Docket No. E-100, Sub 157
REDACTED

Analysis of the Duke Energy Integrated Resource Plan

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DEPARTMENT OF JUSTICE N★C ATTORNEY GENERAL

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Introduction

This memorandum is prepared for the North Carolina Attorney General's Office ("AGO") to summarize the Strategen review of the Duke Energy Carolinas ("DEC") and Duke Energy Progress ("DEP"), or together "Duke" or "Companies", Integrated Resource Plans ("IRPs") and the Initial Comments about the IRPs. The memorandum provides analysis that supports Strategen making the following conclusions and recommendations to the North Carolina Utilities Commission ("Commission") regarding the topics below:

- **ENERGY EFFICIENCY and DEMAND-SIDE MANAGEMENT**
  - Duke's IRPs should be modified to include a more robust consideration of modern energy efficiency ("EE") and demand-side management ("DSM") measures:
    - Duke should be required to model EE and DSM as supply-side resources;
    - The effects of federal codes and standards should be more clearly reflected in the load forecasts;
    - Duke should be required to develop EE and DSM measures that target winter peaks; and
    - Advanced rate design should be further explored to address peak demands.[1]

- **RISKS ASSOCIATED with FOSSIL FUELS**
  - The Commission should require Duke to more robustly address climate change related risks in future IRPs, including the risk of stranded fossil fuel plants and the ability of energy storage to enhance power system resilience.
    - Consistent with Public Staff Comments, a tool similar to the Comprehensive Risk Analysis model should be incorporated.[2]
    - Further, the model should be made available to regulators to improve oversight and transparency of the IRP.

- **SOLAR PLUS STORAGE MODELING**
  - The Commission should require Duke to more flexibly model solar plus storage resources.

- **CAPACITY VALUE of SOLAR**
  - The Commission should rely on the Public Staff's capacity value calculation for this proceeding.
    - For future IRPs, Strategen believes that, conceptually, an Effective Load Carrying ("ELCC") framework, similar to the one 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.

[1] Public Staff at 52-53.
[2] Public Staff at 73.

- **COAL: MODELING ASSUMPTIONS and COSTS**
  - The Commission should direct Duke to study and report the costs of operating versus retiring coal plants on a station basis and a per unit basis and coal units should be evaluated in modeling of least cost alternatives.

- **CONNECTIONS to INTEGRATED DISTRIBUTION SYSTEM PLANNING**
  - Consistent with North Carolina's Sustainable Energy Association ("NCSEA") recommendation, the resource plans should include Integrated Distribution Planning to integrate and value distributed resources.

- **LOAD FORECASTING**
  - Consistent with the Public Staff's recommendations, the following improvements to Duke's load forecasting should be made:
    - Duke should be required to include the impacts of Integrated Volt Var Control ("IVVC") in load forecasts. Further, the Commission should create performance metrics related to Duke's utilization of IVVC.
    - Duke should be required to utilize more granular AMI data to develop and refine load forecasts.

- **RATEPAYER BILL IMPACTS**
  - The Commission should follow the Public Staff's recommendation to require Duke to include a comprehensive rate impact analysis in its next IRP, and should include a breakout of the portion of bills that are fuel-related.

Energy Efficiency and Demand-Side Management

Modeling as a Supply-Side Resource

In its Initial Comments, the AGO recommended that Demand Side Management ("DSM") resources, including energy efficiency ("EE") and demand response ("DR"),[3] be modeled as supply-side options when selecting resources in the resource plan. Without this modeling approach, DSM cannot be fairly compared to supply-side alternatives, potentially limiting the amount of cost-effective EE and DSM selected in the plan and thereby leading to a higher cost portfolio than necessary. The Southern Alliance for Clean Energy ("SACE"), Sierra Club, and Natural Resources Defense Council ("NRDC") made similar comments, while NCSEA submitted an alternative IRP that modeled EE as a supply-side resource.[4] NCSEA's modeling resulted in incremental EE resources being added above the amount modeled by Duke. Strategen believes that modeling DSM resources in a manner that allows them to be selected in the same way as supply-side resources is a best practice. For that reason, Strategen recommends that the

[3] While EE and DSM are used somewhat interchangeably in the memorandum, it should be noted that EE is technically a subset of DSM, which includes Energy Efficiency (EE) as well as Demand Response (DR and Demand Management resources.

[4] SACE, Sierra Club, and NRDC at 12 and NCSEA Att. 1 at 2.

Commission should require Duke to model DSM as supply-side resources in future IRPs to ensure that a least-cost resource portfolio is selected, subject to other policy constraints and risk factors.

The Impact of Federal Codes

During its review of the intervenor's Initial Comments, Strategen identified three additional DSM-related concerns, all of which were addressed to some degree in the Public Staff's Initial Comments. First, the Public Staff notes that federal codes and standards and decreasing avoided costs make it more difficult for the utilities to design and implement cost-effective EE programs.[5] While it is true that federal standards are having an effect on the availability and cost-effectiveness of a subset of utility-administered EE programs, it is also true that technological advancements continue to provide new opportunities for expanded EE programs and measures. For example, Massachusetts recently became the first state to make energy storage resources eligible for energy efficiency incentives.[6] The program design passed the Total Resource Cost Test and will be utilized for demand reduction benefits. Additionally, even if deployment of certain traditional EE measures (e.g. lighting) is increasingly difficult within utility programs due to federal codes and standards, these measures still have an effect on decreasing overall load. Thus as certain measures become less available as a utility program resource, there should still be a corresponding reduction in the utility's initial load forecast due to the existences of the codes and standards.

It is critical to understand that modern EE approaches will continue to provide benefits to ratepayers. Currently, Duke modeling assumptions appear to suggest that once traditional forms of EE are exhausted, EE will provide little benefit. As noted by SACE, Sierra Club, and NRDC, "DEC assumes that no new DSM capacity will be added to help meet winter or summer peak demand or reserves after 2024, and projects decreasing reductions to peak from EE investments after 2027."[7] Strategen believes that this assumption does not reflect new technological advances, such as automation and load controls, that will likely unlock new forms of cost-effective energy efficiency and demand management.

Targeting Winter Peaks

Second, the Public Staff identified a major shortcoming of the DSM offerings included in Duke's IRP—that is, the DSM offerings included little to no residential DSM that lowers winter peaks.[8] Given the importance that Duke places on the winter peak for determining the need for new resource additions, Strategen believes Duke's IRP lacks adequate emphasis on new or expanded winter DSM programs. While Public Staff discussed one example of a direct load control program that was not found to be cost-effective, there are numerous advanced demand management

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[5] Public Staff at 50-51.
[6] The Order is available at: https://www.mass.gov/files/documents/2019/01/31/2019-2021%20Three-Year%20Energy%20Efficiency%20Plans%20Order_1.29.19.pdf
[7] SACE, Sierra Club, and NRDC at 12.
[8] Public Staff at 52.

programs that have been found to be cost-effective in other jurisdictions that could shave winter peaks.[9]

Advanced demand management programs are being designed in ways to maximize resource participation and minimize the cost to ratepayers. For example, Bring Your Own Device ("BYOD"), including smart thermostat, programs are showing promise. "Simply put, it will cost a utility less money to recruit and acquire participants for a (BYOD) smart thermostat program than it will for a direct install smart thermostat program."[10] Not only are customer acquisition costs lower for BYOD programs, they can also be designed to minimize, or eliminate, installations costs. For example, Green Mountain Power has designed a BYOD program specifically to lower winter peak demand. Green Mountain Power's BYOD program shares access with customer's batter storage systems to lower peaks during "cold winter nights."[11] Customers purchase the batteries and are provided incentives "based on the amount of energy transferred from the customer's battery to the grid."[12]

Duke currently integrates smart thermostats into some of its EE offerings. However, Duke's offerings are limited, do not include other types of devices, and do not appear to focus on obtaining flexible (i.e. dispatchable) HVAC measures that could help address winter peaks. Of the EE programs listed in Duke's IRP filings, three programs incorporate smart thermostats—the Residential Smart Saver ("Residential") Program and EnergyWise for Business and Non-Residential Smart Saver Energy Efficient HVAC Products (together, "Business") Programs.[13] The Residential Program provides an incentive for the smart inverter but does not appear to utilize the device for demand response or load shifting. The EnergyWise for Business Program incentivizes winter DR, but at a lower level than summer, and has a small amount of participating winter capacity.[14] None of the programs allow for customers to bring other devices, such as energy storage, to increase flexible capacity in both the winter and summer.

Advanced Rate Design

The third issue discussed by Public Staff is the belief "that new time-of-use schedules have the greatest potential to help residential customers curtail loads during winter peaking events."[15] Strategen agrees that advanced rate designs are a critical tool for delivering cost-effective reductions in peak demand. While Public Staff encourage utilities to look into these opportunities, Strategen recommends that the Commission take a more proactive approach and require the utilities to embark on a collaborative process for designing time-of-use (TOU) and critical peak

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[9] For exemplary purposes, Strategen assumes that a significant portions of winter peak load is electrical space heating.
[10] See https://www.peakload.org/assets/Groupsdocs/PractitionerPerspectives-UtilityBYOTPrograms-March2018.pdf
[11] See https://greenmountainpower.com/news/gmp-offers-new-bring-device-program-cut-energy-peaks/
[12] See https://greenmountainpower.com/news/gmp-offers-new-bring-device-program-cut-energy-peaks/
[13] DEP at 244 and 246.
[14] DEC at 153.
[15] Public Staff at 52-53.

pricing or peak-time rebates within 60 days after the order in this docket.[16] A general docket approach has been used in Minnesota, New Hampshire, California, and Maryland to discuss design and implementation related to advanced rate designs.[17]

Conclusion

To summarize, there appear to be clear opportunities for Duke to expand and improve its EE and DSM offerings. These opportunities indicate that forward looking projections incorporated into Duke's IRP are likely overly conservative regarding DSM opportunities and lead to over-procurement of traditional generation resources.

Risks Associated with Fossil Fuels

In Initial Comments, the AGO discussed the importance of appropriately evaluating the risks associated with fuel price volatility, fuel source diversity, fuel transportation constraints, emissions, and climate change.[18] Strategen shares these concerns and the belief that these issues were poorly developed in Duke's Proposed IRP.

Risk Analysis Tool

To address similar concerns, Public Staff recommended that Duke utilize an analytical tool, similar to the Comprehensive Risk Analysis employed by Dominion in its IRP, "to determine the least cost plan that provides the lowest risk to its customers, while also providing operational and compliance flexibility to each utility."[19] The Comprehensive Risk Analysis referenced by the Public Staff helps to evaluate tradeoffs between resource "portfolio cost and portfolio risk," which is "not addressed in the traditional least-cost planning paradigm."[20] This includes evaluating tradeoffs between emissions levels and fuel volatility. Therefore, the Comprehensive Risk Analysis tool could be utilized to more robustly evaluate the risks associated with climate change impacts and mitigation efforts. Strategen agrees with Public Staff that an assessment similar to the Comprehensive Risk Analysis could bring valuable information into the IRP docket. However, benefits will only be created with the Comprehensive Risk Analysis if it is complemented with transparency and proper vetting. Much like the other models within the IRP, the Comprehensive Risk Analysis is informed by complex modeling that appears to be controlled and specified by the utility. For this reason, regulators, including the Commission and Public Staff, should have access

[16] Public Staff at 52. Strategen understands that Duke currently has limitations on the rate designs that can currently be implemented. In Strategen experience, the development of advanced rate designs can take a significant amount of time.
[17] See Minnesota Docket No. 15-662, New Hampshire Docket No. 17-189 and Order No. 26,029 in Docket No. 16-576, California Rulemaking 12-06-013, and Maryland PC44.
[18] AGO Initial Comments at 7-11.
[19] Public Staff at 73.
[20] See https://www.dominionenergy.com/library/domcom/media/about-us/making-energy/2018-irp.pdf at 113.

to the model, assumptions should be transparently stated, and the utility should be required to run alternative specifications and scenarios. [21]

Regulatory and Technological Risk

Additionally, another fossil fuel related risk that is not addressed in Duke's plan is that of stranded costs associated with procuring future fossil fuel plants. Future plants could become stranded for numerous reasons, but there are currently two primary risks. First, is the risk associated with future emissions regulation, which was discussed in the AGO's Initial Comments.[22] The risk of stranded fossil fuel assets requires that the IRP not only consider the direct costs of emissions (e.g. if a future carbon price is adopted), but also the risk of ratepayers having to pay for plants that become uneconomic because of emissions regulation. Second, technological change is creating a situation where renewables paired with storage are beginning to outcompete fossil fuel generators not only in terms of energy costs but also for providing many grid services. NCSEA and SACE, SIERRA CLUB, AND NRDC's analysis demonstrates how much of Duke's current coal plants may be uneconomic due to the advent of low-cost renewables and natural gas. This same circumstance could happen with natural gas plants in 10 to 20 years, given natural gas transportation constraints, increasing LNG exports, and the decreasing cost of renewables and storage. Thus, Strategen recommends that the Commission consider the risk of stranded fossil fuel assets in future IRPs.

Solar Plus Storage Modeling

In the AGO's Initial Comments, it noted numerous shortcomings associated with Duke's evaluation and modeling of solar plus storage resources. For example, the AGO noted that Duke's modeling did not consider storage "in combination with solar resources as a way to expand contribution to peak hours of demand."[23] Strategen has worked extensively with states on integrating energy storage into their power system, including through paired solar plus storage resources, and has found that the ability of energy storage to lower demand during peak hours is one of, if not the most, valuable services it provides to the power system. Therefore, because Duke did not model the benefit that solar plus storage provides to peak hours of demand, it did not model solar plus storage in a comprehensive way and calls into question Duke's IRP modeling approach. As noted by the AGO, numerous utilities are transforming their resource portfolio's by incorporating solar plus storage.[24] For that reason, Duke's IRP modeling should not be used as justification to add traditional generation resources, including natural gas generators, to meet peak load until a robust analysis of solar plus storage has been performed as an alternative capacity resource.

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[21] The Public Staff notes more than once that it does not have access to the models that Duke uses in determining future resource needs. Public Staff at 89, 93, 94 n. 72. Not having access to the models used to justify hundreds of millions of dollars of investment presents transpare3ncy concerns.

[22] AGO at 9-10.

[23] AGO at 6.

[24] AGO at 6.

Additionally, the AGO discussed the importance of "analyzing the costs of climate change and the benefits of renewables" and discussed the implications and importance of Executive Order No. 80.[25] Executive Order No. 80 discusses the important role that clean energy plays in creating a resilient power system.[26] However, Duke made no reference to resiliency in its Initial Filings and noted the many shortcomings associated with its modeling of energy storage resources. A significant value that battery storage projects can provide is the ability to enhance resilience of the grid during catastrophic events like hurricanes. A real-world demonstration of this occurred during Hurricane Irma in the Dominican Republic. Two large battery storage projects installed on the island were able to help stabilize grid frequency, and alleviate fluctuations caused when 40% of the generation fleet had suffered an outage.[27] Recent studies have also shown that inverter-based resources (like batteries) can actually respond faster and more accurately than traditional generators in the face of a disturbance.[28] Additionally, some cities are currently seeking to deploy solar plus storage at critical facilities (e.g. emergency shelters) to provide backup power during an emergency. Examples include the following: 1) MA Community Clean Energy Resiliency Initiative;[29] 2) San Francisco's Solar Resilient program;[30] and 3) Maryland Energy Administration Resiliency Hub program.[31]

NCSEA's modeling indicates how more appropriately incorporating solar plus storage resources into an IRP model can greatly impact results. Specifically, NCSEA's alternative model chose "to build out solar and storage resources to meet future capacity and energy needs with zero incremental natural gas-fired unit additions when allowed to select the most cost-effective future resource build."[32] The result was likely driven by a couple of key differences in NCSEA's and Duke's modeling assumptions.

First, NCSEA's modeling allowed more flexible pairings of solar plus storage. For example, while Duke hard coded one option for solar plus storage, a 2 MW of PV system with a 2 MW/8 MWh battery, NCSEA's modeling allowed for large systems with different PV to battery ratios.[33] NCSEA's modeling approach is superior to Duke's for a few reasons. Importantly, the system configuration chosen by Duke is subjective and not tailored to a system need, and the ratio of PV to storage does not necessarily align with recent trends in the industry.[34] On the other hand, NCSEA's approach allowed the optimization model to select sizes and ratios of solar plus storage that fit a system need. The ability to size resources more closely to the system need reduces the cost of

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[25] AGO at 8-9.
[26] See https://files.nc.gov/governor/documents/files/EO80-%20NC%27s%20Commitment%20to%20Address%20Climate%20Change%20%26%20Transition%20to%20a%20Clean%20Energy%20Economy.pdf
[27] See https://cdn2.hubspot.net/hubfs/2810531/Collateral/AES%20Collateral/Fluence%20Case%20Study%20-%20Storm%20Resilience.pdf
[28] https://www.nrel.gov/docs/fy17osti/67799.pdf
[29] https://www.mass.gov/community-clean-energy-resiliency-initiative
[30] https://sfenvironment.org/solar-energy-storage-for-resiliency
[31] https://energy.maryland.gov/Pages/Resiliency-Hub.aspx
[32] NCSEA Att. 1 at 17.
[33] DEC at 184.
[34] A 1:1 solar to storage capacity ratio is not necessarily a standard practice and sensitivities should be conducted. While it occurs, many paired systems have lower energy storage capacity relative to PV.

the resource, because ratepayers don't have to pay for "lumpy" resources that result in excess reserve margins. A major advantage of storage is its modular design, meaning that incremental additions can be made as needed. Notably, there is always substantial uncertainty in future load growth. For traditional power plants that are larger in size (e.g. greater than 200 MW), this presents a challenge since it often necessitates some amount of "overbuild" until load growth catches up to the installed capacity. In contrast, storage can be added relatively quickly as needed or avoided altogether if load growth does not materialize. This reduces the risk of overbuilding thereby providing additional "option value" to Duke's customers by avoiding costs of a large generator that could become "locked in" even when load growth is less than anticipated. Additionally, this model allows for solar plus storage configurations that optimize the system more efficiently—for example, allowing for a 3-hour duration battery to meet a capacity need instead of installing a 4-hour duration battery.

Second, the modeled cost for solar plus storage appears to differ between Duke and NCSEA. Duke relied on cost estimates from multiple sources, but ultimately marked these model inputs as a trade secret and did not provide any discussion of the relationship to publicly available estimates.[35] NCSEA utilized publicly available cost estimates from the National Renewable Energy Laboratory ("NREL") and Lazard.[36] Both of the resources that NCSEA used to inform cost inputs are considered to be industry standards for publicly available data. **[TRADE SECRET BEGINS** [redacted] **TRADE SECRET ENDS]** The difference between Lazard's estimates and Duke's model input could significantly impact the amount of storage and solar plus storage selected in the model.

By utilizing a more flexible modeling approach and publicly available cost data, NCSEA's modeling demonstrated that the AGO's concern about Duke's solar plus storage modeling is valid and needs to be addressed. There are multiple approaches to improving Duke's modeling of solar plus storage resources. First, the Commission should require Duke to update its modeling software to enable more flexible and granular parameters and results. Second, the Commission should require Duke to more robustly model storage plus renewables, specifically by requiring the utility to model multiple configurations of these resources. Third, the Commission should require that future utility RFPs are all-source procurements, and that anonymized results from these solicitations be provided to the Commission. This would provide insight into pricing for different resources in Duke's territory to inform long-term planning while also allowing market participants to bring forward more innovative and cost-effective near-term solutions.

[35] Public Staff at 72.

[36] NCSEA Att. 1 at 3.

[37] [redacted]

Capacity Value of Solar

The Public Staff and SACE, Sierra Club and NRDC, expressed concern in their Initial Comments regarding Duke's representation of the capacity value of solar.[38] The AGO shared similar concerns and believes the calculation of solar capacity value warrants further scrutiny to ensure that solar is not being undervalued as a capacity resource in the IRP. If solar is being undervalued, then Duke's plan may include more traditional thermal capacity resources than are necessary, thus leading to increased costs to Duke's customers. As Public Staff points out, the method used by Duke increases the need for traditional resources by 138 MW for DEC and 168 MW for DEP, relative to Staff's preferred method (described as the "coincident peak method").[39] Strategen has reviewed Duke's analysis on this topic and believes there are aspects of its capacity value calculation that could potentially be biased against solar resources including the following:

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.[40] 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

[38] Public Staff at 82-89. SACE, Sierra Club, and NRDC at 8.
[39] Public Staff at 85.
[40] See https://www.eia.gov/todayinenergy/detail.php?id=30912

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.[41] 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."[42] Strategen agrees with 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."[43] 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 NC. 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.

[41] See https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2018_12202018.pdf
[42] Public Staff at 86
[43] Public Staff at 86.

Coal: Modeling Assumptions and Costs

NCSEA and SACE, Sierra Club, and NRDC filed alternative IRP models to help inform the Commission's review of Duke's IRP. In addition, SACE, Sierra Club, and NRDC filed an analysis of Duke's coal fleet. The analyses submitted by NCSEA and SACE, Sierra Club, and NRDC emphasized numerous questionable assumptions made within Duke's IRP modeling. Ultimately, these alternative IRP models demonstrate the urgency with which the Commission needs to evaluate Duke's coal fleet and require Duke to conduct a more comprehensive analysis of coal economics in future IRPs.

NCSEA and SACE, Sierra Club, and NRDC highlight multiple assumptions within Duke's modeling that do not represent best practices. Two such assumptions are 1) hard coding coal retirements based on depreciated book value and 2) assigning must-run designations to coal units within the service territory, regardless of cost.[44] Neither of these assumptions align with best practices because each violate the premise of the entire optimization process by not allowing the model to determine the least cost outcome. For example, due to the must-run designation, Duke requires the model to dispatch coal facilities even when a solar or natural gas facility would be cheaper to operate. Another example is that, by predetermining coal plant retirement dates, Duke's model does not reflect the fact that fixed O&M costs and fuel costs are avoidable when a coal plant retires.[45] Described another way - Duke does not include economic retirement as an option in the model. Duke claims that it did not allow the model to retire coal units in the optimization model because of the additional time it takes the model to solve.[46] Given the importance of this issue, Duke's reasoning should be closely examined. By hard coding these assumptions, Duke is limiting the model's ability to select the least cost resource portfolio.

As noted above, the modeling assumptions associated with Duke's coal and other generators are extremely important because they are used to determine estimates of the future costs that ratepayers will pay for resource portfolios. NCSEA's and SACE, Sierra Club, and NRDC's modeling demonstrate how important cost and operational assumptions are within the IRP models. NCSEA's model, which removed must-run designations for coal, among other things, estimated that Duke's preferred resource portfolio would cost over $1.5 billion more than NCSEA's Clean Energy Scenario.[47] SACE, Sierra Club, and NRDC's analysis demonstrate that Duke plans to operate numerous coal units extremely inefficiently (i.e. at low capacity factors) over the planning period.[48] Coal facilities are not designed to operate infrequently and at low capacity factors, doing so will likely lead to higher costs than a scenario in which the plants are simply retired. SACE,

[44] NCSEA Att. 1 at 2.
[45] SACE, Sierra Club, and NRDC at 5.
[46] [46] See Duke's response to SACE, Sierra Club, and NRDC Discovery Request 2-1. Duke further notes, in SACE, Sierra Club, and NRDC Discovery Request 2-8, that it only seriously considers natural gas plants when evaluating whether a coal facility should be retired. One reason provided for the limited evaluation is that wind and solar are not dispatchable, but as discussed elsewhere, these resources can be cost-effectively paired with battery resources to lessen this concern.
[47] NCSEA at 7.
[48] SACE, Sierra Club, and NRDC Att. 2 at 6.

Sierra Club, and NRDC were unable to provide an estimate of how much Duke's inefficient operation of coal facilities will cost ratepayers due to lack of available data on the fixed costs of Duke's facilities.[49] In any case, NCSEA's and SACE, Sierra Club, and NRDC's analyses indicate that Duke's preferred resource portfolio could be costing ratepayers billions of dollars above cleaner energy options.

Due to the significance of the costs (and potential cost avoidance) related to coal operations and retirement decisions, Strategen recommends that the Commission direct Duke to study and report the costs of operating versus retiring coal plants on a station basis and a per unit basis in addition to evaluating them in modeling for least cost alternatives.

Connections to Integrated Distribution System Planning

One of the primary drivers for states to implement integrated resource planning requirements was to enable direct comparisons of demand-side resources (e.g. energy efficiency and demand response) to traditional generation resources such as natural gas units.[50] To make direct comparisons, regulators had to create a process that reduced information asymmetry and increased transparency related to utility costs and decision-making. The IRP requires utilities to divulge large amounts of system data and often procure generation resources through a competitive bidding process to address the utility's incentive to over-procure rate-based investments. The IRP primarily focuses on comparing cost-effectiveness at the bulk system level, while later proceedings investigate transmission requirements and costs. IRP was created to integrate emerging technologies into the power system at the lowest possible cost.[51]

Regulators are now facing a similar challenge on the distribution system. Emerging technologies, such as distributed PV and energy storage, can provide grid services that they previously could not. Importantly, the grid services provided by emerging technologies were not available when IRP processes were being developed in most states, and therefore do not account for them. For this reason, additional information is now required to enable direct comparisons between the benefits created by distribution sited grid resources and those sited at the transmission level. The need for additional information at the distribution level has led numerous states to begin dockets on distribution system planning and integrated grid planning.[52]

NCSEA described the importance of a wholistic planning approach in Initial Comments and the shortcomings of Duke's implementation process. Duke has previously requested billions of dollars for grid modernization investments that will enable the utility to better utilize demand side resources, reduce peak costs, and generally manage load and voltage more efficiently.[53] As noted

[49] SACE, Sierra Club, and NRDC Att. 2 at 5.
[50] Steve Isser. "Electricity Restructuring in the United States: Markets and Policy from the 1978 Energy Act to the Present," at 73-75. Cambridge University Press, 2015.
[51] Steve Isser. "Electricity Restructuring in the United States: Markets and Policy from the 1978 Energy Act to the Present," at 73-75. Cambridge University Press, 2015.
[52] See https://nccleantech.ncsu.edu/2018/11/01/the-50-states-of-grid-modernization-39-states-dc-took-action-on-grid-modernization-in-q3-2018/.
[53] See Docket Nos. E-2, Sub 1142 and E-7, Sub 1146.

by NCSEA, however, these capabilities were not demonstrated to have any impact on future resource needs in Duke's IRP filing.[54] This is not only poor planning and modeling on Duke's part, but it is also not likely reflective of the future grid. A recent forecast estimated that distributed energy resources, such as distributed solar and storage, will almost double by 2023.[55]

Given the rapid changes in grid technologies, and adoption of said technologies, regulators must act to ensure that the resources added to the grid provide value to ratepayers. Without appropriate planning, emerging technologies can cause operational challenges. On the other hand, with appropriate planning new distributed resources can be utilized to provide grid services.[56]

To ensure that distributed energy resources are appropriately integrated and valued, NCSEA requested "that the Commission open a rulemaking docket for stakeholders to develop a framework and adequate requirements for Integrated Distribution Planning."[57] Given that grid modernization investments will likely be made in the near future and North Carolina's high-level of solar penetration, Strategen recommends that the Commission open a rulemaking for Integrated Distribution Planning.

Load Forecasting

Integrated Volt Var Control

"Electricity losses occur at each stage of the power distribution process, beginning with the step-up transformers that connect power to the transmission system, and ending with the customer wiring beyond the retail meter."[58] As a total system electricity losses can be as high as 10-15% during peak demand hours, while losses may be as low as 3% during periods of low demand.[59] Electricity losses are partly a function of how the power system is designed and constructed.

Voltage (analogous to pressure in a water pipe) and reactive power are key factors related to electricity losses on the distribution system. With all else constant, a higher voltage results in higher losses. As electricity flows from a transformer through a conductor, voltage begins to drop because of an electrical engineering concept called resistance (think of it as friction). Since voltage must be delivered to customer within a given range, voltages start high, near the transformer (or substation), and begin to drop as the end user get further away.[60] This design element of the power system creates inefficiency (i.e. high low losses) because utilities operate the distribution

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[54] NCSEA at 11.
[55] https://www.greentechmedia.com/articles/read/distributed-energy-poised-for-explosive-growth-on-the-us-grid#gs.5am0it
[56] See https://www.nrel.gov/docs/fy17osti/67296.pdf. See also https://www.bloomberg.com/news/articles/2019-02-07/sunrun-breaking-into-a-power-market-long-off-limits-to-solar. See also http://rmi.org/wp-content/uploads/2018/12/rmi-non-wires-solutions-playbook-report-2018.pdf.
[57] NCSEA at 16.
[58] RAP Chapter 10 at 10-1. Available at: http://www.4cleanair.org/sites/default/files/Documents/Chapter_10.pdf
[59] RAP Chapter 10 at 10-1. Available at: http://www.4cleanair.org/sites/default/files/Documents/Chapter_10.pdf
[60] https://www.elp.com/articles/powergrid_international/print/volume-20/issue-8/features/determining-the-impacts-of-volt-var-optimization-a-tale-of-two-approaches.html

system at a higher voltage than needed. Integrated Voltage Var Control ("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."[61]

Neither DEC nor DEP included impacts from future Integrated Voltage Var Control ("IVVC") programs within their load forecasts. However, NCSEA noted that Duke has previously predicted that IVVC will enable 2% energy savings and 1.4% reduction in peak demand.[62] The Public Staff took issues with Duke's treatment, or lack thereof, of IVVC—recommending that IVVC be included in "future years of capacity planning."[63]

Strategen supports Public Staff's recommendation to include the impacts of IVVC in load forecasts. It is important to note, however, that Duke's previous estimate of the effectiveness of IVVC is likely understated. Traditional, IVVC approaches achieved between 1-2% energy and demand reductions.[64] However, technologies available today can create energy savings above 3% and peak demand reductions of approximately 5%, or three times greater than Duke's estimate.[65] Additionally, smart inverters may be able to enhance the effectiveness of an IVVC solution.[66] For these reasons, Strategen recommends that the Commission conduct robust review of Duke's IVVC solution before cost recovery is approved or any solution is procured to ensure that the most beneficial solution has been selected. In addition, Strategen recommends that the Commission create performance metrics related to Duke's utilization of IVVC.

More Granular AMI Data

In addition, the Public Staff noted concerns with the granularity of the data utilized in some of Duke's forecasts. Specifically, Duke uses monthly data to evaluate peak demand.[67] To address this shortcoming, Public Staff suggests that smart meter data be used to inform load forecasting models.[68] Strategen supports Public Staff's recommendation to better utilize more granular data and agrees that smart meter data should be utilized to better understand trends in winter and summer peaks. Specifically, Strategen recommends that Duke be required to utilize more granular data to develop load forecasts.

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[61] https://www.elp.com/articles/powergrid_international/print/volume-20/issue-8/features/determining-the-impacts-of-volt-var-optimization-a-tale-of-two-approaches.html
[62] NCSEA at 13.
[63] Public Staff at 55.
[64] See http://grouper.ieee.org/groups/td/dist/da/doc/Larry%20Conrad%20-%20IVVC%20Presentation%20IEEE_pptx.pdf
[65] See http://varentec.com/varentec-deploys-grid-edge-control-meet-aggressive-energy-savings-goals-denver-across-472-circuits-xcel-energy/ See Kootenai Electric's presentation under Grid Ops Track: Session Two. Available at: https://smartgridnw.org/gridfwd-2018-presentations/
[66] See https://www.nrel.gov/docs/fy17osti/67296.pdf
[67] Public Staff at 80.
[68] Public Staff at 81.

Ratepayer Bill impacts

Multiple intervening parties discussed the issue of ratepayer bill impacts in their initial comments. The costs that will be borne by ratepayers should be a central consideration when formulating long-term resource plans. While Duke's IRP discusses costs in many forms, it does not translate cost into a customer bill impact analysis.

Both NCSEA and SACE, Sierra Club, and NRDC conducted independent ratepayer bill impact analyses that are highly concerning. SACE, Sierra Club, and NRDC's bill impact analysis estimated that Duke's IRP will result in bills that are 3% higher in 2030 than the economically optimized alternative model they developed.[69] NCSEA's bill impact results were similar suggesting that ratepayers will see rates that are 2.5% to 5.5% higher under Duke's preferred IRP plan.[70] These two estimates suggest that Duke's preferred resource additions would add billions of dollars to ratepayers' bills over the planning horizon when compared to other feasible portfolios.

To better monitor this issue, Public Staff recommended "that in future IRPs, DEC and DEP provide an analysis of the residential annual rate impacts of each of its portfolios similar to that presented in DENC's 2016 and 2018 IRPs."[71] Greater transparency is needed to determine Duke's future resource additions, and ratepayer impacts are a key factor to determining how reasonable a given portfolio of resources is. Utilities in other states include rate impact analysis within the IRP including, as Public Staff noted, North Carolina (i.e. Dominion) and Minnesota.[72] Strategen supports the Staff's recommendation with the slight alteration that rate impacts in general should be analyzed, as well as residential impacts. Residential rate impacts are ultimately determined by cost allocation approaches, so these would more appropriately be analyzed in addition to overall rate increases. Additionally, the bill impact analysis should include a breakout of the portion of rates that are fuel related and therefore bear price risk borne by ratepayers. Finally, it is important that the analysis consider not only the impacts of the plan on customer rates, but also on average customer bills.

[69] SACE, Sierra Club, and NRDC at 5.
[70] NCSEA Att. 1 at 1.
[71] Public Staff at 73.
[72] See Minnesota Docket No. 15-21.

About Strategen

Strategen is an internationally recognized, mission-driven, professional services firm focused on energy sector market transformation for a low carbon grid. Our multidisciplinary team specializes in work with policymakers and regulators, utilities, and unregulated market participants on issues related to zero carbon grid technologies such as energy storage, solar, wind, electric vehicles, demand response and energy efficiency. Our functional expertise includes technical analysis, economic analysis, regulatory thought leadership, and corporate strategy, as well as ability to leverage our thought leadership platform in ways that motivate and empower local leadership and change.

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Education

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Regulatory Strategy

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Performance-Based Regulation

Performance Incentive Mechanisms

Cost of Service Analysis

DER Compensation

Rate Case Support

Electric Vehicles

Renewable Energy Program Design

Expert Testimony

Oklahoma Gas & Electric, Formula Rates and Rate Design, Docket No. 201800140

Public Service Company of Oklahoma, Rate Design and Performance-Based Regulation, Docket No. 201800096

Veteran Energy Delivery of Ohio, CCOS and Rate Design, Docket No. 18-0298-GA-AIR

Professional Bio

Ron is a Manager in the Government and Utility Practice at Strategen. He works with clients to improve regulatory structures in order to more efficiently achieve public policy goals, such as transitioning the power system to clean energy. Additionally, Ron provides expert testimony on numerous topics including multi-year rate plans, performance incentive mechanisms, cost of service modeling, residential and commercial rate design, renewable energy program design, and electric vehicle policy.

Prior to Joining Strategen, Ron worked as an Economist for the Minnesota Attorney General's Office for five years. He has also worked as an economic researcher for two universities and the United States Geological Survey.

Ron earned a Bachelor of Arts and Minor from Western Washington University in Environmental Economics and Mathematics, respectively, and a Master of Science in Resource Economics from Colorado State University.

Speaking Engagements

National Association of State Utility Consumer Advocates Annual Meeting, Orlando, FL, "Grid Mod Strategies for Consumer Advocates", 2018

PBR Technical Workshop I for the Hawai'i Public Utilities Commission, Honolulu, Hawai'i, "PBR Lessons from Minnesota", 2018

National Association of State Utility Consumer Advocates Mid-Year Meeting, Minneapolis, MN, "Methodologies for Calculating an Appropriate Customer Charge", 2018

Previous Experience

Economist

Minnesota Attorney General's Office – St. Paul, MN

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Rate Design

Tech-to-Market Strategy

Energy Policy & Regulatory Strategy

Energy Product Development

Stakeholder Engagement

Publications

"Are Recent Forays into Restructuring a Threat to Energy Efficiency?", American Council for an Energy Efficiency Economy (ACEEE), 2014

"Performance Based Models to Address Regulatory Challenges", The Electricity Journal, 2014

"High-Speed Rail and Reducing Oil Dependence", Transport Beyond Oil, Island Press, 2013

"Transmission and Renewable Energy Planning in California," Western Governors Association, 2012

Professional Bio

Ed helps to lead the Utility and Government consulting practices at Strategen. He specializes in evaluation and design of policies and programs to advance deployment distributed energy resources, demand-side management programs, energy storage and grid integration of renewable energy. Ed has served clients in the renewable energy, energy efficiency, and energy storage industries, including consumer advocates, public interest organizations, Fortune 500 companies, energy project developers, trade associations, utilities, government agencies, universities and foundations. His analysis has given companies strategic insight into clean energy investment opportunities and has helped to guide regulations and policies in many states across the country.

Prior to joining Strategen, Ed worked as an independent consultant where he provided technical analysis to a law firm in Arizona, supporting the firm's clients in cases before the Arizona Corporation Commission. He also worked to provide technical analysis on demand-side management policies in Michigan, Illinois, Pennsylvania and several other states.

Ed earned his bachelor's degree in Chemistry from Princeton University and two degrees from Arizona State University - Master of Science (M.S.) in Sustainability and Professional Science Master (P.S.M.) of Solar Energy Engineering and Commercialization.

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Consultant

Kris Mayes Law Firm – Phoenix, AZ

June 2012 – March 2015

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Arizona State University – Temple, AZ

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