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Dr. Brad Borum, Director of Research, Policy and Planning
Indiana Utility Regulatory Commission
101 W. Washington Street, Suite 1500 E.
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via electronic mail

Re: Indiana Coalition for Affordable and Reliable Electricity's Public Comments on NIPSCO's 2018 Integrated Resource Plan

Dear Dr. Borum:

The Indiana Coalition for Affordable and Reliable Electricity ("ICARE") is an association of companies that support reliable, affordable electric generation sources. ICARE hereby submits the public version of its comments on the Integrated Resource Plan that NIPSCO filed October 31, 2018. ICARE filed an unredacted version of its comments under seal in the Indiana Utility Regulatory Commission's ("IURC") Cause 45160, because certain information in the comments is deemed confidential by NIPSCO and is protected as confidential per the Order issued November 8, 2018 in that Cause. Please feel free to contact me with any questions or concerns.

Sincerely,

Meghan Griffiths
Attorney for Indiana Coalition for Affordable and Reliable Electricity

cc: Claudia J. Earls, cjearls@nisource.com
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INDIANA COALITION FOR AFFORDABLE AND RELIABLE ELECTRICITY
COMMENTS ON NIPSCO'S 2018 INTEGRATED RESOURCE PLAN

TABLE OF CONTENTS

I. Introduction 1

II. Flaws in NIPSCO's IRP 2

- A. The IRP Analyzes Resource Retirement and Portfolio Selection Separately 2
- B. The IRP Does Not Properly Evaluate Retirement Dates or Value the Flexibility Inherent in Delaying Resource Retirements 6
- C. The IRP Uses Inconsistent Solar Resource Cost Assumptions 8
- D. The IRP Uses ELCC and UCAP Values That are Too High For Indiana Wind Resources 10
- E. The IRP Fails to Include Increased Congestion and Transmission Costs 12
- F. The IRP Fails to Include Increased Ancillary Service Costs 12
- G. The IRP Does Not Project Degradation in Output for Owned Wind Generation 13
- H. The IRP Unreasonably Assumes NIPSCO Can Utilize 100% of the Value of Tax Incentives 13
- I. The IRP Ignores Uncertainties Regarding Environmental Regulation 13
- J. The IRP Uses Inflated Assumptions for Maintenance Capital Expenditures 14
- K. The IRP Uses Inflated Assumptions for Fixed Operations and Maintenance Expenditures 15
- L. The IRP Uses Inflated Assumptions for Commodity Costs 16
- M. The IRP Fails to Account for NIPSCO's Plan to Allow Large Industrial Customers to Procure Power From Other Sources 16
- N. The IRP Excludes DSM Resources from Portfolio 1 17
- O. The IRP Uses a Thirty-Year Net Present Value Revenue Requirement Planning Horizon 17

III. Conclusion: The IRP Incorporates Flaws Designed to Enhance NIPSCO's Rate Base 17

INDIANA COALITION FOR AFFORDABLE AND RELIABLE ELECTRICITY COMMENTS ON NIPSCO'S 2018 INTEGRATED RESOURCE PLAN

I. Introduction

The Indiana Coalition for Affordable and Reliable Electricity ("ICARE") appreciates the opportunity to submit these comments to the Indiana Utility Regulatory Commission ("IURC") regarding Northern Indiana Public Service Company, LLC's ("NIPSCO") 2018 Integrated Resource Plan ("IRP"). NIPSCO's IRP calls for early retirement of its entire coal fleet. NIPSCO proposes to close the Schahfer units (Units 14, 15, 17 and 18) by 2023 and the Michigan City 12 by 2028. NIPSCO claims it is cost effective to retire 2,094 MW of existing coal generation, replace that capacity with 3,929 MW of new wind and solar, and have Indiana consumers pay for the sunk costs of the remaining net book value of the shuttered coal units.[1]

ICARE respectfully submits that NIPSCO's IRP does not support its claim. If NIPSCO follows through with the early retirement of its coal fleet, Indiana consumers will ultimately pay higher bills as a result of a costly plan to recapitalize the utility's generation fleet. ICARE has identified a number of flaws in NIPSCO's IRP that are currently the subject of ICARE witness Mr. Charles Griffey's testimony in NIPSCO's pending rate case (IURC Cause No. 45159). ICARE submits that, taking these combined flaws into account, NIPSCO's IRP does not demonstrate that its preferred resource portfolio is a reliable, efficient and cost-effective way to meet electric system demand, nor does its analysis properly consider the appropriate costs, risks and uncertainties.[2] Ultimately, these flaws appear calculated to produce a result in which NIPSCO prematurely retires its coal generation fleet and replaces it with expensive new renewable resources.

As set forth in these comments, NIPSCO's IRP actually demonstrates that its preferred portfolio is more expensive than operating Michigan City 12 through 2035. In addition, the IRP analysis contains numerous flaws and errors that dramatically understate the costs of retiring the plants. When accounting and adjusting for these flaws, it is likely more economic to operate Schahfer 14/15 past 2023 and possibly more economic to operate Schahfer 17/18 past 2023. Thus, the reasonable choice for NIPSCO would be to not retire Michigan City 12 and to defer the retirement decision on the Schahfer units until NIPSCO's next IRP.

[1] The remaining net book value, plus cost of removal of the plants is more than $800 million.
[2] See 170 Ind. Admin. Code 4-7-8(c)(5).

The IRP's flaws and the basis for this conclusion are discussed in detail below.

II. Flaws in NIPSCO's IRP

NIPSCO's IRP compares a number of different resource portfolios that contain different retirement dates for its coal generating units and different forms of replacement capacity. Below is a summary of the IRP portfolios that ICARE will discuss herein:

Figure A

Summary of Coal Unit Retirement Dates and Form of Replacement Capacity

	Portfolio 1[3]	Portfolio 4	Portfolio 5	Portfolio 6	Portfolio F
Mich City 12	2035	2035	2035	2028	2028
Sch 14/15	2038	2028	2023	2023	2023
Sch 17/18	2038	2023	2023	2023	2023
Wind from RFP	None	PPA	PPA	PPA	PPA + Ownership
Solar & Storage from RFP	None	PPA	PPA	PPA	PPA + Ownership
Generic Solar Ownership	Replaces Mich City	Replaces Mich City, Schahfer 14/15	Replaces Mich City	Replaces Mich City	Replaces Mich City

Portfolio 1 is NIPSCO's portfolio in which all of the coal units operate through the end of their planned service lives. Portfolio 4 retires Schahfer 17/18 in 2023 in favor of purchased power agreements ("PPAs") from its recent request for proposals ("RFP"), Schahfer 14/15 in 2028, and Michigan City 12 in 2035 in favor of generic solar resources. Portfolio 5 differs from Portfolio 4 by retiring Schahfer 14/15 in 2023 and replacing it with RFP resources. Portfolio 6 differs from Portfolio 5 by replacing Michigan City 12 in 2028 with generic solar resources. Finally, Portfolio F—NIPSCO's preferred portfolio—differs from Portfolio 6 by inserting NIPSCO ownership of renewables in lieu of relying entirely on the optimized PPAs chosen in Portfolio 6.

A. The IRP Analyzes Resource Retirement and Portfolio Selection Separately

A major flaw in the IRP is that NIPSCO justifies the coal plant retirements by comparing the cost of its coal fleet portfolios against resource portfolios it has no intention of using. This is a

[3] What NIPSCO calls retirement portfolios are all numbered, while its replacement portfolios bear alphabetical designations. For simplicity, ICARE uses the alphanumeric designations and drops "retirement" and "replacement" from the names.

bait and switch. Specifically, NIPSCO's IRP engages in a two-step process that evaluates retirement and replacement decisions separately, rather than conducting truly integrated resource planning. In step 1 of its analysis, NIPSCO's IRP concludes that the optimal plan for retiring its coal generation resources is to retire all four Schahfer coal units (14/15 and 17/18) in 2023 and Michigan City in 2028. It arrives at this conclusion by evaluating the operation of the coal plants with certain retirement dates against optimized portfolios based on aggregated offers from its recent RFP. Based on this comparison, NIPSCO claims that it is cheaper to acquire the optimized new renewable resources (i.e., Portfolio 6) compared to any of the other portfolios where the coal plants might operate for longer.

NIPSCO then switches to comparing different portfolios in step 2 of the IRP analysis. In this step, NIPSCO takes it as a given that the coal units will be retired in the specified years. NIPSCO then discards the optimized portfolio that was purportedly cheaper than the continued coal operation cases, and evaluates six other portfolios with different sets of new resource and market purchases (the "replacement" portfolios). It discards the optimized Portfolio 6 because it appears NIPSCO has no intention of acquiring that particular set of resources, which was entirely made up of PPAs. Instead, NIPSCO selects its preferred Portfolio F from among the non-optimized replacement portfolios, which is $420 million more expensive on a net present value ("NPV") basis than Portfolio 6 due almost solely to NIPSCO owning renewable resources rather than purchasing those resources. Portfolio F is made up of approximately [redacted]% of NIPSCO-owned renewable resources, as shown in the figure below:

Figure B

Comparison of Level of PPAs vs. Owned Resources in Portfolio 6 and Portfolio F[4,5]

	Portfolio 6 (lowest cost portfolio)	**Portfolio F (preferred portfolio)**
Owned Wind	[redacted]	[redacted]
Owned Solar		
PPA Wind		
PPA Solar		
NPV of Portfolio		

4 NIPSCO 2018 IRP Appendix D. NPV is for the Base Case.

5 NIPSCO recently filed for a CPCN for one wind resource and approval for two PPAs, and ICARE anticipates there will be other filings for wind resources. NIPSCO's current plan appears to have slightly less owned wind than the amount shown in the table and presented as its preferred plan.

NIPSCO's own analysis therefore shows that using utility-owned solar and wind resources in Portfolio F is more expensive than either entering into the PPAs (Portfolio 6) *or* operating Michigan City 12 through 2035 instead of 2028 (Portfolio 5). Preferred Portfolio F is more expensive than Portfolio 5, in which Michigan City 12 operates through 2035, in all scenarios and across NIPSCO's Cost Certainty and Cost Risk metrics. The figure below compares NIPSCO's net present value revenue requirement ("NPVRR") of Portfolios 5, 6 and F.

Figure C

NIPSCO's NPVRR of Portfolios by Scenario ($Millions)[6]

NIPSCO IRP Scenario	Column 1 Portfolio 5 (Mich City retires in 2035)	Column 2 Portfolio 6[7] (Step 1 - selected PPA Portfolio)	Column 3 Portfolio F (Step 2 - Preferred Portfolio)	Column 4 = Col. (3)-(1) Portfolio F cost in excess of Portfolio 5[8]
Base	$11,454	$11,343	$11,763	$309
Aggressive Environmental	$12,298	$12,084	$12,424	$126
Challenged Economy	$8,474	$8,428	$8,905	$431
Booming Economy	$11,245	$11,125	$11,585	$340

ICARE believes that these values from NIPSCO's IRP dramatically understate the cost of the replacement renewable resources and overstate the cost of continuing to operate the coal plants (as discussed further below). **Notwithstanding, NIPSCO's own analysis—unadjusted for any errors—shows that, in every scenario, the portfolio wherein Michigan City 12 operates until 2035 is economically preferable to the Preferred Portfolio F that NIPSCO recommends, by hundreds of millions of dollars.**

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[6] NIPSCO 2018 IRP at 151 and 165.

[7] These values may understate the cost of Portfolio 6. It is not uncommon for utilities to include costs for negative credit impacts of PPAs when evaluating build vs. buy decisions. For instance, some utilities apply a 25% debt imputation cost to long-term PPAs. In the case of Portfolio 6, debt imputation by itself would add over $100 million in NPVRR cost.

[8] These values do not account for the CO2 costs put into the Base, Booming Economy, and Aggressive Environmental cases. Each year of delay in the CO2 pricing is worth approximately $[redacted] in the Base and Booming Economy cases and $[redacted] in the Aggressive Environmental case. If one did not think that CO2 pricing would be in place in each of those cases, the NPV difference would increase by $[redacted] in the Base and Booming Economy cases and $[redacted] in the Aggressive Environmental case. Thus, without CO2 pricing, operating Michigan City 12 is even cheaper than Portfolio 6 in one scenario and in a virtual tie in the other scenarios.

NIPSCO's Preferred Portfolio will result in higher annual revenue requirements for its customers. The figure below shows how much more costly NIPSCO's preferred Portfolio F (Michigan City 12 retires in 2028) is compared to Portfolio 5 (where Michigan City 12 operates until 2035).

Figure D

Annual Cost of Preferred Renewable Portfolio over Continued Operation of Michigan City 12

[redacted]

Beginning in 2020, NIPSCO's preferred Portfolio F is more costly on an annual basis than Portfolio 5 by amounts ranging from $[redacted] to over $[redacted] in 2028. This means an election of Portfolio F over Portfolio 5 would result in significant annual rate increases for NIPSCO's customers.

Portfolio 5 is also better than Portfolio F across NIPSCO's Cost Certainty and Cost Risk metrics. Cost Certainty is defined by NIPSCO as the 75th percentile of revenue requirement from the stochastic risk analysis, which means there is a 75% chance of the revenue requirement being that level or lower. In the Base Case, Portfolio 5 has a 75th percentile revenue requirement of $11.634 billion while Portfolio F has a 75th percentile revenue requirement of $11.883 billion, or $249 million more. Cost Risk is defined by NIPSCO as the 95th percentile of revenue requirement; Portfolio 5's Cost Risk value is $12.252 billion while Portfolio F's is $12.634 billion, or $112 million more than operating Michigan City 12 until 2035. NIPSCO's analysis shows higher costs for the Schahfer units, but when accounting and adjusting for the other flaws in its IRP (discussed below), it is likely more economic to operate Schahfer 14/15 past 2023 and possible that it will be more economic to operate Schahfer 17/18 past 2023 as well.

By performing its IRP analysis in two separate steps, NIPSCO has obscured the significant cost increase between the portfolio it used to make its retirement decision and the portfolio it proposes to actually replace the coal units. Moreover, this problem was also present in NIPSCO's 2016 IRP. The *Director's Final Report for the 2016 IRPs* noted that "NIPSCO performed much of the retirement analysis prior to the resource optimization," and also indicated that "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." Two years later, NIPSCO has engaged in the same type of analysis—one that is insufficient to demonstrate that its retirement decision, or its preferred Portfolio F, are economic.

B. The IRP Does Not Properly Evaluate Retirement Dates or Value the Flexibility Inherent in Delaying Resource Retirements

NIPSCO's IRP is also flawed because it arbitrarily limits the potential plant retirement dates. NIPSCO evaluated only 3 possible retirement dates (2023, 2028, and 2035) across its four IRP scenarios. This is not an optimal or reasonable analysis because it ignores that NIPSCO has the flexibility to respond to changing circumstances with its currently owned generation. Rather than having to make a decision at this point in time, NIPSCO can wait to see how the future unfolds before saddling ratepayers with billions of dollars of new long-term commitments to replace existing units that may continue to be economic for many more years.

NIPSCO's IRP is replete with statements regarding the importance of maintaining flexibility to accommodate changing rules and market conditions. In and of itself, flexibility has value. However, NIPSCO only applies flexibility to its future selection of resources *after* making an inflexible choice on early plant retirement dates. If NIPSCO values flexibility, it is unreasonable to abandon the concept when it comes to the retirement decision for the coal units. For example, as discussed below, NIPSCO accepts as a certainty that it will have to spend $1.1 billion on environmental capital expenditures to keep Schahfer 17 and 18 operating past 2023, but there is no basis for that certainty as to either amount or timing.[9] NIPSCO also constructed 3 out of 4 of

[9] See generally the testimony of Mr. Nasi and Ms. Medine in NIPSCO's pending rate case, Cause 45159.

its future scenarios assuming a 2026 imposition of prices or taxes on CO2 emissions, but there is no certainty about that assumption. NIPSCO also assumes the capital expenditures necessary to keep Schahfer 14 and 15 operating in the future will be 50%-75% higher and fixed O&M will also be significantly higher than the level experienced from 2013-2018, but operation in the next several years may prove that incorrect. In short, NIPSCO's analysis does not value the flexibility provided by continuing to run the Schahfer coal units for a period of time after 2023 if allowed by environmental regulations.

ICARE also notes that NIPSCO's analysis of different scenarios with respect to environmental regulation is not sufficient for valuing continued operation of the coal units in an uncertain future. Critically, NIPSCO misapplies scenario analysis in assuming the utility knows immediately what scenario it is in, and is locked into that scenario in the future without the ability to alter the resource plan. NIPSCO should have constructed evaluations of different retirement dates that changed by scenario, because that is an option that it has today. By eliminating that flexibility, NIPSCO values it at zero and creates a false choice that says retirement dates must be determined today.

Finally, as noted in the testimony of witness Charles Griffey in NIPSCO's pending rate case, scenario analysis can help in thinking about what would happen if the future unfolds in a certain way, but it is not a substitute for rationally examining the least-cost path forward as events change. This inherently means not making decisions prematurely about speculative outcomes that will not happen for years into the future. NIPSCO's IRP should have evaluated the value of delaying a decision to retire each of the coal units. This can be done either through having different retirement dates in each portfolio in each scenario, allowing the ability to move between scenarios as the world changes, or analytically by applying option theory to determine the value of delaying decisions that do not have to be made today. NIPSCO could have then evaluated retirement dates beginning in 2023 and moving forward in time every year, rather than assuming only three retirement dates that are fixed in each scenario. As an example, if significant capital expenditures do not have to be made on the coal units because environmental regulations turn out not to require them at this point, it may make sense to operate the units past 2023 and then to see when, if ever, a price is imposed on emissions of CO2. NIPSCO's IRP is flawed because it bookends the potential results by arbitrarily limiting the potential retirement dates.

C. The IRP Uses Inconsistent Solar Resource Cost Assumptions

The IRP also artificially inflates the cost of retiring Schahfer 14/15 in 2028 by NPV $375 million because it uses different pricing assumptions for the solar capacity that replaces the coal units across the different portfolios depending on the retirement date. This mismatch in solar cost assumptions across the portfolios is arbitrary and appears results-oriented to tip the scales in favor of early retirement. For the portfolios where a coal unit retires in 2023, the Schahfer 14/15 coal units are replaced by a solar resource that is priced based on the best bids from the recent RFP. In contrast, for the resource portfolios where coal units are replaced after 2023, NIPSCO's replacement resource does not use the cost from the RFP bids, but instead uses a higher cost assumption for a generic solar resource. This higher solar cost assumption in the later years biases the result in favor of early plant retirements. As explained below, NIPSCO should have updated its generic solar resource costs to reflect actual market conditions from its recent RFP.

Consider, for example, the case of retiring Schahfer 14/15 in 2028 (e.g., Portfolio 4) instead of 2023 (e.g., Portfolios 5 and 6 and Preferred Portfolio F). In the 2023 retirement case, NIPSCO modeled Schahfer 14/15 being replaced by solar bids from the RFP, but in the 2028 case it replaced them with higher cost generic solar resources. Thus, after 2028, the portfolio comparison comes down to a cost comparison between the winning RFP solar resources and the cost assumptions that NIPSCO made about generic solar resources. As a result, purported cost savings between portfolios featuring the earlier and later retirement dates are an artifact of the replacement unit methodology.

Those inconsistent assumptions are not commercially reasonable. NIPSCO estimated the cost of future solar resources by assuming a generic current cost of solar resources and then assuming a decline from that assumed cost in real terms through time. However, the cost assumed for the generic solar resources is higher than NIPSCO's RFP results. The cost of a generic solar resource in 2018 is assumed to be $1,379/kw in constant 2017 dollars. In 2028, the generic cost fell to $904/kw in constant 2017 dollars across all scenarios. While it is reasonable to assume that technological improvement will drive cost reductions, NIPSCO assumed a generic solar resource with a beginning cost that is too high and inconsistent with the actual bids it received in 2018. The lowest RFP price for a solar build resource is $618/kw after accounting for ITC and $951/kw before ITC, and the average price is $698/kw after ITC and $1,073/kw before ITC for the first 906 MW of installed solar capacity (453 MW UCAP). In contrast, NIPSCO's IRP is predicated on a beginning solar price of $1,379/kw (in 2017 dollars) before ITC. The amount NIPSCO assumed in the IRP is, thus, 36% more than the average RFP result for the first 900 MW of solar (before ITC). The cost impact between solar PPAs from the RFP and the assumed generic solar resource cost is even larger. Yet NIPSCO did not align its generic solar resource cost assumptions with the market, nor did it assume that it could replace a retired coal unit later with a PPA at the same real levelized cost as is available from the RFP.

NIPSCO should have updated its replacement generic solar resource costs to reflect a starting point based on actual market conditions using its cost from the RFP, and then accounted for technological improvements if it wished to do so. Failing to update this replacement generic solar cost results in an impact of approximately NPV $375 million in the case of moving the retirement date of Schahfer 14/15 from 2023 to 2028. The figure below shows a comparison of the capital cost assumptions for the period 2029-2034 between Portfolio 4, where Schahfer 14/15 operate until 2028, and Portfolio 5, where Schahfer 14/15 retire in 2023. Other than the generic solar resources compared to the RFP solar resources, there are no resource differences after 2028 between the two portfolios. Thus, the differences in capital costs, taxes, and contract costs reflect the generic solar resource in Portfolio 4 compared to the solar PPAs from the RFP in Portfolio 5. The cost difference is clear, as shown by looking at the first five years after the generic solar units are placed in service:

Figure E

Annual Cost Impact of Generic Solar Resources vs. RFP Solar PPA[10]

$[redacted]

	Generic Solar Return Of, On and Taxes	Generic Solar Fixed O&M	Replaced RFP Solar Contract Cost	Generic Solar Impact on Net Market Purchases	Net Increase from Generic Solar Resource = Sum of All Columns
2029	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2030	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2031	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2032	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2033	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2034	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

[10] Data from NIPSCO 2018 Confidential Appendix D Tab Rev Req Components Retirements. Data is generated by subtracting entries in Portfolio 5 from entries for Portfolio 4. Note that the return of, on and taxes value contain small

For instance, in 2029, the fixed cost of the generic solar resource is $[redacted]annually, while the cost of the solar RFP it replaces is only $[redacted]. While some of that difference is due to a comparison of rate base recovery compared to a levelized RFP bid, note that even after these five years through to the end of the evaluation period, the generic solar resources never become less costly than the RFP PPA resources used in Portfolios 5, 6 and F.

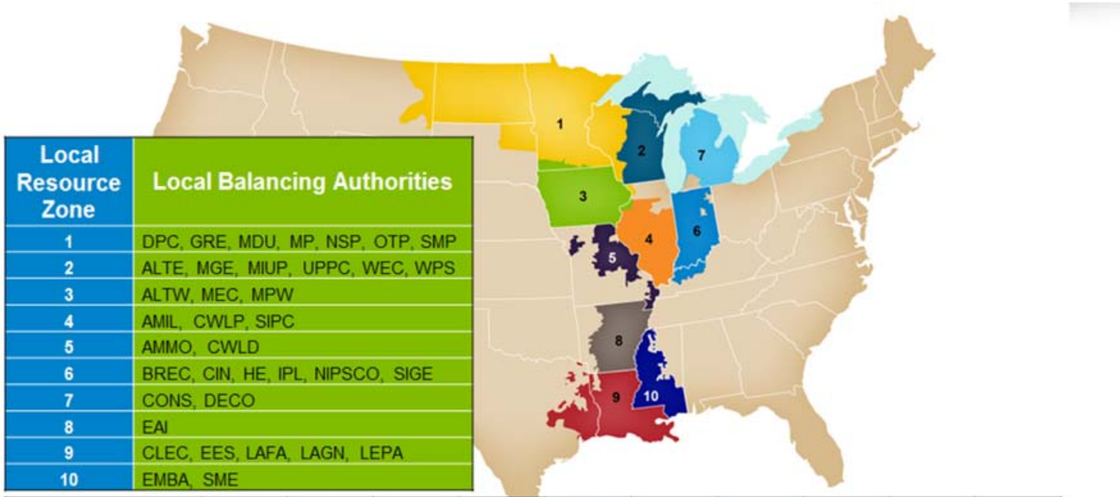
D. The IRP Uses ELCC and UCAP Values That are Too High For Indiana Wind Resources

Another flaw in the IRP is that NIPSCO estimates that the unforced capacity (UCAP) / effective load carrying capacity (ELCC) of wind resources is approximately 15% of the installed capacity of those resources. This is consistent with the average across the MISO system in 2017 of 15.2%, but the assigned UCAP for wind varies across the zones in the MISO system based on how likely the wind resource is to operate during MISO's peak demand hours. Further, MISO projects that, as wind penetration increases, the ELCC of wind resources will fall from the current 15.2% towards 12.5%. The spread of ELCC and UCAP across MISO is shown below:

amounts associated with difference in capital expenditures for Michigan City 12 between the two portfolios, but almost all of the amounts are associated with the generic solar units.

Figure F

Spread of MISO Wind UCAP Across Zones



Local Resource Zone	Local Balancing Authorities
1	DPC, GRE, MDU, MP, NSP, OTP, SMP
2	ALTE, MGE, MIUP, UPPC, WEC, WPS
3	ALTW, MEC, MPW
4	AMIL, CWLP, SIPC
5	AMMO, CWLD
6	BREC, CIN, HE, IPL, NIPSCO, SIGE
7	CONS, DECO
8	EAI
9	CLEC, EES, LAFA, LAGN, LEPA
10	EMBA, SME

Metric	MISO	Zone 1	Zone 2	Zone 3	Zone 4 and Zone 5	Zone 6	Zone 7	Zone 8	Zone 9	Zone 10
Registered Max (MW)	16,761	4,779	734	8,450	644	282	1,872	0	0	0
UCAP (MW)	2,548	873	76	1,310	58	21	210	0	0	0
ELCC %	15.2%	18.3%	10.4%	15.5%	9.0%	7.4%	11.2%	0.0%	0.0%	0.0%
Wind CPNode Count	207	72	11	86	8	4	26	0	0	0

Figure 1-1: MISO Local Resource Zones (LRZs) and Distribution of Wind Capacity

Compared with the 15.2% average ELCC for MISO, wind in Indiana only received an ELCC of 7.4%, i.e, less than half of the 15% used in NIPSCO's IRP. The higher ELCCs are in the Plains states, while the lowest is in Indiana. Using this inflated ELCC means that the cost of wind resources in the IRP is understated. If the UCAP for 1,000 MW of wind in a portfolio was only 74 MW (7.4%) instead of 150 MW (15%), that means NIPSCO should have included costs for an additional 76 MW of capacity. If capacity costs $100/kw-year, for example, that means each year should include an additional $7.6 million in costs, i.e., NIPSCO understates the wind resource cost by $7.6 million annually in this example.

The cost of replacing that capacity will be significant. NIPSCO assumes that MISO capacity costs will be approximately $25/kw-year in constant dollar terms. The UCAP at 15% ELCC for the wind resources in the preferred Portfolio F is 157 MW, so at 7.4% it would be 77 MW; the difference in UCAP between those two levels is 80 MW. At the capacity price level assumed by NIPSCO in its IRP, that is about $2 million annually in constant dollars, or about NPV $20 million by which NIPSCO is understating the cost of wind resources in Portfolio F. But NIPSCO's assumption for capacity pricing is based on a belief that marginal capacity is cheap, because regulated utilities are assumed to overbuild to 17%-19% reserve margins.[11] If one instead assumed that over time capacity would have to be priced at the cost of new entry of $84/kw-year,[12] the understatement of wind resource ELCC and UCAP would be NPV $68 million. In short, the IRP's failure to use the appropriate ELCC and UCAP values significantly understates the costs of the wind resources.

E. The IRP Fails to Include Increased Congestion and Transmission Costs

NIPSCO's IRP is also significantly flawed in that it excludes from consideration the cost of congestion and/or the costs of transmission to alleviate congestion associated with adding new renewable resources. The transmission cost associated with the retirement of the Schahfer coal units may not be all of the transmission cost required to ensure deliverability of a resource's power to NIPSCO's load at the price bid in the RFP. The RFP only required firm transmission delivery to MISO Load Zone 6. Load Zone 6 contains all of Indiana plus part of Kentucky. If a resource is sited or has firm transmission to a point not in NIPSCO's service territory, it could receive a locational marginal price below that required to serve NIPSCO's load. NIPSCO customers would have to make up the difference, either through increased commodity costs or through higher transmission costs to alleviate congestion. It appears that the higher wind ELCCs in MISO are outside of Indiana, so NIPSCO's assumption of a MISO-average wind ELCC without congestion costs is problematic. Further, as more renewables enter the MISO system, congestion and transmission costs will likely increase because the resources are not located where the loads are. NIPSCO has not evaluated those costs, as it notes in its IRP.[13]

F. The IRP Fails to Include Increased Ancillary Service Costs

NIPSCO's IRP has not included any estimate of higher ancillary service costs from portfolios that rely primarily on renewable resources. As more renewable resources are added to the MISO system, NIPSCO may see higher costs as MISO procures more spinning reserve, non-spinning reserve and regulation reserve products to fill in the gaps left by intermittent resources. Utilities elsewhere have estimated the cost of additional ancillary services to support renewables. There is no reason for NIPSCO not to perform such estimates in its IRP.

[11] NIPSCO IRP at 121.
[12] 2017 MISO State of the Market Report Analytical Appendix at 9.
[13] NIPSCO IRP at 177.

G. The IRP Does Not Project Degradation in Output for Owned Wind Generation

NIPSCO's IRP also fails to account for degradation in output as the resources age. Other utilities have recognized that degradation in output for wind resources does occur. As such, these limitations should have been reflected in the IRP's analysis of the value of new wind resources.

H. The IRP Unreasonably Assumes NIPSCO Can Utilize 100% of the Value of Tax Incentives

NIPSCO has not evaluated whether it can actually use all of the production tax credits (PTCs) and investment tax credits (ITCs) generated by a decision to move to a largely renewable portfolio including owned renewable generation, and instead unreasonably assumes it can use tax equity financing without any apparent loss of tax efficiency. If it cannot use all of the tax credits, or if there is leakage to outside investors in tax equity financing, then the costs of the renewable portfolios will be higher than it has estimated in its IRP.

I. The IRP Ignores Uncertainties Regarding Environmental Regulation

NIPSCO has included approximately $1.1 billion in capital costs as being required for continued operation of Schahfer 17/18, $220 million for Schahfer 14/15, and $54 million for Michigan City. These include costs for coal combustion residuals ("CCR") work, effluent limitation guideline ("ELG") requirements, a selective catalytic reduction ("SCR") system to control NOx emissions, and undefined other capital expenditures.

NIPSCO has also unreasonably included the equivalent of a continually escalating carbon tax in three out of four scenarios beginning in 2026, which adds hundreds of millions in cost on the coal units in each of those scenarios. While there is no certainty that most of these costs must be incurred in order to keep the coal units operating past 2023, the IRP opts for assumptions that drive costs for the coal units higher. If it is possible that environmental compliance costs may be delayed or go down, NIPSCO assumes with 100% certainty that they won't, but where there is uncertainty of whether a cost will be imposed in the future, as with CO2, NIPSCO assumes that either the cost will be imposed in a particular year or that it will only not be imposed if natural gas costs are also low (as in the Challenged Economy scenario). The fact that NIPSCO treats these costs as certain essentially preordains the outcome of the IRP for the Schahfer units.

On average for the years 2026-2035, the figure below shows an approximation of the annual NPVRR impact of NIPSCO's assumption that CO2 pricing will happen precisely in 2026 for each of the coal units by scenario:

Figure H
Average Annual NPVRR Impact of CO2 Tax for Coal Units by Scenario ($[redacted]
Years 2026-2035

	Base & Booming Economy	Aggressive Environmental
Michigan City 12	$[redacted]	$[redacted]
Schahfer 14&15	$[redacted]	$[redacted]
Schahfer 17&18	$[redacted]	$[redacted]

These impacts can be used to adjust comparisons of NPVRR between portfolios. For example, to adjust the cost of Portfolio 5 (the case with Michigan City operating until 2035), if one assumed no CO2 price, you would multiply the number of years from 2026 to 2035 (10 years) by the average annual NPVRR impact in the Base case of $[redacted] and determine the NPVRR of that case would decrease by approximately $[redacted] Similarly, in the Aggressive Environmental case, each year of delay has a $[redacted] annual revenue requirement impact, so a ten-year delay is worth NPV $[redacted]. To compare Portfolio 5 to Retirement Portfolio 6, you also have to adjust Portfolio 6 by three years of revenue requirement impact when the CO2 tax was in effect and Michigan City 12 was operating (2026-2028). So there is a net difference of seven years of NPVRR of CO2 costs at $[redacted] per year, or $[redacted] in the Base and Booming Economy cases. This puts Portfolio 5 on par with Portfolio 6 if the CO2 cost assumption is excluded for the years 2028-2035 (and without even considering the additional transmission and ancillary service costs discussed above that would need to be added to renewable heavy portfolios). Further, Portfolio 5 is even better than preferred Portfolio F by an additional $[redacted] in the Base and Booming Economy cases and $[redacted] in the Aggressive Environmental case.

J. <u>The IRP Uses Inflated Assumptions for Maintenance Capital Expenditures</u>

The IRP also uses inflated assumptions for maintenance capital expenditures. The six-year average maintenance capital expenditures for the Schahfer units for the years 2013-2018 was $[redacted] annually. This comes out to be $[redacted] kw-year for the Schahfer units in 2018 constant dollars. However, NIPSCO assumes the following maintenance capital expenditures going forward:

Figure I

Maintenance CapEx by Unit ($2018/kw-year)

	2013-2018 Average	Operate to 2023	Operate to 2028[14]	Operate to 2035
Schahfer 14/15	$[redacted]	$[redacted] (Preferred Portfolio)	$[redacted]	$[redacted]
Schahfer 17/18	$[redacted]	$[redacted] (Preferred Portfolio)	NA	$[redacted]

One can see that NIPSCO actually decreases assumed annual maintenance capital expenditures by nearly 1/4 from the average of the most recent six years in the cases it prefers, i.e., retire the Schahfer coal units in 2023. But in the cases where the units keep operating, NIPSCO increases the assumed maintenance capital expenditures by anywhere from 50% to 75%. The impact of these assumptions on NPRR relative to the six-year average is significant. For Schahfer 14/15, the case where the units run until 2028 should be cheaper by $[redacted] NPV compared to the preferred case where they retire in 2023, and for the 2035 operation case it would be NPV $150 million cheaper. For Schahfer 17/18 it would be NPV $[redacted] cheaper to operate until 2035.

K. The IRP Uses Inflated Assumptions for Fixed Operations and Maintenance Expenditures

NIPSCO has similarly inflated the cost of fixed O&M. For Michigan City, the average fixed O&M cost was $41/kw-year from 2013-2017. Allocating general administrative, engineering, fuel and environmental support costs of $7/kw-year leads to a five-year historical average of $48/kw-year. In the IRP, however, NIPSCO increases the fixed O&M assumption by [redacted]% from the five-year historical average. This leads to an increase of NPV $[redacted] for operation of Michigan City 12 from 2029-2035. For Schahfer 14/15, NIPSCO assumed that fixed O&M would increase on a constant dollar basis by [redacted]% from the historical average with overhead of $56/kw-year. This is an increase of NPV $[redacted] for operation through 2028. While one might expect fixed O&M to increase because of greater cycling demand on the coal units, it appears that the coal units cycle far less in the IRP modeling than actual results in 2013-2018. On

[14] Excludes the last two-three years prior to retirement from the average, as NIPSCO reasonably assumes lower capex for the last years of operation. Data from NIPSCO 2018 IRP Confidential Attachment D, tab UNIT FOM Capital – Retirements.

average in the modeling, Michigan City 12 and the Schahfer units run similarly to how they operated in 2013-2014, unlike the much lower capacity factors seen in 2015-2018.[15]

L. The IRP Uses Inflated Assumptions for Commodity Costs

NIPSCO did not use its recently renegotiated fuel prices in its IRP. Since lower fuel prices can change the dispatch of the units, the Aurora model would have to be re-dispatched to accurately calculate the decrease in costs associated with lower fuel costs. The impacts reported below are therefore minimums. If NIPSCO had used current prices as a baseline and then escalated those prices as before, without redispatch it would have lowered the cost of operating Michigan City 12 through 2035 in lieu of 2028 by NPV $[redacted] and lowered the cost of operating Schahfer 14/15 through 2028 in lieu of 2023 by NPV $[redacted]

M. The IRP Fails to Account for NIPSCO's Plan to Allow Large Industrial Customers to Procure Power From Other Sources

Another flaw in the IRP is its failure to account for NIPSCO's plan to allow large industrial customers to procure power from the wholesale market. NIPSCO is proposing changes in its tariffs to allow its five largest industrial customers, which make up 40% of its energy demand and 1,200 MW of load,[16] to access the market for most of their power needs. This could significantly decrease NIPSCO's need for capacity and energy from resources that it controls. These changes, which were not accounted for in the IRP, could significantly change its results. The portfolios are all constructed and dispatched based on a defined amount of needed capacity and energy, and purchases/sales to the market are used to balance each portfolio based on that defined need. If future needs are expected to decrease, it makes little sense to analyze long-term commitments based on ignoring that expected decrease.

ICARE also notes that although the Challenged Economy scenario assumes decreased industrial load, this is not sufficient to reflect NIPSCO's proposed new industrial structure across all of the IRP. There are any number of different things going on in the Challenged Economy scenario, and it cannot be relied upon as a guide to what would happen in the remainder of the scenarios if industrial load is significantly lower. For instance, the Challenged Economy case has high coal prices, but low natural gas and low power prices. The commodity price assumptions will

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[15] Comparison of capacity factors from NIPSCO 2018 IRP Confidential Appendix D to EIA 923 data.
[16] Director's Comments to NIPSCO's 2016 IRP at 26.

squeeze the economics of coal plants in the Challenged Economy case, and that result should not be transferred to other cases that do not have those commodity assumptions.

N. The IRP Excludes DSM Resources from Portfolio 1

No comparison can readily be made between Portfolio 1 (which is the only portfolio where all of the coal units operate beyond 2023 and the only one where Schahfer 17/18 operate past 2023) to any of the other portfolios on a NPVRR basis in terms of selecting resources or making retirement decisions. That is because the DSM resources that are acquired in all other portfolios are not included in Portfolio 1. As a result, Portfolio 1 will automatically have a higher cost because it must serve higher load and energy needs. NPVRR comparisons are a Utility Cost Test, and it is inappropriate to solely use that test as a basis for resource selection when the load forecasts being met are different.

O. The IRP Uses a Thirty-Year Net Present Value Revenue Requirement Planning Horizon

The IRP claims to present NIPSCO's long-term plan to supply electricity to its customers over the next twenty years. It also uses twenty year assumptions for the modeling inputs. In contrast, the IRP determines "cost to customer" using a 30-year period to determine the NPVRR of its portfolios.[17] This mismatch in planning horizon and NPVRR planning period appears inconsistent. The 30-year NPVRR planning period also stands in contrast to NIPSCO's 2016 IRP, which used a 20-year NPVRR to determine portfolio cost impact.[18]

The further one goes out in time for a forecast, the less certain the forecast assumptions can be. In addition, wind and solar resources typically have shorter service lives than conventional resources. Thus, it makes little sense to use a longer-term 30-year NPVRR when one cannot reasonably guess what type of resource will replace a renewable PPA or utility-build renewable resources.

III. Conclusion: The IRP Incorporates Flaws Designed to Enhance NIPSCO's Rate Base

The flaws ICARE has identified above are not mere errors in NIPSCO's IRP analysis; they reveal a process that was systematically biased towards early retirement of the coal units in favor of adding new renewable generation, including significant owned renewable generation, in order

[17] NIPSCO IRP at 150.
[18] NIPSCO 2016 IRP Appendix A, Exhibit 3 at p. 6.

to recapitalize NIPSCO's rate base and reward its investors. The table below shows the NPVRR impact of flaws that ICARE has been able to quantify:

Figure J

Aggregate Impact of Flaws and Unreasonable Assumptions
Base Case ($ Millions)

	AMOUNT BY WHICH PREFERRED PORTFOLIO F IS LOWER COST THAN PORTFOLIO 5 (Michigan City 12 retires in 2028 in Portfolio 5 and 2035 in Portfolio F)	**AMOUNT BY WHICH PREFERRED PORTFOLIO F IS LOWER COST THAN PORTFOLIO 4** (In Portfolio 4 Schahfer 14/15 retires in 2028 and Michigan City 12 retires in 2035, while in portfolio F Schahfer 14/15 retire in 2023 and Michigan City 12 in 2028)
NIPSCO'S IRP[19]	**(310)**	**572**
SOLAR COST MISMATCH	**NA**[20]	[redacted]
WIND UCAP AND COST OF NEW ENTRY	**(4)**[21]	**(4)**
CO2 PRICING	[redacted]	[redacted]
MAINTENANCE CAPEX	[redacted]	[redacted]
FIXED O&M	[redacted]	[redacted]
FUEL	[redacted]	[redacted]
TOTAL	**(442)**	**(216)**

As can be seen from the chart, it is always more economic to operate Michigan City 12 through 2035 compared to NIPSCO's preferred portfolio, even without adjustments, and there are no cases where it makes sense to declare a retirement date of 2028 for Michigan City in any scenario or under the Cost Certainty or Cost Risk metrics.

Furthermore, if more reasonable assumptions are made regarding the ongoing cost to operate Schahfer 14/15, it is likely that it is in ratepayers' interest not to decide today to retire those two units in 2023 in favor of preferred Portfolio F, while waiting to see if it is actually necessary

[19] NIPSCO 2018 IRP at 155 and 165, taking the difference in NPVRR between the portfolios.

[20] There is no mismatch in this case because NIPSCO's assumed generic solar resources replace Michigan City 12 in both scenarios. The mismatch between owned renewable generation in Portfolio F and renewable PPAs in Portfolio 5 is already captured in the first line of the table.

[21] Value is based on difference in the amount of wind resources between Portfolios 4 and 5 compared to Portfolio F. These portfolios have similar amounts of wind. The higher value for the impact of the high assumed wind ELCC discussed earlier applies where portfolios do not have similar amounts of wind, such as comparing Portfolio 1 to Portfolio F or Portfolio F to Portfolio F - No Wind.

to spend $133 million for ELG compliance by 2023.[22] If the ELG cost can be delayed and/or reduced, then it is likely economic to operate Schahfer 14/15 through at least 2028. Thus, it is in ratepayers' interest to at least wait until the next IRP to gather more data on possible changes to environmental regulations and more knowledge of operating cost. Finally, NIPSCO did not make a serious effort to gauge the optimal retirement date for Schahfer 17/18. Only one portfolio was evaluated with operating those units past 2023, and that portfolio simply cannot be compared to any other scenario because of the differences in DSM assumptions. Further, NIPSCO assumed such high costs for meeting environmental regulations that either do not exist (NOx requirement)[23] or are very uncertain (ELG and other costs) that it preordained a decision to retire these two units as soon as possible.

A primary goal of the IRP process is "a well-reasoned, transparent, and comprehensive IRP that will ultimately benefit customers, the utility, and the utility's investors."[24] ICARE believes that NIPSCO's IRP strays from this standard by skewing the results in favor of a resource portfolio that would increase the utility's profits. This IRP must be considered in context with NIPSCO's pending rate case, in which it requests accelerated depreciation to recover the sunk costs of the coal units, so that it can set the stage for recapitalizing its generation fleet with expensive new resources.

Based on its IRP analysis, in ten years, NIPSCO's rate base and earnings would be 5 times as large in its Preferred Portfolio F as in Portfolio 5 where Michigan City operates until 2035, and approximately twice as large as in Portfolio 6:

[22] The NPV changes shown for Schahfer 14/15 would also make Portfolio 4 superior to Portfolio F on the Cost Certainty and Cost Risk metrics in the IRP by $169 million and $47 million, respectively.
[23] The "preliminary" environmental compliance costs presented in NIPSCO's IRP at Appendix A, p. 247 assumed $448 million in incremental NOx capital expenditures for operating Schahfer 17/18 beyond 2023.
[24] Final Director's Report for the 2017 IRPs at p. 1.

Figure K

Rate Base and Earnings in 2029 ($[redacted][25]

	Portfolio 5 (Retire Michigan City in 2035)	Portfolio 6 (PPA Portfolio)	Portfolio F (Preferred Portfolio)
Rate Base	[redacted]	[redacted]	[redacted]
Return on Equity	[redacted]	[redacted]	[redacted]

As a comparison, rate base at the end of 2018 according to the IRP model was approximately $[redacted] and return on equity was approximately $[redacted]. By manipulating the results of the IRP, NIPSCO can move from an outcome where its rate base and earnings erode from operating coal units that become mostly depreciated over the next decade to one which recapitalizes its rate base with new, high-capital-cost resources. Moreover, it can do this despite the recapitalization portfolio costing ratepayers hundreds of millions more on a NPV basis and having large rate impacts over the next decade.

ICARE respectfully asks the Director to consider these comments in reviewing NIPSCO's 2018 IRP.

[25] NIPSCO 2018 IRP Confidential Appendix D at tabs DetailedFinOutputs Retirements 5, DetailedFinOutPuts Retirements 6 and DetailedFinOutputs Replacements F at cells N11 and N89.