BEFORE THE
INDIANA UTILITY REGULATORY COMMISSION

FILED
October 30, 2019
INDIANA UTILITY
REGULATORY COMMISSION

Petition of Duke Energy Indiana, LLC Pursuant to Ind. Code §§ 8-1-2-42.7 and 8-1-2-61, for (1) Authority to Modify Its Rates and Charges for Electric Utility Service Through a Step-In of New Rates and Charges Using a Forecasted Test Period; (2) Approval of New Schedules of Rates and Charges, General Rules and Regulations, And Riders; (3) Approval of a Federal Mandate Certificate Under Ind. Code § 8-1-8.4-1; (4) Approval of Revised Electric Depreciation Rates Applicable to Its Electric Plant In Service; (5) Approval of Necessary and Appropriate Accounting Deferral Relief; and (6) Approval of a Revenue Decoupling Mechanism for Certain Customer Classes	)))))))))))))))	**Cause No. 45253**

Direct Testimony

of

Tyler Comings

Public, Redacted Version

On Behalf of
Sierra Club

October 30, 2019

TABLE OF CONTENTS

I. INTRODUCTION AND PURPOSE OF TESTIMONY

Q. Please state your name, business address, and position.

A. My name is Tyler Comings. I am a Senior Researcher at Applied Economics Clinic, located at 1012 Massachusetts Avenue, Arlington, Massachusetts.

Q. Please describe Applied Economics Clinic.

A. The Applied Economics Clinic is a 501(c)(3) non-profit consulting group housed at Tufts University's Global Development and Environment Institute. Founded in February 2017, the Clinic provides expert testimony, analysis, modeling, policy briefs, and reports for public interest groups on the topics of energy, environment, consumer protection, and equity, while providing on-the-job training to a new generation of technical experts.

Q. Please summarize your work experience and educational background.

A. I have 14 years of experience in economic research and consulting. At Applied Economics Clinic, I focus on energy system planning, costs of regulatory compliance, wholesale electricity markets, utility finance, and economic impact analyses. I have provided testimony on these topics in Colorado, the District of Columbia, Hawaii, Indiana, Kentucky, Maryland, Michigan, New Jersey, Ohio, Oklahoma, West Virginia, and Nova Scotia (Canada). I am also a Certified Rate of Return Analyst (CRRA) and member of the Society of Utility and Regulatory Financial Analysts (SURFA).

I have provided expertise for many public-interest clients including: American Association of Retired Persons, Appalachian Regional Commission, Citizens Action Coalition of Indiana, City of Atlanta, Consumers Union, District of Columbia Office of the People's Counsel, District of Columbia Government, Earthjustice, Energy Future Coalition, Hawaii Division of Consumer Advocacy, Illinois Attorney General, Maryland Office of the People's Counsel, Massachusetts Energy Efficiency Advisory Council, Michigan Agency for Energy, Montana Consumer Counsel, Mountain Association for Community Economic Development, Nevada State Office of Energy, New Jersey Division of Rate Counsel, New York State Energy Research and Development, Nova Scotia Utility and Review Board Counsel, Rhode Island Office of Energy Resources, Sierra Club, Southern Environmental Law Center, U.S. Department of Justice, Vermont Department of Public Service, West Virginia Consumer Advocate Division, and Wisconsin Department of Administration.

I was previously employed at Synapse Energy Economics, where I provided expert testimony and reports on coal plant economics and utility system planning. Prior to that, I performed research on consumer finance and behavioral economics at Ideas42 and conducted economic impact and benefit-cost analysis of energy and transportation investments at EDR Group.

I hold a B.A. in Mathematics and Economics from Boston University and an M.A. in Economics from Tufts University.

My full resume is attached as Exhibit TFC-1.

Q. On whose behalf are you testifying in this case?

A. I am testifying on behalf of Sierra Club.

Q. Have you testified in front of the Indiana Utility Regulatory Commission?

A. Yes, on two occasions. Most recently, in August 2018, I testified in Cause No. 45052 involving Southern Indiana Gas and Electric Company's (Vectren) petition for approval to construct a new natural gas plant near the A.B. Brown power plant and to continue operation of the F.B. Culley 3 power unit. Prior to that, in August 2013, I testified in Cause No. 44339 involving Indianapolis Power and Light's (IPL) petition for approval to construct a new natural gas plant at Eagle Valley and re-fuel Harding Street Units 5 and 6 to natural gas.

Q. Have you testified in other jurisdictions?

A. Yes. I have also testified before public utility commissions in Colorado, the District of Columbia, Hawaii, Kentucky, Maryland, Michigan, New Jersey, Ohio, Oklahoma, West Virginia, and Nova Scotia (Canada).

Q. Have you filed comments on Integrated Resource Plans in Indiana?

A. Yes. I co-wrote comments on Duke Energy Indiana's 2013 Integrated Resource Plan (IRP) and Indianapolis Power and Light's 2014 IRP.

Q. Have you filed comments on Duke Energy Integrated Resource Plans in other jurisdictions?

A. Yes. I was the lead author on comments on the 2018 Duke Energy Carolina and Duke Energy Progress IRPs in North Carolina, on behalf of Natural Resources Defense Council, Sierra Club, and Southern Alliance for Clean Energy.

Q. What is the purpose of your testimony?

A. My testimony addresses the requested rate recovery for the Duke Energy Indiana (Duke or Company) coal fleet. I discuss both Duke's long-term resource planning and the day-to-day operations of its existing coal fleet.

Q. Please summarize your findings

A. Based on my review of the Company's filing and data responses in this case, I conclude that:

1. **The Edwardsport plant is uneconomic and should be retired as soon as possible.** The Company is requesting $300 million in recovery for this plant in 2020 alone. However, the plant is clearly uneconomic as it [redacted] and has [redacted] fixed costs than those from replacing it—[redacted] costs than a typical coal unit. When it is available, the Company is dispatching the plant far more often than it should—leading to [redacted] on a variable basis from 2016 through 2018. There is no economic justification for continuing to operate this plant, yet the IRP does not consider its retirement before 2045—twenty six years from now.

2. **Duke has failed to conduct prudent resource planning by failing to justify continued operation of its coal fleet.** The Company's recent IRP does not justify the Company's fixed retirement dates by failing to consider near-term economic retirement for most of its units. Without such an analysis, it is unclear if Duke and its ratepayers should continue to invest in these units.

3. **Duke's operation of its coal units is imprudent.** In almost every hour that the coal units are available, the Company "self-commits" them to the MISO market, which leads to long periods of time where the units are [redacted]. The Company attempts to justify this behavior by saying it applies its own logic to determine whether the units are economic (or otherwise needed), then self-commits them based on that logic. However, this methodology produces [redacted] over long periods of time where the units should not have been operated. These [redacted] are most apparent for the Edwardsport plant but also apply to other units at Cayuga and Gibson.

Q. Please summarize your recommendations.

A. Based on my findings in this Cause, I recommend the following:

1. **Edwardsport costs should be denied and the Company should develop a plan for retiring the plant.** Once the Company develops such a plan, then the Company may recover prudently incurred costs prior to retirement.

2. **Cayuga and Gibson units should be evaluated for retirement prior to 2024.** The Company should consider robust retirement options for all its remaining coal units as soon as possible in order to assess whether these units have going-forward value for customers. The Company should also conduct an all-resource RFP and evaluate replacement options for these units.

3. [redacted] **associated with uneconomic dispatch should be disallowed from rates.** I estimate that Edwardsport has produced [redacted] in energy market [redacted] from

2016 through 2018. If this plant is allowed to recover operating costs in future rates, this recovery should at least be reduced by this amount of [redacted]. Also, Gibson and Cayuga produced [redacted] for months at a time, including [redacted] and [redacted] over the same period, respectively. These amounts should be disallowed from rates for costs associated with Cayuga and Gibson.

4. **Going forward, all units should be dispatched on an economic basis**. Duke should either offer the units for MISO to dispatch economically or, if it must make its own determination, then Duke's own dispatch decision-making process should be readily transparent and justify the frequency of the units' operation.

5. **In light of the [redacted] incurred and the potential for harm to ratepayers from routine self-commitment, the Commission should open an investigation into this practice, as other states have done.**

II. EDWARDSPORT NEEDS TO BE CONSIDERED FOR IMMINENT RETIREMENT AND ITS COSTS SHOULD BE DENIED IN THIS CAUSE.

Q. Please summarize your findings regarding Edwardsport.

A. Edwardsport is costing ratepayers significantly and should be retired. First, I estimate that on a variable basis alone (i.e., excluding fixed costs) the plant has [redacted] ratepayers [redacted] from 2016 through 2018. These [redacted] are caused by: 1) Duke operating [redacted] plant as "must run" instead of MISO economic dispatch and 2) Duke bidding in the plant [redacted] its variable costs. Second, the plant's fixed costs of operation are [redacted] than those of replacing it. The combination of these findings is a clear indication that the plant is uneconomic and should be retired as soon as possible.

Q. What Edwardsport costs are the Company seeking to recover in rates in this case?

A. Duke is seeking to include $300 million in costs for Edwardsport in 2020 alone. This includes $146 million in operations and maintenance (O&M), $103 million in fuel costs, and $51 million in capital costs.[1]

Q. Should Duke evaluate Edwardsport for retirement prior to 2045?

A. Yes. The plant is expensive on both a variable and fixed basis and its retirement is in the public interest. Despite the fact that the plant is [redacted] money relative to the wholesale energy market and could be replaced with new generation with [redacted], the Company has neglected to pursue this question as part of its long-term planning and is asking for 2020 operating, fuel, and capital costs to be included in rates, as if the plant were operating under business-as-usual.

At a minimum, customers should not be locked into paying (potentially, for many years until the next rate case) the full production costs associated with operating a plant that is uneconomic and appears to be operating far more frequently than its variable production costs and energy market revenues [redacted].

[1] Exhibit TFC-2. Data responses CAC 4.26-B, C, and D.

Q. Please describe how plants are dispatched in MISO.

A. Duke is a member of MISO which coordinates the movement of electricity in a large, multi-state region on an economic basis. One of the many ways in which MISO performs this function is through scheduling of generators to meet load on a day-ahead and real-time basis in the region. In the day-ahead energy market, MISO projects energy demand to occur the next day and dispatches generators to operate in order to serve that demand. In the real time market, generators are dispatched at five-minute intervals in order to serve load fluctuations.

Owners of generating units typically bid the variable cost of the unit, i.e., the cost it takes the unit to produce the next unit of energy. MISO dispatches the least-cost units available first and works its way up the offers by price until demand is satisfied. The highest-cost unit that clears the market in a given hour (the "marginal unit") sets the energy price for that hour (without factoring in transmission limitations). The lower a unit's variable costs are below the market price, the more profitable the unit will be over the time period it is dispatching. If the unit's variable costs are above that market price, MISO will not dispatch the unit.

One exception to this process, however, is that units can "self-commit" or operate as "must-run" in MISO. This means that a minimum capacity is provided to the market and MISO can decide to dispatch the remaining capacity.[2] This exception is more commonly the rule for Duke's coal units.

Q. Should any generating unit be losing money on a variable basis if it is being dispatched economically?

A. No. Generating units require fixed costs to be available to operate (including fixed operations and maintenance or O&M, and capital costs) and variable costs (including fuel and variable O&M) for each megawatt hour of generation. If a unit is being dispatched on an economic basis, it only operates when its variable costs are at or below the energy revenue it will collect. If the unit operates at a loss—that is, it did not bring in sufficient energy revenue to cover its variable costs—ratepayers would have been better off purchasing the energy from the wholesale market over that period instead of paying to operate the unit. Because coal units take many hours to ramp and de-ramp, there can be consecutive hours where the unit is operating at a loss; but over a longer period, the unit should be making money or breaking even, if a utility is making prudent dispatch decisions.

Q. Has Edwardsport been operating at a [redacted] in recent years?

A. [redacted] Based on the historical variable costs (including fuel and variable O&M), and energy revenues provided in this case, I estimate that the plant has [redacted] approximately [redacted] dollars from 2016 through 2018, on a variable basis. This means that ratepayers have [redacted] for energy produced at Edwardsport by

[2] See MISO Business Practices Manual, Energy and Operating Reserve Markets (available at: https://www.misoenergy.org/legal/business-practice-manuals/) for further detail.

[redacted].[3] Or put another way: if the plant had not operated from 2016 through 2018, ratepayers would have [redacted] in energy costs. Importantly, these [redacted] exclude all fixed costs associated with the plant.

Figure 1 below shows the annual variable costs and energy revenues for the plant and its resulting net energy margin (energy revenues minus variable costs):

- In 2016, the plant's variable costs were [redacted] million but it collected [redacted] million in energy revenue, **leading to a** [redacted]
- In 2017, the plant's variable costs were [redacted] million but it collected [redacted] million in energy revenue, **leading to a** [redacted]
- In 2018, the plant's variable costs were [redacted] million but it collected [redacted] million in energy revenue, **leading to a** [redacted]

[3] Exhibit TFC-2. Attachment Sierra Club 1.18-F, Exhibit TFC-3. Confidential Attachment Sierra Club 1.18-D, Exhibit TFC-3. Confidential Attachment OUCC 6.3-A(2). Variable O&M (VOM) was taken from Duke's analysis in Confidential Attachment OUCC 6.3-A(2). Remaining O&M was assigned to fixed O&M. Net energy margin is energy revenue minus variable costs (including VOM and fuel).

[redacted]

Figure 1: Edwardsport Energy Revenue and Variable Costs ($millions) CONFIDENTIAL[4]

Q. Is the Edwardsport unit being dispatched economically by MISO?

A. Rarely. Instead of offering the plant for economic dispatch from MISO, Duke has elected to submit the unit to MISO as "must run" in most hours which means that MISO will take at least an "economic minimum" of MWs at that hour.[5] MISO can then dispatch the *remaining* capacity on an economic basis. But for Edwardsport the economic minimum is [redacted] of the plant's capacity.

Based on hourly bids submitted by Duke, when the Edwardsport was not on an outage, it was submitted as "must run" in [redacted]% of hours in [redacted] and [redacted] of hours in [redacted], and 100% of hours in 2018.[6] Therefore, in [redacted] hour, Duke made

[4] *Id*.
[5] Exhibit TFC-2. Data response to Sierra Club 3.1.
[6] Exhibit TFC-3. Confidential Attachments 1.15 A, Confidential Attachments 1.22-C and D, and Exhibit TFC-2. Attachment CAC 5.1-A

the decision to operate the plant rather than allow MISO to decide whether to operate it at that hour.

For those hours where the plant was submitted as "must run," the minimum level of capacity submitted was [redacted] maximum capacity submitted.[7] While, in theory, Duke claims that MISO can dispatch capacity above the minimum level if it elects to,[8] in practice MISO had [redacted] in which to do so. Figure 2 shows the average minimum must-run capacity submitted and the maximum capacity available for the plant:

- In 2016, the plant's average must-run minimum was [redacted] MWs and its average maximum was [redacted] MWs.[9] On average, [redacted]% of the plant's capacity was submitted as "must-run." MISO could only economically dispatch [redacted] MWs—or [redacted]% of the plant's capacity.
- In 2017, the plant's average must-run minimum was [redacted] MWs and its average maximum was [redacted] MWs.[10] On average, [redacted]% of the plant's capacity was submitted as "must-run." MISO could only economically dispatch [redacted] MWs—or [redacted]% of the plant's capacity.
- In 2018, the plant's average must-run minimum was 415 MWs and its average maximum was 474 MWs.[11] On average, 88% of the plant's

[7] *Id.*
[8] Exhibit TFC-2. Data response to Sierra Club 3.1.
[9] Exhibit TFC-3. Confidential Attachments 1.15 A and Confidential Attachment 1.22-C.
[10] Exhibit TFC-3. Confidential Attachments 1.15 A and Confidential Attachment 1.22-D.
[11] Exhibit TFC-2. Attachment CAC 5.1-A and Attachment SC 2.4-A

capacity was submitted as "must-run." MISO could only economically dispatch 59 MWs—or 12% of the plant's capacity.

[redacted]

Figure 2: Edwardsport Average Must-Run (Minimum) and Maximum Capacity Available CONFIDENTIAL[12]

Q. Is the plant economic to operate in most hours that it is available for dispatch?

A. [redacted], the plant is [redacted] to operate than the energy revenue it collects from MISO. Put differently: purchasing energy from the MISO wholesale market would be [redacted]. Figure 3 shows the average energy price (i.e., MISO Locational Marginal Price or LMP) and variable cost (including fuel and variable O&M) for 2016 through 2018:

- In 2016, the plant's average variable cost was [redacted] per MWh while the average energy price was [redacted] per MWh. In [redacted] of hours that year, the plant was more [redacted] than wholesale energy.

[12] *Id.*

- In 2017, the plant's average variable cost was [redacted] per MWh while the average energy price was [redacted] per MWh. In [redacted] of hours that year, the plant was more [redacted] than wholesale energy.
- In 2018, the plant's average variable cost was [redacted] per MWh while the average energy price was [redacted] per MWh. In [redacted] of hours that year, the plant was more [redacted] than wholesale energy.

[redacted]

Figure 3: Edwardsport Average Energy Price and Variable Cost ($/MWh) CONFIDENTIAL[13]

[13] Exhibit TFC-2. Attachment Sierra Club 1.18-F, Exhibit TFC-3. Confidential Attachment Sierra Club 1.22-G, Exhibit TFC-3. Confidential Attachment OUCC 6.3-A(2). Variable O&M (VOM) was taken from Duke's analysis in Confidential Attachment OUCC 6.3-A(2). Remaining O&M was assigned to fixed O&M. Net energy margin is energy revenue minus variable costs (including VOM and fuel).

Q. Does the Company provide the actual variable cost of operating the plant to MISO?

A. [redacted] When the Company offers a portion of its units for economic dispatch (i.e., the capacity above an economic minimum), it often bids the units [redacted] their variable cost.[14] This sends a price signal that [redacted] leading MISO to dispatch the unit [redacted] I will explain this in more detail later in my testimony.

Q. Is the frequency of Edwardsport's operation an indication of its economic viability?

A. No. Edwardsport's capacity factor in the past three years has been [redacted] respectively.[15] After excluding planned and forced outages, the plant operated at [redacted] of available capacity in 2016, 2017, and 2018, respectively.[16] However, the frequency of operation is only an indicator of economic viability if a unit is: 1) always being dispatched on an economic basis, and 2) bid into the market at its true variable cost. But [redacted] for Edwardsport. Most of the plant's generation is due to Duke forcing the plant to operate as "must run" and the remainder is dispatched by MISO based on an [redacted] of variable costs.

The frequency of the Edwardsport's operation belies its economic viability. Moreover, the annual variable costs and energy revenue (Figure 1) clearly show

[14] Exhibit TFC-3. Confidential Attachments Sierra Club 1.15-D, E, and F.
[15] Exhibit TFC-3. Confidential Attachment Sierra Club 1.18B.
[16] *Id*. Capacity factor divided by Equivalent Availability Factor (EAF), which excludes planned and forced outages.

that the plant has [redacted] ratepayers substantially in recent years, purely on a variable basis. If the plant were run less frequently—ideally for a small percentage of hours—ratepayers would [redacted].

Q. Does Edwardsport also have high fixed costs?

A. Yes. Edwardsport's fixed costs (including fixed O&M and new capital costs) are significant. From 2016 through 2018, the plant had approximately [redacted] the fixed costs of either the Cayuga or Gibson plants, on a per kW basis. Figure 4 shows the fixed costs of the three coal plants for 2016 through 2018. Edwardsport had an average fixed cost of [redacted] per kW over that period, compared to [redacted] per kW for Cayuga and Gibson. If Edwardsport had cost as much as the next most expensive plant (Cayuga or Gibson) it would have required [redacted] in fixed costs alone from 2016 through 2018. (These figures do not include unavoidable capital costs already invested in the plants, such as costs of constructing the plants.)

[redacted]

Figure 4: Fixed Costs of Cayuga, Gibson and Edwardsport Plants CONFIDENTIAL ($/kW)[17]

Q. What is the main driver for high fixed costs at Edwardsport?

A. In recent years, the key driver of its high fixed costs (shown above) is fixed O&M. Edwardsport's fixed O&M costs [redacted] that of either Cayuga or Gibson, on a per kW basis. Figure 5 shows the fixed O&M of the three coal plants for 2016 through 2018. Edwardsport had an average fixed cost of [redacted] per kW over that period, compared to [redacted] per kW for Cayuga and Gibson. These represent a subset of costs shown above in Figure 4.

[17] Exhibit TFC-3. Confidential Attachment Sierra Club 1.18-C, Exhibit TFC-2. Attachment Sierra Club 1.18-F, Exhibit TFC-3. Confidential Attachment OUCC 6.3-A(2). Variable O&M (VOM) was taken from Duke's analysis in Confidential Attachment OUCC 6.3-A(2). Remaining O&M was assigned to fixed O&M.

[redacted]

Figure 5: Annual Fixed O&M for Cayuga, Gibson and Edwardsport Plants CONFIDENTIAL ($/kW)[18]

Q. Do the high fixed costs indicate that retiring the plant could be beneficial?

A. Yes. The Company may argue that despite the plants high variable costs that it provides "capacity value." But this argument would not hold water because the plant is actually [redacted] to operate than it would be to replace it with a new resource—even after accounting for energy revenues.

Edwardsport's fixed costs are [redacted] than other coal plants in the fleet, as shown above, and are also [redacted] than replacing the plant. Edwardsport's total net costs (shown below in Figure 6) include annual fixed costs (not including unavoidable capital already invested, such as construction costs) and variable costs minus energy revenue (i.e., as a credit). The remaining annual costs of operating the Edwardsport are [redacted] the annual costs of a new

[18] Exhibit TFC-2. Attachment Sierra Club 1.18-F and Exhibit TFC-3. Confidential Attachment OUCC 6.3-A(2).

combustion turbine (CT)—the basis for MISO's Cost of New Entry (CONE) which is used to set a maximum capacity price bid. The incremental net cost of Edwardsport [redacted] those of a new CT was [redacted] for 2016 through 2018. Therefore, ratepayers would have saved significantly on fixed costs alone if Edwardsport [redacted].

[redacted]

Figure 6: Edwardsport Net Costs (Fixed and Variable) Compared to MISO Cost of New Entry (CONE) CONFIDENTIAL[19]

The plant is already [redacted] than the maximum cost of capacity allowed on the MISO market. In practice, capacity prices have been substantially lower than CONE—for instance, in the latest auction for MISO Zone 6, the price was $2.99

[19] MISO 2016/2017, 2017/2018 and 2018/2019 Planning Resource Auction Results (available at: https://cdn.misoenergy.org/2016-2017%20PRA%20Results87167.pdf; https://cdn.misoenergy.org/2017-2018%20Planning%20Resource%20Adequacy%20Results87196.pdf; https://cdn.misoenergy.org/2018-19%20PRA%20Results173180.pdf)

per MW-day (or just above 1% of CONE).[20] In the short-term, MISO capacity purchases could fulfill capacity need for an [redacted] compared to the costs of Edwardsport. In the meantime, long-term replacement options should be pursued that would be lower-cost than combustion turbine replacement—on a fixed and/or variable cost basis. Yet the Company has failed to even entertain such a prospect in its long-term planning.

Q. Does the Company expect that the plant will continue to have high fixed costs?

A. Yes. In the IRP, the Company projects that it will spend more than [redacted] ($2017) from 2019 through 2037 on new capital and fixed O&M at Edwardsport—an average of [redacted] million per year or [redacted]/kW.[21] The annual projections of fixed costs for the plant from the IRP are shown below in Figure 7. This shows that high fixed costs are not going away for Edwardsport, even taking the Company's projections as-read, i.e., without scrutiny.

[20] MISO 2019/2020 Planning Resource Auction Results (available at: https://cdn.misoenergy.org/20190412_PRA_Results_Posting336165.pdf)
[21] Exhibit TFC-3. Confidential Attachment Sierra Club 1.19A

[redacted]

Figure 7: Duke's Projection of Edwardsport New Fixed Costs ($/kW and $mil) CONFIDENTIAL[22]

Q. Edwardsport was converted to an IGCC (integrated gasification combined cycle) plant in 2013 at great expense. Should this factor into a forward-looking retirement decision?

A. No. A retirement assessment would evaluate all future revenues and avoidable costs from the plant. The capital already invested in the plant is a "sunk cost" (or unavoidable) and should not be incorporated in a forward-looking decision. The handling of these sunk costs is a separate decision from whether the plant should be retired. Nor should the recency of the plant's renovation be a factor in deciding its future, as that also cannot be undone.

[22] *Id.*

Q. How do you recommend that the Commission address Edwardsport in this Cause?

A. The Commission should deny Duke's request for Test Year capital, fuel, and O&M for Edwardsport because the Company cannot meet its burden to show that those costs are prudently incurred. The Commission should not allow the Company to charge ratepayers substantial fixed costs for a plant that is [redacted] uneconomic to operate on a variable basis and would [redacted] ratepayer money if replaced. Once the Company develops a plan for the plant's retirement, Duke should be permitted recovery of fixed costs that have been adjusted to plan for imminent retirement. (If the Commission does not agree that there is evidence that the plant should retire, then it should compel Duke to conduct a retirement assessment, comparing continued operation of the plant to all available replacement options.)

Duke should only collect variable costs that correspond to economic dispatch of the plant. At the very least, Duke should be disallowed the [redacted] associated with the plant from the past three years—as ratepayers were [redacted] this amount for energy. Going forward, Duke should either offer the plant MISO to dispatch economically or, if the Company must make its own determination, then its dispatch decision-making process should be readily transparent and justify the frequency of the plant's operation. In any event, the Commission should open an investigation into this self-commitment practice, as other states have done.

III. Duke has Failed to Justify Continued Operation of Cayuga and Gibson and Should be Required to Do So Going Forward.

Q. Is there a connection between the Company's recent IRP and this rate case?

A. Yes. In any rate case, the Commission is asked to review the prudence of spending at generation units, which may involve a review of the utility's resource planning. In this rate case, Duke is asking for cost recovery for 2020 test year capital and operating costs of its existing units and is specifically relying on the IRP for justifying continued operation of these units.[23] But the IRP analysis was severely limited in its economic evaluation, and erred on the side of keeping older coal units operating. If the IRP analysis had concluded that some units should retire in the near-term then, in anticipation, the Company could ramp down spending on capital and operating costs in this rate case. Because of the connection between the IRP and the rate case, and because the Commission does not hold an evidentiary hearing and typically does not approve or deny the IRP around the time it is filed, this rate case affords the opportunity to rule on long-term planning issues.

Q. Please summarize the rate recovery requested for 2020 in this case for Cayuga, Edwardsport, and Gibson.

A. The Company is requesting almost $1 billion in costs for these three coal plants in 2020 alone. A breakdown of these costs is provided in Table 1.

[23] *See* July 18, 2019 Order in this Cause (granting Duke's motion for administrative notice of its 2019 IRP).

Table 1: Test Year (2020) Cost Estimates[24]

	Cayuga ($mil)	Edwardsport ($mil)	Gibson ($mil)
Non-fuel O&M	$50	$146	$133
Fuel	$107	$103	$334
Capital	$12	$51	$40
2020 Total	**$168**	**$300**	**$508**

Q. Please summarize your main concerns with the Company's long-term plan for its coal fleet, resulting from the IRP.

A. In Witness Keith Pike's testimony in this Cause, Duke has provided updated retirement dates for its coal units, based on the Company's IRP. These dates and the ages of each unit at retirement are shown below in Table 2.

Table 2:Duke Energy Indiana Dates of Coal Unit Retirement[25]

Coal Unit	Date of retirement	Age at retirement
Cayuga 1	2028	57.7
Cayuga 2	2028	55.9
Edwardsport	2045	32
Gallagher 2	2022	64.1
Gallagher 4	2022	61.8
Gibson 1	2038	62.1
Gibson 2	2038	63.1
Gibson 3	2034	56.3
Gibson 4	2026	47.2
Gibson 5	2034	51.7

[24] Exhibit TFC-2. Attachments CAC 4.26-B, C, and D; Attachments CAC 5.3-B, C, and D.
[25] Direct Testimony of Keith Pike, p.12.

The IRP analysis that led to these retirement dates, however, was flawed. First, the IRP fails to even consider retirement of Edwardsport within the 20-year analysis period,[26] even though the plant is [redacted] a significant amount of money. The Company also does not consider retirement of Cayuga or Gibson units prior to 2024. Second, the IRP also fails to consider competitive bidding for new resources that could compete with existing resources. The most recent IRP from Northern Indiana Public Service Company (NIPSCO) conducted such an evaluation and found that replacement of its entire coal fleet was the lowest-cost option.[27]

Q. Why is it problematic to limit evaluation of coal retirements in the IRP?

A. It would save customers money if a utility accelerated the retirement of a unit and replaced its energy and capacity with a cheaper option. Studying a unit's retirement is a primary way that a utility can test the going forward value of an existing generation unit; but the limiting of such retirements shows a lack of fundamental analysis for Duke's fleet.

Duke claims to have conducted "economic optimization modeling" in its IRP.[28] However, the Company also placed limitations on that modeling that would skew the outcome. First, the Company did not allow for the possibility of retiring the Edwardsport plant within the analysis period—assuming the plant would operate

[26] Duke Energy Indiana IRP, p. 58-9.
[27] NIPSCO 2018 IRP, p.155 (available at: https://www.nipsco.com/our-company/about-us/regulatory-information/irp)
[28] Duke Energy Indiana IRP, p.28

until 2045.[29] This means the Company has not made an economic case that Edwardsport should continue operating over the next year or over the next two decades. Second, the Company also did not study a retirement of any Cayuga or Gibson units prior to 2024, citing a need for enough time to plan for such an event.[30] But it is unclear why the Company would need five years to plan for retirement. Third, the Company did not allow for competitive suppliers to compete with existing units.

Q. Did you raise similar issues in comments on the Duke Energy Carolinas and Duke Energy Progress 2018 IRPs in North Carolina?

A. Yes. As noted above, I was the lead author on comments on the 2018 Duke Energy Carolina (DEC) and Duke Energy Progress (DEP) IRPs in North Carolina, on behalf of Natural Resources Defense Council, Sierra Club, and Southern Alliance for Clean Energy.[31] In those IRPs, DEC and DEP fixed the retirement dates for all of their coal units' retirements until the units were fully depreciated. I raised the concern of lack of economic justification for Duke's North Carolina coal fleet, as I am raising it with Duke's Indiana fleet in this testimony.

[29] *Id.* p.59
[30] *Id.* p.58
[31] Exhibit TFC-4. NC IRP Comments.

Q. Did the North Carolina Utilities Commission agree with your concerns about Duke's retirement analysis in that IRP?

A. Yes, in large part. The North Carolina Utilities Commission (NCUC) approved the 2018 DEC and DEP IRPs but it issued requirements for coal retirement analysis in the 2020 IRPs, after agreeing that the coal unit analysis was lacking rigor:

> …the Commission determines that it should require Duke to provide an analysis showing whether continuing to operate each of its existing coal-fired units is the least cost alternative compared to other supply-side and demand-side resource options, or fulfills some other purpose that cannot be achieved in a different manner.
>
> To address the issue of economic retirement of aging coal plants, in the 2020 IRPs DEC and DEP shall include an analysis that removes any assumption that their coal-fired generating units will remain in the resource portfolio until they are fully depreciated. Instead, the utilities shall model the continued operation of these plants under least cost principles, including by way of competition with alternative new resources.[32]

The NCUC also directed Duke to include a discussion of all-resource requests for proposals (RFP).[33] These concerns that I outlined in comments in North Carolina, and that were addressed by the NCUC, also apply in Indiana because Duke's Indiana IRP suffers from similar flaws. By failing to evaluate Edwardsport's economics and limiting the retirement of Cayuga and Gibson units relative to all

[32] Exhibit TFC-5. NCUC order, p. 90
[33] *Id.* Appendix A, p. 5

viable resource options, Duke Energy Indiana could be forgoing a lower-cost, lower-risk plan for ratepayers.

Q. Is this rate case a reasonable forum for the Commission to address resource planning issues?

A. Yes. As noted above, Duke is seeking cost recovery in this docket for all of its generation units, and is unclear when it will file another rate case.[34] In the context of this case, the Commission must assess resource planning as it reviews the prudence of Duke's continued generation spending. In addition, this current Cause offers an opportunity for the Commission to incentivize prudent long-term planning and operations of Duke's fleet. The Commission has limited opportunity to do so elsewhere. The IRP process in Indiana involves stakeholder meetings, stakeholder comments, and culminates in a report from the IURC Staff which summarizes the stakeholder commentary and offers the staff's views on each utility's IRP. While this process is important, the Commission itself does not typically issue an order approving or denying each IRP at the time of its filing. The IRP process also does not include an evidentiary hearing. Those who developed the IRP are not subjected to cross examination from other parties or the Commission.

To my knowledge, the only forums available for the Commission to rule on long-term resource planning for its generating units would be in a rate case or certificate of public convenience and necessity (CPCN) docket. The latter opportunity,

[34] Exhibit TFC-2. Data response Sierra Club 4.1.

however, only arises when a utility is asking for approval to make a large capital investment such as a new power plant or retrofit of an existing plant.

Q. How should the Commission address long-term planning for Cayuga and Gibson in this Cause?

A. The Company is permitted to recover reasonable and prudently-incurred costs only. But by limiting the analysis of coal units' retirement, it has failed to justify their continued operation and associated expenses in this rate case. I have already recommended in the previous section that Edwardsport costs be denied and the plant be retired. Regarding Cayuga and Gibson, the Company should be compelled to evaluate all reasonable options for retiring these units, including allowing for retirement prior to 2024 and pursuing lower-cost replacement options—such as through an all-resource RFP.

Now is an opportune time to address resource planning issues. Duke has indicated that it does not know when it will file another rate case, which means there will be limited opportunity for the Commission to compel Duke to conduct prudent resource planning.[35]

[35] *Id.*

IV. THE COMPANY'S COAL UNITS ARE OPERATED IMPRUDENTLY AND ASSOCIATED [redacted] SHOULD BE DISALLOWED.

Q. Please summarize your concerns with how the Company operates its units.

A. I have several concerns with how the units are operated on a variable basis that I have already discussed regarding Edwardsport. However, my concerns with variable costs outlined in that previous section also extend to the Cayuga and Gibson plants. Like Edwardsport, the Company also "self-commits" the Cayuga and Gibson plants for most hours of the year. Also, the bid prices for Cayuga and Gibson [redacted] with variable costs of operating the plants. Both concerns are more pronounced regarding Edwardsport but still occur with Cayuga and Gibson.

Q. Should Duke's units be dispatched on an economic basis?

A. Yes. The Company claims that it self-commits after making its own determination of whether the unit should be operated or not. However, especially with Edwardsport, that system is failing ratepayers by [redacted] are expected to continue—unless a cheaper alternative path forward is chosen.

Figure 8, Figure 9, and Figure 10 below show the Company's designation of dispatch status for all hours in 2016, 2017, and 2018, respectively. This shows that in these three years, the units were bid in as "must run"—or self-committing—in [redacted] available. The "econ" designation is when the Company determines that the unit is likely not economic but allows MISO the option to dispatch it economically.[36]

[redacted]

Figure 8: Coal Unit Bid Status by Hour, 2016 CONFIDENTIAL[37]

[36] *Id.* Exhibit TFC-2. Data response to Sierra Club 3.1.
[37] Exhibit TFC-3. Confidential Attachments Sierra Club 1.15A and Confidential Attachments Sierra Club 1.22-C.

[redacted]

Figure 9: Coal Unit Bid Status by Hour, 2017 CONFIDENTIAL[38]

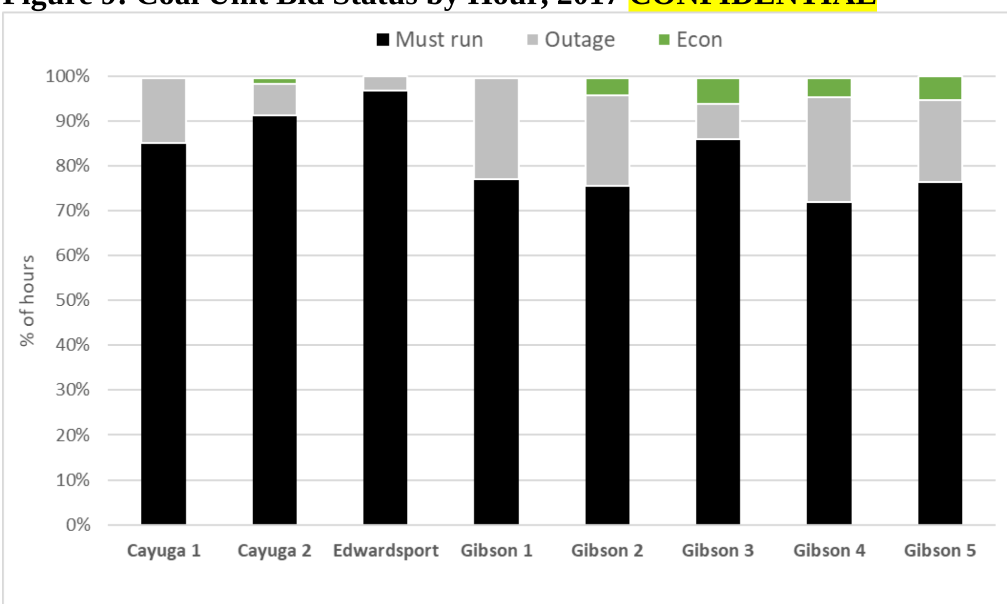


Figure 10: Coal Unit Bid Status by Hour, 2018[39]

I have already discussed the significant [redacted] from Edwardsport in the past three years resulting from Duke's dispatch behavior for that plant. My analyses for

[38] Exhibit TFC-3. Confidential Attachments Sierra Club 1.15A and Confidential Attachments Sierra Club 1.22-D.
[39] Exhibit TFC-2. Attachment CAC 5.1-A and Attachment SC 2.4-A

Cayuga and Gibson show that the plants have been making [redacted], annual net energy margin in 2017 and 2018 when excluding capital and other fixed costs but had annual [redacted] in 2016. The estimates are shown below in Table 3.

Table 3: Coal Plant Annual Net Energy Margin, 2016-2018 ($mil), CONFIDENTIAL[40]

[redacted]

Cayuga and Gibson had [redacted] net energy margins in 2016 and [redacted] net energy margins in 2017 and 2018, on an annual basis. But even in 2017 and 2018, these plants did [redacted] net energy margins every month.[41] Table 4 shows that in 2017 and 2018, both plants had [redacted] margins in February and Gibson had [redacted] margins in March of both years. Over the 2016 through 2018 period, Cayuga had $[redacted] in monthly losses, Gibson had [redacted] and Edwardsport had [redacted]. While the issue is more pronounced Edwardsport, and [redacted] from Cayuga and Gibson have decreased in the past two years, there is also room for customer savings in how the Cayuga and Gibson units are dispatched by the Company.

---

[40] Exhibit TFC-2. Attachment Sierra Club 1.18-F, Exhibit TFC-3. Confidential Attachment Sierra Club 1.18-D, Exhibit TFC-3. Confidential Attachment OUCC 6.3-A(2). Variable O&M (VOM) was taken from Duke’s analysis in Confidential Attachment OUCC 6.3-A(2). Remaining O&M was assigned to fixed O&M. Net energy margin is energy revenue minus variable costs (including VOM and fuel).

[41] *Id.* Exhibit TFC-3. REVISED Confidential Attachment Sierra Club 1.22-G.

Table 4: Coal Plant Monthly Net Energy Margin, 2016, 2017, and 2018 ($mil), CONFIDENTIAL[42]

[redacted]

Q. Should the units bid their variable cost for each megawatt hour?

A. Yes. The variable cost (including fuel and variable O&M) is also the marginal cost of operating the unit for one more MWh. The Company's bids into MISO, however, [redacted] with their variable costs—as shown in Table 5 below. Edwardsport is an extreme example where in 2016 and 2018 the average bid was about [redacted] variable cost of the plant. Cayuga's bid offers are [redacted] to its variable costs in 2017 and 2018. Gibson's bids are typically [redacted], per MWh, than its variable costs. This indicates that when MISO is allowed to dispatch the units, above their must-run minimum, it is being given estimates that

[42] *Id.*

[redacted] and would lead to [redacted] in some hours. This [redacted] means that MISO is dispatching the plant when Duke's customers would [redacted] if the plant did not operate.

Table 5: Coal Plant Bid Offer Comparison to Variable Costs ($/MWh), CONFIDENTIAL[43]

[redacted]

Q. Are other commissions and regions exploring "self-commitment" of units and possible policy solutions to this issue?

A. Yes. The day-ahead market in MISO (as well as PJM, ISO-New England, and SPP) asks for hourly bids one day in advance and dispatches units based on the marginal price of energy in each hour. But coal and nuclear units are not able to simply turn on or off each hour; they take hours to ramp up and down. These characteristics mean that the units are likely to lose money for some hours of the day but should more than make up for those losses later. Thus, the decision to dispatch can be

[43] Confidential attachments SC 1.15D, E and F. Average bid value excludes first bid round which is [redacted].

based on a multi-day outlook whereby the operator self-commits based on what it anticipates the unit will collect in revenue over a longer period.

Commissions in Minnesota and Missouri have opened dockets to investigate self-commitment and its impact on ratepayers.[44] The Southwest Power Pool (SPP), which is adjacent to MISO, has identified self-commitment as a concern, stating that:

> "…long lead-time and long run-time resources are often self-committed and contribute to depressing prices in the SPP market. These resources are not appropriately evaluated in the current market structure and can be committed by market participants during uneconomic periods.[45]

SPP is exploring the option of a multi-day ahead market, as an alternative to its single day-ahead market, in part because of concern with self-commitment.[46] ISO-New England is also considering a multi-day market.[47]

Q. Did you estimate what a multi-day ahead market could look like?

A. Yes, with the above concerns about the single day-ahead market in mind, I have estimated a four day-ahead market using hourly 2018 data for units at Cayuga,

[44] Missouri Public Service Commission, Docket No. EW-2019-0370; Minnesota Public Utilities Commission Docket No. E-999/A-17-492. Order Issues February 7, 2019

[45] Southwest Power Pool Market Monitoring Unit, State of the Market Report 2018, p.243 (available at: https://www.spp.org/documents/59861/2018%20annual%20state%20of%20the%20market%20report.pdf)

[46] *Id*. p. 243-5

[47] ISO-New England, Energy Security Improvements, ISO Discussion Paper, April 2019, p.5 (available at: https://www.iso-ne.com/static-assets/documents/2019/04/a00_iso_discussion_paper_energy_security_improvements.pdf

Gibson, and Edwardsport. First, I looked at the energy revenues and variable costs at each hour of 2018 and 2019 (through April). Second, I aggregated those data to daily data to estimate net gains and losses on a daily rather than hourly basis. This allowed me to see when there were multi-day losses or gains from the units' operation. Table 6 shows the longest streak of daily losses for each unit.[48] Edwardsport is consistently the [redacted] case shown, with more than [redacted] in 2018.[49]

Table 6: Longest Consecutive days with Losses, CONFIDENTIAL[50]

[redacted]

I constructed a four-day ahead look, starting on January 1, 2016, whereby the energy revenue and variable costs for that day and proceeding three days would be combined in order to determine a dispatch decision for a four-day period. This method is illustrative of what a four-day dispatch could look like. Because I am using historical data, I am assuming perfect foresight on the part of the operator. In

[48] As a favorable measure to the units, I limited daily losses to those above $10,000.
[49] Data for 2019 was not available for the full year so I decided to not report it here.
[50] Exhibit TFC-3. Confidential Attachment OUCC 6.3-A(2), Exhibit TFC-2. Data response SC 1.18-F, Exhibit TFC-3. Confidential Attachments SC 1.15 A, Exhibit TFC-3. Confidential Attachments SC 1.22-D, Exhibit TFC-3. Confidential Attachment SC 1.22-G.

order to account for this, however, I allowed the units to operate even if there were less than $40,000 in losses (less $10,000 of losses per day, on average).

The results of this four-day-ahead dispatch showed that all of the coal units would have operated less often *and* would have made higher net energy margin. These results are shown in Table 7.

Cayuga and Gibson would run less often under this scheme whereas Edwardsport would hardly operate at all. Edwardsport would operate effectively as a peaking plant, which makes sense given its high costs of operation. However, it has much [redacted] fixed costs than a typical peaking plant as I have shown previously.

Importantly, the increase in net energy margin from Edwardsport would bring the annual [redacted] from [redacted] on a variable basis. Cayuga and Gibson had [redacted] in 2017 and 2018 already but these could be [redacted] under a multi-day scheme.

Table 7: Four-day Ahead Dispatch of Duke's Coal Units in 2016, 2017, 2018 CONFIDENTIAL[51]

[redacted]

Q. Has Duke shared details of its dispatch decision-making with you?

A. No. Duke claims to have a manual that supports its dispatch decisions, but it will only allow this manual to be viewed in-person at a location in Indiana. This is rather onerous and shows a lack of transparency. The Commission and stakeholders should be able to readily review and discuss the Company's dispatch methodology.

Q. Does Duke self-commit Cayuga for other reasons?

A. Yes. The Company commits Cayuga for many hours a year because it is needed to provide steam to an industrial customer.[52] If the units are costing ratepayers money

[51] Exhibit TFC-3. Confidential Attachment OUCC 6.3-A(2), Exhibit TFC-2. Data response SC 1.18-F, Exhibit TFC-3. Confidential Attachments SC 1.15 A, Exhibit TFC-3. Confidential Attachments SC 1.22-D,Exhibit-TFC-3. Confidential Attachment SC 1.22-G.

on their bills to provide steam for one industrial customer, that is unfair cross-subsidization. Duke also notes that this deal is a barrier to retiring the plant:

> Even further complicating the ultimate retirement of Cayuga Station is the provision of steam to the neighboring industrial customer. This steam service cannot be effectively maintained by only one steam unit, making the current two-year gap in retirement dates of the units impractical.[53]

If the plant should be retired because it would save ratepayers, a deal with one customer should not prevent that from occurring. At the very least, ratepayers should be compensated for any losses in that event.

Q. Should Duke consider Cayuga and Gibson for an early retirement?

A. Yes. While Edwardsport is clearly the most pressing plant to address, Duke should consider whether it is in the public interest to retire units at Cayuga and Gibson earlier than expected in its long-term planning. Duke should provide periodic forward-looking assessments of these units in order to justify their continued operation.

Q. How do you recommend that the Commission address variable costs for Cayuga and Gibson?

A. First, I recommend a disallowance of operating and/or fuel costs of $[redacted] at Cayuga and [redacted] at Gibson. This is based on the monthly [redacted] these plants

[52] Exhibit TFC-2. Data response Sierra Club 3.1(c).
[53] Pike, p.14, lines 18-22

had in 2016, 2017, and 2018 (see Table 4) where ratepayers were [redacted] for energy for months at a time. As I recommended for Edwardsport, Duke should only collect variable costs that correspond to economic dispatch of Cayuga and Gibson. Duke should either offer these units for MISO to dispatch economically or, if it must make its own determination, then Duke's own dispatch decision-making process should be readily transparent and justify the frequency of their operation. In any event, given the past losses borne by ratepayers due to Duke's self-commitment of its units, the Commission should open an investigation into this practice, as other states have done.

Q. Does this conclude your testimony?

A. Yes.

VERIFICATION

I, Tyler Comings, affirm under penalties of perjury that the foregoing representation are true and correct to the best of my knowledge, information and belief.

____
Tyler Comings

10/30/19
Date

EXHIBIT TFC-1

Applied Economics Clinic
Economic and Policy Analysis of Energy, Environment and Equity

Tyler Comings, Senior Researcher
1012 Massachusetts Avenue, Arlington MA 02476 ⌘ tyler.comings@aeclinic.org ⌘ 617-863-0139

PROFESSIONAL EXPERIENCE

Applied Economics Clinic, Somerville, MA. *Senior Researcher*, June 2017 – Present.

Provides technical expertise on electric utility regulation, energy markets, and energy policy. Clients are primarily public service organizations working on topics related to the environment, consumer rights, the energy sector, and community equity.

Synapse Energy Economics Inc., Cambridge, MA. *Senior Associate*, July 2014 – June 2017, Associate, July 2011 – July 2014.

Provided expert testimony and reports on energy system planning, coal plant economics and economic impacts. Performed benefit-cost analyses and research on energy and environmental issues.

Ideas42, Boston, MA. *Senior Associate*, 2010 – 2011.

Organized studies analyzing behavior of consumers regarding finances, working with top researchers in behavioral economics. Managed studies of mortgage default mitigation and case studies of financial innovations in developing countries.

Economic Development Research Group Inc., Boston, MA. *Research Analyst*, *Economic Consultant*, 2005 – 2010.

Performed economic impact modeling and benefit-cost analyses using IMPLAN and REMI for transportation and renewable energy projects, including support for Federal stimulus applications. Developed a unique web-tool for the National Academy of Sciences on linkages between economic development and transportation.

Harmon Law Offices, LLC., Newton, MA. *Billing Coordinator, Accounting Liaison,* 2002 – 2005.

Allocated IOLTA and Escrow funds, performed bank reconciliation and accounts receivable. Projected legal fees and costs.

Massachusetts Department of Public Health, Boston, MA. *Data Analyst* (contract), 2002.

Designed statistical programs using SAS based on data from health-related surveys. Extrapolated trends in health awareness and developed benchmarks for performance of clinics for a statewide assessment.

EDUCATION

Tufts University, Medford, MA
Master of Arts in Economics, 2007

Boston University, Boston, MA
Bachelor of Arts in Mathematics and Economics, Cum Laude, Dean's Scholar, 2002.

Affiliations

Society of Utility and Regulatory Financial Analysts (SURFA)
Member

Global Development and Environment Institute, Tufts University, Medford, MA.
Visiting Scholar, 2017 – Present

Certifications

Certified Rate of Return Analyst (CRRA), professional designation by Society of Utility and Regulatory Financial Analysts (SURFA)

Papers and Reports

Lopez, R., T. Comings, E.A. Stanton, and E. Tavares. 2019. *Home Heat Pumps in Massachusetts*. Applied Economics Clinic. Prepared for Green Energy Consumers Alliance. [Online]

Comings, T., B. Woods, and M. Majumder. 2019. *Updated Costs of Community Choice Energy Aggregation in Boston*. Applied Economics Clinic. Prepared for Barr Foundation. [Online]

Comings, T., R. Lopez, and B. Woods. 2018. *A Critique of an Industry Analysis on Claimed Economic Benefits of Offshore Drilling in the Atlantic*. Applied Economics Clinic. Prepared for the Southern Environmental Law Center. [Online]

Stanton, E.A., and T. Comings. 2018. *Massachusetts Clean Energy Bill Provisions Boost Jobs and Strengthen the State's Economy.* Applied Economics Clinic. Prepared for Barr Foundation. [Online]

Stanton, E.A., T. Comings, R. Wilson, S. Alisalad, E.N Marzan, C. Schlegel, B. Woods, J. Gifford, E. Snook, and P. Yuen. 2018. *An Analysis of the Massachusetts 2018 'Act to Promote a Clean Energy Future' Report*. Applied Economics Clinic. Prepared for Barr Foundation. [Online]

Comings, T., E.A. Stanton, and B. Woods. 2018. *The ABCs of Boston CCE*. Applied Economics Clinic. Prepared for Barr Foundation. [Online]

Stanton, E.A., T. Comings, and A. Sommer. 2018.*The Husker Energy Plan: A New Energy Plan for Nebraska*. Applied Economics Clinic. Prepared for the Nebraska Wildlife Foundation. [Online]

Comings, T. and B. Woods. 2017. *The Future of the Martin Drake Power Plant*. Applied Economics Clinic. Prepared for Green Cities Coalition and Southeastern Colorado Renewable Energy Society. [Online]

Comings, T., E.A. Stanton, and B. Woods. 2017*. An Analysis of Community Choice Energy for Boston.* Applied Economics Clinic. Prepared for Barr Foundation. [Online]

Wilson, R., T. Comings, and E.A. Stanton. 2017. *Ratepayer Impacts of ConEd's 20-Year Shipping Agreement on the Mountain Valley Pipeline.* Applied Economics Clinic. Prepared for the Environmental Defense Fund. [Online]

Knight, P., A. Horowitz, P. Luckow, T. Comings, J. Gifford, P. Yuen, E. Snook, and J. Shoesmith. 2017. *An Analysis of the Massachusetts Renewable Portfolio Standard*. Synapse Energy Economics and Sustainable Energy Advantage. Prepared for NECEC in Partnership with Mass Energy. [Online]

Knight, P., S. Fields, F. Ackerman, T. Comings, and A. Allison. 2017*. Empowering Kentucky*. Synapse Energy Economics. Prepared for Kentuckians for the Commonwealth. [Online]

Comings, T. and A. Allison. 2017. *More Mileage for Your Money: Fuel Economy Increases While Vehicle Prices Remain Stable*. Synapse Energy Economics. Prepared for Consumers Union. [Online]

Cook, R., J. Koo, N. Veilleux, K. Takahashi, E. Malone, T. Comings, A. Allison, F. Barclay, and L. Beer. 2017. *Rhode Island Renewable Thermal Market Development Strategy*. Meister Consultants Group and Synapse Energy Economics. Prepared for Rhode Island Office of Energy Resources. [Online]

Fisher, J., P. Luckow, A. Horowitz, T. Comings, A. Allison, E.A. Stanton, S. Jackson, and K. Takahashi. 2016*. Michigan Compliance Assessment for the Clean Power Plan: MPSC/MDEQ EPA 111(d) Impact Analysis*. Prepared for Michigan Public Service Commission, Michigan Department of Environmental Quality, and Michigan Agency for Energy. [Online]

White, D., P. Peterson, T. Comings, and S. Jackson. 2016. *Preliminary Valuation of TransCanada's Hydroelectric Assets*. Prepared for the State of Vermont. [Online]

Comings, T., S. Jackson, and J. Fisher. 2016. *The Economic Case for Retiring North Valmy Generating Station*. Synapse Energy Economics. Prepared for Sierra Club. [Online]

Comings, T., A. Allison, and F. Ackerman. 2016. *Higher Fuel Economy Standards Result in Big Savings for Consumers*. Synapse Energy Economics. Prepared for Consumers Union. [Online]

Jackson, S., P. Luckow, E.A. Stanton, A. Horowitz, P. Peterson, T. Comings, J. Daniel, and T. Vitolo. 2016*. Reimagining Brayton Point: A Guide to Assessing Reuse Options for the Somerset Community.* Synapse Energy Economics. Prepared for Coalition for Clean Air South Coast, Clean Water Action, and Toxics Action Center. [Online]

Stanton, E.A., P. Knight, A. Allison, T. Comings, A. Horowitz, W. Ong, N. R. Santen, and K. Takahashi. 2016. *The RGGI Opportunity 2.0: RGGI as the Electric Sector Compliance Tool to Achieve 2030 State Climate Targets*. Synapse Energy Economics. Prepared for Sierra Club, Pace Energy and Climate Center, and Chesapeake Climate Action Network. [Online]

Stanton, E.A., P. Knight, A. Allison, T. Comings, A. Horowitz, W. Ong, N. R. Santen, and K. Takahashi. 2016. *The RGGI Opportunity: RGGI as the Electric Sector Compliance Tool to Achieve 2030 State Climate Targets*. Synapse Energy Economics. Prepared for Sierra Club, Pace Energy and Climate Center, and Chesapeake Climate Action Network. [Online]

Ackerman, F. and T. Comings. 2015. *Employment after Coal: Creating New Jobs in Eastern Kentucky*. Synapse Energy Economics. Prepared for the Mountain Association for Community Economic Development. [Online]

Vitolo, T., M. Chang, T. Comings, and A. Allison. 2015. *Economic Benefits of the Proposed Coolidge Solar I Solar Project*. Synapse Energy Economics. Prepared for Coolidge Solar I, LLC. [Online]

Wilson, R., T. Comings, and E.A. Stanton. 2015. *Analysis of the Tongue River Railroad Draft Environmental Impact Statement.* Synapse Energy Economics. Prepared for Sierra Club and Earthjustice. [Online]

Synapse Energy Economics, Labor Network for Sustainability, and 350.org. 2015. *The Clean Energy Future: Protecting the Climate, Creating Jobs, and Saving Money*. [Online]

Fisher, J., T. Comings, F. Ackerman, and S. Jackson. 2015. *Clearing Up the Smog: Debunking Industry Claims that We Can't Afford Healthy Air*. Synapse Energy Economics. Prepared for Earthjustice. [Online]

Stanton, E. A., T. Comings, S. Jackson, and E. Karaca. 2015. *Atlantic Coast Pipeline Benefits Review*. Synapse Energy Economics. Prepared for Southern Environmental Law Center. [Online]

Takahashi, K., T. Comings, and A. Napoleon. 2014. *Maximizing Public Benefit through Energy Efficiency Investments*. Synapse Energy Economics. Prepared for Sierra Club. [Online]

Comings, T., S. Fields, K. Takahashi, and G. Keith. 2014. *Employment Effects of Clean Energy Investments in Montana.* Synapse Energy Economics. Prepared for Montana Environmental Information Center and Sierra Club. [Online]

Comings, T., J. Daniel, P. Knight, and T. Vitolo. 2014. *Air Emission and Economic Impacts of Retiring the Shawnee Fossil Plant*. Synapse Energy Economics. Prepared for the Kentucky Environmental Foundation. [Online]

Comings, T., K. Takahashi, and G. Keith. 2013. *Employment Effects of Investing in Select Electricity Resources in Washington State*. Synapse Energy Economics. Prepared for Sierra Club. [Online]

Stanton, E. A., T. Comings, K. Takahashi, P. Knight, T. Vitolo, and E. Hausman. 2013. *Economic Impacts of the NRDC Carbon Standard.* Synapse Energy Economics. Prepared for Natural Resources Defense Council (NRDC). [Online]

Ackerman, F., T. Comings, and P. Luckow. 2013. *A Review of Consumer Benefits from a Corporate Average Fuel Economy (CAFE) Standards*. Synapse Energy Economics. Prepared for Consumer Union. [Online]

Comings, T., P. Knight, and E. Hausman. 2013. *Midwest Generation's Illinois Coal Plants: Too Expensive to Compete? (Report Update).* Synapse Energy Economics. Prepared for Sierra Club. [Online]

Stanton, E. A., F. Ackerman, T. Comings, P. Knight, T. Vitolo, and E. Hausman. 2013. *Will LNG Exports Benefit the United States Economy?* Synapse Energy Economics. Prepared for Sierra Club. [Online]

Keith, G., S. Jackson, A. Napoleon, T. Comings, and J. Ramey. 2012. *The Hidden Costs of Electricity: Comparing the Hidden Costs of Power Generation Fuels*. Synapse Energy Economics. Prepared for Civil Society Institute. [Online]

Vitolo, T., G. Keith, B. Biewald, T. Comings, E. Hausman, and P. Knight. 2013. *Meeting Load with a Resource Mix Beyond Business as Usual: A regional examination of the hourly system operations and reliability implications for the United States electric power system with coal phased out and high penetrations of efficiency and renewable generating resources*. Synapse Energy Economics. Prepared for Civil Society Institute. [Online]

Fagan, R., M. Chang, P. Knight, M. Schultz, T. Comings, E. Hausman, and R. Wilson. 2012. *The Potential Rate Effects of Wind Energy and Transmission in the Midwest ISO Region*. Synapse Energy Economics. Prepared for Energy Future Coalition. [Online]

Bower, S., S. Huntington, T. Comings, and W. Poor. 2012. *Economic Impacts of Efficiency Spending in Vermont: Creating an Efficient Economy and Jobs for the Future*. Optimal Energy, Synapse Energy Economics, and Vermont Department of Public Service. Prepared for American Council for an Energy-Efficient Economy (ACEEE). [Online]

Comings, T. and E. Hausman. 2012. *Midwest Generation's Illinois Coal Plants: Too Expensive to Compete?*. Synapse Energy Economics. Prepared for Sierra Club. [Online]

Woolf, T., J. Kallay, E. Malone, T. Comings, M. Schultz, and J. Conyers. 2012. *Commercial & Industrial Customer Perspectives on Massachusetts Energy Efficiency Programs*. Synapse Energy Economics. Prepared for Massachusetts Energy Efficiency Advisory Council. [Online]

Hornby, R., D. White, T. Vitolo, T. Comings, and K. Takahashi. 2012. *Potential Impacts of a Renewable and Energy Efficiency Portfolio Standard in Kentucky*. Synapse Energy Economics. Prepared for Mountain Association for Community Economic Development and the Kentucky Sustainable Energy Alliance. [Online]

Hausman, E., T. Comings, and G. Keith. 2012*. Maximizing Benefits: Recommendations for Meeting Long-Term Demand for Standard Offer Service in Maryland*. Synapse Energy Economics. Prepared for Sierra Club. [Online]

Tantia, P., M. Dimova, T. Comings, and K. Davis. 2012. *Budget Finance Company: A Loan Modification Case Study.* [Online]

Keith, G., B. Biewald, E. Hausman, K. Takahashi, T. Vitolo, T. Comings, and P. Knight. 2011. *Toward a Sustainable Future for the U.S. Power Sector: Beyond Business as Usual 2011*. Synapse Energy Economics. Prepared for Civil Society Institute. [Online]

Hausman, E., T. Comings, K. Takahashi, R. Wilson, W. Steinhurst, N. Hughes, and G. Keith. 2011. *Electricity Scenario Analysis for the Vermont Comprehensive Energy Plan 2011*. Synapse Energy Economics. Prepared for the Vermont Department of Public Service. [Online]

Steinhurst, W. and T. Comings. 2011*. Economic Impacts of Energy Efficiency Investments in Vermont.* Synapse Energy Economics. Prepared for the Vermont Department of Public Service. [Online]

Datta, S., P. Tantia, and T. Comings. 2011. *WING Mobile Payments: A Product Design Case Study*. Ideas42. Prepared for International Finance Corporation. [Online]

Tantia, P. and T. Comings. 2011. *Kilimo Salama – Index-based Agriculture Insurance: A Product Design Case Study*. Ideas42. Prepared for International Finance Corporation. [Online]

Tantia, P. and T. Comings. 2011. *Emergency Hand Loan: A Product Design Case Study*. Ideas42. Prepared for International Finance Corporation. [Online]

Tantia, P. and T. Comings. 2011. *Commitment Savings Accounts in Malawi: A Product Design Case Study*. Ideas42. Prepared for International Finance Corporation. [Online]

Petraglia, L. and T. Comings, and G. Weisbrod. 2010. *Economic Development Impacts of Energy Efficiency and Renewable Energy in Wisconsin.* Economic Development Research Group and PA Consulting Group. Prepared for Wisconsin Department of Administration. [Online]

Economic Development Research Group. 2010. *The Economic Impact of Atlanta Hartsfield-Jackson International Airport*. Prepared for City of Atlanta. [Online]

Economic Development Research Group. 2009. *Economic Assessment of Proposed Brockton Power Facility*. Prepared for Brockton Power Company. [Online]

Economic Development Research Group and KEMA NV. 2009. *Economic Benefits of Connecticut's Clean Energy Program.* Prepared for the Connecticut Clean Energy Fund. [Online]

Howland, J., D. Murrow, L. Petraglia, and T. Comings. 2009. *Energy Efficiency: Engine of Economic Growth in Eastern Canada*. Economic Development Research Group and Environment Northeast. [Online]

Economic Development Research Group and KEMA NV. 2008. *New York Renewable Portfolio Standard: Economic Benefits Report*. Prepared for New York State Energy Research and Development (NYSERDA). [Online]

Colledge Transportation Consulting and Economic Development Research Group. 2008. *Northwest Corridor Trade and Manufacturing Strategy.* Prepared for Northern Development Initiative Trust and Canadian Manufacturers & Exporters. [Online]

Weisbrod, G. and T. Comings. 2008. *The Economic Role of the Gateway Transportation System in the Greater Vancouver Region*. Prepared for Greater Vancouver Gateway Council. [Online]

Cambridge Systematics and Economic Development Research Group. 2008. *Economic Impact Study of Completing the Appalachian Development Highway System*. Prepared for Appalachian Regional Commission. [Online]

Lynch, T., T. Comings, and G. Weisbrod. 2007*. Spatial Geography: Effects of Population Base and Airport Access*. Prepared for Appalachian Regional Commission. [Online]

BizMiner and Economic Development Research Group. 2007. *Program Evaluation of the Appalachian Regional Commission's Infrastructure and Public Works Projects*. Prepared for Appalachian Regional Commission. [Online]

Mead & Hunt and Economic Development Research Group. 2007. *Oregon Aviation Plan 2007*. Prepared for Oregon Department of Aviation. [Online]

Economic Development Research Group. 2007. *The Economic Impact of Philadelphia Convention Center*. Prepared for Pew Charitable Trusts. [Online]

Economic Development Research Group. 2006. *Environmental Impacts of Massachusetts Turnpike and Central Artery/Tunnel Projects*. Prepared for the Massachusetts Turnpike Authority. [Online]

TESTIMONY AND EXPERT COMMENTS

Comings, T. 2019. *Testimony on Sooner Coal Plant Scrubbers*. Testimony to the Oklahoma Corporation Commission on behalf of Sierra Club, Cause No. PUD 201800140. [Online]

Sierra Club, assisted by Comings, T., B. Woods, R. Lopez, and E. Tavares. 2019. *Comments on Southwestern Electric Power Company's Draft 2019 Integrated Resource Plan*. Comments to the Louisiana Public Service Commission on behalf of Sierra Club, Docket No. I-34715. [Online]

Sierra Club, assisted by Comings, T., B. Woods, R. Lopez, and E. Tavares. 2019. *Comments on Cleco Power's Draft 2019 Integrated Resource Plan*. Comments to the Louisiana Public Service Commission on behalf of Sierra Club, Docket No. I-34693. [Online]

Sierra Club, assisted by Comings, T., E.A. Stanton, and E. Tavares. 2019. *Comments on Xcel Energy Minnesota's 2018 Mankato Proposal*. [Online]

Comings, T., B. Woods, E.A. Stanton, and E. Tavares. 2019. *Review of Duke Energy's North Carolina Coal Fleet in the 2018 Integrated Resource Plans*. Applied Economics Clinic. Prepared for Southern Environmental Law Center. [Online]

Comings, T. 2018. *Testimony on Consumers Energy Integrated Resource Plan (IRP)*. Testimony to Michigan Public Service Commission, Case No. U-20165. [Online]

Comings, T. 2018. *Testimony on the Economics of Karn Coal Units in Michigan*. Testimony to Michigan Public Service Commission, Case No. U-20134. [Online]

Comings, T. 2018. *Testimony on Vectren's Proposed Natural Gas Plant and Coal Retrofits*. Testimony to the Indiana Utility Regulatory Commission, Cause No. 45052. [Online]

Comings, T. 2018. *Testimony on Stranded Costs of Public Service Company of Colorado's Comanche 1 & 2 Coal Units*. Testimony to the Public Utilities Commission of Colorado, Proceeding No. 17A-0797E. [Online]

Comings, T. 2017. *Testimony on the economic impact analysis of the proposed merger between AltaGas and WGL Holdings*. Testimony to the District of Columbia Public Service Commission, Formal Case No. 1142. [Online]

Comings, T. 2017. *Testimony on the economics of the proposed acquisition of the Pleasants plant*. Testimony to the West Virginia Public Service Commission, Case No. 17-0296-E-PC. [Online]

Fagan, B. and T. Comings. 2017. *Joint testimony regarding the economic analysis of the Maritime Link Project*. Testimony to the Nova Scotia Utility and Review Board, Matter No. 07718. [Online]

Comings, T., A. Horowitz, and K. Takahashi. 2017. *Comments on Portland General Electric's 2016 Integrated Resource Plan*. Comments filed with the Oregon Public Utility Commission, Docket LC 66. [Online]

Comings, T. 2016. *Testimony regarding Dayton Power & Light's proposed Distribution Modernization Rider and the value of the Company's coal fleet*. Testimony to the Ohio Public Utilities Commission, Cases No. 16-0395-EL-SSO, 16-396-EL-ATA, and 16-397-EL-AAM. [Online]

Comings, T. 2016. *Testimony evaluating the economics of Oklahoma Gas & Electric's application to install dry scrubbers at the Sooner generating facility*. Testimony to the Oklahoma Corporation Commission, Cause No. PUD 201600059. [Online]

Comings, T. and A. Horowitz. 2016. *Comments on Portland General Electric's Draft 2016 Integrated Resource Plan*. Comments filed with the Oregon Public Utility Commission, Docket LC 66. [Online]

Comings, T. 2015. *Testimony on the economic impacts of the proposed merger of NextEra Corporation and Hawaiian Electric Companies (HECO)*. Testimony to the Hawaii Public Utilities Commission, Docket No. 2015-0022. [Online]

Daniel, J., A. Napoleon, T. Comings, and S. Fields. 2015. *Comments on Entergy Louisiana's 2015 Integrated Resource Plan.* Synapse Energy Economics. Prepared for Sierra Club. [Online]

Comings, T., S. Jackson, and K. Takahashi. 2015. *Comments on Indianapolis Power & Light Company's 2014 Integrated Resource Plan.* Synapse Energy Economics. Prepared for Sierra Club. [Online]

Comings, T. 2014. *Testimony evaluating the assumptions and analysis used by FirstEnergy Ohio in support of its application for approval of an electric security plan and related Retail Rate Stability Rider*. Testimony to the Ohio Public Utilities Commission, Case No. 14-1297-EL-SSO. [Online]

Comings, T. 2014. *Testimony evaluating the assumptions in the analysis supporting Oklahoma Gas & Electric's request for authorization and cost recovery of a Clean Air Act compliance plan and Mustang modernization*. Testimony to the Oklahoma Corporation Commission, Cause No. PUD 201400229. [Online]

Comings, T. 2014. *Testimony on the economic impact analysis filed by Exelon Corporation and Pepco Holdings, Inc. in their joint petition for the merger of the two entities*. Testimony to the Maryland Public Service Commission, Case No. 9361. [Online]

Comings, T. 2014*. Testimony on the economic impact analysis filed by Exelon Corporation and Pepco Holdings, Inc. in their joint petition for the merger of the two entities*. Testimony to the State of New Jersey Board of Public Utilities, Docket No. EM14060581. [Online]

Comings, T. 2014. *Testimony on the economic impact analysis filed by Exelon Corporation and Pepco Holdings, Inc. in their joint petition for the merger of the two entities*. Testimony to the District of Columbia Public Service Commission, Formal Case No. 1119. [Online]

Daniel, J., T. Comings, and J. Fisher. 2014. *Comments on Preliminary Assumptions for Cleco's 2014/2015 Integrated Resource Plan*. Synapse Energy Economics. Prepared for Sierra Club. [Online]

Fisher, J., T. Comings, and D. Schlissel. 2014*. Comments on Duke Energy Indiana's 2013 Integrated Resource Plan.* Synapse Energy Economics and Schlissel Consulting. Prepared for Mullet & Associates, Citizens Action Coalition of Indiana, Earthjustice and Sierra Club. [Online]

Comings, T. 2013. *Testimony regarding East Kentucky Power Cooperative's Application for Cooper Station Retrofit and Environmental Surcharge Cost Recovery*. Testimony to the Kentucky Public Service Commission, Case No. 2013-00259. November 27, 2013 and December 27, 2013. [Online]

Comings, T. 2013. *Testimony in the Matter of Indianapolis Power & Light Company's Application for a Certificate of Public Convenience and Necessity for the Construction of a Combined Cycle Gas Turbine Generation Facility*. Testimony to the Indiana Utility Regulatory Commission, Cause No. 44339. [Online]

Hornby, R. and T. Comings. 2012. *Comments on Draft 2012 Integrated Resource Plan for Connecticut.* Synapse Energy Economics. Prepared for AARP. [Online]

Resume dated July 2019

Exhibit TFC-2

Duke Energy Indiana Responses to Requests for Information, Public

	Data Request	Format
1.	Attachment Sierra Club 1.18-F	PDF
2.	Attachment SC 2.4-A (Bate No. 090013918-055739)	Excel
3.	IURC 45253 - Duke's Response to Sierra Club Data Request Set No. 3.1	PDF
4.	IURC 45253 - Duke's Response to Sierra Club Data Request Set No. 4.1	PDF
5.	Attachment CAC 4.26-B	PDF
6.	Attachment CAC 4.26-C	PDF
7.	Attachment CAC 4.26-D	PDF
8.	Attachment CAC 5.1-A (Bate No. 090013918-004828)	Excel
9.	Attachment CAC 5.3-B	PDF
10.	Attachment CAC 5.3-C	PDF
11.	Attachment CAC 5.3-D	PDF

*All Excel files have been filed with the Commission via the IURC Online Services Portal.

FERC Form 1 Data Compilation

Year	FERC Account	Description	Steam Cayuga	Steam Edwardsport IGCC	Steam Gibson
2010	501	Fuel	164,639,205		387,056,236
2010	547	Fuel			
2011	501	Fuel	166,639,448		368,596,995
2011	547	Fuel			
2012	501	Fuel	152,591,736		467,518,033
2012	547	Fuel			
2013	501	Fuel	172,810,494	28,540,706	436,858,828
2013	547	Fuel		16,226,172	
2014	501	Fuel	143,775,083	64,024,368	453,289,284
2014	547	Fuel		30,588,790	
2015	501	Fuel	125,950,556	56,557,521	351,605,121
2015	547	Fuel		27,530,141	
2016	501	Fuel	142,079,794	47,323,750	380,255,226
2016	547	Fuel		25,615,177	
2017	501	Fuel	127,650,739	70,545,727	361,659,700
2017	547	Fuel		22,020,473	
2018	501	Fuel	145,590,321	69,969,275	341,883,869
2018	547	Fuel		38,071,495	

Year	FERC Account	Description	Steam Cayuga	Steam Edwardsport IGCC	Steam Gibson
2010		TOTAL Power Production Expenses-Steam Power (Entr Tot lines 13 & 20)	195,704,713		500,396,012
2011		TOTAL Power Production Expenses-Steam Power (Entr Tot lines 13 & 20)	201,272,293		493,441,020
2012		TOTAL Power Production Expenses-Steam Power (Entr Tot lines 13 & 20)	186,423,167		582,210,137
2013		TOTAL Power Production Expenses-Steam Power (Entr Tot lines 13 & 20)	205,531,494	77,090,368	555,208,717
2014		TOTAL Power Production Expenses-Steam Power (Entr Tot lines 13 & 20)	185,907,230	159,782,437	581,292,608
2015		TOTAL Power Production Expenses-Steam Power (Entr Tot lines 13 & 20)	175,143,228	173,551,919	494,985,147
2016		TOTAL Power Production Expenses-Steam Power (Entr Tot lines 13 & 20)	182,969,559	199,022,061	505,524,401
2017		TOTAL Power Production Expenses-Steam Power (Entr Tot lines 13 & 20)	165,614,734	197,834,796	496,106,242
2018		TOTAL Power Production Expenses-Steam Power (Entr Tot lines 13 & 20)	190,539,233	205,812,277	471,188,129
2010		Total Fuel	164,639,205	0	387,056,236
2011		Total Fuel	166,639,448	0	368,596,995
2012		Total Fuel	152,591,736	0	467,518,033
2013		Total Fuel	172,810,494	44,766,878	436,858,828
2014		Total Fuel	143,775,083	94,613,158	453,289,284
2015		Total Fuel	125,950,556	84,087,662	351,605,121
2016		Total Fuel	142,079,794	72,938,927	380,255,226
2017		Total Fuel	127,650,739	92,566,200	361,659,700

2018	Total Fuel	145,590,321	108,040,770	341,883,869
2010	Total Non-Fuel O&M	31,065,508	0	113,339,776
2011	Total Non-Fuel O&M	34,632,845	0	124,844,025
2012	Total Non-Fuel O&M	33,831,431	0	114,692,104
2013	Total Non-Fuel O&M	32,721,000	32,323,490	118,349,889
2014	Total Non-Fuel O&M	42,132,147	65,169,279	128,003,324
2015	Total Non-Fuel O&M	49,192,672	89,464,257	143,380,026
2016	Total Non-Fuel O&M	40,889,765	126,083,134	125,269,175
2017	Total Non-Fuel O&M	37,963,995	105,268,596	134,446,542
2018	Total Non-Fuel O&M	44,948,912	97,771,507	129,304,260

Sierra Club
IURC Cause No. 45253
Data Request Set No. 3
Received: September 18, 2019

Sierra Club 3.1

Request:

Please refer to Confidential Attachments Sierra Club 1.15A(1) through (21).

a. A frequent reason for the Company offering a unit was that the "Unit was economic to run and thus made MR in DA Market"--please explain how the Company determines that a unit is "economic" including supporting documentation and/or analyses in making that determination.
b. Please explain the difference between offering the unit under "economic" status (instead of "must run") differs from the reason cited above.
c. Please explain the need to operate one of the Cayuga units for steam, including details of the arrangement, whether this arrangement is expected to change and its impact on how the units are bid.

Response:

a. The term "economic", as used in Confidential Attachment Sierra Club 1.15-A(1) through (21), in the Duke Energy Indiana analysis of whether to commit a unit does not correspond to the MISO designation of an "Economic" offer status. As described in response to Sierra Club 1.25, Duke Energy Indiana performs a daily review of unit commitment status. The analysis is slightly different for online and offline units as offline units must clear the hurdle of startup costs that online units have already incurred. In either case, ongoing unit variable costs are compared to the expected revenue from expected MISO dispatch. An online unit would be considered "economic" if it either recovers its variable costs for the next day or if the total expected revenue shortfall during that next day or future days is less than the cost required to cycle the unit off then back online for the next profitable period. An offline unit is considered "economic" if its commitment period revenues exceed the unit startup and ongoing variable costs. Given that MISO only considers revenues over a 24-hour period, it is generally unlikely that it would commit generation like coal units with high start-up costs. Consequently, if the unit is determined to provide "economic" value described above, it will be offered with a designation of "Must Run". With an offer status of "Must Run", MISO commits to dispatch the unit at its variable costs but not below its economic minimum. The supporting documentation is referenced in the Sierra Club 1.25 response.

b. The logic and analysis is the same. If an offline unit is not expected to return market revenues that exceed its startup and ongoing costs it is deemed “uneconomic” and is offered to MISO with “Economic” status. In other words, an “Economic” offer status implies that Duke Energy Indiana, given market indications, does not believe that the unit provides value to the market. With an offer status of “Economic”, MISO is free to commit the unit; but must make Duke Energy Indiana whole to its offer price and commitment parameters if the unit is committed by MISO and in fact doesn’t recover its costs as defined by the units offer. In addition, MISO can also de-commit a unit with an offer status of “Economic” if the unit is currently on-line.

c. Duke Energy Indiana serves a long-term native load steam offtake customer at the Cayuga site. As part of the contract, Duke Energy Indiana is required to provide steam for the customer’s manufacturing operation. From a practical perspective that obligation requires that at least one Cayuga unit be online at at least 300 MW output. At this time, the arrangement is not expected to change. The impact on the Cayuga bid is a steam equivalent de-rate of up to 15 MWs, depending on customer requirements. There is no impact to the bid price in order to provide steam.

Witness: John Verderame

Sierra Club
IURC Cause No. 45253
Data Request Set No. 4
Received: September 30, 2019

Sierra Club 4.1

Request:

Does Duke Energy Indiana have a current plan to file another general rate case after the completion of this rate case? If yes, please state the estimated date on which Duke Energy Indiana expects to file such a general rate case.

Response:

The timing of the next rate case is dependent on many assumptions. The outcome of this case will also impact the timing. There is no specific plan to file the next general rate case.

Duke Energy Indiana, LLC
2020 Fossil Hydro Operation Budget O&M
$ in Thousands

	Edwardsport
Jan-20	12,559
Feb-20	12,573
Mar-20	11,619
Apr-20	11,338
May-20	11,587
Jun-20	12,137
Jul-20	12,558
Aug-20	12,592
Sep-20	12,207
Oct-20	12,191
Nov-20	12,221
Dec-20	12,215
Total	145,798

Duke Energy Indiana, LLC
2020 Fossil Hydro Operation Budget Capital
$ in Thousands

	Edwardsport
Jan-20	926
Feb-20	1,422
Mar-20	3,620
Apr-20	5,164
May-20	104,732
Jun-20	(74,237)
Jul-20	981
Aug-20	1,611
Sep-20	2,113
Oct-20	1,720
Nov-20	1,140
Dec-20	2,090
Total	51,282

Duke Energy Indiana, LLC
Forecasted Native Fuel Costs for 2020
(dollars in 000's)

		Edwardsport
Jan-20	$	9,264
Feb-20		8,909
Mar-20		10,828
Apr-20		3,582
May-20		2,338
Jun-20		9,854
Jul-20		10,399
Aug-20		10,245
Sep-20		8,369
Oct-20		7,898
Nov-20		10,047
Dec-20		11,220
Total	$	102,953

Duke Energy Indiana, LLC
2020 Fossil Hydro Operation Budget O&M
$ in Thousands

	Cayuga[1]	Gibson[2]
Jan-20	4,448	14,047
Feb-20	4,043	11,814
Mar-20	3,795	11,077
Apr-20	5,054	11,245
May-20	5,157	10,529
Jun-20	3,652	9,309
Jul-20	5,064	12,112
Aug-20	3,996	9,508
Sep-20	3,472	9,651
Oct-20	3,433	11,025
Nov-20	3,309	10,716
Dec-20	4,088	12,377
Total	49,511	133,410

1) Cayuga Units 1 and 2.

2) Gibson Units 1 through 5 reflecting Duke Energy Indiana portion of Unit 5 jointly-owned unit.

Duke Energy Indiana, LLC
2020 Fossil Hydro Operation Budget Capital
$ in Thousands

	Cayuga[1]	Gibson[2]
Jan-20	825	2,118
Feb-20	951	4,429
Mar-20	1,275	5,993
Apr-20	2,179	3,285
May-20	2,062	3,228
Jun-20	537	2,748
Jul-20	851	3,949
Aug-20	329	2,332
Sep-20	307	2,805
Oct-20	1,279	3,551
Nov-20	481	2,554
Dec-20	436	3,504
Total	11,511	40,495

1) Cayuga Units 1 and 2.

2) Gibson Units 1 through 5 reflecting Duke Energy Indiana portion of Unit 5 jointly-owned unit.

Duke Energy Indiana, LLC

Forecasted Fuel Costs by Unit for 2020

(dollars in 000's)

	Cayuga		Gibson				
	Unit 1	Unit 2	Unit 1	Unit 2	Unit 3	Unit 4	Unit 5 (1)
Jan-20	$ 6,460	$ 4,246	$ 9,611	$ 9,978	$ 9,454	$ 9,302	$ 4,412
Feb-20	6,038	3,995	8,300	8,684	9,270	8,415	4,471
Mar-20	7,456	6,054	0	8,265	7,802	7,862	3,932
Apr-20	728	6,615	2,649	7,254	5,059	6,162	3,833
May-20	4,596	2,054	7,168	7,306	0	5,508	3,465
Jun-20	6,923	0	6,164	7,206	3,283	4,283	3,648
Jul-20	7,394	5,654	7,645	8,109	7,702	7,472	4,045
Aug-20	7,136	3,523	7,310	7,410	6,181	6,362	3,731
Sep-20	7,042	86	6,744	6,587	0	1,544	3,100
Oct-20	6,901	0	7,082	7,188	0	2,438	3,399
Nov-20	6,569	0	6,705	6,774	157	391	3,191
Dec-20	7,150	0	8,234	8,650	3,979	4,908	4,219
Total	$ 74,393	$ 32,227	$ 77,612	$ 93,411	$ 52,887	$ 64,647	$ 45,446

(1) Reflects Duke Energy Indiana portion of this jointly-owned unit.

Exhibit TFC-3

Duke Energy Indiana Responses to Requests for Information, Confidential

	Data Request	Format
1.	Confidential Attachment Sierra Club 1.8-B	PDF
2.	Confidential Attachment Sierra Club 1.15-A	Excel
3.	Conf. Attachment Sierra Club 1.15-D (Bate No. 090013918-007175)	Excel
4.	Conf. Attachment Sierra Club 1.15-E (Bate No. 090013918-007176)	Excel
5.	Conf. Attachment Sierra Club 1.15-F (Bate No. 090013918-007177)	Excel
6.	Confidential Attachment Sierra Club 1.18-B	PDF
7.	Confidential Attachment Sierra Club 1.18-C	PDF
8.	Confidential Attachment Sierra Club 1.18-D	PDF
9.	Confidential Attachment Sierra Club 1.19-A	PDF
10.	Conf Attachment Sierra Club 1.22-C (Bate No. 090013918-006899)	Excel
11.	Conf Attachment Sierra Club 1.22-D (Bate No. 090013918-006900)	Excel
12.	Conf Attachment Sierra Club 1.22-G (Bate No. 090013918-006903)	Excel
13.	REVISED Confidential Attachment Sierra Club 1.22-G	Excel
14.	Confidential Attachment OUCC 6.3-A(2) - Bate No. 090013918-007149	Excel

*All Excel files have been filed with the Commission via the IURC Online Services Portal.

EXHIBIT TFC-4

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-100, SUB 157

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
2018 Biennial Integrated Resource Plans and Related 2018 REPS Compliance Plans	)))))	ORDER ACCEPTING INTEGRATED RESOURCE PLANS AND REPS COMPLIANCE PLANS, SCHEDULING ORAL ARGUMENT, AND REQUIRING ADDITIONAL ANALYSES

HEARD: Monday, February 4, 2019, at 7:00 p.m. in Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

BEFORE: Chairman Edward S. Finley, Jr., Presiding, and Commissioners ToNola D. Brown-Bland, Jerry C. Dockham, James G. Patterson,[1] Lyons Gray, Daniel G. Clodfelter, and Charlotte A. Mitchell.

APPEARANCES:

For Duke Energy Carolinas, LLC, and Duke Energy Progress, LLC (Duke):

Robert W. Kaylor, Law Office of Robert W. Kaylor, PA, 353 East Six Forks Road, Suite 260, Raleigh, North Carolina 27609

For Virginia Electric and Power Company, d/b/a Dominion Energy North Carolina:

E. Brett Breitschwerdt, McGuireWoods LLP, 434 Fayetteville Street, Suite 2600, Raleigh, North Carolina 27601

For North Carolina Sustainable Energy Association:

Benjamin Smith, Regulatory Counsel, 4800 Six Forks Road, Suite 300, Raleigh, North Carolina 27609

[1] Chairman Edward S. Finley, Jr., resigned from the Commission effective June 1, 2019, and Commissioners Jerry C. Dockham and James G. Patterson resigned from the Commission effective June 30, 2019.

For NC WARN, INC.:

Kristen Wills, Post Office Box 61051, Durham, North Carolina 27715-105

For the Using and Consuming Public:

Teresa Townsend, Special Deputy Attorney General, Department of Justice, 114 West Edenton Street, Raleigh, North Carolina 27603

Dianna Downey, Heather Fennell, and Bob Gillam, Staff Attorneys, Public Staff - North Carolina Utilities Commission, 4326 Mail Service Center, Raleigh, North Carolina 27699-4326

BY THE COMMISSION: Integrated Resource Planning (IRP) is intended to identify those electric resource options that can be obtained at least cost to the utility and its ratepayers consistent with the provision of adequate, reliable electric service. IRP considers demand-side alternatives, including conservation, efficiency, and load management, as well as supply-side alternatives in the selection of resource options. Commission Rule R8-60 defines an overall framework within which the IRP process takes place in North Carolina. Analysis of the long-range need for future electric generating capacity pursuant to N.C. Gen. Stat. § 62-110.1 is included in the Rule as a part of the IRP process.

North Carolina General Statute § 62-110.1(c) requires the Commission to "develop, publicize, and keep current an analysis of the long-range needs" for electricity in this State. The Commission's analysis should include: (1) its estimate of the probable future growth of the use of electricity; (2) the probable needed generating reserves; (3) the extent, size, mix, and general location of generating plants; and (4) arrangements for pooling power to the extent not regulated by the Federal Energy Regulatory Commission (FERC). Further, N.C.G.S. § 62-110.1 requires the Commission to consider this analysis in acting upon any petition for the issuance of a certificate for public convenience and necessity for construction of a generating facility. In addition, the statute requires the Commission to submit annually to the Governor and to the appropriate committees of the General Assembly a report of its: (1) analysis and plan; (2) progress to date in carrying out such plan; and (3) program for the ensuing year in connection with such plan. N.C. Gen. Stat. § 62-15(d) requires the Public Staff to assist the Commission in making its analysis and plan pursuant to N.C.G.S. § 62-110.1.

North Carolina General Statute § 62-2(a)(3a) declares it a policy of the State to:

> assure that resources necessary to meet future growth through the provision of adequate, reliable utility service include use of the entire spectrum of demand-side options, including but not limited to conservation, load management and efficiency programs, as additional sources of energy supply and/or energy demand reductions. To that end, to require energy

> planning and fixing of rates in a manner to result in the least cost mix of generation and demand-reduction measures which is achievable, including consideration of appropriate rewards to utilities for efficiency and conservation which decrease utility bills....

Session Law (S.L.) 2007-397 (Senate Bill 3), signed into law on August 20, 2007, amended N.C. Gen. Stat. § 62-2(a) to add subsection (a)(10) that provides that it is the policy of North Carolina "to promote the development of renewable energy and energy efficiency through the implementation of a Renewable Energy and Energy Efficiency Portfolio Standard (REPS)" that will: (1) diversify the resources used to reliably meet the energy needs of North Carolina's consumers, (2) provide greater energy security through the use of indigenous energy resources available in North Carolina, (3) encourage private investment in renewable energy and energy efficiency, and (4) provide improved air quality and other benefits to the citizens of North Carolina. To that end, Senate Bill 3 further provides that "[e]ach electric power supplier to which N.C. Gen. Stat. § 62-110.1 applies shall include an assessment of demand-side management and energy efficiency in its resource plans submitted to the Commission and shall submit cost-effective demand-side management and energy efficiency options that require incentives to the Commission for approval."[2]

Senate Bill 3 also defines demand-side management (DSM) as "activities, programs, or initiatives undertaken by an electric power supplier or its customers to shift the timing of electric use from peak to nonpeak demand periods" and defines an energy efficiency (EE) measure as "an equipment, physical or program change implemented after 1 January 2007 that results in less energy being used to perform the same function."[3] Energy Efficiency measures do not include DSM.

To meet the requirements of N.C.G.S. § 62-110.1 and N.C.G.S. § 62-2(a)(3a), the Commission conducts an annual investigation into the electric utilities' IRPs. Commission Rule R8-60 requires that each utility, to the extent that it is responsible for procurement of any or all of its individual power supply resources,[4] furnish the Commission with a biennial report in even-numbered years that contains the specific information set out in Rule R8-60. In odd-numbered years, each of the electric utilities must file an annual report updating its most recently filed biennial report.

Further, Commission Rule R8-67(b) requires any electric power supplier subject to Rule R8-60 to file a REPS compliance plan as part of each biennial and annual report. In addition, each biennial and annual report should (1) be accompanied by a short-term action plan that discusses those specific actions currently being taken by the utility to implement the activities chosen as appropriate per the applicable biennial and annual

[2] N.C. Gen. Stat. § 62-133.9(c).

[3] N.C. Gen. Stat. §§ 62-133.8(a)(2) and (4).

[4] During the 2013 Session, the General Assembly enacted S.L. 2013-187 (House Bill 223), which exempted the EMCs from the requirements of N.C. Gen. Stat. § 62-110.1(c) and N.C. Gen. Stat. § 62-42, effective July 1, 2013. As a result, EMCs are no longer subject to the requirements of Rule R8-60 and are no longer required to submit IRPs to the Commission for review.

reports, and (2) incorporate information concerning the construction of transmission lines pursuant to Commission Rule R8-62(p).

Within 150 days after the filing of each utility's biennial report and within 60 days after the filing of each utility's annual report, the Public Staff or any other intervenor may file its own plan or an evaluation of, or comments on, the utilities' biennial and annual reports. Furthermore, the Public Staff or any other intervenor may identify any issue that it believes should be the subject of an evidentiary hearing. The Commission must schedule one or more hearings to receive public testimony.

2018 BIENNIAL REPORTS

This Order addresses the 2018 biennial reports (2018 IRPs) filed in Docket No. E-100, Sub 157, by Duke Energy Progress, LLC (DEP); Duke Energy Carolinas, LLC (DEC); and Dominion Energy North Carolina (DENC) (collectively, the investor-owned utilities, utilities or IOUs). In addition, this Order also addresses the REPS compliance plans filed by the IOUs.

The following parties have been allowed to intervene in this docket: North Carolina Sustainable Energy Association (NCSEA); Carolina Industrial Group for Fair Utility Rates I, II, and III (CIGFUR); North Carolina Waste Awareness and Reduction Network (NC WARN); North Carolina Clean Energy Business Alliance (NCCEBA); Carolina Utility Customers Association, Inc. (CUCA); Environmental Defense Fund (EDF); jointly, Southern Alliance for Clean Energy, the Sierra Club, and the Natural Resources Defense Council (SACE, the Sierra Club, and NRDC); Ecoplexus, Inc. (Ecoplexus); and Broad River Energy, LLC (Broad River). The Public Staff's intervention is recognized pursuant to N.C. Gen. Stat. § 62-15(d) and Commission Rule R1-19(e). The Attorney General's intervention is recognized pursuant to N.C. Gen. Stat. § 62-20.

PROCEDURAL HISTORY

On May 1, 2018, DENC filed its 2018 biennial IRP report and REPS compliance plan. DEC and DEP (collectively, Duke) filed their 2018 biennial IRP reports and REPS compliance plans on September 5, 2018.

On September 27, 2018, the Commission issued an Order Scheduling Public Hearing on 2018 IRP Reports and Related 2018 REPS Compliance Plans. That Order set the public witness hearing for 7:00 p.m. on February 4, 2019, in Raleigh.

On November 8, 2018, NC WARN filed a motion for an expert witness hearing.

On November 15, 2018, DEC and DEP filed a response in opposition to NC WARN's motion for an expert witness hearing, as did DENC on November 27, 2018.

On December 14, 2018, NC WARN filed initial comments on the utilities' 2018 IRPs.

On December 19, 2018, Duke filed notification of the retirement of its 99 Islands hydroelectric units 5 and 6 located near Gaffney, South Carolina.

On January 17, 2019, NCSEA filed a motion for extension of time to file initial comments and reply comments, which the Commission granted on January 24, 2019.

On January 22, 2019, the Public Staff and DENC filed a joint motion for an additional sixty (60) days after DENC files its corrected 2018 IRP in early March 2019 for the filing of initial comments and 60 days after the initial comments for the filing of reply comments. On January 24, 2019, the Commission granted the joint motion of the Public Staff and DENC.

On February 4, 2019, the public hearing was held in Raleigh, as scheduled, with forty-nine (49) public witnesses in attendance. In summary, the public witnesses focused on the need to encourage energy efficiency and clean renewable resources, such as solar and wind. A few witnesses commented on the value of integrating batteries, and other storage technologies, with the utilities' distributed resources. In addition, the witnesses encouraged the Commission to promote an economy and energy future focused on renewables and distributed energy systems. Other witnesses contended that coal and gas perpetuate climate issues because of greenhouse gas emissions, and further, that the utilities should stop investing in hydraulic fracked gas infrastructure, including the Atlantic Coast Pipeline.

On February 7, 2019, the Public Staff filed a motion for extension of time for all parties to file comments on Duke's 2018 IRPs, which the Commission granted on February 8, 2019.

On February 15, 2019, EDF filed initial comments on the utilities' 2018 IRPs.

On February 21, 2019, the City of Charlotte and Mecklenburg County Local Government Officials requested an additional public hearing and an expert witness hearing on the 2018 IRPs, as did members of the General Assembly from Western North Carolina on March 11, 2019 and Representative Verla Insko from Orange County on March 22, 2019.

On March 7, 2019, initial comments were filed by the Public Staff, the Attorney General's Office, NCSEA, and jointly by SACE, NRDC and the Sierra Club. On March 12, 2019 and May 24, 2019, the Public Staff filed corrections to its initial comments.

On March 7, 2019, DENC filed corrections to its 2018 IRP and REPS Compliance Plan.

On April 29, 2019, Duke filed a motion for extension of time to file reply comments, which the Commission granted on May 1, 2019.

On May 6, 2019, the Public Staff filed initial comments on DENC's 2018 IRP.

On May 20, 2019, Duke filed reply comments, as did the Attorney General and NC WARN.

On June 16, 2019, the Commission issued an order requiring the filing of proposed orders.

On July 5, 2019, DENC filed reply comments.

On July 23, 2019, the Commission issued an order scheduling a technical conference on Integrated Systems and Operations Planning for August 28, 2019. The Order also included several Commission questions to be answered by Duke on or before August 21, 2019.

On July 26, 2019, proposed orders were filed by Duke, DENC, the Public Staff, AGO, NCSEA, and jointly by SACE, NRDC and Sierra Club.

PUBLIC HEARING

Pursuant to N.C.G.S. § 62-110.1(c) the Commission held a public hearing in Raleigh on Monday, February 4, 2019, at 7:00 p.m., where 49 public witnesses provided testimony. In summary, the testimonies of the public witnesses focused on the need to encourage energy efficiency and clean renewable resources, such as solar and wind. A few of the witnesses commented on the value of integrating batteries, and other storage technologies, with the utilities' distributed resources. In addition, the witnesses encouraged the Commission to promote an economy and energy future focused on renewables and distributed energy systems. Many of the witnesses discussed the imminent danger that climate change presents and the failure of the IOUs' IRPs to address the need for aggressive action. Other witnesses contended that coal and gas perpetuate climate issues because of greenhouse gas emissions, and further, that the utilities should stop investing in hydraulic fracked gas infrastructure, including the Atlantic Coast Pipeline. Several owners of independent small hydroelectric plants testified in opposition to the assumption in Duke's IRPs that no existing PURPA small hydroelectric contracts would be renewed.

CONSUMER STATEMENTS OF POSITION

As of August 21, 2019, the Commission has received and filed in this docket approximately 1,789 consumer statements of position on a variety of topics from people all across the state. A sampling of 705 statements found 56 from Asheville, 21 from Winston-Salem, 35 from Chapel Hill, 17 from Wilmington, 3 from Sylva, 40 from Charlotte, 51 from Durham, 11 from Brevard, 8 from Black Mountain, 7 from Boone, 7 from High Point 4 from Waynesville, 3 from Murphy, 6 from Hendersonville, 18 from Greensboro, 5 from Salisbury, 3 from Pffaftown, and 3 from Concord.

SUMMARY CONCLUSION

The Commission has carefully considered the full record in this proceeding, including the public witness testimony, the consumer statements of position, the various consultants' reports, and the parties' comments. The Commission concludes that the record raises several issues that are worthy of more in-depth examination. Within an IRP that spans a 15-year planning horizon, there are a myriad of policy issues, technology choices, models and other components that could be examined. The Commission has identified several topics and sub-topics that it deems to merit additional analysis and examination. The Commission believes that a focused inquiry into these specific topics and sub-topics in the 2020 IRPs will yield a more useful outcome than could be achieved by holding further hearings in the present proceeding relating to the 2018 biennial IRPs. The Commission will accept DENC's 2018 IRP as adequate for planning purposes, subject to DENC's 2019 IRP Update. The Commission will accept DEC's and DEP's 2018 IRPs as adequate to be used for planning purposes during the remainder of 2019 and in 2020, subject to DEC's and DEP's 2019 IRP Updates. However, the Commission does not accept some of the underlying assumptions upon which DEC's and DEP's IRPs are based, the sufficiency or adequacy of the models employed, or the resource needs identified and scheduled in the IRPs beyond 2020. Instead, the Commission will use the 2018 IRPs and this Order as an opportunity to provide direction to the IOUs, the Public Staff and intervenors for an orderly presentation of answers to the specific topics and sub-topics identified herein by the Commission and for preparation of the 2020 biennial IRP reports by the utilities. The Commission commends the utilities, intervenors, public witnesses, and authors of position statements for the quality of presentation and analyses. The following sections summarize issues significant to the Integrated Resource Plans filed by the utilities and reflect the full record in the proceeding.

I. PEAK AND ENERGY FORECASTS

Summary of Growth Rates

The following table summarizes the growth rates for the IOUs' system peak and energy sales forecasts in their IRP filings.

	Summer Peak	Winter Peak	Energy Sales	Annual MW Growth
DEP	0.8%	0.7%	1.0%	127
DEC	1.0%	1.0%	0.9%	186
DENC	0.7%	1.5%	0.7%	124

A. Public Staff Initial Comments – Peak and Energy Forecasts

The Public Staff reviewed the 15-year peak and energy forecasts (2019–33) of DEP, DEC, and DENC. The compound annual growth rates (CAGRs) for the forecasts are within the range of 0.7% to 1.0% for DEC and DEP and 0.7% to 1.5% for DENC. The Public Staff noted that all the utilities used accepted econometric and end-use analytical models to forecast their peak and energy needs. They commented that with any forecasting methodology, there is a degree of uncertainty associated with models that rely, in part, on assumptions that certain historical trends or relationships will continue in the future. The Public Staff noted that in its Compliance Filing, DENC revised the peak demand forecasts it filed in its May 1, 2018 IRP, modeling them using the PJM DOM Zone non-coincident peak forecast, which resulted in a significant reduction of peak demand over the forecast horizon.

In assessing the reasonableness of the forecasts, the Public Staff first compared the utilities' most recent weather-normalized peak loads to those forecasted in their 2017 IRP updates. The Public Staff then analyzed the accuracy of the utilities' peak demand and energy sales predictions in their 2012 IRPs by comparing them to their actual peak demands and energy sales. They commented that a review of past forecast errors can identify trends in the IOUs' forecasting and assist in assessing the reasonableness of the utilities' current and future forecasts. Finally, in reviewing DEC and DEP's IRPs, the Public Staff reviewed the forecasts of other adjoining utilities in the VACAR region and the SERC Reliability Corporation.

In regard to DEC and DEP, the Public Staff commented that except for a brief time in the 1980's, the dominant seasonal peak has occurred during summer afternoons. The Public Staff noted that the Companies' annual peak sporadically occurred in the winter season, but since 2013, all of DEP's annual peaks have been during January or February, while DEC's annual peaks have occurred during both the winter and the summer seasons. After DEC and DEP experienced their all-time system peaks in February 2015, they conducted a new reserve margin study, the results of which were incorporated in their 2016 and 2018 IRPs. The Public Staff stated that DEC's and DEP's 2018 IRPs forecast DEP to be a winter peaking system and DEC to be a summer peaking system; however, DEC's planning is based on the winter season. The Public Staff further noted that DEP's weather normalized winter peaks have grown at annual rates significantly greater than the growth rates in DEP's peak forecast. For DENC, the Public Staff commented that its 15-year forecast in the Compliance Filing is based on PJM's peak load and energy sales forecast, scaled down for the Dominion load serving entity, which predicts that DENC will become a winter peaking system in 2024.

1. Public Staff Initial Comments – DEP's Peak and Energy Forecasts

The Public Staff noted that since the 2016 IRP, DEP has projected that it will be a winter peaking system and winter planning utility. It stated that DEP's forecasted winter peak loads reflect a combined average growth rate (CAGR) of 0.7% over the forecast years of 2019 through 2033, which is significantly lower than the 1.2% CAGR in its 2016 IRP and the 1.2% CAGR in its 2014 IRP. The Public Staff pointed out that as with DEC's 2018 IRP and DEP's prior IRPs, relatively little demand reduction is forecasted as being available from EE and DSM programs during the winter seasons, a 0.2% reduction in the CAGR from EE through 2033 of DEP's system peaks and a reduction of the winter demands from DSM by approximately 4%. The Public Staff noted that DEP expects to have the ability to reduce its summer peak loads by 7% through DSM. According to the Public Staff, over the next 15 years, the average annual growth of DEP's winter peak is projected to be approximately 127 MW and the winter peaks are projected to be approximately 604 MW greater than the forecasted summer peaks.

The Public Staff noted that DEP's energy sales, including reductions associated with its EE programs, are predicted to grow at a CAGR of 0.5%, a significantly lower growth rate than the 0.9% in the 2016 IRP and the 1.0% in the 2014 IRP. Further, the Company's EE programs are predicted to reduce its energy sales by approximately 1% in 2019 to 3% in 2033 according to the Public Staff.

The Public Staff's review of DEP's actual and weather adjusted peak load forecasting accuracy for one year showed that DEP's 2017 IRP forecast underestimated the actual 2018 winter peak load by 17%, and by 11% using a weather-normalized peak. When the Public Staff compared the current forecast to the 2012 IRP forecasts for 2013 – 2018, DEP's forecasts indicate a mean average error (MAE) of 9%. Each of the six forecasts used to calculate the MAE was lower than the actual loads, reflecting forecast errors ranging from -18% in 2018 to -0.3% in 2014. The MAE fell to 6% when the forecasts were compared with weather-adjusted loads.

The Public Staff also reviewed DEP's 2012 energy sales forecast, based on the 2012 IRP forecasts for 2013 - 2018, calculating a 13% MAE, reflecting actual sales being significantly less than expected. The Public Staff noted that DEP predicts that over the next 15 years, its EE programs will reduce its annual energy sales by approximately 0.5% in 2019, increasing to 3% in 2033. In addition, the Public Staff found it noteworthy that DEP's predicted load factor is approximately 51% over the next 15 years, significantly lower than the average 55% load factor predicted in the 2016 IRP and the 56% load factor predicted in the 2014 IRP. According to the Public Staff, a decreasing load factor generally indicates a greater need for peaking plants.

The Public Staff found the economic, weather-related, and demographic assumptions underlying DEP's 2018 peak and energy forecasts to be reasonable, but stated that the excessive forecast errors associated with DEP's winter peak indicate that review and revision of DEP's statistical and econometric forecasting practices may be warranted. However, the Public Staff expressed concerns that DEP's actual winter peaks were significantly greater than predicted; such that the 9% MAE equates to an average forecast that is 1,456 MW lower than predicted.

2. Public Staff Initial Comments – DEC's Peak and Energy Forecasts

The Public Staff commented that DEC's forecasted winter peak loads reflect a significantly lower CAGR of 1.0% as compared to the 1.3% CAGR in its 2016 IRP and 1.4% CAGR in its 2014 IRP. The Public Staff pointed out that relatively little demand reduction is forecasted as being available from EE and DSM programs during the winter seasons: a forecasted 0.1% reduction in the CAGR of DEC's system peaks due to EE programs and a reduction in winter demand from DSM programs of approximately 2%. For summer peak loads, the Public Staff noted that DEC forecasts being able to reduce its summer peak loads by 6% through use of DSM. The Public Staff noted that the predicted average annual growth of DEC's winter peak is 186 MW over the next 15 years, as compared to 232 MW in the 2016 IRP and 286 MW in the 2014 IRP. The Public Staff stated that DEC's energy sales, including the effects of its EE programs, are expected to grow at a CAGR of 0.9%, as compared to a 1.0% growth rate in the 2016 IRP and 1.4% in the 2014 IRP. Further, the Company's EE programs are expected to reduce energy sales by approximately 1% in 2019 and 4% in 2033.

The Public Staff's review of DEC's actual and weather adjusted peak load forecasting accuracy for one year indicated that DEC's 2017 IRP forecast was under-predicted by 4% and that on a weather-normalized basis, the actual peak was 2% greater than predicted. When the accuracy of DEC's forecasts is reviewed since 2012, the Public Staff's analysis shows the 2012 IRP yielded a MAE of 5%. It further showed that of the six predicted load forecasts comprising the MAE, two were higher than expected and four were lower than expected, and that the MAE fell to 4% when the forecasts were compared with peaks that were adjusted for abnormal weather.

The Public Staff made a similar review of DEC's 2012 energy sales forecast, which had a 13% MAE. The Public Staff noted that DEC predicts that over the next 15 years, its EE programs will reduce its annual energy sales by approximately 0.8% in 2019, increasing to 4% in 2033. Further it commented that DEC's predicted load factor remains reasonably constant at 58% over the next 15 years, similar to the 59% load factor in the 2016 IRP and the 57% load factor from the 2014 IRP.

The Public Staff concluded that the economic, weather-related, and demographic assumptions underlying DEC's 2018 peak and energy forecasts were reasonable, but that DEC has overestimated its energy sales relative to the 2012, 2014, and 2016 IRPs. The Public Staff noted that DEC had maintained in discussion that its retail energy sales forecast is reasonably accurate when adjusted for abnormal weather. The Public Staff stated that since the Company continues to reduce the predicted growth rates for its projected energy sales and as the peak demand forecast has a direct influence on its capacity expansion plans, the Public Staff places more weight on its review of the Company's peak demands. Noting that the MAE based on actual versus forecasted loads was 5%, but fell to 4% when compared using weather-normalized loads, the Public Staff concluded that DEC's peak load and energy sales forecasts were reasonable for planning purposes. The Public Staff recommended that both DEC and DEP continue to review their winter peak equations in order to better quantify the response of customers to low temperatures. The Public Staff suggested that the Companies may wish to evaluate multiple approaches such as a single equation that relies on multiple observations that focus on customer's response to cold weather in January and February, in conjunction with a separate equation that examines responses during July and August. Given the different customer responses to extreme cold and winter temperatures, the use of separate equations for the summer peak and winter peak may allow for improved understanding of how customers respond to extreme temperatures, which is in contrast to Duke's current use of a single equation for all twelve months of the year.

3. Public Staff Initial Comments – DENC's Peak and Energy Forecasts

Noting that DENC will become a winter peaking system in 2024, the Public Staff pointed out the faster CAGR of 1.5% for DENC's winter peaks as compared to a 0.7% CAGR of its summer peaks. The Public Staff stated that the predicted winter peak CAGR is slightly higher than the 1.3% growth rate from the 2016 IRP, while the CAGR for the summer peak is significantly lower than the 1.5% CAGR from the 2016 IRP. It noted that while the DOM Zone is predicted to become a winter peaking system, PJM is a summer peaking system and thus the Company must procure adequate capacity for the summer peak demand forecast. To do so, the Company's IRP is modeled to procure both supply-side and demand-side resources with the annual forecast of summer peak demands. According to the Public Staff, on average over the 15-year forecast, the winter peaks are approximately 173 MW greater than the forecasted summer peaks, DENC's EE programs are predicted to provide approximately 1% to 2% reduction of the summer and winter peaks through 2033, and the activation of DSM programs is expected to reduce the peak demands by approximately 1% of MW load. The Public Staff commented that the average annual growth of DENC's winter peak is predicted to be 267 MW and 124 MW for the summer peak over the next 15 years, as compared to the 293 MW annual growth of its summer peaks from the 2016 IRP.

The Public Staff stated that DENC's Compliance Filing projected average annual energy sales growth of 0.7%, a significant decrease from the 1.5% growth rate of the 2016 IRP, and a decrease from the original IRP forecast of 1.4%. It noted DENC's estimate that its EE programs would reduce its energy sales by approximately 2% by 2033, as opposed to the 1% reduction in energy sales due to EE forecasted in its 2016 IRP.

The Public Staff's review of DENC's actual peak load forecasting accuracy for one year showed that DENC's 2017 IRP over-predicted the 2018 summer peak load by 7% and under-predicted the 2018 winter peak load by 15%. The Public Staff reviewed DENC's peak load forecasting accuracy based on the 2012 IRP forecasts for 2013 - 2018. Its review indicated that all of the predicted annual peak demands were greater than the actual peaks, with a MAE of 6%, while its energy sales from the 2012 IRP generated an 11% error rate, with four of the previous six annual peaks occurring during the winter season.

The Public Staff stated that based on its review of DENC's forecast accuracy and pattern of predicting loads greater than the actual loads, it supported DENC's use of the relatively lower PJM peak demand forecast as ordered by the VSCC. The Public Staff found DENC's revised peak load and energy sales forecasts to be reasonable for planning purposes, but noted the growing dominance of morning winter peaks, which appears to represent a shift in the use of electricity and warrants further examination of the Company's econometric and statistical forecast models.

4. Public Staff Areas of Concern and Recommendations – Peak and Energy Forecasts

In its comments on Duke's IRPs, the Public Staff identified several areas of concern, including peak load forecasts and use of smart meter data. In regard to peak load forecasts, the Public Staff expressed concern about DEP's forecast errors of its winter peaks. It noted a continuing pattern of under-forecasting, pointing out that DEP's weather-normalized winter peak of 15,165 MW for 2018 is over 1,000 MW greater than the predicted 2019 winter peak of 14,161 MW. The Public Staff also expressed concern regarding the predicted annual growth rate of DEP's winter peaks of 0.7%, which is a significant departure from the 3.0% CAGR of its actual winter peaks from 2013 through 2018, and 2.1% CAGR of its weather-normalized peaks. It noted the faster growth of DEP's winter peaks over its summer peaks, as opposed to the more balanced growth of DEC's summer and winter peaks.

A key area of concern for the Public Staff with DEP's winter forecasting accuracy was that all of the Company's peaks occurred in the winter season and all of the errors were due to forecasts being below the actual peak demands; as compared to DEC's errors being balanced between forecasts both too high and too low. The Public Staff posited that one reason for the growing dominance of DEP's winter peak may be the lack of heating alternatives to electric heat pumps in DEP's service area, pointing out that heat pumps rely on inefficient heat strips or resistance heating at certain operating conditions. It stated that a second reason may be that natural gas is relatively less available in DEP's service area than DEC's territory.

The Public Staff recommended that Duke evaluate alternative equations and modeling tools that would provide a check on forecasts based on monthly data, as it questioned whether the equation current used by Duke is accurately modeling customers' responsiveness to extreme weather, especially in relation to extreme cold temperatures in the DEP service territory. The Public Staff also noted that the data period used for the regression ended on December 31, 2017, excluding the extreme cold that occurred over several days in January 2018. The Public Staff stated that it may be appropriate to expand the data period to include the full winter season to better capture customers' response to extreme weather.

The Public Staff also noted that it had asked Duke how it used smart meter usage data in developing and informing the Companies' load forecasting models and developing improved rate designs, but neither of the utilities reported incorporating usage data obtained from smart meters in its load forecasting models. Additionally, the Public Staff stated that an Integrated Volt-Var Control (IVVC) program could be utilized to provide a variety of grid services to enhance the operability of the grid (e.g., peak reduction), as well as provide a cost savings aspect to ratepayers. IVVC is the process of optimally managing voltage levels and reactive power to achieve more efficient grid operation by reducing system losses, peak demand, energy consumption, or a combination of all three. The Public Staff indicated that while it had not fully reviewed the cost-benefit analysis and assumptions of an IVVC program installed on the DEC system, it recommended that DEC should continue to revise its estimates and cost benefit analysis for the IVVC program in future IRP filings, and consider scenarios that take into account the impact of multiple assumptions, including the installation of IVCC, on the capacity need. The Public Staff recommended that as smart meters are deployed and data from those meters becomes available, the utilities should include in their IRPs a discussion on how they are using that data to inform their load forecasting and improved rate designs.

The Public Staff also recommended that the Companies continue to review their winter peak equations in order to better quantify the response of customers to low temperatures. The Public Staff further recommended that DEC and DEP continue to review their load forecasting methodology to ensure that assumptions and inputs remain current and use appropriate models quantifying customers' response to weather, especially abnormally cold winter weather events.

In regard to DENC, the Public Staff recommended that the Company's 2020 IRP rely on the PJM coincident peak scaled down for the DENC load serving entity forecast for its baseline peak and energy forecasts and encouraged the Company to present its internal peak demand and energy forecasts as a comparison and to allow for a sensitivity analysis with an alternative expansion plan.

B. SACE, Sierra Club, and NRDC Initial Comments – Peak and Energy Forecasts

According to comments filed by SACE, NRDC and the Sierra Club (SACE et al.), the load forecast is a major factor determining a utility's need for new resources to meet system energy and demand. Overstating load growth will result in excess capacity on the system, and excess costs borne by ratepayers. In their comments, SACE et al. observed that over the 15-year planning horizon, DEC forecasts an annual average growth rate of 1.0% (summer) and 0.9% (winter) with energy growth of 0.8%. DEP forecasts an annual average growth rate of 0.8% (summer) and 0.7% (winter) with energy growth of 0.5%. SACE et al. retained James F. Wilson, an economist and independent consultant in the electric power and natural gas industries, to evaluate the peak load forecasts used in the 2018 IRPs.

Mr. Wilson concluded in his report that while the DEC and DEP load forecasts appear more reasonable than in the past, they should be carefully examined.[5] Moreover, it is too soon to draw a conclusion about the Companies' winter peak load forecasts because the instances of loads exceeding the forecasts have generally occurred under very unusual extreme cold events (such as "Polar Vortex" events). Mr. Wilson recommended that the Companies further research the drivers of sharp load spikes under extreme winter cold conditions, and develop demand response programs and other strategies for shifting load or shaving these spikes. In addition, DEC and DEP should develop a more sophisticated model of how extreme winter weather affects their loads. Mr. Wilson also recommended that the Companies further evaluate wholesale customers' contribution to system peak loads, which affect required reserve margins and capacity needs.

C. Environmental Defense Fund Initial Comments – Peak and Energy Forecasts

EDF points out that using load forecasts that are too high can lead to costly excess capacity. It recommends that the Commission carefully analyze the utilities' load growth assumptions, including a thorough backcast analysis, to determine whether the load growth assumptions are reasonable.

D. NCSEA Initial Comments – Peak and Energy Forecasts

NCSEA pointed out that while Duke continues to promote its grid improvement plans, the plans are not reflected in the IRPs. NCSEA noted that Duke's grid improvement plans include IVVC, which will allow Duke to manage distribution and allow the utilization of peak shaving and emergency modes of operation.

E. Attorney General's Office Initial Comments – Peak and Energy Forecasts

The AGO supported the Initial Comments of the Public Staff and other parties who recommended that the Integrated Volt-Var Control (IVVC) program be included in Duke's load forecasts developed in IRPs for future years of capacity planning.

[5] James F. Wilson, Review and Evaluation of the Load Forecasts for the Duke Energy Carolinas and Duke Energy Progress 2018 Integrated Resource Plans (March 7, 2019), Attachment 3 to the Comments of SACE, NRDC and Sierra Club.

F. Duke Reply Comments – Peak and Energy Forecasts

As noted above, the Public Staff generally found DEC and DEP's 2018 IRP load forecasts to be reasonable for planning purposes and compliant with Commission rules and requirements. The Public Staff, NCSEA, and the joint comments of SACE, NRDC and Sierra Club (SACE et al.) all made recommendations to the Commission regarding the load forecasts in the 2018 IRPs and future IRP load forecasting requirements, to which Duke replied as follows.

i. That DEC and DEP continue to review their winter peak equations in order to better quantify the response of customers to low temperatures.

Duke commented that it continues to review and improve the load forecast peak model specifications in accordance with the Commission's Order from the 2016 IRP proceeding (Docket No. E-100, Sub 147). Recently, Duke completed an extensive review of the entire peak load forecasting process, including load definition verification, peak weather methodology, and model specification. The results were summarized in the 2018 IRPs.

Duke stated that the peak forecast model objective is to provide a reasonable forecast of future peak demand under the assumption of normal peak conditions. Duke noted that extreme historical peak demand and weather conditions are captured both in the history used by the peak model, as well as in the weather normalization processes. Duke cautioned that any additional attempt to directly or intentionally model extreme peak conditions within the current IRP peak model process would increase the probability of over-forecasting peak demand.

ii. That DEC include in its forecasted load the projected impact of Integrated Volt-Var Control (IVVC) programs.

NCSEA alleged that Duke continues to promote its grid improvement plans, but does not reflect it in its IRPs.[6] NCSEA noted that Duke's grid improvement plans, which would prepare the grid for decentralized, distributed generation over a 10-year period, includes IVVC, a voltage management program, which will allow Duke to manage distribution circuits (to reduce impacts to customers with large motors sensitive to voltage control) and allow the utilization of peak shaving and emergency modes of operation. Duke commented that the original grid improvement plan proposed in DEC's last general rate case in Sub 1146 did not contain a DEC IVVC program. Duke noted that, based upon stakeholder feedback received through the subsequent grid improvement stakeholder workshops hosted by Duke, it has added a DEC IVVC program and plans to reflect the DEC IVVC program in future IRPs. The Commission expects to see the results of this program reflected in the 2020 biennial IRP filing.

[6] NCSEA Comments, at p. 11.

iii. That DEC and DEP continue to review their load forecasting methodology to ensure that assumptions and inputs remain current and that appropriate models quantifying customers' response to weather, especially abnormally cold winter weather events, are employed.

Duke noted that, in response to the Commission's request in 2016, it completed a thorough review of the peak forecasting methodology in 2018, which led to raising the peak forecast significantly. Duke agreed with the Public Staff that the revised methodology provides a reasonable forecast of normal peak demand. Duke noted that the peak forecast process is also continuously adapting to changing weather and demand trends as it receives additional history. This process will result in higher forecasted peaks if extreme winter weather becomes more prevalent. The process will also prevent the models from over-reacting to one or two years where extreme winter weather was an outlying event. Duke explained that an example of this would be comparing the winter of 2017-18, which was a very extreme winter from a demand perspective, to the winter of 2018-19, which was very mild.

Finally, Duke cautioned against attempting to model extreme winter peaking conditions, noting that one of the key drivers of the Companies' 17% reserve margin is to cover such events. According to Duke, attempting to model customer responsiveness to extreme weather would force it to make broad assumptions about customers' actions during an extreme peak period that could lead to significant over-forecasting of peak demand.

iv. That DEC and DEP include in future IRPs and updates a discussion of their use of data from smart meters to inform their load forecasting, cost of service studies, and rate designs.

Duke noted its agreement that smart meter data has the potential to be very informative from a load forecasting perspective. Duke also noted that the Commission has initiated a rulemaking on certain data access issues in Docket No. E-100, Sub 161, which is pending and may help inform the load forecasting review. Duke further replied, however, that the Commission has existing Smart Grid Technology Plan dockets, which provide the Commission and parties with extensive information about smart meters and how DEC and DEP are utilizing this technology and data issues, so Duke does not believe that additional formal reporting should be required in the IRPs. Nonetheless Duke committed to update the Public Staff on their progress in incorporating smart meter data into the load forecasting process.

Duke stated that SACE et al. consultant, James F. Wilson of Wilson Energy Economics, generally found DEC and DEP's 2018 IRP load forecasts to be reasonable for planning purposes and compliant with Commission rules and requirements. On pages 21 to 23 of his Evaluation of Load Forecasts, Mr. Wilson summarized several recommendations to the Commission regarding the 2018 load forecasts, to which Duke responded to selected recommendations as set forth below:

v. Duke should research the drivers of the very high loads that have occurred in each service territory under very cold weather.

Duke commented that it agrees with the Public Staff's assessment in its 2018 IRP comments that primary drivers of high peak demand during extreme temperatures are the predominance of electric heat pumps, and the lack of availability of natural gas as a heating source. According to Duke, these factors are more significant in DEP's than in DEC's service territory, which is indicative by how much more sensitive the DEP region is to extreme winter weather. Duke noted that it will continue to share information on this topic with the Public Staff and other intervenors as more information becomes available.

. **vi. Duke should develop a more sophisticated model of how extreme winter weather affects their loads, drawing upon the experience gained over the past five years. The focus should be on accurately modeling not just the usual (that is, long-term typical) peak-producing weather, but also more extreme conditions, which have occurred in recent years and can cause loads well above the usual annual peaks. Detailed analysis might show, for example, that an average of temperatures over an extended period leading up to the morning peak hour (perhaps 12 preceding hours) better predicts the peak than the single hourly or daily average temperature, and that other conditions, such as wind speeds and cloud cover, also have predictive value. A similar model for extreme summer weather could also be developed.**

Duke noted that its understanding is that the peak forecast should provide a reasonable forecast of system demand, under the assumption of peak normal weather. According to Duke, the model does account for any historical extreme weather and peak conditions within the past 7 years for model specification, and the past 30 years for the development of peak weather normal conditions. Duke disagrees with the suggestion to modify the current peak model to capture extreme conditions, as this would conflict with the NCUC's Order from the 2016 IRP proceeding, Docket No. E-100, Sub 147. More specifically, such a modification would increase the standard errors of the peak model coefficients, resulting in a peak forecast that will not satisfy the Commission's mandate of a peak forecast that predicts probable growth. Duke noted that although both jurisdictions have seen several extreme winters recently, these few data points are clearly outliers. Structuring the peak model to model historical outliers would result in peak forecasts that may drastically over- or under-forecast peaks, even under normal circumstances. Finally, Duke commented that it does not share Mr. Wilson's perception regarding the lack of sophistication of the peak models. Duke explained that it continuously evaluates the peak model specifications to improve peak forecast accuracy, in accordance with the Commission's Order from the 2016 IRP proceeding, Docket No. E-100, Sub 147.

vii. Duke should provide more comprehensive documentation of their peak load forecasting methodology. Duke should consider enhancing their approach to make use of a broader set of high load data (not just monthly peaks), and an enhanced relationship between weather conditions and load as described above. Duke should also consider providing sensitivity analysis of the peak forecasts to key drivers and assumptions, to

demonstrate whether the forecasts are likely to be stable over time, or instead may change substantially due to new data.

Duke noted that it is committed to transparency regarding all aspects of the load forecast methodology. Duke explained that it cannot endorse Mr. Wilson's recommendations suggested above, which would conflict with producing a reasonable peak forecast, as mandated by N.C. Gen. Stat. § 62-110.1(c). Finally, Duke questioned how Mr. Wilson defines "stability over time." Duke explained that its peak models use actual monthly peaks and the average daily weather on the day of peak as inputs. In recent years, some of these historical data points reflect extreme or mild peak conditions. According to Duke, while Mr. Wilson may perceive these extreme historical data points as instability, Duke views each historical data point as vital information that will provide guidance in identifying vital information that leads to improving load forecast accuracy.

viii. Duke should develop a more effective method for estimating historical weather-normalized peak loads. Weather-normalized values are very useful for understanding load trends, and Duke's new approach appears to have shortcomings (the approach used in the 2016 IRPs accounted for weather variation more completely). The more sophisticated model of how weather affects loads, recommended above, should contribute to a more accurate weather-normalization methodology.

Duke noted that it agrees with Mr. Wilson about the importance of the peak weather-normalization process in understanding peak history and evaluating peak forecasts. Duke also agreed that its methodology is "imperfect," as are all its processes (and those of every load forecaster who attempts to predict the future), due to the dynamic nature of load forecasting. However, Duke disagrees with Mr. Wilson's following assertions regarding their weather-normalization process:

- Mr. Wilson's comments inaccurately describe Duke's weather-normalization process via simplification, compared to the summary description provided in the 2018 IRPs.

- Mr. Wilson asserts that Duke recognizes that the weather normalization process is "imperfect" and does not fully remove the impact of actual weather. Duke agrees that the methodology is imperfect, primarily due to the natural chaotic behavior of weather. Specifically, the more extreme (normal) peak conditions are, the less (more) likely the peak normalization process will be to capture weather impacts accurately.

- Mr. Wilson refers to the previous weather-normalization process (2016 IRP) as being superior to the current methodology. According to Duke, Mr. Wilson mistakenly describes Duke's process as focusing solely on the peak day. Part of Duke's revised peak weather normalization process implicitly includes a "build-up" effect from the previous day(s) of the peak. This enhancement has proven to be more effective in generating peak weather normal than the previous methodology, which focused solely on the coldest day, which may or may not have aligned with the day of peak. Duke explained that it is important to note that Mr. Wilson's comments appear to be directed more at extreme peak events, which are outliers in history, versus the normal peak demand history that typically occurs.

- Duke disputes Mr. Wilson's assertions that the weather-normalization process does not produce a clear historical trend. Tables C-5 and C-6 of the 2018 IRPs provide annual historical trends of DEC and DEP actual and weather normal peak trends. In comparison, Mr. Wilson's charts (JFW-5 to JFW-8) provide an "alternate" view of this data by narrowing the magnitude of the Y-Axis, which gives the perception of nonlinearity. Finally, Mr. Wilson asserts that the Companies' peak weather normal history should be a steady linear trend. In his comments, he assumes that the underlying drivers of the peak weather-normalization history were relatively stable. However, according to Duke, from 2011 to 2018, both DEC and DEP saw various economic, weather, industrial, and jurisdictional load definition disruptions that impacted the weather normalization process.

ix. With respect to wholesale loads, Duke should provide historical aggregate wholesale firm commitments. Weather-normalized historical peaks should be estimated for the wholesale customer loads separately (and such estimates should exclude quantities associated with any short-term wholesale transactions that may have been in place at the time of the peak). The Companies should further evaluate wholesale customers' contribution to system peak loads, which affect required reserve margins and capacity needs.

Duke currently incorporates an energy and demand forecast methodology like the retail energy and peak forecasts, with the following exceptions:

- All forecasts are econometric models; and
- Duke does not forecast North Carolina Electric Membership Corporation (NCEMC) and North Carolina Eastern Municipal Power Agency (NCEMPA) contracts per agreement, and incorporate those forecasts into the system forecast as given.

G. DENC Reply Comments – Peak and Energy Forecasts

Chapter 2 of DENC's 2018 IRP describes DENC's methodology for forecasting its peak demand and energy sales needs. DENC presented its 15-year peak and energy forecasts (2019-2033) and compound annual growth rates (CAGRs) for the relevant years. In its Compliance Filing, DENC revised its peak demand forecast using the PJM Interconnection, L.L.C. (PJM) DOM Zone non-coincident peak forecast (the PJM load forecast), which resulted in a reduction of the 2018 IRP's peak demand forecast. This revision is addressed at Section 3.d of the Compliance Filing. DENC's 2018 IRP is modeled to procure both supply-side and demand-side resources with the annual forecast of summer peak demands. While PJM predicts that the DOM Zone will become a winter peaking system in 2024because DENC is part of PJM and the Compliance Filing uses the PJM load forecast, DENC continued to model its 2018 IRP based on summer peak demand. DENC predicted its energy sales to grow at an average annual rate of 0.7%, which is a decrease from the 1.5% growth rate predicted in DENC's 2016 IRP. Relatedly, DENC's 2018 IRP predicted that the savings from EE programs is anticipated to reduce energy sales by 2% by 2033, which is a greater reduction compared to the 1% reduction in energy sales predicted in DENC's 2016 IRP.

DENC stated in its reply comments that it is not opposed to showing both the PJM and Company load forecasts for the 2020 IRP. In addition, consistent with the Public Staff's recommendation, DENC stated that it is committed to studying the effects of the winter peak on its econometric and statistical forecast models either through its own analysis or that of an outside consultant. DENC noted that in its final order on its 2018 IRP and Compliance Filing,[7] the VSCC directed DENC to continue to use the PJM load forecast, reduced by the energy efficiency spending requirement of Virginia Senate Bill 966, both as an energy reduction and a supply resource, and separately identify the load associated with data centers in its 2020 IRP. Therefore, DENC noted, the PJM load forecast is now required to be used in DENC's future full IRP filings.

With regard to smart meter data, DENC noted that Virginia now requires it to evaluate "[l]ong-term electric distribution grid planning and proposed electric distribution grid transformation projects" in preparing its full IRPs beginning with the 2020 IRP, and that information about the use of smart meters will also be part of DENC's Grid Transformation Plan, which it intends to refile with the VSCC in 2019. DENC also noted that its ability to use smart meter data to inform load forecasting, cost of service studies, and rate designs will be limited until it can fully deploy smart meters throughout its service territory. Nevertheless, DENC stated that it intends to use data from its smart meters to inform these matters when sufficient data is available.

II. RESERVE MARGINS

A. Public Staff Initial Comments – Reserve Margins

1. DEP and DEC

The Public Staff explained that based upon the 2016 Resource Adequacy Study performed by Astrapé (Resource Adequacy Study), both Companies used a combined 17% reserve margin for planning purposes. The Public Staff noted that the study was warranted due to extreme weather experienced in the Companies' service territories and was first presented during the 2017 IRP update in Docket E-100, Sub 147. The Public Staff pointed out that the use of peak system load for system planning is relevant in the context of the capacity value of solar resources. Both DEP and DEC have target reserves of 17%, with DEP having a 17% minimum reserve over the planning horizon and DEC at 16.8%, and DEP having a maximum reserve over the planning horizon of 33.8% in the summer of 2025 and DEC at 22.4% in the summer of 2023. For the planning period 2019 to 2033, the Public Staff stated that the range of reserve margins reported by the electric

[7] In re: Virginia Electric and Power Company's Integrated Resource Plan filing pursuant to Va. Code § 56-597 <u>et seq.</u>, Case No. PUR-2018-00065 (June 27, 2019) (VSCC Compliance Order).

utilities continues to be similar to those seen in previous IRPs, i.e., a loss of load expectation (LOLE) of 0.1 days/year of 16.7% for DEC, 17.5% for DEP, and an average of 17.1% for the combined Companies.

The Public Staff noted that in its April 2, 2018, Joint Report with Duke discussing the Resource Adequacy Study, the Public Staff raised several concerns with the Astrapé study, including the use of forced outrage rates, load regression during extreme events, economic load growth error, load multiplier values, and joint utility operations. The Public Staff recommended a 16% reserve margin. On the other hand, Duke argued it was more appropriate to take a holistic view of the study's reasonableness as opposed to focusing on specific individual factors that could potentially result in a lower reserve margin. The Public Staff noted that the Commission's April 16, 2018 Order Accepting Filing of 2017 Update Reports and Accepting 2017 REPS Compliance Plans, concluded DEC and DEP could continue to use the minimum 17% winter reserve margin for planning purposes, but should present a sensitivity analysis in their resource plan discussion illustrating the impact of a 16% winter reserve margin for planning, including the risk impacts. Duke was also required to address how to model economic load forecast uncertainties in its 2018 IRPs.

The Public Staff explained that the Companies' 2018 IRPs examined the impact of a 16% reserve margin on the timing of future resource additions as well as on system LOLE. DEC found that a 16% reserve margin would not have any effect on future resource additions, and that LOLE would increase to 0.116 days/year, or one expected firm load shed event every 8.6 years. DEP found that the 16% reserve margin would reduce its short-term market purchases and defer a portion of the combustion turbine (CT) blocks in 2029 and 2032 by two years each. The Public Staff also noted that DEP calculated a LOLE of approximately 0.13 days/year based upon these changes, which is equivalent to one expected load shed event every 7.7 years.

In addition to the effects of a 16% reserve margin, the Public Staff noted that Duke's IRPs addressed load forecast error (LFE) assumptions involving uncertainty and probability distribution. With respect to LFE uncertainty, the Public Staff explained that the Companies presented additional Resource Adequacy Study results with no LFE that indicated that the required reserve margin is only 0.28% less than the Public Staff's recommendation of 16%. The Public Staff further noted the Companies' belief that there is meaningful load growth uncertainty over a two to four-year period, requiring reserves greater than 0.28%

With respect to LFE probability distribution, the Public Staff pointed out that the Companies predict a symmetrical probability distribution, where there is equal likelihood of a significant under or over-forecast. However, the Public Staff's LFE probability distribution used a log-normal distribution so that the probability of a lower-than-expected economic growth rate is greater than a higher-than-expected economic growth rate. The Public Staff noted that Duke indicated that it found it inappropriate to use the over-forecast bias recommended by the Public Staff.

The Public Staff stated that it continues to believe that use of a 2-year LFE is appropriate, given that IRPs are required to be filed every two years and that the effects of cold weather outages should be removed. The Public Staff noted that it agreed with Duke that several modeling and market assistance assumptions should be revisited in the next resource adequacy study. As such, the Public Staff continued to recommend a 16% reserve margin, but indicated its willingness to work with the Companies to reach consensus within the constructs of the next resource adequacy study.

2. DENC

The Public Staff noted that DENC, as a member of PJM, is a summer planning and summer peaking utility, and generally considers summer peak load as the load upon which the reserve margin is based. The Public Staff pointed out that in its original filing, DENC used PJM's reserve margin of 15.9%, adjusted based on the coincident factor between the DOM Zone coincidental and non-coincidental peak load, resulting in a reserve margin target of 11.7%. This reserve margin calculation is the same in both the original IRP and the Compliance Filing, but the Public Staff noted that the load forecast is reduced to comply with the VSCC Order in DENC's Compliance Filing. The Public Staff pointed out that the original IRP projected a deficit under Alternative Plan E of 5,275 MW, while the Compliance Filing projects a deficit of 3,028 MW – a 43% reduction in capacity need by 2033.

B. SACE, Sierra Club, and NRDC Initial Comments – Reserve Margins

According to comments filed by SACE et al., the planning reserve margin is a key element of an IRP because it determines how much extra capacity the utility maintains on its system to meet demand in the event of an outage or other unanticipated capacity gap. Both of the Duke 2018 IRPs use a 17% winter planning reserve margin, an increase relative to the 16% reserve margins used before the 2016 IRPs. These planning reserve margins used in developing the IRPs were, in turn, based on resource adequacy studies conducted by Astrapé Consulting in 2016 (2016 RA Studies). SACE et al. retained James F. Wilson, an economist and independent consultant in the electric power and natural gas industries, to evaluate reserve margins used in the 2018 IRPs. Mr. Wilson concluded that due to a number of flaws in the 2016 RA Studies, the DEC and DEP planning reserve margins are improperly inflated, and the 17% planning reserve margins should be rejected.

According to the SACE et al.'s summary of Mr. Wilson's findings, the 2016 RA Studies exaggerated the risk and magnitude of extreme winter peak loads, calling into question the shift by DEC and DEP to planning for "winter-peaking" systems. The RA Studies also substantially overstated the risk of very high loads under extreme cold, mainly due to a faulty approach to extrapolating the increase in load due to very low temperatures. In addition, due to the RA Studies' assumptions about demand response capacity and operating reserves applicable to winter peak conditions, the resource adequacy risk in winter was substantially overstated relative to the risk in summer and other periods of the year. Mr. Wilson also suggested that including multi-year economic load forecast uncertainty in the resource adequacy studies is not appropriate because many short lead-time actions could and very likely would be taken if load grows faster than expected. These findings, along with corresponding recommendations for improvement, are discussed in detail in the Wilson Energy Economics report.[8] Based on Mr. Wilson's analysis, SACE et al. commented that the use of overly high reserve margins in the IRPs means that DEC and DEP are planning to add too much new capacity on the system, which would add unnecessary costs for ratepayers.

C. NCSEA Initial Comments – Reserve Margins

NCSEA commissioned the Synapse Study in order to perform "a rigorous, scenario-based analysis to evaluate an alternative clean energy future compared to the more traditional portfolio of fossil-fueled resource additions included in Duke Energy Carolinas and Duke Energy Progress's (collectively Duke Energy) IRPs". Synapse Study, p. 1. The study found that the energy portfolio in Duke's 2018 IRPs is not the least cost mix of energy resources, and that the Synapse Study's Clean Energy Scenario was a more economical energy portfolio for the state. Id. As part of its least-cost analysis, Synapse evaluated the reserve margin that would achieve its Clean Energy Scenario.

> The Clean Energy Scenario maintains the required 15 percent reserve margin and EnCompass projects no loss-of-load hours and sees zero hours with unserved energy, proving that the retirement of fossil fuels and build-out of renewables leads to no new system reliability issues.

NCSEA Initial Comments, p. 8. As indicated above, according to Synapse's analysis, a 15% reserve margin achieves both aspects of an adequate reserve margin as defined by Duke: it is high enough to ensure reliable energy for Duke customers without burdening ratepayers.

D. DEC and DEP Reply Comments – Reserve Margins

DEC and DEP noted that they used a 17% minimum winter reserve margin target in development of their 2018 IRPs, consistent with results from the 2016 resource adequacy studies. DEC and DEP stated that since completion of the 2016 studies, they have worked extensively with the Public Staff and other intervenors to explain study results and methodology and respond to discovery in efforts to address intervenor questions and concerns.

As an initial matter, DEC and DEP stated that they have complied with all Commission orders regarding the 2016 resource adequacy studies. The NCUC's 2016 IRP Order in Docket No. E-100, Sub 147 concluded that the reserve margins included in the DEP and DEC 2016 IRPs are reasonable for planning purposes. They pointed out, however, that the Commission also directed DEP and DEC to work with the Public Staff

[8] James F. Wilson, Review and Evaluation of Resource Adequacy and Solar Capacity Value Issues with Regard to the Duke Energy Carolinas and Duke Energy Progress 2018 Integrated Resource Plans and Avoided Cost Filing (February 12, 2019).

to address outstanding concerns raised by the Public Staff and SACE consultant Wilson. The Commission further directed the DEC, DEP, and the Public Staff to file a Joint Report summarizing their review and conclusions within 150 days of the filing of Duke's 2017 IRP updates. The Joint Report was filed on April 2, 2018 and noted that although the discussions between the Public Staff, DEC and DEP were helpful, the parties did not reach agreement regarding the methodology used to incorporate economic load forecast uncertainty. Ultimately, the Public Staff recommended that DEC and DEP utilize a 16% reserve margin in their IRPs, and DEC and DEP recommended a minimum 17% winter reserve margin in their IRPs. The Commission's April 16, 2018 Order Accepting Filing of 2017 Update Reports and Accepting 2017 REPS Compliance Plans, in Docket No. E-100, Sub 147 (Sub 147), accepted the parties' Joint Report and concluded that DEC and DEP may continue to utilize the minimum 17% winter reserve margin for planning purposes in their 2018 IRPs. In addition, the Commission ordered DEC and DEP to further address the economic load forecast uncertainty issue in their 2018 IRPs. The Commission also required the Companies to present a sensitivity analysis in their 2018 IRPs that illustrates the impact of a 16% winter reserve margin, including the specific risk impact (LOLE) of using a 16% minimum reserve margin versus a 17% minimum reserve margin. DEC and DEP assert that they complied with the Commission orders in developing their 2018 IRPs.

1. Economic Load Forecast Uncertainty

In this docket, the Public Staff continues to support a 16% reserve margin target based on their PS-S2 scenario proposed in Sub 147 which reflects the removal of short duration cold weather-related outages primarily experienced during the winter of 2014, and also incorporates different economic load forecast uncertainty assumptions as compared to assumptions used in the 2016 studies. As a result of these differences, the PS-S2 scenario results in a reserve margin target of 16%, though DEC and DEP continue to support a reserve margin target of 17%.

DEC and DEP stated that they had previously demonstrated that removal of the cold weather outages, as requested by the Public Staff, is insignificant to the 2016 Resource Adequacy study results and impacts the average reserve margin by less than 0.1%. DEC and DEP explained that, as documented extensively in the Joint Report and the Companies' 2018 IRPs, the Companies believe that the Public Staff's load forecast uncertainty assumptions overstate the probability that actual load will be at or below the Companies' forecast levels. DEC and DEP commented that they are not comfortable with the over forecast bias that is assumed in the Public Staff's load forecast error assumptions, which reflect a probability of over forecasting load approximately 48% of the time and under forecasting load approximately 17% of the time.

Instead, DEC and DEP believe that because the load forecast represents a 50/50 forecast, the load forecast uncertainty should reflect possible loads that are equally likely to fall either above or below the forecast. That is, 50% of the time load growth is expected to be higher than projected, and 50% of the time it is expected to be lower than projected. This load forecast uncertainty distribution more reasonably captures expected fluctuations in load growth as compared to the PS-S2 scenario, which reflects an over-forecast of load the majority of the time.

Further, DEC and DEP commented that, as demonstrated in the Companies' 2018 IRPs, assuming perfect knowledge of its 50/50 weather normal forecast, the Public Staff's recommended 16% reserve margin is only 0.28% greater than the reserve margin needed with perfect forecasting knowledge. DEC and DEP believe that there is meaningful load growth uncertainty over a two to four-year period and that reserves of greater than 0.28% of load are required to manage that risk.

DEC and DEP explained that, given the disagreement in methodology and assumptions for incorporating load uncertainty in the resource adequacy studies, it is notable that the Public Staff expressed concerns in their IRP comments regarding DEP's projected annual peak demand growth rate reflecting a significant departure as compared to higher growth of actual winter peaks.[9] Through discovery[10] DEC and DEP asked the Public Staff to reconcile that concern with their position regarding the economic load forecast uncertainty included in the resource adequacy studies which reflects a significantly greater probability of over-forecasting load growth compared to under-forecasting load growth. The Public Staff explained that their concerns about the forecasting accuracy of DEP's winter peak demands relate to the inability of the forecasting process to adequately capture how customers' use of energy changes in response to extreme weather events. The Public Staff further noted that this issue is unrelated to the economic load uncertainty referred to in the Public Staff's scenario PS-S2. DEC and DEP noted that they appreciate and recognize this difference but also noted that this issue further illustrates the uncertainty in the non-weather-related load forecast, and that DEC and DEP believe that the uncertainty included in the resource adequacy studies is not unreasonable.

2. Multi-Year Economic Load Forecast Uncertainty

SACE et al. consultant Wilson suggests that including multi-year economic load forecast uncertainty in the resource adequacy studies is not appropriate and suggests that many short lead-time actions could and very likely would be taken if load grows faster than expected.[11] Mr. Wilson suggests that if the rate of load growth raised concerns about resource adequacy, utilities would have time adjust their plans and take actions such as accelerating the development of new resources, increasing demand response or energy efficiency programs, delaying a planned retirement, adjusting firm purchases or allowing wholesale contracts to expire. DEC and DEP commented that while these are all worthy ideas and actions that they would likely consider in the event of a significant increase in the load forecast due to economic or other uncertainty, such alternatives are not always sufficiently available or practical to satisfy a resource deficit. In particular, large quantities

---

[9] Reference page 78 of Public Staff's Comments which states: "The Public Staff is also concerned with the predicted annual growth rate of DEP's winter peaks of 0.7%, reflecting a significant departure from the historical growth of its actual winter peaks that have grown at a 3.0% CAGR from 2013 through 2018, while the weather-normalized peaks have grown at 2.1%."

[10] Public Staff response to DEC/DEP data request No. 1-1.

[11] SACE et al. Comments, Attachment 4, at 15.

of demand response and energy efficiency programs are typically not achievable within a short timeframe.

According to DEC and DEP, the 2018 DEP IRP saw a 600 MW increase in winter peak demand from the 2017 IRP Update, which contributed to an approximate 2,000 MW near-term need for capacity and energy resources in DEP. As a result of that increase, and as identified in the IRP, DEP conducted a capacity and energy market solicitation that sought to extend existing purchase power contracts and identify new capacity proposals from similar operationally capable existing generation facilities or systems with firm transmission deliverability into DEP. While the response to the market solicitation was robust, the capacity need in DEP is significant, and additional steps may be needed to ensure that DEP can continue to meet its 17% minimum reserve margin requirement. DEC and DEP noted that options, including deferring unit retirements, are limited, however. Additionally, due to the influx of solar in the Carolinas, which has limited contribution to meeting winter peak capacity needs, the transmission interconnection queue is operating with a significant delay, which makes building new generation that requires transmission interconnection studies, very challenging to execute in an expedited manner. As the timing required to site new generation increases, and older generating units are asked to operate longer to meet capacity requirements, the need to include multi-year economic load forecast uncertainty in the resource adequacy studies only increases. The reality of these circumstances suggests that including only one year of load forecast uncertainty, as suggested by Mr. Wilson, to establish a long-term reliability planning target, is inadequate.

3. Relationship between Winter Load and Cold Temperatures

DEC and DEP noted that SACE et al. consultant Wilson echoes many of the same arguments he presented in the 2016 IRP proceeding concerning the Companies' 2016 Resource Adequacy studies. In particular, they stated that he again argues against the methodology used to capture the relationship between winter load and cold temperatures.[12] DEC and DEP asserted that they have complied with all Commission orders regarding the 2016 Resource Adequacy studies, including working with the Public Staff to address Mr. Wilson's concerns.

Mr. Wilson notes that including "more rather than less historical weather data is preferred" but also suggests that the 15-year period from 1982-1996 should be excluded because it results in flawed regressions and overstates winter resource adequacy risk.[13] This is also apparent from his statement "…the 2016 RA Studies results are very sensitive to the choice of 20 or 30 historical weather years…"[14] DEC and DEP commented that the purpose of a reserve margin is to cover uncertainties such as extreme load and generator outages and it would be irresponsible to ignore the potential for these extreme cold weather events when assessing resource adequacy. They argued that excluding 15 years of the 36-year weather history used in the study just because it reflects colder

---

[12] Id., at 6-13.

[13] Id., at 12.

[14] Id., at 25.

temperatures compared to other historical years is irresponsible. These are precisely the periods that the reserve margin is designed to cover. DEC and DEP explained that, in fact, as noted in the Joint Report, NCUC Rule R8-61 (CPCN) requires utilities to provide "a verified statement as to whether the facility will be capable of operating during the lowest temperature that has been recorded in the area…"[15] DED and DEP noted that the Commission is concerned and expects utilities to provide reliable service to customers even during extreme weather events.

DEC and DEP explained that, pursuant to the Commission's June 27, 2017 Order accepting the Companies' 2016 IRPs, the Public Staff, DEC and DEP reviewed the cold weather load modeling in the 2016 studies and performed a sensitivity analysis that reduced the regression equations significantly for temperatures below the levels seen in recent years.[16] This sensitivity analysis showed a relatively small decrease in reserve margin (0.3%) given that the sensitivity reduced the cold weather impact by half of that assumed in the base case. According to DEC and DEP, the reason that the impact is not larger is because the sensitivity only impacts 7 occurrences in the 36-year weather history. As stated by the Public Staff in the Joint Report, after having further discussions with DEC and DEP, the Public Staff was satisfied that the approach taken in the 2016 studies by the Companies is reasonable.[17]

DEC and DEP further noted that the 2016 resource adequacy studies reflected a maximum summer peak that was 7.5% above the expected summer peak for both DEC and DEP. In comparison, the 2018 PJM Reserve Requirement Study reflects a maximum summer peak that is 24% higher than the expected summer peak.[18] For winter, the 2016 study for DEC reflected a maximum winter peak that was 18.3% greater than the expected winter peak while the DEP study reflected a winter peak that was 21.5% greater than the expected winter peak. In comparison, the 2018 PJM study reflected a maximum winter peak that was 21% higher than the expected winter peak. DEC and DEP explained that the variability in load due to temperature extremes that was modeled in the 2016 resource adequacy studies for DEC and DEP were at or below the peak load variability included in the 2018 PJM study.

DEC and DEP noted that they and Astrapé recognize that appropriately capturing the relationship between extreme cold weather and load are key drivers of the resource adequacy study results. Although there is limited data at extreme cold temperatures, DEC, DEP, and Astrapé believe that the modeling included in the 2016 studies was reasonable. DEC and DEP therefore asserted that Mr. Wilson's comments on this topic are not persuasive.

4. Operating Reserve Assumptions

---

[15] Joint Report filed in Docket No. E-100, Sub 147, April 2, 2018, at slide 10.

[16] Id., at slide 20.

[17] Id., at 2.

[18] 2018 PJM Reserve Requirement Study: https://www.pjm.com/-/media/planning/res-adeq/2018-pjm-reserve-requirement-study.ashx?la=en

DEC and DEP argued that Mr. Wilson initiated a new unfounded claim in SACE et al.'s comments by claiming that the 2016 Resource Adequacy studies exaggerate winter risk through the operating reserve assumptions. They asserted that Mr. Wilson's claim that over 1,000 MW for DEC, and about 750 MW for DEP, of operating reserves are held back in the SERVM model resulting in firm load curtailments is grossly inaccurate.[19] In fact, DEC and DEP noted that SERVM allows operating reserves to drop to the regulation requirement which was 216 MW in DEC and 134 MW in DEP for the resource adequacy and solar capacity value studies. DEC and DEP commented that it is interesting to note that they responded in detail to this exact question in response to DEC-DEP SACE DR 2-19 in Sub 147, yet Mr. Wilson still makes these unsubstantiated claims regarding the operating reserves policy used in the studies. DEC and DEP argued that Mr. Wilson's arguments have no basis in fact and should be rejected.

5. Demand Response Assumptions

SACE et al. consultant Wilson concludes that the DEC's and DEP's demand response winter assumptions should be "brought up to the summer level."[20] Although DEC and DEP agree that winter demand response programs are a reasonable tool for reducing winter peak demand and winter LOLE, when available, they note that the levels of reduction proposed by Mr. Wilson are extremely optimistic and not reasonably achievable in the near term, if at all. DEC and DEP commented that, as an example, the residential DEP EnergyWise Home program currently offers winter measures (Hot Water Heaters & Heat Pump Heat Strips) in its Western region in and around Asheville. These measures have been in place for 10 years and have been marketed aggressively with direct mail, email, outbound calling, and door-to-door canvassing. Over that 10-year period, the program has achieved 15 MW for a residential customer base of approximately 150,000. According to DEC and DEP, assuming the same level of achievable potential in the rest of DEP and DEC, a more reasonable estimate of residential winter DSM would be 150 MW in each jurisdiction in 10 years, which would only be true if those measures remained cost-effective into the future.

DEC and DEP stated that, moreover, actual program experience from DEP EnergyWise Home has shown that winter residential program potential is actually more difficult to achieve than summer potential for several reasons. First, not all residential customers have electric resistance hot water heaters or heat pumps with electric resistance strip heat. Instead, almost all have compressorized cooling in the form of straight air conditioning or heat pumps. Second, residential winter measure installations require appointments to enter the customer's home that are often rescheduled and more costly than a summer air conditioning installation, which does not require an in-home installation.

DEC and DEP also noted their plans to implement new winter DSM programs as proposed in the 2018 IRPs, and to continue their work toward implementation of those programs. According to DEC and DEP, however, the extreme amounts of winter demand

[19] SACE et al. Comments, Attachment 4, at 20.

[20] Id., at pp. 19-20.

response programs anticipated to be cost-effective and reasonably achievable as cited by Mr. Wilson cannot prudently be included in the IRP forecast. They explained that Mr. Wilson attempts to support his claim by stating that the most recent Market Potential Study for DEC and DEP identified additional winter demand response technical and economic potential up to 2,300 MW;[21] however, the amount of potential that is reasonably achievable must be based on DEC's and DEP's experience with DSM program adoption and, in DEC and DEP's experience, adoption of high levels of DSM programs has been challenging despite significant effort by the Companies. According to DEC and DEP, therefore, Mr. Wilson's claim that winter demand response can be magically brought up to the summer level to reduce winter resource adequacy risk should be rejected.

6. Load Net of Solar Resources

Mr. Wilson makes the following assertion on page 22 of Attachment 4 to SACE et al.'s Comments:

> A more balanced seasonal weighting is also suggested by the simple fact that the vast majority of high load hours are in summer on both systems. According to DEC's load forecast, 83% of the highest load hours (top 1%) are in summer; for DEP's load forecast, 74% of the top 1% load hours are in summer.

DEC and DEP commented that, as Mr. Wilson points out, DEC and DEP do experience significant summer loads; however, summer peaks occur in late afternoon hours when solar has significantly greater energy contributions as compared to dark winter mornings where very little – if any -- solar is available at the time of peak. Thus, the summer peak loads net of solar output are reduced relative to winter peak loads net of solar. DEC and DEP explain that this load net of solar has a significant impact on summer versus winter LOLE values and represents the net load that the remainder of the Companies' resources must satisfy. They noted, however, that when asked whether Mr. Wilson's analysis of seasonal weighting reflected consideration of load net of solar resources, SACE et al. responded, "…that comment referred to load, not load net of any particular resources."[22] Further, when asked to provide a detailed explanation of why Mr. Wilson believes it is appropriate to exclude the impact of solar generation when evaluating seasonal loss of load risk, SACE et al. responded, "Not applicable."

DEC and DEP stated that they appreciate constructive feedback regarding their planning processes and studies. They argued, however, that misleading (winter load and temperature relationship), unachievable (demand response potential) and false (operating reserves policy) claims regarding the 2016 resource adequacy studies largely do not add value and are counter-productive. DEC and DEP also noted that their review of Mr. Wilson's comments was also limited by insufficient information and late responses to the Companies' data requests (SACE et al.'s responses to DEC/DEP Data Requests Nos. 4-2 and 4-5).

---

[21] Id., at 20.

[22] SACE et al. response to Duke Data Request 4-5.

7. Resource Adequacy Summary Comments

DEC and DEP noted that, as stated in the 150 Day Joint Report and 2018 IRPs, they believe that a holistic review and consideration of resource adequacy study inputs and assumptions is appropriate when judging the reasonableness of the study results. DEC and DEP stated that while some parties may believe that certain study inputs and assumptions may have overstated the required reserve margin (i.e., resulting in a reserve margin that is too high), they believe that certain assumptions in the 2016 studies, including outage rate modeling and market assistance assumptions, may have been aggressive and understated the required reserve margin (resulted in a reserve margin that is too low). DEC and DEP agree with Mr. Wilson's comment that resource adequacy and reserve margin requirements can change over time and they note that this is precisely why DEC and DEP conduct periodic resource adequacy assessments in order to capture significant changes in inputs and assumptions that may impact study results. DEC and DEP expressed their plans to work with the Public Staff to refresh inputs and assumptions and complete new resource adequacy studies in support of their 2020 IRPs. According to DEC and DEP, it is prudent to maintain a minimum 17% winter reserve margin to provide adequate reliability and satisfy the target of less than one firm load shed event every 10 years. As a result, DEC and DEP recommend use of a 17% winter reserve margin until such time as a new study is completed.

E. DENC Reply Comments – Reserve Margins

Chapter 4 of DENC's 2018 IRP discusses its Planning Assumptions, and states that DENC participates in the PJM capacity planning process for short- and long-term capacity planning. As a PJM member, DENC is a signatory to PJM's Reliability Assurance Agreement, which obligates it to own or procure sufficient capacity to maintain overall system reliability. PJM determines these obligations for each zone through its annual load forecast and reserve margin guidelines, and then conducts a capacity auction through its Short-Term Capacity Planning Process for meeting these requirements three years into the future. This auction process determines the reserve margin and the capacity price for each zone for the third year. DENC is obligated to obtain enough capacity to cover its PJM-determined capacity requirements either from the auction or through bilateral trades.

DENC uses PJM's reserve margin guidelines in conjunction with its own load forecast to determine its long-term capacity requirement. PJM's 2017 Reserve Requirement Study recommended using a reserve margin of 15.9%. DENC uses a coincidence factor to account for the historically different peak periods between DENC and PJM and determine the reserve margin needed to meet reliability targets. The coincidence factor reduces DENC's reserve margin requirement to 11.7%. The same 11.7% requirement was utilized in the Compliance Filing.

In its reply comments, DENC stated that it does not oppose the Public Staff's recommendation that, in future IRPs, DENC should provide information regarding PJM's capacity value for renewable resources as well as a justification for any difference between DENC's and PJM's calculated capacity values or methodology. Accordingly, DENC stated that it would provide such information in its 2019 IRP update. In addition, DENC noted that the VSCC has directed DENC to, in future full IRPs, model future solar PV tracking resources using two alternative capacity factor values: (a) the actual capacity performance of Company-owned solar tracking fleet in Virginia using an average of the most recent three-year period; and (b) 25%. Finally, DENC stated that it will evaluate incorporating a sub-hourly analysis into the 2020 IRP. DENC noted that because it uses internal information to establish the adjusted reserve margin and coincidence factor and the use of advanced analytical techniques requires a level of detail not provided in the PJM forecast, it will therefore use available internal data and forecasts when evaluating the feasibility and benefits of advanced analytical techniques in the 2020 IRP.

III. SYSTEM PEAKS, DEMAND-SIDE MANAGEMENT (DSM) AND ENERGY EFFICIENCY (EE)

A. System Peaks

1. Public Staff Initial Comments – System Peaks (DEP)

The Public Staff noted that DEP's 2018 annual system peak demand of 16,191 MW occurred on January 7, 2018, at the hour ending 7:00 a.m., at a system-wide temperature of 11 degrees Fahrenheit (ºF). DEP activated its DSM resources and reduced its winter peak hourly load by 225 MW. The Public Staff noted that during the Company's nine other highest hourly winter loads, DEP activated its DSM six more times when the average system temperature was between 15ºF and 24ºF.

Based on the Public Staff's comments, DEP's summer system peak of 13,403 MW occurred on June 19, 2018, at the hour ending 5:00 p.m., at a system-wide temperature of 94ºF. DEP activated its DSM resources and reduced its summer peak hourly load by 22 MW. During the Company's nine other highest hourly summer loads, the Public Staff noted that DEP activated its DSM program five more times between 91ºF and 93ºF.

2. Public Staff Initial Comments – System Peaks (DEC)

The Public Staff noted that DEC's 2018 annual system peak demand of 19,436 MW, occurred on January 5, 2018, at the hour ending 8:00 a.m., at a system-wide temperature of 12ºF. DEC's summer system peak was 18,008 MW occurred on June 19, 2018, at the hour ending 4:00 p.m., at a system-wide temperature of 94ºF. According to the Public Staff, DEC did not activate any of its DSM resources during either the winter system peak or the summer peak. During the Company's nine other highest hourly winter peak loads, DEC activated its DSM program during five of those hours when the average temperature at the peak was 10ºF and 13ºF .In regard to the nine other highest hourly summer loads, the Public Staff noted that DEC activated its DSM once during its ninth highest hourly load, when the average temperature was 91ºF.

In its recommendations regarding Duke's IRPs, the Public Staff recommended that the Companies maximize the use of their DSM to reduce fuel costs, especially when marginal costs of energy are high, as well as to ensure reliability. The Public Staff also recommended that the Companies' DSM resource forecast represent the reasonably expected load reductions that are available at the time the resource is called upon as capacity. Finally, the Public Staff proposed that DEC and DEP investigate the potential for new time-of-use rate designs that could encourage customers to shift usage from peak to off-peak periods, particularly during winter peaks.

3. Public Staff Initial Comments – System Peaks (DENC)

The Public Staff noted that DENC's 2018 annual system peak of 17,792 MW occurred on January 7, 2018, at the hour ending 8:00 a.m., at a system-wide temperature of 7ºF. DENC's summer system peak of 16,528 MW occurred on July 2, 2018, at the hour ending 5:00 p.m., at a system-wide temperature of 91°F. The Public Staff indicated that DENC activated DSM during both of these peaks. During its 15 highest peak loads from July 2017 through August 2018, the Public Staff noted that DENC activated its Residential AC Cycling program nine times and its Distributed Generation program 13 times over the 15 highest peak demands.

4. Public Staff Conclusions – System Peaks

The Public Staff acknowledges that load conditions, energy prices, generation resource availability, and customer tolerance for the use of DSM are all important considerations in determining which DSM resources should be deployed. Use of DSM resources is largely dependent on the circumstances and cannot be prescribed in any definitive manner. Nevertheless, the Public Staff concluded that the utilities should maximize the use of their DSM to reduce fuel costs, especially when marginal costs of energy are high.

In its review of DENC's DSM activations at the time of its 15 highest hourly peaks, the Public Staff notes an ongoing concern regarding the difference in DSM resources available in the winter and the summer due, in part, to the fact that winter season programs are typically not cost effective. The Public Staff stated that DENC activated its Distributed Generation program during the Company's 2018 winter peak and most of the other near peaks during the winter season; however, the activations only led to 4 - 6 MW of load reduction. As with DEC and DEP, the Public Staff recommends that each IOU investigate and implement any cost-effective DSM that would be available to respond to the growth of the winter peak demands.

B. DSM/EE

1. Public Staff Initial Comments – DEC and DEP'S DSM/EE

The Public Staff stated that its review of DEC and DEP's DSM/EE forecasts and programs indicated that the Companies had complied with the requirements of Commission Rule R8-60 and previous Commission orders regarding the forecasting of DSM and EE program savings, as well as the presentation of data related to those savings. DEC and DEP included information about their DSM/EE portfolios similar to the information reported in their 2017 IRP updates. The Public Staff opined that DEC and

DEP appropriately addressed the changes in their forecasts of DSM and EE resources and the peak demand and energy savings from those programs. The Public Staff noted that while DEC's forecast did not change by more than 10%, DEP's forecast did vary by more than 10%.

The Public Staff noted several factors that will continue to affect the utilities' ability to develop and implement cost-effective EE programs: changes to federal standards for future lighting measures to take effect January 1, 2020, changes in other appliance standards, and efforts to modify building and energy codes. The Public Staff also pointed to recent decreases in the utilities' avoided costs that have decreased the value of avoided energy and capacity benefits from an EE program, making it more difficult to design, implement, and maintain cost-effective programs. Further, the large contribution of EE savings to portfolios from lighting measures are unlikely to continue beyond one to two more years. Additionally, technologies such as space heating/cooling and building envelop measures will continue to face similar headwinds.

The Public Staff stated its belief that an increased nationwide emphasis on EE is producing EE savings outside of utility-sponsored programs; these EE savings are being incorporated into the IRP load forecasts. Factors influencing load forecasts include the "roll-off" of utility EE savings, savings from more stringent appliance and lighting standards, more efficient heating and cooling equipment, greater emphasis on incorporating efficiency standards into building and energy codes, self-installation of EE measures by large commercial and industrial customers, and consumer adoption of EE. While measuring the EE embedded in the load forecasts is challenging, the Public Staff states its belief that EE has contributed to the lower sales growth rates identified in the utilities' IRPs, which is likely to continue into the near future.

The Public Staff pointed out that DEC does not offer any residential DSM program that can be used during winter peaking events, while DEP's EnergyWise program offers a limited DSM program for controlling water heaters and strip heat on heat pumps in its western service area. The Public Staff also noted that DEC had received Commission approval to cancel a pre-Senate Bill 3 water heater load control program in its most recent general rate case because the costs of continuing the program exceeded the benefits.

The Public Staff stated that it has worked with utilities to find new cost-effective programs to reduce residential demands during winter peaking events, but no program design has proven to be cost effective. The Public Staff indicated that it would continue to encourage utilities to look for new residential DSM opportunities, including the potential for new rate designs that incorporate a more dynamic pricing structure. According to the Public Staff, new time-of-use schedules have the greatest potential to help residential customers curtail loads during winter peaking events. Further, as smart meter technologies are deployed and more customer data become available, customers should have the opportunity to better understand their usage patterns and how those patterns impact system peaks, offering residential customers opportunities to curtail load.

The Public Staff indicated that DEC's and DEP's portfolios of EE programs are not materially different from those in their 2016 IRPs and 2017 IRP updates, and that they continue to align their new and existing DSM and EE programs. The Public Staff also noted that as observed in the last few DSM/EE rider proceedings, both utilities' portfolios continue to shift the source of EE savings away from lighting measures toward behavioral programs such as the My Home Energy Report. The Public Staff pointed out that DEC's projections of portfolio energy savings decline by approximately 9% and DEP's by 20% from the energy savings identified in their 2017 IRP updates. Both DEC and DEP continue to treat DSM as a capacity resource and EE as a reduction to their load forecast.

The Public Staff explained that both utilities produce EE-related savings through their respective portfolios of EE programs over the measure lives of each program. At the end of the measure's life, the utilities assume that as customers replace EE measures with other as or more efficient measures, those savings will continue in the form of reductions to the load forecast, which is designated as historical savings ("roll-off" savings). New measures are separately identified and incorporated into the load forecast tables as new savings. The Public Staff noted that the assumption that EE measures will be replaced with other or new measures differs from the assumptions Duke uses regarding non-utility generator (NUG) contract renewals as discussed *infra*. The Public Staff indicated that the use of these different assumptions may affect the timing and type of resources in the IRP.

As discussed in regard to peak forecasts, the Public Staff recommended that DEC and DEP put a renewed emphasis on designing new DSM programs to meet winter peak demands, as well as summer peak demands. Additionally, the Public Staff recommended that DEC and DEP continue to identify any changes in EE-related technologies, regulatory standards, or other drivers that would impact future projections of EE savings regardless of the 10% threshold for which a discussion is required.

2. Public Staff Initial Comments – DENC’s DSM/EE

The Public Staff commented that DENC's portfolio of EE programs has undergone significant changes since the 2017 IRP update and that changes to the portfolio are greatly influenced by the DSM/EE activities of Dominion Energy Virginia and the decisions of the VSCC. The Public Staff indicated that DENC's 2018 IRP reduced the energy savings by 30% over the planning horizon from the savings identified in the 2017 IRP update, primarily due to the cancellation of several programs in Virginia that had been offered on a system-wide basis. The Public Staff noted that DENC requested approval for a North Carolina-only program from the Commission for any program that was cost-effective on a North Carolina-only basis.

The Public Staff also noted that DENC completed a market potential study in late 2017 that identified 3,042 GWhs of achievable savings over a ten-year period, but the measures identified in the market potential study have not been incorporated into DENC’s 2018 IRP. The study found that the greatest economic potential for residential and non-residential sectors was in lighting and space heating and cooling measures. However, the Public Staff noted that there were no recommendations for specific measures that would contribute toward the achievable potential for either customer class, and the achievable potential excluded the impact of customers eligible to opt-out of utility-sponsored EE portfolios.

The Public Staff explained that while the market potential study would likely have limited influence on DENC's EE portfolio, Virginia Senate Bill 966, the "Grid Transformation and Security Act of 2018"(GTSA)[23] would more likely drive the Company's future EE deployment. Under the GTSA, the Company is required to spend $870 million over the next ten years on EE, including existing and new EE programs. The Public Staff noted that the Company had filed 11 DSM/EE programs for approval before the VSCC, which the Commission notes were approved by the VSCC in April.[24] The proposed portfolio of 11 new programs has a spending projection of approximately $262 million over the next five years, and the Company has indicated that this will count toward the $870 million targeted by the GTSA. The Public Staff stated that DENC's 2018 IRP does not include impacts from these proposed programs. DENC filed eight of the programs for approval before this Commission on July 13, 2019.[25]

As it recommended for DEC and DEP, the Public Staff recommended that DENC put a renewed emphasis on designing new DSM programs to meet winter peak demands, as well as summer peak demands, and that it continue to identify any changes in EE-related technologies, regulatory standards, or other drivers that would impact future projections of EE savings regardless of the 10% threshold for which a discussion is required. The Public Staff also recommended that the IOUs continue to pursue all cost- effective EE and DSM. Finally, the Public Staff proposed that DENC should continue to evaluate the potential to cost-effectively implement an EE program on a North Carolina-only basis, should the program be denied approval by the VSCC to implement the program on a system-wide basis.

3. SACE, Sierra Club, and NRDC Initial Comments – DEC and DEP'S DSM/EE

SACE et al. commented that the 2018 IRP Plans underutilize cost-effective energy efficiency and demand-side management. They assert that Duke prematurely limited the amount of energy efficiency that its IRP model could select as an available resource. SACE et al. commented that screening out efficiency options prior to running the resource planning models biases the analysis in favor of supply-side options. They further commented that Duke's planning process does not allow energy efficiency to be easily compared with supply-side resources in a capacity expansion model. The underutilization of cost-effective energy efficiency results in a higher-cost "preferred" portfolio than necessary. SACE et al. recommended that EE and DSM be evaluated on a level playing field with supply-side resources by allowing the IRP planning models to

[23] 2018 Virginia Acts of Assembly, Ch. 296 (effective July 1, 2018).

[24] Petition of Virginia Electric and Power Company for approval to implement demand-side management programs and for approval of two updated rate adjustment clauses pursuant to § 56-585.1 A 5 of the Code of Virginia, Order Approving Programs and Rate Adjustment Clauses, Case No. PUR-2018-00168 (May 2, 2019).

[25] Docket Nos. E-22, Subs 567-574.

"select" DSM or EE as a resource, or by modeling varying levels of efficiency without screening out a subset of efficiency potential based on flawed assumptions.

SACE et al. also commented that the 2018 IRP Plans assume declining savings from energy efficiency and demand-side management over the fifteen-year planning period. They stated that DEC assumes that no new demand-side management capacity will be added to help meet winter or summer peak demand or reserves after 2024, and projects decreasing reductions to peak from energy efficiency investments after 2027; And that DEC anticipates no additional growth in load impacts from its demand-side management programs on summer or winter peak after 2023. SACE et al. stated that DEP anticipates no growth in several of its demand response programs after 2024 and practically no growth in savings from its energy efficiency EnergyWise for Home program after 2022. They noted that Duke's EE and DSM projections are at odds with Duke's statement that it "is committed to continuing to grow the amount of EE and DSM resources utilized to meet customer growth."

4. AGO Initial Comments – DEC and DEP'S DSM/EE

The AGO recommended that Duke's plans be supplemented to include a more robust consideration of modern EE and DSM measures that reduce consumption or shift load to off-peak times -- including measures that are targeted to winter peaks. The AGO discussed three concerns.

First, the AGO, like the Public Staff, identified as a major shortcoming in Duke's plans that they offer little to no residential demand-side measures to lower winter peaks. The lack of emphasis on winter EE/DSM measures is particularly problematic given the importance Duke placed on planning to meet winter peaks in the analysis of its requirements for additional generating resources.

According to the AGO, Duke evaluated a direct load control program as a possible DSM measure, and found it to be too costly. However, that result is not cause to overlook other opportunities. The AGO's consultant Strategen Consulting, LLC, commented that there are numerous advanced demand-side management programs that have been found to be cost effective in other jurisdictions; these programs could be used to shave winter peaks. Strategen gave examples of two such programs that are being designed with reasonable costs for ratepayers by encouraging customers to use their own devices (called "Bring Your Own Device" or BYOD measures). One such measure is a smart thermostat program where, instead of directly installing smart thermostats, the utility recruits and acquires participants who bring their own devices. Another example is a utility BYOD program in which the utility shares access with the customer's battery storage system to lower peaks on cold winter nights. Customers purchase the batteries and are provided incentives that are based on the amount of energy transferred from the customer's battery to the grid.

Strategen noted that Duke currently integrates smart thermostats into three of its energy efficiency offerings, but observed that Duke's offerings are limited, Duke's offerings do not include other types of devices, and Duke's offerings do not appear to focus on obtaining flexible (i.e. dispatchable) HVAC measures that could help address winter peaks. For example, one of the Duke programs provides an incentive for using a smart thermostat, but does not appear to make use of the device for demand response or load shifting. Another Duke program incentivizes winter demand reduction, but at a lower level than in summer, and has a small amount of participating winter capacity. None of the Duke programs allow for customers to bring other devices, such as energy storage, to increase flexible capacity in both the winter and summer. As such, more emphasis is needed in Duke's plans on the design and development of measures that address winter resource requirements.

The AGO also agreed with the Public Staff that new time-of-use schedules have great potential for helping residential customers curb loads during winter peaking events.

The second concern addressed in the AGO comments is about how DSM programs are evaluated in Duke's planning process. The AGO agreed with NCSEA, and SACE et al. that it would be valuable to model energy efficiency measures and demand-side management on a level playing field with other resources. Strategen noted that modeling demand-side resources alongside supply-side resources is considered a best practice in the industry. Without that approach, demand-side measures cannot be fairly compared to supply-side alternatives, potentially limiting the amount of cost-effective energy efficiency and demand-side measures selected, resulting in a higher cost portfolio.

The third concern raised by the AGO is that Duke's plans appear to assume that additional energy efficiency savings will not be achieved in future planning years once current measures have been tapped out. That assumption overlooks advances in technology, including automation and load controls. Strategen predicts that such advances will most likely "unlock new forms of cost-effective energy efficiency and demand management."

5. DEC and DEP Reply Comments – DSM/EE

Several intervenors commented or made recommendations regarding Duke's DSM and EE plans. In response, Duke stated it disagreed with the statement made by SACE et al., at pages 12-13 of their IRP Comments, that the Companies' projections of DSM/EE peak savings in the later years of the IRP are "inconsistent with its declared commitment to continue to grow the amount of DSM/EE resources to meet customer demand." Duke explained that, specifically for the DSM projections, the amounts of DSM included in the IRP forecast are based on Duke's past experience with customer acceptance of these programs and the expectation that the amount of DSM capacity savings will reach a steady-state level beyond the first few years of the IRP forecast is consistent with this experience. As explained in detail in the response to comments of NCSEA in the 2018 Avoided Cost proceeding, Docket No. E-100, Sub 158, Duke believes that the forecast of DSM program savings are reasonable and accurately reflect a continued effort to add new customers; however, the forecast recognizes customer response to these programs has been limited, despite targeted and ongoing efforts to increase participation.[26] According to Duke, DEC and DEP's forecast of additional increases in DSM peak savings for the next few years followed by a period of steady-state peak savings is reasonable and prudent and accurately reflects the amount of "customer demand" for these programs.

Also, regarding the impact of EE programs on peak demand, Duke disagreed with the intervenors' conclusion that Utility Energy Efficiency (UEE) program disinvestment occurs in the outer years of the IRP forecast. Duke commented that incremental annual UEE savings projection levels are similar throughout the entire forecast period as shown in the tables in Appendix D of the IRPs. However, as shown in the LCR tables in the IRPs (Tables 12-E and 12-F), the outer year UEE projections are being offset by UEE programs initiated 8 to 10 years prior that have reached the end of their useful life. Once UEE savings reach this stage, they no longer contribute to future UEE cumulative savings and are therefore removed from the cumulative savings amounts. Failure to remove these savings from the cumulative amounts would result in over-stating, or "double-counting" the impact of the Companies' UEE programs on sales.

6. DENC Reply Comments – DSM/EE

DENC stated that it will continue to identify and seek approval to implement DSM and EE programs that are cost effective or meet public policy goals. With respect to the design of DSM programs to meet winter as well as summer peak demands, DENC commented that its Distributed Generation program is currently available in Virginia during winter periods to non-residential customers who meet participation requirements based upon size. DENC further explained that it recently received approval for a demand response residential thermostat control program in Virginia and will be filing for approval of that program in North Carolina in July 2019. In addition, DENC commented that 10 new EE programs addressing both summer and winter peaks as well as energy requirements were approved by the VSCC in May 2019 and will be brought to the Commission for approval in July 2019. DENC explained that while demand response programs can be used to reduce peak periods explicitly, EE programs can also provide reductions during winter hours. Nevertheless, DENC noted that these reductions are not dispatchable and instead occur because a measure installed through the program is providing energy savings during a peak hour and thus providing a winter peak reduction. DENC underscored that since the actual system peak drives the need for additional resources to meet reliability requirements, it is difficult for programs that provide benefits in mainly non-peak hours to provide a meaningful amount of benefits. Finally, DENC noted that it is participating in a stakeholder process required by the GTSA to help it identify potential opportunities for EE and demand response and is hopeful this will lead to additional DSM resources in the future that will address both summer and winter peak hours.

[26] See Duke Energy Reply Comments, Docket No. E-100, Sub 158, at pp. 63-66 (Mar. 27, 2019).

IV. NATURAL GAS ISSUES

For purposes of calculating longer-term avoided energy rates, DEC and DEP propose to use forward natural gas prices through 2028; transition to Duke's fundamental forecast through 2033, which shows little growth over the ten year period; and then use an assumption that natural gas prices will grow at 2.5% through 2040. This approach is similar to the approach proposed by DEC and DEP in recent years,[27] and has been the subject of extensive testimony and discussion before the Commission, most recently in the comments filed by parties in the 2018 avoided cost proceeding in Docket No. E-100, Sub 158.

DENC utilized natural gas prices derived from the forward market for natural gas for the first 18 months, and then it gradually (over the next 18 months) blends the monthly prices from the forward market with the monthly prices from the long-term price projection from ICF International, Inc. (ICF).

A. Public Staff Initial Comments – Natural Gas Issues

The Public Staff commented that it appreciates the difficulty in forecasting long-term prices of natural gas as well as other fuel prices, and found reasonable DENC's reliance on forecasts from ICF. However, the Public Staff expressed concerns with the natural gas price forecasts utilized by DEP and DEC in their 2018 IRPs. As discussed in its Initial Statement filed in Docket No. E-100, Sub 158, which were incorporated by reference, the Public Staff believes that the proposed use of forward natural gas prices for ten years by DEP and DEC leads to natural gas prices that are overly conservative and inappropriate for planning purposes. On page 22 of the Initial Statement, the Public Staff noted that Duke Energy Florida, Duke Energy Kentucky, and Duke Energy Indiana each rely wholly on market prices for the first five years and blend market and fundamental prices for the next five years, before switching to the fundamental forecast for the remainder of the planning period in their IRPs. As in previous IRPs and avoided cost proceedings,[28] the Public Staff indicated its preference for DENC's approach with its use of three years of forward price data before transitioning to its long-term fundamental natural gas price forecast.

The Public Staff noted in its comments that the use of an excessively conservative natural gas price forecast is unlikely to alter DEP and DEC's generation expansion plans, however, the use of a low gas price forecast will depress the avoided energy costs that are paid to qualifying facilities, and also reduce the avoided energy costs that are used to evaluate the cost-effectiveness of DSM and EE programs. Duke's conservative natural

---

[27] This issue was also addressed in Phase Two of the Sub 140 proceeding, but the focus during that time was primarily consistency between the methodologies used for avoided cost and IRP purposes. In its December 17, 2015, Order Establishing Standard Rates and Contract Terms for Qualifying Facilities in Docket No. E-100, Sub 140 (Phase Two Order), the Commission directed DEC and DEP to recalculate their avoided energy rates using natural gas and coal price forecasts that were developed in a manner consistent with those utilized in their 2014 IRPs, which at the time relied on market data for the first five years before switching to their fundamental forecast.

[28] Docket No. E-100, Sub 147, and Docket No. E-100, Sub 148.

gas price forecast is graphically displayed on page 27 of the Public Staff's Initial Statement relative to DENC's natural gas price forecast. Therefore, the Public Staff recommended that DEP and DEC, in future expansion models, reflect the use of no more than five years of forward natural gas prices before transitioning to their fundamental forecast.

B. AGO Comments – Natural Gas Issues

The AGO expressed concern that Duke's reliance on natural gas raises a risk that ratepayers will face unanticipated, unmodeled costs from natural gas price volatility.

C. DEC and DEP Reply Comments – Natural Gas Issues

In its reply comments, Duke responded to the comments and recommendations of the parties related to natural gas price issues as follows:

1. Duke disagrees with Public Staff's recommendation to revise the natural gas fuel price forecast used in developing the generation expansion plans to use no more than five years of forward market data before transitioning to the fundamental forecast.

As the Public Staff references in their comments, the duration that DEC and DEP use for forecasting market-based natural gas prices prior to transitioning to fundamental natural gas forecasts has been the subject of extensive testimony and discussion before the Commission, most recently in the initial comments filed by parties in the 2018 avoided cost proceeding in Docket No. E-100, Sub 158. The Public Staff references the "same arguments and perspectives it raised on pages 21-28 of its February 12, 2019, initial comments in Docket No. E-100, Sub 158"[29] where they argued that Duke should use five years of market data before switching to the fundamental forecast.

Duke similarly incorporated by reference their Reply Comments, filed on March 27, 2019 in Docket No. E-100, Sub 158 on pages 10-19, as evidence for continuing to rely on 10 years of forward market data in the Duke filed IRPs. Specifically, the Commission directed Duke to maintain consistency between the fuel forecasts presented in their IRPs and those used in their avoided cost filings and that "to the extent the Utilities wish to propose changes in the way they utilize forward prices and long-term forecasts…these changes should be made in the Utilities' biennial [IRPs], and the same approach should be used in their biennial avoided cost filings for that same year."[30] Generally, Duke made the following arguments as part of a broader discussion of natural gas prices in the referenced reply comments:

- Duke's customers are facing a $4.5 billion long-term financial obligation and an approximately $2 billion overpayment risk as a consequence of an unprecedented

[29] Public Staff Comments, at p. 71.

[30] Order Establishing Standard Rates and Contract Terms for Qualifying Facilities, Docket No. E-100, Sub 140, at 27 (Dec. 17, 2015).

number of Qualifying Facilities (QFs) obligating Duke to purchase their output, coupled with the use of lagging and inaccurate fundamental forecasts to calculate avoided cost rates.

- As demonstrated by the continued, regular purchase of 10 years of forward market natural gas, the market for purchasing 10 years of forward market natural gas is liquid.
- In these regular purchases of 10 years of forward market natural gas, Duke obtained multiple price quotes, each with similar prices, evidencing that there are multiple sellers in the current 10-year natural gas market, and there is a lack of price volatility in the 10-year forward natural gas market.
- Duke is not alone in North Carolina in its ability to purchase 10-year forward natural gas, as another market participant in North Carolina (name filed under seal in Docket No. E-100, Sub 158) purchased significant quantities of 10-year forward natural gas.

Duke commented that using 10 years of forward market natural gas prices in their IRPs is appropriate for evaluating future generation needs and allows for an appropriate head-to-head comparison of long-term purchase power obligations from QFs required under PURPA.

2. Contrary to the AGO's suggestion, Duke already considers the impacts and future costs from natural gas price volatility in their filed IRPs.

On page 10 of its comments, the AGO asserts as a concern that, "Duke's reliance on natural gas raises a risk that ratepayers will face unanticipated, unmodeled costs from natural gas price volatility." Duke noted that this concern, however, is precisely why Duke considers a range of future fuel price scenarios, including high and low natural gas prices, in the development of their IRPs. As described in Chapter 13 of the 2018 DEP IRP and Chapter 12 of the 2018 DEC IRP, and in greater detail in Appendix A of both IRPs, Duke considers natural gas prices that are both significantly lower and significantly higher than base assumptions in both the short- and long-term. The impacts of these sensitivities on each of the seven portfolios are detailed in the above referenced sections in the IRP. Duke noted that the AGO's suggestion that Duke does not "thoroughly evaluate…potential future costs from natural gas price volatility" is inconsistent with the analysis that is actually filed in the DEC and DEP IRPs. Duke stated that it should be noted the AGO does not mention the risk of falling gas prices that has contributed to the current projection of an approximately $2 billion customer overpayment for solar QF generation that was based on natural gas price forecasts significantly above the current market prices for natural gas.

V. CAPACITY VALUE OF SOLAR

A. Public Staff Initial Comments – Capacity Value of Solar

The Public Staff commented that the assumption of both DEP and DEC regarding the contribution of solar energy to peak capacity has a significant impact on future capacity requirements. According to the Public Staff, even a small adjustment in the percent of nameplate capacity available at peak demand has the potential to delay or even eliminate the need for additional capacity. As such, the Public Staff recommended that the issue of aggregate solar generation coincidence at peak for both winter and summer be evaluated further, given the growing importance of solar generation in North Carolina.

The Public Staff noted that in prior IRPs, DEC and DEP calculated the capacity value for solar facilities by averaging actual solar output at the typical peak load hour, using several years of historical load data. The Public Staff indicated that this methodology provided a reasonable estimate for how much intermittent, non-dispatchable capacity would be available during the system peak. For their 2018 IRPs, Duke retained Astrapé Consulting (Astrapé) to perform a reliability-based analysis using techniques similar to those used in resource adequacy planning. The Capacity Value of Solar study (CVS Study) modeled each Company's system at varying levels of solar capacity to identify the timing of projected firm load shed events for each level of solar penetration, and the contribution of solar during those hours. This analysis establishes the capacity value of solar resources, as well as the seasonal allocation of LOLE.

The CVS Study results are presented in the form of a seasonal capacity value for each level of solar penetration in DEC and DEP, with different values for fixed and tracking solar photovoltaic (PV) because tracking results in a higher capacity value. Using these findings, Duke then discounts the amount of installed solar capacity, both utility and third party-owned, by this capacity value in each utilities' Load, Capacity, and Reserves Tables (LCR Tables),[31] thereby reducing the amount of available capacity and increasing the need for traditional thermal resources to meet peak system load. Using the values from the CVS Study, as opposed to its previously used coincident peak method, the need for traditional resources in 2033 increases by 138 MW in DEC and 168 MW in DEP.

The Public Staff expressed concern regarding the difference between how Duke plans to meet its peak system load and how it values the capacity contribution of solar resources. In past IRPs, the Companies discounted the available solar capacity to match the estimated solar output during the hour of peak system load, and thus planned future resource additions to meet the peak system load, and also considered the availability of solar resources during that same peak system load.

The Public Staff contended that use of the CVS Study results effectively bifurcates the treatment of solar resources and the treatment of traditional utility-owned thermal resources. By discounting the solar contribution based on its output during projected firm load shed events (High Risk Hours), yet planning future resource additions to meet the output needed during the hour of peak system load (Peak Load Hours), the actual contribution of solar resources during the Peak Load Hours is ignored. The Public Staff also pointed to the disparate treatment of solar resources versus dispatchable thermal resources, which receive a capacity value of 100%, despite their not having guaranteed availability at the time of all High Risk Hours due to planned and forced outages.

[31] DEC IRP, Tables 12-E and 12-F; DEP IRP, Tables 13-E and 13-F.

The Public Staff proposed that DEC and DEP either plan future capacity resource additions based upon the estimated load during High Risk Hours or discount the capacity value of solar resources by their output during the Peak Load Hours, rather than their output during High Risk Hours. The Public Staff proposed a coincident peak methodology that relies upon utility data and statistical analysis to determine the capacity value, and can be applied to any intermittent resource with a history of hourly generation data. According to the Public Staff, this methodology addresses the perceived disconnect between Peak Load Hours and High Risk Hour, and considers both the operational history of intermittent resources in each utility's service territory and forecasted system operational models that employ numerous assumptions related to load forecasting, solar output, and generation performance characteristics. The Public Staff stated that while it did not have access to the models used by Duke in determining the future resource need, it estimates that using the capacity values produced using its methodology would delay the need for future resource additions.

The Public Staff also noted that the CVS Study considers such factors as load uncertainty and unit outages when it calculates LOLE and capacity value, and that these factors may lower solar capacity value and increase the required minimum reserve margin. The Public Staff contends that these factors should cause either an increased reserve margin or a decreased solar capacity value, but not both. Thus, the Public Staff is concerned that the need for future resource additions may be overstated.

The Public Staff recommended that DEC and DEP utilize the coincident peak methodology for establishing the capacity value of solar, rather than the Astrapé Solar Capacity Value Study. For planning purposes in this IRP, the Public Staff recommended that DEC and DEP use a Capacity Value for solar of 3% in winter and 55% in summer. Finally, the Public Staff recommended that the Commission require DEC and DEP to file a report discussing the impact of this change, and if the first year of capacity need changes, in the 2018 avoided cost proceeding.

In regard to DENC, the Public Staff recommended that DENC continue to discuss mitigation strategies to address high levels of solar penetration and system operations, including revising and improving its estimates of both fixed and variable integration costs. Further, to the extent that the Company identifies required mitigation strategies to address the aggregate effect of distributed solar PV, such as the addition of a supplemental CT to address generation volatility or ramp rates, the Public Staff stated that those applicable costs should be assigned to the overall installed cost of solar.

The Public Staff pointed out that PJM publishes a methodology for calculating capacity values for non-dispatchable resources and recommends using a three-year average of historical wind and solar facility output during the summer peak hours to determine the applicable capacity value for use in reserve margin planning. For facilities less than three years old, PJM publishes "class average capacity factors" for use in the determination of capacity values. The Public Staff indicated that DENC's proposed capacity values for solar are significantly lower than the PJM class average, and recommended that DENC continue to evaluate renewable resources' contribution to coincident peak and update its models to reflect the additional research. The Public Staff also recommended that in future IRPs and updates, the Commission require DENC to provide PJM's capacity value for renewable resources as comparison benchmark, and to the extent that DENC's calculated capacity values or methodology differ from PJM's, provide a justification for the difference.

The Public Staff also noted that it had recommended in the avoided cost docket that DENC's proposed re-dispatch cost be reduced based on the Public Staff's proposed modifications. The Public Staff agreed that a re-dispatch or solar integration charge are important concepts as increasing levels of intermittent and non-dependable generation are added into the electrical grid. The Public Staff recommended that to the extent possible, the modeling programs used by the utilities within the IRP process for selection of future projects evaluate and use appropriate price signals to reasonably demonstrate the costs to ratepayers as new generation units are selected.

B. SACE, Sierra Club, and NRDC Initial Comments – Capacity Value of Solar

Like the Public Staff, SACE et.al. commented that Duke undervalued the capacity that solar resources provide to the DEC's and DEP's systems. They also commented that the 2018 IRPs under-project future solar and solar-plus-storage resources.

SACE et.al. commented that Duke has grossly undervalued the capacity value that solar provides by relying on the Astrapé study that relies on flawed data and methodology. SACE et.al. retained expert consulting firm Wilson Energy Economics to evaluate Duke's calculation of the capacity value of solar resources. The Wilson report concluded that Astrapé had overstated the winter resource adequacy risk, and that the winter/summer capacity values of solar resources on which the 2018 IRP Plans were based should be rejected.

SACE et.al. also commented that Duke's projections fail to account for likely improvements in solar technology and are on the low end of what has been observed from projects that have been put in service in recent years. For example, DEP projects summer solar PV capacity values of 8.2 to 12.4 percent, far lower than the weighted average of 27.6 percent observed in projects installed nationally over the last ten years.

SACE et.al. recommended that Duke reevaluate its projections for addition of new solar resources. DEP's 2018 IRP Plan projects the addition of 1,441 MW of solar over the next 15 years, with approximately 1,000 MW occurring in the next five years (a 36% increase), but with only an 11.6% increase between 2023 and 2033. DEC's 2018 IRP Plan projects the addition of 1,314 MW of solar between 2019 and 2023, but additions of only about 90 MW per year between 2023 and 2033. Duke assumes in its IRPs that it effectively stops adding significant solar resources after it has satisfied the procurement obligations in House Bill 589. The groups noted that these projections do not reflect the recent trends in accelerated solar installations in the Carolinas nor the continuing and steep cost declines for solar. SACE et.al. recommended that Duke reevaluate its projections for future solar installations using more realistic assessments of current and likely future cost declines and improved panel efficiencies.

In addition, SACE et.al. commented that the 2018 IRP Plans include only token amounts of solar-plus-storage resources and do not fairly evaluate the addition of these resources. Greater additions of grid-connected battery storage will support addition of solar and other clean energy resources on the DEC and DEP systems, as well as providing a new resource for balancing grid supply and demand, a new tool for peak shaving, and other benefits. SACE et.al. identified examples from across the country of the steadily declining costs of solar-plus-storage projects, including prices for battery energy storage that are less costly than fossil fuel-fired generation. They recommended that Duke incorporate higher levels of solar-plus-storage in its long-term plans, especially given North Carolina's position as a national leader in solar development.

C. AGO – Capacity Value of Solar

The AGO agreed with concerns expressed by the other intervenors about Duke's assessment of the capacity value of solar energy. To the extent that solar capacity is undervalued, that causes Duke's plans to include more traditional thermal capacity resources than are necessary, leading to increased costs to Duke's customers.

AGO consultant Strategen reviewed the Astrape analysis prepared for Duke and detailed multiple aspects of Astrape's capacity value calculation that could potentially undervalue solar resources. Strategen described the following flaws:

1. Underlying load and non-solar resources within each solar tranche

Duke's analysis shows declining capacity value as solar penetration increases in subsequent MW tranche additions. While this general trend is to be expected, it is not clear if each subsequent solar tranche also included changes to the underlying load and non-solar resources on Duke's system. In reality, higher MW solar scenarios would coincide with other changes. For example, a) load growth may occur predominately in the summer, thus shifting the share of loss of load expectation (LOLE) towards summer months, or b) the mix of non-solar generators may change towards those with fewer outages. Both of these could affect the calculated solar capacity value and potentially increase it relative to what has been portrayed.

2. Demand response availability in winter

In Duke's analysis, it is assumed that there are significantly less demand response resources available in winter versus summer (625 MW less for DEC, and 503 MW less for DEP). This has the effect of increasing LOLE during winter hours, and in turn could decrease solar capacity value. If in fact Duke's system is increasingly a winter peaking system, it is not clear why existing/new demand response resources couldn't be targeted more towards winter peak load hours instead and modeled accordingly.

3. Share of tracking PV resources

Duke's analysis assumes a 25% share of single-axis tracking systems versus 75% fixed tilt. While this appears consistent with historical deployment in NC, other jurisdictions have shown a greater trend towards tracking systems. It's possible this broader trend could also occur in NC going forward and would lead to a higher overall capacity value for the solar fleet.

4. Assistance from neighboring Balancing Areas

A critical underlying assumption in Duke's analysis is the availability of resources from neighboring balancing areas. The reported occurrence of a greater share of LOLE hours during winter signifies a greater unavailability of neighboring resources during this season. However, several of the balancing areas neighboring Duke not only have significant excess capacity exceeding their reserve margins but they are also summer peaking systems. Thus, it appears that there should be substantial winter resources available from neighboring systems. If the availability of neighboring resources in winter is modeled at too low a level it could have the effect of increasing LOLE at these times, and in turn reducing solar capacity value.

5. Outage rates for combustion turbines

Public Staff points out that in Duke's analysis, "Solar resources are also treated differently than dispatchable thermal resources in that those thermal resources receive a capacity value of 100%, despite the fact that even dispatchable thermal resources are not guaranteed to be available 100% of the time in High Risk Hours due to planned and forced outages." Strategen agrees with Public Staff's assessment that this reflects inconsistent treatment between resource types that should be remedied. Either capacity value of non-solar resources should be de-rated according to their outage rates, or a different methodology should be adopted.

6. Adjustment of combustion turbine versus load

As the Public Staff points out in their comments, Duke's approach of adjusting the combustion turbine value to determine capacity value "varies slightly from a traditional (effective load carrying capacity) study, where load is adjusted to achieve a (loss of load expectation) of 0.1 events/year." Strategen agrees with Public Staff's observation. Furthermore, since DEP is modeled as two load centers (east and west), Duke's approach could also lead to a lower solar capacity value than the traditional method, depending on where the combustion turbine is located in the model and what transmission constraints are assumed.

Strategen believes that, conceptually, an effective load carrying capability (ELCC) framework, such as that used by Duke can be a sound approach to determining the capacity value of solar for resource planning. However, before such a framework can be adopted, more information is needed regarding certain underlying assumptions in Duke's analysis. Thus, for the purposes of the 2018 IRP, the method proposed by Public Staff seems acceptable and would be consistent with past practice in North Carolina. An ELCC approach could be explored for future IRPs but stakeholders should have additional opportunities to review the evaluation framework proposed by Duke and the Commission should provide guidance on it as well. For these reasons, Strategen believes Public Staff's recommendations regarding solar capacity value are reasonable."[32]

D. DEC and DEP Reply Comments – Capacity Value of Solar

On page 85 of its Comments, the Public Staff states its concern that "there is a disconnect between how Duke plans to meet its peak system load and how it values the capacity contribution of solar resources." A remedy is proposed by the Public Staff to calculate the Capacity Value of Solar utilizing a Coincident Peak methodology which would address the perceived disconnect between Peak Load Hours and High Risk Hours.

Duke noted that, although it had not yet reviewed the models used by the Public Staff in determining the Coincident Peak methodology, it was trying to ascertain why the Public Staff's proposed capacity values in Table 11 remain static despite the fact that possibly over 10,000 MW of solar capacity could be installed in the Carolinas over the next 15 years. In Tables S5 and S6 of the Capacity Value of Solar (CVS) study completed by Astrapé Consulting, each additional tranche of solar capacity provides diminishing marginal capacity value to the system

.

Duke explained that Astrapé calculated its results in the CVS study by modeling thousands of iterations in its proprietary Strategic Energy Risk Valuation Model (SERVM) using 36 different weather years developed from a National Renewable Energy Laboratory (NREL) dataset dating back to 1980. Both the seasonal and hourly pattern changes were captured across different solar penetration levels. As solar increases across the system resulting in optimal performance on sunny days, system Loss of Load Expectation (LOLE) shifts to the winter; firm load shed events no longer occur during solar hours and become more prominent during hours of little to no daylight. According to Duke, it cannot ascertain from Figure 7, Table 10, or Table 11 in the Public Staff's comments that any research into the shift in LOLE has been performed, which therefore does not support fixed winter/summer capacity values that do not adapt to the level of solar installed on the DEC and DEP systems.

As further support for Duke's probabilistic approach to valuing solar capacity, Duke referred the Commission to the direct testimony of Brian Horii[33] on behalf of the South Carolina Office of Regulatory Staff in Public Service Commission of South Carolina (PSCSC) Docket No. 2019-2-E. On page 8 and beginning on line 17 of his testimony, Mr. Horii states as follows:

---

[32] Strategen Attachment to the AGO Reply Comments, at 10-11.

[33] Mr. Horii is a Senior Partner with Energy and Environmental Economics, Inc. (E3) and was retained by the South Carolina Office of Regulatory Staff (ORS) to assist in the analysis of South Carolina Electric & Gas Company's avoided cost calculations, and review the Value of Distributed Energy Resource (DER) methodology, in PSCSC Docket No. 2019-2-E.

E3 has been at the forefront of evaluating the impact of renewable resources on utility planning and operations. Through our work it is clear that resources such as wind and solar generation must be evaluated using probabilistic methods that evaluate all hours of a given period, not just a single peak hour. Moreover, the importance of probabilistic models is generally recognized across the industry, as noted by the North American Electric Reliability Corporation's (NERC) Probabilistic Adequacy and Measures Technical Reference Report (April, 2018)*:*

> There is a recognized need to support probability-based resource adequacy assessment resulting from the changing resource mix with significant increases in variable and energy-limited resources (intermittent in nature), changes in net demand profiles resulting in the shifting of the hour of the peak demand, and other factors can have an effect on resource adequacy. NERC, p. 6.

In his testimony, Mr. Horii disputes the appropriateness of using a coincident peak hour approach to valuing the capacity contribution of solar generation and notes that such an approach fails to recognize the capacity value provided not just by output at the time of the peak hour but also by the output during the myriad of other peak hours for which there is a non-zero risk of the utility being unable to meet all customer demand.[34] Mr. Horii further referenced the detailed hourly solar capacity value studies performed by Astrapé Consulting for DEC and DEP to infer a capacity value contribution for incremental solar for another utility's system.[35]

1. Duke disagrees with the AGO's assessment that the Companies may be undervaluing the peak load contribution of solar technologies.

The AGO disputes Duke's assertion that additional solar resources beyond those shown in the 2018 IRPs have limited value because additional solar capacity only provides negligible contribution to meeting peak load needs (AG) IRP Comments, pp. 3-4). The AGO cites a "study performed by the National Renewable Energy Lab [NREL] in California, where solar resources have a higher penetration rate" as the basis for the argument that solar resources may have more capacity value than that attributed by the Companies. Id. Duke notes that while North Carolina is number 2 in the U.S. in installed solar behind only California, the AGO's argument is flawed for two reasons: (1) California has significantly higher solar irradiance than North Carolina, and (2) California's electricity demand profile is significantly different than North Carolina's electricity demand profile simply based on the range of temperatures seen in California versus North Carolina, as well as different sources of heating and cooling in the two jurisdictions. Duke points out that consumers in North Carolina and South Carolina have significantly higher energy needs due to much greater electrical heating and cooling demand than California. Simply put, regional differences in solar output, as well as customer usage profiles make such a comparison meaningless. Duke noted its disappointment that the AGO used a study that is based on California electricity demand and solar conditions to criticize Duke for not

[34] Brian Horii Direct Testimony in PSCSC Docket No. 2019-2-E, at 8.

[35] Id., at 10-11.

placing enough value on solar in North Carolina - - when North Carolina is second only to California in installed solar capacity.

2. Duke acknowledges that inclusion of additional storage and solar plus storage resources in the IRPs may be warranted, as suggested by the AGO; however, Duke is committed to studying the true value of energy storage on the DEP and DEC systems before arbitrarily assigning value in the IRPs.

For the first time, Duke included battery storage as a resource in the 2018 IRPs. In total, DEC and DEP included nearly 300 MW (nameplate) of lithium-ion battery storage as capacity resource placeholders which were assumed to provide 80% of their nameplate capacity towards meeting the Companies' winter peak capacity needs per the Electric Power Research Institute (EPRI) study cited in the 2018 IRPs. Additionally, Duke acknowledged in the IRPs that "Battery storage costs are expected to continue to decline, which may make this resource a viable option for grid support services, including frequency regulation, solar smoothing during periods with high incidences of intermittency, as well as, the potential to provide overall energy and capacity value."[36] Furthermore, despite the AGO's assertion that Duke "does not thoroughly evaluate [the downward trend of storage technology costs],"[37] to the contrary, the Duke IRPs assume that battery storage costs drop by nearly 40% by year 2025 in the IRP Base Case.[38] Additionally, Duke noted that its IRPs include an aggressive capital cost sensitivity that would further the decline in battery storage costs to 60% by 2025. Finally, Duke included a sensitivity of replacing a future undesignated CT with a grid-tied battery storage option in both the DEC and DEP IRPs.[39]

Even though Duke acknowledged the potential benefits of storage, included steep cost declines for battery storage technologies, evaluated a sensitivity of replacing a future CT with battery technology, and went as far as to include upwards of 300 MW of battery storage as capacity assets in the DEC and DEP IRPs, the AGO argues the Companies did not go far enough by not evaluating multiple storage plus solar technologies. Duke commented that there is the potential for battery storage technologies to provide value to the DEP and DEC systems, but pairing storage with solar to allow "the storage component to benefit from federal investment tax credits"[40] as suggested by the AGO may not always be in the best interest of the Companies' customers. According to Duke because North Carolina's peak conditions occur in both summer afternoons and winter mornings and afternoons, and can be at least several hours in duration, there may be limitations to the capacity value of batteries, particularly batteries charged solely from solar resources. Furthermore, on May 10, 2019, the Commission issued its Order Granting Certificate of Public Convenience and Necessity with Conditions for the DEP Hot Springs Microgrid

---

[36] DEC IRP, p. 33; DEP IRP, p. 33.

[37] AGO's Comments, p.5.

[38] DEC IRP, p. 101; DEP IRP, p. 102.

[39] Portfolio #7 (CT Centric / High Renewables with Battery Storage) is assessed in a variety of CO_2, fuel price, and capital cost scenarios.

[40] AGO's Comments, p. 4.

Project, which is a combination 3 MW (DC) solar and 4 MW lithium-ion based battery energy storage system. The Commission held that although it is not clear that the Hot Springs Microgrid is the most cost-effective way to address reliability and service quality issues at Hot Springs, the overall public convenience and necessity would be served by granting the certificate (CPCN) for the solar generation components of the microgrid because the system benefits of the microgrid are difficult to quantify and DEP will gain valuable experience by operating the Hot Springs Microgrid as a pilot project. The Commission further stated that it supports "cost-effective development of solar and battery storage by DEP . . . and encourages DEP to continue to pursue such projects on behalf of its customers."[41]

Duke noted that it is committed to further studying the capacity value of incremental battery storage (both grid-tied storage and solar plus storage systems) in the Carolinas at increasing penetration levels. Like the Capacity Value of Solar Study Duke completed in 2018, a similar study is required to study the capacity value of storage. Duke explained that a study of this type is both time and data intensive; however, Duke expects to include the results of a capacity value of storage study as early as the 2020 biennial IRP filings. The Commission expects the 2020 filings to include such results, absent a showing as to why the necessary study could not be completed.

E. Duke's NREL Study

In NCSEA's initial comments, NCSEA noted that Duke has recently retained the National Renewable Energy Laboratory (NREL), to study how Duke's grid can accommodate a renewable energy penetration of 50% of peak demand. NCSEA stated that the fact that Duke is undertaking such a study "undermines the credibility of their own IRPs, and calls into question how Duke has modeled clean energy resources."[42] NCSEA further alleged that its Synapse study shows that Duke has "unfairly marginalized clean energy resources." Id. NCSEA also cited the Virginia State Corporation Commission's rejection of Dominion's IRP because of failure to adequately model clean energy resources.

In its reply comments, Duke *explained* that it plans to study a number of scenarios. The entire study including Phase II will take as much as two years and possibly longer to complete, which would not be timely for the current IRPs. According to Duke, when Duke's General Manager, Distributed Energy Technologies Renewable Integration & Operations, Ken Jennings, recently spoke at the University of North Carolina at Chapel Hill, he acknowledged that Duke will be examining a number of scenarios but did not state that the system would definitely be able to accommodate that much intermittent solar. He also mentioned that the study would be similar to the TECO Study which states that:

> Must-Take solar becomes infeasible once solar penetration exceeds 14% of annual energy supply due to unavoidable oversupply during low demand periods, necessitating a shift to the Curtailable mode of solar

[41] Hot Springs Order, at p. 17.

[42] NCSEA Comments, p. 14.

> operations. As the penetration continues to grow, the operating reserves needed to accommodate solar uncertainty become a significant cost driver, leading to more conservative thermal plant operations and increasingly large amounts of solar curtailment.

The TECO Study further states:

> The energy value on the TECO system of additional solar energy in Curtailable operating mode decays rapidly above about 14% solar energy penetration. The energy value (or, equivalently, the production cost savings) is calculated as the change in annual production costs as solar penetration increases, excluding the capital cost of additional solar resources. Solar provides very little marginal energy value at penetration levels above 19%. In the extreme – above 23% solar energy production potential – solar has a negative marginal energy value.

According to Duke, at that time, it did not know exactly what the scenarios would be. Currently, Duke projects for Phase I a penetration level as high as 35% solar as a component of energy rather than summer peak demand, which is about 28,000 MW of solar and actually closer to 70% of summer peak demand. Duke argues that, absent results from both the Phase 1 and Phase II versions of the study, it would be imprudent to make assumptions about the utility's ability to manage such levels of intermittent solar, and if the results of the NREL study are similar to the results of the TECO study, such levels of intermittent solar may actually require more thermal generation than is currently called for in the IRPs.

F. DENC Reply Comments – Capacity Value of Solar

In response to the Public Staff's comments, DENC indicated that it is committed to continuing and improving its efforts to analyze solar integration costs, the results of which will be provided in the 2020 IRP. DENC also stated that it intends to further refine its integration costs analysis in future IRPs and updates based on the methodology used in the 2017 and 2018 IRPs. As part of that analysis, the Company committed to consider the costs associated with any identified strategies to mitigate the aggregate effect of distributed solar PV on the Company's system. As previously discussed, DENC also agrees to include in future filings the PJM class average capacity value for solar as a comparison to its proposed capacity value, and provide justification for any difference.[43]

VI. BATTERY STORAGE

In Docket No. E-100, Sub 147, the Commission noted that the evaluations of battery storage technology in the 2016 IRPs have "not been fully developed to a level sufficient to provide guidance as to the role this technology should play going forward."[44]

[43] DENC Reply Comments, at 9.

[44] Docket No. E-100, Sub 147, Order Accepting Integrated Resource Plans and Accepting REPS Compliance Plans (2016 IRP Order), at 60 (June 27, 2017).

As such, it required utilities to "provide in future IRPs or IRP updates a more complete and thorough assessment of battery storage technologies including the 'full value' as discussed in the NCSEA comments. If the standard technical and economic analyses of generation resources somehow preclude the complete and thorough assessment of battery storage technologies, then a separate discussion of this point should be included in the IRPs."[45]

A. DEC and DEP Integrated Resource Plans – Battery Storage

According to DEC and DEP, they are assessing the integration of battery storage technology into their portfolio of assets. DEC and DEP note that battery storage costs are expected to continue to decline, which may make it a viable option for grid support services, including frequency regulation, solar smoothing during periods with high incidences of intermittency, as well as, the potential to provide overall energy and capacity value.

DEC and DEP further note that energy storage can also provide value to the transmission and distribution (T&D) system by deferring or eliminating traditional upgrades and can be used to improve reliability and power quality to locations on the Company's distribution system. This approach results in stacked benefits which couples value streams from the Transmission, Distribution, and Generation systems. This evaluation process falls outside of the Company's traditional IRP process which focuses primarily on meeting future generation needs reliably and at the lowest possible cost. This new approach to evaluating technologies that have generation, transmission and distribution value is being addressed through the Integrated System and Operations Planning (ISOP) process as discussed later in this Order.

DEC and DEP state that they will begin investing in multiple grid-connected storage systems dispersed throughout their North and South Carolina service territories that will be located on property owned by the Companies or leased from their customers. These deployments will allow for a more complete evaluation of potential benefits to the distribution, transmission and generation system while also providing actual operations and maintenance cost impacts of batteries deployed at a significant scale.

DEC and DEP included battery storage in its screening analysis for the 2018 IRP: a 5 MW / 5 MWh Li-ion Battery, a 20 MW / 80 MWh Li-ion Battery, and 2 MW Solar PV plus 2 MW / 8 MWh Li-ion Battery. In their IRPs, DEC and DEP have included 150 MW and 140 MW of lithium-based battery storage "placeholders" in their Portfolio 1, respectively. This is reflected in their short-term action plans, in which DEC begins with four MW deployed in 2020, growing to 60 MW by 2023, and DEP begins with 12 MW deployed in 2019, reaching 64 MW by 2023. Both utilities plan to begin investing in grid-connected storage systems dispersed throughout their service territories, with specific

[45] Id. at 60.

investments identified in DEP's discussion of the Western Carolinas Modernization Project (WCMP).[46]

Both DEC and DEP refer to the planned lithium-based battery storage devices as "placeholders" largely due to the way in which energy storage was modeled in the IRP. First, they performed a technical screening of various energy storage technologies. While they identify many types of energy storage, only lithium-ion batteries are actually modeled in System Optimizer and Prosym; the remaining choices are screened out from quantitative analysis for various reasons, including technological feasibility and commercial availability.[47] Traditional generation technologies are made available to the System Optimizer for economic selection, based upon techno-economic characteristics, to meet load and reserve margin requirements over the planning horizon. However, energy storage provides a range of benefits, such as transmission investment deferral and ancillary services,[48] which are difficult, if not nearly impossible, to quantify over the long-term period of the capacity expansion model.

To address the difficulty in modeling energy storage, DEC and DEP specified the battery storage capacity to be included exogenously, effectively "forcing" storage into the capacity expansion plan. The cost impact of energy storage was evaluated in the production cost model Prosym, where battery resources were assumed to have the primary responsibility of providing generation, energy, and ancillary benefits, except in cases where the primary purpose was transmission or distribution benefits.[49] Pumped storage, such as the Bad Creek facility, is analyzed using a two-pass approach: First, Prosym runs without energy storage; then, energy storage inflows and outflows are scheduled to levelized marginal costs subject to physical and technical constraints; finally, Prosym is run a second time with the additional scheduled load or generation from pumped storage. This analysis captures the benefits of bulk energy time shifting, but does not quantify additional energy storage benefits as defined in the recently published Energy Storage Options for North Carolina study (Storage Study).[50]

DEC and DEP discuss the limitations of the IRP in relation to energy storage in a discussion of the insights gained from an analysis of Portfolio 7, which is based on Portfolio 6, except the next planned CT resource is replaced with battery storage. In DEP, this change actually resulted in a lower PVRR than Portfolio 6 (in no sensitivity scenario was Portfolio 7 more cost effective than Portfolio 1 or 2). These projections depend upon the energy storage device being grid-tied and controlled by the utility in real-time. DEC and DEP both conclude that the difficulty in understanding the value of energy storage

[46] DEP IRP, at 51.

[47] DEC and DEP screen out the following energy storage technologies from future capacity deployments: pumped storage, compressed air storage, liquid air storage, flow batteries, and high temperature batteries.

[48] See the Storage Applications and Services section of the NC State Energy Storage Team's Energy Storage Options for North Carolina, at 10-13, https://energy.ncsu.edu/storage/.

[49] DEC and DEP's response to PS DR 4-4.

[50] The full study is available for download at https://energy.ncsu.edu/storage/.

makes it "important for the Company to operate utility storage on its system to properly evaluate the abilities and value of battery storage."[51]

B. DENC Integrated Resource Plan – Battery Storage

DENC stated in its IRP that batteries serve a variety of purposes that make them attractive options to meet energy needs in both distributed and utility-scale applications, including providing energy for a power station blackstart, peak load shaving, frequency regulation services, or peak load shifting to off-peak periods. DENC noted that batteries have gained considerable attention due to their ability to integrate intermittent generation sources, such as wind and solar, onto the grid. DENC pointed out that the primary challenge facing battery systems is the cost, and that other factors such as recharge times, variance in temperature, energy efficiency, and capacity degradation are also important considerations for utility-scale battery systems. DENC did not consider batteries for further analysis in the Company's busbar curve. However, under the GTSA, DENC is required to propose a plan to deploy 30 MW of battery storage under a new pilot program. In its revisions to its IRP, the Company modeled 30 MW battery storage pilots as a proxy generation resource.

C. Public Staff Initial Comments – Battery Storage

1. DEC and DEP

The Public Staff recognized that modeling the various uses of energy storage presents challenges such as capturing and quantifying the various value streams. High capital costs of energy storage (even under assumptions of a 50% decline in capital costs by 2028), coupled with the aforementioned challenges, make it nearly impossible for DEC and DEP's existing modeling software to economically select energy storage in its System Optimizer. The Public Staff noted that DEC and DEP have identified the need for improved modeling capabilities in the Integrated System Operations Planning (ISOP) sections of their IRPs, which envision future IRPs that are capable of recognizing the benefits energy storage can provide on a sub-hourly and "stacked" basis.[52] In addition, the increasing cost of integrating solar energy identified in the Astrapé Ancillary Service Study[53] indicates the need for a more flexible system, which energy storage is well suited to provide. With improved modeling, energy storage could also be assessed for cost-effectiveness in different renewable energy penetration scenarios.[54] The Public Staff encouraged DEC and DEP to continue to enhance their modeling capabilities as described in the ISOP sections of their IRPs, with the eventual goal of accurately

---

[51] DEP IRP, at 107; DEC IRP, at 105.

[52] Value stacking refers to the ability of energy storage devices to provide benefits over a range of service categories, i.e., one energy storage facility providing frequency regulation, improved reliability, and transmission asset deferral. See Storage Study, p. 137, for a discussion of "value stacking".

[53] Referenced in DEC and DEP's Initial Statement, filed November 1, 2018, Docket No. E-100, Sub 158.

[54] Public Service of New Mexico's 2017-2036 IRP retained Astrapé Consulting to quantify the effect of energy storage on reliability and system flexibility at various levels of solar PV penetration, using similar methodologies to Duke's Ancillary Service Study.

quantifying energy storage benefits and costs so that there would be no need to force storage into the IRP modeling.

2. DENC

The Public Staff noted that DENC discussed battery storage in extremely broad terms, while recognizing that energy storage could provide grid stability as more renewables are integrated into the grid and reduce the intermittency of wind and solar generation. As DENC states did not consider battery storage for further analysis in the Company's busbar curve, the Public Staff concluded that DENC failed to thoroughly assess battery storage technologies or include a separate discussion justifying their absence from the IRP.

The Public Staff stated its belief that DENC did not comply with the Commission's 2016 IRP Order to provide a more complete and thorough analysis of battery storage technologies, as opposed to DEC and DEP's 2018 IRPs where battery storage was included as a technology which their models could select and placeholders were input to the model and production cost runs reflected the effect of bulk energy shifting. The Public Staff noted that the Energy Information Administration (EIA) estimates that there were approximately 700 MW of installed battery storage projects at the end of 2017, with 40% of that capacity in PJM.[55] The Public Staff recommended that DENC be required to submit a supplemental filing to its 2018 IRP with a more detailed analysis showing why battery storage technologies were excluded from the Company's busbar curves, including a quantitative analysis of energy storage costs. The Public Staff also noted that DENC should address how its solar integration cost estimates are affected by battery storage, including a discussion of whether the legislatively mandated 5,000 MW of solar could be more cost-effectively integrated if coupled with energy storage technologies in future IRPs and IRP updates.

D. SACE, Sierra Club, NRDC Initial Comments – Battery Storage

SACE, et al. noted that DEC and DEP had recognized the declining cost of battery storage and included battery storage in their resource plans, but contended that there should be greater additions of grid-connected battery storage. Additional battery storage would support additional solar and other clean energy resources, as well as provide balancing of grid supply and demand, peak shaving, and other benefits. These parties noted the steady fall of the costs of solar-plus-storage technologies, and contended that contracted and demonstrated prices for battery storage are already least-cost compared with traditional fossil fuels in some applications and are expected to continue to fall. Thus,

[55] EIA, U.S. Battery Storage Market Trends, May 2018. Accessed at https://www.eia.gov/analysis/studies/electricity/batterystorage/pdf/battery_storage.pdf

SACE, et al. recommended that DEC and DEP incorporate higher levels of battery storage into their long-term plans.

E. AGO Comments – Battery Storage

The AGO commented that DEC's and DEP's plans, when modeling resource alternatives, do not adequately address solar-plus-storage resources as options to meet peak hours of demand. The AGO believes that this issue is important to the development of reasonable resource plans because, as was pointed out in NCSEA comments, battery storage technologies provide flexibility that enables a larger part of DEC's and DEP's energy and capacity requirements to be satisfied at lower economic and environmental costs. Given the current broad array of storage technologies with different sizes, configurations, and operating characteristics, modeling should include an array of storage alternatives consistent with industry best practice.

According to the AGO, DEC and DEP considered only one solar-plus-storage technology configuration in the initial screen of the model used to evaluate resource options: a 2-MW battery with 8 MWh of duration paired with a 2-MW solar facility. In contrast, DEC's and DEP's initial modeling screen included nine natural gas-burning technologies, two coal technologies, two nuclear technologies, and two stand-alone storage technologies. Further, the ratio of PV to storage in DEC's and DEP's one option does not necessarily align with recent trends in the industry. Strategen noted that batteries recently procured by utilities in other states (Hawaii, Arizona, Nevada, and Colorado) have been much larger in order to benefit from economies of scale and lower siting and interconnection costs (e.g., installing one 100 MW battery is cheaper than fifty 2 MW batteries).

The AGO asserted that battery storage offers several advantages as described in Strategen's memorandum that are not sufficiently evaluated in Duke's plans:

- Storage is a valuable tool to address peak demand.

- Storage has a modular design and can be added in small increments that fit growth. Whereas larger traditional power plants often add more capacity than is needed, at least until load growth catches up to the installed capacity, storage can be added relatively quickly as needed or avoided altogether if load growth does not materialize.

- Storage enhances the resilience of the grid during catastrophic events like hurricanes. The effectiveness of storage was demonstrated during Hurricane Irma, when two large battery storage projects in the Dominican Republic helped stabilize grid frequency and alleviate fluctuations caused when 40% of the generation fleet had suffered an outage.

- The importance of creating a resilient electric grid that integrates clean energy resources is a factor discussed in Executive Order No. 80, the North Carolina policy addressing climate change.

- Recent studies have shown that inverter-based resources (like batteries) have actually responded faster and more accurately than traditional generators in the face of a disturbance.

The AGO recommended two improvements to DEC's and DEP's analyses of storage. First, multiple storage alternatives should be modeled alongside other resource alternatives. That way, DEC's and DEP's models would select the sizes and ratios of solar plus storage that fit a system need (rather than pre-selecting more limited options). Second, the model should use publicly-available cost estimates wherever possible to make the assumptions underlying the model results more transparent. The model used by intervenor NCSEA relied on publicly-available cost estimates from the National Renewable Energy Laboratory and Lazard that are considered to be industry standards.

F. NC WARN Comments – Battery Storage

NC WARN provided a number of examples of the decline in costs of battery storage and breakthroughs in battery technology. It also highlighted plans of utilities and governmental entities that include substantial amounts of solar coupled with battery storage. NC WARN recommended that DEC and DEP redirect their reliance upon gas turbine generation to reliance upon battery storage, especially solar combined with battery storage.

G. DEC and DEP Reply Comments – Battery Storage

DEC and DEP noted that for the first time, they included battery storage as a resource in the 2018 IRPs; in total, nearly 300 MW (nameplate) of lithium-ion battery storage as capacity resource placeholders were assumed to provide 80% of their nameplate capacity towards meeting the Companies' winter peak capacity needs. The Companies also noted their agreement as indicated in their filed IRPs that battery storage costs are expected to continue to decline, making batteries an option for grid support services, including frequency regulation, solar smoothing during periods with high incidences of intermittency, as well as, the potential to provide overall energy and capacity value. DEC and DEP dispute the AGO's contention that they did not thoroughly evaluate the downward trend of storage technology costs, noting that its IRPs assume that battery storage costs drop by nearly 40% by year 2025 in the IRP Base Case. DEC and DEP also indicated that the Companies' IRPs include an aggressive capital cost sensitivity that would further the decline in battery storage costs to 60% by 2025. Additionally, the Companies include a sensitivity of replacing a future undesignated CT with a grid-tied battery storage option in both the DEC and DEP IRPs. DEC and DEP also argued that pairing storage with solar to allow "the storage component to benefit from federal investment tax credits as suggested by the AGO may not always be in the best interests of ratepayers." They pointed out that because North Carolina's peak conditions occur in both summer afternoon and winter morning and afternoon, and can be at least several hours in duration, there may be limitations to the capacity value of batteries, particularly batteries charged solely from solar resources. DEC and DEP noted the Commission's recent approval of a Certificate of Public Convenience and Necessity for DEP's Hot Springs Microgrid Project, a combination 3 MW (DC) solar and 4 MW lithium-based battery energy storage system. They indicated that they are committed to further studying the capacity value of incremental battery storage (both grid-tied storage and solar plus storage systems) in the Carolinas at increasing penetration levels. They stated that a study of the capacity value of storage is needed, and that the Companies expect to include the results of a capacity value of storage study as early as the Companies' 2020 biennial IRP filings.

H. DENC Reply Comments – Battery Storage

DENC addressed battery storage at Section 5.1.2 of the 2018 IRP and Section 3.c.iv of the Compliance Filing. As referenced in the Compliance Filing and by the Public Staff, in addition, the GTSA requires DENC to submit a proposal to deploy a battery storage pilot of up to 30 MW.

The Public Staff acknowledged DENC's recognition that energy storage could have value to provide grid stability as more renewable energy sources are integrated into the grid and could reduce the intermittency of wind and solar generation. The Public Staff contended, however, that DENC did not comply with the Commission's directive to assess battery storage technology. The Public Staff noted that DENC did not consider battery storage technologies for further analysis in its busbar curve, and asserted that DENC did not appear to thoroughly assess battery storage technologies and did not otherwise justify their absence from the IRP. The Public Staff therefore recommended that DENC be required to submit a supplemental filing to its 2018 IRP with a more detailed analysis of why battery storage technologies were excluded from its busbar curves, including a quantitative analysis of energy storage costs. The Public Staff also encouraged DENC to address how its solar integration cost estimates are affected by battery storage, including a discussion of whether the legislatively mandated 5,000 MW of solar could be more cost effectively integrated if coupled with energy storage techniques. The Public Staff suggested that DENC should also be required to file this information in future IRPs and IRP updates.

In its reply comments, DENC noted that many types of technologies can store energy, including electrical, thermal, mechanical, and electrochemical technologies. DENC explained that hydroelectric pumped storage, a form of mechanical energy storage, accounts for the greatest share of large-scale energy storage power capacity in the United States. DENC explained further, however, that large-scale energy storage capacity additions since 2003 have been almost exclusively electrochemical (or battery) storage. According to DENC, as of May 2019, there has been limited operating experience in utility scale applications of batteries with 901 MW for the entire United States (298 MW in PJM).

DENC further explained that it is in the early stages of battery research and has relied on publicly available industry guidance regarding battery storage projects to help evaluate the technology's merits as compared to traditional generation sources. DENC acknowledged that battery storage can be a viable future option for peak shifting at a stand-alone storage facility or while co-located at a solar farm and may also improve overall energy production at a solar facility via capturing energy that may be clipped by the inverters.

Because battery storage is still in its early stages of development, DENC stated that the estimates for a battery storage facility in the 2018 IRP were more reflective of a pilot program versus a larger utility scale facility. In addition, DENC explained that CTs can provide backup for periods of lower production from solar facilities, such as prolonged weather patterns or projected variations in capacity factors over the course of a year. DENC stated that CTs in the 2018 IRP short-term action plan were slated for deployment in 2022 and 2023, at approximately 458 MW nominal capacity per facility and an overnight installed cost of $476 per kilowatt (kW). According to DENC, pricing of an equivalent battery storage facility was not cost competitive based on those 2018 estimates. As a result, based on the 2018 economics and technology, DENC stated that it does not expect battery storage facilities to significantly displace CT facilities supplementing the solar generation profile within the next several years.

DENC stated that in the 2018 IRP, it screened out battery storage resources as part of its future resource analysis because of (1) limited utility scale operating experiences, (2) PJM being in the process of revising its tariffs for energy storage resources due to FERC Order 841, and (3) high costs. In the Compliance Filing, a 30 MW battery storage pilot program was available as an option in the "final" PLEXOS IRP modeling based on the directive in the VSCC 2018 IRP Order. DENC stated that the 30 MW battery storage pilot was not chosen by the model as a least-cost option in Plan A. According to DENC, this validates its decision in the 2018 IRP to screen out battery storage resources in its 2018 IRP future resource process because of their then (i.e., 2018) high cost relative to their benefits as a generating resource. Nevertheless, DENC acknowledged that the battery storage pilot was forced into all other Plans (Alternative Plans B through F) as required by the VSCC 2018 IRP Order. Notwithstanding their treatment in the 2018 IRP, DENC stated that it will include battery storage and other energy storage options such as pumped storage facilities in the busbar analysis and provide the results of that revised analysis in its 2019 IRP update.

Finally, DENC stated that it disagrees with the recommendation from Public Staff that the Commission require DENC to submit a supplemental filing to specifically address how its solar integration cost estimates are affected by battery storage. According to DENC, it will not have sufficient information to analyze the effect on solar integration for the 2020 IRP because DENC's experience with battery storage technologies is still in its early stages of development. Nevertheless, DENC stated that it will continue to assess battery storage technologies in future IRPs and IRP updates as required by prior Commission orders, and will report and incorporate the results of any relevant experience with battery storage. As part of that effort, DENC will, as directed by the VSCC Compliance Order, model battery storage using the most updated cost estimates available in its future full IRP filings.

VII. INTEGRATED SYSTEMS AND OPERATIONS PLANNING (ISOP)

Duke stated in its IRPs that it is examining ways of enhancing the traditional methods of utility resource planning in order to keep pace with changes occurring in the industry. As an example, Duke stated that it has not been able to identify the locational value of distributed generation sources, and is now developing models to do so. Duke indicated that it is addressing this and other issues through an Integrated Systems and Operations Planning (ISOP) effort. Further, Duke indicated that the future enhancements in planning are expected to be addressed over the next several years, as soon as the modeling tools, processes, and data development will allow.

The Commission has carefully considered the importance of the evolving nature of integrated resource planning. The Commission recognizes that some of the most promising emerging resource solutions, such as battery storage and leading-edge intelligent grid controls, are still in the early stages and will require enhanced capabilities, such as those promoted through ISOP. As a result, the Commission concluded that it would be helpful for the Commission to receive additional information from Duke about ISOP and ordered that a Technical Conference be held on August 28, 2019 for that reason. (See Commission Order dated July 23, 2019 in Docket No. E-100, Sub 157)

A. Public Staff Initial Comments – ISOP

The Public Staff recognizes the complexity of fully valuing battery storage, and encourages the development of improved modeling capabilities envisioned by ISOP.[56] The Public Staff also recommended that in future IRPs, the Companies continue to evaluate the feasibility and benefits of advanced analytic techniques that incorporate sub-hourly modeling and more granular system performance data, and to the extent these advanced analytics are available at reasonable cost, utilize these resources to provide better information and understanding on optimizing reserve margin needs, as well as overall system operations.

B. EDF Comments – ISOP

EDF commends Duke for using this innovative planning approach, which it maintains can save customers money through deferring or avoiding costly investments. However, EDF recognizes that there are not many details in Duke's IRP, and encourages the Commission to open a rulemaking or separate docket to explore the most effective and systematic way to implement ISOP.[57]

[56] Initial Comments of the Public Staff, at 76.

[57] Initial Comments of EDF, at 5.

C. NCSEA Comments – ISOP

In its initial comments, NCSEA stated that it is encouraged by the statements made regarding Duke's ISOP process, and compares it to Integrated Distribution Planning (IDP), stating that the proposed ISOP description is similar but for its exclusion of a hosting capacity map.[58] NCSEA criticizes Duke for not including more detail or a timeline associated with ISOP, and calls upon the Commission to create a rulemaking proceeding to implement ISOP in order to establish a set of rules by which the ISOP process is governed. NCSEA believes such a rulemaking procedure would guarantee that the process has sufficient oversight and transparency so as to allow ratepayers real opportunities to see if the investment decisions are in their best interests.

D. AGO Comments – ISOP

The AGO supported the recommendation made by intervenor NCSEA that a holistic approach should be adopted for the evaluation of the improvements and investments that will be needed to modernize Duke's distribution and transmission grid to better enable use of energy resources such as storage or demand-side measures. Planning and modeling for the future grid – including the integration of distributed resources into distribution and transmission systems – are important pieces of developing integrated resource plans. Strategen noted that some forecasts indicate that distributed resources will almost double by 2023, and North Carolina has witnessed tremendous growth in solar installations and projects. These forecasts need to be considered when formulating integrated resource plans. Accordingly, the AGO recommended that the Commission review and take a proactive role in the planning of integrated distribution planning, either by opening a rulemaking for that purpose or by other appropriate procedures.

E. DEC and DEP Reply Comments – ISOP

In their comments, EDF and NCSEA asked the Commission to initiate a rulemaking proceeding to adopt procedures related to ISOP and Integrated Distribution Planning (IDP), respectively. Duke commented that it does not oppose a rulemaking, but recommended that the Commission allow interested parties to participate in a pre-rulemaking stakeholder process to facilitate common understanding of ISOP issues, and attempt to reach consensus on as many areas as possible to make the formal rulemaking process more collaborative and efficient. Duke indicated it has discussed this stakeholder proposal informally with the Public Staff, and believes that such a process could be beneficial to the Commission and interested stakeholders.

[58] Initial Comments of NCSEA, at 19.

VIII. QUANTIFICATION OF THE VALUE OF FUEL DIVERSITY AND RISK ANALYSIS

A. Public Staff Initial Comments – Fuel Diversity and Risk Analysis

The Public Staff noted that the Comprehensive Risk Analysis used by DENC provides valuable information in trying to identify which least cost portfolio is best in an uncertain world. The Public Staff found that the approach taken by DENC to analyze the various scenarios with regard to exposure to fuel price volatility scenarios, consideration of rate impacts to customers, and utilizing a probabilistic risk assessment framework provides insightful information to its customers and the Commission. The Public Staff recommended that DEC and DEP develop similar analytical tools to those utilized by DENC, such as the Comprehensive Risk Analysis, to determine the least cost plan that provides the lowest risk to its customers, while also providing operational and compliance flexibility to each utility.

B. SACE, Sierra Club, and NRDC Initial Comments – Fuel Diversity and Risk Analysis

SACE, et al. commented that Duke's 2018 IRP Plans rely excessively on new gas-fired generating capacity. Gas-fired generation is subject to numerous uncertainties, including fuel cost volatility, and carbon regulation. The groups noted that as more energy efficiency programs, renewable energy resources, and battery storage are added to Duke's resource mix, the need for additional gas-fired capacity is diminished.

NRDC commissioned energy consulting firm ICF to perform a power sector analysis using ICF's Integrated Planning Model (IPM®), a power sector dispatch model. SACE, et al. commented that ICF's IPM analysis shows that greater reliance on cleaner energy sources, rather than fossil fuel generation, delivers cost savings and pollution reductions for North Carolina compared to the "business-as-usual" approach in the Duke IRPs. With respect to gas-fired generation, ICF's "economically optimized" case, which allowed the model to optimize for a least-cost outcome, coal-fired capacity was reduced and replaced primarily with new solar; no new gas capacity was selected by the model based on economics. If North Carolina were to follow this economically optimized path, electric sector carbon emissions would fall to 41% below 2005 levels by 2025. The business-as-usual case would have a total system cost of $5.6 billion more that the economically optimized case—or, 3% higher bills for the average residential customer by 2030 and 5% higher by 2035.

C. NCSEA Initial Comments – Fuel Diversity and Risk Analysis

It is NCSEA's position that, with a heavy reliance on natural gas and other traditional generating resources, the IRP plans fail to account for cost-effective clean energy alternatives to the increasingly uneconomic operations of Duke's existing coal plants. NCSEA argues that the Synapse Study details a realistic clean energy future that provides both the energy and capacity to meet the needs of Duke's customers, while effectively meeting future reliability requirements as traditional generating resources are retired.

D. AGO Initial Comments – Fuel Diversity and Risk Analysis

The AGO commented that Duke's continued reliance on natural gas plants as the primary way to meet future resource needs is not justified because Duke's plans have not adequately considered the economic and environmental risks of that option.

The AGO stated that one concern about Duke's heavy reliance on natural gas generation for planning purposes is that natural gas production and consumption are associated with significant carbon dioxide and methane emissions, greenhouse gases that contribute to climate change, whereas alternatives that use renewables paired with storage are not. Climate change has real costs affecting ratepayers. The economic costs associated with frequent and intense hurricanes, such as those experienced in North Carolina in the past year, were cited as key factors motivating Executive Order No. 80. That order highlights a State commitment to fight climate change and transition to a clean economy, setting a goal of reducing statewide greenhouse gas emissions to 40% below 2005 levels by 2025. The AGO advocated that the Commission broaden its consideration of environmental factors in light of the policy goals announced in Executive Order 80.

Another concern about Duke's increased reliance on natural gas power production is the economic risk of that option. The AGO and Strategen agreed with the recommendation made by the Public Staff that Duke should be directed to use an analytical tool similar to the Comprehensive Risk Analysis that was employed in the initial IRP report of DENC in order to address the relative riskiness of alternative resources. That tool considers tradeoffs between the costs and riskiness of the resources that make up the portfolio. The risk assessment may take into account not only the potential volatility of prices but also risks associated with climate change impacts and mitigation efforts. If Duke is directed to perform a Comprehensive Risk Analysis, Strategen notes that there should be transparency about the assumptions used in the analysis and recommends that Duke should either supply a working copy of the model so that assumptions may be evaluated by other parties in detail or should run alternative specifications and scenarios for others.

According to the AGO, Duke's increased reliance on natural gas power production also poses a longer-term risk that the investment may become stranded before the end of the useful life of such plants. Conventional gas-fired plants are built to last for decades, and new emission standards or technological change may cause the plants to become uneconomic. This concern was identified by the Indiana Utility Regulatory Commission when it rejected an 850 MW natural gas plant proposal. The Indiana Commission directed Vectren to evaluate alternatives to the large, centralized generation approach, given the potential that the plant could become a stranded asset as the cost of renewable energy declines.

E. NC WARN Initial Comments – Fuel Diversity and Risk Analysis

NC WARN noted in its initial comments that public utility commissions, such as in Arizona and Virginia, have rejected proposed IRPs and required utilities to consider opportunities for renewable energy before considering new natural gas infrastructure. NC WARN recommended that the Commission direct Duke to consider battery storage options as opposed to new natural gas infrastructure. NC WARN filed an updated version of its North Carolina Clean Path 2025 Plan, which provides for replacement of 50% of all coal and gas used for electricity with clean energy by 2025, and 100% by 2030. NC WARN's plan indicates that solar combined with battery storage is now more reliable and cost effective than new natural gas power plants. The Plan indicates that gas turbine manufacturing is declining due to this shift to renewables with storage. The Plan states that Duke's contention that it must build gas turbines to back up solar is "unsubstantiated."

In its reply comments, NC WARN encouraged the Commission to carefully review Duke's plan to meet demand mostly from resources using fracked gas. It contended that the demand for fracked gas would likely decline as renewable energy technologies grew and battery costs fell. NC WARN also recommended that the Commission reject Duke's proposal to add over 9,000 MW of natural gas infrastructure and direct Duke to seek renewable generation instead. NC WARN contends that Duke's proposal to build natural gas plants and pipelines is not the least-cost option and exposes customers to significant risk.

F. DEC and DEP Reply Comments – Fuel Diversity and Risk Analysis

The Public Staff suggests that DEC and DEP adopt a fuel diversity analysis similar to the analysis provided by DENC in its IRP filings. DEC and DEP commented that their high-level understanding of DENC's approach is the deployment of a long-term stochastic modeling approach. Under such an approach, long-term fuel prices are statistically simulated over hundreds or even thousands of scenarios to examine a distribution of potential outcomes dependent on the mean forecast of various fuels such as coal, natural gas and fuel oil. In addition, statistical parameters such as long-term commodity volatility curves and long-term cross commodity correlations would be required in such an approach. While such an approach provides a comprehensive distribution of potential production cost outcomes, it is dependent upon these forward-looking statistical assumptions that are difficult to ascertain and verify. Currently, parties to the IRP docket have varying opinions on the long-term fuel price forecasts used by DEC and DEP. DEC and DEP noted that moving to a long-term statistical approach greatly expands the debate given the dependence on long-term forecasts of fuel volatility, mean reversion parameters and correlation variables. They continue to assert that the use of discrete fuel price sensitivity and scenario analysis provides a more transparent view of fuel diversity benefits. Furthermore, DEC and DEP commented that their discrete sensitivity and scenario approach is consistent with Rule R8-60 that outlines variables such as fuel prices should be varied so portfolio results can be viewed under these varying assumptions.

IX. OTHER ISSUES

A. UTILITY STATEMENT OF NEED

The Public Staff noted the fundamental link between each IOU's IRP and avoided costs, formalized with the passage of HB 589, which provided that a "future capacity need shall only be avoided in a year where the utility's most recent biennial [IRP] filed with the Commission … has identified a projected capacity need to serve system load…" The Public Staff pointed out that a number of assumptions used by the IOUs in the avoided cost proceeding have not been clearly specified by each utility. To remedy this issue and mitigate the potential for paying for more capacity than what is needed, the Public Staff recommended that the utilities, in their IRP Update to be filed in 2019 and all future IRPs and updates, include a new Utility Statement of Need section. The Public Staff explained that the Utility Statement of Need section will specifically address the link between the first year of capacity need and avoided cost proceeding and specifically address:

1. The year in which the utility would fall below its planning reserve margin without commitment(s) to procure additional resources.

2. Whether QF contracts expiring within the avoided cost term are renewed / replaced in kind, or excluded.

3. Whether utility uprates are solely installed for additional capacity and if they could be considered avoidable.

4. Whether new EE measures are included in the determination of capacity need.

5. The quantity of MW needed in the first year, and a discussion of whether avoided capacity payments will be made to QF contracts executed in excess of that capacity.

6. The year in which the utility's first avoidable capacity need becomes unavoidable.

7. Whether it is appropriate to create a separate "Avoided Cost Portfolio" in the IRP's portfolio analysis section, which might present a more objective determination of capacity need that could ensure QFs providing capacity are not treated as captive.

The Public Staff explained that this section would then be directly referenced by each utility in its avoided cost proceeding, establishing a clear and well-understood methodology to establish the first year of capacity need for the calculation of avoided capacity payments. The Public Staff contended that the utilities should continue to conduct the foundational analysis of the IRP, with incorporation of the Public Staff's recommendations.

In its reply comments, Duke agreed with the Public Staff's recommendations and stated that it will include a Statement of Need section to more clearly identify the undesignated capacity needs for each utility in DEC's and DEP's 2019 IRP Updates and in future biennial IRP filings.

B. RETAIL RATE IMPACT OF PORTFOLIOS

In Docket No. E-100, Sub 147, the Public Staff previously recommended that DEC and DEP "file a residential rate analysis of the proposed expansion plans, along with a comprehensive risk analysis that addresses similar key risk factors employed by DNCP" in future IRPs. The Commission did not rule on the issue of including a residential rate analysis of the proposed expansion plans in its June 27, 2017 Order Accepting Integrated Resource Plans and Accepting REPS Compliance Plans in Docket No. E-100, Sub 147 (2016 IRP Order).

In the current docket, the Public Staff noted that an analysis of the rate impacts of each portfolio would inform the comments of intervenors, as well as testimony and comments from the using and consuming public, how changes in generation plans and costs would impact a retail customer, particularly residential customers as to an estimate of the short and long-term costs of the various portfolios. The Public Staff indicated that while there is not currently a statutory or regulatory requirement for Duke to include rate impacts in future IRPs as there is in Virginia,[59] such information could also be useful in other forums, such as the North Carolina Climate Change Interagency Council and the stakeholder workshops formed to facilitate the implementation of Executive Order 80. Therefore, the Public Staff recommended that the Commission require DEC and DEP in future IRPs to evaluate the residential rate impacts of each portfolio evaluated against a no CO_2 scenario and present this information in a manner similar to that used by DENC.

The Public Staff noted that DENC presents the incremental cost of compliance of each of the Alternative Plans compared to the least cost plan, but due to the significant changes in investment decisions between the filings of the original IRP and its revisions, these estimates are no longer valid. Thus, the Public Staff recommended that DENC submit as a supplemental filing with a recalculated rate impact analysis of the modified Alternative Plans found in its Compliance Filing. DENC requested instead that it be permitted to provide an updated rate impact analysis of the Alternative Plans in its 2019 IRP Update due to be filed by September 1, 2019.

The AGO supported the recommendations of the Public Staff and other parties that Duke should be required to provide an analysis of the residential annual rate impacts of each of its portfolios similar to that presented in Dominion's 2016 and 2018 IRPs. The AGO recommended that the analysis should show the impacts of the portfolios on ratepayer bills, and the analysis should not be limited to residential ratepayers, but rather, should be applied generally to all customer classes. Further the bill impact analysis should

[59] Va. Code § 56-599 B 9 requires DENC to evaluate "[t]he most cost effective means of complying with current and pending state and federal environmental regulations, including compliance options to minimize effects on customer rates of such regulations." Accordingly, DENC evaluates the residential rate impact of each Alternative Plan against its Plan A: No CO_2 Tax. This analysis may be found in Section 6.6 of DENC's 2018 IRP filed May 1, 2018.

include a breakout of the portion of rates that are fuel-related and thus bear the price risk borne by ratepayers.

C. DENC NUGs

The Public Staff noted that some facilities DENC listed as NUGs in Appendix 3B to its IRP are not included in the NUG capacity in Figure 3.1.1.3, while some utility-scale solar facilities are considered as NUG capacity in Figure 3.1.1.3 and others not. The Public Staff also noted that DENC considers all utility-scale solar facilities to be behind the meter, but these facilities typically separate the metering of electricity sales from electricity purchases. The Public Staff recommended that in future IRPs, DENC clarify its definition of a NUG facility; use that definition consistently through the IRP; re-evaluate which generating facilities sell energy directly to DENC and identify them separately from facilities that do not; separately identify facilities that sell energy/capacity directly to DENC from facilities that sell directly into PJM; and be consist in references to nameplate rating or equivalent firm capacity rating.

In its reply comments, DENC indicated that it had discussed these recommendations with Public Staff and had agreed to make changes to Appendix 3B and Figure 3.1.1.3 in future full IRPs and to provide an updated version of Appendix 3B as part of the 2019 IRP Update filing to the extent the information is available.

D. QF CONTRACT EXPIRATION IN THE IRP

In its Initial Comments, NCSEA takes exception with the method used by Duke in the treatment of QF contract expirations in the IRPs. NCSEA states that, "despite the fact the PPAs with QFs will eventually expire, Duke assumes that the PPAs will 'be either renewed or replaced in kind.' However, there is no guarantee, or requirement, that a QF will continue to provide the utility with capacity past the end of its initial PPA, even if the QF has remaining operational life." [60] This statement was made in reference to a data request response provided by the Companies to the Public Staff in this docket.[61]

Duke commented that this data request response refers only to solar QF contracts, as existing contracts of any other technology are assumed to expire at the end of the purchased power agreement ("PPA") term. Solar capacity, however, will continue to grow in the future, increasing the Companies' planned solar capacity. As such, the capacity of existing solar QFs will either be procured by the renewal of existing contracts or replaced with other solar PPAs. Whether the capacity is from an existing QF or another QF does not matter in the context of the IRP, only that the capacity comes from a solar resource.

NCSEA goes on to allege that "Duke assumes for planning purposes that a QF's PPA will be renewed despite the fact that it has made numerous efforts in other

---

[60] NCSEA Comments, p. 25, Paragraph 1.

[61] Duke Energy Carolinas, LLC's Response to Public Staff Data Request No. 6-4 and Duke Energy Progress, LLC's Response to Public Staff Data Request No. 4-12, included in NCSEA's Comments as Attachment 2.

proceedings to make it more difficult for a QF to renew a PPA,"[62] going on to cite Docket No. E-100, Sub 101 and Docket No. E-100, Sub 158, as examples. Duke argued that both dockets cited by NCSEA relate to the upgrade of QF equipment, which is in no way impactful to the 2018 IRPs.

NCSEA continues its argument by stating that "other wholesale PPAs are removed from DEC and DEP's respective generation stacks when they expire and create capacity needs. However, Duke treats PPAs with QFs differently in its planning process."[63] Duke noted that it is true that DEC and DEP have consistently assumed across multiple planning cycles that all wholesale purchase contract capacity, including QFs, is removed in the year after a wholesale contract expires and that QFs are not presumptively assumed to establish a new PPA to deliver capacity and energy to the Companies over a new fixed term in the future. According to Duke, if, however, the QFs have already executed a contract extension or renewal with Duke, the specific contract capacity will be included past the original contract expiration year to the year of expiration of the extended/new contract. Thus, the existing QF contracts may either be renewed or replaced with other new solar facilities so that, in the aggregate solar penetration reaches levels projected in the IRP. The IRP is agnostic as to which choice is made but rather focuses on an expected level of solar penetration. Furthermore, Duke commented that the IRPs present scenarios with both higher and lower levels of solar penetration that are also agnostic to the decision of renewal versus replacement with new solar facilities. Duke noted that this is consistent with the approach for all contracted generation. For example, at the time DEP's 2018 IRP was filed, several natural gas PPAs were expiring. The IRP did not explicitly assume these contracts were renewed but rather put in a generic undesignated PPA that was deemed avoidable by QFs for the purpose of establishing avoided cost rates. Therefore, NCSEA's argument that the Companies are treating existing QF contracts differently and unfairly in the IRPs is untrue.

Duke noted that, based upon the foregoing circumstances, it continues to find its IRP planning approach of assuming a capacity reduction after expiring QF contracts reasonable and consistent with the objectives of their IRPs to determine the long-range generation needs to reliably serve their customers' energy needs in North Carolina. Thus, Duke argues that DEC and DEP are justified in removing from their respective IRPs the third-party wholesale contract capacity (both QF and non-QF) in the year when the contract expires.

According to Duke, DEC and DEP have taken a reasonable and consistent approach to recognizing expiring wholesale purchase contracts, including QF contracts, in their 2018 IRPs. Duke's IRPs actually assume that, upon expiration of any third-party wholesale purchase contract (both QF and non-QF), DEC and DEP recognize a reduction in capacity by the amount of the capacity provided in the expiring wholesale purchase contract in the year following contract expiration. Duke noted that this approach to capacity planning is not new. Since the Duke Energy/Progress Energy merger, Duke's 2012, 2014, 2016, and 2018 biennial IRPs have all consistently assumed the expiration

[62] NCSEA Comments, p. 25, Paragraph 2.

[63] Id. p. 26, Paragraph 1.

of wholesale purchase PPAs, including QF PPAs, that result in a need for replacement capacity to be procured through each utility's resource planning process to meet the targeted reserve margin during a given year. Thus, the expiration of each PPA has the potential to impact the timing of DEC and DEP's first capacity need, particularly when viewed in aggregate with other contract expirations or retirements. Fundamentally, it is prudent resource planning not to rely upon assumed future third-party owned capacity in years where no contract or other legally enforceable commitment guaranteeing delivery exists.

E. CLIMATE CHANGE

Duke responded to intervenor comments on climate change issues as follows.

1. Duke agrees with the AGO that incorporating environmental considerations into resource planning is critical even if specific standards are not yet defined in environmental regulations, which is why Duke models the potential costs of future carbon dioxide (CO_2) legislation as part of their comprehensive scenario analysis described in the IRP.

Duke noted that, as described in Chapter 13 of the DEP IRP and Chapter 12 of the DEC IRP, and in more granular detail in Appendix A of both IRPs, Duke analyzed the potential costs associated with multiple government-imposed limitations on greenhouse gas emissions. These CO_2 sensitivities are placeholders for future legislations, and the IRPs reflect the costs associated with the implementation of those potential regulations. Any benefits to Duke's customers associated with those potential regulations are largely driven by state and federal rules and standards that are also evolving and will influence how technologies are deployed. Duke asserted that, to be clear, the IRP does not set policy, but it responds to regulations and can provide a view of the impacts of potential regulations, as Duke has shown with potential greenhouse gas emission regulations.

2. Duke supports lowering carbon emissions, and the IRPs are consistent with Duke Energy's Sustainability Report. Furthermore, the DEC and DEP systems are projected to exceed Executive Order No. 80 which set a goal of reducing statewide greenhouse gas emissions to 40% below 2005 levels by 2025.

Duke noted that it has been aggressive with its pace of retiring coal plants (having retired more than half of its Carolinas coal plants over the last decade), adding renewables to the resource mix, increasing EE/DSM offerings to its customers, and operating a reliable nuclear fleet that provides half of its customers' energy demand with zero CO_2 emissions. These actions, along with operating efficient natural gas generation with low cost fuel, will allow the DEC and DEP systems to meet and exceed the goals of Executive Order No. 80, signed in the Fall of 2018, as well as the Companies' own sustainability targets, all while meeting the Commission's Rule R8-60 requirement to "provide reliable electric utility service at least cost over the planning period."[64] Duke explained that it is participating in the Executive Order No. 80 stakeholder meetings and, although the State's specific plans to implement the order are currently unknown, with the final report not expected until October 2019, Duke will address any additional requirements in future IRPs once any additional requirements are known.

In the introduction to its reply comments, Duke noted that the IRP is a "snapshot in time" view of DEC's and DEP's proposed mix of diverse resources to reliably meet customers' needs over the fifteen (15) year planning horizon. The IRP process is lengthy and dynamic. Duke commented that a consistent theme reflected in numerous consumer statements of position filed with the Commission is a call for accelerated retirement of the Companies' remaining coal plants, less reliance on natural gas or other fossil fuels, and greater reliance upon renewable resources, energy storage, DSM and EE. These same general themes are expressed in the comments filed by many of the intervenors to this docket. Duke explained that the 2018 Duke IRPs reflect a diverse mix of least-cost generation, storage, DSM and EE resources: in 2019, 46% of DEC's capacity is expected to come from carbon-free resources, and 39% of DEP's capacity is expected to come from carbon-free resources. Using the assumptions embedded in the 2018 IRPs, 60% of the combined DEC and DEP energy would come from carbon-free resources in 2019. Of the proposed resource additions over the 2018 IRP planning horizon, 46% of the DEC additions and 23% of the DEP additions would come from renewables, storage, DSM and EE.

However, change is constant in the energy industry, and Duke noted that successful companies are those that recognize and adapt to the changing landscape. Duke stated that it shares its stakeholders' desire to provide increasingly clean energy for the benefit of its North Carolina and South Carolina customers. A lower carbon future requires a delicate balancing act with no one-size-fits-all solution, as Duke must continue to provide all of its customers with safe, reliable and affordable energy. In its 2017 Climate Report to Shareholders and its 2018 Sustainability Report, Duke Energy Corporation reiterated its voluntary goal to reduce carbon emissions 40% across its six state generation fleets by 2030, and noted that its long-term strategy is to continue to drive carbon out of its system. The specific potential path forward and timing to a low-carbon energy future, however, will depend on a number of challenging and uncertain factors, including market forces, public policy, technology innovation/ commercialization and customer demand. Duke routinely evaluates retirement of its generation assets, but as Duke considers a course specific to the Carolinas, DEC and DEP will evaluate accelerated retirement of their remaining North Carolina coal units, coupled with other necessary supply and demand-side investments to reliably meet customer needs. Because such plans would not only impact Duke's future generation mix, but would also impact customer rates, any such accelerated coal unit retirement plans would also need to be considered in ratemaking dockets. Duke noted its commitment to make appropriate filings with the Commission in future dockets after it has completed its analysis and reached any conclusions.

[64] Commission Rule R8-60 – Integrated Resource Plans and Filings.

F. ALTERNATIVE FILED RESOURCE PLANS

NCSEA, SACE et al., and NC WARN filed what might be styled as alternative resource plans as part of their comments on the 2018 IRPs. Duke responded to these alternative plans as follows.

1. The Synapse Report filed by NCSEA is the product of a special interest group that appears to make assumptions in their model with a predetermined outcome in mind. The Synapse Report would not conform to the regulated utilities' requirement to provide reliable electric utility service at least cost over the planning period and should be dismissed.

Duke noted that the Synapse report filed by NCSEA as Attachment 1 to its comments claims to detail "a realistic clean energy future that provides both the energy and capacity to meet the needs of Duke's customers, while effectively meeting future reliability requirements as traditional generating resources are retired"[65]; however, the report's cost savings are based on multiple assumptions that, if implemented, would cripple the reliability of the DEC and DEP systems.

Duke argues that, first, the Synapse report, which purports to gain an immediate cost savings of 28% through "removal of [coal generation] must-run designations"[66] does not consider "transmission implications that may or may not be associated with must-run designations."[67] The must-run designations that Synapse removes are not required at all energy demand levels on the DEP and DEC systems, and Duke is not seeking "to find a use for the costly must-run coal generation"[68] as Synapse suggests. Duke instead notes that, in fact, in Synapse's attempt to match the DEC and DEP IRP base cases (with must-run designations included), "one-third of the coal generation shown in 2019 is exported to neighboring utility service territories rather than being used to meet Duke's own load requirements."[69] Duke states that it does not model sales to neighboring utilities unless those are firm sales with co-owners that are part of nuclear generation contracts or the new Lee CC, and DEC and DEP generally do not sell energy to external markets unless there are economic incentives for consumers to do so. Generally, must-run requirements increase as system energy demand levels increase or other generating units near the must-run units are not available. This level of detail was not considered relevant to Synapse as they relied on Horizons Energy's National Database for their EnCompass model[70] which greatly oversimplifies must-run requirements on the DEC and DEP

[65] NCSEA Comments, pp. 5-6

[66] North Carolina's Clean Energy Future: An Alternative to Duke's Integrated Resource Plan, Prepared for the North Carolina Sustainable Energy Association by Synapse Energy Economics, Inc. (Synapse Report), p. 6

[67] NCSEA Response to Duke Data Request No. 1, Item No. 1-3 part c.

[68] Synapse Report, p. 6.

[69] Id., p. 5.

[70] NCSEA Response to Duke Data Request No. 1, Item No. 1-3 part b.

systems. Must-run requirements are in place to maintain stability on the transmission system by providing voltage support or other services. According to Duke, without these must-run requirements, the transmission system would be in jeopardy of not being able to serve load, which is a risk that Synapse and NCSEA have ignored.

Another source of cost savings in the Synapse report is the reduction of the required minimum reserve margins in DEC and DEP from 17% to 15% based on the NERC 2018 Long Term Reliability Assessment.[71] As noted in footnote 4 on page 53 of the NERC report, SERC Reliability Corporation (SERC) members perform individual reliability assessments, and SERC does not provide reference margin levels for its sub-regions. Further, page 151 of the NERC report states that NERC applies a 15% margin for predominately thermal systems if a reference margin is not provided by a given assessment area. In short, the SERC and NERC reports cited by NCSEA as a basis for a lower reserve margin do not reflect the level of solar penetration that exists in the Carolinas or the need for a winter reserve margin target as determined by the Companies' resource adequacy studies. The minimum reserve margin requirement in DEC and DEP has been a point of extensive comment since the 17% reserve margin was introduced in the 2016 IRP Reports. The minimum reserve margin requirement is based on comprehensive resource adequacy studies that the Companies conducted with Astrapé Consulting in 2016. Duke explained that, although some of the intervening parties apparently still chose to stubbornly debate the findings of the study, the Commission found the 17% reserve margin requirement reasonable for planning purposes, with the requirement that the Companies and the Public Staff file a joint report summarizing their review after filing the 2017 IRP Update.[72] Synapse took it upon themselves to ignore the 17% requirement that was developed through a study that focused on the issues facing the DEC and DEP systems, and instead used the NERC study that did not consider the level of solar penetration facing the Carolinas, which was a major driver of the increased reserve margin requirement. Duke argued that, again, Synapse and NCSEA are relying on a reduction in system reliability to drive the results of their biased resource report.

Duke commented that the third source of cost savings that is inconsistent with maintaining a reliable energy system in the Carolinas is Synapse's reliance on energy imports into the Carolinas. The Synapse "Clean Energy scenario" relies on 14% energy imports from neighboring utilities to meet demand by 2033.[73] According to Duke, this reliance on neighboring utilities to meet the Carolinas' energy and capacity needs is inconsistent with the reality that there is not enough firm transmission available to reliably import this level of energy, and the Synapse study makes no mention of the costs required to obtain firm transmission into the region. Duke argued that NCSEA and Synapse are either ignorant of the realities of transmission constraints into DEC and DEP, or they have intentionally ignored them.

[71] Id., Item No. 1-2 part b.

[72] Order Accepting Integrated Resource Plans and Accepting REPS Compliance Plans, Docket No. E-100, Sub 147.

[73] Synapse Report, p. 5.

Duke further pointed out that it is not clear that increasing energy imports from neighboring utilities, as NCSEA proposes to do, would result in fewer CO_2 emissions for the Carolinas. In fact, relying on other states' generation, including those states that may still rely mainly on coal generation, would be contrary to the spirit of Executive Order No. 80's goal to reduce CO_2 emissions in the state to 40% of 2005 emission levels by 2025. As stated above, Duke's plan already exceeds Executive Order No. 80's directive by using resources located in the Carolinas.

Duke argued that perhaps the comment that most clearly shows the lack of understanding by NCSEA and Synapse as to what constitutes a reliable system is the following statement:

> The Clean Energy Scenario maintains the required 15 percent reserve margin and EnCompass projects no loss-of-load hours and sees zero hours with unserved energy, proving that the retirement of fossil fuels and build-out of renewables leads to no new system reliability issues.[74]

As Duke explained, one does not simply use Duke's weather-normalized peak demand forecast, along with an hourly load shape from the EnCompass National Database as Synapse did, and claim no reliability concerns when the model converges without unserved energy hours. According to Duke, that is equivalent to someone guaranteeing that because they did not run out of gas when they drove from Chapel Hill to Raleigh at 7:00 a.m. on a Sunday morning with their low fuel light on, then they could successfully complete that drive at any time with little gas in the tank. How would they fare at 5:00 pm on a Friday in rush hour? Duke noted that when asked to explain their understanding of why the Companies carry a reserve margin, NCSEA's consultant, Ric O'Connell responded:

> NCSEA understands the reserve margin used in the IRP is a "planning reserve margin" which is defined by NERC as: Planning reserve margin is designed to measure the amount of generation capacity available to meet expected demand in [the] planning horizon.

Duke commented that such a definition may be accurate for the NERC study, but the Companies carry a reserve margin to be able to meet unexpected demand due to extreme temperatures, economic load forecast uncertainty, and unexpected outages of its operating units. The reserve margin that Duke requires is there not just to meet expected demand, but to be able to reliably serve customers under extreme and unexpected circumstances.

In summary, Duke noted that any party can claim that their plan is lower cost than the Companies' plans, but to achieve those costs savings in the manner that NCSEA and Synapse did, while still claiming to meet the reliability standards that the NCUC, Duke, and its customers demand, is unrealistic and lacks regulatory rigor. Duke, as the regulated utility in North Carolina, has the sole obligation to meet its customers' energy

[74] NCSEA Comments, p.8.

needs at all times throughout the year, and the Companies are steadfast in their belief that the DEC and DEP IRPs achieve that standard by doing so at the lowest reasonable cost while meeting and exceeding environmental regulations at the state and federal levels. Duke noted that, simply put, other parties to this docket do not have the obligation to serve, nor do they have an obligation to maintain a reliable electric system. Their use of overly simplistic modeling approaches to reach a predetermined ideological outcome would not be compliant with reliability standards and as such should be rejected.

2. SACE et al.'s consultant Applied Economics Clinic's (AEC) Report, "Review of Duke Energy's North Carolina Coal Fleet in the 2018 Integrated Resource Plans" includes misleading and false accusations regarding the Companies' business practices.

Duke commented that the assertion of the Applied Economics Clinic in Attachment 2 of the SACE et al. comments that "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"[75] is misleading. The retirement dates for existing coal units are projections for planning purposes in the IRPs, and are based on retirement dates in depreciation studies approved in the most recent general rate cases by the Commission (and PSCSC).

Additionally, Duke argued that AEC's assertion that "…the Companies make major decisions about their resources behind closed doors"[76] is disingenuous. Multiple analyses are performed regarding the retirement options of the Companies' coal units, as confirmed in data requests received and cited by AEC in the SACE et al. Attachment 2. The results of those analyses are utilized and represented in the next filed IRP. Furthermore, Duke's IRPs and depreciation studies are open to scrutiny in the public and transparent dockets this Commission oversees with the intervention and active participation of parties like SACE et al.

Duke commented that while SACE et al. and AEC attempt to discredit Duke and its commitment to meet customers' energy needs at the lowest reasonable costs, the full picture is not considered. Duke is regulated by this Commission and the PSCSC and is under an obligation to provide reliable and affordable service to their customers. Duke pointed out that the special interest group intervenors, on the other hand, may freely utilize whatever data sources and reports that support their intended purpose, while ignoring the realities of the obligation of serving customers. Statements made by the intervenors criticizing Duke's analysis techniques, assumptions, and generally, any decision that does not meet their agenda are presented as fact in their comments, without regard for realistic actualities. In reality, the statements and assertions aimed at discrediting Duke are incorrect. Duke noted that, notwithstanding its criticism of SACE et al.'s tactics, as noted above, Duke will continue to evaluate potential accelerated retirement of their remaining North Carolina coal units and advise the Commission in future dockets.

---

[75] Review of Duke Energy's North Carolina Coal Fleet in the 2018 Integrated Resource Plans, p. 18, Part A.

[76] Id.

3. NRDC's commissioned ICF analysis is unable to be reviewed and should be considered inconsequential.

SACE et al.'s comments state that NRDC commissioned the energy consultant, ICF, to perform analyses to develop its own "optimum" resource plan based upon inputs developed by NRDC. ICF utilized their Integrated Planning Model ("IPM") to develop what they call an "economically optimized" case and an "IRP" case, which is intended to replicate the No Carbon Base Case presented by the Companies in its filed IRP.

In a data request to SACE et al., [77] Duke requested a copy of the report developed by ICF in the study, to which SACE et al. responded that, "ICF did not develop a report. All written materials were developed by NRDC, based on data outputs provided by ICF using their IPM model with all assumptions and policy scenarios provided by NRDC."[78] According to Duke, in the data request response, NRDC provided a file including the inputs developed by them. Duke explained that there is no discussion or detailed information about the calculation and algorithm details of the models. Additionally, how the input data was actually utilized in the model is unclear. In the same response, NRDC provided a single page of outputs for each case developed by the IPM model.[79] While two cases were provided, an "economically optimized" case was not one of them. SACE et al.'s data request response provides outputs for a "reference case" (also titled as "BAU No CCS") and an "IRP case." It is unclear if the "reference case" and the "economically optimized" case are the same case. As such, Duke noted it is impossible for the Companies to adequately review and comment on the outputs at this time.

Duke further commented that, even so, NRDC presents ICF's "economically optimized" case as a least cost option as compared to the "IRP" scenario that was created. There are several issues in question from Duke's point of view. First, in the ICF results presented as Attachment 1 of NRDC's Comments, in the description of the "economically optimized" case, it is stated that, "the model was allowed to endogenously retire and add generating resources to determine a least-cost pathway for the state given existing federal and state regulations."[80] Once again, in the absence of information regarding the calculation methodology and rigor of the ICF study, it is not clear how the model does this, what units are retired or when they are retired.

Duke explained that, additionally, NRDC states in Attachment 1 that "the only additional natural gas capacity added is from units already under construction" in the "economically optimized" case.[81] However, the capital costs and fuel prices utilized by ICF for new natural gas units are based on publicly-available generic data that is proven

[77] Southern Alliance for Clean Energy, Natural Resources Defense Council and the Sierra Club Responses to Second Data Request of Duke Energy Carolinas, LLC and Duke Energy Progress, LLC, Docket No. E-100, Sub 157, April 29, 2019.

[78] Id., Response to DEC/DEP Data Request No. 2-1.

[79] Id., Response to DEC/DEP Data Request No. 2-2 including Input and Output Excel Files.

[80] Economically Optimized Independent Power Sector Modeling Shows Multiple Benefits when Compared to Duke's IRP, p. 2, bullet one.

[81] Id., p. 1, bullet three.

to be higher than in-house new-build costs developed for Company-specific locations and that consider economies of scale/scope that make these resources economic options. The costs utilized to make this statement are inordinately high and likely give any natural gas resources an unfair disadvantage.

NRDC claims, also, that "this 'optimized' case only represents a possible future in which decisions are made by an infallible market operator, instead of a reality where regulators may have to base their decisions on imperfect or incomplete information, and utilities are driven by incentives that do not always align with their customers' interests."[82] Duke argues that, first, there is no such thing as an "infallible market operator," which discredits the "optimized" case as being unrealistic. Second, Duke suggests that the inference that utilities make decisions based on "incentives" that do not "align with customers' interests" is outrageous. Duke also notes that the SACE et al. inference that the information utilized by the Companies is incomplete is absolutely false. Duke explains that its resource plans are based on best-available information that takes months to gather, vet, and include properly in modeling and analysis utilized to develop the resource plans.

Finally, NRDC claims that renewable generation (primarily solar) replaces any existing coal or future natural gas resources by stating, "renewable energy generation more than makes up for the generation reductions…"[83] Duke commented that it is impossible for intermittent solar to replace baseload resources required to reliably meet the Companies' customer demand, particularly during peak times when solar is only available to a small degree. The IPM model outputs provided in SACE et al.'s data request response mentioned above do not provide any discernable information about the operational reliability assumptions and load shapes of the solar generation or the impacts of even higher levels of intermittent solar to Duke's generating system. As determined by the Capacity Value of Solar study presented in the Companies' filed IRPs,[84] solar resources provide very little capacity value at the time of winter peak demand and capacity values decrease as the penetration of solar increases. Duke explains that infinitely high amounts of solar cannot be added to a generating system and still maintain the integrity and reliability of the system and meet required NERC reliability standards.

Duke argues that, once again, SACE et al. fail to consider the real world in which the Companies operate. DEC and DEP are regulated utilities that have real obligations to its customers. Duke noted it is DEC and DEP's highest commitment to serve their customers in the most reliable, dependable, environmentally-friendly and economical manner possible. There are real-world consequences to the theoretical exercises SACE et al. continue to present as fact. Duke argues that the misleading and incomplete information presented by the intervenors consistently supports their own agenda but is developed without full consideration of the best interest of all customers.

4. NC WARN Comments – Alternative Filed Resource Plans

---

[82] Id., p. 5, paragraph two.

[83] Id., p. 1, bullet 4.

[84] DEC 2018 IRP, Chapter 9, and DEP 2018 IRP, Chapter 9.

In its comments and attached report, NC WARN alleged, among other things, that DEC and DEP can achieve 100% fossil-free energy by 2030, getting halfway there by 2025. In response, Duke noted that NC WARN has, yet again, argued that the Commission should adopt an energy plan for North Carolina that is unrealistic and would jeopardize the reliable and affordable energy system that this Commission has consistently required from Duke in fulfilling the Commission's mission under the Public Utilities Act. Duke noted that although NC WARN objected to 8 of the 13 data requests DEC and DEP sent to it seeking analytical and factual support for statements made in its filed IRP comments and report, the information NC WARN did provide in its responses reveals that its comments and report are not supported by competent analysis or facts. For example, in DEC and DEP Data Request 1-4, the Companies asked NC WARN to:

> Please provide all documents and analyses including inputs, assumptions, calculations, results, models, spreadsheets with working formulas, or other data or information supporting your position that sufficient and cost-effective battery storage can be online by 2025 to displace thousands of megawatts of natural gas generation.

In response, NC WARN simply referred the Companies to the reports filed by NC WARN in connection with its 2017 and 2018 IRP comments. Duke notes that, in other words, NC WARN asserted that the underlying analysis supporting its comments was simply its own comments. Likewise, in DEC and DEP Data Request 1-7, the Companies asked NC WARN:

> On page 9 of your initial comments, you state that, "In his report, Mr. Powers establishes that DEC and DEP can achieve one-hundred (100) percent fossil-free energy by 2030, getting halfway there by 2025." Please identify and produce all documents and analyses including inputs, assumptions, calculations, results, models, spreadsheets with working formulas, or other data or information upon which you and/or Mr. Powers rely upon in support of this statement.

In response, NC WARN simply stated, "This statement is explained in detail, with applicable citations, in Mr. Powers' N.C. Clean Path 2025 Report and the Update: N.C. Clean Path 2025." This lack of quantitative analysis and circular reasoning is found throughout NC WARN's data request responses. See DEC/DEP Exhibit 1. Duke explains that although NC WARN's simplistic and hyperbolic conclusions may advance its own interests, its arguments should not, and cannot, be credibly relied upon by the Commission or anyone who truly values a reliable and affordable supply of energy for the State of North Carolina.[85]

X. REQUESTS FOR EXPERT WITNESS HEARING

[85] The Commission notes that NC WARN's assertion that North Carolina can retire all coal and gas-fired power plants by 2030 is directly contradicted by even its own admission in response to DEC and DEP Data Request 1-10, that gas plants would be needed to serve in a backup role in 2030 even under its proposed energy plan.

NC WARN, as well as many of the consumer statements of interest filed with the Commission, have asked for an expert witness hearing on the 2018 IRPs. The Commission concludes that an expert witness hearing with respect to the 2018 biennial plans is not necessary because the Commission has a voluminous record before it, including studies and reports from various technical witnesses, which is adequate to review and rule on the adequacy of the 2018 IRPs. All intervenors have had the opportunity to make legal, factual, and technical arguments to the Commission in their filed comments, and the Commission has received the testimony of public witnesses in a public hearing, as well as numerous statements of consumer position filed with the Commission. Finally, the comments of some consumers appear to reflect an incorrect assumption that Commission acceptance of an IRP constitutes Duke's request for, or Commission approval of, specific generation resources contained therein. As the Commission noted in its June 26, 2015 Order Approving Integrated Resource Plans and REPS Compliance Plans, in Docket No. E-100, Sub 141, at pages 11-12:

> General Statute 62-110.1(c), in pertinent part, requires the Commission to "develop, publicize, and keep current an analysis of the long-range needs for expansion of facilities for the generation of electricity in North Carolina, including its estimate of the probable future growth of the use of electricity." In State ex rel. Utils. Comm'n v. North Carolina Electric Membership Corporation, 105 N.C. App 136, 141, 412 S.E.2d 166, 170 (1992), the Court of Appeals discussed the nature and scope of the Commission's IRP proceedings. The Court affirmed the Commission's conclusion that
>
> > [t]he Duke and CP&L plans were "reasonable for the purposes of [the] proceeding" before it. That is to say, the plans submitted by Duke and CP&L were reasonable for the purpose of "analy[zing]…the long-range needs for expansion of facilities for the generation of electricity in North Carolina…" See N.C. Gen. Stat. § 62-110.1(c).
>
> The Court further explained that the IRP proceeding is akin to a legislative hearing in which the Commission gathers facts and opinions that will assist the Commission and the utilities to make informed decisions on specific projects at a later time. On the other hand, it is not an appropriate proceeding for the Commission to use in issuing "directives which fundamentally alter a given utility's operations." With regard to the Commission's authority to issue specific directives, the Court cited the availability of the Commission's certificate of public convenience and necessity (CPCN) proceedings and complaint proceedings. Id., at 144, 412 S.E.2d at 173.

As such, by statute the Commission's decisions on the need, cost, and timing of a specific generation resource are made only after a CPCN application is filed and considered by the Commission in a public and transparent CPCN proceeding conducted pursuant to N.C.G.S. §§ 62-110.1 and 62-82.

The Commission finds and concludes that for the purposes of N.C.G.S. § 62-110(c) and Rule R8-60 the record in this docket is sufficient, and that NC WARN and the other interested persons requesting an expert witness hearing have not shown good cause for such a hearing. Accordingly, the requests for an expert witness hearing on the 2018 IRPs are denied. As will be noted later in this Order, however, and based on the record compiled in connection with the 2018 filings, the Commission will require certain supplemental filings and proceedings and will direct that certain specific matters be addressed in the utilities' 2020 biennial IRPs.

XI. REPS COMPLIANCE PLANS

North Carolina General Statute § 62-133.8 requires all electric power suppliers in North Carolina to meet specified percentages of their retail sales using renewable energy and energy efficiency. One megawatt-hour (MWh) of renewable energy, or its thermal equivalent, equates to one renewable energy certificate (REC), which is used to demonstrate compliance. An electric power supplier may comply with the REPS by generating renewable energy at its own facilities, by purchasing bundled renewable energy from a renewable energy facility, or by buying RECs. Alternatively, a supplier may comply by reducing energy consumption through implementation of EE measures or electricity demand reduction.[86] The electric public utilities (DEP, DEC, and DENC) may use EE measures to meet up to 25% of their overall requirements in N.C. Gen. Stat. § 62-133.8(b). One MWh of savings from DSM/EE or demand reduction is equivalent to one energy efficiency certificate (EEC), which is a type of REC. All electric power suppliers may obtain RECs from out-of-state sources to satisfy up to 25% of the requirements of N.C. Gen. Stat. §§ 62-133.8(b) and (c), with the exception of DENC, which can use out-of-state RECs to meet its entire requirement. The total amount of renewable energy or EECs that must be provided by an electric power supplier for 2018, 2019, and 2020 is equal to 10% of its North Carolina retail sales for the preceding year.

Commission Rule R8-67(b) provides the requirements for REPS Compliance Plans. Electric public utilities must file their plans on or before September 1 of each year, as part of their IRPs, and explain how they will meet the requirements of N.C. Gen. Stat. §§ 62-133.8(b), (c), (d), (e), and (f). The plans must cover the current year and the next two calendar years, or in this case 2018, 2019, and 2020 (the planning period). An electric power supplier may have its REPS requirements met by a utility compliance aggregator as defined in R8-67(a)(5).

[86] "Electricity demand reduction," as used herein, is defined in N.C. Gen. Stat. §62-133.8(a)(3a).

A. Public Staff Initial Comments – REPS Compliance Plans

The Public Staff commented on DEP, DEC, and DENC's plans to comply with N.C. Gen. Stat. §§ 62-133.8(b), (c), and (d), the general[87] and solar energy requirements. The Public Staff also provided consolidated comments on the IOUs' plans to comply with N.C. Gen. Stat. §§ 62-133.8(e) and (f), the swine and poultry waste set-asides.

According to the Public Staff, DEP has contracted for and banked sufficient resources to meet the REPS requirements of N.C. Gen. Stat. §§ 62-133.8(b), (c), and (d). As of December 31, 2017, DEP's compliance services contracts with the Towns of Sharpsburg, Stantonsburg, Black Creek, Lucama, and Winterville terminated, and DEP no longer provides REPS compliance services for any other electric suppliers.

DEP intends to use EE programs to meet 25% of its REPS requirements. A substantial portion of the general requirement will be met by executed purchased power agreements and REC-only purchases from biomass power providers, some of which are combined heat and power (CHP) facilities. Hydroelectric facilities of 10 MW or less, and power generated from landfill gas, will also provide RECs for DEP's retail customers. In addition, DEP plans to continue using solar energy to help it meet the general requirement. It may also use wind energy, either through REC-only purchases or through energy delivered to its customers in North Carolina, to satisfy this requirement.

To meet the solar set-aside, DEP will obtain RECs from its own solar facilities, its residential solar V program, and REC-purchase contracts with other solar PV and solar thermal facilities. DEP is the owner of 140.7 MW of solar facilities that are now operational and available for use to meet a portion of its REPS compliance obligations.[88]

DEP plans to evaluate additional projects through the competitive procurement process established in HB 589. HB 589 allows for competitive procurement of 2,660 MW of additional renewable energy capacity in the Carolinas, with proposals issued over a 45-month period. DEP may develop up to 30% of its required competitive procurement capacity using self-owned facilities.

DEP anticipates that its incremental REPS compliance costs will remain below the cost caps in N.C. Gen. Stat. §§ 62-133.8(h)(3) and (4), but it expects them to rise by approximately 20% over the planning period, reaching approximately 85% of the cost cap in 2020.

DEP files evaluation, measurement, and verification (EM&V) plans for each EE program in the respective program approval docket.

---

[87] The overall REPS requirement of N.C. Gen. Stat. §62-133.8(b), less the requirements of the three set-asides established by N.C. Gen. Stat. §§ 62-133.8(d)-(f), is frequently referred to as the "general requirement."

[88] See DD Fayetteville Solar, Inc., Docket No. E-2, Subs 1054, 1055, and 1056, Order Transferring Certificate of Public Convenience and Necessity (Dec. 16, 2014); Duke Energy Progress, Inc., Docket No. E-2, Sub 1063, Order Issuing Certificate of Public Convenience and Necessity (Apr. 14, 2015).

According to the Public Staff, DEC has contracted for or procured sufficient resources to meet the REPS requirements of N.C. Gen. Stat. §§ 62-133.8(b), (c), and (d) for the planning period, both for itself and for the electric power suppliers for which it is providing REPS compliance services. These suppliers are Rutherford EMC, Blue Ridge EMC, the Town of Dallas, the Town of Forest City, the City of Concord, the Town of Highlands, and the City of Kings Mountain (collectively, DEC's Wholesale Customers). DEC's contractual obligation to provide REPS compliance for the City of Concord and the City of Kings Mountain ended effective December 31, 2018; therefore, these comments reflect REPS compliance services for the City of Concord and the City of Kings Mountain only through 2018.

DEC intends to use EE programs to meet 25% of its REPS requirements. Hydroelectric facilities with a capacity of 10 MW or less and energy allocations from the Southeastern Power Administration (SEPA) will be used to meet up to 30% of the general requirement of DEC's Wholesale Customers.

Hydroelectric facilities of 10 MW or less, together with incremental capacity from the 2012 modifications to DEC's Bridgewater hydroelectric plant, will provide RECs for DEC's retail as well as its wholesale customers. DEC has entered into a contract to sell five of its hydroelectric facilities. All of these facilities intend to register as new renewable energy facilities, so as to retain the option of selling the RECs produced to DEC for REPS compliance purposes.[89]

A substantial portion of DEC's general requirement will be met by purchased power agreements and REC-only purchases from biomass power providers, some of which are CHP facilities. In addition, DEC will continue to use solar energy and power generated from landfill gas to comply with the general requirement. It may also use wind energy, through either REC-only purchases or energy delivered onto its system.

To meet the solar set-aside, DEC will obtain RECs from its self-owned solar PV facilities and from other solar PV and solar thermal facilities. DEC's solar resources include 75 MW of capacity at the Monroe and Mocksville solar facilities, approximately 20 MW from the small distributed solar facilities approved in Docket No. E-7, Sub 856, and 6 MW of anticipated capacity from the Woodleaf facility, which became fully operational in January 2019.

DEC anticipates that its REPS compliance costs will increase, but will be below the cost caps in N.C. Gen. Stat. §§ 62-133.8(h)(3) and (4), for the planning period.

According to the Public Staff, DENC has contracted for and banked sufficient resources to meet the REPS requirements of N.C. Gen. Stat. §§ 62-133.8(b) and (c) through 2019 for itself and for the Town of Windsor (Windsor), for which it provides REPS compliance services. DENC has contracted for and banked sufficient resources to meet

[89] See Joint Notice of Transfer, Request for Approval of Certificates of Public Convenience and Necessity, Request for Accounting Order and Request for Declaratory Ruling, filed on July 5, 2018, by DEC, Northbrook Carolina Hydro II, LLC, and Northbrook Tuxedo, LLC, in Docket Nos. E-7, Sub 1181, SP-12478, Sub 0, and SP-12479, Sub 0.

the REPS requirement of N.C. Gen. Stat. § 62-133.8(d) as well. DENC plans to use EE and purchased RECs to meet the general REPS requirements of N.C. Gen. Stat. §§ 62-133.8(b) and (c) for itself and indicated that it may also use Company generated RECs. For Windsor's general REPS requirement, DENC will use out-of-state wind RECs, in-state biomass and solar RECs, and Windsor's SEPA allocation. For the solar set-aside, DENC plans to purchase in-state and out-of-state solar RECs for itself and Windsor. DENC will rely on out-of-state RECs to meet its compliance requirements, as allowed by N.C. Gen. Stat § 62-133.8(b)(2)(e), but will obtain in-state RECs to meet Windsor's 75% in-state requirement. Its total costs are the same as its incremental costs because, unlike DEC and DEP, it currently plans to purchase only unbundled RECs, rather than RECs that are bundled with renewable electric energy, to meet its REPS requirements.

DENC anticipates that during the planning period, it will incur annual research costs of $50,000 for the continued development of its Microgrid Project. The Microgrid Project consists of wind, solar and fuel cell energy generation and battery storage at DENC's Kitty Hawk District Office.

DENC expects that the REPS compliance costs for itself and Windsor will be well below the cost caps in N.C. Gen. Stat. §§ 62-133.8(h)(3) and (4) for the planning period.

DENC files EM&V plans for each EE program in the respective program approval docket.

B. REPS Compliance Summary Tables

The following tables are compiled from data submitted in DEP, DEC, and DENC's Plans. Table 1 shows the projected annual MWh sales on which the utilities' REPS obligations are based. It is important to note that the figures shown for each year are the utilities' MWh sales for the preceding year; for instance, the sales for 2018 are MWh sales for calendar year 2017. The totals are presented in this manner because each utility's REPS obligation is determined as a percentage of its MWh sales for the preceding year. The sales amounts include retail sales of wholesale customers for which the utility is providing REPS compliance reporting and services. Table 2 presents a comparison of the projected annual incremental REPS compliance costs with the utilities' annual cost caps.

TABLE 1: MWh Sales for Preceding Year

	Compliance Year		
Electric Power Supplier	**2018**	**2019**	**2020**
DEP	36,829,899	37,521,080	37,685,819
DEC	59,518,351	60,104,379	60,285,246
DENC	4,203,708	4,217,958	4,239,131
TOTAL	100,551,958	101,843,417	102,210,196

TABLE 2: Comparison of Incremental Costs to the Cost Cap

		DEP	DEC	DENC
2018	Incremental Costs	$41,294,711	$27,120,881	$1,052,998
	Cost Cap	$63,874,278	$94,975,829	$5,632,261
	Percent of Cap	65%	29%	19%
2019	Incremental Costs	$47,421,825	$36,738,176	$1,224,857
	Cost Cap	$64,583,052	$93,929,320	$5,288,797
	Percent of Cap	73%	39%	23%
2020	Incremental Costs	$55,445,392	$48,524,154	$1,419,320
	Cost Cap	$65,271,008	$94,623,837	$5,304,517
	Percent of Cap	85%	51%	27%

C. Swine Waste and Poultry Waste Set-Asides

North Carolina General Statute § 62-133.8(a) provides that in 2012 at least 0.02% of the electric power sold to customers should be produced from swine waste, and this percentage increases to 0.14% by 2015 and 0.20% by 2018. Subsection (f) provides that in 2012 at least 170,000 MWh of power sold to retail customers will be generated from poultry waste, and that this requirement will increase to 700,000 MWh in 2013 and 900,000 MWh in 2014.

In every year from 2012 through 2017, the electric suppliers moved that the swine waste requirement be delayed until the following year, and the Commission granted their requests. In 2018, they moved that the requirement be set at 0.02% for the electric public utilities and zero for the EMCs and municipalities, and this request likewise was granted.

With respect to poultry waste, the electric suppliers moved in 2012 and again in 2013 to delay the 170,000-MWh annual requirement for a year, and the Commission granted their motions. The Commission's 2013 order set the requirement at 170,000 MWh for 2014 and 700,000 MWh for 2015. The electric suppliers were able to meet the 170,000-MWh requirement in 2014, but they could not comply with the increase to 700,000 MWh for 2015. In that year, and again in 2016 and 2017, they moved that the poultry waste requirement be kept at 170,000 MWh, and their motions were granted. In their 2018 motion, the electric suppliers proposed that the poultry waste requirement be set at 300,000 MWh, and the Commission approved their proposal.

In its annual orders granting delays or reductions in the swine and poultry waste requirements, the Commission has also required the electric power suppliers to file reports describing the state of their compliance with the set-asides and their negotiations with the developers of swine and poultry waste-to-energy projects, initially on a tri-annual basis and now semiannually. These reports are filed confidentially in Docket No. E-100, Sub 113A. The Commission has further required the electric power suppliers to provide internet-available information to assist the developers of swine and poultry waste-to-energy projects in getting contract approval and interconnecting facilities. Additionally, the Commission has directed the Public Staff to hold periodic stakeholder meetings to facilitate compliance with the swine and poultry waste set-asides. In response, the Public Staff organized a stakeholder meeting held on June 23, 2014, and eight subsequent occasions. The attendees have included farmers, the North Carolina Pork Council, the North Carolina Poultry Federation, waste-to-energy developers, bankers, state environmental regulators, and the electric power suppliers. The meetings allow the stakeholders to network and voice their concerns to the other parties. Due to advancements in compliance, all parties agreed that semiannual meetings were no longer necessary and requested that they only be held yearly. The Commission granted this request in its 2017 order.

Up to now, the State's electric power suppliers have been able to comply only to a limited extent with the poultry waste set-aside requirement, and to an even lesser extent with the swine waste requirement. Nevertheless, the REPS statute has served as a stimulus for several important advances in waste-to-energy technology.

First, several swine farms have installed anaerobic digesters at their swine waste lagoons and have produced biogas that has been used as fuel to operate small electric generators at these farms. Electric power suppliers have purchased the electricity produced by these generators – or, alternatively, have purchased the RECs when the electricity was used on the farm where it was generated – and this represented the initial step toward compliance with the swine waste set-aside.

Second, poultry waste has been transported by truck to existing and new generation facilities, where it has been co-fired with wood or other fuels.

Third, there has been progress in the development of large centralized anaerobic digestion plants in areas where numerous swine farms are located. These plants receive swine waste from numerous sources, produce biogas from the waste by the digestion process, and eliminate impurities from the biogas so that it meets quality standards and is eligible to be injected into the natural gas pipeline system. A specified amount of this biogas, which is referred to as "directed biogas" or "renewable natural gas," is injected into a pipeline, and an equivalent amount of natural gas is delivered by the pipeline operator to a gas-fired electric generating plant. These directed biogas facilities were first built in Midwestern states with extensive swine farming activity, but on December 2, 2016, Carbon Cycle Energy, LLC, began construction of a directed biogas facility in Warsaw, North Carolina.[90]

Four days after the start of construction at the Carbon Cycle facility, Piedmont Natural Gas Company, Inc., petitioned the Commission for approval of a new

[90] See Order Accepting Registration of New Renewable Energy Facilities, Docket No. E-7, Subs 1086 and 1087 (Mar. 11, 2016). In this docket, DEC stated that it had entered into contracts to purchase directed biogas from High Plains Bioenergy, LLC, in Oklahoma, and Roeslein Alternative Energy of Missouri, LLC. On March 18, 2016, DEC supplemented its registration statement to indicate that it also entered into contracts to purchase directed biogas from Carbon Cycle Energy for nomination to its Buck Combined Cycl Station.

Appendix F to its service regulations, authorizing the company to accept "Alternative Gas" (which includes, subject to various restrictions, biogas, biomethane, and landfill gas) onto its system and deliver it to purchasers. In an order issued on June 19, 2018, the Commission approved Piedmont's proposed Appendix F and established a three-year pilot program to implement it. The Commission has authorized six firms – C2E Renewables NC, Optima KV, LLC, Optima TH, LLC, GESS International North Carolina, Inc., Foothills Renewables LLC and Catawba Biogas, LLC – to participate in the pilot program.

In March of 2018, Optima KV completed its interconnection to the Piedmont Natural Gas system and began delivering biogas to DEP's Smith Energy Complex in Hamlet, North Carolina. The Optima KV facility thus became the first operational directed biogas facility in North Carolina.

The Public Staff stated that the electric power suppliers will likely continue to have difficulty meeting the swine and poultry waste set-asides. However, they have made substantial progress toward complying with these difficult obligations, and as advances in waste processing technology are made, they may be able to achieve full compliance with the statutory requirements in the not too distant future. The supplier best positioned to reach full compliance is DENC, since it can obtain all of its RECs from out-of-state. Indeed, DENC's compliance plan indicates that already "both DENC and the Town of Windsor have sufficient RECs in [NC-RETS] to meet the 2018-2020 requirements" for swine waste. DENC does not express quite as high a degree of certainty about its compliance with the poultry waste set-aside, given the possibility that between now and 2020 some of its suppliers may default on their contracts; however, it does state that its efforts have "yielded multiple poultry waste REC contracts and sufficient delivered volume to comply with both the Company's and Town of Windsor's out-of-state requirements for years 2018, 2019 and 2020."

D. Public Staff Conclusions – REPS Compliance Plans

In summary, the Public Staff concluded that:

1. Overall, the electric public utilities believe they are in a better position to comply with all of the requirements of the REPS, including the set-asides, than in previous years.
2. DEC, DEP, and DENC should be able to meet their REPS obligations during the planning period, with the exception of the swine and poultry waste set-asides, without nearing or exceeding their cost caps; however, DEP may approach the caps in 2020.
3. All three utilities should be able to meet the swine and poultry waste requirements in 2018, after the issuance of the Commission's order of October 8, 2018, reducing the requirements.
4. DEC and DEP indicated in their REPS compliance plans that they could comply with the poultry waste set-aside in 2018, and DEC stated that it could meet the swine waste requirement as well; but both companies indicated that

compliance would deplete their supply of swine and poultry RECs so severely that they could not comply in 2019 and 2020. Both subsequently joined in the electric suppliers' motion to reduce the swine and poultry requirements for 2018, and their motion was granted. However, the fact that DEC and DEP were even able to consider the possibility of compliance in 2018 represents progress in comparison with previous years.

5. DENC expects to meet the swine waste requirements for 2018 through 2020, both for itself and the Town of Windsor, and it is confident, although not certain, that it will also meet the poultry waste requirement for all three years of the planning period.
6. DEC and DEP are actively seeking energy and RECs to meet the set-aside requirements for the years in which they expect to fall short of compliance. DENC is also seeking to acquire RECs and thus strengthen its position for compliance with the swine and poultry requirements in future years.
7. The Commission should approve the 2018 REPS Compliance Plans filed by DEC, DEP, and DENC.

Commission Conclusions – REPS Compliance Plans

The Commission concludes that the REPS Compliance Plans filed by the utilities contain the information required by Commission Rule R8-67(b). As such, and based on the recommendation of the Public Staff, the Commission accepts the REPS Compliance Plans filed in this docket.

CONCLUSION

Integrated Resource Planning is intended to identify those electric resource options that can be obtained at least cost to the utility and its ratepayers consistent with the provision of adequate, reliable, and safe electric service. Potential significant regulatory changes, particularly at the federal level, and evolving marketplace conditions create additional challenges for already detailed, technical, and data-driven IRP processes. The Commission finds the IRP processes employed by the utilities to be both compliant with State law and reasonable for planning purposes in the present docket. However, the Commission recognizes that the IRP process continues to evolve.

The Commission carefully considered the full record in this proceeding with respect to the 2018 IRPs and concludes that the record is sufficient to enable the Commission to assess whether the 2018 IRPs comply with the requirements of N.C.G.S. § 62-110.1 and Commission Rule R8-60. The Commission finds and concludes that DENC's 2018 IRP is adequate for planning purposes, and should be accepted, subject to DENC's 2019 IRP Update. The Commission finds and concludes that DEC's and DEP's 2018 IRPs are adequate to be used for planning purposes during the remainder of 2019 and in 2020, subject to DEC's and DEP's 2019 IRP Updates. However, the Commission declines to accept all of the underlying assumptions upon which DEC's and DEP's IRPs are based, the sufficiency or adequacy of the models employed, or the resource needs identified and scheduled in them beyond 2020.

The parties raised many issues that are worthy of more in-depth examination, along with additional issues that the Commission itself finds pertinent. Some of the issues will require the parties to conduct a considerable amount of research in order to fully address them. In addition, some of the issues may be more effectively addressed by means other than typical IRP hearings. At this point, the Commission's judgment is that the most productive course is to focus the utilities, Public Staff, and other interested parties on the parameters and contents of the IRPs due to be filed in 2020. The Commission will do so by using several different procedures. The first will be the technical conference on ISOP that has been scheduled by the Commission for August 28, 2019. The additional steps are described as part of the following summary of four of the issues that were not fully resolved by the 2018 IRPs.

Load Forecasts and Reserve Margins

On June 27, 2017, in Docket No. E-100, Sub 147, the Commission issued an Order Accepting Integrated Resource Plans and Accepting REPS Compliance Plans (2016 IRP Order). In the 2016 IRP Order, the Commission concluded that the electric utilities' peak load and energy sales forecasts were reasonable for planning purposes. However, the Commission expressed concern about DEC's forecast.

> The Commission further concludes that the DEC load forecast may be high. In reaching this conclusion, the Commission recognizes the Wilson Report.[91] To quote from Mr. Wilson's report, "Overall, the DEC winter peak forecast seems somewhat high compared to the trend in the weather-adjusted peaks . . ." Mr. Wilson notes in his report on page 9 that for DEC, there has been a steady differential between the weather-adjusted summer and winter peaks during recent years, averaging 750 MW over 2009 to 2016, and averaging 683 MW over 2014 to 2016. The report states that DEC's current forecast breaks from this pattern, again suggesting that the winter peak forecast is high (see Figure JFW-6: DEC Summer and Winter Peaks, Historical and Forecast).
>
> Continuing to address the DEC winter forecast, Mr. Wilson states in his report on page 7 that changes in end-use technologies may be affecting these brief, extreme winter peak loads under extreme cold conditions. The report points out that DEC stated it has not performed any formal analysis to determine which end uses are contributing to these load spikes on extremely cold winter mornings (response to Data Request SACE 2-11).

2016 IRP Order, at 15.

[91] On behalf of Southern Alliance for Clean Energy, Sierra Club, and Natural Resources Defense Council (hereinafter, SACE), James F. Wilson of Wilson Energy Economics prepared a report entitled "Review and Evaluation of the Peak Load Forecasts for the Duke Energy Carolinas and Duke Energy Progress 2016 Integrated Resource Plans" (Wilson Report).

As a result, the Commission directed DEC to address in its 2017 IRP Update any refinements in its load forecasting methodology. Id.

With respect to reserve margins, in the 2016 IRP Order the Commission concluded that the electric utilities' reserve margins in their IRPs were reasonable for planning purposes. However, the Commission noted concerns identified by the Public Staff and the Wilson Report regarding Duke's proposed 17% winter reserve margin target. Consequently, the Commission directed that

> [D]EC and DEP should work with the Public Staff to address the Public Staff's and Mr. Wilson's reserve margin concerns and to implement changes as necessary to help ensure that the reserve margin target(s) are fully supported in future IRPs. Further, the Commission requests that Duke and the Public Staff file a joint report summarizing their review and conclusions within 150 days of the filing of Duke's 2017 IRP Updates. In addition to addressing the reserve margin concerns identified by the Public Staff and Mr. Wilson, the report should clearly define the support and basis for the targeted reserve margins incorporated into the IRPs. If the parties cannot reach consensus, then the report should outline their differences and recommend a procedure for the Commission to pursue in reaching a conclusion about the reserve margins recommended by DEC and DEP in their IRPs.

Id. at 22-23.

On April 2, 2018, Duke and the Public Staff submitted their joint report on their discussions and conclusions (Joint Report). The Commission accepted the Joint Report in its April 16, 2018 Order Accepting Filing of 2017 Update Reports and Accepting 2017 REPS Compliance Plans, in Docket No. E-100, Sub 147 (2017 IRP Order). The Commission noted that Duke and the Public Staff had engaged in discussions, Duke responded to multiple requests for information and evaluated multiple inputs and scenarios that were suggested by the Public Staff, and Duke and its consultant, Astrapé Consulting, met with the Public Staff to present results of the additional analyses and to work toward a consensus. The Commission stated that the Public Staff and Duke did not reach consensus on all of the issues, one such unresolved issue being how to model economic load forecast uncertainties. In the Joint Report, the Public Staff recommended that DEC and DEP utilize a 16% reserve margin for planning purposes in their 2018 IRPs, and until such time that a new resource adequacy study is conducted. On the other hand, Duke stayed with its position that DEC and DEP utilize a minimum 17% winter reserve margin for planning purposes until such time that a new resource adequacy study is conducted. Both recommended that DEC and DEP update their reserve margins no later than the 2020 biennial IRP filings to reflect updated peak load and forecast data, weather, and other relevant inputs. In the 2017 IRP Order, the Commission directed that Duke further address the reserve margin issue in its 2018 IRPs, including additional review and assessment of the Public Staff's proposed approach versus that employed by Astrapé in its 2016 Resource Adequacy Study. 2017 IRP Order, at 8-9.

In its 2018 IRPs, DEC stated that the use of a 16% reserve margin versus 17% reserve margin would not impact DEC's 2018 IRP. However, DEP acknowledged that DEP's resource plan would be impacted if the lower reserve margin were used for planning. DEP noted that a 16% reserve margin would result in lesser short-term purchase quantities, as well as deferral of some of the undesignated future resources.

Both DEC and DEP discussed the impact of 16% reserves on loss of load expectation (LOLE). DEC stated that allowing the reserve margin to decline to 16% for a given year would increase the LOLE to approximately 0.116 days/year, which equates to one expected firm load shed event approximately every 8.6 years. According to DEP, a comparable increase in LOLE for it is approximately 0.13 days/year, or one expected firm load shed event approximately every 7.7 years.

The Public Staff stated in its comments that it continues to recommend a 16% reserve margin, but will work with Duke "to reach consensus within the constructs of the next resource adequacy study." Comments of the Public Staff, at 46-47.

SACE, et al. included with its comments an updated report by James Wilson. Mr. Wilson again raises concerns about Duke's load forecasts and reserve margins being too high.

To address the above issues surrounding Duke's reserve margin and load forecasts, the Commission will hold an oral argument on Wednesday, January 8, 2020, at 10:00 a.m. The parties who submitted comments on Duke's load forecasts and reserve margins – the Public Staff, SACE et al., and NCSEA – will be given 30 minutes each to present their positions, and Duke will be given 30 minutes to respond. In order to facilitate this hearing, on or before November 4, 2019, Duke and the Public Staff shall file written responses to the questions and information requested in item numbers 1 and 2 of Appendix A, which is attached to this Order. The Commission expects that the hearing will focus on the topics in these two items in Appendix A.

Carbon Dioxide Reductions and Coal Plant Retirements

On October 29, 2018, North Carolina Governor Roy Cooper issued Executive Order No. 80 that, among other things, sets a goal of by 2025 reducing statewide greenhouse gas emissions to 40% below 2005 levels. This goal being well within the IRPs' 15-year planning horizons, the Commission concludes that DEC and DEP should be required to model their IRPs to show the efforts that will be required by each of them to contribute to the attainment of the goal. In particular, the two utilities should model plans that result, on a combined basis, in at least a 40% reduction in CO_2 emissions in 2030 compared to their combined 2005 CO_2 emission levels.

To address the issues surrounding carbon dioxide reductions, on or before November 4, 2019, Duke shall file written responses to the information requested in item number 3 of Appendix A. Based on these responses, the Commission may issue further orders related to the preparation of the utilities' 2020 IRPs.

In their 2018 IRPs DEC and DEP contemplate that their remaining coal-fired generating plants will continue in use until they have been fully depreciated. However, today's capacity factors for these plants are substantially lower than the historical capacity factors of the plants. It does not appear from the information in the IRPs that DEC and DEP have fully considered early retirement of any of these coal plants by replacing their contributions with other alternative generation resources or with energy efficiency (EE) and demand-side management (DSM) resources. As a result, the Commission determines that it should require Duke to provide an analysis showing whether continuing to operate each of its existing coal-fired units is the least cost alternative compared to other supply-side and demand-side resource options, or fulfills some other purpose that cannot be achieved in a different manner.

To address the issue of economic retirement of aging coal plants, in the 2020 IRPs DEC and DEP shall include an analysis that removes any assumption that their coal-fired generating units will remain in the resource portfolio until they are fully depreciated. Instead, the utilities shall model the continued operation of these plants under least cost principles, including by way of competition with alternative new resources. In this exercise the full costs of disposal of coal combustion wastes shall be included in making any comparison with alternative resources. If such analysis concludes that continued operation of the utilities' existing coal-fired units until they are fully depreciated is the least cost resource alternative, then the utilities 2020 IRPs shall separately model an alternative scenario premised on advanced retirement of one or more of such units and shall include in that alternative scenario an analysis of the difference in cost from the base case and preferred case scenarios.

Storage Resources

In the 2016 IRP Order, the Commission noted the potential that battery storage could play in the electric utilities' resource planning. The Commission stated:

> [T]he Commission is of the opinion that evaluations of this technology, as documented in the IRPs, have not been fully developed to a level sufficient to provide guidance as to the role this technology should play going forward. As such, the utilities should provide in future IRPs or IRP updates a more complete and thorough assessment of battery storage technologies including the "full value" as discussed in the NCSEA comments.[92] If the standard technical and economic analyses of generation resources somehow preclude the complete and thorough assessment of battery storage technologies, then a separate discussion of this point should be included in the IRPs.

2016 IRP Order, at 60.

In DEC's and DEP's 2018 IRPs, they provided some discussion of the potential for battery storage, as well as information about its present and planned projects that utilize

[92] NCSEA's Comments, Docket No. E-100, Sub 147 (February 17, 2017), Storage in the Integrated Resource Plans at 5-15.

battery storage. However, DEC and DEP did not model the incorporation of storage facilities as a part of its supply side resources. On the other hand, public witnesses and intervenors have asserted that energy storage is rapidly becoming more cost effective. The Commission concludes that DEC and DEP should be required to provide additional analysis of battery storage in Portfolio 7 of their 2018 IRPs, as described more fully below.

To address the issues surrounding energy storage, on or before November 4, 2019, DEC, DEP, and the Public Staff shall file written responses to the information requested in item number 4 of Appendix A,

Consideration of All Resources

Commission Rule R8-60 (d), (e), (f) and (g) requires the electric utilities to assess the benefits of purchased power solicitations, other alternative supply side resources, potential DSM/EE programs, and a comprehensive set of potential resource options and combinations of resource options. Although Duke's IRPs include some discussion and general information about its consideration of these alternatives, the Commission determines that Duke should be required to explicitly describe all analyses that it has undertaken in developing the IRPs. For example, Duke simply accepts its presently established levels of EE and DSM for planning purposes, and plugs those amounts into its IRP. However, Rule R8-60(f) requires the electric utilities to "assess on an on-going basis programs to promote demand-side management," which under the rule includes EE and conservation programs. The Commission acknowledges that in Portfolio 5 Duke modeled a high EE case, in conjunction with a high renewables scenario. However, the Commission concludes that the IRP information, and the spirit of the rule, will be better served by requiring Duke to separately assess the potential for increased EE and DSM, and model the increase in those resources without combining that modeling with additional renewables, as described more fully below.

To address the requirement that DEC and DEP consider all resource options in developing its IRPs, each utility shall in its 2020 IRPs provide the information and modeling specified in item number 5 of Appendix A.

Finally, after the utilities file their 2019 IRP Updates, the Commission may identify additional issues to be addressed or information to be provided by the utilities and parties.

IT IS, THEREFORE, ORDERED as follows:

1. That the IRP filed herein by Dominion Energy North Carolina is adequate for planning purposes, subject to DENC's 2019 IRP Update, and the Commission hereby accepts DENC's IRP.

2. That the IRPs filed herein by Duke Energy Carolinas, LLC, and Duke Energy Progress, LLC, are adequate for planning purposes during the remainder of 2019 and for 2020, subject to DEC's and DEP's 2019 IRP Updates, and the Commission hereby accepts the IRPs, subject to the questions raised in this Order concerning the underlying

assumptions upon which the IRPs are based, the sufficiency or adequacy of the models employed, or the resource needs identified and scheduled in the IRPs beyond 2020.

3. That the 2018 REPS compliance plans filed by the IOUs are hereby accepted.

4. That pursuant to the Regulatory Conditions imposed in the Merger Order, DEC and DEP shall continue to pursue least-cost Integrated Resource Planning and file separate IRPs until otherwise required or allowed to do so by Commission order, or until a combination of the utilities is approved by the Commission.

5. That NC WARN's motion for an expert witness hearing, and the other requests for expert witness and additional public witness hearings on the 2018 IRPs, are denied.

6. That on Wednesday, January 8, 2020, at 10:00 a.m., the Commission will hold an oral argument to address reserve margin and load forecasting issues in DEC's and DEP's IRPs, as specified in the body of this Order. The oral argument will be held in Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina.

7. That on or before November 4, 2019, DEC, DEP, and the Public Staff shall file responses to the information requested in Appendix A, as specified in the body of this Order.

8. That in their 2020 IRPs DEC and DEP shall include the information, analyses, and modeling regarding economic retirement of coal-fired units and consideration of all resource options, as specified in the body of this Order.

ISSUED BY ORDER OF THE COMMISSION.

This the 27th day of August, 2019.

NORTH CAROLINA UTILITIES COMMISSION

Janice H. Fulmore, Deputy Clerk

1. DEC and DEP's basis for using a 17% winter reserve margin target, including:

(a) Additional details for the contention that a holistic view of the Astrapé study's reasonableness is more appropriate than focusing on specific individual factors (such as those raised by the Public Staff) that could potentially result in a lower reserve margin. [See Page 18 of the Joint Report]

(b) An explanation and/or additional support for the following statement: "The 2016 resource adequacy studies also demonstrated the economic benefits of minimizing total reliability costs to customers and showed economic reserve margin ranges of up to about 19% for DEC and 20% for DEP (95^{th} percentile confidence level) to minimize substantial firm load shed and high cost risk. On a probabilistic weighted average basis, the net cost to customers of going from 15% to 17% is small compared to the potential risk of expensive market purchases and customer outage costs that can be avoided in extreme years." [See Page 38 of slide deck attached to the Joint Report] Produce all analyses supporting this cost-benefit claim.

(c) A discussion detailing the "sensitivity analysis items noted in the Wilson report" referred to on Page 34 of the slide deck attached to the Joint Report.

(d) An explanation of "Firm Load Shed Event" and discussion of significance in Astrapé's Resource Adequacy Studies. [See Page 43 of Duke Energy Carolinas and Duke Energy Progress Solar Ancillary Service Study]

(e) An explanation and additional characterization of the potential impact of increasing the loss of load expectation for DEP to approximately 0.13 days/year (one firm load shed event every 7.7 years) and for DEC to approximately 0.116 days/year (one firm load shed event every 8.6 years). [See Page 42 in DEP's IRP and Page 42 in DEC's IRP]

(f) A discussion of the following statement included in Astrapé's 2016 Resource Adequacy Studies: "Across the industry, the traditional 1 day in 10 year standard is defined as 0.1 LOLE. Additional reliability metrics calculated are Loss of Load Hours (LOLH) in hours per year, and Expected Unserved Energy (EUE) in MWh." [See Page 30 of both DEP's and DEC's 2016 Resource Adequacy Studies]

Include a discussion and assessment of the following statement: "One event in ten years translates to 0.1 loss of load events (LOLE) per year, regardless of the magnitude or duration of the anticipated individual involuntary load shed events. Alternatively, one day in ten years translates to 2.4 loss of load hours (LOLH) per year, regardless of the magnitude or number of such outages. As we show, the difference between these interpretations of the 1-in-10 standard translates to differences in planning reserve margins that may exceed five percentage points, with planning reserve margins of possibly less than 10% based on the 2.4 LOLH standard and more than 15% based on the 0.1 LOLE standard." [Brattle Group and Astrapé Consulting for FERC, Resource Adequacy Requirements: Reliability and Economic Implications, by J. Pfeifenberger and K. Carden (2013), Executive Summary Page iii, www.ferc.gov/legal/staff-reports/2014/02-07-14-consultant-report.pdf]

(g) An analysis and conclusion as to what DEC's and DEP's reserve margins would be using an economically-optimal analysis, as discussed in the Brattle and Astrapé report noted in (f) above. Address the following statement: "Utilities, system operators, and regulators across North America have relied on variations of the 1-in-10 standard for many decades, and typically enforce the standard without evaluating its economic implications." [See reference in (f) above]

(h) A detailed work plan for developing the update to Astrapé's Resource Adequacy Studies proposed for 2020. [See Page 32 of the Joint Report]

(i) A characterization and discussion of the impact and risks of potentially delaying the awarding of contracts associated with DEP's capacity and energy market solicitation until an updated Resource Adequacy Study is completed and effectively vetted. [See Page 81 of DEP IRP]

(j) A listing of the reserve margins included in DEC's and DEP's IRPs from 2003 through 2018;

(k) An explanation of why DEC's and DEP's reserve margins have increased over the last 15 years;

(l) DENC's reserve margin is 11.87% and PJM's reserve margin is 15.9%. DENC's and PJM's resource mix is comparable to Duke's. Explain why DEC's and DEP's reserve margins are higher than DENC's and PJM's.

(m) NERC's 2018 SERC-Southeast reference reserve margin level is 15%. Explain why DEC's and DEP's reserve margins are higher than NERC's.

2. Duke's basis for its load forecasts, including:

   (a) Tables that show DEC's and DEP's summer and winter load forecasts prepared in each of the years 2003 through 2018 and the corresponding actual summer and winter peak loads for each year;

   (b) Analyses performed by Duke to determine which end uses are contributing to load spikes on extremely cold winter mornings.

   (c) As a part of DEP's Blue Horizons Project (BHP), DEP has had success in employing DSM in the Western Region to shave winter peaks. Discuss whether DEP's success in using DSM could be replicated by DEC in its North Carolina service territory. If that success can be replicated, explain why DEC has not done so. If not, explain why not.

3. DEC's and DEP's most current strategic plans to reduce carbon dioxide (CO_2) emissions, including:

   (a) The implementation plan (including CO_2 glide path) that results in the attainment of DEC's and DEP's most current goals for reductions in CO_2 emissions.

   (b) Modelling of the carbon reduction goals in the draft Clean Energy Plan released for public comment on August 16, 2019, by the North Carolina Department of Environmental Quality and Duke's current carbon reduction plan. The modelling should not only show the resource portfolio needed to achieve these goals but should also show any cost differentials (increases or savings) from the base case and the preferred case. In modelling cost differentials, the plans should include anticipated costs attributable to disposal of coal wastes from ongoing and continued operation of coal-fired plants and anticipated cost savings attributable to earlier retirement of such plants.

   (c) A comparison of DEC's and DEP's most current plans for CO2 emission reductions to the Governor's Executive Order No. 80 which states that "The State of North Carolina will strive to accomplish the following by 2025: a. Reduce statewide greenhouse gas emissions to 40% below 2005 levels."

4. With regard to Portfolio 7 in DEC's and DEP's 2018 IRPs (CT Centric with Battery Storage and High Renewables):

(a) A discussion of the differences of executing this portfolio compared to the base case (including the differences in Present Value of Revenue Requirement as well as specific changes to resource plans). [See Page 60 of DEP's IRP and Page 56 of DEC's IRP]

(b) An examination of the cost of battery storage at existing distributed resource sites compared to the expected cost of DEP's capacity and energy market solicitation.

(c) Do the modeling and results in Portfolio 7 provide a statistically representative sample that can be extrapolated into a broader analysis and result by assuming the use of individual battery storage on existing and planned solar facilities, specifically including distribution interconnected QFs and the solar capacity to be brought on line pursuant to HB 589, on Duke's system? If not, explain how the modeling of battery storage added to or included in these solar facilities would differ from that employed in Portfolio 7.

5. 2020 biennial IRPs prepared by DEC and DEP that explicitly include and demonstrate assessments of the benefits of purchased power solicitations, alternative supply side resources, potential DSM/EE programs, and a comprehensive set of potential resource options and combinations of resource options, as required by Commission Rule R8-60(d), (e), (f) and (g), including:

(a) A detailed discussion and work plan for how Duke plans to address the 1,200 MW of expiring purchased power contracts at DEP and 124 MW at DEC. [See Page 80 of DEP 2018 IRP and Page 78 of DEC 2018 IRP]

(b) A discussion of the following statement: "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 meet customers' future energy needs. This analysis intended to produce a base case through a least cost analysis where each company's system was optimized independently. However, the modeling exercise fails to consider whether existing resources can

(c) be cost effectively replaced with new resources. Therefore, Duke has not performed a least-cost analysis to design its recommended plans." [See Page 2 of the Report for the Natural resources Defense Council, the Sierra Club and the Southern Alliance for Clean Energy entitled Review of Duke Energy's North Carolina Coal Fleet in the 2018 Integrated Resource Plans (March 7, 2019)]

(d) A stand-alone analysis of the cost effectiveness of a substantial increase in EE and DSM, rather than the combined modeling of EE and high renewables included in DEC's and DEP's Portfolio 5 in their 2018 IRPs.

(e) In 2009, in Docket No. E-100, Sub 122, the Commission examined the benefits to be derived if the electric utilities fully utilized the wholesale market to meet their resource needs. Although in the end the Commission did not adopt new IRP requirements, it reiterated the importance of Rule R8-60(d), which requires that the utilities "assess on an ongoing basis the potential benefits of soliciting proposals from wholesale power suppliers and power marketers." Provide a discussion of the advantages and disadvantages of periodically issuing "all resources" RFPs in order to evaluate least-cost resources (both existing and new) needed to serve load.

EXHIBIT TFC-5

Attachment 2
Docket E-100, Sub 157

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

Authors:

Tyler Comings

Bryndis Woods

Elizabeth A. Stanton, PhD

Eliandro Tavares

March 7, 2019

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

Applied Economics Clinic
Economic and Policy Analysis of Energy, Environment and Equity

Table of Contents

Applied Economics Clinic
Economic and Policy Analysis of Energy, Environment and Equity

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.

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 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

Applied Economics Clinic
Economic and Policy Analysis of Energy, Environment and Equity

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/.

Applied Economics Clinic
Economic and Policy Analysis of Energy, Environment and Equity

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.

Applied Economics Clinic
Economic and Policy Analysis of Energy, Environment and Equity

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]

[redacted]

[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.

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

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

Applied Economics Clinic
Economic and Policy Analysis of Energy, Environment and Equity

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]

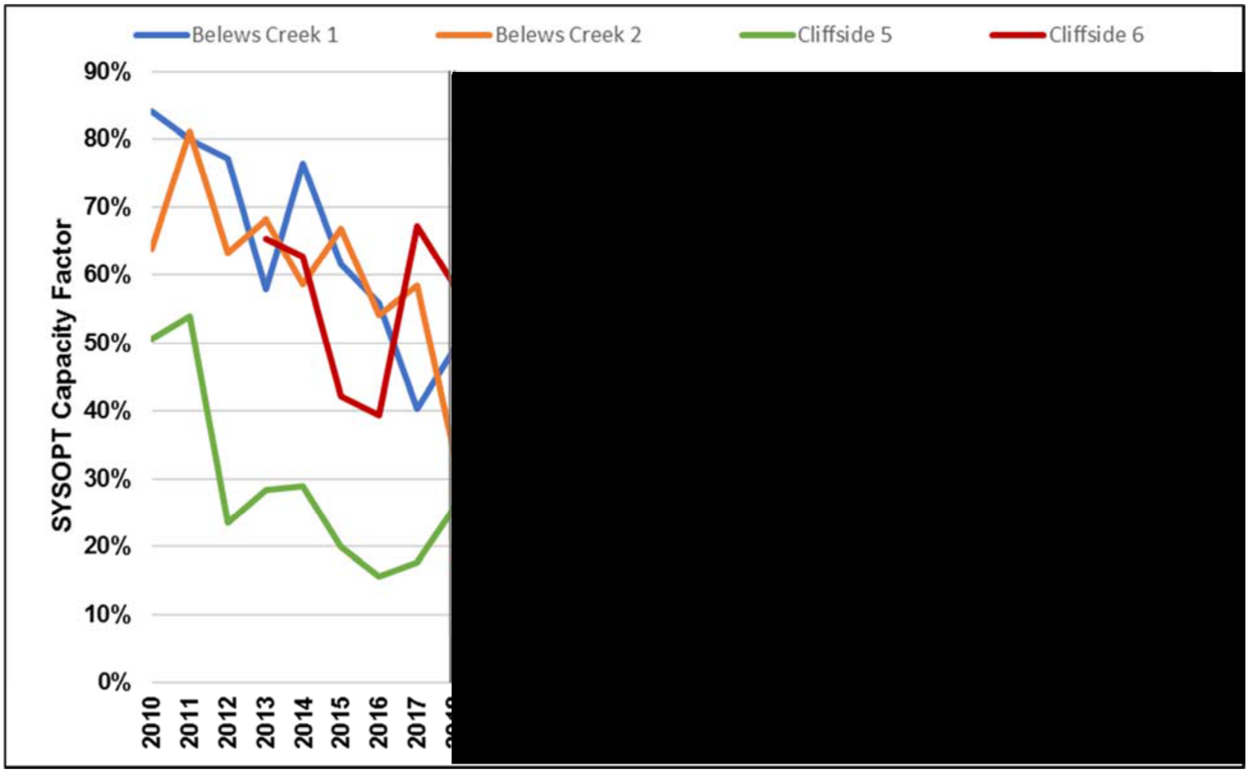
Figures 5 and 6, below, show that in this base scenario, the capacity factors of Belews Creek and Cliffside units (Figure 5) as well as the Marshall units (Figure 6) are expected to [redacted] their operation in the next 10 years. By 2028, seven of the eight units are operating below [redacted] percent 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).

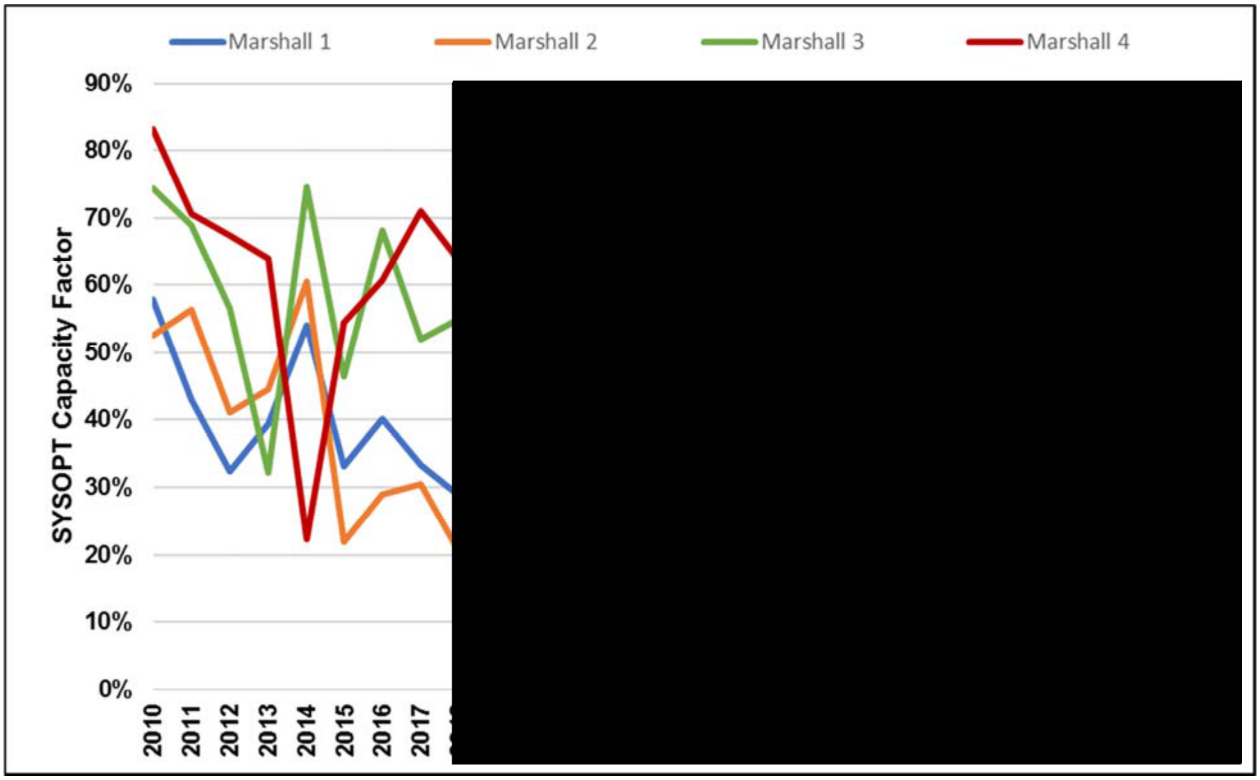
Applied Economics Clinic
Economic and Policy Analysis of Energy, Environment and Equity

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



[redacted]

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.

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

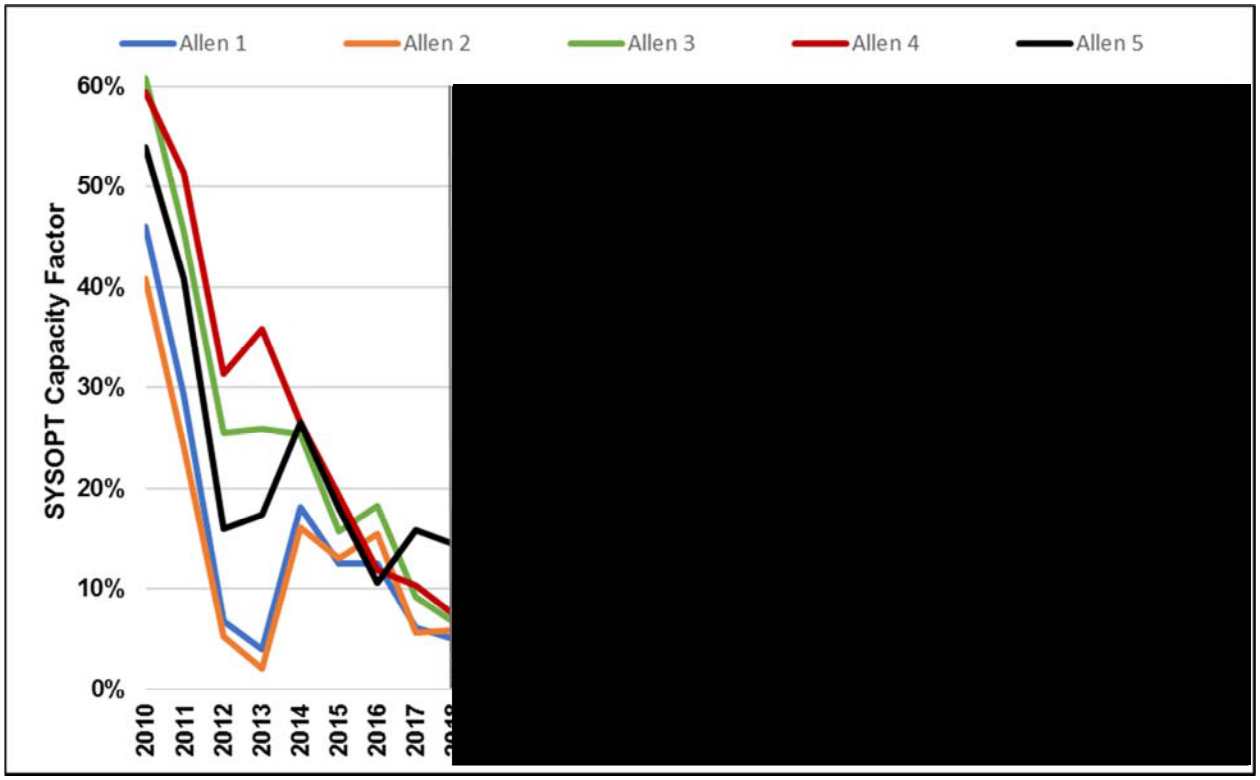
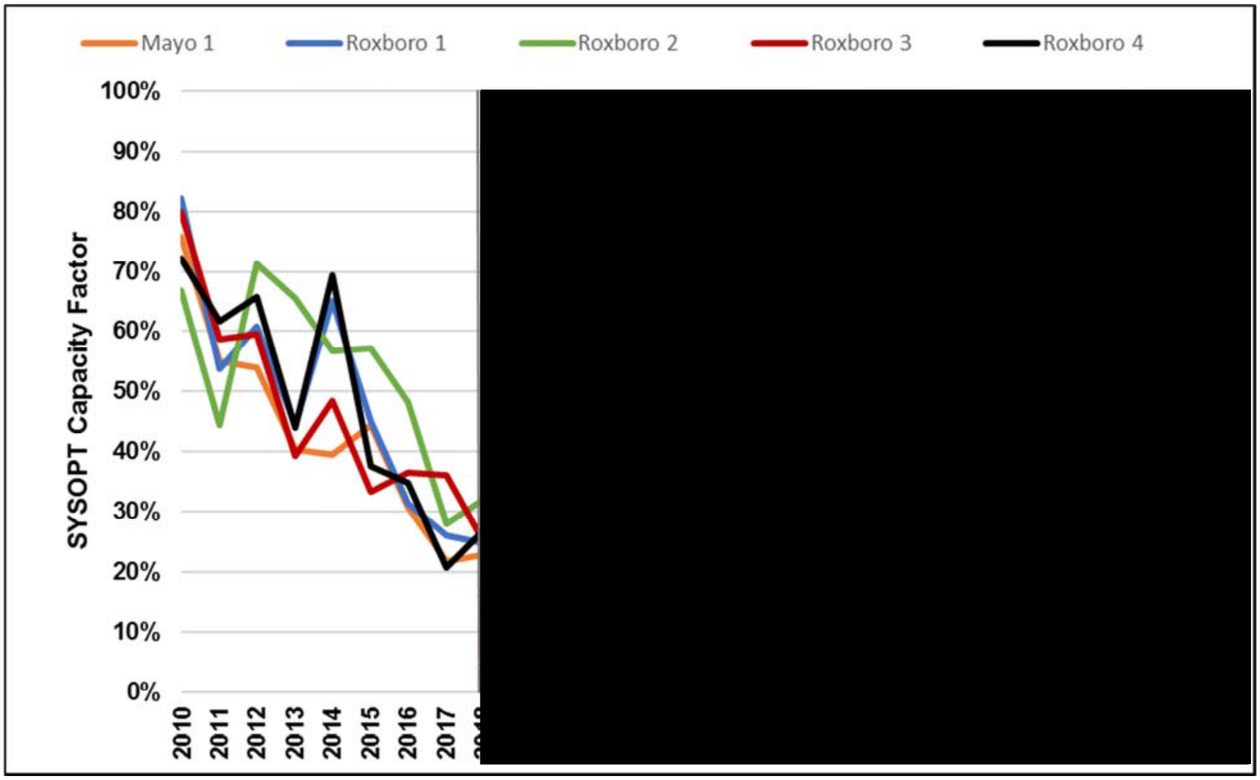


Figure 8: Forecasted Capacity Factor for Mayo and Roxboro Units, Companies' Base CO_2 Scenario in System Optimizer model - CONFIDENTIAL



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

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]
[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.

[CONFIDENTIAL APPENDIX NOT ATTACHED TO PUBLIC VERSION]