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October 12, 2020

Ms. Lynn Jarvis
Chief Clerk
North Carolina Utilities Commission
430 N. Salisbury Street
Raleigh, NC 27603

Re: NTE CAROLINAS II, LLC
Supplemental Testimony of Michael C. Green, Exhibit 3
Docket No. EMP-92, SUB 0

Dear Ms. Jarvis:

On behalf of NTE Carolinas II, LLC ("NTE"), we are herewith electronically submitting separately EXHIBIT 3, System Impact Study Report, to the Supplemental Direct Testimony of Michael C. Green on behalf of NTE Carolinas II, LLC in Support of Motion to Renew CPCN and to Respond to Additional EMP Questions in Docket No. EMP-92, Sub 0.

If you have any questions or comments regarding this filing, please do not hesitate to call me. Thank you in advance for your assistance.

Very truly yours,

/s/M. Gray Styers, Jr.

Gray Styers

MGS:clj

Enclosure

cc: NC Public Staff
All parties of record

EXHIBIT 3

DUKE ENERGY.
CAROLINAS

System Impact Study Report

For: NTE Carolinas II, LLC ("Customer")

Queue #: 42432-01

Service Location: Rockingham County, NC

Total Output: 477 MW (summer) / 540 MW (winter)

Commercial Operation Date: 12/1/2020

Prepared by:

Orvane Piper, Duke Energy Carolinas

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Date: **12/6/2016**

1.0 Introduction

Following are the results of the Generation System Impact Study for the installation of 477 MW (540 MW in the winter) of generating capacity in Rockingham County, NC. This site is located near Ernest Switching Station and has an estimated Commercial Operation Date of 12/1/2020. This study includes Network Resource Interconnection Service (NRIS).

2.0 Study Assumptions and Methodology

The power flow cases used in the study were developed from the Duke Energy Carolinas (DEC) internal year 2020 winter peak and 2021 summer peak cases. The results of DEC's annual screening were used as a baseline to identify the impact of the new generation. All cases were modified to include 477 MW (540 MW in the winter) of additional generation at the Customer's facility. To determine the thermal impact on DEC's transmission system, the new generation was modeled as a new interconnection at Ernest Switching Station. The economic generation dispatch was also changed by adding the new generation and forcing it on prior to the dispatch of the remaining DEC Balancing Authority Area units. The study cases were re-dispatched, solved and saved for use. The impacts of changes in the Generator Interconnection Queue were not evaluated, because it was determined that no earlier queued generators would have a significant impact on the study results.

The NRIS thermal study uses the results of DEC Transmission Planning's annual internal screening as a baseline to determine the impact of new generation. The annual internal screening identifies violations of the Duke Energy Power Transmission System Planning Guidelines and this information is used to develop the transmission asset expansion plan. The annual screening provides branch loading for postulated transmission line or transformer contingencies under various generation dispatches. The thermal study results following the inclusion of the new generation were obtained by the same methods, and are therefore comparable to the annual screening. The results are compared to identify significant impacts to the DEC transmission system.

The ERIS thermal study utilizes a model that includes the new generation with relevant earlier queued projects and associated known upgrades. The new generation economically displaces DEC Balancing Authority Area units. Transmission capacity is available as long as no transmission element is overloaded under N-1 transmission conditions. The thermal evaluation will only consider the base case under N-1 transmission contingencies to determine the availability of transmission capacity. ERIS is service using transmission capacity on an "as available" basis; adverse generation dispatches that would make the transmission capacity unavailable are not identified. The study will also identify the maximum allowable output without requiring additional Network Upgrades at the time the study is performed.

Short circuit analysis is performed by modeling the new generator and earlier queued generation ahead of the new generator in the interconnection queue. Any significant changes in short circuit current resulting from the new generator's installation are identified. Various faults are placed on the system and their impact versus equipment rating is evaluated.

Stability studies are performed using a Multiregional Modeling Working Group dynamics model that has been updated with the appropriate generator and equipment parameters for the new unit(s). The SERC dynamically reduced 2020 summer peak case was used for this study. The case was modified to turn off some existing generation to offset the new generation. Several transmission system improvements that needed to be added to the dynamics case were identified for the addition of the new generation during the power flow portion of the interconnection request. NERC TPL-001-4 Planning Events and Extreme Events were evaluated.

Reactive Capability is evaluated by modeling a facility's generators and step-up transformers (GSU's) at various taps and system voltage conditions. The reactive capability of the facility can be affected by many factors including generator capability limits, excitation limits, and bus voltage limits. The evaluation determines whether sufficient reactive support will be available at the Connection Point. The DEC Facilities Connection Requirements (FCR) for generators connected to the Transmission System requires that the generator must be capable of supplying power factor in the range from .93 lagging (producing VARs) to .97 leading (absorbing VARs) measured at the Connection Point. For more information on generator reactive requirements, reference the 'Generator Power Factor Requirements' document on the DEC OASIS site: http://www.oatioasis.com/DUK/DUKdocs/Generator_Interconnection_Information.html.

Any costs identified in the short circuit current, stability or reactive capability studies are necessary for NRIS service.

3.0 Thermal Study Results

3.1 NRIS Evaluation

No earlier queued projects were deemed to have a material impact on the results of the study.

The following network upgrades were identified as being attributable to the Customer's generating facility:

Facility Name/Upgrade	Existing Size/Type	Proposed Size/Type	Mileage	Estimated Cost	Lead Time (months)
A. Interconnection Cost	[redacted]			\$3.5 MM	36
B. Upgrade Jacobs 230 kV Lines (Belews Creek-Ernest)	1272 ACSR	1533 ACSS/TW	13.71	\$30.4 MM	42
C. Add 2% Reactors on Sadler 230 kV Lines	N/A	2%	N/A	\$6 MM	36
D. Add 230/100 kV Transformer at North Greensboro	N/A	448 MVA	N/A	\$5.9 MM	36
CUSTOMER TOTAL COST ESTIMATE (THERMAL)				\$45.8 MM	42

For a NERC TPL-001-4 Category P6 multiple contingency Planning Event involving the loss of both 230 kV circuits between Ernest and Belews Creek, the Customer may be directed to reduce the output of its facility as a pre-second contingency system adjustment. Under the transmission configuration resulting from the aforementioned P6 event, the thermal capacity of the 230 kV circuits between Ernest and Sadler is adequate when considering the full output of the existing generation facility interconnected at Ernest; however, if the Customer's facility is constructed, the thermal capacity of the 230 kV circuits between Ernest and Sadler will be inadequate for the same transmission configuration when considering the full output of both the existing generation facility and the Customer's facility.

For a NERC TPL-001-4 Category P7 multiple contingency Planning Event involving the loss of both 230 kV circuits between Ernest and Belews Creek, an automatic runback scheme will be required because time for operator action is not available given the emergency rating of the circuits. The presence of an automatic runback scheme would also mitigate the P6 event described in the preceding paragraph. As with the aforementioned P6 event, the thermal capacity of the 230 kV circuits between Ernest and Sadler is adequate considering the full output of the existing generation facility interconnected at Ernest but inadequate when considering the full output of both the existing generating facility and the Customer's facility.

Alternative solutions to mitigate the potential thermal issues caused by the P6 and P7 events described in the preceding paragraphs would require either 1) rebuilding the 230 kV circuits between Ernest and Sadler or 2) building new transmission out of Ernest. Cost estimates associated with either of these alternative solutions are not provided in this report.

3.2 ERIS Evaluation

The Customer did not request evaluation of ERIS service.

4.0 Short Circuit Analysis Results

No earlier queued projects were deemed to have a material impact on the results of the study. The following breakers will need to be replaced:

1. At North Greensboro Tie the following eight 100 kV breakers: Dan River Bl & Wh, Graham Bl & Wh, Guilford Bl & Wh, Page Bl & Wh
2. At Belews Creek Steam Station the following ten 230 kV breakers: PCB 5, PCB 10, PCB 11, PCB 12, PCB 13, PCB 14, PCB 15, PCB 24, PCB 25, PCB 27

Total estimated cost for breaker replacements: $8.3 MM

5.0 Stability Study Results

The instability observed at local generating facilities for some Category P6 and P7 Planning Events was attributable to the Customer's generating facility. The P6 events involved a three-phase fault on a transmission circuit followed by a system adjustment and the loss of another transmission circuit. The P7 event involved a single-phase fault resulting in the loss of two adjacent circuits on a common structure. An additional 230/100 kV transformer at Sadler has been identified as the solution to the instability caused by the P6 and P7 events.

The following network upgrade was identified as being attributable to the Customer's generating facility:

Facility Name/Upgrade	Existing Size/Type	Proposed Size/Type	Mileage	Estimated Cost	Lead Time (months)
E. Add 230/100 kV Transformer at Sadler	N/A	448 MVA	N/A	$5.9 MM	36
CUSTOMER TOTAL COST ESTIMATE (STABILITY)				$5.9 MM	36

Because weakly damped generator oscillations were observed for P6 and P7 events, the Customer's generators are required to be equipped with power system stabilizers (PSS), which shall be enabled.

Instability was also observed for some Extreme Events involving a three-phase fault with delayed clearing due to breaker or relay failure. NERC does not require stability for Extreme Events because of their low probability of occurrence. As such, no transmission improvements are required for Extreme Events.

Because instability was observed for some events in this study, it is recommended that the Customer's generators have out-of-step protection installed and operational.

The addition of the proposed 477 MW at the Customer's facility does present some problems when considering Planning Events and Extreme Events. However, with the solutions outlined in this report, the Customer's proposed 477 MW facility will not negatively impact the overall reliability of the generators or the interconnected transmission system.

6.0 Reactive Capability Study Results

With the proposed addition, the level of reactive support supplied by the units has been determined to be acceptable at this time. Evaluation of MVAR flow and voltages in the vicinity of Ernest Switching Station indicates adequate reactive support exists in the region. The recommended tap setting at the high side of the GSU is 241.5 kV.

Study completed by: ______________________
Orvane Piper, Duke Energy Carolinas

Reviewed by: ______________________
Edgar Bell, Duke Energy Carolinas
Director, Transmission Planning Carolinas

Date: **12/6/2016**