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November 4, 2019

VIA ELECTRONIC FILING

Ms. Kimberley A. Campbell
Chief Clerk
North Carolina Utilities Commission
4325 Mail Service Center
Raleigh, North Carolina 27699-4300

RE: Duke Energy Carolinas, LLC and Duke Energy Progress, LLC's Response to Commission Questions in August 27, 2019 Order Docket No. E-100, Sub 157

Dear Ms. Campbell:

I enclose Duke Energy Carolinas, LLC and Duke Energy Progress, LLC's (collectively, the "Companies") Response to questions and requests for information contained in the Commission's August 27, 2019 *Order Accepting Integrated Resource Plans and REPS Compliance Plans, Scheduling Oral Argument, and Requiring Additional Analyses*, for filing in connection with the referenced matter.

Portions of the response to Questions 1.a., 1.i, 4.a. and 4.b. contain confidential information and are being filed under seal. The table in the Question 1.a response contains confidential business and technical information which the Companies have designated as "trade secrets" under N.C. Gen. Stat. §66-152(3). The information in the Question 1.i response contains commercially-sensitive information regarding wholesale contracts and needs while the related market solicitation is still underway. The information in Quesiton 4.a. and 4.b. responses contain proprietary confidential cost information and analysis related to an open-market solicitation. If this trade secret and commercially sensitive business and technical information were to be publicly disclosed, it would allow competitors, vendors and other market participants to gain an undue advantage, which may ultimately result in harm to customers. The Companies respectfully request that the commercially sensitive and trade secret information be treated confidentially pursuant to N.C. Gen. Stat. 132-1.2. The Companies will provide a copy of the confidential information to parties to this proceeding upon execution of an appropriate confidentiality agreement.

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

Sincerely,

Lawrence B. Somers

Enclosures

cc: Parties of Record

Duke Energy Carolinas, LLC and Duke Energy Progress, LLC's
Response to August 27, 2019 Order
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1. DEC and DEP's basis for using a 17% winter reserve margin target, including:

(a) Additional details for the contention that a holistic view of the Astrapé study's reasonableness is more appropriate than focusing on specific individual factors (such as those raised by the Public Staff) that could potentially result in a lower reserve margin. [See Page 18 of the Joint Report]

Response:

The 2016 resource adequacy studies for DEC and DEP incorporated the uncertainty of weather, economic load growth, unit availability, and the availability of transmission and generation capacity for emergency assistance. The resource adequacy studies relied upon many inputs and assumptions that can impact reliability. Some of the key inputs and assumptions included:

- Study year
- Study topology
- Load modeling
  - Use of historic weather data
  - Correlation of load and extreme temperatures
- Economic load forecast error
- Conventional thermal resources modeling
- Unit outage data from GADS
- Renewables modeling
- Hydro and pumped storage modeling
- Demand response modeling
- Operating reserve requirements
- External assistance modeling
  - Neighboring utility systems' load and resources
  - Transmission import capability
- Minimum economic reserve margin analysis would also include assumptions for the cost of unserved energy, capacity cost for additional reserves and fuel cost assumptions

As documented in the Joint Report,[1] the Public Staff and the Companies reached agreement on some of the issues identified by the Public Staff and Southern Alliance for Clean Energy (SACE) consultant Wilson, but did not reach agreement on all issues.

[1] Joint Report filed April 2, 2018 in Docket No. E-100, Sub 147.

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The Public Staff focused on several assumptions that they believed were conservative (i.e., assumptions that they believed may have led to the adoption of higher reserve margins). The goal of a resource adequacy study is to determine the lowest planning reserve margin that will allow the Companies to provide adequate reliability to its customers using an industry standard of 1 day in 10 years Loss of Load Expectation (LOLE). Importantly, by recommending a "holistic" view, the Companies believe that the focus of a review of a resource adequacy study should be on the reasonableness of the complete body of work in the study rather than seeking out only one or two items that one party may view as "conservative." As discussed in more detail later in this response, certain aspects of the study could be viewed as too aggressive leading to a lower reserve margin.

Following the discussions between the Public Staff and the Companies in December 2017, the Public Staff put forth two scenarios that they believed were important for arriving at an appropriate reserve margin (reference page 9 of the Joint Report). As noted by the Public Staff, the most important element in each of their scenarios is the load forecast error assumption.

It should be noted, however, that the Companies and Astrapé had identified two other areas of the study that they believed may have been overly aggressive (i.e., assumptions that may have led to the adoption of lower reserve margins). These areas include the modeling of market assistance and unit outage rate modeling. Regarding market assistance, during high demand periods neighboring utilities are often constrained and purchases are expensive, non-firm and recallable. Slide 33 of the December 12, 2017 presentation (attached to the Joint Report and reproduced below) shows that the SERVM model simulated non-firm market purchases of up to 3,000 MW for DEC and 2,600 MW for DEP during high load periods for the most severe weather year. The slide also shows that approximately 750 MW was purchased at the time of the highest simulated peak demand for DEC, and approximately 800 MW was purchased at the time of the highest simulated peak demand for DEP. Based on these results, the Companies and Astrapé believe that the robustness of the power market assumed in the resource adequacy studies should be reviewed again based on more recent data in the next study to ensure the assumptions are not overly aggressive (i.e., may lead to the adoption of lower reserve margins).

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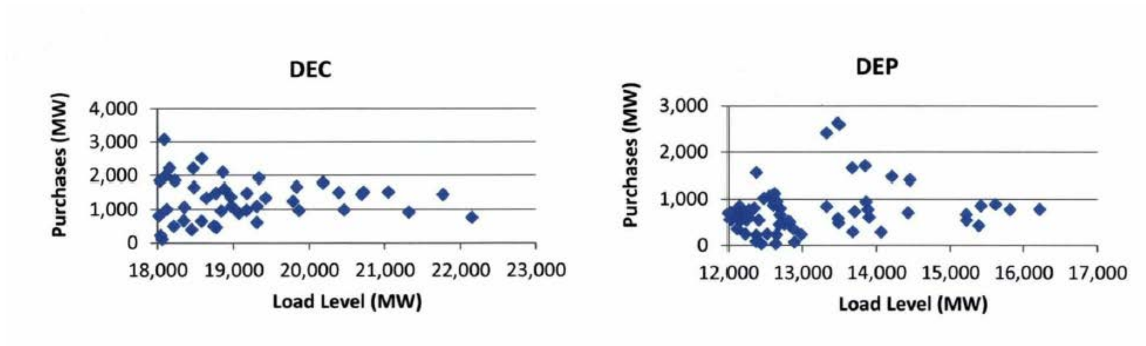
Purchases from Neighbors During Worst Weather Year (1982)
(from Slide 33 of the December 12, 2017 Presentation to the Public Staff)



Regarding outage rate modeling, the Astrapé studies did not include the correlation of outage rates and extreme temperatures in the 2016 studies. Inclusion of this correlation would likely result in the need for a greater reserve margin since historic data may show that outage rates tend to be higher during extreme cold temperatures. The confidential figure below, from the 2016 studies, shows greater amounts of capacity on forced outage at extreme low temperatures; however, this correlation was not captured in the 2016 studies. The Public Staff recognized that outage rates may be higher with extreme cold weather because although winterization has been implemented, it may not prevent all cold weather outages.[2] The Public Staff and the Companies agree that further research on this issue is appropriate in subsequent resource adequacy studies.

[2] *Id*. at 16.

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[redacted]

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In summary, a holistic view of the Astrapé studies' reasonableness is more appropriate than focusing on one or two specific individual factors. The Companies believe that the market assistance modeling and outage rate modeling could more than offset the reduction in reserve margin if the Public Staff's load forecast error assumptions were adopted. The Companies plan to work with the Public Staff and the South Carolina Office of Regulatory Staff (ORS) to update all inputs and assumptions in conducting new resource adequacy studies to support development of the Companies' 2020 IRPs.

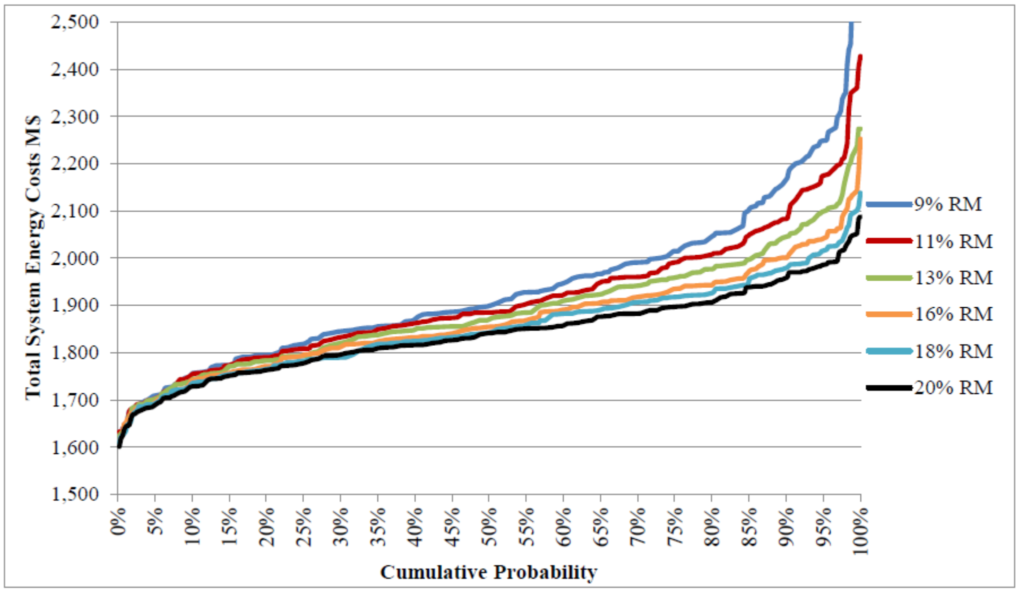
(b) An explanation and/or additional support for the following statement: "The 2016 resource adequacy studies also demonstrated the economic benefits of minimizing total reliability costs to customers and showed economic reserve margin ranges of up to about 19% for DEC and 20% for DEP (95th percentile confidence level) to minimize substantial firm load shed and high cost risk. On a probabilistic weighted average basis, the net cost to customers of going from 15% to 17% is small compared to the potential risk of expensive market purchases and customer outage costs that can be avoided in extreme years." [See Page 38 of slide deck attached to the Joint Report] Produce all analyses supporting this cost-benefit claim.

Response:

Astrapé analyzed the optimal planning reserve margin based on (i) providing an acceptable level of physical reliability and (ii) minimizing economic costs to customers. The most common physical reliability metric used in the industry is to target a system reserve margin that satisfies the one day in 10 years LOLE standard. This standard is interpreted as one firm load shed event every 10 years due to a shortage of generating capacity. The one day in 10 years LOLE was used as the target level of physical reliability in the 2016 studies which resulted in the 17% winter reserve margin planning target.

From an economic perspective, Astrapé analyzed total system energy costs (Fuel Burn + O&M + Purchase Costs - Sales Revenue + Cost of Unserved Energy) at various reserve margin levels. As an example, below is Figure 12 from the 2016 DEC study report that shows the distribution of system energy costs for DEC. As the reserve margin increases, total system energy costs decrease, providing economic benefits to customers. In the high confidence levels (85th percentile and above), substantial savings are realized in more extreme scenarios by adding capacity (i.e., the tails of the distribution), while in the mild scenarios, limited savings are realized. This is a perfect illustration of system reliability for most utilities, in that capacity is justified to lower the risk in the tails of the distribution and is not utilized as often in years when weather is mild and generators perform well.

DEC Total System Energy Cost Distribution at Varying Winter Reserve Margin Levels



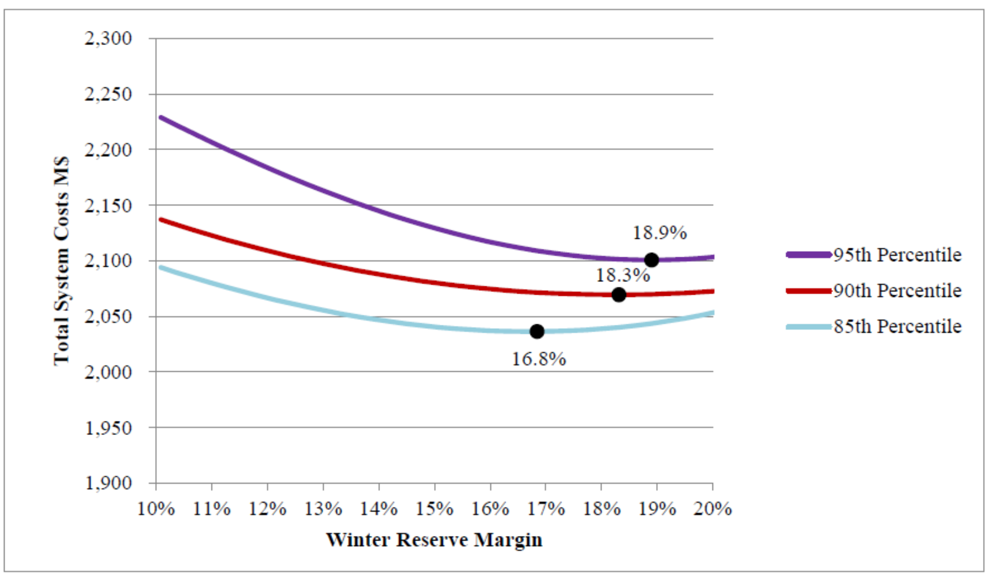
To understand the total system costs at each reserve margin level, the incremental system capacity costs (carrying costs of incremental CTs) were added to the distribution creating the bathtub curves found in the figure below (Figure 13 from the 2016 DEC study report) at different confidence levels. The bathtub curves represent the total system costs at each reserve margin by adding the carrying cost of combustion turbine capacity to the system energy cost shown in the previous figure. The lowest point on each curve reflects the point where total system costs are minimized. For example, the 90th percentile curve represents the 90th percentile points on the system energy cost distributions (above) with the system capacity costs added.

As shown in the figure below, a winter reserve margin target of 16.8% to 18.9% represents the level at which system costs are balanced for the 85th to 95th percentile confidence scenarios for DEC. In the insurance industry, premiums are frequently set using anywhere between 85% - 95% confidence level that the insurance company will be covered in the long term. A similar method for determining the appropriate risk adjustment can be used for setting the target reserve margin. For these reasons, Astrapé does not recommend using a lower confidence level, as it results in substantial firm load shed and high cost risk.

Given that resources are typically added in large blocks of capacity to take advantage of economies of scale, the reserve margins shown in the Company's IRP will likely be at or above the minimum physical target. The economic reserve margin range recognizes the economic benefits to customers of being above the minimum level of reserves and firmly supports the 1 day in 10-year target of 17%. Similarly, the 2016 study results for DEP show an economic reserve margin range of 17.8% to 20.1% based on the 85th and 95th percentiles, respectively (reference Section VII of the 2016 study report).

In summary, the Companies' recommendation for a minimum 17% winter planning reserve margin was based on satisfying the 1 day in 10 years LOLE physical reliability metric. Further, the economic reserve margin results show that the net cost to customers for slightly increased reserve margins is small compared to the potential risk of expensive market purchases and customer outage costs that can be avoided in extreme years. The Companies and Astrapé view the economic reserve margin results as supporting a reserve margin at or above the 17% reserve margin which was based on the 1 day in 10 years LOLE physical metric.

DEC Economic Results



For further information, please reference the information below from the 2016 study reports. The Companies would be happy to provide any further information as needed by the Commission.

- Section III.L. – Cost of Unserved Energy
- Section VII. – Base Case Economic Results

- Section VIII. – Economic Sensitivities
- Section XI. – Confidential Appendix – CT Economic Carrying Cost

(c) A discussion detailing the "sensitivity analysis items noted in the Wilson report" referred to on Page 34 of the slide deck attached to the Joint Report.

Response:

SACE/NRDC/Sierra Club filed initial 2016 IRP comments in Docket No. E-100, Sub 147 on February 17, 2017. In Appendix A of Wilson Attachment B of that filing, Mr. Wilson outlines the limitations of his review of the 2016 Resource Adequacy studies due to an alleged lack of information provided in response to certain data requests. Specifically, Mr. Wilson states in Item 1 of Appendix A, at 20:

1. Resource adequacy studies necessarily involve numerous assumptions about loads and resources. To evaluate such a study properly requires a careful review of the various assumptions and how they interact through the simulation to create the study results. Of critical importance is the probabilistic representation of loads and resources. Because the goal is to find the reserve margin to satisfy LOLE = 0.1 (one outage event in ten years), the loss of load will occur only under extremely low-probability combinations of load and resource conditions. Therefore, to validate such a simulation (to gain confidence that the various assumptions are realistic in combination and lead to realistic results) requires careful review of, among other things, the combinations of multiple rare events that lead to the loss of load. To fully understand and value how the loss of load occurs, the following questions should be explored:
    - When loss of load occurs, what is the day of week, hour, weather condition, and load level?
    - What conditions have combined to cause the extremely high load, if applicable?
    - Which resources are unavailable at that time and in what quantities, and why are they unavailable? In particular, what is the state of demand response, pumped hydro, and purchases through the interties?

Mr. Wilson further states in Item 4 of Appendix A, at 21:

4. Furthermore, it appears that the Astrapé Consulting staff who performed the analyses also did not complete such a validation exercise; responses to data requests indicate that the basic model output reports that would be used in such

> an effort were not even created, nor was additional sensitivity analysis performed (beyond the few documented in the reports) (responses to SACE 3-4, SACE 3-18, SACE 3-19). The apparent lack of basic validation of the simulation results raises concern about the accuracy of the RA Studies and the reliability of the resulting reserve margin recommendations.

Mr. Wilson's accusation that Astrapé did not perform an adequate validation exercise is simply not true. Astrapé conducts extensive data validation and model debugging as part of the normal study process. Slide 29 from the attachment to the Joint Report outlines the typical data validation and model debugging process conducted by Astrapé. For convenience, this information is also provided below:

- Hourly reports (i.e., SERVM debug reports) for many scenarios and iterations from the model with a focus on LOLE hours and validates the following:
  - Load
  - Unit Outages and Planned Maintenance
  - Hydro Output
  - Thermal Resource Output
  - Hydro and Pump Storage
  - Demand Response
  - Renewable Output
  - Market Purchases
- Load uncertainty distributions
- Forced outages and system cumulative outage reports; cold weather outages
- Neighbor reliability and assistance
- Dispatch and unit operations
- Hourly unit output/temperature correlations

The "sensitivity analysis items noted in the Wilson report" referred to on Page 34 of the slide deck (attached to the Joint Report) refers to the screen shots taken from a detailed Excel file which is shown on slides 30 and 31. Consistent with Mr. Wilson's recommendation (Item 1 above), this file includes all hours when expected unserved energy (EUE) occurred for all 3,600 scenarios simulated at a specific reserve margin level. For any hour with EUE, the report includes the year, season, day of week, hour of day, iteration number, weather conditions, load, capacity available by category, demand response, forced outages, EUE, etc. Such reports are necessary to ensure the reasonableness of study inputs and model output and to ensure that conditions during EUE events are sensible. Following the December 2017 meeting with the Public Staff, an EUE report from the study was produced and subsequently provided to the Public

Staff at a single reserve margin scenario for their review.

The data validation outlined by Mr. Wilson is a routine part of the Astrapé study process and was appropriately performed to ensure the reasonableness of the study results. After providing the detailed EUE file to the Public Staff for their review, the Companies note that they did not receive any further requests for SERVM reports, and the Public Staff did not notify the Companies of any further concerns regarding data validation and review.

It should also be noted that thousands of model runs are simulated in the data validation phase as well as in producing the final study results. Given the voluminous nature of the data and file sizes, such reports are typically not retained once the validation process is completed, and these reports are typically not turned-on when running all the model simulations. As such, these reports were not available to provide to Mr. Wilson at the time of his discovery without rework and rerunning scenarios. As noted above, this report was created and provided to the Public Staff at a single reserve margin during the 150-day review period leading up to the filing of the Joint Report.

(d) An explanation of "Firm Load Shed Event" and discussion of significance in Astrapé's Resource Adequacy Studies. [See Page 43 of Duke Energy Carolinas and Duke Energy Progress Solar Ancillary Service Study]

<u>Response</u>:

Brief Overview of Astrapé Study Methodology

Calculating physical reliability metrics, such as Loss of Load Expectation (LOLE), is challenging because the conditions which lead to reliability events are relatively infrequent. Reserves, by definition, are held for unexpected conditions - extreme weather, rapid load growth, and generating unit outages. For this reason, a wide distribution of possible scenarios must be considered at a range of reserve margins to evaluate resource adequacy. To calculate physical reliability, Astrapé utilized the SERVM (Strategic Energy and Risk Valuation Model) reliability model. Load uncertainty due to extreme weather has the greatest impact on reserve margin requirements. To model the effects of weather uncertainty, temperature data from 36 historical weather years (1980 - 2015) was used in the 2016 resource adequacy studies to reflect the range of possible future weather conditions. Then, based on the most recent five years of actual historic weather and load, a neural network program was used to develop relationships between weather observations and load. These relationships were then applied to the last 36 years of weather to develop 36 synthetic load shapes for the study year and equal probabilities were given to each of the 36 load shapes in the simulations.

SERVM utilized the 36 years of historical weather and their associated load shapes, 5 points of economic load growth forecast error, and 20 iterations of unit outage draws (calibrated to actual historic unit performance) for each scenario to represent the full distribution of realistic outcomes. The number of yearly simulation cases equals 36 weather years * 5 load forecast error points * 20-unit outage iterations = 3,600 total iterations for each reserve margin case. It is not appropriate to remove specific extreme weather years as suggested by Mr. Wilson because that is part of the historical distribution. By modeling all the historical weather years, the appropriate weight is being applied to each weather year. Mr. Wilson seems to believe Duke should ignore extreme events so it can lower its reserve margin but this only puts reliability at risk for system operators and Duke's customers. This would be similar to requesting that an insurance company ignore their most extreme outcomes when looking at their actuarial probabilities. It is precisely these types of weather events that require adequate planning reserves. Although Mr. Wilson was critical of the number of historic weather years used in the 2016 studies, when asked through discovery what he believed to be the correct number of historic weather years that should be incorporated in the studies, SACE, NRDC and the Sierra Club replied:[3]

> "Mr. Wilson was not asked to identify or propose a correct number of weather years that should be incorporated into the resource adequacy studies, and therefore has not evaluated this question."

Explanation of Firm Load Shed Event

LOLE was the primary physical reliability metric analyzed in the resource adequacy studies. LOLE is defined as the number of firm load shed events per year. A firm load shed event is caused by a generation capacity shortage in which the amount of resources available, including demand response and external purchases from neighboring systems, was not sufficient to meet the system load plus a minimum operating reserve level. Across the industry, the traditional 1 day in 10-year standard (0.1 LOLE) is considered an acceptable level of physical reliability and this standard was used in the Companies' resource adequacy studies.

The objective of the study was to perform stochastic modeling of weather (and impact on load), economic load forecast uncertainty and generator outages to determine the reserve margin that would satisfy the 1 day in 10 years LOLE reliability standard. The 3,600 total iterations were re-run at different reserve margin levels by varying the amount of CT capacity. For any given day of an iteration, LOLE was either zero (load

[3] SACE response to the Companies' Data Request 2-8, Docket No. E-100, Sub 147.

was met in all hours) or one (load was not met in one or more hours). Thus, although hourly data was simulated in SERVM, when counting LOLE events, only one event is counted per day even if an event occurs in more than one hour of a day. LOLE does not indicate the magnitude or duration of an event, it only indicates the expectation of the number of days that an event will occur. The LOLE at a given reserve margin is the expected value (i.e., average weighted by probability) of the 3,600 iterations. Since a minimum level of operating reserves is required to maintain system stability, the minimum operating reserve requirement was maintained in the study and was equal to the regulation requirement (216 MW for DEC and 134 MW for DEP). Mr. Wilson's claim that the modeling assumption used in the resource adequacy study held back over 1,000 MW of operating reserves for DEC and about 750 MW for DEP causing firm curtailment is again simply not true.[4] As noted, the model allows for the operating reserves to be depleted during an event down to the minimum regulation required to maintain grid reliability.

(e) An explanation and additional characterization of the potential impact of increasing the loss of load expectation for DEP to approximately 0.13 days/year (one firm load shed event every 7.7 years) and for DEC to approximately 0.116 days/year (one firm load shed event every 8.6 years). [See Page 42 in DEP's IRP and Page 42 in DEC's IRP]

<u>Response</u>:

As noted in response to item 1.d above, the resource adequacy studies utilized the 1 day in 10 years standard (or, 0.1 days per year) as the target level of reliability. While customer expectations may be to never experience a loss of load event, an extremely high reserve margin would be required to guarantee with certainty that a loss of load will never occur since there is always a possibility, albeit an extremely low probability, that extreme weather combined with a significant level of generator outages and economic load forecast uncertainty could result in a loss of load event even with a very high planning reserve margin. Thus, since it is not reasonable to determine a reserve margin based on a zero LOLE scenario, the Companies view the 1 day in 10 years standard as providing a high level of reliability with the goal of rarely experiencing a load shed event due to insufficient resource capacity. However, the 1 day in 10 years standard does not guarantee that a loss of load event will never occur, since planning to a 1 day in 10 years LOLE standard there is a probability of 1 loss of load event over a 10 year period. For example, during the Polar Vortex of 2014, SCANA had to resort to organized load shedding, and the Companies were close to the same outcome despite going into the year with reserves well above a 17% reserve margin.

[4] Docket No. E-100, Sub 157, Initial Comments of SACE/Sierra Club/NRD, Wilson Attachment 4, at 20.

At the Commission's directive, the Companies included a 16% reserve margin sensitivity in their 2018 IRPs. Astrapé determined that a 16% reserve margin for DEC would increase LOLE from 0.1 days per year to 0.116 days per year which corresponds to one expected firm load shed event every 8.6 years instead of every 10 years. For DEP, a 16% reserve margin would increase LOLE from 0.1 days per year to 0.13 days per year which corresponds to one expected firm load shed event every 7.7 years instead of every 10 years. Thus, the Companies believe that adopting a reserve margin lower than 17% would result in a level of reliability that does not satisfy the 1 day in 10 years LOLE standard.

(f) A discussion of the following statement included in Astrapé's 2016 Resource Adequacy Studies: "Across the industry, the traditional 1 day in 10-year standard is defined as 0.1 LOLE. Additional reliability metrics calculated are Loss of Load Hours (LOLH) in hours per year, and Expected Unserved Energy (EUE) in MWh." [See Page 30 of both DEP's and DEC's 2016 Resource Adequacy Studies] Include a discussion and assessment of the following statement: "One event in ten years translates to 0.1 loss of load events (LOLE) per year, regardless of the magnitude or duration of the anticipated individual involuntary load shed events. Alternatively, one day in ten years translates to 2.4 loss of load hours (LOLH) per year, regardless of the magnitude or number of such outages. As we show, the difference between these interpretations of the 1-in-10 standard translates to differences in planning reserve margins that may exceed five percentage points, with planning reserve margins of possibly less than 10% based on the 2.4 LOLH standard and more than 15% based on the 0.1 LOLE standard." [Brattle Group and Astrapé Consulting for FERC, Resource Adequacy Requirements: Reliability and Economic Implications, by J. Pfeifenberger and K. Carden (2013), Executive Summary Page iii, www.ferc.gov/legal/staff-reports/2014/02-07- 14-consultant-report.pdf]

Response:

The FERC Report referenced was a study conducted by the Brattle Group and Astrapé Consulting. The industry overwhelmingly uses 0.1 LOLE to represent the 1 day in 10-years standard as shown in Appendix A of the FERC report. This represents 1 day in 10 years or 0.1 days per year LOLE. As part of a resource adequacy study, other reliability metrics can be calculated. Loss of Load Hours (LOLH) represents the number of hours per year that firm load was shed and is different than LOLE which measures days per year. Expected unserved energy (EUE) is the actual load in MWh that was not served. The Executive Summary of the FERC report referenced is showing the difference in target reserve margin for a hypothetical system if different reliability metrics were used.

Notably, a 2.4 hour per year metric, which is not the industry standard, is much less stringent than a 0.1 LOLE standard. This is logical because 1 event typically lasts about 3-4 hours, meaning that an LOLE of 0.1 equates to an LOLH of approximately 0.3 – 0.4 hours per year. Allowing 2.4 hours per year would be a much easier metric for a utility to meet.

(g) An analysis and conclusion as to what DEC's and DEP's reserve margins would be using an economically-optimal analysis, as discussed in the Brattle and Astrapé report noted in (f) above. Address the following statement: "Utilities, system operators, and regulators across North America have relied on variations of the 1-in-10 standard for many decades, and typically enforce the standard without evaluating its economic implications." [See reference in (f) above]

<u>Response</u>:

The Companies agree that utilities and system operators generally enforce a reliability standard without evaluating its economic implications. However, the 2016 Resource Adequacy Study did study the economics of adding additional reserves as discussed in response to item (b) above. The Companies believe that the reserve margin determined by the 1 day in 10-year standard was reasonable when studied under an economic framework. The economic analysis determined that a winter reserve margin target of 16.8% to 18.9% balanced system costs for DEC, and a winter reserve margin target of 17.8% to 20.1% balanced system costs for DEP. This analysis showed that there was benefit to having reserve margins slightly higher than the 17% winter target that met the 1 day in 10 year standard. (also reference Section VII of the 2016 study report).

(h) A detailed work plan for developing the update to Astrapé's Resource Adequacy Studies proposed for 2020. [See Page 32 of the Joint Report]

<u>Response</u>:

- Develop input assumptions (February 2020)
  - Data collection
    - Historical weather data
    - Historical irradiance data
    - Historical load data
    - Load forecast data
    - Historical GADS data

        - Historical purchase data and transmission data
        - Hydro data by weather year
        - Historical renewable generation data
        - Production cost model input data
        - Historical demand response calls
        - Fuel prices
        - Combustion turbine carrying costs
        - Cost of unserved energy
    - Develop synthetic loadshapes based on 1980 – 2018 weather data
    - Determine peak winter and summer load variability based on weather
    - Develop economic load forecast multipliers for 3-year ahead load forecasts
    - Update GADS data for generators and determine if cold weather outages should be correlated based on recent history
    - Update solar profiles for 1980 -2018 weather data
    - Update hydro for 1980 – 2018 weather data
    - Update demand response resources
    - Update thermal fleet unit characteristics
    - Update external neighbor modeling and calibrate to recent history
    - Update economic parameters
    - Host review with North Carolina Public Staff and South Carolina ORS to validate all data and assumptions before simulating the models
- Simulate Models (Mar-April 2020)
    - Debugging/Validation: Validate simulations, hourly reports, loads, generator outages, solar profiles, hydro output, pump storage operation, demand response, and neighbor assistance
    - Simulate DEC Reserve Margin Study – vary reserves margins from 10% - 20 %
    - Simulate DEP Reserve Margin Study – vary reserve margins from 10% - 20%
    - Validation of Results and Outputs including hourly reports
    - Determine reserve margin target to meet 1 day in 10-year standard

  - Determine economic reserve margin results

- Sensitivities (April 2020)
  - Island Scenario
  - Solar Penetration Sensitivities
  - Economic sensitivities of CT cost and EUE cost
  - Additional Company requested sensitivities
- Review preliminary results of analyses with the North Carolina Public Staff and South Carolina ORS
- Incorporate any Public Staff and ORS input as appropriate and finalize results
- Finalize Report for use in the Companies' 2020 IRPs (May 2020)

(i) A characterization and discussion of the impact and risks of potentially delaying the awarding of contracts associated with DEP's capacity and energy market solicitation until an updated Resource Adequacy Study is completed and effectively vetted. [See Page 81 of DEP IRP]

__Response__:

Based on the 2019 IRP Update, the DEP resource need through 2025 is significant. Through expiring purchase power contracts, load growth, and potential retirements of older CT units, the capacity need in DEP reaches approximately 2,700 MW by January 1, 2024. To provide context, each potential 1% move in reserve margin would change the need by approximately 150 MW. In order to meet this need, the Company is pursuing the referenced capacity and energy market solicitation. As described below, the market solicitation is prudent under a broad range of potential reserve margin targets.

As part of the market solicitation, the Company identified up-to approximately **[BEGIN CONFIDENTIAL]** [redacted]

[redacted]

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[redacted]

[END CONFIDENTIAL]

Given the relatively modest impact of lowering the minimum planning reserve margin, the time required to execute and have an approved updated resource adequacy study, and the potential risk of the third parties walking away from the market solicitation if it is not expeditiously executed, the Company feels it is prudent to continue executing the short-list contracts it has identified as being cost-effective for the Company's customers.

(j) A listing of the reserve margins included in DEC's and DEP's IRPs from 2003 through 2018;

<u>**Response**</u>:

Historic Planning Reserve Margin

	DEC	DEP
2003 IRP	17% Summer Reserve Margin	11%-13% Summer Capacity Margin[1,2]
2004 IRP	17% Summer Reserve Margin	11%-13% Summer Capacity Margin[1,2]
2005 IRP	17% Summer Reserve Margin	11%-13% Summer Capacity Margin[1,2]
2006 IRP	17% Summer Reserve Margin	11%-13% Summer Capacity Margin[1,2]
2007 IRP	17% Summer Reserve Margin	11%-13% Summer Capacity Margin[1,2]
2008 IRP	17% Summer Reserve Margin	11%-13% Summer Capacity Margin[1,2]
2009 IRP	17% Summer Reserve Margin	11%-13% Summer Capacity Margin[1,2]
2010 IRP	17% Summer Reserve Margin	11%-13% Summer Capacity Margin[1,2]
2011 IRP	17% Summer Reserve Margin	11%-13% Summer Capacity Margin[1,2]
2012 IRP	14.5% Summer Reserve Margin[3]	14.5% Summer Reserve Margin[3]
2013 IRP	14.5% Summer Reserve Margin	14.5% Summer Reserve Margin
2014 IRP	14.5% Summer Reserve Margin	14.5% Summer Reserve Margin
2015 IRP	17% Summer Reserve Margin[4]	17% Summer Reserve Margin[4]
2016 IRP	17% Winter Reserve Margin[5]	17% Winter Reserve Margin[5]
2017 IRP	17% Winter Reserve Margin	17% Winter Reserve Margin
2018 IRP	17% Winter Reserve Margin	17% Winter Reserve Margin
2019 IRP	17% Winter Reserve Margin	17% Winter Reserve Margin

Notes:

[1]An 11%-13% capacity margin corresponds to a 12.4%-14.9% reserve margin.

[2]The Company determined that an 11% capacity margin may be acceptable in the near term when there is greater certainty in forecasts. A 12%-13% capacity margin is appropriate in the longer term to compensate for possible load forecasting uncertainty, uncertainty in DSM/EE forecasts or delays in bringing new capacity additions online.

[3]Based on results of the 2012 Resource Adequacy Studies.

[4]Based on interim results of the 2016 Resource Adequacy Studies.

[5]Based on final results of the 2016 Resource Adequacy Studies.

(k) An explanation of why DEC's and DEP's reserve margins have increased over the last 15 years;

<u>Response</u>:

As shown in the table in response to item 1(j) above, prior to completion of the 2012 resource adequacy studies, DEC used a 17% summer reserve margin target. DEC reduced its summer reserve margin target to 14.5% based on results of the 2012 studies. DEP used an 11%-13% summer capacity margin target, rather than reserve margin target, prior to completion of the 2012 studies. This level of capacity reserves corresponds to reserve margins ranging from 12.4% to 14.9%. DEP determined that an 11% capacity margin (12.4% reserve margin) may be acceptable in the near term when there is greater certainty in forecasts; however, a 12%-13% capacity margin (13.6%-14.9% reserve margin) is appropriate in the longer term to compensate for possible load forecasting uncertainty, uncertainty in DSM/EE forecasts, or delays in bringing new capacity additions online. Thus, DEC reduced its target reserve margin from 17% summer to 14.5% summer based on the 2012 studies, and DEP's reserve margin remained relatively unchanged as a result of the 2012 studies.

The significant penetration of solar resources and the load volatility experienced during the winters of 2014 and 2015 were the key drivers for conducting the new resource adequacy studies in 2016. As discussed in the Executive Summary and Conclusions sections of the 2016 Resource Adequacy Study report, the level of solar penetration and the load response experienced in recent cold weather periods (2014 and later) have transitioned the Companies to winter planning, and a 17% winter reserve margin is needed to ensure adequate generation system reliability. Also, as noted in a prior response, the Companies and other southeast utilities have experienced actual winter load levels that have caused near load shed events, or in SCANA's case an actual load shed event. These cold weather events, such as the first week of January 2018, have resulted in high load levels that have persisted across multiple days. It is worthy of noting that these events occurred when actual weather normal planning reserves for the utilities were well in excess of the 17% minimum planning reserve target used in resource planning.

Beyond winter load response, as further discussed in Section VI (Physical Reliability Sensitivities) of the study report, the relationship between the summer and winter reserve margin changes as the level of solar penetration changes since solar has a greater capacity contribution on hot summer afternoons compared to cold winter mornings. Thus, as solar penetration increases, the summer reserve margin increases relative to the winter reserve margin which ultimately shifts the reliability risk to the winter. The 2012 study only included a forecast of 49 MW of solar for DEC whereas the 2016 study included a forecast of 1,251 MW of solar for the study year. DEP showed an even greater change in solar assumptions between the two studies with 54 MW of solar in the 2012 study and 2,057 MW of solar in the 2016 study. The combination of the solar penetration and winter load volatility in the 2016 study led to the recommendation of a 17% winter reserve margin in order to provide adequate generation system reliability.

As previously discussed, Astrapé used the correlation of historical load and temperature data based on the most recent five years, to develop synthetic loadshapes for the 36 weather years used in the 2012 and 2016 studies. Thus, the extreme winter load response seen in the 2014 and 2015 winters was captured in the 2016 studies but not in the 2012 studies. Furthermore, neither the 2012 nor the 2016 study captured actual January 2018 weather and load data that will be accounted for in the 2020 studies. These cold temperatures and their correlated load responses were not seen in the previous decade and therefore the load response to these temperatures in the 2012 studies was under estimated relative to current observations of actual weather and load relationships. In the 2012 study, given the absence of frequent actual events with low temperatures, Astrapé was forced to extrapolate from customer usage patterns at higher winter temperatures to predict electricity usage during colder weather. The 2014 and 2015 actual events demonstrated load at low temperatures was not accurately predicted from higher temperature usage patterns in the 2012 studies. It was only after observing real time load response at colder temperatures that a more representative deviation could be modeled in the 2016 studies.

The summer correlation of temperature and load did not change significantly between the 2012 and 2016 studies. Thus, the summer reserve margin requirements have remained relatively unchanged over the years. In fact, in the Conclusions section of the 2016 study reports, Astrapé recommended that the Companies ensure a minimum 15% reserve margin is maintained across the summer. Astrapé further noted that, based on the current portfolios, the 15% summer reserve margin will always be met if a 17% winter target is met.

In summary, DEC reduced its summer reserve margin target based on results of the 2012 resource adequacy studies, and the reserves needed in the summer have remained at about 14%-15% for both Companies. The winter reserve margin target has changed significantly with the high penetration of solar resources and the greater winter load volatility seen during recent winter periods. The winter load volatility for DEP is greater than DEC, likely due to the higher percentage of residential load versus commercial and industrial load in DEP compared to DEC. Residential load is more weather sensitive than commercial and industrial load due to residential electric heating. According to the EIA, the southeast is the only region in the country that has the majority of its residential heating through electric sources. Other regions rely predominantly on non-electric sources such as natural gas.[5]

(l) DENC's reserve margin is 11.87% and PJM's reserve margin is 15.9%. DENC's and PJM's resource mix is comparable to Duke's. Explain why DEC's and DEP's reserve margins are higher than DENC's and PJM's.

Response:

The DENC 11.87% reserve margin is a summer reserve margin and is reflective of DENC being part of the PJM RTO. PJM determines a system wide summer reserve margin of 15.9% using its LOLE Study. It is the Companies' understanding that based on DENC's weather diversity with the PJM coincident peak, PJM rules allow DENC to maintain an 11.87% summer reserve margin. As stated in the 2016 Resource Adequacy Studies, a 15% summer reserve margin is reasonable for DEC and DEP and is in line with PJM's summer reserve margin level of 15.9%.

As discussed previously, the winter loads and increased solar have shifted DEC and DEP to winter planning utilities. So, while 15% is reasonable for the summer, a higher 17% reserve margin is needed for the winter. The PJM RTO and DENC have lower winter loads compared to summer loads and do not experience the same winter risk. Below are the summer and winter peak forecasts from the PJM 2019 Load Report[6] and DENC's 2018 IRP[7]. As shown below, the PJM summer forecast of 150,870 MW is much larger than the winter forecast of 131,148 MW. DENC's summer forecast of 19,938 MW is also significantly above its winter forecast of 18,666 MW, making winter risk not as challenging for DENC as it is for DEC and DEP. In addition to lower winter loads, the 2019 Quarterly State of the Market Report for PJM reports 1,598.8 MW of solar capacity of which 722 MW is reported by Dominion.[8] Given the 150,870 MW peak load reported, solar resources represent about 1% in penetration compared to much larger penetrations seen in DEC and DEP. For example, based on 2020 projections from the Companies' 2019 IRPs, DEC and DEP project winter peak demands to exceed summer peak demands (as shown in the table below)[9]. In addition, DEC projects 1,137 MW of solar resources in 2020, and DEP projects 3,005 MW of solar resources in

[5] EIA Today in Energy article, *One in four U.S. homes is all electric*, May 1, 2019; https://www.eia.gov/todayinenergy/detail.php?id=39293

[6] https://www.pjm.com/-/media/library/reports-notices/load-forecast/2019-load-report.ashx?la=en
[7] https://www.dominionenergy.com/library/domcom/media/about-us/making-energy/2018-irp.pdf
[8] https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2019/2019q2-som-pjm.pdf; pg 566 Table 12-1
[9] Reference DEC 2019 IRP, Tables 8-A and 8-B and DEP 2019 IRP, Tables 9-A and 9-B, filed in Docket No. E-100, Sub 157,

2020.[10] As a percentage of 2020 winter peak demand, DEC nameplate solar resources represent an approximate 6% penetration, and DEP nameplate solar resources represent an approximate 21% penetration. Thus, the relationship of winter versus summer peak demands and the penetration of solar resources are significantly different for DEC and DEP compared to PJM and Dominion, and these relationships have a direct impact on winter versus summer planning reserve requirements.

- PJM RTO 2020 Summer forecast is 150,870 MW
- PJM RTO 2019/2020 Winter peak forecast is 131,148 MW
- DENC 2018 Summer Peak – 19,938 MW
- DENC 2018 Winter Peak – 18,666 MW
- DEC Projected 2020 Summer Peak is 18,282 MW
- DEC Projected 2020 Winter Peak is 18,589 MW
- DEP Projected 2020 Summer Peak is 13,283
- DEP Projected 2020 Winter Peak is 14,623 MW

The Companies' resource adequacy studies capture the load diversity and generator outage diversity that exist in the one tier away interconnected system. The 2016 studies showed that market assistance allows the Companies to carry a reserve margin approximately 6% lower than would otherwise be required without market assistance. PJM is an integral part of the interconnected system providing capacity support to DEC and DEP and this support is captured in the resource adequacy studies. As previously noted, the Companies and Astrapé plan to revisit and update the market assistance modeling (import capability and capacity support available from neighboring systems) as part of the 2020 Resource Adequacy Study.

(m) NERC's 2018 SERC-Southeast reference reserve margin level is 15%. Explain why DEC's and DEP's reserve margins are higher than NERC's.

Response:

As noted in footnote 4 on page 53 of the NERC 2018 Long-Term Reliability Assessment[11], 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. Thus, SERC members

[10] Reference Table 6-B from DEC and DEP 2019 IRPs filed in Docket No. E-100, Sub 157.

[11] https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2018_12202018.pdf

establish their own reserve margin targets, and SERC does not provide reference margin levels of its sub-regions to NERC. Further, NERC defaults to a 15% reserve margin assumption for SERC since SERC does not provide a reference margin.

As discussed above, the 2016 Resource Adequacy studies demonstrated the need for DEC and DEP to transition to winter peak demand planning as a result of the high penetration of solar resources and the greater volatility of winter peak demands compared to summer peak demands. The NERC reserve margins reflect summer peak demand conditions for a broad group of utilities whereas the Companies' reserve margin target is based on winter peak demand. In short, the SERC and NERC reliability assessments do not reflect Company specific winter load conditions, nor do they reflect the level of solar penetration that exists in the Carolinas that drives the need for a winter reserve margin target as determined by the Companies' 2016 resource adequacy studies.

2. Duke's basis for its load forecasts, including:

(a) Tables that show DEC's and DEP's summer and winter load forecasts prepared in each of the years 2003 through 2018 and the corresponding actual summer and winter peak loads for each year;

Response:

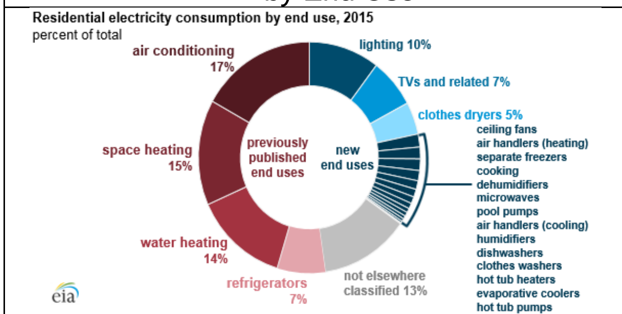
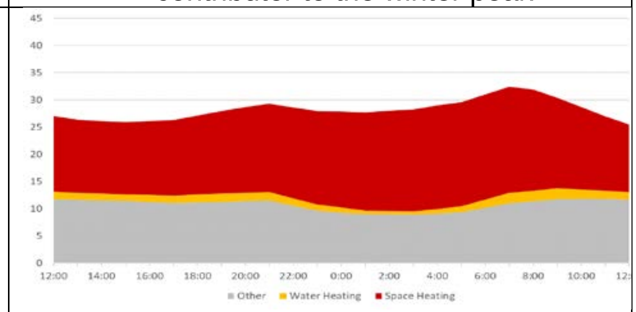
Please see Question 2, Attachment 1.

(b) Analyses performed by Duke to determine which end uses are contributing to load spikes on extremely cold winter mornings.

Response:

The Company continuously conducts research and leverages relevant subject-matter studies to better understand what end-uses are impacting peaks in extreme weather conditions.

Chart 1 illustrates the Energy Information Administration's (EIA) last Residential Energy Consumption Survey (RECS) showing residential electric consumption end-use estimates for the average American household. Chart 2 reflects results received from EPRI that show what end uses are the largest contributors to a typical winter peak experienced in the Carolinas. Both these charts illustrate that, during the winter periods, space heating is the largest end-use driver contributing to both usage and winter peaks, and water heating is a secondary contributor.

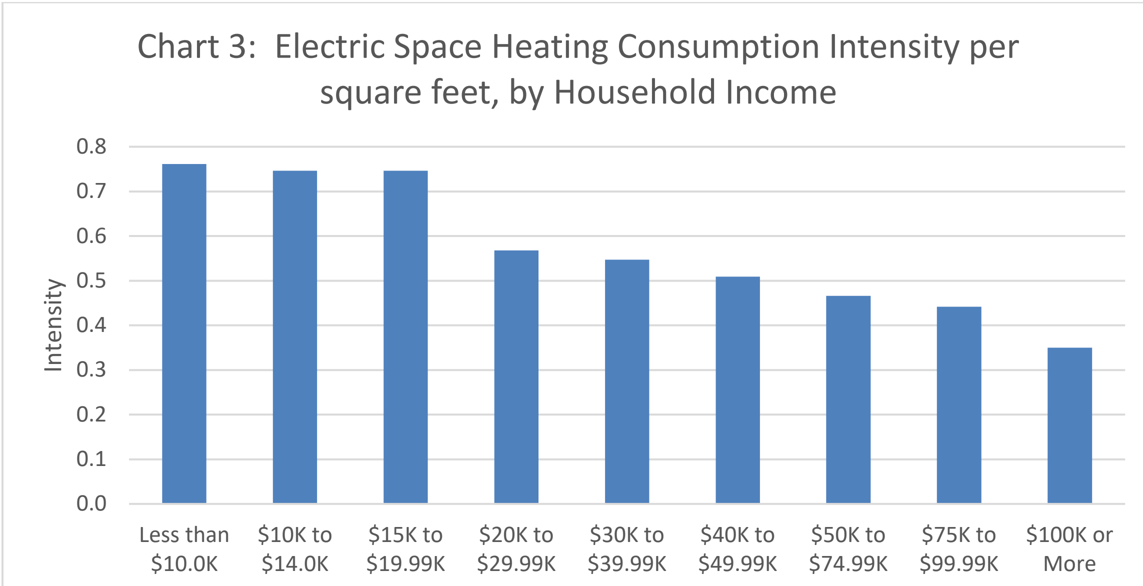
Chart 1: Residential Electricity Consumption by End Use	Chart 2: Space heating is the single largest contributor to the winter peak
	
Source: U.S. Energy Information Administration	**Source: EPRI's**

Note that the end-use history and projections used in the Company's energy and demand forecast models originate from the EIA data.

In addition, the Company conducts a Residential End-Use Survey for its customers every three years to help understand the changing trends of our customer's end-use inventory, housing characteristics, and demographics. Pairing the Company's most recent survey results (2016 and 2019) with the EPRI study and EIA research results provides additional insight on factors impacting electric space heating on extreme cold winter mornings. A few of these findings are summarized below.

***Household income and metropolitan proximity*.** EIA research concludes electric space heating intensity per square feet is negatively correlated with household income, as Chart 3 illustrates. EIA's research is in line with Company and industry assumptions: Higher household incomes increase the likelihood of more energy-efficient homes with lower intensity levels that consume less electricity.

Duke Energy Carolinas, LLC and Duke Energy Progress, LLC's
Response to August 27, 2019 Order
Docket No. E-100, Sub 157
November 4, 2019



Source: EIA 2005 RECS: Energy Consumption and Expenditures Tables

EIA research also concludes that, on average, homes in metro areas consume less than the average home for space heating, while homes in micropolitan and rural areas spend more on average on space heating, as Table 1 illustrates.

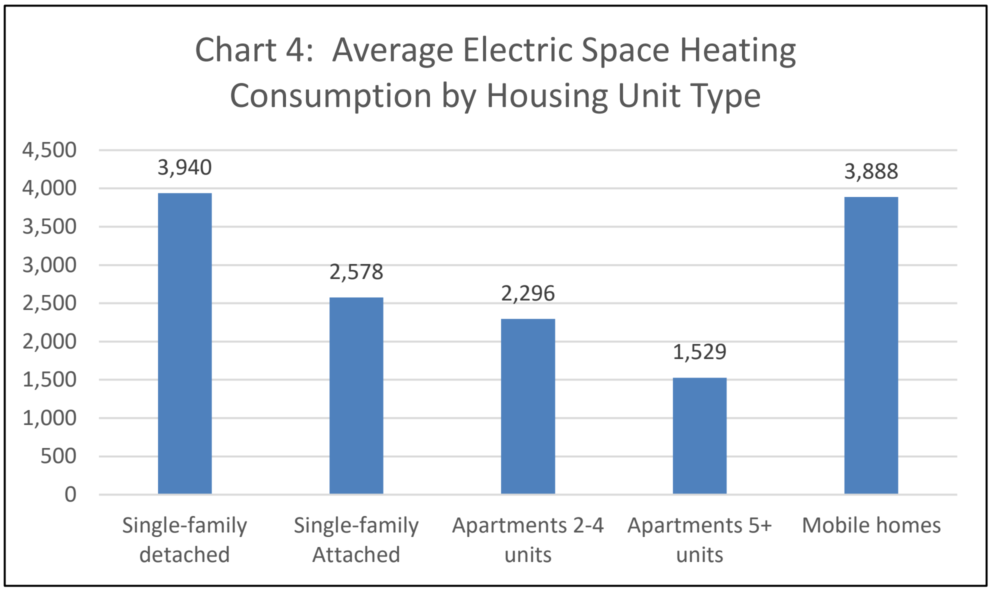
Table 1: Average Site Electricity Consumption Comparison by Statistical Area for Space Heating

Metropolitan or Micropolitan Area	Space Heating, kWh per Household	Percent of All Homes
All homes	3,242	100%
In metropolitan statistical area	2,893	89%
In micropolitan statistical area	4,647	143%
Not in metropolitan or micropolitan area	4,684	145%

Source: EIA 2015 Residential Energy Consumption Survey-Energy Consumption and Expenditure Tables

EIA findings are consistent with the Company's NC/SC jurisdictional footprint. While DEC is predominately metropolitan, DEP is predominately micropolitan and rural. In addition, the metropolitan areas of DEC and DEP have grown significantly in recent years in population and household income, while many of the micropolitan and rural areas have seen flat or negative growth. Finally, most metropolitan areas have natural gas as a heating source, which is utilized by a significant percentage of households. In contrast, most of the micropolitan and rural areas have little to no access to natural gas, forcing them to rely primarily on electric space heating. Combined with the lower incomes, and the higher likelihood of living in less efficient homes and having less efficient heating sources, it can be established the large percentage of households in rural and micropolitan areas of DEP and DEC are likely contributors to load spikes during extremely cold mornings.

***Housing Unit Type*.** "The less efficient a housing shell, the higher its electric space heating consumption and intensity will be" is a standard assumption for the Company and the industry. EIA research concludes that despite mobile homes having far less square footage than a single-family home on average, they consume almost as much electricity for space heating (see Chart 4). The Company's surveys indicate that 5% to 7% of DEC customers reside in mobile homes, compared to 6% to 10% for DEP.



Source: EIA 2015 RECs-Energy Consumption and Expenditure Tables

***Renters vs. Owners*.** In addition to higher consumption, electric space heating intensity is greater in mobile homes and apartments compared to single-family housing unit types, as Table 2 illustrates.

Table 2: Electric Space Heating Consumption Intensity by Housing Type			
Housing Unit Type	Ownership of Housing Unit		
	Overall	Owned	Rented
Overall		0.473	0.676
Single-family detached	0.450	0.442	0.529
Single-family attached	0.473	0.376	0.582
Apartments in 2-4 Unit Buildings	0.824	*	0.835
Apartments in 5 or More Unit Buildings	0.709	0.559	0.731
Mobile Homes	0.846	0.821	1.066

Source: EIA 2005 Residential Energy Consumption Survey (RECS): Energy Consumption and Expenditure

Tables
***Data withheld due to Relative Standard Error (RSE) was greater than 50 percent or fewer than 10 households were sampled**

EIA's research results in Table 2 also illustrate that electric renter household space heating intensity is greater than in owned homes, regardless of housing type. This finding is significant for both DEC and DEP in that both jurisdictions have a significant percentage of homeowners who rent. Table 3 illustrates the percentage change between the Company's 2013 and 2016 surveys, which also illustrates the high rate of renters in the DEP and DEC regions, and that the percentage of renters are increasing in both jurisdictions. Coupled with the percent of mobile households and the intensity level of both housing unit types, it is likely these household types also contribute positively to demand spikes on cold winter mornings.

Table 3: Duke Energy Carolinas Residential Saturation Survey Result Comparison: Percent of Renter Households

Jurisdiction by State	2016 Survey	2019 Survey	Delta
DEC-NC	28%	29%	+1
DEC-SC	22%	23%	+1
DEP-NC	26%	29%	+3
DEP-SC	24%	28%	+4

Duke Energy Residential Saturation Surveys, 2013, 2016

Housing Stock Age: EIA research concludes that housing stock age is positively correlated to electric space heating intensity, indicating that older homes have the propensity to produce higher electric space heating intensity, leading to higher demand and consumption during extremely cold winter mornings. The Company's survey responses indicate that the percentage of housing stock built before 1970 is declining; however, that percentage is still substantial in each territory. Note that the decline in these older homes is faster in DEC than in DEC.

Chart 5: Electric Main Space Heating Consumption Intensity

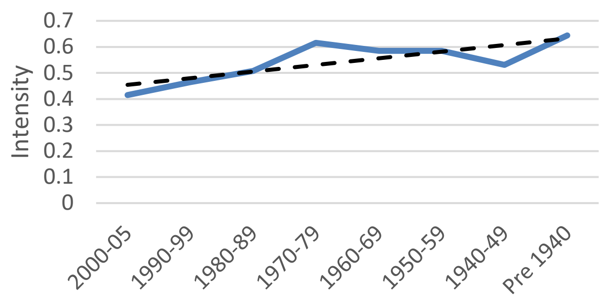


Table 4: Percentage of Duke Residential Customers Living in Homes Built Prior to 1970

Jurisdiction by State	2016 Survey	2019 Survey	Delta
DEC-NC	26%	19%	-5
DEC-SC	24%	20%	-4
DEP-NC	16%	14%	-2
DEP-SC	29%	30%	+1

Energy Information Agency research results: Electric main space heating intensity generally increases with the age of the home unit.

Duke Saturation Surveys: Approximately 20% of Duke customers live in homes that were built in 1970 or earlier, according to our two most recent residential saturation surveys (2016 and 2019). This housing stock is declining in DEP, but at a slower rate than in DEC.

Source: EIA 2005 RECS: Energy Consumption and Expenditures Tables, Table SH12; Duke Energy Residential Saturation Surveys, 2013, 2016

Finally, the Company Residential survey concludes that the number of households in DEC and DEP using portable electric heaters has increased in both DEC and DEP from 29% to 32%.

(c) As a part of DEP's Blue Horizons Project (BHP), DEP has had success in employing DSM in the Western Region to shave winter peaks. Discuss whether DEP's success in using DSM could be replicated by DEC in its North Carolina service territory. If that success can be replicated, explain why DEC has not done so. If not, explain why not.

<u>Response</u>:

The Company believes that some winter peak reduction programs through DSM could be replicated by DEC in its North Carolina services territory and plans for that implementation are underway; however, the implementation of those programs will be challenging.

The amounts of DSM included in the 2018 IRP forecast are based on the Companies' 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, the Companies believe 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.

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. Assuming the same level of achievable potential in the rest of DEP and DEC, a 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.

Moreover, actual program experience from DEP EnergyWise Home has shown that winter residential program potential is difficult to achieve for several reasons. First, not all residential customers have electric resistance hot water heaters or heat pumps with electric resistance strip heat. Second, residential winter measure installations require appointments to enter the customer's home that are often rescheduled and more costly than a summer air conditioning installation, which does not require an in-home installation. The Companies note their plans to implement new winter DSM programs as proposed in the 2018 IRPs, and continue to work toward implementation of those programs.

3. DEC's and DEP's most current strategic plans to reduce carbon dioxide (CO2) emissions, including:

(a) The implementation plan (including CO2 glide path) that results in the attainment of DEC's and DEP's most current goals for reductions in CO2 emissions.

<u>Response</u>:

In mid-September 2019, Duke Energy Corporation announced its new, enterprise-wide climate strategy, including updating its CO_2 reduction goals to at least 50% reduction by 2030 and achieving net-zero for electricity generation by 2050. Both goals are reductions from 2005 CO_2 levels. The specific trajectory for each Duke Energy utility contributions for achieving those goals will vary by jurisdiction.

For DEC and DEP, the base case in both the 2018 IRP and the 2019 IRP Update plans achieves at least 50% CO_2 reduction by 2030, which is aligned with Duke Energy

Corporation's current climate strategy. However, DEC and DEP plan to work with regulators, customers and other stakeholders to determine how best to achieve reductions greater than 50% by 2030 and ultimately achieve net-zero emission by 2050 in a manner that balances reliability, affordability and sustainability.

(b) Modelling of the carbon reduction goals in the draft Clean Energy Plan released for public comment on August 16, 2019, by the North Carolina Department of Environmental Quality and Duke's current carbon reduction plan. The modelling should not only show the resource portfolio needed to achieve these goals but should also show any cost differentials (increases or savings) from the base case and the preferred case. In modelling cost differentials, the plans should include anticipated costs attributable to disposal of coal wastes from ongoing and continued operation of coal-fired plants and anticipated cost savings attributable to earlier retirement of such plants.

Response:

Since the Commission issued its August 27, 2019 Order accepting the 2018 IRPs and requesting this additional information, the North Carolina Department of Environmental Quality (DEQ) released their "final" version of the Clean Energy Plan. The final plan, released on September 27, 2019, included several significant changes from the "draft" Clean Energy Plan released on August 16, 2019. Two of these changes were:

1. A shift in focus from CO_2 emissions to Greenhouse Gas (GHG) emissions, and
2. A narrowing of the emissions reduction target from a 60% - 70% reduction in CO_2 emissions to a 2030 GHG emissions reduction target of 70%.

In order to model plans to achieve the full 70% reduction in GHG emissions, the Companies would first need to work with DEQ to understand:

1. How are GHGs being defined (what is included, what is not)?
2. What is the baseline (from what levels are reductions required)?
3. What are DEC and DEP's fair share of the statewide reductions? and
4. How is DEQ considering tracking GHG emissions reductions?

When only considering CO_2 emissions, there are many potential paths that could be taken to move closer to a 70% reduction target by 2030, and the Companies look forward to working with DEQ and other stakeholders on the best way to achieve these goals in a manner that balances reliability, affordability and sustainability. Given there are multiple paths, and uncertainties around how GHG is defined, the Companies have not developed a preferred plan for how these GHG emissions reduction targets could be met. However, in response to the request by the Commission, the Companies are presenting two potential, illustrative scenarios that would move the Companies closer to achieving 70% CO_2 reduction target by 2030, utilizing a 2005 baseline. These reductions are achieved by increasing the pace of coal plant retirements while significantly increasing the Companies' mix of renewables (including wind generation), battery storage, energy efficiency, and combustion turbine (CT) generation.

The scenarios presented do not fully account for the real-world challenges that would be faced in adding a significant number of new grid resources in a short amount of time. Issues not addressed, but required to implement this pace of system transformation, include physical and regulatory challenges affecting the time to construct new assets and their associated interconnection and system upgrade requirements. Implementation would require addressing issues in the areas of supply-chain, siting, permitting, right-of-way acquisition, transmission queue studies, comprehensive network upgrades, gas pipeline expansion and acquiring facility certificates of public convenience and necessity (CPCN) for all new facilities. At a minimum, existing legislative and regulatory processes governing resource additions (including, but not limited to, siting, permitting, and CPCN processes). may be needed to be modified to accommodate the pace of transition outlined in the scenarios studied.

Notwithstanding implementation challenges, the scenarios do provide a high level economic assessment that accounts for a potential decline in system operating costs, including fuel costs, as more renewables and more efficient gas generation are added to the system, decreased or eliminated expenses associated with ongoing coal operations including anticipated reductions in costs attributable to disposal of coal wastes from ongoing and continued operation of coal-fired plants. To be clear, coal ash costs associated with ash that was generated prior to this study are included in the base and change cases and early retirement of operating coal plants does not impact those costs. The scenarios account for the estimated capital and operating costs associated with accelerating the replacement generation, storage and DSM programs. However, given the magnitude of these projected system changes in the relatively short time span, it is extremely difficult to predict the total network transmission costs needed to implement these changes. As such, these costs have been excluded and could materially impact the economics in the presented scenarios. The Atlantic Coast Pipeline (ACP) is already considered in the base case, but the scenarios do include the incremental cost of pipeline infrastructure to support incremental gas generation above what is in the base case. Finally, the economic analysis also assumes significant reductions in the installed cost of renewable and storage resources compared to today's levels, which help to lessen the economic impact of the scenarios.

The Companies are presenting a comparison of two potential paths that achieve 60% and

64% CO_2 emission reductions by 2030 versus the "Base Case" plan that achieves 51% CO_2 emission reductions. Again, these are not the Companies' actual plans but rather are simply intended to provide context to the potential impacts of achieving closer to 70% CO_2 reduction by 2030. Because DEC and DEP serve customers in both North Carolina and South Carolina through the respective integrated Carolinas systems, the emissions reductions shown in the cases below are total system reductions across the two utilities and are not specific to North Carolina. Additionally, the Base Case is derived from the 2018 IRP Joint Plan scenario that was developed to show the impacts of DEC and DEP jointly planning for future capacity needs. This case was updated with inputs from the 2019 IRP Update including fuel prices and load forecast updates. A description of the 3 cases is presented below in Table 1.

Table 1: Resource Mix at Varying Levels of CO_2 Reduction

	Base Case	60% CO_2 Reduction by 2030	64% CO_2 Reduction by 2030
CO2 Reduction vs 2005 Baseline	51%	60%	64%
Coal Retired by 2030, MW and as % of Coal Generation Available as of October 1, 2019	2,567 MW (25%)	6,028 MW (58%)[1]	10,415 MW (100%)[2]
Generation Mix by 2030, MW and % of Total Capacity in 2030			
Total Nameplate Solar	7,543 *(15%)*	8,212 *(15%)*	9,643 *(18%)*
Total Storage[3]	452 *(1%)*	1,710 *(3%)*	2,984[4] *(5%)*
Total Wind, MW[5]	0 *(0%)*	750 *(1%)*	750 *(1%)*
Incremental EE/DSM, MW[6]	1,979 *(4%)*	2,942 *(5%)*	2,942 *(5%)*
New CC, MW	4,023 *(8%)*	4,023 *(8%)*	4,023 *(7%)*
New CT, MW	1,880 *(4%)*	3,760 *(7%)*	6,110 *(11%)*
Other Renewables & Hydro	1,365 *(3%)*	1,365 *(3%)*	1,365 *(3%)*

	Base Case	60% CO_2 Reduction by 2030	64% CO_2 Reduction by 2030
Existing Nuclear	11,188 *(22%)*	11,188 *(21%)*	11,188 *(21%)*
Existing Pumped Storage	2,400 *(5%)*	2,400 *(4%)*	2,400 *(4%)*
Existing & Designated CC/CHP	5,836 *(11%)*	5,836 *(11%)*	5,836 *(11%)*
Existing & Designated CT	6,519 *(13%)*	6,519 *(12%)*	6,519 *(12%)*
Coal	7,848 *(15%)*	4,387 *(8%)*	0 *(0%)*
Conventional Purchases	528 *(1%)*	528 *(1%)*	528 *(1%)*

Notes:

1. Includes Allen 1-5, Cliffside 5, and Marshall 1&2 in DEC and Asheville 1&2, Mayo, and Roxboro 1-4 in DEP.
2. Includes all units in Note 1, along with Belews Creek and Marshall 3&4 in DEC. Additionally, Cliffside 6 is 100% gas fired from 2030 and beyond.
3. Values represent total usable capacity. A 4-hour battery storage is assumed to provide 80% contribution to winter peak. As level of 4-hour storage increases, contribution to winter peak may be reduced significantly.
4. Assumes approximately 1,300 MW of existing solar resources install storage behind existing solar inverter along with a portion of new build solar also installing storage behind solar inverter in "Retire All Coal by 2030" case.
5. Assumes "on-shore" wind. Does not include potential for off-shore generated wind energy.
6. EE MWs based on Market Potential Study included in 2018 IRP. Study will be updated for the 2020 Comprehensive IRP.

The following table summarizes the preliminary economic analysis conducted that compares the two potential illustrative scenarios to the base case. Results are shown by estimated present value revenue requirements (PVRR) through 2034 and are presented in 2019 dollars. **PLEASE NOTE:** These estimates do **NOT** include the impact of network transmission upgrades necessary to support the system which would likely increase the total PVRR significantly. This preliminary, high-level analysis shows the estimated incremental PVRR for each of these two scenarios ranges from $2.0B to $5.1B when compared to the base case excluding transmission costs.

It is important to recognize that capital costs in the PVRR calculation are based on real-levelized cash flows through 2034, and are not suitable for directly calculating rate impacts. However, when considering nominal cash flows, the PVRR below represents an acceleration of $6 Billion to $13 Billion of potential capital spend into the 2020s. This acceleration of capital yields an average annual operating cost savings, including fuel savings and avoided costs relative to on-going coal plant operations, of approximately $170 Million to $340 Million through 2030 when compared to the base case.

Table 2: Approximate PVRR through 2034 (2019$)
(Negative numbers shown in parentheses represent a cost savings vs the base case)

	60% CO_2 Reduction by 2030	64% CO_2 Reduction by 2030
CO_2 Reduction vs 2005 Baseline	60%	64%
System Production Cost Savings (fuel, start costs, VOM)	($2,100,000,000)	($3,000,000,000)
Incremental Solar & Storage Capital & FOM	$700,000,000	$4,800,000,000
Incremental Grid-Tied Storage Capital & FOM	$1,700,000,000	$1,700,000,000
Incremental Wind Capital & FOM	$600,000,000	$600,000,000
Incremental EE Cost	$1,300,000,000	$1,300,000,000
Incremental Gas Generation Capital & FOM	$200,000,000	$200,000,000
Coal Plant On-going Capital, Environmental Capital & FOM Savings	($300,000,000)	($1,100,000,000)
Total (+ Cost vs Base / - Savings vs Base)	$2,000,000,000	$5,100,000,000

	60% CO_2 Reduction by 2030	64% CO_2 Reduction by 2030
Approximate % PVRR Increase vs Base Case	5%	12%

Notes:

- Costs are only calculated through 2034, as such, the lifetime costs and benefits of the assets are not fully captured in this analysis.
- Analysis did not include increased transmission interconnection or system upgrade costs associated with replacement generation.
- For ease of calculation, all incremental generation additions are assumed to be utility owned and do not reflect any assumptions regarding future third-party ownership or PURPA avoided cost assumptions.
- EE costs are based on the 2018 Market Potential Study which is being updated and will be included in the 2020 IRP.
- Includes a 35% reduction in solar PV costs (real 2019$) from 2019 through 2028.
- Includes a 50% reduction in battery storage costs (real 2019$) from 2019 through 2028.

(c) A comparison of DEC's and DEP's most current plans for CO2 emission reductions to the Governor's Executive Order No. 80 which states that "The State of North Carolina will strive to accomplish the following by 2025: a. Reduce statewide greenhouse gas emissions to 40% below 2005 levels."

Response:

Similar to the response in Part (b), Executive Order 80 focuses on GHG emissions and the Companies would need to work with DEQ to understand:

- How are GHGs being defined (what is included, what is not)
- What is the baseline (from what levels are reductions required)
- What is Duke Energy's fair share of the state-wide reductions, and
- How they are considering tracking GHG emissions reductions.

However, in terms of CO_2 emissions, the Company's base case achieves at least a 50% CO_2 reduction below 2005 levels in 2025.

4. With regard to Portfolio 7 in DEC's and DEP's 2018 IRPs (CT Centric with Battery Storage and High Renewables):

(a) A discussion of the differences of executing this portfolio compared to the base case (including the differences in Present Value of Revenue Requirement as well as specific changes to resource plans). [See Page 60 of DEP's IRP and Page 56 of DEC's IRP]

<u>Response</u>:

Portfolio 7 in the 2018 IRP examined the impact of replacing the first 460 MW of CT capacity in DEC and DEP with 575 usable-AC MW[12] (or just "MW") 4-hour lithium ion (Li-ion) battery storage. This battery storage was assumed to be "grid-tied" meaning it could be charged from any generation on the grid (if "DC coupled with solar" the battery could only be charged with solar energy behind the solar inverter). This storage was in addition to the 140 MW of storage placeholders already included in DEP and 150 MW of storage placeholders in DEC. Additionally, Portfolio 7 was not meant to be an exhaustive study of battery capacity on the DEP and DEC systems, but rather it was meant to provide a high-level analysis of the potential value that incremental battery storage used for capacity deferral and energy arbitrage purposes can have on those systems.

To calculate the value of the addition of storage, Portfolio 7 was compared to Portfolio 8. Both Portfolio 7 and Portfolio 8 included high renewables and a more CT Centric resource mix, and the only difference between the two portfolios was the addition of battery storage in place of a CT in Portfolio 7. In DEP, battery storage was added in place of a CT in 2029, and in DEC the replacement was made in 2028[13]. Portfolio 8, which was essentially the No CO_2 base case but with a higher concentration of

[12] "Usable-AC" MW represents the amount of capacity that is available to use in any given hour without impacting the useful life of the battery beyond the life specified in the manufacturer's warranty. In order to meet the life specified in the manufacturer's warranty, the battery is limited to a certain number of cycles over its lifetime, and the battery must not be discharged or charged beyond certain thresholds specified by the manufacturer. Additionally, the battery is usually "overbuilt" to account for natural degradation of the battery. The amount of overbuild can vary depending on the application, but the Company has typically been accounting for approximately 20% overbuild in the case of battery storage used for generation deferral and energy arbitrage purposes. The usable-AC capacity plus the amount of overbuild is equal to the "Total" or "Nameplate" A/C capacity. Typically, when Duke represents the cost of battery storage on a $/MW or $/MWh basis, the MW or MWh represent the usable-AC capacity.

[13] The Company assumed that 4-hour Li-ion battery storage could contribute 80% of its usable-AC capacity to meeting winter peak demand in the 2018 IRP.

renewable energy before 2030, was selected as the basis for the analysis for two reasons. First, the base CO_2 constrained case in DEC did not show the need for CT capacity until 2033 while DEP showed a need for CT capacity in 2029 in all portfolios (see Table A-4 in DEP and Table A-5 in DEC). In generation dispatch models, 4-hour Li-ion battery storage tends to act like a peaking asset, so replacing CT capacity was the appropriate method for evaluating the value of battery storage. The second reason for selecting Portfolio 8 as the base case for this evaluation was to place the level of renewables in DEP and DEC on more equal footing by 2030 since the Company believes the level of renewable energy on a system has a direct impact on the value of battery storage on that system. In the High Renewable scenario, DEP was projected to have 4,474 MW of nameplate capacity renewables while DEC was projected to have 4,533 MW of renewables. This compares to the base renewable case which projected DEC to have approximately 700 MW lower renewable capacity than DEP by 2030.

When comparing the change case (Portfolio 7) to the base case (Portfolio 8 which did not include additional battery storage), DEP saw a PVRR benefit under all CO_2 constrained and fuel price sensitivities while DEC saw a PVRR cost under the same set of sensitivities as shown in the table below.

PVRR Impact of Replacing CT Capacity with 4-hour Battery Storage Under Multiple Fuel & Carbon Scenarios

PVRR ($2018M, thru 2068)

	DEP	DEC
Base Fuel / Base CO2	($417)	$146
Base Fuel / High CO2	($622)	$87
Base Fuel / No CO2	($183)	$236
High Fuel / BaseCO2	($580)	$189
High Fuel / High CO2	($834)	$105
High Fuel / No CO2	($373)	$258
Low Fuel / Base CO2	($219)	$103
Low Fuel / High CO2	($445)	$47
Low Fuel / No CO2	($63)	$213

There are several drivers for the results shown above including:

- The cases were run in a "high renewable" environment where the value of storage is increased as there is more opportunity for gaining benefits from energy arbitrage, or shifting energy from periods of low-cost power (i.e., middle of day when solar output is high or middle of night when demand is low) to periods of higher-cost power (i.e., summer afternoons and winter mornings when demand is high and solar output is lower or non-existent).

- The Company assumed battery storage costs would continue to decline through 2027. By the time the additional storage was added in 2028 in DEC and 2029 in DEP, storage costs would have been approximately 50% lower than storage costs in 2018$ **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** This is in comparison to CT costs of approximately **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**
- DEC already includes 2,400 MW of Pumped Hydro Storage which tends to lower the value of incremental storage on the DEC system. Furthermore, DEP has a greater percent penetration of solar resources than DEC driving larger "net load" differences which advantage batteries in DEP relative to DEC. Since the DEP and DEC systems were modeled as two separate balancing areas (BAs), DEP has limited access to storage, other than the 140 MW of placeholder storage, so incremental storage on the DEP system should have provided more value.

It is important to note that, as discussed in the Commission's Order regarding the 2018 IRPs, the Company is planning to incorporate a Capacity Value of Storage study into the 2020 Comprehensive IRPs that will provide estimates for the capacity value that battery storage can provide over a range of storage durations, storage penetration levels, and renewable penetration levels. The study will consider both grid-tied and storage coupled with solar configurations when conducting the study.

(b) An examination of the cost of battery storage at existing distributed resource sites compared to the expected cost of DEP's capacity and energy market solicitation.

__Response__:

The average all-in cost (energy and capacity) of the shortlist bids in DEP's capacity and energy market solicitation is approximately **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** which is well below new-build CT costs. These contracts generally have a 5-year life with an option to extend up to an additional 5 years in some cases.

For purposes of comparison to battery storage, the Company assumed an on-line date of 1/1/2022 for the storage project. In that case, based on current cost decline estimates, a 4-hour distribution sized battery (10 MW/40 MWh) would cost approximately **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** (usable-AC) while a 4-hour transmission sized battery (50 MW/200 MWh) would cost approximately **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** in 2022. When those costs are converted to real-levelized annual costs, they come out to approximately **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** and **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** respectively for a 10-year asset. FOM costs associated with these storage options are estimated to be approximately **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** and **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** for the distribution and transmission sized battery respectively.

The illustrative example presented below is not an attempt to quantify the value of replacing the entire **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** of potential PPAs, but rather looks at comparing the costs of a 10 MW / 40 MWh distribution battery and a 50 MW / 200 MWh transmission battery to 10 MW and 50 MW PPAs. Assuming both the PPA contract and the battery storage project begin providing benefits in 2022, and both the PPA contract and battery storage projects have lives of 10 years, the PVRR cost of the battery options versus the PPA in 2019$ are:

<u>10 MW Distribution Battery vs 10 MW PPA</u>

- 10 MW/40 MWh Distribution Battery (CAPEX + FOM) = **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**
- Avoided 10 MW PPA = **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**

Capital & FOM PVRR (2019$) Savings from PPA = [BEGIN CONFIDENTIAL] [redacted] **[END CONFIDENTIAL]**

<u>50 MW Transmission Battery vs 50 MW PPA</u>

- 550 MW / 200 MWh Distribution Battery (CAPEX + FOM) = **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**
- 50 MW PPA = **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**
- **Capital & FOM PVRR (2019$) Savings from PPA = [BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**

While detailed PROSYM analysis was not performed, the realized production cost savings from the battery would only offset a fraction of the Capital and FOM costs of the battery. Also, the numbers above assume that a 4-hour battery could replace a CT PPA on a 1:1 MW basis. However, the CT PPA is available year-round, 24 hours per day which provides additional value during long-duration, cold winter events.

It is important to recognize that the PPAs are generally 5 years in duration, and at the end of the contracts there will likely still be a need for new generation. Assuming capital costs of battery storage projects continue to fall, and renewable generation growth continues on the DEP system, the value of battery storage will increase. While the potential depth of the battery market will be studied as part of the Capacity Value of Storage study referenced in other responses, it is more likely that some amount of 4-hour battery storage will be valued on the DEP system sometime in the mid to late 2020s if prices for storage decline as projected in the IRP. However, at today's price levels the use of battery storage as a generation only resource is not cost-effective.

(c) Do the modeling and results in Portfolio 7 provide a statistically representative sample that can be extrapolated into a broader analysis and result by assuming the use of individual battery storage on existing and planned solar facilities, specifically including distribution interconnected QFs and the solar capacity to be brought on line pursuant to HB 589, on Duke's system? If not, explain how the modeling of battery storage added to or included in these solar facilities would differ from that employed in Portfolio 7.

Response:

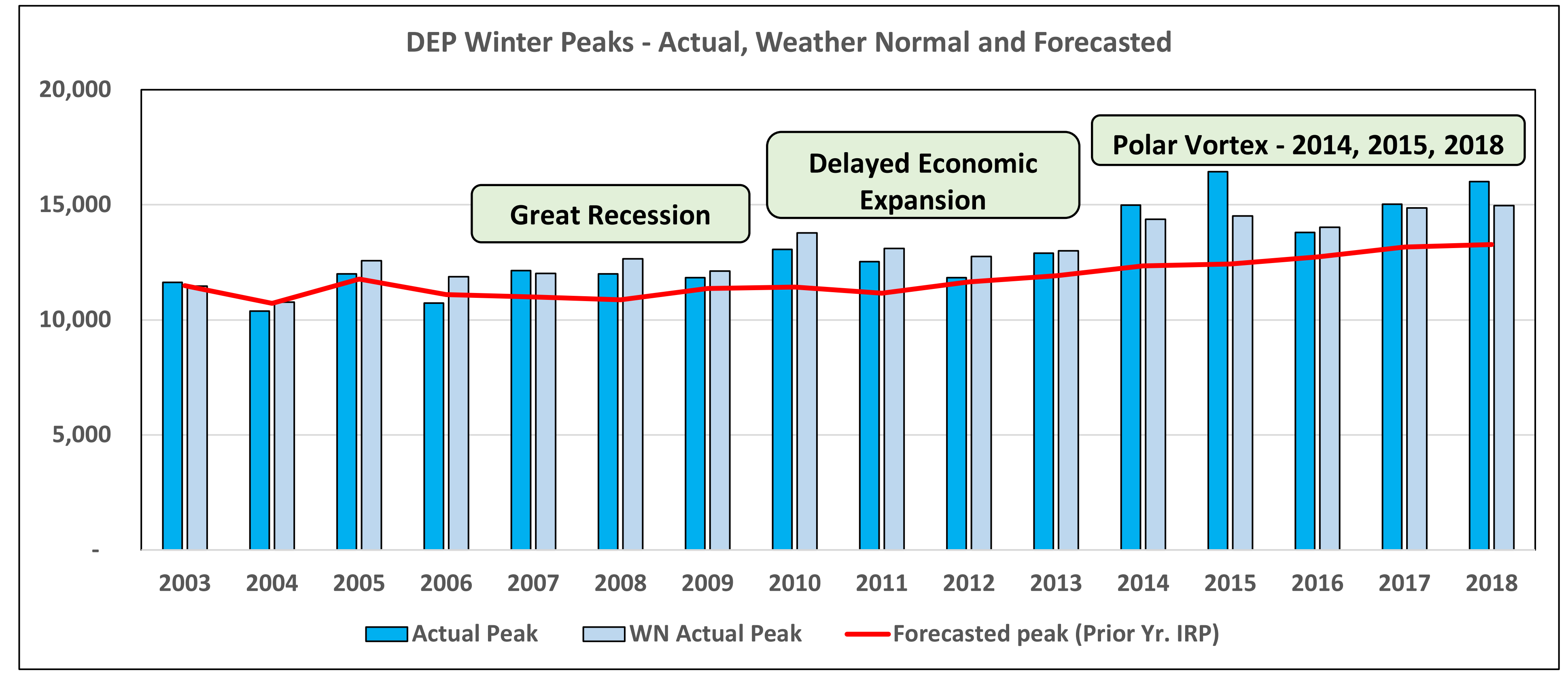
The results from Portfolio 7 cannot be used to extrapolate the value of individual battery storage on existing and planned solar facilities, if those batteries can only be charged from the solar facility (i.e., storage installed behind the solar inverter) and not charged from the grid. The batteries included in Portfolio 7 were able to be charged from the grid which enhances the flexibility of the storage system.

As an example, a battery installed like the battery installed in portfolio 7 could be available to provide capacity and energy on a cold winter morning, then that battery could be charged from the grid during the day as demand drops. The battery would then be available to again provide capacity and energy as demand increases in the evening. Because the battery can be charged from the grid, that battery could then be charged at night and be available to meet demand the next morning. This battery could be available on both sunny and cloudy days.

In the example above, a battery installed with existing solar or on planned facilities, could only be available to provide capacity and energy on a winter morning if it was not used to provide capacity and energy the previous evening because it would not be re-charged by the morning. While being able to charge the battery only from solar is a significant limitation, a benefit of adding storage behind the solar inverter is the ability to capture "clipped" energy, or energy generated by over-paneled solar installations that cannot be added to the grid due to inverter limitations. The amount of clipped energy available depends on the amount that the solar facility is over-paneled, and the amount of clipped energy varies by season depending on the duration that solar output is at its peak (i.e., clipped energy during winter months will be less than clipped energy during shoulder and summer months). This ability to capture clipped energy would be another difference in the modeling of the battery storage system that was added in Portfolio 7 versus battery installed on existing solar facilities. It is unlikely that capturing clipped energy in battery storage behind the inverter outweighs the flexibility benefits that grid-tied solar provides.

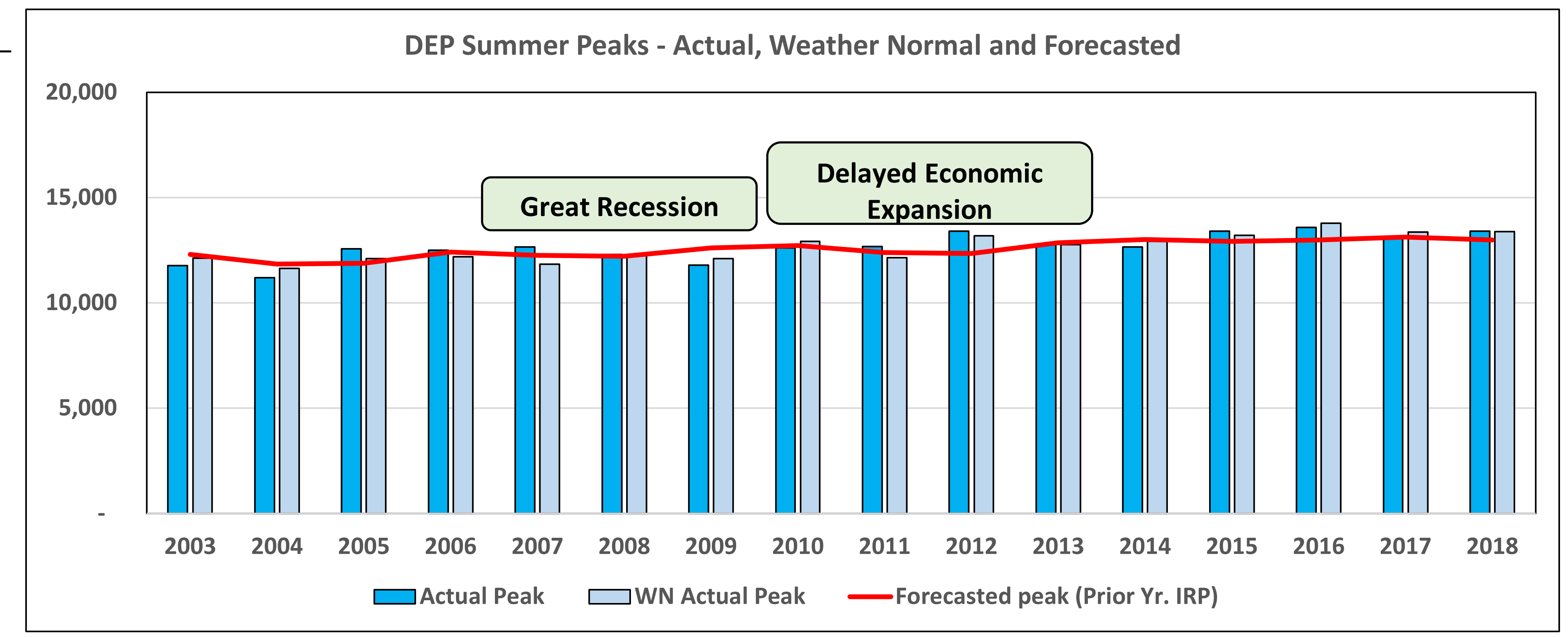
DEP Winter Peaks

Year	Forecasted peak (Prior Yr. IRP)	Actual Peak	Actual Vs. Forecast	Var %	WN Actual Peak	WN Actual Vs. Fcst	Var %	Comments
2003	11,486	11,629	143	1%	11,469	(17)	-0.1%	
2004	10,717	10,391	(326)	-3%	10,774	57	0.5%	
2005	11,780	12,004	224	2%	12,570	790	6.7%	
2006	11,099	10,736	(363)	-3%	11,866	767	6.9%	
2007	11,003	12,142	1,139	10%	12,020	1,017	9.2%	Great Recession Begins
2008	10,873	11,993	1,120	10%	12,655	1,782	16.4%	Great Recession Continues
2009	11,358	11,831	473	4%	12,122	764	6.7%	Great Recession Continues
2010	11,420	13,058	1,638	14%	13,780	2,360	20.7%	Expected economic expansion, did not materialize
2011	11,158	12,522	1,364	12%	13,107	1,949	17.5%	Expected economic expansion, did not materialize
2012	11,655	11,826	171	1%	12,760	1,105	9.5%	Expected economic expansion, did not materialize
2013	11,907	12,897	990	8%	12,994	1,087	9.1%	Economic Expansion begins during late 2013
2014	12,342	14,993	2,651	21%	14,374	2,032	16.5%	Polar Vortex - Yr. 1
2015	12,429	16,429	4,000	32%	14,519	2,090	16.8%	Polar Vortex - Yr. 2, partial year - NCEMPA Wholesale Contract
2016	12,727	13,801	1,074	8%	14,026	1,299	10.2%	First full year of NCEMPA Wholesale Contract
2017	13,158	15,020	1,862	14%	14,857	1,699	12.9%	
2018	13,273	16,016	2,743	21%	14,967	1,694	12.8%	Polar Vortex - Yr. 3



DEP Summer Peaks

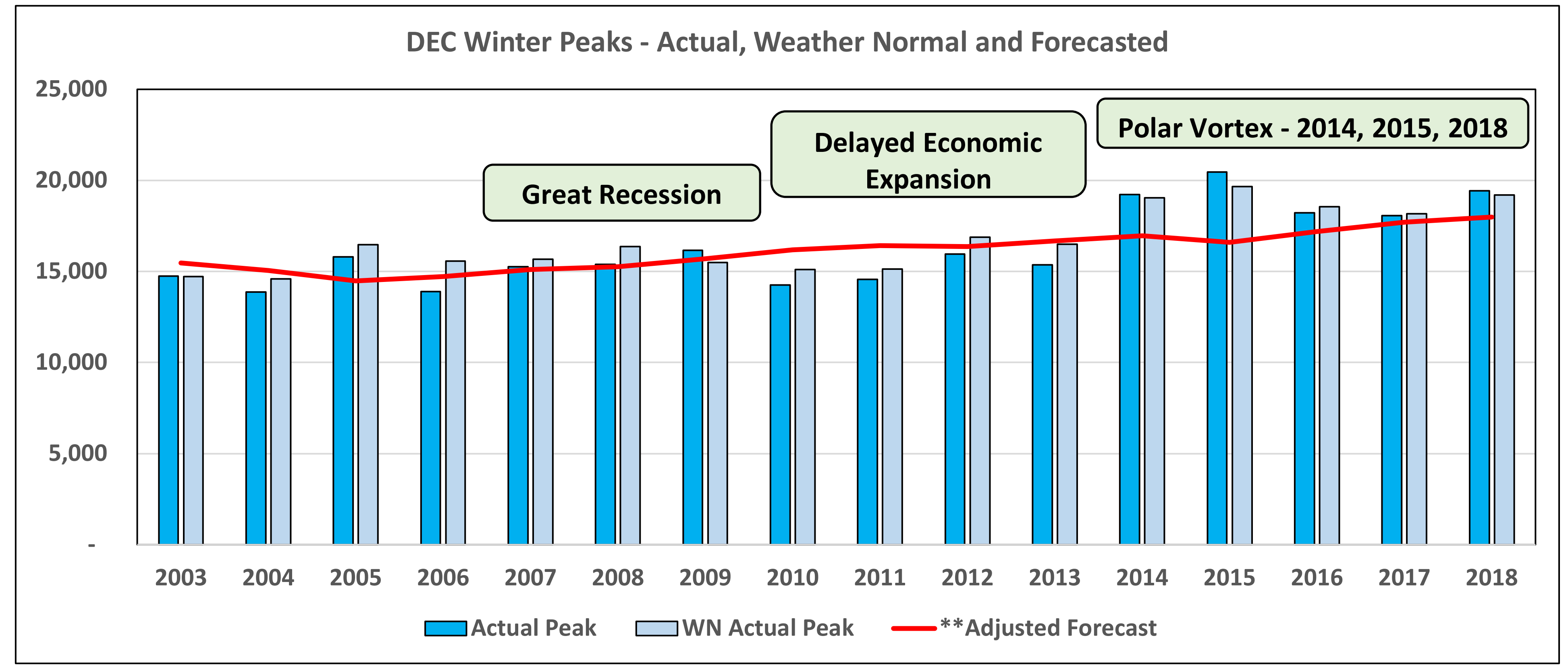
Year	Forecasted peak (Prior Yr. IRP)	Actual Peak	Actual Vs. Forecast	Var %	WN Actual Peak	WN Actual Vs. Fcst	Var %	Comments
2003	12,312	11,771	(541)	-4%	12,138	(174)	-1.4%	
2004	11,846	11,192	(654)	-6%	11,638	(208)	-1.8%	
2005	11,875	12,577	702	6%	12,104	229	1.9%	
2006	12,425	12,496	71	1%	12,204	(221)	-1.8%	
2007	12,269	12,656	387	3%	11,844	(425)	-3.5%	Great Recession Begins
2008	12,209	12,297	88	1%	12,306	97	0.8%	Great Recession Continues
2009	12,621	11,796	(825)	-7%	12,095	(526)	-4.2%	Great Recession Continues
2010	12,731	12,618	(113)	-1%	12,927	196	1.5%	Expected economic expansion, did not materialize
2011	12,389	12,686	297	2%	12,146	(243)	-2.0%	Expected economic expansion, did not materialize
2012	12,340	13,405	1,065	9%	13,198	858	7.0%	Expected economic expansion, did not materialize
2013	12,862	12,785	(77)	-1%	12,757	(105)	-0.8%	Economic Expansion begins during late 2013
2014	13,016	12,663	(353)	-3%	12,922	(94)	-0.7%	
2015	12,924	13,415	491	4%	13,206	282	2.2%	Partial year - NCEMPA Wholesale Contract (Began mid 2015)
2016	12,981	13,578	597	5%	13,777	796	6.1%	First full year of NCEMPA Wholesale Contract
2017	13,127	13,143	16	0%	13,375	248	1.9%	
2018	12,990	13,403	413	3%	13,381	391	3.0%	



DEC Winter Peaks (700-900 MW Backstand/Firm Commitments Included in Forecast, not in Actuals for years 2003-2018)

Year	Forecasted peak (Prior Yr. IRP)	**Adjusted Forecast	Actual Peak	Actual Vs. Adj. Forecast	Var %	WN Actual Peak	WN Actual Vs. Fcst	Var %	Comments
2003	16,176	15,476	14,741	(735)	-5%	14,711	(1,465)	-9.1%	
2004	15,747	15,047	13,865	(1,182)	-8%	14,600	(1,147)	-7.3%	
2005	15,182	14,482	15,810	1,328	9%	16,475	1,293	8.5%	
2006	15,425	14,725	13,899	(826)	-5%	15,582	157	1.0%	
2007	15,798	15,098	15,272	174	1%	15,678	(120)	-0.8%	Great Recession Begins
2008	15,954	15,254	15,395	141	1%	16,364	410	2.6%	Great Recession Continues
2009	16,402	15,702	16,175	473	3%	15,503	(899)	-5.5%	Great Recession Continues
2010	16,885	16,185	14,249	(1,936)	-11%	15,116	(1,769)	-10.5%	Expected economic expansion, did not materialize
2011	17,115	16,415	14,561	(1,854)	-11%	15,141	(1,974)	-11.5%	Expected economic expansion, did not materialize
2012	17,069	16,369	15,962	(407)	-2%	16,875	(194)	-1.1%	Expected economic expansion, did not materialize
2013	17,383	16,683	15,363	(1,320)	-8%	16,500	(883)	-5.1%	Economic Expansion begins during late 2013
2014	17,654	16,954	19,232	2,278	13%	19,040	1,386	7.9%	Polar Vortex - Yr. 1
2015	17,303	16,603	20,455	3,852	22%	19,674	2,371	13.7%	Polar Vortex - Yr. 2
2016	17,896	17,196	18,213	1,017	6%	18,544	648	3.6%	
2017	18,416	17,716	18,069	353	2%	18,162	(254)	-1.4%	
2018	18,687	17,987	19,436	1,449	8%	19,204	517	2.8%	Polar Vortex - Yr. 3

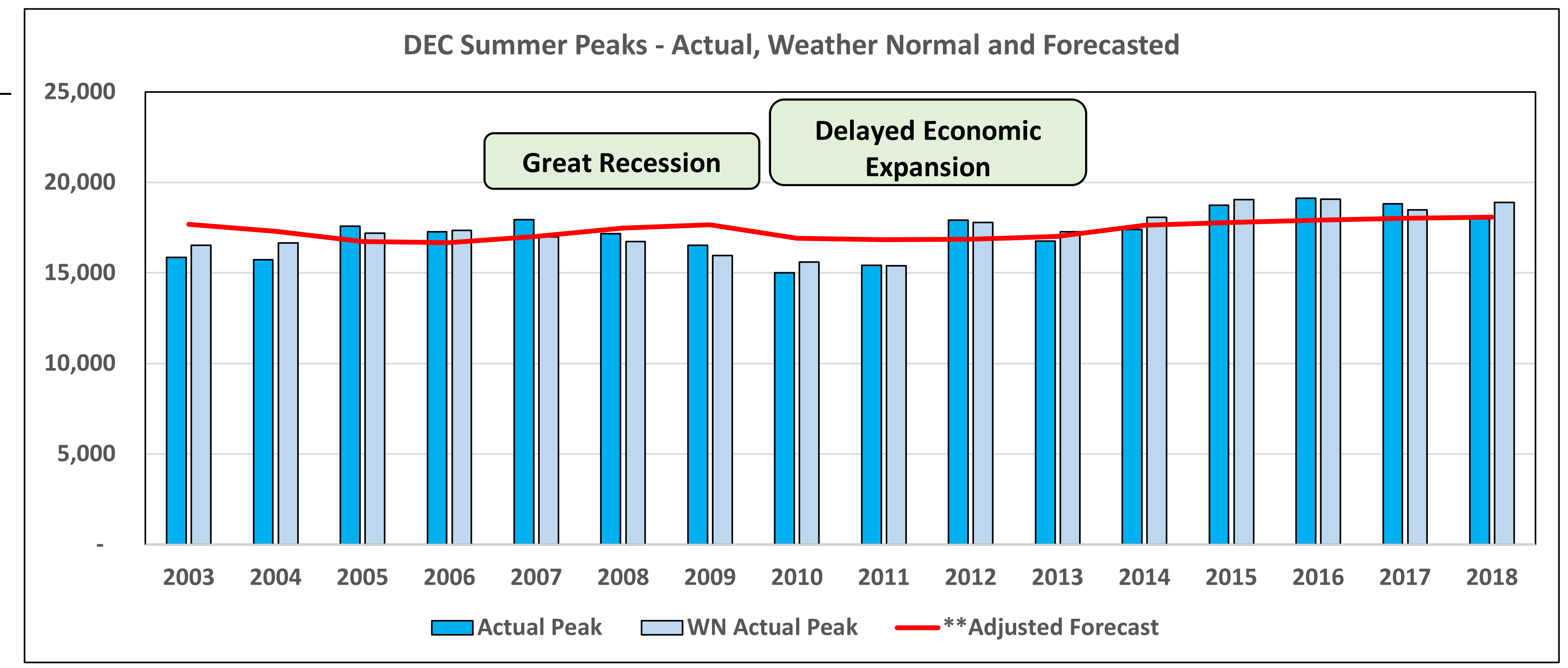
****Adjusted Forecast Values to Remove Backstand Agreements/Commitments that are not in actuals**



DEC Summer Peaks (700-900 MW Backstand/Firm Commitments Included in Forecast, not in Actuals for years 2003-2018)

Year	Forecasted peak (Prior Yr. IRP)	**Adjusted Forecast	Actual Peak	Actual Vs. Adj. Forecast	Var %	WN Actual Peak	WN Actual Vs. Fcst	Var %	Comments
2003	18,396	17,696	15,860	(1,836)	-10%	16,540	(1,856)	-10.1%	
2004	17,997	17,297	15,722	(1,575)	-9%	16,654	(1,343)	-7.5%	
2005	17,448	16,748	17,581	833	5%	17,191	(257)	-1.5%	
2006	17,376	16,676	17,268	592	3%	17,357	(19)	-0.1%	
2007	17,731	17,031	17,954	923	5%	17,006	(725)	-4.1%	Great Recession Begins
2008	18,187	17,487	17,162	(325)	-2%	16,745	(1,442)	-7.9%	Great Recession Continues
2009	18,362	17,662	16,539	(1,123)	-6%	15,966	(2,396)	-13.1%	Great Recession Continues
2010	17,629	16,929	15,020	(1,909)	-11%	15,602	(2,027)	-11.5%	Expected economic expansion, did not materialize
2011	17,529	16,829	15,420	(1,409)	-8%	15,410	(2,119)	-12.1%	Expected economic expansion, did not materialize
2012	17,557	16,857	17,933	1,076	6%	17,803	246	1.4%	Expected economic expansion, did not materialize
2013	17,716	17,016	16,757	(259)	-1%	17,269	(447)	-2.5%	Economic Expansion begins during late 2013
2014	18,332	17,632	17,397	(235)	-1%	18,063	(269)	-1.5%	
2015	18,486	17,786	18,742	956	5%	19,051	565	3.1%	
2016	18,625	17,925	19,119	1,194	6%	19,086	461	2.5%	
2017	18,729	18,029	18,811	782	4%	18,495	(234)	-1.2%	
2018	18,786	18,086	18,008	(78)	0%	18,899	113	0.6%	

****Adjusted Forecast Values to Remove Backstand Agreements/Commitments that are not in actuals**



CERTIFICATE OF SERVICE

I certify that a copy of Duke Energy Carolinas, LLC and Duke Energy Progress, LLC's Response to Commission Questions in August 27, 2019 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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