REBUTTAL TESTIMONY OF KEITH B. PIKE
STRATEGIC ANALYTICS DIRECTOR - FHO
DUKE ENERGY CAROLINAS, LLC
ON BEHALF OF DUKE ENERGY INDIANA, LLC
CAUSE NO. 45253
BEFORE THE INDIANA UTILITY REGULATORY COMMISSION

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Keith B. Pike, and my business address is 1000 East Main Street, Plainfield, Indiana.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by Duke Energy Carolinas, LLC, a utility affiliate of Duke Energy Indiana LLC ("Duke Energy Indiana" or "Company" or "DEI") as Strategic Analytics Director – FHO, in the Analytical Engineering Group.

Q. ARE YOU THE SAME KEITH PIKE THAT PRESENTED DIRECT TESTIMONY IN THIS PROCEEDING?

A. Yes, I am.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. I will respond to the testimony of Wabash Valley Power Alliance ("WVPA") and Indiana Municipal Power Agency ("IMPA") witnesses Messrs. Wilmes and Smardo regarding the retirement date of Gibson Unit 5. I will rebut an analysis performed by OUCC witness Mr. Alvarez concerning operations and maintenance ("O&M") costs used in the 2018 Duke Energy Indiana Integrated Resource Plan ("IRP"). Lastly, I will also address at a high level various conceptual issues raised by the Sierra Club and Joint Intervenors[1] as it relates to the applicability of the 2018 IRP in this proceeding. Duke Energy Indiana rebuttal witness Mr. Scott Park will address challenges to the IRP process in greater detail.

II. GIBSON UNIT 5 RETIREMENT DATE

Q. WVPA AND IMPA WITNESSES MESSRS. WILMES AND SMARDO DISAGREE WITH YOUR STRATEGY REGARDING THE RETIREMENT OF GIBSON UNITS 4 AND 5, AND PROPOSE THAT DUKE ENERGY INDIANA RETIRE GIBSON UNIT 5 IN 2026.[2] HOW DO YOU RESPOND?

A. As the Gibson Unit 5 Joint Ownership Agreement requires unanimous agreement among the owners in order to retire the unit, achieving a consensus on the retirement date is a capital opportunity for Duke Energy Indiana that should not be dismissed. To the extent there is no material difference in the cost or performance of Gibson Unit 4 and Gibson Unit 5 (other than the Unit 5 scrubber), and the proposed scrubber flue gas crossover duct would be eliminated, I can fully support WVPA's and IMPA's recommendation as I indicated in my direct testimony on page 20 at lines 17-23.

Q. IF GIBSON UNIT 5 WOULD RETIRE IN 2026, WHEN WOULD GIBSON UNIT 4 RETIRE?

[1] Collectively the Citizens Action Coalition of Indiana Inc., Indiana Community Action Association, and Environmental Working Group.
[2] Wilmes direct testimony, pages 3-4, Q/A7 and Q/A8; Smardo direct testimony, pages 3-4, Q/A7 and Q/A8.

A. I view this change as a simple swapping of the retirement dates of Gibson Units 4 and 5. So, Gibson Unit 5 would retire in 2026, and Gibson Unit 4 would retire in 2034 along with Gibson Unit 3 and Noblesville. Please see Table 1 below, reflecting this change. Accelerating Gibson Unit 5's retirement date without also deferring Gibson Unit 4's retirement date would result in a further increase in depreciation expense in this proceeding, which would be undesirable for customers, and is unnecessary at this time. Duke Energy Indiana witnesses Mr. John Spanos and Ms. Diana Douglas present the impact of this change on depreciation rates and expenses in their rebuttal testimonies.

1 **Table 1: Generating Unit Existing and Updated Depreciation Retirement Dates**

Unit	Type	In Service Date	Current Dates: Retire Date	Current Dates: Age at Retirement	Updated Dates: Retire Date	Updated Dates: Age at Retirement
Cayuga 1	Coal	10/4/1970	2035	65.2	5/31/2028	57.7
Cayuga 2	Coal	6/22/1972	2037	65.5	5/31/2028	55.9
Edwardsport IGCC	Syngas CC	6/7/2013	2045	32.6	5/31/2045	32.0
Gallagher 2	Coal	12/1/1958	2023	65.1	12/31/2022	64.1
Gallagher 4	Coal	3/1/1961	2026	65.8	12/31/2022	61.8
Gibson 1	Coal	5/3/1976	2041	65.7	5/31/2038	62.1
Gibson 2	Coal	4/16/1975	2040	65.7	5/31/2038	63.1
Gibson 3	Coal	3/28/1978	2043	65.8	5/31/2034	56.2
Gibson 4	Coal	3/27/1979	2044	65.8	5/31/2034	55.2
Gibson 5	Coal	10/1/1982	2047	65.2	5/31/2026	43.7
Noblesville ST 1-2	CC	1/1/1950	2038	89.0	5/31/2034	84.4
Noblesville CT3-5	CT	4/1/2003	2038	35.8	5/31/2034	31.2
Cayuga CT4	CT	6/29/1993	2033	40.5	5/31/2028	34.9
Cayuga Diesel 3a-d	IC	6/1/1972	2015	43.6	5/31/2028	56.0
Henry County CT1	CT	7/31/2001	2041	40.4	5/31/2038	36.8
Henry County CT2	CT	8/11/2001	2041	40.4	5/31/2038	36.8
Henry County CT3	CT	8/25/2001	2041	40.4	5/31/2038	36.8
Madison CT1	CT	5/29/2000	2040	40.6	5/31/2041	41.0
Madison CT2	CT	5/29/2000	2040	40.6	5/31/2041	41.0
Madison CT3	CT	5/29/2000	2040	40.6	5/31/2041	41.0
Madison CT4	CT	5/29/2000	2040	40.6	5/31/2041	41.0
Madison CT5	CT	6/15/2000	2040	40.5	5/31/2041	41.0
Madison CT6	CT	6/29/2000	2040	40.5	5/31/2041	40.9
Madison CT7	CT	6/15/2000	2040	40.5	5/31/2041	41.0
Madison CT8	CT	6/29/2000	2040	40.5	5/31/2041	40.9
Vermillion CT1	CT	6/1/2000	2040	40.6	5/31/2043	43.0
Vermillion CT2	CT	6/1/2000	2040	40.6	5/31/2043	43.0
Vermillion CT3	CT	6/1/2000	2040	40.6	5/31/2043	43.0
Vermillion CT4	CT	6/1/2000	2040	40.6	5/31/2043	43.0
Vermillion CT5	CT	6/1/2000	2040	40.6	5/31/2043	43.0
Vermillion CT6	CT	6/1/2000	2040	40.6	5/31/2043	43.0
Vermillion CT7	CT	6/1/2000	2040	40.6	5/31/2043	43.0
Vermillion CT8	CT	6/1/2000	2040	40.6	5/31/2043	43.0
Wheatland CT1	CT	6/1/2000	2040	40.6	5/31/2043	43.0
Wheatland CT2	CT	6/1/2000	2040	40.6	5/31/2043	43.0
Wheatland CT3	CT	6/1/2000	2040	40.6	5/31/2043	43.0
Wheatland CT4	CT	6/1/2000	2040	40.6	5/31/2043	43.0
Markland 1-3	Hydro	1/1/1967	2030	64.0	4/30/2061	94.3
Crane	Solar	1/31/2017			5/31/2047	30.3
Camp Atterbury	Solar+Stor	12/31/2019			5/31/2045	25.4

Average Lives

	Current Dates: Age at Retirement	Updated Dates: Age at Retirement
Coal	65.5	57.7
CT	40.4	40.8

Q. HOW WOULD THIS CHANGE AFFECT THE DIVERSIFICATION OF DUKE ENERGY INDIANA'S GENERATING FLEET?

A. As I discussed in my direct testimony on page 18 at lines 13-16, the strategic fleet diversification benefit of retiring Gibson Unit 4 first was the opportunity to install a larger amount of renewable energy resources early in the planning horizon and reduce Duke Energy Indiana carbon emissions. Because Duke Energy Indiana only owns about half of Gibson Unit 5, swapping the retirement dates of Gibson Units 4 and 5 will reduce this need by 2026 in half, slowing the pace of diversification, and decreasing Company carbon emission reductions.[3] However, the opportunity to capitalize on unanimous agreement with the Gibson Unit 5 Joint Owners has more immediate value to customers. Absent this agreement now, there would be uncertainty even in the original proposed retirement date of 2034. Further, if Duke Energy Indiana objected now and held out its option to continue to operate the unit, the long-standing productive relationship we have had with the Joint Owners could become stressed, impacting other business relationships, such as wholesale, that are beneficial for retail customers.

On the surface, when Gibson Unit 4 retires with Gibson Unit 3 and Noblesville in 2034, that difference in capacity need would be carried forward allowing the 2034 natural gas combined cycle unit as shown in the 2018 IRP preferred portfolio to be supplemented with additional renewable resources.

[3] While there would be little net difference to the environment in total, retiring a jointly owned unit first versus a wholly owned unit will decrease the amount of Company-owned carbon emission reductions.

Duke Energy Indiana rebuttal witness Mr. Scott Park further discusses the potential portfolio impacts associated with this change.

Q. WOULD THIS CHANGE IMPACT DUKE ENERGY'S ABILITY TO ACHIEVE ITS 2030 CARBON EMISSION REDUCTION GOAL THAT YOU DISCUSSED IN YOUR DIRECT TESTIMONY[4] IN THIS PROCEEDING?

A. No, not materially. However, it is important to note that on September 17, 2019, Duke Energy announced[5] revisions to the corporate climate goal that was originally established in 2017.

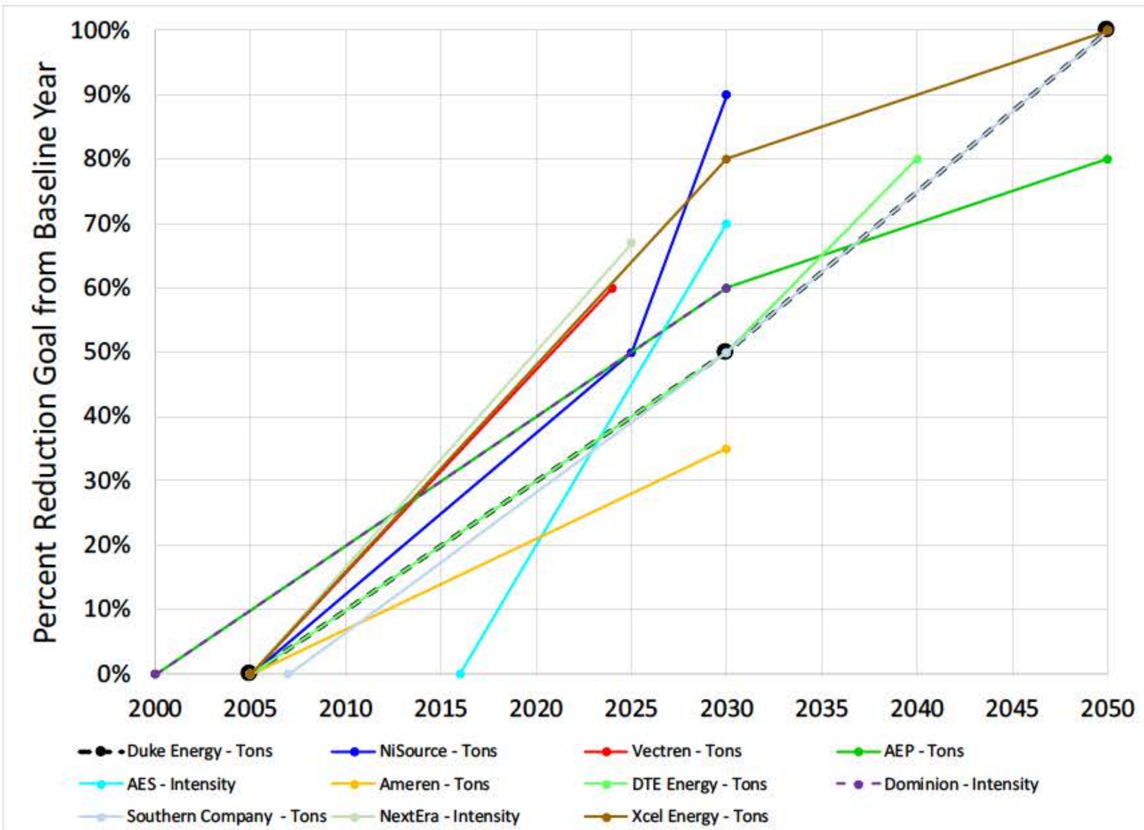
Q. PLEASE DESCRIBE THE REVISIONS TO THE GOAL THAT HAVE BEEN MADE.

A. The development of this new goal was informed by recent resource planning updates, ongoing changes in the industry, continued uncertainty and risk in national climate regulatory policy, and the continued evolution of our stakeholders' expectations. The changes are two-fold. First, the 2030 carbon emission reduction goal has been increased from 40% to "at least 50%," still from a 2005 emissions baseline. Second, consistent with more recent goals announced by our peer utilities, we have established a second-phase goal. This second-phase goal is for "net-zero" carbon emissions by 2050. Figure 1 below shows an updated compilation of CO_2 emission reduction goals over time for several Duke

[4] Duke Energy Indiana Direct Testimony, Exhibit 15, page 32 line 13 through page 35 line 2.
[5] https://news.duke-energy.com/releases/duke-energy-aims-to-achieve-net-zero-carbon-emissions-by-2050

Energy regional peer utilities. Our new 2030 goal is now the same as Southern Company and DTE Energy, while the new 2050 goal places Duke Energy in step with the most aggressive carbon reduction plans in the industry.

Figure 1: Peer Utility Carbon Reduction Goals



Q. PLEASE DISCUSS THE IMPLICATIONS OF THE NEW 2030 GOAL ON DUKE ENERGY INDIANA'S OPERATIONS, AND SPECIFICALLY THE CHANGE IN RETIREMENT DATES FOR GIBSON UNITS 4 AND 5.

A. As I indicated, the new Duke Energy 2030 corporate climate goal was informed by the results of the 2018 Duke Energy Indiana IRP. The Cayuga Station and Gibson Unit 4 retirements as shown in the preferred portfolio in 2028 and 2026 respectively would support the Company in meeting the new 2030 goal. While Company-owned carbon emissions in 2030 will increase versus the IRP preferred portfolio, all else the same, a swapping of the Gibson Unit 4 and Gibson Unit 5 retirement dates should not materially impact our ability to achieve this goal. Again, the goal is corporate-wide, so ebbs and flows in emissions will be strategically managed across the enterprise.

Q. WHAT ARE THE RESULTING USEFUL LIVES OF THE GIBSON UNITS 4 AND 5 FOR THE DEPRECIATION STUDY AS A RESULT OF THIS CHANGE?

A. The swapped retirement dates for Gibson Units 4 and 5 result in lives of 55 years for Gibson Unit 4 and 44 years for Gibson Unit 5.

Q. DO YOU CONSIDER THE RESULTING USEFUL LIVES OF THESE GIBSON UNITS STILL TO BE REASONABLE?

A. Yes, I do. In our original proposal with the scrubber flue gas crossover duct, the units' scrubbers were already retiring on this schedule. Further, referring back to Table 1 on page 10 of my direct testimony, numerous of our peer utilities in the state have proposed coal unit retirements in the upper-30s to lower-40s years of life, and a retirement age of 55 years is in the mid-to-high end of the range of our peers. Both lives are reasonable, and are in line with the range seen in industry based on unit-specific circumstances.

III. OUCC IRP-BASED O&M ANALYSIS

Q. OUCC WITNESS MR. ALVAREZ CONDUCTS AN ANALYSIS USING THE O&M COSTS INCLUDED IN THE 2018 IRP, EXCLUDING EDWARDSPORT, AS A BASIS FOR RECOMMENDING A REDUCTION TO DUKE ENERGY INDIANA'S O&M EXPENSE REQUEST AS DISCUSSED IN THE DIRECT TESTIMONY OF COMPANY WITNESS MR. MOSLEY.[6] DO YOU AGREE WITH MR. ALVAREZ'S ANALYSIS AND CONCLUSIONS?

A. No, I do not agree. While Mr. Alvarez's general theory that Duke Energy Indiana could recover O&M costs as represented in the IRP is intriguing, there are several problems with his analysis that render his conclusions faulty and moot.

Q. WHAT ARE THE PROBLEMS WITH MR. ALVAREZ'S ANALYSIS?

A. There are three critical problems with Mr. Alvarez's analysis. First, his assessment of planned outage costs is completely arbitrary and meritless. As this issue is beyond the scope of the IRP, Duke Energy Indiana witness Mr. Mosley addresses it in his rebuttal testimony. Second, Mr. Alvarez only included the fixed component of O&M cost as modeled in the IRP in his analysis. In the IRP, there are two components of total O&M: fixed and variable. His omission of the variable O&M component excludes significant real costs from his analysis, including emission control reagents, coal and waste handling, and other outage

[6] Alvarez direct testimony, page 6 line 10 through page 9 line 13.

and non-outage variable maintenance expenses as so-modeled. Third, Mr. Alvarez failed to recognize that the source for the fixed O&M costs in the IRP he used as a basis for his analysis were in constant year 2017 dollars; Mr. Alvarez failed to inflate the costs into the appropriate year nominal dollars.

Q. IF THESE PROBLEMS REGARDING USE OF THE AS-MODELED IRP O&M COSTS WERE CORRECTED, WHAT WOULD BE THE RESULT OF MR. ALVAREZ'S ANALYSIS?

A. Table 2 below depicts the spirit of Mr. Alvarez's analysis, but with the correct inclusion and treatment of all the as-modeled IRP O&M cost data[7] (still excluding Edwardsport). This corrects his Confidential Table 1 from page 9 of his direct testimony.

[7] As provided to the Commission and the OUCC with the submission of the 2018 IRP, and also as provided in discovery in Confidential Attachment Sierra Club 1.16-D(3).

Table 2: 2018 IRP As-Modeled O&M Costs, Excluding Edwardsport

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The resulting 2020-2024 average of the total O&M cost as-modeled in the IRP is \$258M, which in converse to Mr. Alvarez's conclusion, is actually much higher than the \$229M of total 2020 O&M proposed by Duke Energy Indiana.[8] However, the IRP includes some O&M costs that are outside the purview of Mr. Mosley's functional budget, namely property taxes and insurance costs. Deducting the IRP as-modeled property taxes and insurance costs[9] results in an apples-to-apples comparison of \$243M, which is nearer yet still higher than the

[8] Mosley direct testimony at page 27, line 14 (Table 9).
[9] A breakdown of fixed O&M costs, including property taxes and insurance, was provided in discovery response IG 20.2.

Company's request. However, this outcome is logical considering that we are taking an average of escalating costs into the future; for example, the average of twenty years of escalating costs is logically higher than the first-year cost. So as a final comparison, I de-escalate the future costs into constant year 2020 dollars, and the 2020-2024 average is $232M.

Considering that the IRP O&M cost forecast is still just from a model, compared to Mr. Mosley's detailed operations and maintenance budget, the remaining difference is immaterial to the Company's $229M request. As such, Duke Energy Indiana would not propose to seek this additional amount, up to $243M in nominal terms, based on Mr. Alvarez's proposal of using IRP as-modeled O&M costs to establish O&M expense for this proceeding. And as a final point, the IRP O&M does not include a line-item cost for Crane Solar, so its appropriate inclusion would only serve to even further increase the request.

Q. MR. ALVAREZ PERFORMED HIS ANALYSIS USING A SEVEN-YEAR AVERAGE PERIOD OF 2020-2026, WHEREAS YOU HAVE ASSESSED THE PERIOD 2020-2024? WHY THE DIFFERENCE IN YOUR ANALYSIS?

A. Mr. Alvarez's use of a seven-year average period was based on a flawed and meritless assessment of planned outage costs. Typically, Duke Energy Indiana models O&M costs (fixed and/or variable) used for long-term IRP modeling purposes as long-run costs. They are not generally intended to be comparable to any specific year of near-term cost projection that may be budgeted and/or otherwise forecasted with fine detail, including any expectations of timing for planned outages. Therefore, the use of an averaging period is appropriate.

However, when properly including the variable O&M component in the analysis as I have done, it is clear that starting in 2025 the variable O&M costs decrease notably. That is because this set of data is from the Reference Carbon scenario as modeled in the IRP, and includes the inception of a carbon price in 2025 that drives down the dispatch of the coal units in the IRP model. Some of this reduction in variable O&M is from emission control reagents; as Duke Energy Indiana is requesting to continue to track emission control reagent costs in this proceeding, those reductions would naturally flow to customers if such a future were to occur. Therefore, it is inappropriate to consider that cost reduction in the average, as it would essentially be double-counted. I therefore stop my averaging period in 2024. However, solely for demonstration purposes, in Table 2 I do also include results for the nominal averages through 2025 ($238M) and 2026 ($232M), both of which are still in excess of the Company's $229M request.

Q. HOW DO YOU SUGGEST THE COMMISSION CONSIDER MR. ALVAREZ'S RECOMMENDATIONS DERIVED FROM HIS ANALYSIS?

A. Mr. Alvarez's attempt to undermine Duke Energy Indiana's rigorous and thoughtful O&M expense budget is turned upside down when the correct, complete, and apples-to-apples comparable cost data from the IRP is used. I am not at all surprised that the O&M cost as-modeled in the IRP is in fact very representative of the Company's costs, and consistent with our O&M expense request in this proceeding – Duke Energy Indiana takes seriously its IRP modeling process. The Commission should therefore disregard Mr. Alvarez's recommendations on this topic, and approve Duke Energy Indiana's O&M expenses as indicated in Mr. Mosley's direct testimony.

Q. OUCC WITNESS MR. ALVAREZ CONDUCTS A VERY SIMILAR ANALYSIS USING THE O&M COSTS INCLUDED IN THE 2018 IRP FOR EDWARDSPORT, TO REACH A SIMILAR RECOMMENDATION TO REDUCE THE COMPANY'S O&M EXPENSE REQUEST FROM THAT DISCUSSED IN THE DIRECT TESTIMONY OF COMPANY WITNESS MR. GURGANUS.[10] WHAT IS YOUR OPINION OF MR. ALVAREZ'S ANALYSIS AND CONCLUSIONS REGARDING EDWARDSPORT'S O&M COST?

A. My opinion of Mr. Alvarez's analysis and recommendations regarding Edwardsport's costs is the same as for his analysis of the rest of the generation fleet: it is fundamentally flawed. He mixes information from various discovery responses that span different scenarios from the IRP, as well as different dollar basis (constant 2017 dollars vs nominal dollars) for which he fails to correct.[11]

[10] Alvarez direct testimony, page 17 line 8 through page 19 line 13.
[11] Confidential Attachment IG 8.3-A depicts fixed O&M costs for Edwardsport as modeled in the Reference No-Carbon scenario in the IRP in nominal dollars, which Mr. Alvarez intermixes with fixed O&M cost streams from the Reference Carbon scenario depicted in constant year 2017 dollars.

And just as above, he again also completely omits the variable O&M component of the as-modeled IRP costs.[12]

Q. IF THESE PROBLEMS REGARDING USE OF THE AS-MODELED IRP O&M COSTS FOR EDWARDSPORT WERE CORRECTED, WHAT WOULD BE THE RESULT OF MR. ALVAREZ'S ANALYSIS?

A. Table 3 below depicts the spirit of Mr. Alvarez's analysis for Edwardsport, but again with the correct inclusion and treatment of all the as-modeled IRP O&M cost data. To create an apples-to-apples comparison, I also include a reasonable and appropriate correction for the inadvertently omitted portion of the Edwardsport variable O&M rate, as well as a deduction for the 2020 planned outage. The nominal average result, about \$83M, compares to the Company's non-outage request of about \$99M from Mr. Gurganus' direct testimony.[13] The IRP 2020 test year value is about \$86M, with costs declining in real dollars thereafter due to embedded assumed cost savings and efficiencies as discussed by Mr. Gurganus. Table 3 below corrects Confidential Table 5 from page 18 of Mr. Alvarez's direct testimony.

[12] In response to discovery request OUCC 30.4, Duke Energy Indiana also recognized and disclosed an error in the 2018 IRP modeling wherein a portion of the Edwardsport variable O&M rate was inadvertently omitted from the IRP model. Therefore, it would be appropriate to correct (increase) the as-modeled variable O&M cost component for purposes of this analysis to reflect the total variable O&M rate for Edwardsport that would be consistent with the fixed O&M cost component as modeled. Mr. Alvarez failed to recognize or to address this in his analysis.

[13] Gurganus direct testimony at page 16, line 18. \$145.8M total - \$46.4M outage = \$99.4M non-outage.

Table 3: 2018 IRP As-Modeled O&M Costs - Edwardsport

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Q. FROM YOUR ANALYSIS, EDWARDSPORT'S AS-MODELED AVERAGE COST IN THE IRP IS STILL SIGNIFICANTLY LOWER THAN THE COMPANY'S REQUEST, EVEN IN THE 2020 TEST YEAR. HOW SHOULD THE COMMISSION EVALUATE THIS RESULT?

A. I have already properly demonstrated above that using as-modeled long-run O&M costs from an IRP is not an appropriate substitute for rigorously developed budgets at the functional level. The Commission should avoid establishing this as any type of precedent for setting O&M expenses in a rate case, and approve the Company's O&M expenses as requested by Messrs. Mosley and Gurganus. Any future cost savings that may be achieved at Edwardsport will help offset any real cost escalation at the other generating facilities in between rate cases, and will be reflected in rates set in future rate cases.

However, should the Commission find compelling Mr. Alvarez's argument to use the IRP as-modeled costs for Edwardsport, then I would argue for an "all-or-nothing" approach. All combined, the as-modeled O&M costs in the IRP are materially the same as the Company's total request for Generation (see Table 4 below). While Mr. Alvarez broke out Edwardsport in his analysis, he did not break out every Gibson unit, or the Cayuga units, to perform a similar comparison of the IRP as-modeled costs to the Company's functional budgets; some are likely higher, and some are likely lower. The Commission should not pick and choose which aspects of the IRP analysis to consider based on an individual unit breakout from the total. The Commission should therefore either approve the Company's request in total, or approve the as-modeled IRP costs in total.

Table 4: Summary Comparison of IRP and Company O&M Requests

millions of dollars	Duke Energy Indiana Generation O&M Request	2018 IRP Comparable As-Modeled Costs, 2020-2024 Average
Generation, excluding Edwardsport	$228.7	$243.6[14]
Edwardsport, non-outage	$99.4	$82.8
Total	$328.1	$326.4

IV. INTEGRATED RESOURCE PLANNING CONCEPTS

Q. SIERRA CLUB AND JOINT INTERVENORS CONTEND THAT DUKE ENERGY INDIANA PERFORMED THE 2018 IRP WITH A BIAS AGAINST COAL UNIT RETIREMENTS, AND THAT DUKE ENERGY INDIANA SHOULD REASSESS ITS COAL UNITS FOR NEAR-TERM RETIREMENT. HOW DO YOU RESPOND?

A. The fundamental purpose of the IRP in this proceeding is to support reasonable depreciation rates for the Company's generation assets. Duke Energy Indiana is not requesting any type of formal approval of future generating unit retirements, nor pre-approval of future new generation resources in this proceeding. There are no notable resource actions planned between now and the time the Company will file its next IRP in 2021, when the system will be re-evaluated again. Nothing is locked-in at this point. Sierra Club and Joint Intervenors are attempting to use their criticisms of the IRP as a platform to advance their own radical agenda of

[14] As mentioned above, the $243.3M value from the IRP analysis still excludes O&M costs for Crane Solar. That amount, roughly $325k, is added on for purposes of the comparison table.

shutting down coal-fired generating units as fast as possible, whether or not that is in the best interests of customers. It would clearly be a great disservice to customers to assume such dramatic coal unit retirements as implied by Sierra Club and Joint Intervenors in this proceeding – it would only go to dramatically raising depreciation expense, and is unnecessary at this time. Sierra Club and Joint Intervenors are the only parties that seem to protest our IRP preferred portfolio as unreasonable. Other interests, such as the witness for the Indiana Laborers District Council, Mr. Frye, espouse the negative impacts on the workforce and the economies of local communities from accelerated plant shutdowns. And, other intervenors, such as the OUCC and Industrial Group, generally do not take issue with the planned retirement dates. The Company's goal is to find a balance that takes measure of all of the implications of our proposed resource plan, and we believe our preferred portfolio does that.

Q. SIERRA CLUB WITNESS MR. COMINGS CONTENDS THAT DUKE ENERGY INDIANA'S COAL FIRED GENERATING UNITS ARE MORE EXPENSIVE TO OPERATE THAN OTHER ALTERNATIVE RESOURCES TODAY. DO YOU AGREE?

A. No. Mr. Comings focuses on a dollar per megawatt-hour ($/MWHR) energy cost metric. This is a flawed and meritless comparison in my opinion. A simple "profit-and-loss" analysis is not resource planning. Further, Duke Energy Indiana witness Mr. John Swez discusses the inaccuracies in his dispatch assessment.

Duke Energy Indiana is obligated to provide service to customers 24x7x365. Mr. Comings' premise would have us shut down our high capacity factor dispatchable coal-fired units (and presumably everyone else's similarly situated fossil-fuel units in the State and elsewhere), and replace them with market purchases,[15] peaking units,[16] or other alternatives (presumably solar and/or wind resources) as that would purportedly be a lower cost. However, it would clearly not provide equivalent energy resources to the system. In addition, ironically, Joint Intervenors witness Ms. Sommer's report on the 2018 IRP conversely alleges that the market purchases in our modeling portfolios are already too high.[17]

A clear shortfall in Mr. Comings' analysis is his failure to address market depth in any way; if Duke Energy Indiana were to remove his estimated **<<CONFIDENTIAL BEGIN>>** [redacted] **<< CONFIDENTIAL END>>** of energy per year from the grid,[18] the market price would most certainly have to increase to incent its production from other resources. That is simple supply and demand. This would erode his purported cost savings and risk the reliability of the grid.

The contradiction between Mr. Comings and Ms. Sommer highlights a very important facet of resource planning. If we follow Mr. Comings' premise

[15] Comings direct testimony, page 13 lines 8-9.
[16] Comings direct testimony, page 20 lines 3-4.
[17] Joint Intervenor Exhibit 4, Attachment AS-2, page 13 Section 3.2.
[18] Comings direct testimony, page 39, Confidential Table 7.

further, and we installed all solar energy resources, for example, this would result in everyone having lights on and access to power during the day (assuming that day is sunny), and everyone having no power at night. And if all utilities and power producers followed the same strategy, then there would be no market, as all entities would be trying to sell excess solar to each other during the day, while trying to buy from absent resources at night. While this simple example would perhaps have achieved Sierra Club and Joint Intervenors' goal of purportedly lowest cost of energy, such a scenario obviously fails miserably from a resource planning perspective. To remedy this 24x7x365 service deficiency, the system would have to be bolstered with additional resources, as well as extended-range energy storage, rapidly eroding the Sierra Club and Joint Intervenors' contention of lowest cost. Simple profit-and-loss analyses are not instructive for resource planning, which is one reason why we utilize complex modeling and forecasting tools that take consideration of all service obligations. The goal of resource planning is not merely to find the lowest cost system, but rather to find the lowest cost system that can actually succeed in serving customers reliably.

Q. MR. COMINGS DERIVES THE VARIABLE O&M COST COMPONENT OF HIS PROFIT AND LOSS ANALYSIS FROM THE PRODUCTION DEMAND/ENERGY STUDY.[19] IS THIS AN APPROPRIATE SOURCE

[19] Comings direct testimony, footnote 3, page 10, for example.

TO ESTIMATE THE VARIABLE O&M COMPONENT OF THE COMPANY'S PRODUCTION COST OFFERS?

A. No, it is not. Mr. Comings has used the annual absolute dollar-cost data within the Production Demand/Energy Study (roughly three years of historical data, 2016-2018) to calculate annual variable O&M costs and rates (*i.e.,* $/MWHR) for each facility that he uses in his analysis. He then concludes that the Company's generating units suffered economic losses, and that the units' production cost offers to MISO were two low. While the execution of the Production Demand/Energy Study is an important and necessary part of the Cost of Service Study, it is inappropriate and inaccurate to consider it explicitly representative of a fixed O&M (demand) and variable O&M (energy) split on an absolute-dollar cost basis for consideration in a unit's annual economic position, or instant production cost offer. The results of the Production Demand/Energy Study are only intended to inform a high-level percentage apportionment of test year O&M costs in the Cost of Service Study.

Q. PLEASE DESCRIBE HOW MR. COMINGS HAS MISUSED THE PRODUCTION DEMAND/ENERGY STUDY.

A. Within the Production Demand/Energy Study, the historical O&M cost data is parsed into demand and energy segments via a "definition" of variable O&M – that is, specific cost types residing in specific FERC accounts. These variable O&M costs can generally be thought of in two buckets. The first bucket of variable O&M contains variable costs that are instantly incurred as a generating unit operates. Those costs include emission control reagents (*i.e.,* limestone, ammonia, etc.) that are instantly consumed as fuel is burned, fuel handling and waste handling costs, and emission allowance costs. These costs are characterized and included in the Company's production cost offers. It is reasonable and appropriate to include them in an annual assessment of profit and loss as Mr. Comings has done, because they are instantly incurred. For example, if a generating unit runs more, the costs instantly incurred increase, but the variable O&M cost rate stays the same.

The second bucket of the variable O&M definition contains costs that are not instantly incurred, but rather accumulate with time and are eventually periodically expensed. Planned outage maintenance expenses are the largest component of such costs. From a variable O&M cost rate perspective (again, *i.e.*, $/MWHR), we estimate a long-run average variable O&M rate for planned outage expenses across a full maintenance cycle of a unit and include that in the Company's production cost offers. Large planned outage expenses are concentrated in time but provide operating value to the units across time. Therefore, for these types of variable costs, it is not reasonable or appropriate to include them in an annual assessment of profit and loss as Mr. Comings has done.

Q. PLEASE DESCRIBE HOW MR. COMINGS' MISUSE OF THE PRODUCTION DEMAND/ENERGY STUDY HELPS LEAD HIM TO HIS CONCLUSIONS.

A. It clearly stands to reason that a variable O&M cost (or rate) calculated on an individual historical year basis that includes a large planned outage maintenance expense (which the Production Demand/Energy Study contains) would be much higher than a long-run average variable O&M cost (or rate). Yet further, the fact that net generation output is typically reduced in planned outage years makes such an individual year calculated variable O&M rate even more biased. And that is exactly the result we see from Mr. Comings' analysis.[20]

First take Cayuga Station for example. The Cayuga units only experienced small short planned maintenance outages, one per unit per year during the reference timeframe, and Mr. Comings' analysis notes relatively small cost rate differences, even negative, for Cayuga in his cost analysis. Conversely for Edwardsport, there is a very significant cost rate difference in his analysis in 2016, the year of a full site major outage, but then smaller differences in 2017 and 2018 which each had only minor outages. Similarly, the cost rate differences for Gibson are largest in 2016 and 2017 where there were major outages on some units, and smaller in 2018 where there were no large planned outages performed. The trend fits exactly.

Q. HOW SHOULD THE COMMISSION CONSIDER MR. COMINGS' RECOMMENDATIONS REGARDING DISALLOWANCES FOR THE LOSSES HE CALCULATES?

[20] Comings direct testimony page 35, Confidential Table 5.

A. While Company witness Mr. Swez demonstrates in his rebuttal testimony that Mr. Comings is comparing apples and oranges anyway in mixing average and incremental cost bases, his use of the Production Demand/Energy Study as a basis for annual variable O&M cost and rate only further undermines the reasonableness and validity of his analysis. Logically, concentrated expenses for the execution of planned maintenance outage events should not be perceived as contributing to "losses" on an annual basis as Mr. Comings attempts to do. The Commission should therefore disregard his recommendations and find that the Company's operating and maintenance practices are reasonable.

Q. JOINT INTERVENOR WITNESS MS. SOMMER TAKES ISSUE WITH DUKE ENERGY INDIANA'S LIMITATION ON COAL UNIT RETIREMENTS IN THE 2018 IRP, SPECIFICALLY THAT TRANSMISSION CONSTRAINT ASSUMPTIONS LIMITING RETIREMENT ELIGIBILITY TO 2024 WERE IMPROPER, AND NEWER ANALYSIS INDICATES MINIMAL CONSTRAINTS.[21] IS THIS CORRECT?

A. It is true that Duke Energy Indiana established assumptions regarding coal unit retirement transmission constraints for 2018 IRP modeling purposes based on a vintage 2016 internal retirement transmission impact analysis, which was the information available at the time. And it is also true that the Company updated

[21] Sommer direct testimony, page 5 lines 28-32.

this study in 2019, but that it was too late to be taken into consideration in the 2018 IRP. It is further true that the 2019 study revealed fewer transmission constraints to coal unit retirements than the 2016 study. However, such transmission impacts are constantly changing as various generation and transmission projects enter and leave the MISO planning queue. The internal studies that Duke Energy Indiana performs are informal, directional, and at a point in time. In the end, MISO performs the actual formal transmission impact study once an entity actually files for a unit retirement, at which point such retirement becomes a non-rescindable commitment. Since it would be imprudent to commit to a unit retirement a long time in advance, we must rely on the internal studies as directional only, at whatever point in time they are available.

Q. SO, BASED ON THE LATEST 2019 TRANSMISSION IMPACT STUDY, SHOULD DUKE ENERGY INDIANA REASSESS THE OPPORTUNITY TO RETIRE ITS COAL UNITS BEFORE 2024?

A. No. I believe that 2024 is still a reasonable date for early coal unit retirements for IRP modeling purposes. There is much more to it than just remedying any transmission system impact. Other practical constraints and considerations include a smooth and thoughtful transition of the labor force; managing local community impacts; allowing sufficient lead-time to manage the roll-off of long-term coal contracts; allowing sufficient minimum lead-time for the construction of new dispatchable resources (if we were to promptly retire thousands of megawatts of high capacity factor dispatchable resources, the system would demand replacement units with similar dispatchable characteristics, which as I have already established, intermittent renewable generating facilities alone could not provide); managing the rate impacts to customers of dramatically accelerated depreciation; and also giving due consideration to corporate cash flow and credit constraints for funding what would be a large replacement build in a short timeframe. Quite clearly, the Duke Energy Indiana 2018 IRP preferred portfolio, as modified with the Gibson Unit 4-5 retirement date swap, spreads out the coal unit retirements in a prudent and reasonable way so as to enable effective management of these challenges.

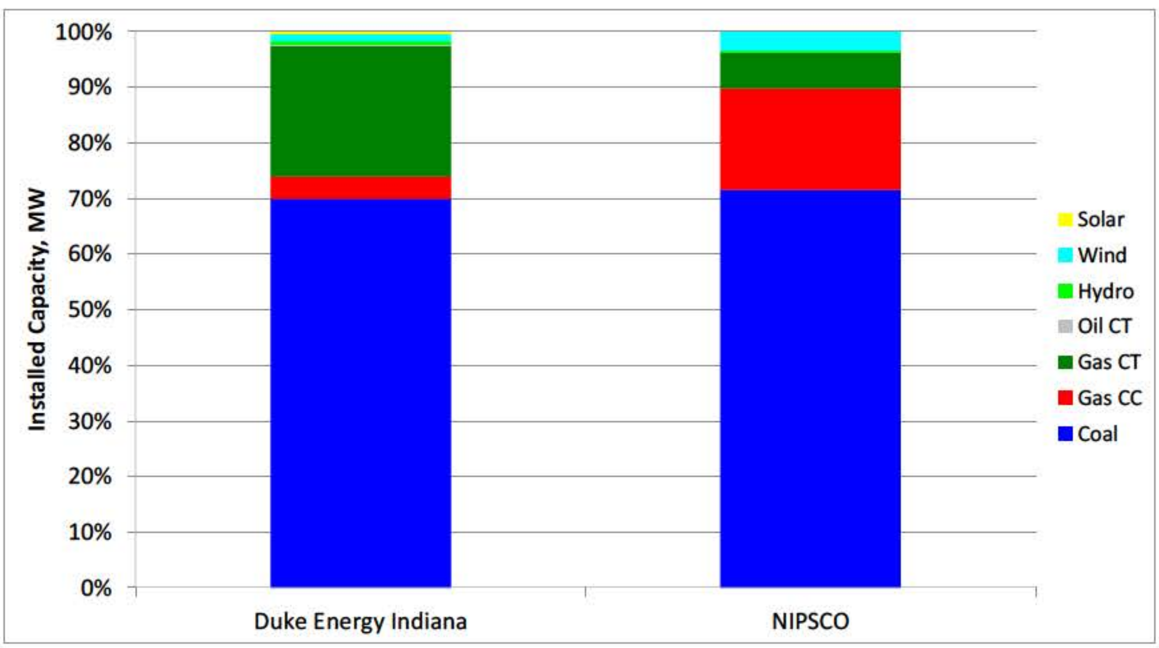
Q. MR. COMINGS POINTS TO THE NIPSCO[22] RESOURCE PLAN AND IMPLIES THAT RAPID COAL UNIT RETIREMENTS AND TRANSITION TO RENEWABLE RESOURCES COULD BE ECONOMIC FOR DUKE ENERGY INDIANA.[23] DO YOU AGREE?

A. No. No two utilities, let alone any two coal units, are situated exactly alike. There are very notable structural and cost differences between NIPSCO and Duke Energy Indiana that help explain why the NIPSCO coal units may be more economic to retire than the Duke Energy Indiana coal units in an IRP. Four important differences are the existing fleet makeup, degree of environmental compliance, coal supply and cost, and O&M cost rates.

[22] Northern Indiana Public Service Company.
[23] Comings direct testimony, page 25, lines 6-8.

First, NIPSCO already has a newer-technology larger-scale natural gas combined cycle installed on its system, the Sugar Creek combined cycle. This existing lower carbon emitting dispatchable resource provides NIPSCO a head-start towards managing a system with a higher portion of renewable energy. Figure 2 below shows the percentage split by resource type for Duke Energy Indiana and NIPSCO. As I have already discussed, Duke Energy Indiana would need to install similar higher capacity factor dispatchable resources along with renewables in order to manage any significant level of coal unit retirements.

Figure 2: Existing Capacity Resource Breakdown



Second, the Duke Energy Indiana coal units at Cayuga and Gibson Stations are fully controlled for sulfur dioxide, nitrogen oxides, particulate matter, and mercury, and have already been converted to full dry flyash and bottom ash management, with water re-direction away from legacy ash ponds. Edwardsport

IGCC also represents the most advanced emissions controls available for a coal-fired unit. Conversely, three of the NIPSCO coal units lack selective catalytic reduction systems for nitrogen oxide control, and NIPSCO has deferred some Coal Combustion Residuals Rule ("CCR") and Steam Electric Effluent Limitations Guidelines Revisions ("ELG") compliance investments. These deferred investments act as avoidable capital and O&M cost benefits in an IRP retirement analysis.[24]

Next, Duke Energy Indiana utilizes predominantly Illinois Basin coals, most of which comes from within Indiana. NIPSCO burns a mix of sub-bituminous coals from the Powder River Basin (Wyoming) along with some Illinois and Appalachian coals (see Figure 3). As discussed by Duke Energy Indiana witnesses Mr. Mosley and Mr. Phipps in their direct testimonies, with its buying power Duke Energy Indiana has achieved notable reductions in its coal contract costs in recent years. As a result, Duke Energy Indiana's production costs are lower than NIPSCO's, and that is directly reflected in the higher realized capacity factors of the Duke Energy Indiana coal units, by at least a full twenty to twenty-five percentage points (see Figure 4).

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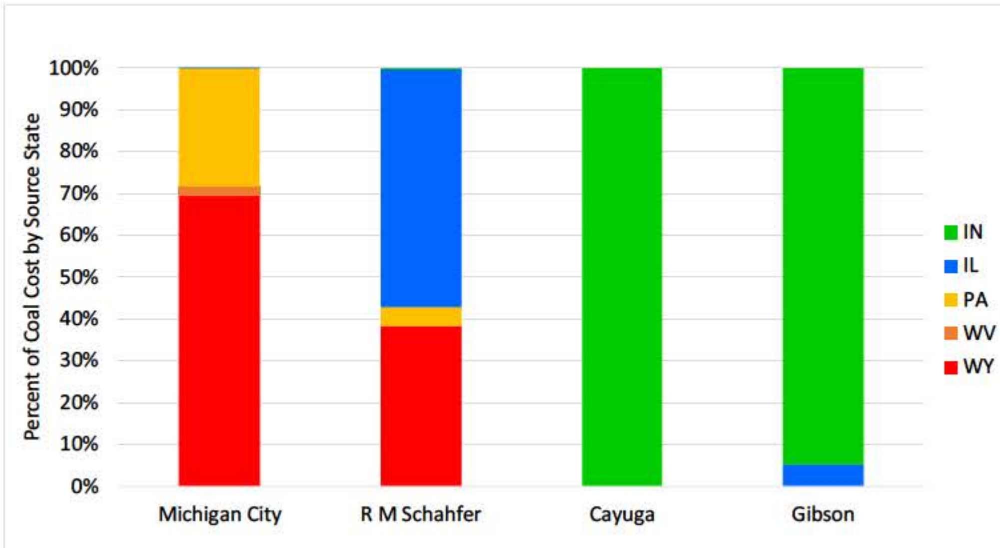
[24] For example, NIPSCO assumed selective catalytic reduction system installations at Schahfer Units 17-18 were avoided with 2023 retirement, saving $448M. They also assumed up to $460M in avoided CCR/ELG investment at Schahfer Units 17-18, and up to $170M in avoided ELG investment at Schahfer Units 14-15. See Appendix A, pages 244-247 of the NIPSCO 2018 IRP for details. Interestingly, the NIPSCO unit with no material avoided environmental compliance investment, Michigan City 12, lives the longest in their preferred portfolio, to 2028. This is a good indication of the impact of assuming such avoided costs in the retirement analysis for Schahfer.

1 **Figure 3: 2013-2018 Coal Supply by State**

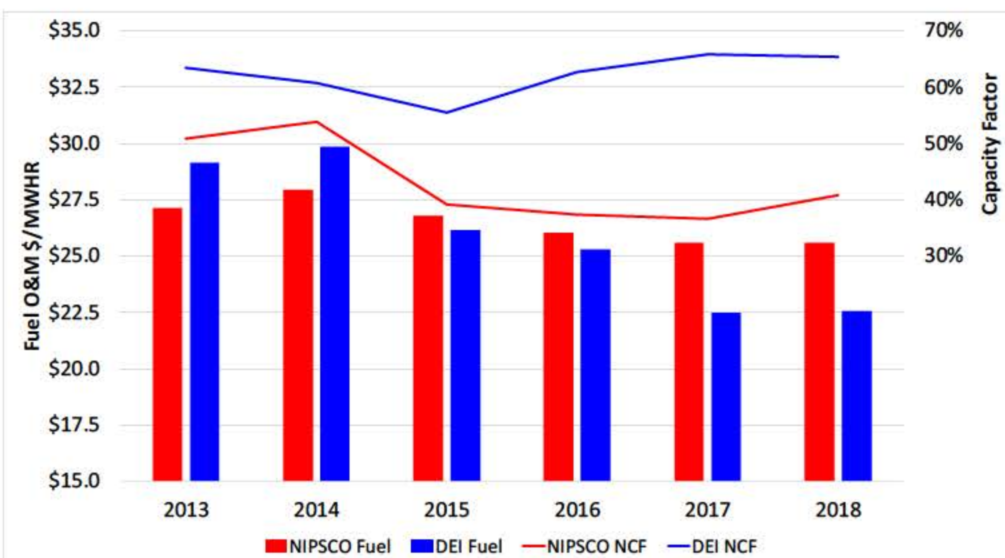
(Michigan City and RM Schahfer – NIPSCO; Cayuga and Gibson – DEI)



(Source: EIA923 Data)

2 **Figure 4: Fuel Production Cost Rate and Capacity Factor Comparison:**

NIPSCO Coal Units and Duke Energy Indiana Gibson and Cayuga Stations

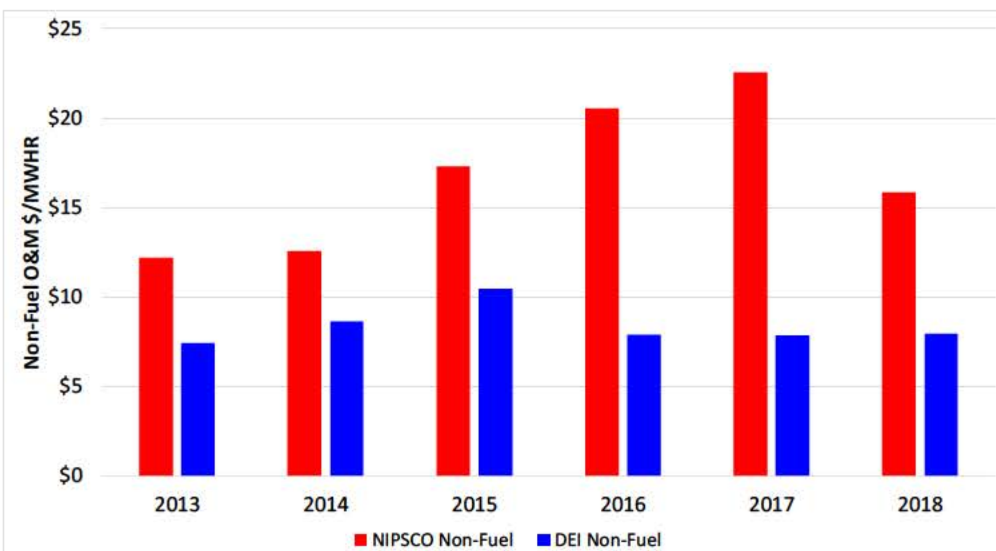


(Source: FERC Form 1 Data)

Lastly, like the fuel cost rate, the non-fuel O&M cost rate for the NIPSCO coal units is higher than that of Duke Energy Indiana's Gibson and Cayuga coal units, roughly double or more (see Figure 5). Utilizing sub-bituminous coals generally requires more housekeeping and maintenance than bituminous coals. Additionally, as discussed by Duke Energy Indiana witness Mr. Mosley in his direct testimony, Duke Energy Indiana has implemented numerous cost efficiency improvements to keep O&M costs under control. In an IRP retirement analysis, lower existing unit O&M costs translates into lower avoidable costs with retirement, which makes continued operation of the existing units more attractive.

<u>Figure 5: Non-Fuel O&M Cost Rate Comparison:</u>

<u>NIPSCO Coal Units and Duke Energy Indiana Gibson and Cayuga Stations</u>



(Source: FERC Form 1 Data)

In conclusion, there are clearly material differences in the structural and cost circumstances between NIPSCO and Duke Energy Indiana that make any assignment of NIPSCO's resource planning strategy to Duke Energy Indiana inappropriate and uninformative.

Q. HOW DO YOU SUGGEST THE COMMISSION WEIGH THE SIERRA CLUB AND JOINT INTERVENORS' CONCLUSIONS REGARDING DUKE ENERGY INDIANA'S RESOURCE PLAN?

A. Sierra Club and Joint Intervenors make no compelling arguments that Duke Energy Indiana's 2018 IRP preferred portfolio, as used for depreciation rate purposes in this proceeding, should not be considered reasonable by the Commission. Despite their complaints regarding Duke Energy Indiana's IRP process and assumptions, we must always remember that models only inform us; models do not make reasoned recommendations or decisions. We must be pragmatic, and we must acknowledge the reality that most if not all of the assumptions used within any IRP are probably wrong to some degree, as no one can actually predict the future. The future is not likely to be any of the five scenarios that we modeled. Therefore, the preferred portfolio is not necessarily intended to be optimized to a specific future, but rather designed to perform robustly across a potential range of futures, and take into consideration reasonable and realistic constraints, and impacts beyond raw economics. The Commission should therefore disregard Sierra Club and Joint Intervenors' unsupported recommendations for unnecessarily accelerated coal unit retirements, and approve Duke Energy Indiana's depreciation expenses as presented by Mr. Spanos and Ms. Douglas.

V. <u>CONCLUSION</u>

Q. DID YOU DIRECT MR. SPANOS TO SWAP THE GIBSON UNITS 4 AND 5 RETIREMENT DATES FOR THE DEPRECIATION STUDY FOR THIS PROCEEDING?

A. Yes, I did.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes, it does.

VERIFICATION

I hereby verify under the penalties of perjury that the foregoing representations are true to the best of my knowledge, information and belief.

Signed: ______________________
Keith B. Pike

Dated: 12-4-2019