STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-100, SUB 165

In the Matter of 2020 Biennial Integrated Resource Plans and Related 2020 REPS Compliance Plans	)))	**INITIAL COMMENTS OF TECH CUSTOMERS**

Intervenors Apple Inc., Facebook, Inc., and Google LLC (collectively, "Tech Customers"), by and through counsel, respectfully submit these initial comments regarding the 2020 Integrated Resource Plan ("IRP") for Duke Energy Carolinas, LLC ("DEC").

INTRODUCTION

North Carolina's energy needs should be met by uses of resources that are both environmentally sustainable and affordable to the consumer. These goals are no longer mutually exclusive, and a long-range plan that does not move decisively in this direction will not be successful. The ongoing evolution in the energy sector promises within the next decade to produce large-scale generation resources that are both environmentally and economically sustainable.[1]

DEC's IRP appropriately models several different scenarios based on differing assumptions and, in this regard, its filing presents additional granularity that is useful in considering different approaches to resource management. However, its proposed base

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[1] *See*, *e.g.*, Order Accepting Filing of 2019 Update Reports and Accepting 2019 REPS Compliance Plans, Docket No. E-100, Sub 157 (Apr. 6, 2020), at 11 [hereinafter 2019 IRP Update Order] ("[A]ll parties agree that the near and intermediate term periods will be marked by rapid technological change accompanied and reinforced by potentially dramatic changes in the costs of new generating technologies and compounded by an increasing emphasis on reduction in greenhouse gas emissions from electric power generation. The Commission's view is no different." (emphasis added)).

case appears to be largely modeled on a "status quo" approach, reflecting additional investment in capital-intensive, non-renewable generation for at least the next decade. Tech Customers are concerned that DEC's IRP presents an inaccurate picture of the future because DEC (1) underestimates the financial benefits of switching to renewables, (2) overstates the financial impediments to adopting renewables, and (3) fails to account for impending market reform. The result is that DEC is planning to invest billions of dollars in a traditional generation portfolio that might become a financial albatross to ratepayers for decades to come.

LEGAL STANDARD

The General Statutes require the Commission to analyze "the long-range needs for expansion of facilities for the generation of electricity in North Carolina."[2] In aid of this analysis, the Commission may require utilities to present their "proposals as to the future needs for electricity to serve the people of the State[.]"[3] By statute, the analysis of the State's future-generation needs must include an assessment of demand forecasts, reserve margins, and the generation portfolio, as well as power sharing "and other arrangements with other utilities and energy suppliers" that will "achieve maximum efficiencies."[4]

Consistent with the Commission's statutory obligations, Rule R8-60 requires electric utilities to provide IRPs that include a fifteen-year forecast of demand and a comprehensive analysis of the generation portfolio needed to satisfy the forecasted demand. The objective of the IRPs are "to identify those electric resource options that can

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[2] N.C. Gen. Stat. § 62-110.1(c).

[3] *Id.*

[4] *Id.*

be obtained *at least cost* to the utility and its ratepayers consistent with the provision of adequate, reliable electric service."[5] The IRPs are explicitly required to include an assessment of the benefits of renewable generation and purchasing energy from the wholesale market.[6]

After the utilities submit their IRPs, intervenors are permitted to file alternative generation plans or file evaluations of or comments on the utilities' IRPs.[7] From the IRPs, comments, and other evidence presented, the Commission determines the sufficiency of the information provided as well as the reasonableness of the utilities' IRPs and may direct further action based on conclusions drawn in the proceeding.[8]

INITIAL COMMENTS

Because DEC's IRP does not account for all the benefits of renewables, assigns inaccurate costs to the adoption of renewables, and fails to address the benefits that might be associated with market reform, Tech Customers respectfully ask that the Commission direct DEC to resubmit an IRP that remedies these shortcomings.

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[5] Order Accepting Integrated Resource Plans and Accepting REPS Compliance Plans, Docket No. E-100, Sub 147 (June 27, 2017), at 2 (emphasis added) [hereinafter "2016 IRP Order"]; *see* N.C. Gen. Stat. § 62-2(3a) ("to require energy planning and fixing of rates in a manner to result in the least cost mix of generation and demand-reduction measures which is achievable").

[6] *See* Rule R8-60(e) (renewables); Rule R8-60(d) ("soliciting proposals from wholesale power suppliers and power marketers to supply it with needed capacity").

[7] *See* Rule R8-60(k).

[8] *See*, *e.g.*, 2019 IRP Update Order, at 14–15.

I. DEC'S IRP DOES NOT APPEAR TO ACCOUNT FOR ALL THE BENEFITS OF RENEWABLE GENERATION.

DEC's IRP does not appear to account fully for some key financial benefits of adding more renewable generation to its portfolio: the avoidance of carbon taxes, stranded assets, and the risk of higher natural gas prices.

A. Renewables avoid costs caused by carbon emissions.

Given the recent political developments at the national level, it seems increasingly likely that there will be a meaningful shift in federal policy regarding carbon emissions in the near term. DEC's financial modeling, however, does not fully account for the costs of carbon emissions. DEC's financial modeling includes the assumption that a carbon tax will first appear in 2025 at $5/ton and escalate at $3/ton per year.[9]

DEC's own report, however, reveals that its estimates are far below recent proposals.[10] The American Opportunity Carbon Free Act of 2019 started at $52/ton—a *ten-fold* increase over DEC's starting rate—and will escalate at $10/ton per year. Similarly, the Climate Leadership Council suggests $40/ton (eight times greater than DEC's model) with escalation at 5% per year. The Energy Innovation and Carbon Dividend Act starts at $15/ton with annual increases of $10/ton. The lone proposal that comes close to DEC's assumption is the CLEAN Futures Act that starts at $5/ton, but then escalates at $7/ton per year—more than twice the rate DEC's assumes. While prior forecasts of a carbon tax have not been borne out, DEC's current modeling of the cost of carbon emissions appears to be

[9] DEC, *2020 Integrated Resource Plan*, Docket No. E-100, Sub 165 (Sept. 1, 2020), at 152 [hereinafter "DEC 2020 IRP"].

[10] DEC 2020 IRP, at 152–53.

too conservative based on these *past* proposals—proposals made before the arrival of the Biden Administration and its commitment to emission reductions.[11]

A carbon tax, moreover, is only one type of potential cost imposed by DEC's reliance on gas generation. In addition to this measurable financial risk, carbon emissions from gas generation also create the hard-to-quantify costs of health problems (caused by air pollution) and severe weather (stimulated by climate destabilization). In this regard, DEC's proposals do not appear to fully consider recent research suggesting that gas leakage and the environmental impact of methane might make gas generation less of an improvement over coal generation than originally believed.[12]

Underestimating the cost of emissions is very costly to ratepayers. It results in an unhurried pace of shuttering coal plants, as opposed to an aggressive plan to decommission these (already uneconomical) plants before they become even larger financial liabilities. Compounding the problem, DEC's current plan is to replace its coal plants with natural gas plants—which will also be subject to the future carbon tax. In sum, by downplaying the future cost of carbon emissions, DEC is justifying the continuation of a traditional generation portfolio that, based on more realistic assumptions, might pose greater financial burdens on ratepayers than a portfolio enhanced with more renewables.

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[11] *See*, *e.g.*, White House Briefing Room, *FACT SHEET: President Biden Takes Executive Actions to Tackle the Climate Crisis at Home and Abroad, Create Jobs, and Restore Scientific Integrity Across Federal Government* (Jan 27, 2021) (highlighting executive order targeting emission reductions), available at https://www.whitehouse.gov/briefing-room/statements-releases/2021/01/27/fact-sheet-president-biden-takes-executive-actions-to-tackle-the-climate-crisis-at-home-and-abroad-create-jobs-and-restore-scientific-integrity-across-federal-government/.

[12] *See*, *e.g.*, Lavoie, Shepson, *et al.*, *Assessing the Methane Emissions from Natural Gas-Fired Power Plants and Oil Refineries*, Environ. Sci. Technol. 2017, 51, 3373−3381, available at https://pubs.acs.org/doi/pdf/10.1021/acs.est.6b05531.

B. Renewables will not become stranded assets.

Gas generation faces the risk of accelerated obsolescence as the cost of renewables continues to decline, carbon emissions are penalized, and policy (whether federal, state, or Duke-internal policy) moves closer to a zero-emissions standard. As gas plants become obsolete, ratepayers face the risk of continuing to pay for these enormous investments for years after the plants are no longer used and useful. DEC should meticulously assess—and mitigate against—the risk of stranded assets in its generation portfolio.

DEC does acknowledge that its IRP presents a real risk of stranded assets. In response to concerns about stranded assets, DEC ran a stress test in which DEC assumed its natural gas plants would have shortened lifespans of only 25 years,[13] compared to normal lives of 40 years.[14] Pointing to its stress test, DEC defends its reliance on natural gas plants because it is more economical to build gas generation with shortened lives than build renewable generation. DEC's defensive logic—that investments in future stranded assets are better than investments in renewable generation—raises serious concerns. At an analytical level, it calls into question DEC's assumptions about the costs of renewable generation. At a philosophical level, it is troubling that DEC's strategy for future generation is built on a belief that wasteful investments—i.e., building multi-million-dollar plants that are likely to be needed only for a portion of their useful lives—could be in ratepayers' best interests.

[13] DEC 2020 IRP, at 136.

[14] DEC 2020 IRP, at 159; *see* id. at 204–07 (showing expected lifespan of 40 years for current gas plants).

The Commission has rightly cautioned DEC about the risk of stranded assets in its long-term generation portfolio.[15] The concerns animating this warning remain relevant to DEC's current plan.

C. Renewables are not dependent on future fuel prices.

Tech Customers also have concerns that DEC could be underestimating the future prices for natural gas. As DEC replaces its coal plants with natural gas plants, the demand for natural gas in North Carolina will increase substantially. Pressing against this surge in demand is the cancellation of the Atlantic Coast Pipeline, which constrains DEC's ability to transport additional natural gas into the state; and, assuming DEC can work around this supply constraint without increasing its costs, the likelihood of federal impediments to shale-gas production will further reduce the availability of natural gas in North Carolina.

In short, the demand for natural gas in North Carolina will likely substantially increase while its supply will likely decrease meaningfully. DEC, in defiance of fundamental economic theory, nonetheless forecasts that natural gas prices in North Carolina will likely remain relatively stable over the next decade at around $2.50/MMBtu but might rise to $4/MMBtu.[16] In contrast, the U.S. Energy Information Administration ("EIA") forecasts that natural gas prices will likely rise to almost $3.50/MMBtu by 2030 and could double to $5/MMBtu—and EIA's forecast does not address the unique economic dynamics present in North Carolina.[17] Understating future gas prices could wrongly skew

[15] 2019 IRP Order, at 11 ("[I]t is important . . . that the Companies avoid near term investments in long-lived generating assets that may, due to market forces and technological change, become economically stranded over the course of the longer planning period.").

[16] DEC 2020 IRP, at 158 (Table A-2).

[17] U.S. Energy Information Administration, *Annual Energy Outlook 2021 (AEO2021) – Narrative* (Feb. 3, 2021), at 23 (Figure 17: "Natural gas spot price at Henry Hub AEO 2021"), available at https://www.eia.gov/outlooks/aeo/pdf/AEO_Narrative_2021.pdf.

DEC's financial analysis in favor of gas generation to the exclusion of investments in fuel-free renewable generation.

II. DEC'S PLAN IMPOSES QUESTIONABLE COST BARRIERS TO RENEWABLE GENERATION.

Some of the financial roadblocks that DEC identifies for the adoption of large-scale renewables appear suspect. DEC seems to speculate about huge transmission costs, insist on an inflexible reserve margin, and refuse to model third-party construction of solar generation. The result is that renewables appear more costly than they actually might be.

A. DEC offers cursory estimates of huge transmission costs for importation and renewables.

DEC's ability to import capacity from neighboring jurisdictions will help smooth the intermittent generation of renewables. DEC, though, has offered high-level estimates of the transmission investments needed to accommodate a greater shift to importation of capacity and renewable generation.

To allow DEC to import an additional 5,000 MW of capacity into North Carolina, DEC projects that DEC and Duke Energy Progress, LLC ("DEP") would collectively have to invest between $4 billion and $5 billion in transmission upgrades; to import twice as much (10,000 MW), DEC and DEP would have to invest twice as much ($8 billion to $10 billion).[18] The costs of integrating large-scale renewables—such as in the 70%-carbon-reduction scenario and no-new-gas scenario—were not as staggering, yet still huge: between $1.7 billion and $1.9 billion in transmission upgrades.[19]

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[18] DEC 2020 IRP, at 58–59.

[19] DEC 2020 IRP, at 57.

These estimates on which DEC relied in its IRP, however, are not reliable. DEC admitted that it used only "high level assessments" for the transmission costs, which fell short of qualifying as a Class 5 level estimate.[20] A Class 5 level estimate—the lowest cost-estimate class recognized by AACE International—requires merely that 0% to 20% of the project be defined and the accuracy of the cost estimate vary between +100% and -50%.[21] DEC's transmission estimates are so cursory that they fail to satisfy even this minimum threshold of reliability. DEC admitted that it did not model transmission costs that would be required with its future generation or the importation of neighboring capacity.[22] As for the transmission costs of adding solar generation, DEC simply used the average cost for past solar-related transmission upgrades, without any analysis of whether certain economies of scale could be achieved with future large-scale solar.[23]

Moreover, these estimates fall far short of the level of analysis required to fully analyze the potential benefits from improvements to DEC's transmission assets. For example, the Commission recently denied an application for a certificate of public convenience and necessity for the construction of a 70-MW transmission-interconnected solar PV facility on the grounds that further information was needed concerning quantifiable ratepayer benefits, emission reductions, or other environmental or health

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[20] DEC 2020 IRP, at 55 & n.1.

[21] *See*, *e.g.*, AACE International, *Cost Estimate Classification System – As Applied in Engineering, Procurement, and Construction for the Process Industries*, at 2, available at https://www.costengineering.eu/Downloads/articles/AACE_CLASSIFICATION_SYSTEM.pdf.

[22] *See* DEC Response to NCSEA Data Request Nos. 8-5 & 8-9 (attached as Exhibit 1).

[23] *See* DEC Response to NCSEA Data Request Nos. 8-7 (attached as Exhibit 2); *see also* DEC 2020 IRP, at 56.

benefits associated with the significant network upgrades necessitated by the project.[24] In so holding, the Commission specifically noted its expectation that such issues would be explored more fully in connection with the IRP process:

> Until such time as compliance with Executive Order 80 and the policy recommendations in the Clean Energy Plan are fully investigated and considered in the context of Duke's integrated resource planning (IRP) process, any benefits associated with the construction of the Facility and the Network Upgrades are not sufficiently known and measurable to be given substantial weight in support of the Application.[25]

Tech Customers agree that this proceeding is the appropriate venue for exploration of such issues and request that DEC be directed to more fully analyze the potential costs and benefits associated with network improvements.

B. An inflexible reserve margin favors the introduction of traditional generation.

DEC insists on maintaining an inflexible reserve margin, which impedes introduction of renewables. As illustrated by recent events in Texas, it is important to maintain sufficient capacity reserves and Tech Customers strongly support DEC retaining reserves sufficient to provide reliable service. However, Tech Customers question whether DEC's modeling approach is consistent with the expectations articulated by the Commission in its most recent IRP order.

DEC's IRP is based on the premise that it must build enough generation capacity to maintain a strict 17% reserve margin.[26] The Commission has already questioned the

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[24] *See* Order Denying Certificate of Public Convenience and Necessity for Merchant Generating Facility, Docket No. EMP-105, Sub 0 (June 11, 2020) (Friesian Holdings).

[25] *Id.* at 7 (Finding of Fact 15).

[26] DEC 2020 IRP, at 66.

prudency of DEC's impenetrable 17% reserve margin when making long-term planning decisions:

> [I]t is important when applying the principle of long-term least cost planning for generation assets that the Companies avoid near term investments in long-lived generating assets that may, due to market forces and technological change, become economically stranded over the course of the longer planning period. Prudent investments in additional generating capacity in the short term must take this longer-term risk into account, and an absolute insistence on a single fixed and unvarying planning reserve margin does not . . . permit sufficient flexibility to do so.[27]

In short, some flexibility in DEC's reserve margin could avoid large capital expenditures on generation plants that could become stranded assets.

DEC's persistence in maintaining a 17% reserve margin also appears to lack firm grounding. Temporarily lowering the reserve margin to avoid excess capacity would appear to be a low risk strategy. Table 9-A in DEC's report shows that, of the 13 highest surges in demand since 2014, DEC always retained some excess capacity; and in nine of these surges, it still had 5% or more capacity that was never needed.[28] Indeed, in its Order approving the 2019 IRP Updates, the Commission noted "with interest that the Companies appear to acknowledge that it is possible that short-term reserve capacity could fall below the long-term target of 17% without posing a significantly increased risk of resource inadequacy."[29]

[27] 2019 IRP Update Order, at 11.

[28] DEC 2020 IRP, at 71.

[29] DEC 2020 IRP, at 12 (footnote omitted).

DEC's 2020 IRP seems to include at least one example of the unnecessary costs imposed by DEC's rigid reserve margin. In Table 12-E of its report, DEC forecasts that it must construct a 402-MW natural gas plant in 2025 to stay above its 17% reserve margin.[30] However, if DEC would allow its reserve margin to drop to 16.3% in 2025, it would not need to build the plant. In other words, if DEC had a more flexible reserve margin, it might avoid the entire cost of a natural gas plant. In subsequent years, DEC could then return to its target reserve margin of 17% by incrementally adding (lower-cost) renewables or contracting to import more capacity from neighbors. DEC's report, though, persists with a fixed reserve margin and the investment of millions of dollars of ratepayer's money in a natural gas plant—a plant that DEC concedes might not be needed for its entire useful life (*see supra* at p. 6).

DEC's inflexibility in its reserve margin is, by its own admission, unnecessary and appears to result in massive investments in carbon-emitting plants that risk becoming stranded, rather than incremental construction of renewable generation that avoids such risks.

C. DEC did not assess whether investor-owned solar would be cheaper than utility-owned solar.

DEC chose not to model whether solar generation constructed by third-party investors would be less expensive than utility-owned solar. DEC defended its decision by explaining that "an IRP is intended to be ownership agnostic."[31] Neither North Carolina's General Statutes nor Rule R8-60 seem to say anything—either explicitly or implicitly—

[30] DEC 2020 IRP, at 100.

[31] DEC Response to South Carolina Office of Regulatory Staff Data Request No. 6-2 (attached as Exhibit 3).

about the analysis of future electric resources being "ownership agnostic." The statutes and the Commission, though, do explicitly command utilities "to identify those electric resource options that can be obtained *at least cost*."[32] DEC admitted that the cost profile of solar generation might differ based on whether it is investor- or utility-owned,[33] but did not investigate further. In order to fulfill the mandate of obtaining least-cost generation, DEC's IRP should assess whether third-party solar is cheaper than utility-owned solar.

III. DEC's PLAN FAILS TO CONSIDER THE POTENTIAL FOR SIGNIFICANT CONSUMER BENEFITS FROM MARKET REFORM.

Market reform is inevitable. Indeed, DEC has already sought the Federal Energy Regulatory Commission's approval of the Southeast Energy Exchange Market ("SEEM"), an automated intra-hour energy exchange market that could be operational by early 2022[34]—which is a modest first step towards additional regional energy coordination. In addition, the South Carolina legislature has authorized, and is moving forward with, a study to be completed by November 1, 2021 of the benefits of various restructuring options.[35] DEC's 15-year plan for adding generation, though, fails to account for SEEM and broader wholesale market restructuring. DEC's failure to account for impending market reform undermines the value of the entire IRP.

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[32] 2016 IRP Order, at 2 (emphasis added); *see* N.C. Gen. Stat. § 62-2(3a).

[33] DEC Response to South Carolina Office of Regulatory Staff Data Request No. 6-2 ("Third parties' cost of capital may be higher or lower given differences in total cost of project financing for a utility vs a third party.").

[34] Duke Energy, *Southeast electric providers submit filing with FERC for proposed advanced bilateral market platform* (February 12, 2021), available at https://news.duke-energy.com/releases/southeast-electric-providers-submit-filing-with-ferc-for-proposed-advanced-bilateral-market-platform [hereinafter "Duke SEEM article"].

[35] *See* Act No. 187 of 2020 Session of South Carolina Legislature (H.B. 4940).

A. The IRP does not address consumer benefits, if any, from SEEM.

DEC has already committed to SEEM, yet the IRP does not factor in the impact of SEEM on DEC's resource planning. DEC's participation in the forthcoming energy exchange market should result in several changes that would impact DEC's generation needs.

First, one would expect SEEM to have some impact on DEC's reserve planning. Having access to a larger source of intra-hour energy should afford some flexibility in the reserves DEC itself needs to maintain. While SEEM does not establish a formal imbalance market,[36] for illustrative purposes, the Western Energy Imbalance Market has calculated that its participants were able to reduce flexible reserves by 48% on average.[37] In theory, as DEC is able to buy more energy as needed, it will have more flexibility in how it will build future generation.

Second, SEEM could cause DEC to revise the "high level assessments" of its future transmission investments. In its FERC filing, DEC explained that SEEM is designed to make better use of existing transmission.[38] For example, if SEEM were to operate a

[36] Somewhat similar to SEEM, traditional energy markets allow utilities to trade their excess energy in real time with neighboring utilities. *See* Duke Nicholas Institute, *Evaluating Options for Enhancing Wholesale Competition and Implications for the Southeastern United States* (Mar. 2020), at 16, available at https://nicholasinstitute.duke.edu/sites/default/files/publications/Evaluating%20Options%20for%20Enhancing-Wholesale-Competition-and-Implications-for-the-Southeastern-United-States-Final.pdf [hereinafter "*Evaluating Options for Enhancing Wholesale Competition*"].

[37] Western EIM, *Benefits Report Fourth Quarter 2020* (Jan. 29, 2021), at 3, available at https://www.westerneim.com/Documents/ISO-EIM-Benefits-Report-Q4-2020.pdf.

[38] *DEC's Concurrence to SEEM Agreement*, FERC Docket No. ER21-1111-000 (Feb. 12, 2021), at 4-5 ("A central objective of the Members' efforts to identify potential regional improvements, which has led to the development of the Southeast EEM, is finding ways to enable the use of available transmission and increase opportunities for economic energy purchases and sales.").

dispatch process—similar to the Western EIM—then it should be able to reduce transmission congestion and better optimize the transmission capacity already available from its participants.[39] However, because of SEEM's emphasis only on using currently unused transmission capacity, SEEM appears unlikely to accomplish the same level of optimization of DEC's current transmission system. Nevertheless, because DEC claims SEEM will improve its transmission usage, DEC should address how such optimization will impact the scope of future transmission upgrades that DEC has cursorily estimated to be in the billions.

Third, SEEM will, according to DEC, allow for "improved integration of all energy resources, including renewables[.]"[40] To the extent DEC perceives such benefits, they should be modeled in the IRP.

If these common benefits of an energy market are equally true for SEEM, then DEC should analyze the impact of SEEM on its resource planning. If DEC takes the position that SEEM will not produce such benefits that are common to other energy markets, then DEC should otherwise explain the advantages of SEEM and account for SEEM's role in capacity and transmission planning.

B. SEEM is but the first step towards true market reform that will bring significant benefits to North Carolina consumers.

As DEC describes it, SEEM is merely an "incremental improvement" to the status quo.[41] The ultimate destination to which SEEM is pointing is a structural reorganization of

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[39] *Evaluating Options for Enhancing Wholesale Competition*, at 18.

[40] Duke SEEM article, *supra* n.32.

[41] *DEC's Concurrence to SEEM Agreement*, FERC Docket No. ER21-1111-000 (Feb. 12, 2021), at 5. SEEM has many shortcomings. It is a narrow bilateral-matching system, rather than a broader open-market among all participants. SEEM allows only for intra-hour trading (which

the market, such as a regional transmission organization ("RTO"), that will facilitate inter-regional energy exchanges and efficient integration of renewable energy. An RTO, as an example, balances supply and demand by allocating the cheapest generation resources through both day-ahead and real-time energy markets.[42] RTOs demonstrate that market reorganization will significantly, and beneficially, impact DEC's future resource planning.

Studies show that an RTO would introduce additional improvements that build upon the initial benefits offered by an energy market like SEEM. First, although energy markets create the opportunity for participants to balance real-time supply and demand over a large footprint, RTOs often go further by compelling participants to purchase cheaper wholesale energy during peak demand rather than producing it themselves, which allows for further savings and reductions in reserve margins.[43] Second, because of the ways RTOs are operated, RTOs allow for joint transmission planning and the reduction of transmission congestion.[44] Third, RTOs have even greater ability to deploy renewables because RTOs automatically dispatch the lowest-cost resources (which are often wind and solar generation) and integrate the variability of renewables over a more diverse load.[45]

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covers possibly 5% of energy scheduling) and does not create a (much, much larger) market for day-ahead trading. *See Evaluating Options for Enhancing Wholesale Competition*, at 16. SEEM does not guard against participants favoring the use of their own (more expensive) generation resources. SEEM fails to compel participants to engage in joint planning of capacity and transmission across the entire footprint.

[42] *Evaluating Options for Enhancing Wholesale Competition*, at 9–10.

[43] Energy Transition Institute, *An Energy Imbalance Market in the Southeastern United States* (Sept. 2020), at 7 [hereinafter "*An Energy Imbalance Market*"]; *Evaluating Options for Enhancing Wholesale Competition*, at 3.

[44] *An Energy Imbalance Market,* at 8; *Evaluating Options for Enhancing Wholesale Competition*, at 14.

[45] *An Energy Imbalance Market,* at 7; *Evaluating Options for Enhancing Wholesale Competition*, at 10.

In addition, an RTO's ability to balance supply and demand over a larger footprint—and the resulting diversity of capacity and load—reduces the need for participants to curtail the intermittent generation of renewables.[46] This diversity, when coupled with advancements in demand-side-management and energy-efficiency programs, should provide more supply-demand flexibility to help boost the integration of renewables. In turn, greater diversity in generation resources would mitigate against the risk of widespread shortfalls in supply.

It has been well documented that RTOs can produce efficiencies that result in massive cost savings for participants. Studies have forecasted that a Southeastern RTO could provide cumulative cost savings of up to $384 billion by 2040, with *annual* savings for DEC's and DEP's North Carolina customers ranging from $411 million to $593 million.[47] Indeed, the Commission has concluded that Dominion North Carolina Power's participation in PJM has benefited ratepayers.[48]

Section 62-110.1(c) of the General Statutes mandates that the analysis of North Carolina's future generation include an assessment of, among other things, "other

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[46] *Evaluating Options for Enhancing Wholesale Competition*, at 3, 17.

[47] Vibrant Clean Energy, *Summary Report: Economic and Clean Energy Benefits of Establishing a Southeast U.S. Competitive Wholesale Electricity Market* (Aug. 2020), at 1 (discussing Southeastern RTO), available at https://energyinnovation.org/wp-content/uploads/2020/08/Economic-And-Clean-Energy-Benefits-Of-Establishing-A-Southeast-U.S.-Competitive-Wholesale-Electricity-Market_FINAL.pdf; The Brattle Group, *Potential Benefits of a Regional Wholesale Power Market to North Carolina's Electricity Customers* (Feb. 2019), at 8 (Table 3 shows NC cost savings), available at https://brattlefiles.blob.core.windows.net/files/16092_nc_wholesale_power_market_whitepaper_april_2019_final.pdf; *see also An Energy Imbalance Market,* at 16; *Evaluating Options for Enhancing Wholesale Competition*, at 9.

[48] Order Approving Rate Increase and Cost Deferrals and Revising PJM Regulatory Conditions, Docket No. E-22, Sub 532 (Dec. 12, 2016), at 144.

arrangements with other utilities and energy suppliers" that will "achieve maximum efficiencies." On top of that, an IRP should "identify those electric resource options that can be obtained *at least cost* to the utility and its ratepayers consistent with the provision of adequate, reliable electric service."[49] The Commission should direct DEC to submit an IRP that analyzes a scenario in which DEC participates in a reorganized market, such as an RTO, thus allowing the Commission to assess how DEC's current plan for generation compares to the universally accepted lowest-cost system of energy generation.

CONCLUSION

Tech Customers respectfully request that the Commission ask DEC to submit a revised plan that:

1. Accounts for the financial benefits of increased usage of renewable generation.
2. Provides an accurate calculation of the potential financial costs associated with an increase in renewable generation and with the transmission upgrades necessary to increase the importation of capacity.
3. Incorporates scenarios that account for the impact on DEC's plan for future resources of DEC's participation in SEEM and in a restructured market, like an RTO.

[49] 2016 IRP Order, at 2 (emphasis added).

Respectfully submitted this the 1st day of March, 2021.

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CERTIFICATE OF SERVICE

I hereby certify that a true and accurate copy of the foregoing Initial Comments of Tech Customers was served on all parties or their counsel of record in this docket via electronic mail, this the 1st day of March, 2021.

BROOKS, PIERCE, McLENDON,
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By: ______________________________
Craig D. Schauer

North Carolina Utilities Commission

Docket No. E-100, Sub 165

Initial Comments of Tech Customers

EXHIBIT 1

(DEC Response to NCSEA Data Request Nos. 8-5 & 8-9)

DUKE ENERGY CAROLINAS, LLC AND DUKE ENERGY PROGRESS, LLC

Request:

Regarding the DEC IRP Report, page 55, please list transmission upgrades for each scenario and provide any models/data used in that process.

Response:

See response to NCSEA DR8-3.

Where resource-specific studies were available, i.e., North Carolina Transmission Planning Collaborative (NCTPC) offshore wind study, estimated costs for transmission upgrade projects identified in the study as necessary to enable integrating the specific resource were used.

Specific network upgrades can only be identified with the cost estimated when the location and size of the resource requesting interconnection is known. For the portfolios identified in the DEC and DEP IRPs, the locations nor MW size of the resources are known. DEC and DEP made simplifying assumptions to estimate the network upgrade costs associated with the six portfolios of resources. Cost estimates were developed for network upgrade needs associated with coal plant retirements as well as network upgrade costs for incremental MW resources based on three scenarios: "Base Case with Carbon Policy", "70% CO2 Reduction: High Wind", and "70% CO2 Reduction: No New Gas Generation" in both IRPs. The cost estimates for these three scenarios were applied to the resources for the remaining three scenarios to develop the high-level estimates.

Person Responsible: Bob Pierce, Principal Engineer
Documents consulted: N/A

NCSEA
Docket No. E-100, Sub 165
2020 IRP
NCSEA Data Request No. 8
Item No. 8-9

DUKE ENERGY CAROLINAS, LLC AND DUKE ENERGY PROGRESS, LLC

Request:

Regarding the DEC IRP Report, page 58, please share the details associated with the large transmission expansion plans for the 5-10GW import cases.

Response:

A high-level evaluation (no modeling) exercise conducted by experienced DEC and DEP Transmission Planning personnel for increasing import capability into the DEC/DEP area resulted in the potential corridor upgrades at the 230kV/500kV voltage class level identified on page 58 of the DEC IRP. No Transmission Planning studies have been conducted to assess upgrades and new transmission equipment needed to facilitate 5-10GW of increased import capability into the DEC and DEP transmission systems, and thus there are no specific associated transmission expansion plans. This high-level evaluation was based on the collective knowledge and experience of DEC and DEP Transmission Planning personnel using general cost assumptions for new infrastructure.

Person Responsible: Sammy Roberts, General Manager, Transmission Planning and Operations Strategy
Documents Consulted: N/A

North Carolina Utilities Commission

Docket No. E-100, Sub 165

Initial Comments of Tech Customers

EXHIBIT 2

(DEC Response to NCSEA Data Request Nos. 8-7)

NCSEA
Docket No. E-100, Sub 165
2020 IRP
NCSEA Data Request No. 8
Item No. 8-7

DUKE ENERGY CAROLINAS, LLC AND DUKE ENERGY PROGRESS, LLC

Request:

Regarding the DEC IRP Report, page 56, please provide background evidence regarding the assumption that there would not be any economies of scale for integration costs associated with the first 2GW of renewables, regardless of the overall scope of that development. If economies were captured in subsequent developments, how were those determined?

Response:

The costs associated with the first approximately 2GW was based on present cost estimates from studies of projects that were CPRE Tranche 1 and 2 winners or have pending IAs and other queued generators, so economies of scale would not be associated with these "known" sites. Economies of scale were not assumed for subsequent developments. DEC's and DEP's experience has been that sites with lower development costs are being developed first and future developments will occur in areas of greater congestion requiring greater cost of integration.

Person Responsible: Bob Pierce, Principal Engineer
Documents consulted: N/A

North Carolina Utilities Commission

Docket No. E-100, Sub 165

Initial Comments of Tech Customers

EXHIBIT 3

(DEC Response to South Carolina Office of Regulatory Staff Data Request No. 6-2)

Duke Energy Carolinas, LLC's
and
Duke Energy Progress, LLC's
Response to
SC Office of Regulatory Staff
Data Request No. 6-2

Docket No. 2019-224-E
Docket No. 2019-225-E

Date of Request:	**January 7, 2021**
Date of Response:	**January 13, 2021**

☐ **CONFIDENTIAL**

☒ **NOT CONFIDENTIAL**

Confidential Responses are provided pursuant to Confidentiality Agreement

The attached response to SC Office of Regulatory Staff, was provided to me by the following individual(s):Matthew Kalemba, Director DET Planning and Forecasting, and was provided to the SC Office of Regulatory Staff under my supervision.

Rebecca J. Dulin
Associate General Counsel
Duke Energy Carolinas, LLC and
Duke Energy Progress, LLC

DUKE ENERGY CAROLINAS, LLC and DUKE ENERGY PROGRESS, LLC

To the extent information differs for DEC and DEP, provide the different information, otherwise please note the information provided is the same for both.

Request:

6-2 Indicate if it is the Company's position (either DEC or DEP) that there is no difference in the cost profile of a generic new solar resource owned by the Company compared to a similar resource owned by an unaffiliated third party. If the Company believes there is no difference, then provide all reasons why the Company believes that is the case. In addition to any other reasons, specifically address the following:

a. The potentially lower cost of capital for an unaffiliated third party compared to the Company's incremental cost of capital.

b. The availability of ITC at a potentially higher percentage for an unaffiliated third party that already qualifies or can qualify in the near future for safe harbor provisions of the tax law compared to the Company.

c. The ability of an unaffiliated third party to levelize the costs to customers over the lives of the asset(s) if it owns the resource and sells the output to the Company pursuant to a PPA compared to the inability of the Company to levelize the costs to customers under typical ratemaking.

Response:

It is unclear whether the term "cost profile" is referring to the manner in which cost is recovered over time or the overall cost of the project. This response attempts to respond to both meanings. First with respect to levelized costs versus depreciated costs the two methods by definition PV back to the same number. With respect to utility cost of capital assumptions versus third party cost of capital assumptions there is a potential for differences but it is not appropriate for consideration for inclusion in an IRP framework for the reasons described below. A) Third parties' cost of capital may be higher or lower given differences in total cost of project financing for a utility vs a third party. However, an IRP compares different resources against one another using consistent financial assumptions across resource types. If the Company were to assume third party financing costs for solar, third party financing costs would then need to be assumed for all potential resources such as energy storage and gas units. These third-party financing costs vary from entity to entity, can be very project specific even within the same entity, and finally are difficult to verify and validate. Using different financing costs from one resource to the next in an IRP would essentially pre-assume which entities would build which resources while an IRP is intended to be ownership agnostic and only uses the utility cost of capital as a verifiable constant across resource types. This allows for an appropriate and consistent comparison of various resource types within an IRP process which is a hallmark of resource planning. b) Modeling for the IRP took place in late Spring/Summer 2020 and the Company did not assume an extension of the ITC when modeling solar assets at that time. While it is possible that some solar projects may qualify for safe harbor provision, yielding a potentially higher ITC, the Company assumed a perpetual 10% ITC that was levelized over the life of the solar asset consistent with tax normalization for for-profit utilities. It is possible that any future legislation that includes an extension of the ITC could also provide for removal of the tax normalization requirements for for-profit utilities. Again, because the Company does not make assumptions regarding extensions of tax credits and does not estimate third-party financing mechanisms, the Company feels that the use of the generic cost of solar assumed by the Company was prudent. c) When calculating the revenue requirements of a portfolio, the Company levelizes all capital investments, including solar, using a levelized fixed charge rate. This yields a similar cash flow to a PPA that levelizes its costs over the life of the contract. It should also be noted that even if the Company did not levelize costs in this manner, and instead recovered capital costs in a manner consistent with typical ratemaking, the PVRR result would be the same as the levelized method if the revenue requirements were calculated over the life of the asset.