Attachment 2
Docket E-100, Sub 157

Review of Duke Energy's North Carolina Coal Fleet in the 2018 Integrated Resource Plans

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A Report for the Natural Resources Defense Council, the Sierra Club and the Southern Alliance for Clean Energy

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1. Introduction

The Southern Environmental Law Center (SELC), on behalf of its clients, the Natural Resources Defense Fund, the Sierra Club, and the Southern Alliance for Clean Energy, engaged Applied Economics Clinic (AEC) to review the 2018 Integrated Resource Plans (IRPs) filed by Duke Energy Carolinas (DEC) and Duke Energy Progress (DEP) (collectively the Companies" or Duke) with the North Carolina Utilities Commission (NCUC) under Docket E-100 Sub 157.[1] This report focuses on the Companies' treatment of their existing coal-fired power plants in the 2018 IRPs.

We find that the Companies' analysis underlying their 2018 IRPs falls short of best practices in IRP development. Of particular importance, Duke fails to take the critical step of modeling an optimal allocation of existing and new resources. The Companies have hardwired the retirement dates for their coal units and prevented their capacity expansion model from retiring a unit or units for economic reasons prior to the end of the units' useful life.[2] Thus, the Companies' IRPs do not fully investigate the lowest-cost option for ratepayers. Furthermore, many of the Companies' coal units are identified as peaking resources in the IRPs, which, on a cost- and performance-basis, is unsustainable. Coal plants are physically ill-suited to run as peaking plants, with high start-up costs and long start-up times. Also, frequent cycling of coal units has been found to damage equipment and shorten life expectancies due to cycling-associated thermal fatigue, stress and wear on equipment, and corrosion of parts.[3] Finally, coal plants also have high fixed costs (typically between $40 and $80 per kw-year[4]) making it a costly option to keep them online but run rarely. The Companies' own modeling indicates that they do not [redacted] for these units—in fact, some are expected to [redacted] than in recent years. If the Companies conducted a more rigorous modeling process and allowed for a true cost-optimization of their resource selection, ratepayers could benefit from a lower-cost, lower-risk portfolio.

2. The Companies Did Not Evaluate the Economics of Existing Coal Units

The Companies' analysis of their capacity and energy needs focuses on new resource selection while failing to evaluate other possible futures for existing resources. As part of the development of the IRPs, the Companies conducted a "quantitative analysis of the resource options available to

[1] AEC has reviewed both public and confidential versions of these IRPs as well as the Companies' responses to data requests from NRDC, SACE and the Sierra Club and the Public Staff.
[2] See Data Response to SC 2-1(g)
[3] Nichols, Chris. National Energy Technology Laboratory (NETL). *Characterizing and Modeling Cycling Operations in Coal-fired Units*. June 2016. Available online: https://www.eia.gov/outlooks/aeo/workinggroup/coal/pdf/EIA%20coal-fired%20unit%20workshop-NETL.pdf
[4] Lazard Levelized Cost of Energy. Version 12.0. November 2018. Available online: https://www.lazard.com/media/450784/lazards-levelized-cost-of-energy-version-120-vfinal.pdf

meet customers' future energy needs."[5] This analysis intended to produce a "base case" through a "least cost analysis" where each company's system was optimized independently.[6] However, the modeling exercise fails to consider whether existing resources can be cost-effectively replaced with new resources. Therefore, Duke has not performed a "least-cost" analysis to design its recommended plans.

The Companies' modeling does not allow for retirement based on economics

The Companies' IRPs present portfolios of new resources based on modeling variations in future conditions—such as fuel prices and capital costs. However, the lifetimes of existing resources are fixed in their analyses. Their approach also did not allow for existing resources to compete with new resources to serve customers on a least-cost basis.

The Companies used two types of modeling for their generating fleet: 1) capacity expansion modeling and 2) production cost modeling:

- **Capacity expansion modeling** is commonly used by utilities to evaluate resource decisions, including what types of resources to pursue in the future and what existing resources should be maintained or retired. These models are intended to produce the least-cost portfolios of resources based on future conditions such as: peak demand, capital costs of new resources, fuel prices, and environmental compliance costs (among others). For these IRPs, the Companies used the System Optimizer model, and developed seven resource portfolios based on their forecasts of future conditions and select resource mixes (e.g. "CT Centric" which builds gas combustion turbines to meet future capacity needs). However, these portfolios only differed in the types of new resources added to the system: existing resources' retirement dates were the same in every portfolio modeled.

- **Production cost modeling** simulates the dispatch of a utility's fleet (usually on an hourly or sub-hourly basis). The Companies used the PROSYM model to optimize the seven fixed portfolios discussed above. The Companies modeled these portfolios under varying assumptions of carbon prices, fuel prices and capital costs. Costs were reported as the present value of revenue requirements (PVRR) for each of these sensitivities. They found that the portfolios called "Base CO_2 Future" and "Base No CO_2 Future" were the lowest cost options among those modeled, and therefore selected them as their base cases.

It is common for utilities to conduct capacity expansion modeling and subsequent production cost modeling for resource planning. However, the Companies have neglected to evaluate the future of their existing units in these IRPs. They are effectively treating the existing resources as immune to future conditions while simultaneously assuming that these future conditions determine which new resources will be built.

[5] DEC 2018 IRP, p. 83; DEP 2018 IRP, p. 84
[6] Ibid.

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Unfortunately, with these sophisticated tools at hand, the Companies are squandering an opportunity to evaluate the economics of existing coal units alongside new resources. As we discuss in Section 4 of this report, other utilities have conducted IRP modeling that permitted retirement of existing resources on the basis of economics and found that earlier retirement of coal units produced a lower-cost portfolio. However, such an outcome is prevented by the Companies' framework—regardless of how uneconomic these units may be.

In response to a data request seeking separate retirement analyses conducted by the Companies since 2013, they provided analyses for [redacted] The retirement analysis provided for [redacted] showed that [redacted] In general, each of the analyses was [redacted]

The Companies, like other utilities, have significant leeway in how modeling is conducted—including development and/or selection of portfolios and of input assumptions. At first glance, the Companies' IRP modeling may appear robust. For example, the Companies selected seven portfolios from System Optimizer that they determined would "encompass the impact of the range of input sensitivities" which they had previously identified."[8] However, those seven portfolios were constrained by pre-selected resources chosen in the Companies' own screening process.

The Companies further restricted the scope by testing Duke's seven portfolios using sensitivities developed by the Companies, including "low fuel" and "high fuel" cases where both natural gas and coal prices move in the same direction (relative to a reference case). Yet Duke did not model any sensitivities where natural gas prices stayed low and coal prices rose more than expected (or vice versa).

Given the Companies' flawed, limiting framework, however, a more comprehensive set of future scenarios would still not allow for economic retirements. The most important change to the Companies' analysis would be to allow for the capacity expansion model to retire existing units based on economics or, at the very least, to model other fixed dates of retirement to better understand the costs of running these existing units in the future.

A. The Companies did not forecast fixed costs of existing units

The Companies' IRPs project the fixed costs of new units, but not existing units, making it impossible to review the total costs of all units going forward. The costs to ratepayers (i.e. revenue requirements) include the following:

- Variable costs

[7] Companies' data response to SACE/NRDC/SC DR2-9 CONFIDENTIAL
[8] DEC 2018 IRP, p. 86; DEP 2018 IRP, p. 88

  - Variable operations and maintenance (VOM)
  - Fuel
- Fixed costs
  - Fixed operations and maintenance (FOM)
  - Non-environmental capital investments (including depreciation, taxes, and rate of return)
  - Environmental capital investments (including depreciation, taxes, and rate of return)

The Companies forecasted the variable costs for new and existing units, which determined when these units were dispatched (i.e. called upon to operate) in both models. This process is also known as "merit order dispatch" or "economic dispatch" whereby the models select the lowest variable cost unit available to serve load.

The Companies forecasted fixed costs only for new units, not existing units. Fixed costs do not determine how often the units are dispatched, but they are still costs paid by ratepayers and must be included for an accurate accounting of revenue requirements. Evaluating future fixed costs allows for comparison of total costs for both existing and new units on an "apples-to-apples" basis.

Using the Companies' approach, including the fixed costs of existing resources would not change the outcome of their IRPs because the existing resources remain operational for the same length of time in every portfolio modeled. Therefore, the relative costs between portfolios would not change if fixed costs of existing units were included. However, while it is internally consistent, the analysis framework itself remains invalid because fixed costs should be used in determining whether a unit is retired or not. Critically, Duke's logic ignores the obvious fact that future fixed O&M costs are avoidable if the plant retires.

Moreover, the lack of fixed costs projections provided by the Companies prohibits third-party reviewers and the Commission from viewing the full costs of these resources. When asked for the Companies' most recent forecasts of fixed costs for these units, they refused to provide them.[9] In the absence of forecasts, historical data can be a useful proxy (with assumed cost escalation). In response to a data request, the Companies did provide historical data on fixed O&M costs for these coal units showing an average cost of $215 million per year for the coal fleet (excluding Asheville) between 2014 and 2017.[10] This does not include annual capital expenditures.

[9] Companies' data response to SACE/NRDC/SC DR2-4

[10] Companies' data response to SACE/NRDC/SC DR2-3

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3. Coal Units as "Peakers" is Not a Sustainable Solution

Many of the Companies' coal units operate infrequently, as shown in performance reports filed with the NCUC and by data filed with the U.S. Energy Information Administration. The Companies identify several of their coal units as "peaking" or cycling units in their IRPs. Moreover, the Companies' own modeling indicates that they are planning on operating many of the coal units [redacted]. However, this result [redacted] given the costs and physical impacts of operating coal plants in this way. Coal plants have high start-up costs and long start-up times. Frequent cycling of coal units has also been found to damage equipment and shorten life expectancies for coal plants due to cycling-associated thermal fatigue, stress and wear on equipment, and corrosion of parts.[11] In addition, coal plants have high fixed costs making it a costly option to keep online but run rarely. Given these operating characteristics, it is highly unlikely that operating coal units as "peakers" is economically sound.

A. The Companies' coal units have mostly performed poorly in recent years

Table 1 (below) shows the capacity factors for the Companies' coal units since 2010.[12] Assuming the Companies have been dispatching their units economically (i.e. using the lowest variable cost unit available), this indicates that Duke's coal units have become increasingly more expensive relative to other units on the system. In 2018, only 3 of the 18 coal units shown operated at more than a 50 percent capacity factor.[13] Most of the units (12 of the 18) are running at 30 percent capacity factor or less. Most of the units' performance has trended downward during this decade. On a capacity-weighted basis, the fleet is operating at almost half the rate it did in 2010. This means that—if all costs, including fixed costs, were accounted for—ratepayers are likely paying much more than they were nearly a decade ago for every megawatt-hour of coal generated by Duke's coal fleet.

[11] Nichols, Chris. National Energy Technology Laboratory (NETL). *Characterizing and Modeling Cycling Operations in Coal-fired Units*. June 2016. Available on-line: https://www.eia.gov/outlooks/aeo/workinggroup/coal/pdf/EIA%20coal-fired%20unit%20workshop-NETL.pdf
[12] The analysis in these comments excludes the Asheville coal units, which are being retired later this year.
[13] U.S. Energy Information Administration, Form EIA-923 detailed data with previous form data (EIA-906/920), Last Updated February 28, 2019, https://www.eia.gov/electricity/data/eia923/.

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Table 1: Capacity Factor of Duke Energy's North Carolina Coal Units (%)[14]

Coal Unit	2010	2011	2012	2013	2014	2015	2016	2017	2018
Allen 1	46%	29%	7%	4%	18%	12%	13%	6%	5%
Allen 2	41%	24%	5%	2%	16%	13%	15%	6%	6%
Allen 3	61%	46%	26%	26%	25%	16%	18%	9%	7%
Allen 4	59%	51%	31%	36%	27%	19%	12%	10%	7%
Allen 5	54%	41%	16%	17%	27%	18%	11%	16%	14%
Belews Creek 1	84%	80%	77%	58%	76%	62%	56%	40%	49%
Belews Creek 2	64%	81%	63%	68%	59%	67%	54%	59%	33%
Cliffside 5	51%	54%	23%	28%	29%	20%	16%	18%	26%
Cliffside 6				65%	63%	42%	39%	67%	58%
Marshall 1	58%	43%	32%	39%	54%	33%	40%	33%	29%
Marshall 2	52%	56%	41%	45%	60%	22%	29%	30%	20%
Marshall 3	74%	69%	56%	32%	75%	46%	68%	52%	55%
Marshall 4	83%	71%	67%	64%	22%	54%	61%	71%	64%
Mayo 1	76%	55%	54%	40%	40%	44%	31%	22%	23%
Roxboro 1	82%	54%	61%	44%	65%	45%	31%	26%	25%
Roxboro 2	67%	44%	71%	66%	57%	57%	48%	28%	32%
Roxboro 3	80%	59%	60%	39%	48%	33%	37%	36%	25%
Roxboro 4	72%	62%	66%	44%	69%	38%	35%	21%	27%
Capacity-weighted avg	**68%**	**61%**	**50%**	**48%**	**53%**	**43%**	**41%**	**38%**	**35%**

[14] EIA Forms 923 and 860 data. Excludes Asheville coal units.

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The Companies' projections of variable O&M and fuel costs along with the units' availability are used to determine how often the units will operate. The order in which units are dispatched is expected to change as fuel prices change, units retire, and new units are added by the model. Figure 1 shows units from lowest cost to highest cost (left to right) by the generation provided by each unit for the Duke Energy Carolinas (DEC) system in 2019 at the winter peak hour. The Allen, Belews Creek, Cliffside and Marshall coal units are [redacted] to operate than natural gas combined cycle (NGCC) units, most renewables, and nuclear units. Only DEC's natural gas combustion turbines and DSM[15] (demand response) are [redacted] generation currently.[16]

Figure 1: Generation Supply Stack for DEC units in 2019, Winter Peak (Variable Cost, $/MWh) CONFIDENTIAL[17]

[15] Duke refers to demand response as "Demand Side Management" or "DSM" in its IRPs, per North Carolina law and NCUC rules.

[16] This effect is even more pronounced in the summer peak whereby the some of the coal units [redacted] than natural gas combustion turbines (NGCT)—these figures are shown in the appendix.

[17] DEC PSDR 2-24 DEC Generation Resource Stack_CONFIDENTIAL.

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Figure 2 shows how the dispatch order changes in 2031. DEC's remaining coal units are among the [redacted] to operate at peak time, with costs [redacted] DSM (demand response).[18] The Companies are planning major investments, so that they can burn both coal and gas at the coal units shown below.[19] The production cost modeling in the IRP accounts for these investments. However, it is unclear if the investments in dual-fuel capability are [redacted] because the units remain [redacted]s in the winter and are [redacted] in the summer (see appendix).

Figure 2: Generation Supply Stack for DEC units in 2031, Winter Peak (Variable Cost, $/MWh) CONFIDENTIAL[20]

[redacted]

[19] Downey, John. "Duke Energy wrapping up $65M gas co-firing project for its Cliffside coal units". Charlotte Business Journal. November 19, 2018.
[20] DEC PSDR 2-24 DEC Generation Resource Stack_CONFIDENTIAL

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Figure 3 shows the dispatch order for the Duke Energy Progress (DEP) units in 2019 at the winter peak hour. The Mayo and Roxboro units in the DEP system are in the [redacted]e of variable costs in 2019 (shown in Figure 3).

Figure 3: Generation Supply Stack for DEP units in 2019, Winter Peak (Variable Cost, $/MWh) CONFIDENTIAL[21]

[redacted]

[21] DEP PSDR 2-24 DEP Generation Resource Stack_CONFIDENTIAL

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By 2031 (Figure 4), DEP's coal units are [redacted] including natural gas combustion turbine (NGCT or CT) units, which are commonly referred to as "peakers" as they only operate at peak times. CT's are intended to cycle on and off quickly in order to respond to quickly rising or falling demand, respectively. In the summer peak, the coal units are [redacted] compared to CT's (as shown in the appendix).[22]

Figure 4: Generation Supply Stack for DEP units in 2031, Winter Peak (Variable Cost, $/MWh) CONFIDENTIAL[23]

[redacted]

[22] NGCT's typically run at a 10 percent capacity factor or less. (Lazard Levelized Cost of Energy. Version 12.0. November 2018. Available online: https://www.lazard.com/media/450784/lazards-levelized-cost-of-energy-version-120-vfinal.pdf.) Duke expects some of its NGCTs to operate [redacted]. For example, production cost modeling of the Richmond CT's shows them collectively operating at [redacted] percent capacity factor in the early 2020's. (Modeling results from 2020 through 2023 from PROSYM Base CO2 and Base No CO2 scenarios, provided in response to SACE 2-1 CONFIDENTIAL.) This is more frequently than most of Duke's [redacted]ds of typical CT usage. It is unclear how the Duke expects to operate CT's at this level.

[23] DEP PSDR 2-24 DEP Generation Resource Stack_CONFIDENTIAL

B. The Companies' modeling shows that they expect many coal units to run as [redacted]

The outputs from the Companies' modeling mostly show a [redacted] in their coal fleet's performance. Figures 1 – 4, above, showed the changing variable cost, relative to existing and new units, which is a key determinant of how often the units are called upon. Figures 5 - 8 below show the Companies' historical and projected capacity factors for their coal units under the Base CO_2 scenario.[24]

Figures 5 and 6, below, show that in this base scenario, the capacity factors of Belews Creek and Cliffside units (Figure 5) as well as the Marshall units (Figure 6) are expected to [redacted] their operation in the next 10 years. By 2028, seven of the eight units are operating below [redacted] percent capacity factor. This is [redacted] the historically low performance for these units. The modeling shows some [redacted] for these units in the 2030's but the highest predicted levels are [redacted] compared to recent history.[25]

[24] The projected data for their units comes from the results of the System Optimizer model. (The appendix to these comments shows the modeling results for the Base No CO_2 scenario and both base scenario results from the PROSYM model.)

[25] Note that the expected [redacted] trends in the next decade are similar when there is no carbon price assumed (see Appendix).

Figure 5: Forecasted Capacity Factor for Belews Creek and Cliffside Units, Companies' Base CO_2 Scenario in System Optimizer model - CONFIDENTIAL

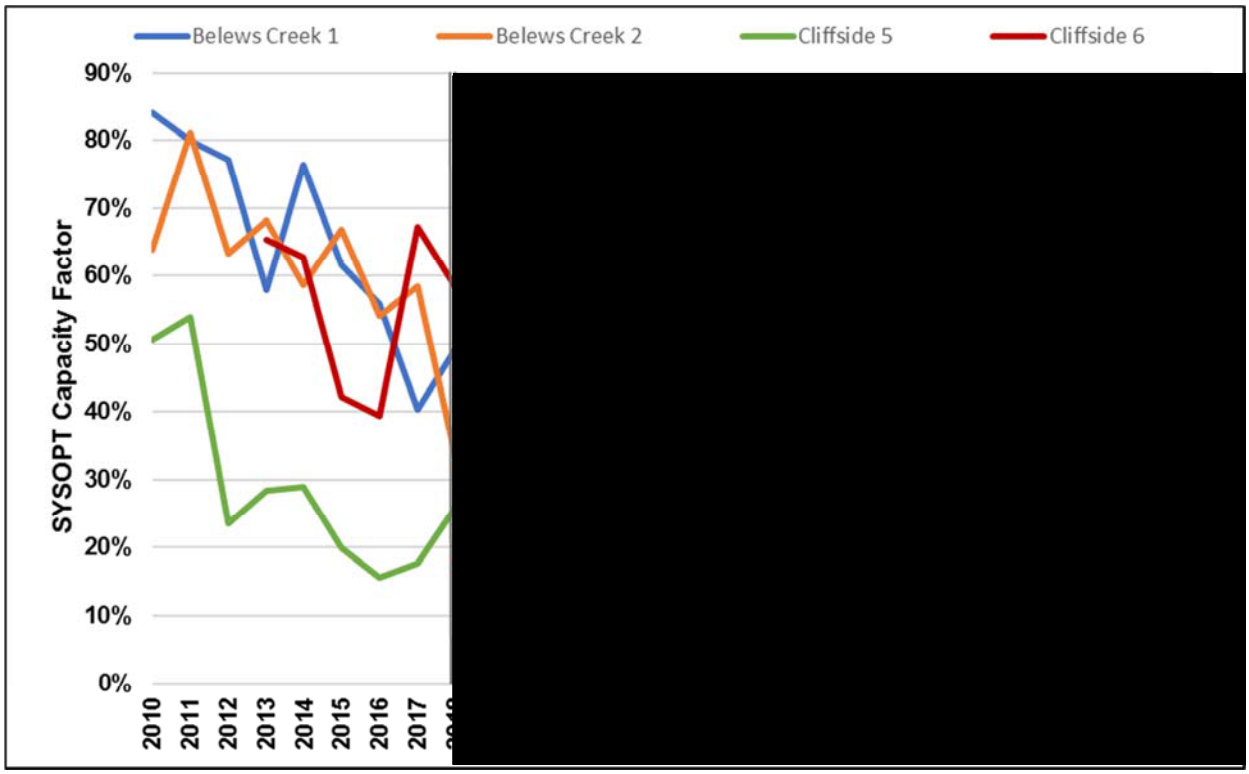

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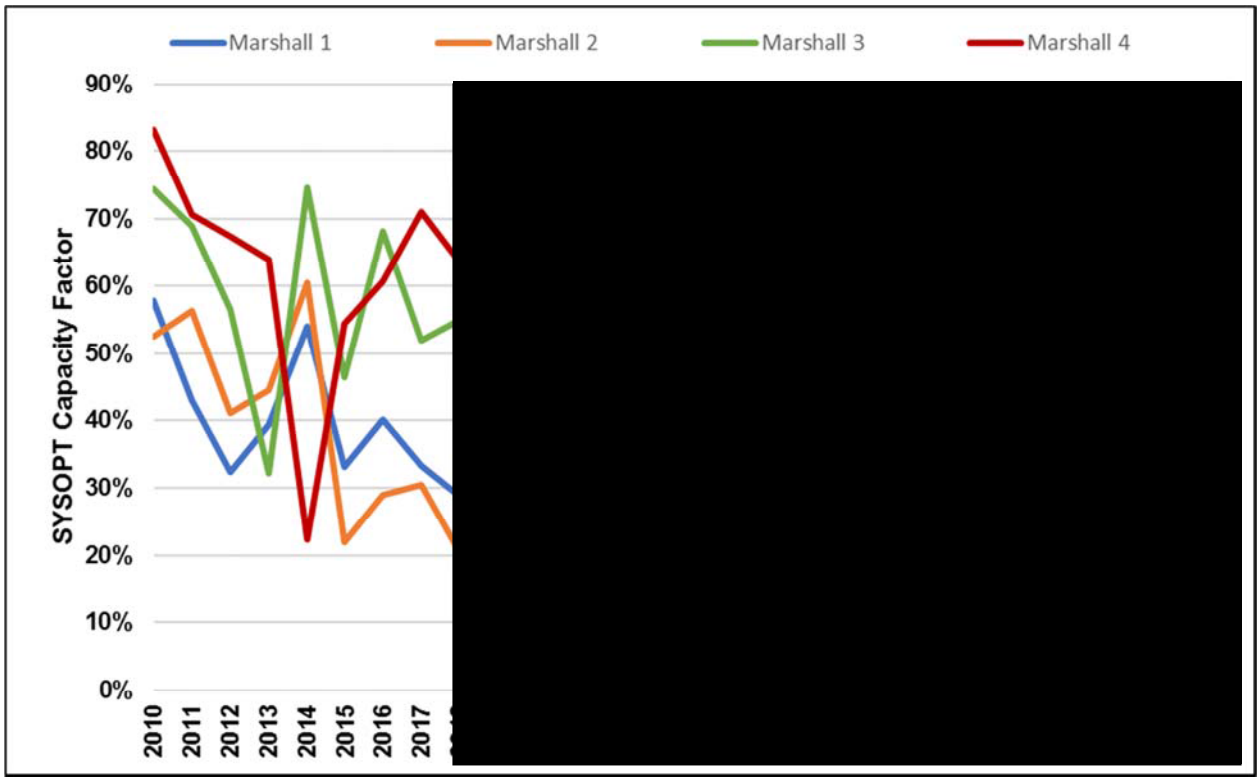
Figure 6: Forecasted Capacity Factor for Marshall Units, Companies' Base CO_2 Scenario in System Optimizer model - CONFIDENTIAL



As shown in Figures 7 and 8, below, the capacity factors of the Allen units (Figure 7) and Mayo and Roxboro units (Figure 8) all [redacted] to [redacted] percent for most years of the planning horizon. These units are expected to act as [redacted] in [redacted] According to the Companies' modeling, Allen units remaining on the system after 2023 only operate during [redacted] of the year ([redacted]). In this scenario, the Roxboro units only operate during [redacted] for 2026 through 2031 and Mayo Unit 1 only operates in [redacted] for 2021 through 2032. Notably, this means that these units are not called upon during [redacted] hours. As shown in the Appendix, the [redacted] performance of these units also occurs when there is no anticipated carbon price.

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Figure 7: Forecasted Capacity Factor for Allen Units, Companies' Base CO_2 Scenario in System Optimizer model - CONFIDENTIAL

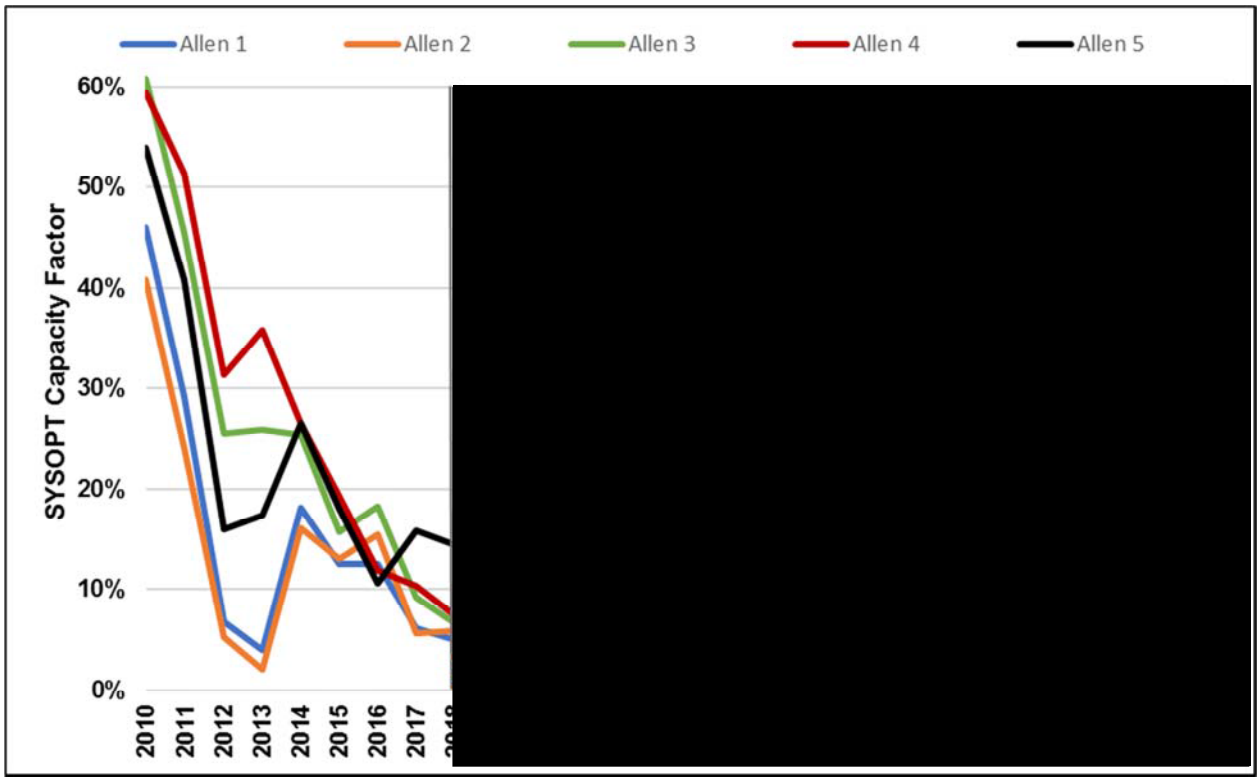

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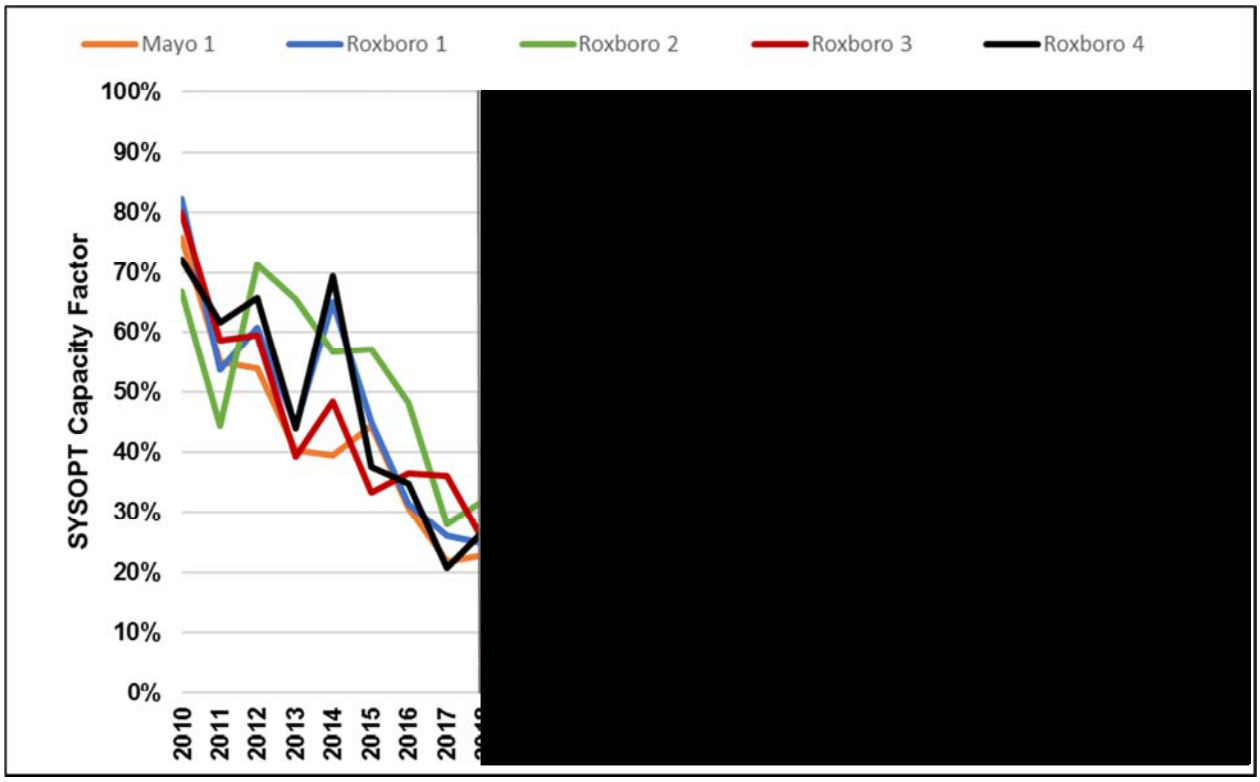
Figure 8: Forecasted Capacity Factor for Mayo and Roxboro Units, Companies' Base CO_2 Scenario in System Optimizer model - CONFIDENTIAL



C. Duke expects some of its coal units to be [redacted]

The Companies' modeling assumptions include how often it anticipates the units will be unavailable due to a forced (i.e. unplanned) outage. This means that even when it may be economic to operate—for instance, during a winter peak time—the unit may not be available to operate. While all coal units in the United States have outages from time to time, some of the Companies' units are expected to have [redacted] of outage—meaning they are [redacted] to serve customers. The average equivalent forced outage rate (EFOR) for coal units in PJM from 2008 through 2017 was 10.25 percent.[26] Shown below in Table 2, seven of the Companies' coal units are projected to have [redacted] PJM fleet-wide average. Allen 3, Allen 5, and Cliffside 5 all have rates [redacted]. This means that at any given time there is more than [redacted] chance that the unit will be unavailable. Coal units are not built to run sporadically, and operating coal units that way can lead to more mechanical problems, and by extension, more outages. It is unclear if the Companies are anticipating this effect in their forced outage rate assumptions.

[26] Monitoring Analytics. State of the Market Report for PJM. p. 280. Available at: https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2017/2017-som-pjm-volume2.pdf

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Table 2: Equivalent Forced Outage Rates Assumed in Modeling - CONFIDENTIAL[27]

[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]

The anticipated [redacted] of the Companies' coal fleet further undermines any arguments for failing to allow economic retirement of existing units in their IRP modeling. Coal units have high fixed costs in order to remain available as capacity. The Companies anticipate that many of their coal fleet will operate at [redacted] levels because they will only be cost-effective [redacted]; and some of those units will be frequently [redacted] to operate even if they were cost-effective. Planning to have coal units operate as [redacted]—some of which are [redacted] providers of capacity and energy to the system—is not a low-cost, low-risk path forward for ratepayers. Duke's coal units have [redacted] variable costs, [redacted] expected unplanned outage rates, and [redacted] expected capacity factors—as shown in their modeling. Moreover, the average age of the current fleet (excluding Asheville) is 49 years old; ten years older than the average age of all coal units operating in the US as of 2017.[28] Yet the Companies expect most of their already old fleet to continue operating past 60 years of age—shown below in Table 3. Indeed, some units are expected to operate for almost 70 years. It is in ratepayers' best interest that Duke re-examine its assumption that these aged units will nonetheless remain in operation, using the expensive and sophisticated modeling but under-utilized tools already at the Companies' disposal.

[27] DEC PSNC 2-3_2018 IRP_Model Inputs_CONFIDENTIAL
[28] EIA. "Most coal plants in the United States were built before 1990". April 17, 2017. Available online: https://www.eia.gov/todayinenergy/detail.php?id=30812

Table 3: Ages of Duke Energy's North Carolina Coal Units (%)[29]

Coal Unit	Year operational	Duke planned retirement	Current age	Age at planned retirement
Allen 1	1957	2024	62	67
Allen 2	1957	2024	62	67
Allen 3	1959	2024	60	65
Allen 4	1960	2028	59	68
Allen 5	1961	2028	58	67
Belews Creek 1	1974	2038	45	64
Belews Creek 2	1975	2038	44	63
Cliffside 5	1972	2032	47	60
Cliffside 6	2012	2048	7	36
Marshall 1	1965	2034	54	69
Marshall 2	1966	2034	53	68
Marshall 3	1969	2034	50	65
Marshall 4	1970	2034	49	64
Mayo 1	1983	2035	36	52
Roxboro 1	1966	2028	53	62
Roxboro 2	1968	2028	51	60
Roxboro 3	1973	2033	46	60
Roxboro 4	1980	2033	39	53

4. Rigorous Analysis and Competition Lead to Lower Costs

In light of the flaws and omissions discussed in the previous sections, Duke has failed to present an adequate evaluation of its existing resources as part of the 2018 IRPs. Below, we discuss specific requirements for the IRP process that would be in the best interest of ratepayers. We also discuss two examples of utility IRP processes that had more in-depth stakeholder engagement and scrutiny, both of which lead to better outcomes for customers.

A. In the absence of other forums, the IRP is an opportunity to evaluate existing resources

The Companies have hard-wired the useful lives for their existing coal units, preventing a fair comparison of the economics of these units relative to replacement resources. This methodology prevents the pursuit of potentially lower-cost options. Ratepayers are subject to the Companies' major decisions about their existing resources with little, if any, recourse. Currently, the Companies

[29] Year operational: 2017 Form EIA-860 Data - Schedule 3; Duke planned retirement: DEC IRP p. 118 and DEP IRP p. 117.

make major decisions about their resources behind closed doors. For example, while pre-approval is required for building a new power plant, there is no pre-approval required for retrofits of existing power plants in North Carolina. This means that the Companies need not economically justify such investments in the context of a comparison to unit retirement and replacement. In the absence of a pre-approval process for retrofits to existing units, the IRP is the appropriate forum for the Companies to evaluate the future of those units, and for the Commission to review that evaluation.

The main opportunity for the Commission to review major capital investment in existing units is in rate cases, where typically the project would have already been built or would be under construction. We are not aware of any opportunity other than the biennial IRP dockets for the Commission to evaluate the Companies' retirement decisions. Therefore, to encourage rigor, Duke's analysis of coal unit economics should have more transparency and stakeholder engagement, preferably throughout the decision-making process, as is the practice of the two utilities we discuss later.

B. The Companies should encourage competitive resource options

The Companies should consider a wide range of new or replacement resources, when needed. The most recent RFP provided by DEP claims there is a "near term need" of 2,000 MWs due to power purchase agreements (PPA) lapsing.[30] To achieve the best results for ratepayers, the Companies should issue all-resource RFPs that are reasonably flexible. The results of such an RFP could then be evaluated as part of the IRP modeling.

C. Other utilities have found lower-cost resource replacement in similar forums to this one

There are many examples of utilities that routinely evaluate the economics of existing units. Below are two recent examples of IRP modeling that determined that replacement of coal units with new resources was cost-effective for customers. In both cases, the utilities also had an in-depth stakeholder engagement as part of the IRP process.

Northern Indiana Power Supply Company (NIPSCO)

According to Northern Indiana Public Service Company's (NIPSCO) 2018 IRP submission to the Indiana Utility Regulatory Commission (IURC), its preferred portfolio is expected to "[l]ead to a lower cost, cleaner, diverse and flexible portfolio by accelerating the retirement of 85% of NIPSCO's coal capacity by the end of 2023 and 100% by the end of 2028" and "[r]eplace retired coal generation resources with lower cost renewables including wind, solar and battery storage."[31] This outcome was the result of capacity expansion modeling, using the Aurora model, whereby NIPCSO tested various retirement dates for its coal units (Schahfer 14, 15, 17 and 18 and Michigan City 12). The Company found that retiring all of its coal units by 2023 was the lowest-cost

[30] SACE/NRDC/Sierra Club 2-18. "DEP_Capacity_and_Energy_Market_Solicitation"
[31] Ibid, p.3.

option for ratepayers. However, it chose a portfolio where the Michigan City unit retirement was delayed until 2028, out of reliability concerns.[32]

Prior to this analysis, NIPSCO hired an independent consultant to conduct an all-source request for proposals (RFP) for new capacity and energy. NIPSCO's RFP put all resources on an even playing field and made available the most up-to-date, real-world pricing information for inclusion in their IRP modeling. The RFP results were then incorporated into NIPSCO's modeling of various retirement scenarios. The RFP included the following key design elements:[33]

- Technology – All solutions regardless of technology
- Size
  - Minimum total need of 600 megawatts ("MW") for the portfolio but without a cap
  - Allowed smaller resources to offer their solution as a piece of the total need
  - Also encouraged larger resources to offer their solution for consideration
- Ownership Arrangements
  - Sought bids for asset purchases (new or existing) and purchase power agreements
  - Resource had to qualify as Midcontinent Independent System Operator ("MISO") internal generation (not pseudo-tied) or load (demand response or "DR")
- Duration
  - Requested delivery beginning June 1, 2023 but evaluated deliveries before 2023
  - Minimum contractual term and/or estimated useful life of 5 years (except for DR, which is 1 year)

In the months that led up to NIPSCO's IRP submission[34] to the Indiana Utility Regulatory Commission, NIPSCO gave stakeholders access to the proposed RFP under a nondisclosure agreement. NIPSCO also enabled stakeholders to comment on and recommend improvements to the RFP, and stakeholders were able to review the RFP responses and to ensure the IRP categorized its tranches of various resource technologies accurately. Beyond the RFP itself, stakeholders were provided access to—and the opportunity to comment and recommend improvements on—the inputs to the model and the model settings. NIPSCO also ran a requested alternative energy efficiency modeling proposal which included cost-effective energy efficiency programs.

[32] NIPSCO. October 18, 2018. "NIPSCO Integrated Resource Plan 2018 Update: Public Advisory Meeting Five". Slide 33. Available online: https://www.nipsco.com/docs/default-source/about-nipsco-docs/nipsco-irp-public-advisory-meeting-october-18-2018-presentation.pdf

[33] NIPSCO. July 24, 2018. "NIPSCO Integrated Resource Plan 2018 Update: Public Advisory Meeting Three". Available online: https://www.nipsco.com/docs/default-source/about-nipsco-docs/7-24-2018-nipsco-irp-public-advisory-presentation.pdf.

[34] NIPSCO. October 31, 2018. "2018 Integrated Resource Plan". Available online: https://www.nipsco.com/docs/default-source/default-document-library/2018-nipsco-irp.pdf.

In Indiana, collaboration between utilities and stakeholders is mandated in the Indiana Utility Regulatory Commission's IRP rule[35]:

- 170 IAC 4-7-4(30): "The IRP must include a summary of the utility's most recent public advisory process, including key issues discussed, how the utility responded to the issues, and a description of how stakeholder input was used in developing the IRP."

This means that, in Indiana, utility IRPs present a thorough documentation of stakeholder processes. NIPSCO's IRP submission, for example, included "Section 2.1: IRP Public Advisory Process" that summarized their 2018 stakeholder process, including how stakeholder input was used to develop their all-source RFP.[36]

Through its stakeholder process, RFP and subsequent modeling, NIPSCO found that its model selected "DSM and renewables as the replacement resources in all retirement cases" and that "retaining more coal in the NIPSCO portfolio results in higher costs to customers."[37]

Consumers Energy

In Consumers Energy's ("Consumers") most recent IRP, filed in June of 2018 before the Michigan Public Service Commission (PSC), it concluded that it would expedite the retirement of two of its coal units: Karn 1 and 2. As a result of its modeling in the IRP, Consumers posited a Proposed Course of Action (PCA) including: 1) retiring the two coal units in 2023 instead of 2031 (the end of their design lives); and 2) replacement with renewable, demand-side and battery storage resources.[38] Consumers did not issue an RFP prior to the IRP, but only because there was no capacity need for the next three years.[39]

Consumers used the Strategist model (provided by ABB, the same vendor that provided System Optimizer and PROSYM to DEC and DEP) to conduct capacity expansion modeling for testing of both new and existing resources. Using this model, Consumers tested earlier retirement of its "Medium Four" coal units (Karn 1 and 2 and Campbell 1 and 2) in select combinations. It found that earlier retirement of the two Karn units would save ratepayers $30 million (in Consumers' Business-as-Usual scenario).[40] Consumers concluded that the units should be retired based on

[35] Indiana Utility Regulatory Commission. "Proposed Rule: LSA Document #18-127". Available online: https://www.in.gov/iurc/files/20180725-IR-170180127PRA.xml.pdf.
[36] NIPSCO. October 31, 2018. "2018 Integrated Resource Plan". Available online: https://www.nipsco.com/docs/default-source/default-document-library/2018-nipsco-irp.pdf. p.6.
[37] NIPSCO. October 18, 2018. "NIPSCO Integrated Resource Plan 2018 Update: Public Advisory Meeting Five". Slide 27-28. Available online: https://www.nipsco.com/docs/default-source/about-nipsco-docs/nipsco-irp-public-advisory-meeting-october-18-2018-presentation.pdf
[38] Application of Consumers Energy. Before Michigan PSC. Case No. U-20165. p.2.
[39] Testimony of Richard T. Blumenstock. Before Michigan PSC. Case No. U-20165. p.3, lines 23-24.
[40] Testimony of Thomas P. Clark. Before Michigan PSC. Case No. U-20165. p.17.

this savings as well as pending environmental compliance costs.[41]

The Consumers' analysis was not without flaws; chiefly the modeling focused on only a few, fixed retirement dates: 2021, 2023, and 2031. Consumers did, however, test its existing units along with new resources. Consumers also projected fixed costs of the existing units, allowing other parties to review future plans for these units. DEC and DEP have failed to conduct even a limited analysis of existing units' fixed costs.

Notably, the Consumers Energy IRP was a unique docket before the Michigan PSC that included several rounds of testimony and an evidentiary hearing. Prior to the filing of the IRP before the PSC, Consumers also held multiple public meetings and technical conferences for stakeholders—as recommended by the Michigan PSC. The more stringent requirements for the Consumers IRP allowed for more in-depth stakeholder involvement and subsequent transparency in the docket provided for closer scrutiny of Consumers' analytical process.[42]

In contrast to the companies discussed above, DEC and DEP do not encourage competition for resources and they make retirement decisions outside of the IRP processes. If DEC and DEP were to provide a rigorous, transparent analysis as part of the IRP process, their ratepayers would benefit—as the ratepayers of Consumers and NIPSCO have.

5. Conclusion

The Companies have provided a flawed and incomplete analysis in these IRP filings.

First, and most importantly, they have failed to provide a full, cost-based comparison of existing and new resources. The tools being used by the Companies are sophisticated, but they are not being used to their full potential. A capacity expansion model is commonly used by other utilities to determine the economics of all resources—as our examples discussed above show.

Second, while the Companies' modeling exercise is limited, the modeling they conducted tells a compelling story. Mainly it shows that many of these coal units are expected to operate only as [redacted]. Indeed, some units were projected to run only [redacted] a year. Given the high fixed costs of maintaining coal units on-line, it is highly unlikely that this can be a least-cost solution for North Carolina ratepayers.

Third, the Companies have also failed to encourage competition from potentially lower-cost resources. An all-resource RFP should be done in anticipation of a full economic analysis—casting the widest net possible.

[41] Ibid. p. 20, lines 7-11.
[42] Ibid. p. 6

Finally, there is a troubling lack of transparency in these IRPs. The Companies have failed to provide forecasted fixed costs for their coal units—even though they were requested in this docket. If the Companies are not going to do a complete analysis, at the very least they should provide the information with which third-party reviewers and the Commission could attempt to construct a fuller picture.

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