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July 26, 2019

VIA ELECTRONIC FILING

M. Lynn Jarvis, Chief Clerk
North Carolina Utilities Commission
4325 Mail Service Center
Raleigh, North Carolina 27699-4325

RE: Duke Energy Carolinas, LLC and Duke Energy Progress, LLC's Proposed Order
Docket No. E-100, Sub 157

Dear Ms. Jarvis:

I enclose the Proposed Order of Duke Energy Carolinas, LLC and Duke Energy Progress, LLC for filing in connection with the referenced matter. An electronic copy is being emailed to briefs@ncuc.net.

Thank you for your attention to this matter. If you have any questions, please let me know.

Sincerely,

Lawrence B. Somers

Enclosure

cc: Parties of Record

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-100, SUB 157

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of 2018 Biennial Integrated Resource Plans and Related 2018 REPS Compliance Plans	)))))))) PROPOSED ORDER OF DUKE ENERGY CAROLINAS, LLC AND DUKE ENERGY PROGRESS, LLC ACCEPTING INTEGRATED RESOURCE PLANS AND ACCEPTING REPS COMPLIANCE PLANS

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

BEFORE: Chair Charlotte A. Mitchell; and Commissioners ToNola D. Brown-Bland, Lyons Gray, and Daniel G. Clodfelter

APPEARANCES:

For Duke Energy Carolinas, LLC and Duke Energy Progress, LLC (DEC, DEP and collectively, Duke):

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

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

G.S. §62-15(d) requires the Public Staff to assist the Commission in making its analysis and plan pursuant to G.S. §62-110.1.

G.S. §62-2(a)(3a) declares it a policy of the State to:

> assure that resources necessary to meet future growth through the provision of adequate, reliable utility service include use of the entire spectrum of demand-side options, including but not limited to conservation, load management and efficiency programs, as additional sources of energy supply and/or energy demand reductions. To that end, to require energy planning and fixing of rates in a manner to result in the least cost mix of generation and demand-reduction measures which is achievable, including consideration of appropriate rewards to utilities for efficiency and conservation which decrease utility bills....

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

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

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

Further, Commission Rule R8-67(b) requires any electric power supplier subject to Rule R8-60 to file a REPS compliance plan as part of each biennial and annual report. In addition, each biennial and annual report should (1) be accompanied by a short-term action plan that discusses those specific actions currently being taken by the utility to implement the activities chosen as appropriate per the applicable biennial and annual reports, and (2) incorporate information concerning the construction of transmission lines pursuant to Commission Rule R8-62(p).

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

2018 BIENNIAL REPORTS

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

The following parties have been allowed to intervene in this docket: Broad River Energy, LLC; Carolina Industrial Group for Fair Utility Rates I, II, and III ("CIGFUR"); Carolina Utility Customers Association, Inc. ("CUCA"); Ecoplexus, Inc. ("Ecoplexus"); Environmental Defense Fund ("EDF"); North Carolina Clean Energy Business Alliance

(“NCCEBA”); North Carolina Sustainable Energy Association (“NCSEA”); North Carolina Waste Awareness and Reduction Network (“NC WARN”); and jointly, Southern Alliance for Clean Energy (“SACE”), the Sierra Club, and the Natural Resources Defense Council (“NRDC”). The Public Staff’s intervention is recognized pursuant to G.S. §62-15(d) and Commission Rule R1-19(e). The Attorney General’s intervention is recognized pursuant to G.S. §62-20.

PROCEDURAL HISTORY

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

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

On November 8, 2018, NC WARN filed a motion for evidentiary hearing.

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

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

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

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

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

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

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

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

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

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

12, 2019 and May 24, 2019, the Public Staff filed corrections to its initial comments.

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

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

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

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

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

DISCUSSION

The Commission finds and concludes that the record in this proceeding includes sufficient detail to allow the Commission to decide all contested issues without the necessity of a further hearing. The Commission commends the utilities and intervenors for the quality of presentation and analyses. The following sections summarize issues significant to the Integrated Resource Plans filed by the utilities and reflect the full record in the proceeding.

PUBLIC STAFF COMMENTS

In its March 7, 2019 Comments, the Public Staff generally supports Duke's 2018 IRPs and Renewable Energy and Energy Efficiency Portfolio Standard ("REPS") Compliance Plans as reasonable for planning purposes and compliant with Commission rules and requirements. Some specific findings by the Public Staff include:

- The Utilities used accepted econometric and end-use analytical models to forecast their peak and energy needs. (Public Staff Comments at p. 22); DEP's peak load and energy sales forecasts are reasonable for planning purposes, but the Public Staff noted concerns about DEP under-forecasting its winter peaks (*Id*. at pp. 29; 77-81); and DEC's peak load and energy sales forecasts are reasonable for planning purposes (*Id*. at p. 26);
- DEC and DEP should maintain their reserve margins as filed, but continue to present a 16% reserve margin sensitivity analysis in future IRPs (*Id*. at p. 98);
- DEC and DEP forecasted DSM and EE program savings in compliance with Commission Rule R8-60 and previous Commission orders, as well as the presentation of data related to those savings (*Id*. at p. 50);
- DEC and DEP included 150 MW and 140 MW of nameplate battery storage placeholders, respectively, in their IRPs, and the Public Staff encouraged the Companies to continue to enhance their modeling capabilities as described in the Integrated System Operations Planning ("ISOP") sections of the IRPs (*Id*. at pp. 73-77);
- DEC and DEP should be able to meet their REPS obligations during the planning period, with the exception of the swine and poultry waste set-asides, without nearing or exceeding their cost caps, although DEP may approach the caps in 2020; and DEC and DEP's 2018 REPS Compliance Plans should be approved as filed (*Id*. at pp. 113-14).

DOMINION'S ANALYTIC TOOL

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

Commission Conclusions – Dominion Analytic Tool

Based on the foregoing, the comments of the parties, and the entire record in this proceeding, the Commission concludes that Duke's current method of fuel forecasting and modeling in its IRPs is reasonable, and the Commission will not require Duke to adopt the Dominion fuel diversity analytic approach.

LOAD FORECAST

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

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

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

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

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

NCSEA alleged that Duke continues to promote its grid improvement plans, but does not reflect it in its IRPs.[1] NCSEA notes that Duke's grid improvement plans, which would prepare the grid for decentralized, distributed generation over a 10-year period, includes IVVC, a voltage management program, which will allow Duke to manage distribution circuits (to reduce impacts to customers with large motors sensitive to voltage control) and allow the utilization of peak shaving and emergency modes of operation. (NCSEA Comments, pp. 10-13) Duke commented that the original grid improvement plan proposed in DEC's last general rate case in Sub 1146 did not contain a DEC IVVC program. Duke noted that, based upon stakeholder feedback received through the subsequent grid improvement stakeholder workshops hosted by Duke, it has added a DEC IVVC program and plans to reflect the DEC IVVC program in future IRPs.

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

Duke noted that, in response to the Commission's request in 2016, it completed a thorough review of the peak forecasting methodology in 2018, which led to raising the peak forecast significantly. Duke agreed with the Public Staff that the revised methodology provides a reasonable forecast of normal peak demand. Duke noted that the peak forecast process is also continuously adapting to changing weather and demand trends as it receives additional history. This process will result in higher forecasted peaks if extreme winter

[1] NCSEA Comments at p. 11.

weather becomes more prevalent. The process will also prevent the models from over-reacting to one or two years where extreme winter weather was an outlying event. Duke explained that an example of this would be comparing the winter of 2017-18, which was a very extreme winter from a demand perspective, to the winter of 2018-19, which was very mild.

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

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

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

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

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

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

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

Duke noted that its understanding is that the peak forecast should provide a reasonable forecast of system demand, under the assumption of peak normal weather.

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

G. Duke should provide more comprehensive documentation of their peak load forecasting methodology. Duke should consider enhancing their approach to make use of a broader set of high load data (not just monthly peaks), and an enhanced relationship between weather conditions and load as described above. Duke should also consider providing sensitivity analysis of the peak forecasts to key drivers and assumptions, to demonstrate whether the forecasts are likely to be stable over time, or instead may change substantially due to new data.

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

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

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

- Mr. Wilson's comments inaccurately describe Duke's weather-normalization process via simplification, compared to the summary description provided in the 2018 IRPs.
- Mr. Wilson asserts that Duke recognizes that the weather normalization process is "imperfect" and does not fully remove the impact of actual weather. Duke agrees

that the methodology is imperfect, primarily due to the natural chaotic behavior of weather. Specifically, the more extreme (normal) peak conditions are, the less (more) likely the peak normalization process will be to capture weather impacts accurately.

- Mr. Wilson refers to the previous weather-normalization process (2016 IRP) as being superior to the current methodology. According to Duke, Mr. Wilson mistakenly describes Duke's process as focusing solely on the peak day. Part of Duke's revised peak weather normalization process implicitly includes a "build-up" effect from the previous day(s) of the peak. This enhancement has proven to be more effective in generating peak weather normal than the previous methodology, which focused solely on the coldest day, which may or may not have aligned with the day of peak. Duke explained that it is important to note that Mr. Wilson's comments appear to be directed more at extreme peak events, which are outliers in history, versus the normal peak demand history that typically occurs.
- Duke disputes Mr. Wilson's assertions that the weather-normalization process does not produce a clear historical trend. Tables C-5 and C-6 of the 2018 IRPs provide annual historical trends of DEC and DEP actual and weather normal peak trends. In comparison, Mr. Wilson's charts (JFW-5 to JFW-8) provide an "alternate" view of this data by narrowing the magnitude of the Y-Axis, which gives the perception of nonlinearity. Finally, Mr. Wilson asserts that the Companies' peak weather normal history should be a steady linear trend. In his comments, he assumes that the underlying drivers of the peak weather-normalization history were relatively stable. However, from 2011 to 2018, both DEC and DEP saw various economic,

weather, industrial, and jurisdictional load definition disruptions that impacted the weather normalization process.

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

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

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

<u>Commission Conclusions – Load Forecast</u>

Based on the foregoing, the comments of the parties, and the entire record in this proceeding, the Commission concludes that DEC and DEP's peak load and energy sales forecasts are reasonable for planning purposes. In its 2018 IRPs, Duke summarized the extensive review of its entire peak load forecasting process that it completed in accordance with the Commission's order in the 2016 biennial IRP proceeding, Docket No. E-100, Sub 147. The Commission agrees that Duke has made appropriate refinements to its load forecasting process and should continue to do so.

NCSEA commented that Duke should include the impacts of IVCC in future load forecasts, to which Duke agreed. The Commission accepts Duke's commitment to include the impacts of IVVC in its future load forecasts. The Commission also agrees with Duke that smart meter information is already provided in the Smart Grid Technology Plans filed with the Commission and there is no need for Duke to include information about how it is using smart meter data to inform load forecasting, cost of service studies or rate designs in future IRPs. Finally, as in the 2016 biennial IRP proceeding, some parties again raised concerns about how Duke forecasts extreme weather events. SACE et al. witness Wilson also offered critiques of Duke's weather-normalization process, which Duke disputed. The Commission agrees with Duke that its current methodology accounts for any historical extreme weather and peak conditions and any modification to the current peak model to capture extreme conditions would conflict with the Commission's order from the 2016 biennial IRP proceeding. Nonetheless, the Commission determines that DEC should address in its 2020 biennial IRP, any refinements it makes to its forecasting methodology to better address load response in general, but especially the previous extreme winter weather events.

NATURAL GAS PRICES

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

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

As the Public Staff references in their comments, the duration that DEC and DEP use market-based natural gas prices prior to transitioning to fundamental natural gas forecasts has been the subject of extensive testimony and discussion before the Commission, most recently in the initial comments filed by parties in the 2018 avoided cost proceeding in Docket No. E-100, Sub 158. The Public Staff references the "same arguments and perspectives it raised on pages 21-28 of its February 12, 2019, initial comments in Docket No. E-100, Sub 158"[2] where they argued that Duke should use five years of market data before switching to the fundamental forecast.

Duke similarly incorporated by reference their Reply Comments, filed on March 27, 2019 in Docket No. E-100, Sub 158 on pages 10-19, as evidence for continuing to rely on 10 years of forward market data in the Duke filed IRPs. Specifically, the Commission directed Duke to maintain consistency between the fuel forecasts presented in their IRPs and those used in their avoided cost filings and that "to the extent the Utilities wish to propose changes in the way they utilize forward prices and long-term forecasts…these changes should be made in the Utilities' biennial [IRPs], and the same approach should be used in their biennial avoided cost filings for that same year."[3] Generally, Duke made the following arguments as part of a broader discussion of natural gas prices in the referenced reply comments:

- Duke's customers are facing a $4.5 billion long-term financial obligation and an approximately $2 billion overpayment risk as a consequence of an unprecedented number of Qualifying Facilities ("QFs") obligating Duke to purchase their output, coupled with the use of lagging and inaccurate fundamental forecasts to calculate avoided cost rates.

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[2] Public Staff Comments at p. 71.

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

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

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

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

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

Commission Conclusions – Natural Gas Prices

Based on the foregoing, the comments of the parties, and the entire record in this proceeding, the Commission concludes that Duke's current fuel forecasting methodology is appropriate for IRP planning in this docket. As noted by Duke in its reply comments, this issue is also presented in the avoided cost proceeding pending in Docket No. E-100, Sub 158. Rather than address the Public Staff's recommendation on DEC and DEP's use of forward and fundamental natural gas forecasts, the Commission will defer to decisions pending in the avoided cost proceeding.

RATE IMPACTS INCLUDED IN IRP

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

Resource Plans and Accepting REPS Compliance Plans in Docket No. E-100, Sub 147 ("2016 IRP Order").

However, in the 2016 IRP Order, the Commission stated that "The Commission recognizes that risk analyses, such as that utilized by DENC, may better inform the Integrated Resource Planning process. However, the Commission is without sufficient evidence of the value derived from such risk analyses to require DEP and DEC to utilize similar analytical tools in the development of their IRPs."[4] Duke noted that, as such, it will continue to perform sensitivity analyses on multiple variables in future IRPs. These sensitivities are intended to determine the impacts to portfolios when variables are stressed. Therefore, the sensitivities are utilized to help mitigate risks of the selected portfolio to the customer.

Commission Conclusions – Rate Impacts in IRP

Based on the foregoing, the comments of the parties, and the entire record in this proceeding, the Commission concludes that it is without sufficient evidence of the value derived from such risk analyses to require DEP and DEC to utilize similar analytical tools in the development of their IRPs.

CAPACITY VALUE OF SOLAR AND STORAGE

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

[4] *Order Accepting Integrated Resource Plans and Accepting REPS Compliance Plans,* Docket No. E-100, Sub 147 (June 27, 2017) at 61.

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

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

As further support for Duke's probabilistic approach to valuing solar capacity, Duke referred the Commission to the direct testimony of Brian Horii[5] on behalf of the

[5] Mr. Horii is a Senior Partner with Energy and Environmental Economics, Inc. ("E3") and was retained by the South Carolina Office of Regulatory Staff ("ORS") to assist in the analysis of South Carolina Electric &

South Carolina Office of Regulatory Staff in PSCSC Docket No. 2019-2-E. On page 8 and beginning on line 17 of his testimony, Mr. Horii's states as follows:

> E3 has been at the forefront of evaluating the impact of renewable resources on utility planning and operations. Through our work it is clear that resources such as wind and solar generation must be evaluated using probabilistic methods that evaluate all hours of a given period, not just a single peak hour. Moreover, the importance of probabilistic models is generally recognized across the industry, as noted by the North American Electric Reliability Corporation's ("NERC") *Probabilistic Adequacy and Measures Technical Reference Report (April, 2018): There is a recognized need to support probability-based resource adequacy assessment resulting from the changing resource mix with significant increases in variable and energy-limited resources (intermittent in nature), changes in net demand profiles resulting in the shifting of the hour of the peak demand, and other factors can have an effect on resource adequacy. (NERC, p.6)*

In his testimony, Mr. Horii disputes the appropriateness of using a coincident peak hour approach to valuing the capacity contribution of solar generation and notes that such an approach fails to recognize the capacity value provided not just by output at the time of the peak hour but also by the output during the myriad of other peak hours for which there is a non-zero risk of the utility being unable to meet all customer demand.[6] Mr. Horii further referenced the detailed hourly solar capacity value studies performed by Astrapé Consulting for DEC and DEP to infer a capacity value contribution for incremental solar for another utility's system.[7]

A. Duke disagrees with the AG's Office assessment that the Companies may be undervaluing the peak load contribution of solar technologies.

The AG's Office disputes Duke's assertion that additional solar resources beyond those shown in the 2018 IRPs have limited value because additional solar capacity only

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Gas Company's avoided cost calculations, and review the Value of Distributed Energy Resource ("DER") methodology, in PSCSC Docket No. 2019-2-E.

[6] Brian Horii Direct Testimony in PSCSC Docket No. 2019-2-E, at 8.
[7] Brian Horii Direct Testimony in PSCSC Docket No. 2019-2-E, at 10-11.

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

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

For the first time, Duke included battery storage as a resource in the 2018 IRPs. In total, DEC and DEP included nearly 300 MW (nameplate) of lithium-ion battery storage as capacity resource placeholders which were assumed to provide 80% of their nameplate capacity towards meeting the Companies' winter peak capacity needs per the Electric Power Research Institute ("EPRI") study cited in the 2018 IRPs. Additionally, Duke acknowledged in the IRPs that "Battery storage costs are expected to continue to decline, which may make this resource a viable option for grid support services, including frequency regulation, solar smoothing during periods with high incidences of intermittency, as well as, the potential to provide overall energy and capacity value."[8] Furthermore, despite the AG's Office assertion that Duke "does not thoroughly evaluate [the downward trend of storage technology costs],"[9] to the contrary, the Duke IRPs assume that battery storage costs drop by nearly 40% by year 2025 in the IRP Base Case.[10] Additionally, Duke noted that its IRPs include an aggressive capital cost sensitivity that would further the decline in battery storage costs to 60% by 2025. Finally, Duke included a sensitivity of replacing a future undesignated CT with a grid-tied battery storage option in both the DEC and DEP IRPs.[11]

Even though Duke acknowledged the potential benefits of storage, included steep cost declines for battery storage technologies, evaluated a sensitivity of replacing a future CT with battery technology, and went as far as to include upwards of 300 MW of battery storage as capacity assets in the DEC and DEP IRPs, the AG's Office argues the Companies did not go far enough by not evaluating multiple storage plus solar technologies. Duke commented that there is the potential for battery storage technologies to provide value to

[8] DEC IRP p. 33; DEP IRP p. 33.
[9] AG's Office Comments, p.5.
[10] DEC IRP p. 101; DEP IRP p. 102.
[11] Portfolio #7 (CT Centric / High Renewables with Battery Storage) is assessed in a variety of CO_2, fuel price, and capital cost scenarios.

the DEP and DEC systems, but pairing storage with solar to allow "the storage component to benefit from federal investment tax credits"[12] as suggested by the AG's Office may not always be in the best interest of the Companies' customers. According to Duke, because North Carolina's peak conditions occur in both summer afternoons and winter mornings and afternoons, and can be at least several hours in duration, there may be limitations to the capacity value of batteries, particularly batteries charged solely from solar resources. Furthermore, on May 10, 2019, the Commission issued its *Order Granting Certificate of Public Convenience and Necessity with Conditions* for the DEP Hot Springs Microgrid Project, which is a combination 3 MW (DC) solar and 4 MW lithium-ion based battery energy storage system. The Commission held that although it is not clear that the Hot Springs Microgrid is the most cost-effective way to address reliability and service quality issues at Hot Springs, the overall public convenience and necessity would be served by granting the certificate ("CPCN") for the solar generation components of the microgrid because the system benefits of the microgrid are difficult to quantify and DEP will gain valuable experience by operating the Hot Springs Microgrid as a pilot project. The Commission further stated that it supports "cost-effective development of solar and battery storage by DEP . . . and encourages DEP to continue to pursue such projects on behalf of its customers."[13]

Duke noted that it is committed to further studying the capacity value of incremental battery storage (both grid-tied storage and solar plus storage systems) in the Carolinas at increasing penetration levels. Like the Capacity Value of Solar Study Duke completed in 2018, a similar study is required to study the capacity value of storage. Duke

[12] AG's Office Comments, p. 4.
[13] Hot Springs Order at p. 17.

explained that a study of this type is both time and data intensive; however, Duke expects to include the results of a capacity value of storage study as early as the 2020 biennial IRP filings.

C. NREL Study

NCSEA alleged that the fact that Duke is studying how the grid can accommodate renewable energy penetration of 50% of peak demand somehow "undermines the credibility of their own IRPs, and calls into question how Duke has modeled clean energy resources."[14] NCSEA further alleged that their Synapse study shows that Duke has "unfairly marginalized clean energy resources." *Id*. NCSEA also cited the Virginia State Corporation Commission's rejection of Dominion's IRP because of failure to adequately model clean energy resources. (p. 14)

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

> Must-Take solar becomes infeasible once solar penetration exceeds 14% of annual energy supply due to unavoidable oversupply during low demand periods, necessitating a shift to the Curtailable mode of solar operations. As the penetration continues to grow, the operating reserves needed to accommodate solar uncertainty become a significant cost

[14] NCSEA Comments, p. 14**.**

driver, leading to more conservative thermal plant operations and increasingly large amounts of solar curtailment.

The TECO Study further states:

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

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

<u>Commission Conclusions – Capacity Value of Solar and Storage</u>

Based on the foregoing, the comments of the parties, and the entire record in this proceeding, the Commission concludes that Duke has reasonably valued solar and storage capacity in its 2018 IRPs. The Commission notes that issues related to solar capacity values have also been raised in the pending avoided cost docket. Duke included battery storage as a resource for the first time in the 2018 IRPs and, in fact, included nearly 300 MW (nameplate) of lithium-ion battery storage. In its reply comments, Duke noted that it is committed to further study of the capacity value of incremental battery storage (both grid-tied storage and solar plus storage systems) and to including the results of its study as early as the 2020 biennial IRP filings. The Commission accepts Duke's commitment and, subject to the study being complete, orders Duke to include the results of its capacity value of storage study in its 2020 biennial IRPs.

STATEMENT OF NEED SECTION IN IRP

Duke commented that it determines each utility's future (avoidable) generation need based on the difference between customer demand, net of energy efficiency, and the sum of the utility's existing resources and projected resources, to meet a required annual planning reserve margin (currently 17% for both DEC and DEP). When this difference causes the annual planning reserve margin to fall below 17%, a new resource is required in order to reliably meet customer needs. Duke explained that DEC's and DEP's IRP models select the most economic resources to meet customers' needs in the first year that a new capacity resource is required to maintain the planning reserve margin.

In its filed comments, the Public Staff stated that, "the assumptions made regarding qualified facility (QF) capacity; the treatment of QF contracts that expire within the planning period, planned utility uprates, energy efficiency programs, load assumptions, generation unit retirement assumptions, and avoidable and unavoidable planned generation units, all directly impact the first year of capacity need, which is used to calculate avoided capacity payments in the Avoided Cost proceeding. It is clear from the initial comments in Docket No. E-100, Sub 158 (2018 Avoided Cost), that these assumptions have not been clearly specified by each of the Utilities."[15] The Public Staff goes on to recommend that

[15] Public Staff Comments, p. 90 Paragraph 1.

"the Utilities, in their IRP Update to be filed in 2019 and all future IRPs and updates, include a new Utility Statement of Need section." Utilities could then reference this in biennial avoided cost proceedings, establishing clearly the first year of capacity need for the calculation of avoided capacity payments.[16] The Public Staff believes that, at a minimum, the proposed Statement of Need section should include the following:

1. The year in which the Utility would fall below its planning reserve margin without commitment(s) to procure additional resources.
2. Whether QF contracts expiring within the Avoided Cost term are renewed / replaced in kind, or excluded.
3. Whether Utility uprates are solely installed for additional capacity and if they could be considered avoidable.
4. Whether new EE measures are included in the determination of capacity need.
5. The quantity of MW needed in the first year, and a discussion of whether avoided capacity payments will be made to QF contracts executed in excess of that capacity.
6. The year in which the Utility's first avoidable capacity need becomes unavoidable.
7. Whether it is appropriate to create a separate "Avoided Cost Portfolio" in the IRP's portfolio analysis section, which might present a more objective determination of capacity need that could ensure QFs providing capacity are not treated as captive.

[16] Public Staff Comments, p. 90 Paragraph 2.

Duke commented that it agrees with Public Staff's recommendation and will include a Statement of Need section to more clearly identify the undesignated capacity needs for each utility in DEC's and DEP's 2019 IRP Updates and in future biennial IRP filings.

Commission Conclusions – Statement of Need Section in IRP

Based on the foregoing, the comments of the parties, and the entire record in this proceeding, the Commission appreciates Duke's agreement with the Public Staff's recommendation and concludes that Duke should include a Statement of Need section to more clearly identify the undesignated capacity needs for each utility in DEC's and DEP's 2019 IRP Updates and in future biennial IRP filings.

QF CONTRACT EXPIRATION IN THE IRP

In its Initial Comments, NCSEA takes exception with the method used by Duke in the treatment of QF contract expirations in the IRPs. NCSEA states that, "despite the fact the PPAs with QFs will eventually expire, Duke assumes that the PPAs will 'be either renewed or replaced in kind.' However, there is no guarantee, or requirement, that a QF will continue to provide the utility with capacity past the end of its initial PPA, even if the QF has remaining operational life." [17] This statement was made in reference to a data request response provided by the Companies to the Public Staff in this docket.[18]

Duke commented that this data request response refers only to solar QF contracts, as existing contracts of any other technology are assumed to expire at the end of the purchased power agreement ("PPA") term. Solar capacity, however, will continue to grow

[17] NCSEA Comments, p. 25 Paragraph 1.
[18] Duke Energy Carolinas, LLC's Response to Public Staff Data Request No. 6-4 and Duke Energy Progress, LLC's Response to Public Staff Data Request No. 4-12, included in NCSEA's Comments as Attachment 2.

in the future, increasing the Companies' planned solar capacity. As such, the capacity of existing solar QFs will either be procured by the renewal of existing contracts or replaced with other solar PPAs. Whether the capacity is from an existing QF or another QF does not matter in the context of the IRP, only that the capacity comes from a solar resource.

NCSEA goes on to allege that "Duke assumes for planning purposes that a QF's PPA will be renewed despite the fact that it has made numerous efforts in other proceedings to make it more difficult for a QF to renew a PPA,"[19] going on to cite Docket No. E-100, Sub 101 and Docket No. E-100, Sub 158, as examples. Duke argued that both dockets cited by NCSEA relate to the upgrade of QF equipment, which is in no way impactful to the 2018 IRPs.

NCSEA continues its argument by stating that "other wholesale PPAs are removed from DEC and DEP's respective generation stacks when they expire and create capacity needs. However, Duke treats PPAs with QFs differently in its planning process."[20] Duke noted that it is true that DEC and DEP have consistently assumed across multiple planning cycles that all wholesale purchase contract capacity, including QFs, is removed in the year after a wholesale contract expires and that QFs are not presumptively assumed to establish a new PPA to deliver capacity and energy to the Companies over a new fixed term in the future. According to Duke, if, however, the QFs have already executed a contract extension or renewal with Duke, the specific contract capacity will be included past the original contract expiration year to the year of expiration of the extended/new contract. Thus, the existing QF contracts may either be renewed or replaced with other new solar facilities so that, in the aggregate solar penetration reaches levels projected in the IRP. The IRP is

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[19] NCSEA Comments, p. 25 Paragraph 2.
[20] *Id*. p. 26, Paragraph 1.

agnostic as to which choice is made but rather focuses on an expected level of solar penetration. Furthermore, Duke commented that the IRPs present scenarios with both higher and lower levels of solar penetration that are also agnostic to the decision of renewal versus replacement with new solar facilities. Duke noted that this is consistent with the approach for all contracted generation. For example, at the time DEP's 2018 IRP was filed, several natural gas PPAs were expiring. The IRP did not explicitly assume these contracts were renewed but rather put in a generic undesignated PPA that was deemed avoidable by QFs for the purpose of establishing avoided cost rates. Therefore, NCSEA's argument that the Companies are treating existing QF contracts differently and unfairly in the IRPs is untrue.

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

According to Duke, DEC and DEP have taken a reasonable and consistent approach to recognizing expiring wholesale purchase contracts, including QF contracts, in their 2018 IRPs. Duke's IRPs actually assume that, upon expiration of any third-party wholesale purchase contract (both QF and non-QF), DEC and DEP recognize a reduction in capacity by the amount of the capacity provided in the expiring wholesale purchase contract in the year following contract expiration. Duke noted that this approach to capacity planning is not new. Since the Duke Energy/Progress Energy merger, Duke's 2012, 2014, 2016, and 2018 biennial IRPs have all consistently assumed the expiration of wholesale purchase PPAs, including QF PPAs, that result in a need for replacement capacity to be procured through each utility's resource planning process to meet the targeted reserve margin during a given year. Thus, the expiration of each PPA has the potential to impact the timing of DEC and DEP's first capacity need, particularly when viewed in aggregate with other contract expirations or retirements. Fundamentally, it is prudent resource planning not to rely upon assumed future third-party owned capacity in years where no contract or other legally-enforceable commitment guaranteeing delivery exists.

Commission Conclusions – QF Contract Expiration in IRP

Based on the foregoing, the comments of the parties, and the entire record in this proceeding, the Commission concludes that Duke has taken a reasonable approach in how it recognizes expiring wholesale purchase contracts, including QF contracts, in its 2018 IRPs.

CLIMATE CHANGE

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

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

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

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

Duke noted that it has been aggressive with its pace of retiring coal plants (having retired more than half of its Carolinas coal plants over the last decade), adding renewables to the resource mix, increasing EE/DSM offerings to its customers, and operating a reliable nuclear fleet that provides half of its customers' energy demand with zero CO_2 emissions. These actions, along with operating efficient natural gas generation with low cost fuel, will allow the DEC and DEP systems to meet and exceed the goals of Executive Order No. 80, signed in the Fall of 2018, as well as the Companies' own sustainability targets, all while meeting the Commission's Rule R8-60 requirement to "provide reliable electric utility service at least cost over the planning period."[21] Duke explained that it is participating in the Executive Order No. 80 stakeholder meetings and, although the State's specific plans to implement the order are currently unknown, with the final report not expected until October 2019, Duke will address any additional requirements in future IRPs once any additional requirements are known.

[21] NCUC R8-60 – Integrated Resource Plans and Filings.

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

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

Commission Conclusions – Climate Change

Based on the foregoing, the comments of the parties, and the entire record in this proceeding, the Commission concludes that Duke has reasonably considered CO_2 sensitivities in its 2018 IRPs and finds the AG Office's comments unpersuasive. The Commission notes and appreciates Duke's efforts to date to reduce carbon emissions across its fleet and its commitment to evaluate accelerated coal unit retirements for DEC and DEP. The Commission agrees with Duke that decisions around accelerated coal retirements and a lower carbon future include not only generation and reliability concerns, but also customer rate impacts that cannot be considered in isolation in the IRP docket. The

Commission appreciates Duke's commitment to make filings with the Commission after it has completed its accelerated coal unit retirement analysis.

DEMAND-SIDE MANAGEMENT AND ENERGY EFFICIENCY

Several intervenors commented or made recommendations regarding Duke's DSM and EE plans. In response, Duke stated it disagreed with the statement made by SACE et al., at pages 12-13 of their IRP Comments, that the Companies' projections of DSM/EE peak savings in the later years of the IRP are "inconsistent with its declared commitment to continue to grow the amount of DSM/EE resources to meet customer demand." Duke explained that, specifically for the DSM projections, the amounts of DSM included in the IRP forecast are based on the Duke's past experience with customer acceptance of these programs and the expectation that the amount of DSM capacity savings will reach a steady-state level beyond the first few years of the IRP forecast is consistent with this experience. As explained in detail in the response to comments of NCSEA in the 2018 Avoided Cost proceeding, Docket No. E-100, Sub 158, Duke believes that the forecast of DSM program savings are reasonable and accurately reflect a continued effort to add new customers; however, the forecast recognizes customer response to these programs has been limited, despite targeted and ongoing efforts to increase participation.[22] According to Duke, DEC and DEP's forecast of additional increases in DSM peak savings for the next few years followed by a period of steady-state peak savings is reasonable and prudent and accurately reflects the amount of "customer demand" for these programs.

Also, regarding the impact of EE programs on peak demand, Duke disagrees with the intervenors' conclusion that Utility Energy Efficiency ("UEE") program disinvestment

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

occurs in the outer years of the IRP forecast. Duke commented that incremental annual UEE savings projection levels are similar throughout the entire forecast period as shown in the tables in Appendix D of the IRPs. However, as shown in the LCR tables in the IRPs (Tables 12-E and 12-F), the outer year UEE projections are being offset by UEE programs initiated 8 to 10 years prior that have reached the end of their useful life. Once UEE savings reach this stage, they no longer contribute to future UEE cumulative savings and are therefore removed from the cumulative savings amounts. Failure to remove these savings from the cumulative amounts would result in over-stating, or "double-counting" the impact of the Companies' UEE programs on sales. Accordingly, the Companies' approach to DSM/EE in the 2018 IRPs is appropriate.

Commission Conclusions – DSM and EE

Based on the foregoing, the comments of the parties, and the entire record in this proceeding, the Commission concludes that Duke has appropriately considered and included DSM and EE forecasts, impacts and programs in its 2018 IRPs and has complied with Rule R8-60 and previous Commission orders.

ALTERNATIVE FILED RESOURCE PLANS

NCSEA, SACE et. al, and NC WARN field alternative resource plans as part of their comments on the 2018 IRPs. Duke responded as follows:

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

Duke noted that the Synapse report filed by NCSEA as Attachment 1 to its comments claims to detail "a realistic clean energy future that provides both the energy and capacity to meet the needs of Duke's customers, while effectively meeting future reliability requirements as traditional generating resources are retired"[23]; however, the report's cost savings are based on multiple assumptions that, if implemented, would cripple the reliability of the DEC and DEP systems.

Duke argues that, first, the Synapse report, which purports to gain an immediate cost savings of 28% through "removal of [coal generation] must-run designations"[24] does not consider "transmission implications that may or may not be associated with must-run designations."[25] The must-run designations that Synapse removes are not required at all energy demand levels on the DEP and DEC systems, and Duke is not seeking "to find a use for the costly must-run coal generation"[26] as Synapse suggests. Duke instead notes that, in fact, in Synapse's attempt to match the DEC and DEP IRP base cases (with must-run designations included), "one-third of the coal generation shown in 2019 is exported to neighboring utility service territories rather than being used to meet Duke's own load requirements."[27] Duke states that it does not model sales to neighboring utilities unless those are firm sales with co-owners that are part of nuclear generation contracts or the new Lee CC, and DEC and DEP generally do not sell energy to external markets unless there are economic incentives for consumers to do so. Generally, must-run requirements increase as system energy demand levels increase or other generating units near the must-run units are not available. This level of detail was not considered relevant to Synapse as

[23] NCSEA Comments, pp. 5- 6
[24] North Carolina's Clean Energy Future: An Alternative to Duke's Integrated Resource Plan, Prepared for the North Carolina Sustainable Energy Association by Synapse Energy Economics, Inc. p. 6
[25] NCSEA Response to Duke Data Request No. 1, Item No. 1-3 part c.
[26] North Carolina's Clean Energy Future: An Alternative to Duke's Integrated Resource Plan, Prepared for the North Carolina Sustainable Energy Association by Synapse Energy Economics, Inc. p. 6.
[27] North Carolina's Clean Energy Future: An Alternative to Duke's Integrated Resource Plan, Prepared for the North Carolina Sustainable Energy Association by Synapse Energy Economics, Inc. p. 5.

they relied on Horizons Energy's National Database for their EnCompass model[28] which greatly oversimplifies must-run requirements on the DEC and DEP systems. Must-run requirements are in place to maintain stability on the transmission system by providing voltage support or other services. According to Duke, without these must-run requirements, the transmission system would be in jeopardy of not being able to serve load, which is a risk that Synapse and NCSEA have ignored.

Another source of cost savings in the Synapse report is the reduction of the required minimum reserve margins in DEC and DEP from 17% to 15% based on the NERC 2018 Long Term Reliability Assessment.[29] As noted in footnote 4 on page 53 of the NERC report, SERC Reliability Corporation ("SERC") members perform individual reliability assessments, and SERC does not provide reference margin levels for its sub-regions. Further, page 151 of the NERC report states that NERC applies a 15% margin for predominately thermal systems if a reference margin is not provided by a given assessment area. In short, the SERC and NERC reports cited by NCSEA as a basis for a lower reserve margin do not reflect the level of solar penetration that exists in the Carolinas or the need for a winter reserve margin target as determined by the Companies' resource adequacy studies. The minimum reserve margin requirement in DEC and DEP has been a point of extensive comment since the 17% reserve margin was introduced in the 2016 IRP Reports. The minimum reserve margin requirement is based on comprehensive resource adequacy studies that the Companies conducted with Astrapé Consulting in 2016. Duke explained that, although some of the intervening parties apparently still chose to stubbornly debate the findings of the study, the Commission found the 17% reserve margin requirement

[28] NCSEA Response to Duke Data Request No. 1, Item No. 1-3 part b.
[29] NCSEA Response to Duke Data Request No. 1, Item No. 1-2 part b.

reasonable for planning purposes, with the requirement that the Companies and the Public Staff file a joint report summarizing their review after filing the 2017 IRP Update.[30] Synapse took it upon themselves to ignore the 17% requirement that was developed through a study that focused on the issues facing the DEC and DEP systems, and instead used the NERC study that did not consider the level of solar penetration facing the Carolinas, which was a major driver of the increased reserve margin requirement. Duke argued that, again, Synapse and NCSEA are relying on a reduction in system reliability to drive the results of their biased resource report.

Duke commented that the third source of cost savings that is inconsistent with maintaining a reliable energy system in the Carolinas is Synapse's reliance on energy imports into the Carolinas. The Synapse "Clean Energy scenario" relies on 14% energy imports from neighboring utilities to meet demand by 2033.[31] According to Duke, this reliance on neighboring utilities to meet the Carolinas' energy and capacity needs is inconsistent with the reality that there is not enough firm transmission available to reliably import this level of energy, and the Synapse study makes no mention of the costs required to obtain firm transmission into the region. Duke argued that NCSEA and Synapse are either ignorant of the realities of transmission constraints into DEC and DEP, or they have intentionally ignored them.

Duke further pointed out that it is not clear that increasing energy imports from neighboring utilities, as NCSEA proposes to do, would result in fewer CO_2 emissions for the Carolinas. In fact, relying on other states' generation, including those states that may

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[30] *Order Accepting Integrated Resource Plans and Accepting REPS Compliance Plans*, Docket No. E-100, Sub 147.
[31] North Carolina's Clean Energy Future: An Alternative to Duke's Integrated Resource Plan, Prepared for the North Carolina Sustainable Energy Association by Synapse Energy Economics, Inc. p. 5.

still rely mainly on coal generation, would be contrary to the spirit of Executive Order No. 80's goal to reduce CO_2 emissions in the state to 40% of 2005 emission levels by 2025. As stated above, Duke's plan already exceeds Executive Order No. 80's directive by using resources located in the Carolinas.

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

> The Clean Energy Scenario maintains the required 15 percent reserve margin and EnCompass projects no loss-of-load hours and sees zero hours with unserved energy, proving that the retirement of fossil fuels and build-out of renewables leads to no new system reliability issues.[32]

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

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

[32] NCSEA Comments, p.8.

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

In summary, Duke noted that any party can claim that their plan is lower cost than the Companies' plans, but to achieve those costs savings in the manner that NCSEA and Synapse did, while still claiming to meet the reliability standards that the NCUC, Duke, and its customers demand, is unrealistic and lacks regulatory rigor. Duke, as the regulated utility in North Carolina, has the sole obligation to meet its customers' energy needs at all times throughout the year, and the Companies are steadfast in their belief that the DEC and DEP IRPs achieve that standard by doing so at the lowest reasonable cost while meeting and exceeding environmental regulations at the state and federal levels. Duke noted that, simply put, other parties to this docket do not have the obligation to serve, nor do they have an obligation to maintain a reliable electric system. Their use of overly simplistic modeling approaches to reach a predetermined ideological outcome would not be compliant with reliability standards and as such should be rejected.

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

Duke commented that the assertion of the Applied Economics Clinic in Attachment 2 of the SACE et al. comments that "the Companies have hard-wired the useful lives for their existing coal units, preventing a fair comparison of the economics of these units relative to replacement resources"[33] is misleading. The retirement dates for existing coal units are projections for planning purposes in the IRPs, and are based on retirement dates in depreciation studies approved in the most recent general rate cases by the Commission (and the Public Service Commission of South Carolina "PSCSC").

Additionally, Duke argued that AEC's assertion that "…the Companies make major decisions about their resources behind closed doors"[34] is disingenuous.[35] Multiple analyses are performed regarding the retirement options of the Companies' coal units, as confirmed in data requests received and cited by AEC in the SACE et al. Attachment 2. The results of those analyses are utilized and represented in the next filed IRP. Furthermore, Duke's IRPs and depreciation studies are open to scrutiny in the public and transparent dockets this Commission oversees with the intervention and active participation of parties like SACE et al.

Duke commented that while SACE et al. and AEC attempt to discredit Duke Companies and its commitment to meet customers' energy needs at the lowest reasonable costs, the full picture is not considered. Duke is regulated by this Commission and the PSCSC and are under an obligation to provide reliable and affordable service to their customers. Duke pointed out that the special interest group intervenors, on the other hand, may freely utilize whatever data sources and reports that support their intended purpose, while ignoring the realities of the obligation of serving customers. Statements made by the intervenors criticizing Duke's analysis techniques, assumptions, and generally, any decision that does not meet their agenda are presented as fact in their comments, without

[33] *Review of Duke Energy's North Carolina Coal Fleet in the 2018 Integrated Resource Plans*, p. 18, Part A.
[34] *Id*.
[35] By this logic, SACE et al.'s comments and AEC's report were also prepared "behind closed doors" as the Companies did not see them until they were filed with the Commission.

regard for realistic actualities. In reality, the statements and assertions aimed at discrediting Duke are incorrect. Duke noted that, notwithstanding its criticism of SACE et al.'s tactics, as noted above, Duke will continue to evaluate potential accelerated retirement of their remaining North Carolina coal units and advise the Commission in future dockets.

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

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

In a data request to SACE et al., [36] Duke requested a copy of the report developed by ICF in the study, to which SACE et al. responded that, "ICF did not develop a report. All written materials were developed by NRDC, based on data outputs provided by ICF using their IPM model with all assumptions and policy scenarios provided by NRDC."[37] According to Duke, in the data request response, NRDC provided a file including the inputs developed by them. Duke explained that there is no discussion or detailed information about the calculation and algorithm details of the models. Additionally, how the input data was actually utilized in the model is unclear. In the same response, NRDC provided a single page of outputs for each case developed by the IPM model.[38] While two cases were provided, an "economically optimized" case was not one of them. SACE et al.'s data

[36] *Southern Alliance for Clean Energy, Natural Resources Defense Council and the Sierra Club Responses to Second Data Request of Duke Energy Carolinas, LLC and Duke Energy Progress, LLC*, NCUC Docket No. E-100, Sub 157 dated April 29, 2019.
[37] *Id*. Response to DEC/DEP Data Request No. 2-1.
[38] *Id*. Response to DEC/DEP Data Request No. 2-2 including Input and Output Excel Files.

request response provides outputs for a “reference case” (also titled as “BAU No CCS”) and an “IRP case.” It is unclear if the “reference case” and the “economically optimized” case are the same case. As such, Duke noted it is impossible for the Companies to adequately review and comment on the outputs at this time.

Duke further commented that, even so, NRDC presents ICF’s “economically optimized” case as a least cost option as compared to the “IRP” scenario that was created. There are several issues in question from Duke’s point of view. First, in the ICF results presented as Attachment 1 of NRDC’s Comments, in the description of the “economically optimized” case, it is stated that, “the model was allowed to endogenously retire and add generating resources to determine a least-cost pathway for the state given existing federal and state regulations.”[39] Once again, in the absence of information regarding the calculation methodology and rigor of the ICF study, it is not clear how the model does this, what units are retired or when they are retired.

Duke explained that, additionally, NRDC states in Attachment 1 that “the only additional natural gas capacity added is from units already under construction” in the “economically optimized” case.[40] However, the capital costs and fuel prices utilized by ICF for new natural gas units are based on publicly-available generic data that is proven to be higher than in-house new-build costs developed for Company-specific locations and that consider economies of scale/scope that make these resources economic options. The costs utilized to make this statement are inordinately high and likely give any natural gas resources an unfair disadvantage.

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[39] *Economically Optimized Independent Power Sector Modeling Shows Multiple Benefits when Compared to Duke’s IRP*, p. 2, bullet one.
[40] Ibid. p. 1, bullet three.

NRDC claims, also, that "this 'optimized' case only represents a possible future in which decisions are made by an infallible market operator, instead of a reality where regulators may have to base their decisions on imperfect or incomplete information, and utilities are driven by incentives that do not always align with their customers' interests."[41] Duke argues that, first, there is no such thing as an "infallible market operator," which discredits the "optimized" case as being unrealistic. Second, Duke suggests that the inference that utilities make decisions based on "incentives" that do not "align with customers' interests" is outrageous. Duke also notes that the SACE et al. inference that the information utilized by the Companies is incomplete is absolutely false. Duke explains that its resource plans are based on best-available information that takes months to gather, vet, and include properly in modeling and analysis utilized to develop the resource plans.

Finally, NRDC claims that renewable generation (primarily solar) replaces any existing coal or future natural gas resources by stating, "renewable energy generation more than makes up for the generation reductions…"[42] Duke commented that it is impossible for intermittent solar to replace baseload resources required to reliably meet the Companies' customer demand, particularly during peak times when solar is only available to a small degree. The IPM model outputs provided in SACE et al.'s data request response mentioned above do not provide any discernable information about the operational reliability assumptions and load shapes of the solar generation or the impacts of even higher levels of intermittent solar to Duke's generating system. As determined by the Capacity Value of Solar study presented in the Companies' filed IRPs,[43] solar resources provide very

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[41] *Economically Optimized Independent Power Sector Modeling Shows Multiple Benefits when Compared to Duke's IRP*, p. 5, paragraph two.
[42] *Id*. p. 1, bullet 4.
[43] *DEC 2018 IRP* Chapter 9 and *DEP 2018IRP* Chapter 9.

little capacity value at the time of winter peak demand and capacity values decrease as the penetration of solar increases. Duke explains that infinitely high amounts of solar cannot be added to a generating system and still maintain the integrity and reliability of the system and meet required NERC reliability standards.

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

NC WARN Comments

In its comments and attached report, NC WARN alleged, among other things, that DEC and DEP can achieve one-hundred (100) percent fossil-free energy by 2030, getting halfway there by 2025. In response, Duke noted that NC WARN has, yet again, argued that the Commission should adopt an energy plan for North Carolina that is unrealistic and would jeopardize the reliable and affordable energy system that this Commission has consistently required from Duke in fulfilling the Commission's mission under the Public Utilities Act. Duke noted that although NC WARN objected to 8 of the 13 data requests DEC and DEP sent to it seeking analytical and factual support for statements made in its filed IRP comments and report, the information NC WARN did provide in its responses reveals that its comments and report are not supported by competent analysis or facts.[44] For example, in DEC and DEP Data Request 1-4, the Companies asked NC WARN to:

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

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

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

In response, NC WARN simply stated, "This statement is explained in detail, with applicable citations, in Mr. Powers' *N.C. Clean Path 2025 Report* and the *Update: N.C. Clean Path 2025*." This lack of quantitative analysis and circular reasoning is found throughout NC WARN's data request responses. See DEC/DEP Exhibit 1. Duke explains that although NC WARN's simplistic and hyperbolic conclusions may advance its own interests, its arguments should not, and cannot, be credibly relied upon by the Commission

[44] NC WARN's Responses to First Data Request of Duke Energy Progress LLC and Duke Energy Carolinas LLC are attached hereto as DEC/DEP Exhibit 1.

or anyone who truly values a reliable and affordable supply of energy for the State of North Carolina.[45]

Commission Conclusions – Alternative Filed Resource Plans

Based on the foregoing, the comments of the parties, and the entire record in this proceeding, the Commission concludes that the reports filed by NCSEA, SACE et. al, and NC WARN with their comments are inadequate for the Commission to rely upon in carrying out its statutory obligations under N.C. Gen. Stat. §§62-110.1 and 62-2(a)(3a). Pursuant to Commission Rule R8-60(j), an intervenor may file an IRP of its own with respect to any utility. If it chooses to propose an alternative IRP, the intervenor's IRP should conform to the information and analytic requirements of Rule R8-60(c) – (i).[46] To the extent that NCSEA, SACE et. al, and NC WARN intended for the reports attached to their comments to be construed as an alternative IRP for Duke, the Commission finds and concludes that these intervenor proposals were inadequate with respect to data, modeling and analysis. Even if these intervenor reports were not intended to be filed as alternative IRPs under Rule R8-60(j), the Commission further finds that the reports filed by NCSEA, SACE et. al, and NC WARN's are not persuasive and the recommendations contained therein are not supported by the evidence in this proceeding. In the context of considering whether the utilities' IRPs are reasonable for planning purposes, the Commission gives substantial weight to the goal of adequate and reliable electric service. Planning for

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

[46] *Order Approving Integrated Resource Plans and REPS Compliance Plans*, Docket No. E-100, Sub 141 (June 26, 2015); *Order Adopting Amendments to Commission Rule R8-60*, Docket No. E-100, Sub 111 (July 20, 2015); *Order Striking NC WARN's Filing as Comments and Accepting the Filing as a Statement of Position*, Docket No. E-100, Sub 147 (November 15, 2017).

adequacy and reliability requires careful analysis that gives due consideration to a myriad of factors, not just special interest group policy goals. The Public Staff discusses its review of Duke's extensive resource modeling techniques, including Duke's use of the System Optimizer and Planning and Risks models. Comments of the Public Staff, at 55-69. As discussed herein, the Commission finds the Duke 2018 IRPs to be reasonable for planning purposes.

ISOP AND IDP RULEMAKING

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

Commission Conclusions – ISOP Rulemaking

On July 23, 2019, the Commission issued its *Order Scheduling Technical Conference and Requiring Responses to Commission Questions* in this docket to obtain additional information from the Public Staff and Duke about ISOP. Based on the foregoing, the comments of the parties, and the entire record in this proceeding, the Commission requests that the Public Staff work with Duke to select a third- party facilitator and convene and facilitate discussions with interested parties on ISOP issues. The Public

Staff should file a report with the Commission which summarizes the discussions, agreements reached on particular points, and points on which agreement has not been reached. This report shall be filed in Docket No. E-100, Sub 157 within 270 days of the date of this Order.

RESOURCE ADEQUACY AND RESERVE MARGINS

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

As an initial matter, Duke notes that they have complied with all Commission orders regarding the 2016 resource adequacy studies. The NCUC's 2016 IRP Order in Docket No. E-100, Sub 147 concluded that the reserve margins included in the DEP and DEC 2016 IRPs are reasonable for planning purposes. Duke pointed out, however, the Commission also directed DEP and DEC to work with the Public Staff to address outstanding concerns raised by the Public Staff and SACE consultant Wilson. The Commission further directed the Companies and the Public Staff to file a Joint Report summarizing their review and conclusions within 150 days of the filing of Duke's 2017 IRP updates. The Joint Report was filed on April 2, 2018 and noted that although the discussions between the Public Staff and Duke were helpful, the parties did not reach agreement regarding the methodology used to incorporate economic load forecast uncertainty. Ultimately, the Public Staff recommended that DEC and DEP utilize a 16% reserve margin in their IRPs, and Duke recommended a minimum 17% winter reserve margin in their IRPs. The Commission's April 16, 2018 *Order Accepting Filing of 2017 Update Reports and Accepting 2017 REPS Compliance Plans* in Docket No. E-100, Sub 147, accepted the parties' Joint Report and concluded that DEC and DEP may continue to utilize the minimum 17% winter reserve margin for planning purposes in their 2018 IRPs. In addition, the Commission ordered DEC and DEP to further address the economic load forecast uncertainty issue in their 2018 IRPs. The Commission also required the Companies to present a sensitivity analysis in their 2018 IRPs that illustrates the impact of a 16% winter reserve margin, including the specific risk impact (LOLE) of using a 16% minimum reserve margin versus a 17% minimum reserve margin. Duke asserts that it complied with the Commission orders in developing its 2018 IRPs.

Economic Load Forecast Uncertainty

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

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

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

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

Duke explained that, given the disagreement in methodology and assumptions for incorporating load uncertainty in the resource adequacy studies, it is notable that the Public Staff expressed concerns in their IRP comments regarding DEP's projected annual peak demand growth rate reflecting a significant departure as compared to higher growth of actual winter peaks.[47] Through discovery[48] Duke asked the Public Staff to reconcile that concern with their position regarding the economic load forecast uncertainty included in the resource adequacy studies which reflects a significantly greater probability of over-forecasting load growth compared to under-forecasting load growth. The Public Staff explained that their concerns about the forecasting accuracy of DEP's winter peak demands relate to the inability of the forecasting process to adequately capture how customers' use of energy changes in response to extreme weather events. The Public Staff further noted that this issue is unrelated to the economic load uncertainty referred to in the Public Staff's scenario PS-S2. Duke noted that it appreciates and recognizes this difference but also notes that this issue further illustrates the uncertainty in the non-weather-related load forecast, and Duke believes that the uncertainty included in the resource adequacy studies is not unreasonable.

Multi-Year Economic Load Forecast Uncertainty

SACE et al. consultant Wilson suggests that including multi-year economic load forecast uncertainty in the resource adequacy studies is not appropriate and suggests that many short lead-time actions could and very likely would be taken if load grows faster than expected.[49] Mr. Wilson suggests that if the rate of load growth raised concerns about resource adequacy, utilities would have time adjust their plans and take actions such as accelerating the development of new resources, increasing demand response or energy efficiency programs, delaying a planned retirement, adjusting firm purchases or allowing

[47] Reference page 78 of Public Staff's Comments which states: "The Public Staff is also concerned with the predicted annual growth rate of DEP's winter peaks of 0.7%, reflecting a significant departure from the historical growth of its actual winter peaks that have grown at a 3.0% CAGR from 2013 through 2018, while the weather-normalized peaks have grown at 2.1%."
[48] Public Staff response to DEC/DEP data request No. 1-1.
[49] SACE et al. Comments, Attachment 4, at 15.

wholesale contracts to expire. Duke commented that while these are all worthy ideas and actions that Duke would likely consider in the event of a significant increase in the load forecast due to economic or other uncertainty, such alternatives are not always sufficiently available or practical to satisfy a resource deficit. In particular, large quantities of demand response and energy efficiency programs are typically not achievable within a short timeframe.

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

Relationship between Winter Load and Cold Temperatures

Duke noted that SACE et al. consultant Wilson echoes many of the same arguments he presented in the 2016 IRP Proceeding concerning the Companies' 2016 Resource Adequacy studies. In particular, he again argues against the methodology used to capture the relationship between winter load and cold temperatures.[50] Duke asserted that it has complied with all Commission orders regarding the 2016 Resource Adequacy studies, including working with the Public Staff to address Mr. Wilson's concerns.

Mr. Wilson notes that including "more rather than less historical weather data is preferred" but also suggests that the 15-year period from 1982-1996 should be excluded because it results in flawed regressions and overstates winter resource adequacy risk.[51] This is also apparent from his statement "…the 2016 RA Studies results are very sensitive to the choice of 20 or 30 historical weather years…"[52] Duke commented that the purpose of a reserve margin is to cover uncertainties such as extreme load and generator outages and it would be irresponsible to ignore the potential for these extreme cold weather events when assessing resource adequacy. Duke argued that excluding 15 years of the 36-year weather history used in the study just because it reflects colder temperatures compared to other historical years is irresponsible. These are precisely the periods that the reserve margin is designed to cover. Duke explained that, in fact, as noted in the Joint Report, NCUC Rule R8-61 (CPCN) requires utilities to provide "a verified statement as to whether

[50] SACE et al. Comments, Attachment 4, at 6-13.
[51] SACE et al. Comments, Attachment 4, at 12.
[52] SACE et al. Comment, Attachment 4, at 25.

the facility will be capable of operating during the lowest temperature that has been recorded in the area…"[53] Duke correctly noted that this Commission is concerned and expects utilities to provide reliable service to customers even during extreme weather events.

Duke explained that, pursuant to the Commission's June 27, 2017 Order accepting the Companies' 2016 IRPs, the Public Staff and Duke reviewed the cold weather load modeling in the 2016 studies and performed a sensitivity analysis that reduced the regression equations significantly for temperatures below the levels seen in recent years.[54] This sensitivity analysis showed a relatively small decrease in reserve margin (0.3%) given that the sensitivity reduced the cold weather impact by half of that assumed in the base case. According to Duke, the reason that the impact is not larger is because the sensitivity only impacts 7 occurrences in the 36-year weather history. As stated by the Public Staff in the Joint Report, after having further discussions with Duke, the Public Staff was satisfied that the approach taken in the 2016 studies by the Companies is reasonable.[55]

Duke further notes that the 2016 resource adequacy studies reflected a maximum summer peak that was 7.5% above the expected summer peak for both DEC and DEP. In comparison, the 2018 PJM Reserve Requirement Study reflects a maximum summer peak that is 24% higher than the expected summer peak.[56] For winter, the 2016 study for DEC reflected a maximum winter peak that was 18.3% greater than the expected winter peak while the DEP study reflected a winter peak that was 21.5% greater than the expected

[53] Joint Report filed in Docket No. E-100, Sub 147, April 2, 2018, at slide 10.
[54] Joint Report filed in Docket No. E-100, Sub 147, April 2, 2018, at slide 20.
[55] Joint Report filed in Docket No. E-100, Sub 147, April 2, 2018, at 2.
[56] 2018 PJM Reserve Requirement Study: https://www.pjm.com/-/media/planning/res-adeq/2018-pjm-reserve-requirement-study.ashx?la=en

winter peak. In comparison, the 2018 PJM study reflected a maximum winter peak that was 21% higher than the expected winter peak. Duke explained that the variability in load due to temperature extremes that was modeled in the 2016 resource adequacy studies for DEC and DEP were at or below the peak load variability included in the 2018 PJM study.

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

Operating Reserve Assumptions

Duke argued that Mr. Wilson initiated a new unfounded claim in SACE's comments by claiming that the 2016 Resource Adequacy studies exaggerate winter risk through the operating reserve assumptions. Duke asserted that Mr. Wilson's claim that over 1,000 MW for DEC, and about 750 MW for DEP, of operating reserves are held back in the SERVM model resulting in firm load curtailments is grossly inaccurate.[57] In fact, Duke noted, SERVM allows operating reserves to drop to the regulation requirement which was 216 MW in DEC and 134 MW in DEP for the resource adequacy and solar capacity value studies. Duke commented that it is interesting to note that Duke responded in detail to this exact question in response to DEC-DEP SACE DR 2-19 in Sub 147, yet Mr. Wilson still makes these unsubstantiated claims regarding the operating reserves policy used in the studies. Duke argued that Mr. Wilson's arguments have no basis in fact and should be rejected.

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

Demand Response Assumptions

SACE et al. consultant Wilson concludes that the Companies' demand response winter assumptions should be "brought up to the summer level."[58] Although Duke agrees that winter demand response programs are a reasonable tool for reducing winter peak demand and winter LOLE, when available, Duke notes that the levels of reduction proposed by Mr. Wilson are extremely optimistic and not reasonably achievable in the near term, if at all. Duke commented that, as an example, the residential DEP EnergyWise Home program currently offers winter measures (Hot Water Heaters & Heat Pump Heat Strips) in its Western region in and around Asheville. These measures have been in place for 10 years and have been marketed aggressively with direct mail, email, outbound calling, and door-to-door canvassing. Over that 10-year period, the program has achieved 15 MW for a residential customer base of approximately 150,000. According to Duke, assuming the same level of achievable potential in the rest of DEP and DEC, a more reasonable estimate of residential winter DSM would be 150 MW in each jurisdiction in 10 years, which would only be true if those measures remained cost-effective into the future.

Duke stated that, moreover, actual program experience from DEP EnergyWise Home has shown that winter residential program potential is actually more difficult to achieve than summer potential for several reasons. First, not all residential customers have electric resistance hot water heaters or heat pumps with electric resistance strip heat. Instead, almost all have compressorized cooling in the form of straight air conditioning or heat pumps. Second, residential winter measure installations require appointments to enter

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

the customer's home that are often rescheduled and more costly than a summer air conditioning installation, which does not require an in-home installation.

Duke also notes their plans to implement new winter DSM programs as proposed in the 2018 IRPs, and to continue its work toward implementation of those programs. According to Duke, however, the extreme amounts of winter demand response programs anticipated to be cost-effective and reasonably achievable as cited by Mr. Wilson cannot prudently be included in the IRP forecast. Duke explained that Mr. Wilson attempts to support his claim by stating that the most recent Market Potential Study for DEC and DEP identified additional winter demand response technical and economic potential up to 2,300 MW;[59] however, the amount of potential that is reasonably achievable must be based on Duke's experience with DSM program adoption and, in Duke's experience, adoption of high levels of DSM programs has been challenging despite significant effort by the Companies. According to Duke, therefore, Mr. Wilson's claim that winter demand response can be magically brought up to the summer level to reduce winter resource adequacy risk should be rejected.

Load Net of Solar Resources

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

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

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

Duke commented that, as Mr. Wilson points out, DEC and DEP do experience significant summer loads; however, summer peaks occur in late afternoon hours when solar has significantly greater energy contributions as compared to dark winter mornings where very little – if any -- solar is available at the time of peak. Thus, the summer peak loads net of solar output are reduced relative to winter peak loads net of solar. Duke explains that this load net of solar has a significant impact on summer versus winter LOLE values and represents the net load that the remainder of the Companies' resources must satisfy. Duke explained, however, when asked whether Mr. Wilson's analysis of seasonal weighting reflected consideration of load net of solar resources, SACE et al. responded, "…that comment referred to load, not load net of any particular resources."[60] Further, when asked to provide a detailed explanation of why Mr. Wilson believes it is appropriate to exclude the impact of solar generation when evaluating seasonal loss of load risk, SACE et al. responded, "Not applicable."

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

Resource Adequacy Summary Comments

Duke notes that, as stated in the 150 Day Joint Report and 2018 IRPs, it believes

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

that a holistic review and consideration of resource adequacy study inputs and assumptions is appropriate when judging the reasonableness of the study results. Duke notes that while some parties may believe that certain study inputs and assumptions may have overstated the required reserve margin (i.e., resulting in a reserve margin that is too high), it believes that certain assumptions in the 2016 studies, including outage rate modeling and market assistance assumptions, may have been aggressive and understated the required reserve margin (resulted in a reserve margin that is too low). Duke agrees with Mr. Wilson's comment that resource adequacy and reserve margin requirements can change over time and Duke notes this is precisely why DEC and DEP conduct periodic resource adequacy assessments in order to capture significant changes in inputs and assumptions that may impact study results. Duke expressed its plan to work with the Public Staff to refresh inputs and assumptions and complete new resource adequacy studies in support of their 2020 IRPs. According to Duke, it is prudent to maintain a minimum 17% winter reserve margin to provide adequate reliability and satisfy the target of less than 1 firm load shed event every 10 years. Duke recommends use of a 17% winter reserve margin until such time as a new study is completed.

Commission Conclusions – Resource Adequacy and Reserve Margins

Based on the foregoing, the comments of the parties, and the entire record in this proceeding, the Commission concludes that the reserve margins included in Duke's IRPs are reasonable at this time for planning purposes. The Commission finds that SACE et al.'s report from Mr. Wilson on resource adequacy and reserve margins is not persuasive and its recommendations are not supported by the evidence in this proceeding.

REQUESTS FOR AN EVIDENTIARY HEARING

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

> General Statute 62-110.1(c), in pertinent part, requires the Commission to "develop, publicize, and keep current an analysis of the long-range needs for expansion of facilities for the generation of electricity in North Carolina, including its estimate of the probable future growth of the use of electricity." In *State ex rel. Utils. Comm'n v. North Carolina Electric Membership Corporation*, 105 N.C. App 136, 141, 412 S.E.2d 166, 170 (1992), the Court of Appeals discussed the nature and scope of the Commission's IRP proceedings. The Court affirmed the Commission's conclusion that
>
> [t]he Duke and CP&L plans were "reasonable for the purposes of [the] proceeding" before it. That is to say, the plans submitted by Duke and CP&L were reasonable for the purpose of "analy[zing]…the long-range needs for expansion of facilities for the generation of electricity in North Carolina…" See N.C. Gen. Stat. § 62-110.1(c).
>
> The Court further explained that the IRP proceeding is akin to a legislative hearing in which the Commission gathers facts and opinions that will assist

> the Commission and the utilities to make informed decisions on specific projects at a later time. On the other hand, it is not an appropriate proceeding for the Commission to use in issuing "directives which fundamentally alter a given utility's operations." With regard to the Commission's authority to issue specific directives, the Court cited the availability of the Commission's certificate of public convenience and necessity (CPCN) proceedings and complaint proceedings. Id., at 144, 412 S.E.2d at 173.

As such, by statute, decisions on the need, cost and timing of a specific generation resource would only be made after a CPCN application was filed and considered by the Commission in a public and transparent CPCN proceeding conducted pursuant to G.S. §§62-110.1 and 62-82. Accordingly, the requests for an evidentiary hearing on the 2018 IRPs are denied.

REPS COMPLIANCE PLANS

G.S. §62-133.8 requires all electric power suppliers in North Carolina to meet specified percentages of their retail sales using renewable energy and energy efficiency. One megawatt-hour ("MWh") of renewable energy, or its thermal equivalent, equates to one renewable energy certificate ("REC"), which is used to demonstrate compliance. An electric power supplier may comply with the REPS by generating renewable energy at its own facilities, by purchasing bundled renewable energy from a renewable energy facility, or by buying RECs. Alternatively, a supplier may comply by reducing energy consumption through implementation of EE measures or electricity demand reduction.[61] The electric public utilities (DEP, DEC, and DENC) may use EE measures to meet up to 25% of their overall requirements in G.S. §62-133.8(b). One MWh of savings from DSM/EE or demand reduction is equivalent to one energy efficiency certificate (EEC), which is a type of REC. All electric power suppliers may obtain RECs from out-of-state sources to satisfy

[61] "Electricity demand reduction," as used herein, is defined in G.S. §62-133.8(a)(32).

up to 25% of the requirements of G.S. §62-133.8(b) and (c), with the exception of DENC, which can use out-of-state RECs to meet its entire requirement. The total amount of renewable energy or EECs that must be provided by an electric power supplier for 2018, 2019 and 2020 is equal to 10% of its North Carolina retail sales for the preceding year.

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

Public Staff Comments – REPS Compliance Plans

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

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

[62] The overall REPS requirement of G.S. §62-133.8(b), less the requirements of the three set-asides established by G.S. §62-133.8(d)-(f), is frequently referred to as the "general requirement."

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

To meet the solar set-aside, DEP will obtain RECs from its own solar facilities, its residential solar photovoltaic (PV) program, and REC-purchase contracts with other solar PV and solar thermal facilities. DEP is the owner of 140.7 MW of solar facilities that are now operational and available for use to meet a portion of its REPS compliance obligations.[63]

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

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

[63] *See Order Transferring Certificate of Public Convenience and Necessity*, Docket No. E-2, Subs 1054, 1055, and 1056 (Dec. 16, 2014); *Order Issuing Certificate of Public Convenience and Necessity*, Docket No. E-2, Sub 1063 (Apr. 14, 2015).

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

Public Staff Comments - DEC's REPS Compliance Plans

According to the Public Staff, DEC has contracted for or procured sufficient resources to meet the REPS requirements of G.S. §62-133.8(b), (c), and (d) for the planning period, both for itself and for the electric power suppliers for which it is providing REPS compliance services. These suppliers are Rutherford EMC, Blue Ridge EMC, the Town of Dallas, the Town of Forest City, the City of Concord, the Town of Highlands, and the City of Kings Mountain (collectively, DEC's Wholesale Customers). DEC's contractual obligation to provide REPS compliance for the City of Concord and the City of Kings Mountain ended effective December 31, 2018; therefore, the Public Staff's comments reflect REPS compliance services for the City of Concord and the City of Kings Mountain only through 2018.

DEC intends to use EE programs to meet 25% of its REPS requirements. Hydroelectric facilities with a capacity of 10 MW or less and energy allocations from SEPA will be used to meet up to 30% of the general requirement of DEC's Wholesale Customers. Hydroelectric qualifying facilities of 10 MW or less, together with DEC's Bridgewater hydroelectric facility, will provide RECs for DEC's retail customers as well as its wholesale customers. DEC has entered into a contract to sell five of its hydroelectric facilities.[64] All of these facilities intend to register as new renewable energy facilities, so as to retain the option of selling the RECs produced to DEC for REPS compliance purposes.

[64] *See* Docket No. E-7, Sub 1181.

A substantial portion of DEC's general requirement will be met by purchased power agreements and REC-only purchases from biomass power providers, some of which are CHP facilities. In addition, DEC will continue to use solar energy and power generated from landfill gas to comply with the general requirement. It may also use wind energy, through either REC-only purchases or energy delivered into its system.

To meet the solar set-aside, DEC will obtain RECs from its self-owned solar PV facilities and from other solar PV and solar thermal facilities.[65] DEC resources include 75 MW of capacity at the Monroe and Mocksville solar facilities, approximately 20 MW from the small distributed solar facilities approved in Docket No. E-7, Sub 856, and 6 MW of anticipated capacity from the Woodleaf facility, which became fully operational in January 2019.

DEC anticipates that its REPS compliance costs will increase, but it will be below the cost caps in G.S. §62-133.8(h)(3) and (4), for the planning period.

DEC files EM&V plans for each EE program in the respective program approval dockets.

REPS Compliance Summary Tables

The following tables are compiled from data submitted in the DEC, DEP, and DENC Plans. Table 1 shows the projected annual MWh sales on which the utilities' REPS obligations are based. It is important to note that the figures shown for each year are the utilities' MWh sales for the preceding year; for instance, the sales for 2018 are MWh sales for calendar year 2017. The totals are presented in this manner because each utility's REPS

[65] DEC has acquired CPCNs for 81.4 MW of solar PV facilities for use to meet a portion of its REPS compliance obligations. See Order Amending Certificate of Public Convenience and Necessity, Docket No. E-7, Sub 1101 (June 16, 2016); Order Amending Certificate of Public Convenience and Necessity, Docket No. E-7, Sub 1079 (Dec. 7, 2016); and Order Transferring Certificate of Public Convenience and Necessity, Docket No. E-7, Sub 1098 (May 16, 2016).

obligation is determined as a percentage of its MWh sales for the preceding year. The sales amounts include retail sales of wholesale customers for which the utility is providing REPS compliance reporting and services. Table 2 presents a comparison of the projected annual incremental REPS compliance costs with the utilities' annual cost caps.

Table 1: MWh Sales for preceding year

	Compliance Year		
Electric Power Supplier	**2018**	**2019**	**2020**
DEP	36,829,899	37,521,080	37,685,819
DEC	59,518,351	60,104,379	60,285,246
DENC	4,203,708	4,217,958	4,239,131
TOTAL	100,551,958	101,843,417	102,210,196

Table 2: Comparison of Incremental Costs to the Cost Cap

		DEP	DEC	DENC
2018	Incremental Costs	$41,294,711	$27,120,881	$1,052,998
	Cost Cap	$63,874,278	$94,975,829	$5,632,261
	Percent of Cap	65%	29%	19%
2019	Incremental Costs	$47,421,825	$36,738,176	$1,224,857
	Cost Cap	$64,583,052	$93,929,320	$5,288,797
	Percent of Cap	73%	39%	23%
2020	Incremental Costs	$55,445,392	$48,524,154	$1,419,320
	Cost Cap	$65,271,008	$94,623,837	$5,304,517
	Percent of Cap	85%	51%	27%

Swine Waste and Poultry Waste Set-Asides

The State's electric power suppliers have encountered continuing difficulties in their efforts to comply with the swine and poultry waste requirements of the REPS. G.S. § 62-133.8(a) provides that in 2012 at least 0.02% of the electric power sold to customers should be produced from swine waste, and this percentage increases to 0.14% by 2015 and 0.20% by 2018. Subsection (f) provides that in 2012 at least 170,000 MWh of power sold to retail customers will be generated from poultry waste, and that this requirement will increase to 700,000 MWh in 2013 and 900,000 MWh in 2014.

In every year from 2012 through 2017, the electric suppliers moved that the swine waste requirement be delayed until the following year, and the Commission granted their requests. In 2018, they moved that the requirement be set at 0.02% for the electric public utilities and zero for the EMCs and municipalities, and this request likewise was granted.

With respect to poultry waste, the electric suppliers moved in 2012 and again in 2013 to delay the 170,000-MWh annual requirement for a year, and the Commission granted their motions. The Commission's 2013 order set the requirement at 170,000 MWh for 2014 and 700,000 MWh for 2015. The electric suppliers were able to meet the 170,000-MWh requirement in 2014, but they could not comply with the increase to 700,000 MWh for 2015. In that year, and again in 2016 and 2017, they moved that the poultry waste requirement be kept at 170,000 MWh, and their motions were granted. In their 2018 motion, the electric suppliers proposed that the poultry waste requirement be set at 300,000 MWh, and the Commission approved their proposal.

In its annual orders granting delays or reductions in the swine and poultry waste requirements, the Commission has also required the electric power suppliers to file reports describing the state of their compliance with the set-asides and their negotiations with the developers of swine and poultry waste-to-energy projects, initially on a tri-annual basis and now semiannually. These reports are filed confidentially in Docket No. E-100, Sub 113A. The Commission has further required the electric power suppliers to provide internet-available information to assist the developers of swine and poultry waste-to-energy projects in getting contract approval and interconnecting facilities. Additionally, the Commission has directed the Public Staff to hold periodic stakeholder meetings to facilitate compliance with the swine and poultry waste set-asides. In response, the Public Staff organized a stakeholder meeting held on June 23, 2014, and seven subsequent occasions. The attendees have included farmers, the North Carolina Pork Council, the North Carolina Poultry Federation, waste-to-energy developers, bankers, state environmental regulators, and the electric power suppliers. The meetings allow the stakeholders to network and voice their concerns to the other parties. With the advancements in compliance, all parties agreed that semiannual meetings were no longer necessary and requested that they only be held yearly. The Commission granted this request in its 2017 order.

Up to now, the State's electric power suppliers have been able to comply only to a limited extent with the poultry waste set-aside requirement, and to an even lesser extent with the swine waste requirement. Nevertheless, the REPS statute has served as a stimulus for several important advances in waste-to-energy technology.

First, several hog farms have installed anaerobic digesters at their swine waste lagoons and have produced biogas that has been used as fuel to operate small electric generators at these farms. Electric power suppliers have purchased the electricity produced by these generators – or, alternatively, have purchased the RECs when the electricity was used on the farm where it was generated – and this represented the initial step toward compliance with the swine waste set-aside.

Second, poultry waste has been transported by truck to existing and new generation facilities, where it has been co-fired with wood or other fuels.

Third, there has been progress in the development of large centralized anaerobic digestion plants in areas where numerous hog farms are located. These plants receive swine waste from numerous sources, produce biogas from the waste by the digestion process, and eliminate impurities from the biogas so that it meets quality standards and is eligible to be injected into the natural gas pipeline system. A specified amount of this biogas, which is referred to as "directed biogas" or "renewable natural gas," is injected into a pipeline, and an equivalent amount of natural gas is delivered by the pipeline operator to a gas-fired utility generating plant. These directed biogas facilities were first built in

Midwestern states with extensive hog farming activity, but on December 2, 2016, Carbon Cycle Energy, LLC, began construction of a directed biogas facility in Warsaw, North Carolina.[66]

Four days after the start of construction at the Carbon Cycle facility, Piedmont Natural Gas Company, Inc. petitioned the Commission for approval of a new Appendix F to its service regulations, authorizing the company to accept "Alternative Gas" (which includes, subject to various restrictions, biogas, biomethane, and landfill gas) onto its system and deliver it to purchasers. In an order issued on June 19, 2018, the Commission approved Piedmont's proposed appendix and established a three-year pilot program to implement it. The Commission has authorized four firms – C2E Renewables NC, Optima KV, LLC, Optima TH, LLC, and Catawba Biogas, LLC – to participate in the pilot program, and two additional firms, GESS International North Carolina, Inc., and Foothills Renewables LLC, have filed applications to participate.

In March of 2018, Optima KV completed its interconnection to the Piedmont Natural Gas system and began delivering biogas to DEP's Smith Energy Complex in Hamlet, North Carolina. The Optima KV facility thus became the first operational directed biogas facility in North Carolina.

The Public Staff believes the electric power suppliers will likely continue to have difficulty meeting the swine and poultry waste set-asides. However, they have made substantial progress toward complying with these difficult obligations, and as advances in

[66] *See Order Accepting Registration of New Renewable Energy Facilities,* Docket No. E-7, Subs 1086 and 1087 (Mar. 11, 2016). In this docket, DEC stated that it had entered into contracts to purchase directed biogas from High Plains Bioenergy, LLC, in Oklahoma, and Roeslein Alternative Energy of Missouri, LLC. On March 18, 2016, DEC supplemented its registration statement to indicate that it also entered into contracts to purchase directed biogas from Carbon Cycle Energy for nomination to its Buck Combined Cycle Station.

waste processing technology are made, they may be able to achieve full compliance with the statutory requirements in the not too distant future. The supplier best positioned to reach full compliance is DENC, since it can obtain all of its RECs from out-of-state. Indeed, DENC's compliance plan indicates that already "both DENC and the Town of Windsor have sufficient RECs in [NC-RETS] to meet the 2018-2020 requirements" for swine waste. DENC does not express quite as high a degree of certainty about its compliance with the poultry waste set-aside, given the possibility that between now and 2020 some of its suppliers may default on their contracts; however, it does state that its efforts have "yielded multiple poultry waste REC contracts and sufficient delivered volume to comply with both the Company's and Town of Windsor's out-of-state requirements for years 2018, 2019 and 2020."

Public Staff Conclusions - REPS Compliance Plans

The Public Staff's conclusions regarding the REPS compliance plans of DEC, DEP, and DENC are as follows:

- Overall, the electric public utilities believe they are in a better position to comply with all of the requirements of the REPS, including the set-asides, than in previous years.

- DEC, DEP, and DENC should be able to meet their REPS obligations during the planning period, with the exception of the swine and poultry waste set-asides, without nearing or exceeding their cost caps; however, DEP may approach the caps in 2020.

- All three utilities should be able to meet the swine and poultry waste requirements in 2018, after the issuance of the Commission's order of October 8, 2018, reducing the requirements.

- DEC and DEP indicated in their REPS compliance plans that they could comply with the poultry waste set-aside in 2018, and DEC stated that it could meet the swine waste requirement as well; but both companies indicated that compliance would deplete their supply of swine and poultry RECs so severely that they could not comply in 2019 and 2020. Both subsequently joined in the electric suppliers' motion to reduce the swine and poultry requirements for 2018, and their motion was granted. However, the fact that DEC and DEP were even able to consider the possibility of compliance in 2018 represents progress in comparison with previous years.

- DENC expects to meet the swine waste requirements for 2018 through 2020, both for itself and the Town of Windsor, and it is confident, although not certain, that it will also meet the poultry waste requirement for all three years of the planning period.

- DEC and DEP are actively seeking energy and RECs to meet the set-aside requirements for the years in which they expect to fall short of compliance. DENC is also seeking to acquire RECs and thus strengthen its position for compliance with the swine and poultry requirements in future years.

- The Commission should approve the 2018 REPS Compliance Plans filed by DEC, DEP, and DENC.

<u>Commission Conclusions - REPS Compliance Plans</u>

The Commission concludes that the REPS Compliance Plans filed by the utilities contain the information required by Commission Rule R8-67(b). As such, and based on the recommendation of the Public Staff, the Commission accepts the REPS Compliance Plans filed in this docket.

COMMISSION CLOSING COMMENTS

Integrated Resource Planning is intended to identify those electric resource options that can be obtained at least cost to the utility and its ratepayers consistent with the provision of adequate, reliable electric service. Potential significant regulatory changes, particularly at the federal level, and evolving marketplace conditions create additional challenges for already detailed, technical, and data-driven IRP processes. The Commission finds the IRP processes employed by the utilities to be both compliant with State law and reasonable for planning purposes in the present docket. The Commission recognizes that the IRP process continues to evolve. The comments, findings, conclusions, and Commission directives included in this Order are intended to inform and guide the electric utilities and parties in their ongoing IRP processes and participation.

IT IS, THEREFORE, ORDERED, as follows:

1. That this Order shall be, and is hereby, adopted as part of the Commission's current analysis and plan for the expansion of facilities to meet future requirements for electricity for North Carolina pursuant to G.S. §62-110.1(c).
2. That the IOUs' forecasts of native load requirements and other system capacity or firm energy obligations, supply-side and demand-side resources expected to satisfy those loads, and reserve margins are reasonable for planning purposes, and the Commission accepts the IRPs

as filed in this docket.

3. That the 2018 REPS compliance plans filed by the IOUs are hereby accepted.

4. That the IOUs, in the preparation of future IRPs, shall adhere to the conclusions and directives of the Commission documented in the body of this Order.

5. That pursuant to the Regulatory Conditions imposed in the Merger Order, DEC and DEP shall continue to pursue least-cost Integrated Resource Planning and file separate IRPs until otherwise required or allowed to do so by Commission order, or until a combination of the utilities is approved by the Commission.

ISSUED BY ORDER OF THE COMMISSION.

This the __ day of ___, 2019.

NORTH CAROLINA UTILITIES COMMISSION

`CERTIFICATE OF SERVICE

I certify that a copy of Duke Energy Carolinas, LLC and Duke Energy Progress, LLC's Proposed Order, in Docket No. E-100, Sub 157, has been served by electronic mail, hand delivery or by depositing a copy in the United States mail, postage prepaid to the following parties of record:

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This is the 26th day of July, 2019.

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