Report on Southern Indiana Gas and Electric Company d/b/a Vectren a CenterPoint Energy Company's 2019-2020 IRP

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Authors:

Chelsea Hotaling, Energy Futures Group
Anna Sommer, Energy Futures Group
Ric O'Connell, GridLab
Priya Sreedharan, GridLab
Dan Mellinger, Energy Futures Group

On behalf of CAC, CGI, Earthjustice, Solarize Indiana, SUN, Valley Watch, and Vote Solar

Table of Contents

Overview

The following comments on the 2019-2020 Integrated Resource Plan ("IRP") submitted by Southern Indiana Gas and Electric Company d/b/a Vectren a CenterPoint Energy Company ("Vectren" or the "Company") were prepared by Chelsea Hotaling, Anna Sommer, and Dan Mellinger of Energy Futures Group and Ric O'Connell and Priya Sreedharan of GridLab. These comments were prepared for Citizens Action Coalition of Indiana ("CAC"), Carmel Green Initiative ("CGI"), Earthjustice, Solar United Neighbors of Indiana ("SUN"), Solarize Indiana, Valley Watch, and Vote Solar ("Joint Commenters") pursuant to the Indiana Utility Regulatory Commission's ("IURC" or "Commission") Integrated Resource Planning Rule, 170 Ind. Admin. Code 4-7.

Our review of Vectren's 2019-2020 IRP is organized in response to guidance on IRP preparation in the IURC's IRP Rule. While we have concerns about the areas mentioned below, Vectren deserves significant credit for the marked improvement it exhibited throughout this IRP in contrast to its prior IRP. In our comments on Vectren's 2016 IRP, we concluded that the 2016 IRP suffered from the following major categories of flaws:

- Failure to communicate core concepts to nontechnical audiences (170 IAC 4-7-4(a)): Despite the non-technical executive summary submitted with the IRP and overall careful explanations of much of its methodology, Vectren's 2016 IRP obscures critical basic information, includes critical errors and inconsistencies. In addition, some materials necessary for a thorough review were not made available to stakeholders.
- Incomplete documentation of inputs, methods, and definitions (170 IAC 4-7-4(b)(1)): Key sections of Vectren's IRP are not transparent to stakeholders, including the scorecard methodology on which the utility bases its selection of its preferred portfolio.
- Numerous modeling errors (170 IAC 4-7-4(b)(9)): Vectren's modeling errors include its failure to actually optimize its resource portfolios, overemphasis of long-term costs over near-term costs, and excess capacity acquisition.
- Biases against coal retirement (170 IAC 4-7-8(b)(3),(b)(4)): Vectren's retirement analysis is biased towards later retirement of uneconomic units.
- Biases against renewable resources (170 IAC 4-7-8(b)(3),(b)(4)): Vectren's modeling includes several assumptions that bias resource selection against renewable generation.
- Demand-side resources not evaluated on consistent and comparable terms with supply-side resources (170 IAC 4-7-8(b)(3),(b)(4)): Vectren's modeling includes a faulty projection of energy efficiency costs that bias resource selection against energy efficiency.
- Flawed scorecard methodology for choosing the preferred portfolio (170 IAC 4-7-8(b)(7)(B),(C)): Vectren's scorecard assessment methodology includes errors in its execution and modeling choices that bias its results.
- Inflated energy forecast (170 IAC 4-7-5)): Vectren's energy forecast is predicated on a significant and subjective assumption about growth in industrial sales as well as overly aggressive near-term growth in key drivers of the commercial sales forecast.

Vectren has diminished many, but not all, of these concerns. For example,

- In the 2016 IRP, Vectren assumed wind and solar costs that were well above the prices seen at the time. For this IRP, Vectren issued an all-source request for proposal ("RFP") to collect real-world data to characterize its near-term resource choices. However, in the post 2024-timeframe, Vectren used an averaging approach that puts storage costs well above current, publicly available projections. Vectren then inappropriately shifts these costs for all renewables and storage two years forward in time, effectively double counting the construction period.
- For this IRP, Vectren no longer used the flawed energy efficiency ("EE") projection cost methodology that it used in the 2016 IRP. However, now its avoided transmission and distribution costs for EE are based upon a methodology that is not robust and likely to underestimate those costs. Additionally, Vectren has grouped EE into bundles in a manner that is inconsistent with how those measures would be offered.
- We see marked improvement in Vectren's load forecasting methodology as it relates to the commercial sector, but remain concerned that industrial sales are seriously overinflated as they were in the 2016 IRP.

We look forward to continuing to work with Vectren to address the issues identified herein in an effort to improve Vectren's next IRP and will be mindful of how these issues impact Vectren cases relying on the 2019-2020 IRP before the IURC including any certificates of need.

Table 1. Summary of Vectren's Achievement of Indiana IRP Rule Requirements gives the Indiana IRP rule sections and provides the section in which those requirements will be addressed in detail. Our review of Vectren's 2019-2020 IRP and our participation in its pre-IRP stakeholder workshops raised the following main categories of concern:

- Vectren applied its reserve margin requirement to all months of the year rather than just the MISO coincident peak (Section 3.1.1);
- Vectren assumed a seasonal capacity value for wind and solar resources that is too low, inconsistent with MISO guidance, and whose correction would eliminate the need for the proposed combustion turbines (Section 3.1.2);
- Vectren modified one of the solar RFP bids to limit the number of projects that could be selected (Section 3.2.1);
- Non-RFP solar, wind, and battery storage resources were not allowed to be selected until 2025 (Section 3.2.2);
- Vectren inappropriately shifted the capital cost projections for new solar, wind, and battery storage resources (Section 3.2.3);
- Vectren assumed unreasonable cost savings for building the second combustion turbine ("CT") in 2025 (Section 3.3);
- Vectren continues to rely on an internally developed near term industrial sales forecast that cannot be validated (Section 4.2); and
- Vectren's sharing of modeling input and output files along with the model manual were limited due to the use of the Aurora model (Section 1).

Table 1. Summary of Vectren's Achievement of Indiana IRP Rule Requirements

IRP Rule Section	Description	Findings	Citation
Integrated Resource Plan Submission	The IRP submission should include a non-technical appendix and an IRP summary that communicates core IRP concepts and results to a nontechnical audience.	**Partial**	See Section 1
Public Advisory Process	The IRP process should be developed and carried out to include stakeholder participation.	**Mostly**	See Section 2
Integrated Resource Plan Contents	The IRP should provide stakeholders with all of the information necessary to understand how the IRP modeling was performed.	**Partial**	See Section 3
Energy and Demand Forecasts	The IRP should clearly explain how energy and demand forecasts were developed and used for the IRP.	**Partial**	See Section 4
Description of Available Resources	The IRP must include important characteristics for existing and new resources included in the IRP.	**Mostly**	See Section 5
Selection of Resources	The IRP should describe the screening process used for evaluating future resources.	**Not Met**	See Section 6
Resource Portfolios	The IRP should discuss the preferred portfolio and discuss how alternative portfolios were developed to consider different scenarios.	**Partial**	See Section 7
Short Term Action Plan	The IRP should discuss how the preferred portfolio will be implemented over the next five years.	**Mostly**	See Section 8

1 Integrated Resource Plan Submission

Section 1 describes our assessment of Vectren's performance in meeting the requirements of 170 IAC 4-7-2 of the Indiana IRP Rule. Please see Table 2 below for our findings.

Table 2. Summary of Vectren's Achievement of Indiana IRP Rule at 170 IAC 4-7-2

IRP Rule	IRP Rule Description	Finding
4-7-2 (c)	Utility must submit electronically to the director or through an electronic filing system if requested by the director or through an electronic filing system if requested by the director, the following documents: (1) The IRP	Met
4-7-2 (c)	(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	Partial
4-7-2 (c)	(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 and (B) A simplified discussion of the utility's resource types and load characteristics. The utility shall make the IRP summary readily accessible on its website.	Met

Vectren used Energy Exemplar's Aurora model for capacity expansion and production cost modeling for this IRP. Vectren and Energy Exemplar have stated that Aurora does not allow for export of its full modeling input and output files. Other modeling software, such as EnCompass, allow for export of full modeling files which can be viewed and evaluated in Excel. Vectren and Siemens worked with stakeholders to provide limited access to the model documentation online through screen shots and provided Excel files with significant model outputs and input tables. To provide full transparency, we would prefer to be able to have access to the input and output modeling files themselves. It's our understanding that Aurora is set up in a way that links tables to each other through time series, so where a time series refers to yet another time series, it is cumbersome to search through multiple tabs to find the sought-after data. In addition, data fields in Aurora are hyperlinked to the model manual to provide contextualized help. This feature is lost without the ability to view files within Aurora's interface, but Energy Exemplar charges $5,000 for a read-only Aurora license, and Vectren did not pay this fee to make the interface available for the Commission staff or stakeholders.

Siemens and Vectren provided CAC with some information on model documentation for input tables, but this often lacked full information since the hyperlink feature was missing. If a user is interested in looking up information for an input in an input table such as the "New Resources" table, the interface permits the user to click on a link in the model documentation to see more information about that specific input. Each capacity expansion and production cost model has its own setup for model inputs that may be different than other similar models. As a result, the model documentation becomes invaluable for users who are trying to interpret the meaning of different inputs. For example, the New Resource table has an input called "Capacity Monthly Shape." Based on the name, it appears that this input would be used as an Effective Load Carrying Capability ("ELCC") value; however, there is also another column in that table called "Peak Credit." Without having access to the model documentation, we are unable to determine the meaning behind each of the columns. CAC was able to submit a discovery question to get clarification from Vectren, but we had to wait the allotted time for Vectren to respond to the discovery request, which is significantly longer than the time it would take to check the model manual.

While we appreciate the steps Vectren and Siemens took to provide us with the Aurora input tables and an output workbook, this presented some challenges due to the amount of time it requires to pull information out of Aurora. The original modeling inputs that were provided to stakeholders only included the candidate portfolios and not the scenarios and sensitivities. During a call with Siemens and Vectren, CAC requested the change sets[1] for the scenarios and sensitivities. CAC did eventually receive the change sets, but this information was not provided as part of the original IRP modeling files submission.

Vectren's 2019-2020 IRP stakeholder process was a significant improvement from the previous IRP. However, we would recommend that Vectren consider a process of releasing and sharing information similar to the process used in Indianapolis Power & Light's ("IPL") most recent IRP, submitted in December 2019. IPL used a file sharing site to share information at several points of time throughout the IRP process. Information was only shared with those stakeholders that signed a nondisclosure agreement ("NDA") with IPL. IPL had a schedule of release dates for when they provided stakeholders with capital cost information, resource constraints, key modeling inputs, and then modeling results. We believe that this data sharing approach helped to facilitate stakeholder involvement, expectations, and input throughout the process and ultimately increased stakeholder engagement.

IPL's approach is much closer to satisfying 170 IAC 4-7-2(c) which requires each utility to provide input and output files in electronic format, as well as include "documentation sufficient to allow an interested party to evaluate the data and assumptions in the IRP".[2]

[1] The term "change sets" is used to mean a record that includes all of the changes that are made to a portfolio. For example, if a scenario is modeling a higher gas price and a lower load than in the base case, then the change set will record that different natural gas price and different load forecast. The change set output will show the higher natural gas price and lower load forecast modeled as inputs to that particular scenario.

[2] 170 IAC 4-7-2.6 also requires a utility to discuss modeling methods and modeling inputs as part of the public advisory process. See also Order, I/M/O Submission by Hoosier Energy Rural Elec. Coop., Inc. of Its 2017 Integrated Res. Plan, Cause No. 45058, 2018 WL 2329333, at *2 (May 16, 2018) (acknowledging that 170 IAC 4-7-2(c)(2) requires disclosure of market price assumptions, production statistics for generating assets, and model data).

We cannot overstate the importance of transparency in IRPs. It is the foundation of public participation, which, in turn, is foundational to the Commission's ability to render decisions based on a comprehensive record. While we appreciate the work Vectren and Siemens did to provide us with modeling inputs and outputs, it is not a substitute for full transparency that a read-only license allows stakeholders to have. The level of transparency must still be improved upon in future dockets and future IRPs.

2 Public Advisory Process

Section 2 describes our assessment of Vectren's performance in meeting the requirements of 170 IAC 4-7-2.6 of the Indiana IRP Rule. Please see Table 3 below for our findings.

Table 3. Summary of Vectren's Achievement of Indiana IRP Rule at 170 IAC 4-7-2.6

IRP Rule	IRP Rule Description	Finding
4-7-2.6 (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.	**Partial**
4-7-2.6 (c)	The utility shall solicit, consider, and timely respond to all relevant input relating to the development of the utility's IRP provided by: (1) the interested parties; (2) the OUCC; (3) the commission staff.	**Mostly**
4-7-2.6 (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 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: (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, (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.	**Met**
4-7-2.6 (e)	(2) The utility may hold additional meetings.	**Met**
4-7-2.6 (e)	(3) The schedule for meetings shall: (A) be determined by the utility; (B) be consistent with its internal IRP development schedule; and (C) provide an opportunity for public participation in a timely manner so that it may affect the outcome of the IRP.	**Met**
4-7-2.6 (e)	(4) The utility or its designee shall: (A) chair the participation process; (B) schedule meetings; (C) develop and publish to its website agendas and relevant material for those meetings at least seven (7) calendar days prior to the meeting; and (D) develop and publish to its website meeting minutes within fifteen (15) calendar days following the meeting	**Met**
4-7-2.6 (e)	(5) Interested parties may request that relevant items be placed on the agenda of the meetings if they provide adequate notice to the utility.	**Met**
4-7-2.6 (e)	(6) The utility shall take reasonable steps to notify: (A) its customers; (B) the commission; (C) interested parties; and (D) the OUCC	**Met**

We appreciate the steps Vectren took to ensure improvement from the 2016 IRP. The sharing of data was a major improvement from the last IRP process as Vectren provided stakeholders with input and output files prior to the filing of its IRP. Vectren was also willing to have additional conversations with CAC and its consultants, as well as with other stakeholders interested in the technical details of its IRP.

One area of the stakeholder process that Vectren can improve upon for future IRPs is having an outside facilitator. Particularly where there are some contested issues, a qualified outside facilitator can greatly improve the degree to which parties feel like their concerns are heard and addressed. For its recent IRP, IPL hired an outside party with no role in producing the IRP to act as facilitator for the stakeholder workshops. We believe his contribution was very helpful in assuring a collaborative process.

One of the main concerns we had with this IRP related to how Vectren interpreted and modeled a monthly resource adequacy construct with a monthly reserve margin and unreasonably low capacity values for wind and solar resources. We expressed concern that the current process to evaluate resource adequacy ("RA") in MISO is still underway and that a monthly construct, particularly one consistent with Vectren's approach, is by no means a foregone conclusion. MISO remains engaged in its stakeholder process to determine what a new RA construct might look like. As we stated in our comments on Duke's 2018 IRP, we have no issue with modeling an alternative RA construct, but it should be a sensitivity not a base case assumption that applies to all modeling runs.[3] We expressed concern about this to Vectren several times throughout the stakeholder process, but Vectren did nothing to address the issue and kept its monthly construct approach in all modeling for the IRP. This issue is further discussed in Section 3.1.

We appreciated the time Vectren and its consultants, Siemens and PACE Global, took to have technical calls with us. However, there were several instances in which Vectren was not transparent or willing to provide information. Vectren refused to answer most of CAC's informal discovery questions about how Vectren developed its industrial sales forecast.[4] While we understand that certain load information is proprietary, we are concerned with Vectren's unwillingness to help us understand what was driving significant growth in the industrial sales forecast. Vectren is projecting a significant increase in industrial sales between 2019 and 2023, and it appears to be the result of growth from a single, existing customer. This issue is further discussed in Section 4.2.

[3] CAC et al.'s Report on DEI 2018 IRP, Section 3.1, available at https://www.in.gov/iurc/files/Duke%202018%20IRP--CAC%20EFG%20Public%20Report--12-6-19FINAL.pdf

[4] Vectren Responses to CAC/Vote Solar Set 7 (included as Attachment 1).

3 Integrated Resource Plan Contents

Section 3 describes our assessment of Vectren's performance in meeting the requirements of 170 IAC 4-7-4 of the Indiana IRP Rule. Please see Table 4 below for our findings.

Table 4. Summary of Vectren's Achievement of Indiana IRP Rule at 170 IAC 4-7-4

IRP Rule	IRP Rule Description	Finding
4-7-4 (1)	At least a twenty (20) year future period for predicted or forecasted analyses.	Met
4-7-4 (2)	An analysis of historical and forecasted levels of peak demand and energy usage in compliance with section 5(a) of this rule.	Met
4-7-4 (3)	At least three (3) alternative forecasts of peak demand and energy usage in compliance with section 5(b) of this rule.	Met
4-7-4 (4)	A description of the utility's existing resources in compliance with section 6(a) of this rule.	Met
4-7-4 (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.	Partial
4-7-4 (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.	Partial
4-7-4 (7)	The resource screening analysis and resource summary table required by section 7 of this rule.	Not Met
4-7-4 (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.	Met
4-7-4 (9)	A description of the utility's preferred resource portfolio and the information required by section 8(c) of this rule.	Partial
4-7-4 (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.	Partial
4-7-4 (11)	A discussion of the: (A) inputs; (B) methods; and (C) definitions.	Met
4-7-4 (12)	Appendices of the data sets and data sources used to establish alternative forecasts in section 5(b) of this 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.	Partial
4-7-4 (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.	Met
4-7-4 (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; and (E) Load data developed by a non-utility source.	Met
4-7-4 (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.	Partial
4-7-4 (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.	Partial
4-7-4 (17)	A discussion of the designated contemporary issues designated, if required by section 2.7(e).	Met
4-7-4 (18)	A discussion of distributed generation within the service territory and the potential effects on: (A) generation planning; (B) transmission planning; (C) distribution planning; and (D) load forecasting.	Mostly
4-7-4 (19)	For models used in the IRP, including optimization and dispatch models, a description of the model's structure and applicability.	Partial

4-7-4 (20)	A discussion of how the utility's fuel inventory and procurement planning practices have been taken into account and influenced the IRP development	**Met**
4-7-4 (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.	**Met**
4-7-4 (22)	A description of the generation expansion planning criteria. The description must fully explain the basis for the criteria selected.	**Partial**
4-7-4 (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.	**Met**
4-7-4 (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.	**Partial**
4-7-4 (25)	A description and analysis of the utility's base case scenario, sometimes referred to a business as usual case or reference case. The base 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 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 base case scenario need not align with the utility's preferred resource portfolio.	**Partial**
4-7-4 (26)	A description and analysis of alternative scenarios to the base case scenario, including comparison of the alternative scenarios to the base case scenario.	**Met**
4-7-4 (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); and (C) Reliability criteria for transmission planning as well as the assessment practice used.	**Partial**
4-7-4 (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 and (B)The utility's effort to develop and improve the methodology and inputs.	**Partial**
4-7-4 (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; and (D) The avoided operating cost.	**Partial**
4-7-4 (30)	A summary of the utility's most recent public advisory process, including: (A) Key issues discussed and (B) How the utility responded to the issues.	**Partial**
4-7-4 (31)	A detailed explanation of the assessment of demand-side and supply-side resources considered to meet future customer electricity service needs.	**Partial**

3.1 SEASONAL PLANNING CONSTRUCT

MISO currently provides capacity accreditation of wind and solar resources on an annual basis. MISO is considering moving to either an annual construct that reflects sub-annual needs, or a seasonal or monthly construct where wind and solar would have seasonal (such as winter and summer) accreditation values. MISO is deep in the middle of the Resource Availability and Need ("RAN") stakeholder engagement process where it is evaluating and discussing different constructs for reflecting seasonal needs. Given what has been presented by MISO so far, and the stakeholder views to date, we think it is likely that the reserve margin construct that MISO will ultimately settle on will be very different from that modeled by Vectren in this IRP. Specifically, the likelihood of MISO adopting a monthly construct appears to be low, given that loss of load risk is not present in all months and due to the administrative cost. Throughout the Vectren IRP stakeholder process, we expressed our concern that Vectren's reserve margin requirement would be disconnected from the requirement that MISO will ultimately adopt since the RAN process is still unfolding. It is important to note that, to date, there still has not been a decision made at MISO.

3.1.1 Application of a Monthly Reserve Margin

MISO is exploring a number of rule changes to address MaxGen[5] events and to ensure future reliability, but a seasonal resource adequacy ("RA") construct is by no means a foregone conclusion.

For this IRP, Vectren applied the reserve margin requirement (Planning Reserve Margin or "PRM") to its peak month and then applied the resulting planning reserve margin requirement ("PRMR" or peak load plus reserve obligation) to all months of the year while modeling a monthly capacity credit for wind and solar resources. In the IRP, Vectren discusses the rationale for modeling the reserve margin and capacity credit in this manner:

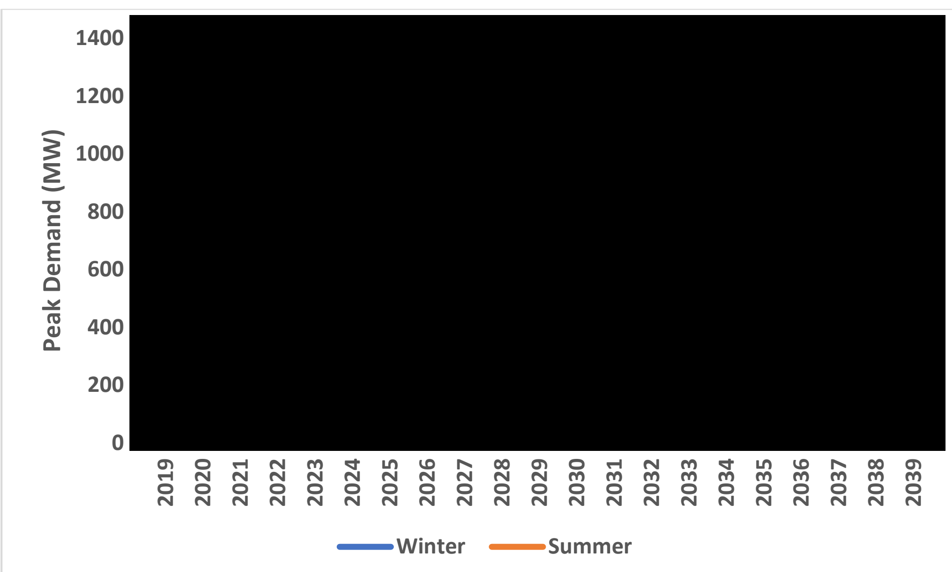
> *MISO has already implemented seasonal coordinated maintenance schedule reporting. Additionally, MISO currently is considering implementing a seasonal construct to capacity accreditation. Based on recent MISO publications, discussions and input, this likely could be a four-season construct which is 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.*[6]

[5] Maximum Generation ("MaxGen") events occur when the economic supply of energy is not sufficient to meet fixed demand.

[6] Vectren 2019-2020 IRP, p. 142.

It is not the use of a monthly (what Vectren terms as "seasonal") requirement that primarily concerns us; rather it is the use of a single point value to represent that requirement and then the application of that single assumption throughout *all* of Vectren's modeling runs. If Vectren had kept only the current peak month requirement but modeled a 15% PRM instead of the 8.9% PRM, we would be equally concerned. The PRM assumption typically has a major impact on modeling results. We have no issue with capturing the uncertainty of MISO's PRM going forward, but Vectren has done the opposite. It has laid all its bets on the idea that the PRM will be modified in a very specific way. Vectren applied the reserve margin requirement to its annual peak load to determine the total requirement and then enforced that PRMR across all months of the year in all modeling runs. This is already inconsistent with the PRM revisions MISO is considering, which, at their core, are based on the principle that resource adequacy needs vary across the year.

Since there is a difference between Vectren's summer and winter peak over the planning period, the application of the PRMR to all months of the year (and in all modeling runs) will likely lead to an overbuild of the system and result in unnecessary costs to ratepayers. Confidential Figure 1. Vectren's Forecasted Summer and Winter Peak shows the comparison between Vectren's projected summer and winter peak over the planning period. In 2023, for example, Vectren's projected summer peak is [redacted] MW[7], already 33% higher than the projected winter peak of [redacted] MW. However, the required capacity in the winter months would still be the summer peak x (1 + PRM) x (Vectren's coincidence MISO peak coincidence factor), i.e. an effective PRMR that is even greater than 33% above the projected winter peak!



Confidential Figure 1. Vectren's Forecasted Summer and Winter Peak

As we told Vectren during the stakeholder process, we see no issue with modeling a monthly reserve margin requirement as a sensitivity, if it is done correctly and reflects differing risk

[7] Summer and winter peak from table 'Copy(1) of Demand Monthly Peak' in the modeling file 'Vectren IRP_Aurora Study Input Tables_Reference Case_05.01.20_rev_CONFIDENTIAL'

across the months, as is the intention of MISO's "monthly construct", one of three new constructs under consideration by MISO in the RAN. However, it is not just inappropriate, but fundamentally flawed, to do so as a base assumption in all runs. Indeed, the IRP Rule at 170 IAC 4-7-4(25)(D) provides three conditions for when the utility can include future resources, laws, or policies in its base case scenario. These three conditions include:

(i) A utility subject to section 2.6 of the IRP 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 monthly RA construct does not meet any of the criteria in the IRP Rule at 170 IAC 4-7-4(25)(D). It would have been fairer to treat a change in PRM in exactly the same way that Indiana utilities treat carbon dioxide regulation – as a scenario driver with multiple, possible outcomes. In the IRP, Vectren discusses a sensitivity that was run to evaluate the seasonal resource accreditation assumptions, however, it does not appear to have varied the monthly reserve margin requirement in any of the modeling runs at all.

3.1.2 Seasonal Solar and Wind Capacity Accreditation

In addition to modeling a monthly reserve margin requirement, Vectren also modeled a summer and winter capacity credit for wind and solar resources. MISO currently accredits wind and solar resources in Zone 6 (Indiana and parts of Kentucky) at average annual values of 8.1%[8] and 50%,[9] respectively.[10] Note there are just 282 MW of wind capacity in Zone 6, and the MISO system-wide capacity value for wind is twice the value in Zone 6, at 16.6%. Depending on the production profile of new wind resources added in Zone 6, it is likely the capacity credit for wind will increase.

Figure 2 illustrates the seasonal solar and wind ELCC inputs for 2022 and 2023. Vectren modeled a steady decline in the ELCC value of solar each year of about [redacted]% during the summer months. By 2039, the solar summer ELCC reaches [redacted]% by [redacted] and the winter ELCC reaches [redacted]%. The wind ELCC in the summer and winter remains steady throughout the planning period and does not have the same downward trajectory that solar does.

[8] MISO Zone 6 wind, Figure 1-1, p. 4. Retrieved from https://cdn.misoenergy.org/2020%20Wind%20&%20Solar%20Capacity%20Credit%20Report408144.pdf

[9] Retrieved from https://cdn.misoenergy.org/2020%20Wind%20&%20Solar%20Capacity%20Credit%20Report408144.pdf

[10] Normally these values are updated annually in November with the release of MISO's Loss of Load Expectation Report, but the values were not included in MISO's LOLE Report for 2020.

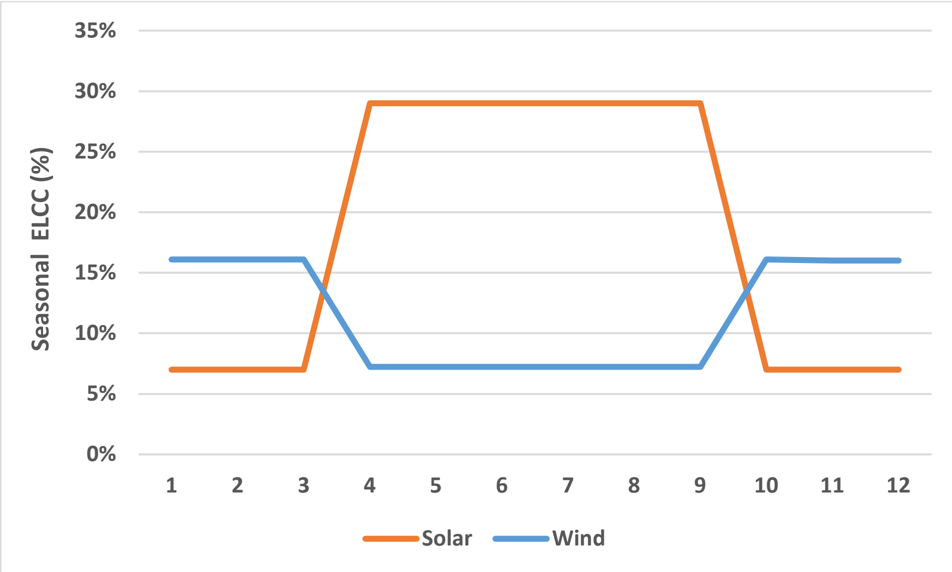


Figure 2. Seasonal Solar and Wind ELCC for 2022-2023

In conjunction with the release of the 2021-2022 Loss of Load Expectation Study Report, MISO also provided stakeholders with an Excel workbook template that can be used to calculate the summer accreditation for intermittent resources.[11] The workbook looks at the top three historical load hours for MISO for June, July, and August. The model is set up to look at the output from the generating resource across the three peak hours during the summer months. The hourly shape information modeled in Vectren's IRP model, AURORA, for Benton and Fowler were input into the MISO template, and the resulting capacity credits are shown in Table 5. The shape information for the wind power purchase agreement ("PPA") from the RFP was modeled on a higher level of granularity, since it was input as a weekly time series. The summer capacity credit using the MISO template is higher than the 8% that Vectren modeled, which would imply an even higher winter time capacity credit for wind resources.

Table 5. MISO Summer Resource Accreditation for Vectren Wind Resources[12]

Resource	Nameplate (MW)	Model (MW)	Capacity Credit (%)
Benton County Wind PPA	30	4.6	15.33%
Fowler Ridge Wind PPA	50	8.7	17.40%
Wind PPA from RFP	200	26	13.00%

In the IRP narrative, Vectren reports that projected future summertime Effective Load Carrying Capability ("ELCC") values for wind and solar resources were derived based on MISO's

[11] Workbook retrieved from https://www.misoenergy.org/planning/resource-adequacy/#nt=%2Fplanningdoctype%3APRA%20Document%2Fplanningyear%3APY%2021-22&t=10&p=0&s=FileName&sd=desc

[12] There was an hourly renewable shape for Benton and Fowler modeled in AURORA; the shape for the wind PPA was not provided on an hourly basis in Aurora.

Renewable Integration and Impact Assessment (RIIA) study[13] and the MISO Transmission Expansion Plan ("MTEP") models for projected renewable installed capacity.[14] Vectren has failed to capture the uncertainty inherent in these estimates. Indeed, MISO has since revised RIIA to show much higher future capacity accreditation for wind and solar resources based on updated siting.[15]

For solar, Vectren modeled a seasonal ELCC that starts out in 2022 at 29% for the summer months[16] and 7% for the winter months.[17] For wind, Vectren modeled a seasonal ELCC of 7% for the summer months and 16% for the winter months. Vectren claims to have derived these figures from MISO's RIIA Phase 1 study, which shows that MISO would reach an annual ELCC of 29% when penetration of solar reached 30%, or about 16.3 GW of solar in the MISO footprint. Given MISO expects just 1.5 GW of solar total by the end of 2020, it is not reasonable to assume that MISO would have 16.3 GW of solar by 2022. Furthermore, MISO's recent work on RIIA shows that, with a more realistic siting approach, the ELCC would be far higher than Vectren assumed (see Figure 3). Under MISO's updated projections, solar would not reach an ELCC of 29% until solar reaches about 46% penetration, i.e., about 57 GW of solar. Thus, Vectren's ELCC assumption of 29% is extremely pessimistic.

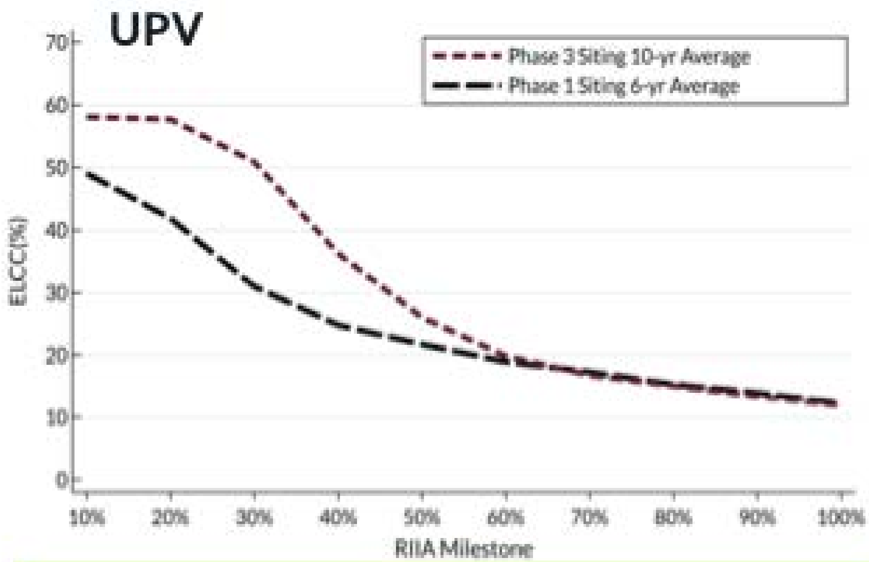
[13] Slide 87 from Vectren October Stakeholder Presentation. Retrieved from https://www.vectren.com/assets/downloads/planning/irp/IRP-2019-Vectren-Stakeholder-Meeting-2.pdf

[14] Figure 2 from MISO Renewable Integration Impact Assessment (RIIA) Assumptions Document Version 6. Retrieved from https://cdn.misoenergy.org/RIIA%20Assumptions%20Doc_v7429759.pdf

[15] MISO RIIA, Phases 2s and 3, June 26 2020, https://cdn.misoenergy.org/20200626%20RIIA%20Item%2003%20Resource%20Adequacy%20Siting%20and%20Expansion%20Sensitivity454963.pdf

[16] Summer months modeled as April to September.

[17] Winter months modeled as October to March.



UPV ICAP (GW)										
Milestone	10%	20%	30%	40%	50%	60%	70%	80%	90%	100%
Phase 1	1.3	9.1	16.3	24.0	31.5	38.6	46.0	53.6	60.5	69.3
Phase 2s and 3	1.5	11.3	26.7	42.9	61.7	83.7	100.1	112.7	128.9	146.6

Figure 3. Updated MISO RIIA Utility Solar ELCC Curve[18]

Had Vectren used a more appropriate ELCC for solar resources, the High Tech scenario would not require the two combustion turbine ("CT") resources Vectren says it needs to meet its capacity obligations. Vectren based its future ELCC values for solar on early versions of MISO's RIIA study that have since been updated, showing Vectren's assumptions to be overly conservative. Other utilities in MISO, such as IPL and Xcel, have used ELCC values ranging from 50% to 60% for solar. If the solar ELCC is changed to 50%, then Vectren has enough capacity without the two CTs. A 50% ELCC assumption is still quite conservative because, as Figure 3 shows, solar only falls to a 50% ELCC at 30% system-wide penetration or 26.7 GW installed.

Figure 4 shows the resource accreditation compared to the PRMR for the High Tech portfolio using Vectren's assumptions (column labeled Vectren), using a 50% ELCC for solar (column labeled Revised ELCC), and using the revised ELCC for solar along with removing the two CTs (Revised ELCC and No CTs). The planning reserve margin across Vectren's assumptions, the revised solar ELCC, and the revised Solar ELCC in combination with the removal of the two CTs are above Vectren's [redacted]% planning reserve margin requirement.

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[18] MISO RIIA, Phases 2s and 3, June 26 2020, https://cdn.misoenergy.org/20200626%20RIIA%20Item%2003%20Resource%20Adequacy%20Siting%20and%20Expansion%20Sensitivity454963.pdf

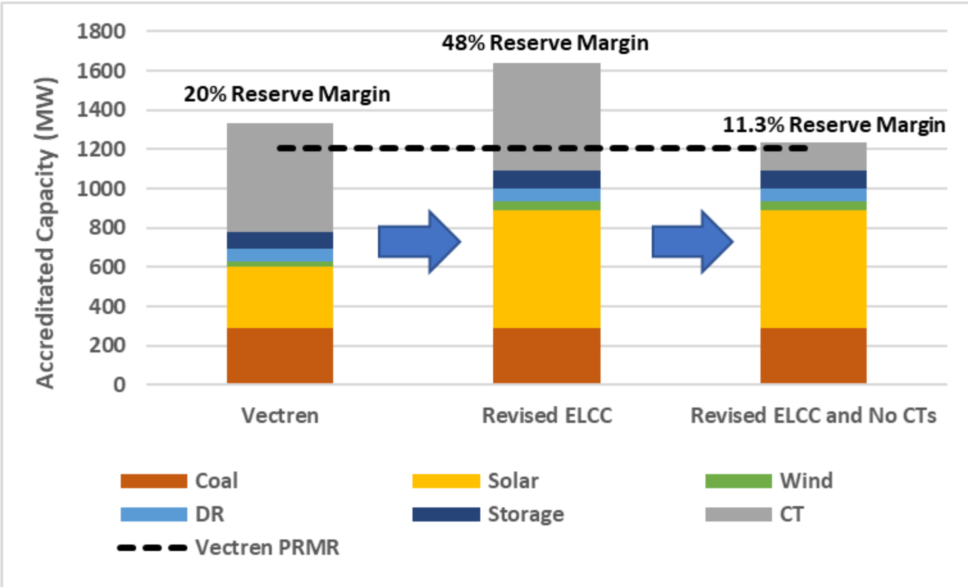

Figure 4. High Tech Portfolio with Revised Solar ELCC for 2025

We also used the revised solar ELCC of 50% to evaluate the impact on the All Renewables by 2030 portfolio. Figure 5 below shows that the revised Solar ELCC would eliminate the need for the capacity market purchases in 2025, which would lower the overall cost of the portfolio and reduce its market exposure.

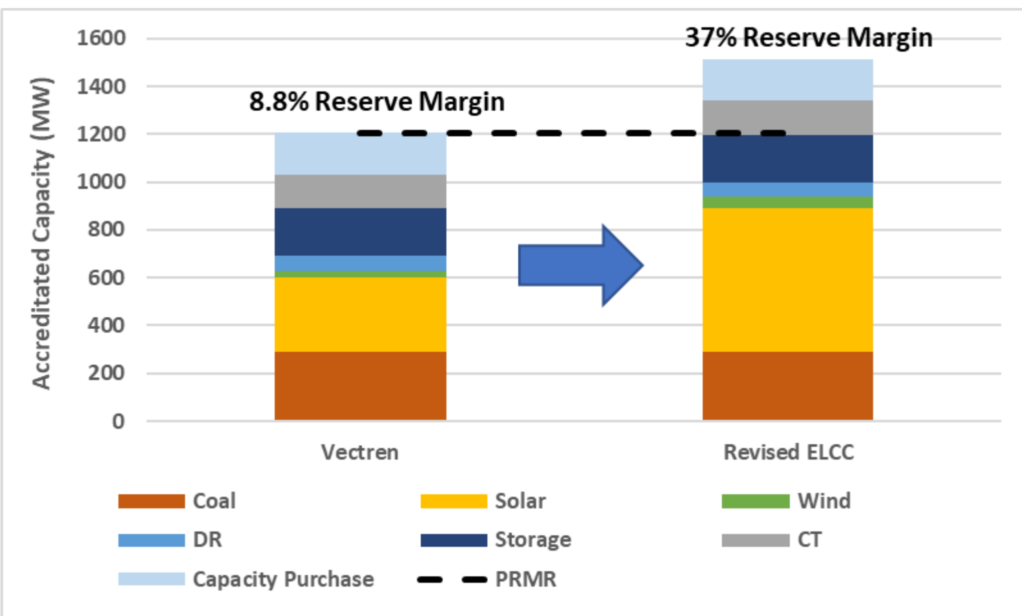

Figure 5. All Renewables by 2030 Portfolio with Revised Solar ELCC for 2025

3.2 RESOURCE CONSTRAINTS THAT BIAS RENEWABLES AND ENERGY STORAGE

3.2.1 Modification of Solar RFP Bid

In addition to applying annual constraints for the resources modeled between 2025 and 2039, Vectren also modified one of the solar RFP bids in order to limit the amount of solar that could be selected by the model. In the first round of modeling input files provided to CAC, AURORA could choose up to the number of projects that were bid into the RFP; in other words, the model was not initially constrained. However, when CAC received updated modeling input files that included the change sets for the different scenarios, we noticed that there were modifications for all projects related to a specific solar RFP bidder. Vectren changed the number of the projects and the timeframe during which those projects could be selected. Confidential Table 6, below, compares the RFP bid input to what was modeled in Aurora after the change sets were applied. The original RFP bid included [redacted] projects for a total capacity of [redacted] MW. Vectren modified the inputs for this RFP bid to allow [redacted] projects in 2023 and [redacted] project in 2024 for a total of [redacted] MW. By placing the annual constraint on this RFP bid, Vectren prevented the modeling from selecting [redacted] MWs of solar. It is important to note that the High Tech Case, upon which the preferred plan is based, selected both solar projects offered to the model in 2023 and the single project offered in 2024. This indicates that the constraint Vectren imposed was binding and that the model most likely would have selected two more projects, if they had been offered to the model.

Confidential Table 6. Comparison of One Solar RFP Bid with Multiple Projects to Vectren's Modeling of this Solar RFP Bid[19]

	Project MW	Years Available	Projects Available	Total MW
RFP Bid	[redacted]	**2023-2024**	[redacted]	[redacted]
Vectren Modeling of Solar RFP in Aurora for 2023	[redacted]	2023	[redacted]	[redacted]
Vectren Modeling of Solar RFP in Aurora for 2024	[redacted]	2024	[redacted]	[redacted]
Total Modeled of Solar RFP Bid in Aurora for 2023-2024			[redacted]	[redacted]

When asked about this change, Vectren referred to the IRP narrative for the rationale on limiting solar resources:

[19] RFP bid inputs from file 'Confidential Vectren RFP IRP Inputs 2020.01.17'; Modeling inputs from file 'Vectren IRP_Aurora Study Input Tables_Reference Case_05.01.20_rev_CONFIDENTIAL'. See Attachment 2-Confidential and Attachment 3-Confidential to this Report, respectively.

> *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.*[20]

We are not clear why lower capacity accreditation for solar would mean that the winter peak was not met. We understand the reserve margin requirement to be binding through all months, meaning that the model would add other resources if the peak requirement could not be met through additional solar. And even if the reserve margin requirement were not a hard constraint, it is not clear why the winter peak could not be met given the differential between Vectren's winter and summer peaks. We do not think is appropriate or reasonable that Vectren modified the number of projects that this particular bidder offered. Limiting this particular solar bid from [redacted] projects to [redacted] projects unfairly biases the model toward selecting the first CT in 2024.

3.2.2 Generic Resources Not Available for Selection until 2025

New supply side resources were offered to the model with different assumptions depending on whether the resource represented an RFP bid or was modeled as a generic new resource outside of the RFP. Vectren allowed the model to select the RFP bids between 2022 and 2024. Vectren then modeled generic resources for selection in different, subsequent years, depending on whether the resource was thermal or renewables and battery storage. New thermal resources were allowed to be selected by the model starting in 2024, while the new generic solar, wind, battery storage, and hybrid resources could not be selected by the model until 2025. The concern with this approach is that since 2024 is a major resource decision year given the retirement of the AB Brown and Culley 2 coal units, all of the technology types should have been available for the model to select in order to ensure an optimal expansion plan. Because no generic renewable or energy storage resources were options in 2024, the model had a limited selection of resources to choose in this key year. The resources that could be selected included three solar RFP bids, energy efficiency, the second demand response bin, and several thermal resources. This seems very likely to distort resource selection since the coal units retire at the end of 2023 making 2024 the key year in which new resource decisions would be made.

Confidential Table 7 shows the RFP bids that were available for selection between 2022 and 2024, and which bids were selected by the model. All but three RFP bids offered to the model were selected.

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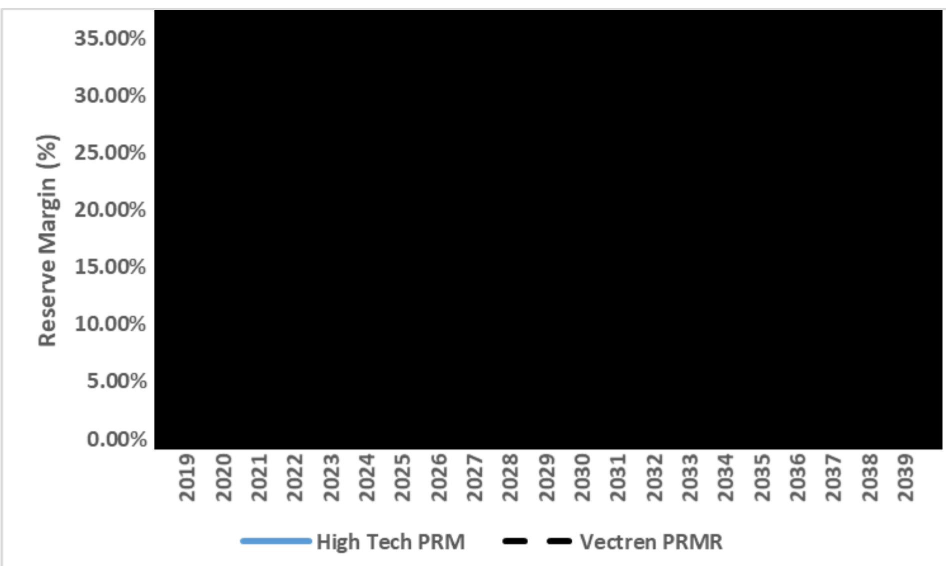
[20] Vectren Response to Informal Discovery CAC 7.7 (Attachment 1); Vectren 2019-2020 IRP, p. 248.

Confidential Table 7. RFP Resources Available for the Model to Select[21]

Resource	Nameplate (MW)	Year Projects Available	Number of Projects Available	Year Selected	Number of Projects Selected
Wind PPA	300	2022	[redacted]	2022	[redacted]
Solar and Storage PPA - Solar	133	2023	[redacted]	2023	[redacted]
Solar and Storage PPA - Storage	42	2023	[redacted]	2023	[redacted]
Low 20 Year Solar PPA	165.46	2023	[redacted]	2023	[redacted]
Low 20 Year Solar PPA	165.46	2024	[redacted]	2024	[redacted]
25 to 30 Year Solar PPA	137.5	2024	[redacted]	2024	[redacted]
12 to 15 Year Solar	112.5	2024	[redacted]	2024	[redacted]
High 20 Year Solar PPA	200	2023	[redacted]	2023	[redacted]
Storage PPA	300	2023	[redacted]	2023	[redacted]

We believe the two solar RFP bids and one battery RFP bid were not selected because the 2023 effective reserve margin was already well in excess of Vectren's reserve margin as illustrated in Confidential Figure 6.



Confidential Figure 6. High Tech Effective Planning Reserve Margin

As discussed in Section 3.2.1, the model took all 2024 RFP projects available to it, which is a strong indication that it would have selected additional solar, hybrid, or energy storage in 2024, if they had been offered to the model.

[21] Based on the input in the New Resources table in file 'Vectren IRP_Aurora Study Input Tables_Reference Case_05.01.20_rev_CONFIDENTIAL' and the output from file 'Vectren IRP Ref Case and Candidate Portfolios_Deterministic_04022020_FINAL_CONFIDENTIAL.' See Attachment 4-Confidential to this Report.

Confidential Table 8 shows the thermal resources that Vectren offered to the model starting in 2024.

Confidential Table 8. Thermal Resources Available in 2024

Resource	Nameplate MW	Annual Units Allowed	Overall Units Allowed	Total UCAP MW Available
Vectren_Gas-F-Class_236.635_MW	236.64	[redacted]	[redacted]	[redacted]
Vectren_Gas-E-Class_84.721_MW	84.72	[redacted]	[redacted]	[redacted]
Vectren_Gas-GH-Class_279.319_MW	279.32	[redacted]	[redacted]	[redacted]
Vectren_Gas-F-Class_236.635_MW	236.64	[redacted]*	[redacted]	[redacted]
Vectren_Gas-E-Class_84.721_MW	84.72	[redacted]*	[redacted]	[redacted]
Vectren_Gas-GH-Class_279.319_MW	279.32	[redacted]*	[redacted]	[redacted]

**Vectren modeled additional units at a lower cost than the first unit for each thermal resource in the table. Vectren specified that the model had to select the first resource before additional resources could be selected.*

Ultimately, the High Tech case added a CT in 2024 followed by a second, lower cost CT (enabled by the first) in 2025. As the High Tech portfolio stands, it is not possible to conclude that the addition of the CT in 2024 is the optimal resource selection, since the model's options were limited to the remaining three solar RFP bids, energy efficiency, some demand response, and the generic thermal resources.

3.2.3 Generic Renewable and Energy Storage Capital Cost

Vectren constructed the capital costs modeled for the generic solar, wind, battery storage, and hybrid projects that were offered to the model starting in 2025 by adjusting the technology averaging assessment. In other words, Vectren modeled the new generic solar, wind, energy storage, and hybrid resources by taking an average of costs from the NREL ATB, Burns and McDonnell, and Pace. Vectren then adjusted the average of those costs based on the bids received in the RFP. Vectren then shifted those capital costs out by two years before the costs were translated into the $/MW-week stream modeled in Aurora. For example, the capital costs for 2023 were shifted to 2025, costs for 2024 were shifted to 2026, etc. Siemens said that the costs were shifted by two years to take into consideration the construction period for the projects. Because generic capital costs decline over time, we are concerned about this approach because it effectively doubles the construction period. RFP bids should already have a construction timeframe baked into the prices so shifting the costs out again would double count the construction period. This has implications for the solar, energy storage, and hybrid resources in particular. The result of the two-year cost shift implemented by Vectren is that a solar resource offered for selection in 2025 contains the capital cost assumptions from 2023. This means that Vectren is modeling higher capital costs than would be anticipated for the year in which the project comes online.

In addition to the concern about the two-year cost shift, we also believe that Vectren is using a conservative capital cost projection for energy storage resources. When the two-year cost shift is then factored into that projection, it makes Vectren's battery cost projections higher than the Advanced and Moderate cases developed by NREL, which is similar to NREL's Conservative case. Figure 7 shows the comparison between the capital costs modeled by Vectren against the three cost projections developed by NREL for the 2020 Annual Technology Baseline ("ATB").

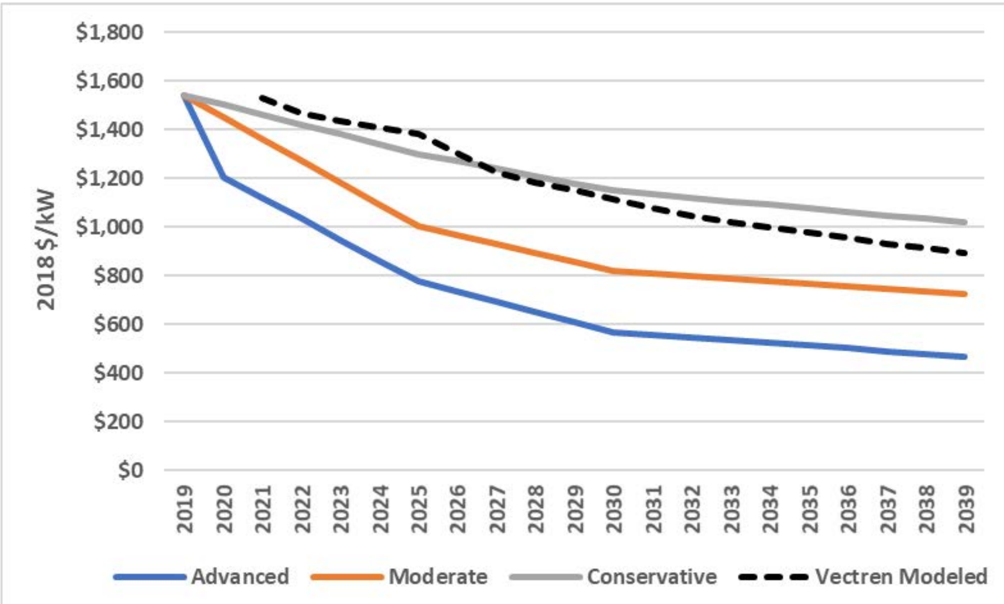


Figure 7. Comparison of Vectren Modeled Battery Storage Capital Costs to NREL[22]

[22] NREL (National Renewable Energy Laboratory). 2020. "2020 Annual Technology Baseline." Golden, CO: National Renewable Energy Laboratory. https://atb.nrel.gov/.

3.3 COMBUSTION TURBINES ADDED IN THE PREFERRED PLAN

Vectren's preferred plan adds one 236.64 MW CT in 2024 and a second 236.64 MW CT in 2025. Vectren assumed that the addition of the second CT will come at a reduction in total cost of about $50 million dollars enabled by siting this CT in the same location and constructing the two units under the same contract, with the second unit immediately after the first.[23] Vectren's assumption overestimates the anticipated construction cost savings for the second CT, which in turn makes the CT added in 2025 seem more economic to the model.

3.3.1 Vectren's Assumption of Cost Savings for the Second CT

Vectren assumes engineer, procure, and construct ("EPC") costs of $125 million for the first CT and $93 million for the second CT. This EPC estimate came from Burns & McDonnell, with no detail provided that would justify the significant cost savings for the second CT. In addition to the construction savings, Vectren assumes owner's costs of $48 million for the first CT and $27 million for the second CT. The savings in owner's costs of $21 million for the second CT appear reasonable, as Vectren provides detailed line items to justify the cost savings. The savings in EPC costs, however, do not seem reasonable. Because Vectren is not likely to obtain a volume discount for the purchase of just two turbines, the remaining savings associated with the second turbine would have to come from construction cost savings. For the second unit, this means that construction cost drops from $63 million to $31 million (Table 9).

Table 9. Cost Comparison for the First and Second CT (Cost in millions of dollars)[24]

	First CT	Second CT	Both
EPC Costs	$125	$93	$218
Estimated Turbine	$63	$63	
Estimated Construction	$63	$31	
Owner's Costs	$48	$27	$75
Total	$173	$121	$293

A construction cost drop of over 50% is highly unlikely, and results in a total cost of $510/kW (Table 10) for the second CT, which is far lower than publicly available cost estimates.

Table 10. Cost Comparison for the First and Second CT in $/kW[25]

	First CT	Second CT
EPC	$530	$390
Owners Costs	$200	$120
Total	$730	$510

[23] Vectren 2019-2020 IRP, p. 255.

[24] Vectren 2019-2020 IRP, Attachment 1.2.

[25] Costs reported in Vectren 2019-2020 IRP, Attachment 1.2.

3.3.2 Vectren Reported Benefits of the Two CTs

In the IRP, Vectren claims several purported benefits that the CTs can provide for Vectren's ratepayers as outlined in Table 11.

Table 11. Vectren's Reported Benefits of the CTs[26]

Benefit Category	Description of Benefit
Capacity	They eliminate the reliance on 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
Renewable Expansion	They are primarily used for peaking and fast ramping, which provides more room for renewables in the future
Cost	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 2nd
Interconnection	Maintains interconnection rights should units be built at the Brown site, shielding customers from future transmission upgrade costs

These are capacity, renewable expansion, cost, and interconnection. We previously discussed why the cost savings are at issue in Section 3.3.1, so we will focus on capacity, renewable expansion, and interconnection here. Vectren claims that the capacity benefits of the CTs is that they "eliminate reliance on capacity at a time when MISO suggests there could be shortages" and "[t]hey provide the capability to convert into a combine cycle unit."[27] Any resource can provide capacity and as Confidential Figure 6 shows, even under Vectren's projection, it would have capacity well in excess of its reserve margin requirement for many years to come. It is not clear, then, why the ability to upgrade the CTs to an even larger CCGT would be a benefit.

On the renewable expansion benefit, energy storage and demand response resources can also provide similar peaking and ramping benefits. As it relates to the interconnection benefit, it seems likely that Vectren could add solar and/or battery storage at the AB Brown site and still utilize its existing interconnection rights.

[26] Vectren 2019-2020 IRP, p. 255.

[27] Vectren 2019-2020 IRP, p. 255.

3.4 AVOIDED COST CALCULATION

Section 4-7-4 (29) of the IRP Rule requires the following components to be included in the avoided cost calculation:

(A) Avoided generating capacity (adjusted for T&D losses and reserve margin requirement)
(B) Avoided transmission capacity cost
(C) Avoided distribution capacity cost
(D) Avoided operating cost
- (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.

Vectren's avoided cost calculation includes generating capacity, avoided transmission and distribution capacity costs, avoided pipeline capital costs, and some of the avoided operating costs under Section D of 170 IAC 4-7-4(29). However, Vectren's calculation is missing a majority of the items listed under Section D, which include spinning reserve, emission allowances, environmental compliance costs, and transmission and distribution operation and maintenance costs.

Vectren's methodology to determine avoided transmission and distribution ("T&D") cost methodology is unprecedented in our experience. Vectren provided the supporting workbooks for the development of the avoided T&D cost in response to CAC Informal Data Request 6.13.[28] One of the first things we noticed in the calculation for the avoided T&D is that Vectren uses a line loss assumption of [redacted]% for both the transmission and the distribution system. Vectren should be using a marginal line loss factor in the calculation instead of a [redacted]% factor. A higher, more realistic line loss factor would have led to higher, more realistic avoided T&D costs.

In addition to not using marginal line losses, Vectren also calculated the avoided distribution cost by taking the following steps.

(1) Vectren takes the average distribution cost "per lot"[29] and multiplies that by the capital recovery factor to arrive at an amortized average distribution cost per lot:

[redacted]

[28] See Attachment 5-Confidential to this Report for the Avoided Cost T&D Workbook provided by Vectren.

[29] Vectren does not say what "per lot" means.

(2) Vectren then multiplies the amortized average distribution cost per lot by the distribution line loss factor:

[redacted]

(3) Vectren then takes the 2020 residential average use per customer and divides that by 8760 and then divides by the load factor to derive the peak hour capacity:

[redacted]

(4) Vectren arrives at the avoided cost per kW by dividing the average investment avoided distribution cost by the peak hour capacity:

[redacted]

This approach does not make sense. First, the line loss factor should just be used to translate avoided costs from generator to the meter. It makes no sense to use this as a downward adjustment to avoided distribution costs. Second, because the avoided distribution cost is already a function of the peak since upgrade costs are related to those times when lines would be most heavily loaded, i.e., peak times, no adjustments for load factor or peak hour capacity would be necessary. The net effect of these flaws is a dramatically lower avoided distribution cost than is realistic.

4 Energy and Demand Forecasts

Section 4 describes our assessment of Vectren's performance in meeting the requirements of 170 IAC 4-7-5 of the Indiana IRP Rule. Please see Table 12 below for our findings.

Table 12. Summary of Vectren's Achievement of Indiana IRP Rule at 170 IAC 4-7-5

IRP Rule	IRP Rule Description	Findings
4-7-5 (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; and (E) Selected daily load shapes, which shall include summer and winter peak days, and a typical weekday and weekend day.	**Mostly**
4-7-5 (a)	(2) Disaggregation of historical data and forecasts by: (A) customer class; (B) interruptible load; and (C) end-use; where information permits.	**Met**
4-7-5 (a)	(3) Actual and weather normalized energy and demand levels.	**Met**
4-7-5 (a)	(4) A discussion of methods and processes used to weather normalize.	**Met**
4-7-5 (a)	(5) A minimum twenty (20) year period for peak demand and energy usage forecasts.	**Met**
4-7-5 (a)	(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, rate classes, or both; and (C) Firm wholesale power sales.	**Met**
4-7-5 (a)	(7) A discussion of how the impact of historical DSM programs is reflected in or otherwise treated in the load forecast.	**Partial**
4-7-5 (a)	(8) Justification for the selected forecasting methodology.	**Partial**
4-7-5 (a)	(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.	**Partial**
4-7-5 (a)	(10) For purposes of subdivisions (1) and (2), a utility may use utility specific data or data such as described in subdivision 4(14) of this rule.	**NA**
4-7-5 (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.	**Met**
4-7-5 (c)	In determining the peak demand and energy usage forecast to establish plausible risk boundaries as well as a forecast that is deemed by the utility, with stakeholder input, to be most probable, the utility shall consider likely based on alternative assumptions such as (1) Rate of change in population; (2) Economic activity; (3) Fuel prices, including competition; (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; (10) State and federal energy policies; and (11) State and federal environmental policies.	**Partial**

4.1 VECTREN LOAD FORECAST

Vectren hired Itron to use its Statistically Adjusted End-Use ("SAE") model to develop residential, commercial, and industrial forecasts. Vectren then modifies the industrial sales forecast with an internal projection of sales for the first five years of the planning period. Vectren used Itron's forecast for the remainder of the planning period. Figure 8, below, shows the forecasted sales across each customer class for the planning period.

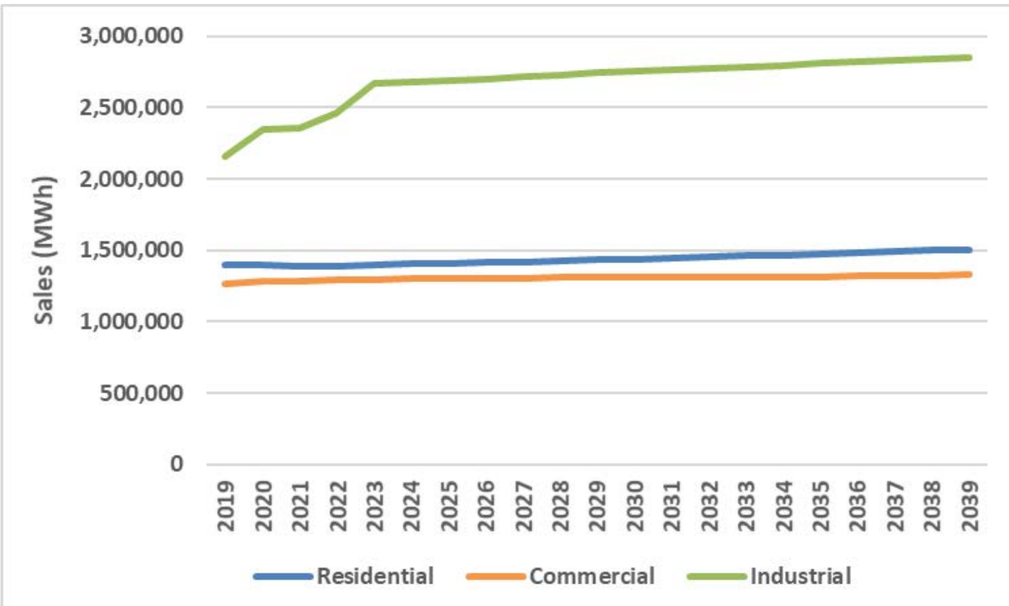


Figure 8. Vectren Sales Forecast by Customer Class[30]

Vectren is forecasting nearly flat sales growth for the residential and commercial classes. On the other hand, Vectren is projecting significant growth from the industrial class between 2019 and 2023 followed by more modest growth thereafter. Vectren's internal sales forecast is the source of the jump in industrial sales shown in this figure above. We discuss our concerns with this trajectory in Section 4.2.

It was helpful that Vectren included Itron's load forecast report as an attachment to the IRP, but we recommend that Vectren include additional analysis and discussion around the load forecast for each customer class in future IRPs. In its most recent IRP, IPL had sections for each customer class and included graphs that compared historical to forecasted sales, customers, and average use.[31] IPL also included a discussion about forecast drivers and which drivers were believed to have the most influence on the sales forecast. This information provided a more

[30] Sales forecast provided in response to Informal Discovery Response to CAC 6.6. See Attachment 6 to this Report.

[31] IPL 2019 IRP, Sections 4.3.1, 4.3.2, and 4.3.3.

helpful summary of what influenced changes in the forecast and which sectors would be the drivers of future consumption.

4.2 VECTREN INDUSTRIAL SALES FORECAST

As discussed in Section 4.1, Vectren is projecting significant near-term growth in industrial sales. In Attachment 4.1 of the IRP,[32] Vectren describes the development of the industrial load forecast as follows:

> *The industrial sales forecast is developed with a two-step approach. The first five years of the forecast is [sic] 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.*

Based on the description above, we understand Vectren to have internally developed an industrial sales forecast for 2019 to 2023 and then applied the forecasted annual growth rate from the Itron report in 2024 and beyond. CAC attempted to ask Vectren several informal discovery questions to better understand the growth projected for the industrial class, but Vectren refused to answer these questions.[33] While we understand that certain customer information is proprietary and subject to an NDA, CAC has an NDA in place for this IRP that would cover disclosure of this information. Furthermore, as Dr. Borum said in his report on NIPSCO's 2016 IRP, "Prudence dictates that credible and transparent analysis is essential for assessing reliability and cost ramifications."[34]

Vectren's refusal to provide any material support for the development of its internal forecast for 2019 to 2023 prevents any critical review of the merits of this forecast. Since industrial sales dominate total service territory load, the industrial sales forecast is immensely consequential to the IRP resource optimization.

[32] Attachment 4.1, 2019 Vectren Long-Term Electric Energy and Demand Forecast Report, p. 12.

[33] Vectren objected to Informal CAC Data Requests 7.1b, 7.1c, 7.2, 7.4a, 7.4b, and 7.5a.

[34] Director's Final Report on the 2016 Integrated Resource Plans, at page 25.

4.2.1 Vectren's Internal Industrial Sales Forecast for 2019 to 2023

Figure 9 below shows the historical industrial sales for 2010 to 2018 compared to the 2019 to 2039 forecast developed for this IRP. The forecasted average annual growth for Vectren from 2019 to 2023 is 5.50%. The projected sales for 2023 are comparable to the level of sales Vectren had in 2015 before the industrial sales dropped in 2016 due to exiting customers.

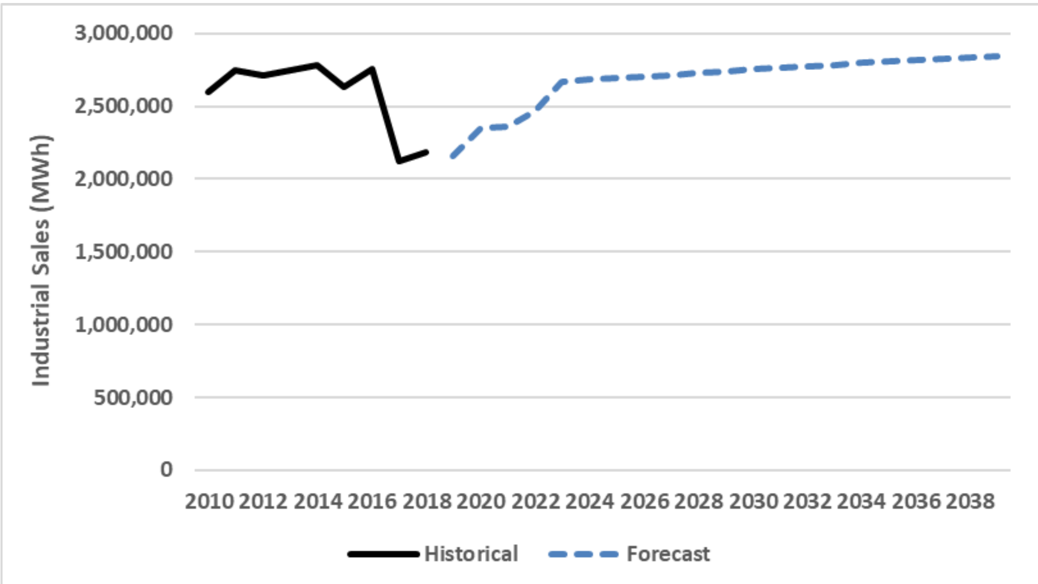


Figure 9. Industrial Sales Forecast (MWh)[35]

Vectren said in response to one of CAC's discovery questions that, "Annual growth rates produced for the Itron model, which do not include expected sales from one existing industrial customer, were utilized to extend the forecast to 2039."[36] This response implies that increased sales to just one existing industrial customer is the main driver for the growth in the sales forecast. However, this explanation does not make sense when one considers the pattern of that growth.

Table 13 shows the annual increase in industrial sales between 2019 and 2023. If the growth was due to the increase in load from one customer, it would make more sense for growth to increase over time until the implied online date for the customer's expansion is reached. However, as Table 13 shows, there is significant growth between 2019 and 2020, minimal growth between 2020 and 2021, and then significant growth again between 2021 and 2022, and 2022 and 2023.

[35] Historical sales provided in response to Informal Discovery CAC 6.7 and projected sales from Informal Discovery CAC 6.6. See Attachment 7 to this Report for Vectren 2010-2019 Historical Sales Attachment provided in Response to CAC DR 6.7. See Attachment 6 for Vectren IRP Sales Forecast provide in response to CAC DR 6.6.

[36] Vectren Response to Informal Discovery CAC 7.1a. See Attachment 1 to this Report for this response.

Table 13. Vectren Industrial Sales Forecast Annual Growth[37]

Year	Vectren	Annual Growth
2019	2,159,155	
2020	2,347,543	8.73%
2021	2,360,025	0.53%
2022	2,463,638	4.39%
2023	2,669,566	8.36%
Avg Ann Growth		**5.50%**

Notably, data reported through the first half of 2020 show total industrial sales of 909,975 MWh[38] or about 42% of 2019 sales. Because the data also show no increase in pre-pandemic 2020 sales, this very much raises the question of the accuracy of Vectren's near term industrial sales forecast.

We compared the Itron industrial sales forecast for 2019 to 2023 against the forecast Vectren developed internally. As Figure 10 shows, in contrast to Vectren, Itron projected flat sales for the industrial class from 2019 to 2023.

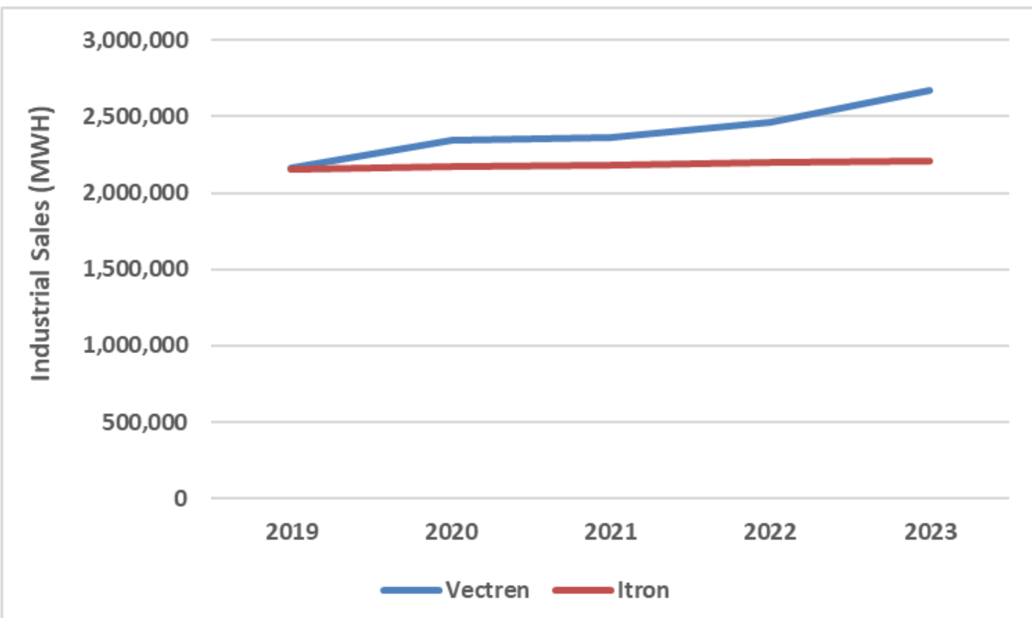


Figure 10. Vectren's Internally Developed Industrial Forecast Compared to Itron's [39]

[37] Vectren sales forecast provided in response to Informal Discovery CAC 6.6.
[38] S&P Global.
[39] Itron forecast for 2019 to 2023 provided in Informal Discovery CAC 7.1d

4.2.2 Comparison to the 2016 IRP

The Itron Long-Term Energy Demand Forecast[40] from the 2016 IRP described the industrial sales forecast as follows:

> *The industrial sales forecast is a two-step approach. The first five years of the forecast is based on VEDS's internal forecast. Industrial sales are forecasted using a historical baseline of 12 months ended December 2015. Vectren reviews baseline volumes at the customer level and is adjusted based on known customer activity such as closures and expansions. New customers are specifically identified and forecasted based on expected load. An overall growth rate of approximately 1% is then applied to the baseline period to capture growth that has not been specifically identified by customer. The forecast after that is based on a model-based forecasted growth rate; the forecasted growth rate is applied to the fifth year industrial sales forecast.*

The industrial sales forecast from the 2016 IRP is compared to the industrial sales forecast in this IRP in Figure 11. It is our understanding that the 2016 IRP accounted for load additions Vectren anticipated from several industrial customers that were planning to build facilities within Vectren's service territory. In addition, based on Vectren's description of the forecast outlined above, a 1% buffer was built into the forecast to account for growth not identified by the customer. We are not certain if Vectren has included the anticipated load from the customers identified in the 2016 IRP, but it does appear that the 1% buffer was removed in the forecast developed for this IRP. Even with these modifications, the forecast for this IRP is significantly higher than the 2016 IRP forecast. If new load in the 2019-2020 forecast is indeed the product of just one customer's growth, this further raises the question about the likelihood of that happening. Either way, this load growth has not been substantiated by Vectren in any way.

[40] Cause No. 45052. Itron Long-Term Energy Demand Forecast 2016, Attachment MAR-1, p. 588.

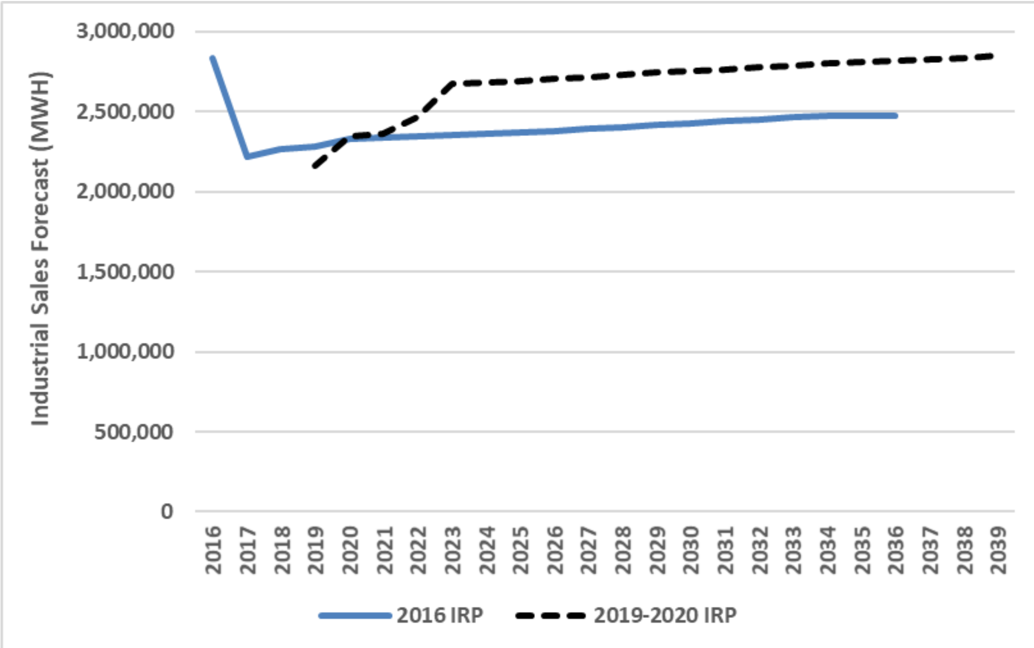


Figure 11. Comparison of 2016 IRP and 2019-2020 IRP Industrial Sales Forecast (MWh)[41]

4.2.3 Providing Supporting Information for the Vectren Industrial Sales Forecast

We understand that Vectren has previously maintained that it is important to protect proprietary information about load expansions by existing customers or planned new industrial facilities. While we do not wish to reargue the issue after litigating it in prior docketed proceedings, we believe that alternative measures could have been taken to remove customer specific information while still being able to provide stakeholders with information to support the development of the internal forecast for 2019 to 2023. 170 IAC 4-7-5(a)(9) makes it clear that the credibility of Vectren's demand forecast is tied to the quality of the date used to create that forecast. Here, Vectren incorporated data on economic activity and customer usage, but did not allow stakeholders to evaluate the quality of that data. Going forward, Vectren can improve the quality of that data (and the credibility of the demand forecast) by allowing stakeholder input into Vectren's assumptions. Indeed, 170 IAC 4-7-5(c) requires Vectren to allow stakeholder input on those specific factors.

We believe IPL's approach, sharing data on economic activity and customer usage, is much closer to satisfying 170 IAC 4-7-5 than Vectren's approach. Table 14 shows a reproduction of a figure provided by IPL in its most recent IRP filing submitted in December 2019. IPL provided information related to specific adjustments that were made to the industrial sales forecast due to anticipated additions from five customers. We believe that Vectren could have taken similar

[41] 2016 IRP forecast from Cause No. 45052, Attachment MAR-1, Table 2-3.

steps as IPL did to provide the projection for the anticipated load additions from the industrial customer(s) that informed the development of the forecast between 2019 to 2023.

Table 14. Expected (MW) Additions by IPL Industrial Customer[42]

Company	2020	2021	2022	2023
Customer #1	2.5	2.5	2.5	2.5
Customer #2	5	5	5	0
Customer #3	0	5	5	0
Customer #4	6.25	6.25	0	0
Total	13.75	18.75	12.5	2.5

4.3 ACCOUNTING FOR DSM IN THE LOAD FORECAST

Vectren's approach for incorporating energy efficiency ("EE") into its load forecast is to model historical EE as a variable in Itron's SAE Model. This approach helps to ensure that the utility has a "No DSM" forecast that can be used in its IRP modeling. As Itron notes in the report, "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."[43]

While Vectren's approach to modeling EE in its load forecast is briefly described in the Long-Term Energy and Demand Forecast in Attachment 4.1 to the IRP, the detail behind the approach is limited. Based on the model information provided in the Itron report and Vectren's responses to informal discovery,[44] Vectren includes an EE variable in the sales forecast model to capture the EE sales impact. The resulting coefficient for the EE variable represents the additional sales impact that EE has that is not explained by other model variables.

Vectren's approach of modeling EE as a variable in the sales forecast model ensures that a "No DSM" forecast is developed. We consider a "No DSM" forecast critical to accurately modeling DSM as an explicit resource in IRPs. For example, this load forecast meant that Vectren did not have to make any distortionary adjustments to energy efficiency in the same way that I&M did in its 2018-2019 IRP. We consider this to be a best practice approach for treating existing and planned DSM in the load forecast and allowing future DSM to be evaluated independent of the load forecast.

[42] IPL 2019 IRP, Figure 4-19, p. 43.

[43] Vectren 2019-2020 IRP, p. 290-291.

[44] Vectren Response to Informal Discovery CAC 6.1, 6.2, and 6.3. See Attachment 8 to this Report.

5 Description of Available Resources

Section 5 describes our assessment of Vectren's performance in meeting the requirements of 170 IAC 4-7-6 of the Indiana IRP Rule. Please see Table 15 below for our findings.

Table 15. Summary of Vectren's Achievement of Indiana IRP Rule at 170 IAC 4-7-6

IRP Rule	IRP Rule Description	Findings
4-7-6 (a)	In describing its existing electric power resources, the utility must include in its IRP the following information relevant to the 20 year planning period being evaluated: (1) The net and gross dependable generating capacity of the system and each generating unit.	**Met**
4-7-6 (a)	(2) The expected changes to existing generating capacity, including the following: (A) Retirements; (B) Deratings; (C) Plant life extensions; (D) Repowering; and (E) Refurbishment.	**Met**
4-7-6 (a)	(3) A fuel price forecast by generating unit.	**Met**
4-7-6 (a)	(4) The significant environmental effects, including: (A) air emissions; (B) solid waste disposal; (C) hazardous waste; (D) subsequent disposal; and (E) water consumption and discharge at each existing fossil fueled generating unit.	**Met**
4-7-6 (a)	(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; (ii) congestion; and (iii) and energy costs. (C) An evaluation of the potential impact of demand-side resources on the transmission network.	**Partial**
4-7-6 (a)	(6) A discussion of demand-side resources and their estimated impact on the utility's historical and forecasted peak demand and energy. The information listed above in subdivision (a)(1) through subdivision (a)(4) and in subdivision (a)(6) shall be provided for each year of the future planning period.	**Met**
4-7-6 (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.	**Met**
4-7-6 (b)	(2) 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.	**Mostly**
4-7-6 (b)	(3) For potential supply-side resources, the utility shall include the following: (A) Identification and description of the supply-side resource considered; (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.	**Met**

4-7-6 (b)	(4) In analyzing transmission resources, the utility shall include the following: (A) The type of the transmission resource; (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.	**Partial**

5.1 ENERGY EFFICIENCY

For this IRP, Vectren models 10 demand side management ("DSM") bins that contained one fixed low-income bin, one fixed demand response ("DR") bin for the A/C Direct Load Control and Smart Thermostat programs, one selectable DR bin and seven selectable EE bins.[45] Vectren's initial modeling results indicated that the model was optimally selecting 0.75% EE in the Reference Case. After reviewing the modeling results, Vectren decided to force in additional EE as a sensitivity to analyze the impact that the additional EE would have on the portfolio cost. As Vectren states in the IRP:

> *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%.*[46]

We appreciate that Vectren performed this sensitivity analysis and decided to test the inclusion of the higher level of EE. Since we started critical review of IRPs in Indiana in 2015, our views about how to properly model energy efficiency have evolved as the utilities' methodologies have changed. IPL similarly forced in additional EE and, unlike Vectren, rather than causing the NPVRR to go up nominally, it lowered the NPVRR, often by a material amount. We believe both these examples speak to the problems with grouping EE measures by cost, and we would like to see Vectren move away from this approach for its next IRP.

[45] Vectren 2019-2020 IRP, pp. 247-248.

[46] Vectren 2019-2020 IRP, p.187.

5.2 DEVELOPING ENERGY EFFICIENCY BINS BASED ON COST

While Vectren took the right step in testing the impact of the addition of more EE bins to the Preferred Portfolio, it still does not alleviate some concerns with the approach that Vectren used to model the bins. Grouping the EE bins based on cost does not reflect how Vectren actually implements its DSM programs. The first 0.25% of savings that Vectren achieves will contain a mix of cost-effective measures. In contrast, the first 0.25% bin modeled in the IRP includes only savings from the least expensive measures. Those measures together would not offer a coherent EE program. Ultimately, Vectren will implement some of the measures included in the bins selected by the model, but other measures implemented will be from bins not selected by the model. Unavoidably, cost-effective measures will be eliminated from implementation because, under this approach, the connection between the IRP and DSM plan is based merely on the level of savings in the preferred plan.

We also think this approach could be masking a result that even more EE would be cost-effective. If Figure 12, below, were reworked to present the MPS savings by program type, then the supply curve of EE would look much more flat. This is because the less expensive measures would average out the costs of the more expensive measures, the result of which would almost certainly be the selection of additional EE as long as not all the bundles are “optimal.” If all of the bins were grouped into one, then the overall levelized cost would be $[redacted] per MWh. This is in contrast to the $[redacted] per MWh levelized cost of Bin 5, which is the last bin forced in by Vectren. If all bins were optimal, the model should take them all regardless of how measures were grouped. However, without forcing in additional bundles, Vectren would not know if additional EE were similar in cost to the “optimal” level in the same way that Bins 4 and 5 were similar in cost.

Additionally, Vectren only tested the addition of most EE in the first three years of the modeling, 2021 – 2023. No other EE bundles were forced in subsequent years.

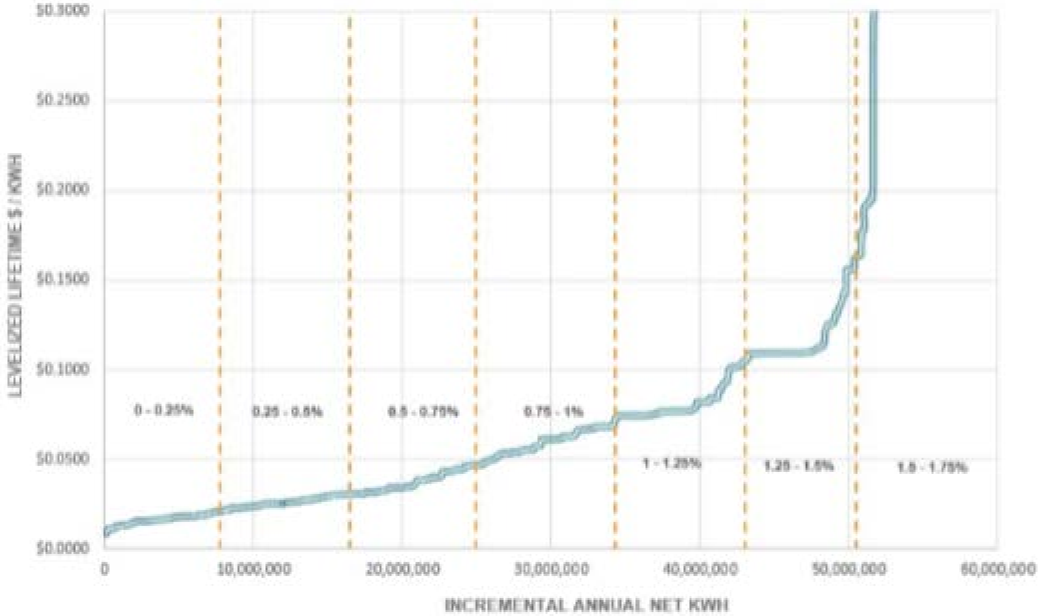


Figure 12. Energy Efficiency Supply Curve for 2024[47]

We are also not clear that EE costs, modeled as a levelized cost of energy, were grossed up for lines losses. Vectren also did not include line losses in the calculation of the levelized cost for each bin. And in response to CAC Informal Data Request 7.13, Vectren stated, "The Energy Efficiency Savings include in the '6.15 EE + DR Loadshape Summary File x7.0 (2018$)' worksheet were not grossed up for line losses. However, the product has been grossed up within the AURORA model." [48] After reviewing the AURORA modeling input files, we could not find any indication that line losses were applied to the EE bins. When the [redacted]% line loss is accounted for, the revised levelized cost for all bins grouped together is $[redacted] per MWh. But again, it is likely that the line loss adjusted levelized cost should actually be even less, because a marginal line loss factor ought to have been used. A [redacted]% factor, in our experience, is unlikely to be even an average figure, let alone a marginal factor.

[47] Vectren 2019-2020 IRP, Figure 6-22, p. 189.

[48] Vectren Response to Informal Discovery CAC 7.13. See Attachment 1 for Response.

5.3 MODELING REALISTIC ACHIEVABLE[49] AND MAXIMUM ACHIEVABLE POTENTIAL[50]

For this IRP, Vectren's EE bins only represented the Realistic Achievable Potential ("RAP") identified in the market potential study ("MPS").[51] One way to bundle measures in coherent portfolios is to simply bundle them into the two levels often identified in a market potential study, realistic and maximum achievable potential. We recognize that this runs the risk of the model selecting no energy efficiency, which is also not a realistic result. Some good faith testing of the best way to represent these bundles, e.g., as a resource that can be picked once over the planning period or not at all or can be picked at different level every ten years, will be necessary to strike the right balance. This also raises the importance of producing a high quality MPS or using a decrement approach to energy efficiency modeling. We are encouraged that we had a very collaborative relationship with Vectren in creating its MPS and look forward to making further improvements in the next IRP that will lead to even more improvement in Vectren's program offerings.

5.4 DEMAND RESPONSE

Vectren currently has two demand response programs which include the Direct Load Control ("DLC") and Interruptible tariffs for larger customers. The DLC program consists of remote dispatch control for residential and small commercial air conditioning, electric water heating and pool pumps. Vectren modeled one fixed DR bundle for the DLC and Smart Thermostat programs and offered one DR bundle for the Bring Your Own Thermostat program, which was selectable.

Vectren modeled the current interruptible load from three customers at 35 MW and did not allow additional interruptible DR to be selected by the model. In the IRP narrative, Vectren expressed concern about losing industrial customers and not being able to attract new customers for this program due to the new MISO testing requirements. Vectren states:

> *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*

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[49] Vectren defines Maximum Achievable Potential as an estimate of "achievable potential on paying incentives equal to 100% of measure incremental costs and aggressive adoption rates." 2019-2020 IRP, p. 186.

[50] Vectren 2019-2020 IRP, p. 189.

[51] Vectren 2019-2020 IRP, p. 189.

> *be very costly to industrial customers' operations. Since implemented, one customer (~7MWs) has left the program.*[52]

Demand response resources, like interruptible tariffs, typically compensate customers to use "less electricity during key hours when electricity prices are high, and/or the electric grid is at risk of having demand exceed supply."[53] And, demand response can meet a significant portion of projected peak demand.

But, Vectren's current interruptible riders are extremely restrictive, and Vectren's model only considered demand response in some of its runs and at levels only slightly higher than its existing level of demand response. Thus, it is not surprising that Vectren's 20 year plan for demand response is relatively static. Vectren's current interruptible riders are so restricted that only 35 MW of demand response from four customers are participating in these riders, despite Vectren having the second highest percentage of sales to industrial customers of any of the Indiana electric investor-owned utilities in 2015 or 2016.[54] Compare that to "NIPSCO [which] ha[d] the highest share of industrial sales (55 percent) and highest percentage of demand response (16 percent), as a share of peak load in Indiana."[55] Vectren continues to just have three distinct interruptible riders: (1) Rider IC, or Interruptible Contract; (2) Rider IO, or Interruptible Option; and (3) Rider MISO DR, or MISO Demand Response.

In Cause No. 45052, it was discovered that Vectren's main interruptible rider, Rider IC, has about 60 customers eligible to participate in this interruptible rider but only four customers that actually do.[56] Vectren's Rider IC is limited and too restrictive, while another Indiana utility "includes a variety of DR options on various tariff riders that dictate the number of hours of availability annually, notification time, and participant compensation via demand charge credit."[57] Offering proper compensation to commercial and industrial customers to participate in Vectren's interruptible tariffs is critical to successfully providing significant opportunity for curtailment. If Vectren does not pay enough for this extremely cost-effective opportunity to shave peak, customers will not want to participate and the resource will not be realized. Unfortunately, Vectren's Rider IC pays poorly at approximately $3.50 per kW per month (and its Rider IO[58] pays even less).

Vectren's Rider IC is also arbitrarily limited to just two rate classes, offering no explanation as to why the other rate classes cannot be eligible for Rider IC. Vectren says these ineligible rate

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[52] Vectren 2019-2020 IRP, p. 169.

[53] Demand Side Analytics (2018). Potential for Peak Demand Reduction in Indiana. Available at: https://info.aee.net/hubfs/IN%20DR%20Study%20Final.Feb.7.2018.pdf.

[54] *Id*., p. 11.

[55] *Id*., pp. 34–35.

[56] IURC Cause No. 45052, Tr. I-14, lines 1–18.

[57] Demand Side Analytics (2018). Potential for Peak Demand Reduction in Indiana, p. 10.

[58] Rider IO provides a Capacity Credit that "is equal to 80% of the 'Capacity Payment to a Qualifying Facility' in effect in Company's Rate CSP." The Company's Rate CSP provides a capacity payment to a qualifying facility at $3.88 per kW per month. 80% x $3.88 = $3.104.

classes could just participate in the less lucrative Rider O; tellingly though, Vectren does "not have any customers participating in the [lesser paying] Rider IO."[59]

Vectren's Rider IC also arbitrarily limits participation to customers who commit to providing 1 MW of Demand Response. This is a very large threshold that many customers cannot meet. Aggregation services could help in overcoming this restriction, but Vectren fails to allow this as an option in Rider IC. These third parties can aggregate customers who cannot provide an entire 1 MW at a time with other customers who cannot provide an entire 1 MW at a time to collectively provide that 1 MW to Vectren during a peak emergency event. Vectren noted that the Rider MISO DR tariff does allow for aggregation to meet its 1 MW requirement, but there are no customers participating in this Rider, probably because it only pays energy payments, not capacity payments.[60] The Commission, in its July 28, 2010 Order on customer participation in wholesale markets, "strongly encourage[d]" its utilities to "explore opportunities with [aggregators or curtailment service providers] which may further enhance participation in demand response by customers of all sizes, classes and sophistication."[61] Unfortunately, 10 years later, Vectren has failed to take seriously this encouragement from the Commission.

Another arbitrary restriction in Vectren's Rider IC is its requirement for 250 hours of availability, meaning that a customer has to agree to be able to provide a total of 250 hours of interrupted service per year in total. Vectren's Rider IO is even worse, requiring 50 more hours of availability than Rider IC for a required total of 300 hours. This is a large quantity of time for a customer to agree to curtailment, especially considering these are primarily working businesses that need variety and options to choose from. By contrast, NIPSCO's former Rider 775 had different availability options at 20-hours, 100-hours, 200-hours, and 400-hours, allowing a business the opportunity to pick an option that works for it.

Vectren's Rider IC also requires a 10-minute response time from its Demand Response resources, which is very onerous for customers. A 10-minute response time means that once Vectren calls upon a customer to curtail load, the customer must do so within 10-minutes. Vectren's Rider IO is not much better, requiring 1-hour response time. Compare this to NIPSCO's former interruptible tariff options, offering varied response times at 4 hours, 2 hours, and 10 minutes.

Finally, Vectren's Rider IC subjects participating customers to a very strong penalty for failure to respond within 10 minutes with 1 MW of demand response, equal to 10 times the capacity credit per kVa. It does not appear that any of the five options under NIPSCO's former Rider 775 assign a monetary penalty from NIPSCO to its participating customers for failure to respond with the curtailment within the required response time besides passing along any penalties from any governmental agencies, but NIPSCO does remove said customer from the program for three years.

Thus, Vectren's expressed concern in its IRP narrative about losing industrial customers and not being able to attract new customers for this program due to the new MISO testing requirements is a red herring argument to avoid offering good interruptible tariffs for its largest customers.

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[59] IURC Cause No. 45052, Tr. I-15, lines 19–20.

[60] IURC Cause No. 45052, Tr. I-18, line 13–Tr. I-21, line 18.

[61] <u>In re Commission's Investigation</u>, Cause No. 43566, at 47–48.

These continued limitations to demand response on a current basis and in its forward-looking model are unreasonable and need to be addressed promptly by Vectren. Vectren's entire customer base suffer when demand response is not properly utilized and forecasted.

6 Selection of Resources

Section 6 describes our assessment of Vectren's performance in meeting the requirements of 170 IAC 4-7-7 of the Indiana IRP Rule. Please see Table 16 below for our findings.

Table 16. Summary of Vectren's Achievement of Indiana IRP Rule at 170 IAC 4-7-7

IRP Rule	IRP Rule Description	Finding
4-7-7	To eliminate nonviable alternatives, a utility shall perform an initial screening of the future resource alternatives listed in subsection 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.	**Not Met**

6.1 RESOURCE SCREENING TABLE

In Vectren's "IRP Rule Requirements Cross Reference Table", Vectren indicates that IRP Rule 4-7-7 is addressed in Section 6.6 regarding the Levelized Cost of Energy Resource Screening Analysis. However, there is no Section 6.6 in the IRP narrative.

Vectren did include Attachment 1.2 which contains Vectren's Technology Assessment Summary Table that provides cost information reported from Burns and McDonnell[62] for new resources including thermal, renewables, and energy storage. The reporting of the Burns and McDonnell costs for renewables, energy storage, and hybrid resources in Attachment 1.2 was confusing since those were not exactly the cost inputs modeled – they were higher. The costs modeled in AURORA for new generic wind, solar, energy storage, and hybrid resources are based on a technology averaging assessment. This technology assessment uses an average of costs from the NREL ATB, Burns and McDonnell, and PACE for new solar, wind, and battery resources. The costs from the technology averaging assessment were then adjusted based on the costs reported from the RFP and translated into inputs to model in AURORA.

[62] Information provided in Attachment 1.2 for new resources matches the information on the 'BMcD' tab of file 'Confidential Technology Assessment Averaging 01.17.2020—received 7-27-2020.'

7 Resource Portfolios

Section 7 describes our assessment of Vectren's performance in meeting the requirements of 170 IAC 4-7-8 of the Indiana IRP Rule. Please see Table 17 below for our findings.

Table 17. Summary of Vectren's Achievement of Indiana IRP Rule at 170 IAC 4-7-8

IRP Rule	IRP Rule Description	Finding
4-7-8 (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 the following: (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.	Met
4-7-8 (b)	With regard to candidate resource portfolios, the IRP must include: (1) An analysis of how each candidate resource portfolio performed across a wide range of potential future scenarios, including the alternative scenarios required under subsection 4(25) of this rule.	Met
4-7-8 (b)	(2) The results of testing and rank ordering of the candidate resource portfolios by key resource planning objectives, including cost effectiveness and risk metrics.	Partial
4-7-8 (b)	(3) The present value of revenue requirement for each candidate resource portfolio in dollars per kilowatt-hour delivered, with the interest rate specified.	Not Met
4-7-8 (c)	Considering the analyses of its candidate resource portfolios, a utility shall select a preferred resource portfolio and include in the IRP the following information: (1) A description of the utility's preferred resource portfolio.	Met
4-7-8 (c)	(2) Identification of the standards of reliability.	Met
4-7-8 (c)	(3) A description of the assumptions expected to have the greatest effect on the preferred resource portfolio.	Met
4-7-8 (c)	(4) An analysis showing that supply-side resources and demand-side resources have been evaluated on a consistent and comparable basis, including consideration of the following: (A) safety; (B) reliability; (C) risk and uncertainty; (D) cost effectiveness; and (E) customer rate impacts.	Partial
4-7-8 (c)	(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.	Partial
4-7-8 (c)	(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.	Not Met
4-7-8 (c)	(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; and (D) The utility's ability to finance the preferred resource portfolio.	Partial
4-7-8 (c)	(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 and (B) An assessment of how robustness of risk considerations factored into the selection of the preferred resource portfolio.	Partial

4-7-8 (c)	(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.	**Partial**
4-7-8 (c)	(10) A workable strategy to quickly and appropriately adapt its preferred resource portfolio to unexpected circumstances, including to the changes in the following: (A) Demand for electric service; (B) Cost of a new supply-side resources or demand-side resources; (C) Regulatory compliance requirements and costs; (D) Wholesale market conditions; (E) Changes in Fuel costs; (F) Changes in 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.	**Partial**

7.1 PORTFOLIO DEVELOPMENT, SCREENING, AND RISK ANALYSIS

Vectren developed fifteen portfolios to evaluate for this IRP process. Vectren's approach better accounted for stakeholder interests and represented a wider variety of portfolio outcomes than in its prior IRP. Vectren's portfolios included cases representing business as usual, coal retirements, a focus on renewables, a combination of renewables and flexible gas, gas conversions, and a portfolio that closely represented House Resolution 763 – a Congressional bill to reduce carbon dioxide emissions.

Ten of the fifteen portfolios were selected as candidate portfolios for analysis in AURORA. Vectren said the reasoning for screening some of the portfolios included high levels of curtailment from renewable resources, large amounts of market sales, and some portfolios providing duplicative information that is captured in another portfolio. Vectren then took those ten portfolios and evaluated them under the four scenarios, which include low regulation, high technology, 80% reduction of CO_2 by 2050, and high regulation.

Vectren performs the risk analysis by using probabilistic modeling for the ten candidate portfolios. Vectren specified several stochastic variables, which include coal prices, natural gas prices, carbon prices, peak and average load, and capital costs. Vectren reruns the portfolios with 200 iterations of each variable. Based on metric evaluations of each portfolio, Vectren then eliminates portfolios that do not meet key criteria or perform worse than other candidate portfolios. Vectren evaluated the portfolios across several criteria and deemed the four portfolios that performed the best across cost, energy sales and purchases, and CO_2 emission reductions to be the Reference Case, Renewables + Flexible Gas, All Renewables by 2030, and the High Technology portfolio. Figure 13 shows the "balanced scorecard" Vectren included in the IRP. Vectren's scorecard evaluated cost, cost uncertainty, reduction of CO_2 emissions, and the dependence on energy and capacity purchases and sales.

	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%

Figure 13. IRP Balanced Scorecard Color-Coded Comparison

We identified several concerns with how Vectren calculated and weighted metrics included in the balanced scorecard in the 2016 IRP. This time around, Vectren removed the weighting of the metrics that it used in the 2016 IRP. However, we still have some concerns around the development of the scorecard, and we still have concerns about how Vectren evaluated the final candidate portfolios which we address in Sections 7.3 and 7.2.

As we were in our 2016 IRP comments, we remain concerned that 200 iterations is not enough to perform the stochastic modeling. It is still not clear how Siemens could conclude that convergence is reached when the tested variables include coal prices, natural gas prices, carbon prices, peak and average load, and capital costs. We very much remain concerned that Siemens' modeling does not reach convergence. In addition, we do not think that stochastic treatment of carbon prices or capital costs is appropriate. These variables are uncertain, not volatile[63] nor would it be possible to create probability distributions for these variables that are not entirely subjective. For example, the price of solar in 2015 is not a useful data point upon which to base a probability distribution of solar capital cost since the circumstances in place at the time are not the same circumstances likely to influence the cost of solar in the future. We are also skeptical that it makes sense to treat peak and load stochastically. Vectren's load has historically been influenced by economic factors more than anything else, which again, are uncertain and not volatile. We believe that sensitivity testing is a much more informative way to test uncertainty and does not rely on black box assumptions in the way that stochastic testing does.

[63] Carbon prices could become volatile in the future when a carbon price is instituted, but without any history of that volatility a probability distribution of carbon prices is inherently entirely subjective.

7.2 ALTERNATIVE CANDIDATE PORTFOLIOS

Vectren identified four candidate portfolios that performed well in multiple categories in its scorecard evaluation. Those portfolios included the High Tech, which was selected as the Preferred Plan, in addition to the Renewables + Flexible Gas, All Renewables by 2030, and the Reference Case. Table 18 shows the different resources contained within each of the final four candidate portfolios.

Table 18. Comparison of Resources Included in Top Performing Portfolios[64]

	Reference	Renewables + Flexible Gas	Renewables 2030	High Tech
2021-2023	1.25% EE	1.25% EE	1.25% EE	1.25% EE
2022	300 MW Wind	300 MW Wind	300 MW Wind	300 MW Wind
2023	731 MW Solar	731 MW Solar	731 MW Solar	731 MW Solar
	126 MW Storage	126 MW Storage	278 MW Storage	126 MW Storage
2023	Retire ABB1, ABB2, FBC2, Exit Warwick	Retire ABB1, ABB2, FBC2, Exit Warwick	Retire ABB1, ABB2, FBC2, Exit Warwick	Retire ABB1, ABB2, FBC2, Exit Warwick
2024	236 MW CT	236 MW CT	-	236 MW CT
	415 MW Solar and DR	415 MW Solar and DR	415 MW Solar and DR	415 MW Solar and DR
2025	-	-	-	236 MW CT
2024-2026	0.75% EE	.75% EE	1.0% EE	.75% EE
2027-2039	0.75% EE	.75% EE	1.0% EE	.75% EE
2029-2032	-	-	Retire FBC3, ABB3, ABB4	-
2029-2032	-	-	360 MW Storage	-
			700 MW Solar	-
2033-2034	-	Retire FBC3	450 MW Solar	-
2033-2034	-	236 MW CT	-	-
2037-39	250 MW Solar	-	-	50 MW Storage
Avg Annual Capacity Purchase	137 MW	135 MW	170 MW	4 MW

Table 19 provides the comparison of all the ten candidate portfolios using the probabilistic NPVRR from the stochastic modeling, ranked from least cost to highest cost. Vectren's selection of the High Tech portfolio is not based on being the least cost portfolio, as both the Reference and Renewables + Flexible Gas are lower in cost. Vectren stated in the IRP narrative that costs within two percent of each other were not considered to be significant enough to differentiate:

[64] Vectren 2019-2020 IRP, pp. 229-230.

> *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.*[65]

Based on Vectren's determination that portfolios within 2% of each other are not enough to differentiate on the basis of cost, this also means that the All Renewables by 2030 portfolio is a viable candidate since it is only 0.89% more costly than the High Tech portfolio. Vectren did say that the All Renewables by 2030 portfolio may need transmission upgrades in the range of $20 to $30 million, which was not included in the NPVRR of the portfolio.[66] Even if those investment costs are just added to the NPVRR, it still would place the All Renewables by 2030 portfolio within the 2% threshold.

Table 19. 20 Year NPV ($ Billion) for Candidate Portfolios[67]

Portfolio	Probabilistic 20 Year NPV	% Difference from Preferred Plan
Renewables + Flexible Gas	$2,526	-2.47%
Reference Case	$2,536	-2.08%
High Technology*	$2,590	-
All Renewables by 2030	$2,613	0.89%
Bridge ABB1 Conversion	$2,675	3.28%
Diverse Small CCGT	$2,680	3.47%
Business as Usual to 2029	$2,689	3.82%
ABB1 + ABB2 Conversions	$2,834	9.42%
ABB1 Conversion + CCGT	$2,872	10.89%
Business as Usual to 2039	$2,912	12.43%

[65] Vectren 2019-2020 IRP, p, 251-252.

[66] Vectren 2019-2020 IRP, p. 276.

[67] Vectren 2019-2020 IRP, Figure 11.37.

7.3 EVALUATION OF THE PREFERRED PORTFOLIO

Vectren selected the preferred portfolio – the High Tech portfolio – based on several objectives. Some of the objectives were included in the balanced scorecard, while others were discussed outside of the scorecard. The objectives Vectren used to evaluate portfolios are outlined in Table 20.

Some of the objectives outlined in Table 20 were not included in the scorecard and were only discussed for the High Tech portfolio which leaves us unable to compare the High Tech portfolio to the other three top-rated portfolios. Vectren says there were no solar energy curtailments and only an average value of 0.02% of wind energy curtailments during the five years evaluated in the 2019-2039 period for the High Tech portfolio,[68] but it did not provide this information for any other portfolio. In addition, Vectren says there was no unserved energy in the High Tech portfolio but we do not know how the other portfolios compare. We tried to locate information on curtailments and unserved energy within the modeling outputs files provided by Vectren, but we were unable to see this information in the output files. As a result, we are unable to say how the other portfolios compare to the High Tech portfolio. Both of these metrics were used to discuss reliability and operational flexibility, which are main arguments that Vectren makes for selecting the High Tech portfolio, since it contains two CTs.

Vectren should also have provided information related to the uneconomic asset risk, reliability, operational flexibility, and transmission/distribution for the candidate portfolios to allow for a comparison across all metrics considered, and not just the metrics reported in the scorecard. Without the information to compare metrics across portfolios, we are unable to say how the other portfolios compare across these categories. This is especially important since Vectren is arguing that reliability, operational flexibility, and transmission/distribution upgrades make the case for the selection of the High Tech portfolio.

[68] Vectren 2019-2020 IRP, p. 262.

Table 20. Factors Used to Evaluate the Preferred Portfolio

Objective	Evaluated Using	Information Explicitly Given in Scorecard
Affordability	20-year NPVRR	Yes
Cost Uncertainty Risk Mitigation	95th percentile of the 20-year NPVRR	Yes
Environmental Emission	Life cycle greenhouse gas emissions reductions	Yes
Market Risk	Amount of energy market sales as a percentage of generation and capacity purchases as a percentage of peak load	Yes
Future Flexibility	Performance under the market conditions of the portfolio and different scenarios	No
Uneconomic Asset Risk	Asset deemed uneconomic if there were three successive years where revenues did not cover costs	No
Reliability	Hours of unserved energy	No
Operational Flexibility	Presence of dispatchable generation with high volumes of intermittent generation	No
Resource Diversity	Mix of different resource technologies contained in the portfolio	No
Local Resources	Vectren's preference for local resources to reduce cost risk, provide tax base, jobs, and grid support	No
Transmission/Distribution	Necessary transmission system network upgrades	No
Economic Development	Assisting with manufacturers' renewable and sustainable energy goals	No

Throughout Section 9.1 of the IRP, Vectren makes several arguments to justify the selection of the High Tech portfolio as the Preferred Plan, even though it is not the least cost plan. Vectren's arguments center around the two CTs which include:

1. Alleviating the need for capacity purchases from MISO;
2. Ability to convert the CTs to a CCGT in the event of load growth, the determination that Culley Unit 3 should be retired, or if market energy prices are higher than expected;[69] and
3. Maintaining adequate reactive power for industrial customers.[70]

We partially addressed the first two rationale in Section 3.3.2. As shown in Table 18, the average annual capacity purchase in the High Tech portfolio is extremely modest. This is because, as shown in Confidential Figure 6, there are only a handful of years in which installed capacity is not well in excess of what is required. Interestingly, the two CTs in this portfolio

[69] Vectren 2019-2020 IRP, p. 274.
[70] Vectren 2019-2020 IRP, p. 278.

were identified as the assets at most risk under Vectren's economic risk assessment. However, Vectren then reverses itself saying:

> *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.*[71]

Given the extremely low capacity prices heretofore exhibited in the MISO capacity auction, we would argue that some market exposure is a good thing. And, this risk can potentially be mitigated by short-term capacity purchases as well. Furthermore, rather than preserving optionality, building capacity in excess of need locks in capacity that Vectren may very well not need.

As it relates to the second argument that CTs provide future flexibility to meet load growth by converting the CTs into CCGTs, we are also skeptical. Vectren seems to be predicating this notion on attracting new industrial customers.[72] But Vectren provides no reason why other resource types cannot also supply new load, should it manifest. We already have concerns about whether the load growth embedded in the forecast is realistic and would strongly caution against adopting the position that it is reasonable to plan for even more new load growth.

In addition, we do not believe a CCGT would be attractive to industrial customers from a rate perspective. The levelized cost of energy ("LCOE") of a combined cycle available in 2024, as modeled by Vectren, is $[redacted] per MWh, much higher than the around the clock market price of $[redacted] per MWh. The ability to secure lower energy prices from the MISO market was a major reason that so much of NIPSCO's industrial load fought and negotiated an exit from NIPSCO's system in 2019 so building a more expensive unit would exacerbate that problem, not help it.

On the third argument regarding the concern for reliability and reactive power for industrial customers, Vectren has other, cheaper technology options that can be pursued to address these concerns including synchronous condensers. This assumes that reactive power is a concern in the other candidate portfolios, although we are unable to confirm that.

Finally, we would point out, as Vectren says in the IRP, "Companies are setting [renewable energy and carbon] 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."[73]

[71] Vectren 2019-2020 IRP, p. 263.
[72] Vectren 2019-2020 IRP, p. 278.
[73] Vectren 2019-2020 IRP, p. 277.

7.4 PRESENTATION OF PORTFOLIO COMPARISONS

We would recommend that Vectren present metrics differently for each portfolio in future IRPs. Figure 14 is a reproduction of one of the figures Vectren included to show the difference in NPVRR compared to the Reference Case. The figure is labeled as being in millions of dollars, but it clearly gives percentages, not dollar figures. Vectren also produced similar figures showing a comparison of CO_2 emissions reductions and average market purchases and sales.

	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 14. Portfolio NPVRR Comparison[74]

We recommend that Vectren include tables that show the actual values of the metrics in addition to the percentage differences.

[74] Reproduced from Figure 8-2 of Vectren 2019-2020 IRP, p. 244.

8 Short Term Action Plan

Section 8 describes our assessment of Vectren's performance in meeting the requirements of 170 IAC 4-7-9 of the Indiana IRP Rule. Please see Table 21 below for our findings.

Table 21. Summary of Vectren's Achievement of Indiana IRP Rule at 170 IAC 4-7-9

IRP Rule	IRP Rule Description	Finding
4-7-9 (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.	**Met**
4-7-9 (b)	The short term action plan is a summary of the utility's preferred resource portfolio and its workable strategy, as described in 170 IAC 4-7-8(c)(9) of this rule	**Met**
4-7-9 (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 and (B) The criteria for measuring progress toward the objective.	**Met**
4-7-9 (c)	(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.	**Partial**
4-7-9 (c)	(3) The implementation schedule for the preferred resource portfolio.	**Met**
4-7-9 (c)	(4) A budget with an estimated range for the cost to be incurred for each resource or program and expected system impacts.	**Not Met**
4-7-9 (c)	(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.	**Met**

Vectren's Short-Term Action Plan gives a helpful summary of the actions that Vectren is likely to take. However, it is not clear why Vectren is issuing a second RFP. Based on the language in the Short-Term Action Plan, it appears that the second RFP will be issued with the intent of filling the need with wind, and solar plus energy storage projects. Vectren stated:

> *The All Source RFP bids remain open until August 2020 and Vectren is in active discussions with short listed bidders for various renewable 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.*[75]

Vectren's High Tech case did not select any generic new renewable, energy storage, or hybrid resources until 2039, so any projects selected from the second RFP seem likely to supplant resources selected from the first RFP. We are not clear why this would be preferable and are concerned about Vectren's procurement process in that it may be losing out on cost-effective projects because of the length of time Vectren is taking to finalize winning bids.

[75] Vectren 2019-2020 IRP, p. 283.

Vectren IRP Comments List of Attachments

1. Combined Vectren Responses to CAC/Vote Solar Data Request 7 **(Public)**
2. RFP Bids inputs from Vectren RFP--IRP Inputs 1.17.20 Modelling File **(Confidential)**
3. RFP Bids inputs from Vectren IRP-- Aurora Study Input Tables 5.1.20 Modelling File **(Confidential)**
4. Vectren IRP-- Ref Case and Candidate Portfolios Deterministic Modelling File **(Confidential)**
5. Vectren Response to CAC 6.13--Avoided Cost T&D Workbook **(Confidential)**
6. Vectren IRP Sales Forecast provided in Response to Informal Discovery CAC 6.6 **(Public)**
7. Vectren 2010-2019 Historical Sales Attachment provided in Response to CAC 6.7 **(Public)**
8. Combined Vectren Informal Discovery Responses to 6.1, 6.2, 6.3 **(Public)**

ATTACHMENT 1

7.1. Please refer to p. 12 of Attachment 4.1.2019 Vectren Long-Term Electric Energy and Demand Forecast Report. The report states, “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.”

a. Please explain if Vectren develops its own industrial sales forecast or if it adjusts Itron’s forecast for the first five years of the industrial sales forecast.

Vectren utilized its own industrial sales forecast for the first five years. Annual growth rates produced from the Itron model, which do not include expected sales from one existing industrial customer, were utilized to extend the forecast to 2039.

b. Please provide the workbooks, with all formulas and links intact, used to create the industrial sales forecast for the first five years of the forecast.

Objection: The information sought in this request includes individual customer information, which Vectren is obligated to protect. As in previous data responses, Vectren does not share confidential customer-specific information. Current and prospective industrial customers treat their load information as proprietary and Vectren is bound to protect this information through NDAs.

c. If Vectren is making adjustments for new industrial customers as part of the development for the first five years of the industrial customer forecast, please provide the demand and energy sales Vectren anticipates that each of those new customers will need.

Please see the answer to 7.1b.

d. Please provide the results from Itron’s industrial sales forecast for 2019 to 2023.

The table below summarizes the model based industrial sales forecast for 2019-2023. Note that this model does not include expected sales to one existing industrial customer, as noted in 7.1a.

Year	Industrial Forecast (MWh)
2019	2,158,167
2020	2,168,490
2021	2,181,742
2022	2,201,536
2023	2,209,240

7.2. Please refer to Vectren's response to CAC Data Request 6.11 in the IRP Stakeholder Process. Please provide the amount of energy and demand added from the new industrial customers for each year between 2015 and 2020.

Please see the answer to 7.1b.

7.3. Please refer to tab 'Annl Model Results' from file '6.6 Final 2019-2020 IRP Forecast'.

a. Please confirm if Vectren is forecasting the number of industrial customers to remain the same between 2019 and 2039 or if this number represents an average number of customers.

Individual industrial customers are not projected to remain the same between 2019 and 2039. For the purposes of the IRP, industrial sales are forecasted, not industrial customer count. Industrial customer count in column K only serves the purpose of providing a place holder for total customer count in column P.

7.4. In Cause No. 45052, CAC asked the following question: Attachment 4.1 of Vectren's 2016 IRP at page 14 states, "Load addition from specific customers contributes to relatively strong sales growth in the near-term." With regards to this statement, please answer the following:

a. Vectren identified several new industrial customers in the 2016 IRP. Please confirm if these customers have been added to Vectren's system.

Objection. Questions regarding the 2016 IRP are not relevant to the 2019/2020 IRP.

b. What demand and energy sales do each of these new industrial customers add to Vectren's system? Please provide any documents including contracts with those customers that support your answer.

Please see answer to 7.4a.

7.5. Please refer Attachment MAR-1 (Attachment 4.1 2016 Vectren Long-Term Electric Energy and Demand Forecast Report, p. 589, Table 2-3) from Cause No. 45052.

a. The industrial sales forecast in Table 2-3 on p. 589 takes into account projected sales growth from new industrial customers. If this forecast takes into accounted anticipated sales from new customers, please explain why this forecast is lower than the projected industrial sales forecast in the 2019-2020 IRP.

Objection. Questions regarding the 2016 IRP are not relevant to the 2019/2020 IRP. Notwithstanding, each forecast utilized for integrated resource planning is unique, utilizing the best information available at the time.

7.6. Please refer to file 'Vectren IRP_Aurora Study Input Table_Reference Case_05.01.2020_rev_CONFIDENTIAL', tab 'Portfolio Resources.'

a. The new resources selected in Vectren's Preferred Plan seem to be coming online in January of the year in which they are selected by the model. Please confirm that January is the month in which new resources come online. If it is not January, then please provide the month in which the new resources come online.

January is the month in which new resources come online.

b. Please confirm if a new resource date of January is specified by the modeler or if Aurora can only add new resources in the month of January.

The new resource date of January is specified by AURORA as part of the Long-term Capacity Expansion process. While new resources can be added in any month, January was utilized to keep the LTCE constant with chronological hourly dispatch.

7.7. Please refer to the tab 'New Resources' in the file 'File name 'Vectren IRP_Aurora Study Input Table_Reference Case_05.01.2020_rev_CONFIDENTIAL' and the file 'Vectren IRP_Aurora Study Input Tables_Reference Case_05.01.20_Confidential'.

a. Resource ID 'RMT_Vectren_15_PPA_Low' has a different annual max and overall max set in these two files. Please explain why Vectren changed the annual max and lowered the overall max in the file 'Vectren IRP_Aurora Study Input Table_Reference Case_05.01.2020_rev_CONFIDENTIAL.'

Please see the rationale for limiting the amount of solar resources from the all-source RFP from initial modeling on page 248 of Vectren's IRP:

"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."

7.8. Please refer to the tab 'New Resources' in the file 'File name 'Vectren IRP_Aurora Study Input Table_Reference Case_05.01.2020_rev_CONFIDENTIAL'.

a. Please confirm that all RFP resources modeled in Aurora with the 'Utility' column set to 'Not Allowed Yet' are RFP bids that are no longer available for Vectren to consider.

Correct.

7.9. Please refer to the tab 'New Resources' in the file 'File name 'Vectren IRP_Aurora Study Input Table_Reference Case_05.01.2020_rev_CONFIDENTIAL'.

a. Please explain why the costs modeled for the 'Fixed O&M', 'Fix Cost Mod1', and 'Fix Cost Mod2' are lower for resource ID 'RMT605Vectren2' than they are for resource ID 'RMT605Vectren', even though they are the same size.

These two CT's are identical but one is assumed to be the first unit built at a to be determined site with the second built at the same site. Technical Appendix Attachment 1.2 Vectren Technology Assessment Summary Table shows under "Fixed O&M Costs" there are costs savings associated with building a second unit when compared to the cost of just one unit.

7.10. Please refer to the tab 'New Resources' in the file 'File name 'Vectren IRP_Aurora Study Input Table_Reference Case_05.01.2020_rev_CONFIDENTIAL'.

a. Please explain why Vectren did not allow the generic wind, solar, and battery resources to be available for the model to select until 2025.

As described on page 212 of the IRP, "Non-bid solar and Non-bid wind resources were not permitted until 2025 after short-term renewables and storage PPAs were no longer available." This also holds for battery resources. All-source RFP resources were model prior to 2025.

b. Please explain why Vectren modeled the three Vectren solar resources named 'Vectren_Solar_10_MW', 'Vectren_Solar_50_MW', and 'Vectren_Solar_100_MW' with the 'Must Run' column set to 0 when all of the solar RFP bid resources have the 'Must Run' column set to 1.

The reason why the RFP bid resources are set to 'Must Run' was due to the assumption that that PPA contracts would likely require delivery of all energy produced by these resources.

c. Please explain why the three Vectren solar resources modeled have a time series input for the 'Capacity Monthly Shape', but the solar RFP resources do not have an input for this column.

The Capacity Monthly Shape is used to shape the capacity by month (see response to 7.5c for more detail). Although there is a time series input on the three Vectren solar resources, all the values are set to 1.0 and are consistent with the other solar resources used in the model.

d. Please explain the difference between the 'Capacity Monthly Shape' and the 'Peak Credit' columns in Aurora.

The Capacity Monthly Shape is used to specify a capacity shape, which is multiplied by the resource capacity value to determine the capacity for the month. The Peak Credit column is used in conjunction with the use of reserve margin capacity targets as options in the model. The column is used to control the level of resource capacity which can be used to meet the reserve margin criteria and is generally appropriate for intermittent resources. The variable defines the fraction of a unit's input capacity to count toward the reserve criteria. If the fraction does not exist, 1.0 will be used as the default in the model.

e. Please explain why the 'Peak Credit' column for resource named 'Vectren_Wind_200_MW' is set to a numerical value instead of the time series to reflect the seasonal ELCC value for wind.

The Peak Credit for the Vectren_Wind_200_MW resource is inconsistent with the Vectren_Wind_50_MW. Both resources should have contained a monthly time series to reflect the seasonality of ELCC for wind resources. The value used for the 200 MW wind resource was a monthly ELCC value set to 7.8%. This figure is slightly higher than the summer ELCC values used for the 50 MW wind resource at 7.2%. Even though the ELCC credit was inconsistent, the 200 MW Wind Facility was not selected as part of the capacity expansion.

7.11. Please refer to the tab 'Operating Pools' in the file 'File name 'Vectren IRP_Aurora Study Input Table_Reference Case_05.01.2020_rev_CONFIDENTIAL.'

a. The 'firm imports' column has a time series input called 'yr_Demand_Response_Dummy'. Please confirm that the inputs for the 'yr_Demand_Response_Dummy' are in MWs. If they are not in MWs, please provide the units for that time series.

Confirmed.

b. Please explain how Vectren determined the level of firm imports modeled in Aurora.

The amount of firm imports for capacity and energy available in the model were based on industrial and residential/commercial demand response (DR) programs. The programs modeled reflect existing DR programs starting in 2019 and the energy delivered is dependent on the number of times the product is called upon.

7.12. Please refer to tab 'Costs Summary' in the 'Vectren IRP Ref Case and Candidate Portfolios_Deterministic_04022020_FINAL_CONFIDENTIAL'.

a. Row 13 shows the 'NPV of Capacity Market Costs (2018$ Thousands)' as a hard coded value. Please provide the supporting workpaper for that calculation, with all formulas and links intact.

Row 13, NPV of Capacity Market Costs (2018$ Thousands), is not a hard-coded value. The question is assumed to be addressing Row 14 of the referenced workbook and worksheet. NPV of Capacity Market Revenues from Sales (2018$ Thousands) can be derived from the PRM Summary Tab. The Excess Capacity can be found from the 'Amount Resources Exceed Coincident Peak' and the 'Coincident Peak Demand (MW) - 95.99%' rows. The Capacity Revenue ($) is the result of Excess Capacity and Capacity Market Price.

7.13. Please refer to the file '6.15 EE+DR Loadshape Summary File v7.0 (2018$)' provided in response to CAC Data Request 6.15. Please confirm if the EE savings included in this workbook have been grossed up for line losses.

The Energy Efficiency Savings included in the '6.15 EE+DR Loadshape Summary File v7.0 (2018$)' worksheet were not grossed up for line losses. However, the product has been grossed up within the AURORA model.

7.14. Please confirm if the costs for all supply and demand side resources modeled in Aurora are modeled in 2018 or 2019 dollars.

All supply and demand side resources are modeled in $2018 dollars.

ATTACHMENT 2—CONFIDENTIAL

See separately filed Excel workbook.

ATTACHMENT 3—CONFIDENTIAL

See separately filed Excel workbook.

ATTACHMENT 4—CONFIDENTIAL

See separately filed Excel workbook.

ATTACHMENT 5—
CONFIDENTIAL
See separately filed Excel workbook.

ATTACHMENT 6

See separately filed Excel workbook.

ATTACHMENT 7

See separately filed Excel workbook.

ATTACHMENT 8

CAC/Vote Solar Data Request Set 6 to Vectren
Vectren 2019-2020 IRP
August 25, 2020

6.1 Please refer to workbook 'ComSales' provided in 'Attachment 8.4 Confidential Sales and Demand Input Output Tables' included in the Technical Appendix files.

a. Please confirm if the variable 'ma_DSMFilled' represents Vectren's historical energy efficiency programs for the commercial class. If not, what does it represent?

The "ma_DSMFilled" variable represents historical and forecasted energy efficiency programs for the commercial class. Annual program savings are transformed into a monthly series and smoothed for input into the commercial sales model.

6.2 Please refer to workbook 'ResAvgUse' provided in 'Attachment 8.4 Confidential Sales and Demand Input Output Tables' included in the Technical Appendix Files.

a. Please confirm if the variable 'DSM_wOPow' represents Vectren's historical energy efficiency programs for the residential class. If not, what does it represent?

The "DSM_wOPow" variable represents historical and forecasted energy efficiency on a per customer basis, this includes savings from the OPower Home Energy Report ("HER") program. Annual program savings are transformed into a monthly series and smoothed for input into the residential average use model.

6.3 Please explain how Vectren treats historical DSM in developing its load forecast.

a. Please provide any workbooks, in electronic spreadsheet format, used to incorporate DSM into the load forecast.

The sales and demand forecast did not assume the continuation of utility sponsored DSM programs, as DSM was a selectable resource in the IRP model. Historical levels of DSM are included in the projected sales forecast modeling as a variable. Historical and forecasted DSM savings are derived from reported annualized savings. Annualized savings represent what savings would be if all measures for that year were installed in the beginning of the year; it is not the actual sum of the monthly DSM savings. The annualized savings are used in constructing a monthly DSM model variable designed to capture DSM sales impact. Estimated model coefficient on DSM (generally less than 1.0) represents the additional impact of DSM on sales not captured by the other model variables. As a result of this specification, Vectren South avoids "double counting" DSM savings. Please see attached 6.*3_Residential.xlsx* and 6.*3_Commercial.xlsx.*