Jason A. Higginbotham
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Jason.Higginbotham@duke-energy.com

February 3, 2023

VIA ELECTRONIC FILING

Ms. Shonta A. Dunston
North Carolina Utilities Commission
4325 Mail Service Center
Raleigh, North Carolina 27699-4300

RE: Duke Energy Carolinas, LLC and Duke Energy Progress, LLC's Third Submission of Responses to the Public Staff's Data Request No. 2 re: Winter Storm Elliott
Docket No. M-100, Sub 163

Dear Ms. Dunston:

Please find enclosed for filing Duke Energy Carolinas, LLC ("DEC") and Duke Energy Progress, LLC's ("DEP", and together with DEC, "Duke Energy") Third Submission of Reponses to the Public Staff's Data Request ("PSDR") No. 2 re: Winter Storm Elliott in the above-referenced docket. Included with this submission are responses to PSDR Item Nos. 13, 14, 15, 18, 20, 21, 22 and 27 ("3rd Data Request Responses"). Certain information included in the 3rd Data Request Responses is being filed under seal pursuant to N.C. Gen. Stat. § 132-1.2. Parties wishing to obtain non-public versions of the responses may contact Duke Energy's undersigned counsel to obtain an appropriate confidentiality agreement.

If you have any questions, please let me know.

Sincerely,

Jason Higginbotham

Jason A. Higginbotham

Enclosure

cc: Parties of Record

CERTIFICATE OF SERVICE

I certify that a copy of Duke Energy Carolinas, LLC and Duke Energy Progress, LLC's Third Submission of Responses to the Public Staff's Data Request No. 2 re: Winter Storm Elliott, in Docket No. M-100, Sub 163, has been served by electronic mail, hand delivery, or by depositing a copy in the United States Mail, 1st Class Postage Prepaid, properly addressed to parties of record.

This the 3rd day of February, 2023.

Jason Higginbotham

Jason A. Higginbotham
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DUKE ENERGY CAROLINAS, LLC and DUKE ENERGY PROGRESS, LLC

Request:

13. Please describe the actions and staffing that occurs at generation plants when a known winter storm or weather event is pending.

a. For each generation plant, how were staff notified of the pending December 2022 storm, the actions they needed to complete in advance, and general staffing requirements?

Response:

[Unless otherwise noted, the response below pertains to both Duke Energy Carolinas, LLC ("DEC") and Duke Energy Progress, LLC ("DEP") (together with DEC, "Duke Energy" or the "Company".]

The Companies' overall winter preparedness effort for generation plants are described in prior responses, including response to PSDR Nos. 2-1 and 2-2. Please see below for additional information:

ALL GENERATING STATIONS. On 12/22 at 1358, Duke Energy's Energy Control Center ("ECC") notified stations via email that a Grid Status-Yellow had been declared. At all generation sites impending cold weather was discussed during the morning Daily Station Status Report ("DSSR"). Discussions were focused on unit readiness, staffing needs, and open items needed prior to the cold weather arrival. Communications from ECC regarding grid status occurred utilizing standard communications with station control operators. Site General Managers also attended Carolinas Tailgate Calls, which occurred on 12/24-12/26. Additionally, all stations continued to regularly monitor weather related equipment such as heat trace, wind breaks, refueling heaters in cold wind-driven areas throughout the weather event.

ALLEN. Leading up to the weekend of 12/24, the system was showing adequate reserves through the weekend without needing the Allen units. Therefore, employees were released for the Christmas weekend and the units remained in extended planned reserve (EPR). Per the EPR procedure, there is a 5-day call-back requirement to put Allen units in service. On 12/22 at 1409, the Company determined that the Allen units should come out of EPR and be put online. In general, a normal startup for the two units would be around 36 hours to get both online. As a result, the Company estimated that the units could be placed back online on Monday 12/26 or early Tuesday 12/27. By that time, temperatures were forecast to be increasing and the units would not be needed.

BELEWS CREEK. A meeting occurred on 12/20/2022 lead by Manager Operations with all plant leadership (Ops OTS, Maint MTS, I&C MTS, FGD OTS, Ops Coordinator, Station HS, Station Environmental and Management Team) to discuss winter weather preparations in addition to the sites October NERC EOP-011 preventative maintenances (PMs). Staffing requirements needed during winter weather events were also discussed. All identified items were assigned and addressed/evaluated prior to freezing weather.

BUCK CC. Communicated during morning DSSR meetings daily about preparing for cold weather. EOP-011 PMs were discussed, scheduled and completed through the weekly scheduling meetings. Staffed an additional 1-2 operators per shift (on top of normal staffing of 3-4 per shift) from morning of 12/24 through morning of 12/27. Staffed 1-2 maintenance technicians from evening of 12/23 through evening of 12/24 (typically would be none during this time). At least 1 member of station leadership team was on-site for most of the period between evening of 12/23 and morning of 12/27.

DAN RIVER CC. Communicated during morning DSSR meetings daily about preparing for cold weather. EOP-011 PMs were discussed, scheduled and completed through the weekly scheduling meetings. Staffed an additional 1-2 operators per shift (on top of normal staffing of 3-4 per shift) from morning of 12/24 through morning of 12/26. Staffed 1-2 maintenance technicians from evening of 12/23 through evening of 12/24 (typically would be none during this time). At least 1 member of station leadership team was on-site for most of the period between evening of 12/23 and night of 12/24.

ROCKINGHAM CT. Communicated during morning DSSR meetings daily about preparing for cold weather. Due to fuel oil runs, adjusted staffing to two techs per shift instead of one tech per shift on 12/23.

BLEWETT CC. Communicated during morning DSSR meeting daily about preparing for cold weather. Was not planned to be staffed. Onsite CT Tech was stationed at Darlington CC to help facilitate Fuel Oil runs. CT Tech relocated to Blewett CC after ECC remote started Blewett units.

DARLINGTON CC. Communicated during morning DSSR meeting daily about preparing for cold weather. Normal operation would have been unmanned on 12/24 - in preparation of fuel oil burns, two CT Techs were scheduled per 12-hour shift beginning on 12/23 until 12/26.

WEATHERSPOON CC. Communicated during morning DSSR meeting daily about preparing for cold weather. Normal operation would have been unmanned 12/24. Site was remote-started, two CT Techs responded.

LINCOLN CC. Supt of Operations communicated daily with Operations Team about cold weather preparation and concerns. Brought in contract labor (3) and Duke Energy Transmission teammate (1) on 12/23 0600 to facilitate 24-hour operation.

MILL CREEK CC. Superintendent of Operations communicated daily with Operations Team about cold weather preparation and concerns. Added additional staffing to support cold weather on 12/23 0600.

MARSHALL. Email forwarded to site Managers to inform them of the grid status change. Verbally discussed with Operations Managers to ensure adequate staffing was in place for operation of units 3&4 (Units 1&2 offline in FO).

SMITH: Prior to the onset of the cold weather event the station discussed readiness status each morning during the daily plant meeting. This was a daily focus for the entire week leading up the event. Staffing was discussed, and the decision was made to bring in a supervisor on night shift 12/23, day shift 12/24 and night shift 12/24 to help with overall direction and response to issues. Operations shift staffing on 12/23 was adequate to support any issues that occurred. Additional operations support was scheduled to come in the morning of 12/24 to support any issues that arose overnight. Additional support was scheduled for Saturday and Sunday night after the issues occurred on Friday night.

SUTTON: Discussions held between Operations Superintendent and Operations Staff with a focus on cold weather preparedness, equipment readiness, and staffing needs. Normal operations staffing was needed during the cold weather event, and operator call in list would be used if needed.

CLIFFSIDE: Prior to the event the Company ensured Ops. shifts were fully staffed, and maintenance support and station personnel clearly understood on-call expectations. Cold weather was discussed during DSSRs, and CS management held a staff call on 12/24/22 @ 11am for unit/system updates.

WS LEE. Offline in forced outage ("FO"). No action taken

ASHEVILLE. Due to Asheville Stations physical location several conversations were had between Zone GM and Station GM beginning on 12/19 regarding additional staffing for cold weather. On 12/22 at 1141 Station GM informed Zone GM that call-out coverage for additional operations personnel was in place in the event of weather-related issues.

HF LEE. Staffing was discussed during station meetings in the days prior to the event. Staffing was augmented with two additional CT Techs that worked from 0400 -1600 daily on 12/24 and 12/25.

MAYO. An email was forwarded from the CDG Staff that covered the forecast cold weather and high winds. It instructed to ensure cold weather checks were completed, suggested suspending weekend equipment swaps to minimize risk, and urged conservative decision making as grid reliability alerts approached. The forecast cold weather was discussed during the Person County staff call on Monday, 12/19/2022. Staffing needs were discussed during this call. Staffing was discussed during the station DSSR meeting in the days leading up to the event. The station was called to service for the forecast high loads. Normal shift staffing was scheduled for Unit operations. Supplemental contract resources scheduled for nightshift on 12/23, 12/24, and 12/25. Additional dayshift resources were called in on 12/24 and 12/25 to assist with ongoing freezing issues.

ROXBORO. An email was forwarded from the CDG Staff that covered the forecast cold weather and high winds. It instructed to ensure cold weather checks were completed, suggested suspending weekend equipment swaps to minimize risk, and urged conservative decision making as the

Company approached grid reliability alerts. The forecast cold weather was discussed during the Person County staff call on Monday, 12/19/2022. Staffing needs were discussed during this call. An email was sent on 12/22 warning of high winds and discussing the need for preparations.

HYDRO UNITS. During the Weekly Operations Outlook meeting at 0830 on 12/19/22 the forecasted low temperatures and elevated load projection was discussed. It was discussed the water levels were being held above target in many locations to provide greater generation during the forecasted higher load periods. In addition, the following communications were provided to the hydro units related to the winter storm:

- Between 12/20 and 12/22 emails were sent to the Regulated and Renewables Staff and general managers communicating the tailgate meeting, DEP/DEC declaring grid level yellow alerts, and emphasizing the cold weather and load impacts in each region.
- 12/23/22: Email to all Regulated Hydro and Solar employees to provide notice that DEC and DEP were declaring Grid Status Yellow-Hands Off effective immediately (1413 12/23) through 12/26. Any work during this period would require coordination through operations.
- 12/24/22 at 0627: Text from the Regulated Renewables Operations Center via the Assurance Notification Tool to all hydro and solar leadership notifying them of a system emergency and that all available hydro units had been committed.
- 12/26/22: Email to all Regulated Hydro and Solar employees to provide notice that DEC and DEP were declaring Grid Status Orange for the following day (12/26). Any work during this period would require coordination through operations.

Responder: Mitchel Beason, COSO General Manager

DUKE ENERGY CAROLINAS, LLC and DUKE ENERGY PROGRESS, LLC

Request:

14. On a daily basis, beginning December 19, 2022, describe how the Company viewed the pending storm from both a wind and outage event and then followed by a cold weather event.

Response:

The Companies' overall winter preparedness effort are described in prior responses, including PSDR Item Nos. 2-1, 2-2, 2-4, 2-6, and 2-13. See below for additional information.

RRE

The RRE organization always prepares cold weather given that they can bring undesirable conditions to stations and impact operations. As part of the Company's annual winter preparedness, the generating stations had already completed their winter preparations prior to winter season. These preparations incorporated learnings from prior cold weather events and had been iterated over many years of experience with winter weather. Following the winter preparedness actions, the stations continue to stay abreast of any upcoming weather issues through their Daily station Status Report Meetings.

NUCLEAR

Nuclear generating units had already completed initial winter readiness items prior to December 19, 2022. The on duty operating shift reviewed company weather forecasts and communications to ensure appropriate actions were taken in preparation for any severe weather. Each site took additional compensatory measures as necessary based on actual and/or forecasted conditions at their location.

TRANSMISSION/ENERGY CONTROL CENTER ("ECC')

Response for Duke Energy Carolinas

For the duration of the event, the wind event was not anticipated to be a significant transmission concern. Given the holiday no significant transmission work was taking place and ECC staffing was adequate to handle any outages. ECC management did monitor and was ready to provide assistance as needed with outage coordination and procedure writers for outages.

- 12/19 – DEC System Operations was aware of cold front coming through over the holiday weekend and made notifications to stakeholders to be aware of potential needs for internal communication if conditions were to worsen (see tailgate email provided in #7). Loads for the weekend were ~17,500MW with reserves of 3,000MW plus and no concerns.

- 12/20 – Load forecasts for the weekend reflected lower temperatures and thus increased projected loads. The projected loads were ~18,500MW with reserves of 2,400MW plus. With forecasted highs near the freezing mark there were some concerns of Monday's load forecast continuing to rise. Conversations occurred about bringing on additional generation for Monday. Reserves reflected sufficient margin without additional generation for Monday.
- 12/21 – Forecasted temperature lowered for the weekend, the peak load increased to ~18,900MW with reserves lowering to 2100MW plus. Saturday was the forecasted peak, however there were concerns of the forecast for Monday possibly increasing based on models and potential heat loss across the weekend. Adequate reserves were forecasted for the weekend.
- 12/22 – Loads again increased for the weekend with a Saturday peak anticipated of ~19,400MW. Marshall #2' return (380MW) from forced outage was delayed through Sunday. This lowered Saturday's reserve to ~1500MW. There were still concerns of Monday's forecast potentially increasing based on the potential heat loss, some business openings the day after a holiday and concerns for a further delay for Marshall #2. Power Trading was requested to secure capacity purchases for Saturday. Adequate reserves were forecasted for the weekend and Monday. System Operations entered a conservative mode going to Grid Status Yellow for the 24th -26th based on increasing forecasts.
- 12/23 – Load forecasts remained consistent with slight increased from those on 12/22. Power Trading secured 400MW of capacity purchases for Saturday 12/24. DEC increased conservative measures by entering a Grid Status Yellow "hands-off" for the 24th-26th. Adequate reserves were forecasted through the weekend (1600MW+).

On the evening of December 23rd, DEC experienced wind related outages on the distribution system but no significant impacts to transmission equipment. Actual load increased above forecast and DEC was able to serve the demand while providing external emergency assistance. Forecasted loads for the 24th did not exceed what was served the evening of the 23rd. DEC proactively scheduled PowerShare DSM and entered an EEA 1. While margins were tighter than forecasted, DEC anticipated being able to meet customer demand and carry reserves through the morning peak.

<u>Response for Duke Energy Progress:</u>

DEP ECC anticipated that the wind event would be mostly a Distribution level event. DEP ECC's forecasted margin thresholds varied from Grid Status Yellow and Orange. The low temperatures on12/26 presented the greatest challenge the Reserve Margin due to the simultaneous preceding days of low temperatures. Load Forecast decreasing and external power procurement brought us back to Grid Status Green projection for 12/26. The table below provides the load forecast, reserve margin, and Grid Status projection for the dates 12/24-26 beginning with forecasts on 12/19 and through 12/23.

Date	12/24 Load Forecast / Reserve Margin / Grid Status Projection	12/25 Load Forecast / Reserve Margin / Grid Status Projection	12/26 Load Forecast / Reserve Margin / Grid Status Projection
12/19	11818 / 3,569 / Green	12446 / 2993 / Green	Outside the 7-day forecast window
12/20	11625 / 3317 / Green	12641 / 1961 / Green	13175 / 1419 / Green
12/21	13377 / 1244 / Green	13521 / 1069 / Yellow	13948 / 928 / Yellow
12/22	13657 / 1173 / Yellow	13401 / 1993 / Green	14139 / 739 / Orange
12/23	13913 / 1136 / Yellow	13401 / 1893 / Green	13897 / 1256 / Green

FUELS & SYSTEMS OPTIMIZATION

Please see attachments "NC PS DR2-14 Duke Meteorology Carolinas Forecast 12/19/22" through "NC PS DR2-14 Duke Meteorology Carolinas Forecast 12/24/22" for information that is responsive.

Responder: Mitchel Beason, COSO General Manager

Responder: Mandi Brigman, Director Plant Reliability

Responder: Tom Pruitt, Principal Engineer

Responder: Tiffany Weir, Dir. Rates & Regulatory Filings

DUKE ENERGY CAROLINAS, LLC and DUKE ENERGY PROGRESS, LLC

Request:

15. Please discuss how the Company was preparing for and forecasting cold temperatures and system responses compared to its responses to the 2014 and 2015 polar vortexes prior to the beginning of the cold weather event, including daily updates.

a. Were the predicted peak loads performed in-house? Please describe the predictive methods employed in 2014 and 2015 versus today.

b. Discuss similarities between the December 2022 cold weather event versus those of the 2014 and 2015 polar vortexes, including whether the prior cold weather events had both a storm component (wind event that contributed to outages) in addition to the extreme cold weather events.

c. Explain the complications, from a system operational standpoint, that occurred during this event compared to the 2014 and 2015 polar vortex events. Please include a discussion of the challenges of the storm restoration efforts versus load reduction efforts.

Response:

[Unless otherwise noted, the response below pertains to both Duke Energy Carolinas, LLC ("DEC") and Duke Energy Progress, LLC ("DEP") (together with DEC, "Duke Energy" or the "Company".]

Below are perspectives from multiple organizations within the Company.

Fuel & Systems Optimization

Please see responses to PS DR2-1 and DR2-4 as well as response to PS DR2-15b for a discussion of how the Company was forecasting cold temperatures prior to the cold weather event including compared to its response to the 2014 and 2015 polar vortexes.

a. The peak loads forecasts were created in-house by Duke Energy personnel utilizing external third-party load forecasting tools. Duke Energy continues to utilize multiple third-party load forecasting models and various other tools available to its Load Forecasting/Unit Commitment analysts to plan for extreme weather event scenarios. These load forecasting models utilize both Duke Energy Meteorology BA specific weather forecasts as well as National Weather Service statistical model forecasts for Duke's balancing authority areas to create a deterministic short-term load forecast for all hours of the day for the current day plus 6 days ahead. Since

2014, Duke Energy has implemented multiple vendor updates to the load forecasting engines to ensure the Company is remaining current with evolving modeling tools. Also, in 2016 the Company developed a new user interface so that all model outputs could be displayed in one user interface so users could review multiple model forecasts side by side and adjust as needed.

b. See attachments "NC PS DR2-15.b 2014 Polar Vortex vs. 2022 Winter Storm" and "NC PS DR2-15.b 2015 Polar Vortex vs. 2022 Winter Storm" for a discussion of the similarities and differences between Winter Storm Elliot and the 2014/2015 polar vortexes.

Duke Energy has always automatically received the most recent weather forecasting model updates from the National Weather Service ensuring that Duke Energy has the most up-to-date improvements to the forecasting outputs. One of the most recent examples occurring after 2015 is improvements in the National Weather Service High Resolution Rapid Refresh ("HRRR") capabilities which in its last update received 12/2/2020 included the following enhancements: 1) improved cloud representation for boundary-top clouds, especially for shallow cold-air layers with cold-air retention; 2) better cloud bands (snow squalls, hurricane bands, lake-effect bands); 3)3km ensemble data assimilation for improved storm prediction for 1-12h; 4) improved lake temperatures; and 5) extension to 48h forecast every 6h.

c. n/a

<u>Customer Delivery</u>

a. n/a

b. n/a

c. The 2014 and 2015 polar vortexes differed from the 2022 cold weather event in that, the polar vortexes were not preceded by a high wind event and were not complicated by the impact of cold load pickup following rotating outages. The events in December 2022 included restoration from a high wind event in addition to restoration from the cold weather event. With both situations occurring within a close timeframe, any restoration for the wind event needed to be isolated from the system in order to not bring on unexpected load.

<u>Nuclear</u>

a. n/a

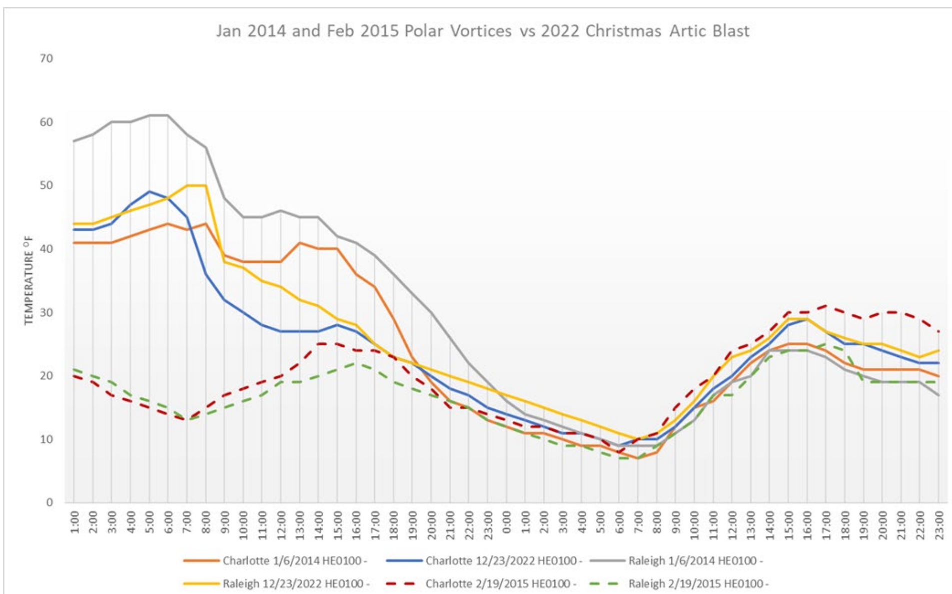
b. n/a

c. Nuclear generation did not have any operational challenges related to the cold weather or wind events that required any unit derates. None of the nuclear sites sustained any significant damage from the weather events; therefore, no recovery or restoration efforts were required.

Transmission/ECC

a. n/a

b. Below are the hourly temperatures for our major load centers of Charlotte and Raleigh for the day prior and day of historical peak demand occurring on 1/7/2014, 2/20/2015, and 2/24/2022. Aside for the low temperatures occurring on a Christmas weekend, from a temperature perspective the temperature changes and values on January 6-7, 2014 are somewhat similar to those that occurred on December 23-24, 2022. The material difference in temperatures occurring on February 19-20, 2015 was the prior days/hours leading up to the February 20, 2015 peak were very cold close to freezing or sub-freezing.



Source: *https://www.wunderground.com/history/daily/us/nc/*

There were no significant wind-related customer outages during either the 2014 or the 2015 polar vortex events.

Winds were much higher on 12/23/2022, up to 54 mph wind gusts with 28 mph sustained winds in Raleigh and up to 49 mph wind gusts with 25 mph sustained winds in Charlotte and sustained winds for the morning of 12/24/2022 were up to 14 mph in Raleigh and up to 12 mph in Charlotte

For comparison, winds on 1/6/2014 were up to 35 mph wind gusts with 23 mph sustained winds in Raleigh and up to 29 mph wind gusts with 16 mph sustained winds in Charlotte and sustained winds for the morning of 1/7/2014 were up to 14 mph in Raleigh and up to 6 mph in Charlotte

For comparison, winds on 2/19/2015 were up to 23 mph wind gusts with 15 mph sustained winds in Raleigh and up to 25 mph wind gusts with 15 mph sustained winds in Charlotte and sustained winds for the morning of 2/20/2015 were up to 10 mph in Raleigh and up to 8 mph in Charlotte.

Source: https://www.wunderground.com/history/daily/us/nc/

c. For the 12/23 – 12/24, 2022 event, the following list describes certain of the similarities and significant differences as compared with the 2014 and 2015 polar vortex events.

Similarities included:

- As described in 15.b. the temperature profile for the 12/23 – 12/24, 2022 period was very similar to the 1/6 – 1/7, 2014 temperature profile.
- The day ahead BA peak load forecast for DEP for 1/7/2014 morning peak was 13,516 MW at 14 degrees at HE0800 and the actual peak BA load was 14,215 MW at 13 degrees at HE0800 and this load had been reduced by LLC, DSM/DR, and 5% voltage reduction. This load vs temperature correlation was similar to that realized in DEP for 12/24/2022.
- For the extreme peak demand in 2014, 2015, and 2022, System Operators followed/implemented the necessary Load Reduction Plan measures
- Event evolved quickly from 1/6/2014 through morning of 1/7/2014 with little time for communications for appeals for conservation ahead of peak hours. Similarly, the 12/23/2022 through morning of 12/24/2022 event evolved quickly with little time for communications for appeals for conservation ahead of peak hours.

Differences included:

- Christmas Weekend, December, close to Winter solstice
- Generator freezing issues impacting performance on 12/23-24/2022 were substantially lessened as compared with 1/6-7/2014 (due in part to the Companies' winterization efforts)
- Generators capable of running on fuel oil performed more reliably in starting and running on oil or switching from gas to oil for 12/23-24/2022, as compared with 1/6-7/2014
- Power purchases, including firm purchases were curtailed for the peak hours on 12/24/2022 whereas firm power purchases were not curtailed in 2014 or 2015
- Firm Load Shed event – first time implementing Grid Status Purple in our Load Reduction Plans

- With several cold days preceding the 2/20/2015 cold weather peak demand event, the 2/20/15 day ahead DEP BA peak load forecast was more accurate. The day ahead peak DEP BA load forecast was 15,700 MWh at a minimum temperature of 7 degrees and the actual DEP BA peak demand was 15,569 MWh for HE0800 at a minimum temperature of 10 degrees.
- Abrupt drops in the temperatures in the service area and significant winds leading up to the 12/24 peak had a significant impact on customer demand
- The Load Reduction Plans and the Grid Status communications improvements since the 2/20/2015 cold weather event have improved the operators' ability to provide Company-wide awareness and with its execution

Responder: Tiffany Weir, Dir. Rates & Regulatory Filings

Responder: Barbara Coppola, Dir. Planning & Reg. Support

Responder: Mandi Brigman, Director Plant Reliability

Responder: Tom Pruitt, Principal Engineer

DUKE ENERGY CAROLINAS, LLC and DUKE ENERGY PROGRESS, LLC

Request:

18. Please provide graph(s) and supporting data that illustrate the following, at a minimum: load; aggregate Duke owned generation; imports; exports; frequency; and ACE from December 23, 2022, through December 28, 2022, with DEP East, DEP West and DEC specific information in as granular periods as possible, but no less than hourly. (Note: Individual graph(s) or a composite of graph(s) may be provided to illustrate key elements that were taking place during the period in question.) Please provide as granular information as the historian (data recorder) allows, as ACE, frequency, and generation information will likely be more granular than hourly intervals.

   a. Please provide any other key values the Company believes appropriate to illustrate system conditions and monitoring related to the real time operations and balancing of the BES, include supporting data.

Response:

[Unless otherwise noted, the response below pertains to both Duke Energy Carolinas, LLC ("DEC") and Duke Energy Progress, LLC ("DEP") (together with DEC, "Duke Energy" or the "Company".]

Response for Duke Energy Carolinas:

Regarding Item No. 18, all data used for the graphs is SCADA rate (nominally 4 second interval). The data associated with all graphs in this document are in the related comma separated value (csv) files (Q18-DEC 12_24 Summary - DR2022-12-xx.csv where xx is the day of the data in the file) included in the zip package. Due to size limitations, each day's data for all graphs are in separate csv files. Data for the Duke-owned generation (a subset of BA generation) is in a separate csv file for the entire period (Q18_duke_owned_total_gen_dec_12232022_12292022.csv) due to the additional processing needed to produce those values. The graph is of a different style due to the use of a different application to produce that graph. Graphs requested are provided in the following order:

- Balancing Authority (BA) load
- Area Control Error (ACE)
- Frequency
- Actual Net Interchange with neighboring BAs (interchange covers both imports and exports)
- BA Aggregate Generation (NOTE: not actually requested but a key value used)

- Duke Owned Aggregate Generation in the DEC BA

Regarding Item No. 18a, in addition to the BA aggregate generation key value listed above, graphs of the Joint Dispatch Algorithm (JDA) flow and the Balancing Authority ACE Limit (BAAL) exceedance counter are also provided. Data for these two graphs are included in the daily csv files described above.

Response for Duke Energy Progress:

Regarding Item No. 18, all data used for the graphs is SCADA rate (nominally 4 second interval for CPLE, 6 second for CPLW). The data associated with all graphs in this document are in the related comma separated value (csv) files (Q18-DEP System Summary2022-12-xx.csv where xx is the day of the data in the file) included in the zip package. Due to size limitations, each day's data for all graphs are in separate csv files. Data for the Duke-owned generation (a subset of BA generation) is in a separate csv file for the entire period (Q18_duke_owned_total_gen_dep_12232022_12292022.csv) due to the additional processing needed to produce those values. The graph is of a different style due to the use of a different application to produce that graph. Graphs requested are provided in the following order:

- Balancing Authority Area (BAA) load (CPLE and CPLW BAAs shown as separate traces)
- Area Control Error (ACE) (CPLE and CPLW BAAs shown as separate traces)
- Frequency (CPLE and CPLW BAAs shown as separate traces)
- CPLE BAA Actual Net Interchange with neighboring BAs (interchange covers both imports and exports)
- CPLW BAA Actual Net Interchange with neighboring BAs (interchange covers both imports and exports)
- BAA Aggregate Generation (CPLE and CPLW BAAs shown as separate traces) (NOTE: not actually requested but a key value used)
- Duke Owned Aggregate Generation in the DEP BA

Regarding Item No. 18a, in addition to the BA aggregate generation key value listed above, graphs of the Joint Dispatch Algorithm (JDA) flow and the Balancing Authority ACE Limit (BAAL) exceedance counter are also provided. Data for these two graphs are included in the daily csv files described above.

Responder: Tom Pruitt, Principal Engineer

DUKE ENERGY CAROLINAS, LLC and DUKE ENERGY PROGRESS, LLC

Request:

20. In regard to generation unit availability, unit tripping, load shedding, and load exceeding predicted demand, provide dates and times of meetings, emails, discussions, and other communications in which decisions were made, as well as a list of all persons participating in decision making, including their job titles.

Response:

[Unless otherwise noted, the response below pertains to both Duke Energy Carolinas, LLC ("DEC") and Duke Energy Progress, LLC ("DEP") (together with DEC, "Duke Energy" or the "Company".]

Please see the responses below from the various stations with details on unit availability and unit derates including dates and times:

- Belews Creek - U1 Derate - 1B Booster Fan. Kirk Burton (Ops Coordinator/WCC Supv) and Doug Julian (Manager Operations, POC for General Mgr. CDG Central), discussed issue with Todd Conrad (Portfolio Manager) via telephone call on 12/22 and the decision was made to derate 125MW's for load reliability.
- Buck CC - 12/24/22 0943 – Buck Operations received Fuel Gas Low Pressure alarm. Ryan Snider (Buck Control Room Operator) notified Jake Stover (ECC System Operator) via telephone and was instructed to reduce unit load as necessary to maintain units online. Awareness notifications also initiated to Charles Sammons (Buck Operations Superintendent), Kris Eisenrieth (Buck/Dan River Station Manager), Doug Julian (Point of Contact for CDG Central Zone), and Antonio Price/Jeff Flanagan (POC for CDG).
- Dan River CC - 12/23/22 2340 – Darryl Powell (Dan River Control Room Operator) notified Bobby Salyers (ECC System Operator) via telephone that Unit 9 was being brought offline in a controlled manner to avert a pending unit trip due to freezing drum level transmitters. Awareness notifications were also initiated to Doug Metcalf (Dan River Operations Superintendent), Kris Eisenrieth (Buck/Dan River Station Manager), Doug Julian (Acting Point of Contact for CDG Central Zone), and Antonio Price (Acting POC for CDG).
    - 12/25/22 0300 – Darryl Powell (Dan River Control Room Operator) notified Nathan Smock (ECC System Operator) via telephone that Fuel Gas Supply Pressure had reached low pressure limit and was instructed to reduce unit load as necessary to maintain units online. Awareness notifications also initiated to Doug Metcalf (Dan River Operations Superintendent), Kris Eisenrieth (Buck/Dan River Station Manager), Doug Julian (Acting Point of Contact for CDG Central Zone), and Jeff Flanagan (Acting POC for CDG).

- Blewett CT - U1 Derate - Failed to start 12/24 at 0538 - CT Tech dispatched to location to inspect units after remote start initiated. CT Tech and DCS System owner made adjustments and the unit was returned to service on 12/24 at 1105.
    - U2 Derate - Failed to start 12/24 at 0538 - CT Tech dispatched to location to inspect units after remote start initiated due to fuel card issues. Fuel card repaired and unit returned to service on 1/4/23
    - U4 Derate - Failed to start 12/24 at 0538 - CT Tech dispatched to location to inspect units after remote start initiated. CT Tech reset thermocouples and unit was returned to service on 12/24 at 0710. 12/24 0730 – All issues have been reported to ECC and Lee Caudell, Maintenance Team Supervisor.
- Lincoln CT - 12/24 LCT6 was removed from service due to exhaust temperature spreads. Paul Beatty (Supt Operations) discussed with ECC the need to remove from service and switch from natural gas to fuel oil to help with exhaust temperature spreads. The unit was removed from service at 0536 and returned to service on fuel oil at 0600.
- Darlington CT - N/A
- Weatherspoon CT - N/A
- Rockingham CT - N/A
- Mill Creek CT - 12/23 CT7 – 1804 Swapped from Oil to Gas, 1839 CT Tech requested permission from Nathan Smock (ECC BA) to return CT7 to Fuel Oil at 1842.
- Marshall - Communications regarding Unit 2 FO (tube leak). Initial communication on 12/20 at 1641 to Paul Draovitch (SVP, Chief Regulated & Renewable Energy Officer) via phone call that U2 had tripped offline due to a tube leak.
    - 12/23 1340 - Email to Paul Draovitch, Julie Turner, Antonio Price following phone call with Daniel Stephens regarding status update of Marshall U2 and decision not to move BCP from Unit 2 to Unit 1 due to long term failure risk. U2 estimated RTS 12/26 1700
- Cliffside – 12/24 Cliffside operations submitted COA to the ECC for a 71MW derate at 11:49 due to 5E FWH being bypassed.
- Sutton – 12/24 at 0742 Ed Bronish (Operations Superintendent) notified Antonio Price that CT4 was only available on fuel oil due to fuel gas heater issues.
- Smith – Smith Unit 1 Failed Start
    - 12/23 at 1563 Unit 1 failed to start due to 89ND showing dual indication

- 1732 Antonio Price (GM CDG South) notified Paul Draovitch that Unit 1 is entering a forced outage due to 89ND issues.
- 2037 Antonio Price notified Paul Draovitch that Unit 1 was being placed online on with a must run COA until Monday 12/26.
- Smith PB4 Derate
- PB4 derated 273MW on 12/24 at 0835 due to frozen impulse lines. Station operations responded to mitigate the derate.
- 0906 Marcus Canipe (Operations Superintendent) notified Antonio Price (GM CDG South) of the cause of the derate and the actions being taken by operations.
- 0906 Antonio Price notified Jeff Flanagan (GM CDG West) of the derate and actions being taken by station operations.
- 2029 Antonio Price notified Jeff Flanagan that the issue with Unit 8 was corrected and the unit was increasing to base load.
- Smith Unit 1 Maintenance Outage
- Jeff Ruest (Operations Coord/WCC Supv) submitted COA to the ECC on 12/27 at 1342 requesting a maintenance outage to inspect the Unit 1 89ND.

- Allen -
  - 12/22 1301 - Email and follow up phone call to Dave Styer regarding staffing of Allen for weekend of 12/24 & 12/25 on short notice.
  - 12/22 1409 - Email from Daniel Stephens requesting Allen out of EPR to be online for Monday 12/26
  - 12/22 - Follow up to previous email, phone call with Julie Turner regarding staffing of Allen for 12/26
- Cowans Ford – Aaron Dale (Director Regulated Renewables Operations) provided verbal approval to Hydro Operations at approximately 0600 (12/24) to operate all Cowans Ford Units as needed in response to the DEC emergency up to a maximum Mountain Island reservoir elevation of 102'. This would exceed the FERC license normal maximum elevation and result in a controlled spill across the Mountain Island Dam.
- Pump Storage – Jake Stover (DEC ECC Generation Desk) called Hydro Operations at 1022 (12/24) and requested pumping operations to begin. All available pumps were added by 1155. It should be noted that pumping operations did not delay restoration efforts as manual restoration efforts were occurring slower than load was declining. As a result, this allowed the ECC to pump and prepare the pump storage units for the subsequent high load forecasts in the days to come.

- Bad Creek – At 1915 (12/24) texts were exchanged between Randy Herrin (VP Regulated Renewables), Aaron Dale (Dir Regulated Renewables Operations), and Preston Pierce (GM Hydro West) concerning validating the ability to operate the Bad Creek units down to a minimum elevation of –60' local data. This conversation was to ensure the units could respond as directed at lower head than has been tested since unit upgrades were commissioned. Validation of BC ability to operate down to –60ft reservoir level occurred.

- Dearborn Hydro – At 1041(12/24) Ryan Juarez (Operations Supervisor) called the on-call technicians to have the headworks raked, reducing debris loading, to prepare for the following day's high loads. At 1128 Aaron Dale (Dir Regulated Renewables Operations) exchanged Teams IMs with Ryan Juarez (Operations Supervisor) to validate reservoir levels above and below the headworks to ensure optimized operations of the Fishing Creek and Dearborn Hydro units and to rake debris. At 1136 Aaron engaged Dustin Sipes (Lead RROC Coordinator) in an IM chat to develop an optimized plan for Dearborn that managed levels across the headworks. At 1348 Aaron called Ryan to discuss the plan to optimize flows for the following days.

- All Conventional Hydro – On Friday 12/16/22, Hydro Operations began holding reservoirs above target (additional generation capability) at the request of the Regulated Renewables VP Randy Herrin, to support peak load as result of the forecasted low temperatures in the week to come.

- Rhodhiss Hydro – The week of 12/19/22, Rhodhiss unit 2 was in a planned outage to support project work through 12/30/22. The hydro team met on 12/20 and determined work should be discontinued on 12/21 to enable the units return to service to meet peak demand through the weekend of 12/23. The unit was returned successfully on 12/21 and was dispatched on 12/24 to meet demand.

- Mayo - 12/24/2022 06:47 - Jason Talbott (GMIII CDG North) notified by Tom Copolo (GMIII Roxboro/Mayo) via phone that, starting at 06:09, Mayo was derated due to a frozen drum level sensing line on 1B Boiler. On same call, was notified that, starting at 02:30, Roxboro was derated due to 3B Boiler Feed Pump (BFP) being out of service due to frozen feed water flow sensing line and subsequent 3B BFP control issues.
    - 12/24 – Numerous calls into plant control room updating status of various issues confronting the operating team – freezing issues, freezing coal, scrubber issues including freezing gypsum.
    - 12/24/2022 Afternoon - Jason Talbott notified by Tom Copolo that 1B Boiler was ready to fire but operating team was dealing with numerous challenges including Scrubber pH was trending low and placing 1B Boiler would exacerbate the Scrubber chemistry issues by adding additional flue gas and jeopardize the available load Mayo was producing.

- 12/25 Morning – Continued status updates with plant and between Jason Talbott and Tom Copolo on plant status.
- 12/25 12:15 – Meeting held between Thomas Carver (on-duty Operations Team Supervisor), Cale Walker (Operations Coordinator), Jason Talbott and Tom Copolo to update operational status and review sequence of priorities confronting the operating team in pursuit of returning 1B boiler to service. Group agreed, although 1B boiler was ready to fire, operational challenges with scrubber first needed to be mitigated – challenges included scrubber pH trending low; placing 1B boiler in service would exacerbate the scrubber chemistry resulting from increased flue gas flow/volume, thus jeopardizing the available load Mayo was producing.
- 12/25 15:00 - An update meeting was held with Preston Gillespie (EVP, Chief Generation Officer), Paul Draovitch (SVP, Chief Regulated & Renewable Energy Officer), Julie Turner (VP, Carolinas Generation), Jason Talbott, Tom Copolo, Gary Rogers (Mgr. Maintenance), Patrick Bowen (Mgr. Operations), and Amber Sarver (Mgr. Technical). Update given on Mayo 1B Boiler with expected return service.
- 12/25 Afternoon – Scrubber challenges were adequately addressed through the afternoon and Mayo 1B Boiler was returned to service at 18:00 on 12/25/2022.

- <u>Roxboro</u> 3B BFP - 12/24 06:46 – Jason Talbott (GMIII CDG North) notified by Tom Copolo (GMIII Roxboro/Mayo) via phone and forwarding of morning status report email that Roxboro was derated due to 3B Boiler Feed Pump (BFP) being out of service due to frozen feedwater flow sensing line and subsequent 3B BFP control issues; follow-up calls at various times through the day, beginning at 0838 to update details and status and to communicate failed 7B conveyor belt.
    - 12/24 08:51 – Phone discussion between Gary Rogers (Manager Roxboro Maintenance) and Tom Copolo regarding actions being taken in response to overnight freezing issues, 3B BFPT and failed 7B conveyor belt.
    - 12/24 10:56 – Phone discussion between Patrick Bowen (Manager Roxboro Main Plant Operations) and Tom Copolo regarding continuing control response issues with 3B BFPT and notifying that Chuck Jones (Roxboro Tech Team, Turbine/Generator SME) was responding to site to assist with further troubleshooting.
    - 12/24 13:45 – Phone discussion between Patrick Bowen and Cedric Lloyd (Sr. Mgr. System Operations) updating troubleshooting efforts on 3B BFPT.
    - 12/24 21:35 – Update from Patrick Bowen that troubleshooting efforts and subsequent attempts to run 3B BFPT had been unsuccessful.
    - 12/25 07:34 – Status update call between Jason Talbott and Tom Copolo and calls continuing throughout the day.

  - 12/25 08:33 – Status/plan-for-the-day call between Gary Rogers and Tom Copolo regarding continuing freeze protection follow-up and continuing troubleshooting of 3B BFPT; plan tentatively set for leadership, craft and specialist meeting at 13:00 to overview 3B BFPT troubleshooting status.

  - 12/25 13:33 – Phone discussion between Patrick Bowen and Cedric Lloyd updating troubleshooting efforts on 3B BFPT.

  - 12/25 14:00 – Meeting referenced in preceding bullet shifted to 14:00; various participants including Operations and Maintenance craft and supervision involved with troubleshooting efforts, Chuck Jones, Gary Rogers, Patrick Bowen and Tom Copolo. Current status and next steps reviewed; decision made to engage contract Turbine/Generator specialist to assist efforts.

  - 12/25 15:00 – Update meeting held with Preston Gillespie (EVP, Chief Generation Officer), Paul Draovitch (SVP, Chief Regulated & Renewable Energy Officer), Julie Turner (VP, Carolinas Generation), Jason Talbott, Tom Copolo, Gary Rogers, Patrick Bowen, and Amber Sarver (Roxboro Manager Technical/Planning). Update given on Roxboro 3B BFP status, troubleshooting efforts and plans.

  - 12/25 16:00 – Follow-up meeting between Roxboro managers to assure alignment on follow-up action items resulting from 15:00 call noted in preceding bullet.

  - 12/25 17:34 – Phone discussion between Patrick Bowen and Cedric Lloyd updating troubleshooting efforts on 3B BFPT.

  - 12/25 18:10 – Troubleshooting efforts successful and 3B BFPT returned to service.

- <u>Roxboro</u> 7B Conveyor Derates - 12/24 08:38 – Jason Talbott notified by Tom Copolo via phone that 7B conveyor belt had failed.
  - 12/24 08:51 – Phone discussion between Gary Rogers (Manager Roxboro Maintenance) and Tom Copolo regarding actions being taken in response to overnight freezing issues, 3B BFPT and failed 7B conveyor belt.
  - 12/24 11:34 – Phone discussion between Paul Draovitch and Tom Copolo that 7B cleanup and repair would not be quick and would probably result in load curtailment.
  - 12/24 12:30 – Jason Talbott notified by Tom Copolo that plan set in place for cleanup and repair of 7B conveyor belt.
  - 12/24 13:45 – Phone discussion between Patrick Bowen and Cedric Lloyd regarding reclaim tactics for Units Roxboro 1&2 and dispatch of units on 12/24 and morning of 12/25.
  - 12/24 14:47 – Phone discussion between Jason Talbott and Tom Copolo discussing plans to tactically constrain unit load on Units 1&2 over the evening hours to make them full load available for the morning peak.

- 12/25 15:00 – Update meeting held with Preston Gillespie (EVP, Chief Generation Officer), Paul Draovitch (SVP, Chief Regulated & Renewable Energy Officer), Julie Turner (VP, Carolinas Generation), Jason Talbott, Tom Copolo, Gary Rogers, Patrick Bowen, and Amber Sarver (Roxboro Manager Technical/Planning). Discussion held on tactic for managing Roxboro Units 1&2 coal supplies to assure full load availability over Monday morning peak load hours.
- 12/25 16:00 – Follow-up meeting between Roxboro managers to assure alignment on follow-up action items resulting from 15:00 call noted in preceding bullet, specifically including proper alignment on execution of Units 1&2 availability tactic.
- 12/25 17:34 – Phone discussion between Patrick Bowen and Cedric Lloyd regarding reclaim tactics for Rox 1&2 and to understand why ECC needed to raise load ahead of Christmas morning peak even though a plan was in place with COAs to assist with conserving coal on Units 1&2 for the peak loads.
- 12/25 17:42 – Phone discussion between Greg Moody (Principal Portfolio Mgmt. Manager) and Tom Copolo to ensure execution of Units 1&2 availability tactic.
- 12/25 18:12 – Phone discussion between Patrick Bowen and Greg Moody regarding reclaim tactics for Rox 1&2 for 12/26 morning peak.
- 12/25 18:22 – Phone discussion between Patrick Bowen and Cedric Lloyd regarding reclaim tactics for Rox 1&2 for 12/26 morning peak.
- 12/26 morning peak – Units 1&2 operated at full load per tactic.

Responder: Mitchel Beason, COSO General Manager

DUKE ENERGY CAROLINAS, LLC and DUKE ENERGY PROGRESS, LLC

Request:

21. From December 23, 2022, through December 26, 2022, please provide generation from each Company asset, purchase, and aggregated QFs in five-minute intervals.

    a. Please include the primary fuel source used for each unit's generation in each time interval. To the extent the fuel source used from power purchases is unknown, please provide the Company's base assumption of fuel use.

Response:

Response for Duke Energy Carolinas ("DEC"):

- The requested five-minute interval data for Company assets in the DEC BA is in the file titled "CONFIDENTIAL-qf_5_min_intervals_dec_20221223__20221226.csv".
- The corresponding mapping of resource type for each of these assets is in the file titled "DEC-duke_owned_resource_types.json.txt".
- The requested five-minute interval data for QFs in the DEC BA is in the file titled "CONFIDENTIAL-qf_5_min_intervals_dec_20221223__20221226v2.csv".
- The corresponding mapping of resource type for each of these assets is in the file titled "DEC-QF_resource_types.csv".

Response for Duke Energy Progress ("DEP"):

- The requested five-minute interval data for Company assets in the DEP BA is in the file titled "CONFIDENTIAL-qf_5_min_intervals_dep_20221223__20221226.csv".
- The corresponding mapping of resource type for each of these assets is in the file titled "DEP-duke_owned_resource_types.json.txt".
- The requested five-minute interval data for QFs in the DEP BA is in the file titled "CONFIDENTIAL-qf_5_min_intervals_dep_20221223__20221226v2.csv".
- The corresponding mapping of resource type for each of these assets is in the file titled "DEP-QF_resource_types.csv".

Responder: Adam Guinn, Principal Engineer

DUKE ENERGY CAROLINAS, LLC and DUKE ENERGY PROGRESS, LLC

Request:

22. Please provide the following unit outage information:

a. A list of units that that were known to be unavailable going into December 23, 2022.

b. A list of units that were expected to be online or available but failed or failed to respond when called upon from December 23, 2022, through December 28, 2022.

c. A list of units that underperformed or were derated (energy production below expected output) from December 23, 2022, through December 28, 2022.

i. A list of the de-rate amount in MWs and the dates and hours impacted for each unit and or power purchase.

Response:

[Unless otherwise noted, the response below pertains to both Duke Energy Carolinas, LLC ("DEC") and Duke Energy Progress, LLC ("DEP") (together with DEC, "Duke Energy" or the "Company".]

a) A list of units that were known to be unavailable going into 12/23/22 can be found on the "Carolinas 12-23" tab of the attached document, " Carolinas Unit Capability_Timeline_Load Curve 12_22_2022 to 12_28_2022_Rev0.xlsx"("Timeline Spreadsheet"). This is a status of all known unit planned outages, forced outages, and forced derates as of 12/23/22 @ 07:00.

b) A list of unit outages and derates from 12/23/22 - 12/28/22 can be found on the Timeline Spreadsheet under tabs "Carolinas 12-23" through "Carolinas 12-28".

c) A list of unit outages and derates from 12/23/22 - 12/28/22 can be found on the Timeline Spreadsheet under tabs "Carolinas 12-23" through "Carolinas 12-28".

i. Please refer to Duke Energy's response to PSDR2-22(a) for information regarding the units. Please refer to the Company's response to PSDR2-19(4) for the de-rate amount in MWs and the dates and hours impacted for power purchases over the period 12/23/22 through 12/26/22. In addition, there were no power purchase schedules cut on 12/27/22 and 12/28/22.

Responder: Mitchel Beason, COSO General Manager

Responder: Tiffany Weir, Dir. Rates & Regulatory Filings

Public Staff
Docket No. M-100, Sub 163
Public Staff Data Request No. 2
Winter Storm Elliott
Item No. 2-27

DUKE ENERGY CAROLINAS, LLC and DUKE ENERGY PROGRESS, LLC

Request:

27. Provide a timeline of the Company's Grid Status changes from December 23, 2022, through December 28, 2022.

Response:

A timeline of the grid status changes for Duke Energy Carolinas, LLC ("DEC") and Duke Energy Progress, LLC ("DEP") is provided below:

Date/Time	DEC	DEP
12/23/23	Yellow Hands Off	Yellow Hands Off
12/23/23 20:25	Orange	-
12/24/23 04:30	Red	-
12/24/23 05:37	-	Orange
12/24/23 06:06	-	Red
12/24/23 06:10	Purple	-
12/24/23 06:18	-	Purple
12/24/23 16:00	Orange	-
12/24/23 16:20	-	Orange
12/24/23 17:15	-	Red
12/25/23 05:04	-	Orange
12/25/23 11:00	Yellow Hands Off	Yellow Hands Off
12/26/23	Orange	Orange
12/27/23	Green	Green
12/28/23	Green	Green

Responder: Tom Pruitt, Principal Engineer