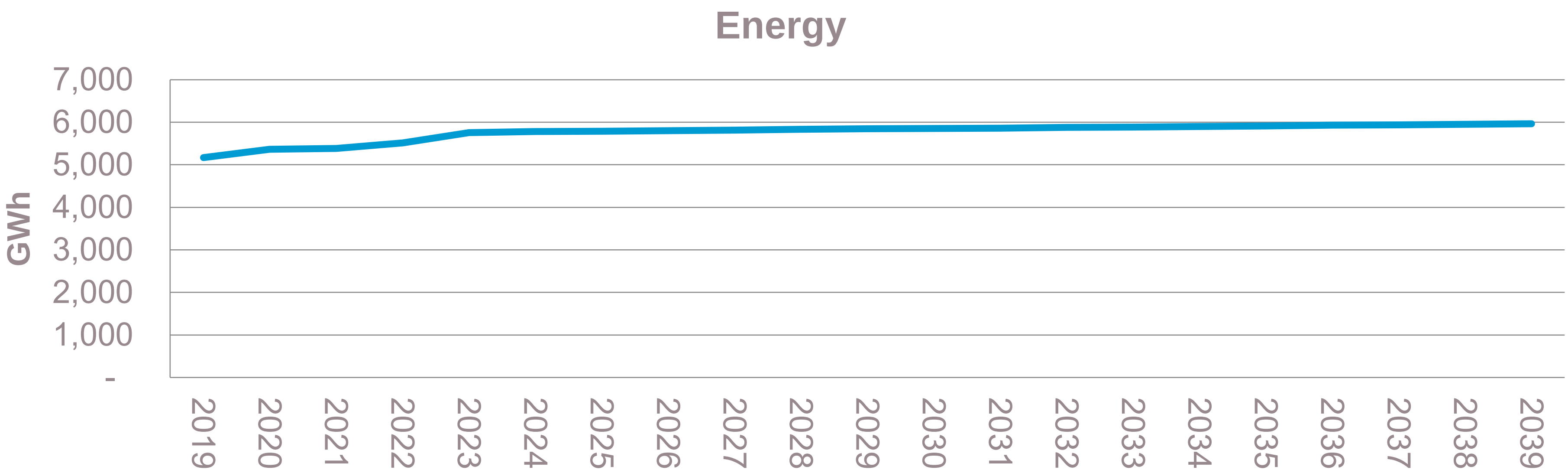
Note: Vendors used were PIRA, Wood Mackenzie, Pace, ABB, & EVA

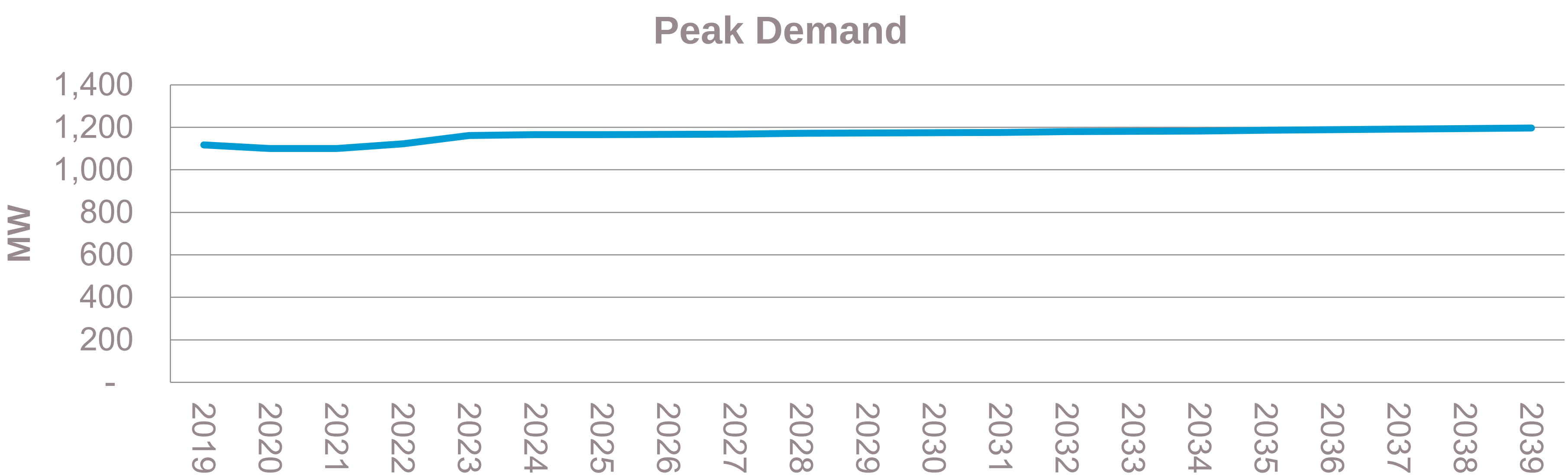
BASE CASE CONSENSUS FUEL FORECASTS



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

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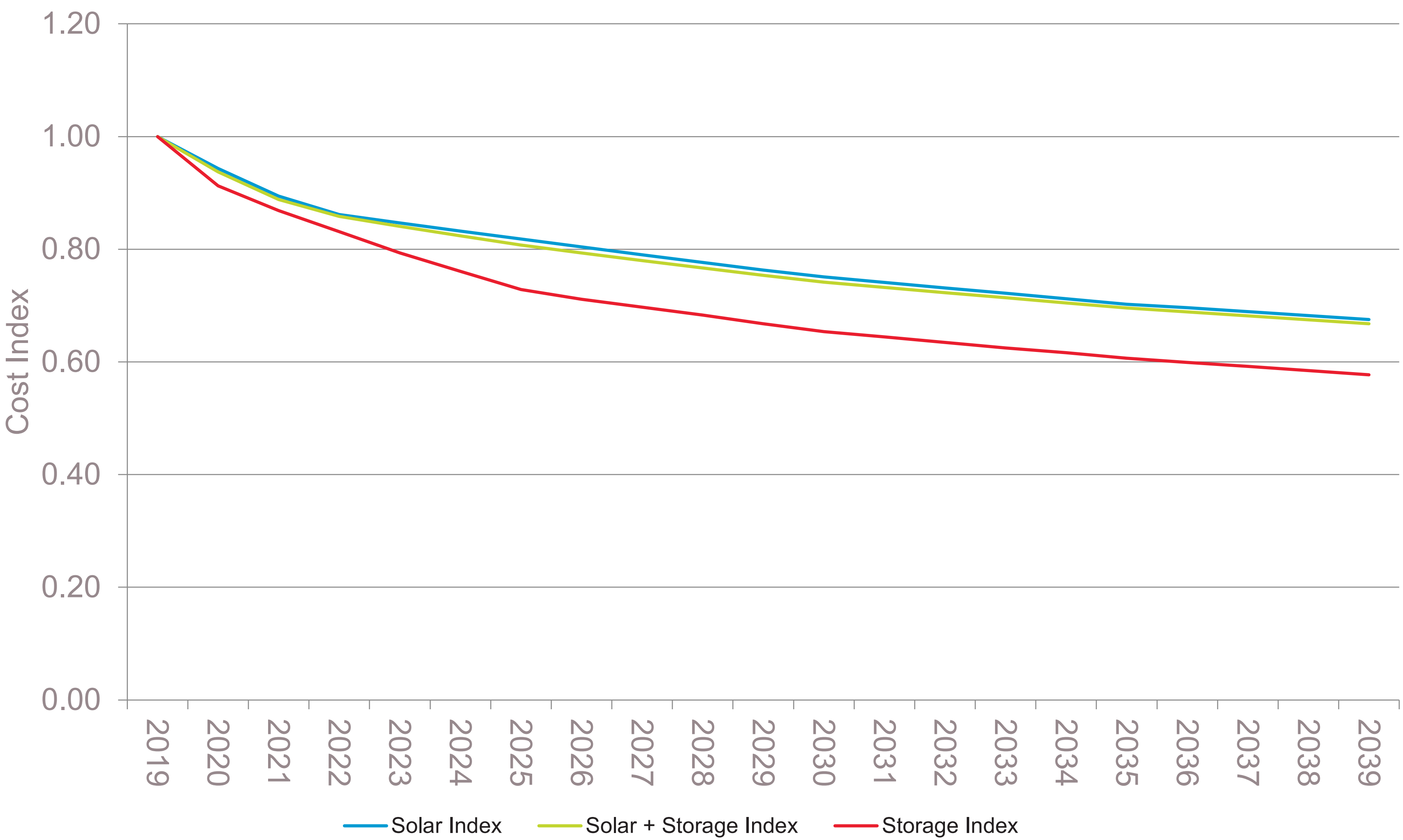

SCENARIO DEVELOPMENT

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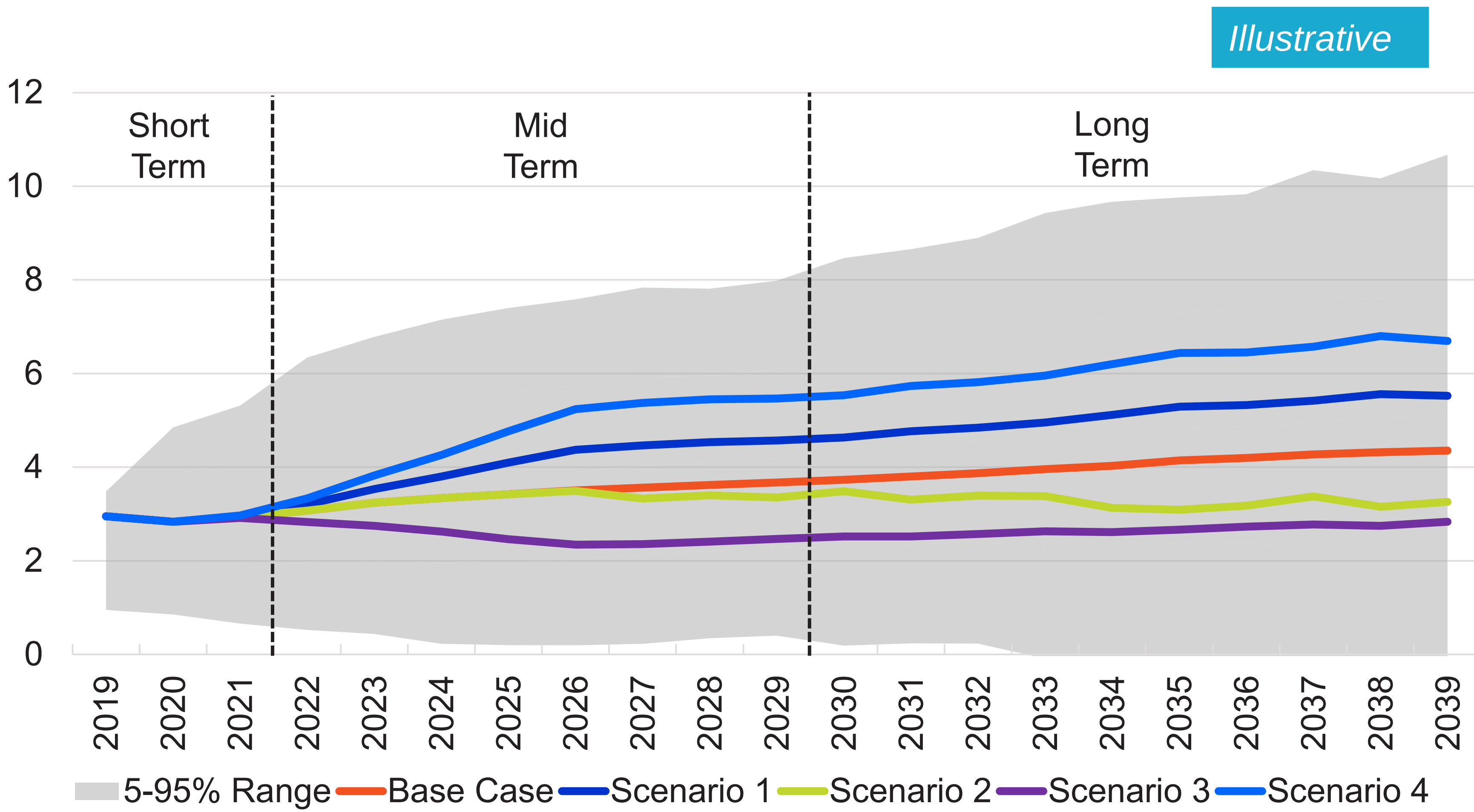
Vectren worked with Pace to develop a base case and four alternative, internally consistent scenarios (potential futures), to test which portfolios are optimal over a wide range of future market and regulatory conditions.

- 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

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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

	CO_2	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 CO_2 Tax		ELG	Higher	Higher	Lower	Lower	Lower	Lower
80% CO_2 Reduction by 2050	Cap and Trade	Methane	ELG	Lower	Lower	Base	Lower	Higher	Higher
High Reg.	High CO_2 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

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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

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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

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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

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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

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STAKEHOLDER PROCESS RECAP AND Q&A

STAKEHOLDER PROCESS RECAP

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

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Q&A

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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

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.

Angila Retherford – 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 CO2?
        - Response: We will have to verify, but it is around 26x. We will clarify at the next meeting.
    - Question: Are you talking about CO2-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 CO2 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.

Gary Vicinus – 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.

<u>Open Q&A Session</u>

- 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.

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VECTREN PUBLIC STAKEHOLDER MEETING

OCTOBER 10, 2019

WELCOME AND SAFETY SHARE

LYNNAE WILSON

INDIANA ELECTRIC CHIEF BUSINESS OFFICER

SAFETY SHARE

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 • Objectives and Measures • All-Source RFP • Environmental Update • Draft Base Case Market Inputs & Scenarios	• RFP Update • Draft Resource Costs • Sales and Demand Forecast • DSM MPS/ Modeling Inputs • Scenario Modeling Inputs • Portfolio Development	• Draft Portfolios • Draft Base Case Modeling Results • All-Source RFP Results and Final Modeling Inputs • Probabilistic Modeling Approach and Assumptions	• Final Base Case Modeling • Probabilistic Modeling Results • Risk Analysis Results • Preview the Preferred Portfolio

1 Snow date is December 19, 2019

AGENDA

VECTREN
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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.

VECTREN
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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

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

VECTREN
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- Conduct an All Source RFP
- Create Objectives, Risk Perspectives and Scorecard Development
- Create Base 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

REVIEW ROLE OF THE ALL SOURCE RFP

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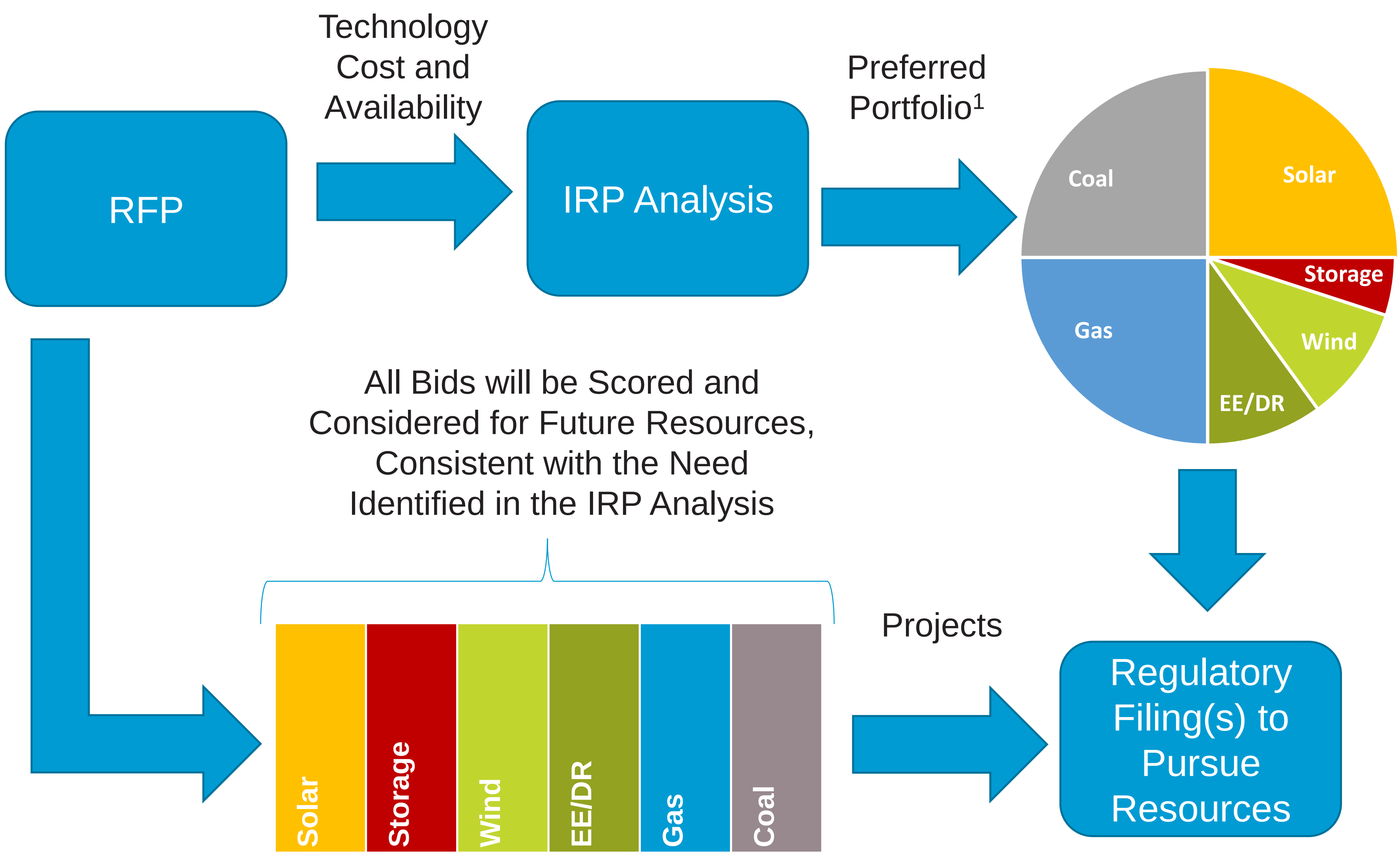

1 Illustrative example

STAKEHOLDER FEEDBACK

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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_2e rates per MWh will be applied to both retail sales covered by Vectren portfolios, as well as a CO_2e 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

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- 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

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- 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 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

Increasing Environmental Regulation

	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

*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

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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

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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

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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~~ 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~~ Uneconomic Asset Risk	~~MWh~~ $

Revised from last meeting

ENVIRONMENTAL RISK MINIMIZATION
LIFE CYCLE GREENHOUSE GAS EMISSIONS

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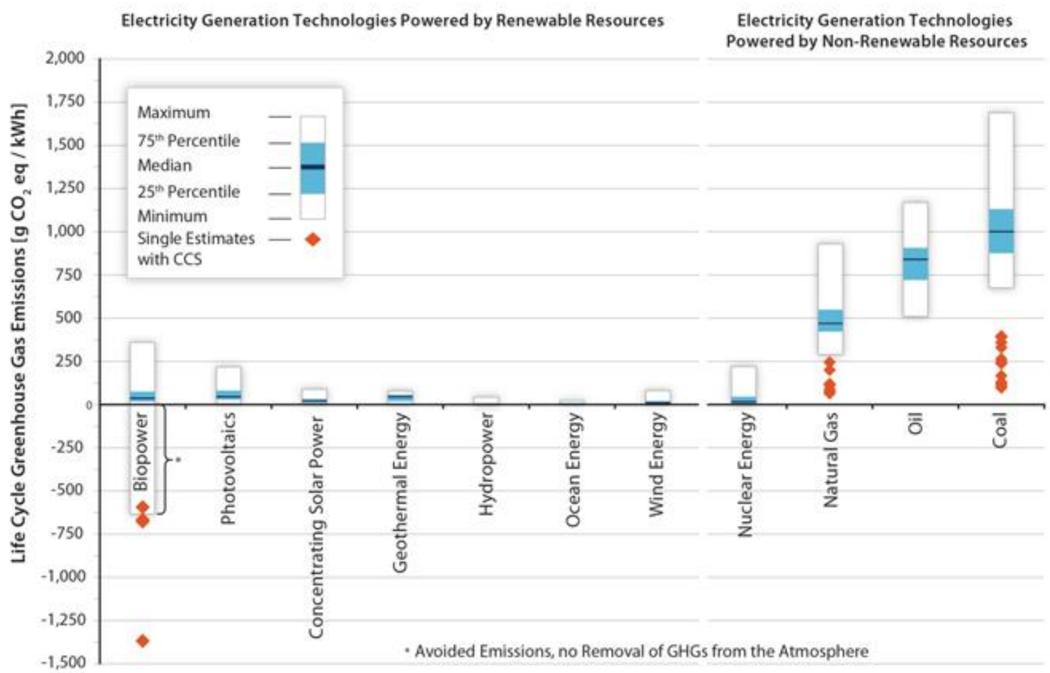
- Stakeholders requested a Life Cycle Analysis (LCA) and CO_2 equivalent on the scorecard
- LCA can help determine environmental burdens from “cradle to grave” and facilitate more consistent comparisons of energy technologies, including upstream, fuel cycle, operation, and downstream emissions
- NREL 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…

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- NREL utilizes median values[2] listed in the table to the right for life cycle analyses
- We plan to apply NREL rates (g CO_2e/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_2e 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

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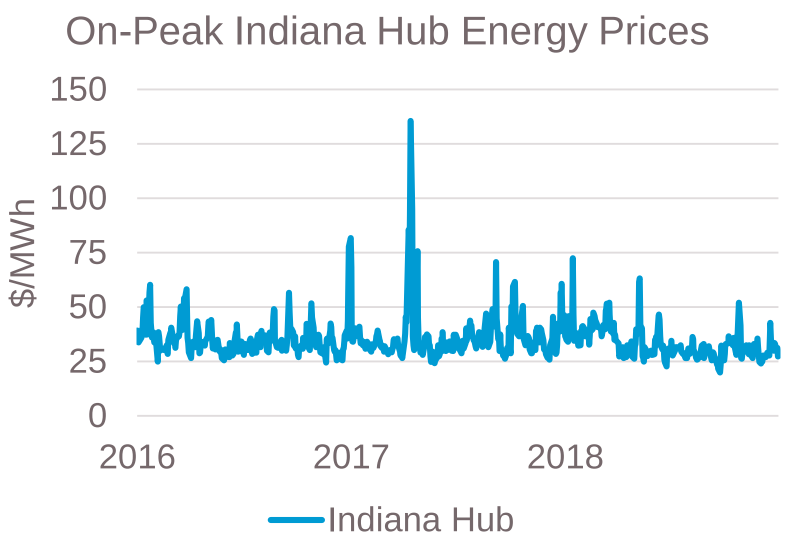
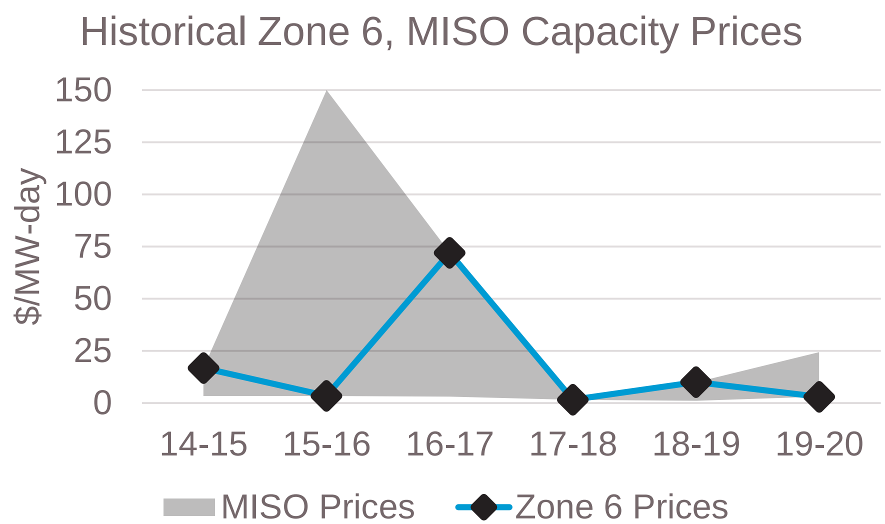
- Market transactions carry the risk for Vectren of buying when prices are high and selling when price are low.
- Vectren energy purchases are 1-2% of regional volumes* and 10-30% below regional prices for similar long-term transactions. On-peak power prices demonstrate ongoing volatility. To reduce 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

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- 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:

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

- 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

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MISO CONSIDERATIONS

JUSTIN JOINER

VECTREN DIRECTOR OF POWER SUPPLY SERVICES

MISO SUMMARY

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- 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?

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Midcontinent **I**ndependent Transmission **S**ystem **O**perator

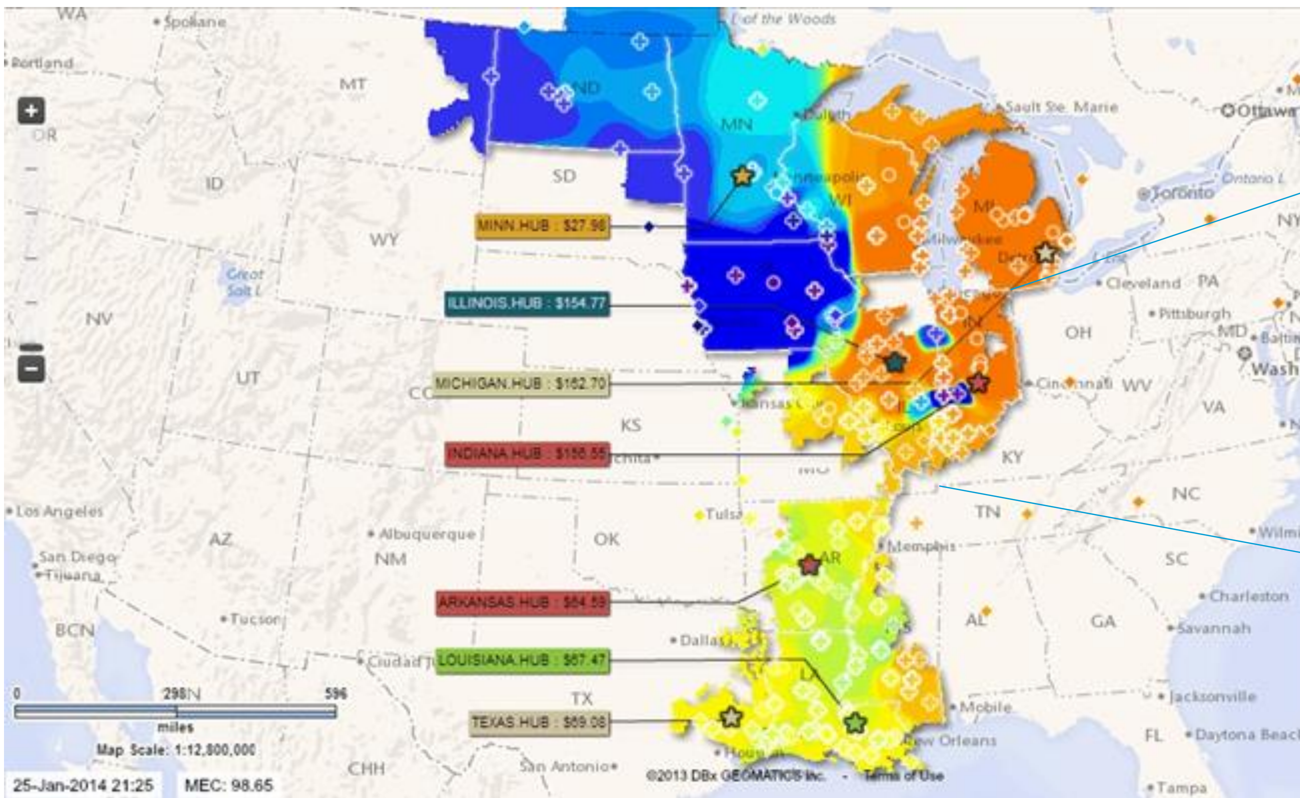
- In 2001, MISO was approved as the first Regional Transmission Organization (RTO)
  - MISO has operational authority: the authority to control transmission facilities and coordinate security for its region to ensure reliability
  - MISO is responsible for dispatch of lowest cost generation units: MISO's 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

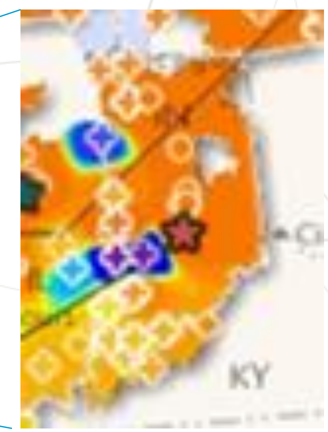
Local Resource Zones

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

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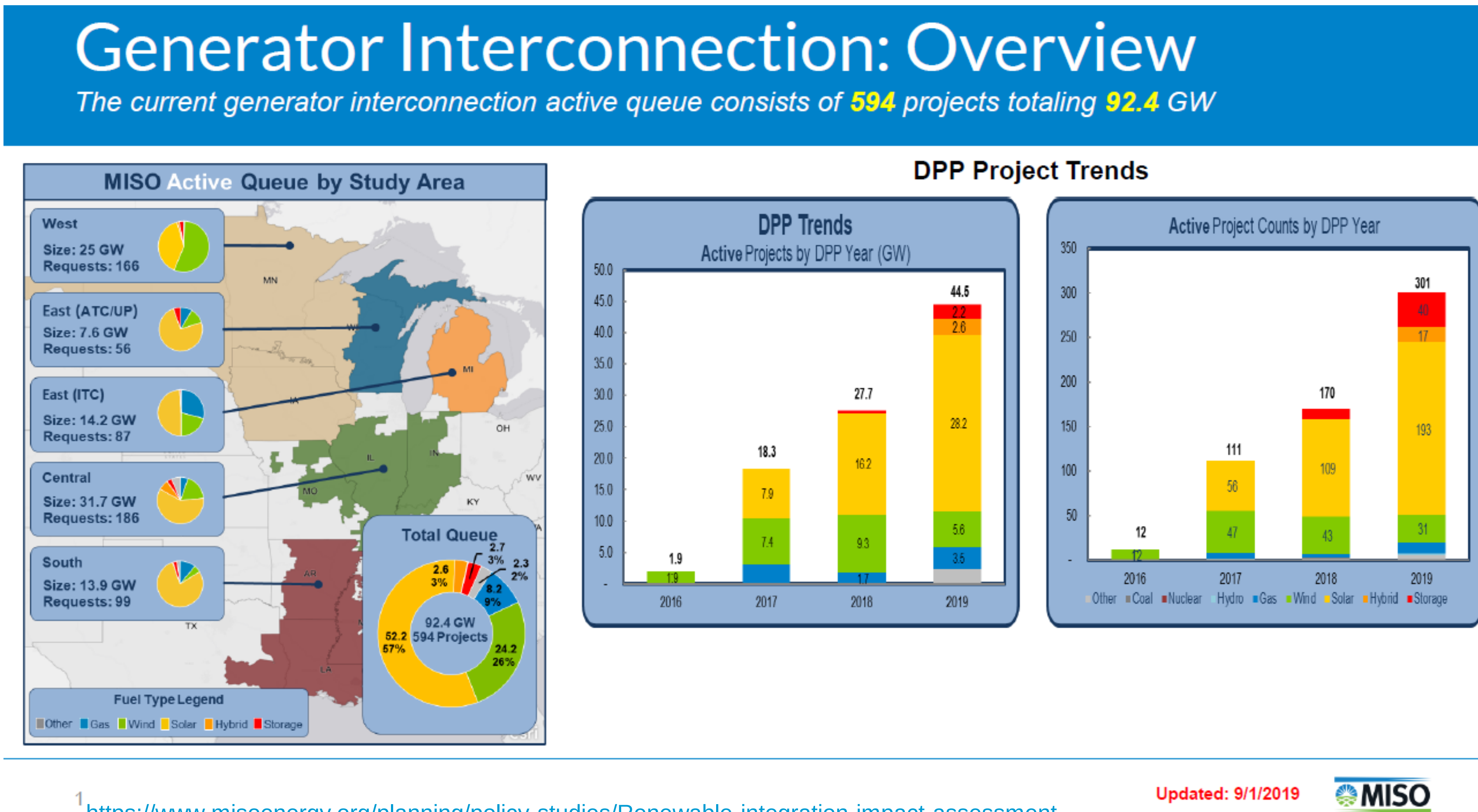
- Lengthy process that involves studies that are susceptible to many variables and cost allocation based on position in queue
- MISO Interconnection is predominantly composed of renewables (76%), followed by natural gas
- MISO's Renewable Integration Impact Assessment[1] is studying system impacts as 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

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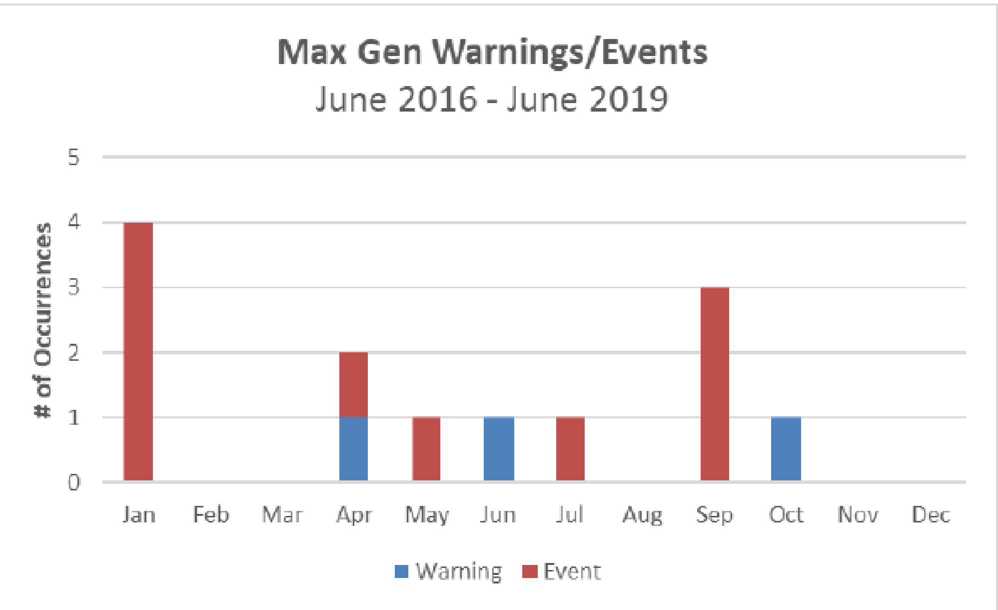
- Less capacity and lower generator availability have led to tighter operating conditions in all four seasons
- MISO has experienced 10 Max Generation Events in the last 4 years; a Max Gen Event used to occur once every couple years
- As such, the RAN Initiative is to ensure resource accreditation aligns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

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

MISO

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

ALL MISO CONSIDERATIONS NEED TO BE ACCOUNTED FOR DURING THE IRP

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- 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

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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

Cause No. 45564

PROBABILISTIC MODELING CONT.

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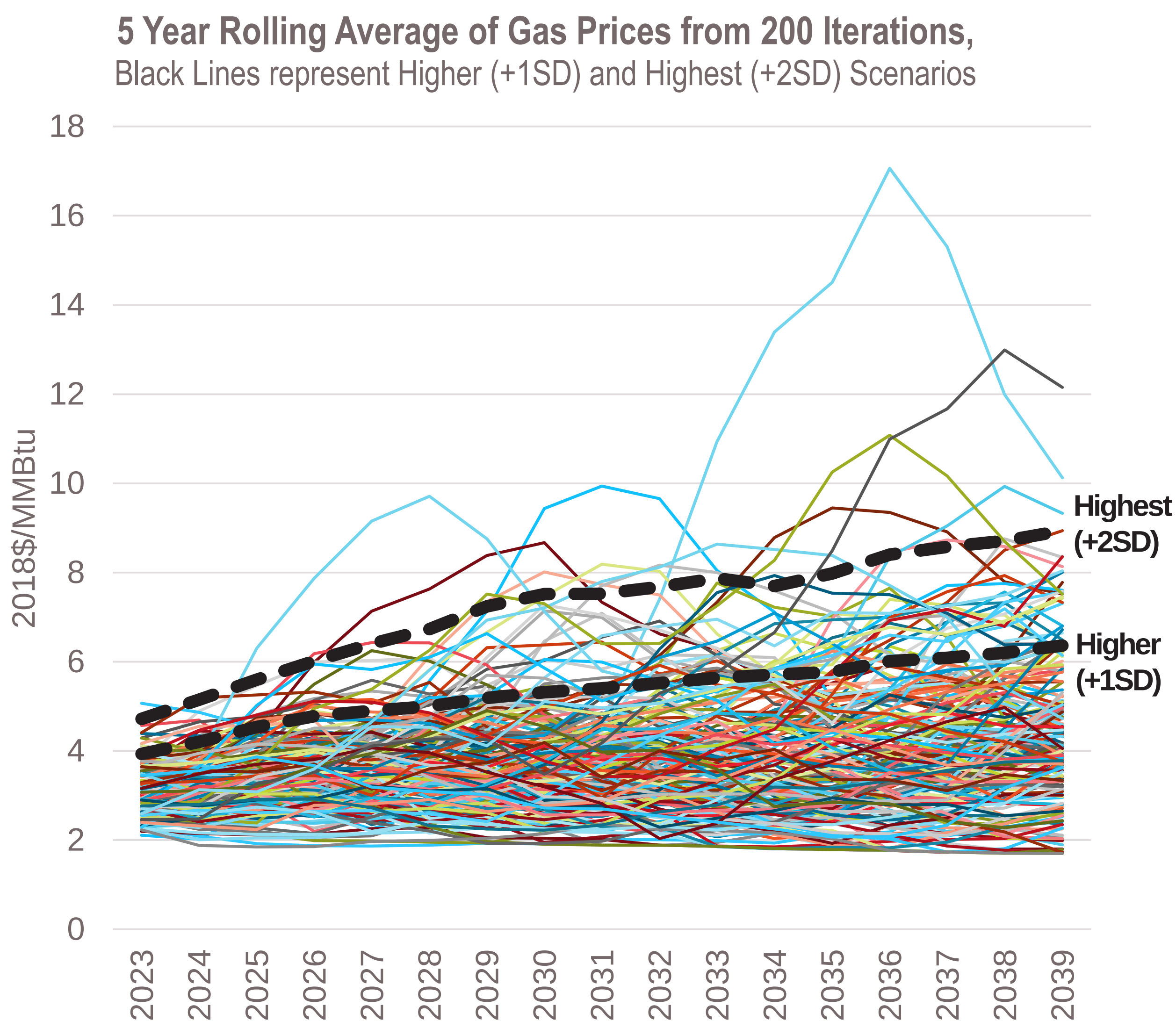
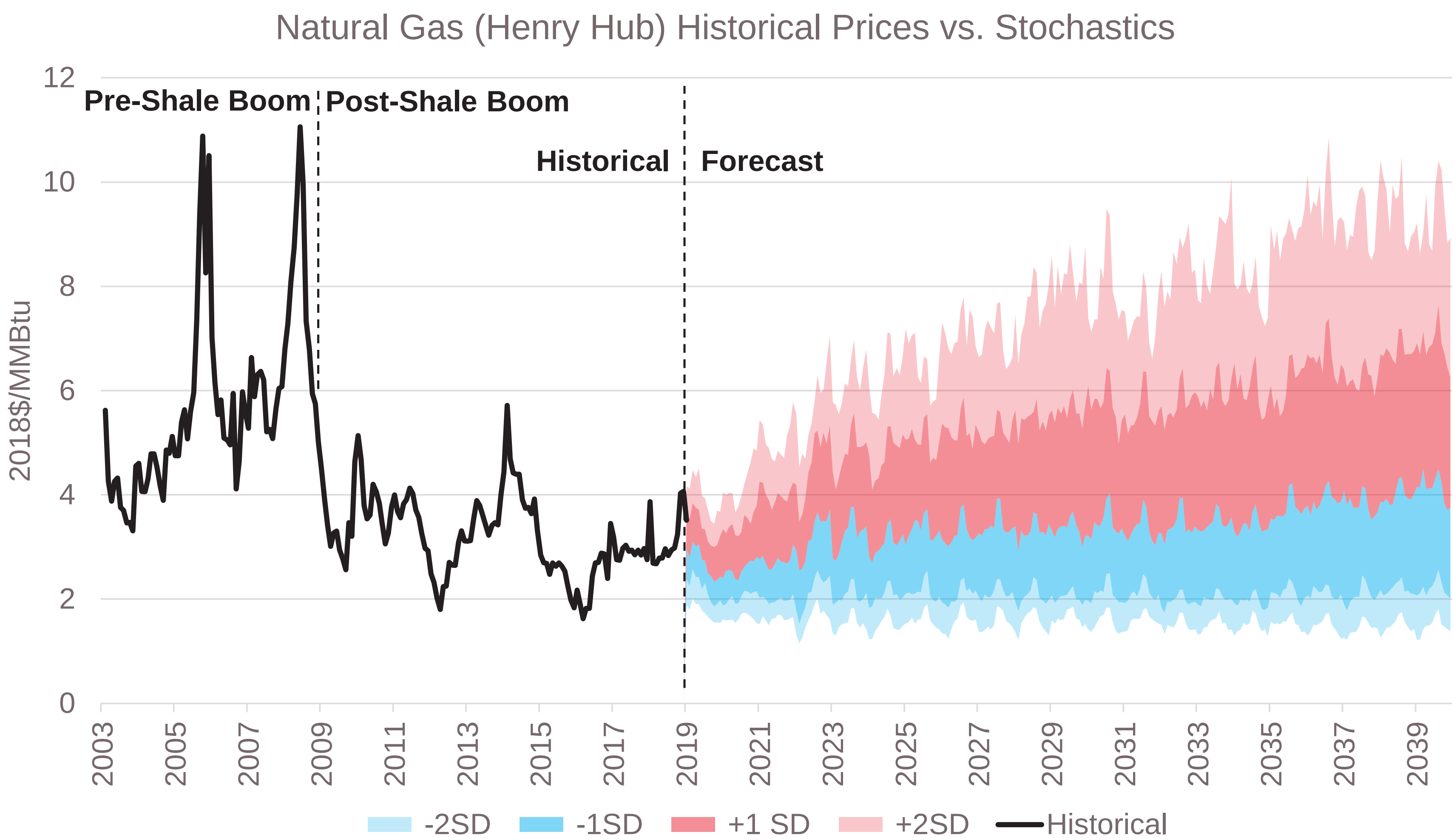
- This spaghetti diagram shows a 5-year rolling average of all 200 gas price iterations against the Higher and Highest gas price scenarios.
- In any given year, about 16% of prices are above the Higher line and about 2% are above the Highest line.
- Looking at the 20 year price average, about 7% of the 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

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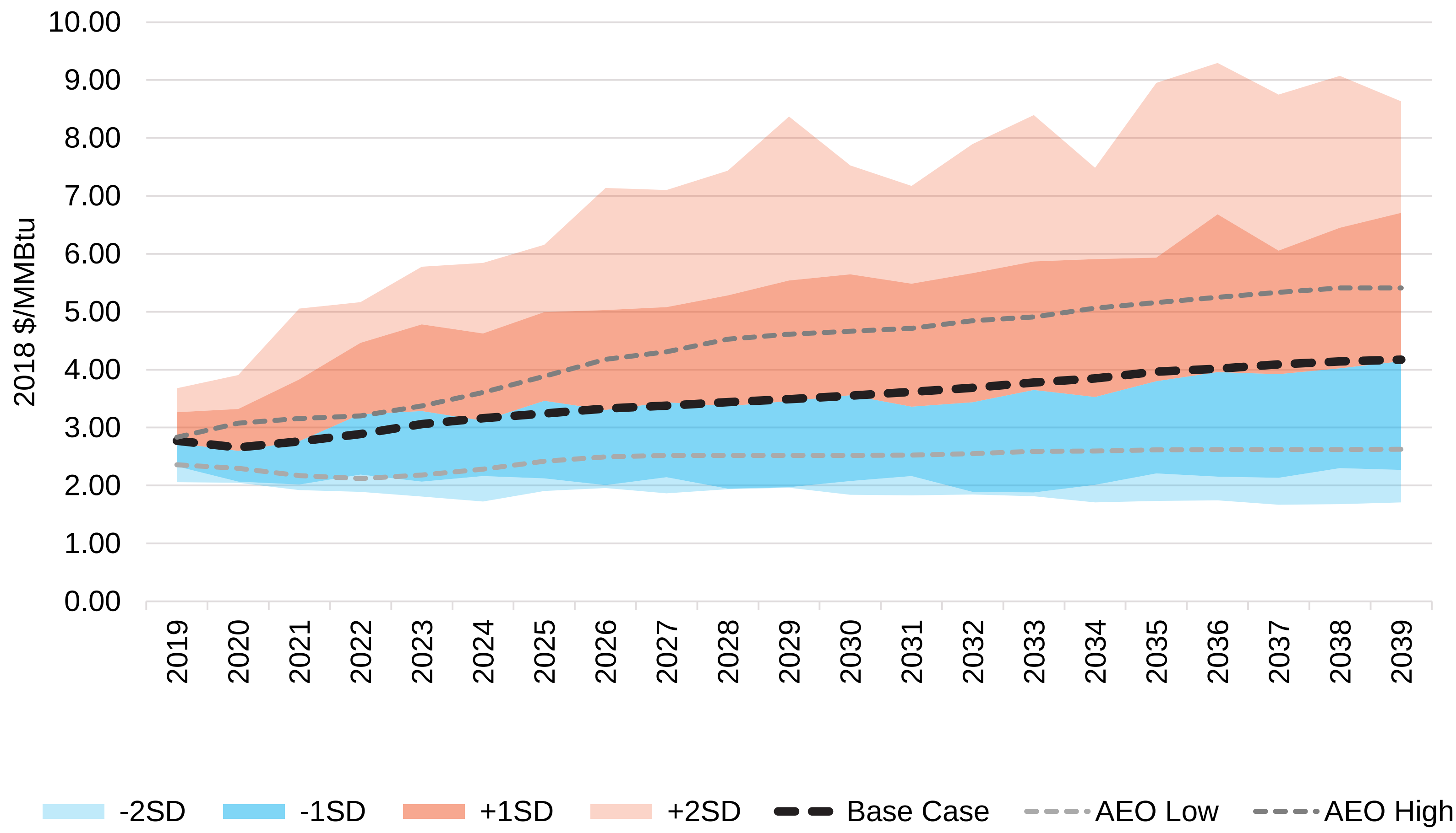

1Source:Energy Information Administration (EIA) Annual Energy Outlook (AEO) https://www.eia.gov/outlooks/aeo/
EIA Low = AEO 2019: High Oil & Gas Resource and Technology scenario
EIA High = AEO 2019: Low Oil & Gas Resource and Technology scenario

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

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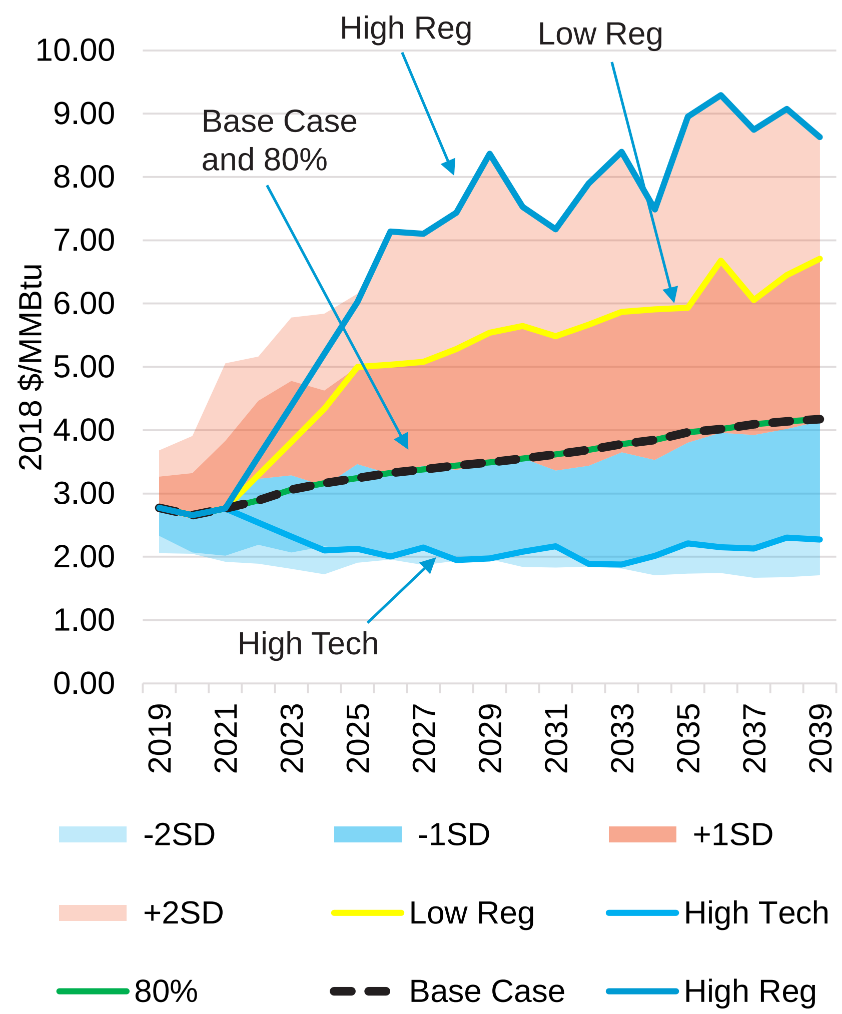
	Base Case	Low Reg	High Tech	80% Reduction	High Reg
2019	2.77	2.77	2.77	2.77	2.77
2020	2.66	2.66	2.66	2.66	2.66
2021	2.76	2.76	2.76	2.76	2.76
2022	2.89	3.46	3.01	2.89	3.58
2023	3.06	4.10	2.82	3.06	4.39
2024	3.16	4.75	2.64	3.16	5.21
2025	3.24	5.12	2.33	3.24	6.03
2026	3.33	5.27	2.08	3.33	7.14
2027	3.38	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]

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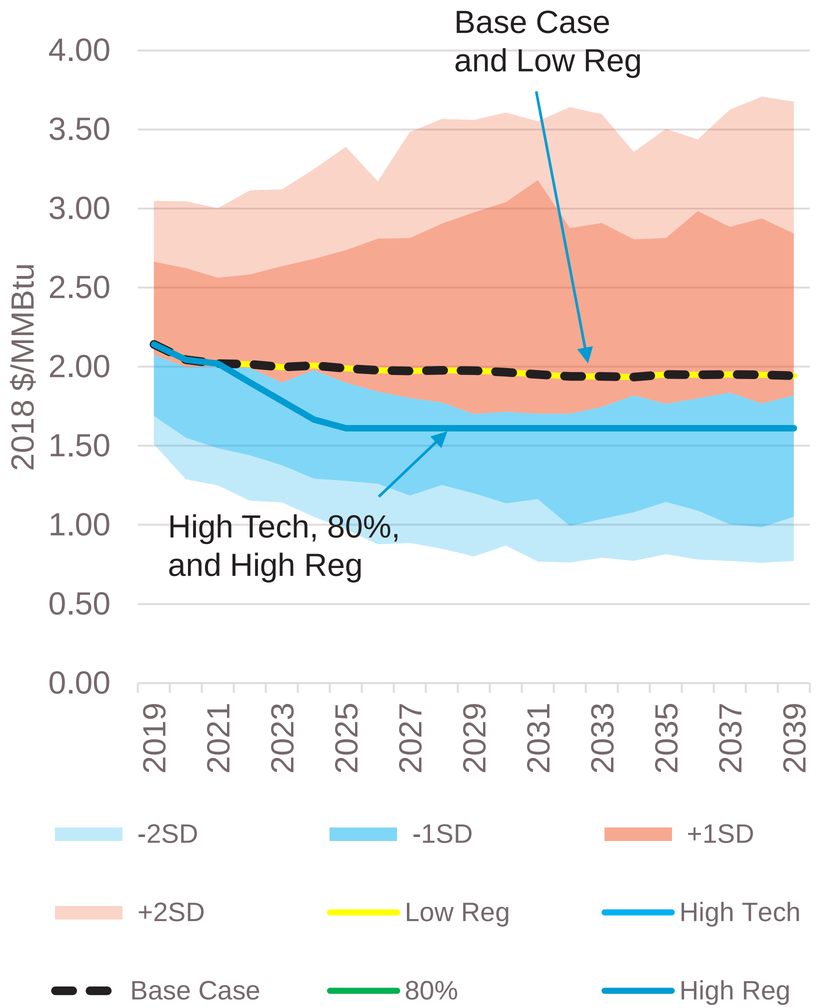
	Base Case	Low Reg	High Tech	80% Reduction	High Reg
2019	2.14	2.14	2.14	2.14	2.14
2020	2.04	2.04	2.04	2.04	2.04
2021	2.02	2.02	2.02	2.02	2.02
2022	2.02	2.02	1.90	1.90	1.90
2023	2.00	2.00	1.78	1.78	1.78
2024	2.01	2.01	1.67	1.67	1.67
2025	1.99	1.99	1.61	1.61	1.61
2026	1.98	1.98	1.61	1.61	1.61
2027	1.97	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

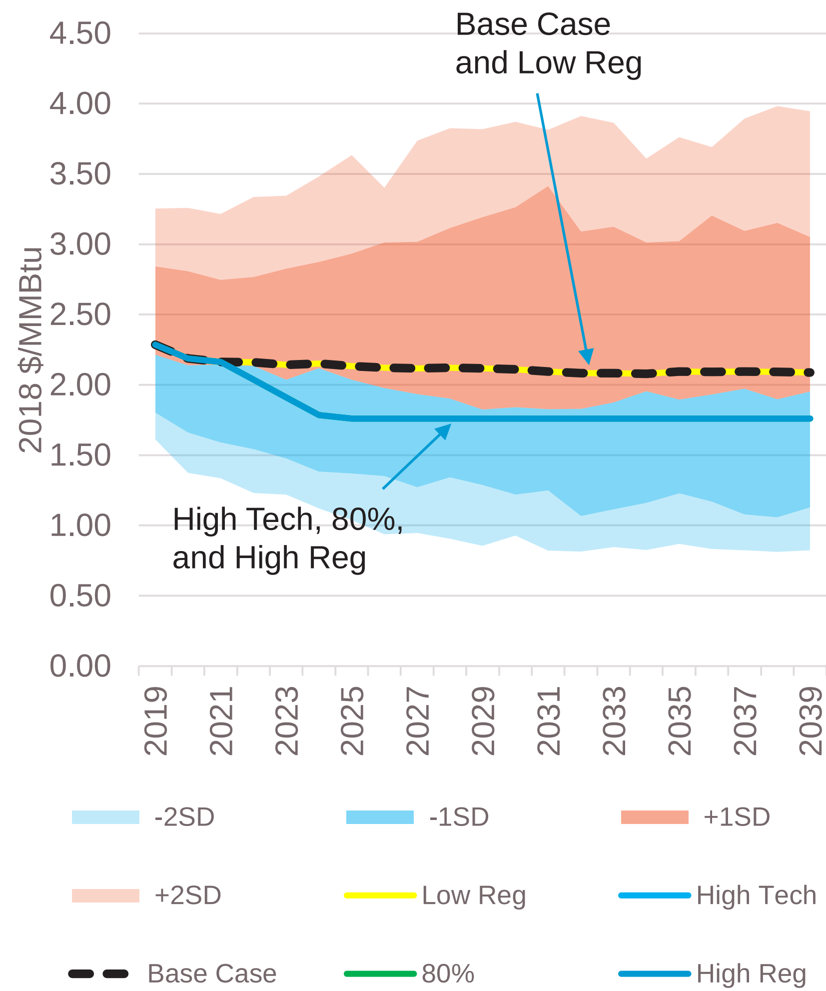


A price floor is set at $1.61/MMBtu

1 Modeling will include estimated inflation of 2.2% per year

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

	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

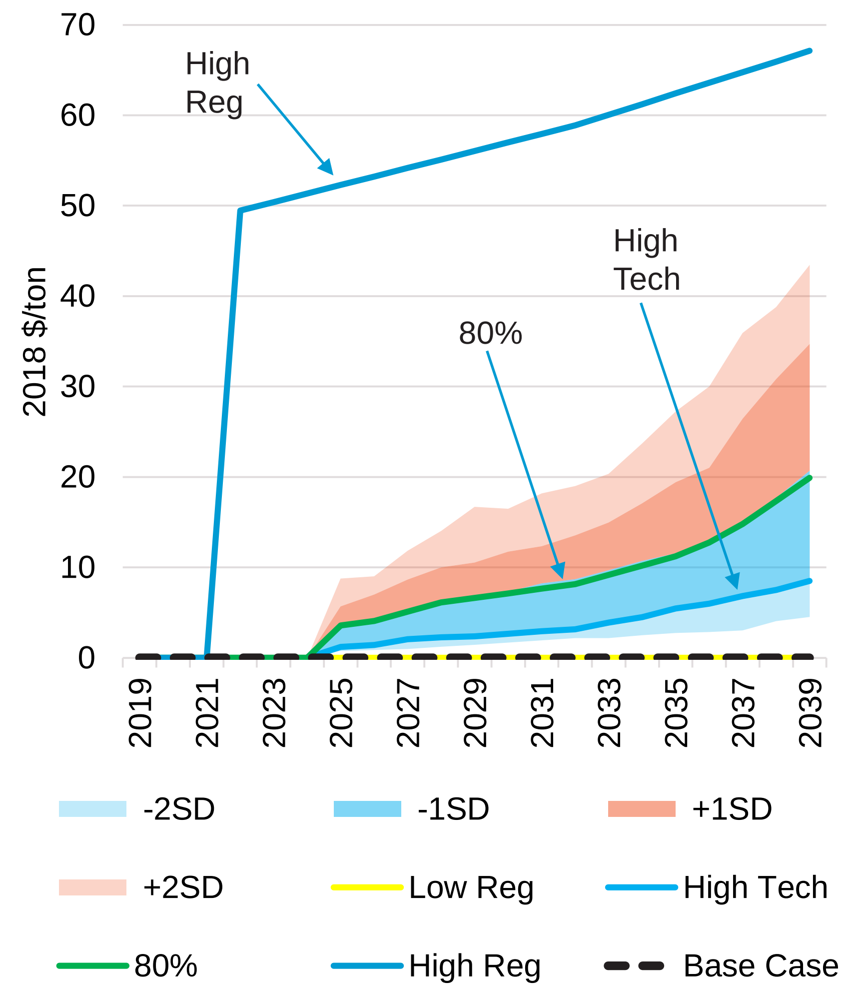


A price floor is set at $1.76/MMBtu

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)

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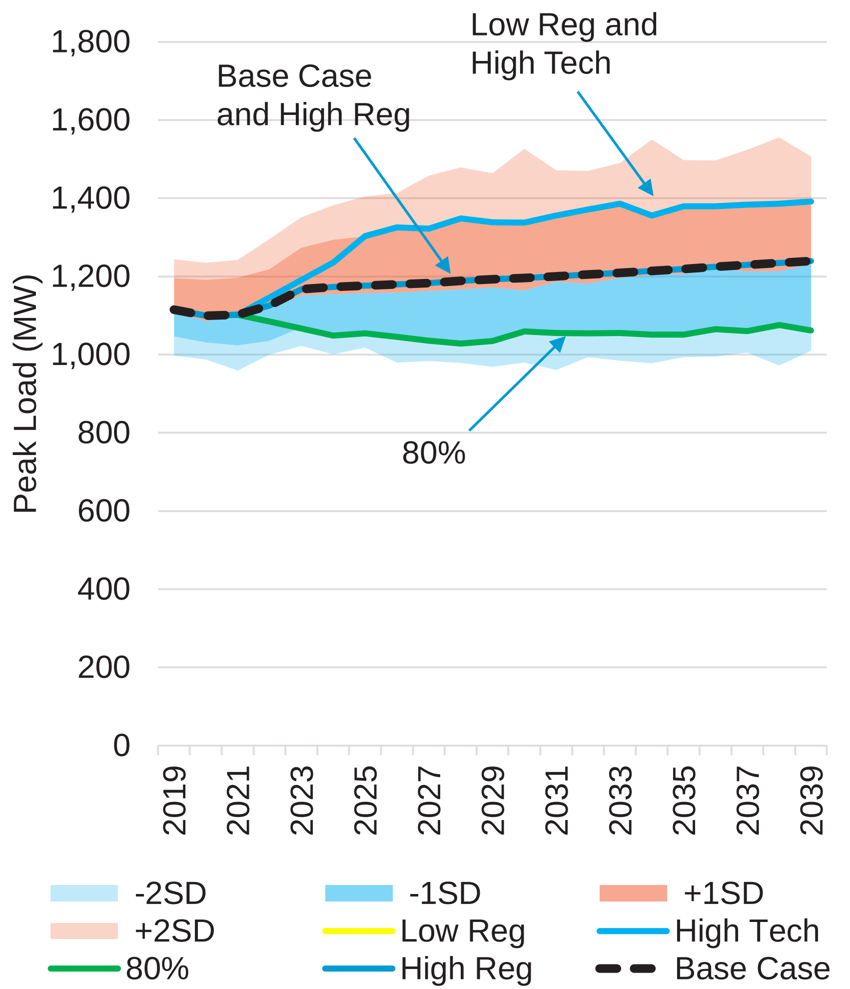
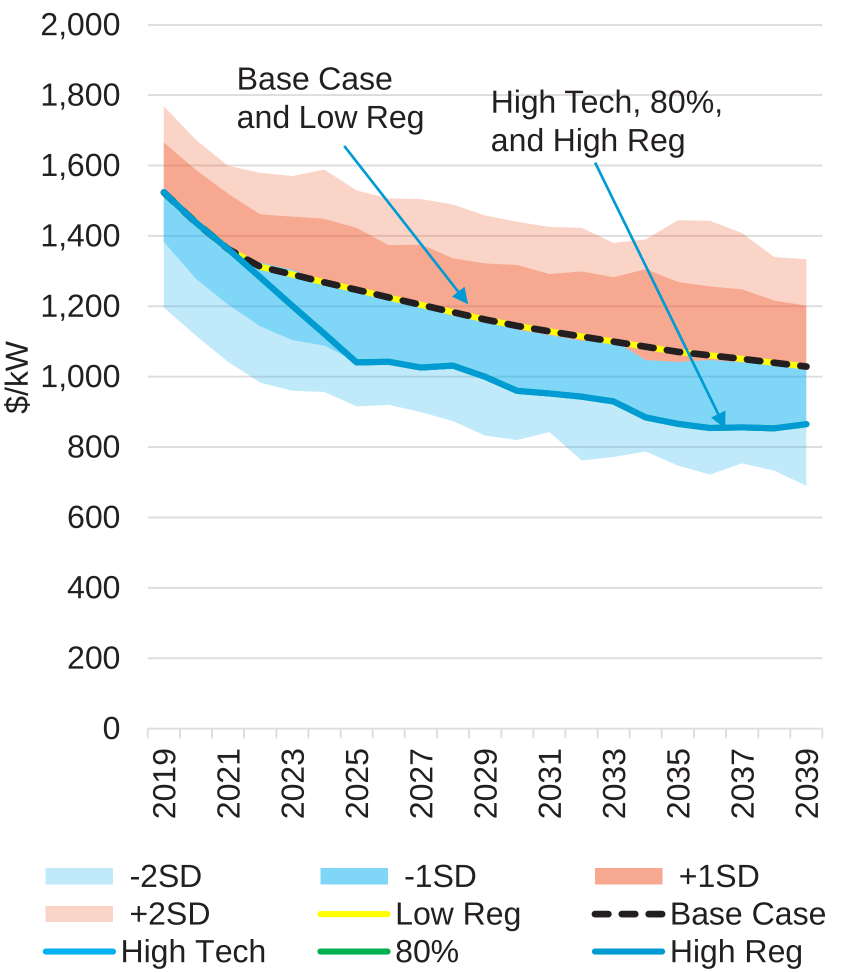
	Base Case	Low Reg	High Tech	80% Reduction	High Reg
2019	1,115	1,115	1,115	1,115	1,115
2020	1,100	1,100	1,100	1,100	1,100
2021	1,102	1,102	1,102	1,102	1,102
2022	1,126	1,146	1,146	1,084	1,126
2023	1,168	1,191	1,191	1,066	1,168
2024	1,173	1,235	1,235	1,049	1,173
2025	1,176	1,303	1,303	1,055	1,176
2026	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]

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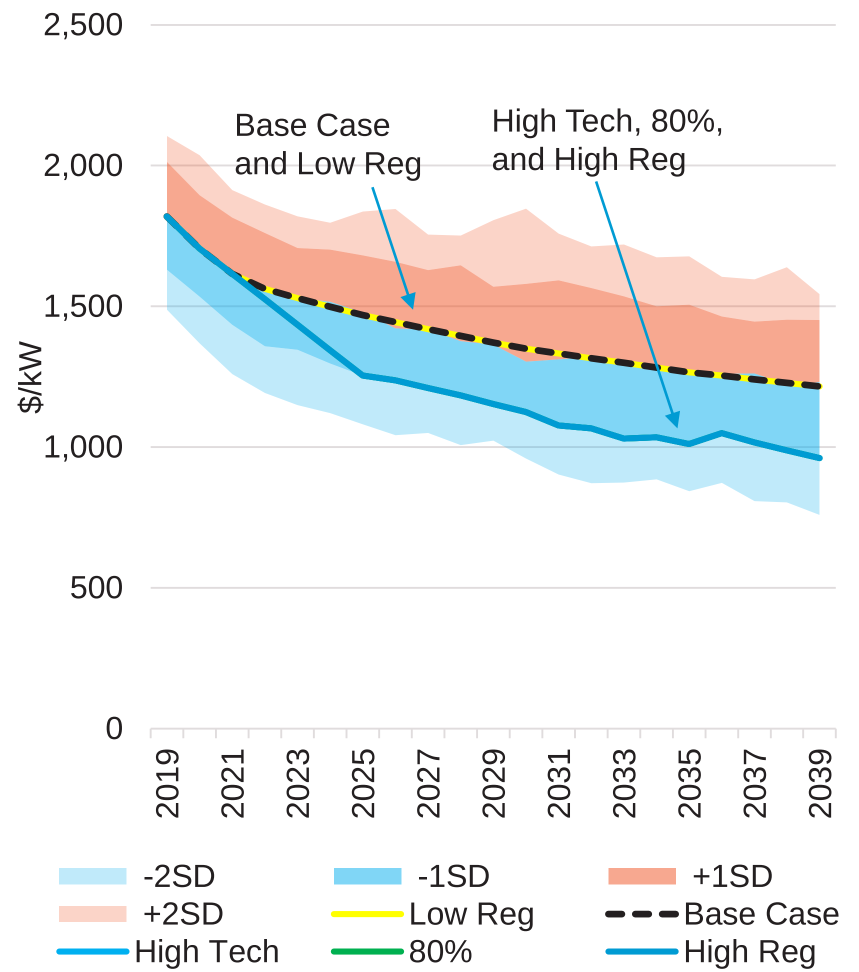
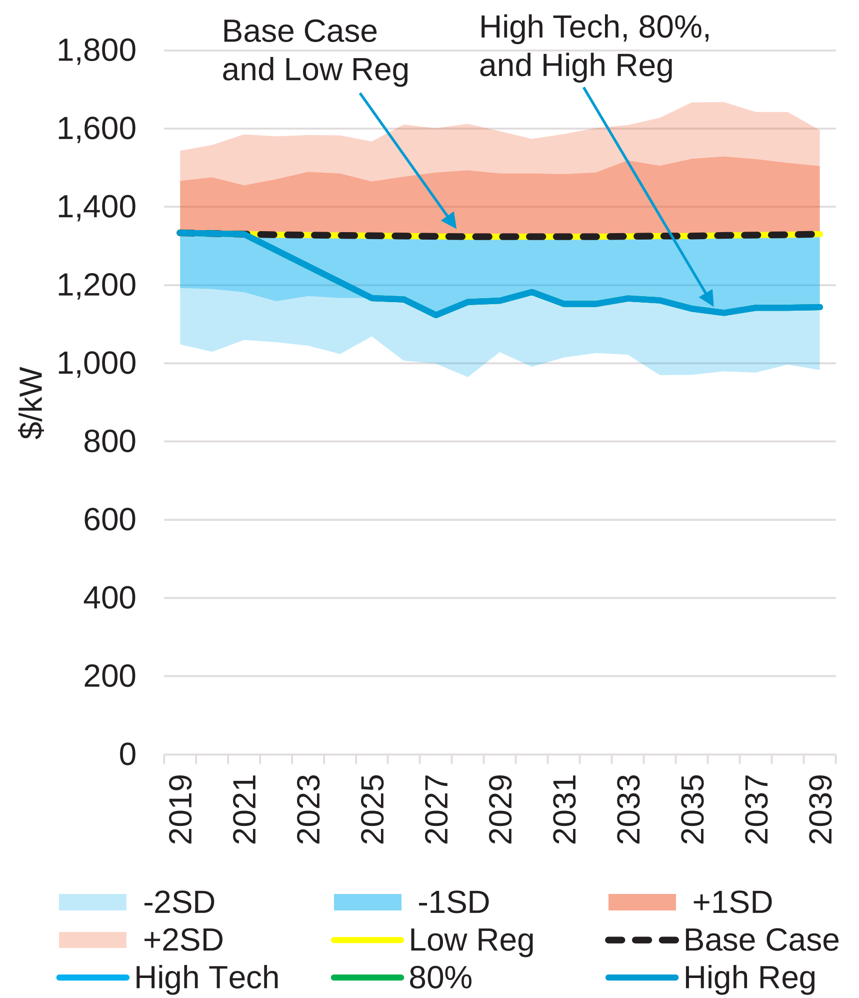
	Base Case	Low Reg	High Tech	80% Reduction	High Reg
2019	1,820	1,820	1,820	1,820	1,820
2020	1,705	1,705	1,705	1,705	1,705
2021	1,616	1,616	1,616	1,616	1,616
2022	1,562	1,562	1,526	1,526	1,526
2023	1,529	1,529	1,435	1,435	1,435
2024	1,499	1,499	1,344	1,344	1,344
2025	1,469	1,469	1,254	1,254	1,254
2026	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

VECTREN
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LONG-TERM BASE ENERGY AND DEMAND FORECAST

Michael Russo, Sr. Forecast Consultant

Itron

FORECAST SUMMARY

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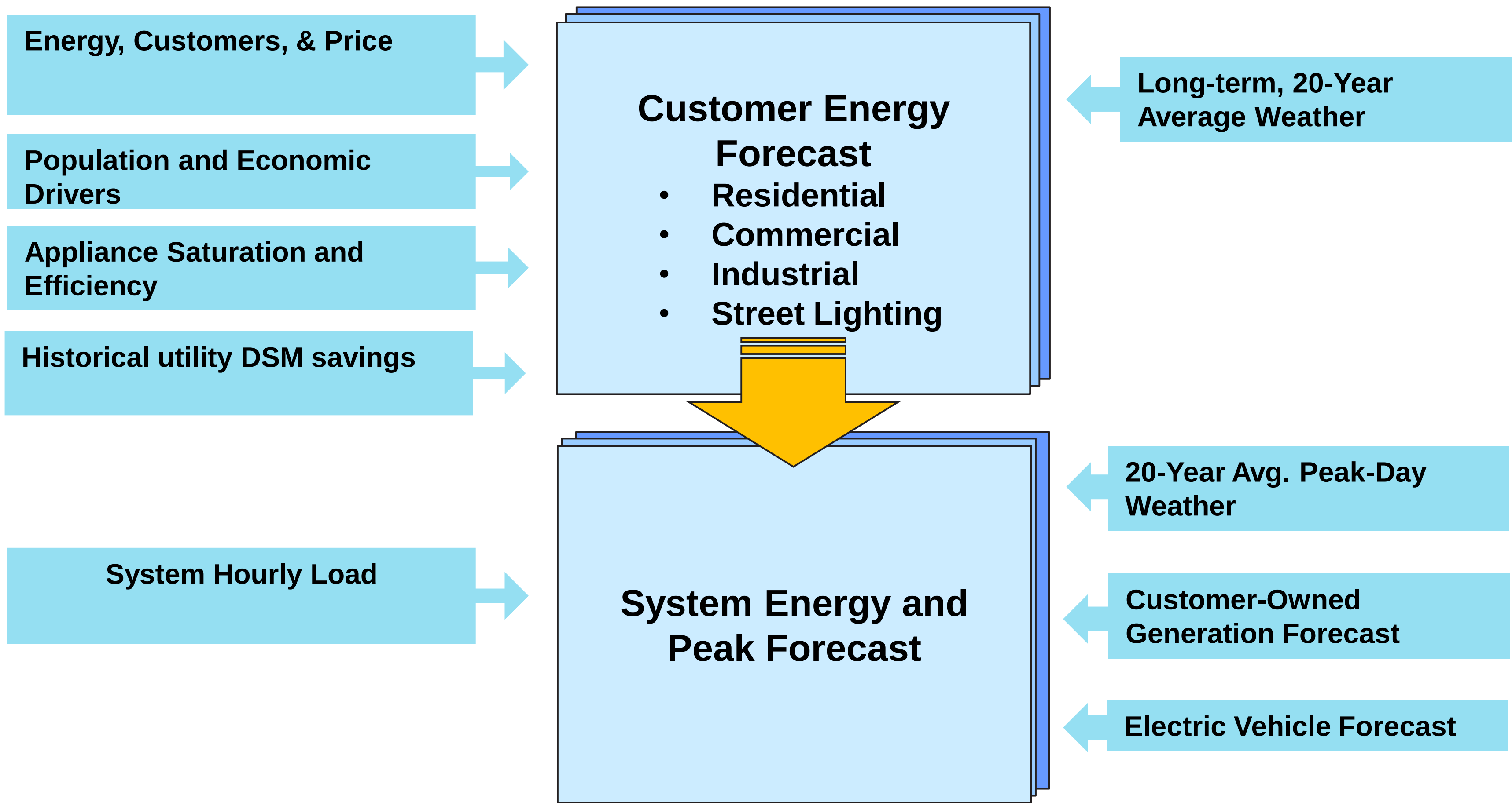
- Moderate energy growth
  - Annual energy and demand growth of 0.6%[1]
  - Slow long-term population growth (0.2% annual growth) & moderate output growth (1.7% annual growth)
  - Strong end-use efficiency gains reflecting new and existing Federal codes and standards
    - Air conditioning, heating, 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

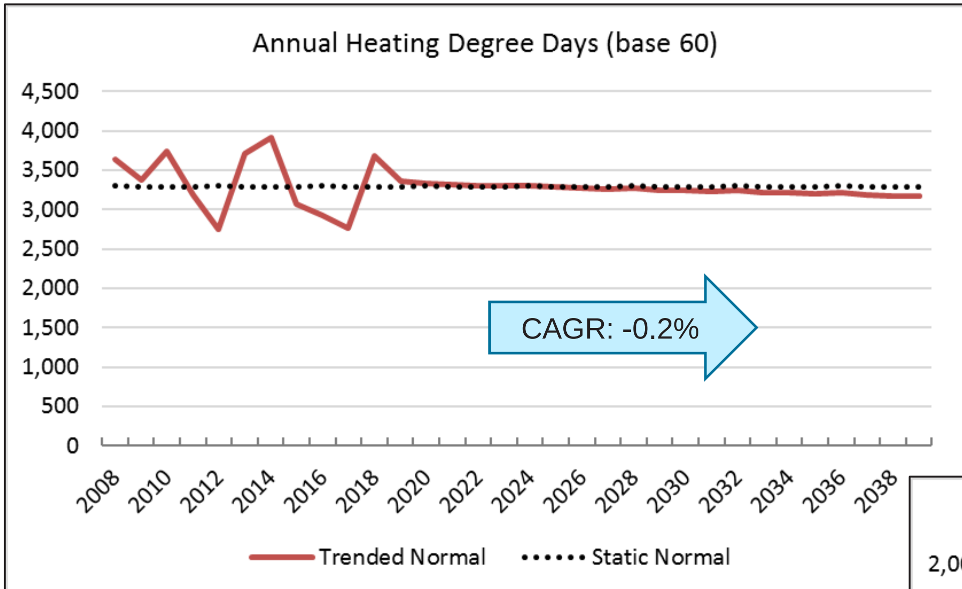


ECONOMIC DRIVERS

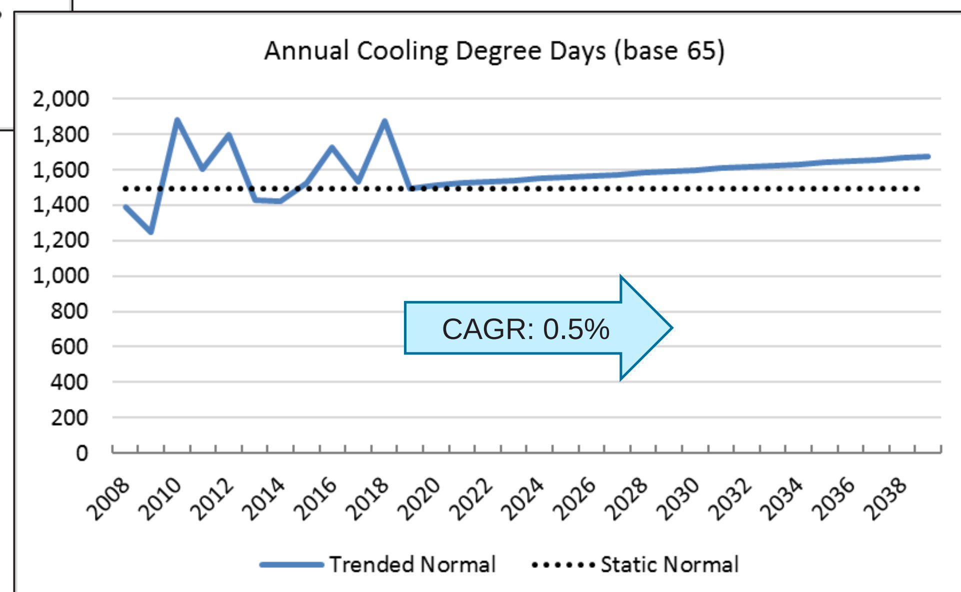
Moody's Analytic forecast for the Evansville MSA

- 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

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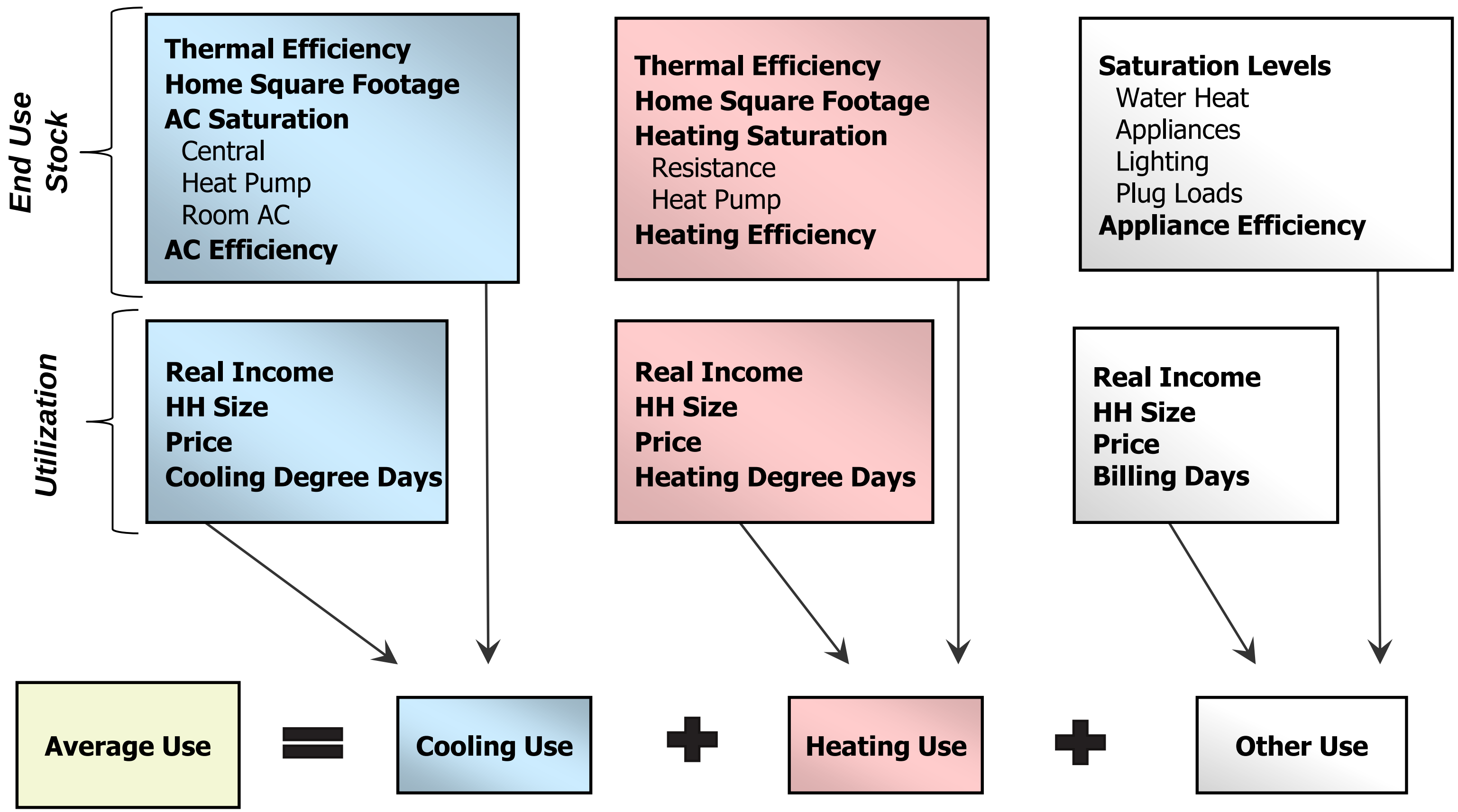
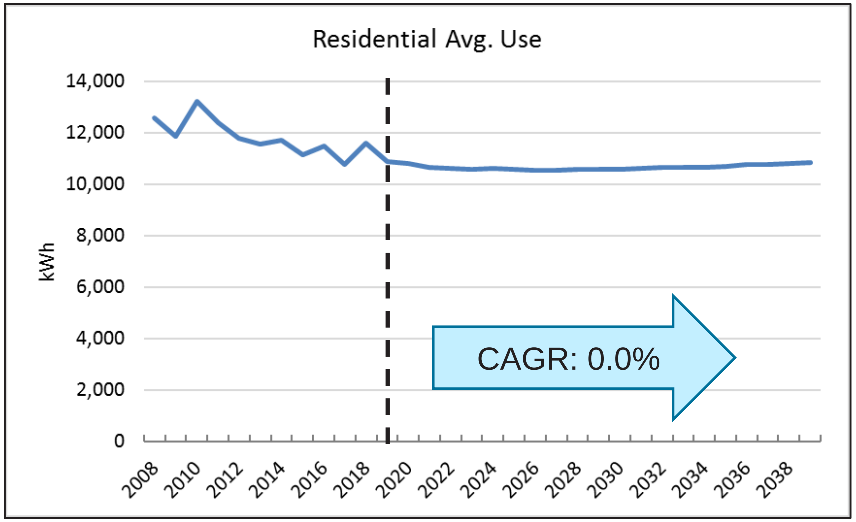
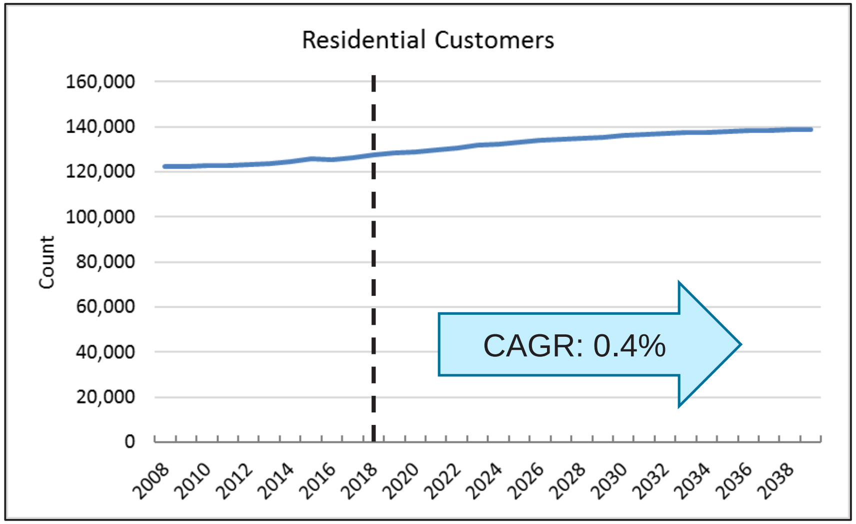


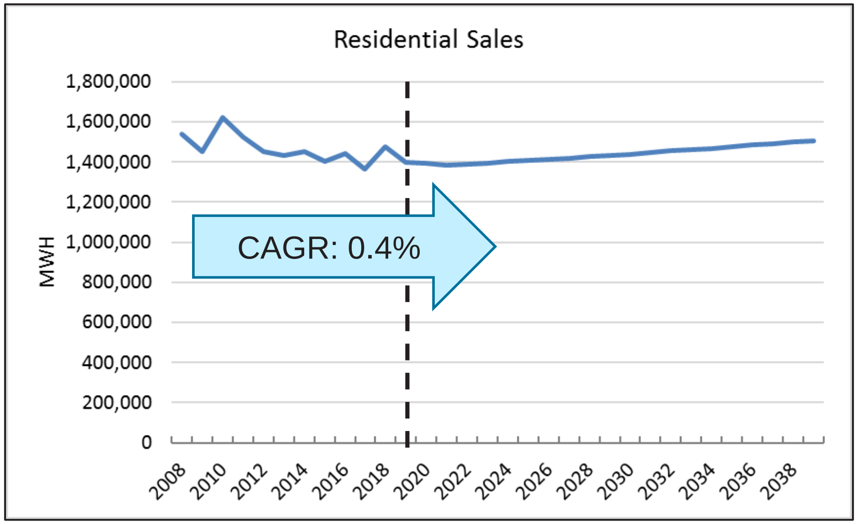
Cause No. 45564

RESIDENTIAL FORECAST





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



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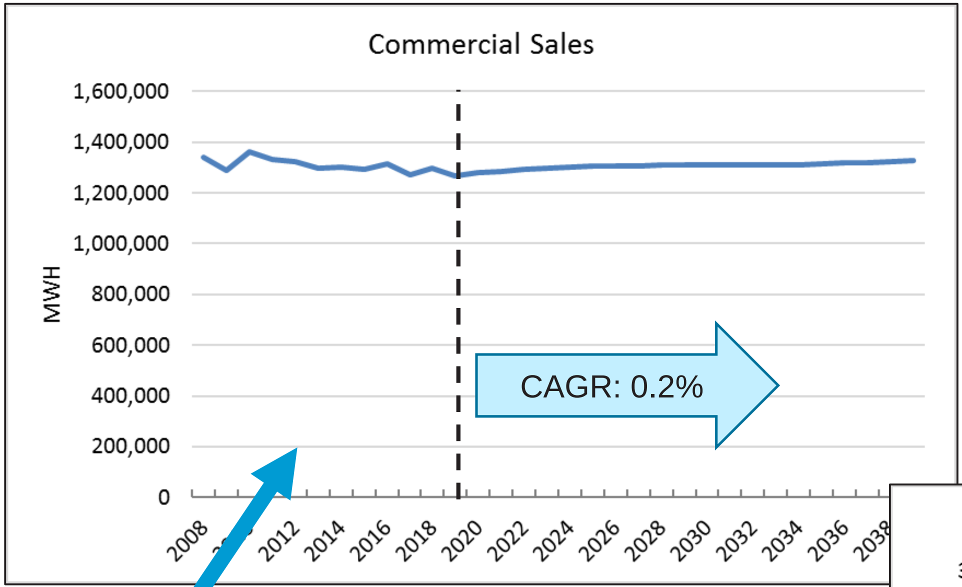
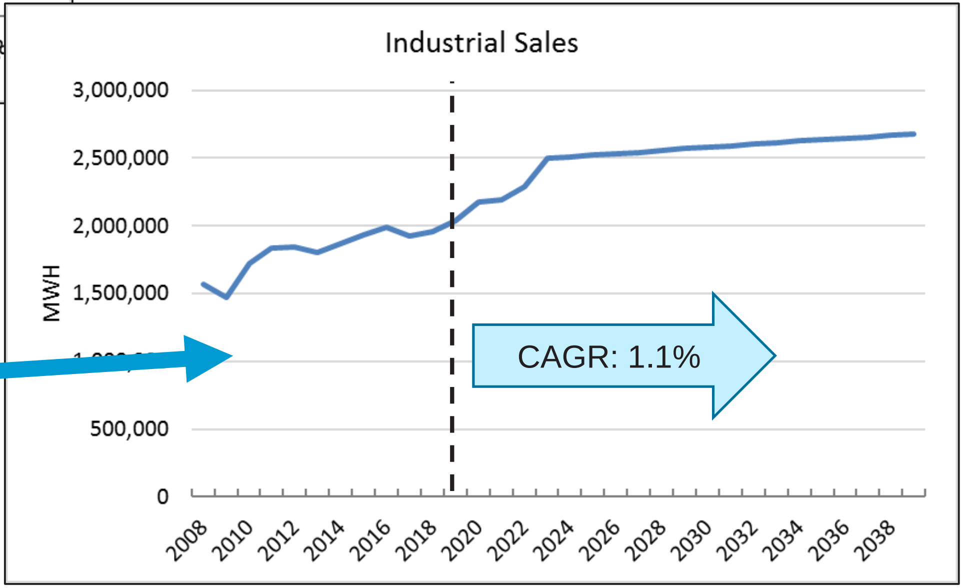
C&I SALES FORECAST





- 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

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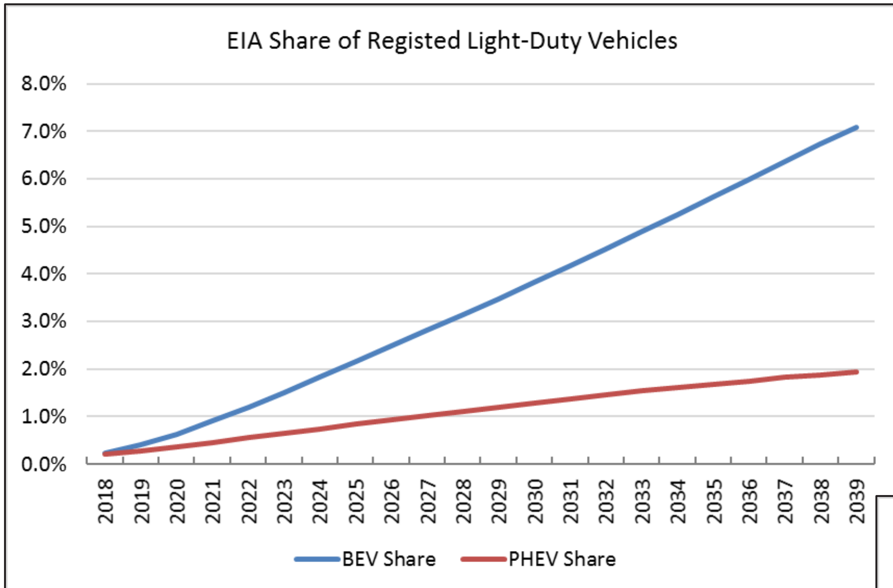
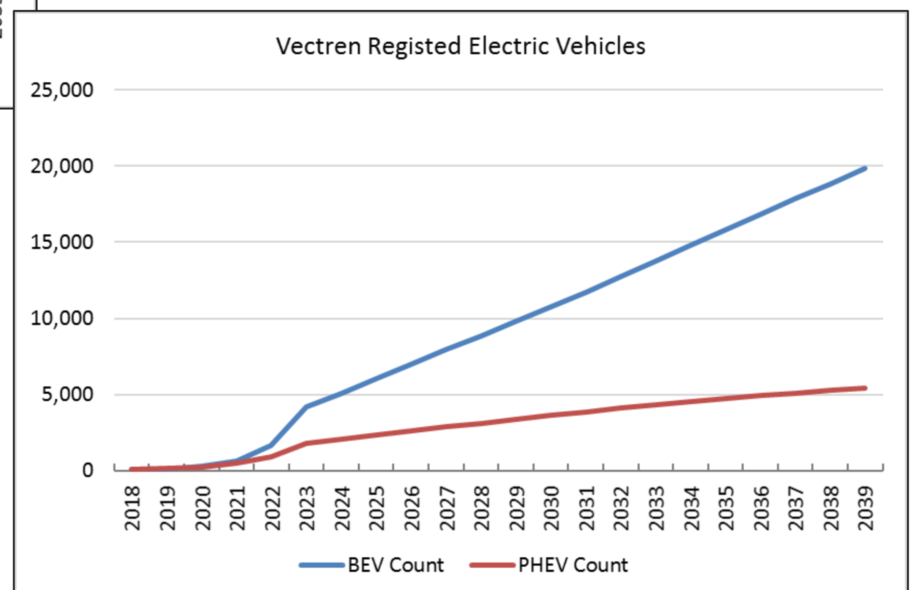
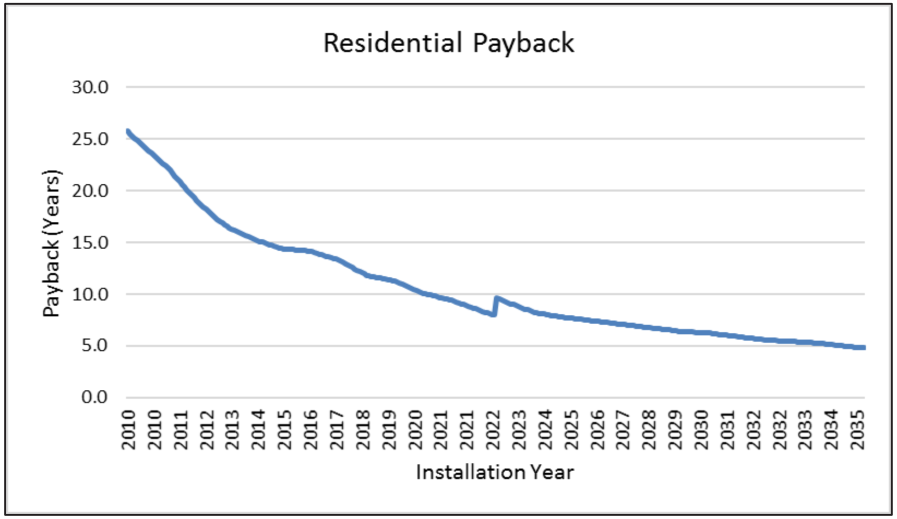


- Energy Information Administration (EIA) forecast based on share of total registered vehicles; differentiating between all electric (BEV) and plug-in hybrid electric (PHEV)

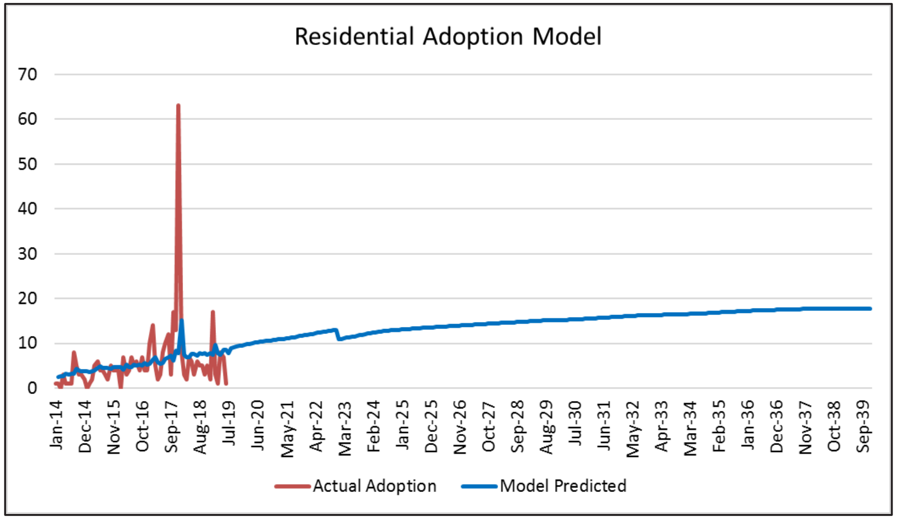
- Average annual kWh per vehicle based on weighted average of current registered BEV/PHEV
  - 3,752 kWh per BEV
  - 2,180 kWh per PHEV



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

Cause No. 45564

ENERGY & DEMAND FORECAST

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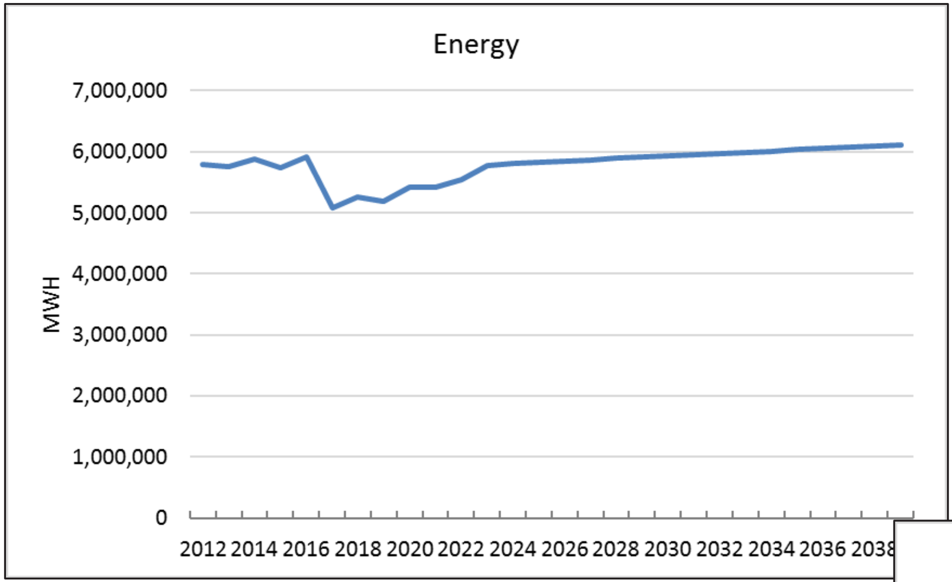

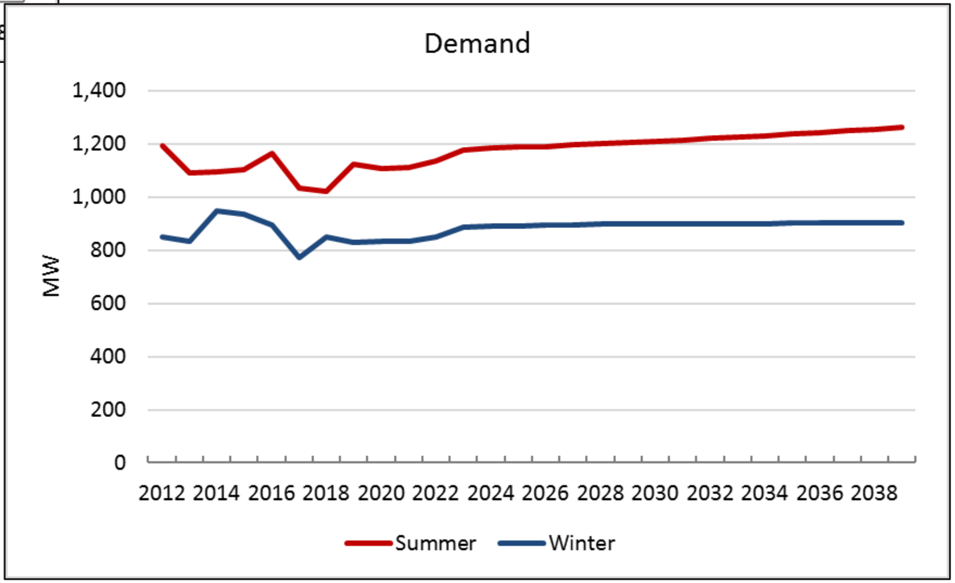

- Combining economic growth, end-use efficiency, and adoption of new technologies, and trended weather results in 0.6% long-term energy and summer demand CAGR (2020-2039)*

* 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

VECTREN
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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

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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

VECTREN
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- 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 • Air heater • Variable Frequency Drives • Boiler program • Condenser work • 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.)

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A CenterPoint Energy Company

- 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 • Air heater Upgrade • Variable Frequency Drives • Boiler Program • Condenser Upgrade • 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
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- 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

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- 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.)

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- 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 • Dry Fly Ash Conversion • 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 • Variable Frequency Drives • Boiler program • Condenser work • 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

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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.)

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- 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

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POTENTIAL NEW RESOURCES AND MISO ACCREDITATION

MATT LIND,

RESOURCE PLANNING & MARKET ASSESSMENTS BUSINESS LEAD, BURNS & MCDONNELL

NEW RESOURCE AND MISO ACCREDITATION SUMMARY

- 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

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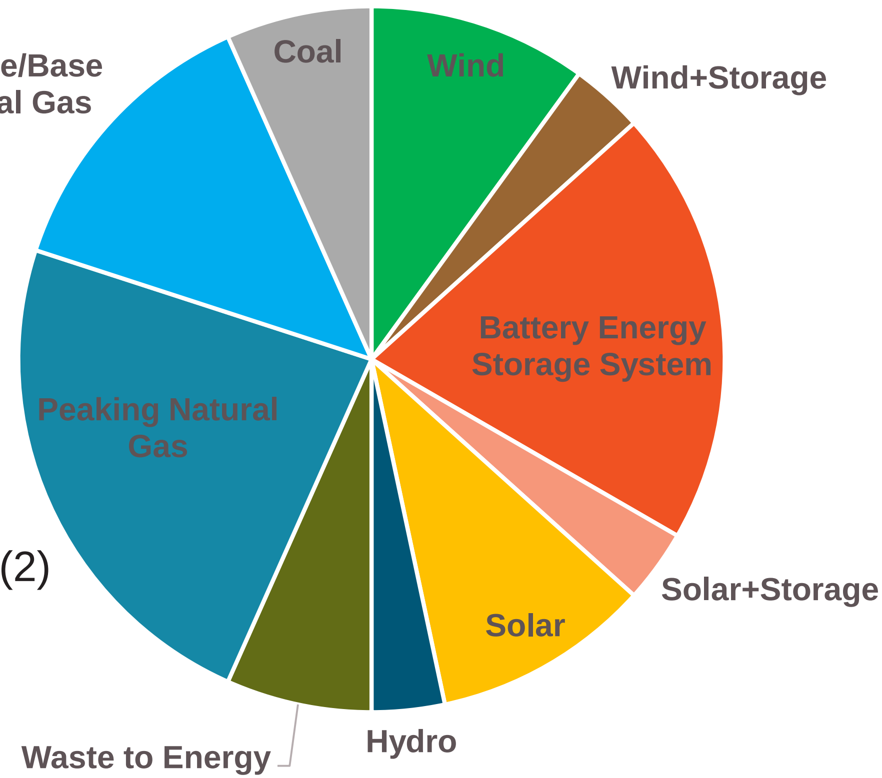
- Base Case Inputs for new power supply options
- Consensus estimates from Burns & McDonnell, Pace Global, and NREL for solar and storage resources
- Supplemental to RFP Bid data
- Resource Options (30):
  - Wind (3)
  - Wind + Storage (1)
  - Solar Photovoltaic (3)
  - Solar + Storage (1)
  - Hydro (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

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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

VECTREN
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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

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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

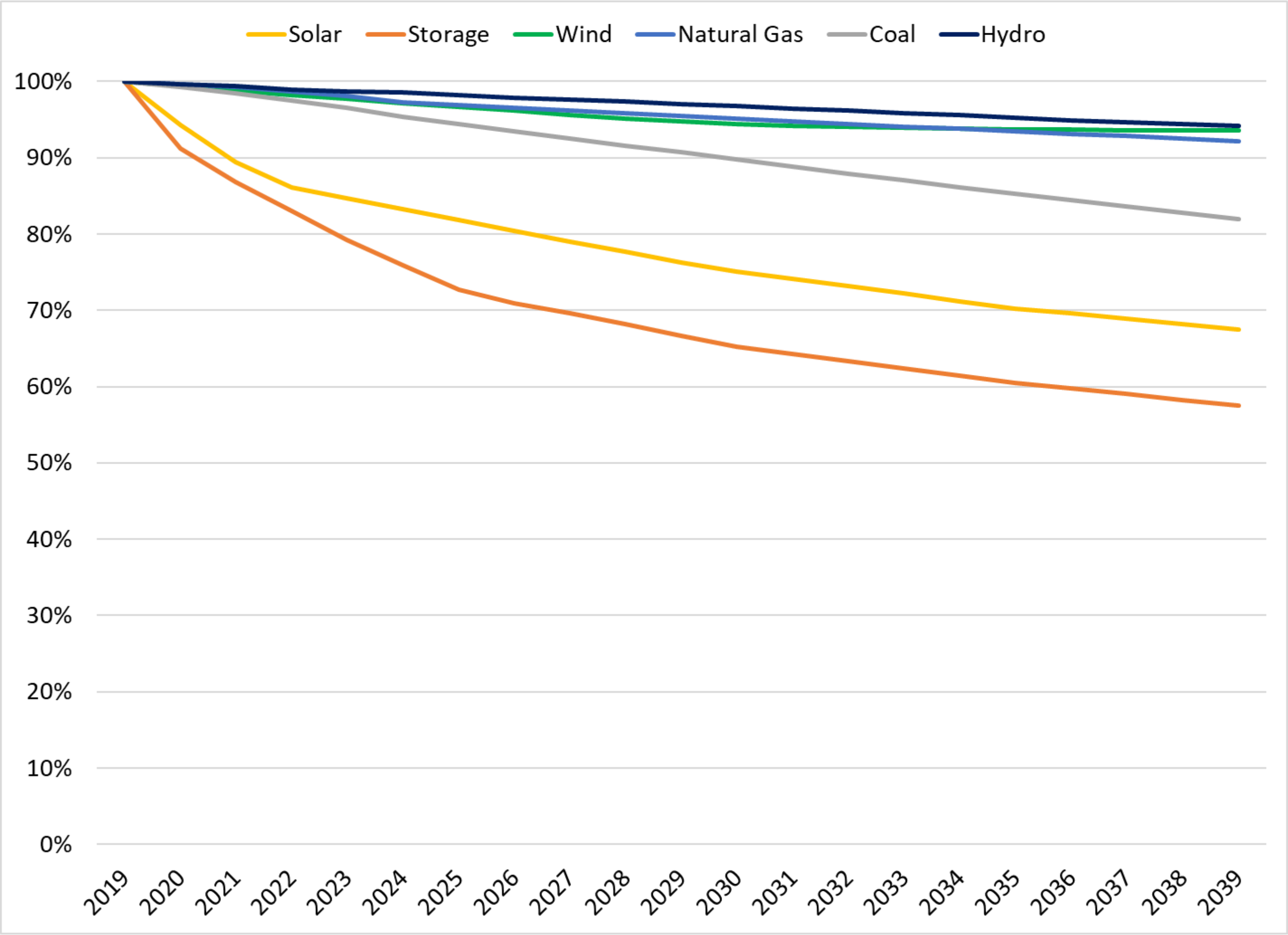
Notes:
In 2019 dollars, the Cannelton hydro project (~84 MW) total cost was approximately $5,500/kW (US Army Corps of Engineers press release)
Transmission upgrades required for the Uniontown dam are estimated at $14 million
Transmission upgrades required for the Newburgh dam are estimated at $10 million

TECHNOLOGY DETAILS

Examples of candidates for coal generation:

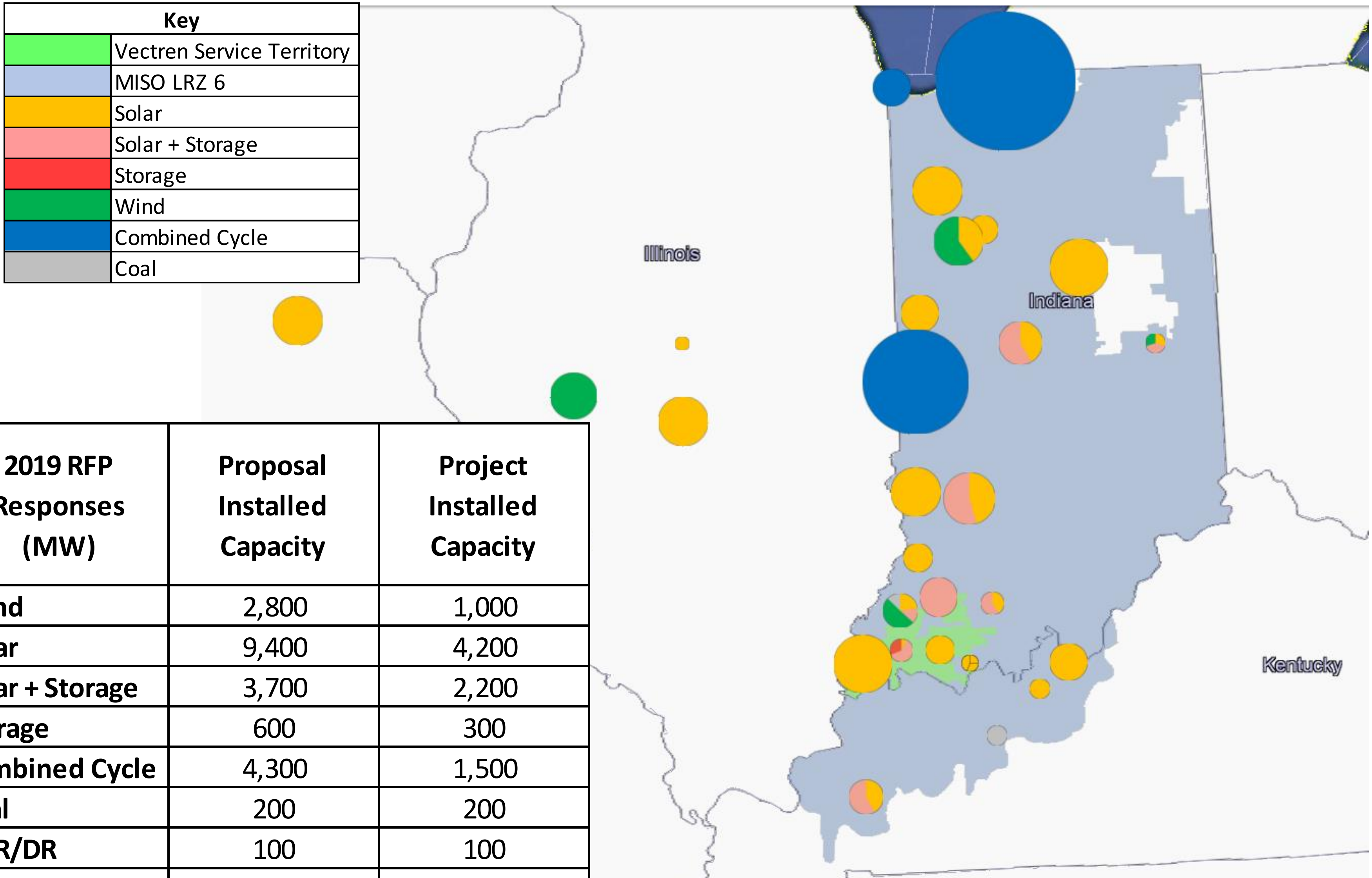
Coal Fired	Example 1	Example 2
Combustion Turbine Type	Supercritical Pulverized Coal with Carbon Capture	Ultra-Supercritical Pulverized Coal with Carbon Capture
Size (MW)	506 MW	747 MW
Fixed O&M (2019 $/kW-yr)	$29	$29
Total Project Costs (2019 $/kW)	~$6,100	~$5,500

FORWARD COST ESTIMATES



Cause No. 45564

PROPOSAL LOCATION REVIEW



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

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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
CapitalDynamics TRULY INVESTED.
TENASKA

PROPOSAL GROUPING

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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

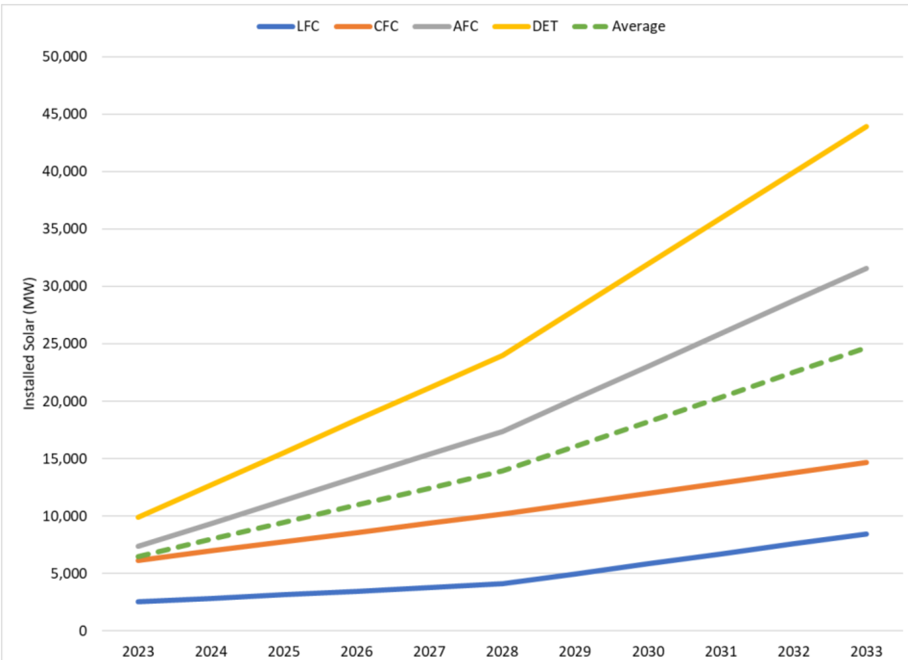
Tier 2
- Non-Binding Pricing
- Congestion / delivery risk

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

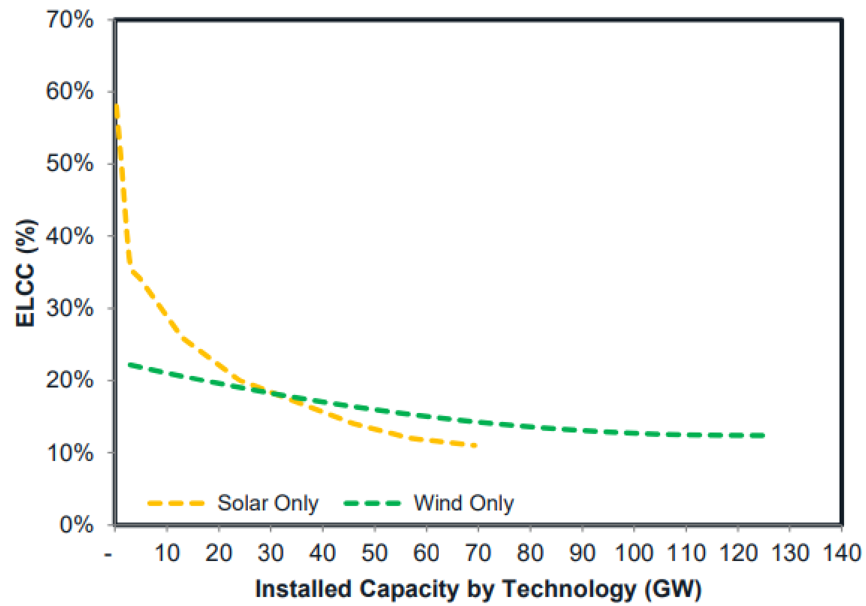
MISO RENEWABLE PENETRATION TRENDS

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

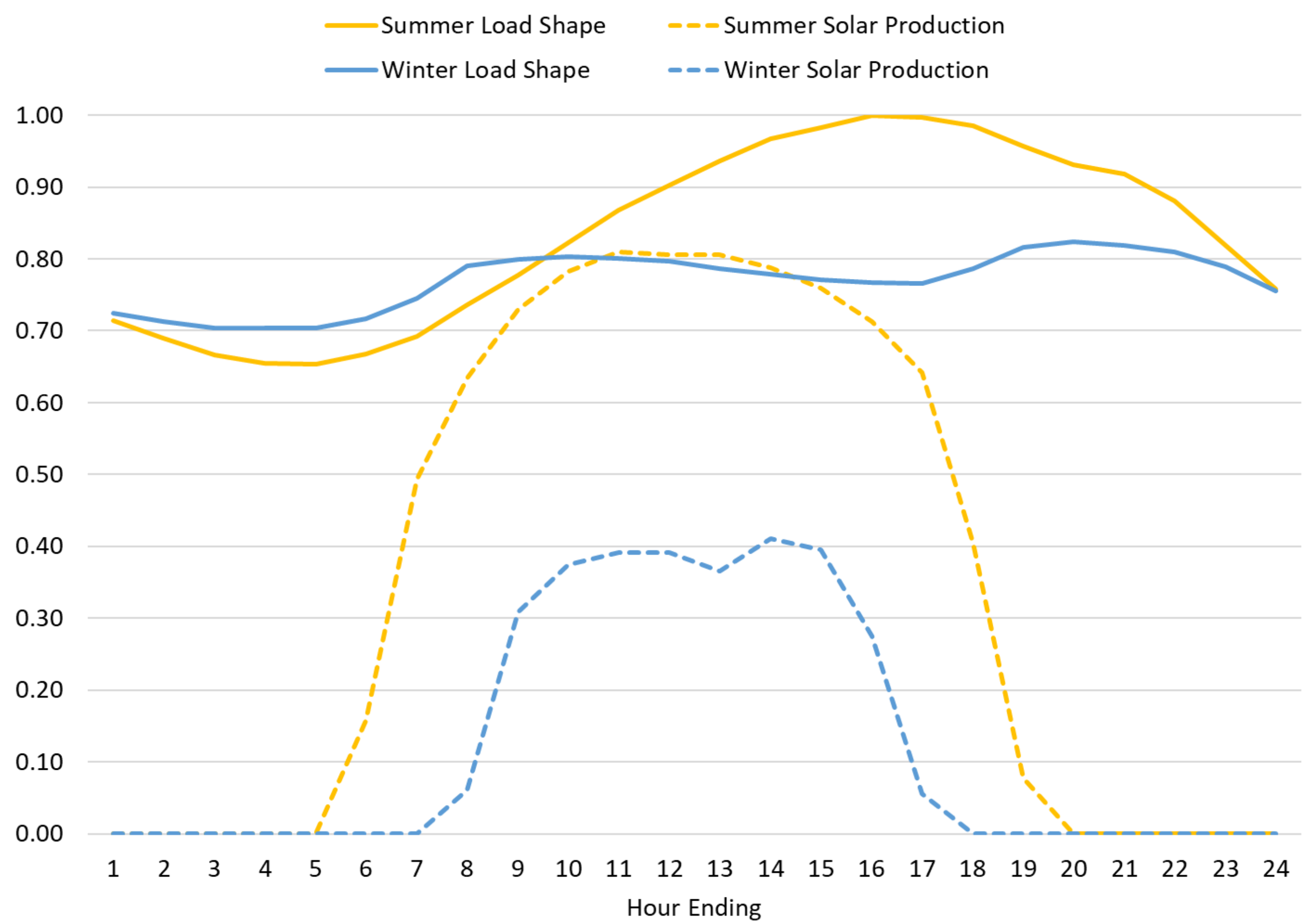


https://cdn.misoenergy.org/RIIA%20Assumptions%20Doc_v7429759.pdf

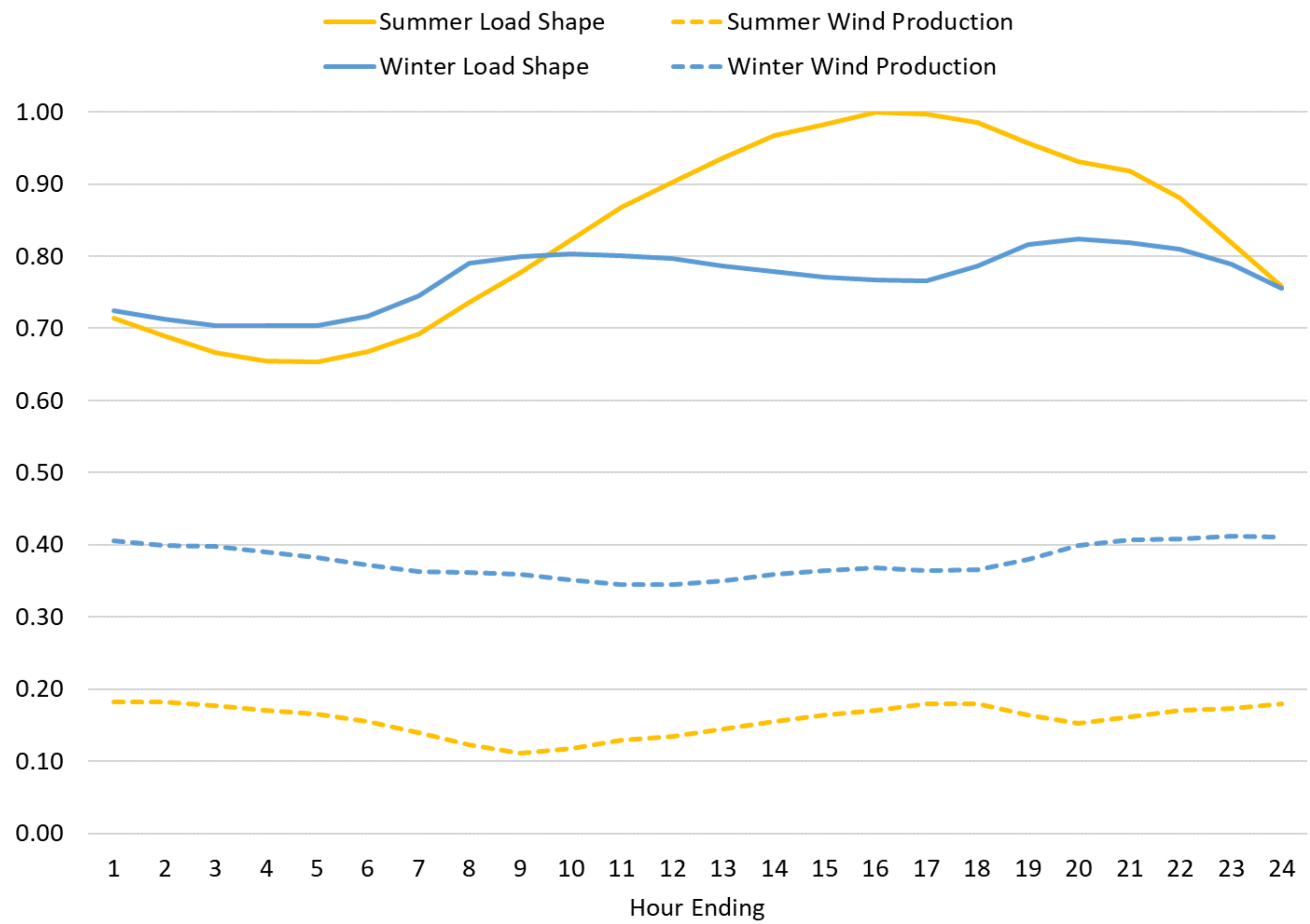
As installed capacity (ICAP) goes ⬆… Accreditable capacity (UCAP) goes ⬇

ELCC – Effective Load Carrying Capability

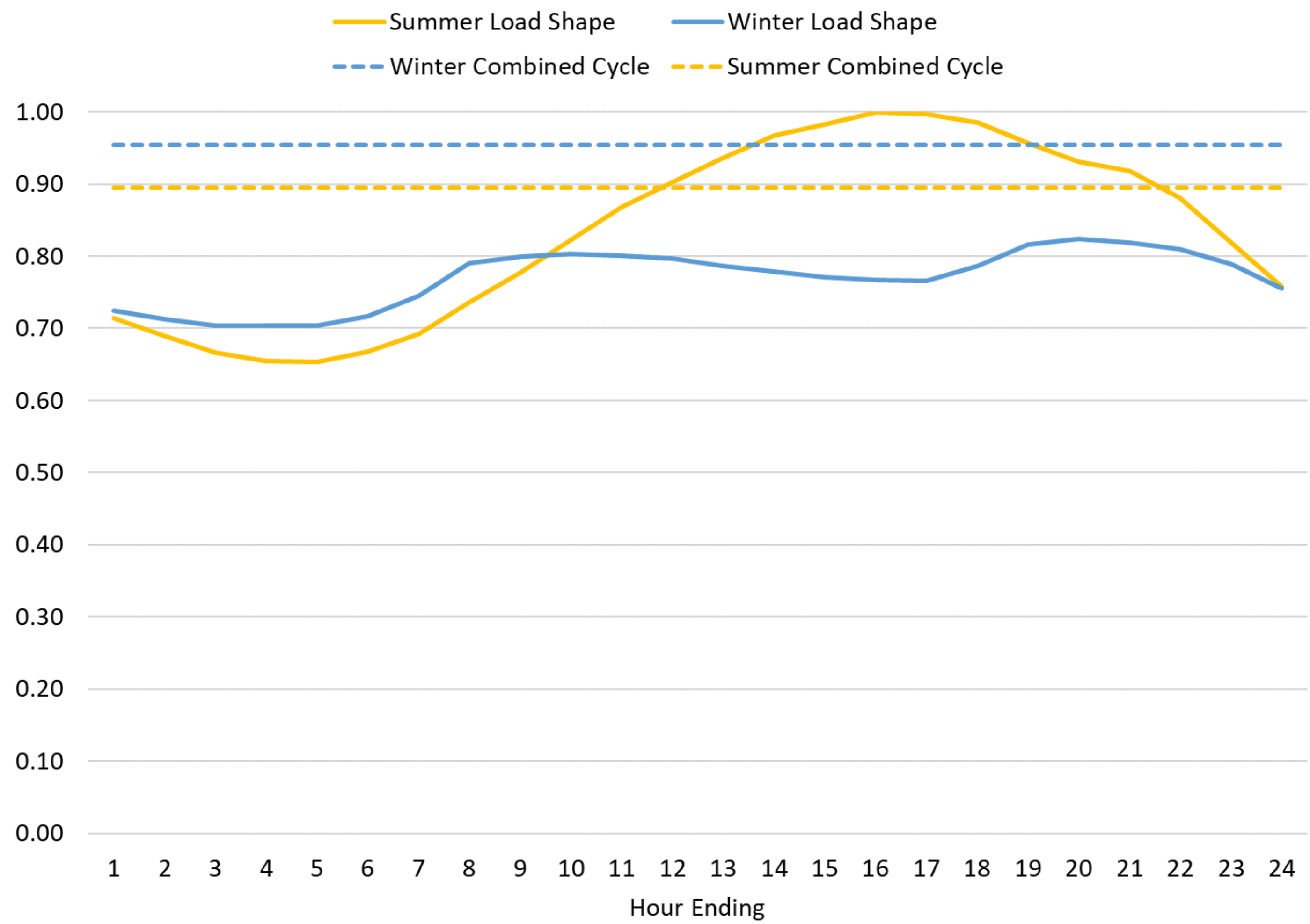
SOLAR SEASONAL DIFFERENCES



WIND SEASONAL DIFFERENCES



COMBINED CYCLE SEASONAL DIFFERENCES



ZONE 6 SEASONAL ACCREDITATION

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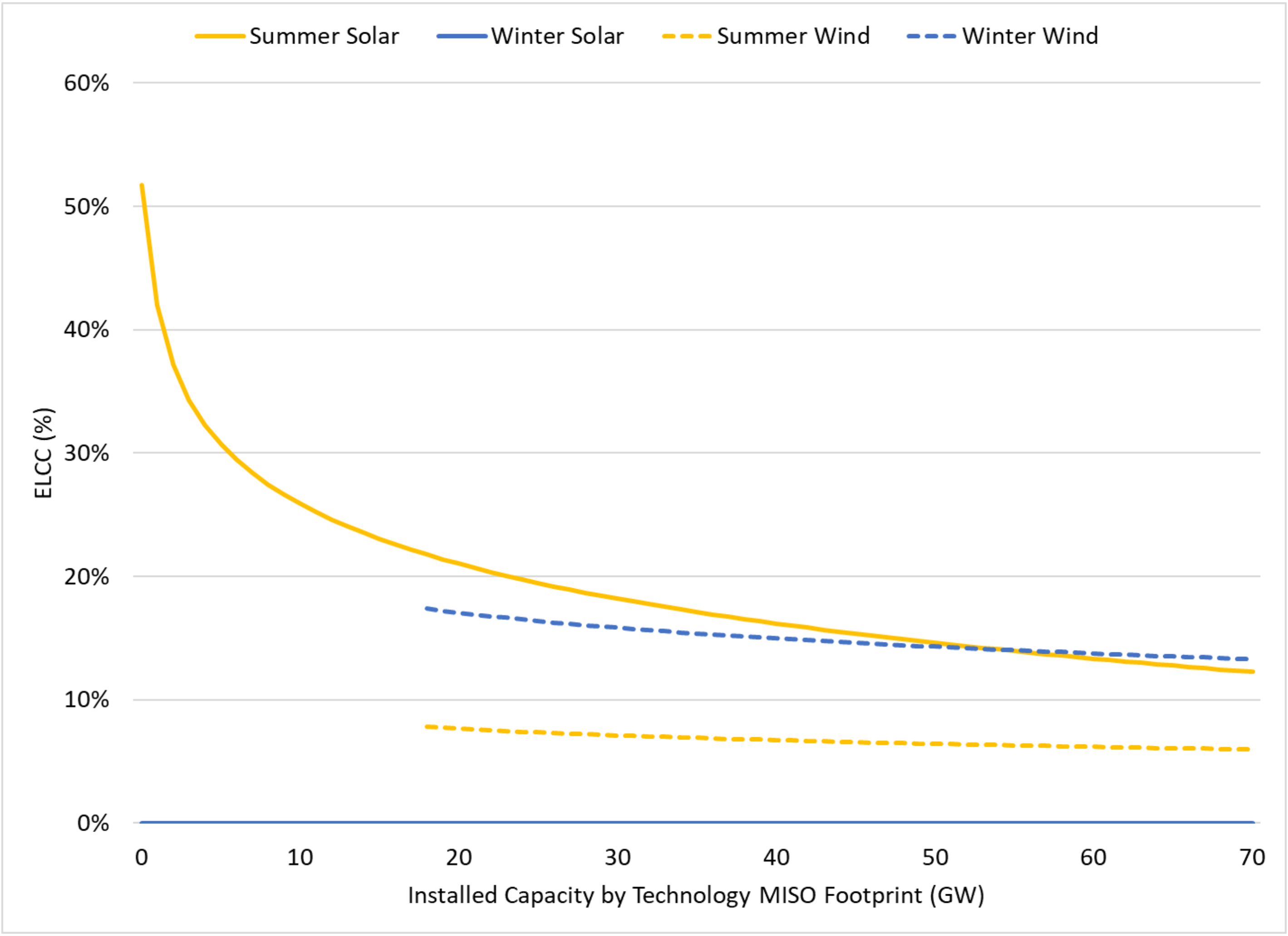

Winter accreditation based on similar methodology to summer

SEASONAL CAPACITY CREDIT FORECAST

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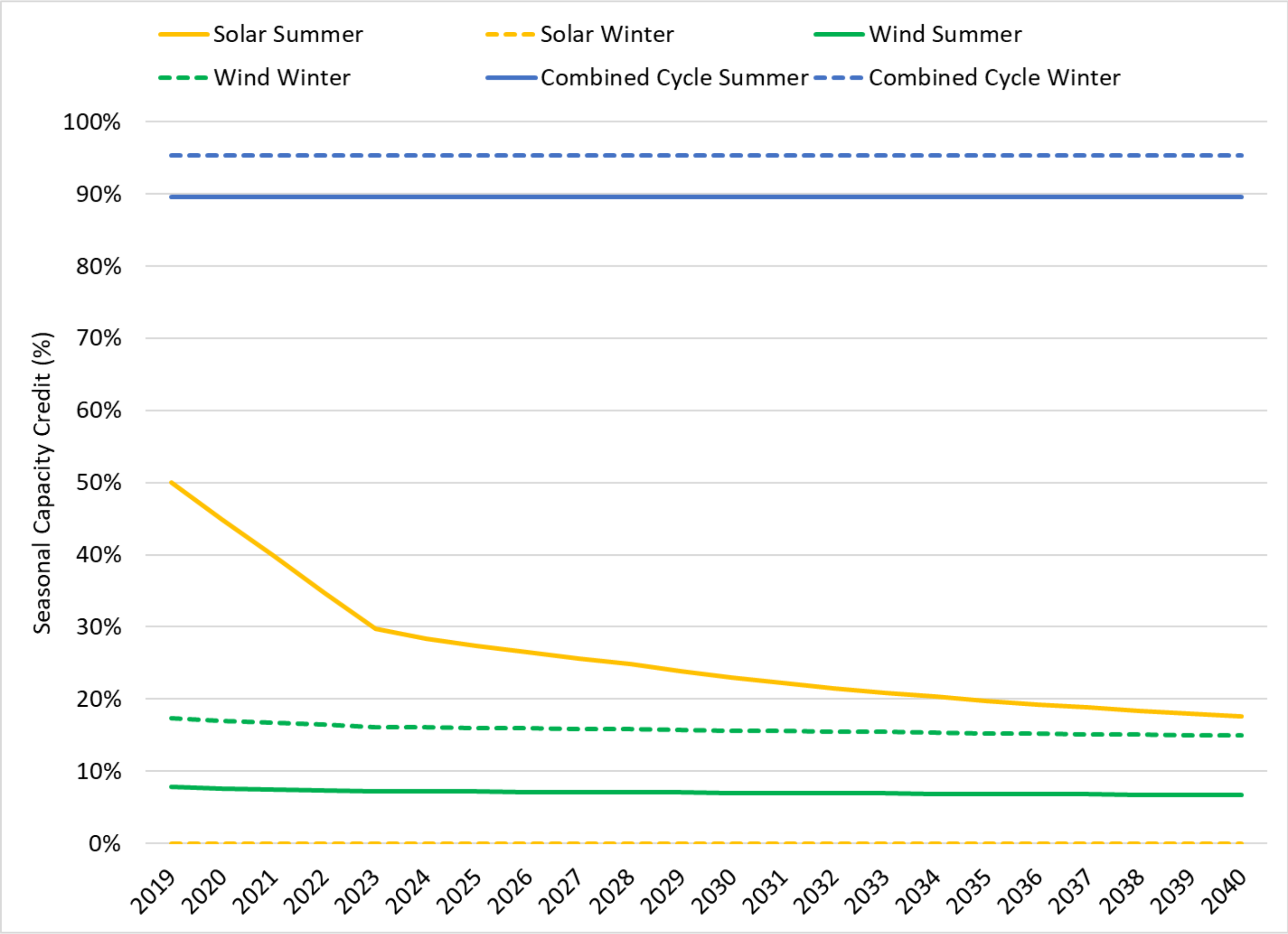

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DSM MODELING IN THE IRP

JEFFREY HUBER

MANAGING DIRECTOR, GDS ASSOCIATES

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

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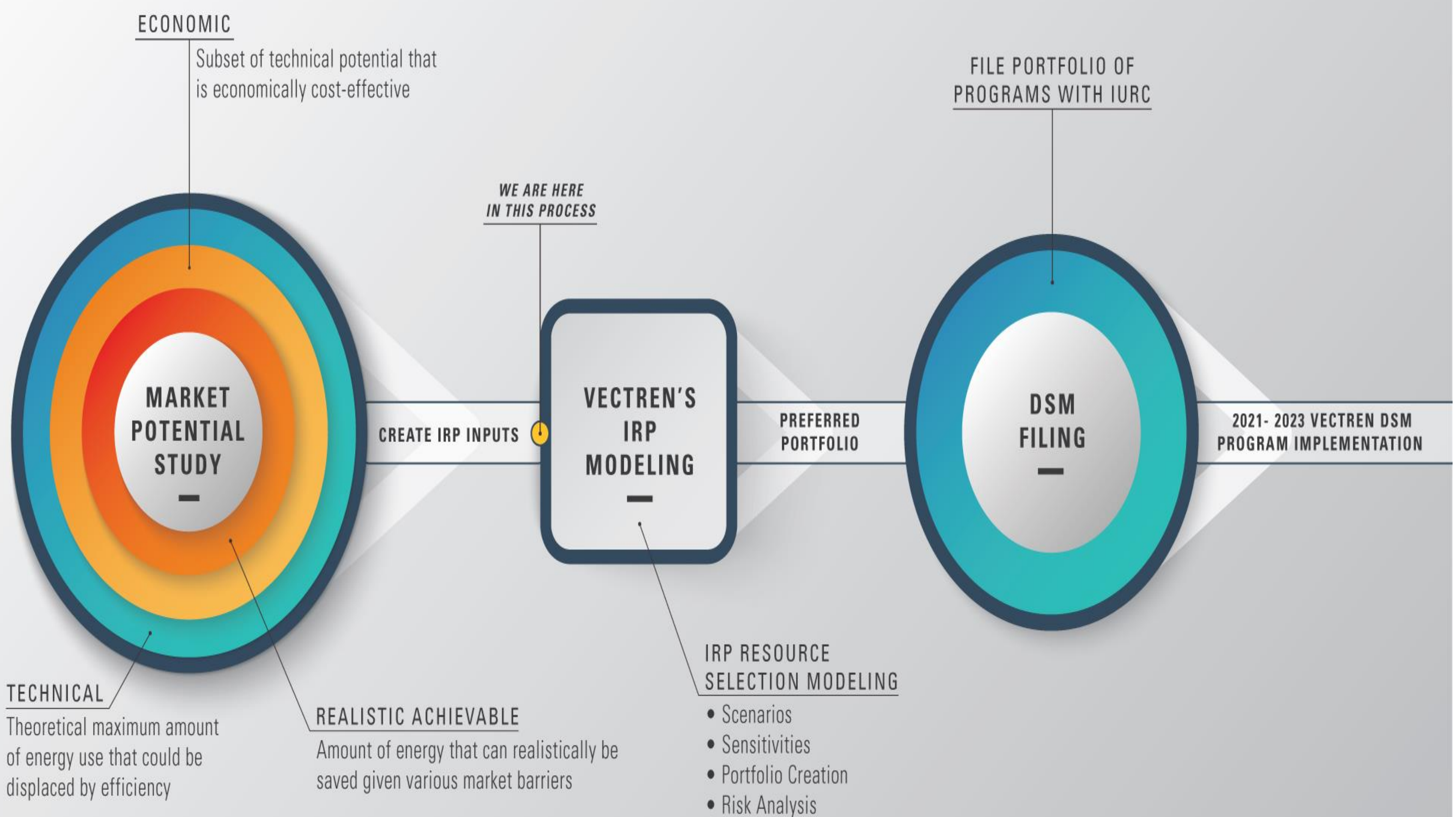

ENERGY EFFICIENCY MODELING ASSUMPTIONS

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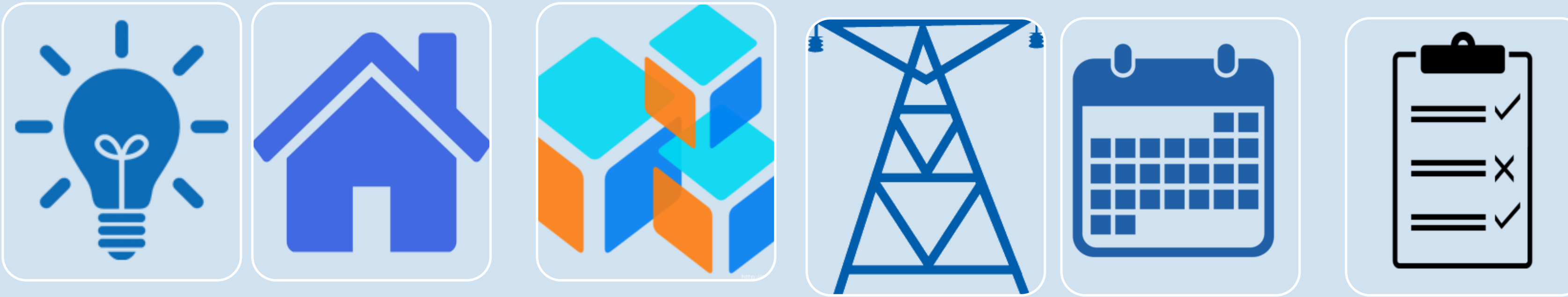

No minimum level of EE has been embedded into our sales and demand forecast

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

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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

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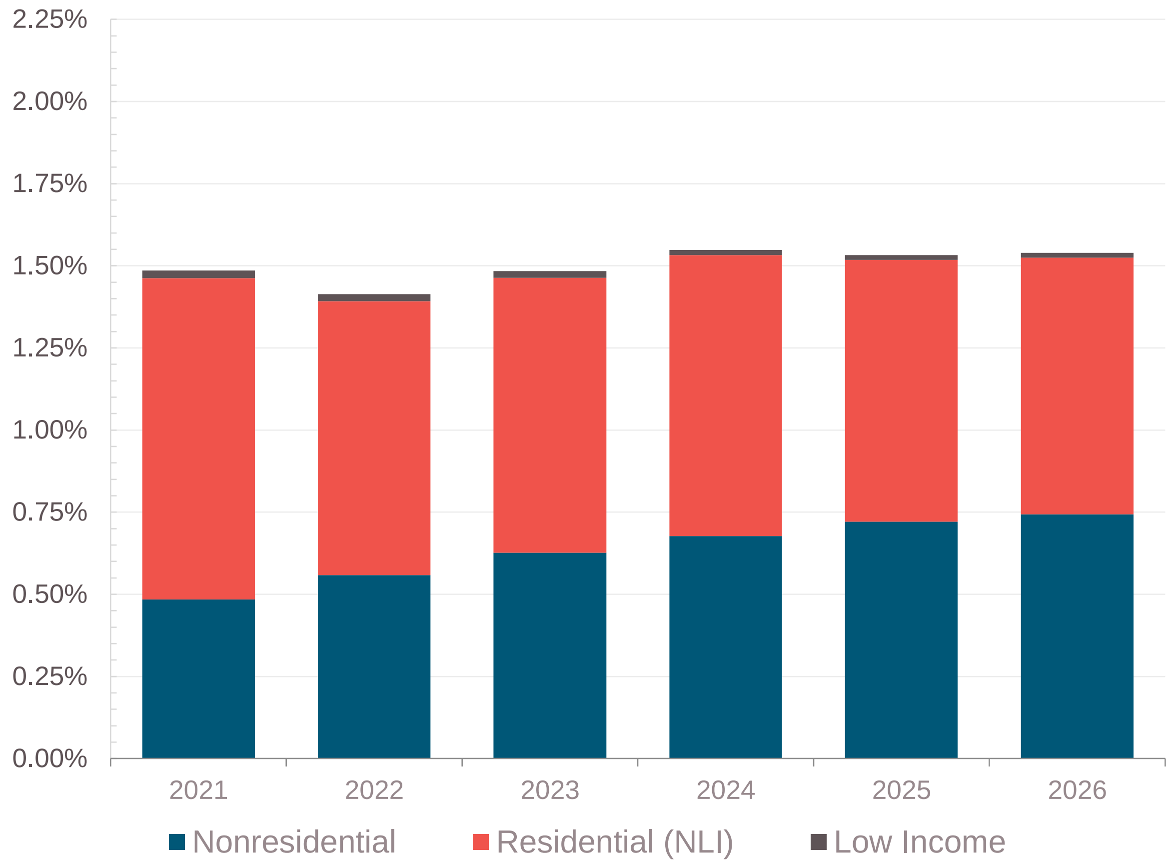
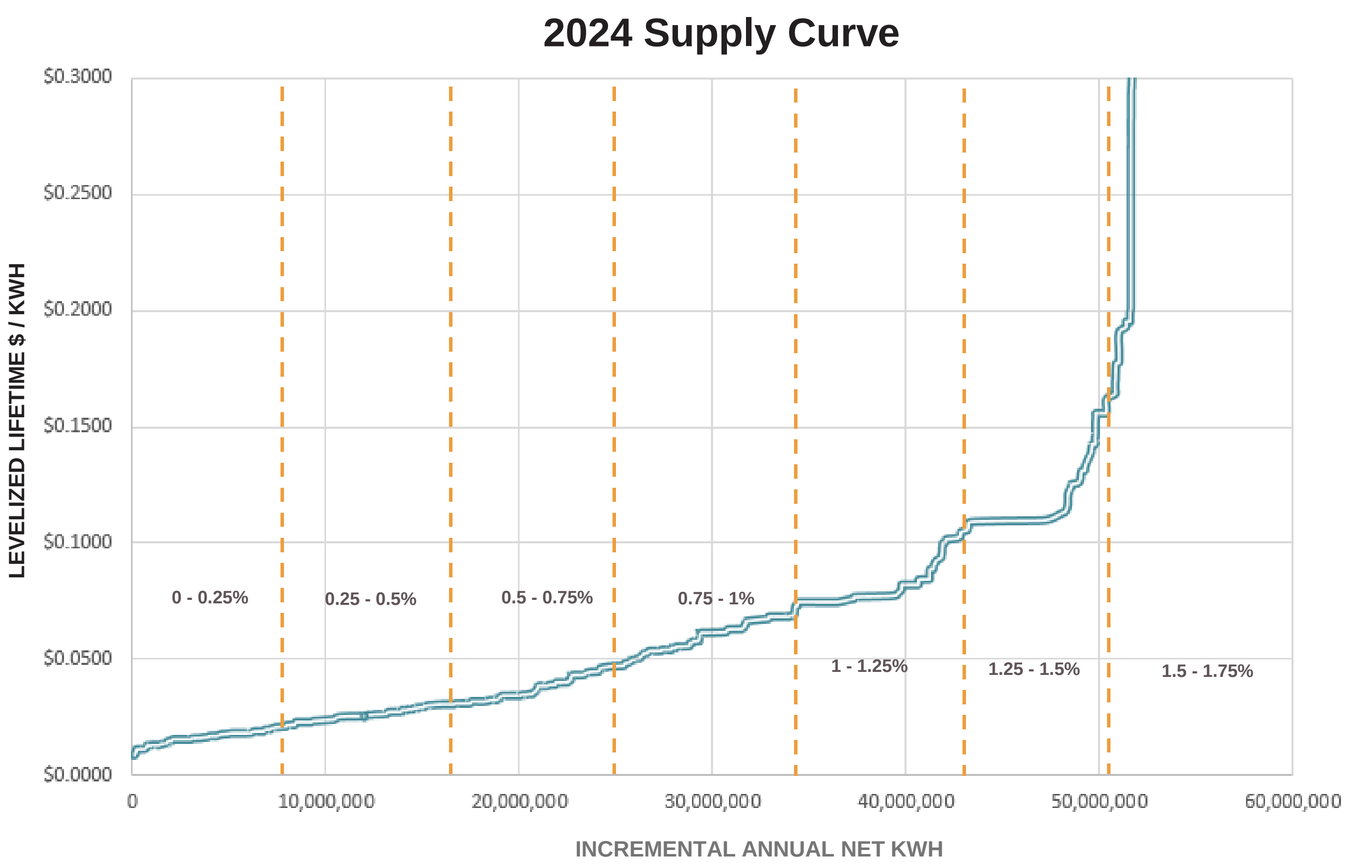
Step 1: ***Initial RAP Potential Estimates from MPS***

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

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	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

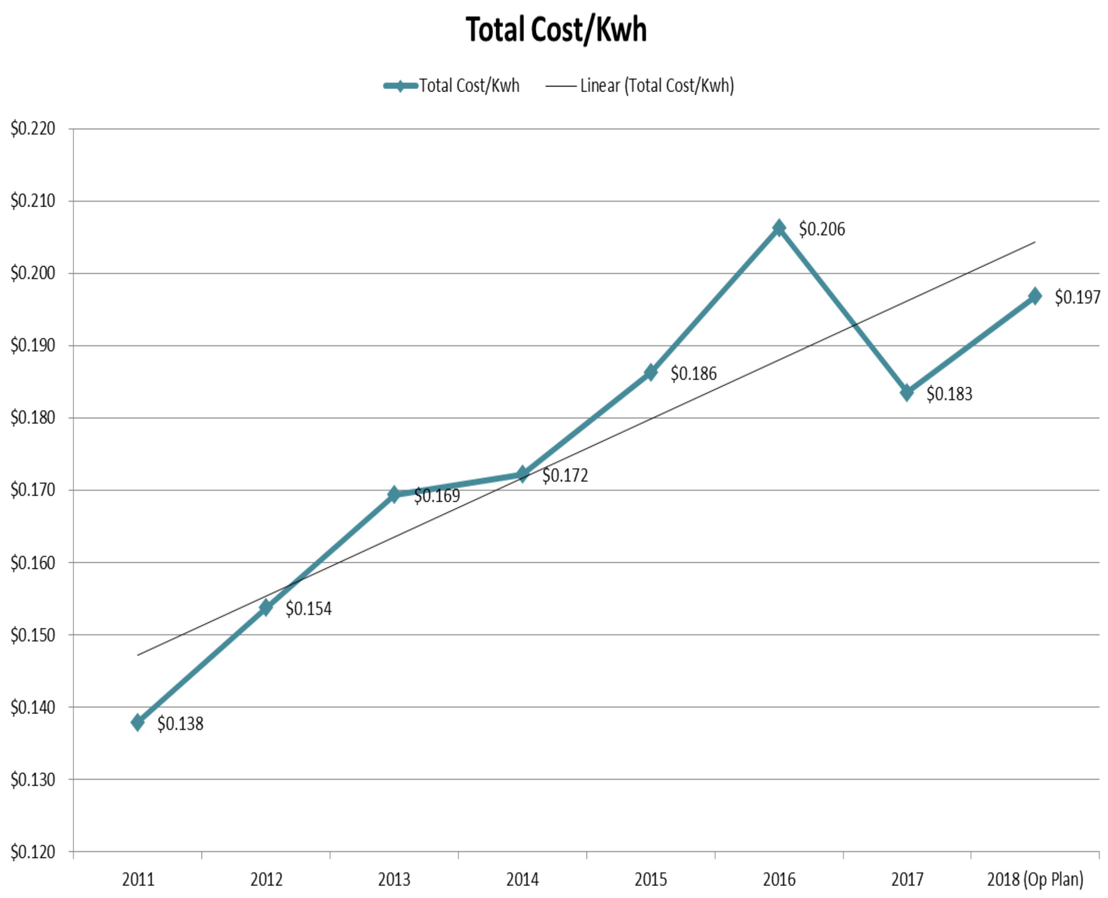
- LI Costs reflect paying 100% incentives for measures.
- Aligned to historical levels to produce an annual budget of $1.15 million per year
- Annual savings range from 457 MWh to 889 MWh

- 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

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- 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

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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

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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

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APPENDIX

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

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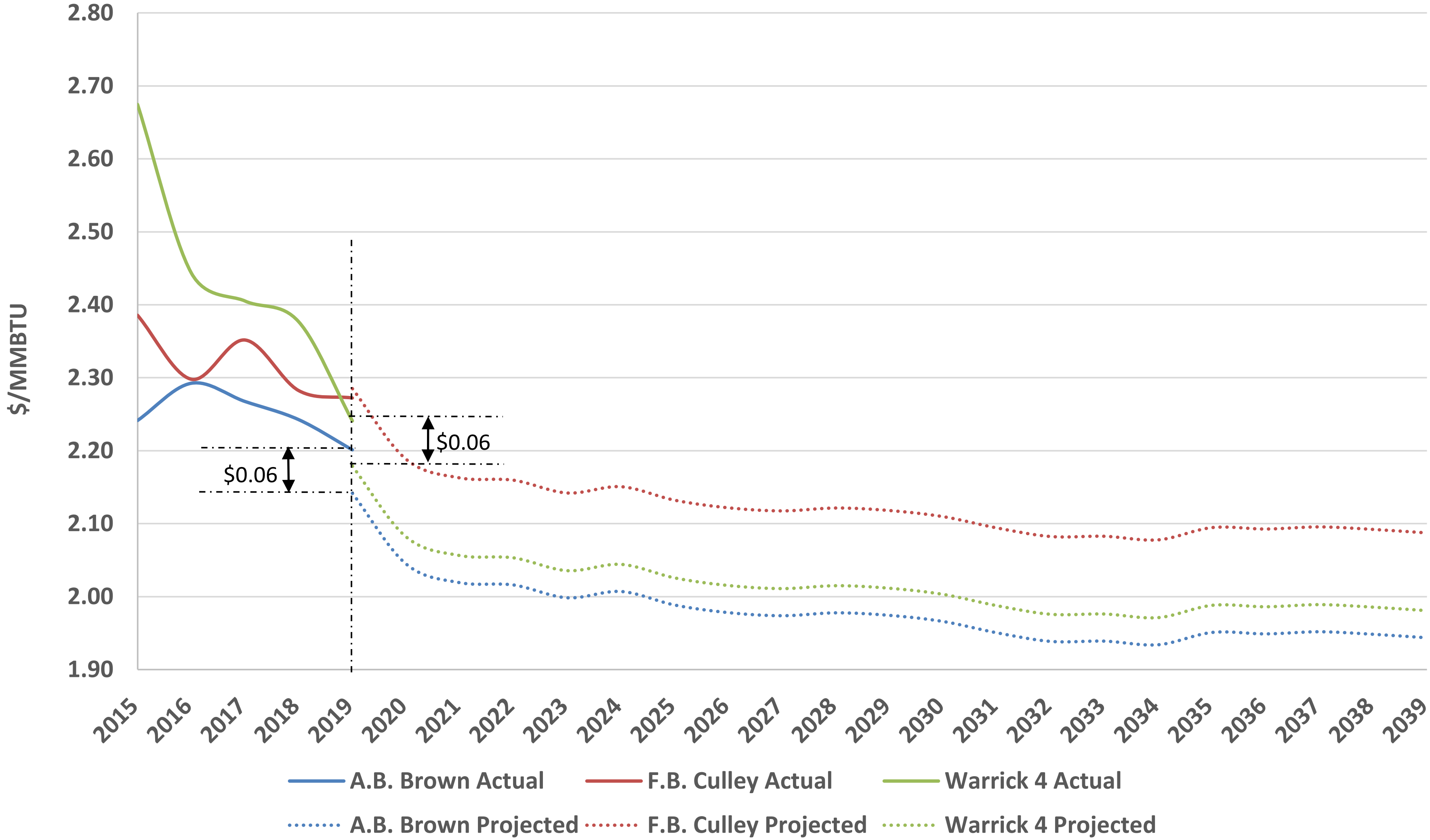

DRAFT BASE CASE INPUTS

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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

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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

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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

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	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

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	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.

<u>Gary Vicinus</u> (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).

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VECTREN PUBLIC STAKEHOLDER MEETING

DECEMBER 13, 2019

VECTREN
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WELCOME AND SAFETY SHARE

LYNNAE WILSON

INDIANA ELECTRIC CHIEF BUSINESS OFFICER

SAFETY SHARE

VECTREN
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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

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

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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

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1. Conduct an All Source RFP
2. Create Objectives, Risk Perspectives and Scorecard Development
3. Create Reference 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

TENTATIVE DATA RELEASE SCHEDULE

VECTREN
A CenterPoint Energy Company

- 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

VECTREN
A CenterPoint Energy Company

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 6^{th} 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

VECTREN
A CenterPoint Energy Company

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

VECTREN
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- 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

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A CenterPoint Energy Company

- 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

VECTREN
A CenterPoint Energy Company

- 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

VECTREN
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- 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

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DRAFT REFERENCE CASE MODELING RESULTS

PETER HUBBARD

MANAGER OF ENERGY BUSINESS ADVISORY, PACE GLOBAL

WIDE RANGE OF PORTFOLIOS

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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

Bridges

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

Scenario Based

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

Diverse

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

Status Quo

- 1) Business as Usual (BAU)

Risk Analysis

Renewables Focused

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

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

VECTREN
A CenterPoint Energy Company

			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

- 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

VECTREN
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- 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

VECTREN
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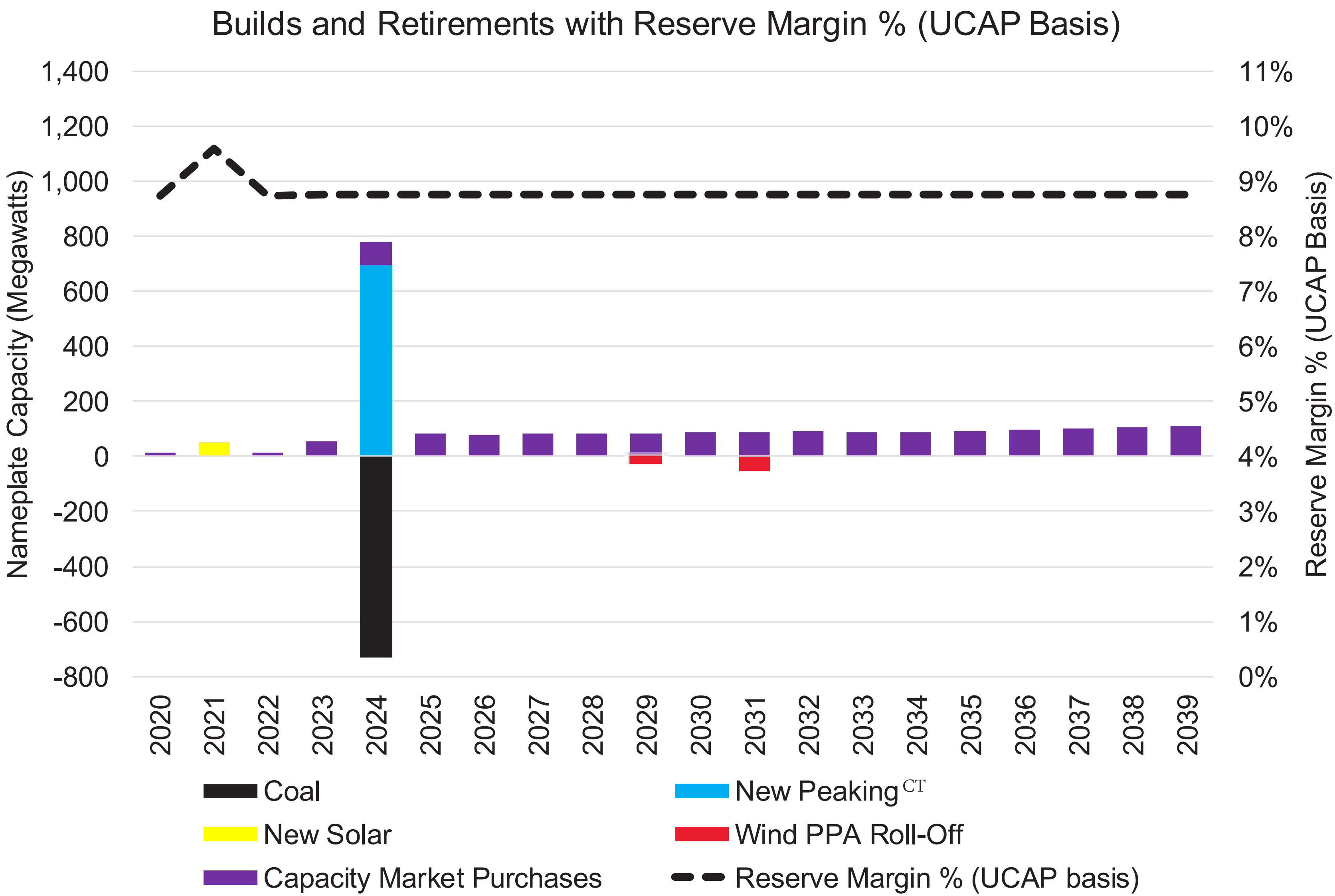
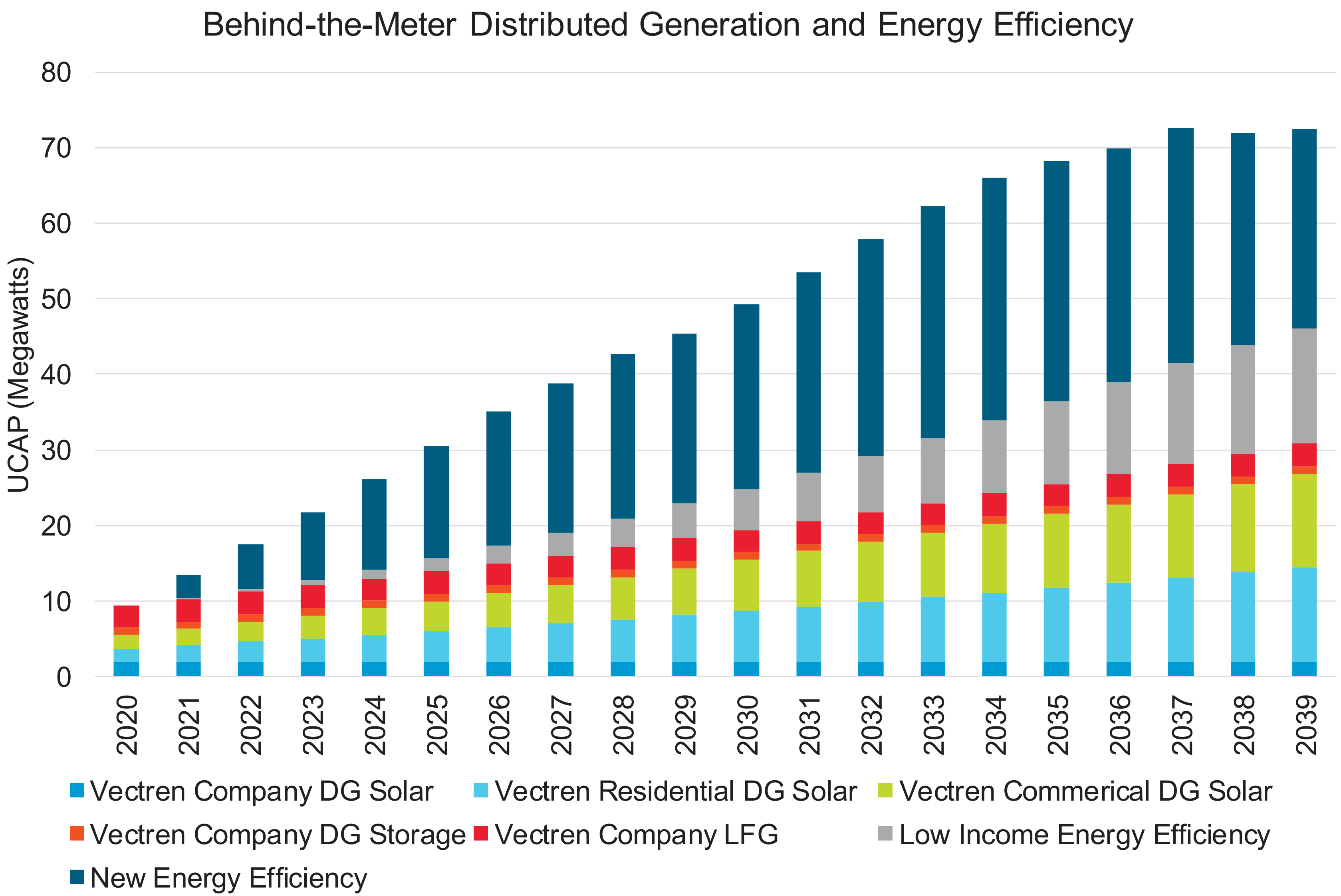
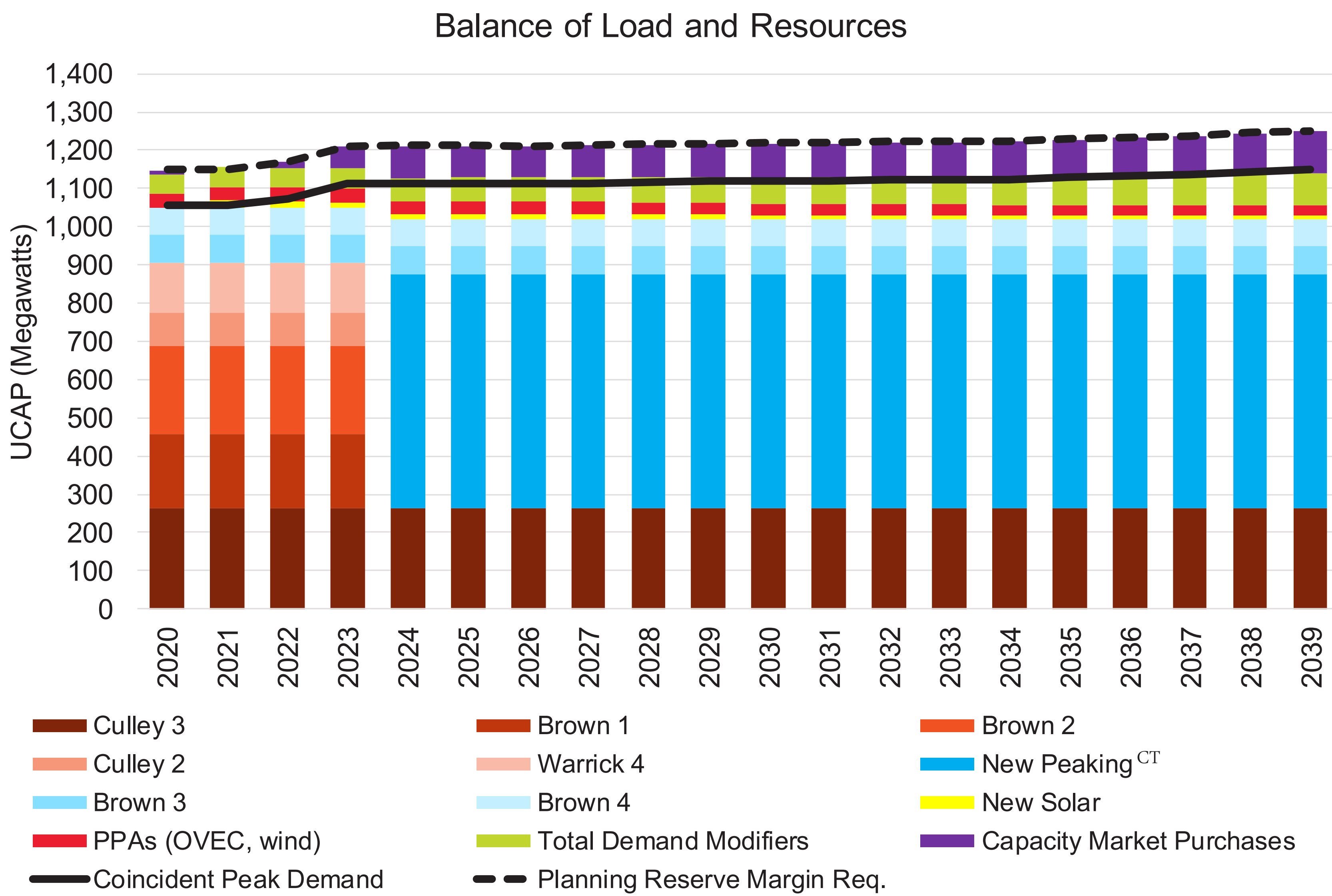


DRAFT REFERENCE CASE DISTRIBUTED GENERATION AND ENERGY EFFICIENCY



DRAFT REFERENCE CASE PORTFOLIO

VECTREN
A CenterPoint Energy Company



SCENARIO MODELING CONSIDERATIONS

VECTREN
A CenterPoint Energy Company

- 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.

VECTREN
A CenterPoint Energy Company

FINAL RFP MODELING INPUTS

MATT LIND

RESOURCE PLANNING & MARKET ASSESSMENTS BUSINESS LEAD, BURNS AND MCDONNELL

RFP PROCESS UPDATE

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
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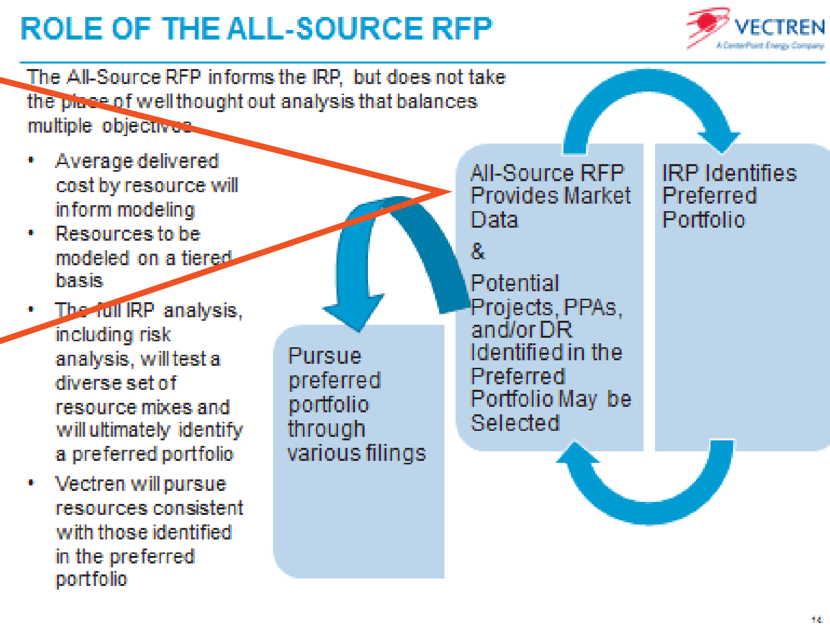
- File Petitions with Regulatory Bodies



RFP PROPOSALS

VECTREN
A CenterPoint Energy Company

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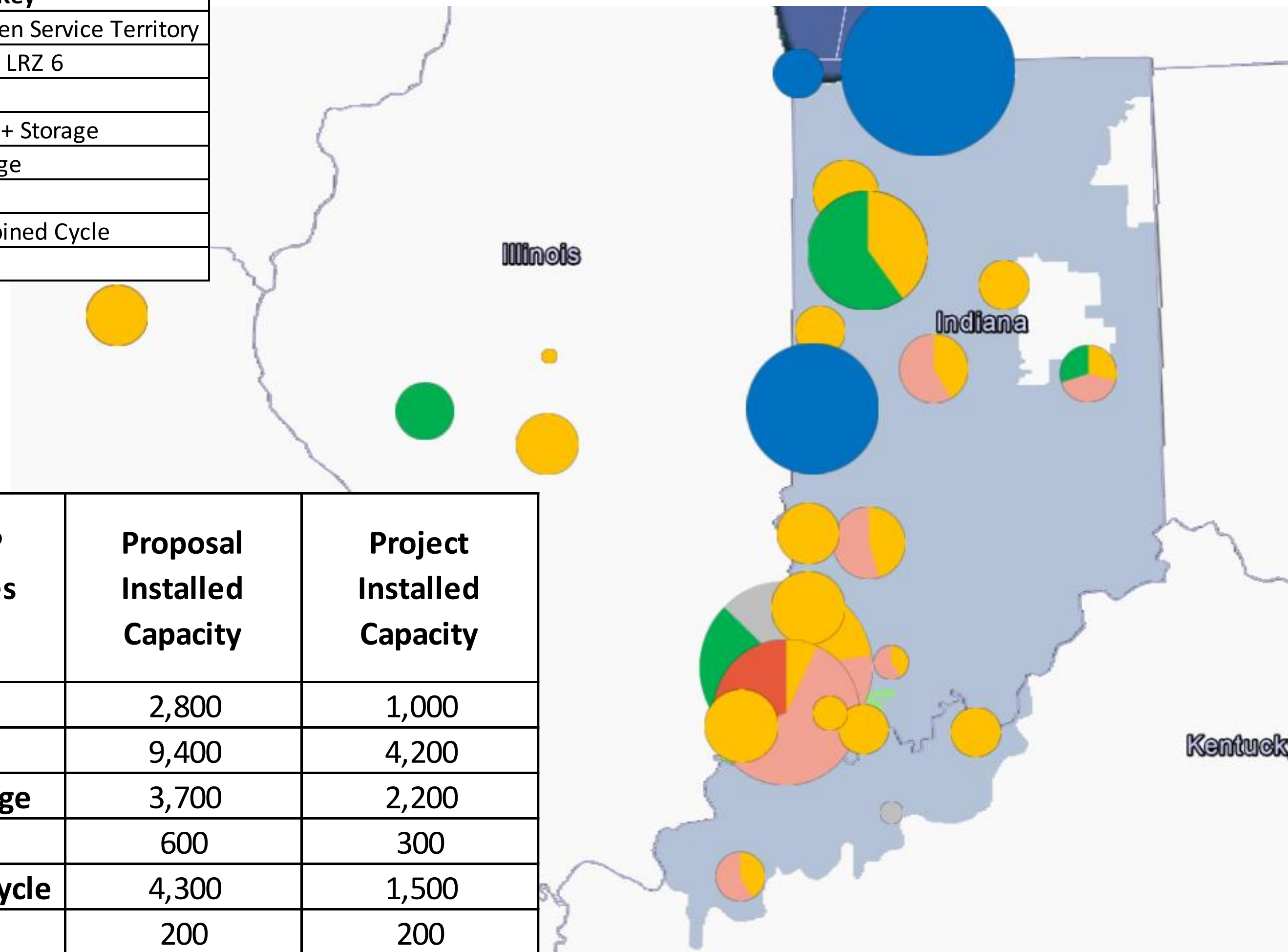
Key	
(light green)	Vectren Service Territory
(light blue)	MISO LRZ 6
(yellow)	Solar
(pink)	Solar + Storage
(red)	Storage
(green)	Wind
(blue)	Combined Cycle
(grey)	Coal



2019 RFP Responses (MW)	Proposal Installed Capacity	Project Installed Capacity
Wind	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

VECTREN
A CenterPoint Energy Company

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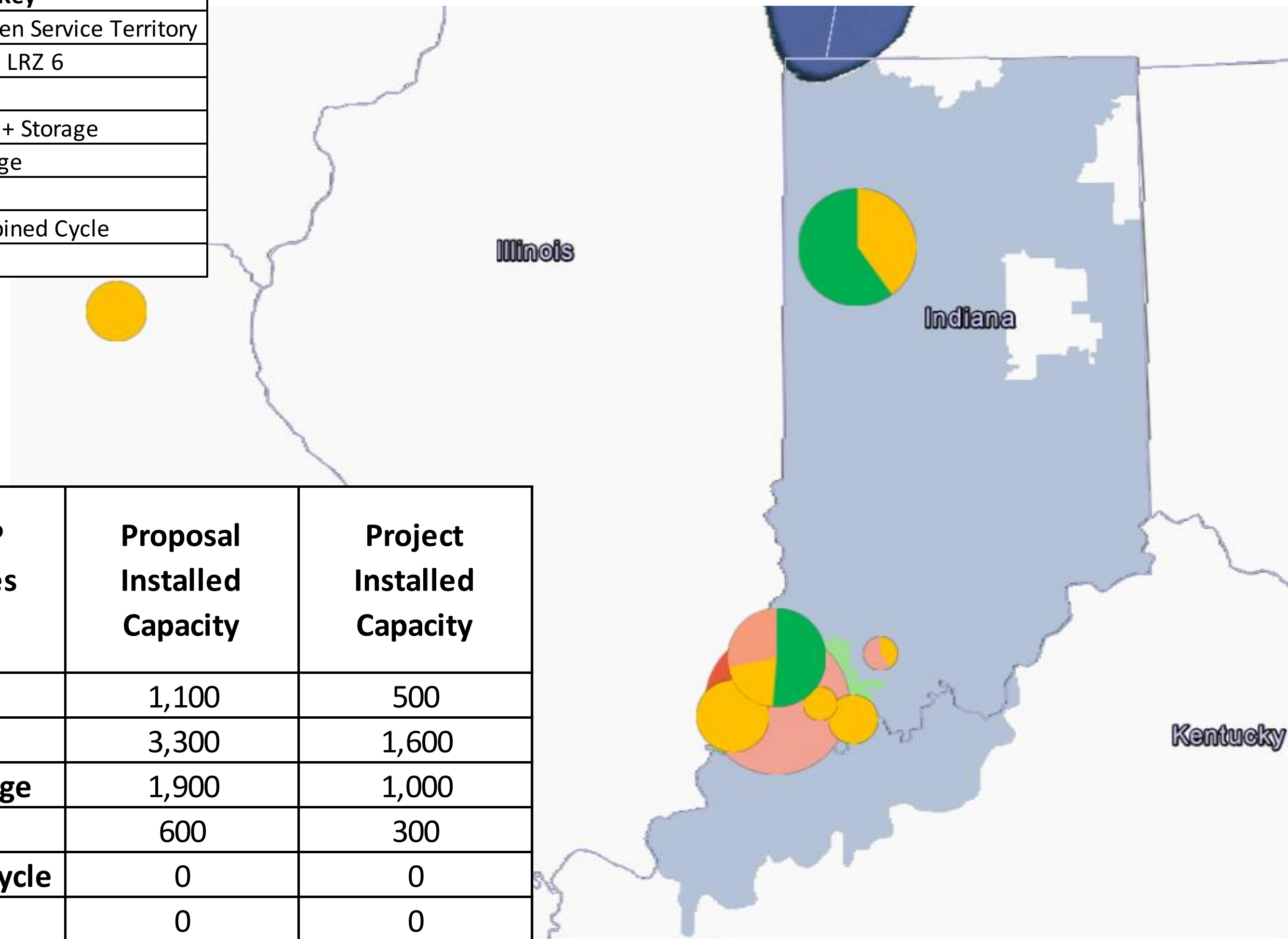
Key
Vectren Service Territory
MISO LRZ 6
Solar
Solar + Storage
Storage
Wind
Combined Cycle
Coal



2019 RFP Responses (MW)	Proposal Installed Capacity	Project Installed Capacity
Wind	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

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	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

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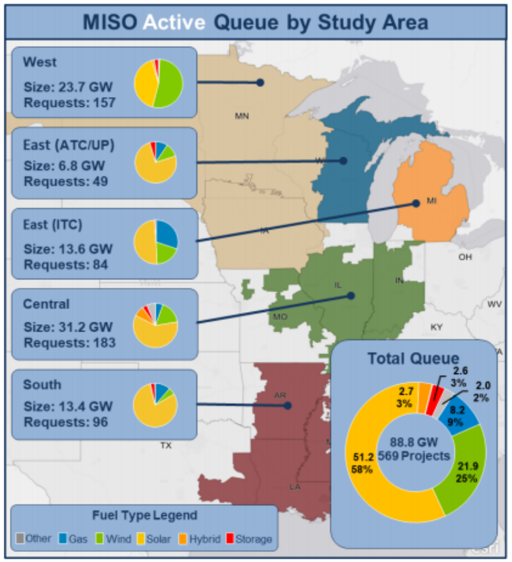
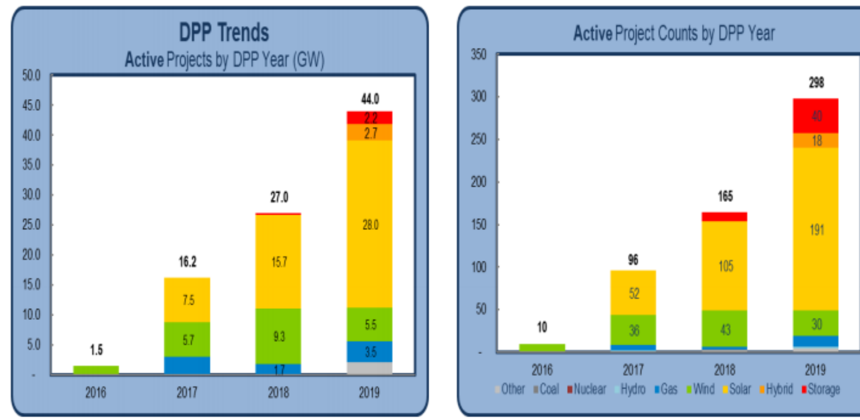
Generator Interconnection: Overview

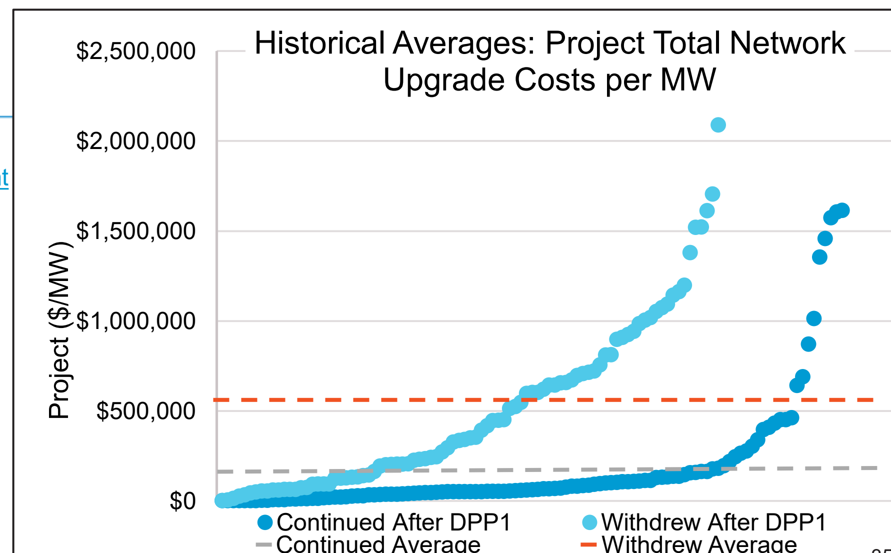
The current generator interconnection active queue consists of 569 projects totaling 88.8 GW



DPP Project Trends



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



TIER 1 COST SUMMARY

VECTREN
A CenterPoint Energy Company

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- 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

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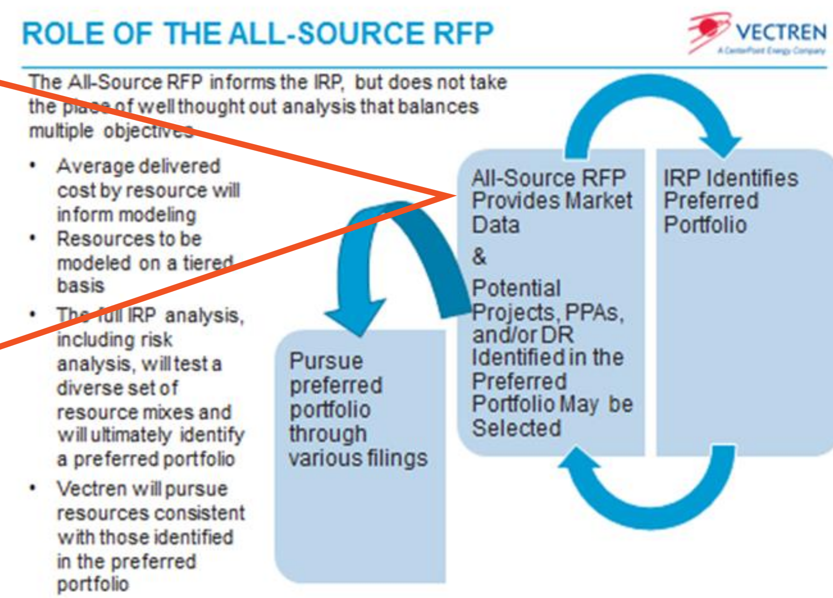
- Received Proposals
- Initial Proposal Review
- Clarified Information with Bidders
- Group Proposals
- Interconnection & Network Upgrade Analysis
- Evaluation of Proposals
- Aggregated Group Data for IRP
- Receive Results from IRP
- Due Diligence and Negotiations
- Definitive Agreements Executed
- File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



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PORTFOLIO DEVELOPMENT

MATT RICE

VECTREN MANAGER OF RESOURCE PLANNING

STAKEHOLDER PORTFOLIO FEEDBACK

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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

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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

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- 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

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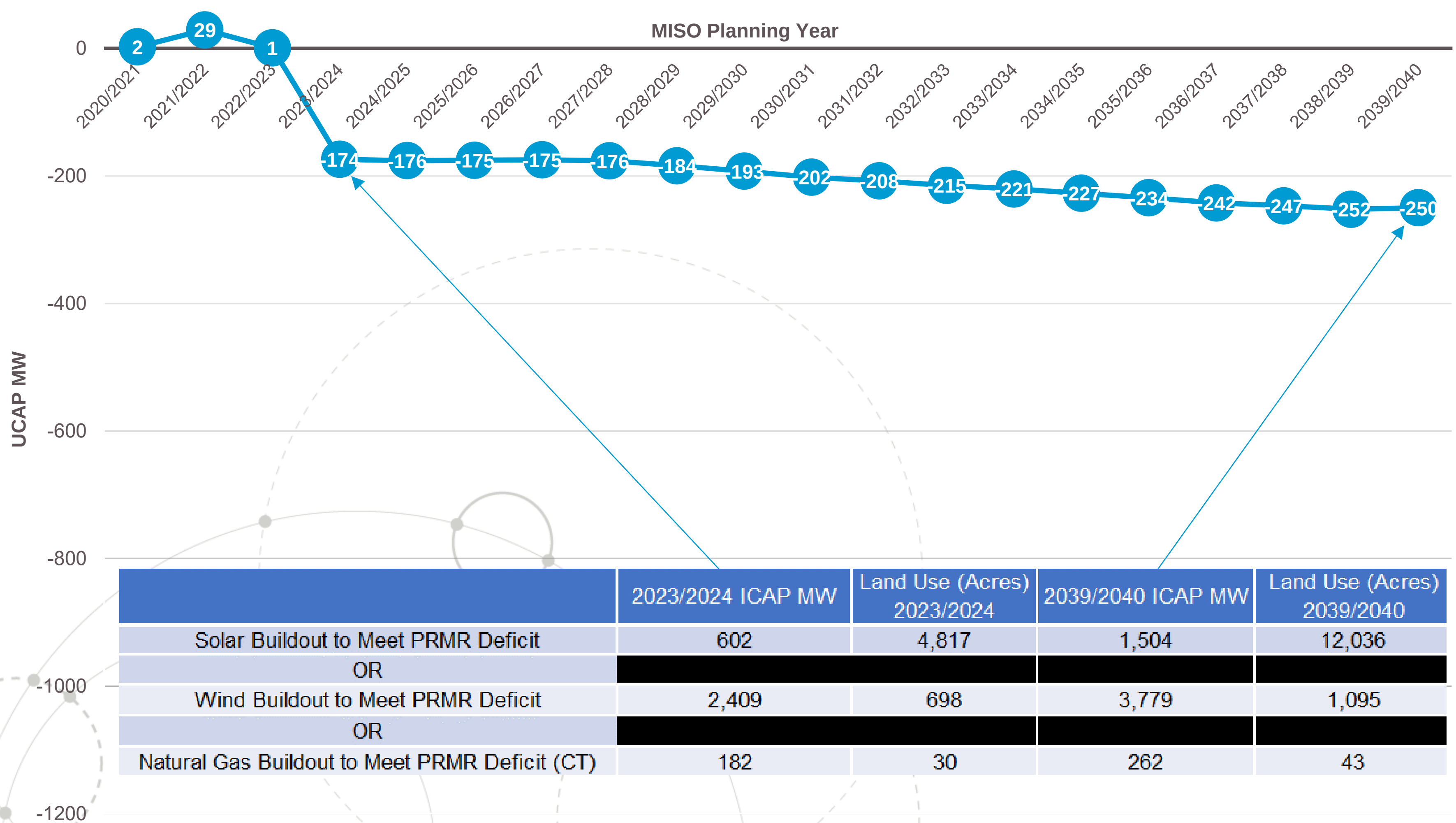

	2023/2024 ICAP MW	Land Use (Acres) 2023/2024	2039/2040 ICAP MW	Land Use (Acres) 2039/2040
Solar Buildout to Meet PRMR Deficit	602	4,817	1,504	12,036
OR				
Wind Buildout to Meet PRMR Deficit	2,409	698	3,779	1,095
OR				
Natural Gas Buildout to Meet PRMR Deficit (CT)	182	30	262	43

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

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- 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

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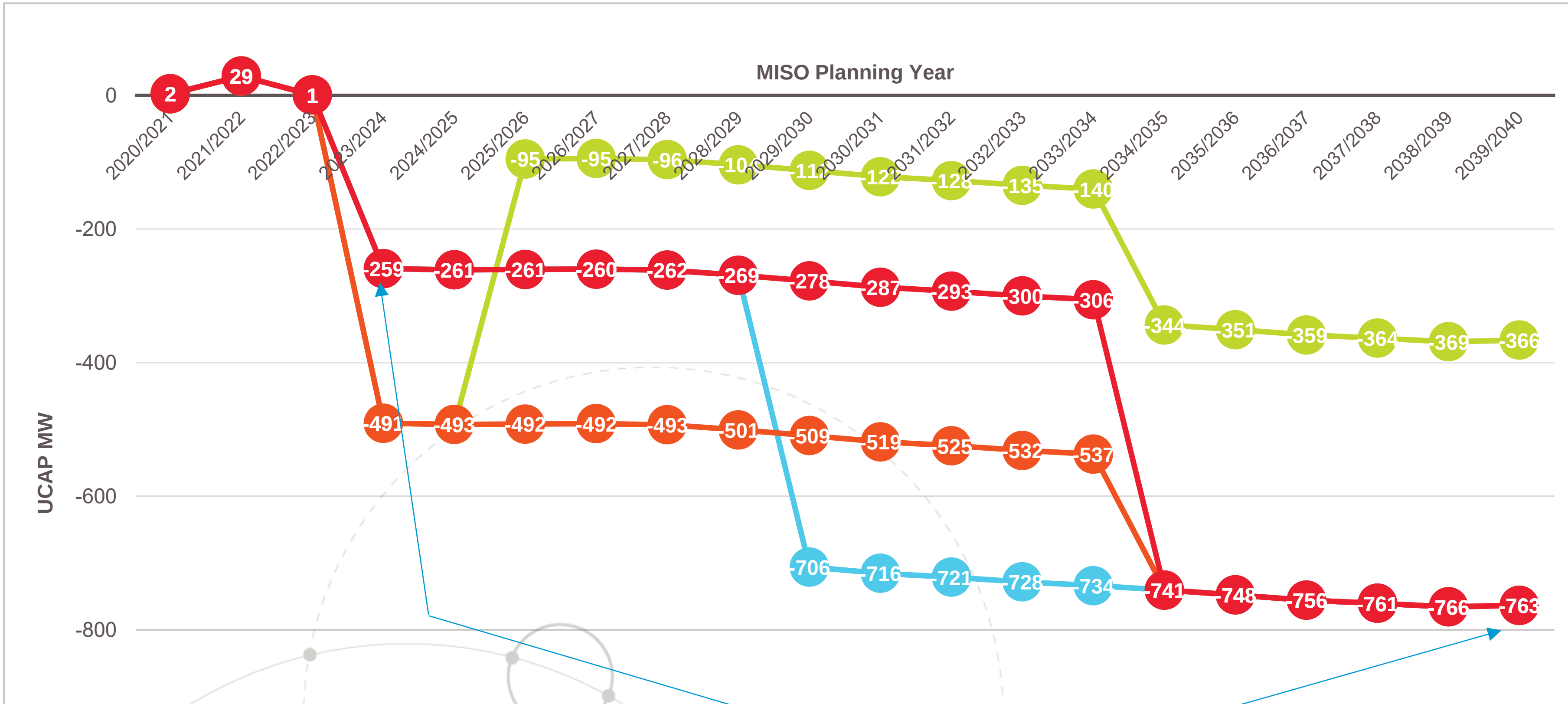

Bridge - Convert Brown 1 & Brown 2	2023/2024 ICAP MW	Land Use (Acres) 2023/2024	2039/2040 ICAP MW	Land Use (Acres) 2039/2040
Solar Buildout to Meet PRMR Deficit	897	7,176	4,594	36,754
OR				
Wind Buildout to Meet PRMR Deficit	3,589	1,040	11,541	3,345
OR				
Natural Gas Buildout to Meet PRMR Deficit (CCGT)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

PRMR - Planning Reserve Margin Requirement

DIVERSE

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- 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

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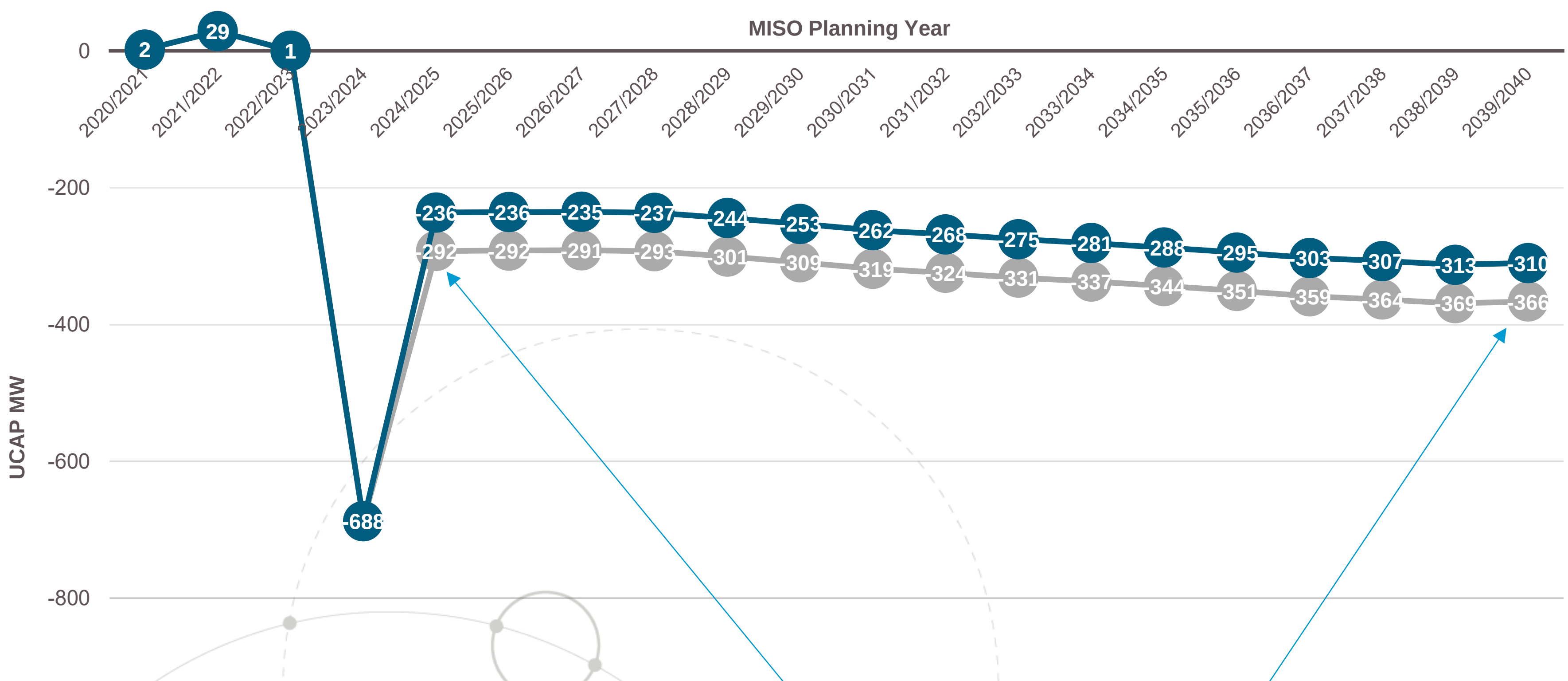

Diverse 400 MW CCGT	2024/2025 ICAP MW	Land Use (Acres) 2024/2025	2039/2040 ICAP MW	Land Use (Acres) 2039/2040
Solar Buildout to Meet PRMR Deficit	1,065	8,518	2,205	17,642
OR				
Wind Buildout to Meet PRMR Deficit	4,065	1,178	5,540	1,606
OR				
Natural Gas Buildout to Meet PRMR Deficit (CCGT)	306	50	384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

PRMR - Planning Reserve Margin Requirement

RENEWABLES FOCUSED

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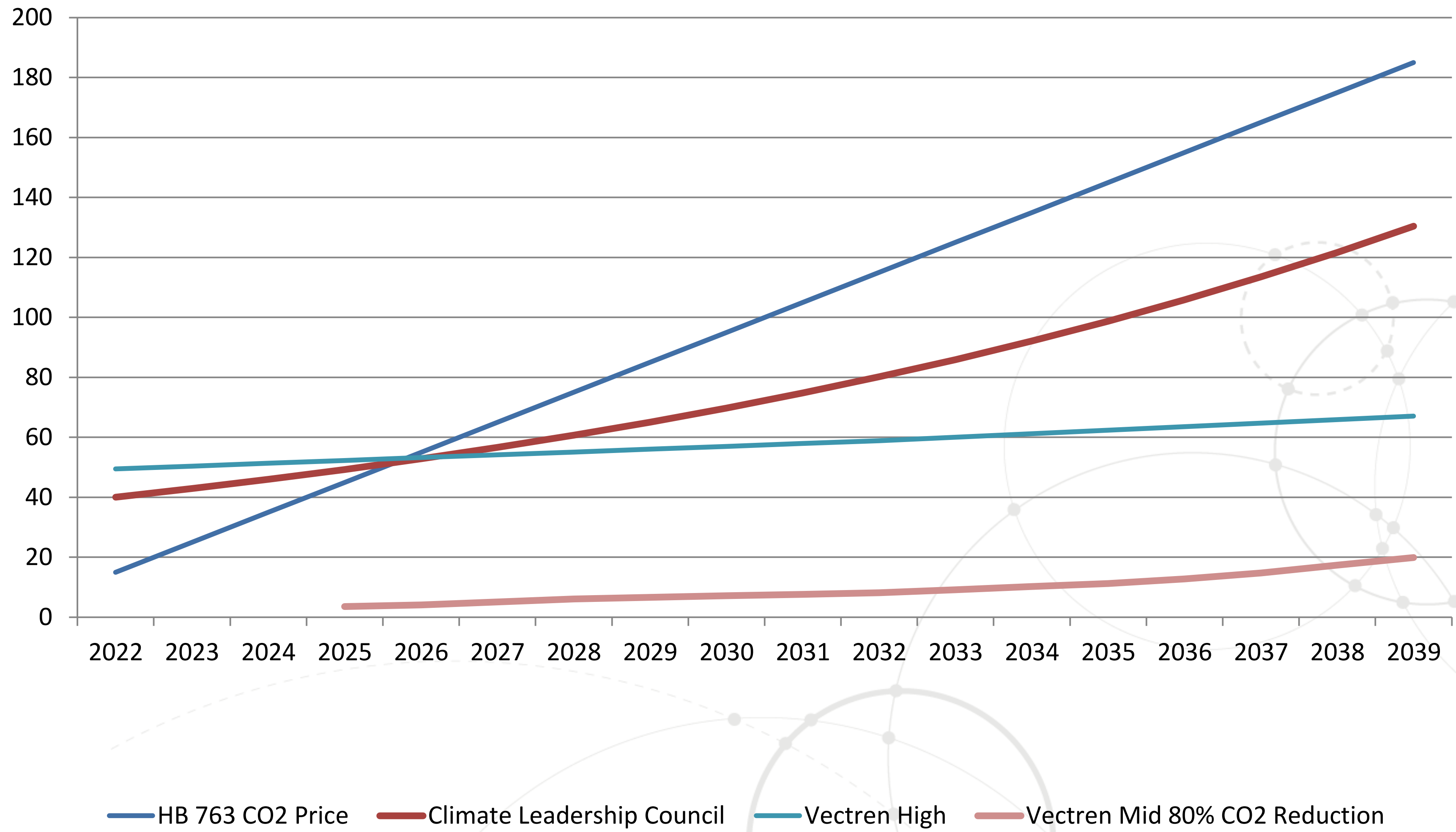
- Vectren continues to fully explore renewable resources through market pricing and portfolio development
  - Close all fossil generation by 2030. Will require voltage support. Optimize for renewables, demand response, energy efficiency, and storage
  - Close all coal by 2034 (All but Culley 3 are closed 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



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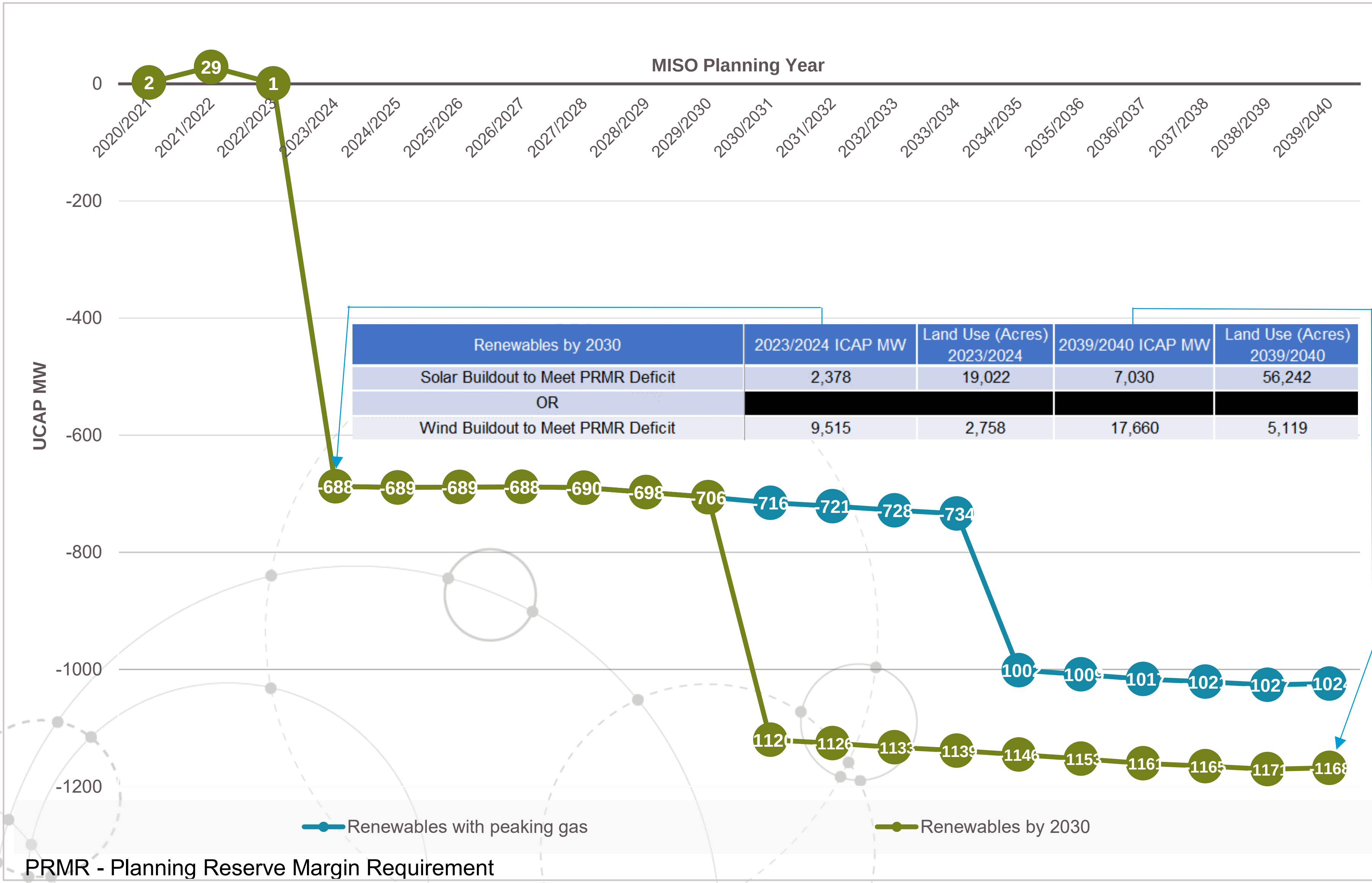
PLANNING RESERVE MARGIN REQUIREMENT SURPLUS\DEFICIT - RENEWABLES



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

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SCENARIO TESTING AND PROBABILISTIC MODELING

PETER HUBBARD

MANAGER OF ENERGY BUSINESS ADVISORY, PACE GLOBAL

PORTFOLIOS WILL BE TESTED BOTH IN SCENARIOS AND PROBABILISTIC FRAMEWORK

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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

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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
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Revised from last meeting

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$/MMBtu	2.77	2.76	3.06	3.24	3.38	3.49	3.62	3.78	3.96	4.09	4.17
Vectren Peak Load	MW	1,115	1,102	1,131	1,060	1,025	1,039	1,038	1,038	1,053	1,053	1,065
Customer-Owned Solar DG Capacity*	MW	9.3	14.6	20.0	24.4	29.6	36.3	42.9	49.5	57.3	64.3	72.5
EV Peak Load**	MW	0.4	2.0	9.5	12.4	15.4	19.0	22.4	25.8	29.5	32.8	36.4
Energy Efficiency and Company DG	MW	6.0	9.2	15.7	22.6	28.8	33.1	39.0	45.2	48.8	50.5	47.6
Demand Response	MW	35.2	51.7	52.7	61.6	64.4	67.3	70.1	73.0	75.8	78.7	81.5
Wind (200 MW)	2018$/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$/kW	1,414	1,264	1,120	975	964	942	897	877	818	809	818
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Flow Battery (50 MW, 6 hr)	2018$/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
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Revised from last meeting

HIGH REGULATORY CASE INPUTS

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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
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Revised from last meeting

PROBABILISTIC MODELING PROVIDES THE BASIS FOR IRP SCORECARD METRICS

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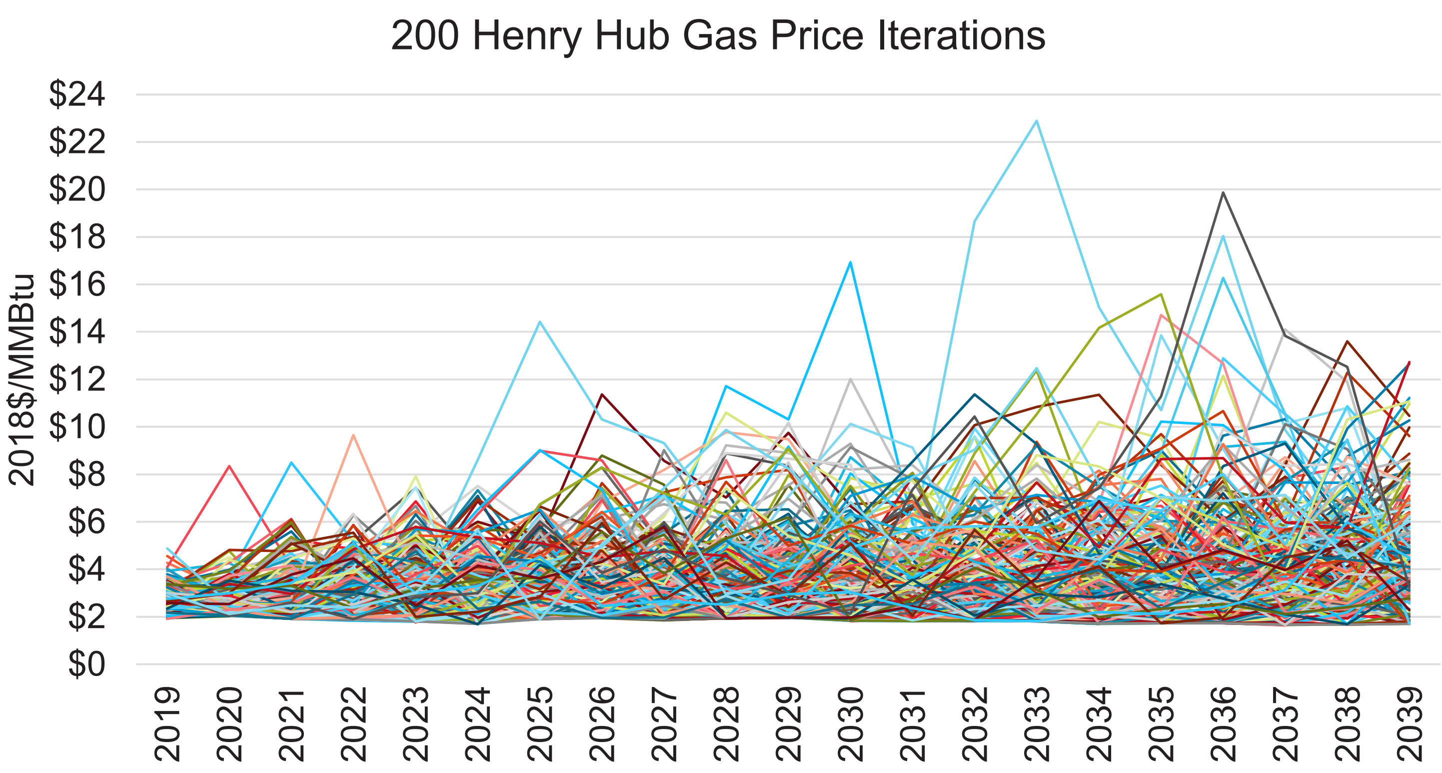
- By measuring each portfolio's performance across 200 iterations, we can quantify each of the measures associated with IRP objectives
- This provides a direct comparison of portfolio performance that will be summarized in the Balanced Scorecard

IRP Objective	Measure	Unit
Affordability	20-Year NPVRR	$
Price Risk Minimization	95th 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:

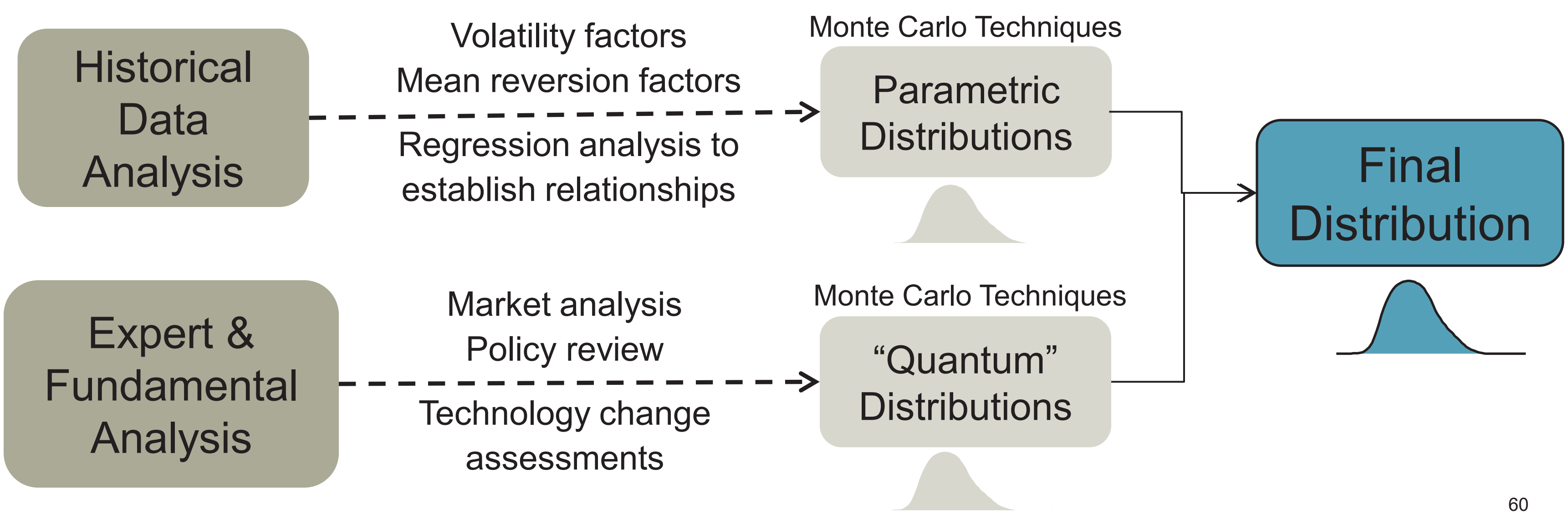
- Analysis of price required for Paris Agreement compliance
- Social cost of carbon analysis
- Expert view on low, mid & high cases

5. Capital Cost

- Relevant technologies included

Modeling based on:

- Expert view on low, mid & high cases



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NEXT STEPS

MATT RICE

VECTREN MANAGER OF RESOURCE PLANNING

NEXT STEPS

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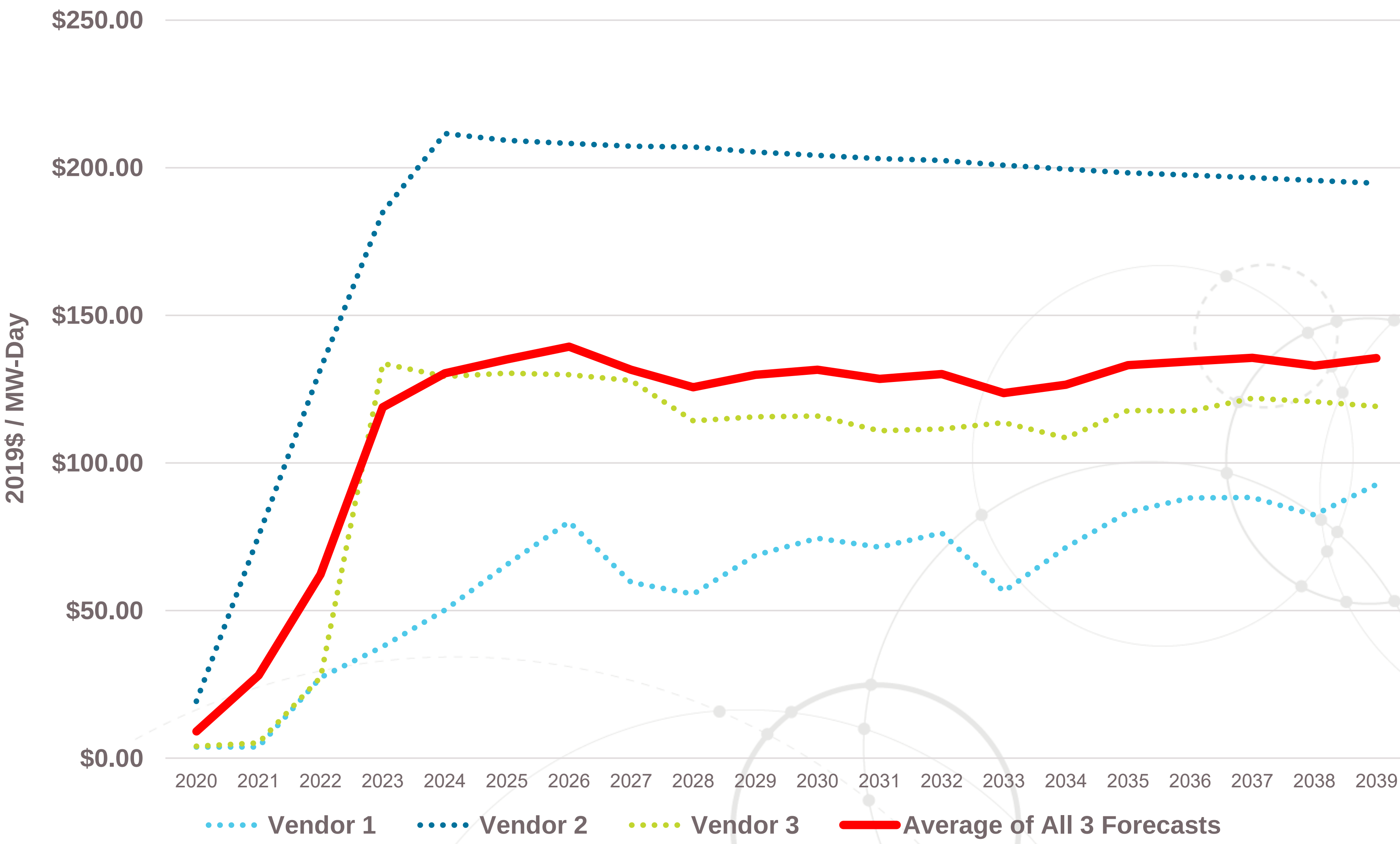
There is a tremendous amount of work to be done between now and our next meeting in March

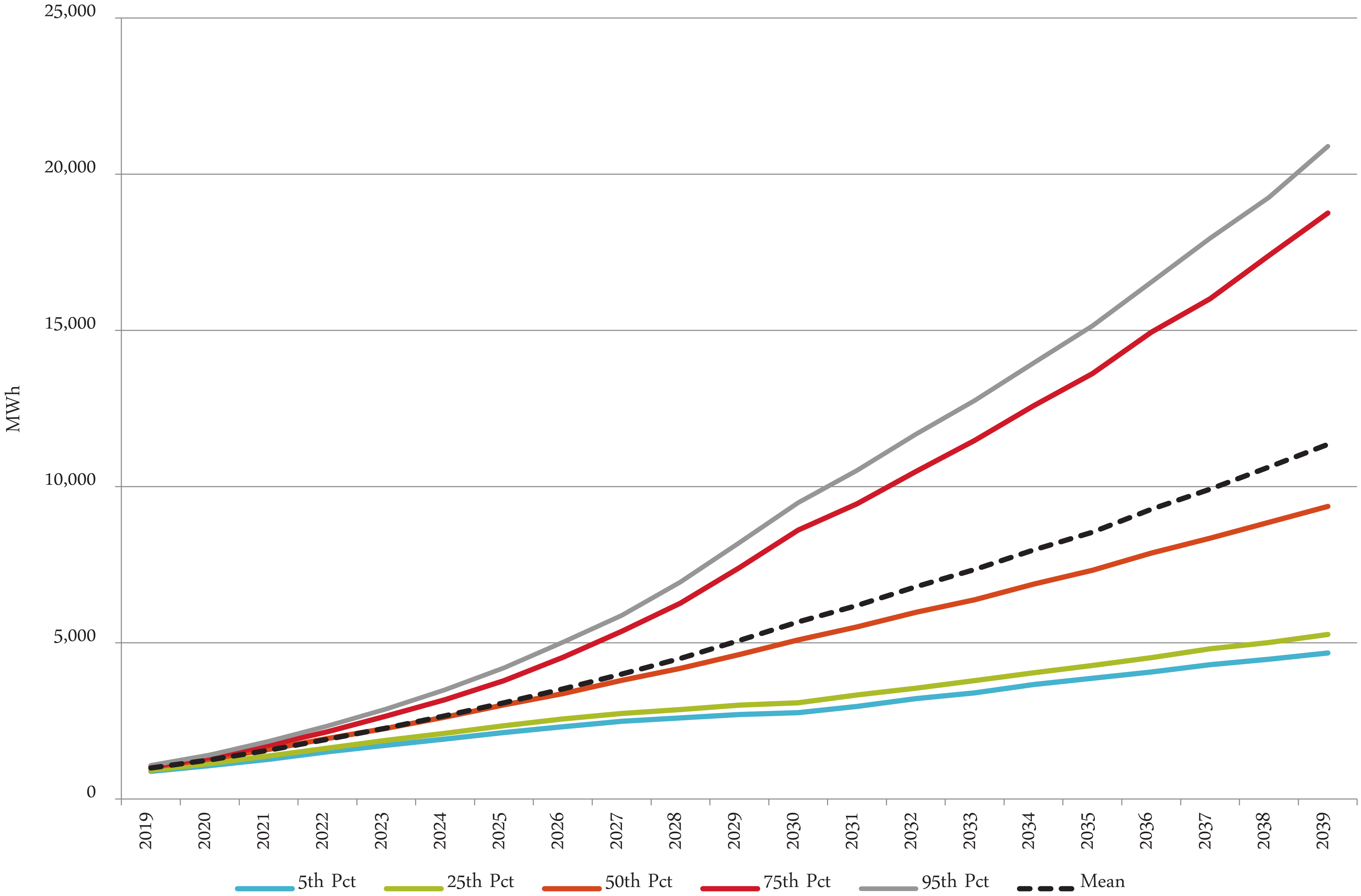
- Finalize all modeling inputs
- Update Reference Case modeling, including RFP results
- Develop scenario based portfolios
- Finalize additional portfolios with insights produced through scenario modeling
- Test portfolios within scenarios and probabilistic modeling
- Analyze results
- Select the preferred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

APPENDIX

CONSENSUS CAPACITY PRICE FORECAST



VECTREN SOLAR DISTRIBUTED GENERATION IS A DECREMENT TO VECTREN LOAD



VECTREN ELECTRIC VEHICLE LOAD IS AN INCREMENTAL TO VECTREN LOAD

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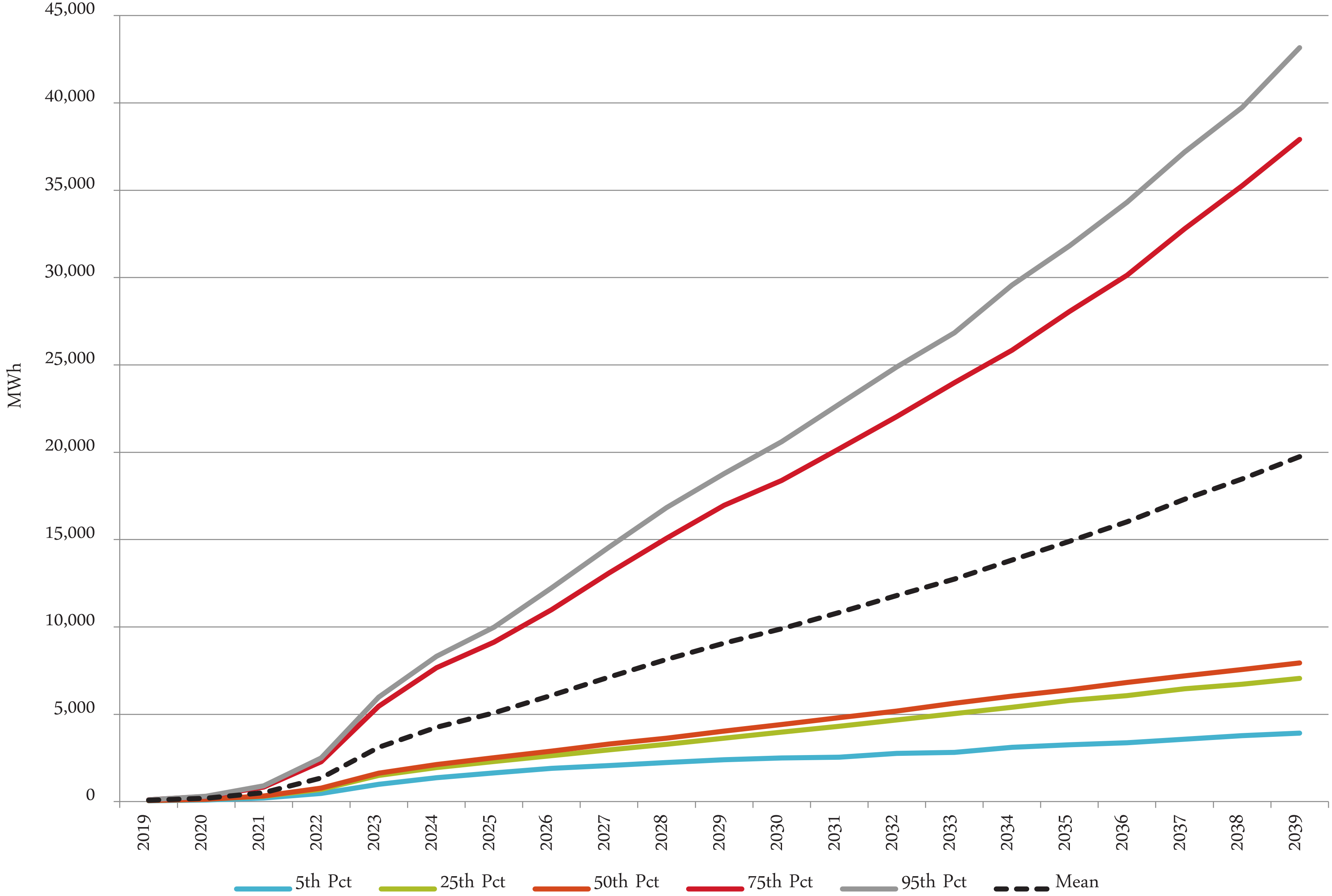

DISTRIBUTIONS: VECTREN PEAK LOAD (NET OF SOLAR DG, EV LOAD)

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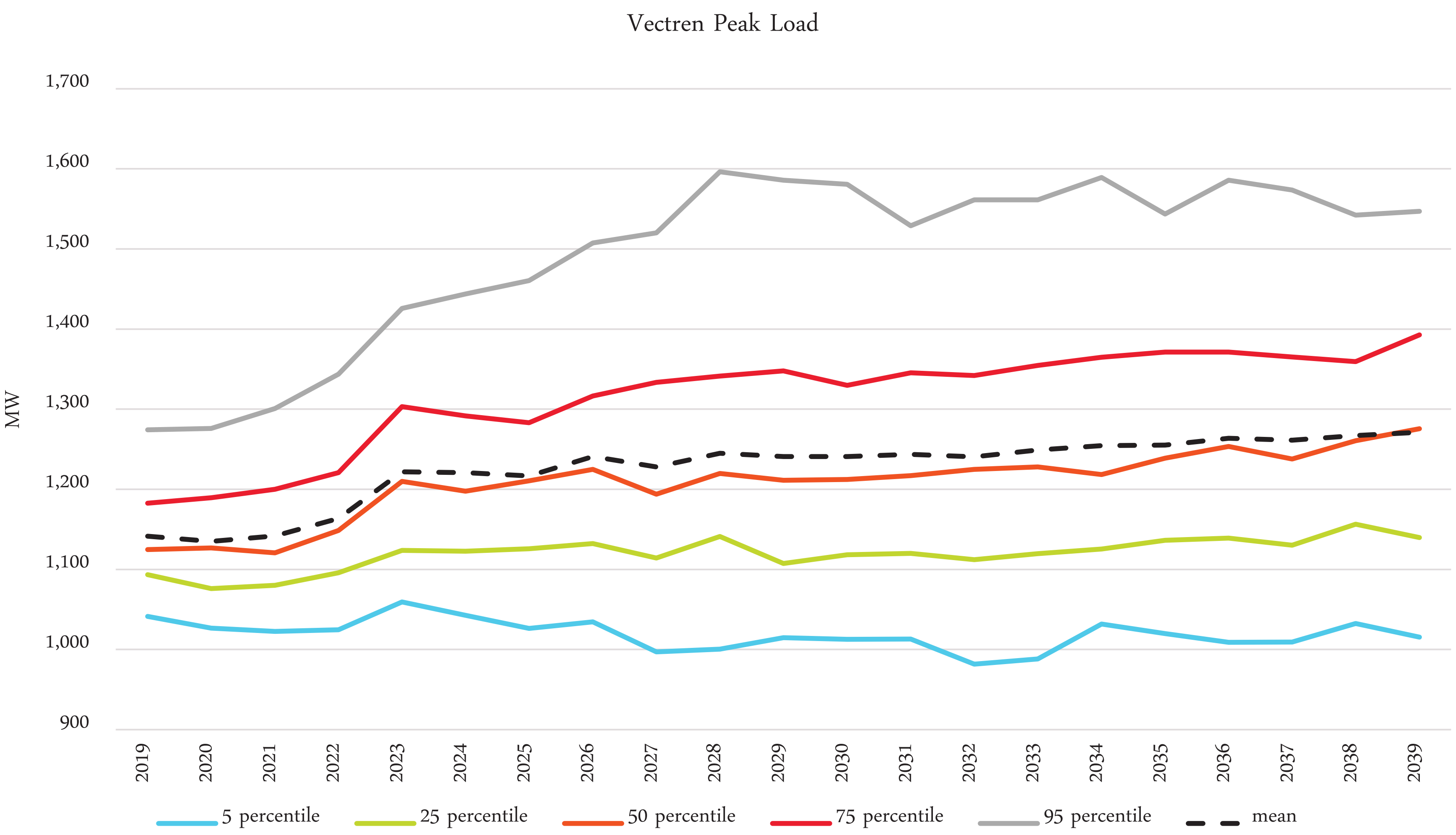

LCA FOR NATURAL GAS ELECTRICITY GEN.

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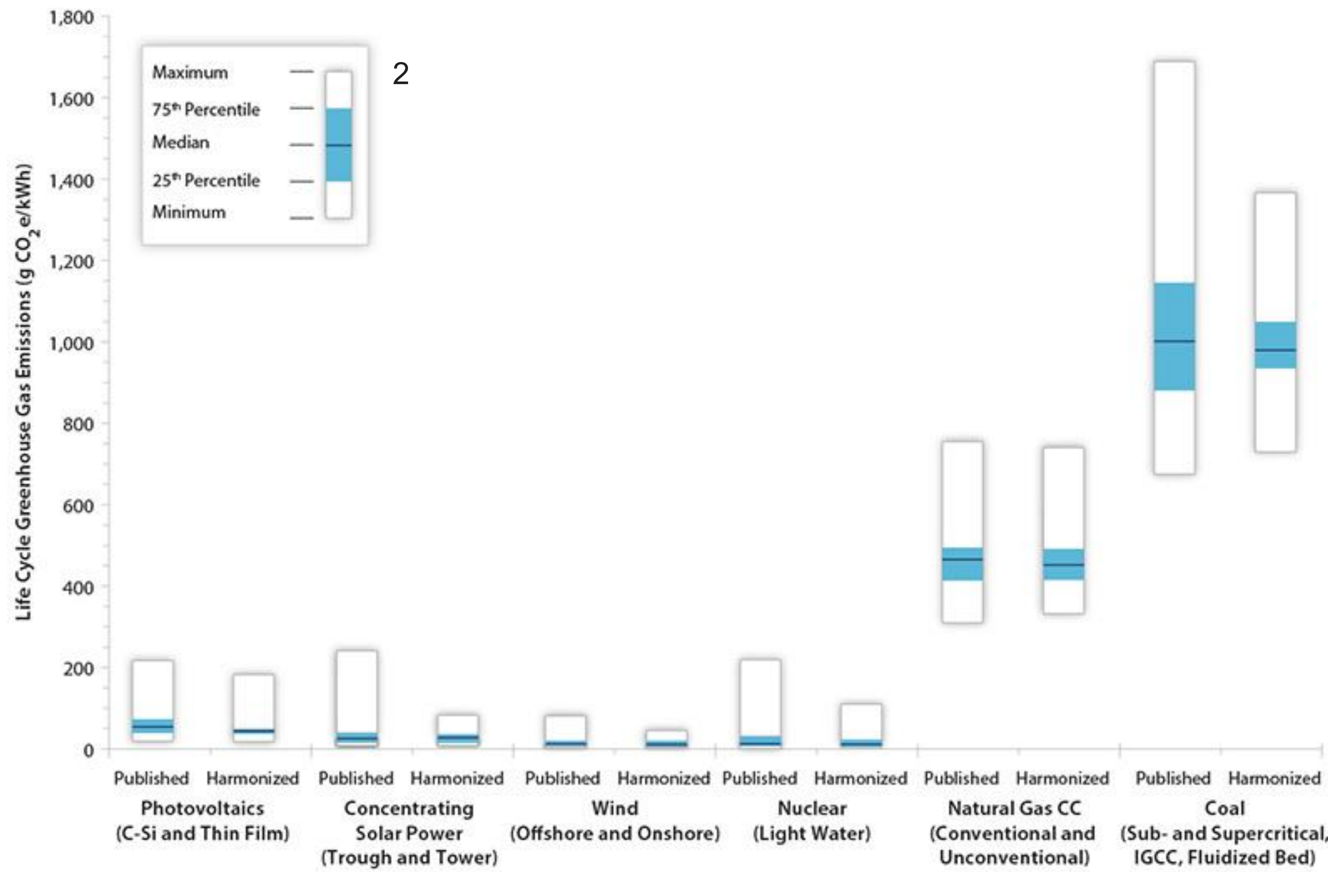
Multiple studies were considered for the NREL study from July 2014[1]

- 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



	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.

Matt Rice (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.

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VECTREN PUBLIC STAKEHOLDER MEETING

JUNE 15, 2020

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WELCOME AND SAFETY SHARE

LYNNAE WILSON

INDIANA ELECTRIC CHIEF BUSINESS OFFICER

SAFETY SHARE – FIREWORK SAFETY

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

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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.

Cause No. 45564

HOW TO CONNECT AUDIO

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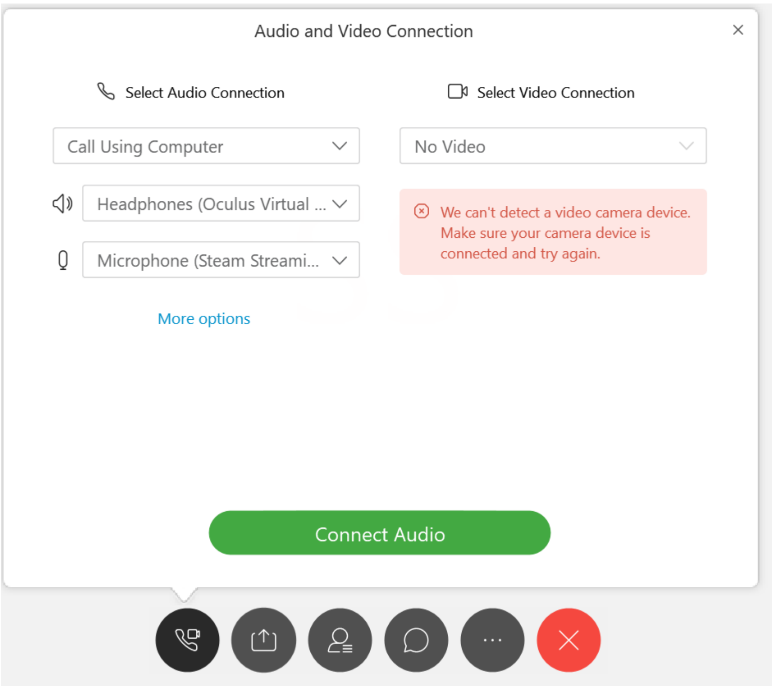
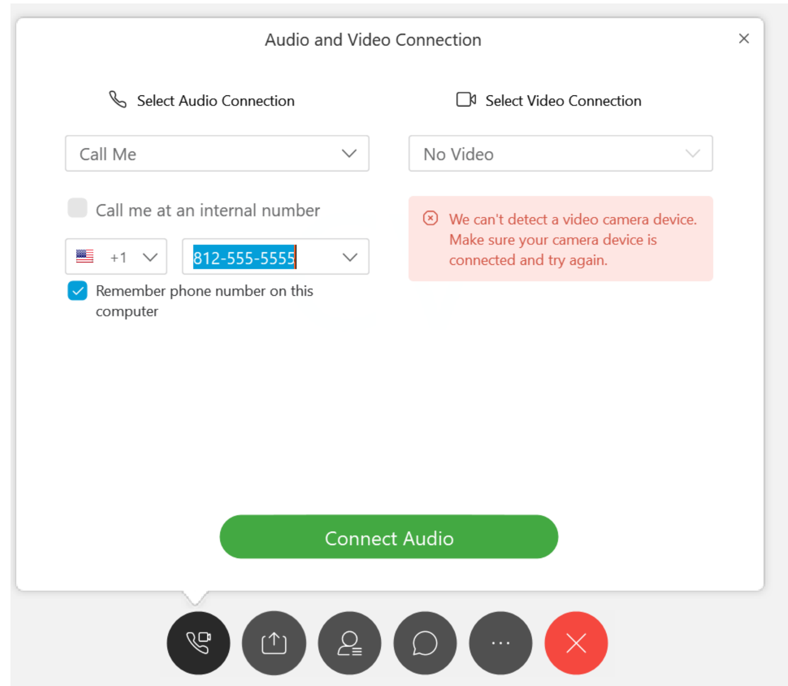


or



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?

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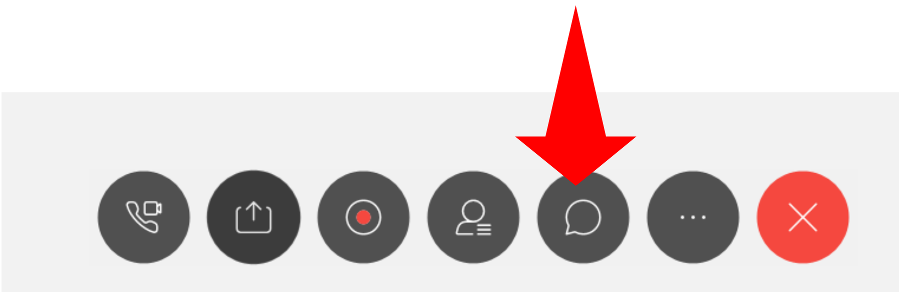
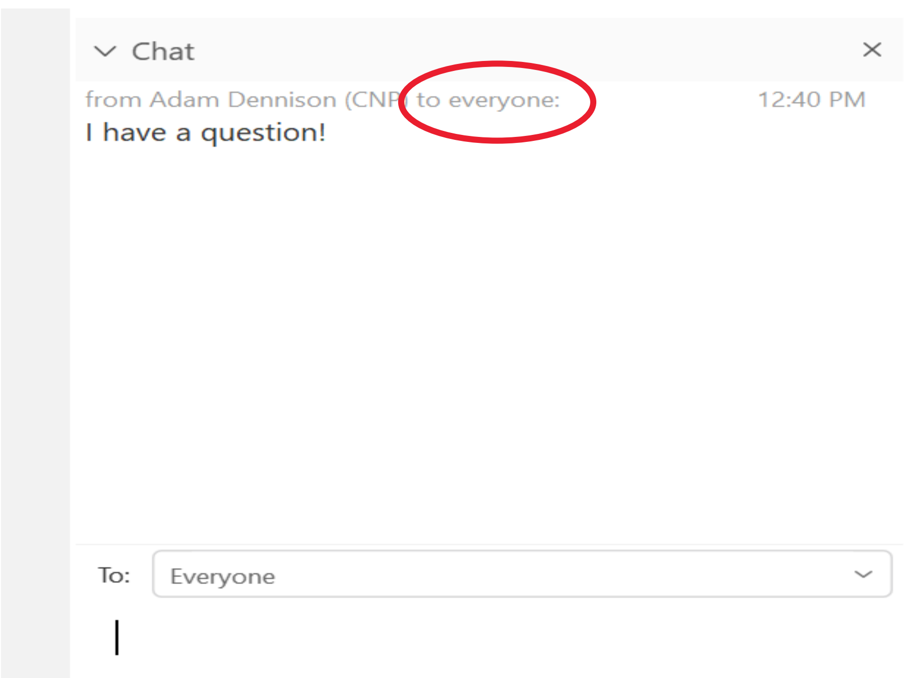
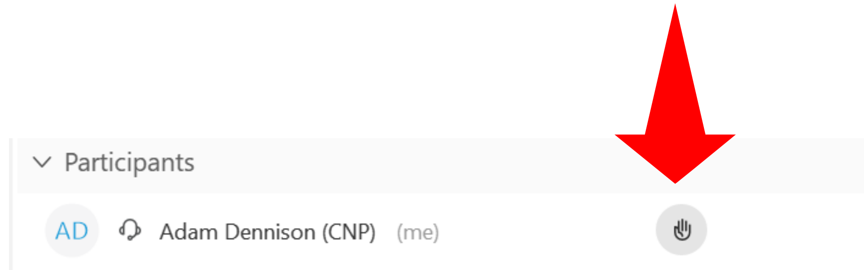
Ask “everyone” in chat.

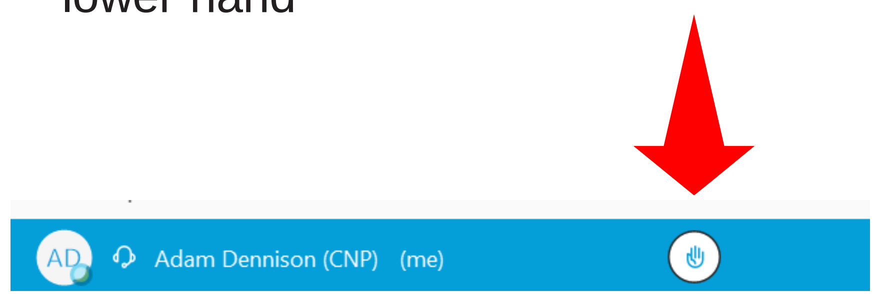




Raise Hand for a Follow-up



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

All Source RFP → Create Objectives, Risk Perspectives and Scorecard Development → Create Reference Case Assumptions and Scenario Development → Portfolio Development → Portfolio Testing in Scenarios, Focused on Potential Regulatory Risks → Portfolio Testing Using Probabilistic Modeling of 200 Potential Futures → Conduct Sensitivity Analysis → Evaluate Portfolios → 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

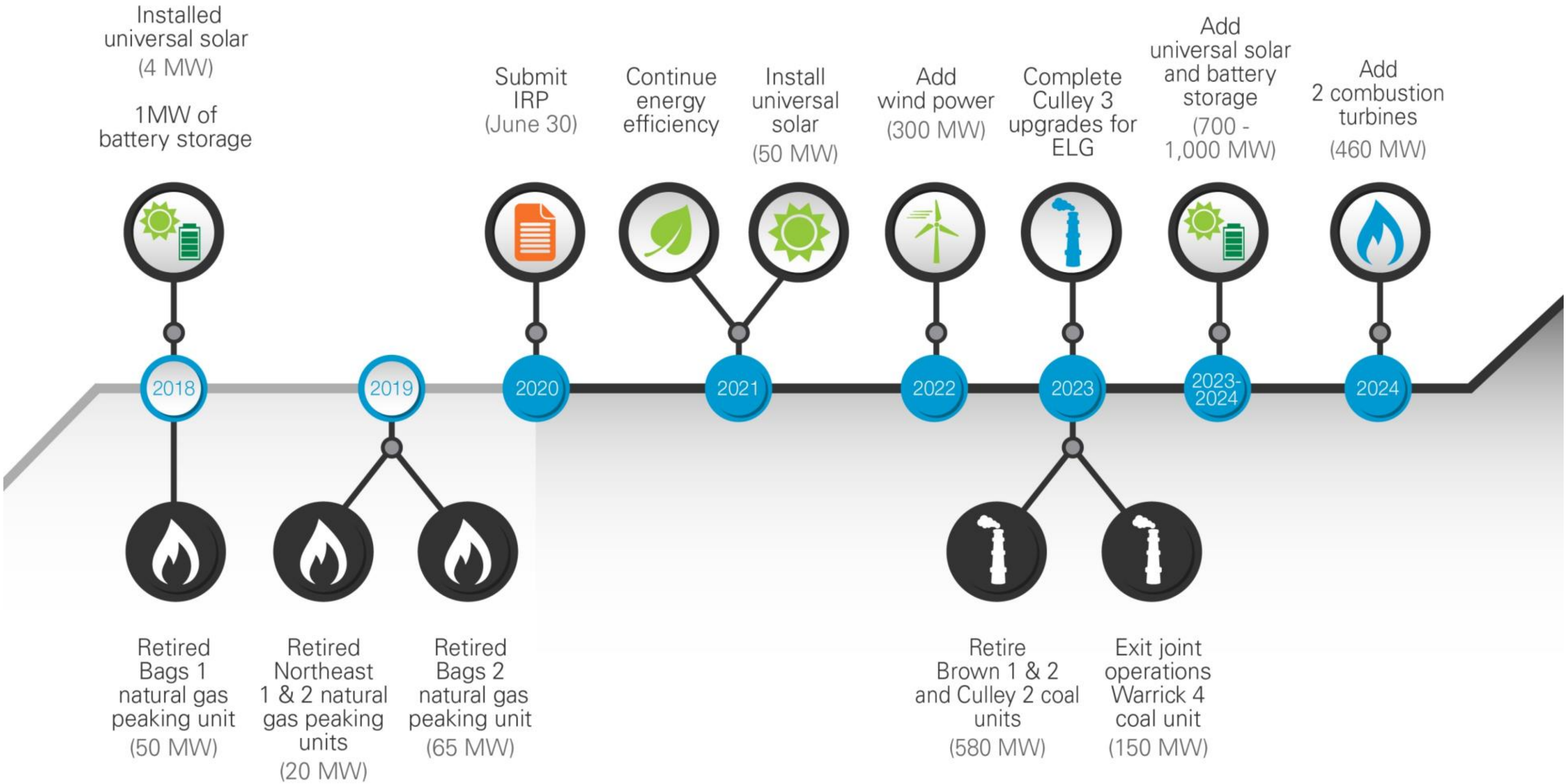
LYNNAE WILSON

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?

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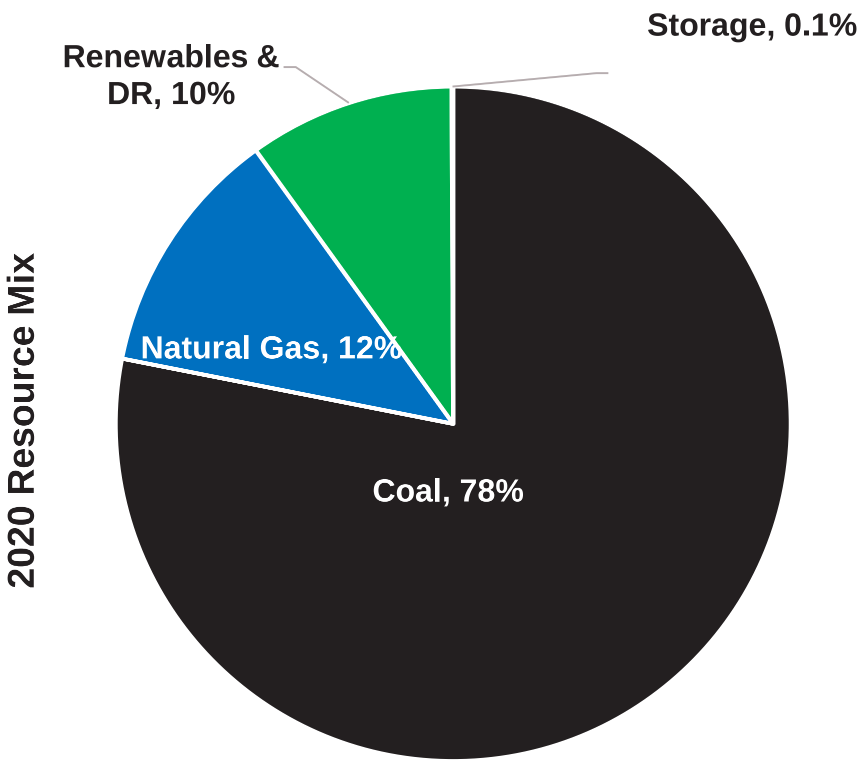
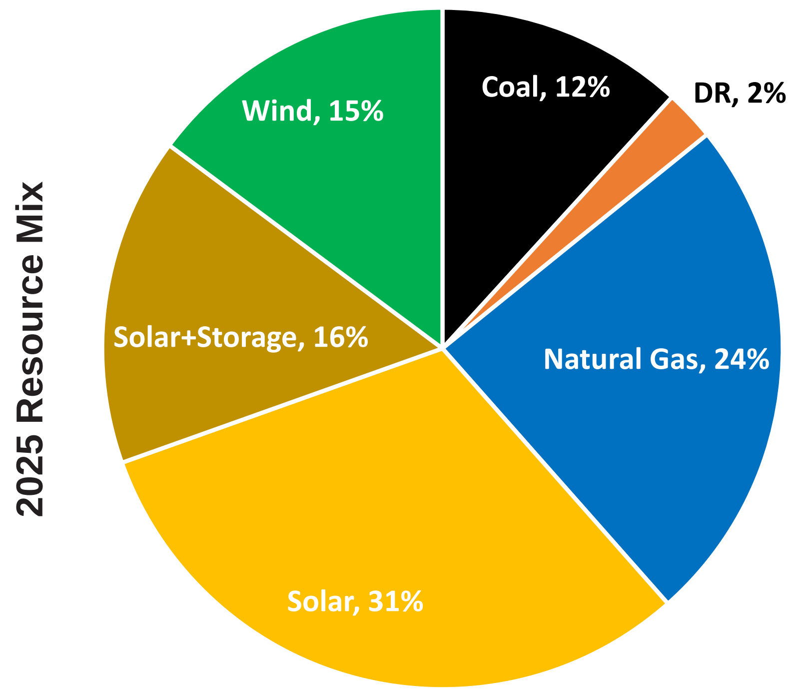
- Preferred portfolio[1] replaces 730 MWs of coal with approximately 700-1,000 MWs of Solar & Solar + Storage, 300 MWs of Wind, 460 MWs of gas Combustion Turbines (CT) and 30 MWs of Demand Response (DR) (aka High Technology Portfolio[2])
- Preferred portfolio provides the following characteristics:
  - 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

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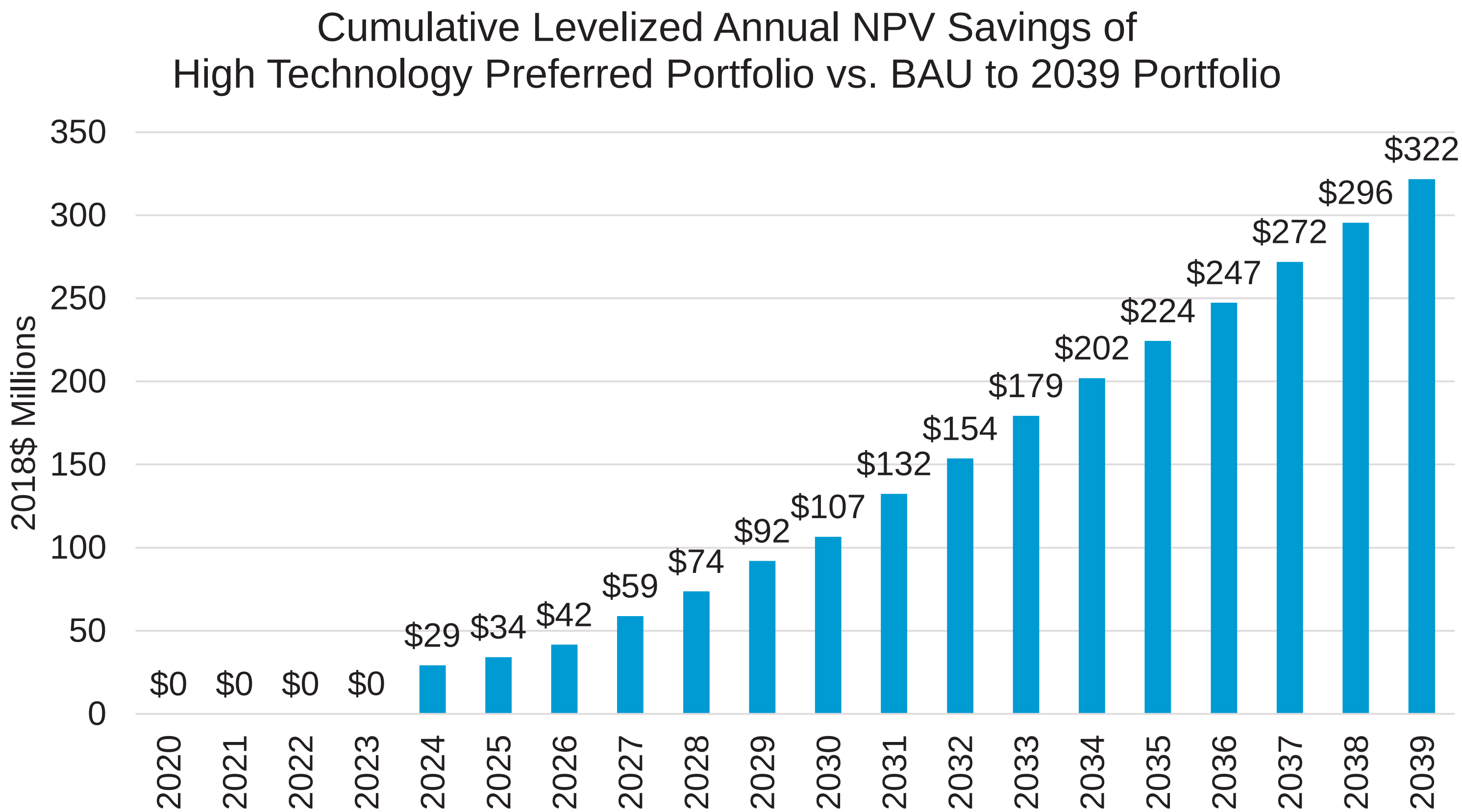
The High Technology (preferred) portfolio provides an annual average savings of $20 million (2024-2039) compared to the Business as Usual to 2039 portfolio and a cumulative savings of more than $320 million in constant NPVRR 2018$.



DIFFERENT DIRECTION FROM 2016 IRP

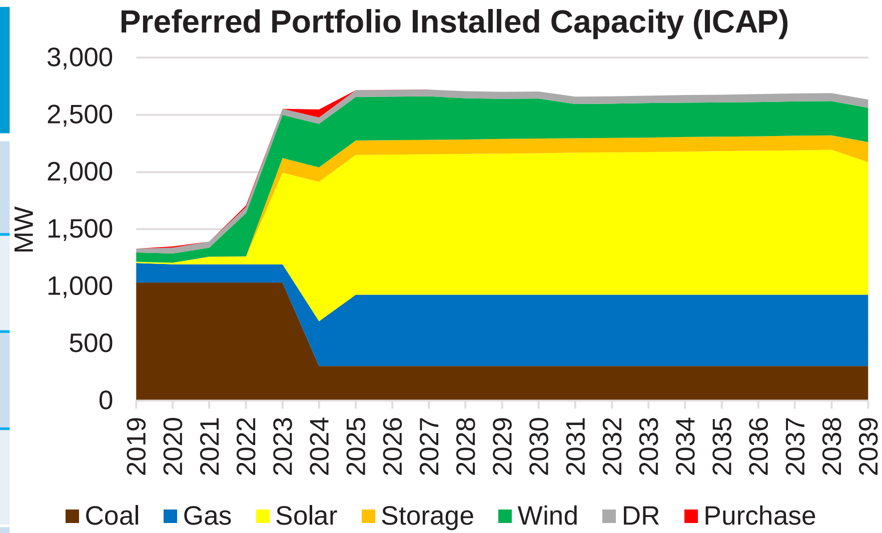
In 2016, Vectren selected a Large 2x1 CCGT (700-850 MWs). In 2020, the preferred portfolio includes a large build out of renewable resources, providing low cost energy, backed up by 2 highly flexible combustion turbines that provide low cost capacity.

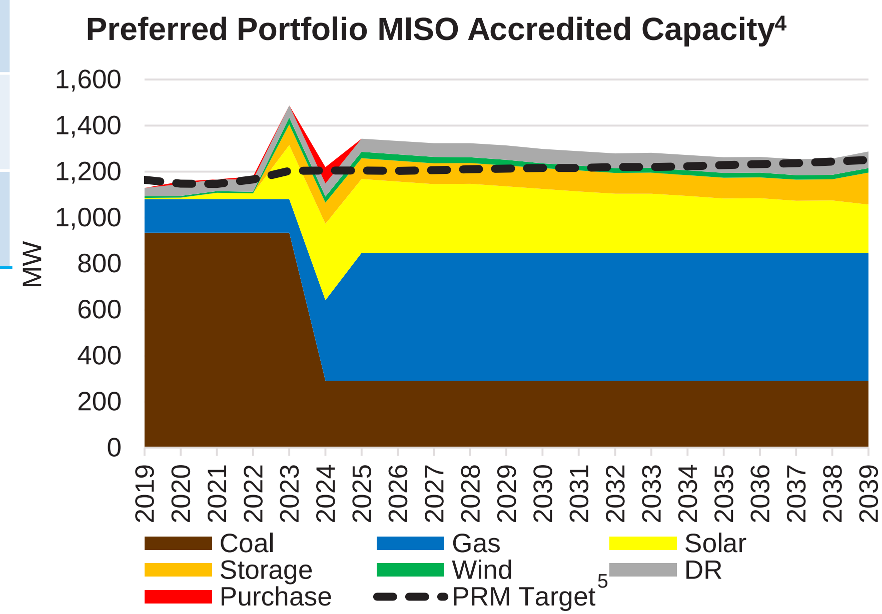
- Lower relative customer impact than many of the portfolio options
- More diverse set of resources, including wind, solar, battery energy storage, EE, DR, gas, and coal
- Faster construction than a CCGT, offsetting market risk more quickly
- Less greenhouse gas emissions and water usage
- Lower dependence 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%

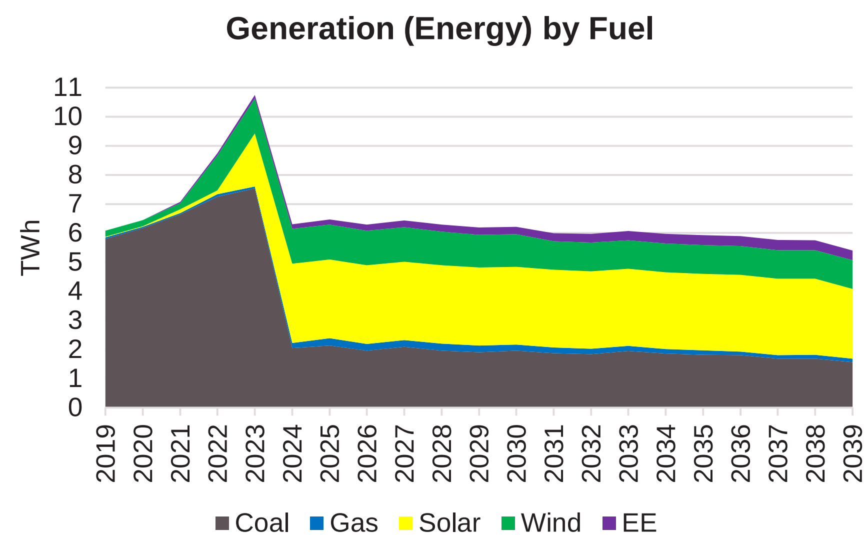
[1] ≈35 MWs at risk due to MISO operational changes
[2] Solar accreditation may vary depending on penetration
[3] UCAP credit includes 90 MW 4-hour battery. Modeled as 126 MW 3-hour battery, consistent with bids
[4] Unforced Capacity (UCAP)
[5] Assumes coincident peak factor of 95.99%, PRM% 8.9%, and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

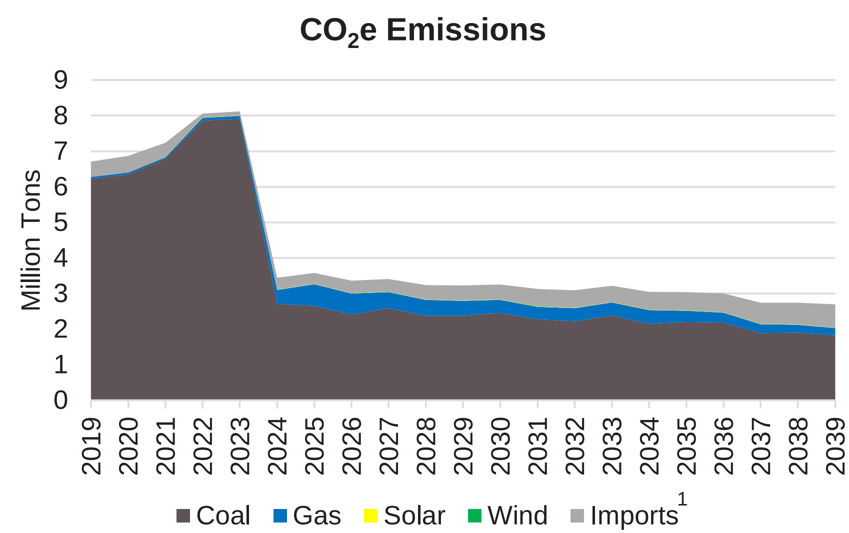




PREFERRED PORTFOLIO ANNUAL GENERATION AND EMISSIONS

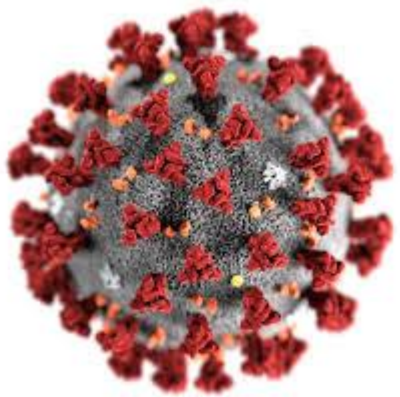
- Generation will shift significantly from coal to renewable resources in the near term, reducing variable fuel costs. Nearly two thirds of total energy produced by 2025 will come from renewable resources.
- The coal retirements and exit by December 31, 2023 result in a significant decline in lifecycle 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 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

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RISK ANALYSIS

PETER HUBBARD

PACE GLOBAL, MANAGER SIEMENS ENERGY BUSINESS ADVISORY

IRP PORTFOLIO EVALUATION AND SELECTION PROCESS

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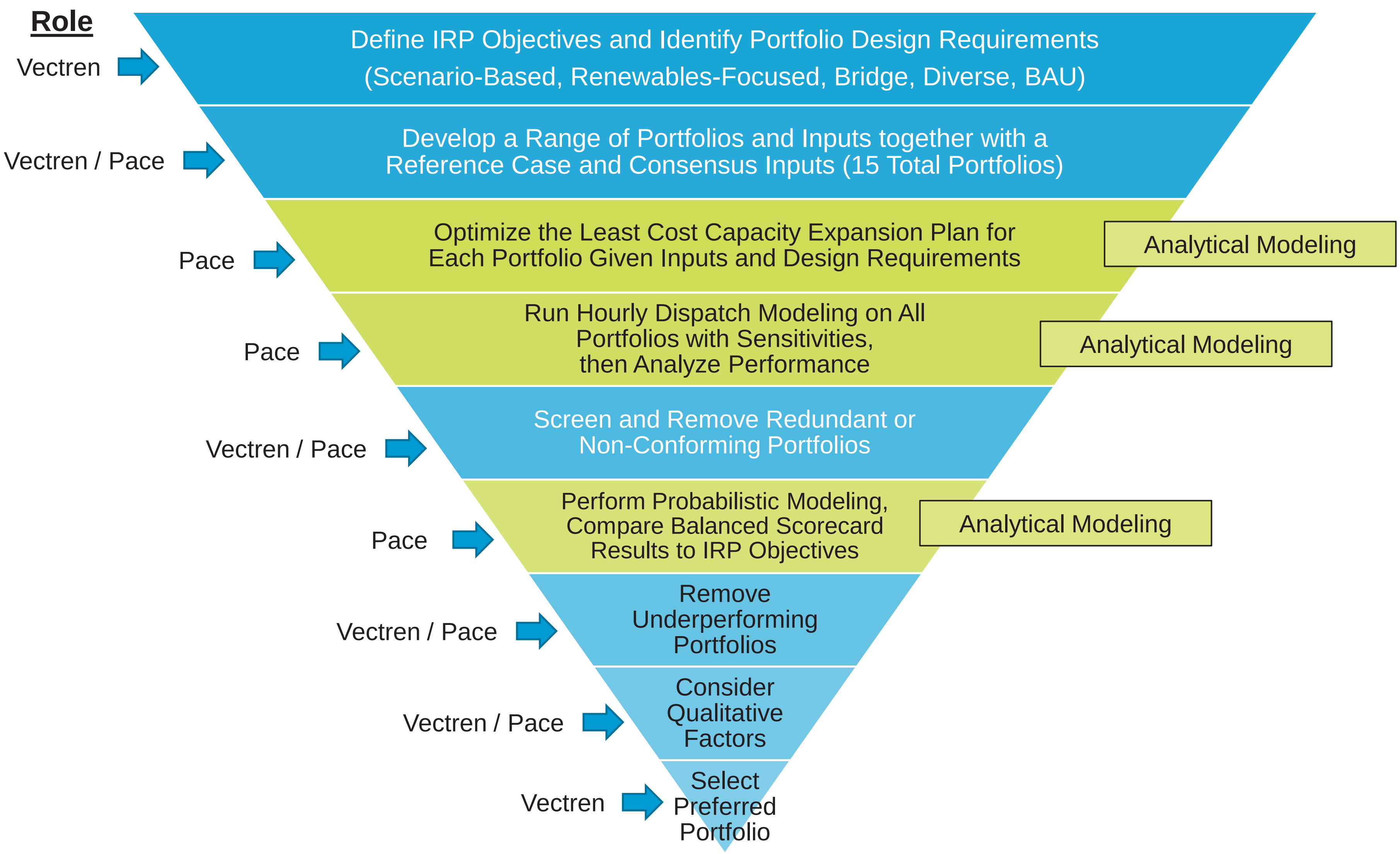

STRUCTURED SCREENING PROCESS TO ADDRESS ISSUES EFFICIENTLY

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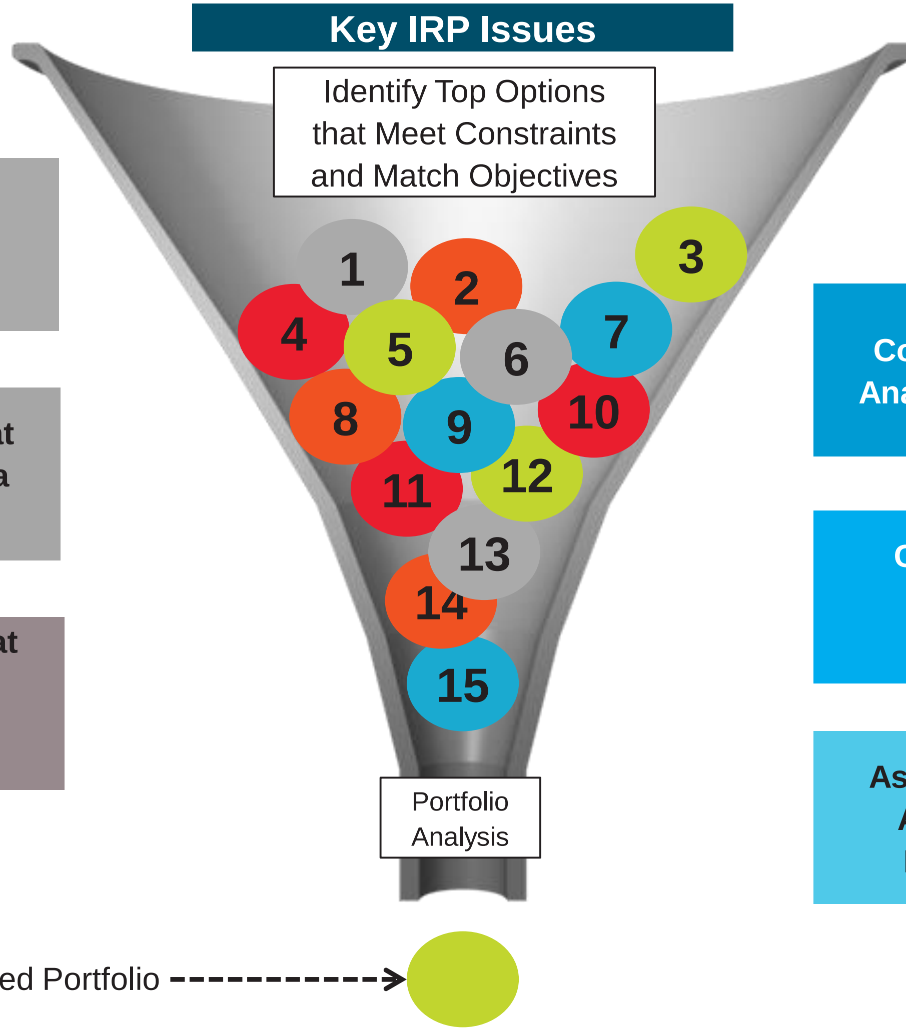
Task

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

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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

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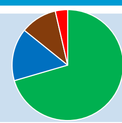
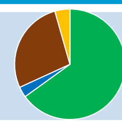
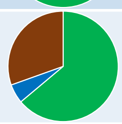
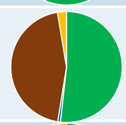
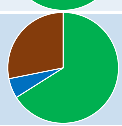
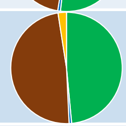
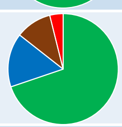
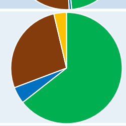
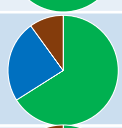
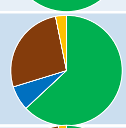
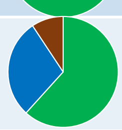
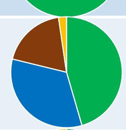
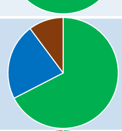
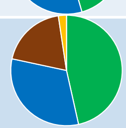
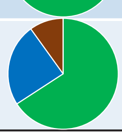
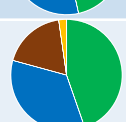
	Portfolio	Portfolio Capacity Mix in 2026	Generation in 2026	NPV $Billion * (% vs. Ref Case)	Net Sales as % of Generation	Average Capacity Mkt Purchases (2024-39)
Ref.	Reference Case			$2.625	7%	138 MW
BAU	Business as Usual to 2039			$3.140 (+19.6%)	23%	0 MW
	Business as Usual to 2029			$2.835 (+8.0%)	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

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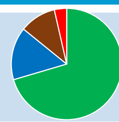
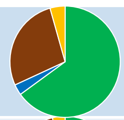
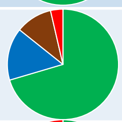
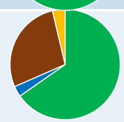
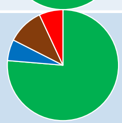
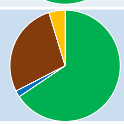
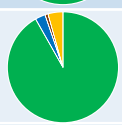
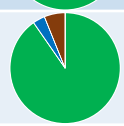
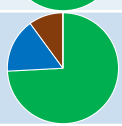
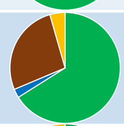
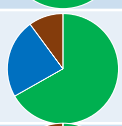
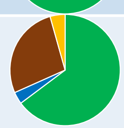
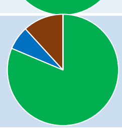
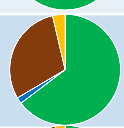
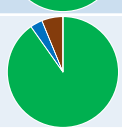
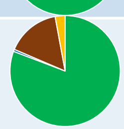
Ref.	Reference Case			$2.625	7%	138 MW
Renewables	Renewables + Flexible Gas			$2.600 (-1.0%)	6%	135 MW
Renewables	Renewable 2030			$2.679 (+2.1%)	10%	170 MW
Renewables	HB 763			$1.425 (-45.7%)	105%	10 MW
Scenario	Low Regulatory			$2.762 (+5.2%)	46%	12 MW
Scenario	High Technology (Preferred Portfolio)			$2.686 (+2.3%)	6%	4 MW
Scenario	80% Reduction			$2.642 (+0.7%)	36%	203 MW
Scenario	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

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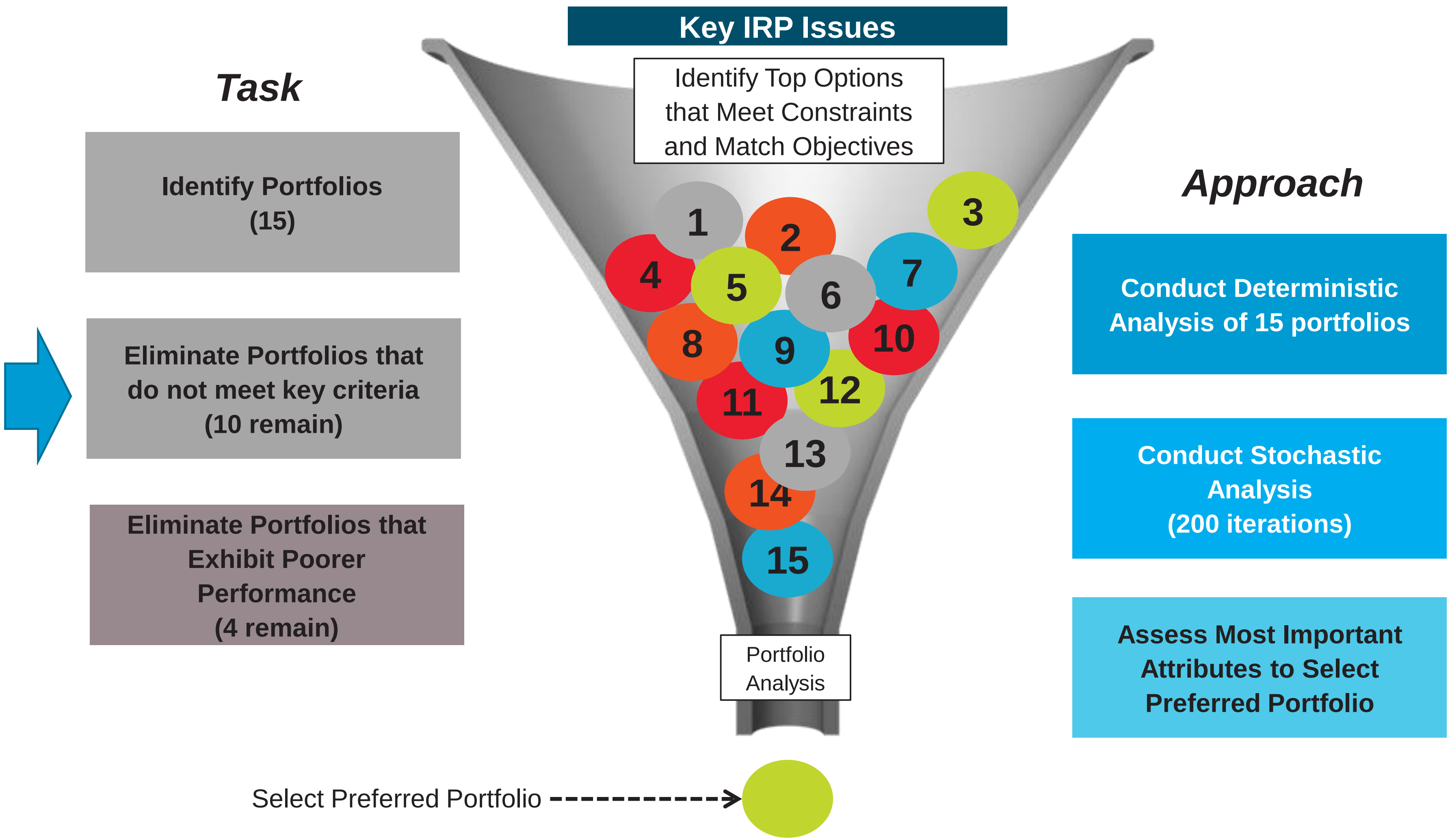

SENSITIVITIES WERE CONDUCTED TO FURTHER UNDERSTAND AND REFINE THE PORTFOLIOS

- 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

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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

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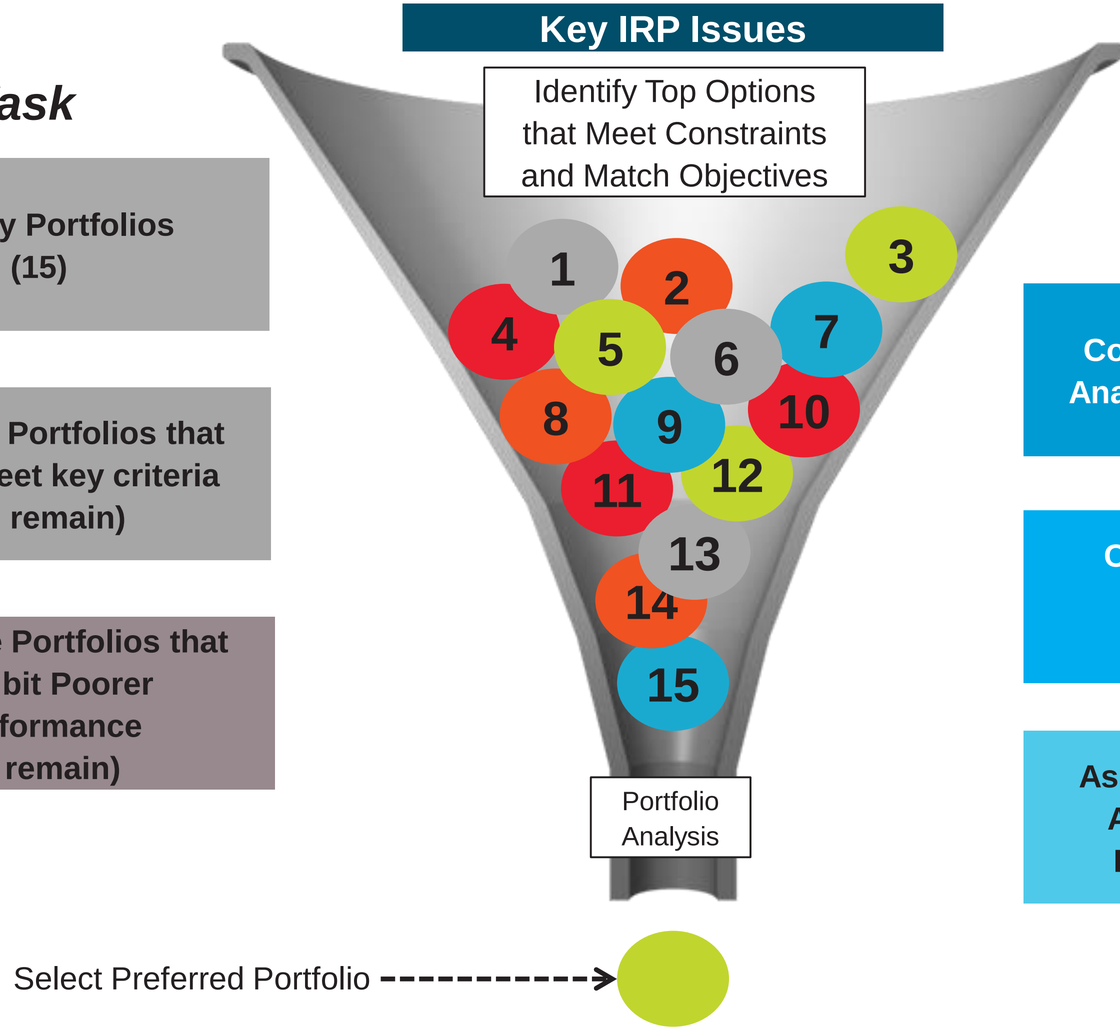
Task

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

BALANCED SCORECARD RESULTS OF PROBABILISTIC ANALYSIS

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- 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

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

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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

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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%
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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 2nd 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

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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 2nd CT (Renewables + Flexible Gas Portfolio – not reflected in NPVRR)
  - Two CTs provide a high degree of flexibility in the future

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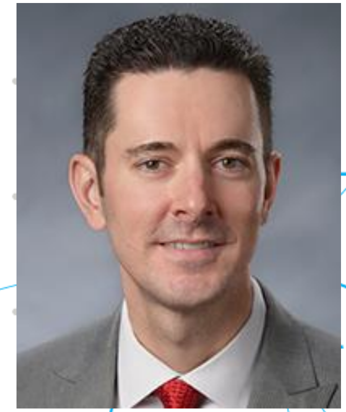
NEXT STEPS

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

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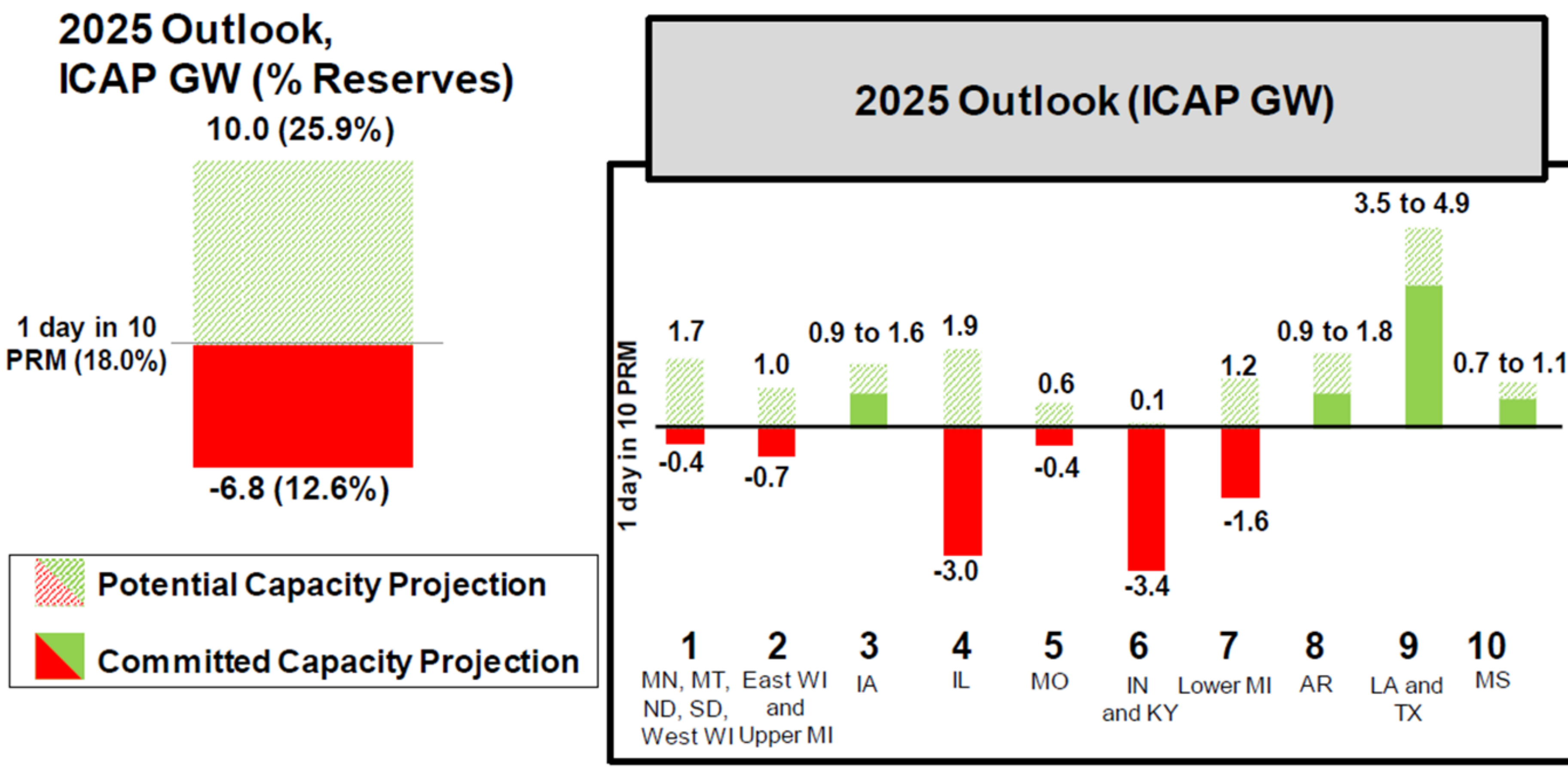
Latest Resource Adequacy results demonstrate the generation shift underway MISO-wide and that is carried out through unit retirements and new generation builds, thus producing less certainty in future years around available capacity



*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

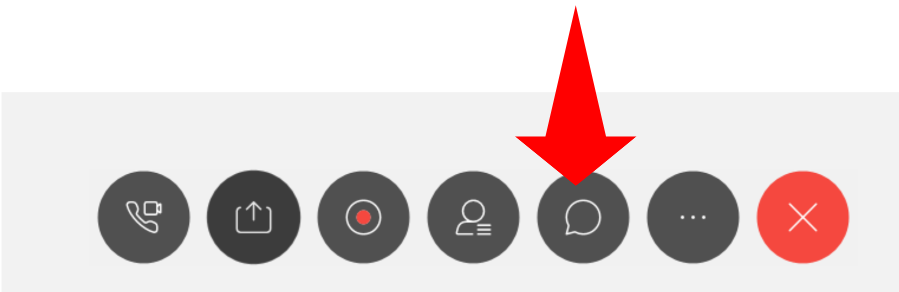
NEXT STEPS

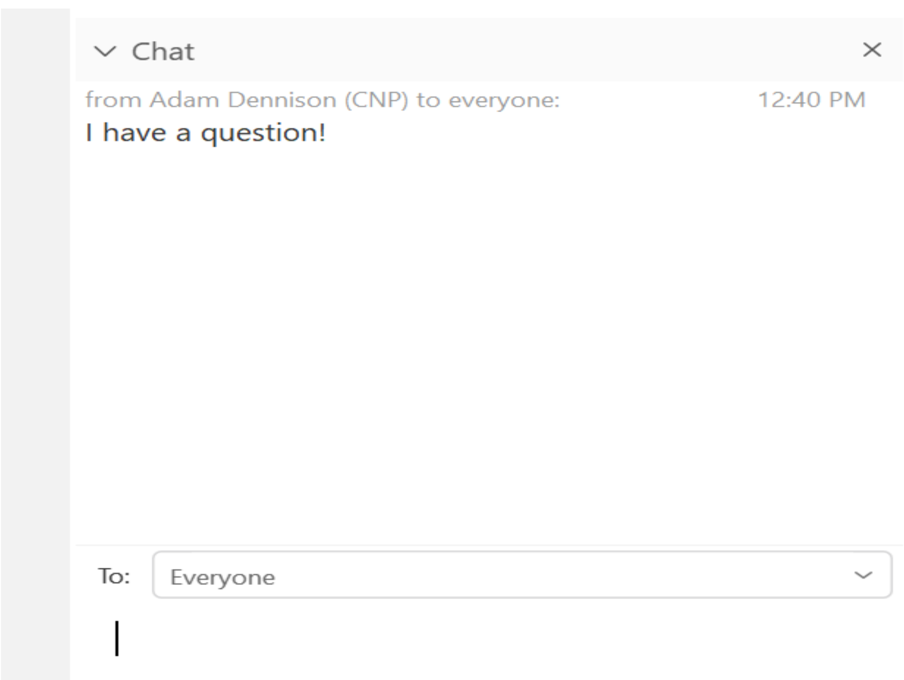
To maximize the $320M in customer savings that the Preferred Portfolio presents, an action plan is in place that is focused on two phases

- **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

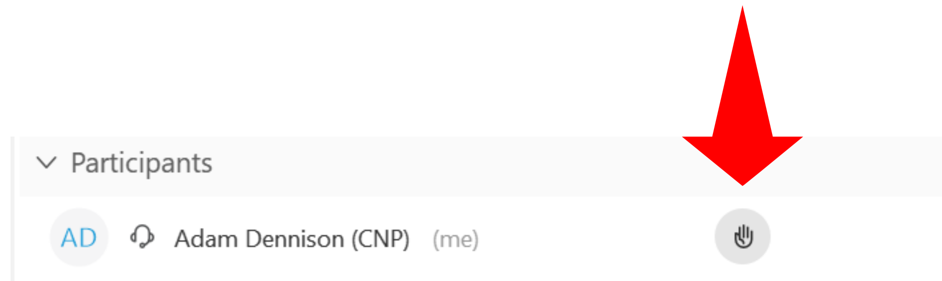
Q&A

Ask “everyone” in chat.

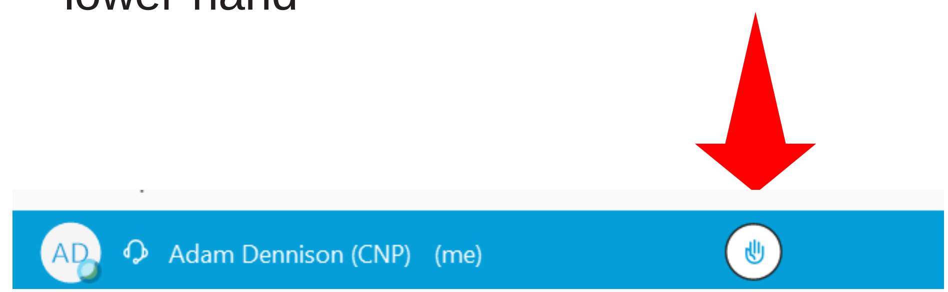




Raise Hand for a Follow-up



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

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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
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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

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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 https://cdn.misoenergy.org/20191106%20RASC%20Item%204b%20RAN%20Capacity%20Accreditation397077.pdf 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

VECTREN
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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

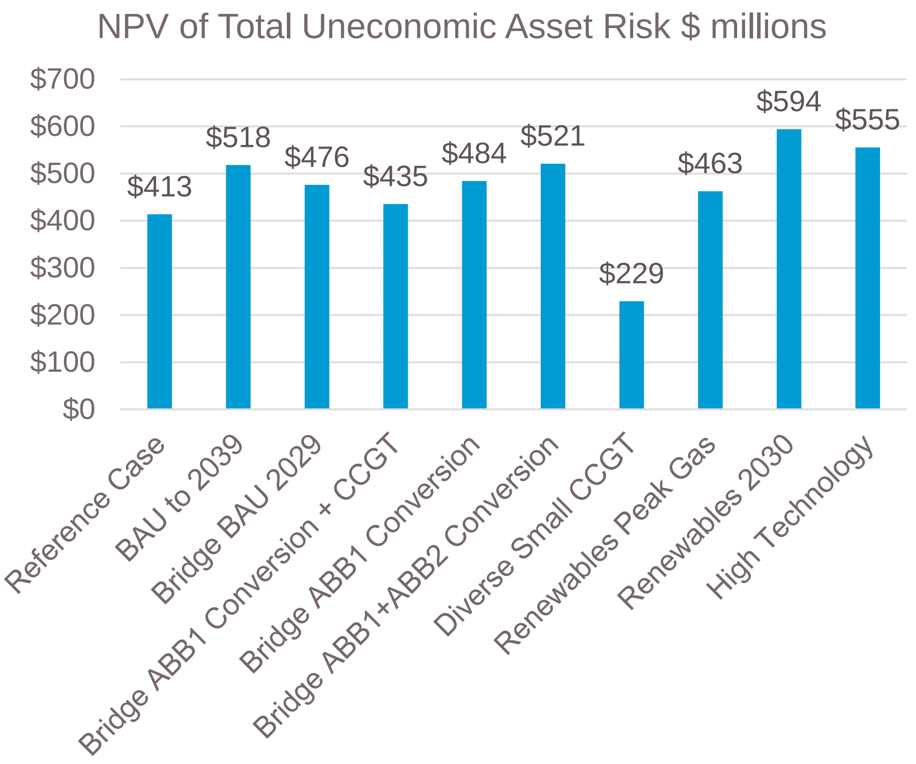
Following the recent order on the 2x1 CCGT, Vectren worked with Pace Global and the stakeholders, to develop the following approach to address the concern over recovering large capital investments:

- 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	[redacted]

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

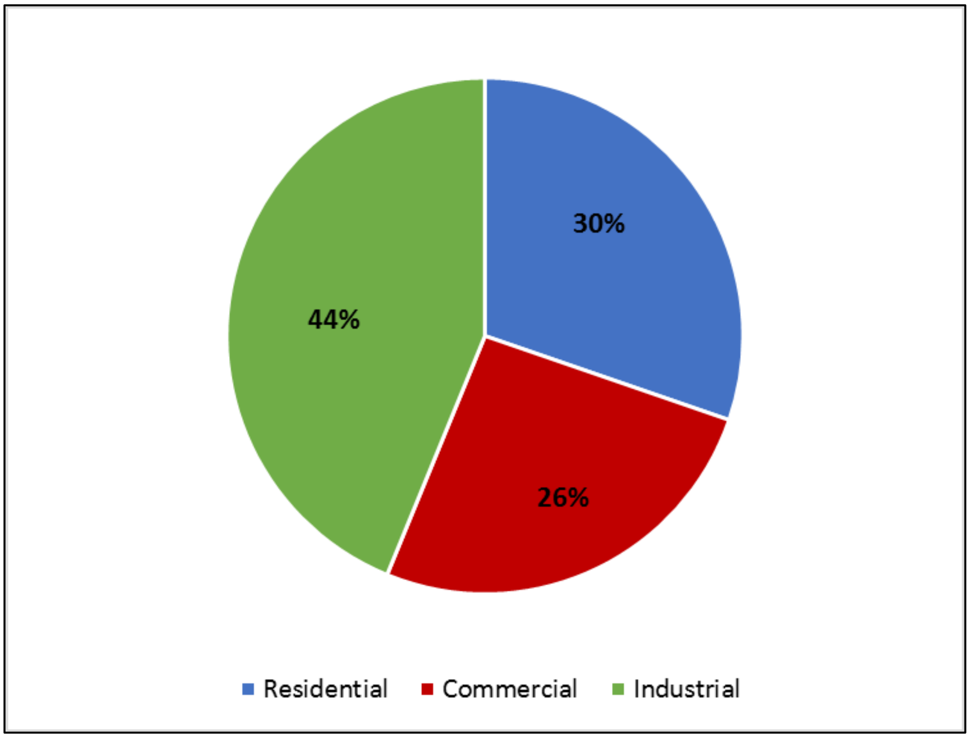
1 Overview

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.

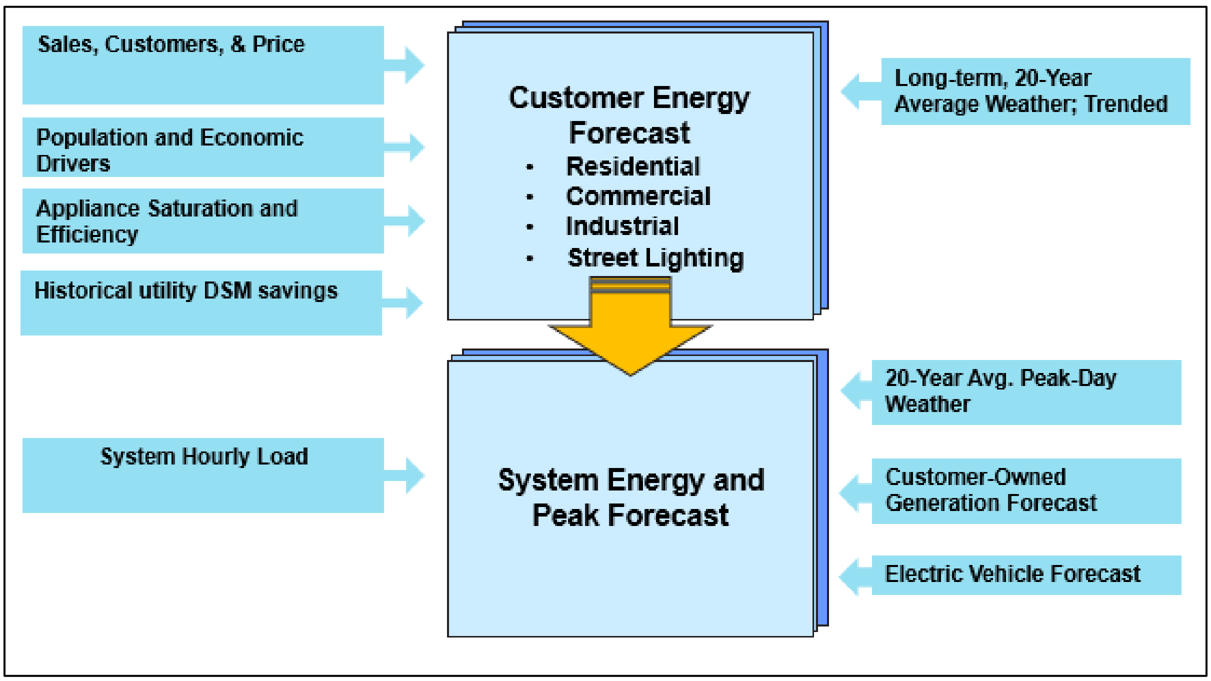
Table 1-1: Energy and Demand Forecast (Excluding DSM Program Savings)

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

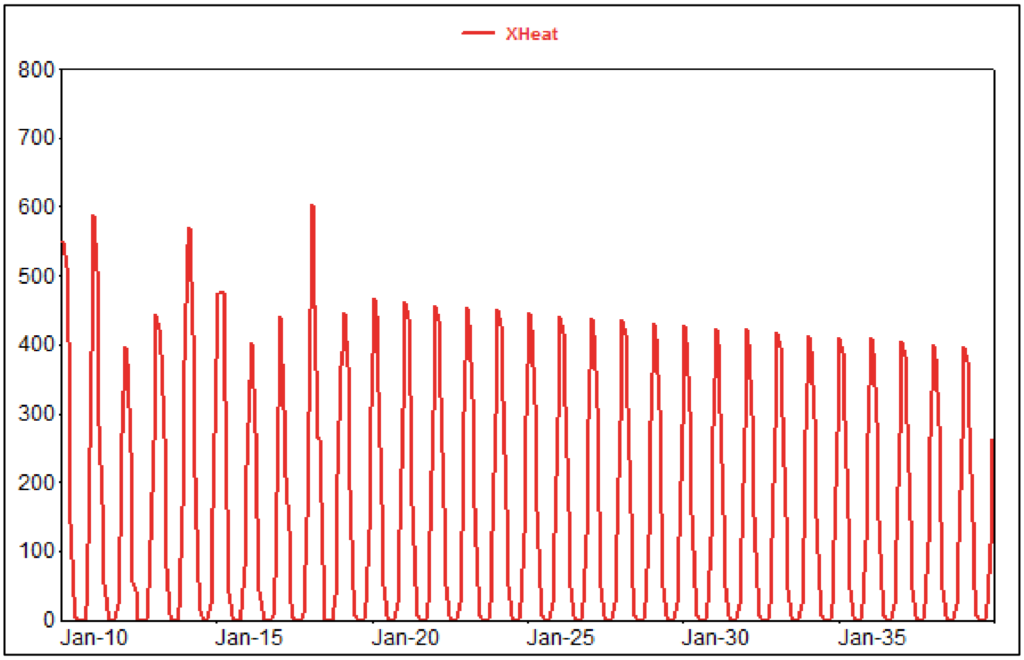


Figure 4: Residential XCool

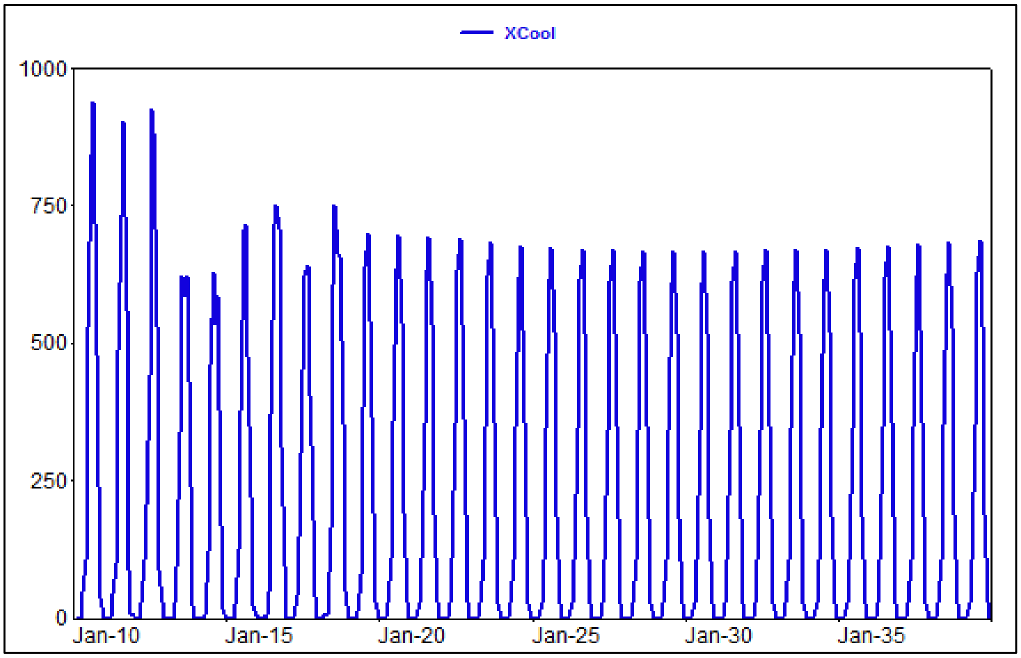
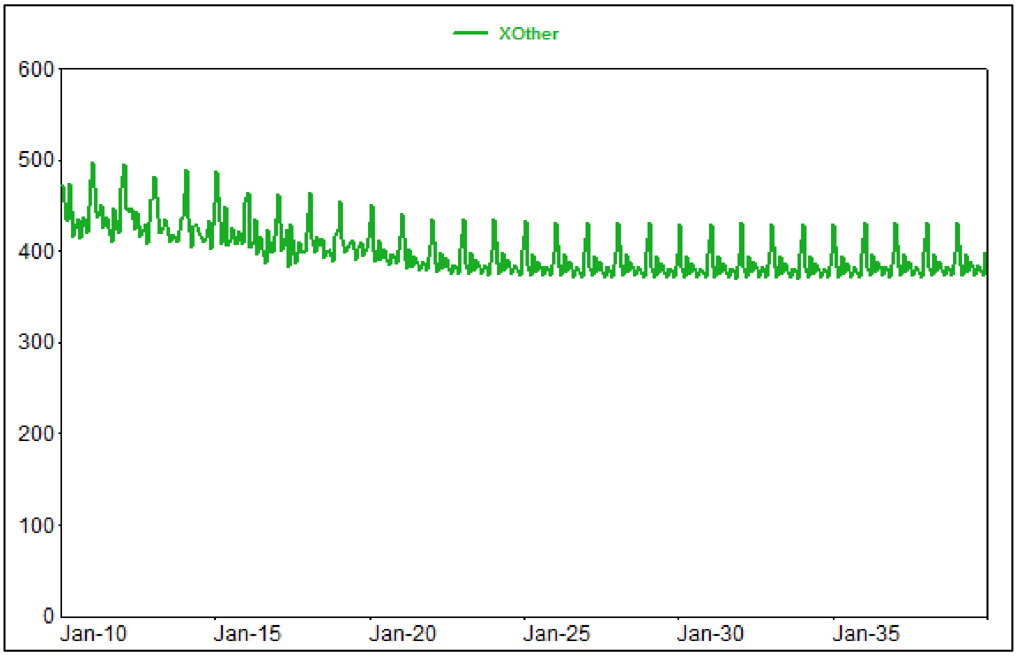


Figure 5: Residential XOther



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

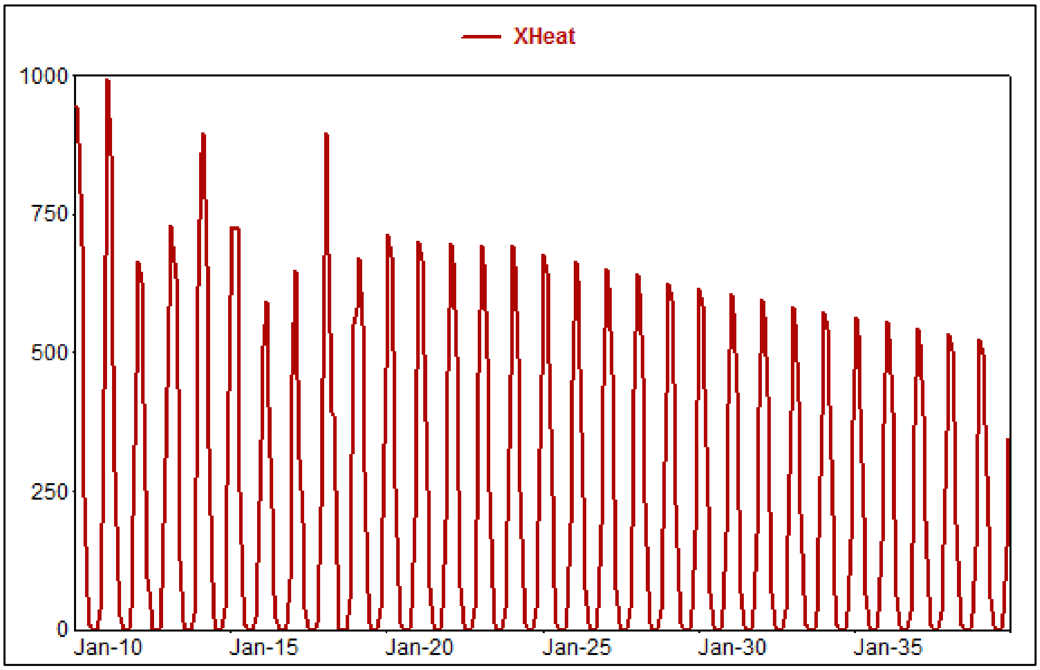


Figure 7: Commercial XCool

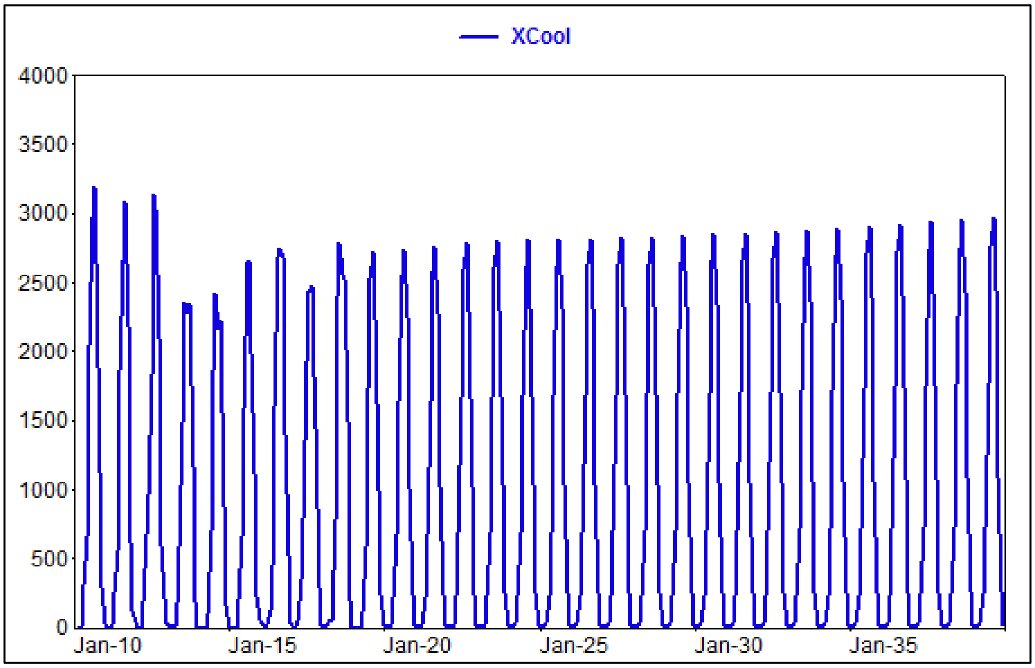
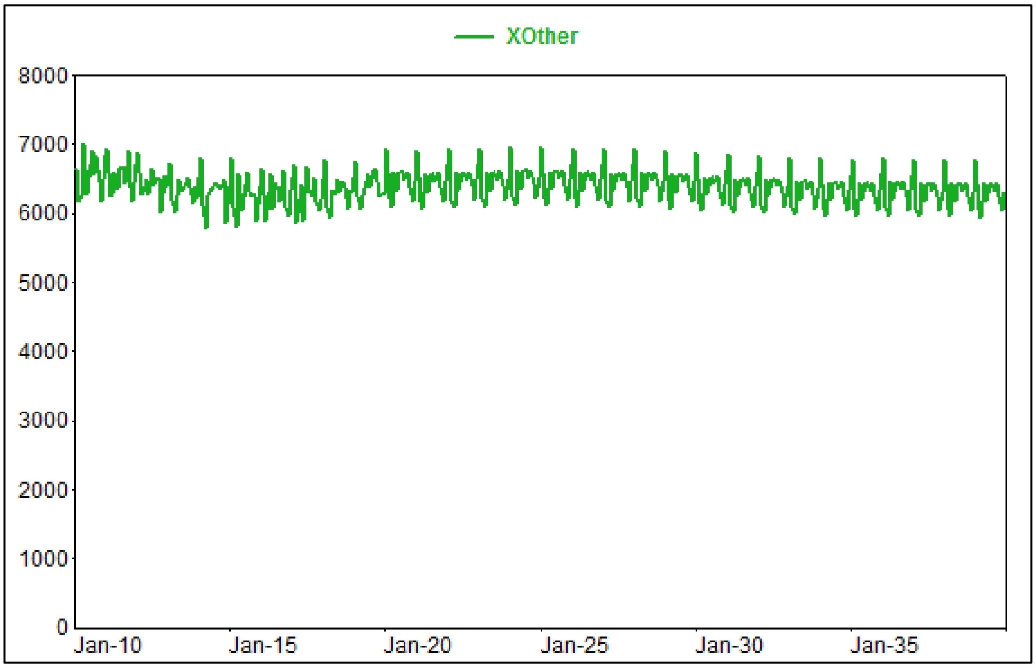


Figure 8: Commercial XOther



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.

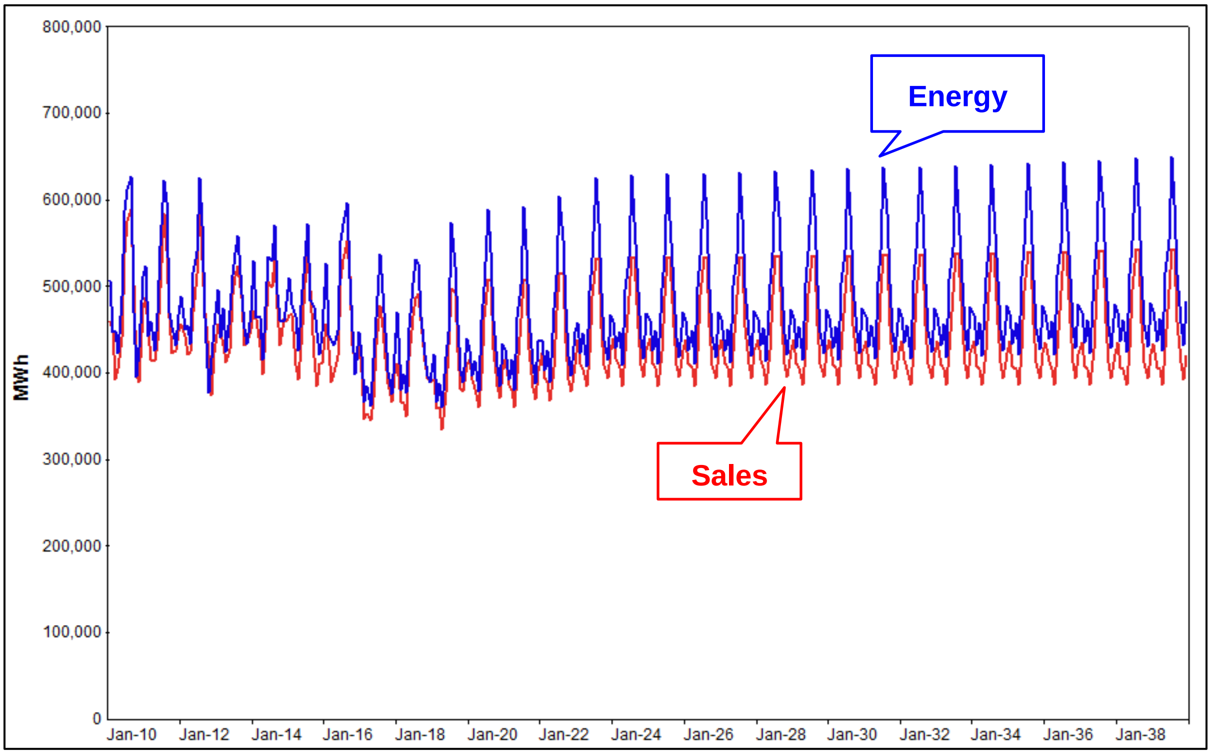
Table 2-4: Street Lighting Forecast

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.

<u>Heating and Cooling Model Variables</u>

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

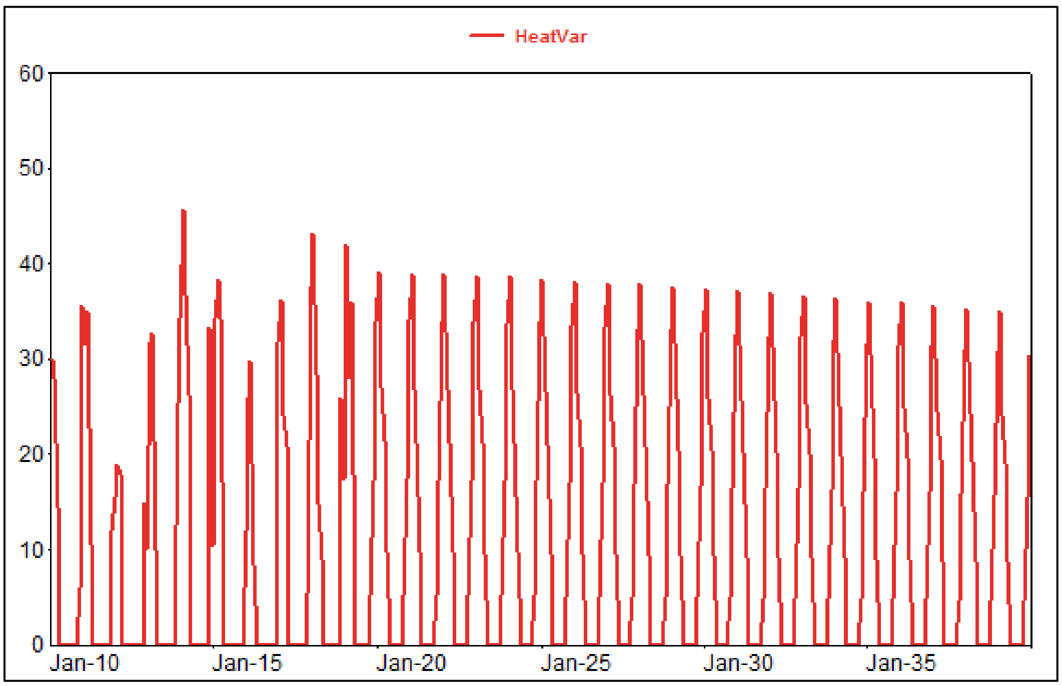
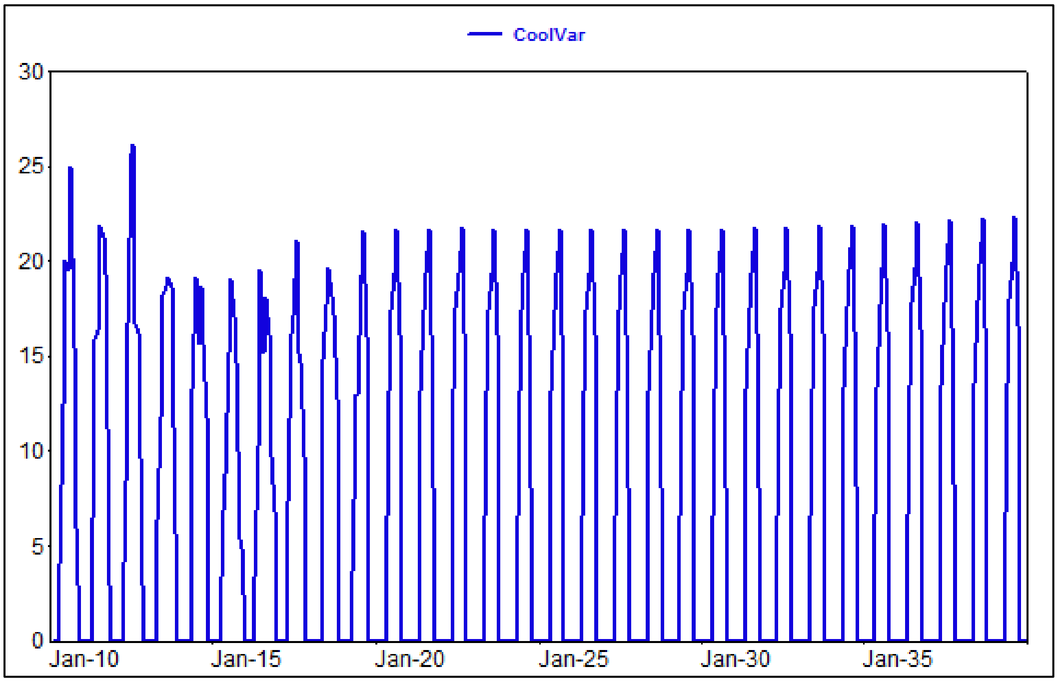


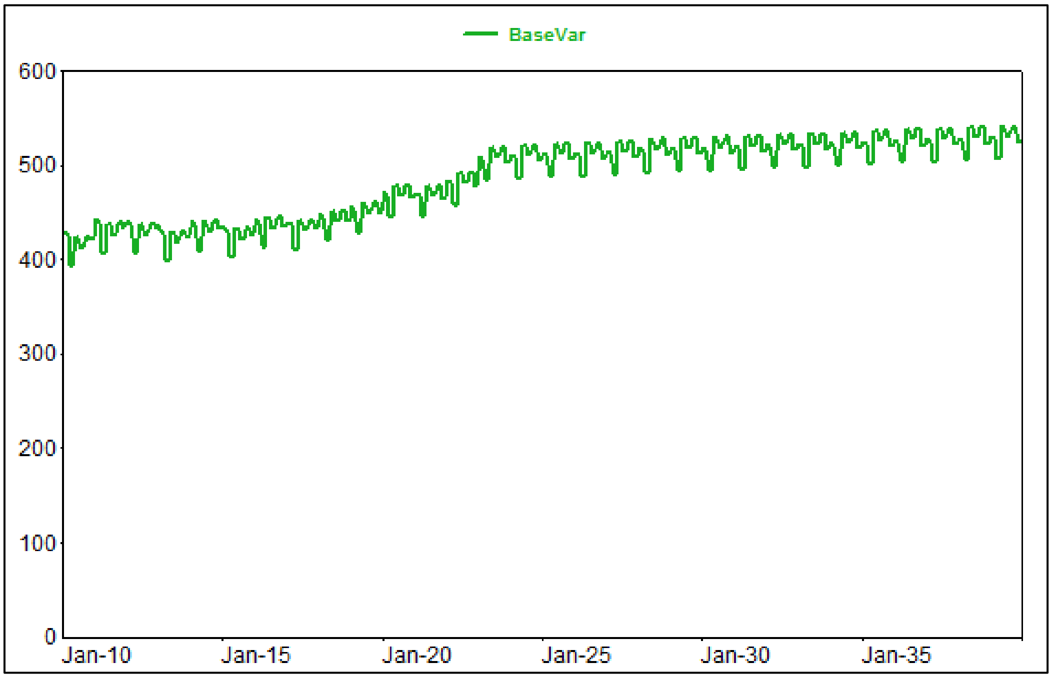
Figure 11: Peak-Day Cooling Variable



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

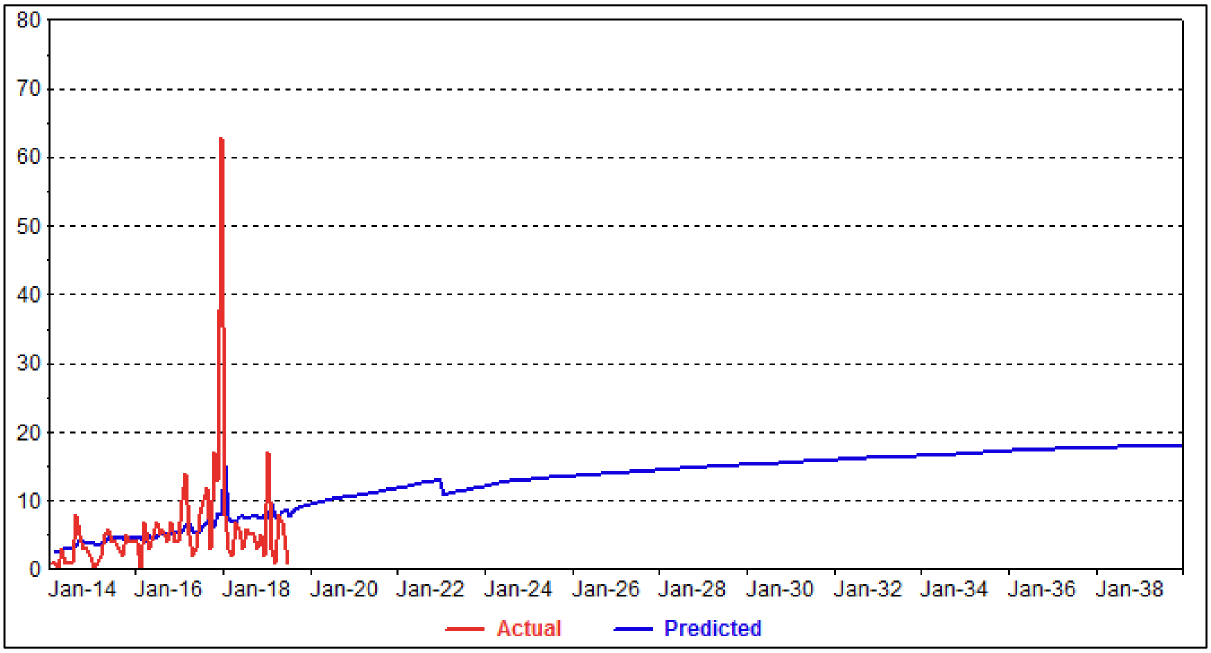
The primary factor driving system adoption is a customer's return-on-investment. A simple payback model is used as proxy. Simple payback reflects the length of time needed to recover the cost of installing a solar system - the shorter the payback, the higher the system adoption rate. From the customer's 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%

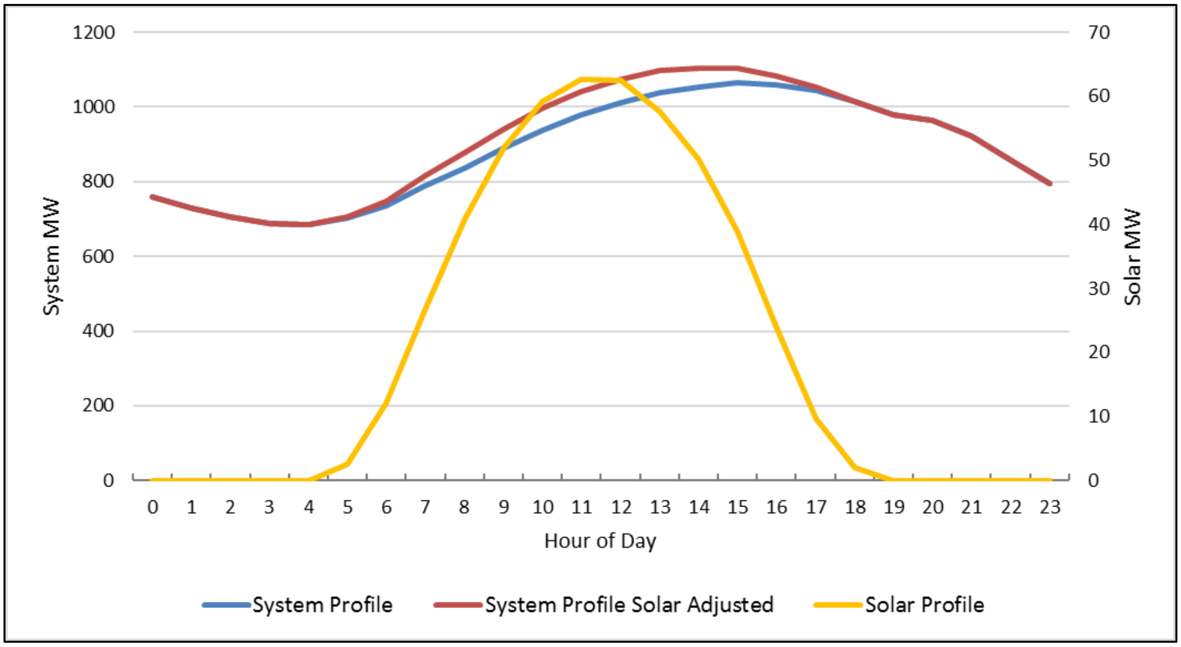
3.2 Solar Capacity and Generation

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

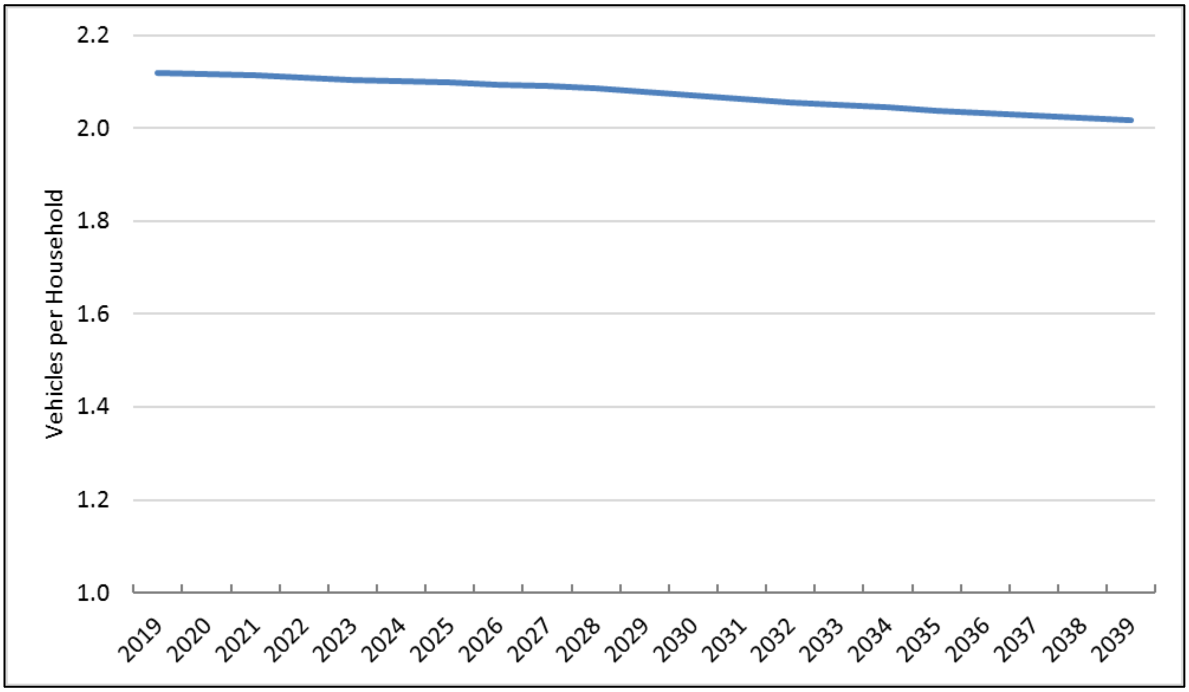
The 2019 Long-Term forecast also includes the impact of electric vehicle adoption. Currently Vectren has relatively few electric vehicles, but this is expected to increase significantly over the next twenty years with improvements in EV technology and declines in battery and vehicle costs. At the time 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

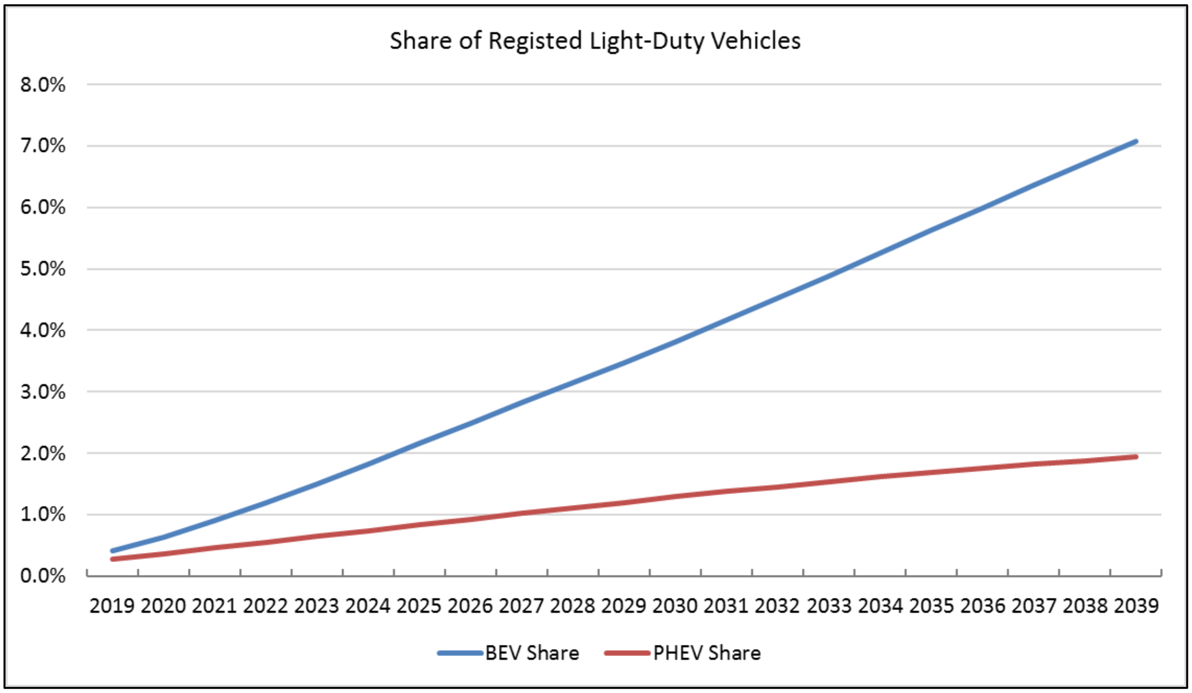


Total service area vehicles are calculated as the product of forecasted customers times EIA projected vehicles per household:

$$Ttl\ Vehicles = \ Custs_{yr} \times EIA\ Vehicle\ Per\ HH_{yr}$$

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

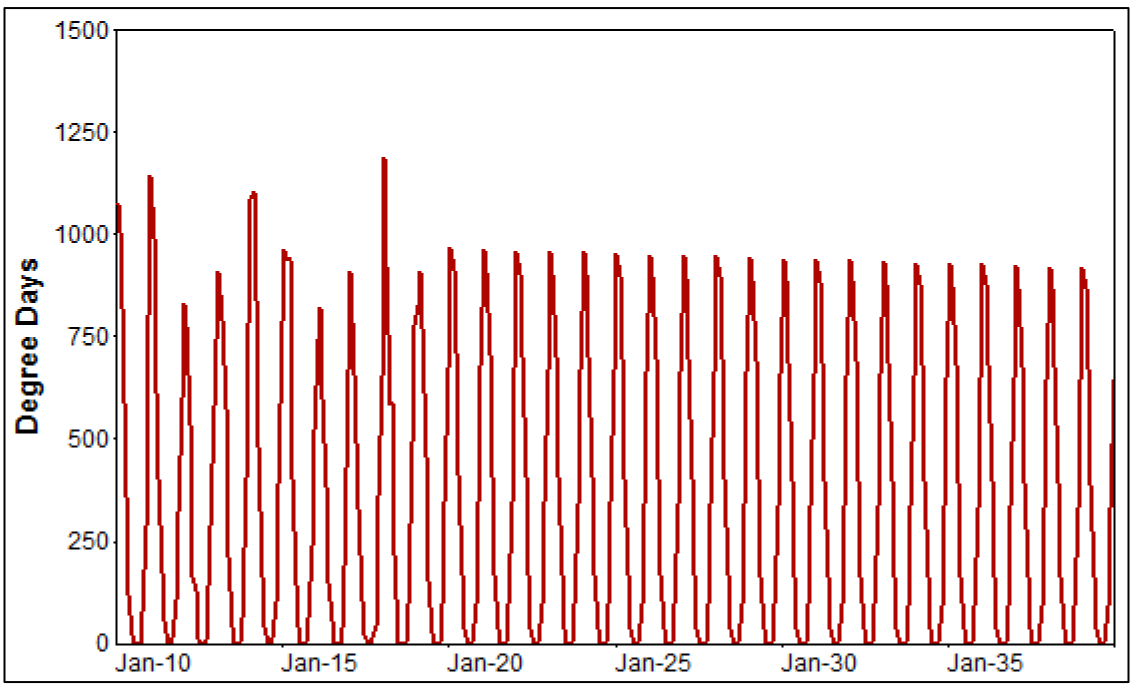
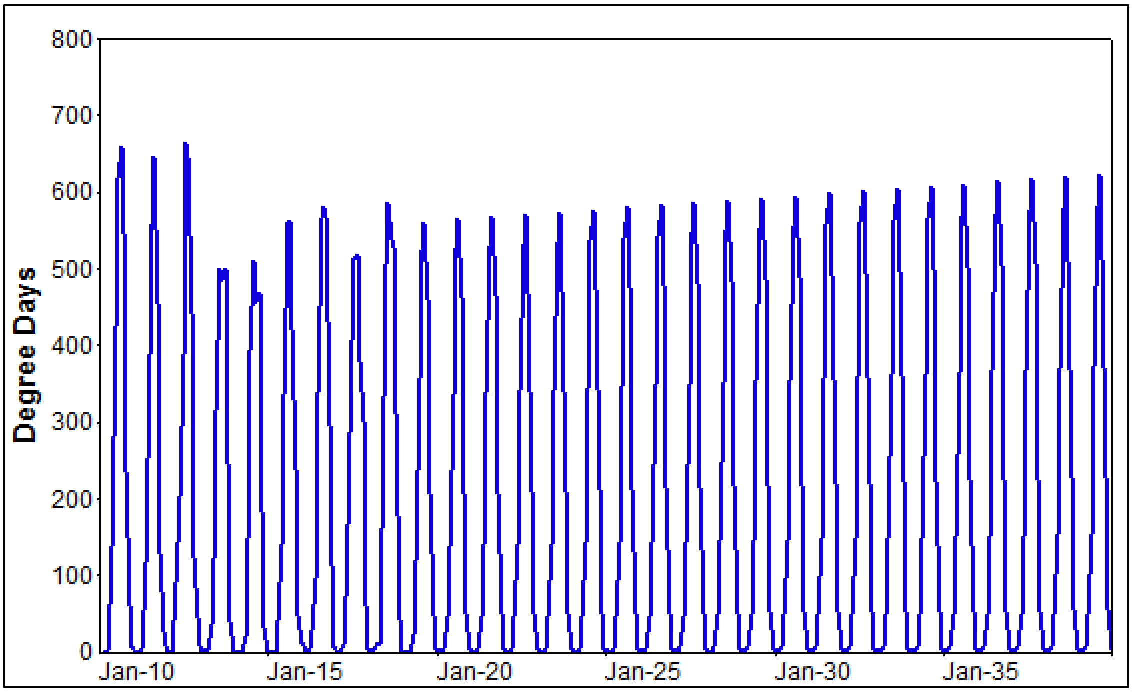


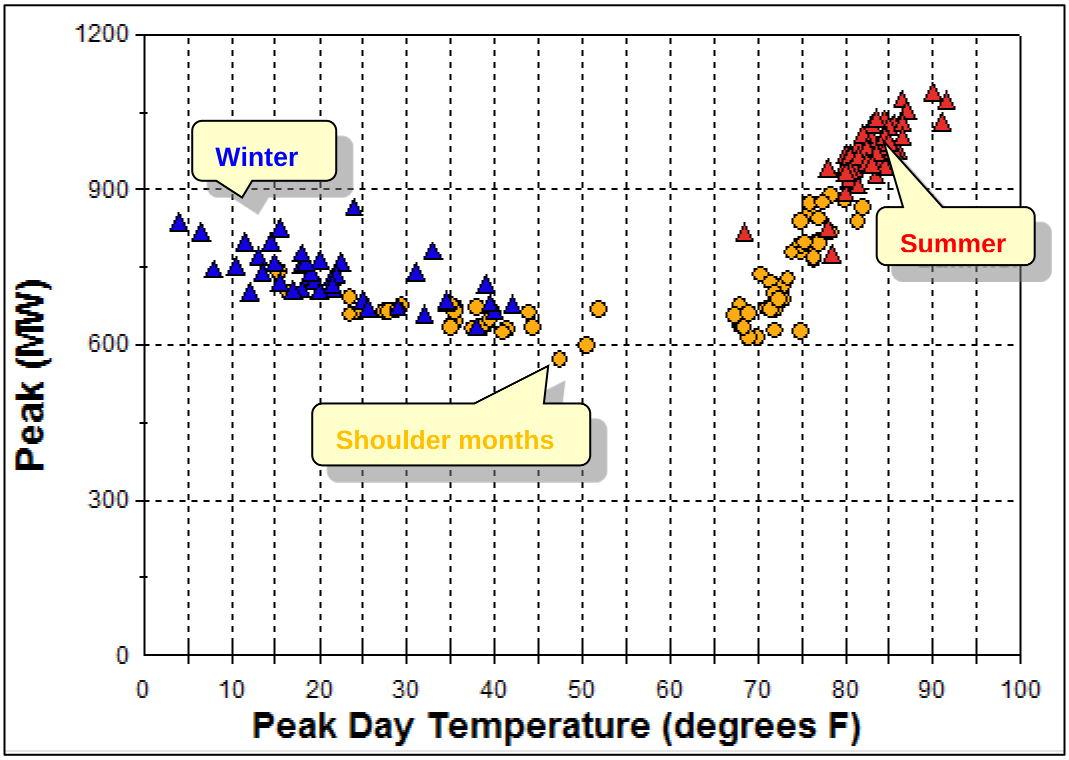
Figure 18: Cooling Degree Days



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.

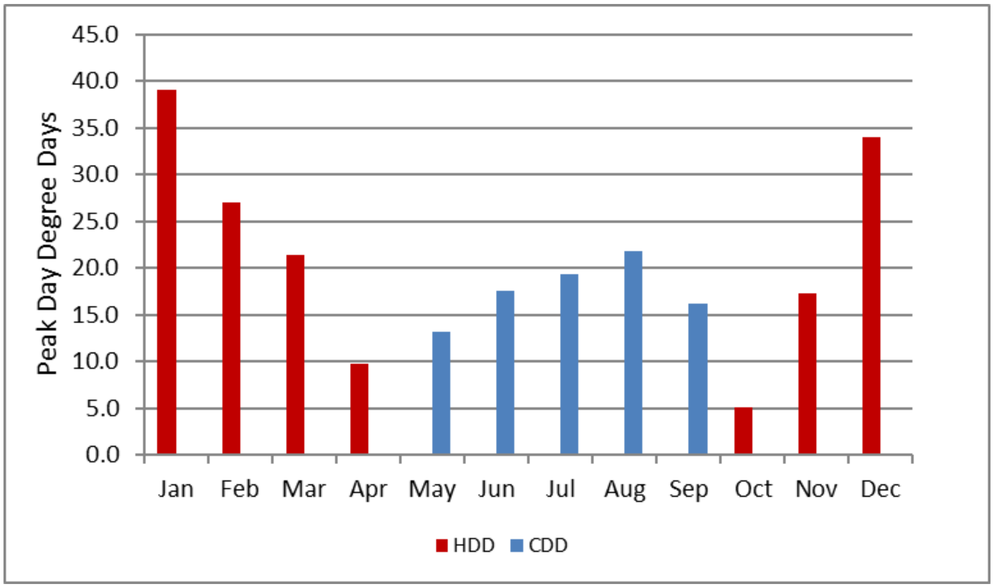
Figure 19: Monthly Peak Demand /Temperature Relationship



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.

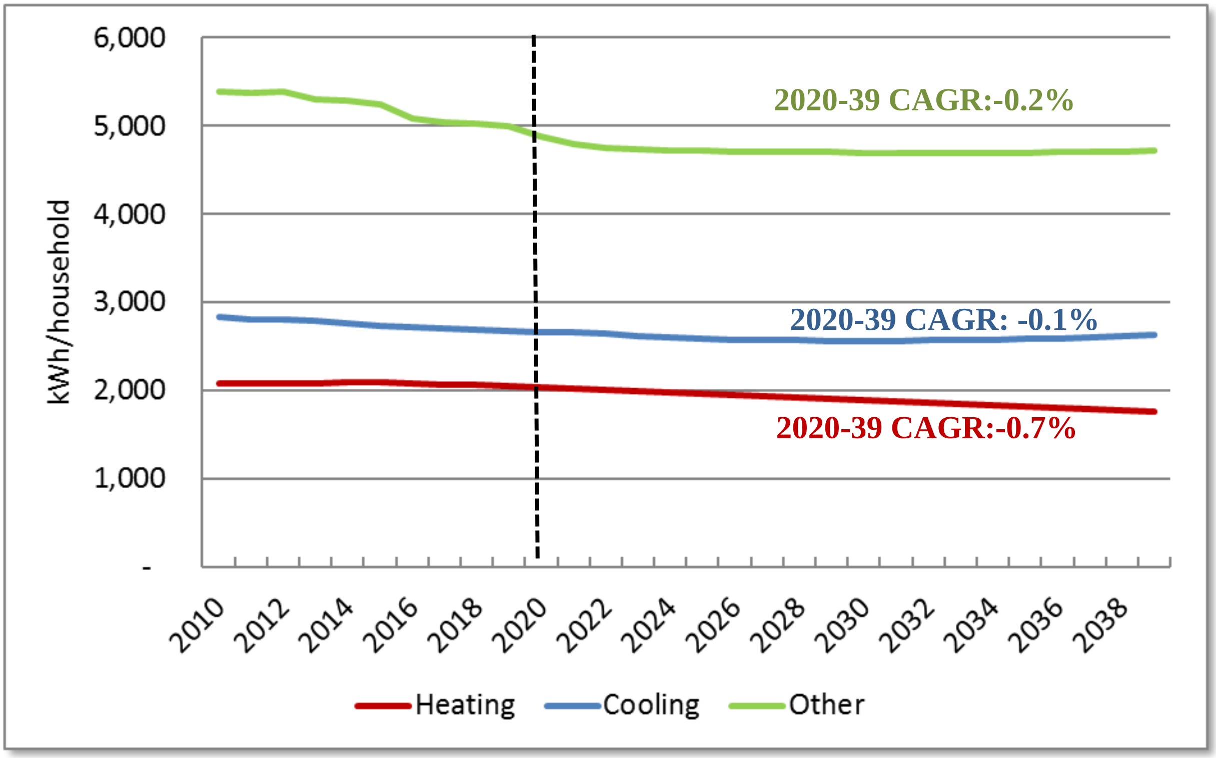
Historical electric prices (in real dollars) are derived from billed sales and revenue data. Historical prices are calculated as a 12-month moving average of the average rate (revenues divided by sales); prices are expressed in real dollars. Prices impact residential and commercial sales through imposed 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

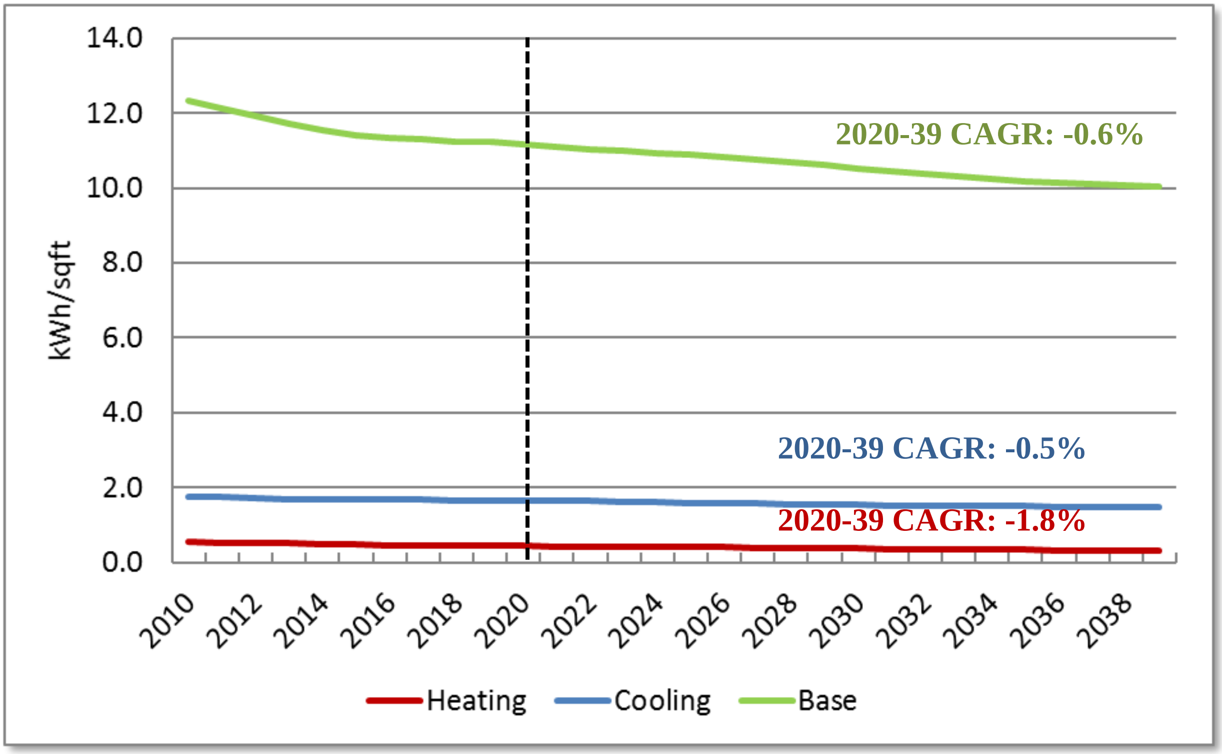


*CAGR=Compound Average Growth Rate

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,

$$USE_{y,m} = Heat_{y,m} + Cool_{y,m} + Other_{y,m} \tag{1}$$

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.

$$USE_m = a + b_1 \times XHeat_m + b_2 \times XCool_m + b_3 \times XOther_m + \varepsilon_m \qquad (2)$$

$XHeat_m$, $XCool_m$, 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:

$$HeatIndex_y = StructuralIndex_y \times \sum_{Type} Weight^{Type} \times \frac{\left(Sat_y^{Type} \big/ Eff_y^{Type} \right)}{\left(Sat_{2015}^{Type} \big/ Eff_{2015}^{Type} \right)} \qquad (4)$$

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:

$$StructuralIndex_y = \frac{BuildingShellEfficiencyIndex_y \times SurfaceArea_y}{BuildingShellEfficiencyIndex_{2015} \times SurfaceArea_{2015}} \qquad (5)$$

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:

$$SurfaceArea_y = 892 + 1.44 \times Footage_y \qquad (6)$$

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:

$$HeatUse_{y,m} = \left(\frac{HDD_{y,m}}{HDD_{05}}\right) \times \left(\frac{HHSize_y}{HHSize_{05,7}}\right)^{0.25} \times \left(\frac{Income_y}{Income_{05,7}}\right)^{0.10} \times \left(\frac{Elec\,Price_{y,m}}{Elec\,Price_{05,7}}\right)^{-0.10} \quad (7)$$

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:

$$CoolIndex_y = StructuralIndex_y \times \sum_{Type} Weight^{Type} \times \frac{\left(Sat_y^{Type} \big/ Eff_y^{Type} \right)}{\left(Sat_{2015}^{Type} \big/ Eff_{2015}^{Type} \right)} \tag{9}$$

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:

$$CoolUse_{y,m} = \left(\frac{CDD_{y,m}}{CDD_{05}}\right) \times \left(\frac{HHSize_y}{HHSize_{05,7}}\right)^{0.25} \times \left(\frac{Income_y}{Income_{05,7}}\right)^{0.10} \times \left(\frac{Elec\,Price_{y,m}}{Elec\,Price_{05,7}}\right)^{-0.10} \tag{10}$$

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:

$$XOther_{y,m} = OtherEqpIndex_{y,m} \times OtherUse_{y,m} \quad (11)$$

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.

$$ApplianceIndex_{y,m} = Weight^{Type} \times \frac{\left(Sat_y^{Type} \Big/ \frac{1}{UEC_y^{Type}} \right)}{\left(Sat_{2015}^{Type} \Big/ \frac{1}{UEC_{2015}^{Type}} \right)} \times MoMult_m^{Type} \times \quad (12)$$

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:

$$ApplianceUse_{y,m} = \left(\frac{BDays_{y,m}}{30.5}\right) \times \left(\frac{HHSize_y}{HHSize_{05,7}}\right)^{0.25} \times \left(\frac{Income_y}{Income_{05,7}}\right)^{0.10} \times \left(\frac{Elec\,Price_{y,m}}{Elec\,Price_{05,7}}\right)^{-0.10} \quad (13)$$

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,

$$USE_{y,m} = Heat_{y,m} + Cool_{y,m} + Other_{y,m} \quad (1)$$

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.

$$USE_m = a + b_1 \times XHeat_m + b_2 \times XCool_m + b_3 \times XOther_m + \varepsilon_m \quad (2)$$

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,

$$XHeat_{y,m} = HeatIndex_y \times HeatUse_{y,m} \quad (3)$$

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,

$$\text{XCool}_{\text{y,m}} = \text{CoolIndex}_{\text{y}} \times \text{CoolUse}_{\text{y,m}} \tag{7}$$

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:

$$OtherIndex_{y,m} = \sum_{Type} Weight_{2013}^{Type} \times \left(\frac{Share_y^{Type} / Eff_y^{Type}}{Share_{2013}^{Type} / Eff_{2013}^{Type}} \right) \tag{12}$$

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:

$$Weight_{2013}^{Type} = \left(\frac{kWh}{Sqft}\right)_{Type} \times \left(\frac{CommercialSales_{04}}{\sum_e {}^{kWh}/_{Sqft_e}} \right) \tag{13}$$

Further monthly variation is introduced by multiplying by usage factors that cut across all end uses, constructed as follows:

$$OtherUse_{y,m} = \left(\frac{BDays_{y,m}}{30.5}\right) \times \left(\frac{EconVar_{y,m}}{EconVar_{05,7}}\right) \times \left(\frac{Price_{y.m}}{Price_{05,7}}\right)^{-0.10} \tag{14}$$

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

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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:

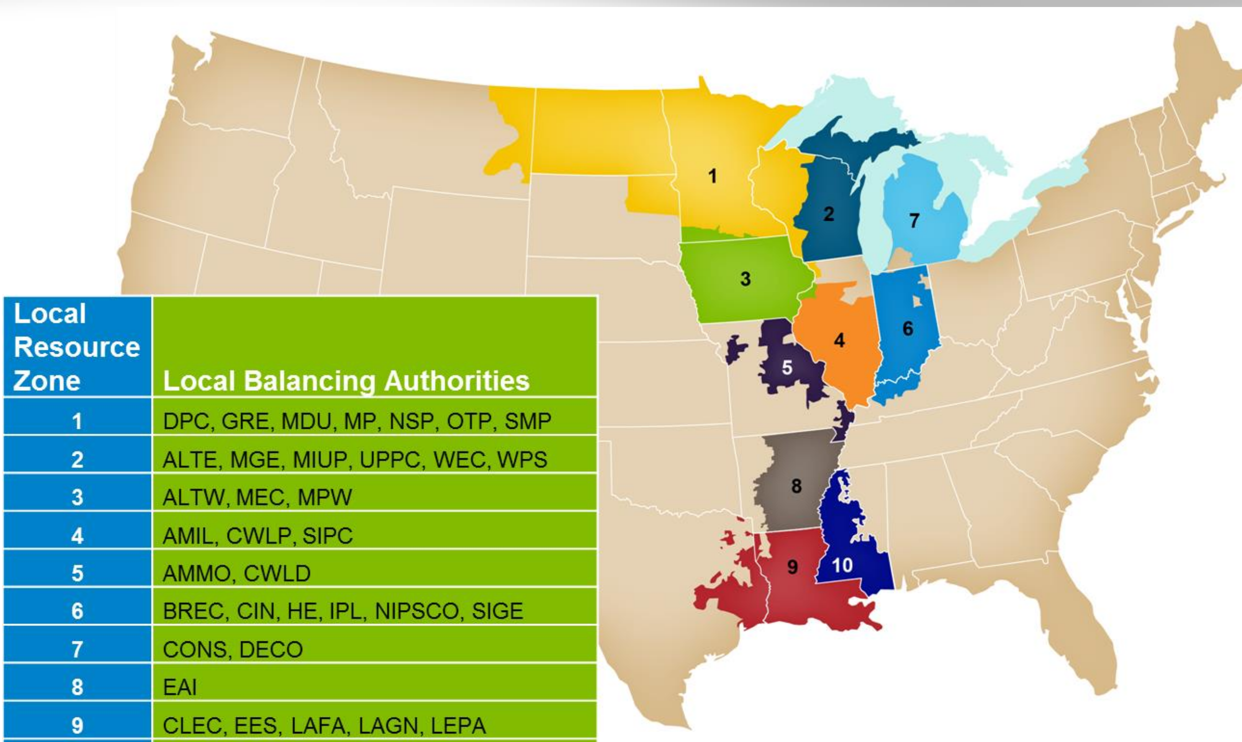
- Establishes a PRM UCAP of 7.9 percent to be applied to the Load Serving Entity (LSE) coincident peaks for the planning year starting June 2019 and ending May 2020
- Uses the Strategic Energy Risk Valuation Model (SERVM) software for Loss of Load analysis to provide results applicable across the MISO 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.

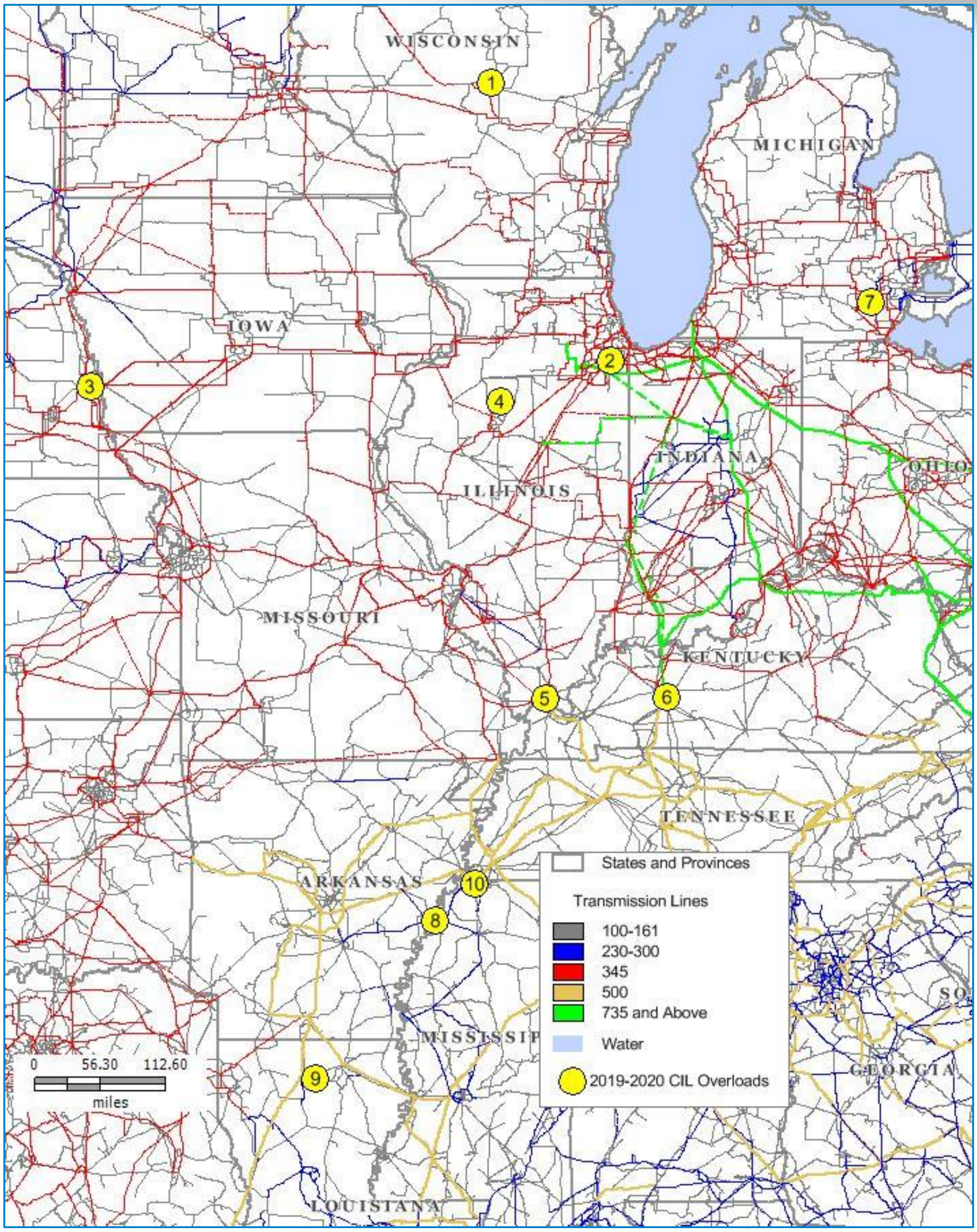


Figure 3-1: Planning Year 2019-20 Import Constraint Map

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

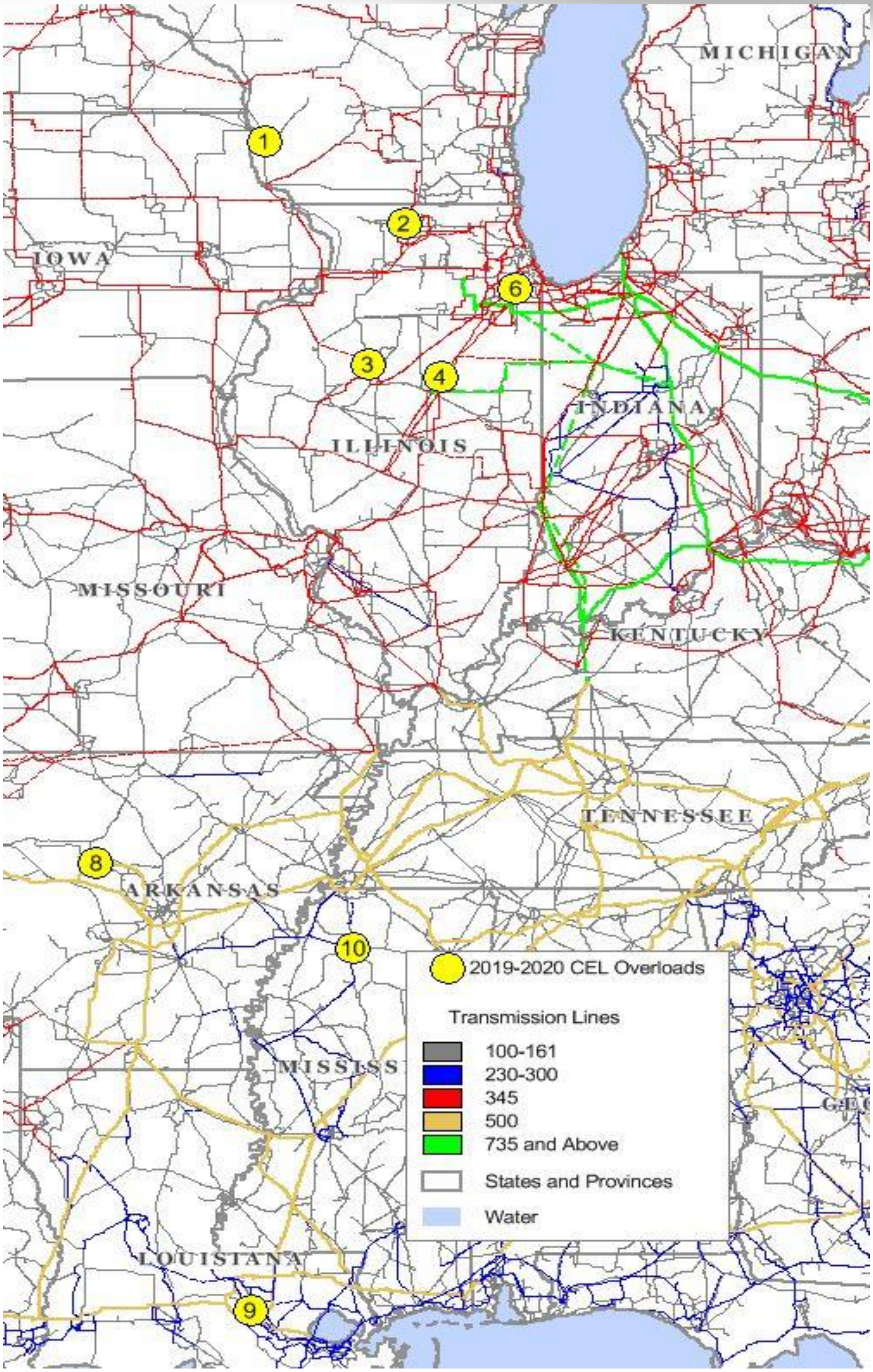


Figure 3-2: Planning Year 2019-20 Export Constraint Map

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.

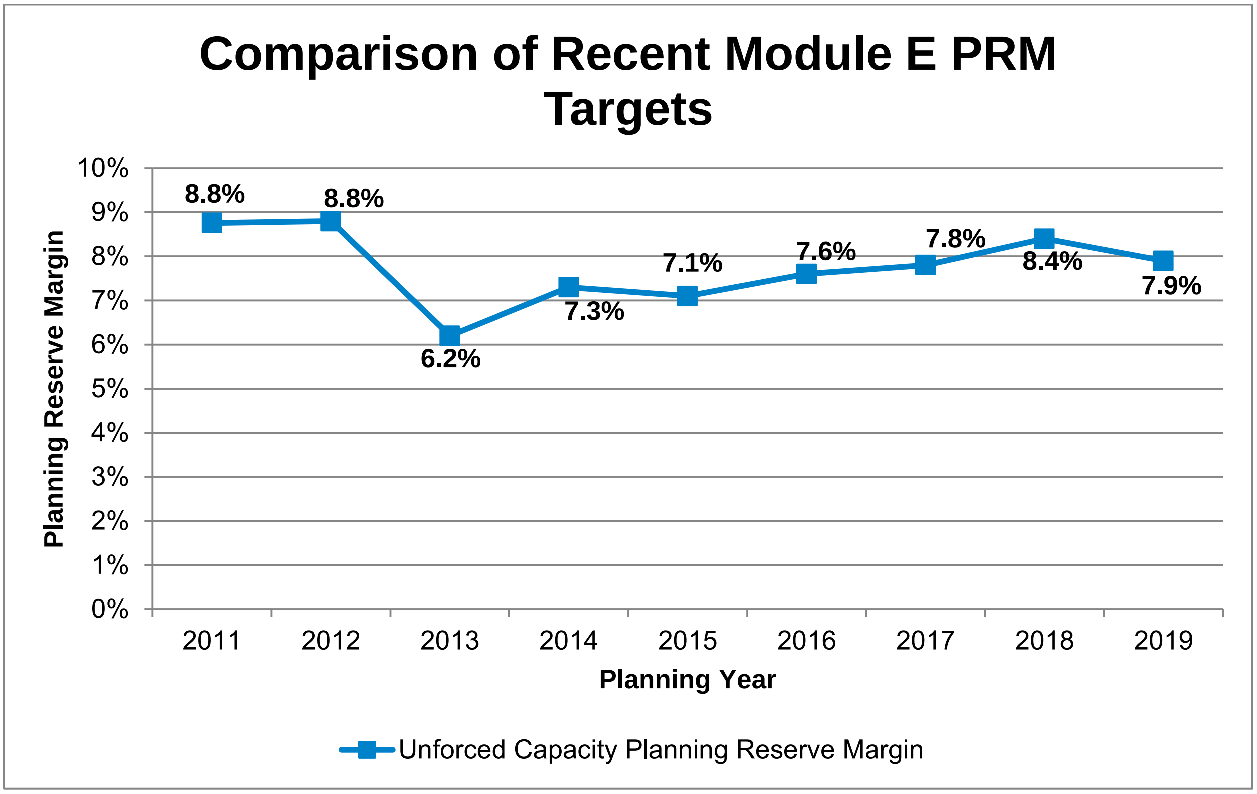


Figure 5-1: Comparison of PRM targets across eight years

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.