Analysis of Parties' Initial Comments on Duke Energy's 2020 Integrated Resource Plans

Prepared by:

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Prepared for:

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) and summarizes Strategen's review of certain parties' Initial Comments on the 2020 Integrated Resource Plans that were submitted by Duke Energy Carolinas (DEC) and Duke Energy Progress (DEP) (referred to collectively as Duke). The memorandum provides additional analysis supporting Strategen's conclusions in Initial Comments, but also expands on these to provide some new conclusions and recommendations for the North Carolina Utilities Commission (Commission).

1. Duke's IRP Portfolios Do Not Reflect Reasonable Resource Choices or Cost Estimates (review of Public Staff and Joint NCSEA/CCEBA/SACE Initial Comments)

Strategen has closely reviewed the analysis conducted by Synapse (on behalf of NCSEA/CCEBA/SACE, *et al.)* to assess the reasonableness of Duke's resource plans.[1] Notably, there is a large disparity between the analysis presented by Duke and the analysis performed by Synapse regarding the cost of meeting clean energy goals while maintaining reliability. This is true despite the relatively few changes that Synapse made to Duke's assumptions when Synapse modeled resource selection.

Synapse's analysis included two portfolios: 1) "Mimic Duke" and 2) "Reasonable Assumptions." In the first scenario, Synapse mimicked Duke's Portfolio B (Duke's base case with carbon policy), and in the second scenario, Synapse made some modifications to the first scenario and ran the model again.[2] In both

[1] Synapse Energy Economics, Inc., prepared its report "Clean, Affordable, and Reliable, A Plan for Duke Energy's Future in the Carolinas" for the North Carolina Sustainable Energy Association (NCSEA), Carolinas Clean Energy Business Alliance (CCEBA), Sothern Alliance for Clean Energy (SACE), Natural Resources Defense Council (NRDC) and the Sierra Club, whose joint initial comments were filed March 1, 2021 and are referred to as Joint NCSEA/CCEBA/SACE Comments. The Synapse report is attached to the Joint NCSEA/CCEBA/SACE Comments as Exhibit A. The Synapse Report was corrected in filings submitted Mar. 22, 2021 and May 27, 2021 and all references here to the Corrected Synapse Report refer to the May 27 filing. Note that NCSEA and CCEBA also filed other comments and exhibits on March 1, 2021 referred to here as NCSEA/CCEBA Comments, and SACE, NRDC, and Sierra Club filed other comments and exhibits on March 1, 2021 referred to here as SACE Comments.

[2] Corrected Synapse Report pg. 11-14. Duke's plans included six portfolios each for DEC and DEP: A through F. Except for Portfolio A (Duke's base case without carbon policy), the portfolios address clean energy policies. B is Duke's base case with carbon policy. Portfolio C closes all coal units at the Earliest Practicable Date (according to Duke's analysis.). Portfolio D is Duke's High Wind plan that reduces carbon by 70%, and Portfolio E is Duke's SMR (Small Modular

cases, Synapse presents the combined results for DEC and DEP, but their report notes that they modeled these as islanded systems, similar to Duke's approach.

Both Synapse Portfolios were developed using the EnCompass capacity expansion model.[3] EnCompass is a widely used commercial tool for developing resource plans that is used by many utilities, consultants, and other industry practitioners, including Strategen. As a capacity expansion model that uses mathematical optimization techniques, EnCompass is similar in nature to the System Optimizer tool used by Duke. However, Strategen believes the approach taken by Synapse to using this type of model is superior to Duke's in many respects.

For example, as Public Staff pointed out, Duke's IRP portfolios include a significant amount of resources that were "forced in" rather than allowing them to be economically selected by the model.[4] This distorts the overall cost of portfolios C, D, E and F, but particularly for portfolios D, E, and F. In contrast, Synapse allowed the model to freely select most resource additions if doing so would be economic. Therefore, Strategen believes Synapse's results provide a more accurate representation of a least-cost portfolio under two different sets of assumptions.

Strategen believes the fact that many resources were forced in by Duke is one of the most critical differences between Duke's and Synapse's analyses that likely led to such different conclusions. Moreover, Strategen believes that Duke's approach of forcing in resources led to an especially distorted notion of the cost of portfolios D, E, and F. For example, under DEC Portfolio F ("No New Gas"), Duke inexplicably forced in 684 MW of SMR[5] and 1,620 MW of Pumped Hydro Storage, both of which are some of the most expensive resource options available. Similarly for DEP Portfolio F ("No New Gas"), Duke inexplicably forced in 2,400 MW of costly offshore wind. Not only are the forced-in resources higher in cost to begin with, but Duke has also assumed additional transmission costs associated with them in some cases. For example, Synapse observed that "Duke's most expensive No New Gas Generation scenario has transmission costs of $8.9 billion, some of which are associated with the interconnection of 2,650 MW of offshore wind."[6] In contrast, Synapse's model did not select any SMR, or pumped hydro storage, and added considerably less offshore wind additions, most likely due to the high costs of these resources.[7]

Reactor) plan that reduces carbon by 70%. Portfolio F is Duke's "no new gas" plan. DEC Corrected IRP pg. 11-12; DEP Corrected IRP pg. 12.

[3] Corrected Synapse Report pg. 1.

[4] See Comments of the Public Staff on 2020 Biennial Integrated Resource Plans filed Feb. 26, 2021 (Public Staff Comments) pg. 119 and 128.

[5] Small Modular Reactors

[6] See Corrected Synapse Report pg. 21.

[7] Corrected Synapse Report pg. 1.

Taking these factors into account, Duke's analysis provides an unrealistic and inflated view of the costs to achieve the higher clean energy targets (e.g., 70% reduction) represented in portfolios D, E, and F. In fact, none of Duke's portfolios modeled a 70% reduction scenario with a focus on lower cost, zero-emissions resources such as solar, on-shore wind, and battery storage. In contrast, Synapse's modeling provides a more sensible approach to achieving this target and a more reasonable approximation of the costs.

Like all models, EnCompass includes certain limitations and simplifying assumptions and does not perfectly represent certain detailed operational considerations. Some of these shortcomings are assessed later in this section. However, in Strategen's view, these limitations do not amount to meaningful deficiencies in the model or the modeling approach. Moreover, they are much less consequential than the deficiencies in Duke's analysis. From this standpoint, Strategen believes that the general methodology used by Synapse is sound.

a) *Synapse's model inputs and assumptions -- comparison to Duke's approach*

- ***Existing Resources and Network Topology****:* The initial setup of the EnCompass model includes existing generation resource characteristics derived from the EnCompass default database, rather than Duke's modeled inputs. As such, there may be some minor differences between the precise values of these characteristics and what Duke uses for its analysis; however, we expect these inputs to be roughly similar.[8] Additionally, Synapse did not include any system topology and instead assumed that DEC and DEP are islands, which Synapse explained is similar to Duke's modeling approach. Strategen believes that, going forward, a more detailed network topology should be incorporated into any future modeling (including Duke's). However, for the purposes of comparison there appears to be no appreciable difference on this matter between Duke's and Synapse's approaches.

- ***Natural Gas Prices****:* In both Synapse portfolios, key changes were made to gas commodity prices that may differ from Duke's forecast, including: 1) the use of the Horizon's Energy Database for gas price forecasts, 2) a book life for new gas ending in 2050, and 3) the inclusion of a firm gas transportation price adder of $1.50/MMBtu.[9] In Strategen's view these changes are not unreasonable. In particular, if Duke did not fully account for gas transportation

[8] Strategen is also aware that Synapse's initial model configuration contained an error that led to counting about 1.7 GW of nuclear generation as part of Duke's portfolio when in fact the Catawba plant is jointly owned and the portion owned by a different entity is not attributable to Duke's portfolio (see: https://www.bizjournals.com/charlotte/news/2021/05/05/witness-stands-by-clean-energy-report.html). This was corrected in the Corrected Synapse Report, which showed a largely similar outcome, except for the addition of 750 MW of offshore wind.
[9] Corrected Synapse Report pg. 12.

costs as part of its optimal resource selection analysis, then it would have significantly underrepresented the cost of new gas resources. See more discussion of this issue in Section 4 below. Given these concerns about the ability to transport low-cost gas to Duke's system, the inclusion of a gas transportation adder appears to be more accurate and would reflect an improvement over Duke's modeling. However, Strategen has not evaluated the exact level of the transportation adder and that may be a question of fact for the Commission to examine further and/or determine in an evidentiary hearing.

- ***Assessment of "Reasonable Assumptions"***: There are several key differences in Synapse's "Reasonable Assumptions" portfolio that are key drivers of the different outcomes from both Duke's analysis and Synapse's "Mimic Duke" portfolio.[10] Strategen provides an assessment of the reasonableness of these assumptions below:

    - *Coal Retirements*: Synapse used Duke's "Earliest Practicable" dates for the Reasonable Assumptions portfolio versus Duke's "Economic" coal retirement dates. Strategen believes this is a reasonable modification due to the myriad problems with Duke's economic coal retirement analysis which were detailed in our analysis attached to AGO's Initial Comments. However, as explained in those comments, Strategen believes the Earliest Practicable dates specified by Duke – like the Economic dates Duke specified - may be later than necessary and may extend beyond the true economic retirement dates. It is worth noting that EnCompass is capable of selecting economic retirement dates endogenously. Synapse chose not to include this option, and to focus instead on other modifications. In this sense Synapse's approach is similar to Duke's. However, going forward Strategen believes it would be instructive to allow the endogenous option (at least as a sensitivity analysis) within EnCompass. This could identify whether some plants should theoretically be retired even sooner than what Duke has identified as the "Earliest Practicable" date. If so, the Commission could then examine those practical limitations more closely to see if they could be accelerated.

    - *Renewable and Battery Storage Costs*: Synapse relied upon the NREL ATB 2020 database for wind and battery capital costs, and solar O&M costs. The ATB is a thoroughly vetted and authoritative source of public data on these costs and therefore is reasonable to use. However, Strategen notes that Synapse relied on the ATB "Low" cases for wind and batteries rather than the "Moderate" or "High" case, which could have some influence on the final results. Regarding wind, this likely had a

[10] Corrected Synapse Report pg. 14.

minor impact given the relatively small amount of wind additions Synapse's model selected compared to other resources, however an additional sensitivity analysis is probably warranted to test this. Regarding batteries, the use of the "Low" case likely had a more significant effect. While the ATB Low case for batteries may be considered somewhat optimistic, it is not inconsistent with other industry estimates Strategen is familiar with. In contrast, Duke's cost estimates are much higher than both industry estimates and the ATB, as well as what other utilities have assumed in their IRPs. Regarding offshore wind costs, one potential gap in Synapse's analysis is that the potentially significant transmission costs associated with this resource do not appear to have been explicitly modeled. Instead, the report states: "the difference in PVRR between the two modeled scenarios demonstrates that new transmission could be constructed to support offshore wind development with no detrimental effect on ratepayers relative to the Mimic Duke scenario."[11] Ideally, these costs would have been included in the model. However, Strategen notes that, if transmission costs are similar to Duke's estimates on a per unit basis (i.e. $8.9 billion for 2400 MW, or about $3.7 million per MW), then this would add approximately $2.8 billion in costs to the Reasonable Assumptions portfolio. For comparison the difference in PVRR that Synapse alluded to in the statement above is $7.4 billion. Thus, there may be enough headroom in the Reasonable Assumptions portfolio for some additional transmission costs to accommodate offshore wind, without raising overall costs above the Mimic Duke portfolio.

- *Levelization of Wind and Solar Costs*: A key difference in Synapse's approach is the use of levelized wind and solar costs (i.e., $/MWh) for resource selection rather than solely adding resources based on MW of capacity needed. Strategen believes this reflects a substantial and warranted improvement over Duke's approach since it more accurately captures the full value that a new resource provides to the system, including both energy and capacity benefits rather than evaluating resources solely based on their capacity contribution. In fact, Strategen believes that Duke's approach leads to a suboptimal outcome that arbitrarily disadvantages resources that provide inexpensive energy but may have lower capacity value (e.g., solar PV). Strategen agrees with comments in the Lucas Report presented by NCSEA/CCEBA on this issue, which stated: "Duke erroneously did not allow the model to add new capacity or [Power Purchase Agreements] unless there was a capacity need, eliminating the potential to incorporate less expensive energy-only resources earlier in the planning horizon."[12]

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[11] Corrected Synapse Report, pg. 22.
[12] See Lucas Report pg. 73. Mr. Kevin Lucas, Senior Director of Utility Policy and Regulation for the Solar Energy Industries Association prepared "Comments on Duke Energy Carolinas, LLC and Duke Energy Progress, LLC's Integrated Resource Plans" (the Lucas Report), which was filed March 1, 2021 as Exhibit 3 to NCSEA/CCEBA Comments.

- *EE/DSM Forecast*: Synapse's analysis assumed that total EE/DSM deployment is substantially increased relative to Duke's assumptions and would reach 1.5% in incremental annual savings as a percentage of retail sales. This substantially reduced the overall need for new resources in the Reasonable Assumptions portfolio. Synapse pointed to evidence from other states, primarily in New England, that have achieved greater than 1.5% annual savings. Strategen notes that utilities in other states outside of New England have also achieved savings levels greater than 1.5% in recent years, such as Arizona Public Service which achieved 2.28% savings in 2017.[13] North Carolina may not be totally comparable to these other regions in terms of its building stock, customer composition, economic outlook, and policy preferences. As such, a savings target of 1.5% level may be ambitious, but is within reach, particularly if more large C&I customers are encouraged to participate in EE/DSM rather than opt out. Even if 1.5% is considered too ambitious as a target for utility-administered EE/DSM programs, however, there are several other factors that are likely to offset Duke's load growth and suggest that the load Duke serves under Synapse's assumptions are still reasonable for planning purposes. These factors are discussed in more detail in Section 3 (b) below.

- *Restrictions on New Gas Additions*: In the "Reasonable Assumptions" portfolio, Synapse did not allow the addition of new natural gas resources. This approach allowed the model to evaluate the cost implications of advancing clean energy goals by eschewing investments in new gas plants, in recognition of clean energy goals and concerns about the cost of stranded investment in fossil plants.[14] Strategen generally supports an approach that allows the model to select from any resource type (including fossil resources), but recognizes that Synapse's Reasonable Assumptions portfolio is still helpful in demonstrating that clean energy goals may be advanced more quickly and at a much lower cost than Duke's portfolios suggest. Indeed, the resulting Synapse Reasonable Assumptions portfolio has a *lower* overall cost than the "Mimic Duke" portfolio (which is based on Duke's Portfolio B - the bases case with carbon policy) and a much lower overall cost than Duke's Portfolio F (Duke's No New Gas scenario). Additionally, Strategen understands that there may be some minor discrepancies in how the EnCompass model optimizes resource selection and how the revenue requirement is subsequently calculated that could lead to a gas resource being added that is in fact uneconomic from a PVRR[15] perspective. To the extent this was true when evaluating

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[13] *See* http://docket.images.azcc.gov/0000186159.pdf?i=1620704002475
[14] *See* Joint NCSEA/CCEBA/SACE Comments pg. 12-13.
[15] The Present Value Revenue Requirement (PVRR) is estimated to compare the relative costs of alternative resource portfolios.

the results of the "Reasonable Assumptions" portfolio, then it would justify the restriction that Synapse applies.

b) Ability of Synapse's Portfolio to meet grid reliability needs

In light of the recent grid outages in Texas, Strategen recognizes that there is widespread concern about ensuring that utility system operators can meet the grid's needs during peak load hours across a range of extreme weather conditions. Synapse's results provide a high-level indication that the Reasonable Assumptions portfolio can meet grid reliability needs. This is because one of the fundamental constraints included in the EnCompass model is to ensure that peak load needs are met, plus a reserve margin. This is done for a series of days across each year that are representative of a range of system conditions. This represents a good indication that the portfolio is generally reliable, and Strategen believes that additional follow-on actions could provide even greater assurance.

For example, Strategen recommends that, for greater assurance, a logical next step would be to analyze the portfolio using a Production Cost Model simulation. This would provide a more granular, hour-by-hour view of how the resources in the portfolio would be expected to perform and would readily identify any potential gaps or shortfalls at any point in time. Strategen notes that EnCompass can be operated in production cost mode, and that Synapse has already done this hourly analysis for the winter peaking month of January in 2030, though other time periods should be tested as well. Additionally, there are also several other possible models that could be used by Duke or other stakeholders. Ideally this analysis would be conducted for multiple weather years to test a range of possible system conditions.

Additionally, it may be helpful for Duke (or a third party) to examine the Reasonable Assumptions portfolio, or any other credible resource portfolio, using the same approach it uses for Resource Adequacy planning by conducting an LOLE[16] analysis. Accordingly, Strategen recommends in the next IRP cycle, that the Commission require Duke to analyze two or three alternative portfolios proposed by stakeholders as part of its Resource Adequacy stakeholder process using the same model and methodology used by Duke.

2. Response to Public Staff's Initial Comments Regarding Coal Retirement

[16] Loss of Load Expectation

As detailed in our Initial Comments, Strategen identified significant concerns with the reasonableness of Duke's approach to evaluating coal retirements. Public Staff also expressed concerns, although it did not conclude that Duke's model inputs for evaluating coal retirement were unreasonable for planning purposes. The Public Staff concerns included 1) the choice of a peaking combustion turbine as the replacement resource rather than other possible options, 2) potential customer bill impacts of accelerated depreciation rates, 3) transmission impacts, and 4) the stranded asset risk associated with the replacement of coal plants with natural gas units.

a) Evaluation of replacement resource options

Strategen agrees with Public Staff's criticism that Duke's reliance on a combustion turbine as the replacement resource may make Duke's sequential planning method inaccurate.[17] This criticism adds to the concern that Duke's retirement analysis is a fairly crude assessment and does not account for portfolio-wide resource needs or additions that could be changing in parallel with coal retirement decisions. For instance, some plants may not require a 100% replacement resource at the time they are retired. Strategen believes these considerations simply underscore the importance of including retirement decisions endogenously in Duke's economic modeling, as was recommended in AGO's Initial Comments. Public Staff agreed with this point and recommended that Duke "use economically optimal endogenous plant retirement dates in future IRPs resulting from the Encompass model."[18] To avoid further delay in assessing early coal retirement, Strategen believes it would be possible for Duke to rerun its System Optimizer model runs with endogenous retirement as an option. A post-analysis could then be used to easily address any issues related to dynamic capital expenditures linked to the retirement date.

b) Potential customer bill impacts of accelerated retirement

Strategen reviewed Public Staff's initial assessment of the customer bill impacts of early retirement for the Roxboro and Mayo coal plants. This analysis is very helpful for demonstrating the potential advantages of a regulatory asset treatment in terms of avoiding or delaying any potential bill increases associated with accelerated depreciation. Strategen also suggests further assessment and clarification of four factors. First, it is unclear what fuel cost changes were assumed, and fuel costs are generally the largest category of incremental costs at Duke's coal plants. As such, it is important to have an accurate assessment of whether fuel savings might offset the replacement resource costs. Second, the default replacement resource is assumed to be a natural gas combined cycle unit, which may not be a necessary or economic choice. Third, it is not readily apparent whether a MW for MW new build would be needed at the exact time of

[17] *See* Public Staff Comments pg. 103.
[18] Public Staff Initial Comments pg. 110.

each plant's retirement. If a full portfolio analysis were conducted, with endogenous retirements, it could reveal that a partial or deferred replacement resource would be sufficient. Fourth, it is unclear what book life was used for the replacement resource, which could in turn affect the near-term customer bill impacts.

c) Transmission impacts

Public Staff noted that "the Companies' transmission requirements are dynamic as related to the retirement of coal units" and recommended that if an early retirement is considered that "Duke analyze the transmission impacts and file a more detailed plan with refined cost estimates, including timelines of required activities and potential synergies with future grid improvement plans."[19]

Strategen strongly agrees that more detailed information is necessary on the transmission requirements that are triggered by plant retirements. As described in our Initial Comments, there are many unanswered questions about the required upgrades that Duke forecasts will be needed, and Strategen has serious concerns that the forecasts may be overstated in some instances. For example, Duke claimed that upgrades were needed to address global frequency regulation when coal plants retire,[20] but this claim needs more explanation because system frequency is a property of the entire eastern interconnection and is not linked to any individual plant.

Moreover, Strategen believes that more detailed information is necessary for the current IRP proceeding, and it is not sufficient for the details to be delayed until future proceedings that may consider individual plant retirement decisions. This is because key aspects of Duke's coal retirement analysis depended upon assumed transmission costs. In turn, the coal retirement dates were used by Duke as the starting point for the rest of Duke's IRP resource decisions.

d) Stranded asset risk associated with the replacement of coal plants with natural gas units.

Strategen agrees with Public Staff that stranded asset risk is a real concern if Duke intends to replace its coal plants primarily with new natural gas generation.[21] This is described further below in Section 3 (a). Instead, Duke should consider other alternatives, ideally through a portfolio-wide economic modeling process. Strategen notes that Duke's plans to use gas resources for replacement is a reason why some coal units have earliest practicable dates in the late 2020s. Thus, if other resources, like battery storage, are considered

[19] Public Staff Comments pg. 108.
[20] Duke Response to DR AGO 1-5b.
[21] Public Staff Comments pg. 7-8. See also Duke's discussion of replacement options in the DEC 2020 IRP pg. 176.

(which Public Staff has implied could be a possibility), then these earliest practicable dates may need to be revisited.

e) *Use of Storage and Other Inverter-Based Resources to Provide Grid Stability*

In addition to these items, Public Staff raised the prospect that battery storage might be a complete or partial replacement for retired coal units.[22] Moreover, Public Staff implied that these storage resources could be comparable in many ways to traditional generation in terms of their role in helping Duke to meet its reserve margin. Thus, as retirements occur and replacement resources are needed, there may be an increased need for the Commission to review and approve large-scale battery projects. Public Staff suggested that "the Commission initiate a rule making proceeding that would evaluate whether, and under what circumstances, an electric supplier should be required to receive Commission approval prior to construction of a battery energy storage facility."[23] Strategen agrees that a clear policy is warranted to determine the approval process for new large scale battery storage facilities. In addition, such a rulemaking would provide an opportunity to address any concerns the Commission may have regarding grid stability issues as the transition occurs from more traditional thermal resources to inverter-based resources like battery storage.

One concern, for instance, relates to Duke's point that its coal plants are currently providing grid reliability functions such as global frequency regulation and local transmission voltage support.[24] As Strategen noted in Initial Comments, modern inverter-based resources, including solar PV and batteries, can also provide these functionalities. In fact, recent demonstrations conducted by the grid operator in California have illustrated that an inverter-based resource (in this case solar PV) can actually be superior at providing these services than conventional resources.[25] The chart below provides an illustration of this capability, showing that a recent solar project provides regulation services more accurately than conventional resources.

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[22] Public Staff Comments pg 108-109.
[23] Public Staff Comments pg 109.
[24] Duke Response to AGO DR 1-5.
[25] *See*: https://www.caiso.com/Documents/Briefing_UsingRenewables_IncorporateRenewables-Presentation-Dec2016.pdf.

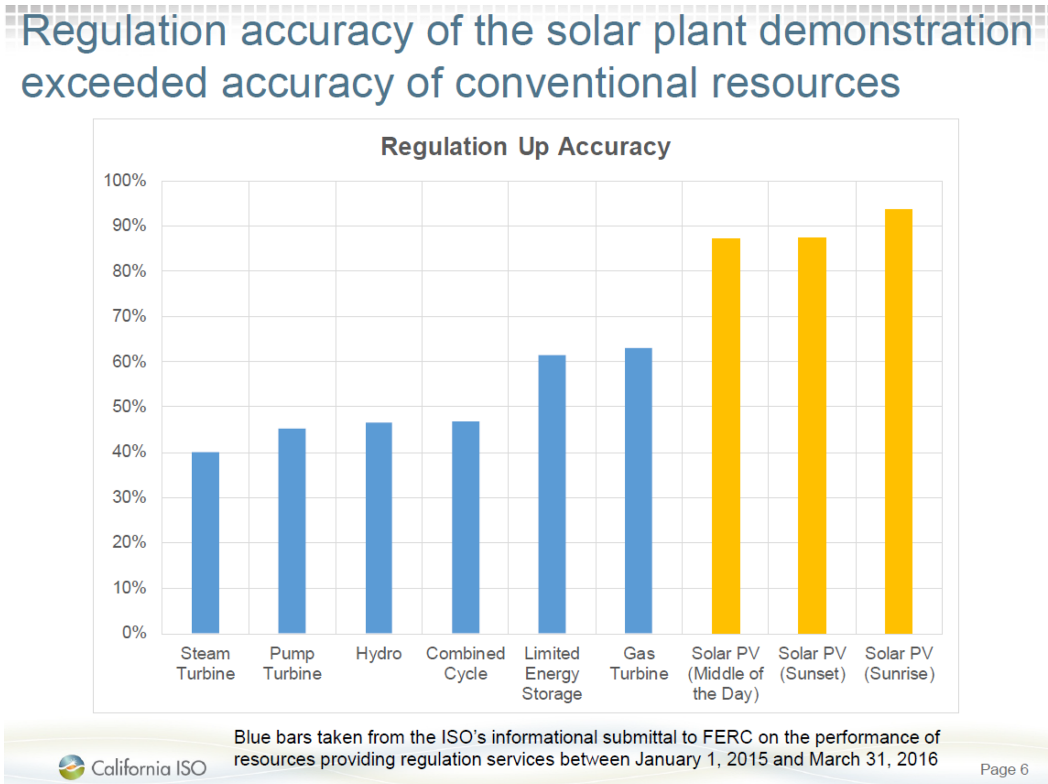

Figure 1. Ancillary services provided by the CAISO/First Solar/NREL demonstration project[26]

However, this will only occur if batteries and other similar resources are designed, configured, and operated to provide the desired capabilities. This could be accomplished by setting technical standards for certain grid functionalities that new storage resources must provide as part of the Commission's approval process. Absent a technical standard, this could also be advanced through specific compensation mechanisms for resources that do provide such grid services – particularly in the case of third-party assets. If the Commission pursues Public Staff's recommendation to open a rulemaking for approval of large-scale battery storage systems, Strategen suggests that the rulemaking also address such grid-supportive functionalities as part of the approval process.

f) *Duke's approach to coal retirement suffers from flaws analogous to Public Staff's critique of "forced in" resources*

Public Staff has argued, in part, that Duke's Portfolios s C, D, E, and F should be rejected because they include a significant amount of resources that were "forced in" rather than being economically selected. By the same logic, Strategen believes that the Commission should also reject Duke's portfolios A and B

[26] *Id* at 6.

because they effectively force in existing coal units until retirement dates that are similarly applied independently of the optimal solution.

3. Review of specific concerns about Duke's plans and analysis raised in parties' Initial Comments

a) Duke's Natural Gas Assumptions (review of Public Staff and NCSEA/CCEBA's Initial Comments)

Strategen generally agrees with the Initial Comments of Public Staff and NCSEA/CCEBA that Duke did not perform an adequate risk analysis to inform its plan for an extensive buildout of natural gas capacity. First, as pointed out by Public Staff, **BEGIN CONFIDENTIAL** [redacted] **END CONFIDENTIAL.**[27] Considering the cancellation of the Atlantic Coast Pipeline and the generally unfavorable regulatory landscape for additional pipeline construction (as evidenced by the recent rejection of the Mountain Valley Pipeline's extension into North Carolina),[28] there is no guarantee that Duke will have access to this lower-cost natural gas. NCSEA/CCEBA also agreed with this point, stating that "it is increasingly unlikely that new or upgraded pipeline capacity will be available."[29] Duke's optimistic natural gas price projections undoubtedly have an impact on the portfolio of resources selected in its IRP modeling and would favor natural gas additions. A less optimistic projection of gas prices based on **BEGIN CONFIDENTIAL** [redacted] **END CONFIDENTIAL** would likely result in less natural gas capacity in Duke's portfolios. Furthermore, since natural gas costs are fully recovered from ratepayers through the fuel clause,[30] the higher natural gas prices will be borne by ratepayers, while posing little risk to Duke itself.

Second, the volatility of natural gas prices could considerably raise the PVRR of Duke's modeled portfolios that rely more heavily on natural gas. Severe weather events, which could be increasingly more frequent and severe due to climate change, will introduce even more uncertainty in natural gas prices. As an example, the figure below shows the price of natural gas at the Transco Zone 4,

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[27] Public Staff Comments pg. 13-14.
[28] https://www.reuters.com/world/us/north-carolina-again-denies-permit-mountain-valley-gas-pipe-extension-2021-04-30/
[29] NCSEA /CCEBA Comments pg. 19.
[30] *See* N.C.Gen.Stat. § 62-133.2.

Transco Zone 5, and Dominion South hubs between May 2020 and May 2021, with a significant spike in February 2021 as a result of the historic cold wave:[31]

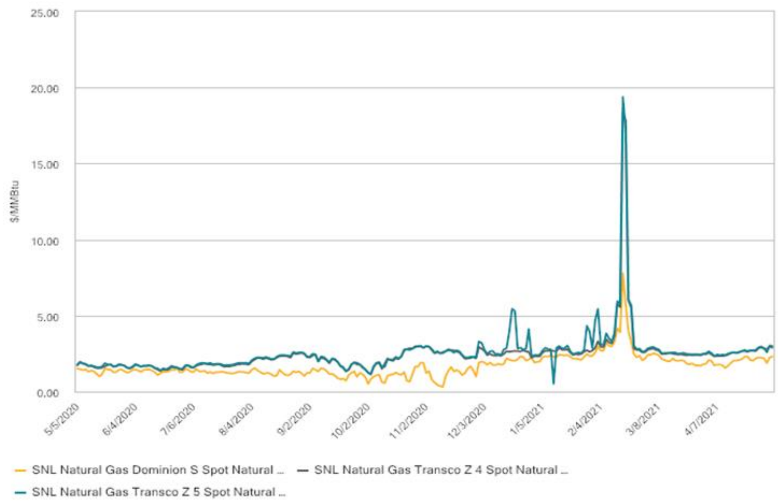

Figure 2. Natural Gas Spot Prices in Duke's Region from May 2020 through May 2021

The data show that the average price in Transco 4 and Transco 5 for the full year was about $2.50/MMBtu. However, if the month of February 2021 is excluded, the average price would have been only $2.27/MMBtu. Thus, the presence of the price spikes in February increased annual average natural gas price by more than 10%. This demonstrates that even infrequent price spikes like this can have a significant impact on ultimate customer costs.

Third, Strategen agrees with NCSEA/CCEBA's comments that the futures-based forecast data on which Duke relied for its projections of natural gas prices are flawed. Their expert, Kevin Lucas, explained:

> Long-term futures prices primarily reflect short-term volatility rather than being reflective of the macroeconomic dynamics that influence long-run prices… The sizable week-to-week volatility that occurred in 2020 meant that if Duke had locked in its gas forecast a few weeks earlier or a few weeks later, it would have produced a meaningfully different result."[32]

For its natural gas prices forecast, Duke used futures contracts for years 1 through 10, a linear blend from years 11 to 15, then a fundamentals-based forecast from year 16 forward. [33] Mr. Lucas explained that futures prices fluctuate heavily based on short-term trends driven by weather or trading activity and that the futures market is very illiquid a year or eighteen months in the future.[34] In

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[31] Data obtained from S&P Global Market Intelligence on May 5, 2021.
[32] Lucas Report pg. 38.
[33] DEC IRP pg. 157-158.
[34] Lucas Report pg. 41-43.

contrast, a forecast based on fundamentals uses a model that simulates entire sectors of the economy to determine supply, demand, and prices for commodities, and thus is more effective at predicting long-term trends.[35] As a result, he proposed that Duke should only use 18 months of futures prices for its forecast, transition linearly for the next 18 months, and utilize a fundamentals-based forecast from month 37 and forward.[36] Strategen agrees that reduced reliance on a futures-based forecast is appropriate unless Duke is planning to secure contracts for fuel delivery commensurate with its overall portfolio needs. As NCSEA/CCEBA further notes, Duke has not secured contracts in this way, even for peak needs.

> "...Duke does not plan to contract for firm natural gas delivery to its combustion turbine ("CT") units, despite adding gigawatts of new CT capacity. These CTs will be utilized during cold winter mornings and evenings – the exact same time when the natural gas distribution system will be under stress from building heating loads."[37]

Strategen notes that the lack of firm natural gas delivery for combustion turbine units is one factor that led to the near collapse of the ERCOT power grid in Texas in February 2021. If Duke assumes that gas will be available at such low prices, this likely does not capture the full cost of the deliverability risk that a firm contract seeks to avoid.

Furthermore Duke has not adequately accounted for the risk of new natural gas units becoming stranded assets if stronger State or Federal carbon policies are implemented or if Duke advances its stated carbon goals. Strategen agrees with NCSEA/CCEBA[38] and Public Staff[39] that the current status of early coal plant retirements could be repeated, and accelerated retirements of natural gas units would then burden customers by rates that are fixed to pay for generation assets from which they no longer derive any benefits.

Moreover, even though natural gas emits less carbon dioxide than coal, it releases significant amounts of methane, another greenhouse gas driving climate change. If more stringent restrictions on methane emissions are implemented, this could further weaken the economics of natural gas plants and exacerbate stranded asset risks. In fact, the Biden Administration has already signaled that it intends to set methane emissions reduction requirements more stringent than those implemented by the Obama Administration.[40]

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[35] Lucas Report pg. 41.
[36] Lucas Report pg. 54-55.
[37] NCSEA/CCEBA Comments pg. 19.
[38] NCSEA/CCEBA Comments pg. 21.
[39] Public Staff Comments pg. 110.
[40] US News, "Biden Admin's Methane Emission Curbs to Exceed Obama's: EPA Chief," https://www.usnews.com/news/us/articles/2021-04-09/biden-admins-methane-emission-curbs-to-exceed-obamas-epa-chief

In comparison, renewables such as wind or solar do not have the same associated risks. Wind and solar, as zero marginal cost resources, do not impose fuel prices or suffer from price volatility. Further, in contrast to natural gas and other fossil fuel resources, renewables do not face potentially restrictive carbon policies in the future. Thus, they are all but guaranteed to be operational for their whole useful lives. Although some renewables may require additional transmission capacity, thus raising potential siting and permitting challenges, these same challenges would also apply to other resources that require transmission and/or natural gas pipelines to be sited and permitted.

b) *EE/DSM Assumptions (review of Public Staff and SACE's Initial Comments)*

In Initial Comments, Strategen concluded that Duke is likely underestimating the potential load reduction that could be achieved from EE/DSM[41] in its 2020 IRP. Several parties including Public Staff and SACE also commented on Duke's assumptions regarding the level of EE/DSM that are assumed in the IRP and that could be achieved over the next 15 years. While Public Staff generally believed that Duke's assumptions were reasonable for the purposes of the IRP process, they identified some potential deficiencies and made other observations discussed below.

1) Response to Public Staff Comments

Measure Level Screening Versus Portfolio Level Screening:

Public Staff noted that Duke's Market Potential Study excluded certain measures or programs from the Economic and Program potentials because they were either difficult to offer, raised Net to Gross concerns, or did not screen on an individual level.[42] Generally speaking, Strategen agrees with Public Staff's concerns that certain measures were omitted and believes the primary focus for evaluating EE/DSM should be at the portfolio level. By focusing on the portfolio level, if there are certain programs or measures that do not pass an initial screening step, they could still be included as long as the overall portfolio is cost-effective. This would provide greater flexibility and synergies in terms of how individual programs are administered. For example, a more comprehensive package of measures could be offered to customers during a single point of contact. Additionally, this would allow flexibility for programs to adapt over time as costs of the measures, avoided cost metrics, and screening methodologies evolve. It would also allow for more seamless implementation than having to start and stop programs. Incentive and budget levels could be used to right-size measures that may be less cost-effective. Additionally, allowing a broader portfolio of measures could expand the overall level of savings that occur, thus providing greater certainty that meaningful, long-term savings can be achieved.

[41] Energy Efficiency/Demand-Side Management
[42] Public Staff Comments pg. 56-57.

Given the significant co-benefits energy efficiency provides to customers -- including meaningful improvements to health and safety, and contributions to system reliability during cold weather – Strategen believes that Duke should offer a robust set of EE/DSM offerings.

Building Envelope Measures

Public Staff noted that it is difficult for IOUs to develop EE programs related to building envelopes due to "fear of creating adverse conditions for other utility sectors, like natural gas."[43] Strategen believes that this "fear" should not be a barrier to pursuing reasonable building envelope measures, particularly in cases where electricity is used for space heating, and agrees with the Public Staff's suggestion that greater efficiency would be achieved through comprehensive programs that encompass electric and gas utilities.[44] Pursuing these measures would also be consistent with Strategen's recommendation in Initial Comments to refocus Duke's EE/DSM efforts on long-lived measures.

EE Embedded in Load Forecast

Public Staff noted that EE originating outside of utility-sponsored programs (e.g., from more efficient building codes and appliance standards) are increasingly being incorporated into utility load forecasts, and that these effects are increasingly limiting opportunities for new utility-sponsored measures. On the other hand, Public Staff noted that certain federal lighting standards were actually withdrawn in 2019, meaning that there should be a corresponding opportunity to increase EE/DSM potential for utility sponsored programs.

While we agree with Public Staff that codes and standards are playing an increasingly important role in the baseline for EE/DSM programs that may limit traditional program opportunities, this is not a reason to abandon robust development of programs. Further, Duke may advance these codes and standards directly themselves. For example, in at least six states, utilities can actually receive credit towards their EE obligations by assisting local jurisdictions to adopt more advanced building codes and standards (i.e., "stretch codes").[45] These have been some of the most cost-effective approaches to delivering EE/DSM, and have also produced long-lasting effects. Strategen recommends that a similar approach be considered in North Carolina.

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[43] Public Staff Comments pg. 51.
[44] *Id*.
[45] The six states Strategen is aware of that take this approach are Arizona, California, Illinois, Massachusetts, Oregon, and Rhode Island.

Public Staff also found that the effects of codes and standards on opportunities for utility programs are "difficult to measure."[46] Even if difficult to measure, Strategen believes the influences of such programs need to be well documented so that savings are accurately reflected either in EE/DSM programs or in load forecasts. As Public Staff noted, Duke has consistently overestimated its load growth over the course of multiple IRP cycles.[47] This could reflect, among other things, a certain amount of "naturally occurring" energy efficiency improvements that are occurring outside of EE/DSM programs but would have a similar effect on Duke's overall resource needs. As noted in Initial Comments, Strategen is unclear if this effect is adequately captured in Duke's current load forecast.

New Opportunities from Advanced Metering Infrastructure (AMI)

In addition to the "naturally occurring" energy efficiency that may occur outside of utility programs due to codes and standards, there may be additional actions customers could take with the advent of increased usage data available through AMI. As Public Staff noted, "advancement in data acquisition and application provides a far better opportunity for customers to make their homes or workplaces operate more efficiently, as opposed to the previous method where customers would see their total monthly usage 30 to 45 days after the energy was consumed."[48] While Strategen agrees that AMI data presents new opportunities for customers to better track their energy usage, we also caution that the ability for customers to benefit from energy savings opportunities is highly dependent on availability of both rate options and technologies that allow customers to better monetize these savings. Thus, the development of more advanced time of use rates and real-time pricing options must also be pursued to encourage customers to unlock some of these savings. Furthermore, national studies have shown that coupling advanced TOU rate options with energy savings programs that offer smart devices (e.g., thermostats) is the most effective approach to reducing peak energy usage.[49]

Additionally, Strategen believes that increasing customers' access to their AMI usage data, and the option to seamlessly provide this data to third party service providers (e.g. via Green Button) could unlock new and innovative EE/DSM opportunities. For example, several companies now offer remote energy audit services that have been shown to be very effective for identifying low-cost efficiency solutions for Commercial and Industrial customers. As customer access to meter data becomes more widely implemented by Duke, these opportunities should become more readily available to all customers.

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[46] Public Staff Comments pg. 52.
[47] Public Staff Comments p 45-46.
[48] Public Staff Comments, pg. 53.
[49] https://energy.gov/sites/prod/files/2016/12/f34/CBS_Final_Program_Impact_Report_Draft_20161101_0.pdf

Role of Policy

Strategen agrees with the Public Staff's observation that public policy can play an important role in the level of energy efficiency that is ultimately achievable. As their Initial Comments stated, "Recent legislation, such as the VCEA[50], has had a major influence on Dominion's DSM and EE portfolio in Virginia, which redounds to the North Carolina service territory."[51]

In Strategen's experience, it is often not the technical studies of EE potential, but rather policies like the VCEA or Energy Efficiency Resource Standards (EERS), that are the overriding factors in determining how much energy efficiency utilities ultimately pursue. This is shown below in some recent data that Strategen compiled from the 2019 ACEEE annual scorecard. It shows that the higher performing states generally tend to have an EERS in place. While ACEEE technically includes North Carolina in this category due to the EE provisions in North Carolina's Renewable Energy Performance Standard, it is likely not an overriding factor in North Carolina's performance since this is not a standalone target.

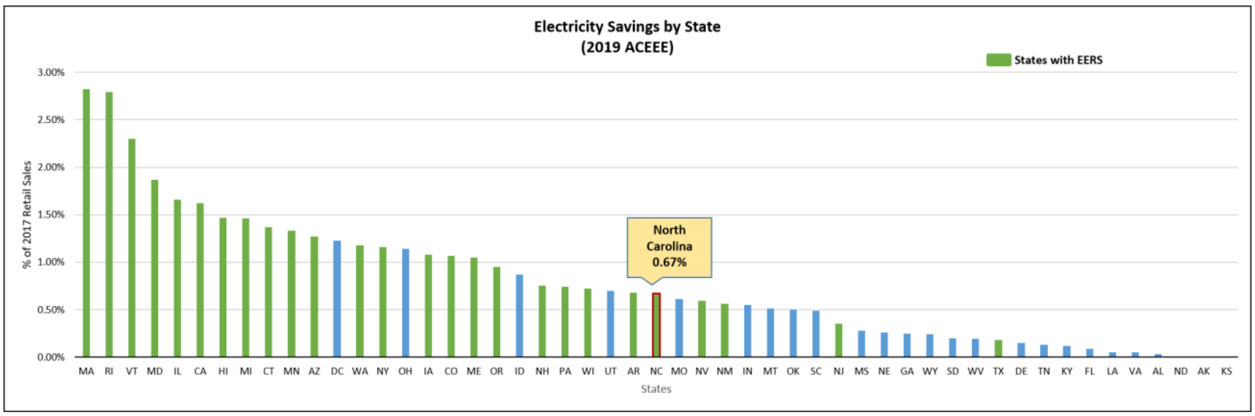

Figure 3. Comparison of electric utility energy efficiency savings levels in 2018 by state (Data Source: 2019 ACEEE Scorecard)

2) Response to SACE, et al.

In addition to Public Staff, Strategen also reviewed SACE's Initial Comments which were more critical of Duke's EE/DSM potential estimates. Strategen responds to some of the points below.

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[50] Virginia Clean Economy Act

[51] Public Staff Comments pg. 64.

Use of TRC Versus UCT Test

SACE pointed out that Duke's market potential study was based upon the Total Resource Cost ("TRC") test, but the actual screening test adopted more recently in North Carolina applies the Utility Cost Test ("UCT").[52] Thus, while this change was not finalized at the time of Duke's IRP, it means that the IRP is now out of date. Strategen finds it especially noteworthy that Duke's market potential study identifies about 40-50% more savings for the Residential and Commercial sectors under the UCT test than under the TRC test.[53] This suggests that Duke's EE/DSM assumptions in the IRP may be underrepresented by a corresponding amount.

Omitted Measures

Strategen is particularly concerned by SACE's expert's observation that the Duke potential studies omitted certain known measures, including at least 19 categories of measures[54] This suggests that Duke's potential study was not comprehensive and that the Duke's estimates of the potential savings should be considered a lower bound of what may be achievable.

Future Measures from Emerging Technologies

SACE's comments discuss future technologies that may expand the overall potential for EE/DSM measures. While this is somewhat speculative, SACE's expert provided a compelling reason that the potential should not be underestimated, since: "nearly half of the efficiency savings in the Northwest Power and Conservation Council's Draft Seventh Power Plan were from efficiency measures not included in the Council's sixth plan published just five years prior."[55] There is no guarantee that future measures will emerge on the same scale in North Carolina, but Strategen agrees that some amount of forecasted increase in EE/DSM potential is appropriate. Such a forecast is comparable to the forecasts Duke incorporates in its IRP for future natural gas

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[52]Order Approving Revisions to Demand-Side Management and Energy Efficiency Cost Recovery Mechanisms issued 20 October 2020 In the Matter of Application of Duke Energy Progress, LLC, for Approval of Demand-Side Management and Energy Efficiency Cost Recovery Rider Pursuant to N.C.G.S. § 62-133.9 and Commission Rule R8-69 in Docket Nos. E-2, Sub 931 and E-7, Sub 1032 at 4, 14.https://starw1.ncuc.net/NCUC/ViewFile.aspx?Id=66f2e52d-9639-48d7-aa98-4d2e546b9a5d
[53] SACE Comments pg. 10-13.
[54]See Figure 1 in the "Review of DEC and DEP Market Potential Studies - Underestimation of Energy Efficiency and Demand Side Management" (the Grevatt Report) prepared by Energy Futures Group and filed as Attachment 1 to the SACE Comments filed Mar. 1, 2021, pg. 7.
[55] Grevatt Report pg 5.

prices, or future cost declines in renewable technologies. As a concrete example, Duke recently completed an assessment of Winter DSM potential that was not included in the initial IRP filing. If this potential were pursued, it could bolster the achievable peak savings substantially.

New Customer Engagement Strategies and Program Design

SACE also pointed out that Duke based its potential estimates on existing customer engagement strategies and program designs.[56] Strategen agrees with the general critique that these strategies and designs are evolving, and such evolutions should be considered in the IRP. In particular, Strategen believes Duke could do more to move from downstream programs towards midstream programs for non-lighting technologies. For example, rebates can be applied to regional distributors of efficient appliances which can be a more efficient method of delivering rebate programs than working directly with retail providers. These approaches have already been very successful in other states like Colorado and could be ramped up in the Carolinas.

3) Comparison to Synapse's Assumptions

Given the shortcomings that SACE identified in Duke's market potential study, and the experience of other states, Strategen believes the 1.5% energy efficiency savings level (or higher) modeled by Synapse is technically achievable. As a simple illustration, Duke's potential study initially identified an Achievable Program Potential under their Enhanced Scenario of about 1% as the Average Annual percent of base sales (5-yr sum).[57] A 40-50% adjustment for the UTC test as described above would increase this to 1.4-1.5% annual savings. The additional inclusion of omitted or future measures would assure that the 1.5% savings level is achieved. However, the opt out for large customers make the savings target more challenging to meet. To improve the savings achieved for large customers, Strategen suggests that the Commission consider additional reporting requirements for those who opt out and pursue self-directed energy efficiency investments. This would allow Duke to properly capture the savings in its load forecast from any EE/DSM pursued independently. Additionally, it would allow for a comparison to leading Commercial and Industrial (C&I) programs around the country to identify areas where Duke could improve its offerings to these customers, potentially encouraging customers to opt back into the programs.

c) Transmission, and Resource Adequacy (review of Public Staff and NCSEA/CCEBA's Initial Comments)

[56] SACE Comments pg. 9-10; Grevatt Report pg. 8.
[57] Duke Market Potential Study pg. 3-4.

Public Staff recognized that treating DEC and DEP as islands requires a significantly higher reserve margin than when they can rely on their neighbors, and that there are potential operational benefits associated with treating DEC and DEP as a combined system for the purposes of sharing reserves and firm capacity.[58] NCSEA/CCEBA also pointed out that Duke did not take into account the benefits of operating DEC and DEP as one balancing authority and of being interconnected to neighboring utilities.[59] Strategen agrees with these parties' assessments and believes that Duke should include an analysis of imports and exports as a cost-saving alternative to presuming a high reserve margin under an islanded scenario that requires additional natural gas capacity.

Additionally, Strategen agrees with Public Staff's assessment that future IRPs can "improve how costs for required imports and exports are assigned to each portfolio, which the Utilities acknowledge may be necessary to accommodate some future resource mixes."[60] A more detailed assessment of the opportunities for imports and exports is not only more realistic, but it is consistent with Duke's approach to Resource Adequacy, which assumes some level of import capability and neighbor assistance.[61] This will also allow for a more careful examination of the potential costs and benefits of regional transmission projects. Many recent studies have shown the overwhelming benefits of regional transmission as an enabler of achieving higher clean energy goals.[62] However, careful planning is still needed to make sure the right projects are being built. Public Staff also recognizes that co-optimizing generation and transmission planning is a complex exercise and solicited input from other parties on how to address this concern in future IRPs.[63] Strategen notes that there have been some successful examples (although computationally challenging) of efforts to include transmission elements in capacity expansion models. For example, the Western Electricity Coordinating Council has developed a Long-Term Planning Tool that "co-optimizes generation and transmission additions, meaning that the solution depends upon the generation and transmission capital costs taken together, rather than independently."[64] Additionally, the National Renewable Energy Laboratory has recently conducted its Interconnection Seam Study which used "a multi-model analysis that used co-optimized generation and transmission

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[58] Public Staff Comments pg. 73-75.
[59] NCSEA/CCEBA Comments pg. 41.
[60] Public Staff Comments pg. 125.
[61] *See* DEC and DEP 2020 Resource Adequacy Studies, Sections III-K.
[62] For example, see the following:

- https://westernenergyboard.org/wp-content/uploads/2019/12/12-10-19-ES-WIEB-Western-Flexibility-Assessment-Final-Report.pdf
- https://environmenthalfcentury.princeton.edu/sites/g/files/toruqf331/files/2020-12/Princeton_NZA_Interim_Report_15_Dec_2020_FINAL.pdf
- https://open.bu.edu/handle/2144/41451

[63] Public Staff Comments pg. 146.
[64] *See* WECC Data Sets at https://www.wecc.org/SystemAdequacyPlanning/Pages/Datasets.aspx#:~:text=The%20Long%2Dterm%20Planning%20Tool,in%20the%2020%2Dyear%20cases

expansion planning and production cost modeling."[65] Although this was a national scale study, the tools and approaches used may be applicable for future consideration by Duke and other parties to future IRPs. While this would be a complex undertaking, it may be one worth doing given the significant potential costs at stake. Strategen suggests one potential approach would be for the Commission to hire or partner with a third party (e.g., a national lab) to identify and conduct an independent analysis of a co-optimized generation and transmission buildout for the North Carolina region, with a focus on Duke.

Resource Adequacy Study

Public Staff concluded that Duke's Resource Adequacy Study is adequate for planning purposes but noted that "the effect of extremely low temperatures on load is still not well understood and recommend[ed] that Duke continue to utilize AMI data to improve this predicted relationship."[66] Strategen agrees with this assessment. Further, as will be discussed in the next section, Duke relied heavily upon synthetic load data generated from recent historical correlations when conducting its analysis, rather than actual load data. Future improvements to the RA Study should include better use of actual load data.

Additionally, Public Staff noted that several improvements to the RA Study were ultimately included due to feedback from the stakeholder process Duke conducted. Strategen recommends that the Commission require Duke to continue holding stakeholder meetings in future iterations of the RA Study, in order to bring about other similar improvements. Furthermore, Strategen believes transparency on this matter is especially important since Duke's target reserve margin of 17% is higher than that of most other jurisdictions. In NERC's 2020 Long-Term Reliability Assessment, only three out of 20 assessment areas across North America have a 2025 target reserve margin of 17% or above.[67] Most areas (including SERC where Duke resides) have smaller target reserve margins.

d) Other Key Details Used in Duke's Development and Analysis of the Plans

1) Weather Data used by Duke in its Resource Adequacy Study

NCSEA/CCEBA pointed out several problems with the underlying data that Duke relied upon for its Resource Adequacy study.[68] For example, Duke relied upon

[65] *See* NREL SEAM Study at https://www.nrel.gov/analysis/seams.html
[66] Public Staff Comments pg. 75.
[67] NERC 2020 Long-Term Reliability Assessment pg. 14. https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2020.pdf
[68] NCSEA/CCEBA Comments pg. 26.

weather data spanning 39 years from 1980-2019. However, this is longer than the 30-year period typically used for meteorological studies to reflect temperature changes over time. As NCSEA/CCEBA noted, including weather data from the 1980s skewed the overall results towards extreme winter peaks that may not be representative of weather patterns for Duke's system going forward.[69] However, in light of the recent extreme cold weather event in Texas, Strategen agrees with the approach recommended by NCSEA/CCEBA's expert (Justin Sharp) that would include the 1980s data but give it less weight.[70] That would strike an appropriate balance by using weather data more reflective of the recent climate, while ensuring appropriate caution is taken to account for the possibility of extreme cold weather events.

Additionally, Strategen agrees with NCSEA/CCEBA's points that Duke's use of synthetic load data may be skewing the results by over-predicting cold temperature loads,[71] and we recommend that actual load data be used as much as possible.

2) Use of Static ELCC Values Versus an ELCC Surface

NCSEA/CCEBA points out that Duke's ELCC[72] calculations may undervalue the capacity contributions of specific resources (e.g., solar and storage) since they do not account for diversity benefits that arise when certain resources are combined.[73] Strategen generally agrees with this and believes that Duke's approach may not fully capture the benefits different combinations of resources could bring, or reflect how these benefits might evolve over time. For example, a standalone solar facility might have very little capacity value today due to Duke's early winter morning peaking needs. However, that value could increase over time as a result of Winter DSM efforts. In Initial Comments, Strategen noted that this possibility was supported by Duke's RA Study results, which show an increase in the share of summer LOLP[74] hours versus winter LOLP hours when winter DSM was included. In other words, the ELCC value of solar might be increased in the future if winter DSM resources are successfully deployed. These

[69] "Comments on Duke Energy Carolinas and Duke Energy Progress 2020 Integrated Resource Plan" (the Kirby Report) prepared by Brendan Kirby, P.E., was Exhibit 1 to NCSEA/CCEBA Comments filed Mar. 1, 2021. See Kirby Report pg. 10.
[70] "Duke Energy IRP Resource Adequacy Comments" (the Sharp Report) prepared by Justin Sharpe, Ph.D. Meteorologist, was Exhibit 4 to NCSEA/CCEBA Comments filed Mar. 1, 2021. See Sharp pg. 2.
[71] NCSEA/CCEBA Comments pg. 26.
[72] Effective Load Carrying Capability (ELCC) is the equivalent amount of "perfect capacity" that could be replaced with a specified resource while maintaining the same level of reliability and is frequently used to evaluate the reliability contribution of intermittent resources.
[73] NCSEA/CCEBA Comments pg. 32.
[74] Loss of Load Probability (LOLP) is a metric frequently used by utility planners to assess the probability of an outage based on the statistical likelihood of load exceeding generation availability for specific hours within a defined study period.

synergies should be carefully evaluated since they could have a significant impact on the overall portfolio of resources. Strategen believes that NCSEA/CCEBA's proposed "ELCC Surface" is a sound approach to do this.[75] This would be appropriate to include in the next IRP cycle.

3) Relative Portfolio Risk Analysis

Strategen largely agrees with NCSEA/CCEBA's criticism that Duke's plans fail to adequately address the sensitivity of its base portfolios to potential risks.[76] Moreover, Strategen believes that going forward Duke should assess the riskiness of its portfolios using a similar method to that explained in the Lucas Report submitted by NCSEA/CCEBA.[77] Public Staff has also suggested that Duke use a stochastic approach to evaluating portfolios. Strategen believes this would be a more sophisticated approach to pursuing this risk analysis that could be beneficial. Absent a more sophisticated stochastic analysis, there may also be simpler options that provide much of the same value. For example, each portfolio could be compared by using the "Max Regret" analysis included in the Lucas report,[78] and the portfolio with the lowest maximum could be considered the least risky. Moreover, any risk analysis (including stochastic analysis) will not be meaningful until other deficiencies in Duke's analysis of portfolio costs are addressed.

4) Renewable Energy and Storage Cost Assumptions

NCSEA/CCEBA expert Lucas conducted a detailed comparison of Duke's assumptions for battery storage costs versus other sources that are publicly available. [79] Duke relied on a third-party source, rather than a publicly available benchmark, and attributed the high cost to differing assumptions. [80] Strategen generally agrees with NCSEA/CCEBA's critique that Duke's assumed costs are too high, and both the capital and O&M costs are above the costs that Strategen has seen in other recent utility IRPs. It would be less problematic if either one or the other of the capital and the O&M costs were higher than normal since that could reflect different accounting practices that offset each other. However, *both* the capital and the O&M costs appear to be high in Duke's inputs. Additionally, as described in Initial Comments, Strategen does not believe all of Duke's differing assumptions are reasonable (such as the depth of discharge for batteries, and the integration costs).

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[75] NCSEA/CCEBA Comments pg. 37.
[76] NCSEA/CCEBA Comments pg. 14.
[77] Lucas Report pg. 11-14.
[78] Id.
[79] Lucas Report pg. 20.
[80] Id.

According to NCSEA/CCEBA expert Lucas, there has also been a shift from fixed-tilt systems to single-axis trackers since the mid-2010s and more than 80% of solar capacity completed in the Carolinas in 2019 used single-axis or dual-axis trackers.[81] This trend is expected to continue in the future and would be consistent with Strategen's understanding of trends within broader U.S. solar industry. Yet, Duke's assumptions do not take this into account.

5) Accounting methodology for outages of thermal resources

NCSEA/CCEBA's Initial Comments pointed out that Duke's accounting methodology overvalues thermal resources' contributions to the reserve margin by not accurately taking into account forced outages.[82] This is in contrast to Duke's treatment of renewable resources using the ELCC value, which does account for times when the resource is unavailable.[83] These observations are consistent with Strategen's analysis in Initial Comments, and the recommendation that Duke should use a UCAP[84] framework for its thermal resources to ensure an apples-to-apples treatment. This is especially noteworthy given the relatively high outage rates that some of Duke's thermal resources have experienced in recent years. For example, the winter equivalent forced outage rate (EFOR) for, one of DEC's coal units was as high as **BEGIN CONFIDENTIAL** [redacted] **END CONFIDENTIAL** and at one of its natural gas units it was as high as **BEGIN CONFIDENTIAL** [redacted] **END CONFIDENTIAL** yet these units were treated as if they have perfect availability during winter peaking hours (i.e., a 0% outage rate). [85]

6) Other Resource Cost Assumptions

Pumped Hydro Storage

Duke plans to upgrade some of its existing pumped storage units to add about 260 MW of capacity between 2020 and 2024, but its Portfolios D, E, and F would also deploy about 1,600 MW of new pumped hydro capacity by 2034. As noted in the Lucas Report submitted by NCSEA/CCEBA, Duke's own data on the lead time for pumped hydro is incompatible with this timeline.[86] Pumped hydro storage

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[81] Id at 34.
[82] NCSEA/CCEBA Comments pg. 36.
[83] Id.
[84] Unforced Capacity (UCAP) is the actual dependable capacity of a resource that should be considered for planning purposes. The UCAP value adjusts the resource's nameplate value to derate its capacity contribution based on the typical outage rates of the specific plant or resource type.
[85] DEC 2020 Resource Adequacy Study, Confidential Appendix, Table CA4.
[86] Lucas Report pg. 35-36.

are very large projects and have very long development cycles, with complex environmental and other permitting requirements. **BEGIN CONFIDENTIAL** [redacted] **END CONFIDENTIAL**
Strategen agrees with NCSEA/CCEBA that Duke's reliance on pumped hydro for its deep decarbonization portfolios is too optimistic. Moreover, the inclusion of this resource is likely a significant driver of higher costs in these portfolios since they were forced in rather than economically selected.

Hydrogen

Duke included some references in its IRP to hydrogen as a potential fueling option for new combustion turbines.[87] However, it does not appear that Duke has given much consideration at this stage to estimating the investment costs and lead time for new infrastructure necessary to accommodate hydrogen. While Duke has claimed that new natural gas units will also be designed to run on hydrogen, gas turbines able to operate on 100% hydrogen while meeting NOx emission limits are not yet commercially available and, as NCSEA/CCEBA expert Lucas noted,[88] it is not clear whether Duke would install units with this capability. Additionally, Duke has not answered several fundamental questions regarding the hydrogen fuel stock. For example, where will Duke purchase hydrogen fuel? Or does Duke plan to produce hydrogen itself? What are the costs associated with each of these options? How will the hydrogen be transported and stored? Or will hydrogen be produced on-site? Does Duke plan to blend hydrogen into existing gas fuel? If so, it is worth noting that existing natural gas pipelines can accommodate blends of up to 20-30% hydrogen, but higher percentages of hydrogen would necessitate either upgrades to existing pipelines or the construction of new pipelines. Considering stranded asset risks, a more detailed plan on the potential transition of its combustion turbines from natural gas to hydrogen is warranted.

7) Recent ITC Extension

NCSEA/CCEBA noted that Duke's modeling assumptions require a modification to account for the extension in the federal ITC for solar and solar plus storage, which was included in the December 2020 omnibus spending bill that passed through the US Congress.[89] Strategen agrees that this amounts to a material change to Duke's resource planning environment. Strategen has had recent experience modeling another utility's resource plan in EnCompass. After updating the ITC assumptions to incorporate this change, we noted a significant increase in solar and solar plus storage deployments through the mid-2020s.

[87] Lucas Report pg. 8-9
[88] *Id.*
[89] https://www.solarpowerworldonline.com/2020/12/solar-investment-tax-credit-extended-at-26-for-two-additional-years/

8) EV Charging

NCSEA/CCEBA noted that Duke's IRPs assumed that Electric Vehicles will be contributors to the winter morning peak, and will not be grid resources that could minimize that peak.[90] Strategen generally agrees with NCSEA/CCEBA that this is not a reasonable assumption on Duke's part. EVs can easily reduce their contribution to the winter peak through "V1G"[91] approaches that reduce or delay charging during peak hours. This has successfully been implemented in other locations, through time of use rates as well as off-peak charging rebates.[92] "V2G," whereby EVs discharge to the grid, is also technically feasible today and is being implemented in several demonstration projects around the country.[93] This capability could allow EVs to effectively double their contribution to reducing peak load. While there are few V2G capable vehicles on the road today, manufacturers have made recent announcements that they will be including this feature in future EV models.[94] As such, Strategen believes some amount of either EV load reduction and/or V2G potential should be reflected in Duke's IRPs.

4. Areas of General Alignment with AGO's Initial Comments

Strategen notes that the AGO's Initial Comments were generally aligned with other key stakeholders. The following lists issues where we perceive there is strong alignment:

[90] NCSEA/CCEBA Comments pg. 31.
[91] V1G refers to managed charging approaches that do not include any bidirectional or "vehicle to grid" capabilities, which are often referred to as "V2G." Thus, charging is curtailed during specific time periods that match the needs of the grid or an individual customer.
[92] For example, see: https://efiling.energy.ca.gov/GetDocument.aspx?tn=228787-14&DocumentContentId=60075
[93] For example, see: https://www.fermataenergy.com/news-press/proven-results-and-cost-savings-with-v2g-technology
[94] https://thedriven.io/2021/04/07/volkswagen-wants-to-stabilise-grid-by-adding-v2g-in-all-its-electric-cars/

Table 1. Comparison of Selected Parties' Initial Comments

Issue	Recommendation/ Conclusion	AGO Initial Comments - Strategen	Public Staff Initial Comments	NCSEA/CCEBA/ SACE Initial Comments
Coal Retirements	Duke should allow its primary planning model to simultaneously optimize resource additions and retirements rather than evaluate retirements in a separate analysis	P 5	p 15 & p 110	NCSEA/CCEBA Exhibit 2 (E3 Report), p 21
Transmission	Not enough information was provided by Duke about their transmission planning assumptions	P 7	P 16	NCSEA/CCEBA P 42
Resource Adequacy	There are substantial reliability benefits from neighbor assistance and regionally coordinated operations that Duke did not fully explore	P 10-12	P 75	NCSEA/CCEBA P 4
Natural Gas	Duke's analysis did not adequately consider potential stranded cost risk from natural gas additions	P 17	P 7-8	NCSEA/CCEBA P 12, 21
Clean Energy Resource Assumptions	Duke's analysis did not adequately capture potential synergies between the capacity value of resources such as solar, storage, and DSM.	P 15-16	[N/A]	NCSEA/CCEBA P 32-40
Clean Energy Resource Assumptions	Battery storage costs were higher than other estimates and 2-hr duration was arbitrarily excluded	P 13-15	[N/A]	NCSEA/CCEBA P 18
EE/DSM	Duke should consider a more comprehensive list of EE/DSM measures	P 16	P 18	SACE Grevatt Report p 7

5. Recommendations

Taking into account the analysis presented in this report, and the analysis provided other parties Initial Comments on Duke's IRP, Strategen makes the following priority recommendations:

1. The Commission should determine that the plans presented by Duke are inadequate for planning purposes and should be rejected. The rationale for this is described throughout this report, but most directly in Section 1.
2. The Commission should require Duke to present revised plans that simultaneously model resource additions and retirements and also include updated input assumptions as discussed here and in the AGO's Initial Comments.
3. Continue the stakeholder process for resource adequacy and direct Duke to analyze alternative portfolios proposed by others in the group.
4. Initiate a rulemaking to address storage certificate requirements and technical standards.
5. Since there are disputes about certain critical facts, Strategen believes the Commission would benefit from an Evidentiary Hearing in this proceeding. Below is a partial list of potential Issues that appear to be disputed and may require this:
   - Gas forecast assumptions, especially firm delivery costs
   - Transmission impacts and costs associated with coal retirements
   - Earliest practicable dates and economic dates for coal retirements
   - Annual limits on wind/solar additions
   - Reasonableness of "forcing in" certain resources for Duke and reasonableness of alternative analyses (i.e. Synapse)
   - Reasonableness of excluding 2-hr battery storage
   - EE/DSM potential estimates