STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

VERIFIED PETITION OF NORTHERN INDIANA PUBLIC SERVICE COMPANY LLC FOR APPROVAL PURSUANT TO IND. CODE §§ 8-1-2-42(a), 8-1-8.8-11, AND TO THE EXTENT NECESSARY IND. CODE § 8-1-2.5-6, OF A RENEWABLE ENERGY POWER PURCHASE AGREEMENT WITH ROAMING BISON WIND, LLC, INCLUDING TIMELY COST RECOVERY.	)	CAUSE NO. 45196

DIRECT TESTIMONY

OF

EMILY S. MEDINE

ON BEHALF OF

INDIANA COAL COUNCIL

March 15, 2019

TESTIMONY OF

EMILY S. MEDINE

ON BEHALF OF THE INDIANA COAL COUNCIL

I. INTRODUCTION AND SUMMARY

Q. PLEASE STATE YOUR NAME, TITLE AND BUSINESS ADDRESS.

A. My name is Emily S. Medine. I am a Principal in the consulting firm of Energy Ventures Analysis, Inc. ("EVA"). My business address is 1901 N. Moore Street, Suite 1200, Arlington, Virginia 22209-1706.

Q. PLEASE DESCRIBE YOUR WORK EXPERIENCE AND EDUCATIONAL BACKGROUND.

A. I have been with EVA, an energy consultancy formed in 1981, since 1986. EVA engages in a variety of energy-related projects for private and public sector clients. Prior to EVA, I worked for Consolidation Coal Company (now "CONSOL Energy"). I received a Bachelor of Arts degree from Clark University in 1976 and a Masters of Public Affairs from the Woodrow Wilson School of Public and International Affairs at Princeton University in 1978.

My education and experience are set out in Attachment ESM-1.

Q. PLEASE DESCRIBE EVA.

A. EVA is a consulting firm that engages in a variety of projects for private and public sector clients related to energy and environmental issues. EVA also has a subscription business and currently produces about 15 publications, the frequency of which range from weekly to annual. In the energy area, much of our work is related to analysis of the electric utility industry and fuel markets, particularly oil, natural gas and coal. Our clients in these areas include coal, oil and natural gas producers, electric utility and industrial energy consumers, and gas pipelines and railroads. We also work for a number of public agencies, including the U.S. Department of Justice, the U.S. Department of the Interior, state public utility commissions. as well as intervenors in utility rate proceedings, such as consumer counsels and municipalities. Another group of clients include trade and industry associations. EVA has provided testimony in numerous state public utility commissions. Principals in the firm have also filed testimony in a number of cases in both state and federal courts, as well as before the Federal Energy Regulatory Commission.

Q. WHO ARE YOU TESTIFYING ON BEHALF?

A. My testimony is on behalf of the Indiana Coal Council.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. On February 1, 2019 Northern Indiana Public Service Company LLC (NIPSCO) filed Cause 45196 for approval to enter into a Power Purchase agreement with Roaring Bison which is an indirect, wholly-owned subsidiary of Apex Clean Energy Holding, LLC. Roaming Bison will have an installed capacity of approximately 300 MW. The term of the PPA is 20 years. The purchase is for a bundled product consisting of energy, capacity, and Renewable Energy Credits (RECs). My testimony provides comments on this filing.

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS.

A. NIPSCO fails to demonstrate that Roaming Bison is needed to meet system demand. NIPSCO fails to demonstrate that the Roaming Bison project is the lowest cost energy choice. Finally, NIPSCO's request to be insulated from the 42(d) and FAC benchmarks is inappropriate.

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS.

A. The Commission should deny this petition. Should IURC approve NIPSCO proceeding with Roaming Bison, the Commission should decline to insulate NIPSCO from the 42(d) Test or FAC benchmarks.

II. SYSTEM NEED

Q. HOW DID NIPSCO FAIL TO DEMONSTRATE NEED?

A. NIPSCO repeatedly states as its justification, its Integrated Resource Plan (IRP) filed on October 31, 2018 (Cause 45160). There are provisions in the Indiana Administration Code (IAC) which govern the submission and review of the required IRP filings.[1] The review process for that IRP has not yet been completed. Stakeholder comments were filed February 28, 2019, and the full review of that IRP remains far from finished. Stakeholders await the Director's[2] draft report, after which written comments to that draft may be submitted. Only after those steps will the Director issue a final report. Given the timeframes outlined in the Commission's rules, it will be the end of June at the earliest, before the Director's Final Report may be expected. Therefore, the reliance on the IRP in a proceeding to be heard in May, is premature.

Q. WHAT IS THE PROBLEM PROCEEDING WITH THIS CASE BEFORE THE IRP REVIEW IS COMPLETE?

A. The IRP process, including the involvement of Stakeholders and the Director, loses meaning if utilities implement their preferred outcomes before IRP analysis and review is complete. Here, in NIPSCO particularly abuses the IRP process by:

(i) proceeding with a rate case (45159) in which it prematurely uses its IRP as justification for (a) early retirement of its remaining coal fleet which consisted of over 2500 MW of coal generation; (b) acceleration of depreciation on those units; and (c) regulatory asset treatment to insure recovery of stranded costs in those units.

(ii) proceeding with this 300 MW Wind PPA case (45196 – Roaming Bison) in which NIPSCO prematurely uses its IRP as justification to commit customers to twenty years of must-take wind energy;

---

[1] 170 IAC 4-8

[2] "Director" means an employee of the commission designated as the IRP director by the commission's agency head appointed under IC 8-1-1-2(d).

(iii) proceeding with a 400 MW Wind PPA case (45195 – Jordan Creek) in which NIPSCO prematurely uses its IRP as justification to commit customers to twenty years of must-take wind energy; and

(iv) proceeding with a 102 MW Wind case (45194 – Rosewater) in which NIPSCO prematurely uses its IRP as justification to commit customers at least 20 years of must-take wind energy.

Numerous flaws and inconsistencies in NIPSCO IRP analysis have been identified in Stakeholder comments to the IRP, in prefiled testimony in the 45159 rate case, and in prefiled testimony 45194, 45195, and 45196. The Director's draft or final reports may identify more problems.

Q. DO YOU HAVE ANY CONCERNS BEYOND NIPSCO'S PREMATURE RELIANCE ON THE IRP?

A. Yes. A major component of NIPSCO's pending rate case (45159) is NIPSCO's proposal to alter its tariff for its largest industrial customers. Under proposed Rate 831, NIPSCO's five largest customers could reduce their firm demand to just 50 MW in the aggregate, a huge reduction in firm load for NIPSCO. Those five customers account for approximately 40% of NIPSCO's energy demand and approximately 1,200 MW of peak load plus reserves when viewed on a non-coincident, individual customer basis.[3]

The fundamental purpose of integrated resource planning is to determine how a utility may most economically and reliably satisfy its future customer demand. Accordingly, a reliable IRP must be based on a reasonably accurate forecast of future demand. Here, however, NIPSCO did not attempt to model in its IRP any potential reduction in industrial load that might result from the implementation of Rate 831. Accordingly, if Rate 831 is implemented, any reliance on NIPSCO's current IRP must be suspect.

That suspicion, and the burden on NIPSCO to overcome it, must be especially high when, as here, implementation of the IRP involves early retirement of all existing base load generation (creating stranded cost recovery issues), and committing customers to billions

[3] IRP, Page 4

of dollars of fixed contractual costs for capacity, the long-term need for which cannot be accurately assessed given the current uncertainty about NIPSCO's future load profile.

Q. IN THE RATE CASE, DOES NIPSCO INDICATE HOW MUCH IT EXPECTs ITS FIVE LARGEST CUSTOMERS TO PARTICIPATE IN RATE 831?

A. Under the proposed Rate 831, those customers could reduce their firm demand to 10 MW each, for a total of 50 MW. In the rate case, NIPSCO says it believes all five customer would participate in Tariff 831 but does not know to what extent. NIPSCO assumes those five would reduce their demand to 184 MW rather than 50 MW, but it just does not know unless and until Rate 831 is implemented.[4] Accordingly, NIPSCO proposes later true-up in rates after it knows.

Q. WOULD THE IRP RESULTS BE DIFFERENT UNDER A LOWER LOAD FORECAST?

A. Probably. First, the impact on rates of stranded cost recovery caused by early retirement of coal assets would be even greater with a materially smaller industrial load, perhaps driving a different strategy. NIPSCO showed a potential 32 percent increase in residential rates as a result of the new tariff which other parties believe understates the impact. This impact could potentially be reduced through a different resource plan. Second, the resource needs will be lower if the expected load is lower, and that almost by definition, means a different IRP outcome in one way or another.

Q. IS IT APPROPRIATE THAT THE IURC AND STAKEHOLDERS HAVE TO GUESS ABOUT THE IMPACTS OF A LOWER LOAD FORECAST OR SHOULD NIPSCO PERFORM THAT MODELING AND PROVIDE IT?

A. An accurate load forecast is fundamental to a reliable IRP. So, if NIPSCO's proposed Rate 831 is implemented, then NIPSCO must redo its IRP entirely with a proper load forecast before the Commission should allow NIPSCO to use its IRP as justification for any

[4] Direct Testimony of Company Witness Kelly, Cause 45159, page 8, line 4.

adjustment in its resources. Further, numerous other flaws in the current IRP modeling need to be corrected.

Q. ARE YOU SAYING THE JUSTIFICATION FOR THE REQUEST IN THIS POSITION IS COMPROMISED BY NIPSCO'S RELIANCE ON THE IRP?

A. Yes. Because of its many flaws, the 2018 IRP cannot support a conclusion that a need for the Roaming Bison resource (or Jordan Creek or Rosewater) exists. NIPSCO has not proffered any other evidence of need. I am not alone in this concern. Citizens Action Coalition of Indiana, Earthjustice, Indiana Distributed Energy Alliance, Sierra Club, and Valley Watch in their joint comments on the IRP suggest that "(a)s NIPSCO comes to the IURC to seek approval for new resources, … (it) would like to see a robust evaluation of the impacts of potential lost industrial load."[5]

Q. DID NIPSCO PROVIDE A "ROBUST" EVALUATION OF THE IMPACTS OF POTENTIAL LOST INDUSTRIAL LOAD IN THIS CASE OF IN 45194 OR 45196?

A. NIPSCO confirmed in its response to ICC 2-001 it did not develop a 20-year load forecast that assumes the impact of potential loss of load with the industrial tariff during the first five-year contract period or subsequent contract periods.[6] Therefore, NIPSCO provided no analysis of the impacts of potential lost industrial load with this petition, robust or otherwise. It only provided a Challenged Economy scenario in its IRP in which it assumed flat load. But it put a thumb on the scale in that scenario by biasing the outcome in favor of early retirement of existing coal resources by assuming both high coal prices and carbon taxes.

[55] https://www.in.gov/iurc/files/NIPSCO%202018%20IRP--CAC%20EJ%20INDG%20SC%20VW%20Comments--3-1-19FINAL.pdf, page 38.

[6] Company Response to ICC 2-001.

III. DEMONSTRATION OF COST SAVINGS

Q. DID YOU PROVIDE COMMENTS ON THE IRP TO THE IURC?

A. Yes. My testimony was submitted in Cause 45159, the base rates case, and I participated in drafting the comments the ICC filed in Cause 45160, the IRP case. Attachments ESM-2 and ESM-3 respectively provide the testimony and comments.

Q. DO THESE COMMENTS ACCURATELY REFLECT YOUR OPINIONS AS TO THE DEFICIENCES WITH THE IRP?

A. Yes, however, those comments were filed February 28, 2019, and therefore new information gained in discovery thereafter was not incorporated into those comments.

Q. COULD YOU PLEASE SUMMARIZE YOUR CONCERNS?

A. Starting with its 2016 IRP and continuing through the 2018 IRP, NIPSCO has demonstrated a strong preference for the closure of its remaining coal fleet. This preference has manifested in multiple ways including the following:

- The construction of the scenarios was biased. For example, the only scenario with zero carbon pricing was the Challenged Economy Scenario, which also assumes slow economic growth and high coal prices.

- The commodity assumptions with respect to coal and carbon have been shown to disadvantage coal without justification.

- The regulatory assumptions considered the worst cases including almost $0.5 billion for a non-existent regulation and ignored actual and impending regulatory changes.

- Regulatory compliance did not seek least-cost solutions or explore evolving options and strategies.

- The methodology which considered retirement independent of replacement sequentially considered lower cost replacement resources in the retirement decisions and higher cost replacement options after the retirements were "locked in." NIPSCO failed to look at all-in costs with respect to the incorporation of renewables into its resource portfolio.

- NIPSCO failed to determine the impact on customer rates by considering only at the NPV's. NPVs are not a proxy for rate impact. Capital intensive scenarios will start with a large rate impact that declines over time as the capital asset is depreciated. Labor and/or fuel intensive scenarios will have a more levelized rate impact.

- NIPSCO inflated the "benefits" of the preferred scenario by extending the NPV analysis period from 20 to 30 years without actually doing a 30-year analysis.[7]

Further, NIPSCO showed no interest in finding solutions related to its existing coal fleet that would reduce customer impact. Such efforts would have included efforts to reduce operating costs, efforts to increase the dispatch of the coal units, and efforts to identify lower cost regulatory compliance options. Nor did NIPSCO look at options to reduce closure costs including the engagement of an investment banker to conduct a sale of the coal plants.

Q. WHAT ADDITIONAL INFORMATION HAS BEEN LEARNED WITH THE SUBMISSION OF THE THREE WIND CASES?

A. As summarized in the testimony of ICC Witness Griffey, the cost and operating assumptions that NIPSCO used to conclude its Scenario F was preferred were fraught with poor assumptions. From the guaranteed capacity, to assumptions regarding tax equity investment, to the cost of the facility, to the assumed capacity factor, to the UCAP, NIPSCO misstated the numbers in the direction which favored the wind recommendation.

[7] NIPSCO did not disclose this fact in the IRP itself. Only upon questioning, did NIPSCO acknowledge that its analysis was for only 20 years and a 10 year tail was added through assumption.

Further, NIPSCO's failure to include congestion and curtailment costs in its analysis also accounts for a significant difference in expected project costs.

Q. WHAT CONCLUSION DID YOU REACH GIVEN THESE STATED CONCERNS ABOUT THE IRP?

A. NIPSCO has not met its burden of proof that its preferred strategy is optimal. Therefore, approval of the Roaming Bison PPA which is put forth as part of the action plan resulting from the IRP should be denied.

IV. THE PETITION

Q. DO YOU HAVE ANY SPECIFIC COMMENTS ABOUT THE PETITION?

A. Yes.

I am concerned about NIPSCO's request that the cost recovery, which is to be administered through the Fuel Adjustment Clause (FAC), not be subject to the Indiana Code 42(d) tests or any other FAC benchmarks.

Q. WHAT ARE YOUR CONCERNS ABOUT NIPSCO'S REQUEST REGARDING THE 42(D) TESTS OR ANY OTHER FAC BENCHMARK?

A. The 42(d) tests relate to the utility's obligation to demonstrate to the IURC that it "has made every reasonable effort to acquire fuel and generate **or purchase power** or both" at the lowest costs. NIPSCO asked for and received 42(d) waivers for its two prior wind PPA's. I believe this policy should be reconsidered for NIPSCO and other utilities going forward.

Like long-term coal contracts, long-term PPA's commitments require active management. In other words, there may be reasons, unforeseeable at this time, that would improve PPA economics through a renegotiation or even a buy-out. If a utility receives a pass on ever being subject to regulatory review during the pendency of an agreement, there may be less incentive for the utility to actively manage its PPA agreement. This issue will become more significant over time if NIPSCO enters into multiple PPAs discussed in its IRP.

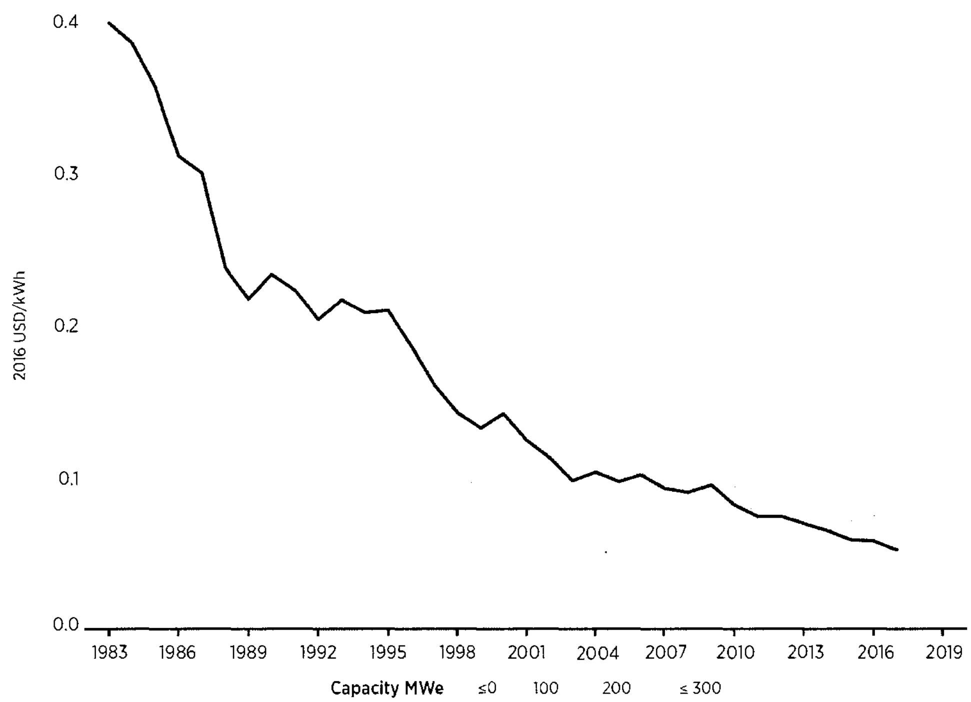
Q, WHAT ARE YOUR CONCERNS ABOUT A LONG-TERM PPA FOR WIND?

A. Locking into a 20-year wind contract exposes NIPSCO customers to potentially higher costs if the cost of wind generation declines.

Q. HAVE WIND PRODUCTION COSTS DECLINED OVER TIME?

Y. Yes. The International Renewable Energy Agency (IRENA) shows a continuous decline in real dollars for onshore wind, as shown below.

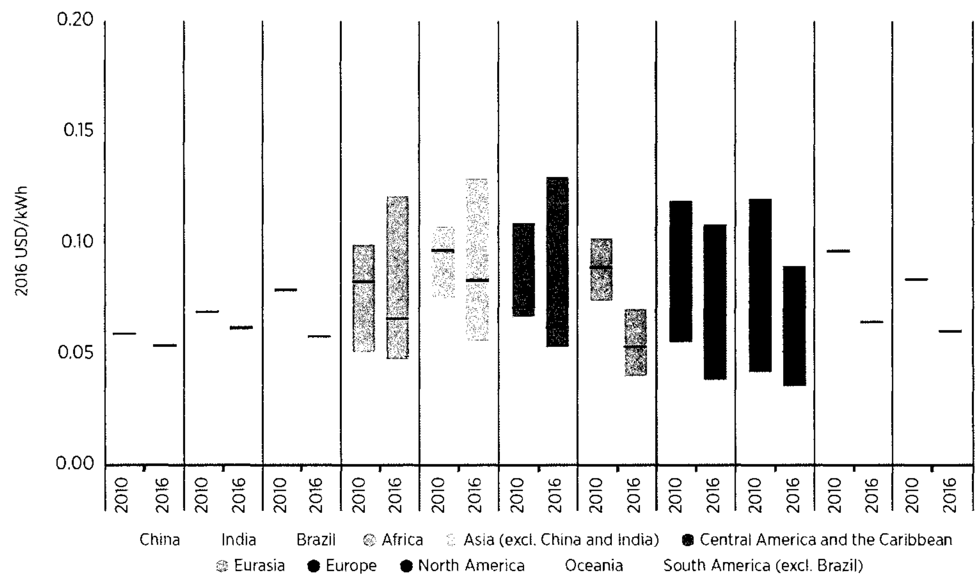
Figure 5.17 The global weighted average levelised cost of electricity of onshore wind, 1983-2017



Sources: IRENA Renewable Cost Database.

IRENA compares the costs on a regional basis as shown below. U. S. onshore wind production costs fell by over 30 percent in real dollars between 2010 and 2016.

Figure 5.19 Regional weighted average LCOE and ranges of onshore wind in 2010 and 2016



Source: IRENA Renewable Cost Database

Q. TO WHAT DOES IRENA ATTRIBUTED THE COST DECLINES?

A. IRENA believes the cost reductions are due to three main factors which are expected to increase over time. These are (1) competitive procurement of renewable power generation, (2) increasing international competition for projects, and (3) continuous technology innovation. [8]

Q. DO OTHER INDEPENDENT RESARCH GROUPS ALSO AGREE?

A. The National Energy Research Laboratory (NREL) in its 2017 review of wind generation costs confirms the downward trend in costs.[9] According to NREL, "(l)and-based wind power plant LCOE estimates continue to show a downward trend from the 2010 Cost of Wind Energy Review (Tegen et al. 2012) to the 2017 review. NREL is not overly concerned about continued wind investment without the PTC. NERL believes that "(a)s the production tax credit ramps down and expires permanently over the next few years, it

[8] file:///C:/Users/emedi/Documents/EVA/NIPSCO/WIND/IRENA_2017_Power_Costs_2018.pdf
[9] https://www.nrel.gov/docs/fy18osti/72167.pdf?gathStatIcon=true, page xiii.

is likely that wind project weighted-average cost of capital or discount rate will be reduced as leverage increases and tax equity is replaced with cheaper debt."[10]

Q. IF THE PPA PRICE IS BASED UPON CURRENT COSTS, WILL NIPSCO CUSTOMERS BENEFIT FROM TECHNOLOGY ADVANCES THAT OCCUR DURING THE TERM OF THE PPA.

A. No. The pricing will be locked in.

Q. ARE YOU AWARE OF PROBLEMS THAT HAVE ARISEN WITH LONG-TERM PPA'S?

A. Yes. One need go no further than NIPSCO's own experience. NIPSCO entered into two wind PPA's (Buffalo Ridge and Barton) in 2009. In its latest Fuel Adjustment Clause (FAC) filing, NIPSCO shows the cost of wind under its PPA's is $53.107 per MWH. This cost is more than twice NIPSCO steam generation costs ($23.540 per MWH) and combined-cycle costs ($18.156 per MWH) and 25 percent higher than the cost of purchases through MISO ($41.388 per MWH). They are even higher than the costs of peaking gas combustion turbines.

[10] https://www.nrel.gov/docs/fy18osti/72167.pdf?gathStatIcon=true, page xiii.

NORTHERN INDIANA PUBLIC SERVICE COMPANY

COMPARISON OF CURRENT FILING AND PRIOR APPROVED FUEL COST FACTOR

CAUSE NO. 38706-FAC 122 AND CAUSE NO. 38706-FAC 121

		ESTIMATED COST		MWH		UNIT COST (MILLS/KWH)		
LINE NO.	SOURCE	CURRENT FILING CAUSE NO. 38706-FAC 122	PRIOR FILING CAUSE NO. 38706-FAC 121	CURRENT FILING CAUSE NO. 38706-FAC 122	PRIOR FILING CAUSE NO. 38706-FAC 121	CURRENT FILING CAUSE NO. 38706-FAC 122	PRIOR FILING CAUSE NO. 38706-FAC 121	LINE NO.
1	STEAM GENERATION	$ 43,081,144	$ 51,494,306	1,830,120	2,097,082	23.540	24.555	1
2	NUCLEAR GENERATION	-	-	-	-	-	-	2
3	HYDRO GENERATION	-	-	16,316	16,820	-	-	3
	OTHER GENERATION							
4	Combined Cycle Unit	19,693,830	22,775,659	1,084,719	987,319	18.156	23.068	4
5	Gas Combustion Turbines	689,231	1,070,234	16,653	22,253	41.388	48.094	5
6	PURCHASES THROUGH MISO	30,569,639	32,592,023	1,088,612	1,048,904	28.081	31.072	6
7	MISO COMPONENTS OF COST OF FUEL	4,318,044	4,243,095	-	-	-	-	7
	PURCHASED POWER OTHER THAN MISO					-	-	
8	FIT PURCHASES	4,564,536	4,540,110	30,945	30,801	147.505	147.401	8
9	WIND ENERGY PURCHASES	3,530,695	4,146,504	66,483	77,945	53.107	53.198	9
10	OTHER	-	-	-	-	-	-	10
	LESS:							
11	ENERGY LOSSES AND COMPANY USE	-	-	211,475	214,447	-	-	11
12	INTERSYSTEM SALES THROUGH MISO	942	2,040,887	44	88,881	21.409	22.962	12
13	INTERSYSTEM SALES OTHER THAN MISO	-	-	-	-	-	-	13
14	JURISDICTIONAL SALES NOT SUBJECT TO FAC	329,241	452,373	13,317	16,576	24.723	27.288	14
15	WIND PPA ADJUSTMENT	87,300	78,927	-	-	-	-	15
16	PURCHASE POWER BENCHMARK ADJUSTMENT	-	-	-	-	-	-	16
17	TOTAL	$ 106,029,636	$ 118,289,744	3,909,012	3,961,218	27.124	29.862	17

Q. DID NIPSCO REPRESENT THESE PROJECTS WOULD REDUCE COSTS WHEN APPROVAL WAS SOUGHT IN 2008?

A. Yes. According to the Commission's order, NIPSCO's case-in-chief represented that these PPAs were in response to energy needs identified in the 2007 IRP. NIPSCO stated among other things it believed that the wind PPA's would be "economic over their respective terms" (15 years at a fixed price for Buffalo Ridge and 20 years at an escalating price for Barton).[11]

Q. ARE THE BUFFALO RIDGE AND BARTON WIND PPAs LIKELY TO BE ECONOMIC OVER "THEIR RESPECTIVE TERMS?"

A. No.

Q. WHAT DID NIPSCO GET WRONG WHEN SEEKING APPROVAL OF THE BUFFALO RIDGE AND BARTON WIND PPAs?

[11] Order in Cause 43393. https://iurc.portal.in.gov/legal-case-details/?id=d6df683f-db81-e611-8107-1458d04eabe0

A. Many things. NIPSCO assumed wind would be needed to comply with GHG regulations (which did not materialize), that wind would help comply with inevitable federal and/or state renewable portfolio standards (there are no federal or Indiana RPS standards), other renewables would experience price increases (prices declined), the PTC would be unavailable after December 21, 2008 (the PTC was extended in 2015 and could be again), and the increasing value of RECs would offset PPA costs (REC prices have fallen).

Q. IS THE PRICING UNDER THE BARTON AND BUFFALO RIDGE PPA'S HIGHER THAN THE PRICING UNDER THE PROPOSED ROAMING BISON AND JORDAN CREEK PPA'S?

A. The pricing under the Roaming Bison and Jordan Creek PPA's are lower than the reported prices of the Barton and Buffalo Ridge PPA's even with the adjustments made by ICC Witness Griffey. This speaks only to how high priced the existing PPA's are, not the reasonableness of the new PPA's. The pricing under the proposed PPA's are higher than current steam and combined-cycle generation.

Q. HAVE THERE BEEN OTHER ISSUES WITH THESE PPA'S?

A. Yes. The IURC is well aware of a dispute NIPSCO had related to Buffalo Ridge and Barton PPA's. In 2013, a dispute arose following MISO's implementation of its Dispatchable Intermittent Resources (DIR) tariff that had been approved by FERC in February 2011. Under the DIR tariff, MISO started to dispatch wind generation in a manner similar to the dispatch of the rest of the fleet.[12] Following the implementation of the DIR tariff, NIPSCO started to receive two invoices each month from Buffalo Ridge and Barton, one for energy received and one for curtailed power. NIPSCO disputed the invoices for curtailed power.[13] Litigation followed.

In June 2018, the U.S. District Court for the Northern District of Illinois, Eastern Division issued a ruling that NIPSCO was obligated to pay for the "cost to cover" the curtailed

---

[12] Cause No. 38706-FAC-100, Direct Testimony of Andrew S. Campbell, page 8, lines 9-15.

[13] Cause No. 38706-FAC-100, Direct Testimony of Michael D. Eckert, page 6, lines 9-24

power when the wind farms are told by MISO to reduce generation.[14] In September 2018, the parties settled the case for about $13.95 million and agreed that payments for the curtailed power would be paid in the regular course of business moving forward.[15]

Q. WILL THIS BE AN ISSUE IN THE PROPOSED PPAs IN THIS CASE AND 45194 AND 45195?

A. Yes I believe so. As discussed by ICC Witness Griffey, NIPSCO RFP evaluation included no costs related to curtailments under the DIR tariff. Further it is worth noting that, if history teaches us anything, with these and other wind additions congestion will increase, requiring transmission system upgrades to mitigate.

Q. ARE YOU PERSUADED BY NIPSCO'S REPRESENTATION THAT ROAMING BISON PLAYS A ROLE IN NIPSCO ACHIEVING $500 MILLION SAVINGS BECAUSE OF THE DECLINING VALUE OF THE PRODUCTION TAX CREDITS[16]?

A. No. First, the number is totally contrived as it is simply comparing Scenario F to itself modified to assume all solar with storage replacements instead of some wind replacements, a scenario that is not under consideration. Second, the number assumes no adjustments related to the problems identified with the IRP including the artificial contrivance associated with the extension of the NPV from 20 to 30 years. Third, the wind investments provide virtually no UCAP. MISO states that its values wind UCAP in Zone 6 at 7.4 percent. NIPSCO suggests it could be higher but that it could also be 7.4 percent. Since NIPSCO's analysis credited about double this UCAP, the capacity difference must be reflected.

Q. IF NIPSCO DOES NOT NEED CAPACITY WHICH COULD BE THE CASE IF THE COAL PLANT RETIREMENTS ARE DEFFERED AND/OR THE

[14] Cause No. 38706-FAC-210, Direct Testimony of Benjamin J. Turner, page 8, lines 14-18, page 9, lines 1-2.
[15] Cause No. 38706-FAC-211, Direct Testimony of Benjamin J. Turner, page 8, lines 15-17, page 9, lines 1-5.
[16] Direct Testimony of Campbell, page 27.

INDUSTRIAL TARIFF IS APPROVED, DOES THIS PROJECT SAVE CUSTOMERS MONEY?

A. There is no reason to believe it will. Certainly, NIPSCO did not demonstrate that it will.

Q. IS THERE ANY OTHER REASON CUSTOMERS SHOULD NOT TAKE THE RISK OF THESE PROJECTS??

A. If the economics of these projects are as rosy as NIPSCO represents, then one has to ask why the developers would not proceed with the projects without a PPA commitment from NIPSCO. The growth of renewables is no longer in its infancy, and there is no longer any reason for customers to subsidize their development by taking risk that the developers and their investors are unwilling to take.

Q. ARE YOU FAMILIAR WITH OTHER ATTEMPTS BY UTILITIES TO GET WIND PROJECTS INTO RATE BASE WHEN CAPACITY IS NOT NEEDED?

A. Yes. The situation most analogous is the recent failed attempt by Southwestern Electric Power Company (SWPECO) to obtain a CPCN for its ownership share (70 percent) of the 2000 MW Wind Catcher Project in Oklahoma. The Public Utilities Commission of Texas (PUCT) found the sole issue it had to address was would the project result in the probable lowering of costs to customers as there was no dispute that the capacity was not needed

Q. WHAT DID THE PUCT FIND?

A. SWEPCO represented that its customers would benefit to the tune of $1.5 billion on a NPV basis. The PUCT did not find SWEPCO had met its burden of proof that this was the case and over-ruled the Administrative Law Judge (ALJ) that had supported the project conditioned upon the inclusion of sufficient customer protections. Of note, the ALJ had reduced the benefits of the project by $550 million to remove the costs related to an assumed future carbon tax used in SWEPCO's modeling due to lack of credible evidence to show that a carbon tax is likely in the future.[17] Parties in the SWEPCO case strongly disagreed with other (non-carbon) assumptions in SWEPCO'S analysis. The Office of

[17] PUCT Decision, page 5.

Public Utility Counsel and the Texas Industrial Energy Consumers both argued that rather than a savings, approval of the Wind Catcher would result in a net cost. Notably, the PUCT was well aware of the Production Tax Credit. The full PUCT decision is provided as Attachment 4.

Q. WHAT DO YOU BELIEVE ARE THE TAKEAWAY MESSAGES FROM THE WIND CATCHER RULING WITH RESPECT TO NIPSO?

A. I believe there are several takeaway messages. First, it is the utility's burden to demonstrate customer savings. SWEPCO did not do this and NIPSCO has not either. Reliance on NIPSCO'S 2018 IRP that has not been reviewed, is plagued with analytical problems, and is out-of-date with respect to the load forecast is not sufficient. Second, the existence of the PTC was an insufficient reason to enter into wind commitments for SWEPCO and the same is true for NIPSCO. Customers can be negatively affected by long-term commitments that are out-of-the-money. Third, it is not the industry standard to assume carbon pricing in resource analyses.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes but I reserve the right to update if additional information becomes available.

VERIFICATION

The undersigned, Emily S. Medine, affirms under the penalties of perjury that the answers in the foregoing Testimony in Cause No. 45196 are true to the best of her knowledge, information, and belief.

Emily S. Medine

Emily S. Medine

Attachment ESM-1

RESUME OF
EMILY S. MEDINE

EDUCATIONAL BACKGROUND

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

PROFESSIONAL EXPERIENCE

Current Position

Emily Medine, a Principal, has been with Energy Ventures Analysis since 1987. 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 to regulatory commissions and in arbitration and litigation proceedings. The types of projects in which she is involved are described below:

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).

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.

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.

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 has also provided support to the Department of Justice on coal industry bankruptcies.

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.

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.

Market Strategy Development

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

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 a variety of issues. 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.

STATE OF INDIANA
INDIANA UTILITY REGULATORY COMMISSION

PETITION OF NORTHERN INDIANA PUBLIC SERVICE COMPANY LLC PURSUANT TO IND. CODE §§ 8-1-2-42.7, 8-1-2-61 AND, IND. CODE § 8-1-2.5-6 FOR (1) AUTHORITY TO MODIFY ITS RATES AND CHARGES FOR ELECTRIC UTILITY SERVICE THROUGH A PHASE IN OF RATES; (2) APPROVAL OF NEW SCHEDULES OF RATES AND CHARGES, GENERAL RULES AND REGULATIONS, AND RIDERS; (3) APPROVAL OF REVISED COMMON AND ELECTRIC DEPRECIATION RATES APPLICABLE TO ITS ELECTRIC PLANT IN SERVICE; (4) APPROVAL OF NECESSARY AND APPROPRIATE ACCOUNTING RELIEF; AND (5) APPROVAL OF A NEW SERVICE STRUCTURE FOR INDUSTRIAL RATES.	)	CAUSE NO. 45159

INTERVENOR INDIANA COAL COUNCIL EXHIBIT 1

Prefiled Direct Testimony of

EMILY S. MEDINE

Principal at Energy Ventures Analysis

Sponsoring Attachment ESM-1

TESTIMONY OF
EMILY S. MEDINE
ON BEHALF OF THE INDIANA COAL COUNCIL

Q. PLEASE STATE YOUR NAME, TITLE AND BUSINESS ADDRESS.

A. My name is Emily S. Medine. I am a Principal in the consulting firm of Energy Ventures Analysis, Inc. ("EVA"). My business address is 1901 N. Moore Street, Suite 1200, Arlington, Virginia 22209-1706.

Q. PLEASE DESCRIBE YOUR WORK EXPERIENCE AND EDUCATIONAL BACKGROUND.

A. I have been with EVA, an energy consultancy formed in 1981, since 1986. EVA engages in a variety of energy-related projects for private and public sector clients. Prior to EVA, I worked for Consolidation Coal Company (now "CONSOL Energy"). I received a Bachelor of Arts degree from Clark University in 1976 and a Masters of Public Affairs from the Woodrow Wilson School of Public and International Affairs at Princeton University in 1978.

My resume is provided in Attachment ESM-1.

Q. PLEASE DESCRIBE EVA.

A. EVA is a consulting firm that engages in a variety of projects for private and public sector clients related to energy and environmental issues. EVA also has a subscription business and currently produces about 15 publications, the frequency of which range from weekly to annual. In the energy area, much of our work is related to analysis of the electric utility industry and fuel markets, particularly oil, natural gas and coal. Our clients in these areas include coal, oil and natural gas producers, electric utilities, industrial energy consumers, and gas pipelines and railroads. We also work for public agencies, including the U.S. Department of Justice, the U.S. Department of the Interior, state public utility commissions, as well as intervenors in utility rate proceedings, such as consumer counsels and municipalities. Another group of clients include trade and industry associations. EVA has provided testimony in numerous state public utility commissions. Principals in the firm have also filed testimony in a number of cases in both state and federal courts, as well as before the Federal Energy Regulatory Commission.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING?

A. My testimony is on behalf of the Indiana Coal Council.

Q. PLEASE SUMMARIZE YOUR TESTIMONY?

A. My testimony addresses the following components of NIPSCO's Rate Case:

- **NIPSCO's proposal to allow its largest industrial customers to opt into retail wheeling and reduce or eliminate paying for generation assets built to serve their firm and interruptible loads.**

  I conclude this proposal should be rejected for a variety of reasons:

  1. It will have significant adverse impacts on NIPSCO's other customers. NIPSCO's own analysis shows that without mitigation, residential customers could see a 32.4 percent rate increase. NIPSCO is optimistic in its calculations, which assume a retained load for the large industrial customers of 184 MW. In fact, NIPSCO acknowledges the uncertainty of this assumption, stating that should its assumptions be incorrect, a Phase II true-up may be required.
  2. This proposal was not modeled in NIPSCO's Integrated Resource Plan (IRP) as it was not considered until after the IRP process was underway.
  3. NIPSCO has invested heavily in generation assets to serve the firm and interruptible loads of those large industrial customers. To the extent those customers are allocated less of the cost of those assets, NIPSCO will seek to

recover those stranded costs from other customers (smaller industrial, commercial, and residential).

4. NIPSCO's proposal for retail wheeling for large industrial customers raises statewide policy issues that are inappropriate for resolution in a rate case.

- **NIPSCO's proposed acceleration of depreciation for coal generation units and proposed accounting authority to defer remaining net book value of coal generation assets as regulatory assets after early retirement.**

I conclude these proposals should also be rejected for the following reasons:

1. These proposals are premature because they rely upon an Integrated Resource Plan (IRP) that is still under review and comment.
2. NIPSCO's 2018 IRP modeling suffers from the same fatal flaw as its 2016 modeling—NIPSCO's resource planning is not integrated because it separates (a) the modeling of retirement decisions (using hardwired retirement dates selected by NIPSCO rather than optimized by the model), from (b) replacement portfolio decisions. When doing the modeling of retirement decisions, NIPSCO biased the retirement modeling in favor of early retirement by (i) assigning undue certainty its regulatory concerns, and (ii) assuming lower cost replacement portfolios that it has no intention of acquiring.
3. NIPSCO did not adequately address customer rate impacts that will result from the premature retirements of its remaining coal fleet, accelerated depreciation of the remaining costs and the creation of a regulatory asset.
4. NIPSCO expended no effort in seeking to minimize the costs of the early retirement of the Schahfer units, including but not limited to, actively marketing the units for sale to third-parties.

- **NIPSCO'S proposed discontinuation or Rider 772 – adjustment of charges for environmental cost Recovery Mechanism and Appendix D – Environmental Cost Recovery Mechanism Factor.**

  I conclude that if Rider 772 is discontinued, NIPSCO should be prohibited from including such variable operating costs associated with said environmental projects in the calculation of its offer prices when bidding its units into the market. This is required to constrain a perverse incentive to minimize unit dispatch—and thereby avoid incurring the variable cost—yet recover revenue for that cost in base rates.

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS.

A. **Recommendation #1**: NIPSCO's request to allow its largest industrial customers to opt for retail wheeling should be denied without prejudice so that: (a) NIPSCO can perform truly integrated resource planning in its next IRP and include the migration of large industrial firm and interruptible load to retail wheeling; (b) the Commission can include in its Statewide Analysis and annual reporting to the legislature the issues surrounding potential migration of load to market resources in lieu of local utility resources; (c) the issue of stranded cost allocation can be considered from a policy perspective on a statewide basis.

Recommendation #2: In connection with doing a truly integrated resource plan in its next IRP, NIPSCO should, as part of its retirement planning, solicit and meaningfully consider offers from third parties to purchase those assets in order to properly assess the costs of retirement. NIPSCO should not reject without due economic analysis purchase offers that may include proposals for NIPSCO to purchase capacity or energy from those units.

Recommendation #3: Approval to discontinue Rider 772 should only be provided if NIPSCO agrees to exclude all variable costs currently in Rider 772 and in base rates from offer bids.

Q. DO YOU HAVE ANY CONCERNS ABOUT THE TIMING OF THE RATE CASE?

A. Yes. The simultaneous filing of a proposed IRP and this Rate Case—in which some of the relief requested is premised on that proposed IRP—seems to get the cart in front of the horse. Interested stakeholders have not yet commented on NIPSCO's IRP. The Director's draft report on the IRP is not due until after the closing of pre-filing in the Rate Case. The Director's final report is not due until after the evidentiary record will close in the Rate Case, and those reporting deadlines are subject to enlargement by the Director. Yet, in this Rate Case, NIPSCO asks the Commission to approve accelerated depreciation and accounting treatment on the basis of what is presently only a proposed IRP.[1] In effect, the Commission is being asked to approve an IRP that has not been vetted through the IRP process.

Q. MIGHT THERE BE MATERIAL COMMENTS FROM THE DIRECTOR THAT COULD AFFECT WHETHER ANY ASPECT OF NIPSCO'S PROPOSED IRP SHOULD ACTUALLY BE IMPLEMENTED?

A. Yes. Comments in the Director's Report on the 2016 NIPSCO IRP[2] included the following significant observations:

- *"Given the importance of fuel forecasts in retirement decisions that are a focal point of this IRP, it is surprising that NIPSCO only relied on one projection for fuel prices."*
- *"The use of a single vendor forecast made the lack of a narrative to articulate the rationale for the forecast more problematic."*
- *"The fuel forecast narrative is that the price of natural gas and coal is merely a function of demand. This seems to be an over simplistic explanation to price forecasts for coal and natural gas."*

[1] Response to Sierra Club 1-026.

[2] https://www.in.gov/iurc/files/Director%27s%20IRP%20Report%20-%2011-2-2017%20Final.pdf

- *"NIPSCO should consider technological change in the production of oil, natural gas, and coal."*
- *"(T)he long-term projections of the major commodities lacked explanations, which detracted from the explanatory value of the descriptions."*
- *"One shortcoming of this modeling methodology is a lack of competition among DSM groups of different end-uses, which is highly likely to lead to a portfolio different from modeling all 26 DSM groups simultaneously."*
- *"Moreover, with the increase in peak demand relative to energy use, it would seem there are opportunities for more demand response that were not modeled."*
- *"Based on information provided at the August stakeholder workshop, capital costs for all technologies increase in nominal dollars at the same rate, based on proprietary consultant information. The reasonability of this is questionable considering that some technologies are less mature commercially (e.g., battery storage) than others."*
- *"NIPSCO performed much of the retirement analysis prior to the resource optimization. NIPSCO recognized the modeling limitations and said it intends to procure modeling software that is better able to simultaneously optimize more resources and reduce the reliance on pre-processing important decisions."*

Q. IS IT REASONABLE TO ASSUME THAT GIVEN THE CHANGES NIPSCO HAS MADE TO ITS PROCESS, SIMILAR COMMENTS ARE UNLIKELY?

A. No. While NIPSCO has endeavored to improve its IRP process since its 2016 IRP, the 2018 IRP contains significant problems (some of which the Director commented on in his 2016 report), which will presumably be addressed in the Director's Report and provide the IURC a basis upon which to consider the 2018 IRP.

Q. WAS NIPSCO'S PROPOSAL TO ALLOW ITS LARGEST INDUSTRIAL CUSTOMERS TO ENGAGE IN RETAIL WHEELING MODELED IN THE IRP?

A. No. The sole direct mention of the requested changes to the industrial tariff are found on page 73 of the IRP, which states:

> *"On October 31, 2018, NIPSCO filed an electric rate case that revises its industrial service structure by replacing Rider 775 and Rates 732, 733, and 734 with Rates 830 and 831. The new industrial service structure requires NIPSCO's largest industrial customers on Rate 831 to designate their firm service with the remainder of their service requirements being registered as a MISO LMR which is by definition curtailable. NIPSCO expects an increase in registered LMRs as a result of this new industrial service structure unless those Rate 831 customers utilize other options within the rate to acquire capacity from the MISO annual Planning Resource Auction or through a bilateral agreement between NIPSCO and a third party entered on their behalf. In addition, the large industrial customers will continue to be eligible to participate in MISO's Demand Response Resource program discussed below."*

There is an indirect reference to this issue in a section entitled "Emerging Issues." Under Customer Risk, NIPSCO notes that the loss of one or more of its largest industrial customers "for whatever reason" would result in a significant loss of revenue. NIPSCO concedes that such a loss of load would adversely affect residential, commercial, and smaller industrial customers.[3]

---

[3] IRP page 4.

Q. DID THE IRP EVALUATE THE POSSIBLE LOSS OF INDUSTRIAL FIRM OR INTERRUPTIBLE LOAD UNDER THE PROPOSED RETAIL WHEELING TARIFF?

A. No. The IRP showed no results related to the modeling of the proposed tariff. As shown in the excerpt below, the IRP discussion of the industrial demand forecast does not mention the proposed change in tariffs.

"The Industrial Energy Forecast Model projects the expected level of industrial energy sales in NIPSCO's service territory based upon individual discussions with its largest customers, recent historical industrial sales trends, and regional and global trends for specific industries. Accordingly, the Industrial Energy Forecast Model contains individual forecasts for the major industrial account customers. This year, the loss of energy demand for a major industrial account customer caused NIPSCO's industrial energy sales forecast to trend downwards compared to previous years' forecasts.

Information specific to the creation of the Industrial sales forecast is obtained through outreach by the NIPSCO Major Accounts Departments to each of its 25 individually-forecast industrial customer accounts. NIPSCO discusses individual business, economic, and strategic objectives with each of its individually forecasted industrial accounts. As a part of these discussions, the projected effect of the customer's energy efficiency programs are already taken into account with the forecast provided to NIPSCO. The goals, plans, and concerns outlined in these one-on-one discussions form the basis of a recommendation for each customer's forecast. Other items considered in the development of the forecast include historical consumption, industry trade publications, global market news, business outlook conferences, and routine customer interaction. The resulting forecast incorporates the outlook for steel producers, refiners, industrial gases and a variety of other industrial manufacturing companies in NIPSCO's service territory. Notably, for the development of NIPSCO's industrial energy forecast for the 2018 IRP, this forecast integrates the economic and business projections of *these customers and their consumption related to each of their major industrial production sites in NIPSCO's service territory.*

The industrial sales forecast model also integrates a sales forecast for the remaining industrial accounts (identified as Other Industrial). This portion of the NIPSCO electric forecast is based primarily on historical data (billed volume) from the past six years with greater consideration given to use for the most recent year. Annual and monthly volumes were analyzed – min, max, and averages were calculated. Historical trends, if any, were identified and are reflected in the forecast."[4]

Q. WHAT IS THE BASE ASSUMPTION IN THE IRP FOR INDUSTRIAL DEMAND?

A. According to the IRP, "(a)nnual industrial use remains relative **flat** through the forecast horizon . . . . Overall, industrial annual electricity use . . . increases from 2,031 GWh in 2014 to 2,076 GWh in 2036."[5]

Q. DOESN'T NIPSCO ARGUE THAT THE LOW LOAD CASE IS EXAMINED IN THE CHALLENGED ECONOMY SCENARIO?

A. Yes. NIPSCO argues that, because its Challenged Economy scenario assumed lower load, the scenario essentially modeled the proposed changes to the industrial tariff. However, industrial load was only one of many variables changed in the Challenged Economy scenario. Further, there is a difference between low load as a result of a challenging economy and a deliberate tariff change that results in loss of industrial load and considerably higher costs for non-Large Industrial classes. The correct evaluation would have been to consider the proposed changes to the industrial tariff in the context of the Base scenario.

---

[4] IRP, page 22.

[5] IRP, Appendix B, Page 45.

Q. WAS THERE ANY DISCUSSION IN THE IRP STAKEHOLDER MEETINGS ABOUT THE PROPOSED CHANGE IN THE INDUSTRIAL TARIFF?

A. No. The proposed change in the Industrial Tariff was not discussed. NIPSCO effectively acknowledges this in its response to CAC 2-026. When asked when discussions started with the Large Industrials, NIPSCO states May 2018. When asked whether other stakeholder groups were represented in these discussions, NIPSCO says "No. Given the complexity and the time pressure, NIPSCO needed to work with these specific customers initially to design a novel but viable solution before engaging other stakeholder groups."

Q. WHAT IS THE GENESIS OF THIS REQUEST?

A. NIPSCO in its response to CAC 2-033 states "(t)he timing of the preparation of this rate case was compressed due to the fact that it was caused by the filing by Whiting Clean Energy to begin providing energy to BP, which is one of NIPSCO's largest customers, and only large customer that currently takes 100% firm service."

Q. WHY SHOULD THE REQUESTED CHANGES IN THE INDUSTRIAL TARIFF HAVE BEEN CONSIDERED IN THE IRP?

A. The IRP is performed to evaluate resource needs in the context of load requirements. The load assumptions in the Rate Case do not tie into the load assumptions in the IRP.

Q. DOES THE FAILURE TO MODEL THE PROPOSED RETAIL WHEELING TARIFF PRECLUDE RELIANCE ON THE IRP IN THE RATE CASE?

A. It should. NIPSCO's failure to consider a range in load forecasts that could result from a change in the industrial tariffs is a fatal flaw of the both the IRP and by extension the Rate Case.

Q. WILL CHANGES IN THE PRICE OF POWER CHANGE THE LOAD FORECAST?

A. Yes. Company Witness Efland states that residential use "is estimated using an econometric model incorporating **the residential price of electricity**, appliance saturations and efficiencies as defined in an end use variable supplied by Itron, Inc., real per capita income, HDD and CDD[6]." Similarly, "(c)ommercial usage … is a function of the commercial customer count, employment, **commercial electric price**, HDD and CDD."[7] (emphasis added) Given the expected 11 plus percent increase in rates for every customer class (except the large industrials),[8] demand would presumably be affected.

Q. WHAT ELSE DOES THE IRP SAY WITH RESPECT TO CUSTOMER RISK?

A. The IRP states that "the five largest industrial customers (ArcelorMittal, US Steel, NLMK, BP and Praxair) account for approximately 40% of NIPSCO's energy demand and approximately 1,200 MW of peak load plus reserves when viewed on a non-coincident, individual customer basis. Most of these customers are tied to global steel industry cycles. This concentration of customers tied to a single industry poses significant customer risk. Loss of one or more of these customers, **for whatever reason**, would result in a significant decline in billing revenues." (emphasis added)

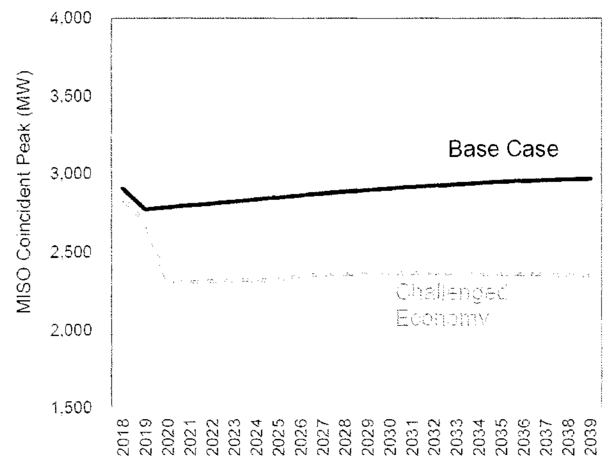
Q. WHAT IS THE LOAD FORECAST IN THE CHALLENGED ECONOMY SCENARIO?

A. The load forecast in the challenged economy scenario is provided in the IRP in Figure 8-31. It is less than 20 percent below the Base Case in the 2020-2025 period.

---

6 HDD – Heating Degree Days; CDD – Cooling Degree Days
7 Verified Direct Testimony of Amy Efland, page 15, lines 1-10.
8 *Id.*

Figure 8-31: NIPSCO Peak Load Growth Forecast in Challenged Economy Scenario



Q. IS THE LOWER LOAD FORECAST CONSISTENT WITH THE PROPOSED INDUSTRIAL TARIFF IN THE RATE CASE?

A. No. While the low load forecast may have reflected NIPSCO's concerns about BP Whiting, that forecast was developed before Tariff 831 was constructed. It is important to note that NIPSCO states that the lower load in the Challenged Economy scenario is in part due to unspecified loss in industrial demand (presumably all industrial demand, not just from the big five) <u>and</u> "lower regional economic growth."

Under the proposed Tariff 831, the big five could reduce their respective industrial loads to a minimum of 10 MW for a total of 50 MW, not the 184 MW assumed in the Rate Case. If the election was at the minimum levels, the reduction in load would be significantly below the level assumed in the Challenged Economy scenario confirming that the proposed Tariff 831 was not considered in the IRP.

Further, the initial customer contract in Tariff 831 is for only five years. During the five-year contract, there is time for these companies to develop alternative strategies to meet their electricity requirements after the contract expires.

Q. WHAT DOES NIPSCO EXPECT AS A RESULT OF THE CHANGE IN THE INDUSTRIAL TARIFF?

A. According to Company Witness Kelly, "NIPSCO expects all five of its largest industrial customers (14 premises) to take service under Rate 831."[9]

Q. WHAT IS THE FORECAST RATE IMPACT OF THE CHANGES IN THE INDUSTRIAL TARIFF?

A. Company Witness Gaske determined residential customers would experience a 32.4 percent increase under the current Allocated Cost of Service. Company Witness Gaske proposes a mitigation plan that would produce an 11.2 percent increase across all customer classes. As shown in Revised Exhibit 18-G from Company Witness Gaske's testimony (reproduced below), the proposed mitigation causes significantly higher rate increases in most other customer classes as the mitigation shifts residential customer costs to other customer classes. [10]

Revised Proposed Mitigation of Rate Increases

		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	
		Current Rate Structure		New Rate Structure	Proposed Revenue	Deficiency	Increase	Revised Deficiency	Increase	Swing (H)-(F)
System Total		1,524,443,776	(90,014,326)	1,434,429,450	1,545,815,189	(111,385,739)				
Residential	Rate 811	476,660,471		476,660,471	630,351,294	(153,690,823)	**32.24%**	(53,465,277)	11.2%	-21%
C&GS Heat Pump	Rate 820	856,616		856,616	984,309	(127,693)	-14.91%	(96,084)	11.2%	**26%**
GS Small	Rate 821	230,447,805		230,447,805	222,562,025	7,885,780	-3.42%	(25,848,507)	11.2%	**15%**
Commi SH	Rate 822	1,135,600		1,135,600	1,041,522	94,078	-8.28%	(127,376)	11.2%	**20%**
GS Medium	Rate 823	170,557,998		170,557,998	157,559,143	12,998,855	-7.62%	(19,130,877)	11.2%	**19%**
GS Large	Rate 824	205,990,902		205,990,902	187,642,508	18,348,394	-8.91%	(23,105,257)	11.2%	**20%**
Metal Melting	Rate 825	6,819,228		6,819,228	6,640,412	178,816	-2.62%	(764,888)	11.2%	**14%**
Off-Peak Serv	Rate 826	91,903,053		91,903,053	110,325,521	(18,422,468)	20.05%	(10,308,434)	11.2%	-9%
Ind. Pwr Serv. - Large	Rate 831	271,041,300	(90,014,326)	181,026,974	151,823,073	29,203,901	-16.13%	29,203,901	-16.1%	0%
Ind. Pwr Serv. - Small	Rate 830	48,089,637		48,089,637	52,665,407	(4,575,770)	9.52%	(5,394,041)	11.2%	**2%**
Muni. Power	Rate 841	3,282,401		3,282,401	3,452,206	(169,805)	5.17%	(368,176)	11.2%	**6%**
INT WW Pumping	Rate 842	104,190		104,190	31,674	72,516	-69.60%	(11,687)	11.2%	**81%**
Railroad	Rate 844	2,205,195		2,205,195	2,101,992	103,203	-4.68%	(247,349)	11.2%	**16%**
Street Lighting	Rate 850	7,405,512		7,405,512	9,752,550	(2,347,038)	31.69%	(830,649)	11.2%	-20%
Traffic Lighting	Rate 855	853,806		853,806	707,231	146,575	-17.17%	(95,768)	11.2%	**28%**
Dusk-to-Dawn	Rate 860	2,452,136		2,452,136	3,165,504	(713,368)	29.09%	(275,049)	11.2%	-18%
Interdepartmental		4,637,924		4,637,924	5,008,816	(370,892)	8.00%	(520,219)	11.2%	**3%**
		1,524,443,774		1,434,429,448	1,545,815,187	(111,385,739)	7.77%	(111,385,737)		

Source: Revised Exhibit 18-6 from Petitioner's Submission of Second Set of Corrections

Customer classes which have higher rates because of mitigation

Q. COULD THE IMPACT OF THE NEW TARIFF BE LARGER?

A. Yes. The new tariffs allow the minimum commitment from the five largest industrial customers to be 10 MW, which is 50 MW in the aggregate. However,

[9] Direct Testimony of Paul S. Kelly, Page 13, Lines 8-9.

[10] Verified Direct Testimony of J. Stephen Gaske

NIPSCO assumes it will retain 184 MW of load from those five largest industrial customers. Also, the proposed tariffs, if approved as is, would allow "multiple premises ... held under common ownership and at the same qualifying service voltage ... to aggregate those loads with interval data recorder (IDR) metering as a single service." Such aggregations are not assumed in the NIPSCO forecast. Also, as previously mentioned, after the first five-year contract, there could be an additional drop in load.

Q. WHAT HAPPENS TO RATES IF THE REVENUE SHORTFALL IS GREATER THAN FORECAST?

A. According to Company Witness Kelly, there will be a Phase 2 Rates True-Up. This will occur if the total amount of Tier 1 firm service elected by the Large Industrials is different from the 184 MW. Final rates will be set to collect the appropriate revenue.

Q. IS THERE A CAP ON WHAT THE ELECTRICITY RATE INCREASE COULD BE?

A. No.

Q. IS THERE AN EQUITY ISSUE RELATED TO THE PROPOSED CHANGES IN THE INDUSTRIAL TARIFFS?

A. Yes. NIPSCO invested in the utility system to meet the needs of all customers including the five largest industrial customers. Rate 831 would enable those customers to significantly reduce their contribution to recovery of those costs, shifting those costs to the other customers.

Q. ARE YOU SYMPATHETIC TO NIPSCO'S CONCERNS THAT IT WILL LOSE THE LARGE INDUSTRIALS IF THIS ALTERNATIVE TARIFF IS NOT PROVIDED?

A. Of course. That being said, NIPSCO has the second highest residential rates in the State of Indiana as shown in the Commission's 2018 Residential Bill Survey Table 2 reproduced below.

Table 2

JURISDICTIONAL ELECTRIC UTILITY RESIDENTIAL CUSTOMER BILLS
[July 1, 2018 Billing]
Overall Ranking for 1,000 kWh of Consumption

		<---------kWh Consumption--------->			
	NAME	500 kWh	1000 kWh	1500 kWh	2000 kWh
1	So. Indiana Gas & Electric Co. D/B/A Vectren	$ 82.74	$ 153.54	$ 224.33	$ 295.12
2	Northern Indiana Public Service Co.	$ 73.21	$ 132.43	$ 191.64	$ 250.85
3	Indiana Michigan Power D/B/A AEP	$ 71.32	$ 132.14	$ 192.95	$ 253.77
4	Duke Energy Indiana	$ 71.95	$ 122.84	$ 168.92	$ 215.00
5	Indianapolis Power & Light Co.	$ 72.27	$ 117.07	$ 161.87	$ 206.67
6	Anderson Municipal	$ 65.44	$ 111.16	$ 156.88	$ 202.61
7	Lebanon Municipal	$ 59.04	$ 108.30	$ 153.77	$ 199.23
8	Crawfordsville Municipal	$ 60.58	$ 106.16	$ 151.74	$ 197.32
9	Kingsford Heights Municipal	$ 53.08	$ 102.65	$ 152.23	$ 201.80
10	Frankfort Municipal	$ 55.06	$ 102.11	$ 149.17	$ 196.23
11	Tipton Municipal	$ 52.66	$ 99.33	$ 143.70	$ 188.07
12	Richmond Municipal	$ 56.74	$ 97.94	$ 139.15	$ 178.62
13	Auburn Municipal	$ 45.91	$ 84.83	$ 123.74	$ 162.65
	Average	$ 63.08	$113.11	$162.31	$211.38
	2017 Survey	$ 63.50	$114.68	$164.76	$214.40
	% Change	-0.67%	-1.37%	-1.48%	-1.41%

A better way to address cost concerns of large industrial customers without negatively impacting other customers might be to focus on controlling other costs. The IURC mandated NIPSCO provide a review of Key Performance Indicators under Cause 44688. The most recent review, filed in June 2018, shows a number of areas in which there is room for considerable improvement.[11] Examples are provided below.

11 file:///C:/Users/emedi/Downloads/44688%20NIPSCO%20ComplianceFilingPMCUpdate%20062918%20(4).pdf

Figure 8. Equivalent availability factor

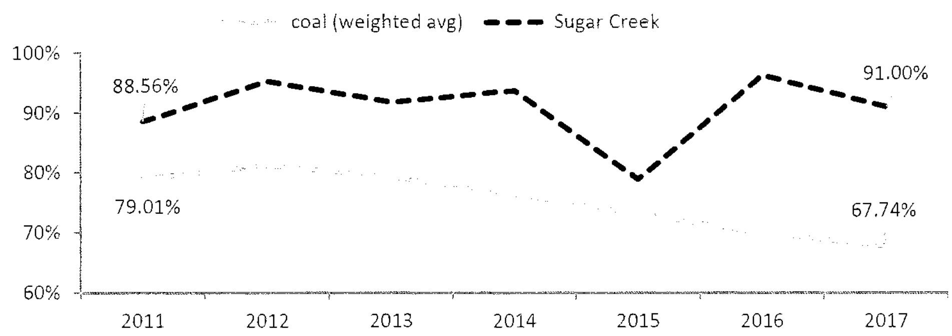


Figure 9. EFOR

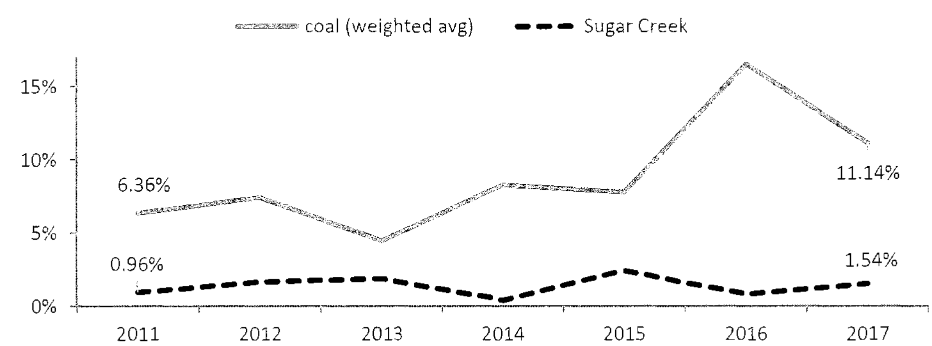


Figure 17. O&M per MWh [3]

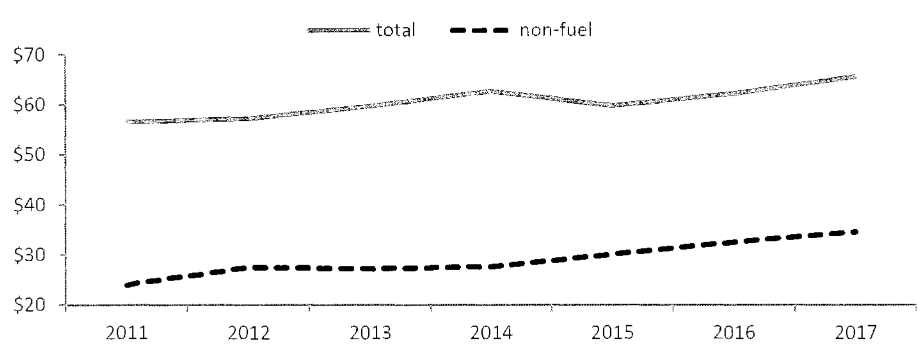


Figure 19. Non-fuel production O&M expense [5]

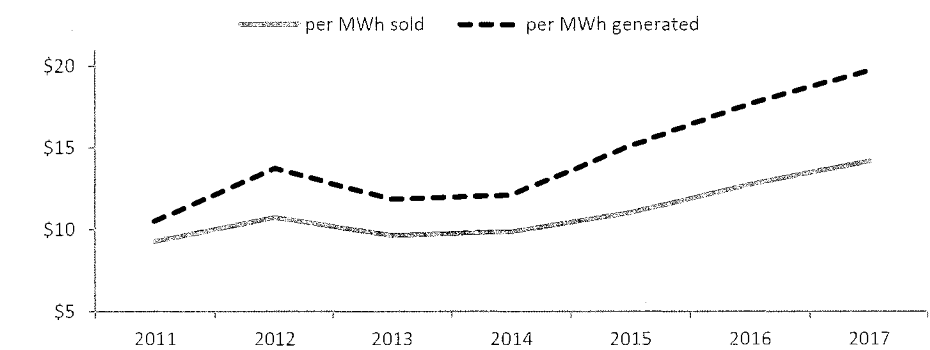
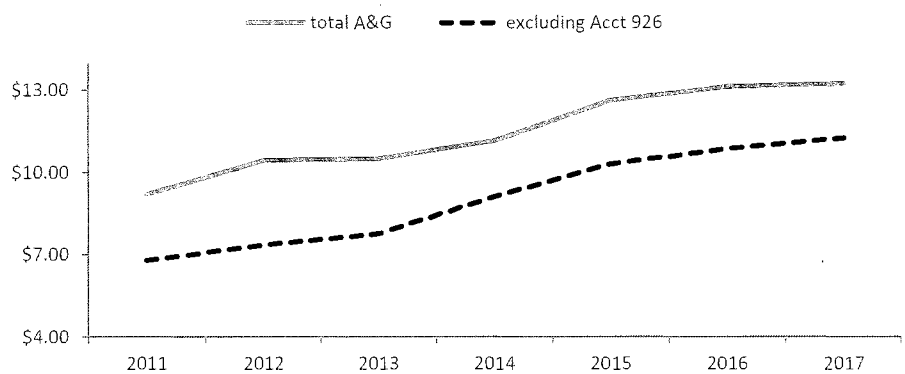


Figure 22. A&G O&M expense per MWh [8]



Q. IS THE RATE CASE THE ONLY FILING NIPSCO HAS MADE THAT IS DEPENDENT UPON THE IRP?

A. No. Subsequent to the filing of the Rate Case, NIPSCO made three additional filings for 802 MW of wind energy pursuant to the IRP. Cause 45194 requests a CPCN to acquire indirectly—through a joint venture—a 102 MW wind farm (Rosewater Project). Cause 45195 seeks approval of a 20-year 400 MW Wind Energy Purchase Agreement with Jordan Creek Wind Farm LLC. Cause 45196 seeks approval of a 300 MW Wind Energy Purchase Agreement with Roaming Bison Wind, LLC.

Q. DO YOU HAVE THE SAME CONCERNS ABOUT THESE CAUSES THAT YOU DO ABOUT THE RATE CASE?

A. Absolutely and for the same reasons. The IRP was not based upon the same load forecast that is anticipated based upon the changes to the Industrial Tariff. Therefore, reliance on the IRP as justification for the wind projects at the same time the Rate Case is pending is not appropriate. Even if that were not the case, the reliance of the wind projects on the IRP is more than problematic given the concerns about the IRP discussed below and by ICC and ICARE Witness Griffey, by Peabody Witness Nasi, and ICC Witness Scott. As discussed below, the IRP suffered from many flaws that make reliance on its conclusions inappropriate. The three new causes further add to NIPSCO's incoherent process, which has focused almost exclusively upon improving its earnings with little regard for rate impacts on all customer classes except the largest industrial customers.

Q. WHAT CONCERNS DO YOU HAVE WITH THE IRP?

A. I have multiple concerns with the IRP, which will be further elaborated upon in my comments submitted in the IRP proceeding. The comments provided here address the cross-over issues in the Rate Case.

Q. WHAT ARE THE CROSS-OVER ISSUES?

A. They are as follows:

- The construction of the scenarios in the IRP
- The commodity price assumptions, particularly for coal and carbon
- Regulatory assumptions
- The retirement analysis
- The all source request for proposal (RFP), particularly how a bid to purchase Schahfer 17/18 was not properly considered
- The lack of consideration of customer rate impacts
- Failure to consider ways to minimize stranded costs

Q. PLEASE DESCRIBE YOUR CONCERNS ABOUT THE CONSTRUCTION OF THE SCENARIOS IN THE IRP?

A. NIPSCO developed four scenarios for its IRP. These scenarios are laid out by NIPSCO as follows:

Scenario Theme	NIPSCO Load	CO_2 Price	Natural Gas Price	[illegible]	Power Price	[illegible]	[illegible]
Base	Base	Base	Base	Base	Base	Base	Base
Aggressive Environmental Regulation	Base	**High**	**High**	**Low**	**High**	**Low** renew./ sto.	**High**
Challenged Economy	**Low**	**Low**	**Low**	**High**	**Low**	Base	Base
Booming Economy & Abundant Natural Gas	**High**	Base	**Low**	**Low**	**Low**	Base	Base

The problem with these scenarios is that they are not properly evaluating the likely ranges of outcomes the IURC should see before making any decisions because of the combinations of critical assumptions. For example, the Challenged Economy Scenario assumes slow economic growth with zero carbon pricing. NIPSCO was specifically asked why this was done when the two are unrelated. NIPSCO agreed the comment was fair (which can only be interpreted that NIPSCO agreed the two are unrelated) and that it was done essentially because there would be too many possible scenarios if all variations were considered. NIPSCO acknowledged that the Challenged Economy is "not the only way a no carbon scenario could play out," but it was an acceptable approach because it would help "bracket the range of future states-of-the-world."[12]

[12] IRP, Appendix A, Page 484.

Q DID NIPSCO'S DECISION TO RUN A NO CARBON SCENARIO IN ONLY THE CHALLENGED ECONOMY SCENARIO HELP BRACKET THE RANGE OF FUTURE OUTCOMES?

A No, it did not help bracket the range of future outcomes. By not considering a zero-carbon price scenario in the Base scenario, NIPSCO—whether deliberately or not—has weighted the scale against coal, which is analytically problematic given that NIPSCO acknowledges that Affordable Clean Energy Rule (ACE), which would replace the Clean Power Plan,[13] would not create a carbon market.

Q DO YOU HAVE ANY CONCERNS REGARDING HOW NIPSCO RAN FUEL PRICE COMBINATIONS IN THE DIFFERENT SCENARIOS?

A Yes, the fuel price combinations for the different scenarios are problematic. The Challenged Economy scenario assumes a high coal price for reasons that were not properly explained, at the same time showing low natural gas prices. This particular combination is reminiscent of the no carbon scenario utilized by NIPSCO in its 2016 IRP, where it discounted natural gas prices when the carbon price was zero but did not discount the coal price, thereby preserving the advantage gas realizes under a carbon tax.

I have the same criticism of this scenario construction that I did with respect to the 2016 IRP. NIPSCO ignores the scenario of low coal prices and high natural gas prices, which seems more likely given the strong export demand growth for natural gas through both liquid natural gas exports and pipeline shipments to Mexico, and is consistent with historic market conditions. NIPSCO is making a billion-dollar, irreversible retirement decision, without considering this scenario. A stochastic analysis of NIPSCO's Challenged Economy scenario does not remedy this flaw. Rather NIPSCO should include all realistic scenarios in its analysis.

---

[13] See more detailed discussion of ACE below.

Q DO YOU HAVE ANY CONCERNS REGARDING HOW NIPSCO MODELED ENVIRONMENTAL REGULATIONS?

A Yes. Despite the acknowledged uncertainty of environmental regulations, NIPSCO considered no scenario in which the compliance obligations for a number of regulations were reduced, eliminated or delayed. Three of the four scenarios contained the same regulatory assumptions and the fourth scenario assumed stronger environmental requirements. The testimony of Peabody Witness Nasi reviews the uncertainties associated with many of these regulations.

Q. PLEASE DESCRIBE YOUR CONCERNS ABOUT THE COAL PRICE ASSUMPTIONS.

A. NIPSCO's assumptions regarding delivered coal prices in the IRP are problematic. It had been clear throughout 2018 that both coal producers and railroads were aggressively pursuing business in order to assist with the viability of coal plants moving forward. As a result, I believed there was a disconnect between the coal prices NIPSCO was assuming in the IRP and the current state of the market. NIPSCO confirmed my suspicion in its response to ICC Data Request 1-029, which asked for the delivered coal prices assumed for 2019 in the IRP versus currently expected coal prices. The results summarized below show differences ranging from \$1.42 to \$3.68 per ton which would have affected dispatch and scenario valuation. These differences are significant given the potential demand from the Schahfer and Michigan City units.

Exhibit ESM-
2019 Delivered Coal Prices in IRP versus Expected

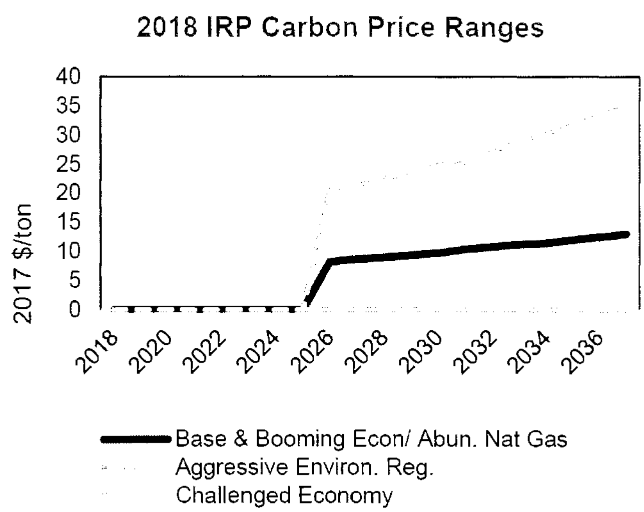
Plant		$/MMBtu	$/Ton
Michigan City 12	IRP	[redacted]	[redacted]
	Expected	[redacted]	[redacted]
	Difference	[redacted]	[redacted]
Schachfer 14	IRP	[redacted]	[redacted]
	Expected	[redacted]	[redacted]
	Difference	[redacted]	[redacted]
Schachfer 15	IRP	[redacted]	[redacted]
	Expected	[redacted]	[redacted]
	Difference	[redacted]	[redacted]
Schahfer 17/18	IRP	[redacted]	[redacted]
	Expected	[redacted]	[redacted]
	Difference	[redacted]	[redacted]

Source: Derived from Confidential Response to ICC Data Request 2-029

Q. WHAT DID NIPSCO ASSUME REGARDING CARBON?

A. NIPSCO assumed the three carbon price scenarios shown in IRP Figure 7-1 provided below.

Figure 7-1: 2018 IRP Carbon Price Ranges



The base carbon pricing scenario assumes a new federal rule or legislative action effective in 2026. The base scenario is used in both the Base and Booming Economy scenarios. A higher priced scenario is assumed in the Aggressive Environmental Regulation scenario. The third scenario, called the Challenged Economy scenario, assumes no carbon pricing.

Q PLEASE ADDRESS YOUR CONCERNS REGARDING THE CARBON PRICES ASSUMED BY NIPSCO.

A There are many issues related to the carbon prices assumed by NIPSCO. NIPSCO acknowledges the ACE rule has been proposed. In the IRP itself, NIPSCO acknowledges ACE does not establish a trading protocol, which means it would not establish a price for carbon.[14] Yet NIPSCO does not consider a zero-carbon price in any scenario but the Challenged Economy scenario when clearly it should have been the primary assumption in the Base scenario. Further, even if carbon pricing is imposed, it would be virtually impossible for a new rule to be developed, proposed, finalized and implemented by 2026, making a 2026 start date more than unlikely.

Q. WHAT ARE YOUR CONCERNS ABOUT THE REGULATORY ASSUMPTIONS?

A. I am concerned that NIPSCO did not properly evaluate certain environmental rules currently or prospectively affecting future related costs. My testimony addresses concerns regarding ACE. I also refer you to Peabody Witness Nasi's testimony, which discusses concerns relating to Coal Combustion Residuals (CCR), Effluent Limitation Guidelines (ELG), Mercury and Air Toxics (MATS), and Cross-State Air Pollution Rule (CSAPR).

[14] IRP, page 131.

Q. WHAT ARE YOUR CONCERNS ABOUT ACE?

A. As I said earlier, NIPSCO's modeling supporting its retirement decision assumed carbon pricing in its Base scenario and two of its other three scenarios starting in 2026. The reasonableness of that assumption seems highly questionable.

Q. WHY DO YOU QUESTION THAT ASSUMPTION?

A. The Clean Power Plan (CPP) promulgated by the U.S. Environmental Protection Agency (EPA) under the prior administration in 2015[15] resulted in significant legal challenges. The full D.C. Circuit heard oral argument *en banc* in September 2016, but did not issue a decision and holds the case in abeyance.[16] During the pendency of that appeal, the United States Supreme Court stayed implementation of the CPP.[17]

In October 2017, EPA proposed to repeal the CPP after completing a thorough review consistent with the Energy Independence Executive Order issued by President Trump in March 2017.[18] In August 2018, EPA proposed the ACE Rule as a replacement for the CPP.[19]

The ACE rule proposes to restore the inside-the-fence interpretation of Best System of Emission Reduction (BSER), makes states responsible for determining appropriate efficiency improvement by source, and eliminates exposure to New Source Review for efficiency improvements. As proposed, ACE allows states to consider the age of a plant in determining what, if any, efficiency improvements should be made. Trading between plants is not allowed although trading between units at individual plants is.

---

15 60 C.F.R. Subpart UUUU; 80 Fed. Reg. 64662.

16 *West Virginia v. EPA*, Case No. 15-1363 (D.C. Cir. Order, Dec. 21, 2018).

17 *West Virginia v. EPA*, 136 S. Ct. 1000 (Feb 9, 2016).

18 https://www.whitehouse.gov/presidential-actions/presidential-executive-order-promoting-energy-independence-economic-growth/

19 83 Fed. Reg. 44746.

Accordingly, the current regulatory environment concerning carbon pricing is highly uncertain. The Energy Information Administration (EIA) does not assume a cost of carbon in its base forecast. Consumers Energy in its June 2018 IRP assumed no carbon regulation in its Business-As-Usual (BAU) case or Emerging Technologies scenario.[20] NIPSCO provided no rationale for assuming carbon pricing would begin in 2026.

For a carbon price to start in 2026, NIPSCO may be assuming the Clean Air Act will be amended to provide for carbon reductions outside of Section 111(d) (which is the section of the Clean Air Act relied upon in the CPP), or that new federal legislation will be enacted which contains a carbon cap and trade program or its equivalent, or that the State of Indiana would impose a carbon program on its own or through a regional alliance.

I believe an amendment to the Clean Air Act is unlikely, given the current administration along with the split control of Congress that will last until at least 2021. Even if the next Congress passed legislation in 2021, it would then have to proceed through regulatory rule making and then likely litigation. For the same reasons, I believe federal legislation containing a cap and trade or some equivalent is unlikely. Under these scenarios, 2026 would be a stretch.

I also believe, given Indiana's political history, it is equally unlikely Indiana would in the near future act at the state level to promulgate its own carbon legislation or regulations, or enter into a regional agreement with other states, such as RGGI, which establishes a carbon market.

As NIPSCO provided no rationale for 2026, the 2026 start date for an assumed carbon regime is not justifiable.

[20] Independent Review of 2018 Integrated Resource Plan, Exhibit 1-36 (Page 7) https://mi-psc.force.com/sfc/servlet.shepherd/version/download/068t000000231ujAAA

Q. WHAT ARE YOUR CONCERNS ABOUT HOW NIPSCO EVALUATED RETIREMENTS?

A. In addition to problematic assumptions regarding commodity prices and regulatory requirements, I believe the methodology employed by NIPSCO was biased to produce the desired results, i.e., the coal plants should be prematurely retired. As ICARE and ICC Witness Griffey explains in his testimony, many of the issues with NIPSCO's analysis are tied to the separation of the retirement analysis from the resource optimization. This problem was specifically raised in the Director's Report on the 2016 IRPs. NIPSCO acknowledged this problem and committed to address it.[21] However, the problem remains in NIPSCO's 2018 IRP. The result of this non-integrated analysis is that NIPSCO's Preferred Portfolio F is not actually the lowest cost and not the plan NIPSCO should have adopted.

Q. PLEASE EXPLAIN YOUR CONCERNS ABOUT THE ALL SOURCE RFP.

A. NIPSCO decided that the best way for it to determine resource costs was to conduct an all-source RFP as part of the IRP process. The RFP attracted multiple bids for solar, wind, natural gas, and even coal. Of the coal options, one party proposed to buy Schahfer 17 and 18. The testimony of ICC Witness Scott summarizes this failed effort. The effort failed for several reasons, including the failure of NIPSCO to provide the information that a potential buyer would need to evaluate a purchase and NIPSCO's refusal even to enter into discussions for a purchase power agreement on any terms following sale of the station. Without even discussing what the potential buyer had in mind, NIPSCO could not know whether it was economic or non-economic.

21 https://www.in.gov/iurc/files/Director%27s%20IRP%20Report%20-%2011-2-2017%20Final.pdf, page 25.

Q. ARE THERE ADDITIONAL REASONS WHY NIPSCO SHOULD HAVE CONSIDERED A POWER PURCHASE AGREEMENT (PPA) FOR SCHAHFER 17/18?

A. Yes. NIPSCO has an obligation to mitigate stranded cost recovery. NIPSCO is asking to be compensated for costs, including a return of and on the undepreciated capital, for the assets it is proposing to strand. To qualify for this cost NIPSCO should be required to demonstrate both that an early retirement is economic and that it is the lowest cost option for the utility to pursue. While we dispute that the early retirement is economic, if a third party were willing to assume any decommissioning costs, that would reduce ratepayer exposure. I believe in order for NIPSCO to be eligible for recovery of the stranded costs it must demonstrate that it has minimized costs by considering a sale even if it requires entering into a PPA for a period of time. To dismiss a PPA period is inconsistent with NIPSCO's due diligence obligations.

Q. DID THE IRP CONSIDER ALL RATEPAYER IMPACTS?

A. No. The costs to customers in the IRP are based only on the Net Present Value (NPV" as shown below.[22]

Figure 9-5: Cost to Customer across All Scenarios – Retirement Portfolios (30-year NPVRR – millions of $)

Retirement Portfolio	Base	Aggressive Env Reg	Challenged Econ	Booming Econ/ Abund Nat Gas
1	15.400	17.557	11.598	15.030
2	12.911	14.271	9.642	12.758
3	12.455	13.304	9.479	12.291
4	12.336	13.184	9.359	12.171
5	11.454	12.298	8.474	11.245
6	11.343	12.084	8.428	11.125
7	11.187	11.820	8.351	11.023
8	10.974	11.688	8.079	10.745

[22] IRP, Page 151.

Q. WHAT IS THE PROBLEM BY LOOKING AT ONLY NPVs?

A. The NPV assumes levelized recovery of return of and on a capital investment (similar to the way residential mortgages recover the loan and interest in equal payments). But that is not the way return of and on capital investments are recovered in ratemaking. In ratemaking, recovery is front-end loaded meaning that customers pay most in the first year, and the least in the last year, with a gradual decline (assuming no change in rate of return) in between.

Therefore, the NPV for high capital cost scenarios, such as what occurs when there is accelerated recovery of stranded costs does not capture the rate impact on customers. Said differently, the estimated 32.4 percent increase on residential customers assuming no mitigation (or even the 11.2 percent with mitigation) makes immaterial any small difference in NPVs over a 20-year period.

Q. DOES NIPSCO HAVE ANY OBLIGATION TO MINIMIZE THE COSTS ASSOCIATED WITH THE EARLY RETIREMENT OF ITS COAL FLEET?

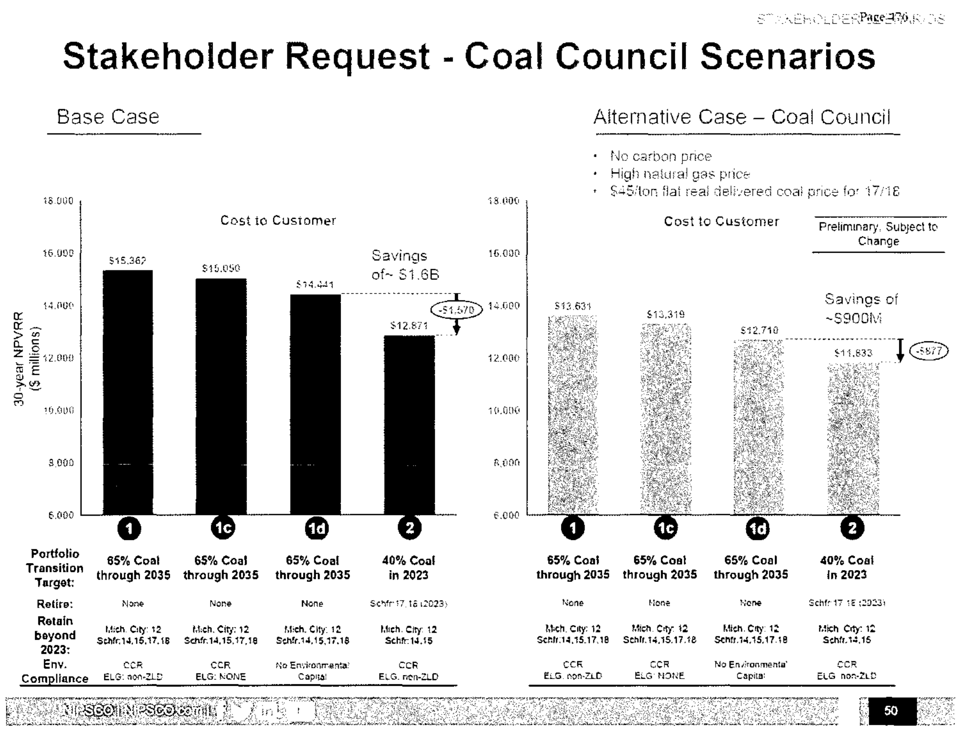
A. Every utility should be required to minimize the costs associated with the early retirements of any plant. Utility ratemaking is supposed to be a proxy for what customers would pay if the utility service were offered in a competitive market. Certainly, a competitive company would need to minimize the extent to which its prices reflect recovery of past investments that are demonstrated to be no longer economic. For NIPSCO, the stranded costs it seeks to recover from customers are significant and include sums that NIPSCO only recently requested and received approval to spend.

Q. PLEASE EXPLAIN WHAT STRATEGIES NIPSCO SHOULD EMPLOY?

A. NIPSCO should recognize that the longer these units stay on line, the lower the rate shock associated with their early retirement will be. In other words, their efforts should be less focused on resource replacement and more focused on cost-effective strategies to extend life. In the alternative, NIPSCO should actively be marketing this capacity to third parties. The marketing efforts should be conducted by an independent third party, most likely an investment banker, that has appropriate capabilities and experience. The sales efforts should be open to an off-take agreement, i.e., a PPA, that would support a purchase for a limited time.

Q. DID NIPSCO RUN ANY SCENARIOS AT THE REQUEST OF ICC?

A. Yes. ICC requested scenarios be run with different commodity price assumptions. The scenarios, which assumed no carbon price, high natural gas prices, and a coal price that is more consistent with the current market, considered alternate regulatory and retirement assumptions. The results NIPSCO produced are shown below.



Q. WHAT DID ICC CONCLUDE FROM THIS ANALYSIS?

A. ICC concluded that the changes in assumptions had significant impacts on the NPV compared to the Base, which warranted a reconsideration of the retirement analysis consistent with the findings of ICARE and ICC Witness Griffey. Further, the results would likely be different if (i) the retirement dates were not artificially constrained to three specific years, (ii) the CCR costs did not include the remediation required whether these plants stayed on line or were retired, and (iii) ELG compliance was not required by 2023.

Q. DO YOU HAVE ANY ISSUES WITH THE ELIMINATION OF THE TARIFF 772?

A. NIPSCO is proposing that Rider 772 which is an adjustment for Environmental Cost Recovery Mechanism (ECRM) be eliminated and the costs be included in base rates. To the extent that associated variable operating costs are included in Rider 772, it is desirable the IURC make clear that any of the variable operating costs recovered in base rates not be included in NIPSCO's bid prices into MISO.

Q. WHY IS THIS DESIRABLE?

A. To the extent that variable operating costs are recovered in base rates, the offer prices should not reflect them given the competitive power market. If the utility is recovering these costs in base rates, and the units are not being dispatched (and therefore the variable costs are not being incurred), the inclusion of such costs in base rates becomes a source of earnings for the utility. That, presumably, was not the intent of including those costs in base rates.

Q. ARE YOU RECOMMENDING THIS FOR ALL VARIABLE COSTS THAT ARE INCLUDED BASE RATES?

A. Yes. NIPSCO acknowledged in response to ICC 6-001 that reagent costs, fuel handling costs and emission allowance costs are included in the rate base. In order to continue to recover these costs in base rates, NIPSCO should not be allowed to include these costs in calculation their offer prices.

Q. DID NIPSCO INDICATE WHETHER IT WAS IN FACT GENERATING EARNINGS AS A RESULT OF THE AMOUNTS INCLUDED IN BASE RATES EXCEEDING ACTUAL COSTS

A. NIPSCO indicated in response to ICC 6-001 that as a result of a settlement in the last rate case there were "no specific line item related to reagent, fuel handling and emission allowance costs," which precluded NIPSCO from answering the question.

Q. ARE YOU RECOMMENDING THAT IF THERE IS A SETTLEMENT IN THIS CASE, THERE SHOULD BE A SPECIFIC LINE ITEM FOR THE VARIABLE COSTS INCLUDED IN BASE RATES?

A. Yes.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, subject to updating if additional information becomes available.

Attachment ESM-1

RESUME OF
EMILY S. MEDINE

EDUCATIONAL BACKGROUND

M.P.A. Woodrow Wilson School of Public and International Affairs, Princeton University, 1978

B.A. Geography, Clark University, 1976 (magna cum laude, Phi Beta Kappa)

PROFESSIONAL EXPERIENCE

Current Position

Emily Medine, a Principal, has been with Energy Ventures Analysis since 1987. 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 to regulatory commissions and in arbitration and litigation proceedings. The types of projects in which she is involved are described below:

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).

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.

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.

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 has also provided support to the Department of Justice on coal industry bankruptcies.

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.

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.

Market Strategy Development

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

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 a variety of issues. 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.

VERIFICATION

The undersigned, Emily S. Medine, affirms under the penalties of perjury that the answers in the foregoing Testimony in Cause No. 45159 are true to the best of her knowledge, information, and belief.

Emily S. Medine

Emily S. Medine

INDIANA COAL COUNCIL'S COMMENTS ON
NIPSCO 2016 INTEGRATED RESOURCE PLAN

The Indiana Coal Council (ICC) conducted a review of the Integrated Resource Plan (IRP) that Northern Indiana Public Service Company (NIPSCO) prepared and submitted to the Indiana Utility Regulatory Commission (IURC) on October 31, 2018.

Contemporaneous with this IRP process, NIPSCO is litigating a general rates case in Cause No. 45159. The ICC intervened in that case, and is represented in the rate case by separate counsel. These comments are not intended to be, and should not be considered, an ex parte communication with the Commission regarding the merits of the rate case. Reference within these comments to the rate case or to evidence prefiled in the rate case is for informational purposes related to the IRP only. To the extent that the ICC wishes to use these comments to advocate its position in the rate case, ICC reserves its option to offer these comments as evidence in the rate case or to request that the Commission take administrative notice of these comments in the rate case.

A. INTRODUCTION AND SUMMARY OF CONCLUSIONS.

The IURC website states:

> Jurisdictional electric utilities are required to submit Integrated Resource Plans (IRPs) **every three years** according to Indiana Code § 8-1-8.5-3(e)(2). The IRPs are subject to a rigorous stakeholder process. **IRPs describe how the utility plans to deliver safe, reliable, and efficient electricity at just and reasonable rates**. Further, these plans must be in the public interest and consistent with state energy and environmental policies. Each utility's IRP explains how it will use existing and future resources to meet customer demand. **When selecting these resources, the utility must consider a broad range of potential future conditions and variables and select a combination that would provide reliable service in an efficient and cost-effective manner.**"[1]

As discussed further below, the ICC's comments on NIPSCO's IRP reach the following conclusions.

1. The NIPSCO IRP is obsolete and not relevant for decision-making purposes, and because NIPSCO filed this IRP one year in advance of the three-year statutory requirement, there is no statutory requirement for this submission until late 2019.

On October 31, 2018, the same day that it filed this IRP, NIPSCO filed a base rates case (Cause 45159), which relies on the IRP and requests among other relief the approval of a new tariff for the Large Industrial customers in NIPSCO's service territory. The load forecast, which is an underlying foundation for the IRP, will radically change if the IURC approves the new large industrial rate structure proposed in the Rate Case. As a result, the load forecast in the IRP is no longer relevant and should not be the basis of any subsequent decisions. The IRP should be withdrawn, corrected, and resubmitted.

2. NIPSCO failed to consider rate impacts despite the IURC's requirement that IRPs describe how the utility plans to deliver safe, reliable, and efficient electricity at just and reasonable rates.

NIPSCO describes in Section 11 (Compliance with Proposed Rule) that "[a] discussion of how the utility's resource planning objectives, such as cost effectiveness, rate impacts, risks and uncertainty, were balanced in selecting its preferred resource plan" (p. 201). The corresponding

[1] Available at https://www.in.gov/iurc/2630.htm (last visited 02/28/19) (emphasis added).

index table points to Section 9 and 9.2.3.[2] As it turns out, there is no discussion of rate impacts in either section. Rather NIPSCO uses a 30-year net present value (NPV) of revenue requirements as a proxy for rate impacts. While a NPV of revenue requirements may be a consideration in evaluating alternative portfolios, it is absolutely not a determination of rate impacts over the review period, or most importantly the next five to 10 years. As discussed in NIPSCO's Rate Case, the accelerated retirements of the coal plants combined with the requested change in the Large Industrial tariff would increase Residential Customer bills by 32 percent without mitigation.[3] NIPSCO makes no mention in the IRP of the rate shock that could occur as a result of the Preferred Plan. NIPSCO should prepare an annual rate analysis for residential customers under all scenarios as part of the IRP.

3. NIPSCO's IRP is biased against continued operations of the remaining coal plants calling into question its conclusions.

The bias is reflected in the construction of the scenarios, the assumptions, the all-source RFP evaluation, the modelling, and the analysis of results. Further, NIPSCO failed to consider the impact of potential changes to its Large Industrial tariffs despite the fact that such changes were being contemplated at the same time the IRP was being developed. NIPSCO failed "to consider a broad range of potential future conditions and variables and select a combination that would provide reliable service in an efficient and cost-effective manner" by demonstrably biasing its analysis in favor of a particular outcome. NIPSCO should revise its IRP to eliminate these biases.

4. NIPSemCO was indifferent to considering a path that would have mitigated rate shock on customers by determining what could be done to maintain existing coal capacity as long as possible.

NIPSCO made no attempt to consider creative alternatives for maintaining its coal fleet to allow an extended period during which the plants could be depreciated while in use. NIPSCO ignored a specific offer to purchase two of its coal units. NIPSCO failed to engage an investment banker to sell the coal plants in an orderly process. NIPSCO should be required to demonstrate a good faith effort to minimize customer impacts as measured by residential customer rates, including a reconsideration of coal plant closure dates and the sale of its coal fleet

[2] The second reference is actually ".2.3". ICC assumes this is simply a typographical omission as section 9.2.3 would appear to be the appropriate reference. To the extent that the reference is to Section 2.3, the argument still holds.
[3] Gaske Direct Testimony, Cause No. 45159, pp. 42-43, and Attachment 18-G.

B. COMMENTS AND ANALYSIS.

1. THE IRP SUBMITTED ON OCTOBER 31, 2019 IS OBSOLETE AND NOT RELEVANT FOR DECISION-MAKING PURPOSES. AS NIPSCO FILED THIS IRP ONE YEAR IN ADVANCE OF THE THREE-YEAR STATUTORY REQUIREMENT, THERE IS NO STATUTORY REQUIREMENT FOR THIS SUBMISSION UNTIL LATE 2019.

RECOMMENDATION #1

THE IRP SHOULD BE WITHDRAWN, CORRECTED, AND RESUBMITTED.

1.1 On October 31, 2018, NIPSCO filed a base rates case in Cause 45159 which among other things requests a material revision to its Large Industrial tariff. The revision will allow NIPSCO's largest industrial customers to opt into retail wheeling and reduce or eliminate paying for generation assets built to serve their firm and interruptible loads.

1.2 The IRP does not consider the impact of the proposed change to the Large Industrial tariff. The only explicit mention of the tariff is the following paragraph on page 73 of the IRP.

> On October 31, 2018, NIPSCO filed an electric rate case that revises its industrial service structure by replacing Rider 775 and Rates 732, 733, and 734 with Rates 830 and 831. The new industrial service structure requires NIPSCO's largest industrial customers on Rate 831 to designate their firm service with the remainder of their service requirements being registered as a MISO LMR which is by definition curtailable. NIPSCO expects an increase in registered LMRs as a result of this new industrial service structure unless those Rate 831 customers utilize other options within the rate to acquire capacity from the MISO annual Planning Resource Auction or through a bilateral agreement between NIPSCO and a third party entered on their behalf. In addition, the large industrial customers will continue to be eligible to participate in MISO's Demand Response Resource program discussed below.

1.3 In a section on Emerging Issues, NIPSCO notes that the loss of one or more of its largest industrial customers "for whatever reason" would result in a significant loss of revenue. NIPSCO concedes that such a loss of load would adversely affect residential, commercial, and smaller industrial customers.[4]

1.4 NIPSCO acknowledges in the IRP that:

> [The] five largest industrial customers (ArcelorMittal, US Steel, NLMK, BP and Praxair) account for approximately 40% of NIPSCO's energy demand and approximately 1,200 MW of peak load plus reserves when viewed on a non-coincident, individual customer basis. Most of these customers are tied to global steel industry cycles. This concentration of customers tied to a single industry poses significant customer risk. Loss of one or more of these customers, for whatever reason, would result in a significant decline in billing revenues.[5]

While suggesting the risk to NIPSCO customers was the cyclic nature of the global steel industry, NIPSCO failed to mention that the real risk to other customers was the Large Industrial tariff

[4] NIPSCO 2018 IRP page 4.
[5] *Id.*

NIPSCO was simultaneously negotiating, which would remove a substantial portion load and revenues related to the large industrial customers.

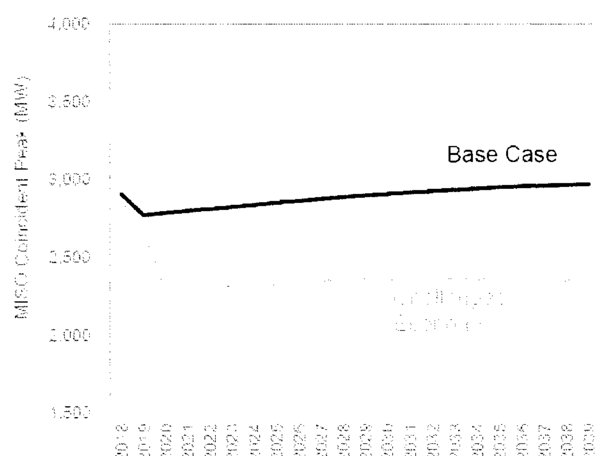
1.5 On February 20, 2019, the IURC approved a settlement between the Petitioners, NIPSCO and the OUCC in Cause No. 45071. The order confirms the change in WCE's status and allows the power to be sold via a private transmission line or through NIPSCO.

1.6 NIPSCO indicated in the Rate Case filing that it expects all five of its largest industrial customers (14 premises) to take service under Rate 831.[6]

1.7 Despite knowing at the time it submitted I s IRP that industrial load could be an issue based on the proposed new rate structure for large industrial customers, NIPSCO chose not to reconsider lower load forecasts in its base IRP assumptions.

1.8 NIPSCO argued that in its Challenged Economy scenario, a lower load forecast was considered. As shown below, there was a lower load forecast in the Challenged Economy scenario.

Figure 8-31: NIPSCO Peak Load Growth Forecast in Challenged Economy Scenario



1.9 If the lower load forecast was the result of the change in the Large Industrial Tariff, it would have been so noted in the description of the scenario. According to NIPSCO, the lower industrial load was due to the Challenged Economy. There is a difference between low load as a result of a challenged economy and a deliberate tariff change that results in loss of industrial load and considerably higher costs for non-Large Industrial classes. In fact, if the challenged economy forecast had considered the reduced Industrial load due to the tariff, it would likely show an even further reduction.

1.10 Given the economic benefit of being excused from participation in NIPSCO's fixed costs, it is reasonable to assume development of self-generation could occur during the initial term causing a further drop in load in 2024, or thereabouts.

[6] Direct Testimony of Paul S. Kelly, Page 13, Lines 8-9.

1.11 There is also the matter of the forecast of the remaining load. As pointed out by NIPSCO, both residential and commercial demand are affected by the price of electricity.[7] If NIPSCO loses revenues from large industrial customers utilizing the new tariff to acquire off-system energy supply, this will likely result in higher electricity prices for NIPSCO's remaining customers. This increase in electricity price would likely result in reduced residential and commercial demand, and thus in a lower overall electricity demand forecast. There is no indication in the IRP that the Challenged Economy incorporated price-related effects of the Large Industrial tariff.

1.12 It is problematic that when NIPSCO decided to proceed with the Rate Case, it did not pause on the submission of the IRP and reconsider the analysis in the context of the considerably diminished load forecast (and higher non-large industrial rates) that is expected to occur with the proposed tariff changes, even if only as an additional scenario. Absent such an analysis, the IRP does not consider the broad range of future conditions as required.

[7] NIPSCO 2018 IRP, pp. 19-20.

2. NIPSCO FAILED TO CONSIDER CUSTOMER RATE IMPACTS DESPITE THE IURC'S REQUIREMENT THAT THE IRPS DESCRIBE HOW THE UTILITY PLANS TO DELIVER SAFE, RELIABLE, AND EFFICIENT ELECTRICITY AT JUST AND REASONABLE RATES. AN NPV COMPARISON IS NOT A PROXY FOR A RATE ANALYSIS.

RECOMMENDATION #3

NIPSCO SHOULD PREPARE AN ANNUAL RATE ANALYSIS FOR RESIDENTIAL CUSTOMERS UNDER ALL SCENARIOS AS PART OF THE IRP.

2.1 NIPSCO failed to consider rate impacts despite the IURC's requirement that the IRPs describe how the utility plans to deliver safe, reliable, and efficient electricity at just and reasonable rates.

2.2 NIPSCO describes in Section 11 of the IRP that a discussion of how its resource planning objectives, such as cost effectiveness, *rate impacts*, risks and uncertainty were balanced in selecting its preferred resources and that discussion is provided in Sections 9.3 and 9.2.3.[8] There is no discussion of rate impacts in either section. Rather, NIPSCO notes in Section 9.2.3 that it measures rate impact through a comparison of NPV's. NIPSCO, in essence, uses the NPV as a proxy for rate impact, whereby a lower NPV equates to a lower rate impact and a higher NPV equates to a higher rate impact.

2.3 This disregards the fact that an NPV analysis assumes a levelized cost of capital, whereas ratemaking factors in the depreciation of capital and the rate impact tends to be higher in the near-term and to reduce gradually over time. In reality, a 30-year NPV, which is the metric NIPSCO used in this IRP,[9] says nothing about a portfolio's rate impact over the next five to 10 years and therefore it is not a proxy for evaluating the rate impact.

2.4 In its rate case, NIPSCO estimates the accelerated retirements of the coal plants combined with the requested change in the Large Industrial tariff could increase residential customer bills by 32 percent without mitigation.[10]

2.5 There is no mention in the IRP of the rate shock that could occur as a result of the Preferred Plan.

2.6 In recognition that a 32 percent increase in residential bills would constitute rate shock, NIPSCO put forth a mitigation plan in the rate case. The mitigation plan summarized below seeks an 11.2 percent across-the-board increase for all customer classes except Large Industrials. In other words, for residential customers to only face an 11.2 percent increase in rates, most other customer classes would face a significantly larger rate than the cost of service study would assign to them.

[8] See fn 3 above.

[9] The 2016 IRP considered 20-year NPV's as the basis for comparison. The NPV was increased in the 2018 IRP without explanation. As discussed in Section 4 below, the increased term served to reduce the NPV of the Preferred Portfolio.

[10] Gaske Direct, Cause No. 45159, p. 42 and Attachment 18-G.

Revised Proposed Mitigation of Rate Increases

		(A) Current Rate Structure	(B)	(C) New Rate Structure	(D) Proposed Revenue	(E) Deficiency	(F) Increase	(G) Revised Deficiency	(H) Increase	Swing (H)-(F)
System Total		1,524,443,776	(90,014,326)	1,434,429,450	1,545,815,189	(111,385,739)				
Residential	Rate 811	476,660,471		476,660,471	630,351,294	(153,690,823)	32.24%	(53,465,277)	11.2%	-21%
C&GS Heat Pump	Rate 820	856,616		856,616	984,309	(127,693)	-14.91%	(96,084)	11.2%	26%
GS Small	Rate 821	230,447,805		230,447,805	222,562,025	7,885,780	-3.42%	(25,848,507)	11.2%	15%
Commi SH	Rate 822	1,135,600		1,135,600	1,041,522	94,078	-8.28%	(127,376)	11.2%	20%
GS Medium	Rate 823	170,557,998		170,557,998	157,559,143	12,998,855	-7.62%	(19,130,877)	11.2%	19%
GS Large	Rate 824	205,990,902		205,990,902	187,642,508	18,348,394	-8.91%	(23,105,257)	11.2%	20%
Metal Melting	Rate 825	6,819,228		6,819,228	6,640,412	178,816	-2.62%	(764,888)	11.2%	14%
Off-Peak Serv	Rate 826	91,903,053		91,903,053	110,325,521	(18,422,468)	20.05%	(10,308,434)	11.2%	-9%
Ind. Pwr Serv. - Large	Rate 831	271,041,300	(90,014,326)	181,026,974	151,823,073	29,203,901	-16.13%	29,203,901	-16.1%	0%
Ind. Pwr Serv. - Small	Rate 830	48,089,637		48,089,637	52,665,407	(4,575,770)	9.52%	(5,394,041)	11.2%	2%
Muni. Power	Rate 841	3,282,401		3,282,401	3,452,206	(169,805)	5.17%	(368,176)	11.2%	6%
INT WW Pumping	Rate 842	104,190		104,190	31,674	72,516	-69.60%	(11,687)	11.2%	81%
Railroad	Rate 844	2,205,195		2,205,195	2,101,992	103,203	-4.68%	(247,349)	11.2%	16%
Street Lighting	Rate 850	7,405,512		7,405,512	9,752,550	(2,347,038)	31.69%	(830,649)	11.2%	-20%
Traffic Lighting	Rate 855	853,806		853,806	707,231	146,575	-17.17%	(95,768)	11.2%	28%
Dusk-to-Dawn	Rate 860	2,452,136		2,452,136	3,165,504	(713,368)	29.09%	(275,049)	11.2%	-18%
Interdepartmental		4,637,924		4,637,924	5,008,816	(370,892)	8.00%	(520,219)	11.2%	3%
		1,524,443,774		1,434,429,448	1,545,815,187	(111,385,739)	7.77%	(111,385,737)		

Source: Revised Exhibit 18-6 from Petitioner's Submission of Second Set of Corrections

Customer classes which have higher rates because of mitigation

2.6 It is worth noting that NIPSCO is not sure that the 11.2 percent increase is adequate to recover costs with the change in the Large Industrial tariff and includes in its proposal the possibility of a true up later in 2019 if it underestimated the increase needed.

2.7 The IURC expects utilities to provide an analysis of rate impacts in their IRPs. NIPSCO did not do so.

2.8 The premature retirement and associated accelerated recovery will likely increase customer rates substantially in the first 10 years of the plan with and without the proposed changes in the Large Industrial tariff. A comparison of annual rate impacts under all scenarios would provide necessary information to the IURC in analyzing the reasonableness of the IRP's recommendations.

3. NIPSCO'S IRP IS BIASED AGAINST CONTINUED OPERATION OF THE REMAINING COAL PLANTS CALLING INTO QUESTION ITS CONCLUSIONS.

RECOMMENDATION #4

NIPSCO SHOULD REVISE ITS IRP TO ELIMINATE THESE BIASES.

3.1 Many aspects of the NIPSCO IRP are biased against continued operation of the remaining coal fleet. The most significant are (1) the construction of the scenarios, (2) the assumptions regarding coal and carbon prices, (3) the evaluation of the all-source RFP results, and (4) the modelling.

3.2 NIPSCO developed four scenarios for its IRP. These scenarios are laid out by NIPSCO as follows:

Scenario Theme	NIPSCO Load	CO_2 Price	Natural Gas Price	Coal Price	Power Price	Capital Costs	Other Enviro. Costs
Base	Base	Base	Base	Base	Base	Base	Base
Aggressive Environmental Regulation	Base	High	High	Low	High	Low renew./ sto.	High
Challenged Economy	Low	Low	Low	High	Low	Base	Base
Booming Economy & Abundant Natural Gas	High	Base	Low	Low	Low	Base	Base

These scenarios do not properly evaluate the likely ranges of outcomes that NIPSCO should have considered before making any decisions because of the combinations of critical assumptions. For example, the Challenged Economy Scenario assumes slow economic growth with zero carbon pricing. NIPSCO was specifically asked why this was done when the two are unrelated. NIPSCO agreed the comment was fair (which can only be interpreted that NIPSCO agreed the two are unrelated) and that it was done essentially because there would be too many possible scenarios if all variations were considered. NIPSCO acknowledged that the Challenged Economy is "not the only way a no carbon scenario could play out, but it was a plausible outcome that helps bracket the range of future states-of-the-world."[11]

3.3 Assuming zero carbon in only the Challenged Economy scenario did not bracket the range of future outcomes. By not considering a zero-carbon price scenario in the Base scenario, NIPSCO—whether deliberately or not—has weighted the scale against coal, which is analytically problematic given that currently there is no carbon market and the Affordable Clean Energy Rule (ACE), which is scheduled to replace the Clean Power Plan (CPP), does not create a carbon market.

3.4 The fuel price combinations for the different scenarios are also weighted against coal. The Challenged Economy scenario assumes a high coal price for reasons that were not properly explained, at the same time showing low natural gas prices. This particular combination is reminiscent of the no carbon scenario utilized by NIPSCO in its 2016 IRP, where it discounted natural gas prices when the carbon price was zero but did not discount the coal price, thereby

[11] IRP, Appendix A, Page 484.

preserving the advantage that natural gas realizes under a carbon tax. NIPSCO considers a low coal/high natural gas price scenario only in the Aggressive Environmental scenario which has high carbon prices and tight environmental requirements. NIPSCO ignores the scenarios that are the most likely to happen, i.e., high natural gas prices and low coals.

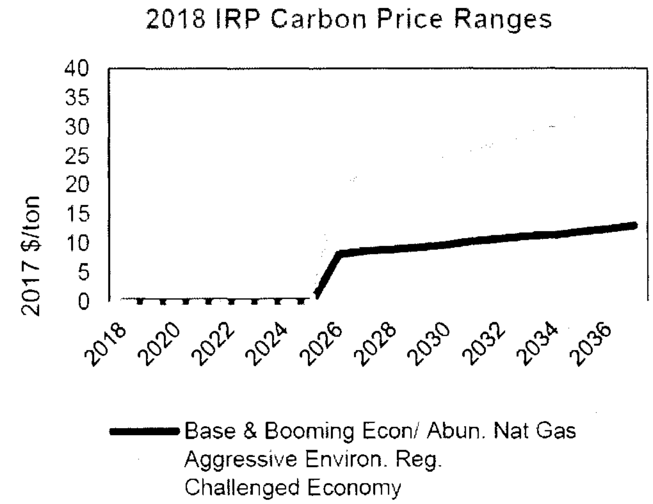
3.4 NIPSCO's assumptions regarding delivered coal prices in the IRP are problematic. It had been clear throughout 2018 that both coal producers and railroads were aggressively pursuing business in order to assist with the viability of coal plants moving forward. As a result, there was a disconnect between the coal prices NIPSCO was assuming in the IRP and the current state of the market.

3.5 NIPSCO confirmed this in its response to ICC Data Request 1-029, which asked for the delivered coal prices assumed for 2019 in the IRP versus currently expected coal prices. The results summarized below show differences ranging from $1.42 to $3.68 per ton which would have affected dispatch and scenario valuation. These differences are significant given the potential demand from the Schahfer and Michigan City units. Fuel prices could be $15 million per year or more lower than what NIPSCO assumed in its analysis.

[redacted]

3.5 NIPSCO assumed the three carbon price scenarios shown in IRP Figure 7-1 provided below.

Figure 7-1: 2018 IRP Carbon Price Ranges



The base carbon pricing scenario assumes a new federal rule or legislative action effective in 2026. The base carbon scenario is used in both the Base and Booming Economy scenarios. A higher priced scenario is assumed in the Aggressive Environmental Regulation scenario. The third scenario, called the Challenged Economy scenario, assumes no carbon pricing.

3.6 There are many issues related to the carbon prices assumed by NIPSCO. The ACE rule has been proposed as a replacement to the CPP. The ACE rule proposes to restore the inside-the-fence interpretation of Best System of Emission Reduction (BSER), which makes states responsible for determining appropriate efficiency improvement by source, and eliminates exposure to New Source Review for efficiency improvements. As proposed, ACE allows states to consider the age of a plant in determining what, if any, efficiency improvements should be made. Trading between plants is not allowed although trading between units at individual plants is.

3.7 ACE does not establish a trading protocol, which means it would not establish a price for carbon. Yet NIPSCO does not consider a zero-carbon price in any scenario but the Challenged Economy scenario.

3.8 The primary assumption in the Base scenario should have been zero cost. This is consistent with how the Energy Information Administration models carbon. This is consistent with how the recently-released Consumers Energy IRP considered carbon. Non-zero carbon forecasts would appropriately be considered as a sensitivity that, as NIPSCO would say, could bracket the results.

3.9 Even in the sensitivities that assumed a carbon cost, a 2026 start year is unlikely and not justified. A review of the CPP shows it was nine years from the start of development (2013) to initial compliance (2022). Full compliance was not scheduled to be completed until 2030. Given the nine year gap from development to initial implementation of the CPP, assuming the next Congress restarted the clock and a rule was developed in 2021, a 2030 implementation would seem to be the earliest. Given the political realities, a later date would seem more likely.

3.10 The CPP was challenged. The full D.C. Circuit heard oral argument *en banc* in September 2016, but did not issue a decision and held the case in abeyance.[12] In February 2016, during the pendency of that appeal, the United States Supreme Court stayed implementation of the CPP.[13] In October 2017, EPA proposed to repeal the CPP after completing a thorough review consistent with the Energy Independence Executive Order issued by President Trump in March 2017.[14] In August 2018, EPA proposed the ACE Rule as a replacement for the CPP.[15]

3.11 Accordingly, the current regulatory environment concerning carbon pricing while uncertain has gained some clarity. The Energy Information Administration (EIA) does not assume a cost of carbon in its base forecast. Consumers Energy in its June 2018 IRP assumed no carbon regulation in its Business-As-Usual (BAU) case or Emerging Technologies scenario.[16] NIPSCO provided an inadequate rationale for assuming carbon pricing.

3.12 Michael Nasi on behalf of Peabody Coal found three problems with NIPSCO's regulatory assumptions regarding Coal Combustion Residuals (CCR) and Effluent Limitation Guidelines (ELG). The problems included assumed regulatory timelines that were too short given currently available extension options and EPA-announced plans to significantly reform these rules; compliance cost assumptions that were too high; and the inclusion of costs that will be incurred regardless of retirement decision.[17]

3.13 Mr. Nasi also found that NIPSCO's assumptions regarding almost $0.5 billion in compliance costs for regulations that have "not yet been proposed" unjustifiable. According to Mr. Nasi, NIPSCO has provided no numerical proof or additional studies for selecting the much more expensive option to include in its IRP. He further notes there is also no basis in the record to explain, let alone justify, NIPSCO's assumptions that additional NOx reductions will be required.

3.14 Mr. Nasi also pointed out that NIPSCO has ignored the potential reduction in compliance costs associated with the recent finding by EPA that the Mercury and Air Toxics Standard (MATS) was not "appropriate and necessary." Mr. Nasi concluded that it is not reasonable for NIPSCO to continue to assume long-term MATS O&M Costs (or savings from their early retirement) for any of these plants given the very real possibility that EPA will withdraw MATS in whole or in part.

3.15 Collectively, NIPSCO assumes a need for well over $1 billion in costs for compliance on a speculative basis. Further, within a relatively short time frame, NIPSCO will have greater clarity on actual requirements and costs.

3.16 It is worth noting that NIPSCO confirms the uncertainty associated with these costs. Kelly Carmichael states in his rate case testimony that cost recovery is not being sought for ELG compliance because the costs and timing are uncertain.[18]

3.17 Despite concerns raised by ICC and others during the IRP stakeholder process, NIPSCO utilized an all source Request for Proposal (RFP) as part of its IRP. NIPSCO indicated the purpose of the RFP was to "fine tune" resource costs. NIPSCO used the same consulting firm for both the IRP

12 *West Virginia v. EPA*, Case No. 15-1363 (D.C. Cir. Order, Dec. 21, 2018).
13 *West Virginia v. EPA*, 136 S. Ct. 1000 (Feb 9, 2016).
14 https://www.whitehouse.gov/presidential-actions/presidential-executive-order-promoting-energy-independence-economic-growth/
15 83 Fed. Reg. 44746.
16 Independent Review of 2018 Integrated Resource Plan, Exhibit 1-36 (Page 7) https://mi-psc.force.com/sfc/servlet.shepherd/version/download/068t000000231ujAAA
17 ICC understands that Peabody Coal and ICARE will be filing comments on the 2018 IRP that mirror or summarize their respective prefiled testimony in the rate case.
18 Direct Testimony of Kelly Carmichael, Cause 45159, Page 13, lines 8-10.

and the RFP. NIPSCO indicated that it could enter into agreements with the low cost bidders from the RFP as part of this process that would be subject only to IURC approval ignoring the time lag between the submission of the IRP and the completion of the review process.

3.18 Among the bids received in the IRP [redacted] It was inappropriate for NIPSCO to decline to explore this offer in its entirety.

3.19 Charles Griffey on behalf of ICARE noted that the RFP evaluation did not consider all of the costs associated with integrating renewables into the NIPSCO system, including congestion costs from remote renewable generation, transmission upgrades required to relieve such congestion, higher ancillary service costs, and degradation in output from its owned wind resources.

3.20 NIPSCO's approach of sequentially determining the retirements and then determining the replacements is problematic. This issue was identified with the 2016 IRP and the Director in his report noted his concern. "NIPSCO performed much of the retirement analysis prior to the resource optimization." The Director related that "NIPSCO recognized the modeling limitations and said it intends to procure modeling software that is better able to simultaneously optimize resources and reduce the reliance on pre-processing important decisions."[19]

3.21 Mr. Griffey states that NIPSCO did not fulfill the spirit of the commitment by continuing to make its retirement decisions separate from its resource decisions. In fact, Mr. Griffey found that NIPSCO's two-step process was actually "a bait and switch" that allowed NIPSCO to justify the retirements with one set of assumptions and then determine resource replacement with a different set of assumptions. He concluded that NIPSCO's 2018 Preferred Portfolio F is not actually the lowest cost and not the plan NIPSCO should have adopted.

3.22 The retirement analysis arbitrarily considered only three retirement dates: 2023, 2028, and 2035, thereby ignoring reasonable alternatives particularly in the context of the uncertain implementation dates for CCR, ELG, and ACE requirements.

3.23 NIPSCO's IRP expanded the 20-year analysis period used in NIPSCO'S 2016 IRP to 30 years without explanation. Given the uncertainty beyond 20 years, 20 years is the appropriate period for planning purposes.

3.24 It appears, based on the text of the 2018 IRP, that NIPSCO also believes that 20 years is the appropriate planning horizon:

"Our 2018 IRP charts a path for how best to meet those needs over the next 20 years."[20]

"Looking 20 years into the future does not come without challenges, so we rely on data driven models to help develop our best estimates."[21]

"NIPSCO's supply strategy for the next 20 years is expected to be . . . ."[22]

19 Final Director's Report for the 2016 Integrated Resource Plans, p. 25.
20 NIPSCO 2018 IRP, p. 2.
21 *Id.*, p. 4.
22 *Id.*, p. 17

> "The long-term strategic plan identifies expected energy and demand needs over a 20-year horizon and recommends a potential resource portfolio to meet those needs."[23]

3.25 All of the commodity price forecasts in the 2018 IRP are for 20 years or through 2040, not for 30 years.[24]

3.36 All of the Aurora runs were performed for a 20-year period.[25] Aurora is the dispatch model that NIPSCO's consultant licenses from Energy Exemplar and uses to determine dispatch and hence the generation mix. Aurora allows for dispatch analyses, subject to user specifications, to 2050.

3.26 NIPSCO did not ask its consultant to rerun the scenarios with Aurora for the 30-year period. Rather, the 20-year period was extended by 10 years through [redacted] The result appears to inflate the NPV advantage for the preferred portfolio.

3.27 A significant share of the NPV advantage for the preferred portfolio over the Portfolio 1 (coal units stay in operation through expected lives) derives from the 10-year term extension. Assuming a 20-year planning period combined with all of the other changes described above, the NPV results would not be dispositive with respect to the preferred portfolio and would have a considerably lower customer rate impact.

---

23 *Id.*, p. 23.

24 *Id.*, Fig. 8-8 (Henry Hub), Fig. 8-11 (Coal), Fig. 8-12 (Carbon), Figs. 8-14 & 8-15 (Power), and Fig. 8-16 (Capacity).

25 NIPSCO's response to ICC 1-003 in Cause No. 45159.

4. NIPSCO WAS INDIFFERENT TO CONSIDERING A PATH THAT WOULD HAVE MITIGATED RATE SHOCK ON CUSTOMERS BY EXPLORING ALL OPTIONS RELATED TO MAINTAINING THE EXISTING COAL FLEET AS LONG AS POSSIBLE.

RECOMMENDATION #5

NIPSCO SHOULD BE REQUIRED TO DEMONSTRATE GOOD FAITH EFFORT TO MINIMIZE CUSTOMER IMPACTS AS MEASURED BY RESIDENTIAL CUSTOMER RATES.

4.1 Starting with its 2016 IRP and continuing through the 2018 IRP, NIPSCO has demonstrated a strong preference for the closure of its remaining coal fleet. This preference has manifested in several ways discussed above but bears repeating.

- The construction of the scenarios was biased. For example, the only scenario with zero carbon pricing was the Challenged Economy Scenario, which also assumes slow economic growth and high coal prices.
- The commodity assumptions with respect to coal and carbon have been shown to disadvantage coal without justification.
- The regulatory assumptions considered the worst cases including almost $0.5 billion for a non-existent regulation and ignored actual and impending regulatory changes.
- Regulatory compliance did not seek least-cost solutions or explore evolving options and strategies.
- The methodology which considered retirement independent of replacement sequentially considered lower cost replacement resources in the retirement decisions and higher cost replacement options after the retirements were "locked in."
- NIPSCO failed to engage with a third party who expressed interest in purchasing two coal units in discussions [redacted] without any basis for dismissing such a consideration.
- NIPSCO failed to determine the impact on customer rates by looking only at the NPV's of the options.
- NIPSCO disguised the impact on customers by extending the NPV analysis period from 20 to 30 years without any additional analysis.

4.2 NIPSCO showed no interest in finding solutions related to its existing coal fleet that would reduce customer impact. Such efforts would have included efforts to reduce operating costs, efforts to increase the dispatch of the coal units, and efforts to identify lower cost regulatory compliance options.

4.3 NIPSCO refused to engage in discussions with a third party that was interested in acquiring two of the coal units [redacted]. By refusing to engage in a discussion about a [redacted], coal was not treated on a level playing field.

4.4 NIPSCO did not engage an investment banker to market the plants. Unlike NIPSCO, an investment banker would be motivated to market the properties given such transactions generally have a success fee component. The investment banker could assist in structuring a PPA to insure value to both sides.

4.5 This failure to pursue the possible sale of the coal plants for continued operation is a concern in other states. For example, a bill was recently passed in the Wyoming Legislature that requires a utility to offer the sale of a coal-fired power plant before the plant can be retired. The bill limits recovery of or earnings on the capital costs of new electric generation to replace coal-fired generation unless the utility made a good-faith effort to sell the facility. The bill also requires the utility to purchase the electricity generated by the purchased coal-fired facility at avoided cost.[26]

[26] Wyoming Senate Enrolled Act No. 74, 65th Legislature, 2019.

ATTACHMENT ESM-4

Control Number: 47461

Item Number: 455

Addendum StartPage: 0

PUC DOCKET NO. 47461
SOAH DOCKET NO. 473-17-5481

2018 AUG 13 AM 10: 30

APPLICATION OF SOUTHWESTERN ELECTRIC POWER COMPANY FOR CERTIFICATE OF CONVENIENCE AND NECESSITY AUTHORIZATION AND RELATED RELIEF FOR THE WIND CATCHER ENERGY CONNECTION PROJECT IN OKLAHOMA	§ § § § § § § §	**PUBLIC UTILITY COMMISSION OF TEXAS**

ORDER

This Order addresses the application of Southwestern Electric Power Company (SWEPCO) for a certificate of convenience and necessity (CCN) to authorize it to acquire, develop, and own a wind generation facility with a nameplate capacity of 2,000 megawatts (MW) and a 765-kilovolt (kV) generation tie-line to transmit electric energy from the Oklahoma Panhandle to eastern Oklahoma (together, the project). SWEPCO proposed to own 70% of the project, with the remaining 30% to be owned by its affiliate, Public Service Company of Oklahoma (PSO). SWEPCO also requested a good-cause exception to 16 Texas Administrative Code (TAC) § 25.236 to allow it to treat the costs associated with the project as a fuel expense and the federal production tax credit as a credit against the fuel expense. In addition, SWEPCO requested Commission approval to defer for ratemaking purposes a portion of the federal production tax credits into a regulatory liability to be credited back to consumers starting 11 years after the project begins operation. Finally, SWEPCO also filed an application under PURA § 14.101 but argued that section does not apply to this proceeding. In the alternative, SWEPCO requested a public interest finding under that section if the Commission were to find that PURA § 14.101 applies.

The Commission referred the application to the State Office of Administrative Hearings (SOAH) and a hearing on the merits was held on February 13 through February 22, 2018. On May 18, 2018, the SOAH administrative law judges (ALJs) issued a proposal for decision (PFD) in which they recommended approval of the application with certain guarantees to protect consumers if the project does not realize the benefits anticipated in the PFD assessment. After exceptions and replies to exceptions were filed by many of the parties, the ALJs issued a letter on July 6, 2018 making changes to some assumptions used in their analysis that reduced the amount

45

of estimated benefits presented in the PFD, but did not change their recommendation to approve the application. The ALJs recommended changes to findings of fact 90, 92, 101, 109, and 123 through 125.

The Commission disagrees with the ALJs' recommendation to approve the application. The Commission finds that SWEPCO did not meet its burden of proof in this proceeding. Based on the evidence admitted in this proceeding, the Commission finds that SWEPCO failed to show that the project will lead to the probable lowering of cost to SWEPCO's consumers and, consequently, that it failed to show that the project is necessary for the service, accommodation, convenience, or safety of the public under PURA § 37.056.[1] Accordingly, the Commission must deny the application and does so for the reasons discussed in this Order. In addition, the Commission adopts only those portions of the PFD as specified in this Order.

I. Discussion

Under PURA § 37.056, the Commission may grant a certificate of convenience and necessity only if the Commission finds it is necessary for the service, accommodation, convenience, or safety of the public. In evaluating whether to grant an application under that section, the Commission must consider certain factors, including the probable lowering of cost to consumers.[2] SWEPCO acknowledged in its application, and all parties in this docket agree, that this project is not needed to meet increased load or address capacity issues and that service is adequate. Instead, SWEPCO stated that it filed this application because it believes this project will provide savings to its consumers.[3] Because the project is located entirely outside of the state of Texas, the ALJs concluded that the Commission should not evaluate the site-specific factors listed in PURA § 37.056, such as community, historical, and aesthetic values.[4] Thus, while the ALJs did address other factors,[5] the main focus of this proceeding and the PFD was a single factor: whether the project would result in the probable lowering of cost to consumers.

[1] Tex. Util. Code Ann. §§ 11.001–58.302 (West 2016 & Supp. 2017), §§ 59.001–66.016 (West 2007 & Supp. 2017 (PURA).

[2] *See* PURA § 37.056(c).

[3] PFD at 2.

[4] *Id.* at 2, 65.

[5] *See* Finding of Fact Nos. 13–18.

The burden of proof in this proceeding resides with SWEPCO, the applicant, to prove that the project is necessary for the service, accommodation, convenience, or safety of the public. SWEPCO calculated the purported benefits of the project, the lowering of cost to consumers, based on certain assumptions. It estimated the likely amount of benefits to consumers over the life of the project to be $1.495 billion on a net-present-value basis.[6]

The ALJs adjusted three of SWEPCO's assumptions[7] and found that the amount of purported benefits was significantly lower than what SWEPCO estimated but still concluded that some benefits were likely to occur.[8] Because of this lower amount of benefits, the ALJs recommended certain protections for consumers, including a guarantee of 100% of the production tax credits that SWEPCO would receive based on the actual output of the facility with an exception for changes in law, a guarantee of a cost cap of 103% of the estimated costs of the project, and a guarantee of a 44.7% net capacity factor without an exception for force majeure or change in law.[9]

Other parties in this case vigorously disagreed with the assumptions used by SWEPCO in its analysis. Using different assumptions, they found that the project would not lead to a probable lowering of cost to consumers and, indeed, could lead to a net cost to consumers. One intervenor, the Office of Public Utility Counsel (OPUC), argued that the net cost could be $912 million,[10] another intervenor, Texas Industrial Energy Consumers (TIEC), argued that the net cost could exceed $1 billion,[11] and yet another intervenor, Cities Advocating Reasonable Deregulation (CARD), argued that the net cost to consumers could be $1.971 billion.[12]

The parties in this case raised many issues in challenging SWEPCO's estimates regarding the costs of the project. SWEPCO's own witness stated that for every 1% of capital-cost overrun, the net present value of the project's benefits would decrease by $30 million.[13] Commission Staff's

[6] PFD at 2, 8.

[7] *Id.* at 8–9, 29–30, 33, 36–37.

[8] *Id.* at 2.

[9] *Id.* at 59-61; ALJs' Exceptions Letter at 2–4 (July 6, 2018).

[10] OPUC's Reply to Exceptions to the Proposal for Decision at 5 (June 25, 2018).

[11] TIEC's Reply to Exceptions to the Proposal for Decision at 4 (June 25, 2018).

[12] CARD's Exceptions to the Proposal for Decision at 13 (June 12, 2018).

[13] Tr. at 1049:14–17 (Pearce Cross) (Feb. 20, 2018).

witness testified that no facility study has been conducted by the Southwest Power Pool (SPP) and without such a study, the full costs of the project are not sufficiently known to provide an adequate cost-benefit analysis.[14] Evidence also showed that because of the length and location of the generation tie-line, difficulty in acquisition of rights-of-way and exposure to weather-related events may occur, which could add delay and additional cost to the project,[15] either of which would lower any projected benefits of the project.

The other parties also raised many issues that cast doubt on the assumptions SWEPCO used to evaluate the economics of the project. A central issue of this case is the forecasted price of natural gas. SWEPCO used an in-house analysis called the *fundamentals forecast*, which was provided to all American Electric Power (AEP) companies in October 2016. The ALJs found SWEPCO's base-case assumption, at a levelized price of $7.35 per million British thermal units (MMBtu), to be too high and based on an out-of-date forecast.[16] Instead, the ALJs used the levelized Energy Information Administration (EIA) 2018 reference forecast of $5.32 per MMBtu.[17] Because a decrease of $1 per MMBtu in gas prices would reduce the estimated base-case savings of the project by approximately $392 million on a net-present-value basis, the ALJs reduced the estimated amount of benefits of the project by $678 million.[18]

Other parties put forth evidence showing that in recent Commission proceedings, lower gas prices were used that are more aligned with the New York Mercantile Exchange (NYMEX) futures pricing, which represents actual transactions between buyers and sellers who put real money at risk in their day-to-day operations.[19] In Docket No. 46936,[20] the Southwestern Public

[14] Direct Testimony of David Smithson, Commission Staff Ex. 3A at 10.

[15] Tr. at 231–233, 669–674 (Weber Cross) (Feb. 13, 2018); Staff Ex.3A at 6 (Smithson Direct); Direct Testimony of Jeffry Pollock, TIEC Ex.1 at 42; TIEC's Initial Brief at 16–17.

[16] PFD at 29.

[17] *Id.* at 29–30; ALJs' Exceptions Letter at 2.

[18] *Id.*

[19] TIEC Ex. 1 at 14 (Pollock Direct).

[20] *Application of Southwestern Public Service Company for Approval of Transactions with ESI Energy, LLC, Invenergy Wind Development North America LLC, to Amend a Certificate of Convenience and Necessity for Wind Generation Projects and Associated Facilities in Hale County, Texas and Roosevelt County, New Mexico and for Related Approvals*, Docket No. 46936, Supplemental Settlement Testimony of David T. Hudson on Behalf of Southwestern Public Service Company (Apr. 19, 2018).

Service Company (SPS), in its low-gas-price forecast, projected a levelized price of natural gas at \$3.55 per MMBtu, and in Docket No. 46416,[21] Entergy Texas, Inc. (ETI) projected \$3.68 per MMBtu.[22] The NYMEX futures price, when trended to 2045, of \$3.58 per MMBtu was also well below SWEPCO's forecast.[23] EIA's lowest gas-price case, at \$4.12 per MMBtu, was also suggested by OPUC because, as noted by the ALJs, it has been the forecast that has more closely tracked the actual prices of natural gas for the last several years.[24] Using either EIA's lowest gas-price case or the SPS's low gas-price forecast, intervenors argued that the net present value of the project's projected benefits would be reduced by over \$1 billion.[25]

Gas-price forecasts were not the only contested factor used in evaluating the economics of the project. The ALJs also reduced the amount of benefits of the project by \$550 million to remove the costs related to an assumed future carbon tax used in SWEPCO's modeling.[26] Other parties strongly criticized this assumption and associated costs, and the ALJs concluded that such costs were not supported by the evidence, stating "there was no credible evidence to show that the imposition of such a carbon tax is likely in the future."[27]

The ALJs also found that approximately 6,000 MW of new wind generation have pending or completed generation interconnection agreements and are likely to be deployed in the SPP footprint, which would decrease the net present value of the project by \$76 million.[28] TIEC presented evidence that the SPP interconnection queue includes an additional 10,000 MW of wind projects in the SPP Facility Study Stage, which is one step away from a generation interconnection agreement, and another 24,000 MW are in the Definitive Interconnection System Impact Study

---

[21] *Application of Entergy Texas, Inc. to Amend its Certificate of Convenience and Necessity to Construct Montgomery County Power Station in Montgomery County*, Docket No. 46416 (Oct. 7, 2016).

[22] TIEC Ex. 1 at 12 (Pollock Direct).

[23] *Id.*

[24] OPUC's Exceptions to the Proposal for Decision at 8 (June 12, 2018); PFD at 28.

[25] *See* TIEC Ex. 1 at 51 (Pollock Direct) (using the SPS low gas case would lead to a reduction of \$1.141 billion in benefits); OPUC's Exceptions at 8 (using EIA lowest gas-price case would lead to a reduction of \$1.266 billion).

[26] PFD at 33.

[27] *Id.*

[28] ALJs' Exceptions Letter at 2–3.

Stage.[29] TIEC advocated for assuming a portion, 14,000 MW, of that interconnection queue will be developed, which would decrease the estimated benefits of the project by $499 million.[30]

Another of SWEPCO's assumptions regarding the benefits of the project challenged by the other parties is the project's assumed net capacity factor. Based on studies performed by independent consulting firms, SWEPCO assumed a 51.1% net capacity factor at a P50 estimate, which means there is a 50% likelihood that the actual output will be greater and a 50% likelihood that the actual output would be less than 51.1%.[31] SWEPCO also acknowledged that each 1% reduction in net capacity factor would lead to a $95.6 million reduction in the net present value of the project benefits.[32] Other parties raised issues with the process used by the consulting firms to reach the 51.1% assumption and concerns about the availability of the generation tie-line, which would affect the actual net capacity factor.[33] Additionally, SWEPCO was not willing to guarantee the full 51.1% net capacity factor, placing the risk of underperformance on the consumers.

SWEPCO's assumption of the future capacity value of the wind facility was also contested. SWEPCO contended that the project will allow it to defer the construction of two natural gas combined-cycle units during the life of the project, and to account for this deferral, it included $269 million in its calculation of project benefits. The ALJs noted that much of the proceeding is based on projections and that SWEPCO's estimate of capacity value was reasonable.[34] Intervenors argued that this amount of capacity value is supported by minimal testimony and is dependent on a number of unknown and speculative factors.[35]

The ALJs also identified, but did not quantify, several issues for the Commission to consider that could affect the benefits of the project. First, the ALJs noted that the contingency percentage in the contract with the wind-facility developer was low, at only 3.2% of the total cost

---

[29] TIEC Ex.1 at 27–28 (Pollock Direct).

[30] TIEC Exceptions at 35.

[31] PFD at 38.

[32] Tr. at 1050–51 (Pearce Cross) (Feb. 20, 2018).

[33] TIEC Ex.1 at 44–45 (Pollock Direct); Commission Staff Ex. 3A at 6–9 (Smithson Direct).

[34] PFD at 45.

[35] Tr. at 1235–1236 (Pollock Direct) (Feb. 21, 2018); PFD at 45.

of the wind facility.[36] Also, the ALJs determined that, as mentioned above, because of the length and location of the generation tie-line, the difficulty in acquiring right-of-way and the exposure to weather-related events may add delay and additional cost to the project.[37] Third, the ALJs noted that SWEPCO's analysis of additional reserve costs due to the project was not reliable or convincing.[38] Fourth, the ALJs stated that the effect on project benefits from additional wind generation may be understated, because SWEPCO's congestion costs, which have an impact on the locational marginal pricing calculation, are likely too high due to a reliance on the natural gas prices in AEP's fundamentals forecast.[39] Fifth, SWEPCO did not offer to guarantee that consumers would receive the full benefits of the production tax credits in the event that a change in law were to occur, and the ALJs noted that the Commission may wish to consider the effect that a change in law would have on its decision.[40] The Commission takes note of these issues and finds that they add additional uncertainties in the projected benefits and further show that SWEPCO has failed to prove the project will lead to a probable lowering of cost to its consumers.

As mentioned above, the ALJs calculated their projection of potential benefits to consumers and found it insufficient without implementing certain guarantees to protect consumers.[41] In rebuttal testimony, SWEPCO offered various conditions to act as hedges against some of the cost risks of the project.[42] Intervenors also proposed different, more stringent guarantees to protect consumers.[43] In the PFD, the ALJs rejected some proposed guarantees and decided to recommend the following four guarantees: first, two cost caps recommended by Commission Staff, one for the cost of the wind facility and the other for the cost of the project, without exceptions for force majeure and change in law;[44] second, a 30-year life span for the

---

[36] PFD at 18.

[37] *Id.* at 19.

[38] *Id.* at 19.

[39] *Id.* at 37.

[40] *Id.* at 44.

[41] *Id.* at 2.

[42] *Id.* at 47.

[43] *Id.* at 56–59.

[44] PFD at 59–60, Proposed Finding of Fact No. 125; *see also* PFD at 48 (discussing Commission Staff's proposal).

depreciation rate of the project;[45] third, a net capacity-factor guarantee of 44.7% without exceptions for force majeure or change in law;[46] and fourth, a guarantee that consumers would receive 100% of the production tax credits that SWEPCO would receive based on a 51.1% net capacity factor with an exception for changes in law.[47] The ALJs rejected a base-case gas-savings guarantee and SWEPCO's 10-year look-back guarantee because they would not properly protect consumers due, in part, to inaccuracies and uncertainties in the methodologies.[48]

After exceptions were filed, the ALJs filed a letter recommending two changes to the guarantees they implemented in the PFD: they changed the project cost cap to 103% on a company-wide basis and clarified that the production tax credit guarantee applied only to the actual output of the facility, not at a 51.1% net capacity factor.[49]

At the Commission's July 12, 2018 open meeting, the Commissioners requested that the parties attempt to reach agreement on the issue of guarantees to protect consumers. Following the open meeting, the parties made various filings that indicated no agreement had been reached between SWEPCO and the other parties in this case regarding the guarantees.

The Commission finds that the guarantees set forth in the PFD and the ALJs' exceptions letter do not sufficiently protect consumers because they do not provide enough certainty of a probable lowering of cost to consumers.

The Commission in this Order does not address the accuracy or reasonableness of any individual assumption made by any party that underlies their analyses in this docket regarding whether this project will provide benefits to consumers. The Commission notes the many assumptions, the range in values of the parties' assumptions, and the significant range of benefits or costs to consumers presented by the parties, ranging from SWEPCO's $1.495 billion in benefits to OPUC's $912 million in costs, TIEC's $1.1 billion in costs, and CARD's $1.971 billion in costs. The bulk of the evidence in this proceeding casts doubt on the assumptions SWEPCO, who bears

[45] PFD at 60, Proposed Finding of Fact No. 140.

[46] PFD at 61; Proposed Findings of Fact Nos. 126–28.

[47] PFD at 61–62, Proposed Findings of Fact Nos. 129–31.

[48] PFD at 60–61, 62, Proposed Findings of Fact Nos. 33–37.

[49] ALJs' Exceptions Letter at 3–4.

the burden of proof, used to determine that benefits to consumers are probable. The Commission need not choose a single number within this range given the uncertainty of assumptions and the magnitude of the risk that could be imposed upon consumers. In addition, sufficient consumer safeguards have not been offered by SWEPCO that would allow the Commission to conclude there is a probability of benefits to consumers from the project.

For the reasons discussed in this Order, the Commission finds that SWEPCO failed to show that it is probable the project will lead to lower cost for consumers and, consequently, the Commission cannot approve the application. The Commission disagrees with the PFD's conclusion and finds that SWEPCO has failed to show that the project is likely to lead to lower cost for consumers. Accordingly, the Commission adopts those portions of the PFD, including findings of fact and conclusions of law, that address procedure and the positions and arguments of the parties, and other portions consistent with this Order and the decision of the Commission.

To reflect its decision in this matter, the Commission deletes as either unnecessary or incompatible with its decision findings of fact 24, 33, 43, 51 through 56, 58, 59, 74, 85 through 88, 98, 100, 102, 107, 108, 121, 127, 128, 130, 131, 139, 145, and 149, and conclusions of law 4 and 10; modifies findings of fact 60, 83, 84, 89, 99, 105, and 136 and conclusions of law 1, 7, and 11; and adds new findings of fact 50A, 60A, 77A, 92A, 99A, 106A, 109A, and 139A and new conclusion of law 10A.

Findings of fact 90 and 123 are modified and finding of fact 125 is deleted as recommended by the ALJs in their July 6, 2018 letter. The Commission deletes as either unnecessary or incompatible with its decision findings of fact 92, 101, 109, and 124, which also included modifications recommended by the ALJs.

Due to the Commission's decision above, the Commission does not address SWEPCO's request for a good-cause exception to 16 TAC § 25.236, SWEPCO's request to defer a portion of the federal production tax credits into a regulatory liability, SWEPCO's likelihood of obtaining the full amount of the production tax credits, the additional guarantees proposed by intervenors, the effect that approving the application would have on Lubbock Power & Light's or Rayburn Country Electric Cooperative's proposal to become part of the Electric Reliability Council of Texas, or the applicability of PURA § 14.101 to this proceeding. Therefore, it does not adopt the

PFD on these issues and deletes findings of fact 19, 110 through 118, 140 through 144, 148, and 150 through 158 and conclusions of law 5 and 8.

Finally, the Commission also makes non-substantive changes to the findings of fact and conclusions of law for such matters as capitalization, spelling, grammar, punctuation, style, correction of numbering, and readability.

The Commission adopts the following findings of fact and conclusions of law:

II. Findings of Fact

Background and Procedural History

1. SWEPCO is a wholly owned subsidiary of AEP and is a fully integrated electric utility serving retail and wholesale consumers in Texas, Arkansas, and Louisiana.

2. On July 21, 2017, SWEPCO filed an application with the Commission to amend its CCN to authorize acquisition of an interest in the project to be located in Oklahoma. The application also requested preapproval of various ratemaking treatments to recover the project costs from SWEPCO's consumers.

3. The Commission referred the application to SOAH on August 2, 2017.

4. SWEPCO provided notice of the application by publication once a week for two consecutive weeks in a newspaper having general circulation in each county in SWEPCO's service territory. SWEPCO's notice by newspaper publication was completed on September 9, 2017.

5. SWEPCO provided notice to SWEPCO's Texas retail consumers by bill insert, which was completed on September 26, 2017.

6. SWEPCO provided individual notice to Commission Staff and OPUC by hand-delivering a copy of SWEPCO's filing to each party's counsel. Individual notice was also provided to the legal representative of all parties in Docket No. 46449, SWEPCO's last base-rate case, and Docket No. 42527, SWEPCO's most recent fuel reconciliation proceeding. Individual notice was completed on July 31, 2017.

7. The following parties intervened and participated in this docket: TIEC; OPUC; Golden Spread Electric Cooperative, Inc.; East Texas Electric Cooperative, Inc. and Northeast

Texas Electric Cooperative, Inc.; Wal-Mart Stores Texas, LLC and Sam's East, Inc.; CARD; South Central MCN, LLC; and Tri-County Electric Cooperative, Inc..

8. On August 18, 2017 in SOAH Order No. 2, the SOAH ALJ established the procedural schedule and issued notice of the time and place of the hearing.

9. The Federal Tax Cuts and Jobs Act (TCJA) was signed into law on December 22, 2017, with an effective date of January 1, 2018.

10. On January 17, 2018, SWEPCO filed a motion to postpone taking evidence until January 22, 2018 because, after further study of the TCJA, SWEPCO determined that certain testimonies and exhibits would need to be amended or supplemented to reflect accurately the impact of the TCJA.

11. The hearing on the merits was held on February 13 through 16 and on February 20 through 22, 2018.

12. The record closed on April 30, 2018, following the admission of evidence to update the status of the regulatory proceedings in other jurisdictions.

CCN Issues

13. The investment in the project will have a significant impact on SWEPCO's finances.

14. Because the project will be located entirely within the state of Oklahoma, there will be no adverse effects on any other electric utility in Texas.

15. There will be no adverse effect on community values, recreational and park areas, historical and aesthetic values, or environmental integrity in Texas because the project is located entirely within the state of Oklahoma.

16. Because there is no need for the project to serve retail load, the addition of the project will not improve service.

17. Texas has already met its renewable energy goals, so the project will have no effect on those goals.

18. SWEPCO is not currently in the process of implementing customer choice in its service territory.

19. DELETED.

Analysis of Economics of Wind Catcher (PO Issues 10, 12, 14, 25, 26)

20. SWEPCO contends that consumers will experience $1.495 billion in net benefits using its base-gas-price case (which it believes is the correct case to use), $1.114 billion in net benefits under its low-gas-price case, and $1.932 billion in benefits under the high-gas-price case.

Project Description and Cost (PO Issues 10 and 12)

21. The project consists of the Wind Catcher generation tie-line and a wind facility with 800 General Electric model 2.5-MW wind-turbine generators that would provide 1,900 MW of delivered and 2,000 MW nameplate wind energy. The total estimated project costs, including allowance for funds used during construction are set forth in the table below:

	SWEPCO (billions)	**TOTAL (billions)**
WIND FACILITY	$2.031	$2.902
GENERATION TIE-LINE	$1.137	$1.624
PROJECT (BOTH)	$3.168	$4.526

22. The wind facility is being constructed by Invenergy Wind Development North American LLC, which commenced construction in 2016 and has continuously maintained construction.

23. Invenergy has targeted completion of the wind facility for September 30, 2020.

24. DELETED.

25. On July 26, 2017, the developers and participants in the wind facility entered into an agreement entitled the Membership Interests Purchase Agreement (MIPA) to acquire, subject to regulatory approvals and other conditions, States Edge Wind I LLC, an Invenergy single-purpose subsidiary that will own the rights and assets of the wind facility.

26. The MIPA is a fixed-price arrangement whereby Invenergy will manage all phases of construction and deliver the wind facility upon completion to SWEPCO and PSO. Invenergy will pay all construction financing costs, which are included in the purchase price.

27. The purchase price for the wind facility is $2.694 billion. The total estimated cost, including the MIPA purchase price and other cost components, is $2.902 billion. SWEPCO's share is approximately $2.031 billion.

28. The generation tie-line would deliver the wind facility's energy directly to the AEP load zone, bypassing congestion and curtailment on the SPP system in western Oklahoma.

29. The generation tie-line would consist of a proposed 345-kV-to-765-kV generation substation at the wind facility; a proposed 350-to-380-mile, radial, single-circuit 765-kV transmission line; and a proposed 765-kV to 345-kV substation, which is in the Tulsa AEP load zone.

30. The purpose of the generation tie-line is to transmit the wind facility's energy from western Oklahoma to the Tulsa AEP load zone.

31. The participating utilities have entered into a fixed-price contract with Quanta Services, a Houston company, for engineering, procurement, and construction services for the generation tie-line.

32. Under the Quanta contract, all engineering, procurement, and construction are covered under the scope of Quanta's work.

33. DELETED.

34. The total estimated capital cost for the generation tie-line is $1.624 billion including $148 million for allowance for funds used during construction. SWEPCO's share of the estimated total cost would be 70%, or $1.1 billion.

35. The generation tie-line has a projected completion date of December 15, 2020.

36. The generation tie-line's projected completion date is slightly more than two weeks before the end of the Internal Revenue Service (IRS) safe-harbor date for wind-production tax credits.

37. Production tax credits are assured for projects in service before the safe-harbor date. Projects that enter into service later may still receive the credits, but must show they meet certain criteria.

38. If the project were to be built on budget, it would increase SWEPCO's rate base established in its most recent rate proceeding by over 72%, leading to a base-rate increase in Texas of at least $150 million in 2021, depending on the timing of a rate case.

39. Although the MIPA includes a provision for contingencies, that amount is $93.3 million, which is only 3.2% of the total wind facility cost.

40. The generation tie-line cost is not guaranteed, but is subject to increases based on a number of factors, including the cost to acquire land (including the cost of possible eminent domain proceedings), internal labor and overhead, allowance for unknown risks, and allowance for funds used during construction.

41. Including those additional costs, the generation tie-line is anticipated to cost a total of $1.624 billion.

42. The generation tie-line contract price is set with limited reopeners, a stringent process for obtaining change orders, and numerous contractual protections.

43. DELETED.

44. The contract with Quanta provides exceptions to the definition of a force majeure event by excluding weather events that are normal weather for the period, season, and geographic area of the generation tie-line except to the extent that such normal weather causes physical damage to towers or the work in progress.

45. If weather that does not cause physical damage occurs, the contractor must provide climatological data over the preceding five years substantiating that the weather conditions were unusually adverse for the period of time and location based on historical data and could not have been reasonably anticipated.

46. The contract with Quanta requires the contractor to spend up to $5 million to mitigate damage to the generation tie-line work and any delay in the project schedule's critical path before claiming additional compensation. It also includes a provision requiring an expedited schedule if a force majeure event creates any delay.

47. SPP's practice in calculating the operating reserve requirement is to base it on 100% of the largest SPP generating unit, plus 50% of the second largest.

48. If approved and built, the project would become the largest generating unit in the SPP system.

49. Although SWEPCO believes that the effect on reserves costs would be only a little over $200,000, it based its estimate on SPP setting the requirement on an hourly basis.

50. SPP currently sets the reserve requirement on a daily basis.

50A. No facility study has been conducted on the project by SPP.

51. DELETED.

52. DELETED.

53. DELETED.

54. DELETED.

55. DELETED.

56. DELETED.

57. The generation tie-line contract is a fixed-cost agreement, with certain additional costs to be determined.

58. DELETED.

59. DELETED.

60. The length and location of the generation tie-line raise greater possibilities of additional delays and costs.

60A. For every 1% in capital cost over-run, the net present value of the project's benefits calculated by SWEPCO would be decreased by $30 million.

61. The record does not include a reliable calculation of the reserve costs based on a daily calculation.

Economic Evaluation Methodology and Assumptions (PO Issues 12 and 14)

Evaluation Methodology

62. To evaluate the economics of the projects, SWEPCO developed and compared three cases—three alternative resource procurement paths.

63. The first case—the base case—assumed no new development or purchase of any wind resources between 2021 and 2045. The second case—the project case—reflected the development of the project.

64. To determine the estimated benefits of the project, SWEPCO compared the difference between the base case and the project case for the period modeled, 2021 to 2045.

65. The third case—the generic wind case—assumed the procurement of 1,900 MW of wind generation at 24 different wind sites across SPP.

66. SWEPCO estimated that the project would produce approximately $685 million more in customer savings than the generic wind case would relative to the base case.

67. The three cases were modeled using PROMOD® and PLEXOS® simulation tools to estimate the production-related costs and benefits of each case. SWEPCO used both models because neither was sufficient on its own to analyze the project's lifetime impact.

68. The PROMOD® model is available only for two years (2020 and 2025) and analyzed only cost impacts for individual SPP transmission zones such as the AEP zone, in the aggregate.

69. The PLEXOS® model does not simulate the entire SPP footprint and does not simulate transmission constraints or marginal losses. Therefore, SWEPCO input data for 2020 and 2025 into the PROMOD® model, interpolated between those two points, and then extrapolated that trend going outward for the life of the project.

70. SWEPCO used that data in PLEXOS® to estimate the costs and the benefits of the project for SWEPCO consumers.

71. SWEPCO and PSO, in the fall of 2016, issued a request for proposal soliciting bids to construct a wind-energy project.

72. The 2016 projects would have connected to the SPP system in congested areas and did not account for economic curtailment costs.

73. The competitive market would not have provided the project, and the timing of a request for proposal would have precluded the construction of the project in time to take full advantage of the production tax credits.

74. DELETED.

Assumptions Impacting Locational Marginal Prices

Natural Gas Prices

75. Future natural gas prices are an essential element of the project benefits calculation. The higher the expected future natural gas prices, the greater the expected benefits from the project.

76. SWEPCO used AEP's Long-Term North American Energy Market Forecast (fundamentals forecast) to forecast the expected project benefits.

77. The fundamentals forecast was made available to all AEP operating companies on October 27, 2016.

77A. The fundamentals forecast contained natural-gas-price projections for a base case, a high case, and a low case. The base case was used by SWEPCO to analyze the economics of the project. The base case used a levelized natural gas price of $7.35 per MMBtu.

78. Natural gas prices are important because fuel prices are a key component in determining the supply stack, or merit order, for the dispatch of generating units.

79. The 2016 fundamentals forecast employed a carbon dioxide dispatch burden on all existing fossil-fuel-fired generating units that escalated from $2.92 per ton in 2024 to $26.31 per ton in 2032 to achieve national mass-based emission targets similar to those proposed in the national Clean Power Plan.

80. Each of AEP's past forecasts, dating back to 2007, has been on the high side of actual natural gas prices.

81. Although the 2016 fundamentals forecast was weather-normalized, the evidence did not quantify the impact of abnormal weather on prior forecasts.

82. SWEPCO's forecasts start out higher than current prices and have been higher than actual prices for several years.

83. The gas prices of the SPS and ETI forecasts used in recent Commission proceedings were significantly lower than SWEPCO's fundamentals forecast. The SPS low case forecast projected a levelized price of natural gas at $3.55 per MMBtu. The ETI low case forecast projected a levelized price of natural gas at $3.68 per MMBtu.

84. The NYMEX futures prices represent actual transactions between buyers and sellers who put real money at risk in their day-to-day operations. The NYMEX futures prices, when trended to 2045, are $3.58 per MMBtu.

85. DELETED.

86. DELETED.

87. DELETED.

88. DELETED.

89. The lowest Energy Information Administration (EIA) case has been the most accurate in recent years.

90. The levelized natural-gas-price forecast from EIA's 2018 reference case for the years 2021 through 2045 is approximately $5.32 per MMBtu.

91. A decrease of $1 per MMBtu in gas prices would reduce the estimated base-case savings for the project by approximately $392 million net present value.

92. DELETED.

92A. The record in this proceeding fails to show that the assumptions made by SWEPCO regarding gas prices will result in a probable lowering of cost to consumers.

Cost of Carbon

93. SWEPCO's three cases employ a carbon dioxide dispatch burden (allowance price) on all existing fossil-fuel-fired generating units.

94. SWEPCO designed the carbon burden to achieve emission targets similar to those proposed in the federal Clean Power Plan.

95. In the base case, the carbon burden is zero in 2021 to 2023, then escalates from $2.92 per ton in 2024 to $26.31 in 2032.

96. Although it is possible that a carbon tax will be imposed in the future, such a tax has not been imposed in the past, there is not one in place now, and there was no credible evidence to show that the imposition of such a tax is likely in the future.

97. SWEPCO's modeling of the locational marginal prices should not have included the carbon-burden component, and the calculation of the estimated benefits of the project should be reduced accordingly.

98. DELETED.

Other Assumptions

99. SWEPCO's modeling understated the amount of new wind generation in SPP.

99A. The SPP interconnection queue includes an additional 6,000 MW of projects with pending or completed interconnection agreements, 10,000 MW of additional wind projects in the SPP Facility Study Stage, and another 24,000 MW in the Definitive Interconnection System Impact Study stage.

100. DELETED.

101. DELETED.

102. DELETED.

103. SWEPCO's calculated congestion costs are likely too high due to high estimated natural gas prices.

Net Capacity Factor

104. A crucial measure of generation output is the wind facility's net capacity factor, which is the ratio of the actual output of a generating unit over a period of time to its potential output at full nameplate capacity.

105. Based on the results of two studies, SWEPCO estimates a project net capacity factor of 51.1% at a P50 estimate, which means there is a 50% likelihood that the actual output will be greater and a 50% likelihood that the actual output would be less than 51.1%.

106. Each 1% reduction in net capacity factor would lead to a $95.6 million reduction in net present value project benefits, considering both production cost savings and lower production tax credits.

106A. If the generation tie-line is not available due to outages, maintenance, or force majeure events, the actual net capacity factor will be diminished.

107. DELETED.

108. DELETED.

Projected Benefits of Wind Catcher

109. DELETED.

109A. SWEPCO failed to provide evidence to show it is probable the project would provide a reduction in cost to consumers.

Production Tax Credits (PO Issues 25 and 26)

110. DELETED.

111. DELETED.

112. DELETED.

113. DELETED.

114. DELETED.

115. DELETED.

116. DELETED.

117. DELETED.

118. DELETED.

Capacity Value of the Wind Facility (PO Issue 14)

119. SWEPCO calculated the future capacity value of the wind facility and included that calculation, $269 million on a net-present-value basis, as one of the financial benefits of the project.

120. The forecasted incremental value was based on the deferral of a future natural gas combined-cycle (NGCC) unit from 2026 to 2033 and the avoidance of a second NGCC unit from 2038 through the end of the modeling period, 2045.

121. DELETED.

SWEPCO's Proposed Guarantees

122. SWEPCO proposed a cost cap for the wind facility, generation tie-line, and all SPP-assigned generation interconnection costs of $3.339 billion, which is 109% of the estimated cost of SWEPCO's 70% share of the project. This cost cap does not include allowance for funds used during construction.

123. In a settlement in Oklahoma, SWEPCO's sister company, PSO, agreed to a cost cap of 103% of project costs including allowance for funds used during construction, which is equivalent to $2,332 per kW of nameplate capacity as measured on a total parent-company gross-plant basis, without exceptions for force majeure or change of law.

124. DELETED.

125. DELETED.

126. SWEPCO proposed a guaranteed net capacity factor of 44.7%, which is 87% of the capacity projected in its application. This guarantee includes exceptions for force majeure and change in law.

127. DELETED.

128. DELETED.

129. SWEPCO's proposed production tax credit guarantee of eligibility for 100% of the production tax credits with exceptions for force majeure and change in law does not provide a sufficient guarantee to customers.

130. DELETED.

131. DELETED.

132. SWEPCO proposed to agree to flow to consumers 100% of the incremental off-system energy sales margins that would not have occurred but for the project and the net proceeds from the sale of renewable energy credits associated with the project.

133. SWEPCO proposed to agree to a 10-year look-back proposal based on the following formula:

> ***Net Benefit for Customers = Fuel Savings + Project Capacity Value + PTCs + Minimum Net Capacity Factor Guarantee Payments + RECs Value + Carbon Savings – Project Revenue Requirement***

134. If the net benefit for customers at the end of the ten-year period is positive, SWEPCO will not owe customers any compensation under this guarantee. If the net benefit calculation for customers at the end of the ten-year period is negative, SWEPCO will compensate customers for that amount under the formula.

135. SWEPCO's look-back proposal is unlikely to yield a calculation of savings given that the methodology does not look at the actual price on the SPP market, and instead looks at SWEPCO's bid stack to determine what SWEPCO's generation cost would have been had the resources been placed into the market.

136. SWEPCO's look-back proposal likely overstates customer benefits.

137. No other party presented sufficient evidence to adopt a different look-back proposal.

138. SWEPCO proposed a most favored nation guarantee such that, if terms more favorable to consumers are agreed to by PSO or SWEPCO in any of the state utility commission proceedings under which they are seeking approval of the project, SWEPCO would disclose the terms and incorporate them into the guarantees for the benefit of SWEPCO Texas consumers for the following: (1) the Gigawatt hours output of the production guarantee; (2) the production-tax-credit eligibility; or (3) the cost cap percentage.

139. DELETED.

139A. The guarantees offered by SWEPCO are not sufficient to protect consumers from the risk of the project.

Commission Staff or Intervenor Proposed Guarantees

140. DELETED.

141. DELETED.

142. DELETED.

143. DELETED.

144. DELETED.

Other CCN Issues

145. DELETED.

146. The project is located entirely outside of the State of Texas, and Texas' community values, parks, historical sites, and environment are unaffected.

147. Texas has met its renewable energy goals.

148. DELETED.

CCN for Economic Purposes

149. DELETED.

Ratemaking Treatments

150. DELETED.

151. DELETED.

152. DELETED.

153. DELETED.

154. DELETED.

155. DELETED.

156. DELETED.

157. DELETED.

158. DELETED.

III. Conclusions of Law

1. The Commission has jurisdiction over this application under PURA §§ 36.203, 36.204, 37.051, 37.053, 37.056, and 37.057.

2. SOAH has jurisdiction over this proceeding, including the preparation of this proposal for decision with findings of fact and conclusions of law under PURA § 14.053 and Texas Government Code § 2003.049.

3. Notice of the application was provided in compliance with PURA § 37.054 and 16 Texas Administrative Code (TAC) § 22.55.

4. DELETED.

5. DELETED.

6. SWEPCO is not implementing customer choice under PURA §§ 39.501(b) and 39.502(b) and 16 TAC § 25.422(e).

7. SWEPCO has not shown that the project will result in the probable lowering of cost to consumers in accordance with PURA § 37.056(c)(4)(e).

8. DELETED.

9. Texas has met its renewable energy goals under PURA § 39.904(a).

10. DELETED.

10A. SWEPCO has not met its burden of proof to show that the project is necessary for the service, accommodation, convenience, or safety of the public under PURA § 37.056.

11. SWEPCO is not entitled to approval of the application.

IV. Ordering Paragraphs

In accordance with these findings of fact and conclusions of law, the Commission issues the following orders:

1. The Commission denies the application, as outlined in this Order.

2. All other motions and any other requests for general or specific relief, if not expressly granted herein, are denied.

Signed at Austin, Texas the 13th day of August 2018.

PUBLIC UTILITY COMMISSION OF TEXAS

DEANN T. WALKER, CHAIRMAN

ARTHUR C. D'ANDREA, COMMISSIONER

SHELLY BOTKIN, COMMISSIONER

W2013
q:\cadm\orders\final\47000\47461fo.docx