CAUSE 45501

TESTIMONY

OF

EMILY S. MEDINE

(Public Version)

On Behalf of

Sunrise Coal, LLC

Date: April 30, 2021

IURC
INTERVENOR'S Sunrise
EXHIBIT NO. 1
6-21-21 DATE
REPORTER

CAUSE 45501

Direct Testimony of Emily S. Medine

Q. **WHAT IS YOUR NAME AND BUSINESS ADDRESS?**

A. My name is Emily S. Medine. I am employed by Energy Ventures Analysis, Inc. My business address is 1901 N. Moore Street, Suite 1200, Arlington, VA 22209.

Q. **FOR WHOM ARE YOU TESTIFYING IN THIS HEARING?**

A. I am testifying on behalf of Sunrise Coal, Inc.

Q. **WHAT IS YOUR EDUCATION AND EXPERIENCE?**

A. My education and experience are set out in Attachment I.

Q. **WHAT IS THE PURPOSE OF YOUR TESTIMONY?**

A. The purpose of my testimony is to provide my expert opinion on whether the Indiana Utilities Regulatory Commission (IURC) should approve the request of Southern Indiana Gas and Electric Company d/b/a CenterPoint Energy Indiana South (CenterPoint) to issue CenterPoint a Certificate of Public Convenience and Necessity (CPCN) to purchase and acquire, through a build transfer agreement (BTA), a 300 MW (ICAP) solar power electric generating facility in Posey County, Indiana (Posey Project) and to enter into a 25-year Power Purchase Agreement (PPA) for 100 MW (ICAP) solar project located in Warrick County (Warrick Project).

Q. **WHAT ARE YOUR CONCLUSIONS?**

A. Approval of the two projects is this filing is premature on multiple levels. While relying on the Preferred Plan from the 2019/2020 IRP, the filing creates issues related to the Preferred Plan. Notably, it is unclear how (1) approval of the Posey Project affects other parts of the Preferred Plan and (2) whether a potential extension of the Joint Operating Agreement (JOA) with Alcoa for Warrick 4 obviates the immediate need for replacement capacity[1]. In either event, according to the 2019/2020 IRP, the need for urgency in approving these projects had been tied to concerns about the expiration of the ITC in 2021. That issue is no longer urgent as the ITC was granted a two-year extension in the 2021 Omnibus Spending Bill. Further, the change in Administration is likely to provide additional extensions through at least 2024.

The filing is further complicated by CenterPoint's detailed requests related to these Project including a 35-year levelized cost recovery for the Posey Project, a 25-year PPA with levelized pricing for the Warrick Project, a Debt Equivalency Recovery for CenterPoint related to the PPA under terms that could be characterized as excessive, and relief from standard FAC prudence reviews. All such terms are not favorable to ratepayers and potentially will result in future stranded costs.

Q. **WHAT INFORMATION DID YOU REVIEW IN THIS ENGAGEMENT?**

A. I reviewed the following documents:

- Filings and the responses to the data requests submitted in this Cause.
- CenterPoint's 2019/2020 Integrated Resource Plan (2020)
- Comments on CenterPoint's 2019/2020 IRP
- Draft Director's Report on CenterPoint's 2019/2020 IRP
- Confidential Information Provided to the Indiana Coal Council related to CenterPoint's 2019/2020 IRP
- Relevant industry activity

[1] https://www.jdsupra.com/legalnews/congress-extends-renewable-energy-tax-98223/ (last viewed 4/30/2021).

II. SUMMARY

Q. PLEASE DESCRIBE CENTERPOINT'S REQUEST?

A. CenterPoint is requesting the following:

- A Certificate of Public Convenience and Necessity (CPCN) to purchase and acquire through a Build Transfer Agreement (BTA) a solar power facility in Posey County that will have an installed capacity (ICAP) of approximately 300 MW,
- A finding that the Posey County Solar Project constitutes a Clean Energy Project under Indiana Code § 8- 1-8.8,
- Approval of associated ratemaking and accounting treatment for the BTA under Indiana Code § 8-1-8.8-11,
- Approval to enter into a Power Purchase Agreement (PPA) to purchase energy and capacity from a 100 MW (ICAP) solar project in Warrick County over a 25-year term,
- A finding that the Warrick County Solar Project constitutes a Clean Energy Project under Indiana Code § 8- 1-8.8,
- Guaranteed full recovery of the PPA costs through the Fuel Adjustment Clause over the entire term of the PPA,
- Approval of associated ratemaking and accounting treatment for the PPA pursuant to Indiana Code § 8-1-8.8-11,
- Recovery of a Debt Equivalency Recovery that increases the price of energy under the PPA by more than 30%
- Confidential Treatment of the BTA and PPA pricing and other negotiated commercial terms and related confidential information.

Q. **WHAT IS THE BASIS FOR THESE REQUESTS?**

A. According to Mr. Greenley's direct testimony[2], this is just the first of multiple filings CenterPoint plans to make in 2021 to implement a Generation Transition Plan, which is just a new name for the preferred plan from its 2019/2020 IRP that calls for retiring A.B. Brown and F.B. Culley 2 and exiting joint operations of Warrick 4 and replacing them with renewables, storage, and natural gas generation. In other words, this request is simply beginning the implementation of CenterPoint's 2019/2020 IRP.

Q. **DO YOU BELIEVE THIS STANDALONE FILING SHOULD BE SUPPORTED?**

A. Not as currently configured. The standalone filing does not address many of the outstanding issues in the IRP including the timing of the Warrick 4 retirement and the implications of the Posey County project on future generation from the AB Brown site. Further, the requested rate making treatment is problematic in that CenterPoint is asking for (i) unconditional cost recovery without future reviews of the administration of either the BTA Project or the PPA, and (ii) a significant Debt Equivalency Recovery associated with the PPA.

Q. **PLEASE SUMMARIZE YOUR RECOMMENDATIONS**

A. Approval of CenterPoint's request should be deferred until the following occurs:

- CenterPoint must revise its resource analysis to address issues raised by Sunrise in the 2019/2020 IRP,
- CenterPoint must disclose the impact of the Posey County Solar Project on both (i) continued operation of the existing the AB Brown plant and (ii) future CTs that might be constructed at the AB Brown site. If transmission from the Posey Project impacts either or both of those scenarios, then CenterPoint should update its resource analysis to consider those impacts before the Posey Project should be considered for approval.

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[2] Direct Testimony of Steven C. Greenley, Petitioner Exhibit 1, p.7, l.27 – p. 8, l.1.

- CenterPoint should revise the levelized costs assumptions and calculations for the Posey Project from 35 years to 20 years.
- CenterPoint's proposal for a Debt Equivalency recovery should be rejected. The issue of whether debt equivalency costs are recoverable, and if so how, should be decided by the Indiana General Assembly. If the Commission must address that issue, it should be addressed uniformly on a statewide basis rather than on an *ad hoc* utility by utility basis. If it must be addressed on an *ad hoc* utility by utility basis, it should be done in the context of a rate case, and not a CPCN or tracker proceeding.
- CenterPoint should either shorten the term of the Warrick Solar PPA to 20 years or modify the PPA to allow for a market-based buy-out at the end of 20 years.
- CenterPoint should confirm that the costs for Posey County and Warrick Solar PPA are consistent with the renewable costs used in the 2019/2020 IRP.
- Before making long-term resource commitments CenterPoint should update its resource analysis to include extending the JOA with Alcoa, given the recent sale of the Warrick Mill to Kaiser Aluminum.
- If the Warrick Solar PPA is approved, it should be subject to regular review over its entire life that CenterPoint is prudently administering that contract.
- If the Posey Solar BTA is approved, it should be subject to a continuing review that it is being prudently performed by both parties.

III. SUNRISE OPPOSES APPROVAL OF THE CPCN AND PPA, AND ANY APPROVAL IN WHOLE OR IN PART OF THE 2019/2020 IRP.

Q. **WHAT WAS THE PREFERRED PORTFOLIO COMING FROM THE CENTERPOINT IRP?**

A. The Preferred Portfolio selected by CenterPoint consists of the following:

- Early addition of solar and wind projects to take advantage of the Production Tax Credit (PTC) for wind and the Investment Tax Credit (ITC) for solar
- The addition of two gas-fired combustion turbines
- The retirement of AB Brown and Culley #2 units by 2024 and withdrawal from the Warrick 4 JOA

Q. **WHAT IS THE STATUS OF THE IRP?**

A. IRPs are reviewed by IURC staff and the Director issues a summary of the IRP and his review. Notably, the Director's draft was just issued on April 9, 2021. Comments on the Director's draft are due in May 2021. A final report will eventually follow.

Commission approval of an IRP, in whole or in part, occurs only within the context of a CPCN proceeding such as this one. However, as explained in my testimony below, CenterPoint's 2019-2020 IRP without having been updated to address both material flaws and material changes in circumstances as they exist at present should not be approved in whole or in part in this proceeding.

Q. **WHAT DOES THE DIRECTOR'S REPORT SAY ABOUT UTILITIES COMMITTING TO UNDERTAKE A PREFERRED PORTFOLIO FROM AN IRP?**

A. The Director specifically notes "the resource portfolios emanating from the IRPs should not be regarded as being the definitive plan that a utility commits to undertake. Rather, IRPs should be regarded as illustrative or an ongoing effort that is based on the best information and judgment at the time the analysis is undertaken. The illustrative plan should provide off-ramps to give utilities maximum optionality to adjust to inevitable changing conditions (e.g., fuel prices, environmental regulations, public policy, technological changes that change the cost effectiveness of various resources, customer needs, etc.) and make appropriate and timely course corrections to alter their resource portfolios."[3] As explained below, even ignoring the flaws in CenterPoint's 2019-2020 IRP, in claiming that these projects implement its IRP, CenterPoint has failed to adjust its thinking and analysis for changes in conditions that have already occurred.

Q. **HAVE MATERIAL CHANGES HAVE OCCURRED THAT REQUIRE UPDATED ANALYSIS?**

A. Yes. As I explain in more detail below there has been a material change in the status of the Alcoa smelter to which Warrick 4 supplies power, and, as I noted above, the expiration of the PTC and ITC has been extended.

Q. **IS THERE ANYTHING IN THE CURRENT FILING THAT SUGGESTS THERE HAS BEEN AN UPDATE TO THE IRP ANALYSIS AS A RESULT OF THESE OR OTHER CHANGES THAT HAVE OCCURRED SINCE THE IRP WAS ISSUED?**

A. No.

Q. **DID SUNRISE COAL OFFER COMMENTS ON THE IRP?**

A. Yes. Sunrise and the Indiana Coal Council offered joint comments. They are appended to this testimony as Attachment II (hereafter "ICC/Sunrise Joint Comments").

Q. **PLEASE PROVIDE A SUMMARY OF THE KEY CONCERNS RAISED IN THESE COMMENTS.**

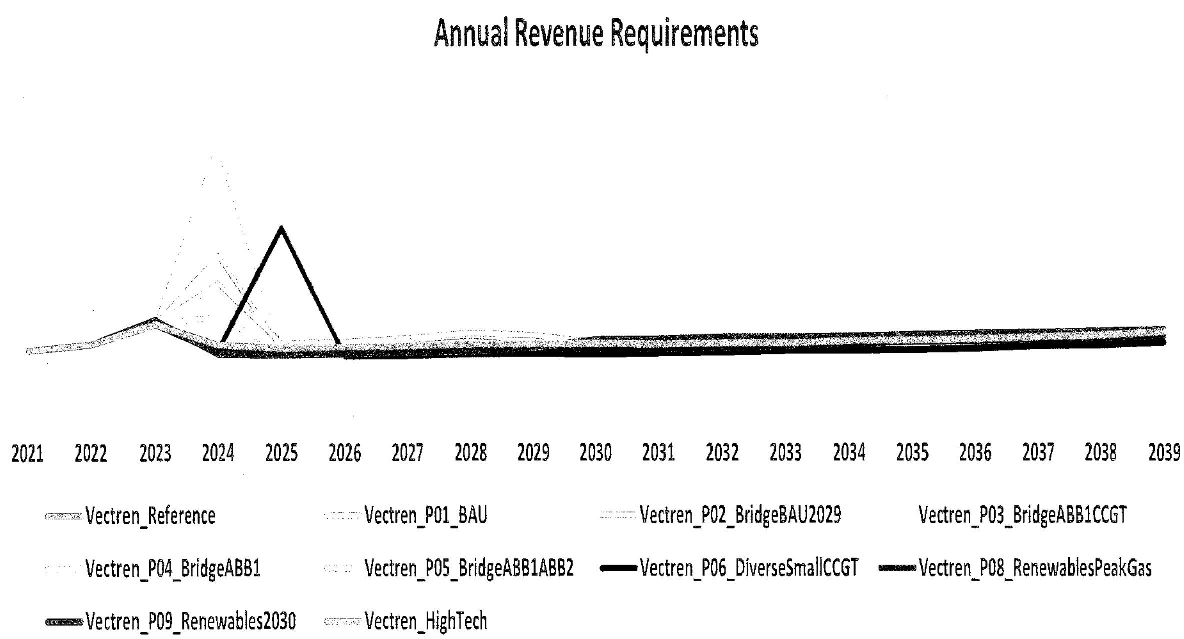
A. The ICC/Sunrise Joint Comments identified significant bias against continued operations at the AB Brown stations in three respects.

- First, the economic analysis was biased against continued operation of AB Brown. The analysis assumed that the capital cost for upgrades required to keep the AB Brown station on-line and burning coal beyond 2023 were entirely recovered in the

[3] Draft Director's Report on 2020 Vectren IRP.

first year, rather than being amortized over the life of the investments. In contrast, for replacement capital investments in solar, wind, and new (as opposed to conversion) gas generation resources CenterPoint assumed amortized recovery over the life of the investments. This differential treatment materially slanted the NPV metric in favor of investing in replacement resources and against the Business-As-Usual cases.

The graph below shows the annual revenue requirements for the cases CenterPoint considered. The orange line represents the Business-As-Usual case assuming AB Brown remained in operation through 2039; the gray line assumed AB Brown remained in operation through 2029. The spike in 2024 annual revenue requirements in both cases represent the full capital costs required to allow continued operation of the AB Brown plant.



CenterPoint confirmed that this differential in assumed recovery of costs occurred but claimed it was the “modeler's decision.

> *The decision to model new resource costs as either levelized or upfront **was the modeler's decision**. The resources that were modeled as upfront investments included modifications to existing resources, for example adding an environmental control option*

> *or a conversion from coal-firing to natural gas-firing....The resources that were modeled as levelized investments included all new solar, wind, battery, gas-fired, and PPA options.*[4] (emphasis added)

However, my company, EVA, is a long-time licensee of the AURORA model and we are well familiar with its capabilities. As explained in the ICC/Sunrise Joint Comments, "[t]here is flexibility in the AURORA model used by Vectren that easily allows the capital investment to be included either as an upfront cost or a levelized cost."[5] Therefore, the decision to make it an upfront cost was neither a modeling necessity nor a modeling convenience. Further, it is difficult to conceive that the CenterPoint IRP team ceded this kind of impactful decision to its modelers. Nor is it credible that the CenterPoint IRP team and the modelers did not understand the impact on the relative NPVs of treating the investments as an upfront investment versus a levelized investment.[6] It is obvious that dollars recovered in early years are discounted very little in an NPV calculation and therefore have an outsized impact increasing the ultimate NPV number. On the other-hand dollars recovered in distant future years are highly discounted and have a comparatively smaller impact of increasing the ultimate NPV number.

- Second, the economic analysis was biased against continued operation of AB Brown because CenterPoint chose not to consider a firm 12-year offer—which it had received well prior to the issuance of the IRP—from the CSX railroad that would have materially reduced the delivered cost of coal and thus lowered both total and dispatch cost.
- Third, CenterPoint accorded no value to deferring commitments to long-term replacement generation given the uncertainty that existed when the IRP was being done in 2019 and 2020 as to new environmental regulations, the rapidly changing

[4] Response to CAC IRP DR Set 4 to Vectren, DR 4.4.
[5] ICC/Sunrise Joint Comments, p. 5.
[6] CenterPoint claimed this assumption did not affect the results. Using CenterPoint's model outputs, EVA concluded using levelized costs eliminated the benefit of the Preferred Portfolio. When the other biases were also adjusted, the Coal case through 2029 showed an advantage and provided optionality to future investments.

landscape of available resource options, and concerns about the cost of integration of a large amount of renewables into MISO.

Q. DID THE ICC/SUNRISE JOINT COMMENTS HAVE ANY CONCERNS RELATED TO NEW GAS GENERATION?

A. With respect to natural gas, CenterPoint failed to consider the possibility of future constraints on the use of natural gas that would limit the time such assets could be utilized. For example, a 2035 net-zero goal would result in only a 12-year life for new natural gas resources unless equipped with carbon capture.[7] For depreciation purchases, CenterPoint assumed in its analysis, a 25-year life for Combustion Turbines and a 30-year life for Combined Cycle. But if net-zero in 2035 becomes the requirement, then either the "cost" of the CT's and CCGT's should be based upon a 12-year year life, or the cost of a carbon capture retrofit should have been added to the costs after 2034.

Additionally, the ICC/Sunrise Joint Comments noted that all but one of the gas price scenarios do not assume methane controls at the well-head, which seems a likely certainty under any net-zero requirement.

Finally, CenterPoint also failed to conduct scenario analyses of low- and high-priced natural gas outlook.

Q. **WHAT CONCERNS WERE EXPRESSED ABOUT RENEWABLES?**

A. Recent experience of Indiana utilities adding renewable resources suggests that the costs for renewable generation are more uncertain that their IRPs assumed. Therefore, reliance on assumed IRP renewable costs when the IRP analysis does not consider scenarios of high and low costs for renewables is not justified for making actual resource decisions.

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[7] At the time the ICC/Sunrise Joint Comments were drafted, information of the assumed life of new gas plants had not been provided. This paragraph contains information that was provided subsequent to the preparation of ICC/Sunrise Joint Comments.

CenterPoint itself provides one recent example. CenterPoint is currently experiencing a delay and significant cost overruns on a project for which it received approval. In May 2018 in Cause 45086, CenterPoint sought and ultimately received approval to construct, own and operate a solar energy facility, referred to as the Solar Project. As part of the approval, CenterPoint's quarterly report at the end of Q1 2021 indicated its current forecast calls for the project to be completed at a cost 21.7% higher than originally forecast.[8]

NIPSCO provides another example. In July 2020, NIPSCO petitioned for approval and associated cost recovery of (1) a Solar Energy Purchase Agreement between NIPSCO and Brickyard Solar, LLC dated June 30, 2020, and (2) a Solar Generation and Energy Storage Energy Purchase Agreement between NIPSCO and Greensboro Solar Center, LLC dated June 30, 2020. Cost information was not provided in the filings as it was deemed commercially sensitive. However, in September 2020, the Office of Utility Consumer Counsel (OUCC) filed testimony in the proceeding. OUCC witness Peter M. Boerger, PhD who found not only were the resource costs materially higher than what had been assumed in NIPSCO's 2018 IRP, they were so much higher that he questioned whether the IURC should require the entire conclusions of the IRP to be reconsidered.[9]

Sunrise does not have sufficient information to determine how cost of the projects proposed in this proceeding compare to the costs assumed in CenterPoint's 2019/2020 IRP.

Q. **WHAT ARE THE LESSONS IN CENTERPOINT'S AND NIPSCO'S EXPERIENCE?**

A. IRP assumptions regarding renewable pricing may not be achievable and even an all-source RFP is not dispositive. CenterPoint which had chosen to rely heavily on the results

[8] Cause 45086, December 31, 2020 Quarterly Report
[9] Cause 45403, Redacted Testimony of OUCC Witness Peter M. Boerger, Ph.D., September 8, 2020. Pp 5-6 (If NIPSCO's solar resources had in its 2018 IRP been modeled to be [redacted] higher, other resource options would have been more attractive and NIPSCO's model may have selected a different resource mix. Thus, the higher solar costs NIPSCO is now seeing call into question whether the resources in this case, which are part of NIPSCO's Short-Term Action Plan, should be reconsidered."

of the RFP admits as much. In the 4th Stakeholder Meeting Minutes provided in Volume 2 of the 2019/2020 IRP, CenterPoint "found there are many difficulties with (the all-source RFP) process. The long timeframe makes it difficult for developers to hold their projects and pricing plus many projects are picked up by other groups while the IRP analysis is being performed." Therefore, prior to filing a request for approval, the utility should update its IRP analysis to determine whether the original strategy makes sense or should be tweaked.

Q. **WHAT CONCERNS, IF ANY, WERE VOICED IN THE ICC/SUNRISE JOINT COMMENTS ABOUT POWER PURCHASE AGREEMENTS?**

A. The concerns about PPA's mostly addressed the fact that PPA's typically do not provide for prices that track market prices and can result in ratepayers paying above market prices for decades.

An example of this was provided related to the first generation of wind PPA's. NIPSCO entered into two wind PPA's (Buffalo Ridge and Barton) in 2009. The wind PPA costs are recover through its Fuel Adjustment Clause (FAC). In the FAC filing[10] for the second quarter of 2020, NIPSCO showed the actual cost of wind under its PPA's is $57.44 per MWH. This cost was more than twice NIPSCO steam generation costs ($27.41 per MWH), about five times combined-cycle costs ($11.33 per MWH), and almost three times higher than the cost of purchases through MISO ($19.36 per MWH). More importantly, it was significantly above the costs NIPSCO represented in its IRP.

NIPSCO is not alone. In or around 2009, AEP Ohio ("Ohio Power") entered into long-term wind renewable energy purchase agreements (REPA's) to comply with the state of Ohio's alternative energy rider (AER). These 20-year contracts have turned out to be out-of-the money particularly when compared to the other Ohio utilities which chose to comply with their statutory obligations without the use of long-term contracts. The ICC/Sunrise Joint Comments showed that in a comparison published by the Public

[10] Cause 38706-FAC 123

Utilities Commission of Ohio (PUCO) which compares AER rates and monthly bill impacts on a quarterly basis for the six electric distribution companies from first quarter 2017 through third quarter 2020, Ohio Power's rates were the highest in 14 of those 15 quarters and exceeded the simple average of all six utilities by 145% to 412% over this period.

AVERAGE MONTHLY BILL IMPACT

	2017				2018				2019				2020		
	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3
Cleveland Electric Illuminating	$0.15	$0.06	$0.24	$0.43	$0.22	$0.43	$0.39	$0.40	$0.27	$0.47	$0.41	$0.44	$0.34	$0.86	$0.48
Dayton Power & Light	$0.19	$0.04	$0.07	-$0.12	$0.06	$0.06	$0.10	$0.10	$0.10	$0.10	$0.34	$0.34	$0.34	$0.34	$0.29
Duke Energy - Ohio	$0.33	$0.42	$0.23	$0.28	$0.44	$0.66	$0.08	$0.22	$0.30	$0.56	$0.04	$0.07	$0.16	$0.13	$0.03
Ohio Edison Company	$0.13	$0.07	$0.15	$0.32	$0.23	$0.47	$0.38	$0.38	$0.37	$0.47	$0.41	$0.44	$0.27	$0.95	$0.44
Ohio Power Company	$0.75	$1.53	$1.31	$0.56	$1.66	$2.07	$1.24	$0.54	$0.69	$1.17	$1.53	$1.92	$2.26	$2.67	$1.39
Toledo Edison Company	$0.23	$0.11	$0.20	$0.53	$0.43	$0.63	$0.51	$0.59	$0.66	$0.36	$0.35	$0.54	$0.37	$0.92	$0.45
Average	$0.30	$0.37	$0.37	$0.33	$0.51	$0.72	$0.45	$0.37	$0.40	$0.52	$0.51	$0.63	$0.62	$0.98	$0.51
Ohio Power/Average	**253%**	**412%**	**357%**	**168%**	**328%**	**288%**	**276%**	**145%**	**173%**	**224%**	**298%**	**307%**	**363%**	**273%**	**271%**

Source: Public Utilities Commission of Ohio, RPS EDU Rate Increases[11]

Q. **WHAT LESSON CAN BE LEARNED FROM THIS EXPERIENCE?**

A. Long-term PPAs with no opportunity to renegotiate or buy-out the agreement are very likely to be out-of-the money at some point during their terms. In order to limit exposure to future ratepayers, it is important to either limit the term of the PPA or negotiate some ability to renegotiate term and/or price as a result of market changes. The ICC/Sunrise Joint Comments made this point assuming only a 10- to 20-year PPA term. CenterPoint opted for a riskier 25-year term for the proposed for the Warrick Solar PPA, even though the developer offered shorter term options that CenterPoint eschewed.

[11] https://puco.ohio.gov/wps/portal/gov/puco/utilities/electricity/resources/ohio-renewable-energy-portfolio-standard/rps-edu-rate-impacts (last viewed 4/30/2021).

Q. IF THE ICC/SUNRISE JOINT COMMENTS WERE BEING MADE TODAY ARE THERE ANY OTHER CAUTIONARY TALES THAT SHOULD GIVE CENTERPOINT AND THE IURC PAUSE?

A. Yes. Big Rivers Electric Cooperative (Big Rivers) in its 2020 IRP concluded that the least cost plan for its Green Station would be to retire the plant and replace the capacity with a capacity purchase of a new combined cycle plant. The economics of this approach was believed to be lower cost that converting the Green station to natural gas. During the transition, Big Rivers planned to purchase capacity from third parties. After pursuing this strategy, Big Rivers concluded that it could not purchase capacity at either the assumed prices or acceptable pricing. Big Rivers switched its plan and is now in front of to the Kentucky Public Service to seek approval for the conversion of the Green units to natural gas.[12] Conversion of the units to natural gas was previously deemed to be the high-cost option.

This is a cautionary tale regarding the replacement of critical capacity resources at competitive pricing. Whether it is building new resources or seeking PPAs to satisfy capacity shortfalls, there can be significant risks to ratepayers.

Q. DID THE ICC/SUNRISE JOINT COMMENTS ON THE IRP ADDRESS THE DEBT EQUIVALENCY RECOVERY?

A. No. There is no indication in the 2019/2020 CenterPoint IRP that it modeled debt equivalency recovery as a cost.

Q. WHAT IS THE POSITION OF SUNRISE REGARDING ANY DEBT EQUIVALENCY RECOVERY AUTHORIZATION IN THIS CASE?

A. Sunrise believes it is a bad idea to authorize debt equivalency recovery in this proceeding. CenterPoint is requesting [redacted] per MWH which is approximately [redacted] percent of the total price over the entire 25-year term of the PPA.[13] That is a very

[12] https://psc.ky.gov/Case/ViewCaseFilings/2021-00079 (last viewed 4/30/2021).
[13] Direct Testimony of Matthew Rice, Petitioner Exhibit 4, p.20, ll.14-19.

significant cost that was not explicitly modeled in the IRP, and without a revised analysis that accounts for that cost, it cannot be determined that the Preferred Portfolio is really preferred.

If debt equivalency recovery is allowed here, CenterPoint (and presumably every other rate regulated Indiana utility) will certainly seek it in all future PPAs. For CenterPoint the two projects at issue in the proceeding represent just 400 MW (ICAP) out of over 2,000 MW of replacement generation in the preferred portfolio. A debt equivalency recovery could incent over-reliance by CenterPoint—and every other rate regulated Indiana utility—on PPAs rather than owned generation assets.

Allowing debt equivalency recovery would be a major, and very material, change in the Indiana regulatory landscape. Such a substantial change seems more appropriate for uniform, statewide application under specific legislative guidance from the Indiana General Assembly. Even were the Commission inclined to undertake such a significant change in a proceeding by a single utility, it is more appropriate for consideration in the context of a full rate case which considers all costs.

Q. **PLEASE REVIEW YOUR UNDERSTANDING OF THE POSEY COUNTY SOLAR PROJECT.**

A. The Posey Project will be a 300 MW (ICAP) solar photovoltaic plant. If approved, it will be built by the Clean Energy Infrastructure business unit of Capital Dynamic through a special purpose limited liability company known as Posey Solar CEI, LLC pursuant to a Build Transfer Agreement with CenterPoint. The Posey Project will interconnect to CenterPoint's AB Brown – Gibson 345 kV transmission line. Upon completion of construction and other conditions precedent, CenterPoint will purchase Posey Solar.

Q. **WHY ARE YOU CONCERNED THAT PROJECT MAY CONFLICT WITH CONTINUED OPERATION OF THAT AB BROWN STATION?[14]**

A. As the ICC/Sunrise Joint Comments show, there are a number of material flaws in the CenterPoint 2019/2020 IRP which resulted in bias against continued operation of the AB Brown plants. Further, the 2019/2020 IRP preferred plan assumed the construction of two combustion turbines, and CenterPoint indicated that the AB Brown site would be the most economical location for those turbines.[15] A commitment of an additional 300 MW from the Posey Solar facility to be connected to the AB Brown – Gibson 345 kV transmission line could impact both continued operation of the AB Brown plants, or it could change the economics of placing replacement CTs at that site. It is unclear whether CenterPoint has even analyzed that potential impact, and if it has, it has not disclosed it in its evidence. If the Posey County Solar Project will impact future operations at the AB Brown site, CenterPoint needs to disclose that impact, and if it could be material, revise its IRP analysis before proceeding.

Q. **WHAT DOES THE FILING STATE AS THE IMPACT OF THE TWO PROJECTS ON CUSTOMER RATES?**

A. CenterPoint provides only a limited analysis of the impact on customer rates.

Q. **HOW DO THE PRICES FOR THE PROJECTS COMPARE TO COST OF GENERATION SHOWN ON THE FAC FILING.**

A. CenterPoint's latest FAC filing is provided below.

[14] As of the time of filing, there is an outstanding data unanswered request about this issue.

[15] 2019/2020 Vectren IRP, Volume 1, Page 172, "The A.B. Brown site was used for this analysis. It is an existing brownfield site with interconnection rights through MISO. The (firm gas supply) cost estimates were developed in partnership with a potential service provider."

Cause No. 38708-FAC130

Petitioner's Exhibit No. 2
Attachment KJT-2
CEI South
Schedule 1
Page 1 of 1

CENTERPOINT ENERGY INDIANA SOUTH
Determination of Fuel Cost Adjustment
Beginning with May 2021 Based on the Estimated
Three Months Average of May, June and July 2021

Line No.	Description	(A)	(B)	(C)	(D)	(E)	Line No.
		Estimated Month of:				Estimated Three Month	
	kWh Source (000's)	May 2021	June 2021	July 2021	Total	Average	
1	Steam Generation	450,523	453,387	507,246	1,411,157	470,386	1
2	Nuclear Generation	-	-	-	-	-	2
3	Hydro Generation	-	-	-	-	-	3
4	Solar Generation	12,673	13,342	13,815	39,830	13,277	4
5	Other Generation	2,164	3,368	3,914	9,445	3,148	5
6	Purchases Through MISO	13,288	40,390	50,778	104,456	34,819	6
7	Purchased Power Other than MISO	32,730	26,385	21,708	80,823	26,941	7
8	Purchased Power for Other Systems	-	-	-	-	-	8
	Less:						0
9	Company Use					-	9
10	Inter-System Sales Through MISO	82,237	36,809	33,886	152,932	50,977	10
11	Inter-System Sales Other Than MISO	-	-	-	-	-	11
12	Sales Not Subject to FAC	-	-	-	-	-	12
13	**Supply (S)**	429,140	500,064	563,575	1,492,779	497,594	13
	Fuel Cost ($)						
14	Steam Generation	$ 11,208,584	$ 11,320,592	$ 12,670,571	$ 35,199,747	$ 11,733,249	14
15	Nuclear Generation	-	-	-	-	-	15
16	Hydro Generation	-	-	-	-	-	16
17	Solar Generation	-	-	-	-	-	17
18	Other Generation	43,620	109,497	137,080	290,197	96,732	18
19	Purchases Through MISO	275,430	864,247	1,144,759	2,284,436	761,479	19
20	MISO Components of Cost of Fuel	(69,229)	(210,432)	(264,555)	(544,216)	(181,405)	20
21	Purchased Power Other than MISO	1,804,545	1,302,590	929,051	4,036,186	1,345,395	21
	Less:						
22	Inter-System Sales Through MISO w/ Transmission Losses	2,276,933	1,082,501	1,011,413	4,370,847	1,456,949	22
23	Inter-System Sales Other Than MISO	-	-	-	-	-	23
24	**Total Fuel Cost (F)**	$ 10,986,017	$ 12,303,993	$ 13,605,493	$ 36,895,503	$ 12,298,501	24

On a dollars per MWH basis, CenterPoint's costs are as follows.

Source	$/MWH
Steam Generation	24.94
Other Generation	21.87
Purchases through MISO	28.26
Total	**24.72**

The costs for the PPA will flow through the FAC. According to the confidential documents, the costs of the PPA are expected to be significantly higher than the current steam generation costs and purchases through MISO.

Q. **DID CENTERPOINT ASSUME REVENUES ASSOCIATED WITH THE SALE OF RENEWABLE ENERGY CERTIFICATES (CREDITS)? IF SO, HOW?**

A. Yes. CenterPoint assumed it would receive $8 per MWH for RECs[16] and credited those revenues against the project costs. A REC represents the generation of one megawatt-hour of electricity from a renewable energy source. REC prices can vary by location and type of renewables. Generators are required to surrender RECs consistent with the generating state's requirements. RECs can also be sold to meet compliance requirements where allowed by state rules.

Future REC values are difficult to predict. Under a Net-Zero plan, it is possible REC value could go to very low levels or even zero. Alternatively, if a future plan includes a Clean Energy Standard or a Renewable Portfolio Strategy, REC prices could go much higher.

Q. **HOW SHOULD REC REVENUES FROM THE PPA GENERATION BE ACCOUNTED FOR?**

A. The entire revenue for RECs, whether it turns out to be the assumed $8 per MWH or some higher or lower amount should be credited to ratepayers who are paying for this "asset" in the PPA price.

Q. **WHAT IS THE STATUS OF WARRICK 4?**

A. Warrick 4 is jointly owned with Alcoa. Witness Games reviews the recent history of this plant. In 2016, Alcoa shut down the Warrick smelter which reduced power demand. In 2018, Alcoa restarted part of the smelter. Also in 2016, the Joint Operating Agreement with Alcoa was renegotiated. While not mentioned by Witness Games, it is my understanding that the restart of the smelter was due in part to the high quality of the output from the smelter that Alcoa found difficult to replace.

Witness Games then goes on to say that in October 2019, Alcoa announced plans to sell up to $1 billion in assets which would likely include Warrick 4. However, his testimony

[16] Direct Testimony of Matthew Rice, Petitioner Exhibit 4, p.26, ll.1-2.

filed in February 2021 did not reflect the November 2020 announced sale of the Warrick Rolling Mill to Kaiser Aluminum Corporation for $670 million.[17] The announcement noted that "(a)s part of the transaction, Alcoa will enter into a market-based metal supply agreement with Kaiser Aluminum at closing. Alcoa will continue to operate the smelter and the power plant, which together employ approximately 660 people." On April 1, 2021, subsequent to the filing of this Cause, Alcoa completed the divestiture under terms consistent with the November 2020 announcement.[18] It is hard to believe that Kaiser Aluminum invested $670 million in a rolling mill that it did not intend to operate well into the future, so clearly, the outlook for the Alcoa smelter (to supply aluminum to the rolling mill), and therefore the Warrick 4 plant (to supply power to both the smelter and rolling mill), seems brighter than reflected in Witness Games testimony.

Q. **IS CONTINUED OPERATION AT WARRICK 4 AN OPTION?**

A. Witness Games stated it is technically still an option subject to negotiation of acceptable terms.

Q. **ARE THERE ADDITIONAL BENEFITS TO CENTERPOINT RATEPAYERS OF CONTINUED OPERATIONS?**

A. The cost of the replacement generation (including the Debt Equivalency Recovery) is extremely high. This cost would need to be compared to the cost of continued participation in the operation of Warrick 4. Any analysis of these costs must also consider the risks on both sides. On the PPA side, the obligation under a 25-year contract at high prices potentially exposes CenterPoint's customers to high rates and a limited ability to take advantage of lower cost resource options in the future. On the Warrick 4 side, there is the benefit of CenterPoint helping to support continued operations at the smelter and

[17] https://news.alcoa.com/press-releases/press-release-details/2020/Alcoa-Announces-Agreement-to-Sell-Rolling-Mill-to-Kaiser-Aluminum/default.aspx (last viewed 4/30/2021).
[18] https://www.businesswire.com/news/home/20210401005085/en/Alcoa-Completes-Divestiture-of-Warrick-Rolling-Mill-to-Kaiser-Aluminum-Corporation-for-670-Million (last viewed 4/30/2021).

rolling mill which is beneficial to the economy of Indiana. As noted by Witness Games, continued operation of the Warrick Rolling Mill is "good for the local economy." [19]

Q. IS THERE A WAY TO TRANSFER FUTURE COST LIABILITY FOR THE PLANT BUT RETAIN CAPACITY RIGHTS?

A. Subject to agreement on terms, the obvious and likely lower cost option for CenterPoint customers is to enter into a PPA with Alcoa for the capacity CenterPoint currently owns at Warrick 4.

[19] Direct Testimony of Wayne D. Games, Petitioner Exhibit 3, p.14, ll.26-30.

V. MISCELLANEOUS ISSUES

Q. CENTERPOINT HAS REQUESTED THAT THE COSTS FLOW THROUGH THE FAC BUT SHOULD NOT BE SUBJECT TO REVIEW. DO YOU AGREE?

A. Absolutely not. There should be no misunderstanding that just because a contract is long-term there is no need for active contract management over the entire term. Just because a contract seemed prudent at inception does not mean that if circumstances change in the future staying in the contract—as opposed to buying out or renegotiating—is prudent. I have been involved in fuel and purchase power auditing for over three decades. I have found multiple instances where fuel and purchase power agreements can be renegotiated and optimized to the benefit of both parties if the agreements are actively managed. As the role of PPA's increase over time, it would be a regulatory mistake to not require these long-term contracts to be actively managed.

Regulatory review of active management of long-term contracts is not hindsight review of the prudency of entering into the contract at the time of inception, nor should it be interpreted as suggesting that contracts should be breached. Active management is, rather, insuring on an ongoing, contemporaneous basis that the contract is being implemented properly and that there are no contractual opportunities to improve upon current position. This process, which is referred to as active management, is a leading practice in contract administration.

Q. CAN YOU PROVIDE AN EXAMPLE OF WHERE SUCH AUDITS HAVE BEEN BENEFICIAL?

A, Yes. In 2020, in an audit of a regulated utility I determined that a legacy PPA was costing the utility customers a significant amount per year. Based upon my knowledge of the operations, I believed that the generator was earning less than the premium the utility was paying. That provided a middle ground where both parties could benefit, and I and recommended that the utility propose a buy-out. The utility and counterparty agreed. A buy-out was approved. It was beneficial to all parties.

Q. **WHAT IS YOUR RECOMMENDATION?**

A. I recommend that all PPA costs recovered through the FAC be subject to continuing review for active management of the PPA.

Q. **CENTERPOINT IS REQUESTING A 25-YEAR TERM FOR THE WARRICK PPA. DO YOU RECOMMEND AN ALTERNATIVE TERM?**

A. Yes. As a rule, I believe a 25-year term without any price reopeners or early termination options is too long. There is significant uncertainty about the future. There is likely to be one or more market "disruptions" during this period that change desired resource types and prices. To avoid creating future stranded costs, PPA contracts should provide a mechanism for early termination that both parties can accept.

In the case of a PPA, there is an obvious solution. A review of the bid analysis showed that generators were willing to lower prices for longer terms. The likely reason for this is a longer term lowers the price at which repayment on the investment is assured. It appears that in the case of the Warrick Project PPA, CenterPoint should seek an early termination right in exchange for a pre-determined payment equal to the price differential for the extended term on all generation with interest. In this case, the counterparty is no worse off and CenterPoint reduces the risk of being encumbered with an out-of-market contract.

Q. **DO YOU BELIEVE THAT IT IS APPROPRIATE THAT THE POSEY PROJECT COSTS BE LEVELIZED OVER A 35 YEAR PERIOD?**

A. No. A 35-year project life is at the upper end of what new solar PV projects are expected to operate. Setting a recovery time that is too long has several problems. First, because return on unrecovered costs lasts longer it increases absolute cost ultimately recovered from ratepayers. Second, by lowering annual costs it gives the appearance that costs are lower than they actually are, because if the facility is retired before the recovery period, there are stranded costs that future ratepayers may have to pay. Some of those future ratepayers, if they are new may have gotten little or no benefit from the facility, but still pay for it—as well as likely paying for a replacement. Third, we know that solar panels degrade over time. Thus, the ratepayers in the later years are paying the full levelized cost of a degraded facility.

Thus, levelizing costs for a new solar facility over 35 years likely does not reflect true cost reality and only creates a bias that may make a new solar facility look more attractive than it should. CenterPoint in its scoring of this project shows a [redacted]-year book life.[20]

Ultimately, the future is uncertain. As noted above, one or more market disruptions are likely during this period making alternative resources including higher efficiency and perhaps lower cost solar more attractive. There is a significant likelihood that the tail of this expenditure could become stranded.

[20] Direct Testimony of Justin M. Joiner, Petitioner Exhibit 2, Attachment JMJ-5 - Proposal Scoring Summary.

ATTACHMENT I

RESUME OF
EMILY S. MEDINE

PROFESSIONAL EXPERIENCE

Current Position

Emily Medine, a Principal, has been with Energy Ventures Analysis since 1987. In 2017 Ms. Medine was named to the National Coal Council, an advisory group to the Secretary of the Department of Energy. Her experience includes forecasting, integrated resource plans, bankruptcy support, market strategy development, fuel procurement audits, fuel procurement, acquisition and investment analyses, and strategic studies. She has also provided expert testimony on utility fuel procurement practices and coal contract disputes. The types of projects in which she is involved are described below:

Fuel and Power Purchase Procurement Audits

Ms. Medine manages and performs fuel procurement audits on behalf of regulatory commissions, utility management, and third-party interveners. She has performed over 25 audits of utilities regulated by the Public Utilities Commission of Ohio and testified in a number of proceedings. She also managed two major audits of the fuel procurement practices of PacifiCorp. Recent audits include Appalachian Power (2006, 2007, 2015, 2016, and 2018) and Monongahela Power (2007, 2015, 2016 and 2018) on behalf of the Consumer Advocate of the State of West Virginia, Tucson Electric Power on behalf of the Arizona Corporation Commission in 2007/2008 and 2012, AEP Ohio on behalf of the Ohio's Consumer Counsel, and AEP Ohio (2009, 2010, 2011, 2012, 2013 and 2014) and Dayton Power & Light (2010, 2011, 2012, 2013, 2014, and 2015) on behalf of the staff of the Public Utilities Commission of Ohio.

Procurement

Ms. Medine develops and implements fuel procurement strategies for U.S. and foreign coal consumers. Fuel procurement assistance has ranged from determining an appropriate strategy to soliciting bids and negotiating purchase agreements. In the last five years, Ms. Medine has advised several international coal consumers of their fuel procurement activities. Ms. Medine continues to advise numerous U.S. and international coal consumers on their coal and petroleum coke procurements. In recent years, Ms. Medine has worked on natural gas and REC procurement evaluations.

Bankruptcy Support

Ms. Medine was an advisor to the Horizon Natural Resource companies which operated as a debtor-in-possession in the development of a plan to accomplish reclamation on all permits not sold and transferred as part of the plan of reorganization. For a period of 15 months, Ms. Medine served as Executive Vice President of Centennial Resources, Inc., a debtor-in-possession, as part of EVA's contract to manage this company post-petition. In this capacity, she managed the day-to-day operations of the company as well as serving as the liaison between the company, state and county regulatory agencies, the bankruptcy court, and the lenders. This assignment ended upon the filing of Centennial's plan of reorganization. Ms. Medine has also served as the advisor to secured lenders in another coal industry bankruptcy. In this capacity, she reviewed and developed independent financial forecasts and operating plans of the debtor-in-possession. Ms. Medine was engaged by the Department of Justice in the Alpha Natural Resource and Arch Coal bankruptcies.

Forecasting

Ms. Medine develops forecasts of U.S. and global solid fuel demand and prices for alternative coal types, coke and market segments. These forecasts are provided to individual clients and are documented in various FUELCAST/COALCAST reports.

Integrated Resource Planning

Ms. Medine works with utilities and/or stakeholders on the development and evaluation of Integrated Resource Plans (IRP). Ms. Medine focuses on validation of all assumptions including fuel, emission allowances, carbon, and renewable energy credits (RECs) and on methodology and modelling.

Acquisition and Investment

Ms. Medine was the agent for Lexington Coal Company in the sale of its assets in Indiana and Illinois. As part of this engagement, Ms. Medine was responsible for the sale of three mines to Peabody Energy. Ms. Medine also routinely evaluates the economics of potential projects or acquisitions for producers, developers, and industrials. For coal projects, this includes market and financial forecasts. In addition to the above, Ms. Medine has completed the sale of multiple mine assets. Ms. Medine was an advisor to and on the board of The Elk Horn Coal Company until its sale to Rhino Energy in June 2011. Ms. Medine managed the sale of a number of distress assets including JWR Resources, Piney Creek Resources, and Rhino Resources.

Market Strategy Development

Ms. Medine assists clients in the development of marketing strategies on behalf of coal suppliers and transporters. She has helped to identify the high value markets and strategies for obtaining these accounts.

Forecasting

Ms. Medine develops forecasts of U.S. and global solid fuel demand and prices for alternative coal types, coke and market segments. These forecasts are provided to individual clients and are documented in various FUELCAST/COALCAST reports.

Expert Testimony and Presentations

Ms. Medine prepares analyses and testimony in support of clients involved in regulatory and legal proceedings. She provides testimony in commission hearings on fuel procurement issues and arbitration proceedings on contract disputes and damages. Ms. Medine regularly speaks at industry meetings.

Prior Experience

Prior to joining EVA, Ms. Medine held various positions at CONSOL including Assistant District Sales Manager – Chicago Sales Office and Strategic Studies Coordinator. Prior to CONSOL, Ms. Medine was a Project Manager at Energy and Environmental Analysis, Inc. where she directed two large government studies. For the Environmental Protection Agency, Ms. Medine directed an evaluation of the energy, environmental and economic impacts of New Source Performance Standards on Industrial Boilers. For the Department of Energy, Ms. Medine directed an evaluation of the financial impacts of requiring utilities with coal capable boilers to reconvert to coal. Ms. Medine worked as a Research Assistant at Brookhaven National Laboratory while she attended graduate school.

EDUCATION

M.P.A.	Princeton School of Public and International Affairs, Princeton University, 1978
B.A.	Geography, Clark University, 1976 (magna cum laude, Phi Beta Kappa)

ICC PUBLIC COMMENTS ON VECTREN'S 2020 IRP

Southern Indiana Gas and Electric Company d/b/a Vectren a CenterPoint Energy Company (Vectren) submitted its 2020 IRP to the Indiana Utility Regulatory Commission (Commission) in June 2020. The Indiana Coal Council (ICC) and Sunrise Coal Company (Sunrise) have reviewed the 2020 IRP and provide the following joint comments for the Commission's consideration.

Conclusion

Vectren's 2020 IRP analysis is biased in a number of ways but perhaps most glaringly by its different treatment of capital costs. For new investments in renewables, gas, and batteries the capital expenses were levelized over the expected useful life of the asset. In contrast, the full incremental capital costs related to the retention of the AB Brown units were front loaded into a single year. This variable treatment of capital costs inflated the Net Present Values (NPV) associated with the Business-As-Usual (BAU) to 2029, BAU to 2039, and the Bridge cases, and thus makes the High Technology case (Vectren's Preferred Portfolio) seem materially more attractive than what it really is. In fact, if the full incremental capital costs related to retention of the AB Brown units are amortized over a reasonable useful life, Vectren's Preferred Portfolio loses its economic advantage.

However, that major analytical flaw is not the only one. Vectren's 2020 IRP: (1) assumes inflated delivered coal costs in the BAU cases; (2) assumes extremely low natural gas prices in the Preferred Portfolio; (3) fails to model what is now considered to be a likely carbon regime; (4) fails to consider a range of market capacity prices; (5) likely understates renewable costs; (6) likely understates renewable integration challenges; and (7) fails to consider a range of potential new technology options.

Because of the material analytical flaws the 2020 IRP does not justify implementation of Vectren's Preferred Portfolio, including both (1) irreversible decisions to retire existing resources, and (2) new investments in other resources (particularly natural gas) which could become stranded investments before their costs are fully recovered. Accordingly, before making any irreversible decisions to retire existing resources or seeking approval for new investments in other resources, Vectren must start fresh, correct the material flaws in its analysis, and consider a full range of reasonable options based on reliable, current cost data.

Finally, because of MISO's concern that above certain renewable penetration levels, renewable integration will become materially more expensive, the IURC or some other state entity should consider the best statewide renewable investment strategy so that individual utilities are cooperating, rather than competing, over limited access to renewable resources. Such a statewide strategy may need to include optimizing in-state renewable generation and funding transmission upgrades.

Summary

Vectren's 2020 IRP recognized the repudiation of its 2016 IRP in one important respect. It is no longer proposing a combined cycle gas plant (CCGT) in its Preferred Plan. Rather it is proposing a more diverse portfolio with more renewables, battery storage, and two combustion turbines (CT's). Vectren has not abandoned its plans for a CCGT, noting one advantage of the CT's is the ability to convert them to CCGT's should the situation change. The 2020 IRP is similar to the prior plan in that it deliberately attempts to justify the closure of the AB Brown coal units in 2023 rather than fairly considering their continued operation. Each of the identified methodological concerns are summarized below.

- Vectren determined the capital cost upgrades that would be required to keep the AB Brown station on-line and burning coal beyond 2023 in two cases, BAU to 2029 and BAU to 2039. In these cases Vectren assumed recovery of those costs in one year, rather than amortizing recovery over the life of the investment. In contrast, for other new capital investments Vectren assumed amortized recovery over the life of the investment. This differential treatment materially slanted the NPV metric in favor of investing in new resources and against the BAU cases.

  See Discussion Section II "Differential Amortization of Capital Costs" below.

- Vectren continued to use the 20-year NPV as the only economic metric for ranking of its scenarios. However, this metric, while useful, provides limited information as to the rate impacts over the 20-year period and beyond. Ratepayers would likely prefer a plan with lower costs in the first five or ten years (but possibly higher costs in the more distant future which is harder to project), over a plan with higher costs in the early years (and more speculative cost savings in the tail years). Both plans, however, might have materially similar NPVs. A proper resource plan should consider both the overall costs as reflected in NPVs and the shape of projected annual rate impacts, recognizing that the farther into the future one attempts to project, the more unreliable one's assumptions become.

  See Discussion Section III "Over-reliance on 20-year NPV" below.

- Vectren failed to give the BAU to 2029 case any value related to the benefit to Vectren of a delay in selecting no- or low-carbon generation sources. By deferring its decision-making on replacement resources until a later period, Vectren will have better visibility into more alternatives.

  See Discussion Section IV "Failure to Adequately Consider Advantages of Deferring Investment in New Resources" below.

- Vectren's carbon analysis used a carbon price as a proxy for a carbon regime, ignoring increasing indications that Resource Portfolio Standards for achieving net zero emissions has become a more likely future scenario. A net zero plan could preclude the use of natural gas CT's or CCGT's or could require they be retrofit with carbon capture.

  See Discussion Section V "Failure to Consider Possible Impact of Potential Resource Portfolio Standards" below.

- In addition to carbon pricing, Vectren's analytics appear to be based upon a number of problematic assumptions including capacity costs, fuel prices, and capital costs, For example, Vectren received an extremely attractive offer that would have reduced the delivery costs of coal to AB Brown by an over $16 million on an NPV basis. The offer, which provided firm and constant pricing for an entire 11-year period, was received well in advance of the publication of the IRP but was not included in the IRP analysis. The estimated plus $16 million NPV benefit does not include the additional benefits afforded by lower costs related to improved dispatchability of the coal units. At the same time it ignored reasonably expected savings in its BAU cases, Vectren represented it used a very low natural gas prices to justify the CT's in the High Technology case.

See Discussion Section VI "Unreliable Assumptions regarding capacity costs, fuel prices, and capital costs" below.

- Vectren has played down the importance of MISO's findings related to renewables, i.e., that MISO is limited with respect to renewables integration and that costs increase significantly above 30 percent renewables. These findings are for MISO as a whole, not an individual utility and they point to the necessity that an entire state plan be integrated, not on a utility by utility basis. MISO's findings further confirm that higher integration levels would result in lower dispatch of renewables, thereby reducing capacity factors and increasing fixed costs.

  See Discussion Section VII "Inadequate Attention to Potential Impact of Future Renewables Saturation of MISO Market" below.

Discussion

I. 2020 IRP cases and the Preferred Portfolio

Vectren ultimately developed the following 10 portfolios.

1	Reference	Reference Case
2	BAU	BAU to 2039
3		BAU to 2029
4	Bridge	ABB1 gas conversion
5		ABB1+ABB2 gas conversons
6		ABB1 gas conversion + CCGT
7	Diverse	Diverse Small CCGT
8	Renewables	Renewables + Flexible Gas
9		Renewables 2030
10	Scenario	High Technology

The BAU to 2039 portfolio included the continued operation of all existing units. The BAU to 2029 portfolio included the continued operation of AB Brown through 2029. The Bridge cases were variants of cases which assumed conversion of one or both AB Brown units to natural gas. The other cases include some combination of renewables, gas, and coal (Culley 3) except for the Renewables 2030 which requires no fossil-fuel fired generation after 2030. All of the scenarios assume Vectren exits its 50 percent of Warrick 4 by 2024 although Vectren indicated an extension is possible.

Vectren developed five scenarios to apply to the portfolios. The key inputs for each scenario are shown below.

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

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

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

Vectren concluded that the portfolio yielded by the High Technology scenario was its Preferred Portfolio. Vectren concluded that the High Technology portfolio produced, on an NPV-basis, $320 million in savings (using the Stochastic Mean 20-year NPV) compared to the Business As Usual to 2039 portfolio.

Figure 8-8 - IRP Portfolio Balanced Scorecard Color-Coded Comparison (NPVRR in millions of dollars)

	Stochastic Mean 20-Year NPVRR	95th Percentile Value of NPVRR	% Reduction of CO2e (2019-2039)	Purchases as a % of Generation	Sales as a % of Generation	Purchases as a % of Peak Demand	Sales as a % of Peak Demand
Reference Case	**$2,538**	**$2,921**	58.1%	16.8%	**26.8%**	**9.7%**	**1.2%**
BAU to 2039	**$2,914**	**$3,308**	**35.2%**	12.0%	**36.5%**	**0.1%**	**11.1%**
Bridge BAU 2029	$2,691	$3,094	61.9%	15.2%	31.4%	7.1%	4.3%
Bridge ABB1 Conversion+CCGT	**$2,875**	**$3,269**	47.9%	**6.6%**	31.8%	1.3%	**10.1%**
Bridge ABB1 Conversion	$2.677	$3,048	61.5%	19.2%	**26.4%**	1.2%	**9.3%**
Bridge ABB1+ABB2 Conversion	**$2,836**	**$3,215**	61.5%	18.5%	27.6%	4.0%	5.6%
Diverse Small CCGT	$2,681	$3,072	47.9%	**6.4%**	31.1%	1.7%	3.7%
Renewables Peak Gas	**$2,528**	**$2,927**	**77.4%**	21.5%	27.7%	9.4%	**1.2%**
Renewables 2030	**$2,614**	$3,003	**79.3%**	**26.1%**	31.9%	**11.9%**	**1.7%**
High Technology	**$2,592**	**$2,978**	59.8%	16.7%	**26.9%**	**0.4%**	4.6%

The Preferred Portfolio selected by Vectren consists of the following:

- Early addition of solar and wind projects to take advantage of the Production Tax Credit (PTC) for wind and the Investment Tax Credit (ITC) for solar
- The addition of two gas-fired combustion turbines
- The retirement of AB Brown and Culley #2 units by 2024

According to Vectren, the five-year action plan to implement its IRP is as follows:

1. Finalize selection of renewables from all-source RFP and seek approval for these projects from the IURC.
2. Continue efforts towards energy efficiency (EE)
3. Pursue two natural gas Combustion Turbines (CT's).

II. Differential Amortization of Capital Costs

Vectren "modeled" the costs that would preserve the AB Brown station in its IRP as upfront costs that were not levelized over the extended life of the asset. For example, the entire cost to replace the scrubber on AB Brown was included 2024 rather than levelized over the extended life of this plant. The costs for new investments in renewables, gas, etc. were modeled as levelized investments. The different approaches served to increase the NPV for each case which treated incremental investments as upfront investments. Vectren provided the rationale in the following Confidential Response to Citizens Action Coalition.

[redacted]

Vectren is justifying this decision as a modeling decision. There is flexibility in Aurora that easily allows the capital investment to be included either as an upfront cost or a levelized cost. Therefore, he decision to make it an upfront cost was neither a modeling necessity nor a modeling convenience. It is not credible that Vectren would have ceded this decision to the modelers. Nor is it credible that Vectren and the modelers did not know the impact on the relative NPVs of treating the investments as an upfront investment versus a levelized investment.

[1] Response to CAC DR Set 4 to Vectren, DR 4.4.

The estimated impact of the change in the NPV from an upfront cost to a levelized cost is shown below. Note that Vectren excluded Culley 2 in its BAU to 2029 case but included Culley 2 in its BAU to 2039. Culley 2 is excluded in both cases below.[2]

	(2018$ Thousands)			Percent	
Portfolio	**20-Year NPV**	**Portfolio vs BAU 2029**	**Portfolio vs BAU 2039**	**Portfolio vs BAU 2029**	**Portfolio vs BAU 2039**
Reference Case	[redacted]	($71,769)	($97,186)	-2.7%	-3.6%
BAU to 2039	[redacted]	$25,417	[redacted]	0.9%	[redacted]
Bridge BAU 2029	[redacted]	[redacted]	($25,417)	[redacted]	-0.9%
Bridge AAB1 Conversion + CCGT	[redacted]	$266,539	$241,121	9.9%	8.9%
Bridge ABB1 Conversion	[redacted]	$38,718	$13,301	1.4%	0.5%
Bridge ABBI + ABB2 Conversion	[redacted]	$199,303	$173,886	7.4%	6.4%
Diverse Small CCGT	[redacted]	$74,855	$49,438	2.8%	1.8%
Renewables Peak Gas	[redacted]	($87,896)	($113,313)	-3.3%	-4.2%
Renewables 2030	[redacted]	($9,844)	($35,261)	-0.4%	-1.3%
High Technology	[redacted]	($9,222)	($34,639)	-0.3%	-1.3%

This recalculation does not include other issues with the Vectren analysis which are discussed below.

III. Over-reliance on 20-year NPV

Vectren uses a 20-year Net Present Value of Revenue Requirements as the sole economic metric to evaluate its scenarios and as a proxy for rate impacts.

This fallacy that a 20-year NPV is a proxy for customer impact was shattered when NIPSCO filed a CPCN in 2019 implementing its plan developed from its IRP. NIPSCO indicated in its filing that if it utilized its standard cost of service calculations, its proposal would result in a plus 30 percent increase in current rates.[3] Yet this was the proposal which supported the IRP preferred scenario had an NPV 20percent lower than the business as usual scenario.[4] As was pointed out in comments related to NIPSCO's IRP, the Preferred Scenario was only economic because NIPSCO extended the standard 20-year term to 30 years to capture what could best be called hypothetical savings in years 20 to 30.[5]

A 20-year NPV says nothing about the shape of the cost curve. Two scenarios can have the same NPV but have very different ratepayer impacts during the first five to 10 years. For example, in a heavy renewable scenario, optimism about the future "savings" related to renewables could offset higher costs in the early years. Vectren is simply wrong that the NPV is a proxy for customer impact.

This is not to say that one metric should not be a 20-year NPV. This is to say, it should not be the metric to determine "affordability" which is what Vectren states it is being used to determine.

At a minimum, 5- and 10-year NPVs should also be included. Preferably, Vectren should provide an estimate of rate-payer impacts.

[2] Culley 2 is a small older unit. There is no dispute over whether it should be retired and, therefore, there is no reason to include incremental costs in BAU to 2039 that would allow it to continue to run.
[3] https://iurc.portal.in.gov/docketed-case-details/?id=94e9d4bf-5126-e911-814c-1458d04e2938
[4] https://www.nipsco.com/docs/librariesprovider11/rates-and-tariffs/irp/2018-nipsco-irp.pdf, page 151.
[5] https://www.in.gov/iurc/files/ICC%20PUBLIC%20COMMENTS%20ON%20NIPSCO%202018%20IRP.pdf

IV. Failure to Consider Advantages of Deferring Resource Commitments

Given the significant uncertainty at this time regarding a future carbon regime, how long constraints in MISO will limit integration of renewables, the pace of development of new low- and no-carbon emitting technologies, battery capability, future natural gas prices, and renewable prices, the ability to defer particularly irreversible decisions has value. In its BAU to 2029, Vectren gives no value to the benefit to Vectren of a delay in selecting no- or low-carbon generation sources. By deferring its decision-making on replacement resources until a later period, Vectren will have better visibility into carbon requirements and resource options.

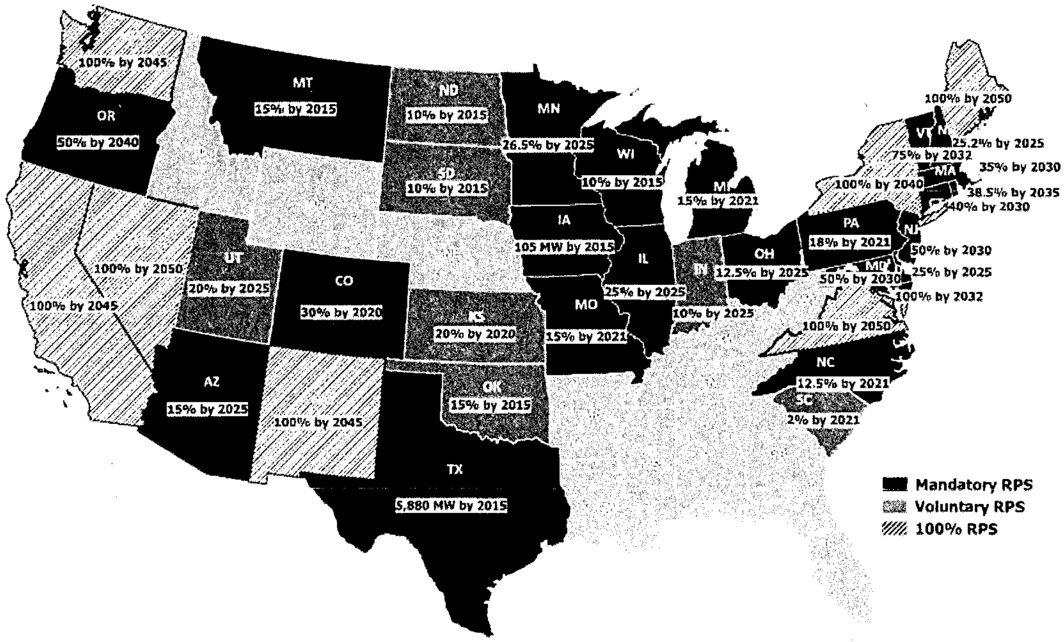
Among the risks associated with Vectren's Preferred Portfolio are (1) the reliance on CT's as the back-up to renewables, (2) the potential use of long-term Power Purchase Agreements (PPAs) that commit Vectren to offtake for 15 to 20 years, and (3) the closure of largely depreciated coal assets that can continue to provide low cost power through at least 2029. Reliance on gas generation is problematic if natural gas cannot be used without carbon capture. Long-term PPAs typically lock in pricing during a period when real price declines are expected to continue. The closure of existing coal plants burden customers with high stranded costs which could otherwise provide low cost generation until there is greater certainty as to the direction of the industry.

V. Failure to Consider Possible Impact of Potential Renewables Portfolio Standards

As shown above, Vectren assumes a carbon regime in the IRP in all cases. Other than the Low Regulatory case, Vectren uses a CO_2 tax as a proxy for the regulations.

A CO_2 tax is certainly one possibility. However, increasingly, it appears that any federal plan would adopt Renewable Portfolio Standards (RPS) or Clean Energy Standards (CES) which the majority of states have already instituted either mandatorily or voluntarily. RPS status by state is shown below.

RPS STATUS BY STATE



Because of federal inaction on climate change, states have ramped up individual decarbonization efforts. In the last four years, six U.S. states, Puerto Rico, and Washington D.C. have enacted legislation committing them to sourcing 100% of their electricity from renewable or clean sources in the coming decades. Several other states across the country are considering similar legislation. In states where there is no mandate, in-state municipalities have in some cases made their own. For example, in Florida, which currently has no state-wide RPS, 17 cities and towns are committed to some form of decarbonization. According to the Sierra Club, 165 cities and towns in the U.S. have committed to completely decarbonizing their electricity supply by varying dates.

Even though the outcome of the 2020 Presidential election is not yet known, it is useful to consider the Biden Clean Energy and Climate Plan. The plan has targeted economy-wide net-zero emissions by no later than 2050 with full power sector decarbonization by 2035. Achieving the 2035 goal would mean power comes from either clean energy sources such as nuclear, hydro, solar or wind or from fossil fuel sources (natural gas and coal) that are equipped with carbon capture. Notably, the Biden plan does not mention a federal carbon tax but does mention the use of carbon capture technologies on existing power plants.

The purpose of this discussion is to point out that a carbon tax at different levels is not in and of itself sufficient to analyze the impact of a carbon regime. While consideration of a range of carbon taxes could be included in Vectren's analysis, the correct analysis would also include consideration of a range in carbon policies including net zero by 2035 as put forth in the Biden plan. A net zero requirement by 2035 would potentially strand new investments in gas absent a retrofit of carbon capture. In either case, i.e., a shorter life or a carbon capture retrofit, the costs of gas would be significantly higher than represented in the IRP. No scenario in the IRP considered this occurrence.

It is also worth noting with respect to gas-fired generation that, with one exception, the gas price forecasts do not assume methane controls at the wellhead as shown above. Not only are methane controls included in the Biden Clean Energy and Climate Plan, requiring aggressive methane pollution limits for new and existing oil and gas operations is a day one item should Biden be elected.

There has been some previous regulation of methane emissions from gas wells. In 2016, EPA issued the first rule expressly targeting methane emissions from oil and gas well-head. These New Source Performance Standards were issued pursuant to Sec. 111(b) of the Clean Air Act. EPA also began the process of developing regulations for existing oil and gas infrastructure for methane leaks, venting, and flaring under Clean Air Act Sec. 111(d).

After the change in administration in 2017, EPA suspended its efforts related to existing wells. In March 2017, President Trump issued his "Executive Order on Promoting Energy Independence and Economic Growth" that included a directive to EPA to reconsider the 2016 methane standards for the oil and gas industry. While the reconsideration was underway, the D.C. Circuit ordered EPA to enforce the 2016 methane rule. In March 2018, EPA finalized an initial amendment to the 2016 NSPS rule to allow leaks to go unrepaired during unscheduled or emergency shutdowns. On August 13, 2020 EPA released two final rules revising and rolling back aspects of the VOC/methane NSPS, effectively eliminating them.

The purpose of providing this history is to demonstrate that methane controls were required at new wells since the 2016 NSPS. That precedent increases the likelihood that a change in administration will restore that requirement. Given methane has 84 times the warming power of carbon dioxide over a 20-year time frame[6], methane controls on existing wells are likely to be included in any carbon regime, not just the most stringent.

VI. Unreliable Assumptions Regarding Costs and Alternatives

A. <u>Renewable Costs</u>

The costs for renewable generation have turned out to be uncertain. Therefore, reliance on assumed IRP renewable costs has created a potential disconnect in the selection of preferred scenarios.

In July 2020, NIPSCO petitioned for approval and associated cost recovery of (1) a Solar Energy Purchase Agreement between NIPSCO and Brickyard Solar, LLC ("Brickyard") dated June 30, 2020 ("Brickyard PPA"), and (2) a Solar Generation and Energy Storage Energy Purchase Agreement between NIPSCO and Greensboro Solar Center, LLC ("Greensboro") dated June 30, 2020 ("Greensboro PPA"), collectively referred to as the "Solar PPAs." Cost information was not provided in the filings as it was deemed commercially sensitive. In September 2020, the Office of Utility Consumer Counsel (OUCC) filed testimony in the proceeding. The testimony is relevant in this proceeding as it demonstrates the uncertainty of the assumptions used in IRP's to conclude a preferred portfolio. The most compelling testimony came from Peter M. Boerger, PhD who found not only were the resource costs higher than what had been assumed in NIPSCO's 2018, they were so much higher that he believed the IURC should consider whether the entire conclusions of the IRP be reconsidered.[7] According to Dr. Boerger,

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[6] https://www.edf.org/climate/methane-other-important-greenhouse-gas

[7] Cause 45403, Redacted Testimony of OUCC Witness Peter M. Boerger, Ph.D., September 8, 2020. Pp 5-6 (If NIPSCO's solar resources had in its 2018 IRP been modeled to be {redacted] higher, other resource options would have been more attractive and NIPSCO's model may have selected a different resource mix. Thus, the higher solar

> This is no small issue considering that the wellbeing of NIPSCO's residential customers and the competitiveness of its business customers relies on keeping rates as low as reasonably possible. NIPSCO apparently made a misjudgment in its Short-Term Action Plan that solar resource prices would not substantially increase in the short term, leading to NIPSCO receiving much higher cost responses than available just two years ago in its first request for proposal ("RFP"). The effects of these misjudged costs will grow as NIPSCO presents additional solar resource proposals grounded in its Short-Term Action Plan, since the installed capacity from its current proposals represents about only 21% of the total amount of solar capacity envisioned in that Plan.

Dr. Boerger challenges the supporting testimony from NIPSCO's witness who argues over a 30-year period the rate impact of the PPA is smaller than what Dr. Boerger represents. Dr. Boerger notes that "Including those far-in-the-future costs makes the cost increase look smaller on a percentage basis than the increase in PPA cost". ICC notes it specifically challenged NIPSCO's use of a 30-year NPV given its sole purpose appeared to be to justify a plan than could not be justified over a 20-year term.[8]

OUCC witness Lauren M. Aguilar also raised the concern about the uncertainty of proposed projects noting that in Cause No. 45207 NIPSCO received approval to enter into a PPA with Roaming Bison Wind, LLC only to in a related case Cause No. 45196 to file notice that Roaming Bison could not preform. The Roaming Bison project was not able to obtain a site permit.

Vectren is currently experiencing a delay and significant cost overrun on a project for which it received approval. In May 2018 in Cause 45086, Vectren sought and ultimately received approval to construct, own and operate a solar energy facility, referred to as the Solar Project. As part of the approval, Vectren is required to provide quarterly reports on the construction of the Solar Project. The report at the end of Q1 2020 indicated a significant problem and at least a four-month delay which it alleged to be related to COVID-19 although at the end of March 2020 there were limited COVID-19 impacts. Further, the EPC contractor withdrew. The report at the end of Q2 2020 showed over a 20 percent increase in project costs. This project had been challenged on the basis of need and cost and ultimately only went forward due to a settlement with the OUCC and the Citizen's Action Coalition.

The lessons from the recent experiences of both NIPSCO and Vectren are that the IRP assumptions regarding renewable pricing may not be achievable and that even an all-source RFP is not dispositive. Vectren which had chosen to rely heavily on the results of the RFP admits as much. In the 4th Stakeholder Meeting Minutes provided in Volume 2 of the 2020 IRP, Vectren "found there are many difficulties with (the all-source RFP) process. The long timeframe makes it difficult for developers to hold their projects and pricing plus many projects are picked up by other groups while the IRP analysis is being performed."

B. Coal Prices

Coal prices are a significant determinant of resource choice. Vectren developed a delivered coal price forecast for the IRP by average forecasts of several consultants. As discussed below with capacity prices, this methodology is problematic because it does not control for other assumptions in the respective

costs NIPSCO is now seeing call into question whether the resources in this case, which are part of NIPSCO's Short-Term Action Plan, should be reconsidered."

[8] https://www.in.gov/iurc/files/ICC%20PUBLIC%20COMMENTS%20ON%20NIPSCO%202018%20IRP.pdf

forecasts which affect pricing because they affect overall demand. For example, one consultant may assume an aggressive carbon regime while another may assume no new regulations.

As the relevant coal price includes transportation costs, the origin of Vectren's assumption is not clear. Vectren, however, did not need to make an assumption for the transportation costs because in early November 2019, CSX made a proposal to Vectren for transporting coal to the AB Brown station at a fixed rate for 11 years. At that time, the IRP was not finalized. CSX provided its proposal so that it could be ascertained whether the rates CSX offered to Vectren for this move were incorporated into Vectren's analysis. Vectren did not include the CSX offer.

The offer was attractive for several reasons. The rate was lower than the current contract. The rate was divided into fixed and variable costs with the variable costs only applying to tonnages above contract minimums, and the fixed and variable rates were fixed and firm for 11 years, i.e., no escalation. CSX indicated that Vectren never engaged in conversations with them about the proposal. (Confirm last sentence is correct.)

There were two impacts associated with Vectren's failure to incorporate the offer. The first was that the delivered costs of coal to the Brown station in the IRP analysis were over-stated. As shown below, putting the rail costs on an equivalent basis, the delivered costs of coal range from $1.62 per ton (2018$) to $2.80 per ton (2018$) below what Vectren assumed in the IRP. For the 11-year contract, the NPV associated with continuing operations at AB Brown would have been reduced by over $16 million assuming annual deliveries of 1.2 million tons per year.

BENEFIT OF LOWER RAIL RATE TO AB BROWN

		2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
IRP Assumption	[redacted]											
CSX Offer												
2019 Tonnage												
NPV	$16,277,106											

The second, and more significant impact, is that the dispatch analysis understated the dispatch of the AB Brown station which had several collateral impacts. Energy costs were over-stated as more expensive power was used. In addition, the efficiency of the AB Brown plants was understated as lower capacity factors reduce efficiency and increase O&M costs.

The magnitude of the modeling errors depends upon how Vectren dispatches the AB Brown units with a lower delivered coal cost than assumed in the existing modeling. As noted, the CSX proposal included a fixed and variable cost. The fixed costs were to be paid quarterly based upon the tonnage nomination. In many respects, this is similar to Firm Transportation for natural gas. If Vectren appropriately modeled the CSX contract it should have assumed the plant was dispatched only on the variable transportation cost. As a result, the transportation costs would have been substantially lower. Modeled properly the plant would have had better dispatch and lower costs and the NPV benefit would have been larger.

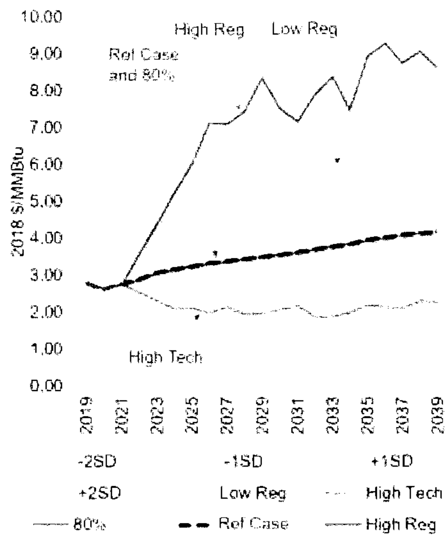
C. Natural Gas Prices

Vectren developed a Reference natural gas price forecast from the averaging of five forecasts it obtained from third parties. Vectren then developed three alternatives9 that are significantly both higher and lower than the Reference forecast. Typically, analyses are based upon the Reference forecast with and without stochastics. Analyses using high and low scenarios are performed to bookend the results. In other words, the scenario analysis is performed to understand how sensitive the outcome is to significant changes in the natural gas price forecast.

The natural gas prices scenarios included in the IRP are provided below. As shown, the natural gas price forecast in the High Tech scenario is below the Reference Case price forecast beginning in 2023 and increasing throughout the forecast period ultimately almost reaching 50 percent of the Reference Case price. If true this is problematic, as the High Tech gas prices would affect power prices as Vectren is unlikely to be the only party to experience low gas prices, CT dispatch, and the justification for the CTs.[10]

Natural Gas Price Scenarios (2018$/MMBtu)

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



D. CT Costs

Vectren acknowledges in its IRP that it does not know what the cost of the CTs it includes in its Preferred Portfolio will be in part because it has not decided upon a location. Vectren includes updating the CT costs as a to-do item.

In 2016, Vectren used a CCGT cost in its IRP that was significantly lower than the CCGT cost it included in its subsequent CPCN filing. The problem in the 2017 was not that the costs were significantly higher but that Vectren chose not to reconsider whether the CCGT at the higher cost still made sense.[11] This mistake should not be repeated in this round.

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[9]The 80% Reduction case gas prices are the same as the Reference Case.

[10] It is not actually clear from the Confidential Data Runs that the "High Tech" gas price was actually modeled.

[11] In 2016, Vectren did a separate retirement analysis and chose not to update the retirement analysis when the CCGT costs came in at a much higher level.

Further concern has been raised by Vectren's comments as to the potential conversion of the CT's to CCGT's if determined to be appropriate at some time in the future. In response to a data request as to whether such a plan increased the cost of the CT's, Vectren indicated it did not have that information.[12]

Additionally, it is not clear whether the CT's require NOx controls and whether that has been priced into the cost of the CT's. Finally, it appears no analysis was performed as to what the cost of carbon capture would be on the CT's or a CCGT if added in the future as would likely be required by a Net Zero RPS.

E. <u>Capacity Market Values</u>

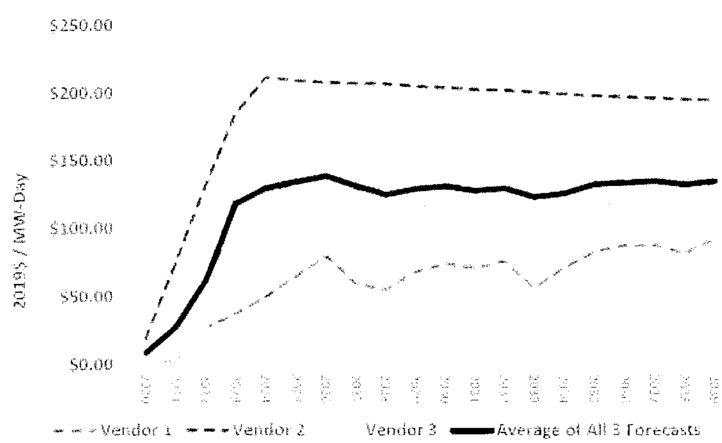
A key modeling uncertainty in MISO is what capacity will be worth over the IRP period. Generators are paid for their UCAP currently based upon the results of an annual auction. The most recent auction results are shown below. Indiana is Zone 6. Michigan is Zone 7.

RESULTS OF MOST RECENT MISO CAPACITY AUCTION[13]

Zone(s)	$/MW-Day
1-6	5.00
7	257.53
8 and 10	4.75
9	6.88

Vectren indicated in its IRP that it obtained MISO capacity market forecasts from three parties. Since the forecasts were so different, they decided to simply use the average for modeling purposes. The logic of this decision is opaque.

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



The price of capacity may be significant to resource decisions. Similar to carbon pricing, different market values could influence the outcome of the analysis. The prices Vectren used in <u>every</u> scenario are shown below.

[12] In its confidential response to ICC DR 1-29 Vectren objects to this request on the grounds that that analysis requested has not been performed and [redacted] solely for the purposes of discovery. (emphasis added)

[13] https://www.misoenergy.org/about/media-center/miso-closes-eighth-annual-planning-resource-auction/

IRP ASSUMPTIONS OF ZONE 6 MARKET CAPACITY PRICES

Year	$/MW-week	$/MW-day
2020	62.42	8.92
2021	192.89	27.56
2022	427.45	61.06
2023	816.11	116.59
2024	895.26	127.89
2025	927.82	132.55
2026	957.37	136.77
2027	903.91	129.13
2028	862.74	123.25
2029	892.13	127.45
2030	903.44	129.06
2031	882.66	126.09
2032	893.66	127.67
2033	849.41	121.34
2034	868.69	124.10
2035	914.49	130.64
2036	922.89	131.84
2037	931.47	133.07
2038	913.26	130.47
2039	930.84	132.98

Traditionally, when there are significant factors that affect resource decisions <u>and</u> there is some uncertainty as to level, sensitivity analyses with alternative assumptions are conducted to, at a minimum, determine the robustness of the results and how significant that factor is to the outcome.

The logic for the higher capacity market prices is that with the shift to increased renewables, the cost of capacity in MISO will increase. As shown above, the results in the most recent MISO auction demonstrate that there can be significant variability in the capacity costs by Zone and there should be a real concern for customer rates as utilities retire high UCAP capacity.

Without any analysis of the impact of capacity prices on resource decisions, Vectren concludes that the best way to manage the uncertainty on future MISO capacity market values is to build the CTs.[14] This appears to be a convenient conclusion.

F. Resource Options

Vectren considers a relatively narrow range of resource options. Two carbon-free sources that should have at least been discussed are small modular reactors (SMR) and fuel cells, not as a specific option for 2023 but as a potential resource in 2030 and beyond. Neither are mentioned in the IRP.

[14]IRP, Volume 1, page 211.

SMR's have become the focus for the next generation of nuclear power in the U.S. Since 1990, nuclear power has accounted for about 20 percent of electricity generation in the U.S.[15] As carbon free generation, they become increasing attractive under a net zero plan.

The Nuclear Regulatory Commission (NRC) has not yet approved the reactors but the process is underway. SMRs require significantly less space than a typical nuclear plant and produce nuclear energy on a comparatively smaller scale. Reportedly SMRs would be designed to ramp up and down, thereby providing greater operating flexibility. The potential designs for the small reactors are expected to reduce the risk of the core overheating.[16] Two U.S. companies, NuScale and TerraPower, are actively moving forward with development.[17,18] The NRC is in the process or reviewing NuScale's plant design. TerraPower, which had planned to construct a demonstration plant in China, is now focused on a U.S. site.

In December 2019, Tennessee Valley Authority (TVA) was the latest entity granted by the Nuclear Regulatory Commission (NRC) an early site permit (ESP) for a SMR project. The ESP is approval from the NRC of one or more sites for a nuclear power facility, independent of an application for a construction permit or combined license. An ESP is valid for 10 to 20 years from the date of issuance and can be renewed for an additional 10 to 20 years. The other utilities that have been granted ESPs are Exelon, Dominion, Southern, and PSEG Power.[19]

Most recently, the Department of Energy awarded two companies, TerraPower LLC and X-energy, $80 million each to build advanced reactors to operate within seven years and approved a cost-share award of nearly $1.3 billion to help develop the first NuScale Power LLC to the Utah Associated Municipal Power System (UAMPS).[20]

A fuel cell is an electrochemical cell that converts the chemical energy of a fuel (often hydrogen) and an oxidizing agent (often oxygen) into electricity. Hydrogen can be produced from a variety of source including water, fossil fuels, or biomass. The most common is steam-reforming in which the hydrogen is separated from the carbon atoms in methane (CH_4). Natural gas is currently the main methane source for hydrogen production by industrial facilities and petroleum refineries. The non-fossil alternative is electrolysis which splits hydrogen from water using an electric current. As there is no carbon associated with electrolysis, the product is referred to as green hydrogen.

Currently, it takes more energy to produce hydrogen than hydrogen produces when it is converted to useful energy. Hydrogen is still preferred in certain applications, e.g., rocket fuel, because it has a high energy content per unit of weight. Current global production of hydrogen is about 70 million tonnes.[21] The primary challenge towards increased use of hydrogen as a fuel is the reduction in the cost to produce hydrogen.

In July 2020, the European Union (EU) set 2024 and 2030 targets for green hydrogen, respectively of six GW and 40 GW of electrolyzers installed within the EU. EU has also established an additional 40 GW goal to be in place in nearby countries that could export to the EU. EU policymakers have indicated

[15] https://www.eia.gov/electricity/annual/
[16] https://e360.yale.edu/features/when-it-comes-to-nuclear-power-could-smaller-be-better
[17] https://www.businesswire.com/news/home/20191212005796/en/NuScale%E2%80%99s-SMR-Design-Clears-Phase-4-Nuclear
[18] https://www.terrapower.com/about/
[19] https://www.nrc.gov/reactors/new-reactors/esp.html
[20] https://www.publicpower.org/periodical/article/doe-cost-share-award-1355-bil-approved-uamps-small-modular-reactor-project
[21] https://www.iea.org/reports/the-future-of-hydrogen

that green hydrogen will be an essential tool to achieve a net-zero economy by 2050. If fuel cells are commercialized, they not only present a zero-carbon option, they also eliminate the need for baseload generation because they do not need to be scaled.

G. Power Purchase Agreements

Most renewable power is purchased through Power Purchase Agreements (PPA). PPA's vary in length but are generally between 10 and 20 years. PPAs typically have predetermined pricing through the PPA term. PPA's typically do not provide for prices to track market prices, and therefore, can diverge by a significant degree.

The best example of this is the first generation of wind PPA's. NIPSCO entered into two wind PPA's (Buffalo Ridge and Barton) in 2009. In its latest Fuel Adjustment Clause (FAC) filing[22], NIPSCO shows the actual cost of wind under its PPA's is $57.44 per MWH for the second quarter of 2020. This cost is more than twice NIPSCO steam generation costs ($27.41 per MWH) and combined-cycle costs ($11.33 per MWH) and almost three times higher than the cost of purchases through MISO ($19.36 per MWH).

NIPSCO is not alone. In or around 2009, AEP Ohio entered into long-term wind renewable energy purchase agreements (REPA's) to comply with the state of Ohio's alternative energy rider (AER). These 20-year contracts have turned out to be out-of-the money particularly when compared to the other Ohio utilities which chose to comply with their statutory obligations without the use of long-term contracts. This can be seen in a comparison published by the Public Utilities Commission of Ohio (PUCO) which compares AER rates and monthly bill impacts on a quarterly basis for the six electric distribution companies.[23] Ohio Power's rates were the highest in 10 of the last 11 quarters and exceeded the simple average of all six utilities by 145 to 363 percent over this period.

AVERAGE MONTHLY BILL IMPACT

	2017				2018				2019				2020		
	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3
Cleveland Electric Illuminating	$0.15	$0.06	$0.24	$0.43	$0.22	$0.43	$0.39	$0.40	$0.27	$0.47	$0.41	$0.44	$0.34	$0.86	$0.48
Dayton Power & Light	$0.19	$0.04	$0.07	-$0.12	$0.06	$0.06	$0.10	$0.10	$0.10	$0.10	$0.34	$0.34	$0.34	$0.34	$0.29
Duke Energy - Ohio	$0.33	$0.42	$0.23	$0.28	$0.44	$0.66	$0.08	$0.22	$0.30	$0.56	$0.04	$0.07	$0.16	$0.13	$0.03
Ohio Edison Company	$0.13	$0.07	$0.15	$0.32	$0.23	$0.47	$0.38	$0.38	$0.37	$0.47	$0.41	$0.44	$0.27	$0.95	$0.44
Ohio Power Company	$0.75	$1.53	$1.31	$0.56	$1.66	$2.07	$1.24	$0.54	$0.69	$1.17	$1.53	$1.92	$2.26	$2.67	$1.39
Toledo Edison Company	$0.23	$0.11	$0.20	$0.53	$0.43	$0.63	$0.51	$0.59	$0.66	$0.36	$0.35	$0.54	$0.37	$0.92	$0.45
Average	$0.30	$0.37	$0.37	$0.33	$0.51	$0.72	$0.45	$0.37	$0.40	$0.52	$0.51	$0.63	$0.62	$0.98	$0.51
Ohio Power/Average	**253%**	**412%**	**357%**	**168%**	**328%**	**288%**	**276%**	**145%**	**173%**	**224%**	**298%**	**307%**	**363%**	**273%**	**271%**

Source: Public Utilities Commission of Ohio, RPS EDU Rate Increases

[22] Cause 38706-FAC 123

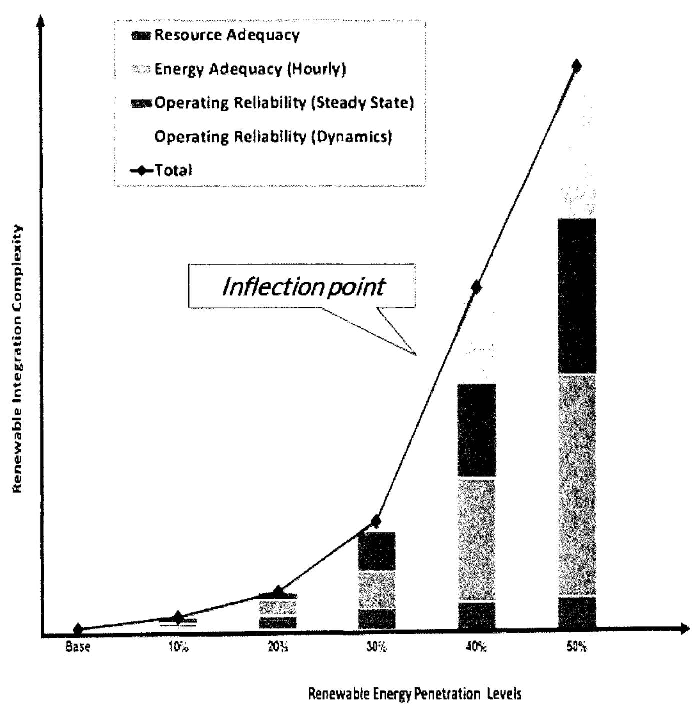
[23] https://www.puco.ohio.gov/industry-information/industry-topics/ohioe28099s-renewable-and-advanced-energy-portfolio-standard/

VII. Inadequate Attention to Potential Impact of Future Renewables Saturation of MISO Market

The Midcontinent Independent System Operator (MISO) is an independent system operator and regional transmission organization under FERC jurisdiction that coordinates, controls, and monitors the use of the electric transmission system in order to optimize power costs within its footprint. MISO membership includes all or part of 15 states and the Canadian province of Manitoba. Most of the generation in Indiana is sold through MISO. MISO provides non-discriminatory service and is independent of the transmission owners and the customers who use its system. MISO performs its obligations by conducting day-ahead and real-time energy and operating reserve markets, managing least cost economic dispatch of generation units, and monitoring and scheduling energy transfers on the high voltage transmission system. MISO is also responsible for long-range transmission planning, generator interconnections (new and retiring), and long-range studies. Of particular relevance to the IRP is MISO's renewable integration impact assessment referred to as RIIA.

Vectren mentions the RIIA in its IRP but only to say that its purpose is to assess the implications of the growth of renewables on transmisson needs and dispatch and to determine whether there are "inflection" point. Vectren did not overlay MISO's key finding to date which is that above 30 percent renewable penetration integration complexity and costs increase sharply.

MISO OPERATING CONCERNS WITH INCREASED RENEWABLE PENETRATION



Source: The Evolving MISO Grid and Multi-State Transmission, February 3, 2020

MISO reached seven conclusions associated high renewable integration.[24]

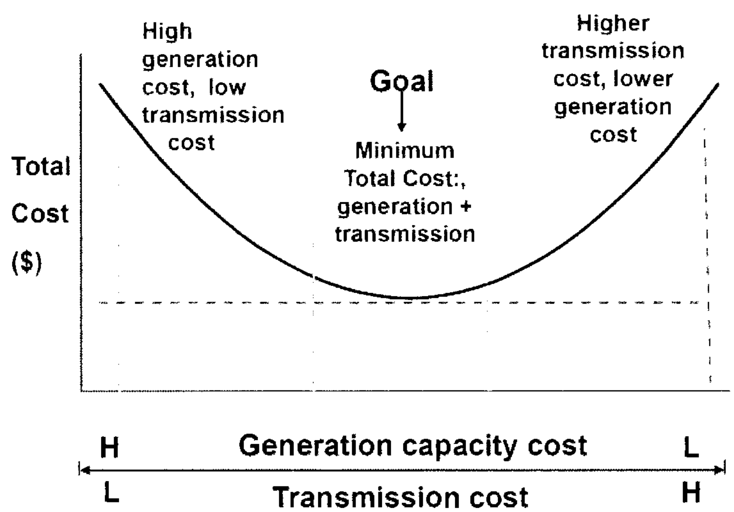
1. Risk of losing load compresses into a small number of hours and shifts into the evening.

[24] https://www.lec.leg.mn/2020/MISO%20for%20MN%20LEC%20Feb%202020%20vf.pdf

2. Existing infrastructure becomes inadequate for fully accessing the diverse resources across the MISO footprint.
3. Regional energy transfer increases in magnitude and becomes more variable leading to a need for increase extra-high voltage line thermal capabilities.
4. Power delivery from low short circuit area many need transmission technologies equipped with dynamic support capabilities.
5. Frequency response is stable up to 60% instantaneous renewable penetration, but may require additional planned headroom beyond.
6. Grid-technology-needs evolve as renewable penetration increases, leading to an increased need for integrated planning.
7. Diversity of technologies and geography improves the ability of renewables to serve load.

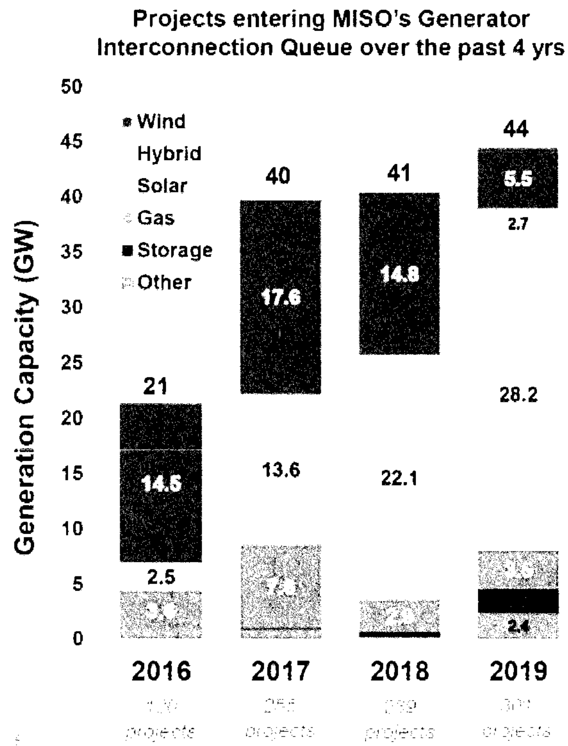
For IRP purposes, the two most important are (1) the need for integrated planning and (2) the importance of diversity. With respect to integrated planning, MISO is not referring to individual utility IRP's. It is a broader statement reflecting MISO, not individual utility systems. With respect to diversity, MISO again is not referring to individual utilities. In other words, parochial planning by individual utilities is likely to increase energy costs in MISO.

MISO further recognizes that a balance must be achieved between generation and transmission costs for affordability.



Source: The Evolving MISO Grid and Multi-State Transmission, February 3, 2020

Another point made by MISO relates to the status of the queues. Renewable projects are overwhelming the queues and could affect the ability of proposed projects to be available on a timely basis where new interconnections are needed.



Source: The Evolving MISO Grid and Multi-State Transmission, February 3, 2020

Because of the lack of adequate transmission, MISO started to dispatch wind generation in 2011 and solar generation in 2020. This change had serious financial consequences to NIPSCO when the wind generators in legacy PPA's prevailed in a legal dispute that NIPSCO (and its ratepayers) were required to make payments for wind even when MISO could not take the power.[25] The dispatching of the intermittent resources will lower expected capacity factors and probably UCAP which is the amount of a resource Vectren can include in meeting its reserve margins. While the modeling captures some decline in UCAP for solar and wind, it is not clear the represented decline is sufficient.

[25] https://casetext.com/case/barton-windpower-llc-v-n-ind-pub-serv-co