REDACTED

INFORMATION SHEET

PRESIDING: Commissioner Duffley, Chair Mitchell, and Commissioner Clodfelter
PLACE: Dobbs Building, Raleigh, NC
DATE: Tuesday, November 30, 2021
TIME: 12:11 p.m. – 1:31 p.m.
DOCKET NOS.: EMP-116, Sub 0
COMPANY: Juno Solar, LLC
DESCRIPTION: Application for a Conditional Certificate of Public Convenience and Necessity to Construct a 275-MW Solar Facility in Richmond County, NC

VOLUME NUMBER: 2

APPEARANCES
See Attached

WITNESSES
See Attached

EXHIBITS
See Attached

CONFIDENTIAL COPIES OF TRANSCRIPTS AND EXHIBITS ORDERED BY: Karen Kemerait, Ben Snowden, Layla Cummings and Robert Josey

REPORTED BY: Tonja Vines — TRANSCRIPT PAGES: 79
TRANSCRIBED BY: Kim Mitchell (under my direction) — PREFILED PAGES:
DATE FILED: January 10, 2022 — TOTAL PAGES: 79

NORTH CAROLINA UTILITIES COMMISSION
APPEARANCE SLIP

DATE: 11/30/2021 DOCKET NO.: EMP-116

ATTORNEY NAME and TITLE: Karen Kemerait

Attorney

FIRM NAME: Fox Rothschild

ADDRESS: ______

CITY: Raleigh STATE: NC ZIP CODE: ______

APPEARANCE ON BEHALF OF: Juno Solar LLC

APPLICANT: ✓ COMPLAINANT: ___ INTERVENOR: ___

PROTESTANT: ___ RESPONDENT: ___ DEFENDANT: ___

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APPEARANCE SLIP

DATE: 11/30/21 DOCKET NO.: EMP-116 Sub Ø

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APPEARANCE ON BEHALF OF: Juno Solar

APPLICANT: ✓ COMPLAINANT: ___ INTERVENOR: ___

PROTESTANT: ___ RESPONDENT: ___ DEFENDANT: ___

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NORTH CAROLINA UTILITIES COMMISSION
PUBLIC STAFF - APPEARANCE SLIP

DATE Nov 30, 2021 DOCKET #: EMP-116, Sub 0

PUBLIC STAFF ATTORNEY Layla Cummings, Robert B. Josey

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Layla Cummings
[signature]

REDACTED

PLACE: Dobbs Building, Raleigh, North Carolina
DATE: Tuesday, November 30, 2021
TIME: 12:11 p.m. - 1:31 p.m.
DOCKET NO.: EMP-116, Sub 0
BEFORE: Commissioner Kimberly W. Duffley, Presiding
Chair Charlotte A. Mitchell
Commissioner Daniel G. Clodfelter

IN THE MATTER OF:

Application of Juno Solar, LLC,
For Conditional Certification of Public
Convenience and Necessity to Construct a 275-MW
Solar Facility in Richmond County,
North Carolina

VOLUME 2

A P P E A R A N C E S:

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T A B L E O F C O N T E N T S

E X A M I N A T I O N S

E X H I B I T S

IDENTIFIED/ADMITTED

I/A

DUKE ENERGY®

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April 1, 2021

VIA ETARIFF
Kimberly D. Bose, Secretary
Nathaniel J. Davis, Sr., Deputy Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, DC 20426

Re: ***Duke Energy Carolinas, LLC, Duke Energy Progress, LLC, and Duke Energy Florida, LLC,*** **Revisions to Attachment J (Large Generator Interconnection Procedures) to Joint OATT**
Docket No. ER21-___-000

Dear Secretaries:

Pursuant to Section 205 of the Federal Power Act[1] and Part 35 of the regulations[2] of the Federal Energy Regulatory Commission ("Commission" or "FERC")), Duke Energy Carolinas, LLC ("DEC"), Duke Energy Progress, LLC ("DEP" and with DEC, the "Duke Carolinas Utilities"), and Duke Energy Florida, LLC ("DEF") (collectively, the "Duke Southeast Utilities" or "Duke Transmission Providers")) hereby submit revisions to Attachment J (Large Generator Interconnection Procedures, "LGIP") including limited revisions to the Large Generator Interconnection Agreement ("LGIA") in Appendix 10 to the LGIP to its Joint Open Access Transmission Tariff ("Joint OATT").[3]

The Duke Southeast Utilities respectfully request an effective date of June 1, 2021 for the revisions to the Joint OATT.[4] The proposed revisions permit DEC, DEP and DEF to each elect on an individual Transmission Provider basis the option to move from a "first-come, first-served" generator interconnection approach to a "first-ready, first-served" generator interconnection approach. For the Duke Carolinas Utilities, Commission approval of these important revisions to the Joint OATT will allow DEC and DEP to immediately reform their generator interconnection queueing, study and cost allocation process by transitioning to a Definitive Interconnection Study Process and to also align these FERC-jurisdictional procedures with queue reform revisions to the state-jurisdictional generator interconnection procedures recently approved by the North Carolina Utilities Commission ("NCUC") and Public Service Commission of South Carolina ("PSCSC"). The Duke Southeast Utilities conducted an

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[1] 16 U.S.C. § 824e.

[2] 18 C.F.R. pt. 35.

[3] Capitalized terms used but not defined in this letter shall have the meanings ascribed to those terms as set forth in the Joint OATT.

[4] As further discussed herein, the Duke Transmission Providers propose that these significant queue reforms not be undertaken until after each Transmission Provider publicizes a Cluster Study transition notice date by posting it to OASIS. This notice date would not occur until after Commission approval. Thus, all Interconnection Customers with Queue Positions established prior to the effective date will be eligible for the Transition Procedures under the Duke Southeast Utilities' proposed revisions to the LGIP presented herein ("Revised LGIP").

extensive stakeholder process to attempt to gain consensus among numerous affected stakeholders and believe the proposed Joint OATT revisions are supported by the vast majority of stakeholders, are just and reasonable, and are consistent with or superior to the *pro forma* LGIP and LGIA approved in Order No. 2003.[5]

I. EXECUTIVE SUMMARY

The Duke Southeast Utilities—especially the Duke Carolinas Utilities, which have experienced significant growth in new transmission-connected and distribution-connected solar generation since 2015—are undertaking these queue reforms to address the growing challenges, backlogs and complexities facing their respective generator interconnection processes. As further described herein, the high volume of serially processed and often speculative Interconnection Requests as well as the serial assignment of Network Upgrade costs under the current LGIP has created a variety of risks and challenges and adversely impacted the cost and timing required to study later-queued Interconnection Requests. Taken together, these factors delay generation developers' ability to make informed investment decisions and efficiently interconnect commercially viable new projects. For the Duke Carolinas Utilities, the existing serial study process is no longer capable of managing the significant number of existing and new Interconnection Customers requesting to connect to the DEC and DEP systems, particularly in light of the substantial Network Upgrades needed to interconnect new generation to their transmission systems. Queue reform is also needed as the states where the Duke Southeast Utilities provide regulated electric service have implemented new renewable generation procurement programs and continue to explore further transition to increasingly distributed and carbon-free generating resources.

In its 2008 Order on Technical Conference, the Commission recognized that reforms to transmission providers' generator interconnection queueing processes may be necessary to improve queue management, and specifically identified that switching to a "first-ready, first-served" cluster study approach may be beneficial.[6] Since that time, both Regional Transmission Organization and Independent System Operators ("RTOs and ISOs") as well as other non-independent transmission providers have pursued queue reforms to improve their generator interconnection study processes, specifically including transitioning to cluster study processes that prioritize the study of ready projects. The Duke Southeast Utilities' queue reform proposals have been carefully developed over an almost two-year period based on prior precedents, most notably the interconnection reforms accepted by the Commission for Public Service Company of Colorado ("PSCo") in December 2019[7], as well as significant stakeholder input. The Duke

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[5] *Standardization of Generator Interconnection Agreements and Procedures,* Order No. 2003, FERC Stats. & Regs. ¶ 31,146 (2003), *order on reh'g*, Order No. 2003-A, FERC Stats. & Regs. ¶ 31,160, *order on reh'g*, Order No. 2003-B, FERC Stats. & Regs. ¶ 31,171 (2004), *order on reh'g*, Order No. 2003-C, FERC Stats. & Regs. ¶ 31,190 (2005), *aff'd sub nom. Nat'l Ass'n of Regulatory Util. Comm'rs v. FERC*, 475 F.3d 1277 (D.C. Cir. 2007) (collectively, "Order No. 2003").

[6] *Interconnection Queuing Practices*, Order on Technical Conference, 122 FERC ¶ 61,252 at P 18 (2008) ("Order on Technical Conference").

[7] *Pub. Serv. Co. of Colo.*, 169 FERC ¶ 61,182 (2019) (accepting OATT revisions subject to compliance filing) ("PSCo Order").

Transmission Providers have undertaken a robust stakeholder process to discuss coordinated queue reform of both their FERC-jurisdictional and state-jurisdictional interconnection processes, including how to efficiently transition from the current serial study process to a Cluster Study process heavily based on PSCo's Definitive Interconnection Study Process framework.

The Duke Southeast Utilities are proposing significant and needed reforms to their generator interconnection processes that will (i) improve the efficiency and consistency of the interconnection study process, (ii) reduce the risk of restudies by dis-incentivizing speculative projects from entering and then remaining in the queue, and (iii) fairly allocate the costs of Network Upgrades amongst Interconnection Customers within annual Definitive Interconnection Study Process clusters. Core components of the Duke Southeast Utilities' queue reform include:

- Enabling each Duke Transmission Provider to transition to a "first-ready, first-served" Cluster Study approach to interconnection processing based on increasing demonstrations of objective and non-discriminatory commercial readiness criteria;
- Adopting a multi-phased Definitive Interconnection Study Process that aligns with the process adopted by PSCo;
- Providing for the sharing of Network Upgrade cost responsibility within the Definitive Interconnection System Impact Study ("DISIS") Cluster by utilizing the same allocation methodology as approved for PSCo;
- Providing developers the option to request customizable Informational Interconnection Studies that can provide valuable information regarding the anticipated cost and timing to interconnect a proposed Generating Facility before entering the interconnection queue; and
- Ensuring project readiness and mitigating risk of later-stage withdrawals, especially by non-ready projects, by imposing increasing Withdrawal Penalties for withdrawing Interconnection Requests within the Definitive Interconnection Study Process.

Each of these core components of the Duke Southeast Utilities' queue reform proposal aligns with the queue reform framework approved for PSCo. Moreover, in the limited respects where the Duke Southeast Utilities' queue reform proposal departs from PSCo or other precedent, the Duke Southeast Utilities demonstrate that the proposed reforms are consistent with or superior to the *pro forma* OATT.

One notable area where the Duke Southeast Utilities' queue reform proposal deviates from the PSCo framework is the Transitional Cluster process. To enable an efficient transition to the Definitive Interconnection Study Process, the Duke Southeast Utilities' Revised LGIP proposes an expedited transition process for Interconnection Customers in the current queue by providing three options: (1) a Transitional Serial Study Process, (2) a Transitional Cluster Study Process, or (3) withdrawal from the queue and the option to reenter the queue and participate in a future DISIS Cluster. While the Transitional Serial process for later-stage Interconnection Requests is consistent with PSCo's process, the Duke Transmission Providers and stakeholders have significantly restructured the PSCo transitional cluster study process from a "significant financial readiness to enter, single study" approach, to a "lower readiness to enter, multi-phased"

Transitional Cluster process more similar to DISIS.[8] The Companies have also agreed to a security-in-lieu-of-project-readiness path to both enter and proceed through the Transitional Cluster. The Duke Southeast Utilities' approach to the Transitional Cluster—which is designed to accommodate stakeholder feedback and to address concerns about mandating definitive project readiness at the outset of the multi-phased Transitional Cluster—demonstrates the significant engagement with stakeholders and is consistent with or superior to the *pro forma* OATT.

The Duke Transmission Providers also plan to keep current and future Interconnection Customers, other stakeholders and the Commission apprised of their respective plans and implementation of the queue reform transition to the Definitive Interconnection Study Process. The Revised LGIP provides a transparent process for each Duke Transmission Provider to publicize its intent to initiate the transition by posting notice to the OASIS website and providing written notice of the planned Cluster Study transition to all current Interconnection Customers. The Duke Southeast Utilities commit to file an informational report with the Commission within two years of the effective date of the enclosed tariff changes on the efficacy of the proposed queue reform initiatives.

II. STANDARD OF REVIEW

The Commission established the *pro forma* LGIP and LGIA in Order No. 2003.[9] In adopting Order No. 2003, the Commission advised transmission providers that it will accept non-independent transmission provider variations from the *pro forma* LGIP and LGIA so long as the transmission provider can demonstrate that the variations are "consistent with or superior to" its final rules in Order No. 2003.[10] The Commission's goal in Order No. 2003 was to "reduce undue discrimination and expedite the development of new generation while protecting reliability and ensuring that rates are just and reasonable."[11] The "serial" interconnection process set out in Order No. 2003 achieved the Commission's articulated policy goals at that time. However, as the Commission has acknowledged, "[s]urges in the volume of new generation development are taxing the current queue management approach in some regions," and "unprecedented demand in some regions for new types of generation, principally renewable generation, places further stress on queue management" because such generation can "be brought online more quickly than traditional generation."[12]

The Order No. 2003 serial approach does not result in timely interconnections of viable generating facilities to the Duke Southeast Utilities' systems. As the Duke Southeast Utilities will demonstrate, the proposed queue reforms in the Revised LGIP satisfy the "consistent with or superior to" standard, and also allow for the effective and efficient management of the Duke Southeast Utilities' interconnection queues.

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[8] Revised LGIP, Section 7.2

[9] *See* Order No. 2003.

[10] *Id.* at P 825.

[11] *Id.* at P 11.

[12] Order on Technical Conference at P 3.

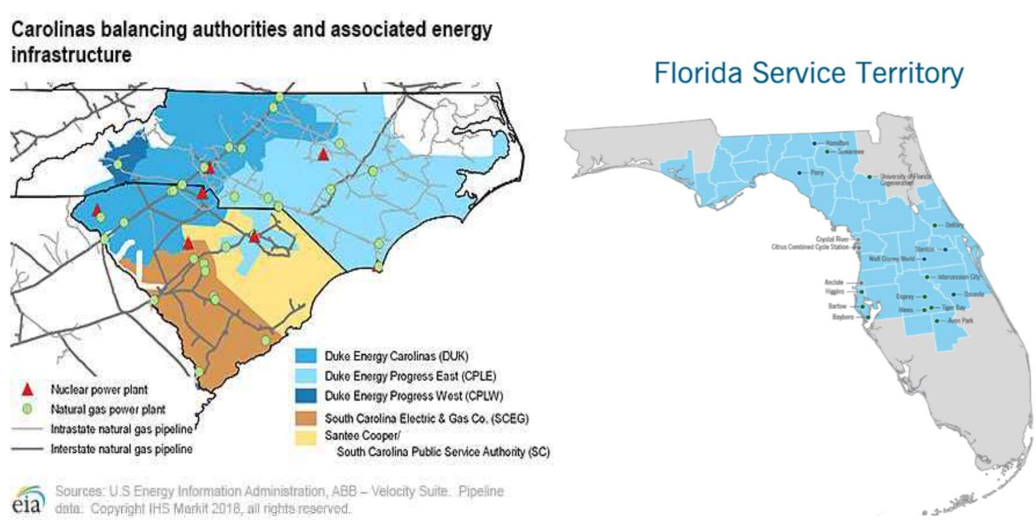
As non-independent transmission providers, the Duke Southeast Utilities do not benefit from the independent entity variation standard, which allows RTOs and ISOs additional flexibility in proposing variations from the *pro forma* interconnection procedures and interconnection agreements to accommodate regional needs.[13] However, as explained below, the proposed reforms are nonetheless just and reasonable because they: (1) are consistent with the Commission's approved OATT revisions in the PSCo and PacifiCorp cases,[14] (2) are designed to address a significant challenge, customers, and adequately accommodate late-stage projects, (3) will make it easier for commercially viable projects to interconnect, (4) will benefit customers by harmonizing federal and state generator interconnection processes, and (5) will treat all Interconnection Customers in a non-discriminatory manner.

III. BACKGROUND

A. The Duke Southeast Utilities

DEC, DEP and DEF are each wholly owned franchised public utility subsidiaries of Duke Energy Corporation that provide generation, transmission, and distribution services to wholesale and retail customers in their respective service territories. The Duke Southeast Utilities are not located in organized markets and serve as their own Balancing Authorities ("BA") in their own Balancing Authority Areas ("BAA"). Figure 1 below are maps showing the BAAs in the Carolinas region and DEF's service territory in Florida.

FIGURE 1
Duke Southeast Utilities
Maps of BAAs and Service Territory



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[13] Order No. 2003 at PP 822-27; Order No. 2003-A at P 759; Order on Technical Conference at P 13.

[14] *See generally* PSCo Order; *PacifiCorp*, 171 FERC ¶ 61,112 (2020) (accepting queue reform tariff revisions subject to compliance filing) ("PacifiCorp Order")*; PacifiCorp*, delegated letter order in Docket No. ER20-924 (Dec. 29, 2020) (accepting compliance filing).

DEC: DEC is an investor-owned utility that provides generation, transmission, and distribution services to wholesale and retail customers in North Carolina and South Carolina. DEC's service territory covers approximately 24,000 square miles and it provides electricity to 2.5 million retail customers. DEC has a total generation capacity (summer) of 19,700 MW. DEC is the BA for the BAA designated "DUK" (medium blue on map) which spans across North Carolina and South Carolina.

DEP: DEP is a separate investor-owned utility that provides generation, transmission, and distribution services to wholesale and retail customers in North Carolina and South Carolina. DEP's service territory covers approximately 32,000 square miles and it provides electricity to 1.5 million retail customers. DEP has a total generation capacity (summer) of 12,900 MW. DEP serves as the BA for its two BAAs designated as "CPLE" and "CPLW" which refer to its eastern BAA (light blue on map) and western BAA (dark blue on map), bisected in the middle by the DUK BAA (medium blue on map).

DEF: DEF is an investor-owned utility that provides generation, transmission, and distribution services to wholesale and retail customers in Florida. DEF's service territory covers approximately 13,000 square miles and it provides electricity to 1.8 million retail customers. DEF has a total generation capacity (summer) of 8,800 MW. DEF serves as the BA for its BAA in peninsular Florida.[15]

B. The Duke Southeast Utilities' Current Generator Interconnection Procedures

Each of the Duke Southeast Utilities are parties to one Joint OATT,[16] which contains Attachment J (Large Generator Interconnection Procedures, including the Large Generator Interconnection Agreement ("LGIA")) ("LGIP") and Attachment M (Small Generator Interconnection Procedures, including the Small Generator Interconnection Agreement ("SGIA")) ("SGIP"). The Duke Southeast Utilities adopted the Commission's *pro forma* LGIP and SGIP containing the first-come, first-served serial generator interconnection process. The Duke Southeast Utilities obtained Commission approval of modifications to the process relating to utility-owned projects which provides that none of the Duke Southeast Utilities is required to (a) pay itself a tax-gross up under the LGIA, (b) provide security to itself to cover the costs of Network Upgrades under the LGIA and SGIA, and (c) repay itself for the costs advanced for Network Upgrades under the LGIA and SGIA.[17] The Duke Southeast Utilities also obtained Commission approval for modifications to the LGIP and LGIA required to comply with Order No. 845.[18]

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[15] Peninsular Florida means "all of that portion of the State of Florida lying east of FPC's points of interconnection with Gulf Power Company, and to the south of the points of interconnection of those transmission lines jointly owned by Florida Power & Light Company and Jacksonville Electric Authority with Georgia Power Company and south of the points of interconnection of the City of Tallahassee and FPC with Georgia Power Company." *Flo. Power Corp. (aka Progress Energy Florida)*, 111 FERC ¶ 61,154 at n. 1 (2005).

[16] *Duke Energy Carolinas, LLC, et al.*, delegated letter order in Docket Nos. ER12-1343, *et al.* (July 18, 2013).

[17] *Duke Energy Carolinas, LLC, et al.*, delegated letter order in Docket No. ER16-1045 (Apr. 15, 2016).

[18] *Duke Energy Carolinas, LLC, et al.*, delegated letter order in Docket No. ER19-1507 (Dec. 18, 2020).

C. Status of the Duke Southeast Utilities' Generator Interconnection Queues

1. Duke Carolinas Utilities

a. State and Federal Policies Promote Solar in the Carolinas

Over the past decade, the Duke Carolinas Utilities have experienced rapid and sustained growth in their generator interconnection queues, as significant development of renewable energy projects has occurred in the Carolinas as a result of various state and federal policies and programs. In 2007, North Carolina adopted a Renewable Energy and Energy Efficiency Portfolio Standard that became effective in 2010, and issued robust state renewable energy tax credits and other policies promoting new renewable generation.[19] From 2012 to 2017, North Carolina's implementation of the Public Utility Regulatory Policies Act ("PURPA"), along with then-available federal and state tax credits and other economic incentives offered in the state, promoted surging development of an unprecedented number of solar Qualifying Facilities ("QF").

An August 2016 report by the U.S. Energy Information Administration found that North Carolina led all 50 states in installed capacity of PURPA-supported utility-scale solar.[20] By the end of 2016, installed QF solar on DEP and DEC systems in North Carolina had rapidly grown to over 1,600 MW of capacity, with more than 1,100 MW concentrated in the rural, flatland of eastern North Carolina. In 2017, North Carolina reformed the state's PURPA implementation by creating significant new solar procurement programs via North Carolina Session Law 2017-192.[21] These factors contributed to surging and sustained growth in utility-scale solar Interconnection Requests resulting in North Carolina becoming a perennial nation-wide leader in installed solar capacity.

North Carolina has recently advocated for addressing climate change by transitioning the power generating fleets within the state to clean energy technologies to significantly reduce carbon emission intensity in the utility sector. Governor Roy Cooper's Executive Order No. 80 issued in October 2018 initiated a statewide "Clean Energy Plan" development process led by the

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[19] *See* N.C. Gen. Stat. § 62-133.8 (enacting Renewable Energy and Energy Efficiency Portfolio Standard requiring DEC, DEP and other North Carolina electric power suppliers to procure 12.5% of their energy needs through renewable energy resources or energy efficiency measures by 2025).

[20] *See* U.S. Energy Information Administration, Today in Energy, *North Carolina has More PURPA-Qualifying Solar Facilities than any other State*, figure entitled *PURPA qualifying facilities (1980-2015) percent of total renewable capacity* (Aug. 23, 2016), https://eia.gov/todayinenergy/detail.php?id=27632.

[21] *See generally* N.C. Gen. Stat. § 62-110.8 (mandating DEC and DEP competitively procure in the aggregate up to 2,660 MW of new controllable renewable energy resources located within their BAAs within 45 months); N.C. Gen. Stat. § 62-159.2 (mandating DEC and DEP establish direct renewable energy procurement for major military installations, public universities, and other large customers).

North Carolina Department of Environmental Quality.[22] NC Executive Order No. 80 established statewide greenhouse gas emissions targets of 40% below 2005 levels by 2025, amongst other commitments. The North Carolina Clean Energy Plan builds on these emissions reductions targets by establishing long-term goals to reduce electric power sector greenhouse gas emissions by 70% below 2005 levels by 2030 and attain carbon neutrality by 2050.[23]

South Carolina has also enacted state policies to encourage development of new renewable energy generation in the DEC and DEP service territories. In 2014, South Carolina enacted a distributed energy resources program mandating solar procurement in South Carolina.[24] In 2019, South Carolina enacted the Energy Freedom Act, further promoting opportunities for solar and other renewable energy development under PURPA and through other procurement channels,[25] as well as overhauling the state's integrated resource planning[26] and directing the PSCSC to undertake a review of the state-jurisdictional generator interconnection process.[27]

North Carolina's climate goals and Clean Energy Plan, as well as the South Carolina Energy Freedom Act's emphasis on expanding renewable energy deployment, align with Duke Energy Corporation's evolving commitments to the environment and doing its part to address climate risks by investing in resilient infrastructure and delivering cleaner, sustainable energy for customers. Duke Energy's 2017 goal to reduce carbon emissions 40% by 2030 was one of the industry's most ambitious at the time. Sustained, low natural gas prices and declining costs for renewables and storage have allowed Duke Energy to accelerate that goal to at least 50% reduction by 2030. Duke Energy expects it can achieve significant reductions in carbon emissions by 2050 with the technology that exists today and has announced a target of achieving net-zero emissions for its operations by 2050. Duke Energy has reported progress toward its carbon goals annually in Duke Energy's Sustainability Report and, most recently, in Duke Energy's 2020 Climate Report.[28] Queue reform under the Duke Southeast Utilities' Joint OATT is a critical component to continuing to progress towards these goals.

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[22] Office of the North Carolina Governor, Executive Order 80: North Carolina's Commitment to Address Climate Change and Transition to a Clean Energy Economy ("NC Executive Order No. 80"), https://deq.nc.gov/energy-climate/climate-change/nc-climate-change-interagency-council/climate-change-clean-energy.

[23] North Carolina Department of Environmental Quality, State Energy Office, "North Carolina Clean Energy Plan." (Oct. 2019), https://files.nc.gov/ncdeq/climate-change/clean-energy-plan/NC_Clean_Energy_Plan_OCT_2019_.pdf

[24] Public Service Commission of South Carolina, Commission Directive, Order No. 2018-633, Docket No. 2015-55-E (Sept. 19, 2018).

[25] S.C. Code Ann. § 58-41-20.

[26] S.C. Code Ann. § 58-37-40.

[27] S.C. Code Ann. § 58-27-460.

[28] Duke Energy 2020 Climate Report Achieving a Net Zero Carbon Future, https://www.duke-energy.com/Our-Company/Environment/Global-Climate-Change.

b. Current Generator Interconnection Queues in the Carolinas

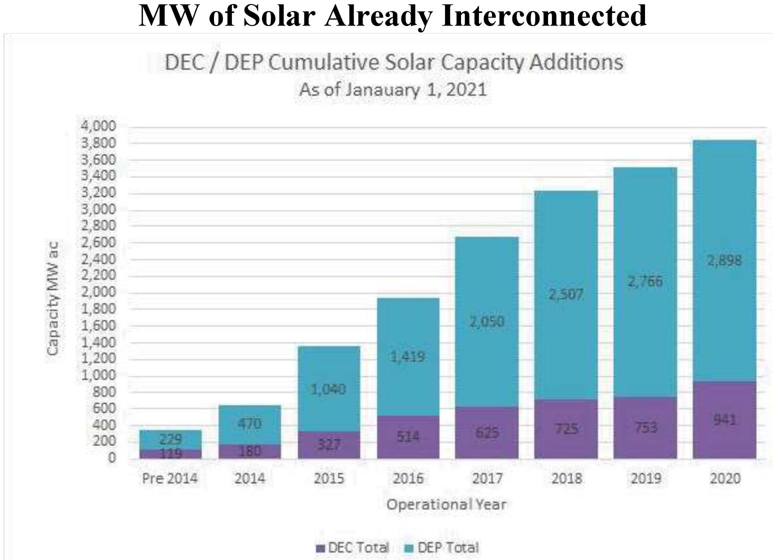
Focusing on the Duke Carolinas Utilities' generator interconnection queues, there are 469 interconnection requests currently in the queues totaling approximately 29,000 MW, and 90% of those are solar projects. See Table 1 below.

TABLE 1
Duke Carolinas Utilities
Active Requests in Queues by Resource Type[29]

Energy Type	DEC Requests	DEP Requests	DEC MW	DEP MW	Total Requests	Total MW	% of Requests
Battery	1.00	6.00	2.75	179.58	7.00	182.33	1.49%
Diesel		1.00		38.00	1.00	38.00	0.21%
Hydroelectric	1.00		320.00		1.00	320.00	0.21%
Natural Gas	15.00	16.00	8,692.20	8,731.43	31.00	17,423.63	6.61%
Nuclear	2.00		61.00		2.00	61.00	0.43%
Other	1.00		4.60		1.00	4.60	0.21%
Solar	160.00	266.00	4,536.12	6,567.65	426.00	11,103.77	90.83%
Grand Total	**180.00**	**289.00**	**13,616.67**	**15,516.66**	**469.00**	**29,133.33**	**100.00%**

From a historical perspective, 4,000 MW of solar generation has already been interconnected to the Duke Carolinas Utilities' systems. See Chart 1 below.

CHART 1
Duke Carolinas Utilities
MW of Solar Already Interconnected

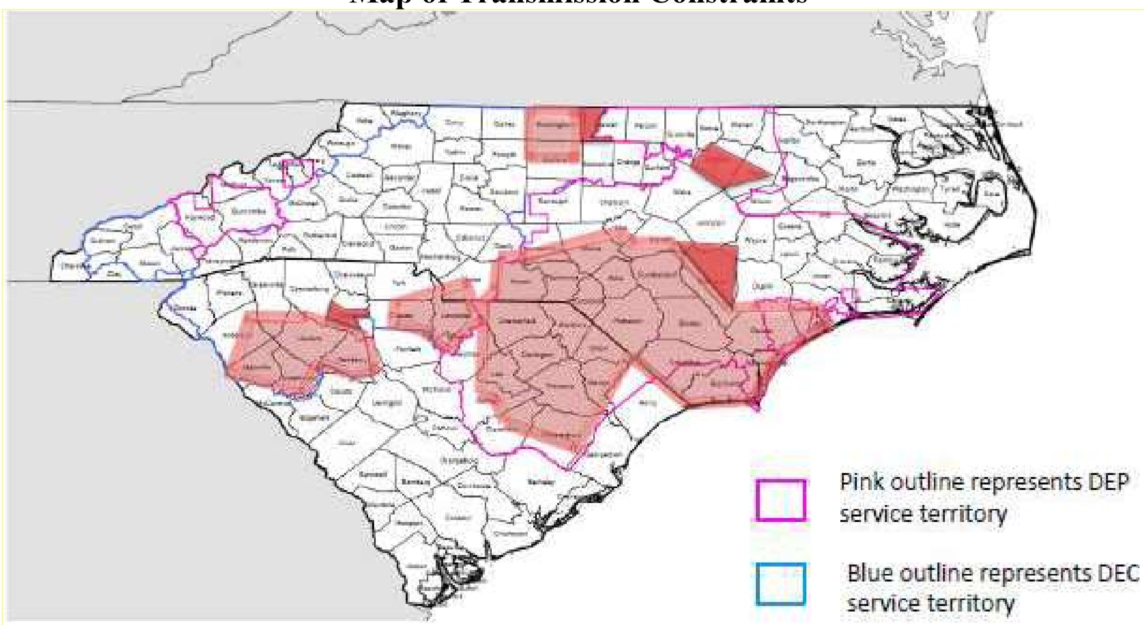


As a result of previous interconnections which were able to connect with relatively few Network Upgrades, there is now little available capacity on the Duke Carolinas Utilities' transmission and distribution systems to interconnect additional generating capacity without causing the need for construction of significant Network Upgrades. The combined impact of this

[29] Data includes all Interconnection Requests ≥ 1 MW.

unparalleled growth in solar along with larger transmission level interconnections has resulted in growing areas of transmission constrained infrastructure on the DEC and DEP transmission systems necessitating costly new investments in Network Upgrades to accommodate additional generation. Figure 2 below, posted on DEC's and DEP's OASIS sites, shows the transmission constrained areas in red across the Duke Carolinas Utilities' BAAs.[30]

FIGURE 2
Duke Carolinas Utilities
Map of Transmission Constraints



Importantly, the cost of constructing new Network Upgrades required to resolve these growing areas of transmission system overloads in order to safely and reliably integrate new generation into the Duke Carolinas Utilities' BAAs are estimated to be $200 million or more.[31] Under the current serial interconnection process, 100% of these costs are assigned to the earliest-queued projects triggering the need for Network Upgrades, even though later-queued projects may also benefit from the Upgrades. In many cases, assignment of such significant Network Upgrade costs can make new generation projects infeasible, incentivizing those projects to delay in committing to fund the upgrades or to withdraw from the queue (most often, at a very late stage). Delays and withdrawals have the same effect – they disadvantage later-queued customers by causing delays and the need for re-studies.

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[30] *See* https://www.oasis.oati.com/duk/index.html (Folder "Generator Interconnection Information", file "DEC-DEP Constrained Areas – CPRE Tranche 2").

[31] In 2020, the NCUC recognized that approximately $187,300,000 in Network Upgrades were needed to construct a proposed merchant solar generating facility in the Southeast region of DEP East. These significant Network Upgrade costs was a primary consideration in the NCUC's Order denying the merchant generator's requested certificate of public convenience and necessity. *See Order Denying Certificate of Public Convenience and Necessity for Merchant Generating Facility*, at 24 NCUC Docket No. EMP-105, Sub 0 (June 11, 2020).

Under the current serial interconnection process, an Interconnection Customer's withdrawal results in reassignment of 100% of their project's estimated costs of Network Upgrades to the next customer behind them in the queue that needs such upgrades. That customer may also choose to withdraw if it can't pay for the significant Network Upgrade costs. As more of these substantial Network Upgrades are triggered, there is a strong likelihood under the existing serial study process that a cascading "waterfall" of withdrawals occurs, as one project after another withdraws because they cannot afford to fund the requisite Network Upgrades.

Finally, the Duke Carolinas Utilities have also experienced significant "interdependencies"[32] between (a) FERC-jurisdictional requests, (b) larger transmission-level state-jurisdictional requests, and (c) the proliferation of utility-scale solar QFs requesting to interconnect to the DEC and DEP distribution systems. As of February 2021, there are over 500 projects between 1 MW and 5 MW (totaling approx. 2,060 MW) interconnected to the DEC and DEP distribution systems in the Carolinas that, in many cases, are now backfeeding onto the transmission system. This situation causes and exacerbates the transmission constraints shown in Figure 1 above.

2. DEF in Peninsular Florida

DEF has experienced more manageable growth in generator interconnection requests. Since 2013, DEF experienced a sharp spike in the number of interconnection requests in 2016 and 2017 after which the number of requests has steadily declined. In 2020, DEF witnessed 60% fewer requests than at the peak in 2016. See Table 2 below.

TABLE 2
Duke Energy Florida
Interconnection Requests by Number and MW

Year	IR Count	IR MW ac
2013	9	2,415
2014	6	1,083
2015	6	633
2016	44	7,275
2017	50	2,806
2018	41	2,942
2019	31	1,929
2020	19	1,223
Grand Total	**206**	**20,305**

[32] The Commission has previously explained that "[w]hen study results and timelines become interdependent, each project in the queue must wait for the results of projects ahead of it in the queue in order to establish an accurate base case for the studies. Due to the potential for repeated delays caused by the effects of withdrawals and re-studies, the Commission has previously determined that the cluster approach is a more efficient process." *S. Cal. Edison Co.*, 135 FERC ¶ 61,093, 61,550 (2011) (citing *see*, *e.g.*, *Cal. Indep. Sys. Operator Corp.*, 133 FERC ¶ 61,223 at PP 69-70 (2010). *See also* Order No. 2006 at P 181 (*citing* Order No. 2003 at P 155).

DEF has received 206 generator interconnection requests amounting to 20,305 MW. Compared with 476 active Interconnection Requests in the Duke Carolinas Utilities' queues, DEF has 68 active interconnection requests (61 in its FERC queue and 7 in its state queue). DEF has 86% fewer active requests in its queue compared to the Duke Carolinas Utilities. DEF has had almost no delayed generator interconnection studies for 2020.[33] See Table 3 below.

TABLE 3
Duke Energy Florida
Timeliness of Generator Interconnection Studies

Percentage of Delayed Studies	Q1 2020	Q2 2020	Q3 2020	Q4 2020
Feasibility Studies	0%	0%	NA	NA
System Impact Studies	0%	0%	0%	0%
Facilities Studies	5.56%	0%	0%	0%

Further, it is important to note that, unlike in the Carolinas where DEC and DEP conduct their own transmission planning processes to comply with FERC Order Nos. 890 and 1000, DEF participates in a coordinated process under which the Florida Reliability Coordinating Council, Inc. ("FRCC") leads those processes for all transmission providers in Florida including DEF. There are three elements of the coordinated transmission planning process that set DEF apart from DEC and DEP.

First, DEC and DEP compile their own base cases used in generator interconnection studies. DEF provides its case data to the FRCC which compiles data it receives from all of the transmission providers in Florida. The FRCC then creates master base cases and disseminates those base cases to the Florida transmission providers within the FRCC footprint to use in conducting generator interconnection studies for requests on each of their individual systems.

Second, DEC and DEP can individually choose to transition to a Cluster Study approach for their BAs. For DEF, that choice has historically been made collectively by all of the transmission providers in the FRCC region and all have agreed that each will follow the FERC-approved serial, first-come, first-served generator interconnection processes. They have ensured that their *pro forma* LGIPs in their individual OATTs are all aligned with one another with respect to serial generator interconnection processing.

[33] For DEF, available in folder "Generator Interconnection Information", subfolder "Interconnection Reporting Metrics", "Order 845 Metrics" file, at https://www.oasis.oati.com/fpc/index.html.

Third, DEC and DEP administer their own Affected System processes and directly inform Affected System Operators of any adverse impacts to their systems that are identified in generator interconnection studies. In Florida, DEF does not administer that process. The FRCC administers the process, coordinates the review of studies that show impacts on Affected Systems, and obtains consensus from all Affected System Operators before moving forward with the process. In comparison to DEC and DEP, DEF has many more neighboring transmission providers, and therefore, many more potentially Affected System Operators with whom it must coordinate generator interconnection studies.

For these reasons, it would be challenging for DEF to be the lone transmission provider in the FRCC applying a clustered, first-ready, first-served generator interconnection process. In recognition that DEF would need to coordinate with the FRCC and other Florida transmission providers if it wishes to transition to a Cluster Study approach, the LGIP provides DEC, DEP, and DEF each with the option to elect to transition to a clustered, first-ready, first-served model. Such optionality permits DEF to continue its implementation of the serial generator interconnection process, allows DEC and DEP to transition to the clustered generator interconnection process, and retains flexibility for DEF to transition to a clustered generator interconnection process in the future, if it so desires.

D. Other Transmission Providers Are Pursuing Significant Queue Reform

Transition from a serial interconnection study process to a "first-ready, first-served" cluster study approach is a growing trend. Queue reform efforts, similar to the Duke Transmission Providers', either have already occurred or are now occurring in other parts of the country where rapid growth in new renewable energy generation is occurring. Queue reform has occurred both in regions where the generator interconnection process is administered by RTOs/ISOs and also in regions without RTOs/ISOs in which transmission providers administer their own generator interconnection processes.[34]

Cluster studies are used to administer the generator interconnection processes in RTO/ISO regions across the country including CAISO,[35] MISO,[36] PJM,[37] and ISO New England.[38] In non-RTO/ISO regions, the Commission has also authorized utilities to achieve queue reform through transitioning from a traditional serial study process to a more definitive cluster study process. In 2011-2012, a number of utilities in the southwestern United States sought approval to reform their queue administration and Interconnection Request processing

[34] In December 2007, FERC held a technical conference on interconnection queue management, and its subsequent order identified potential reforms that may improve interconnection queuing processes, including finding "merit in a first-ready, first-served approach, whereby customers who demonstrate the greatest ability to move forward with project development are processed first." Order on Technical Conference at P 18.

[35] *Cal. Ind. Sys. Op. Corp.*, 170 FERC ¶ 61,112 (2020).

[36] *Mw. Indep. Transmission Sys. Operator, Inc.*, 138 FERC ¶ 61,227 (2012).

[37] *PJM Interconnection, L.L.C.*, 139 FERC ¶ 61,079 (2012).

[38] *ISO New England Inc.*, 161 FERC ¶ 61,123 (2017).

through adoption of cluster studies and other reforms.[39] Notably, in 2011, PNM filed a request to reform its interconnection queue by transitioning from a first-come, first-served serial study process to a first-ready, first-served cluster study process to clear a significant backlog of pending interconnection requests.[40] More recently, in a series of filings in 2018 and 2019,[41] PSCo sought approval of a comprehensive queue reform proposal to address its queue backlog, and to create a more effective set of interconnection procedures by transitioning to a first-ready, first-served cluster study approach called the "Definitive Interconnection Study Process."[42] In December 2019, the Commission issued its Order approving PSCo's transition to the proposed Definitive Interconnection Study Process.[43] In 2020, the Commission has also reviewed and approved other queue reform initiatives to transition to a Definitive Interconnection Study Process similar to PSCo's for PacifiCorp[44] and Tri-State Generation & Transmission Association, Inc.[45]

The Duke Southeast Utilities and stakeholders have reviewed PSCo's and other utilities' queue reform initiatives,[46] and propose to adopt many of their reforms in order to address the issues confronting the Duke Carolinas Utilities' interconnection queues in North Carolina and South Carolina. As explained further in Section IV below, the Duke Southeast Utilities' queue reform proposal incorporates much of PSCo's framework for its Definitive Interconnection Study Process, but is tailored to the specific needs and concerns of the Duke Southeast Utilities and their stakeholders.

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[39] *See, e.g.*, *Ariz. Pub. Serv. Co.*, 137 FERC ¶ 61,099 (2011) (approving Arizona Public Service Companies' LGIP revisions implementing standardized six-month cluster studies and increasing initial deposit amounts for existing interconnection requests for which a feasibility study had not yet been commenced); *El Paso Elec. Serv. Co.*, 137 FERC ¶ 61,101 (2011) (approving El Paso Electric Company's Revised LGIP implementing six-month queue cluster windows and requiring increasingly non-refundable study deposits for requests which had not executed a feasibility study agreement); *NV Energy, Inc.*, 142 FERC ¶ 61,165 (2013) (approving Nevada Power Company's proposal to create a pre-application requirement intended to ensure that interconnection customers had obtained the proper land permits for their projects, to eliminate feasibility studies, to adjust the required deposit amounts, and to group requests into standardized six-month clusters).

[40] *See Pub. Serv. Co. of N.M.*, tariff revisions filed in Docket No. ER11-3522 (filed May 5, 2011); *Pub. Serv. Co. of N.M.*, 136 FERC ¶ 61,231 at PP 12-14 (2011) (approving PNM's queue reform initiatives and proposed cluster study approach and finding that the clearing of PNM's interconnection queue backlog as soon as possible would be beneficial to all customers seeking interconnection and would enable a more efficient interconnection process going forward).

[41] PSCo initially petitioned FERC for approval of queue reform revisions to its tariff in November 2018, which FERC denied by an order issued January 31, 2019. *Pub. Serv. Co. of Colo.*, 166 FERC ¶ 61,076 (2019), *reh'g denied*, 167 FERC ¶ 61,141 (2019). PSCo subsequently refiled its queue reform tariff revisions in September 2019 in Docket No. ER19-2774, *et al.* In the PSCo Order, the Commission accepted the queue reform tariff revisions subject to a compliance filing. *Pub. Serv. Co. of Colo.*, delegated letter order in Docket No. ER19-2774-002 (Mar. 2, 2020) (accepting compliance filing).

[42] PSCo Order.

[43] *Id.*

[44] PacifiCorp Order at P 1.

[45] *Tri-State Generation & Transmission Ass'n, Inc.*, 173 FERC ¶ 61,231 (2020).

[46] As highlighted below, Duke and stakeholders discussed many of these prior queue reform efforts during Stakeholder Meeting #1, while Stakeholder Meeting #6 focused exclusively on the PSCo Order.

E. The Need for Reform in the Carolinas

The Duke Carolinas Utilities' generator interconnection queues have become unmanageable using the serial study process in the current FERC-approved LGIP. The indicia that the process is now unworkable include (1) major delays in completing generator interconnection studies, (2) inequitable cost responsibility and inability of developers to share costs for Network Upgrades, and (3) the presence of non-viable projects in the queue.

1. Major Delays in Completing Generator Interconnection Studies

The requirement that interconnection studies must be conducted assuming that all higher-queued projects will achieve commercial operation does not reflect the reality that many projects end up withdrawing their Interconnection Requests, often late in the serial study process, or after suspending under their LGIA. In such cases, the Duke Carolinas Utilities engage in re-studies of lower-queued projects that are adversely impacted by these actions of higher-queued projects, leading to inefficiencies in the process and material delays for the lower-queued Interconnection Customers. Evidence of the unmanageable nature of the current queue is shown by the widespread delays reported by DEC and DEP in completing all types of generator interconnection studies in their Order No. 845 study metrics for 2020:[47]

TABLE 4
Duke Carolinas Utilities
Timeliness of Generator Interconnection Studies

Percentage of Delayed Studies	Q1 2020	Q2 2020	Q3 2020	Q4 2020
Feasibility Studies	DEC: 100% DEP: 100%	DEC: 100% DEP: 33%	DEC: 100% DEP: 100%	DEC: 100% DEP: 33%
System Impact Studies	DEC: 100% DEP: 100%	DEC: 100% DEP: 100%	DEC: 100% DEP: 100%	DEC: 100% DEP: 67%
Facilities Studies	DEC: 0% DEP: 75%	DEC: 0% DEP: 75%	DEC: 100% DEP: 100%	DEC: 100% DEP: 100%

On November 13, 2020 and February 12, 2021, DEC and DEP filed Informational Reports pursuant to Order No. 845 with the Commission in Docket No. ER19-1507 reporting delayed generator interconnection studies and identified the following reasons for the delays:

- suspension of a prior-queued request;
- high volume of prior-queued requests for projects seeking to interconnect in the same area of the Transmission System as lowered-queued requests;
- need to complete higher-queued study due to similar impacts caused by lower-queued project;

[47] For DEC, available in folder "Generator Interconnection Information", subfolder "FERC 845 Generator Study Metrics", subfolder "2020" at https://www.oasis.oati.com/duk/index.html. For DEP, available in folder "Generator Interconnection Information", subfolder "FERC 845 Generator Study Metrics", subfolder "2020" at https://www.oasis.oati.com/cpl/index.html.

- interdependencies between two Interconnection Requests;
- revisions needed to prior studies completed for a customer caused delays in completing later studies;
- evaluations of multiple Points of Interconnection in one study; and
- iterative requests for additional technical information from the Interconnection Customer.

The high volume of prior-queued requests, as well as growing interdependencies across the DEC and DEP Transmission Systems, are especially challenging to manage and have most significantly contributed to the clogged interconnection queues that are impeding the Duke Carolinas Utilities' efforts to process Interconnection Requests under the current serial LGIP.

2. Inequitable Cost Responsibility and Inability of Developers to Share Costs for Network Upgrades

The first-come, first-served approach can produce inequitable cost responsibility for Network Upgrades, and this inequity could impede the ability for generators to interconnect. More specifically, to the extent that material Network Upgrade costs make any particular project financially non-viable, the Interconnection Request may be withdrawn. Afterwards, the next project in the queue would likely face similar financial burdens for that triggered Network Upgrade, and so on, and so on. Moreover, the existing serial process prevents developers from sharing costs when large upgrades are required creating both market and system congestion.

The Duke Carolinas Utilities submit that queue reform is needed so that costs can be equitably allocated to projects in a manner that most efficiently (1) signals the true costs of interconnecting projects for prospective Interconnection Customers and (2) promotes efficient system planning decisions by ensuring that needed Network Upgrades are appropriately studied and designed to provide maximum benefit at the lowest cost.

3. The Presence of Non-Viable Projects in the Queues

Under the first-come, first-served approach in the existing LGIP, it is inexpensive for Interconnection Customers to enter the queue merely to claim increasingly scarce interconnection capacity, thereby making it more challenging for lower-queued, commercially viable projects to efficiently proceed to interconnection. FERC policy is to provide "the Interconnection Customer with a strong incentive to make efficient siting decisions and, in general, to make good faith requests for Interconnection Service."[48] Instead, speculative Interconnection Requests enter either the FERC-jurisdictional queue, the state jurisdictional queue, or both as early as possible and are not incentivized to expeditiously progress towards readiness or to exit the queue if they determine that they are not viable.[49]

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[48] Order No. 2003-A at P 613.

[49] Order on Technical Conference at P 15 ("[T]he relatively small deposit amounts, coupled with the incentives produced by a first-come, first-served approach to allocating capacity, provides an incentive for developers to secure a place in the queue even for projects that may not be commercially viable.").

FERC's Order No. 2003 policy resolution to this problem – allowing lowered queued projects to utilize the capacity being reserved for a high queued project until the higher-queued project is built[50] – is frustrated, given that a lower-queued project could simply wait to see if it must fund assigned Network Upgrades or use the capacity reserved for the higher-queued project. The prevalence of speculative projects and these f Network Upgrade funding issues are the type of "unexpected consequences" that the Commission determined can and should be remedied by queue reform.[51]

F. State Regulatory Directive to Duke for Queue Reform

Due to the proliferation of state-jurisdictional generators (primarily solar QFs) requesting interconnection to the Duke Carolinas Utilities' distribution and transmission systems in North Carolina, the NCUC has actively overseen the development and refinement of state-jurisdictional generator interconnection procedures to promote more efficient generator interconnections.[52] On June 14, 2019, the NCUC issued an order directing the Duke Carolinas Utilities to "establish a stakeholder process within the first quarter of 2019 to discuss the process of transitioning their North Carolina queues to a grouping study process and that the Duke Utilities shall report to the Commission no later than July 31, 2019, as to the status of that stakeholder process."[53] In response to this NCUC directive to move their North Carolina state-jurisdictional generator interconnection queues from a serial to a cluster study process, the Duke Carolinas Utilities commenced a multi-year stakeholder engagement and coordination process.

The Duke Carolinas Utilities also recognized that they must harmonize any generator interconnection procedures established for their North Carolina state-jurisdictional generator queues with their (a) South Carolina state-jurisdictional generator queues and (b) FERC-jurisdictional queues, in order to effectively model and study all generator Interconnection Requests in their BAAs on a clustered basis. In other words, it would be infeasible for Duke transmission planners to study FERC-jurisdictional projects and South Carolina state-jurisdictional projects on a serial basis and North Carolina state-jurisdictional projects on a clustered basis, given the interdependencies amongst projects all seeking to connect to the same Transmission System within the DEC and DEP BAAs.

In response to the NCUC's directives, the Duke Carolinas Utilities surveyed queue reform initiatives from around the country as part of the foundational work for engaging with stakeholders. At that time, and as discussed above, PSCo was the utility that had most recently developed a queue reform proposal known as the "Definitive Interconnection Study Process" and was working through its stakeholder process. The Duke Carolinas Utilities significantly

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[50] *See* Order No. 2003-A at P 622.

[51] Order on Technical Conference at P 15.

[52] *See generally* NCUC Docket No. E-100, Sub 101.

[53] Order Approving Revised Interconnection Standard and Requiring Reports and Testimony, at 61, NCUC Docket No. E-100, Sub 101 (June 14, 2019). The Duke Carolinas Utilities' initiation of the queue reform stakeholder process prior to the NCUC's issuance of a final order was, in part, based on a partial stipulation entered into with NCUC Public Staff and certain other stakeholders in January 2019.

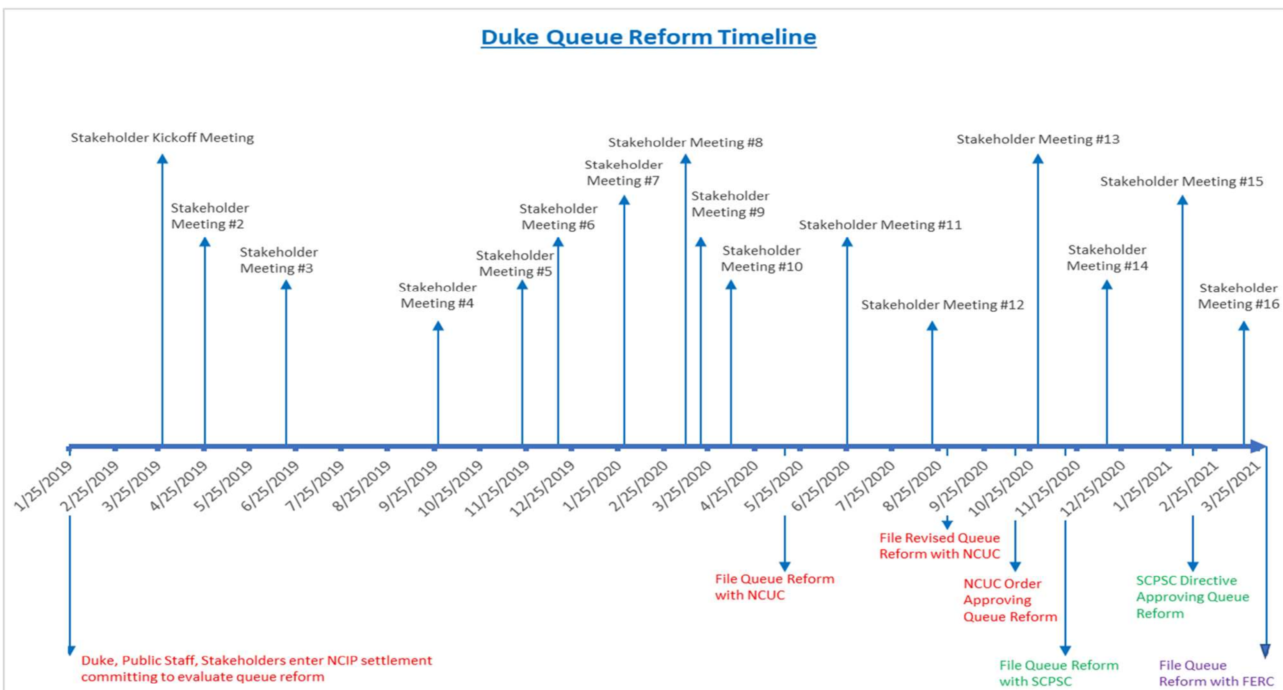
modeled their queue reform proposal on PSCo's Definitive Interconnection Study Process proposal and began honing it through stakeholder engagement.

G. Stakeholder Engagement

The Duke Southeast Utilities began engaging with stakeholders on March 28, 2019. All stakeholder materials, including invitations, documents shared at meetings, presentations to stakeholders, and a Q&A document, are posted on OASIS.[54] The meetings were open to all interested stakeholders and were held in person and telephonically or, since March 2020, have been accessible via web conferencing and videoconferencing applications.

Throughout the stakeholder process, the Duke Southeast Utilities maintained transparency with respect to proposed drafts of queue reform documents to be filed at the state and federal regulatory levels. The Duke Southeast Utilities encouraged active discussion, held breakout sessions on discrete topics during stakeholder meetings, and solicited feedback and questions. The queue reform stakeholder process has included 16 meetings since March 2019 amongst a broad spectrum of interested parties. Figure 3 below is a timeline of the Duke Southeast Utilities' stakeholder process.

FIGURE 3
Duke Southeast Utilities
Timeline of Queue Reform Stakeholder Engagement



[54] Available at https://www.oasis.oati.com/fpc/index.html (Folder "Generator Queue Reform Stakeholder", file "Queue_Reform_Stakeholder_Meetings".

Below is a list of the major stakeholder meetings and their topics, along with an overview of the state regulatory filings and approvals.

1) March 28, 2019 – Stakeholder Kickoff Meeting (#1)

2) April 25, 2019 – Stakeholder Meeting (Interconnection Queue: Current State, - Overview Queue Reform: National Trends and Emerging Best Practices, and Queue Reform: Framework processing, timeline, milestones, cost allocation.)

3) June 18, 2019 – Stakeholder Meeting (DISIS framework and transition processes)

4) September 27, 2019 – Stakeholder Meeting (proposed October 2019 filing with NCUC and transition process)

5) November 22, 2019 – Stakeholder Meeting (cost allocation, cluster study process timeline)

6) December 16, 2019 – Stakeholder Meeting (PSCo queue reform process)

7) January 29, 2020 – Stakeholder Meeting (DISIS study process, Customer Engagement Window, deposits, cost allocation, withdrawal penalty and the transition process)

8) March 10, 2020 – Stakeholder Meeting (North Carolina Interconnection Procedures)

9) March 20, 2020 – Stakeholder Meeting (North Carolina Interconnection Procedures)

10) April 9, 2020 – Stakeholder Meeting (North Carolina Interconnection Procedures)

11) May 15, 2020 – Duke Carolinas Utilities file queue reform proposal with NCUC

12) June 25, 2020 – Stakeholder Meeting (federal queue reform trends, cluster study process, cost, security and the readiness milestone allocation, withdraw penalties and the overall transition process)

13) August 21, 2020 – Stakeholder Meeting (modifications to the North Carolina Interconnection Procedures based on comments filed by intervening parties in NCUC Docket No. E-100, Sub 101)

14) August 31, 2020 – Duke Carolinas Utilities file revised queue reform proposal with NCUC with support of NCUC Public Staff and solar developer trade associations

15) October 15, 2020 – NCUC issues order approving queue reform proposal[55]

16) October 30, 2020 – Stakeholder Meeting (South Carolina Generator Interconnection Procedures)

17) November 17, 2020 – Duke Carolinas Utilities file queue reform proposal with the PSCSC

18) December 15, 2020 – Stakeholder Meeting (draft of LGIP and LGIA)

19) February 3, 2021 – Stakeholder Meeting (revised draft of LGIP and LGIA, including supporting visuals)

20) February 10, 2021 – PSCSC issues Commission Directive approving queue reform proposal[56]

21) March 16, 2021 – Stakeholder Meeting (final draft of LGIP and LGIA)

22) April 1, 2021 – Duke Southeast Utilities file queue reform proposal with FERC

Beginning with the stakeholder meeting #14 held on December 15, 2020, the Duke Southeast Utilities' stakeholder engagement process has focused on facilitating page-by-page reviews of the proposed revisions to the LGIP tariff language. Duke has solicited several rounds of comments and incorporated such comments (received verbally and in writing) into the Revised LGIP. During this period, more than 40 parties participated in the stakeholder process and approximately 24 written stakeholder comments were received, responded to, and posted to OASIS. In addition to the public stakeholder process, Duke Southeast Utilities also met with any interested party who requested an individual meeting. These meetings provided another avenue for Duke Southeast Utilities to obtain feedback and to craft a proposal that could obtain stakeholder support. Overall, the Duke Southeast Utilities believe that the stakeholder process was successful, resulted in a stronger and more effective Revised LGIP proposal, and is likely to garner material support from most affected parties. The Revised LGIP presented in this filing reflects Duke's reasonable accommodation of stakeholder comments and requests.

H. State Regulatory Approvals Obtained for Queue Reform in NC and SC

As described above, the Duke Southeast Utilities have undertaken significant efforts to obtain stakeholder support for the queue reform transition to the Definitive Interconnection Study Process. In conjunction with these efforts, the Duke Carolinas Utilities have pursued and obtained approval of queue reform at the NCUC and PSCSC to align the increasingly interrelated and interdependent state and FERC-jurisdictional generator interconnection study processes.

[55] Order Approving Queue Reform, NCUC Docket No. E-100, Sub 101 (Oct. 15, 2020) ("NCUC Order").

[56] Public Service Commission of South Carolina, Commission Directive, Docket No. 2019-326-E (Feb. 10, 2021) ("PSCSC Directive").

On October 15, 2020, the NCUC issued an order approving the Duke Carolinas Utilities' queue reform filing. In its order, the NCUC characterized the current serial interconnection process as follows:

> "the current serial approach to studying and processing Interconnection Requests has become problematic. In large parts of North Carolina it is not possible to add generation without the construction of expensive transmission upgrades. The current serial process assigns these upgrades to one generator, and the costs of these upgrades are typically too expensive for any one generator to absorb. The Commission agrees with parties who have stated that moving to a grouping study process is necessary in order to share the transmission upgrade costs among the multiple generation projects that contribute to the need for the transmission upgrades."[57]

The NCUC praised the queue reform proposal, stating that "[t]he Commission determines that the revised queue reform proposal is structured to accomplish the objective of transitioning to a grouping study process."[58] The NCUC also noted that the proposal was supported by stakeholders, highlighting that "the proposal has substantial support from the stakeholders involved, and the Commission commends all parties for their efforts to reach consensus."[59]

On February 10, 2021, the PSCSC issued a Commission Directive approving the queue reform proposal.[60] At the meeting in which such directive was issued, the PSCSC complimented the Duke Carolinas Utilities for their work to achieve consensus with stakeholders that will allow for more efficient interconnection of additional renewables to the grid in South Carolina. The proposed order filed in the proceeding references the standard of review of the South Carolina Generator Interconnection Procedures, reciting that the Commission must ensure that the standards are "fair, reasonable, and nondiscriminatory with respect to interconnection applicants, other utility customers, and electrical utilities" and "serve the public interest in terms of overall cost and system reliability."[61] The proposed order highlights the challenges by current queue practices, stating that "reform is needed to address the growing challenges and complexities facing Duke's generator interconnection process in the Carolinas" and "[f]or many Interconnection Customers, bearing the entire cost of these significant upgrades can render new generation projects infeasible, causing projects to either pursue delays or withdraw from the queue altogether."[62]

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[57] NCUC Order at 2.

[58] *Id.* For the Commission's information, the term "grouping study" is a legacy term describing a Cluster Study under the NC Interconnection Procedures. Under the Definitive Interconnection Study Process, the term "Cluster Study" is used to describe the study.

[59] *Id.*

[60] *See* PSCSC Directive.

[61] Proposed Order, at 6 (citing S.C. Code Ann. § 58-27-460(A)(3)).

[62] *Id.* at 7.

The proposed order acknowledges the benefits of a first-ready, first-served approach, explaining that "Duke's proposed Definitive Interconnection Study Process, by promoting transparency and incentivizing "ready" projects, will reduce the number of speculative utility-scale projects entering the queue and will enable the Companies to more timely, fairly and efficiently process new Interconnection Requests."[63] The proposed order also recognizes the need for a coordinated approach from both an operational and regulatory standpoint to remedy queue challenges that cross state boundaries and boundaries between state and federal jurisdiction, stating that the "Commission acknowledges that the integrated nature of the Companies' systems and overlapping system impacts of new Interconnection Customers throughout the Carolinas further supports coordinated and complementary regulatory approvals of Queue Reform by this Commission, the NCUC and FERC."[64] As of the date of this transmittal letter, the Duke Carolinas Utilities are awaiting issuance of the final order in the PSCSC proceeding.

IV. DETAILED EXPLANATION OF DUKE SOUTHEAST UTILITIES' GENERATOR QUEUE REFORMS

The Duke Southeast Utilities' queue reform proposal will better accommodate the Duke Transmission Providers' and stakeholders' goal of more efficiently processing ready or near-ready projects entering the queue by implementing two complementary concepts. First, the Definitive Interconnection Study Process will enable the Duke Transmission Providers to provide more flexibility for developers who desire to obtain interconnection and Network Upgrade cost information before entering the queue. Second, the Definitive Interconnection Study Process will provide greater certainty to developers that are ready to interconnect by incentivizing Interconnection Customers to submit only "ready projects" into the Definitive Interconnection Study Process. By structuring the Definitive Interconnection Study Process to incentivize submission of only ready projects (and dis-incentivizing speculative or non-ready projects), the proposed Cluster Study process will also group projects together to share Network Upgrade costs and minimize delays that can arise from interdependencies and the risk of cascading re-studies when higher-queued projects withdraw from the queue. Implementing these objectives through queue reform will ensure that all Interconnection Customers can proceed through the interconnection process with fewer delays and disruptions.

The Definitive Interconnection Study Process represents a significant reform of the current serial study process under the LGIP and recognizes the collective experience and input of the Duke Southeast Utilities and numerous stakeholders, as well as concepts and procedures adopted by PSCo and other transmission providers to manage the growing challenges of processing expanding generator interconnection queues. Through the extensive queue reform stakeholder meetings held over the past two years, developers have expressed that they value both flexibility and certainty in the interconnection process, which the queue reform revisions presented in the Revised LGIP are intended to balance and address.

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[63] *Id.* at 8.

[64] *Id.* at 9.

Similar to PSCo, the Duke Southeast Utilities' LGIP revisions primarily include (a) revisions to implement Cluster Studies through the Definitive Interconnection Study Process, (b) revisions to offer an Informational Interconnection Study process, and (c) Transition Procedures to facilitate a fair and efficient transition of the current serial study process for Interconnection Customers that are in the Duke Transmission Providers' queues today. Accordingly, the core components of the Duke Southeast Utilities' proposed Definitive Interconnection Study Process do not substantively vary from equivalent procedures recently approved in PSCo's interconnection queue reform proceeding.[65] Where components of the Duke Southeast Utilities' queue reform proposal have evolved from equivalent procedures approved in PSCo's interconnection procedures, these variances have been made in an effort to achieve stakeholder consensus.

In sum, the Definitive Interconnection Study Process is intended to meet the queue management challenges currently being experienced in the Duke Carolinas Utilities' jurisdictions and will enable each Interconnection Customer to continue to refine its understanding of its own project, individually and in relation to other potential projects in the DISIS Cluster, while increasing the certainty for all Interconnection Customers through increasing readiness and/or financial commitments designed to ensure that all projects within the DISIS Cluster pay their allocated portion of Network Upgrades and achieve commercial operation.

A. Applicability of Queue Reform to Large Generators and Small Generators (LGIP §2.1)

As discussed above, the Duke Carolinas Utilities' experience is that complementary queue reforms are needed for both their FERC-jurisdictional and state-jurisdictional generator interconnection processes in order to address growing backlogs and interdependencies between both FERC- and state-jurisdictional projects, and that such reforms need to apply to both large and small generator Interconnection Customers requesting interconnection to the Duke Carolinas Utilities' transmission and distribution systems. Accordingly, the Revised LGIP provides that Small Generating Facilities requesting NRIS will be processed under the Revised LGIP.[66] This consolidated queuing and application of the Definitive Interconnection Study Process for both Large Generating Facilities and Small Generating Facilities requesting NRIS is consistent with PSCo's queue reform process,[67] and also aligns with the Commission's findings that queue reform may be appropriate for state jurisdictional interconnection procedures outside the Commission's jurisdiction.[68]

Importantly, for the Duke Carolinas Utilities which will transition immediately upon Commission approval to the Definitive Interconnection Study Process, both FERC-jurisdictional

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[65] Notable differences from the PSCo queue reform process are highlighted in Section IV of this transmittal letter.

[66] With the exception of the combined Cluster Study process for small generating facilities requesting NRIS, the Duke Transmission Providers will maintain FERC's separate Order No. 2003 and 2006 interconnection processes for small generators either requesting ERIS or progressing under the SGIP "fast track" processing of interconnection requests.

[67] *See* PSCo LGIP at Article 2.1.

[68] PacifiCorp Order at PP 169-170.

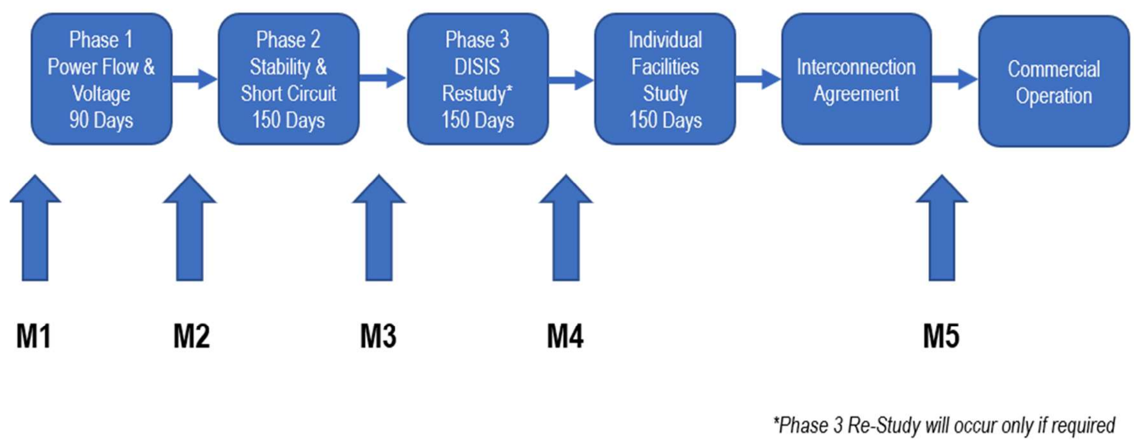
Interconnection Customers under this LGIP and state-jurisdictional Interconnection Customers under the NCIP and SCGIP will be processed in a single queue. This consolidated queueing and processing of Interconnection Requests that may cause or contribute to Network Upgrades will facilitate more efficient processing of all generator requests that may require Network Upgrades and that may otherwise be subject to the same system constraints as large generating facilities.

B. Overview of Definitive Interconnection Study Process

Duke Southeast Utilities propose to implement their Cluster Study process using a multi-phase Definitive Interconnection Study Process that aligns with the Cluster Study process recently adopted by PSCo as well as approaches approved for DEC and DEP by the NCUC and the PSCSC.[69] All Interconnection Customers (FERC, NC and SC) will be studied through the same Definitive Interconnection Study Process.[70]

The Definitive Interconnection Study Process will occur annually and consists of four main phases: (1) the 180-Day DISIS Request Window, (2) an initial pre-DISIS Customer Engagement Window, (3) the DISIS, consisting of Phase 1, Phase 2 and, potentially Phase 3 studies, and (4) Facilities Study.[71]

FIGURE 4
Phases of Definitive Interconnection Process



Under the Definitive Interconnection Study Process, the risk of project delay and need to re-study Interconnection Requests is managed by requiring increasing levels of project readiness and more significant financial commitments as Interconnection Customers move through the process. Interconnection Customers must meet specified project milestones that demonstrate increasing readiness to achieve commercial operation (or increasing financial commitment where

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[69] NCUC Order at 3. PSCSC Directive at 1.

[70] Net energy metering ("NEM") projects, as well as power export Interconnection Customers up to 250 kilowatts (kW), will be exempted from the Definitive Interconnection Study Process, providing a simpler and likely faster path to interconnection for such customers. All non-NEM Interconnection Customers above 250 kW will continue to be evaluated for potential Transmission System impacts through the processes identified in applicable state procedures, and, if identified, will be informed of the need to enter the Definitive Interconnection Study Process.

[71] Revised LGIP, Sections 10.1, 10.7.

readiness cannot be demonstrated) over the course of the Definitive Interconnection Study Process. The milestone or increased financial commitment must be satisfied before moving to the next phase or the Interconnection Request will be withdrawn from the queue but may re-enter a future Cluster Study. Adopting this "first-ready, first-served" Cluster Study approach aligns with the Commission's recognition that increasing the requirements for obtaining a queue position will "increase the likelihood that only projects that are likely to be commercially viable" enter the interconnection process.[72]

Within the Definitive Interconnection Study Process, the System Impact Study is completed through a multi-phase Definitive Interconnection System Impact Study or "DISIS." The objective of the DISIS is to more expeditiously process all definitively ready Interconnection Requests through a phased System Impact Cluster Study process while also minimizing the need to re-study projects' system impacts due to Interconnection Customers withdrawing their Interconnection Requests, especially later in the study process.

The Duke Transmission Providers have developed a more expedited study process within DISIS (at stakeholders' request) where a distribution-level Interconnection Customer is determined not to cause or contribute to the need for Network Upgrades requiring further study in the more detailed Phase 2. Once the DISIS is complete, such distribution-level Interconnection Requests proceeding to Facilities Study will be studied independently similar to the process that exists today. After the Facilities Study is completed, the Definitive Interconnection Study Process concludes and the Transmission Provider and Interconnection Customer proceed to negotiating and executing an LGIA.[73]

1. Initiating an Interconnection Request in the Definitive Interconnection Study Process (LGIP §4.4.2)

Prior to commencing the DISIS, the Transmission Provider will offer enrollment into the upcoming annual DISIS Cluster Study during a 180-day DISIS Request Window. During this period, Interconnection Customers may submit Interconnection Requests to be included in the upcoming DISIS Cluster.[74] The DISIS Request Window will be open each year from January 1 to approximately June 30. If one or more valid Interconnection Requests are received, Duke will commence the initial Customer Engagement Window prior to initiating the DISIS.

Duke's proposed annual Definitive Interconnection Study Process is similar to PacifiCorp's approved Cluster Study process,[75] but varies from PSCo's process because it provides for a single annual Cluster Study process (same as PacifiCorp) and incorporates two additional Customer Engagement Windows (and a third Customer Engagement Window if re-

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[72] Order on Technical Conference at P 16.

[73] Revised LGIP, Section 14.1.

[74] Interconnection Customers will continue to receive a Queue Number for administrative purposes; however, Section 1.8.1 makes clear that queue priority is at the Cluster Study level such that all Interconnection Requests studied in a single Cluster Study shall be considered equally queued.

[75] PacifiCorp Order at P 48 ("We find PacifiCorp's proposal to use an annual Cluster Study to be consistent with or superior to the *pro forma* LGIP.")

study is required) during DISIS.[76] These modifications were discussed with stakeholders and are appropriate for the Duke Transmission Providers. For example, the annual Cluster Study allows the Duke Transmission Providers to administer a more orderly process where each Cluster Study is completed (assuming on re-studies) before the next annual Cluster Study, while the additional Customer Engagement Windows are more advantageous to stakeholders because they provide increased opportunities to interact with the Duke Transmission Providers about study results as they evaluate whether to continue to progress through the study (and development) process. Similarly, the extended[77] 180-day DISIS Request Window will allow potential Interconnection Request Customers more time to demonstrate commercial readiness and prior to submitting an interconnection request and entering the cluster, as explained in detail below. Accordingly, Duke Southeast Utilities believe that its proposed annual Definitive Interconnection Study Process as described fully in LGIP §10 is consistent with or superior to the *pro forma* LGIP.

2. Definitive Interconnection Cluster Study Deposit (LGIP §4.1.2)

To enter the Definitive Interconnection Study Process and be studied during a DISIS Cluster, Interconnection Customers must submit an applicable study deposit amount in addition to a valid Interconnection Request before the close of the DISIS Request Window.[78] Similar to PSCo's approved 3-tiered approach for study deposit amounts required to enter the DISIS Cluster[79], the Duke Southeast Utilities propose a 5-tiered approach to study deposits based on the capacity of the Interconnection Request to be studied.[80]

TABLE 5
Tiers of Study Deposits under Definitive Interconnection Study Process

Size of Project Associated With Interconnection Request	Amount of Deposit
< 20 MW	$20,000 + $1/kW
≥ 20 MW< 50 MW	$35,000 + $1/kW
≥ 50 MW< 80MW	$50,000 + $1/kW
≥ 80 MW < 200 MW	$150,000
≥ 200 MW	$250,000

Over the course of the stakeholder engagement process leading to this filing, the Duke Southeast Utilities' proposed tiered study deposit approach has garnered consensus support from participating stakeholders. Duke's 5-tiered approach contains more intermediate tiers than PSCo's approach and is designed to balance the burden of requiring a higher upfront study deposit to establish an Interconnection Request with the recognition that larger Interconnection Customers are obligated to pay a more significant portion of the Transmission Provider's actual costs of implementing the Definitive Interconnection Study Process. The first 3 tiers up to 80

[76] Revised LGIP, Sections 10.1, 10.8.

[77] PacifiCorp Order. at P 12. PacifiCorp's window was a 45-day Cluster Request Window.

[78] Revised LGIP, Section 4.4.2.

[79] PSCo Order at P 13.

[80] Revised LGIP, Section 4.1.2.

MW align with the state-jurisdictional study deposits approved by the NCUC[81] and PSCPSC.[82] The proposed study deposit amounts for projects entering the DISIS Cluster that are 80 MW or greater are also the same as PSCo's study deposit amounts, while the study deposit amounts for projects entering the DISIS Cluster that are 80 MW or less are lower than the initial deposit amounts required under the PSCo Definitive Interconnection Study Process. Since the Commission approved higher study deposit amounts in the PSCo 3-tiered approach, the Duke Southeast Utilities believe that the proposed 5-tiered study deposit approach is more accommodating towards Interconnection Customers and is consistent with or superior to the *pro forma* LGIP.

3. Definitive Interconnection Study Process: Site Control Requirement (LGIP §4.4.2)

As part of the Definitive Interconnection Study Process, the Duke Southeast Utilities propose to adopt the (a) definition of site control[83] and (b) site control requirements document attached as Exhibit D, each as was approved in the PSCo proceeding.[84] While PSCo's proposal involved escalating percentages of site control required during the Definitive Interconnection Study Process, the Duke Southeast Utilities propose to require full site control through the Definitive Interconnection Study Process.[85] This proposed approach to site control required as part of the Definitive Interconnection Study Process is consistent with the site control required as part of the current FERC-approved serial interconnection study process. Additionally, the proposed site control approach has been approved as part of Duke's queue reform filings in North Carolina and South Carolina.[86] Over the course of the almost two-year stakeholder engagement process, stakeholders have viewed the proposed approach to site control as acceptable, and the Duke Southeast Utilities have not received negative feedback indicating otherwise. For the reasons described herein, Duke believes that its proposed approach to site control required as part of the Definitive Interconnection Study Process is consistent with or superior to the *pro forma* LGIP.

4. Initiation of a Definitive Interconnection System Impact Study Cluster (LGIP §10.1)

Sections 4.4.2 and 10.1 outline the procedures necessary for the initiation of a DISIS Cluster and allow for the implementation of the DISIS Request Window and Customer Engagement Window that occurs prior to the DISIS study phases.

The initial Customer Engagement Window offers Interconnection Customers additional Cluster-specific information in order to inform their ongoing decision-making about whether to enter the DISIS. During this Customer Engagement Window, Duke will work with

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[81] NCUC Order at 3.

[82] PSCSC Directive at 1.

[83] Revised LGIP, Section 1.

[84] PSCo Order at P 58.

[85] Revised LGIP, Section 4.4.2.

[86] NCUC Order at 3. PSCSC Directive at 1.

Interconnection Customers to verify data and obtain all information needed to build study models, cure any deficiencies in the Interconnection Request(s), and generally prepare for the start of the DISIS.[87]

Duke will also hold a Scoping Meeting for all current Interconnection Customers that entered the queue during the DISIS Request Window once the initial DISIS Customer Engagement Window has commenced.[88] The purposes of the Scoping Meeting are to discuss the upcoming DISIS Cluster, including evaluating alternative interconnection options, to exchange information, including any available transmission data that would reasonably be expected to impact such interconnection options, to review such information, and to determine the potential feasible Points of Interconnection. At the close of this Scoping Meeting, the objective is for each Interconnection Customer to have a definitive project size and Point of Interconnection to facilitate an efficient Cluster Study. Specifically, an Interconnection Customer must select a single definitive Point of Interconnection to be studied no later than the execution of the Definitive System Impact Study Agreement. In addition, an Interconnection Customer must also provide affirmation of site control for the proposed Generating Facility site and for all required Interconnection Facilities to the designated Point of Interconnection no later than commencement of Phase 1 of the DISIS process described in Section 10.8.[89] These requirements will ensure that the Interconnection Customer is increasingly committed to achieving commercial operation as it moves through the study process and that there are no site control-related impediments to constructing the proposed Generating Facility and building the facilities needed to deliver power to the designated point of interconnection to the Transmission Provider's Transmission System.

The pre-DISIS Customer Engagement Window is also designed to minimize the risk and cost for Interconnection Customers to withdraw from the process prior to the Transmission Provider commencing the DISIS Cluster Study—which is the point in the study process when other Interconnection Customers will increasingly be impacted by withdrawal. During this preliminary phase of the process, the Interconnection Customer has submitted an Interconnection Request and study deposit, but has not signed a DISIS Agreement or committed to M1 and, therefore, is not subject to a potential Withdrawal Penalty for exiting the queue. An Interconnection Customer withdrawing during the initial Customer Engagement Window would receive a refund for any of the refundable portion of Interconnection Customer's study deposit or study payments that exceeds the share of the costs that Transmission Provider has incurred under Section 4.7.[90] Prior to the conclusion of the initial Customer Engagement Window, the Duke Transmission Provider will provide an updated estimate on the anticipated allocated cost of completing the DISIS and all Interconnection Customers electing to proceed into the DISIS Cluster must: (i) execute a DISIS Agreement; (ii) provide initial security equal to one (1) times

[87] Revised LGIP, Section 10.1.

[88] Revised LGIP, Section 4.4.7.

[89] Revised LGIP, Sections 4.4.7, 10.7.

[90] Revised LGIP, Section 4.7.

the study deposit; and (iii) achieve the M1 readiness milestone or provide increased security (2 times the initial study deposit) in lieu of demonstrating readiness.[91]

5. Definitive Interconnection System Impact Study Procedures (LGIP §10.8)

The objective of the DISIS is to more expeditiously process all definitively ready Interconnection Customers through a phased System Impact Cluster Study process while also minimizing the need to re-study projects' system impacts due to Interconnection Customers withdrawing, especially later in the study process. Once the DISIS is complete, Interconnection Customers proceeding to Facilities Study will be studied independently similar to the process that exists today.

Pursuant to Section 10.6, an Interconnection Customer must execute a DISIS Agreement (included as Appendix 6-3 to the Revised LGIP) no later than the close of the Customer Engagement Window or its Interconnection Request will be withdrawn. Once the DISIS Agreement is executed and the initial security and/or M1 commitments are made, an Interconnection Customer proceeds to the first phase of the DISIS.

Section 10.7 describes the scope of the DISIS.[92] The DISIS consists of three discrete phases: (1) Phase 1 is an initial 90-day power-flow and voltage study, (2) Phase 2 is a detailed 150 day stability and short circuit study, and (3) Phase 3 provides for re-studying of the power flow/voltage analysis, short circuit analysis, and/or a stability analysis, as needed, if an Interconnection Customer(s) withdraws from the DISIS Cluster or otherwise modifies its Interconnection Request such that the results of the DISIS are no longer accurate.[93]

Section 10.8 outlines the procedures that the Duke Transmission Providers must follow in order to implement each phase of the DISIS, and describes the ongoing customer engagement and reporting process that will occur after Phase 1, Phase 2, and Phase 3 (if necessary) culminating in a final Post-DISIS Report and Report Meeting. Section 10.8 also identifies the timing for Interconnection Customers proceeding through DISIS to achieve Readiness Milestone M2 prior to Phase 2 (§10.8(b)) and Readiness Milestone M3 within 20 Calendar Days of the Phase 2 Report Meeting (§10.8(d)). The Readiness Milestones that Interconnection Customers must achieve to proceed through each study phase are discussed in detail in Section IV.B.9.

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[91] Revised LGIP, Section 10.1.

[92] The Duke Transmission Providers have made limited modifications to the PSCo DISIS process to provide Interconnection Customers with the flexibility required per Order No. 2003 to proceed with NRIS, ERIS or both during Phase 1 and Phase 2. The Duke Transmission Providers' modifications are contained in Sections 4.2.2 and 10.8(d)iii of the Revised LGIP. The language is almost identical to the language adopted by PacifiCorp in Section 2.1.5 of Attachment W which was approved by the Commission. *PacifiCorp Order* at P 66 ("we find that PacifiCorp's modified proposal in its Deficiency Response to allow interconnection customers to be studied for both NRIS and ERIS in the initial Cluster Study is consistent with or superior to the *pro forma* LGIP. … We also find that PacifiCorp's proposed requirement that customers make a choice on their service level no later than five business days after the Cluster Study Report Meeting under Section 42.4(c) is reasonable.")

[93] If the Cluster is stable (e.g., no changes to the modeling assumptions), and if no Interconnection Requests withdraw after the Phase 2 study report is published, then the Cluster Study will omit the Phase 3 study. *See* Revised LGIP, Section 10.8(d).

Pursuant to Section 10.8(c), at the close of the final phase of the DISIS, the Duke Transmission Provider will furnish a final Post-DISIS Report to Interconnection Customers within the DISIS Cluster and post the report on the Duke Transmission Providers' OASIS site. In addition, the Duke Transmission Provider will convene an open meeting to discuss the study results and will make itself available for individual Interconnection Customer meetings as well.[94] At this point, the DISIS will be completed and those Interconnection Customers wishing to proceed to Facilities Study may do so.[95]

Within 30 Calendar Days of the notice that no System Impact re-studies are needed and delivery of a Facilities Study Agreement by the Transmission Provider, each Interconnection Customer with an Interconnection Request in the Cluster that has completed the DISIS process is required to (i) return an executed Facilities Study Agreement and (ii) provide Readiness Milestone M4.[96]

6. DISIS for Distribution-Level Interconnection Customers Not Causing or Contributing to Network Upgrades (LGIP §10.8(a))

The Duke Southeast Utilities have also designed the DISIS to accommodate distribution-level Interconnection Customers that have been determined during the initial Phase 1 study not to cause or contribute to the need for Network Upgrades.[97] This process was developed through stakeholder engagement to reflect the more significant development of distribution-connected Interconnection Customers in the Carolinas (both state and FERC-jurisdictional) and is not based on PSCo's Definitive Interconnection Study Process framework.

Phase 1 is a high-level power-flow and voltage analysis that preliminarily identifies the Network Upgrades required to interconnect all Generating Facilities within the DISIS Cluster. The results from DISIS Phase 1 provide the Interconnection Customer with an initial look at its costs to interconnect before determining whether to proceed to Phase 2 and provide Readiness Milestone M2. Where the Transmission Provider determines through the initial Phase 1 study that a proposed distribution-level Interconnection Customer will not cause or contribute to the need for Network Upgrades, the Transmission Provider will notify the Interconnection Customer in writing during the post-Phase 1 Customer Engagement Window that Interconnection Customer will exit the remainder of DISIS and that the Transmission Provider will complete an individual Distribution-level System Impact Study for the proposed Generating Facility within 50 business days.[98]

Under this process, distribution-level Interconnection Customers that do not cause or contribute to Network Upgrades can more expeditiously proceed to Facilities Study and an Interconnection Agreement versus awaiting completion of the more detailed Phase 2 Study (and potential Phase 3 re-studies) required through the DISIS Cluster Study. These projects also

[94] Revised LGIP, Section 10.9.

[95] Revised LGIP, Section 11.2.

[96] Revised LGIP, Section 10.8.f.

[97] Revised LGIP, Section 10.8.a.

[98] *Id.*

avoid DISIS costs after Phase 1, and will be directly assigned only their study costs to complete the distribution-level System Impact Study (§10.8(a)). Interconnection Customers that are studied for distribution level impacts only must continue to meet all Readiness Milestone requirements (or provide security in lieu of the Readiness Milestone) to proceed to Facilities Study under Section 11.

7. Initiation of a Resource Solicitation Cluster (LGIP §10.2)

As part of the transition to the Definitive Interconnection Study Process, the Duke Southeast Utilities are also proposing to incorporate a targeted DISIS Cluster Study option for administering a Resource Solicitation Cluster under the Definitive Interconnection Study Process framework to support the addition of new Network Resources though a Resource Solicitation Process.[99] This concept aligns with Resource Solicitation Cluster concept approved for PSCo[100] and aligns with complementary sections of the recently-approved NCUC- and PSCSC generator interconnection procedures enabling similar resource solicitation clusters. Importantly, the Resource Solicitation Cluster process can be initiated by a Duke Transmission Provider "[a]t any time . . ." and can be implemented "either separately or as part of a [DISIS] Cluster" initiated pursuant to Section 10.2.

The Resource Solicitation Cluster will respect queue position, which means that projects included in an already-initiated DISIS Cluster will be included in the Base Case models for the Resource Solicitation Cluster. Network Upgrades identified in the Resource Solicitation Cluster Study will be allocated to Interconnection Requests in that Cluster in the same manner that similar Upgrades are allocated to Interconnection Customers in an annual DISIS Cluster.[101]

Similar to the Resource Solicitation Cluster option approved for PSCo, the inclusion of Resource Solicitation Cluster option will allow Duke Transmission Providers that transition to the Definitive Interconnection Study Process flexibility to separately administer a Resource Solicitation-specific Cluster Study, which may prove necessary where the timing of the Resource Solicitation Process does not align with an annual DISIS Cluster. The Resource Solicitation Cluster option also provides Interconnection Customers flexibility to establish a Queue Position through the Resource Solicitation Process while also reserving a later Queue Position separate from the Resource Solicitation Cluster for a future DISIS Cluster. Once the Resource Solicitation Cluster process concludes, a selected proposal will proceed through the remainder of the Definitive Interconnection Study Process while a rejected project will lose its Queue Position associated with the Resource Solicitation Cluster.

8. Allocation of Study Costs and Interconnection Facilities and Upgrade Costs (LGIP §§10.3-10.4)

Under the current serial interconnection study process, 100% of study costs, as well as the costs of Interconnection Facilities and Network Upgrades, are allocated to the individual

[99] Revised LGIP, Section 10.2.

[100] PSCo Order at PP 14, 30.

[101] Revised LGIP, Section 10.2

Interconnection Customer being studied and causing the costs to interconnect. Transitioning to a Cluster Study process where multiple Interconnection Customers are being studied and are contributing to the need for Network Upgrades necessitates allocation of (1) the costs of completing the DISIS amongst Interconnection Customers within a DISIS Cluster;[102] and (2) the costs of common Network Upgrades required to interconnect multiple Interconnection Customers proceeding through the DISIS Cluster.[103]

Moreover, in addition to the efficiency improvements that can be achieved through the Definitive Interconnection Study Process, allocating the increasingly significant Network Upgrade costs of interconnecting new Generating Facilities to the Duke Southeast Utilities' Transmission Systems amongst all Interconnection Customers causing or contributing to the need for such Network Upgrades is likely to promote more efficient development of new Generating Facilities, rather than burdening the earliest-queued individual Interconnection Customer with the total cost as occurs under the serial interconnection study process that exists today. Sections 10.3 and 10.4 establish clear procedures for allocating study costs as well as Interconnection Facilities and Network Upgrade costs amongst Interconnection Customers proceeding under the Definitive Interconnection Study Process.

a. Allocation of Study Costs (LGIP §10.3)

Section 10.3 describes the allocation of study costs for the DISIS Cluster. For the clustered DISIS portion of the Definitive Interconnection Study Process, study costs are allocated as follows: (1) 10% of the applicable study costs to Interconnection Customers on a per capita basis based on number of Interconnection Requests included in the applicable Cluster; and (2) 90% of the applicable study costs to Interconnection Customers on a pro-rata basis based on requested megawatts included in the applicable Cluster.

For example, consider a 1000 MW Cluster Study consisting of three projects: one 10 MW Interconnection Request, 90 MW Interconnection Request, and one 900 MW Interconnection Request. 10% of study costs would be allocated amongst the projects on a per capita basis, which would be allocated equally to each of the three requests (3.33% to each request). For the other 90% of costs allocated on a pro rata basis, the costs would be allocated 0.9% to the 10 MW request (4.23% total costs), 8.1% to the 90 MW request (11.43% total costs), and 81% to the 900 MW request (84.33% total cost). This overall allocation results in the 10 MW Interconnection Request being responsible for 4.23% of the total study costs, the 90 MW Interconnection Request being responsible for 11.43% of the total study costs, and the 900 MW Interconnection Request being responsible for 84.33% of the total study costs.

[102] Revised LGIP, Section 10.3.

[103] Revised LGIP, Section 10.4.

TABLE 6
Example of Allocation of Study Costs in DISIS Cluster

1,000 MW capacity in Cluster Study			
	10 MW Interconnection Request	**90 MW Interconnection Request**	**900 MW Interconnection Request**
10% per capita allocation	10% * 1/3= 3.33%	10% * 1/3= 3.33%	10% * 1/3= 3.33%
90% pro rata allocation	90% * 10/1000 = 0.9%	90% * 90/1000 = 8.1%	90% * 900/1000 = 81%
TOTAL	3.33% + 0.9% = **4.23% total**	3.33% + 8.1% = **11.43% total**	3.33% + 81% = **84.33% total**

PSCo utilized a similar approach to allocating study costs; however, instead of applying a 90%/10% allocation, PSCo determined each Interconnection Request's share of the costs of completing the DISIS Cluster Study (including general queue administration costs and overheads) by allocating: (1) fifty percent (50%) of the applicable study costs to Interconnection Requests on a per capita basis based on number of Interconnection Requests included in the applicable Cluster; and (2) fifty percent (50%) of the applicable study costs to Interconnection Requests on a pro-rata basis based on requested megawatts included in the applicable Cluster.[104]

In examining this approach, the Duke Southeast Utilities found that Interconnection Customers requesting to interconnect smaller projects, such as a 10 MW QF, would be obligated to pay significantly more per MW of impact to be studied process than a 900 MW project which creates a much more significant impact, and requires much more time to evaluate in both the Phase 1 and Phase 2 study processes. This creates inequity in the allocation process and forces smaller projects, such as solar QFs, to subsidize the study costs for very large projects.

Recognizing that both large generators and small generators requesting NRIS, as well as state-jurisdictional Interconnection Customers will be subject to the same allocation methodology, Duke Southeast Utilities elected to apply the 90%/10% allocation to provide a more balanced and equitable study cost allocation, based on a relatively simple cost causation principle. Furthermore, the 90%/10% approach aligns well with study deposits that would be submitted based on varying assumptions around the number and size of projects submitted into the Cluster process. The Duke Southeast Utilities structured these two study cost allocations to reflect the Commission's cost causation principle of allocating costs "to those [that] cause the costs to be incurred and reap the resulting benefits."[105] Stakeholder feedback, especially during earlier meetings focused on the state-jurisdictional queue reform efforts, found this allocation to be appropriate. For the reasons described above, the Duke Southeast Utilities believe that its proposed Definitive Interconnection Study Cost Allocation as described fully in LGIP §10.3 is consistent with or superior to the *pro forma* LGIP.

[104] PSCo Order at PP 32, 36.

[105] The Commission recently reiterated its cost causation principle in FERC Order No. 845-A, explaining that its cost causation principle "generally requires that costs 'are to be allocated to those [that] cause the costs to be incurred and reap the resulting benefits.'" FERC Order No. 845-A at P 78 (citing *S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d at 87 (quoting *Nat'l Assoc. of Regulatory Util. Comm'rs v. FERC*, 475 F.3d at 1285).

b. Allocation of Interconnection Upgrade and Interconnection Facilities Costs (LGIP §10.4)

Section 10.4 establishes the allocation procedures that the Duke Transmission Providers will use to equitably allocate Network Upgrade costs (and potentially the cost of shared Interconnection Facilities) to Interconnection Customers within the Cluster based on the relative contribution of the Interconnection Customer to the need for the Network Upgrades. Network Upgrade costs shall be allocated based upon the proportional impact of each individual Generating Facility in the Cluster on such Network Upgrades.[106] Exhibit E provides a detailed example of the cost allocation of Network Upgrades within a DISIS Cluster, and expands on examples and discussions shared with stakeholders. The cost of Interconnection Facilities continue to be directly assigned to Interconnection Customer(s) using such facilities, unless multiple Interconnection Customers are connecting to the Transmission Provider's Transmission System through shared Interconnection Facility(ies), which shall be allocated based on the number of Generating Facilities sharing that Interconnection Facility on a per capita basis.[107] Interconnection Customer funding of Network Upgrades are eligible for credits as provided in Article 11 of the LGIA.[108]

PSCo allocated the costs of Transmission Provider Interconnection Facilities and Network Upgrades based on the proportional impact of each Interconnection Customer within the DISIS Cluster to the need for such Interconnection Facilities and Network Upgrades. The Duke Southeast Utilities' cost allocation proposal is the same as PSCo's cost allocation methodology which was approved by the Commission.[109] The cost allocation methodology proposed in the Revised LGIP also aligns with the cost allocation methodology approved by the NCUC and PSCSC for state-jurisdictional interconnections, which is important as those projects will be studied in the same Clusters and costs will be allocated between all projects in the Clusters.

9. Readiness Milestones (LGIP §10.11)

To address the challenges of the existing serial interconnection process discussed above, the proposed Definitive Interconnection Study Process is a "first-ready, first-served" process that prioritizes projects that are ready to interconnect. Therefore, it is necessary to require Interconnection Customers to demonstrate increasing project readiness as part of the interconnection process, to show that they are making sufficient progress toward achieving commercial operation. Fundamentally, the purpose of mandatory Readiness Milestones is to require each Interconnection Request in the Cluster to demonstrate that it is ready to move forward with interconnection in order to make it less likely that the Interconnection Customer will withdraw its Interconnection Request from the queue, thereby harming other Interconnection Requests proceeding in the same Cluster or a later Cluster.

[106] Revised LGIP, Section 10.4.b.

[107] Revised LGIP, Section 10.4.d.

[108] Revised LGIP, Section 10.4.

[109] PSCo Order at PP 33-34, 36.

Satisfaction of the requirements of Readiness Milestones M1, M2, M3, and M4 are required throughout the Definitive Interconnection Study Process to demonstrate the readiness of the Interconnection Customer to develop the Generating Facility.[110] Satisfaction of the requirements of Readiness Milestones M1, M2, M3 are required during the DISIS Process. Readiness Milestone M4 is required after the DISIS process has concluded, but before the Facilities Study commences. Satisfaction of the requirements of Readiness Milestone M5 is required after the LGIA is executed as described in Section 10.11.5. An Interconnection Customer who does not satisfy the requirements of an applicable Readiness Milestone (or provide additional security in lieu thereof described in Section 10.11.6) is subject to withdrawal of its Interconnection Request from the queue and payment of a withdrawal penalty pursuant to Section 4.7.1. As can be shown in Figure 5 below providing an overview of the required readiness milestones, the Duke Transmission Providers' proposed milestones are substantially similar to those proposed by PSCo and approved by the Commission.[111]

FIGURE 5
Readiness Milestones in Definitive Interconnection Study Process

Readiness?	**M1-** Due by close of 60 CD Cust. Eng. Window	**M2-** Due within 20 CDs of Phase 1 Rpt Mtg	**M3-** Due within 20 CDs of Phase 2 Rpt Mtg	**M4-** Due within 30 CDs of FSA delivery	**M5-** Due within 15 BDs of final LGIA delivery
Yes	Financial Security 1x Study Deposit Readiness options: (1) Executed Term Sheet (2) Reasonable evidence selected in Resource Plan or offered into RSP (3) FERC Accepted Provisional LGIA	Financial Security 1x Study Deposit Readiness options: (1) Executed Term Sheet (2) Reasonable evidence selected in Resource Plan or offered into RSP (3) FERC Accepted Provisional LGIA	Financial Security 1x Study Deposit Readiness options: (1) Executed Contract (2) Reasonable evidence selected in Resource Plan or offered into RSP (3) FERC Accepted, Unsuspended Provisional LGIA	Financial Security 1x Study Deposit Readiness options: (1) Executed Contract (2) Reasonable evidence selected in Resource Plan and applied for CPCN, if required, or selected in RSP (3) FERC Accepted, Unsuspended Provisional LGIA	Financial Security 9x Study Deposit Readiness Reasonable evidence of continued Site Control of the Generating Facility and required Interconnection Facilities (as previously provided at IR submission)
No	Financial Security 2x Study Deposit	Financial Security 3x Study Deposit	Financial Security 5x Study Deposit	Financial Security 7x Study Deposit	

10. Security Requirements (LGIP §10.11.6)

As described above, the Definitive Interconnection Study Process is designed to afford Interconnection Customers flexibility to determine when and how to definitively commit to achieving interconnection and commercial operation of the proposed Generating Facility, while providing all Interconnection Customers increasing certainty as they progress through the Cluster

[110] Revised LGIP, Section 10.11.

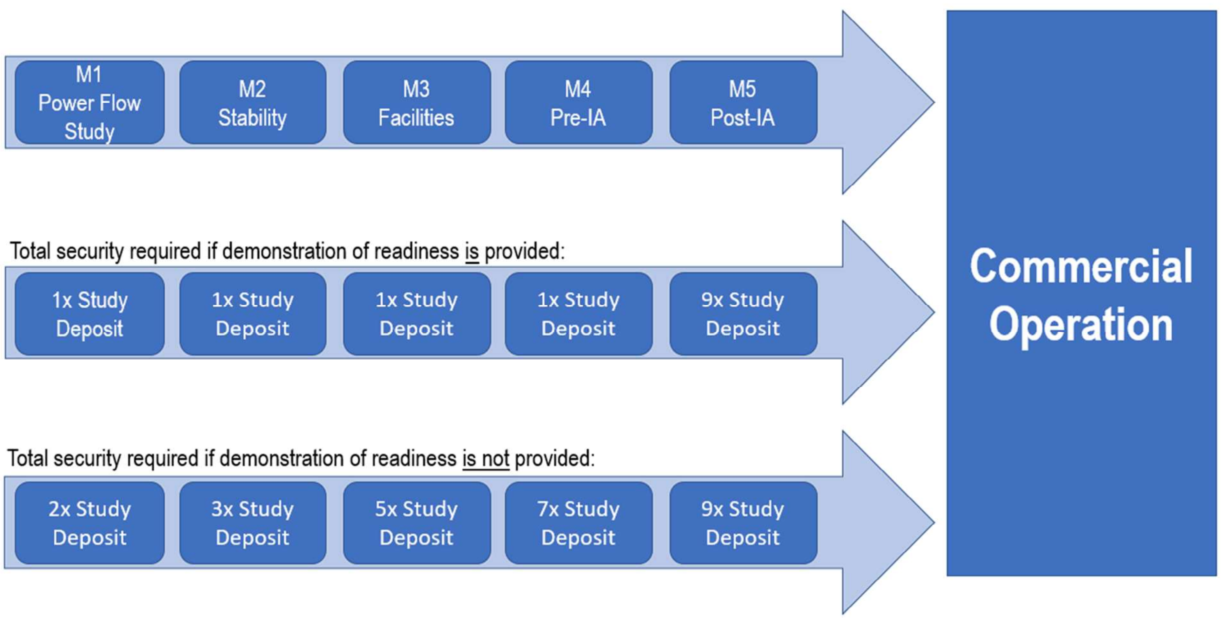
[111] PSCO Order at PP 39, 49-50.

Study process.[112] Requiring increasing security for non-ready projects in conjunction with the imposition of Withdrawal Penalties, where an Interconnection Customer withdraws its Interconnection Request after the DISIS commences, are key components of the Definitive Interconnection Study Process. Because no demonstration of readiness is provided, the additional security helps to prioritize projects under the first-ready, first-served interconnection process that are most committed to achieving commercial operation.

The security amount is dependent on if the Interconnection Customer provided a Readiness Milestone and on the study phase that the Interconnection Customer is entering.[113] All security described below shall be in the form of an irrevocable letter of credit upon which Transmission Provider may draw, or cash. If cash is provided as security, it shall be held in an interest-bearing account. The security is refunded to the Interconnection Customer upon withdrawal, LGIA termination, or Commercial Operation after any final invoice is settled. Security may be drawn upon if costs under this LGIP, including the LGIA, remain unpaid.

Figure 6 showing the security required in each milestone is provided below. The security amount is dependent on if the Interconnection Customer provided a Readiness Milestone and the study phase the Interconnection Customer is entering. All security shall be in the form of (a) cash or (b) an irrevocable letter of credit in a form reasonably acceptable to Transmission Provider.[114]

FIGURE 6
Security Requirements in Definitive Interconnection Study Process



[112] Revised LGIP, Section 10.11.6.

[113] *Id.*

[114] *Id.*

Prior to the close of the Customer Engagement Window, all Interconnection Customers must provide initial security equal to the Section 4.1.2 study deposit amount.[115] The initial security provided in Section 10.8(a.) will be applied towards the amount of security required for Readiness Milestone M5.

An Interconnection Customer may opt to provide security *in lieu* of providing Readiness Milestones M1 through M4, as described above in Sections 10.11.1, 10.11.2, 10.11.3, and 10.11.4. The security provided is applied towards the security amount required for each successive milestone if the Interconnection Customer does not withdraw from the Definitive Interconnection Study Process. For example, the security provided for Readiness Milestone M2 is applied to the amount of security required for Readiness Milestone M3. If an Interconnection Customer is initially required to provide increased security under this Section 10.11.6 because it cannot satisfy the requirements of a Readiness Milestone, but subsequently does satisfy those requirements prior to the next Readiness Milestone, its security should be reduced accordingly.

In lieu of providing a demonstration of readiness for Milestones 1 through 4, the amount of security required is a multiple of the study deposit described in Section 4.1.2 and is in addition to the initial security required for all Interconnection Customers under Sections 10.1 and 10.8(a.). The additional amount of security required for each milestone for Interconnection Customers that do not provide a demonstration of readiness is:

M1 = 1 times the Section 4.1.2 study deposit amount
M2 = 2 times the Section 4.1.2 study deposit amount
M3 = 4 times the Section 4.1.2 study deposit amount
M4 = 6 times the Section 4.1.2 study deposit amount

For clarity, the total (i.e. inclusive of the security required under Section 10.8(a.)) amount of security required for each milestone for Interconnection Customers that do not provide a demonstration of readiness is:

M1 = 2 times the Section 4.1.2 study deposit amount
M2 = 3 times the Section 4.1.2 study deposit amount
M3 = 5 times the Section 4.1.2 study deposit amount
M4 = 7 times the Section 4.1.2 study deposit amount

If the Interconnection Customer withdraws prior to executing an LGIA, the Transmission Provider shall be entitled to use the security as payment for (a) the final invoice for study costs and (b) the Withdrawal Penalty, after which any remaining amount of security shall be returned to Interconnection Customer. If the Interconnection Customer does not withdraw and executes an LGIA, the amount of security shall be increased or decreased as needed in order to reflect the cost estimate for Transmission Provider's Interconnection Facilities and Network Upgrades set forth in Appendix B to the LGIA. Once the LGIA is fully executed, the terms of the LGIA shall govern such security.

[115] Revised LGIP, Sections 10.1, 10.8.a.

The concept of using increasing security as alternative readiness criteria during the Definitive Interconnection Process is utilized by PSCo and was previously approved by the Commission.[116] Moreover, the Duke Transmission Providers' proposed security requirements are substantially similar to PSCo's.[117]

11. Definitive Interconnection Study Process- Withdrawal Penalty (LGIP §4.7.1)

In conjunction with requiring Interconnection Customers to demonstrate increasing levels of readiness or to provide increased security as they progress through the interconnection process, the proposed Definitive Interconnection Study Process also promotes compliance with its "first ready, first studied" framework through imposition of a Withdrawal Penalty where an Interconnection Customer exits the queue and causes harm to other Interconnection Customers.[118] The Withdrawal Penalty structure was developed based upon the PSCo Definitive Interconnection Study Process and is designed to balance the legitimate interests of all Interconnection Customers to have the ability to make the business decision to withdraw from the study process while mitigating the adverse impact of such withdrawals on other Interconnection Customers.[119]

To achieve this balance, there are a number of circumstances where a Withdrawal Penalty would not be imposed under Section 4.7.1. If an Interconnection Customer reaches commercial operation, there is obviously no Withdrawal Penalty. Similarly, if the Interconnection Customer's withdrawal does not harm other customers within the Cluster (such as by requiring re-study or shifting costs to other customers), then there is no Withdrawal Penalty. There would also be no Withdrawal Penalty imposed where (1) the cost responsibility identified for an Interconnection Customer in the current study report associated with new Network Upgrades to the Transmission Provider's Transmission System increased by more than twenty-five percent (25%), compared with the costs identified in the previous report or (2) if the Interconnection Customer withdraws after the Interconnection Facilities Study report is published and before providing Readiness Milestone M5, and the cost responsibility for that Interconnection Customer identified in the Interconnection Facilities Study report increases by more than one hundred percent (100%) compared to the Phase 2 report. More simply, an Interconnection Customer is subject to a Withdrawal Penalty if it elects to withdraw from the interconnection process and the withdrawal has a negative impact on other Interconnection Customers, and where the withdrawing Interconnection Customer's assigned System Upgrade costs did not increase significantly between phases of the DISIS or over the Definitive Interconnection Study Process. This approach fully aligns with PSCo.[120]

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[116] PSCo Order at PP 49-50.

[117] PSCo Order at P 40, fn. 56.

[118] Revised LGIP, Section 4.7.1.

[119] The Withdrawal Penalty concept and structure is closely modeled on the PSCo process. *See* PSCo Order at PP 44-46, 51.

[120] *Id.*

Consistent with the overarching framework of the Definitive Interconnection Study Process, the Withdrawal Penalty structure is designed to incentivize ready projects, as well as the withdrawal of speculative projects early in the study process, so that the potential for harm to other Interconnection Customers is minimized. As described above, no Withdrawal Penalty is imposed if an Interconnection Customer elects to withdraw prior to the DISIS (and providing Readiness Milestone M1). However, during Phase 1, and for both ready and non-ready projects at each subsequent phase, the Withdrawal Penalty is the *higher of* the Interconnection Customer's initial study deposit, or a multiple of the allocated study costs assigned to the Interconnection Customer. Where a Withdrawal Penalty is assigned under Section 4.7.1 requiring a determination that other Interconnection Customers in the Cluster are negatively affected by the Interconnection Customer's withdrawal—Withdrawal Penalty revenues will be used to fund study costs for project in the same Cluster or in a later Cluster.[121]

Calculation of the Withdrawal Penalty amount is dependent on (1) whether a demonstration of readiness was provided, and (2) the phase of the Definitive Interconnection Study Process that the Interconnection Customer is in at the time of withdrawal. (§4.7.1.1). The applicable Withdrawal Penalty amounts for projects participating in the Definitive Interconnection Study Process is depicted in Figure 7 below.

FIGURE 7
Withdrawal Penalty in Definitive Interconnection Study Process

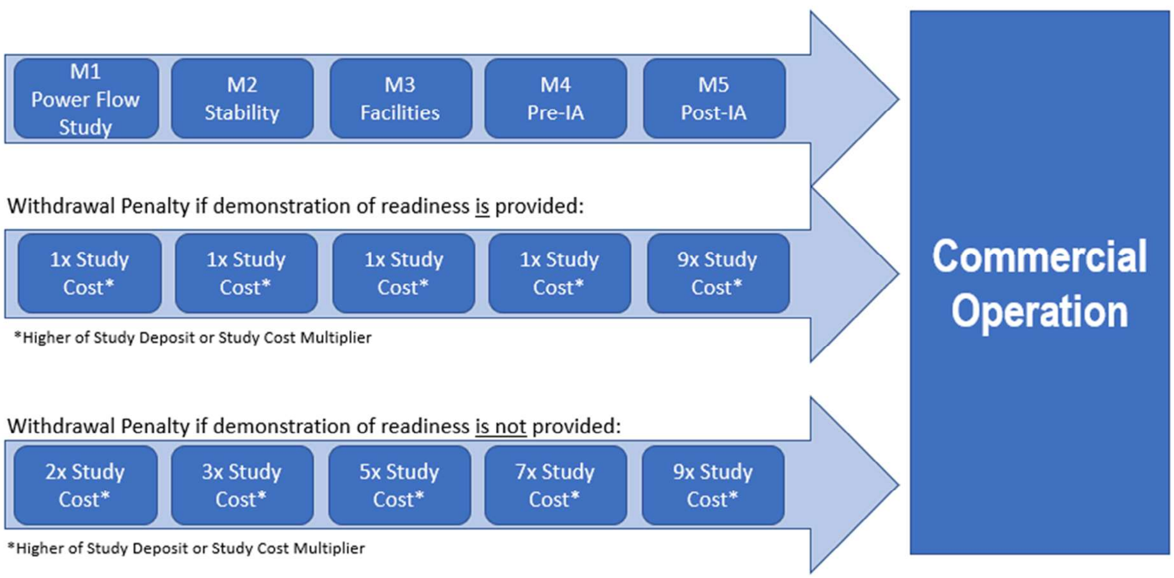
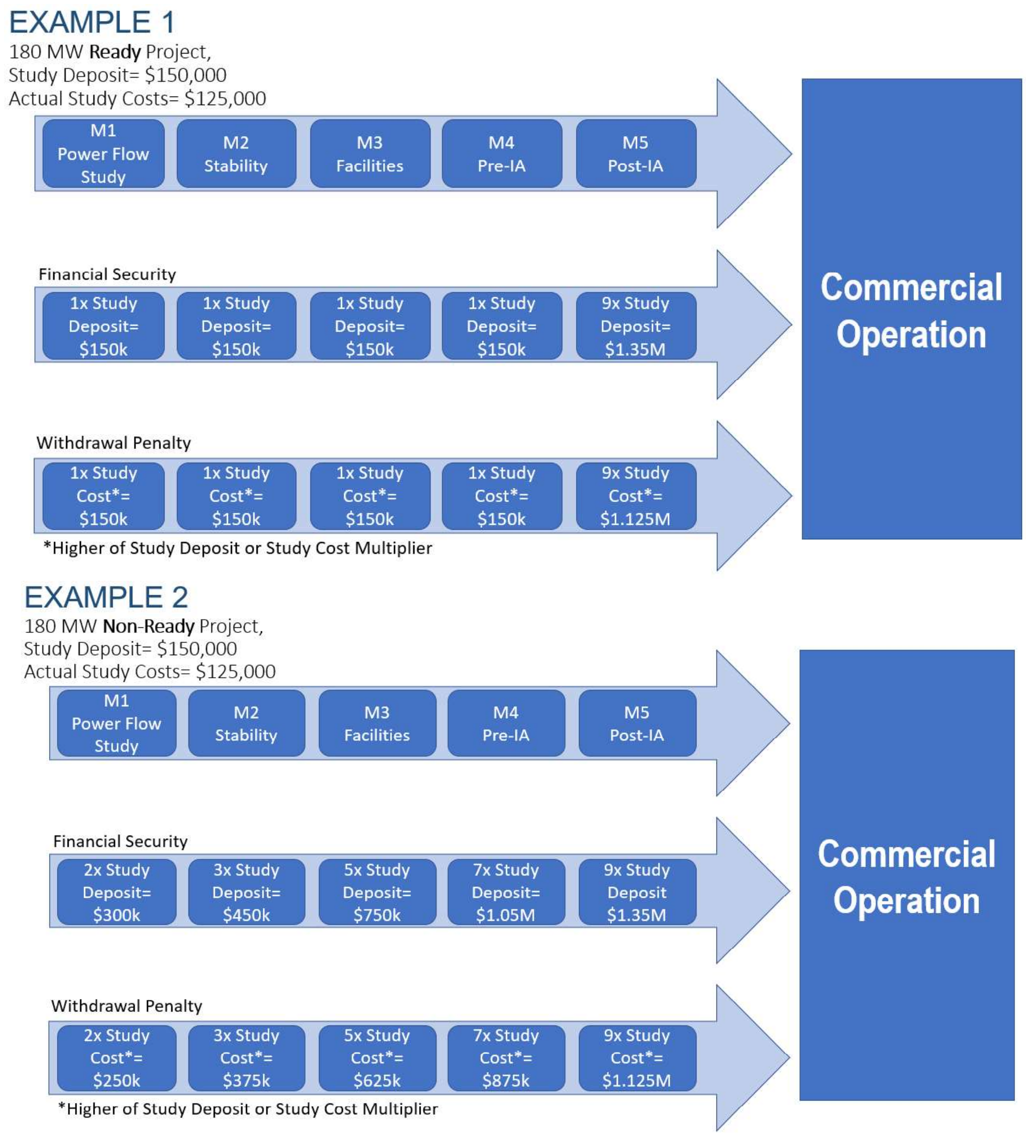


Figure 8 below illustrates how the proposed Withdrawal Penalty structure would apply to both a 180 MW *ready* project (Example 1) vs. a *non-ready* project (Example 2), each with actual study cost totaling $125,000.

[121] Revised LGIP, Section 4.7.1.2.

FIGURE 8
Example of Application of Withdrawal Penalty to Ready and Non-Ready Projects



Withdrawal Penalty revenue will be distributed to Interconnection Customers in a specific Custer in a similar way as study costs are allocated. This distribution will appear as a bill credit on the Interconnection Customers' study invoice but will not exceed the study amount for which the customer is responsible and will not be distributed to the withdrawing customer.[122] To the extent there are additional Withdrawal Penalty revenues after funding not-yet-invoiced studies (e.g. re-studies) for other customers in the same cluster, the Withdrawal Penalty revenue will be distributed to not-yet-invoiced studies for subsequent clusters. (§4.7.1.2). The Commission in the PSCo Order found this use of Withdrawal Penalty revenue "reasonable given

[122] *Id.*

that it offsets the significant cost of re-studies and will not be applied to network upgrades."[123] The same result should apply here.

12. Post DISIS Process (LGIP §11 & §14)

In Revised LGIP Sections 11 and 14 pertaining to the Interconnection Facilities Study process and issuance of the LGIA, the Duke Southeast Utilities have clearly delineated where specific provisions apply to the Definitive Interconnection Study Process after the DISIS concludes. Section 11.4 communicates that the Transmission Provider shall use Reasonable Efforts to complete the study and issue a draft Interconnection Facilities Study report to Interconnection Customer within one hundred fifty (150) Calendar Days after receipt of an executed Interconnection Facilities Study Agreement for all Interconnection Customers within the Cluster. Upon receipt of the Facilities Study report, an Interconnection Customer may provide written comments to Transmission Provider within thirty (30) Calendar Days of issuance.

Within thirty (30) Calendar Days after the comments are submitted or after the Interconnection Customer notifies Transmission Provider in writing that it will provide no comments, Transmission Provider shall tender a draft LGIA.[124] Interconnection Customer shall return the completed draft appendices and execute the LGIA within thirty (30) Calendar Days unless the sixty (60) Calendar Day negotiation period under Section 14.2 has commenced. Pursuant to Section 14.4, the Interconnection Customer shall (a) provide reasonable evidence that continued Site Control exists as defined in Section 1 and (b) post Readiness Milestone M5 (security equal to nine (9) times that Interconnection Customer's share of the Definitive Interconnection Study Process study costs) within fifteen (15) Business Days after receipt of the final LGIA.

13. Dispute Resolution (LGIP §16.6.1)

To facilitate an efficient Definitive Interconnection Study Process, the Duke Southeast Utilities are adding DISIS-specific language governing submission of disputes. Section 16.6.1 makes clear that where an Interconnection Customer opting to participate in a DISIS Cluster initiates a dispute, that Interconnection Customer shall remain obligated to comply with the requirements of Section 10 governing the DISIS process (such as completing Readiness Milestones) if it elects to continue to be considered a part of the DISIS Cluster. While Section 16.6.1 now allows the disputing Interconnection Customer to elect whether to remain in the existing Cluster (an accommodation made to stakeholders), it is critical that all Interconnection Customers progressing through the Definitive Interconnection Study Process achieve their increasing readiness and other commitments in order to reduce potential harm to other Interconnection Customers of future withdrawals.

[123] PSCo Order at P 51.

[124] Revised LGIP, Section 14.1.

C. Informational Interconnection Study (LGIP §3)

To support the Definitive Interconnection Study Process where Interconnection Customers are required to make increased financial and project readiness commitments earlier in the interconnection process, the Duke Southeast Utilities propose that Interconnection Customers be able to preliminarily evaluate interconnection feasibility and cost by requesting a customizable Informational Interconnection Study prior to submitting an Interconnection Request. New LGIP §3 details the Informational Interconnection Study process available to study prospective Generating Facilities.

The Informational Interconnection Study concept was approved as part of PSCo's queue reform process[125] and is designed to aid Interconnection Customers considering entering the Definitive Interconnection Study Process in their preliminary business decision-making regarding the feasibility, timing and cost of interconnecting a planned Generating facility prior to submitting an Interconnection Request.[126] Consistent with this intended purpose, the LGIP provides that the new Informational Interconnection Study process is available to prospective Interconnection Customers where the Transmission Provider has opted to transition to administering a Definitive Interconnection Study Process, while the pre-existing Optional Interconnection Study process established under Order No. 2003 remains available where the Transmission Provider is administering the Serial Interconnection Study Process.[127]

The Informational Interconnection Study will be performed solely for informational purposes based upon assumptions provided by the Interconnection Customer in the Informational Interconnection Study request form.[128] Within five Business Days after receipt of a request for an Informational Interconnection Study, the Transmission Provider will provide the prospective Interconnection Customer an Informational Interconnection Study Agreement in the form of Appendix 2 to the LGIP, including a non-binding good faith estimate of the timing and cost of completing the Informational Interconnection Study.[129]

A request to perform an Informational Interconnection Study does not establish a Queue Number and the prospective Interconnection Customer must still apply to interconnect to the Transmission Provider's System under the Definitive Interconnection Study Process during a future DISIS Request Window.[130] There is also no queue for Informational Interconnection Studies.[131] However, to ensure equitable access for all Interconnection Customers, any one Interconnection Customer (including affiliates) shall have no more than five requests for Informational Interconnection Study reports pending at one time.[132]

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[125] PSCo Order at P 11.

[126] Revised LGIP, Section 3.2.

[127] Revised LGIP, Section 2.1.

[128] The Informational Interconnection Study Request Form is included as Appendix 1 to the Revised LGIP.

[129] The Informational Interconnection Study Agreement is included as Appendix 2 to the Revised LGIP.

[130] Revised LGIP, Section 3.2.

[131] Revised LGIP, Section 5.2.

[132] Revised LGIP, Section 3.1.

The Informational Interconnection Study allows a prospective Interconnection Customer to study almost any interconnection scenario, including the evaluation of different points of interconnection, voltage, and size of a potential Generating Facility. The optional Informational Interconnection Study process may also be used to evaluate the impact of other clustered generation on a specific Interconnection Request. For example, an Informational Interconnection Study may identify the costs associated with a 50 MW request, assuming 150 MW of other requests are proposed in a future DISIS Cluster on the same transmission line or in the same area of the Transmission Provider's Transmission System.

The Informational Interconnection Study scope may be limited, much like a traditional Feasibility Study, or may be expanded to encompass a full System Impact Study analysis that includes fully analyzing the power-flow, voltage, stability, and short circuit impacts of the proposed Generating Facility on the System.[133] Importantly, Informational Interconnection Studies are non-binding and for informational purposes only and a prospective Interconnection Customer must still enter the Interconnection queue during a DISIS Request Window and be studied as part of a DISIS Cluster Study.[134] Because of the varied scope of these studies, the actual costs and time to complete the Informational Interconnection Study may vary.

Consistent with PSCo's approved Informational Interconnection Study process, the Duke Southeast Utilities propose to require a $10,000 deposit for the Informational Interconnection Study subject to true-up based on actual costs.[135] Based upon the scope of study agreed upon between the Transmission Provider and prospective Interconnection Customer, the Transmission Provider will provide a non-binding good faith estimate of the timing and cost of completing the Informational Interconnection Study at the time the Transmission Provider transmits the Informational Interconnection Study Agreement for execution.[136]

D. Transitional Process (LGIP §7)

Transitioning the interconnection process from a serial process to the Definitive Interconnection Study Process will be critical to successfully implementing queue reform. To achieve an effective transition, the Duke Transmission Providers must know for certain that all Interconnection Customers queued ahead of a future DISIS Cluster are definitively committed to interconnection. Put another way, a transition process that allows speculative or non-ready Interconnection Customers to remain in the serial queue will cause an uncertain or unstable Base Case, potentially resulting in cascading re-studies under the transition process and in the initial DISIS Cluster. This result would both clog the queue and frustrate the purpose of queue reform implementation. To solve for these issues, the Duke Southeast Utilities propose a transitional study process to occur prior to the initiation of the Definitive Interconnection Study Process in order to move definitively ready Interconnection Requests to commercial operation or,

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[133] Revised LGIP, Section 3.2.

[134] Revised LGIP, Section 4.1.2 ("Interconnection Customers evaluating different options (such as different sizes, sites, or voltages) are encouraged but not required to use the Informational Interconnection Process (Section 3) before entering the Definitive Interconnection Study Process").

[135] PSCo Order at P 10.

[136] Revised LGIP, Section 3.2.

conversely, to move speculative Interconnection Requests from the current serial process into the upcoming Definitive Interconnection Study Process.

The Duke Southeast Utilities' objective, and the goal of many stakeholders, is to provide an orderly transition that allows the Duke Carolinas Utilities to complete the Transitional Serial process and significantly progress through the Transitional Cluster study in 2021 followed by the initial DISIS Request Window opening on January 1, 2022 and closing on June 30, 2022, as provided for in the Revised LGIP. Accomplishing an efficient transition to the Definitive Interconnection Study Process will require significant commitments from Interconnection Customers, efficient administration by the Duke Carolinas Utilities, and the minimization of the potential for late stage withdrawal or re-study of Interconnection Requests electing to enter the transitional study process.

To accomplish these objectives, the Duke Southeast Utilities' Revised LGIP proposes an expedited transition process for Interconnection Customers in the current queue by providing three options: (1) a Transitional Serial Study Process, (2) a Transitional Cluster Study Process, or (3) withdrawal from the queue and the option to reenter the queue and participate in a future DISIS Cluster. (§1.10).

1. Procedure for Initiating Transition to Definitive Interconnection Study Process

Section 7 of the LGIP is designed to efficiently and fairly transition existing Interconnection Customers into the Definitive Interconnection Study Process after Commission approval and at a time that is most appropriate for DEC, DEP, and DEF based upon their particular circumstances. As explained in Section II above, the Duke Carolinas Utilities have an urgent need to implement queue reform immediately for both FERC-jurisdictional and state-jurisdictional Interconnection Customers, while DEF plans to continue to administer the serial interconnection study process for the immediate future. Accordingly, LGIP §7 has been developed with significant stakeholder input to provide a clear and transparent procedural process for each Duke Transmission Provider to implement the queue reform transitional process after the Commission approves these revisions to the Joint OATT.

Section 2.1 of the Revised LGIP is designed to provide clear notice to prospective Interconnection Customers to notify them as to which process (the legacy Serial Interconnection Study Process or the Definitive Interconnection Study Process) will be administered by each Duke Transmission Provider. Section 2.1 directs prospective Interconnection Customers to Section 7 that details the "Transition Procedures for [the] Definitive Interconnection Study Process," and provides that the Duke Transmission Provider initiating the transition to the Definitive Interconnection Study Process will publicize its intent to transition by posting notice to the OASIS website (the date of posting to be known as the "Cluster Study transition notice date") and providing written notice of the planned transition to all current Interconnection Customers. Through this notification process, both current and prospective Interconnection Customers will be informed of whether a specific Duke Transmission Provider is administering a Serial Interconnection Study process or a Definitive Interconnection Study process under the Revised LGIP.

Upon a Duke Transmission Provider giving notice of its intent to transition to the Definitive Interconnection Study Process, as addressed further below, any Interconnection Customer that has received a Queue Number but has not executed an Interconnection Agreement prior to the Cluster Study transition notice date may elect to be studied under the Transition Procedures by meeting the requirements to enter either the Transitional Serial study Process or Transitional Cluster study process.[137] An Interconnection Customer electing to complete the transitional process must notify the interconnecting Duke Transmission Provider and meet all applicable transitional process readiness requirements within sixty Calendar Days of the Transmission Provider's delivery of written notice of its transition to the Definitive Interconnection Study Process (which shall occur after the Cluster Study transition notice date). If a currently queued Interconnection Customer elects not to transition using either the Transitional Serial or Transitional Cluster process, as further described below, then that Interconnection Customer will be withdrawn from the queue after the sixty Calendar Day notice period ends and will have the option to reenter through a future DISIS Cluster.

2. Eligibility for Transitional Process

Eligibility for the queue reform transitional process, specifically the Transitional Serial Study Process, has been a topic of significant interest and discussion amongst certain stakeholders with existing projects in the interconnection queue. As detailed further below, an existing Interconnection Customer is eligible for the Transitional Serial process if it is in advanced stages of the interconnection process, meaning the Interconnection Customer has completed a System Impact Study (resulting in a determination of system impacts and associated assignment of Network Upgrades) and has executed a Facilities Study Agreement as of the Cluster Study transition notice date.[138] However, where an Interconnection Customer has not completed a System Impact Study and its Network Upgrades are not definitively determined, the Interconnection Customer may elect to enter into the Transitional Cluster study process or to withdraw.

The proposed transition process eligibility requirements for Interconnection Customers seeking to continue in the serial process are consistent with the queue reform transition eligibility requirement recently approved for PSCo and PacifiCorp, in terms of 1) requiring the Interconnection Customer to have received definitively-assigned Network Upgrades through a System Impact Study and have executed a Facilities Study Agreement; 2) requiring the Interconnection Customer to provide a deposit or security definitively committing to funding those Network Upgrades in order to enter the serial transition process; and 3) facilitating a definitive Base Case inclusive of interconnected Generating Facilities, Generating Facilities with executed Interconnection Agreements, and Generating Facilities that demonstrate definitive readiness upon entering the transitional serial process.[139] Specific to PSCo's proposed transition process, the Commission determined it to be a just and reasonable means to resolve its interconnection queue backlog because PSCo considered the interests of interconnection customers with requests far along in the process, as well as all other existing interconnection

[137] Revised LGIP, Section 7.

[138] Revised LGIP, Section 7.1.

[139] PSCo Order at P 67; PacifiCorp Order at PP 144-149.

customers at the time queue reform was proposed. In particular, the Commission noted that PSCo allowed more advanced projects that had received a System Impact Study report and executed a Facilities Study Agreement to move forward in a timely fashion under a transitional serial process if they choose, while allowing other less advanced projects still in System Impact Study or earlier to move ahead under a transitional cluster process.[140] Similarly, for PacifiCorp, the Commission approved a transition process to account for the significant amount of interconnection requests currently in PacifiCorp's queue and to most efficiently process those requests while also moving forward with the more efficient Cluster process.[141] The Duke Southeast Utilities have adhered to these precedents for purposes of establishing eligibility for the transitional processes.

The Duke Southeast Utilities' Revised LGIP also provides additional flexibility to benefit Interconnection Customers in the transition. First, the Duke Carolinas Utilities —which are planning to undertake the queue reform transition as soon as possible—have not suspended studying Interconnection Customers currently in the queue and have proposed eligibility for the transitional process to be determined after Commission approval of the Revised LGIP and as of the date a Duke Transmission Provider issues the Cluster Study transition notice (as opposed to the tariff filing date used by PSCo[142]). Thus, new projects may become eligible for the Duke Carolinas Utilities' Transitional Serial process (or may receive an Interconnection Agreement thereby avoiding the transition altogether) between now and the time of Commission approval and the Duke Carolinas Utilities' posting of the Cluster Study transition notice to OASIS. Second, the Duke Southeast Utilities' proposed transitional process also provides increased optionality to later stage projects that have completed System Impact Study and been definitively assigned Network Upgrades to (a) continue with the serial process under Transitional Serial; or (b) transition into the Transitional Cluster to be restudied as part of the Transitional Cluster DISIS and to be allocated Network Upgrade costs versus being responsible for the costs directly assigned to the Interconnection Customer in its original System Impact Study Report.

The Revised LGIP's eligibility requirements for the Transitional Serial process should be approved as reasonable and necessary to efficiently transition to the Definitive Interconnection Study Process. Allowing projects earlier in the study process to continue to be studied serially would not be reasonable and would fundamentally frustrate the objective of queue reform by creating uncertainty and instability in the Transitional Cluster Base Case model (which is intended to be commenced in parallel and to assume all Transitional Serial projects achieve commercial operation). Similarly, imposing both financial and commercial readiness requirements on projects entering Transitional Serial ensures they are ready projects that are definitively committed to proceeding to commercial operation is necessary effectively transitioning to the Definitive Interconnection Study Process.

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140 PSCo Order at PP 65, 67.

141 PacifiCorp Order at PP 144-49.

142 PSCo Order at P 24.

E. Transitional Serial Process (LGIP §7.1)

An Interconnection Customer is eligible to enter the Transitional Serial Process if the Interconnection Customer has (a) a final System Impact Study Report identifying any required Transmission Provider Interconnection Facilities and Network Upgrades, (b) executed a Facilities Study Agreement prior to the Cluster Study transition notice date, and (c) met the readiness requirements prescribed in Section 7.1.[143] These requirements essentially allow late stage projects to definitively commit to previously assigned Network Upgrades under a completed System Impact Study, and to then continue through the serial study process to an Interconnection Agreement, assuming such projects demonstrate readiness. The Duke Southeast Utilities' proposed Transitional Serial Study Process is described fully in Section 7.1.

The financial and non-financial readiness requirements in Section 7.1 ensure that only ready and non-speculative projects proceed through the Transitional Serial process. To ensure that Interconnection Customers eligible for the Transitional Serial Process are truly ready to connect, they must demonstrate readiness similar to projects under the DISIS Cluster described above. Because these Interconnection Customers know the Interconnection Facilities and Network Upgrades and associated costs required to interconnect, the Interconnection Customers opting to enter the Transitional Serial Process must provide security equal to 100% of the Interconnection Facilities and Network Upgrade costs identified in the System Impact Study.[144] If the Interconnection Customer withdraws the Interconnection Request or otherwise does not reach Commercial Operation, the security will be refunded but the Interconnection Customer will be subject to a Withdrawal Penalty equal to 9 times the Interconnection Request's total study costs.[145]

In addition to providing security, Transitional Serial projects must also demonstrate exclusive Site Control for the entire Generating Facility and the Interconnection Customer's Interconnection Facilities up to the Point of Interconnection to the Utility's System.

Last, and in addition to the security for assigned Interconnection Facilities and Network Upgrades Costs and demonstration of Site Control, Interconnection Customers opting to enter the Transitional Serial Process must provide one of the following readiness demonstrations:

i. A contract, binding upon the parties to the contract, for sale of the Generating Facility's energy, or the entire constructed Generating Facility, where the term of sale is not less than five (5) years, or

ii. Reasonable evidence that the Generating Facility is included in a Resource Planning Entity's Resource Plan or has received a contract award in a Resource Solicitation Process, or

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[143] Revised LGIP, Section 7.1.

[144] For purposes of Transitional Serial security for Network Upgrades and Interconnection Facilities, the Duke Carolinas Utilities have also agreed to consider forms of security proposed by the Interconnection Customer and reasonably acceptable to the Transmission Provider for amounts above the potential Withdrawal Penalty.

[145] Revised LGIP, Section 7.1.

iii. An executed Provisional Large Generator Interconnection Agreement filed with FERC. Such an agreement shall not be suspended and shall include a commitment to construct the Generating Facility.

These requirements to transition are just and reasonable because they provide evidence that the Transitional Serial projects are truly ready to expeditiously proceed to an Interconnection Agreement and commercial operation. If Transitional Serial projects are not ready, then Duke Transmission Provider would not be able to establish a definitive Base Case for the Transitional Cluster thereby harming other ready projects.

The Duke Southeast Utilities' Transitional Serial Process only varies from the Transitional Serial Study Process approved in PSCo's interconnection queue reform proceeding in one limited respect. At stakeholders' request, Section 7.1 incorporates the Withdrawal Penalty exceptions located in §4.7.1 and generally applicable to the Definitive Interconnection Study Process into the proposed Transitional Serial Process.[146] Duke proposes this variation from PSCo to (1) address stakeholder feedback requesting additional flexibility and further mitigation of risks and consequences associated with withdrawal during the Transitional Serial Process and (2) to align with similar exceptions provided in its state-approved Transitional Serial Process. The Duke Transmission Providers believe this variance from PSCo is highly unlikely to be implicated as a result of the significant upfront readiness required to enter the Transitional Serial Process as well as the improbability of a very significant 100%+ increase in serially assigned Network Upgrade and Interconnection Facilities costs between the serial System Impact Study Report and serial Facilities Study Report.[147] Accordingly, the Duke Southeast Utilities submit that their Transitional Serial Process is consistent with or superior to the *pro forma* LGIP.

F. Transitional Cluster Process (LGIP §7.2)

The Transitional Cluster Process was another area of significant stakeholder interest and is one area that has evolved significantly from the PSCo queue reform framework. Through the stakeholder process, many stakeholders expressed concerns about mandating significant readiness requirements to enter the Transitional Cluster without information from the Duke Transmission Providers about their potentially assigned Network Upgrades. This lack of information is in part due to the fact that these early-stage projects have not completed System Impact Study under the existing serial study process and in part due to the fact that the Duke Transmission Providers cannot identify system impacts and provide preliminary Network Upgrade cost estimates without knowing which projects will enter the Transitional Cluster. In an effort to address these concerns, the Duke Transmission Providers have significantly restructured the Transitional Cluster Study process from a "significant financial readiness to enter, single study" Transitional Cluster, similar to PSCo, to a "lower readiness to enter, multi-phased" Transitional Cluster Process more similar to DISIS.[148] The Transitional Cluster will unquestionably take longer than the PSCo Transitional Cluster and, potentially, will require some

[146] Revised LGIP, Section 4.7.1.

[147] Revised LGIP, Section 4.7.1. This is applied to Transitional Serial by using the Interconnection Customer's previously issued System Impact Report as the base cost for assessing the increase in the Transitional Serial Facilities Study Report under subsection (3) of the exemption.

[148] Revised LGIP, Section 7.2.

amount of re-study as Interconnection Customers exit after the Transitional Cluster Phase 1 study; however, the Duke Southeast Utilities support this proposal as just and reasonable and responsive to stakeholder feedback.

The Duke Southeast Utilities have also adjusted the definitive readiness requirements in response to stakeholder feedback to provide current Interconnection Customers that desire to enter the Transitional Cluster and believe their project to be "near-ready" but not capable of demonstrating readiness an alternative security-in-lieu-of-project-readiness path to both enter and proceed through the Transitional Cluster. The Duke Transmission Providers found this variation from PSCo (which mandated all projects demonstrate definitive project readiness to enter the Transitional Cluster) to be reasonable and appropriate to accommodate stakeholder feedback and to address concerns about mandating definitive project readiness at the outset of the multi-phased Transitional Cluster.

The Duke Southeast Utilities also incorporated stakeholder input in terms of the level of financial commitment required and materially reduced these security requirements for ready projects as compared to PSCo. Specifically, PSCo required transitional cluster projects to make a $5 million study deposit to enter the PSCo transitional cluster study.[149] In the Duke Southeast Utilities' proposed Transitional Cluster Study Process, ready projects will be required to make a supplemental Interconnection Request study deposit, if necessary, to increase the Interconnection Customer's total study deposit to equal the amount required under Section 4.1.2 of the LGIP (maximum deposit equaling $250,000 for requests ≥200 MW) but are not required to make a comparable security readiness commitment (a lesser $3 million amount discussed below) until Phase 2. Non-ready projects must make an initial $3 million security commitment to enter Phase 1 and then must make an additional $2 million security commitment if they elect to proceed to Transitional Cluster Phase 2. In addition, the Duke Southeast Utilities have agreed to extend the time for Interconnection Customers to meet the Transitional Cluster Readiness Milestones and to execute a Transitional Cluster System Impact Study Agreement from thirty calendar days to sixty calendar days.[150] During this sixty day period, the Duke Southeast Utilities will also host a general informational meeting for projects considering whether to enter the Transitional Cluster or withdraw and later enter a DISIS Cluster.

1. Overview of Multi-Phased Transitional Cluster

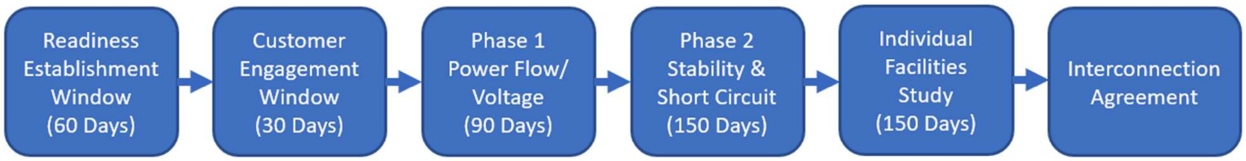
To enter the Transitional Cluster Study Process, Interconnection Customers must (1) have an assigned Queue Position prior to the Cluster Study transition notice date; (2) meet the Transitional Cluster readiness or security requirements prescribed in Section 7.2.1, and (3) execute a Transitional Cluster Study Agreement. All Interconnection Requests that opt for this path will be considered to have an equal Queue Position and will be studied in a single Transitional Cluster. The costs of the study and the identified facilities will be allocated in the same manner as costs are allocated for DISIS Clusters pursuant to Section 10.4 of the Revised LGIP.

[149] PSCo Order at P 65, fn. 83.

[150] Revised LGIP, Section 7.

In response to stakeholder feedback, the Duke Southeast Utilities have significantly redesigned the PSCo Transitional Cluster to a multi-phase study process where more definitive readiness commitments are not required until the Interconnection Customer elects to proceed to Phase 2(more similar to the full DISIS process).

FIGURE 9
Multi-phase Transitional Cluster Study Process



The Transitional Cluster Study Process will begin with a thirty calendar day Customer Engagement period for all Interconnection Customers electing to enter the Transitional Cluster. After the Transitional Cluster Customer Engagement Window, Phase 1 will consist of a power flow and voltage analysis occurring over a 90 calendar day period. After completion, the Duke Southeast Utilities will issue a Transitional Cluster Study Phase 1 Report for Interconnection Customers to evaluate whether to proceed through Phase 2 or withdraw from the queue. In response to stakeholders, the Duke Southeast Utilities have agreed to provide a second, 30 calendar day Customer Engagement window and host a meeting to discuss the results of the Transitional Cluster Study Phase 1 Report. By providing this second Customer Engagement Window, Interconnection Customers will receive additional time to decide whether to make the more significant financial commitments to proceed through Phase 2 of the Transitional Cluster and meet the increasing Readiness Milestones necessary to complete the Transitional Study Process.

An Interconnection Customer electing to withdraw prior to the Phase 2 study will be assigned only its allocated Transitional Cluster Study Phase 1 study costs subject to the withdrawal process under Section 4.7.1, but will not be subject to any Withdrawal Penalty.[151] An Interconnection Customer electing to proceed with Phase 2 of the Transitional Cluster is viewed as definitively committed and will be required to submit security equal to $3 million for ready projects or a total of $5 million for projects that cannot demonstrate readiness to enter Phase 2, as further described below.[152] If an Interconnection Customer withdraws after Phase 2 commences or otherwise does not reach Commercial Operation, a Withdrawal Penalty equal to nine times the Interconnection Customer's total study costs will be assessed under Section 7.2.6 unless the Transmission Provider determines consistent with Good Utility Practice that a Withdrawal Penalty should not be assigned pursuant to Section 4.7.1.[153]

Transitional Cluster Study Phase 2 will consist of an updated power flow/voltage analysis (if necessary), stability analysis and short circuit analysis completed pursuant to Section 7.2.3.

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[151] Revised LGIP, Section 7.2.1.

[152] Revised LGIP, Sections 7.2.3.a; c.iv.

[153] Revised LGIP, Sections 7.2.3, 7.2.6.

The administering Transmission Provider will use reasonable efforts to complete the Phase 2 analysis within 150 calendar days. The results of this analysis will be summarized in the Transitional Cluster Study Phase 2 Report which will identify the Interconnection Facilities and Network Upgrades expected to be required for the Transitional Cluster to interconnect, and will also provide a non-binding good-faith estimate of cost responsibility and a non-binding good-faith estimated time to construct for each transitional Interconnection Customer.

The Duke Transmission Provider administering the Transitional Cluster will determine whether re-study of the Transitional Cluster is required pursuant to the procedures outlined in Section 10.10 prior to executing the Facilities Study Agreement and returning it to the Interconnection Customers.[154] However, the Duke Southeast Utilities do not envision re-studies of the Transitional Cluster to be likely after Phase 2 commences as all projects entering Phase 2 of the Transitional Cluster are required to demonstrate definitive readiness or make a significant financial commitment totaling $5 million. A withdrawing Interconnection Customer would also be subject to the significant Withdrawal Penalty of nine times the Interconnection Request's total study cost.[155] Duke will complete Facilities Study for all Transitional Cluster projects pursuant to Section 7.2.4 and then proceed to an LGIA under Section 7.2.5.

2. Readiness and Financial Commitments under Transitional Cluster

As introduced above, the Duke Southeast Utilities have significantly evolved the Transitional Cluster process from the PSCo "significant financial readiness to enter, single study" construct in response to stakeholder feedback. However, the proposed Transitional Cluster Study still imposes significant readiness requirements and is designed to establish a path for Interconnection Customers to demonstrate their definitive commitment to proceed to an LGIA and to achieve commercial operation.

For eligible Interconnection Customers electing to enter Phase 1 of the Transitional Cluster, Section 7.2.1 of the Revised LGIP specifically requires projects to meet each of the following to be included in the Transitional Cluster, in addition to signing a Transitional Cluster Study Agreement:

- Request either ERIS or NRIS; provided, however, any Interconnection Customer requesting NRIS may also request that it be concurrently studied for ERIS but must make a designation of either ERIS or NRIS by no later than five business days after the Transitional Cluster Study Phase 2 Report is issued;[156]

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[154] See Revised LGIP, Section 7.2.4.

[155] See Revised LGIP, Section 7.2.3.

[156] The Duke Transmission Providers have made limited modifications to the PSCo Transitional Cluster Study process to provide Interconnection Customers with the flexibility required per Order No. 2003 to proceed with NRIS, ERIS or both up until 5 business days after the Transitional Cluster Study Phase 2 Report is issued. Duke Transmission Providers' modifications are contained in Section 7.2.1(b) of the Revised LGIP. The language is almost identical to the language adopted by PacifiCorp in Section 2.1.5 of Attachment W which was approved by the Commission. *PacifiCorp Order* at P 66 ("we find that PacifiCorp's modified proposal in its Deficiency Response to allow interconnection customers to be studied for both NRIS and ERIS in the initial Cluster Study is consistent with or superior to the *pro forma* LGIP. … We also find that PacifiCorp's proposed requirement that

- Make a supplemental Interconnection Request study deposit in cash, if necessary, to increase the Interconnection Customer's total study deposit to equal the amount required under Section 4.1.2 of the LGIP; and
- Demonstrate that Interconnection Customer has exclusive Site Control for the entire Generating Facility and all required Interconnection Facilities to the Point of Interconnection to the Transmission Provider's System. Interconnection Customer may provide a cash deposit equal to $20,000 plus $500/MW in lieu of Site Control to enter Transitional Cluster Study Phase 1.[157]

To demonstrate readiness (or to establish security in lieu of readiness) for Phase 1 of the Transitional Cluster, an Interconnection Customer must also provide one of the following:

a. Executed term sheet (or comparable evidence) related to a contract, binding upon the parties to the contract, for sale of the Generating Facility's energy, or the entire constructed Generating Facility, where the term of sale is not less than five (5) years, or

b. Reasonable evidence that the Generating Facility is included in a Resource Planning Entity's Resource Plan or Resource Solicitation Process, or

c. An executed Provisional Large Generator Interconnection Agreement filed with FERC that is not in suspension with 1) a commitment to construct the facility, 2) a Commercial Operation Date no later than 2024 and 3) a security deposit in addition to amount required under Section 4.1.2 where the total security deposit represents a reasonable estimation of the potential costs that could be ultimately allocated to the project in the Transitional Cluster Study, or

d. Security equal to three million dollars ($3,000,000).[158]

The following Figure provides an overview of the increasing security required for ready and non-ready Interconnection Customers progressing through the Transitional Cluster Process.

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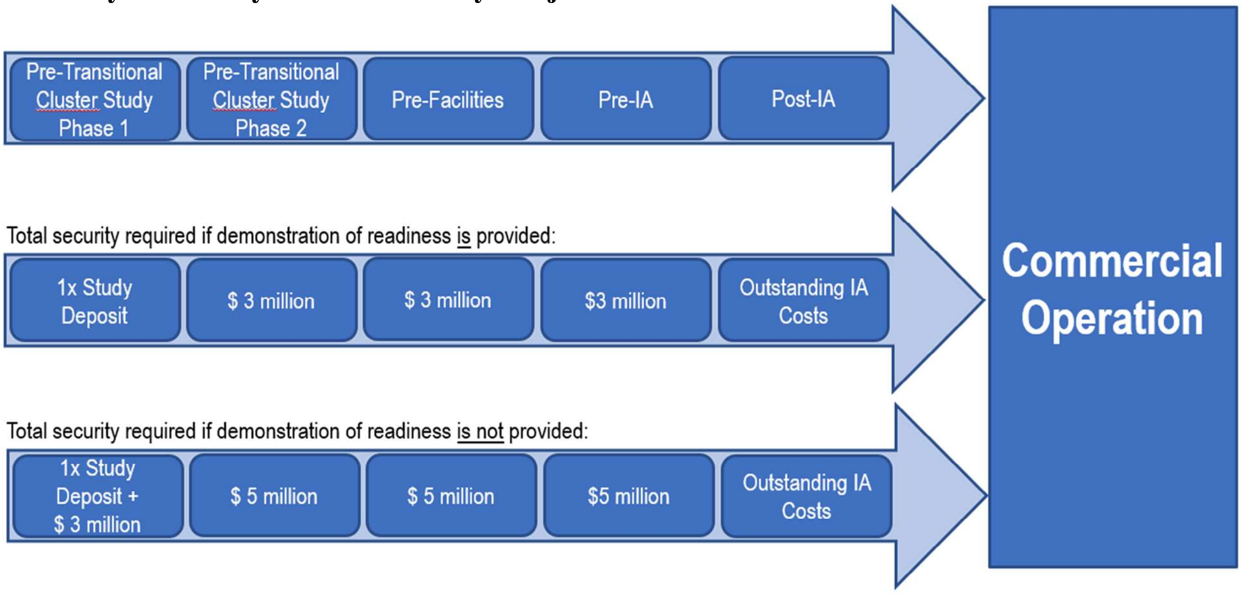
customers make a choice on their service level no later than five business days after the Cluster Study Report Meeting under Section 42.4(c) is reasonable.")

[157] A deposit in lieu of Site Control is not accepted for later Phases of the Transitional Cluster Study Process.

[158] See Revised LGIP, Section 7.2.1.e.

FIGURE 10
Security for Ready and Non-Ready Projects in Transitional Cluster Process



These are reasonable and meaningful readiness requirements that the Duke Transmission Providers believe will incent only ready or near-ready projects to enter the Transitional Cluster. However, similar to DISIS, the Duke Transmission Providers also desire to ensure that any speculative projects that enter the Transitional Cluster to obtain information about their potential Network Upgrade costs within the Cluster are also incented to withdraw prior to the Duke Transmission Providers commencing the more detailed and time-intensive Phase 2 study process. Accordingly, no Withdrawal Penalty is imposed for Interconnection Customers that elect to exit prior to Phase 2 of the Transitional Cluster Process commencing and any such customer will only be assigned its allocated study costs. As introduced above, to enter Phase 2, the Duke Southeast Utilities Transitional Cluster requires Interconnection Customers to either (a) make a significant financial commitment of $3 million and demonstrate definitive readiness (equivalent to M3 of the Definitive Interconnection Study Process) or (b) provide significant additional security ($2 million for a total of $5 million) if the Interconnection Customer cannot demonstrate definitive readiness prior to Phase 2 commencing but desires to continue to proceed through the Transitional Cluster process.[159]

If the Interconnection Customer withdraws after entering Transitional Cluster Phase 2 and prior to executing an LGIA, the Transmission Provider shall be entitled to use the security as payment for (a) the final invoice for study costs and (b) the Withdrawal Penalty, after which any remaining amount of security shall be returned to Interconnection Customer.[160] If the Interconnection Customer does not withdraw and executes an LGIA, the amount of security shall be increased or decreased as needed in order to reflect the cost estimate for Transmission Provider's Interconnection Facilities and Network Upgrades set forth in Appendix B to the

[159] See Revised LGIP, Section 7.2.3. For purposes of Transitional Cluster, the Duke Carolinas Utilities have also agreed to consider forms of security proposed by the Interconnection Customer and reasonably acceptable to the Transmission Provider for amounts above the potential Withdrawal Penalty.

[160] Revised LGIP, Section 7.2.3.

LGIA. Once the LGIA is fully executed, the terms of the LGIA shall govern such security. Due to the significant security already provided, the Readiness Milestone M5 required in Section 14.4 of the Definitive Interconnection Study Process will not apply to Interconnection Customers participating in the Transitional Cluster Study.[161]

If an Interconnection Customer fails to meet any of the above requirements and withdraws at any time after Phase 2 commences, that Interconnection Customer shall be deemed withdrawn from the queue and subject to a Withdrawal Penalty equal to nine times the Interconnection Customer's total study costs, as identified in Revised LGIP Section 7.2.6.

The increasing readiness requirements are just and reasonable for the Duke Transmission Providers' Transitional Cluster Study process and are designed to ensure other ready projects included in the Transitional Cluster or future DISIS Clusters will not be harmed by withdrawals late in the Transitional Cluster Process. The interests of potentially withdrawing projects will also be protected as a Withdrawal Penalty will not be imposed where a Withdrawal Penalty would not be imposed under the Definitive Interconnection Study Process. Accordingly, the Duke Southeast Utilities support this more flexible multi-phased Transitional Cluster as just and reasonable and consistent with or superior to the *pro forma* LGIP, as well as prior transitional cluster mechanisms approved for other Transmission Providers.

V. INFORMATIONAL REPORT

The Duke Southeast Utilities commit to file an informational report with the Commission after two years. The report will include the same elements as the Commission directed in the PacifiCorp proceeding:[162]

- an analysis of whether the queue reforms have improved study timelines for Interconnection Customers,
- an analysis of the commercial readiness criteria,
- information on withdrawals from the interconnection queue, specifically (1) the withdrawal penalty received; (2) the allocation of the withdrawal penalty, and (3) the number of withdrawals, and
- whether improvements can or should be made to the revised process.

[161] Revised LGIP, Section 7.2.5.

[162] PacifiCorp Order at PP 21, 55.

VI. CONTENTS OF FILING

The following documents are included in this filing in addition to the relevant tariff records:

- This transmittal letter;
- Clean copy of Attachment J (LGIP);
- Marked copy of Attachment J (LGIP);
- Exhibit A – Direct Testimony of Ken Jennings;
- Exhibit B – Direct Testimony of Dewey S. Roberts;
- Exhibit C – Direct Testimony of Kendal Bowman;
- Exhibit D – Site Control Business Practice document; and
- Exhibit E – Example of Network Upgrades Cost Allocation under Definitive Interconnection Study Process

VII. REQUESTED EFFECTIVE DATE

The Duke Southeast Utilities respectfully request that the Commission accept the revisions to the Joint OATT effective as of June 1, 2021. No waiver is necessary to permit the requested effective date since such date is more than 61 days after the filing date of this tariff change.[163]

VIII. INFORMATION REQUIRED BY 18 C.F.R. §35.13

The revisions to the Joint OATT do not change any rates that generator Interconnection Customers will be charged under the LGIP and LGIA. The Duke Southeast Utilities will continue to (a) charge Interconnection Customers actual costs for interconnection studies and (b) reimburse Interconnection Customers for 100% of the costs advanced for Network Upgrades.

Therefore, this filing is not a "rate change" within the meaning of section 35.13(a) of the Commission's regulations and likewise is not a "rate increase" within the meaning of section 35.13(a)(2)(iii) of the Commission's regulations. The Duke Southeast Utilities are filing the revisions to the Joint OATT pursuant to the abbreviated procedures set forth in that section and request any waivers necessary to permit it to do so.

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[163] 18 C.F.R. § 35.3(a)(1) ("All rate schedules or tariffs or any part thereof shall be tendered for filing with the Commission and posted not less than sixty days … prior to … the date on which the filing party proposes to make any change in electric service and/or rate, charge, classification, practice, rule, regulation, or contract effective as a change in rate schedule or tariff").

Finally, the information required by 18 C.F.R. §§35.13(b) and (c) is as follows: the agreement of the customer has been obtained, and no expenses or costs in connection with these service agreements have been alleged or judged in any administrative or judicial proceeding to be illegal, duplicative, or unnecessary costs that are demonstrably the product of discriminatory employment practices.

IX. COMMUNICATIONS

All correspondence, communications, pleadings, and other documents related to these proceedings should be addressed to the persons listed below.

Ann L. Warren Associate General Counsel Duke Energy Corporation 550 South Tryon Street (DEC 45A) Charlotte, NC 28202 (704) 382-2108 ann.warren@duke-energy.com	William Sauer Director of Federal Regulatory Affairs Duke Energy Corporation 1301 Pennsylvania Avenue, NW, Suite 200 Washington, DC 20004 (202) 824-8014 william.sauer@duke-energy.com
E. Brett Breitschwerdt McGuireWoods LLP 501 Fayetteville St., Suite 500 Raleigh, NC 27601 (919) 755-6563 bbreitschwerdt@mcguirewoods.com	

X. SERVICE OF FILING

Per 18 C.F.R. §385.2010(f)(2) which requires electronic service of FERC filings, an electronic copy of this filing will be served by email on (a) the persons listed below, (b) all transmission customers taking service from the Duke Southeast Utilities under the Joint OATT, and (c) all generator Interconnection Customers of the Duke Southeast Utilities that have an LGIP Interconnection Request pending but who have not executed an LGIA.[164]

North Carolina Utilities Commission Kim Campbell, Chief Clerk 4325 Mail Service Center Raleigh, NC 27699-4325 kcampbell@ncuc.net chiefclerksoffice@ncuc.net	Public Staff – North Carolina Utilities Commission Dianna Downey, Chief Counsel Lucy Edmonson, Staff Attorney 4326 Mail Service Center Raleigh, NC 27699-4326 dianna.downey@psncuc.nc.gov lucy.edmondson@psncuc.nc.gov

[164] Since the identity of entities requesting generation interconnection is not public, the Duke Southeast Utilities will provide notice through a blind copy email that does not identify the generator interconnection recipient email addresses.

Public Service Commission of South Carolina Jocelyn Boyd, Chief Clerk and Administrator 101 Executive Center Drive Columbia, SC 29210 jocelyn.boyd@psc.sc.gov	South Carolina Office of Regulatory Staff Jeff Nelson Chief Legal Officer 1401 Main Street, Suite 900 Columbia, S.C. 2920 jnelson@ors.sc.gov
Florida Public Service Commission Div. of Records and Reporting Capital Circle Office Center 2540 Shumard Oak Blvd. Tallahassee, FL 32399-0850 atietzman@psc.state.fl.us cstauffe@psc.state.fl.us chairman@psc.state.fl.us	

XI. CONCLUSION

For the reasons above, the Duke Southeast Utilities respectfully request that the Commission issue an order accepting the Joint OATT revisions for filing and grant the requested effective date of June 1, 2021. Please contact the undersigned if you have any questions.

Respectfully submitted,

/s/ Ann L. Warren

Ann L. Warren
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Duke Energy Corporation
550 South Tryon Street, Mail Code DEC 45A
Charlotte, NC 28202
Telephone: (704) 382-2108
E-mail: ann.warren@duke-energy.com

Attorney for the Duke Southeast Utilities

CERTIFICATE OF SERVICE

Per 18 C.F.R. §385.2010(f)(2) which requires electronic service of FERC filings, I hereby certify that I have served this day an electronic copy of this filing by email on (a) the persons listed below, (b) all transmission customers taking service from the Duke Southeast Utilities under the Joint OATT, and (c) all generator Interconnection Customers of the Duke Southeast Utilities that have an LGIP Interconnection Request pending but who have not executed an LGIA.

North Carolina Utilities Commission Kim Campbell, Chief Clerk 4325 Mail Service Center Raleigh, NC 27699-4325 kcampbell@ncuc.net chiefclerksoffice@ncuc.net	Public Staff – North Carolina Utilities Commission Dianna Downey, Chief Counsel Lucy Edmonson, Staff Attorney 4326 Mail Service Center Raleigh, NC 27699-4326 dianna.downey@psncuc.nc.gov lucy.edmondson@psncuc.nc.gov
Public Service Commission of South Carolina Jocelyn Boyd, Chief Clerk and Administrator 101 Executive Center Drive Columbia, SC 29210 jocelyn.boyd@psc.sc.gov	South Carolina Office of Regulatory Staff Jeff Nelson, Chief Legal Officer 1401 Main Street, Suite 900 Columbia, S.C. 2920 jnelson@ors.sc.gov
Florida Public Service Commission Div. of Records and Reporting Capital Circle Office Center 2540 Shumard Oak Blvd. Tallahassee, FL 32399-0850 atietzman@psc.state.fl.us cstauffe@psc.state.fl.us chairman@psc.state.fl.us	

Dated: April 1, 2021

/s/ Marilani Alt

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FERC Compliance Analyst
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ATTACHMENT J -- STANDARD LARGE GENERATOR INTERCONNECTION PROCEDURES (LGIP)

(APPLICABLE TO GENERATING FACILITIES THAT EXCEED 20 MW)

Section 1. Definitions.

Adverse System Impact shall mean the negative effects due to technical or operational limits on conductors or equipment being exceeded that may compromise the safety and reliability of the electric system.

Affected System shall mean an electric system other than the Transmission Provider's Transmission System that may be affected by the proposed interconnection.

Affected System Operator shall mean the entity that operates an Affected System.

Affiliate shall mean, with respect to a corporation, partnership or other entity, each such other corporation, partnership or other entity that directly or indirectly, through one or more intermediaries, controls, is controlled by, or is under common control with, such corporation, partnership or other entity.

Ancillary Services shall mean those services that are necessary to support the transmission of capacity and energy from resources to loads while maintaining reliable operation of the Transmission Provider's Transmission System in accordance with Good Utility Practice.

Applicable Laws and Regulations shall mean all duly promulgated applicable federal, state and local laws, regulations, rules, ordinances, codes, decrees, judgments, directives, or judicial or administrative orders, permits and other duly authorized actions of any Governmental Authority.

Applicable Reliability Council shall mean the reliability council applicable to the Transmission System to which the Generating Facility is directly interconnected.

Applicable Reliability Standards shall mean the requirements and guidelines of NERC, the Applicable Reliability Council, and the Control Area of the Transmission System to which the Generating Facility is directly interconnected.

Base Case shall mean the base case power flow, short circuit, and stability data bases used for the Interconnection Studies by the Transmission Provider or Interconnection Customer.

Breach shall mean the failure of a Party to perform or observe any material term or condition of the Standard Large Generator Interconnection Agreement.

Breaching Party shall mean a Party that is in Breach of the Standard Large Generator Interconnection Agreement.

Business Day shall mean Monday through Friday, excluding Federal Holidays.

Calendar Day shall mean any day including Saturday, Sunday or a Federal Holiday.

Cluster shall mean a group of Interconnection Requests (one or more) that are studied together for the purpose of conducting the Interconnection Studies.

Cluster Study shall mean an Interconnection Study evaluating a Cluster of one or more Interconnection Requests.

Clustering shall mean the process whereby a group of Interconnection Requests is studied together, instead of serially, for the purpose of conducting the Interconnection Studies.

Commercial Operation shall mean the status of a Generating Facility that has commenced generating electricity for sale, excluding electricity generated during Trial Operation.

Commercial Operation Date of a unit shall mean the date on which the Generating Facility commences Commercial Operation as agreed to by the Parties pursuant to Appendix E to the Standard Large Generator Interconnection Agreement.

Confidential Information shall mean any confidential, proprietary or trade secret information of a plan, specification, pattern, procedure, design, device, list, concept, policy or compilation relating to the present or planned business of a Party, which is designated as confidential by the Party supplying the information, whether conveyed orally, electronically, in writing, through inspection, or otherwise.

Contingent Facilities shall mean those unbuilt Interconnection Facilities and Network Upgrades upon which the Interconnection Request's costs, timing, and study findings are dependent, and if delayed or not built, could cause a need for Re-Studies of the Interconnection Request or a reassessment of the Interconnection Facilities and/or Network Upgrades and/or costs and timing.

Control Area shall mean an electrical system or systems bounded by interconnection metering and telemetry, capable of controlling generation to maintain its interchange schedule with other Control Areas and contributing to frequency regulation of the interconnection. A Control Area must be certified by an Applicable Reliability Council. Control Area shall have the same meaning as Balancing Authority Area as defined by NERC.

Customer Engagement Window shall have the meaning set forth in Section 10.1 of the LGIP.

Default shall mean the failure of a Breaching Party to cure its Breach in accordance with Article 17 of the Standard Large Generator Interconnection Agreement.

Definitive Interconnection Study Process ("Definitive Interconnection Study") shall mean an Interconnection Study process adopted at Transmission Provider's option for purposes of administering a Cluster Study inclusive of the Informational Interconnection Study Process, the Transitional Serial Study Process, the Transitional Cluster Study Process, the DISIS Request Window, Customer Engagement Window, the Definitive Interconnection System Impact Study, and the Interconnection Facilities Study. Both the Resource Solicitation Cluster and the DISIS Cluster are processed under the Definitive Interconnection Study.

Definitive Interconnection System Impact Study ("DISIS") shall mean an engineering study that evaluates the impact of a Cluster on the safety and reliability of the Transmission System and, if applicable, an Affected System.

Definitive Interconnection System Impact Study Agreement ("DISIS Agreement") shall mean the form of agreement contained in Appendix 6-3 of the LGIP for conducting the Definitive Interconnection System Impact Study.

Definitive Interconnection System Impact Study Cluster ("DISIS Cluster") shall mean an engineering study that evaluates the impact of a Cluster on the safety and reliability of Transmission System and, if applicable, an Affected System.

DISIS Request Window shall have the meaning set forth in Section 10.1 of the LGIP.

Dispute Resolution shall mean the procedure for resolution of a dispute between the Parties in which they will first attempt to resolve the dispute on an informal basis.

Distribution System shall mean the Transmission Provider's facilities and equipment used to transmit electricity to ultimate usage points such as homes and industries directly from nearby generators or from interchanges with higher voltage transmission networks which transport bulk power over longer distances. The voltage levels at which distribution systems operate differ among areas.

Distribution Upgrades shall mean the additions, modifications, and upgrades to the Transmission Provider's Distribution System at or beyond the Point of Interconnection to facilitate interconnection of the Generating Facility and render the transmission service necessary to effect Interconnection Customer's wholesale sale of electricity in interstate commerce. Distribution Upgrades do not include Interconnection Facilities.

Effective Date shall mean the date on which the Standard Large Generator Interconnection Agreement becomes effective upon execution by the Parties subject to acceptance by FERC, or if filed unexecuted, upon the date specified by FERC.

Emergency Condition shall mean a condition or situation: (1) that in the judgment of the Party making the claim is imminently likely to endanger life or property; or (2) that, in the case of a Transmission Provider, is imminently likely (as determined in a non-discriminatory manner) to cause a material adverse effect on the security of, or damage to Transmission Provider's Transmission System, Transmission Provider's Interconnection Facilities or the electric systems of others to which the Transmission Provider's Transmission System is directly connected; or (3) that, in the case of Interconnection Customer, is imminently likely (as determined in a non-discriminatory manner) to cause a material adverse effect on the security of, or damage to, the Generating Facility or Interconnection Customer's Interconnection Facilities. System restoration and black start shall be considered Emergency Conditions; provided that Interconnection Customer is not obligated by the Standard Large Generator Interconnection Agreement to possess black start capability.

Energy Resource Interconnection Service ("ERIS") shall mean an Interconnection Service that allows the Interconnection Customer to connect its Generating Facility to the Transmission Provider's Transmission System to be eligible to deliver the Generating Facility's electric output using the existing firm or non-firm capacity of the Transmission Provider's Transmission System on an as available basis. Energy Resource Interconnection Service in and of itself does not convey transmission service.

Engineering & Procurement ("E&P") Agreement shall mean an agreement that authorizes the Transmission Provider to begin engineering and procurement of long lead-time items necessary for the establishment of the interconnection in order to advance the implementation of the Interconnection Request.

Environmental Law shall mean Applicable Laws or Regulations relating to pollution or protection of the environment or natural resources.

Federal Power Act shall mean the Federal Power Act, as amended, 16 U.S.C. §§ 791a et seq.

FERC shall mean the Federal Energy Regulatory Commission (Commission) or its successor.

Force Majeure shall mean any act of God, labor disturbance, act of the public enemy, war, insurrection, riot, fire, storm or flood, explosion, breakage or accident to machinery or equipment, any order, regulation or restriction imposed by governmental, military or lawfully established civilian authorities, or any other cause beyond a Party's control. A Force Majeure event does not include acts of negligence or intentional wrongdoing by the Party claiming Force Majeure.

Generating Facility shall mean Interconnection Customer's device for the production and/or storage for later injection of electricity identified in the Interconnection Request, but shall not include the Interconnection Customer's Interconnection Facilities.

Generating Facility Capacity shall mean the net capacity, in kW or MW, as applicable, of the Generating Facility and the aggregate net capacity of the Generating Facility where it includes multiple energy production devices.

Good Utility Practice shall mean any of the practices, methods and acts engaged in or approved by a significant portion of the electric industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather to be acceptable practices, methods, or acts generally accepted in the region.

Governmental Authority shall mean any federal, state, local or other governmental regulatory or administrative agency, court, commission, department, board, or other governmental subdivision, legislature, rulemaking board, tribunal, or other governmental authority having jurisdiction over the Parties, their respective facilities, or the respective services they provide, and exercising or entitled to exercise any administrative, executive, police, or taxing authority or power; provided, however, that such term does not include Interconnection Customer, Transmission Provider, or any Affiliate thereof.

Hazardous Substances shall mean any chemicals, materials or substances defined as or included in the definition of "hazardous substances," "hazardous wastes," "hazardous materials," "hazardous constituents," "restricted hazardous materials," "extremely hazardous substances," "toxic substances," "radioactive substances," "contaminants," "pollutants," "toxic pollutants" or words of similar meaning and regulatory effect under any applicable Environmental Law, or any other chemical, material or substance, exposure to which is prohibited, limited or regulated by any applicable Environmental Law.

Informational Interconnection Study shall mean an analysis based on assumptions specified by Interconnection Customer in the Informational Interconnection Study Agreement as further described in Section 3.2.

Informational Interconnection Study Agreement shall mean the form of agreement contained in Appendix 2 of the LGIP for conducting the Informational Interconnection Study.

Initial Synchronization Date shall mean the date upon which the Generating Facility is initially synchronized and upon which Trial Operation begins.

In-Service Date shall mean the date upon which the Interconnection Customer reasonably expects it will be ready to begin use of the Transmission Provider's Interconnection Facilities to obtain back feed power.

Interconnection Customer shall mean any entity, including the Transmission Provider, Transmission Owner or any of the Affiliates or subsidiaries of either, that proposes to interconnect its Generating Facility with the Transmission Provider's Transmission System.

Interconnection Customer's Interconnection Facilities shall mean all facilities and equipment, as identified in Appendix A of the Standard Large Generator Interconnection Agreement, that are located between the Generating Facility and the Point of Change of Ownership, including any modification, addition, or upgrades to such facilities and equipment necessary to physically and electrically interconnect the Generating Facility to the Transmission Provider's Transmission System. Interconnection Customer's Interconnection Facilities are sole use facilities.

Interconnection Facilities shall mean the Transmission Provider's Interconnection Facilities and the Interconnection Customer's Interconnection Facilities. Collectively, Interconnection Facilities include all facilities and equipment between the Generating Facility and the Point of Interconnection, including any modification, additions or upgrades that are necessary to physically and electrically interconnect the Generating Facility to the Transmission Provider's Transmission System. Interconnection Facilities are sole use facilities (e.g. for generator interconnection) and shall not include Distribution Upgrades, Stand Alone Network Upgrades or Network Upgrades. Interconnection Facilities may be shared by more than one Generating Facility.

Interconnection Facilities Study shall mean a study conducted by the Transmission Provider or a third party consultant for the Interconnection Customer to determine a list of facilities (including Transmission Provider's Interconnection Facilities and Network Upgrades as identified in the Serial Interconnection System Impact Study or the Definitive Interconnection System Impact Study), the cost of those facilities, and the time required to interconnect the Generating Facility with the Transmission Provider's Transmission System. The scope of the study is defined in Section 11 of the Standard Large Generator Interconnection Procedures.

Interconnection Facilities Study Agreement shall mean the form of agreement contained in Appendix 7 of the Standard Large Generator Interconnection Procedures for conducting the Interconnection Facilities Study.

Interconnection Feasibility Study shall mean a preliminary evaluation of the system impact and cost of interconnecting the Generating Facility to the Transmission Provider's Transmission System, the scope of which is described in Section 8 of the Standard Large Generator Interconnection Procedures.

Interconnection Feasibility Study Agreement shall mean the form of agreement contained in Appendix 4 of the Standard Large Generator Interconnection Procedures for conducting the Interconnection Feasibility Study.

Interconnection Request shall mean an Interconnection Customer's request, in the form of Appendix 3 to the Standard Large Generator Interconnection Procedures, in accordance with the Tariff, to interconnect a new Generating Facility, or to increase the capacity of, or make a Material Modification to the operating characteristics of, an existing Generating Facility that is interconnected with the Transmission Provider's Transmission System.

Interconnection Service shall mean the service provided by the Transmission Provider associated with interconnecting the Interconnection Customer's Generating Facility to the Transmission Provider's Transmission System and enabling it to receive electric energy and capacity from the Generating Facility at the Point of Interconnection, pursuant to the terms of the Standard Large Generator Interconnection Agreement and, if applicable, the Transmission Provider's Tariff.

Interconnection Study shall mean any of the following studies: the Interconnection Feasibility Study, the Serial Interconnection System Impact Study, the Definitive Interconnection System Impact Study, and the Interconnection Facilities Study described in the Standard Large Generator Interconnection Procedures. The Transmission Provider shall undertake Interconnection Studies pursuant to either a Serial Interconnection Study Process or a Definitive Interconnection Study Process as described in these Large Generator Interconnection Procedures.

Interconnection Study Agreement shall mean any of the following agreements: the Interconnection Feasibility Study, the Definitive Interconnection System Impact Study Agreement, the Serial Interconnection System Impact Study Agreement or the Interconnection Facilities Study Agreement described in these Large Generator Interconnection Procedures.

IRS shall mean the Internal Revenue Service.

Joint Operating Committee shall be a group made up of representatives from Interconnection Customers and the Transmission Provider to coordinate operating and technical considerations of Interconnection Service.

Large Generating Facility shall mean a Generating Facility having a Generating Facility Capacity of more than 20 MW.

Loss shall mean any and all losses relating to injury to or death of any person or damage to property, demand, suits, recoveries, costs and expenses, court costs, attorney fees, and all other obligations by or to third parties, arising out of or resulting from the other Party's performance, or non-performance of its obligations under the Standard Large Generator Interconnection Agreement on behalf of the indemnifying Party, except in cases of gross negligence or intentional wrongdoing by the indemnifying Party.

Material Modification shall mean (1) in the Serial Interconnection Study Process, those modifications that have a material impact on the cost or timing of any Interconnection Request with a later queue priority date and (2) in the Definitive Interconnection Study Process, those modifications that have a material impact on the cost or timing of any Interconnection Request with (a) a later Queue Position or (b) a Queue Position which is included in the same Cluster.

Metering Equipment shall mean all metering equipment installed or to be installed at the Generating Facility pursuant to the Standard Large Generator Interconnection Agreement at the metering points, including but not limited to instrument transformers, MWh-meters, data acquisition equipment, transducers, remote terminal unit, communications equipment, phone lines, and fiber optics.

NERC shall mean the North American Electric Reliability Council or its successor organization.

Network Resource shall mean any designated generating resource owned, purchased, or leased by a Network Customer under the Network Integration Transmission Service Agreement. Network Resources do not include any resource, or any portion thereof, that is committed for sale to third parties or otherwise cannot be called upon to meet the Network Customer's Network Load on a non-interruptible basis.

Network Resource Interconnection Service ("NRIS") shall mean an Interconnection Service that allows the Interconnection Customer to integrate its Large Generating Facility with the Transmission Provider's Transmission System (1) in a manner comparable to that in which the Transmission Provider integrates its generating facilities to serve native load customers; or (2) in an RTO or ISO with market based congestion management, in the same manner as Network Resources. Network Resource Interconnection Service in and of itself does not convey transmission service.

Network Upgrades shall mean the additions, modifications, and upgrades to the Transmission Provider's Transmission System required at or beyond the point at which the Interconnection Facilities connect to the Transmission Provider's Transmission System to accommodate the interconnection of the Large Generating Facility to the Transmission Provider's Transmission System.

Notice of Dispute shall mean a written notice of a dispute or claim that arises out of or in connection with the Standard Large Generator Interconnection Agreement or its performance.

OASIS shall mean the Transmission Provider's Open Access Same-Time Information System.

Optional Interconnection Study shall mean a sensitivity analysis based on assumptions specified by the Interconnection Customer in the Optional Interconnection Study Agreement.

Optional Interconnection Study Agreement shall mean the form of agreement contained in Appendix 9 of the Standard Large Generator Interconnection Procedures for conducting the Optional Interconnection Study.

Party or Parties shall mean Transmission Provider, Transmission Owner, Interconnection Customer or any combination of the above.

Permissible Technological Advancement shall mean modification to equipment that (1) results in electrical performance that is equal to or better than the electrical performance expected prior to the technology change, (2) does not cause any reliability concerns, (3) does not degrade the electrical characteristics of the generating equipment (e.g., the ratings, impedances, efficiencies, capabilities, and performance of the equipment under steady-state and dynamic conditions) and (4) does not have a material impact on the cost or timing of any Interconnection Request with a later queue priority date, and is therefore not a Material Modification. A Permissible Technological Advancement is a change in equipment that may achieve cost or grid performance efficiencies that may include turbines, inverters, plant supervisory controls or other devices but does not include changes in generation technology type or fuel type.

Phase ("Phase 1", "Phase 2", or "Phase 3") shall mean a distinct part of the Definitive Interconnection System Impact Study Process as described in Section 10.8 herein.

Point of Change of Ownership shall mean the point, as set forth in Appendix A to the Standard Large Generator Interconnection Agreement, where the Interconnection Customer's Interconnection Facilities connect to the Transmission Provider's Interconnection Facilities.

Point of Interconnection shall mean the point, as set forth in Appendix A to the Standard Large Generator Interconnection Agreement, where the Interconnection Facilities connect to the Transmission Provider's Transmission System.

Provisional Interconnection Service shall mean Interconnection Service provided by Transmission Provider associated with interconnecting the Interconnection Customer's Generating Facility to Transmission Provider's Transmission System and enabling that Transmission System to receive electric energy and capacity from the Generating Facility at the Point of Interconnection, pursuant to the terms of the Provisional Large Generator Interconnection Agreement and, if applicable, the Tariff.

Provisional Large Generator Interconnection Agreement shall mean the interconnection agreement for Provisional Interconnection Service established between Transmission Provider and/or the Transmission Owner and the Interconnection Customer. This agreement shall take the form of the Large Generator Interconnection Agreement, modified for provisional purposes.

Queue shall mean a queue for valid Interconnection Requests for the Serial Interconnection Study Process or the Definitive Interconnection Study Process.

Queue Position shall mean the order of a valid Interconnection Request, relative to all other pending valid Interconnection Requests, in either the Serial Interconnection Study Process or the Definitive Interconnection Study Process. In the Serial Interconnection Study Process, the Queue Position is established based upon the date and time of receipt of the valid Interconnection Request by the Transmission Provider. Where a Transmission Provider is administering a Definitive Interconnection Study Process, all Interconnection Requests studied in a single Cluster shall be considered equally queued but Clusters initiated earlier in time shall be considered to have an earlier Queue Position than clusters initiated later. The Queue Position of an Interconnection Request shall have no bearing on the allocation of the cost of the common Network Upgrades identified in the applicable Cluster Study (such costs will be allocated among Interconnection Requests in accordance with Section 10.4).

Readiness Milestone(s) shall have the meaning set forth in Section 10.11 of the LGIP.

Reasonable Efforts shall mean, with respect to an action required to be attempted or taken by a Party under the Standard Large Generator Interconnection Agreement, efforts that are timely and consistent with Good Utility Practice and are otherwise substantially equivalent to those a Party would use to protect its own interests.

Resource Plan shall mean any process authorized or required by Applicable Laws and Regulations for, *inter alia*, the selection of Generating Facilities interconnected to the Transmission System of Transmission Provider.

Resource Planning Entity shall mean any entity required to develop a Resource Plan or conduct a Resource Solicitation Process.

Resource Solicitation Cluster shall mean a Cluster Study associated with a Resource Plan or related process.

Resource Solicitation Process shall mean any process authorized or required by Applicable Laws and Regulations for the acquisition of Network Resources.

Scoping Meeting shall mean the meeting between representatives of the Interconnection Customer and Transmission Provider conducted for the purpose of discussing the proposed Interconnection Request, alternative interconnection options, to exchange information including any transmission data and earlier study evaluations that would be reasonably expected to affect such interconnection options, to analyze such information, and to determine the potential feasible Points of Interconnection.

Serial Interconnection Study Process shall mean the process of studying Interconnection Requests on a serial basis inclusive of the Interconnection Feasibility Study, the Serial Interconnection System Impact Study, the Interconnection Facilities Study, and the Optional Interconnection Study Process.

Serial Interconnection System Impact Study shall mean an engineering study that evaluates the impact of the proposed interconnection on the safety and reliability of Transmission Provider's Transmission System and, if applicable, an Affected System. The study shall identify and detail the system impacts that would result if the Generating Facility were interconnected without project modifications or system modifications, focusing on the Adverse System Impacts identified in the Interconnection Feasibility Study, or to study potential impacts, including but not limited to those identified in the Scoping Meeting as described in the Standard Large Generator Interconnection Procedures.

Serial Interconnection System Impact Study Agreement shall mean the form of agreement contained in Appendix 5 of the Standard Large Generator Interconnection Procedures for conducting the Interconnection System Impact Study.

Site Control shall mean the exclusive land right to develop, construct, operate, and maintain the Generating Facility over the term of expected operation of the Generating Facility. Site Control shall include the right to develop, construct, operate, and maintain Interconnection Customer's Interconnection Facilities. Site Control may be demonstrated by documentation establishing: (1) ownership of, a leasehold interest in, or a right to develop a site of sufficient size to construct and operate the Generating Facility and associated Interconnection Customer's Interconnection Facilities; (2) an option to purchase or acquire a leasehold interest in a site of sufficient size to construct and operate the Generating Facility and associated Interconnection Facilities; or (3) any other documentation that clearly demonstrates the right of the Interconnection Customer to exclusively occupy a site of sufficient size to construct and operate the Generating Facility. Site Control for any co-located project is demonstrated by a contract or other agreement demonstrating shared land use for all co-located projects that meet the aforementioned provisions of this Site Control definition.

Small Generating Facility shall mean a Generating Facility that has a Generating Facility Capacity of no more than 20 MW.

Stand Alone Network Upgrades shall mean Network Upgrades that are not part of an Affected System that an Interconnection Customer may construct without affecting day-to-day operations of the Transmission System during their construction. Both the Transmission Provider and the Interconnection Customer must agree as to what constitutes Stand Alone Network Upgrades and identify them in Appendix A to the Standard Large Generator Interconnection Agreement. If the Transmission Provider and Interconnection Customer disagree about whether a particular Network Upgrade is a Stand Alone Network Upgrade, the Transmission Provider must provide the Interconnection Customer a written technical explanation outlining why the Transmission Provider does not consider the Network Upgrade to be a Stand Alone Network Upgrade within 15 days of its determination.

Standard Large Generator Interconnection Agreement (LGIA) shall mean the form of interconnection agreement applicable to an Interconnection Request pertaining to a Large Generating Facility that is included in the Transmission Provider's Tariff.

Standard Large Generator Interconnection Procedures (LGIP) shall mean the interconnection procedures applicable to an Interconnection Request pertaining to a Large Generating Facility that are included in the Transmission Provider's Tariff.

Surplus Interconnection Service shall mean any unneeded portion of Interconnection Service established in a Large Generator Interconnection Agreement, such that if Surplus Interconnection Service is utilized, the total amount of Interconnection Service at the Point of Interconnection would remain the same.

System Protection Facilities shall mean the equipment, including necessary protection signal communications equipment, required to protect (1) the Transmission Provider's Transmission System from faults or other electrical disturbances occurring at the Generating Facility and (2) the Generating Facility from faults or other electrical system disturbances occurring on the Transmission Provider's Transmission System or on other delivery systems or other generating systems to which the Transmission Provider's Transmission System is directly connected.

Tariff shall mean the Transmission Provider's Tariff through which open access transmission service and Interconnection Service are offered, as filed with FERC, and as amended or supplemented from time to time, or any successor tariff.

Transmission Owner shall mean an entity that owns, leases or otherwise possesses an interest in the portion of the Transmission System at the Point of Interconnection and may be a Party to the Standard Large Generator Interconnection Agreement to the extent necessary.

Transmission Provider shall mean the public utility (or its designated agent) that owns, controls, or operates transmission or distribution facilities used for the transmission of electricity in interstate commerce and provides transmission service under the Tariff. The term Transmission Provider should be read to include the Transmission Owner when the Transmission Owner is separate from the Transmission Provider.

Transmission Provider's Interconnection Facilities shall mean all facilities and equipment owned, controlled, or operated by the Transmission Provider from the Point of Change of Ownership to the Point of Interconnection as identified in Appendix A to the Standard Large Generator Interconnection Agreement, including any modifications, additions or upgrades to such facilities and equipment. Transmission Provider's Interconnection Facilities are sole use facilities and shall not include Distribution Upgrades, Stand Alone Network Upgrades or Network Upgrades. Transmission Provider’s Interconnection Facilities may be shared by more than one Generating Facility in a given study.

Transmission System shall mean the facilities owned, controlled or operated by the Transmission Provider or Transmission Owner that are used to provide transmission service under the Tariff.

Trial Operation shall mean the period during which Interconnection Customer is engaged in on-site test operations and commissioning of the Generating Facility prior to Commercial Operation.

Withdrawal Penalty shall have the meaning set forth in Section 4.7.1 of the LGIP.

Section 2. Scope and Application.

2.1 Application of Standard Large Generator Interconnection Procedures.
Sections 2 through 16 apply to processing an Interconnection Request pertaining to a Large Generating Facility. As provided in Attachment M to the Tariff, Small Generating Facilities that are not eligible for the fast track process (as defined therein) will be processed in a single Queue with Large Generating Facilities. Additionally, Small Generating Facilities requesting NRIS shall be processed under this LGIP.

The study process applicable to all Interconnection Requests subject to these Procedures is dependent upon whether the Transmission Provider is implementing a Serial Interconnection Study Process or has transitioned to a Definitive Interconnection Study Process, as provided for in Section 7 and as detailed in these Large Generator Interconnection Procedures. Where the Transmission Provider transitions to a Definitive Interconnection Study Process, Interconnection Customers with Generating Facilities located in the Transmission Provider's Control Area and requesting Interconnection Service under this LGIP shall adhere to the Definitive Interconnection Study Process provisions of these Procedures and shall not be subject to the Serial Interconnection Study Process provisions herein. The Transmission Provider shall publicize its intent to transition to the Definitive Interconnection Study Process in Section 10 by posting notice to the OASIS website (the date of posting to be known as the "Cluster Study transition notice date") pursuant to Section 7. Such notice shall not be published until after approval of the revised LGIP by FERC. After the Transmission Provider publicizes its intent to transition to the Definitive Interconnection Study Process in Section 10 by posting notice to the OASIS website, the Transmission Provider may not at any time thereafter return to the *pro forma* Serial Interconnection Study Process.

The Informational Interconnection Study process in Section 3 is available only where the Transmission Provider is implementing a Definitive Interconnection Study Process. The Optional Interconnection Study Process in Section 13 is available only where the Transmission Provider is implementing a Serial Interconnection Study Process.

2.2 Comparability.
Transmission Provider shall receive, process and analyze all Interconnection Requests in a timely manner as set forth in this LGIP. Transmission Provider will use the same Reasonable Efforts in processing and analyzing Interconnection Requests from all Interconnection Customers, whether the Generating Facilities are owned by Transmission Provider, its subsidiaries or Affiliates or others.

2.3 Base Case Data.
Transmission Provider shall maintain base power flow, short circuit and stability databases, including all underlying assumptions, and contingency list on either its OASIS site or a password-protected website, subject to confidentiality provisions in LGIP Section 16.1. In addition, Transmission Provider shall maintain network models and underlying assumptions on either its OASIS site or a password-protected website. Such network models and underlying assumptions should reasonably represent those used during the most recent Interconnection Study and be representative of current system conditions. If Transmission Provider posts this information on a password-protected website, a link to the information must be provided on Transmission Provider's OASIS site. Transmission Provider is permitted to require that Interconnection Customers, OASIS site users and password-protected website users sign a confidentiality agreement before the release of commercially

sensitive information or Critical Energy Infrastructure Information in the Base Case data. Such databases and lists, hereinafter referred to as Base Cases, shall include all (1) generation projects and (2) transmission projects, including merchant transmission projects that are proposed for the Transmission System for which a transmission expansion plan has been submitted and approved by the applicable authority.

2.4 No Applicability to Transmission Service.
Nothing in this LGIP shall constitute a request for transmission service or confer upon an Interconnection Customer any right to receive transmission service.

Section 3. Definitive Interconnection Study Process – Informational Interconnection Study.

3.1 Informational Interconnection Study Agreement.
At any time, a prospective Interconnection Customer may request, and Transmission Provider (either itself or through a third-party subcontractor or consultant) authorized and opting to administer a Definitive Interconnection Study Process shall perform one or more Informational Interconnection Studies. Interconnection Customer shall submit a separate Informational Interconnection Study Request for each site and may submit multiple Informational Interconnection Study Requests for different Generating Facility sizes or configurations at a single site. An Informational Interconnection Study Request to evaluate one site at two different voltage levels shall be treated as two Informational Interconnection Study Requests. Any one Interconnection Customer (including affiliates) shall have no more than five (5) requests for Informational Interconnection Study reports pending at one time. Interconnection Customer must submit a deposit with each Informational Interconnection Study Request even when more than one request is submitted for a single site.

The request shall use the form in Appendix 1 of the LGIP and shall describe the assumptions that Interconnection Customer wishes Transmission Provider to study within the scope described in Section 3.2 of the LGIP below. Within five (5) Business Days after receipt of a request for an Informational Interconnection Study, Transmission Provider shall provide to Interconnection Customer an Informational Interconnection Study Agreement in the form of Appendix 2, including a non-binding good faith estimate of the timing and cost of completing the Informational Interconnection Study. Notwithstanding the above, the Transmission Provider shall not be required as a result of an Informational Interconnection Study Request to conduct any additional Interconnection Studies with respect to any other Interconnection Request.

Interconnection Customer shall execute the Informational Interconnection Study Agreement within ten (10) Business Days of receipt of an agreed upon scope of work and deliver the Informational Interconnection Study Agreement, the technical data, and a $10,000 deposit to Transmission Provider. The Transmission Provider shall then countersign and return the Informational Interconnection Study Agreement within ten (10) Business Days of receipt.

3.2 Scope of Informational Interconnection Study.
The intent of the Informational Interconnection Study is to aid Interconnection Customer in its business decisions related to interconnection of Generating Facilities prior to entering the Definitive Interconnection Study Process. The Informational Interconnection Study shall consist of analysis based on the assumptions and scope of work specified by Interconnection Customer in the Informational Interconnection Study Agreement. The Informational

Interconnection Study shall preliminarily identify the potential Transmission Provider's Interconnection Facilities and the Network Upgrades, and the estimated cost thereof, that may be required to provide transmission service or Interconnection Service based upon the results and assumptions of the Informational Interconnection Study. The Informational Interconnection Study shall be performed solely for informational purposes and is non-binding and does not confer any rights, as the Interconnection Customer must still successfully apply to interconnect to the Transmission Provider's System. Transmission Provider shall utilize existing studies to the extent practicable in conducting the Informational Interconnection Study.

3.3 Informational Interconnection Study Procedures.
The executed Informational Interconnection Study Agreement, the deposit, and technical and other data called for therein must be provided to Transmission Provider within ten (10) Business Days of Interconnection Customer's receipt of the Informational Interconnection Study Agreement. Transmission Provider shall use Reasonable Efforts to complete the Informational Interconnection Study within a mutually agreed upon time period specified within the Informational Interconnection Study Agreement. If Transmission Provider is unable to complete the Informational Interconnection Study within such time period, it shall notify Interconnection Customer and provide an estimated completion date and an explanation of the reasons why additional time is required. Any difference between the study payment and the actual cost of the study shall be paid to Transmission Provider or refunded to Interconnection Customer, as appropriate. Upon request, Transmission Provider shall provide Interconnection Customer supporting documentation and work papers and databases or data developed in the preparation of the Informational Interconnection Study, subject to confidentiality arrangements consistent with Section 16.1.

Section 4. Interconnection Requests.

4.1 General.

4.1.1 Serial Interconnection Study Deposit and Process.
An Interconnection Customer shall submit to Transmission Provider an Interconnection Request in the form of Appendix 3 to this LGIP and a refundable deposit of $10,000 where the Transmission Provider is administering a Serial Interconnection Study Process. Transmission Provider shall apply the deposit toward the cost of an Interconnection Feasibility Study. Interconnection Customer shall submit a separate Interconnection Request for each site and may submit multiple Interconnection Requests for a single site. Interconnection Customer must submit a deposit with each Interconnection Request even when more than one request is submitted for a single site. An Interconnection Request to evaluate one site at two different voltage levels shall be treated as two Interconnection Requests.

At Interconnection Customer's option, Transmission Provider and Interconnection Customer will identify alternative Point(s) of Interconnection and configurations at the Scoping Meeting to evaluate in this process and attempt to eliminate alternatives in a reasonable fashion given resources and information available. Interconnection Customer will select the definitive Point(s) of Interconnection to be studied no later than the execution of the Interconnection Feasibility Study Agreement.

Transmission Provider shall have a process in place to consider requests for Interconnection Service below the Generating Facility Capacity. These requests for Interconnection Service shall be studied at the level of Interconnection Service requested for purposes of Interconnection Facilities and Network Upgrades, and associated costs, but may be subject to other studies at the full Generating Facility Capacity to ensure safety and reliability of the system, with the study costs borne by the Interconnection Customer. If after the additional studies are complete, Transmission Provider determines that additional Network Upgrades are necessary, then Transmission Provider must: (1) specify which additional Network Upgrade costs are based on which studies; and (2) provide a detailed explanation of why the additional Network Upgrades are necessary. Any Interconnection Facility and/or Network Upgrade costs required for safety and reliability also will be borne by the Interconnection Customer. Interconnection Customers may be subject to additional control technologies as well as testing and validation of those technologies consistent with Article 6 of the LGIA. The necessary control technologies and protection systems shall be established in Appendix C of the executed, or requested to be filed unexecuted, LGIA.

4.1.2 Definitive Interconnection Study Deposit and Process.
Where the Transmission Provider is administering a Definitive Interconnection Study Process, an Interconnection Customer shall submit to Transmission Provider an Interconnection Request in the form of Appendix 3 to this LGIP, an application fee of $5,000, and a study deposit in cash based upon the requested capacity of the Generating Facility:

a. $20,000 plus one dollar ($1.00) per kWac for requests < 20 MW, or

b. $35,000 plus one dollar ($1.00) per kWac for requests ≥ 20 MW < 50 MW, or

c. $50,000 plus one dollar ($1.00) per kWac for requests ≥ 50 MW< 80MW, or

d. $150,000 for requests ≥ 80 MW < 200 MW, or

e. $250,000 for requests ≥ 200 MW.

Transmission Provider shall apply the deposit toward the cost of administering the Definitive Interconnection Study Process as well as any Network Upgrades and Interconnection Facilities, including overheads under a future Interconnection Agreement. Interconnection Customer shall submit a separate Interconnection Request for each site and may submit multiple Interconnection Requests for a single site. Interconnection Customer must submit a deposit with each Interconnection Request even when more than one request is submitted for a single site. Interconnection Customers evaluating different options (such as different sizes, sites, or voltages) are encouraged but not required to use the Informational Interconnection Process (Section 3) before entering the Definitive Interconnection Study Process.

4.2 Identification of Types of Interconnection Services.

4.2.1 Serial Interconnection Study Process.
At the time the Interconnection Request is submitted, Interconnection Customer must request either Energy Resource Interconnection Service or Network Resource Interconnection Service, as described; provided, however, any Interconnection Customer requesting Network Resource Interconnection Service may also request that it be concurrently studied for Energy

Resource Interconnection Service, up to the point when an Interconnection Facility Study Agreement is executed. Interconnection Customer may then elect to proceed with Network Resource Interconnection Service or to proceed under a lower level of interconnection service to the extent that only certain upgrades will be completed.

4.2.2 Definitive Interconnection Study Process.
At the time the Interconnection Request is submitted, Interconnection Customer must request either Energy Resource Interconnection Service or Network Resource Interconnection Service; provided, however, any Interconnection Customer requesting Network Resource Interconnection Service may also request that it be concurrently studied for Energy Resource Interconnection Service prior to DISIS Phase 3 but must designate either ERIS or NRIS no later than five business days after the DISIS Phase 2 Report Meeting described in Section 10.8(c).

4.2.3 Energy Resource Interconnection Service.

4.2.3.1 The Product. Energy Resource Interconnection Service allows Interconnection Customer to connect the Large Generating Facility to the Transmission System and be eligible to deliver the Large Generating Facility's output using the existing firm or non-firm capacity of the Transmission System on an "as available" basis. Energy Resource Interconnection Service does not in and of itself convey any right to deliver electricity to any specific customer or Point of Delivery.

4.2.3.2 The Study. The study consists of short circuit/fault duty, steady state (thermal and voltage) and stability analyses. The short circuit/fault duty analysis would identify direct Interconnection Facilities required and the Network Upgrades necessary to address short circuit issues associated with the Interconnection Facilities. The stability and steady state studies would identify necessary upgrades to allow full output of the proposed Large Generating Facility and would also identify the maximum allowed output, at the time the study is performed, of the interconnecting Large Generating Facility without requiring additional Network Upgrades.

4.2.4 Network Resource Interconnection Service.

4.2.4.1 The Product. Transmission Provider must conduct the necessary studies and construct the Network Upgrades needed to integrate the Large Generating Facility (1) in a manner comparable to that in which Transmission Provider integrates its generating facilities to serve native load customers; or (2) in an ISO or RTO with market-based congestion management, in the same manner as Network Resources. Network Resource Interconnection Service allows Interconnection Customer's Large Generating Facility to be designated as a Network Resource, up to the Large Generating Facility's full output, on the same basis as existing Network Resources interconnected to Transmission Provider's Transmission System, and to be studied as a Network Resource on the assumption that such a designation will occur.

4.2.4.2 The Study. The Interconnection Study for Network Resource Interconnection Service shall assure that Interconnection Customer's Large Generating Facility meets the requirements for Network Resource Interconnection Service and as a general matter, that such Large Generating Facility's interconnection is also studied with Transmission Provider's Transmission System at peak load, under a variety of severely stressed conditions, to determine whether, with the Large Generating Facility at full output, the aggregate of generation in the local area can be delivered to the aggregate of load on Transmission Provider's Transmission System, consistent with Transmission Provider's reliability criteria and procedures. This approach assumes that some portion of existing Network Resources' output is displaced by the output of Interconnection Customer's Large Generating Facility. Network Resource Interconnection Service in and of itself does not convey any right to deliver electricity to any specific customer or Point of Delivery. The Transmission Provider may also study the Transmission System under non-peak load conditions. However, upon request by the Interconnection Customer, the Transmission Provider must explain in writing to the Interconnection Customer why the study of non-peak load conditions is required for reliability purposes.

4.3 Utilization of Surplus Interconnection Service.
Transmission Provider must provide a process that allows an Interconnection Customer to utilize or transfer Surplus Interconnection Service at an existing Point of Interconnection. The original Interconnection Customer or one of its affiliates shall have priority to utilize Surplus Interconnection Service. If the existing Interconnection Customer or one of its affiliates does not exercise its priority, then that service may be made available to other potential Interconnection Customers.

4.3.1 Surplus Interconnection Service Requests.
Surplus Interconnection Service requests may be made by the existing Interconnection Customer whose Generating Facility is already interconnected or one of its affiliates. Surplus Interconnection Service requests also may be made by another Interconnection Customer.

Transmission Provider shall use the process in Section 4.3.2 in evaluating Interconnection Requests for Surplus Service. Studies for Surplus Interconnection Service shall consist of reactive power, short circuit/fault duty, stability analyses, and any other appropriate studies. Steady-state (thermal/voltage) analyses may be performed as necessary to ensure that all required reliability conditions are studied. If the Surplus Interconnection Service was not studied under off-peak conditions, off-peak steady state analyses shall be performed to the required level necessary to demonstrate reliable operation of the Surplus Interconnection Service. If the original System Impact Study is not available for the Surplus Interconnection Service, both off-peak and peak analysis may need to be performed for the existing Generating Facility associated with the request for Surplus Interconnection Service. The reactive power, short circuit/fault duty, stability, and steady-state analyses for Surplus Interconnection Service will identify any additional Interconnection Facilities and/or Network Upgrades necessary.

4.3.2 Process for Surplus Interconnection Service Requests.
An existing Interconnection Customer, whose facility is already interconnected, may submit a request for Surplus Interconnection Service by using the process outlined in this Section 4.3.2. The original Large Generator Interconnection Customer may retain the surplus for itself, or may make it available to an Affiliate or any other entity.

A. The existing Interconnection Customer, or an Affiliate, may make a Request for Surplus Interconnection Service, by submitting a complete request in the form of Appendix 3 to this LGIP, and a deposit for $10,000. Another entity may make a request, but must include concurrence from the existing Large Generator Interconnection Customer that they are willing to assign Surplus Interconnection Service to the entity ("Surplus Interconnection Customer", regardless of which type). The deposit shall be applied toward any Interconnection Studies pursuant to the Surplus Interconnection Request.

B. A Surplus Interconnection Request will not be considered to be a valid request until all items in Section 4.3.2(A.) have been received and deemed adequate by Transmission Provider. If an Interconnection Request fails to meet the requirements set forth in Section 4.3.2(A.), Transmission Provider shall notify the Surplus Interconnection Customer within five (5) Business Days of receipt of the initial Surplus Interconnection Request of the reasons for such failure and that the Surplus Interconnection Request does not constitute a valid request.

C. Transmission Provider shall acknowledge receipt of the Surplus Interconnection Request within five (5) Business Days of receipt of the request. Transmission Provider shall process the Surplus Interconnection Request outside of the non-Surplus Interconnection queue.

D. Transmission Provider shall tender a Surplus Interconnection Study Agreement to the Surplus Interconnection Customer within 30 Business Days of the original request if no deficiencies or within 30 Business Days from the time deficiencies in the application are cured by the Surplus Interconnection Customer.

E. Surplus Interconnection Customer shall execute the Surplus Interconnection Study Agreement and return to the Transmission Provider, along with a $50,000 study deposit.

F. The Transmission Provider will perform the Surplus Interconnection Study by performing a System Impact Study phase within 60 Business Days and, if necessary, a Facilities Study phase within an additional 90 Business Days.

G. After the Surplus Interconnection Study, the Transmission Provider will provide the results to the Surplus Interconnection Customer and, if applicable, to the original Interconnection Customer.

H. Within 10 Business Days of delivering the study results, the Transmission Provider will schedule a Customer meeting to discuss the results of the studies with the Surplus Interconnection Customer and, if applicable, with the original Interconnection Customer.

I. Within 30 days of the Customer meeting, Transmission Provider will prepare the amendments to the Surplus Interconnection Agreement, which will take the form of an LGIA, and deliver them to the Surplus Interconnection Customer and, if applicable, to the original Interconnection Customer.

J. A 60-day negotiation period will occur to finalize timelines and financial aspects. In the event that the negotiations fail to result in an agreement, the Surplus Interconnection Customer may direct the Transmission Provider that the agreement be filed with the FERC unexecuted.

K. Surplus Interconnection Service cannot be offered unless the original Large Generator Interconnection Customer's Interconnection Facilities, Network Upgrades and any identified Contingent Network Upgrades identified in the original LGIA are In Service. Surplus Service cannot be granted to the Surplus Interconnection Customer if the Surplus Interconnection Study indicates additional Network Upgrades would be needed.

L. Requests for Surplus Interconnection Service cannot exceed the original Interconnected MW amount, and must be for either the same service (ERIS or NRIS) or, if the original LGIA was for NRIS, then the Surplus Interconnection Customer could request the lower level ERIS service if desired.

4.4 Valid Interconnection Request.

4.4.1 Initiating an Interconnection Request in the Serial Interconnection Study Process. To initiate an Interconnection Request, Interconnection Customer must submit all of the following: (i) a $10,000 deposit, (ii) a completed application in the form of Appendix 3, and (iii) demonstration of Site Control or a posting of an additional deposit of $10,000. Such deposits shall be applied toward any Interconnection Studies pursuant to the Interconnection Request. If Interconnection Customer demonstrates Site Control within the cure period specified in Section 4.4.4 after submitting its Interconnection Request, the additional deposit shall be refundable; otherwise, all such deposit(s), additional and initial, become non-refundable.

The expected In-Service Date of the new Large Generating Facility or increase in capacity of the existing Generating Facility shall be no more than the process window for the regional expansion planning period (or in the absence of a regional planning process, the process window for Transmission Provider's expansion planning period) not to exceed seven years from the date the Interconnection Request is received by Transmission Provider, unless Interconnection Customer demonstrates that engineering, permitting and construction of the new Large Generating Facility or increase in capacity of the existing Generating Facility will take longer than the regional expansion planning period. The In-Service Date may succeed the date the Interconnection Request is received by Transmission Provider by a period up to ten years, or longer where Interconnection Customer and Transmission Provider agree, such agreement not to be unreasonably withheld.

4.4.2 Initiating an Interconnection Request in the Definitive Interconnection Study Process. An Interconnection Customer wishing to join the Definitive Interconnection Study Process shall submit its Interconnection Request to the Transmission Provider within, and no later than the close of the annual DISIS Request Window. To initiate an Interconnection Request, the Interconnection Customer must submit all of the following:

a. The study deposit described in Section 4.1.2;

b. A completed application in the form of Appendix 3 to the LGIP (including applicable technical information);

c. A demonstration of Site Control as defined in Section 1 of the LGIP. Specifications for acceptable site size for the purposes of demonstrating Site Control are posted on

Transmission Provider's OASIS website. Interconnection Customer may propose alternative specifications for site size to those posted on OASIS for Transmission Provider's approval. In the event that the Transmission Provider and the Interconnection Customer cannot reach agreement related to adequacy of site size, Transmission Prover will accept a Professional Engineer (licensed in State of service) stamped site plan drawing that depicts the proposed generation arrangement and specifies the maximum facility output for that arrangement. Interconnection Customer may provide a cash deposit equal to $20,000 plus $500/MW in lieu of Site Control to enter Phase 1. A deposit in lieu of Site Control is not accepted for later Phases of the Definitive Interconnection Study Process;

d. A Point of Interconnection;

e. If the request is for NRIS and if Transmission Provider has not been notified pursuant to Section 29.2 of Part III of the Tariff that Interconnection Customer's proposed Generating Facility is to be designated as a Network Resource within Transmission Provider's Control Area, the point of delivery or the geographic location on Transmission Provider's Transmission System at which Interconnection Customer intends to deliver output out of Transmission Provider's Control Area; and

f. The requested capacity of the Generating Facility.

Interconnection Customer shall select the definitive Point of Interconnection to be studied no later than the execution of the Definitive System Impact Study Agreement. For purposes of clustering Interconnection Requests, Transmission Provider may make reasonable changes to the requested Point(s) of Interconnection to facilitate efficient interconnection of Interconnection Customers at common points of interconnection. Transmission Provider shall notify Interconnection Customer(s) in writing of any intended changes to the requested Point(s) of Interconnection and the Point(s) of Interconnection shall only change upon mutual agreement.

Transmission Provider shall have a process in place to consider requests for Interconnection Service below the Generating Facility Capacity. These requests for Interconnection Service shall be studied at the level of Interconnection Service requested for purposes of Interconnection Facilities and Network Upgrades, and associated costs, but may be subject to other studies at the full Generating Facility Capacity to ensure safety and reliability of the Transmission System, with the study costs borne by the Interconnection Customer. If after the additional studies are complete, Transmission Provider determines that additional Network Upgrades are necessary, then Transmission Provider must: (1) specify which additional Network Upgrade costs are based on which studies; and (2) provide a detailed explanation of why the additional Network Upgrades are necessary. Any Interconnection Facility and/or Network Upgrade costs required for safety and reliability also will be borne by the Interconnection Customer. Interconnection Customers may be subject to additional control technologies as well as testing and validation of those technologies consistent with Article 6 of the LGIA. The necessary control technologies and protection systems shall be established in Appendix C of the executed, or requested to be filed unexecuted, LGIA.

The expected In-Service Date of the new Large Generating Facility or increase in capacity of the existing Generating Facility shall be no more than the process window for the regional expansion planning period (or in the absence of a regional planning process, the process window for Transmission Provider's expansion planning period) not to exceed (7) seven years from the date the Interconnection Request is received by Transmission Provider, unless Interconnection Customer demonstrates that engineering, permitting and construction of the new Large Generating Facility or increase in capacity of the existing Generating Facility will take longer than the regional expansion planning period. The In-Service Date may succeed the date the Interconnection Request is received by Transmission Provider by a period up to (10) ten years, or longer where Interconnection Customer and Transmission Provider agree, such agreement not to be unreasonably withheld.

4.4.3 Acknowledgment of Interconnection Request.

Transmission Provider shall acknowledge receipt of the Interconnection Request within five (5) Business Days of receipt of the request and attach a copy of the received Interconnection Request to the acknowledgement.

4.4.4 Deficiencies in Interconnection Request Under the Serial Interconnection Study Process.

An Interconnection Request will not be considered to be a valid request until all items in Section 4.4.1 have been received by Transmission Provider. If an Interconnection Request fails to meet the requirements set forth in Section 4.4.1, Transmission Provider shall notify Interconnection Customer within five (5) Business Days of receipt of the initial Interconnection Request of the reasons for such failure and that the Interconnection Request does not constitute a valid request. Interconnection Customer shall provide Transmission Provider the additional requested information needed to constitute a valid request within ten (10) Business Days after receipt of such notice. Failure by Interconnection Customer to comply with this Section 4.4.4 shall be treated in accordance with Section 4.7.

4.4.5 Deficiencies in Interconnection Request Under the Definitive Interconnection Study Process.

An Interconnection Request will not be considered to be a valid request until all items in Section 4.4.2 have been received by the Transmission Provider.

If an Interconnection Request fails to meet the requirements set forth in Section 4.4.2, Transmission Provider shall notify the Interconnection Customer within five (5) Business Days of receipt of the initial Interconnection Request of the reasons for such failure and that the Interconnection Request does not constitute a valid request. The Interconnection Customer shall provide Transmission Provider the additional requested information needed to constitute a valid request within ten (10) Business Days after receipt of such notice. At any time, if Transmission Provider identifies issues with technical data provided by the Interconnection Customer, Interconnection Customer and Transmission Provider shall work expeditiously and in good faith to remedy any data issues. Failure by the Interconnection Customer to comply with this Section 4.4.5 shall be treated in accordance with Section 4.7.

Transmission Provider shall determine if the information contained in the Interconnection Request is adequately sufficient to start the Definitive System Impact Study by the close of the Customer Engagement Window.

4.4.6 Scoping Meeting for Serial Interconnection Study Process.

Within ten (10) Business Days after receipt of a valid Interconnection Request, Transmission Provider shall establish a date agreeable to Interconnection Customer for the Scoping

Meeting, and such date shall be no later than thirty (30) Calendar Days from receipt of the valid Interconnection Request, unless otherwise mutually agreed upon by the Parties.

The purpose of the Scoping Meeting shall be to discuss alternative interconnection options, to exchange information including any transmission data that would reasonably be expected to impact such interconnection options, to analyze such information and to determine the potential feasible Points of Interconnection. Transmission Provider and Interconnection Customer will bring to the meeting such technical data, including, but not limited to: (i) general facility loadings, (ii) general instability issues, (iii) general short circuit issues, (iv) general voltage issues, and (v) general reliability issues as may be reasonably required to accomplish the purpose of the meeting. Transmission Provider and Interconnection Customer will also bring to the meeting personnel and other resources as may be reasonably required to accomplish the purpose of the meeting in the time allocated for the meeting. On the basis of the meeting, Interconnection Customer shall designate its Point of Interconnection, pursuant to Section 4.4.1, and one or more available alternative Point(s) of Interconnection. The duration of the meeting shall be sufficient to accomplish its purpose.

4.4.7 Scoping Meeting for Definitive Interconnection Study Process.
Within ten (10) Business Days after the close of the DISIS Request Window described in Section 10.1, Transmission Provider shall host an open Scoping Meeting, for all Interconnection Requests received during that DISIS Request Window. If requested by the Interconnection Customer, Transmission Provider shall also hold individual customer specific Scoping Meetings, which must be requested no later than fifteen (15) Business Days after the close of the DISIS Request Window.

The purpose of the Scoping Meeting shall be to discuss alternative interconnection options, to exchange information, including any transmission data that would reasonably be expected to impact such interconnection options, to preliminarily analyze such information; and to determine the potential feasible Point(s) of Interconnection. Transmission Provider and Interconnection Customer will bring to the meeting such technical data, including, but not limited to: (i) general facility loadings, (ii) general instability issues, (iii) general short circuit issues, (iv) general voltage issues, and (v) general reliability issues as may be reasonably required to accomplish the purpose of the meeting. Transmission Provider and Interconnection Customer will also bring to the meeting personnel and other resources as may be reasonably required to accomplish the purpose of the meeting in the time allocated for the meeting. On the basis of the meeting, Interconnection Customer shall designate a single, definitive Point of Interconnection, pursuant to Section 4.4.2. The duration of the meeting shall be sufficient to accomplish its purpose.

At Interconnection Customer's option, the Transmission Provider and Interconnection Customer will identify alternative Point(s) of Interconnection and configurations at the Scoping Meeting to evaluate in the DISIS Cluster Study Process and attempt to eliminate alternatives in a reasonable fashion given resources and information available. Interconnection Customer shall select a single definitive Point of Interconnection to be studied no later than the execution of the DISIS Agreement and shall provide affirmation of Site Control to construct the entire Generating Facility and all required Interconnection Facilities to the designated Point of Interconnection or the deposit in lieu of Site Control prescribed in Section 4.4.2 (c.) no later than commencement of the Phase 1 study process described in Section 10.8.

4.5 OASIS Posting.

Transmission Provider will maintain on its OASIS a list of all Interconnection Requests. The list will identify, for each Interconnection Request: (i) the maximum summer and winter megawatt electrical output; (ii) the location by county and state; (iii) the station or transmission line or lines where the interconnection will be made; (iv) the projected In-Service Date; (v) the status of the Interconnection Request, including Queue Position and Cluster (if applicable); (vi) the type of Interconnection Service being requested; and (vii) the availability of any studies related to the Interconnection Request; (viii) the date of the Interconnection Request; (ix) the type of Generating Facility to be constructed (combined cycle, base load or combustion turbine and fuel type); and (x) for Interconnection Requests that have not resulted in a completed interconnection, an explanation as to why it was not completed. Except in the case of an Affiliate, the list will not disclose the identity of Interconnection Customer until Interconnection Customer executes an LGIA or requests that Transmission Provider file an unexecuted LGIA with FERC. Before holding a Scoping Meeting with its Affiliate, Transmission Provider shall post on OASIS an advance notice of its intent to do so. Transmission Provider shall post to its OASIS site any deviations from the study timelines set forth herein. Interconnection Study reports and Optional Interconnection Study reports shall be posted to Transmission Provider's OASIS site subsequent to the meeting between Interconnection Customer and Transmission Provider to discuss the applicable study results. Transmission Provider shall also post any known deviations in the Large Generating Facility's In-Service Date.

4.5.1 Requirement to Post Interconnection Study Metrics.

Transmission Provider will maintain on its OASIS or its website summary statistics related to processing Interconnection Studies pursuant to Interconnection Requests, updated quarterly. If Transmission Provider posts this information on its website, a link to the information must be provided on Transmission Provider’s OASIS site. For each calendar quarter, Transmission Providers must calculate and post the information detailed in Sections 4.5.2 through 4.5.3.

4.5.2 Serial Interconnection Study Processing Metrics.

4.5.2.1 Feasibility Studies Processing Time.

(A) Number of Interconnection Requests that had Interconnection Feasibility Studies completed within Transmission Provider’s Control Area during the reporting quarter;

(B) Number of Interconnection Requests that had Interconnection Feasibility Studies completed within Transmission Provider’s Control Area during the reporting quarter that were completed more than 45 Calendar Days after receipt by Transmission Provider of the Interconnection Customer’s executed Interconnection Feasibility Study Agreement;

(C) At the end of the reporting quarter, the number of active valid Interconnection Requests with ongoing incomplete Interconnection Feasibility Studies where such Interconnection Requests had executed Interconnection Feasibility Study Agreements received by Transmission Provider more than 45 Calendar Days before the reporting quarter end;

(D) Mean time (in Calendar Days), Interconnection Feasibility Studies completed within Transmission Provider’s Control Area during the reporting quarter, from the date when Transmission Provider received the executed the Interconnection Feasibility Study

Agreement to the date when Transmission Provider provided the completed Interconnection Feasibility Study to the Interconnection Customer;

(E) Percentage of Interconnection Feasibility Studies exceeding 45 Calendar Days to complete this reporting quarter, calculated as the sum of 4.5.2.1(B) plus 4.5.2.1(C) divided by the sum of 4.5.2.1(A) plus 4.5.2.1(C)).

4.5.2.2 Serial Interconnection System Impact Studies Processing Time.
(A) Number of Interconnection Requests that had Serial Interconnection System Impact Studies completed within Transmission Provider's Control Area during the reporting quarter;

(B) Number of Interconnection Requests that had Serial Interconnection System Impact Studies completed within Transmission Provider's Control Area during the reporting quarter that were completed more than 90 Calendar Days after receipt by Transmission Provider of the Interconnection Customer's executed Interconnection System Impact Study Agreement;

(C) At the end of the reporting quarter, the number of active valid Interconnection Requests with ongoing incomplete System Impact Studies where such Interconnection Requests had executed Interconnection System Impact Study Agreements received by Transmission Provider more than 90 Calendar Days before the reporting quarter end;

(D) Mean time (in Calendar Days), Serial Interconnection System Impact Studies completed within Transmission Provider's Control Area during the reporting quarter, from the date when Transmission Provider received the executed Interconnection System Impact Study Agreement to the date when Transmission Provider provided the completed Interconnection System Impact Study to the Interconnection Customer;

(E) Percentage of Serial Interconnection System Impact Studies exceeding 90 Calendar Days to complete this reporting quarter, calculated as the sum of 4.5.2.2(B) plus 4.5.2.2(C) divided by the sum of 4.5.2.2(A) plus 4.5.2.2(C)).

4.5.3 Definitive Interconnection Study Processing Metrics.

4.5.3.1 Definitive Interconnection Study Phase 1 Processing Time.
(A) Number of Interconnection Requests that had DISIS Phase 1 Studies completed within Transmission Provider's Control Area during the reporting quarter;

(B) At the end of the reporting quarter, number of Interconnection Requests that had DISIS Phase 1 Studies completed within Transmission Provider's Control Area during the reporting quarter that were completed more than ninety (90) Calendar Days after Transmission Provider commenced the DISIS Phase 1 Study, the duration (in days) to complete the Phase 1 Study, and an explanation of why Transmission Provider's completion of the Phase 1 study exceeded the timeline set forth in Section 10.8(a.).

4.5.3.2 Definitive Interconnection Study Phase 2 Processing Time.
(A) Number of Interconnection Requests that had DISIS Phase 2 studies completed within Transmission Provider's Control Area during the reporting quarter;

(B) At the end of the reporting quarter, number of Definitive Interconnection Requests that had DISIS Phase 2 Studies completed within Transmission Provider's Control Area during the reporting quarter that were completed more than one hundred fifty (150) Calendar Days after Transmission Provider commenced the DISIS Phase 2 Study, the duration (in days) to complete the Phase 2 Study, and an explanation of why Transmission Provider's completion of the Phase 2 study exceeded the timeline set forth in Section 10.8(c.).

4.5.3.3 Definitive Interconnection Study Phase 3 Processing Time.
(A) Number of Interconnection Requests that were required to undergo DISIS Phase 3 restudies and number of Phase 3 restudies completed within Transmission Provider's Control Area during the reporting quarter;

(B) At the end of the reporting quarter, number of Definitive Interconnection Requests that had DISIS Phase 3 restudies completed within Transmission Provider's Control Area during the reporting quarter that were completed more than one hundred fifty (150) Calendar Days after Transmission Provider commences the DISIS Phase 3 Restudy, the duration (in days) to complete the Phase 3 Restudy, and explanation of why Transmission Provider's completion of the Phase 3 Restudy exceeded the timeline set forth in Section 10.8(e.).

4.5.4 Interconnection Facilities Studies Processing Time.
(A) Number of Interconnection Requests that had Interconnection Facilities Studies that are completed within Transmission Provider's Control Area during the reporting quarter;

(B) Number of Interconnection Requests that had Interconnection Facilities Studies that are completed within Transmission Provider's Control Area during the reporting quarter that were completed (1) under the Serial Interconnection Study Process, more than (a) ninety (90) Calendar Days after receipt by Transmission Provider of the Interconnection Customer's executed Interconnection Facilities Study Agreement if Interconnection Customer requested a +/- 20% cost estimate in such study or (b) one hundred eighty (180) Calendar Days after receipt by Transmission Provider of the Interconnection Customer's executed Interconnection Facilities Study Agreement if Interconnection Customer requested a +/- 10% cost estimate in such study, or (2) under the Definitive Interconnection Study Process, more than one hundred fifty (150) Calendar Days after receipt by Transmission Provider of the Interconnection Customer's executed Interconnection Facilities Study Agreement;

(C) At the end of the reporting quarter, the number of active valid Interconnection Service requests with ongoing incomplete Interconnection Facilities Studies where such Interconnection Requests had executed Interconnection Facilities Studies Agreement received by Transmission Provider (1) under the Serial Interconnection Study Process, more than (a) ninety (90) Calendar Days after receipt by Transmission Provider of the Interconnection Customer's executed Interconnection Facilities Study Agreement if Interconnection Customer requested a +/- 20% cost estimate in such study or (b) one hundred eighty (180) Calendar Days before the reporting quarter end if Interconnection Customer requested a +/- 10% cost estimate in such study, or (2) under the Definitive Interconnection Study Process, more than one hundred fifty (150) Calendar Days after receipt by Transmission Provider of the Interconnection Customer's executed Interconnection Facilities Study Agreement;

(D) Mean time (in Calendar Days), for Interconnection Facilities Studies completed within Transmission Provider's Control Area during the reporting quarter, calculated from the date when Transmission Provider received the executed Interconnection Facilities Study

Agreement to the date when Transmission Provider provided the completed Interconnection Facilities Study to the Interconnection Customer;

(E) Percentage of delayed Interconnection Facilities Studies this reporting quarter, calculated as the sum of 4.5.4(B) plus 4.5.4(C) divided by the sum of 4.5.4(A) plus 4.5.4(C)).

4.5.5 Interconnection Service Requests Withdrawn From Interconnection Queue.
(A) Number of Interconnection Service requests withdrawn from Transmission Provider's interconnection queue during the reporting quarter;

(B) Number of Interconnection Service requests withdrawn from Transmission Provider's interconnection queue during the reporting quarter before completion of any interconnection studies or execution of any interconnection study agreements;

(C) Number of Interconnection Service requests withdrawn from Transmission Provider's interconnection queue during the reporting quarter before completion of an Interconnection System Impact Study or Definitive Interconnection System Impact Study Agreement, as applicable;

(D) Number of Interconnection Service requests withdrawn from Transmission Provider's interconnection queue during the reporting quarter before completion of an Interconnection Facility Study;

(E) Number of Interconnection Service requests withdrawn from Transmission Provider's interconnection queue after execution of a generator interconnection agreement or Interconnection Customer requests the filing of an unexecuted, new interconnection agreement;

(F) Mean time (in Calendar Days), for all withdrawn Interconnection Service requests, from the date when the request was determined to be valid to when Transmission Provider received the request to withdraw from the queue.

4.5.6 Requirement to Post Interconnection Study Metrics.
Transmission Provider is required to post on OASIS or its website the measures detailed from Section 4.5.2 (applicable to Transmission Providers administering Serial Interconnection Study Process only), 4.5.3 (applicable to Transmission Providers administering Definitive Interconnection Study Process only), 4.5.4, and 4.5.5 for each calendar quarter within 30 Calendar Days of the end of the calendar quarter. Transmission Provider will keep the quarterly measures posted on OASIS or its website for three calendar years with the first required report to be in the first quarter of 2020. If Transmission Provider retains this information on its website, a link to the information must be provided on Transmission Provider's OASIS site.

4.5.7 Reporting Requirement for Late Studies.
In the event that any of the values calculated in paragraphs 4.5.2.1(E), 4.5.2.2(E) or 4.5.4(E) exceeds 25 percent for two consecutive calendar quarters, Transmission Provider will have to comply with the measures below for the next four consecutive calendar quarters and must continue reporting this information until Transmission Provider reports four consecutive calendar quarters without the values calculated in 4.5.2.1(E), 4.5.2.2(E) or 4.5.4(E)) exceeding 25 percent for two consecutive calendar quarters:

(i) Transmission Provider must submit a report to the Commission describing the reason for each study or group of clustered studies pursuant to an Interconnection Request that exceeded its deadline (i.e., 45, 90, 150 or 180 Calendar Days) for completion (excluding any allowance for Reasonable Efforts). Transmission Provider must describe the reasons for each study delay and any steps taken to remedy these specific issues and, if applicable, prevent such delays in the future. The report must be filed at the Commission within 45 Calendar Days of the end of the calendar quarter.

(ii) Transmission Provider shall aggregate the total number of employee hours and third party consultant hours expended towards interconnection studies within its Control Area that quarter and post on OASIS or its website. If Transmission Provider posts this information on its website, a link to the information must be provided on Transmission Provider's OASIS site. This information is to be posted within 30 Calendar Days of the end of the calendar quarter.

4.6 Coordination with Affected Systems.
Transmission Provider will coordinate the conduct of any studies required to determine the impact of the Interconnection Request on Affected Systems with Affected System Operators and, if possible, include those results (if available) in its applicable Interconnection Study within the time frame specified in this LGIP. Transmission Provider will include such Affected System Operators in all meetings held with Interconnection Customer as required by this LGIP. Interconnection Customer will cooperate with Transmission Provider in all matters related to the conduct of studies and the determination of modifications to Affected Systems. A Transmission Provider which may be an Affected System shall cooperate with Transmission Provider with whom interconnection has been requested in all matters related to the conduct of studies and the determination of modifications to Affected Systems. It is the responsibility of the Affected System Operator to provide the requirements or potential impediments to providing the requested interconnection service, including a preliminary indication of the cost and length of time that would be necessary to (i) complete any interconnection studies and (ii) construct any necessary Interconnection Facilities and Network Upgrades needed to reliably interconnect at the requested service level.

4.7 Withdrawal.
Interconnection Customer may withdraw its Interconnection Request at any time by written notice of such withdrawal to Transmission Provider. In addition, if Interconnection Customer fails to adhere to all requirements of this LGIP, except as provided in Section 16.6 (Disputes), Transmission Provider shall deem the Interconnection Request to be withdrawn and shall provide written notice to Interconnection Customer of the deemed withdrawal and an explanation of the reasons for such deemed withdrawal. Upon receipt of such written notice, Interconnection Customer shall have fifteen (15) Business Days in which to either respond with information or actions that cures the deficiency or to notify Transmission Provider of its intent to pursue Dispute Resolution.

Withdrawal shall result in the loss of Interconnection Customer's Queue Position. If an Interconnection Customer disputes the withdrawal and loss of its Queue Position, then during Dispute Resolution, Interconnection Customer's Interconnection Request is eliminated from the Queue until such time that the outcome of Dispute Resolution would restore its Queue Position. An Interconnection Customer that withdraws or is deemed to have withdrawn its

Interconnection Request shall pay to Transmission Provider all costs that Transmission Provider prudently incurs with respect to that Interconnection Request prior to Transmission Provider's receipt of notice described above. Interconnection Customer must pay all monies due to Transmission Provider before it is allowed to obtain any Interconnection Study data or results.

Transmission Provider shall (i) update the OASIS Queue Position posting and (i) refund to Interconnection Customer any of the refundable portion of Interconnection Customer's study deposit or study payments that exceeds the share of the costs that Transmission Provider has incurred, including interest calculated in accordance with Section 35.19a(a)(2) of FERC's regulations. In the event of such withdrawal, Transmission Provider, subject to the confidentiality provisions of Section 16.1, shall provide, at Interconnection Customer's request, all information that Transmission Provider developed for any completed study conducted up to the date of withdrawal of the Interconnection Request.

4.7.1 Definitive Interconnection Study Process – Withdrawal Penalty.
Where a Transmission Provider is administering a Definitive Interconnection Study Process and an Interconnection Customer notifies the Transmission Provider of its intended Interconnection Request withdrawal or it is deemed withdrawn, as provided for in Section 4.7, the Transmission Provider shall: (i) update the OASIS Queue Position posting; (ii) impose the Withdrawal Penalty described in this Section and calculated under the methodology in Section 4.7.1.1, (iii), refund any security after settling the final invoice as described in Section 10.11.6, (iv) refund to Interconnection Customer any of the refundable portion of Interconnection Customer's study deposit or study payments that exceeds the share of the costs that Transmission Provider has incurred, including interest calculated in accordance with Section 35.19a(a)(2) of FERC's regulations. In the event of such withdrawal, Transmission Provider, subject to the confidentiality provisions of Section 16.1, shall provide, at Interconnection Customer's request, all information that Transmission Provider developed for any completed study conducted up to the date of withdrawal of the Interconnection Request.

An Interconnection Customer shall be subject to a Withdrawal Penalty if it withdraws its Interconnection Request from the Queue or the Generating Facility does not otherwise reach Commercial Operation unless the Transmission Provider determines consistent with Good Utility Practice that (1) the withdrawal does not negatively affect the timing or cost of equal or lower queued projects; (2) the cost responsibility identified for that Interconnection Customer in the current study report associated with new Network Upgrades to the Transmission Provider's System increased by more than twenty-five percent (25%) compared to the costs identified in the previous report; or (3) if the customer withdraws after the Interconnection Facilities Study report is published and before providing M5, and the cost responsibility for that Interconnection Customer identified in the Interconnection Facilities Study report increases by more than one hundred percent (100%) compared to the Phase 2 report.

4.7.1.1 Calculation of the Withdrawal Penalty.
If the Interconnection Customer provided a demonstration(s) of readiness at Readiness Milestones 1-4, as described in Sections 10.11.1, 10.11.2, 10.11.3, and 10.11.4, that Interconnection Customer's Withdrawal Penalty shall be equal to the higher of the study deposit or one (1) times its actual allocated cost of the Definitive Interconnection Study Process.

If the Interconnection Customer did not provide a demonstration(s) of readiness at Readiness Milestones 1-4, as described in Sections 10.11.1, 10.11.2, 10.11.3, and 10.11.4, that Interconnection Customer's Withdrawal Penalty shall be dependent on the Interconnection Customer's progression through the Section 10 Definitive Interconnection System Impact Study and the Section 11 Interconnection Facilities Study and shall be calculated as follows:

1. If the Interconnection Customer withdraws in DISIS Phase 1 (after M1, but before M2), the Withdrawal Penalty shall be the higher of the study deposit or two (2) times its actual allocated cost of the Definitive Interconnection Study Process. This amount shall be capped at one (1) million dollars.

2. If the Interconnection Customer withdraws in DISIS Phase 2 (after M2, but before M3), the Withdrawal Penalty shall be the higher of the study deposit or three (3) times its actual allocated cost of the Definitive Interconnection Study Process. This amount shall be capped at one and one half (1.5) million dollars.

3. If the Interconnection Customer withdraws after DISIS Phase 2 concludes but before the Interconnection Facilities Study commences (after M3, but before M4), the Withdrawal Penalty shall be the higher of the study deposit or five (5) times the Interconnection Customer's actual allocated cost of the Definitive Interconnection Study Process. This amount shall be capped at two (2) million dollars.

4. If the Interconnection Customer withdraws in the Interconnection Facilities Study (after M4, but before M5), the Withdrawal Penalty shall be the higher of the study deposit or seven (7) times the Interconnection Customer's actual allocated cost of the Definitive Interconnection Study Process. This amount shall be capped at two and a half (2.5) million dollars.

If the Interconnection Customer provided a deposit in lieu of Site Control for Phase 1 and withdraws before entering Phase 2, the Withdrawal Penalty is increased by an amount equal to $20,000 plus $500/MW, which is in addition to the amounts described above.

The Withdrawal Penalty for any Interconnection Customer that has executed an LGIA is the higher of the study deposit or nine (9) times its actual allocated cost of the Definitive Interconnection Study Process.

4.7.1.2 Distribution of the Withdrawal Penalty.
Any Withdrawal Penalty revenues shall be used to fund generation interconnection studies. Withdrawal Penalty revenues shall first be applied, in the form of a bill credit, to not-yet-invoiced study costs for other Interconnection Customers in the same cluster, and to the extent that such studies are fully credited, shall be applied to study costs of future clusters in Queue order. ;Withdrawn Interconnection Customers shall not receive a bill credit associated with Withdrawal Penalties. Distribution of Withdrawal Penalty revenues to a specific study shall not exceed the total actual study costs. Allocation of Withdrawal Penalty revenues within a cluster to a specific customer shall be comparable to the allocation of study costs described in Section 10.3. Specifically, the Withdrawal Penalty revenue distribution to each customer in a specific cluster, shall be (1) ten percent (10%) on a per capita basis based on number of Interconnection Requests in the applicable Cluster; and (2) ninety percent (90%) to Interconnection Customers on a pro-rata basis based on requested megawatts included in

the applicable Cluster. Distribution of Withdrawal Penalty revenue associated with Readiness Milestone 5 shall not be distributed to the remaining customers in that cluster until all customers in that cluster have reached Commercial Operation and thereafter shall be distributed as described above. Transmission Provider shall not change the distribution of Withdrawal Penalty revenue without authorization by the Commission. Transmission Provider shall post the Withdrawal Penalty balance on its OASIS site.

4.8 Identification of Contingent Facilities.

4.8.1 Method for Identifying Contingent Facilities.
The following steps are to be taken by Transmission Provider to identify and list the Contingent Facilities, if any, upon which the Interconnection Customer's costs, timing, and study findings are dependent. Such list is to be provided to Interconnection Customer at the conclusion of either the Serial Interconnection System Impact Study performed pursuant to the requirements of Section 9 or the Definitive Interconnection System Impact Study performed pursuant to the requirements of Section 10 of this LGIP.

Step 1: In preparation for performing an Interconnection Customer's System Impact Study, Transmission Provider will employ the following three methods to identify potential contingent facilities:

(a) reviewing any applicable Interconnection Study associated with generating facilities that have a higher queued interconnection request and determining whether any of those request(s) have unbuilt Interconnection Facilities and/or Network Upgrades that may be necessary to accommodate the Interconnection Customer's requested interconnection,

(b) reviewing its 10-year transmission expansion plan and identifying any planned upgrades to its System which may be necessary to accommodate the Interconnection Customer's requested interconnection, and

(c) coordinating with applicable Affected Systems to obtain from such Affected Systems any completed and available Affected System studies to determine what Contingent Facilities have been identified in such studies based on the Affected Systems' respective criteria.

Step 2: Using the methods identified in Step 1, Transmission Provider will make a list of potential contingent facilities that consist of

(a) any unbuilt Interconnection Facilities and/or Network Upgrades associated with higher queued interconnection requests that are identified as potentially necessary to accommodate the Interconnection Customer's requested interconnection,

(b) any of Transmission Provider's planned upgrades to its system that are identified as potentially necessary to accommodate the Interconnection Customer's requested interconnection, and

(c) any Contingent Facilities that have been identified in Affected System studies as potentially necessary to accommodate Interconnection Customer's requested interconnection.

Step 3: The Transmission Provider will, using the list of potential contingent facilities identified in Steps 2(a) and 2(b), conduct a flow impact analysis on such facilities based on the performance requirements set forth in NERC Reliability Standard TPL-001-4, Table 1 (Transmission System Planning Performance Requirements) or any successor applicable version of such Reliability Standard; provided, however, that the flow impact analysis is not necessary if the related modification or upgrade is the facility the generator is connecting to (effectively 100% flow impact).

Step 4: The criteria that shall apply to the flow impact analysis performed in Step 3 are as follows:

a. the MW size of the Interconnection Request (the distribution factor) and
b. the applicable MVA rating of the existing facility that is mitigated by the potential contingent facility

The thresholds that shall apply to the flow impact analysis performed in Step 3 are as follows:

a. 3% of the MW size of the Interconnection Request (the distribution factor) and
b. 1% of the applicable MVA rating of the existing facility that is mitigated by the potential contingent facility

If Transmission Provider's resulting analysis in accordance with Step 3 and applying the thresholds in this Step 4 demonstrates that the MW impact on the potential contingent facility is either (a) at least 3% of the MW size of the Interconnection Request (the distribution factor) or (b) at least 1% of the applicable MVA rating of the existing facility that is mitigated by the potential contingent facility then Transmission Provider shall deem such potential contingent facilities as Contingent Facilities.

Step 5: In the System Impact Study report, Transmission Provider will list the identified Contingent Facilities and explain why each listed Contingent Facility was identified as such by identifying (a) which threshold in Step 4 was exceeded and (b) the amount by which such threshold was exceeded, which will inform Interconnection Customer of its potential risk exposure should any such Contingent Facility be delayed or not built.

4.8.2 Estimates Available for Contingent Facilities.
Upon request of Interconnection Customer, Transmission Provider shall provide the estimated costs of Interconnection Facilities and/or Network Upgrades and estimated in-service completion times of each Contingent Facility identified in either the Serial Interconnection System Impact Study performed pursuant to Section 9 or the Definitive Interconnection System Impact Study pursuant to Section 10 of this LGIP, if, and to the extent, Transmission Provider determines that such information is readily available and not commercially sensitive.

4.8.3 Inclusion of Contingent Facilities in LGIA.
Any Contingent Facilities identified for Interconnection Customer at the conclusion of either the Serial Interconnection System Impact Study performed pursuant to Section 9 or the Definitive Interconnection System Impact Study pursuant to Section 10 of this LGIP, will subsequently be included in such Interconnection Customer's Large Generator Interconnection Agreement, to the extent they are still applicable.

Section 5. Queue Position and Queue Processing.

5.1 Serial Interconnection Study Process Queue Position.

Where the Transmission Provider is administering a Serial Interconnection Study Process, Transmission Provider shall assign a Queue Position based upon the date and time of receipt of the valid Interconnection Request; provided that, if the sole reason an Interconnection Request is not valid is the lack of required information on the application form, and Interconnection Customer provides such information in accordance with Section 4.4.4, then Transmission Provider shall assign Interconnection Customer a Queue Position based on the date the application form was originally filed. Moving a Point of Interconnection shall result in a lowering of Queue Position if it is deemed a Material Modification under Section 5.4.

The Queue Position of each Interconnection Request will be used to determine the order of performing the Interconnection Studies and determination of cost responsibility for the facilities necessary to accommodate the Interconnection Request. A higher queued Interconnection Request is one that has been placed "earlier" in the queue in relation to another Interconnection Request that is lower queued.

5.1.1 Serial Interconnection Study Process – Clustering.

At Transmission Provider's option, Interconnection Requests may be studied serially or in clusters for the purpose of the Serial Interconnection System Impact Study.

Clustering shall be implemented on the basis of Queue Position. If Transmission Provider administering the Serial Interconnection Study Process elects to study Interconnection Requests using Clustering, all Interconnection Requests received within a period not to exceed one hundred and eighty (180) Calendar Days, hereinafter referred to as the "Queue Cluster Window" shall be studied together without regard to the nature of the underlying Interconnection Service, whether Energy Resource Interconnection Service or Network Resource Interconnection Service. The deadline for completing all Serial Interconnection System Impact Studies for which a Serial Interconnection System Impact Study Agreement has been executed during a Queue Cluster Window shall be in accordance with Section 9.4, for all Interconnection Requests assigned to the same Queue Cluster Window. Transmission Provider may study an Interconnection Request separately to the extent warranted by Good Utility Practice based upon the electrical remoteness of the proposed Large Generating Facility.

Clustering Serial Interconnection System Impact Studies shall be conducted in such a manner to ensure the efficient implementation of the applicable regional transmission expansion plan in light of the Transmission System's capabilities at the time of each study.

The Queue Cluster Window shall have a fixed time interval based on fixed annual opening and closing dates. Any changes to the established Queue Cluster Window interval and opening or closing dates shall be announced with a posting on Transmission Provider's OASIS beginning at least one hundred and eighty (180) Calendar Days in advance of the change and continuing thereafter through the end date of the first Queue Cluster Window that is to be modified.

5.2 Definitive Interconnection Study Process Queue Position.

Where the Transmission Provider is administering a Definitive Interconnection Study Process, the Transmission Provider shall assign a Queue Position to each Interconnection Request as follows: the Queue Position within the Queue shall be assigned based upon the date and time of receipt of all items required pursuant to the provisions of Section 4.4 during the annual DISIS Request Window described in Section 10.1. There is no queue for Informational Interconnection Studies.

A higher Queue Position assigned to an Interconnection Request is one that has been placed "earlier" in the Queue in relation to another Interconnection Request that is assigned a lower Queue Position. All requests studied in a single Cluster shall be considered equally queued but Clusters initiated earlier in time shall be considered to have a higher Queue Position than clusters initiated later. The Queue Position of an Interconnection Request shall have no bearing on the allocation of the cost of the shared Network Upgrades and Transmission Provider's Interconnection Facilities identified in the applicable Cluster study (such costs will be allocated among Interconnection Requests in accordance with Section 10.4). Moving a Point of Interconnection shall result in the withdrawal of the Interconnection Request and loss of the corresponding Queue Position if it is deemed a Material Modification under Section 5.4.

5.3 Transferability of Queue Position.

An Interconnection Customer may transfer its Queue Position to another entity only if such entity acquires the specific Generating Facility identified in the Interconnection Request and the Point of Interconnection does not change.

5.4 Modifications.

Interconnection Customer shall submit to Transmission Provider, in writing, modifications to any information provided in the Interconnection Request. Interconnection Customer shall retain its Queue Position if the modifications are in accordance with Sections 5.4.1, 5.4.2, 5.4.3, or 5.4.5, or are determined not to be Material Modifications pursuant to Section 5.4.3.

Notwithstanding the above, during the course of the Interconnection Studies, either Interconnection Customer or Transmission Provider may identify changes to the planned interconnection that may improve the costs and benefits (including reliability) of the interconnection, and the ability of the proposed change to accommodate the Interconnection Request. Subject to the forgoing sentence, and provided, however, they do not result in a Material Modification, to the extent the identified changes are acceptable to Transmission Provider, Interconnection Customer and potentially impacted Interconnection Customers in the same Cluster, such acceptance not to be unreasonably withheld, Transmission Provider shall modify the Point of Interconnection and/or configuration in accordance with such changes and proceed with any re-studies necessary to do so in accordance with Section 9.6, Section 10.8(e.), and Section 10.10 as applicable and Interconnection Customer shall retain its Queue Position.

5.4.1 Material Modifications Prior to System Impact Study Agreement Execution.

Prior to (a) the return of the executed Serial Interconnection System Impact Study Agreement to Transmission Provider or (b) no later than forty (40) Calendar Days after the close of the DISIS Request Window and prior to the return of the executed Definitive Interconnection System Impact Study Agreement to Transmission Provider, modifications permitted under this Section shall include specifically: (a) a decrease of up to 60 percent of electrical output (MW) of the proposed project; through either (1) a decrease in plant size of (2) a decrease in Interconnection Service level (consistent with the processes described in Section 4.1) accomplished by applying Transmission Provider-approved injection-limiting equipment; (b) modifying the technical parameters associated with the Large Generating Facility technology or the Large Generating Facility step-up transformer impedance characteristics; and (c) modifying the interconnection configuration. For plant increases, the incremental increase in plant output will go to the end of the queue for the purposes of cost allocation and study analysis.

5.4.2 Material Modifications Prior to Facilities Study Agreement Execution.
Prior to the return of the executed Serial Interconnection Facilities Study Agreement or Definitive Interconnection Facilities Study Agreement (as the case may be) to the Transmission Provider, the modifications permitted under this Section shall include specifically: (a) additional 15 percent decrease of electrical output of the proposed project through either (1) a decrease in plant size (MW) or (2) a decrease in Interconnection Service level (consistent with the process described in Section 4.1) accomplished by applying Transmission Provider-approved injection-limiting equipment;, and (b) Large Generating Facility technical parameters associated with modifications to Large Generating Facility technology and transformer impedances; provided, however, any incremental re-study costs or shifts in Network Upgrade costs associated with those modifications that would increase costs assigned to other Interconnection Customers within the same Cluster shall not be allocated pursuant to Sections 10.3 and 10.4 of this LGIP, and, instead, are the responsibility of and shall be fully assigned to the requesting Interconnection Customer; and (c) a Permissible Technological Advancement for the Large Generating Facility after the submission of the Interconnection Request. Section 5.4.5 specifies a separate technological change procedure including the requisite information and process that will be followed to assess whether the Interconnection Customer’s proposed technological advancement is a Material Modification. Section 1 contains a definition of Permissible Technological Advancement.

5.4.3 Modification Inquiry Process.
Prior to making any modification other than those specifically permitted by Sections 5.4.1, 5.4.2, 5.4.3, and 5.4.5, Interconnection Customer may first request that Transmission Provider evaluate whether such modification is a Material Modification. In response to Interconnection Customer's request, Transmission Provider shall evaluate the proposed modifications prior to making them and inform Interconnection Customer in writing of whether the modifications would constitute a Material Modification. Any change to the Point of Interconnection, except those deemed acceptable under Sections 5.4.1, 5.4.2, 9.2, 10.7 or so allowed elsewhere, shall constitute a Material Modification. Interconnection Customer may then withdraw the proposed modification or proceed with a new Interconnection Request for such modification.

5.4.4 Receipt of Request for Modification. Upon receipt of Interconnection Customer's request for modification permitted under this Section 5.4, Transmission Provider shall commence and perform any necessary additional studies as soon as practicable, but in no event shall Transmission Provider commence such studies later than thirty (30) Calendar Days after receiving notice of Interconnection Customer's request.

5.4.5 Commercial Operation Date. Extensions of less than three (3) cumulative years in the Commercial Operation Date of the Large Generating Facility to which the Interconnection

Request relates are not material and should be handled through construction sequencing. The initial requested Commercial Operation Date used for this calculation is determined from the date proposed in the initial Interconnection Request (Revised LGIP Appendix 3). Such cumulative extensions are inclusive of extensions requested after execution by Interconnection Customer of the LGIA.

5.4.6 Technological Change Procedure.
The technological change procedure included in this Section 5.4.6 will be followed to assess whether Interconnection Customer's proposed modification is a Material Modification.

5.4.6.1 Technological Change Request.
If an Interconnection Customer seeks to incorporate a technological advancement into its existing Interconnection Request, it must submit a Technological Change Request ("TCR") as described below to the Transmission Provider in writing any time prior to the return of the signed Interconnection Facilities Study Agreement.

The Interconnection Customer's TCR shall include a description of the proposed change, a $10,000 study deposit, and the following information: (1) updated technical data called for in Attachment A of Appendix 1; (2) type and specifications of equipment being replaced; (3) updated modeling information; (4) make and model of new equipment; (5) dynamic, steady-state and performance characteristics of the new equipment; (6) efficiencies, impedances, and ratings of the equipment; and (7) technical analysis demonstrating that the technological change would (i) result in electrical performance that is equal to or better than the electrical performance expected prior to the technological change, and (ii) not cause any reliability concerns (i.e., would not materially impact the Transmission System with regard to short circuit capability limits, steady-state thermal and voltage limits, or dynamic system stability and response). The Interconnection Customer's analysis should contain engineering evidence and reasoning that clearly demonstrates that the proposed change aligns with the definition of a Permissible Technological Advancement.

Upon receipt by the Transmission Provider of a completed TCR from the Interconnection Customer, the Transmission Provider will evaluate the TCR to determine whether the TCR is a Permissible Technological Advancement or if it necessitates the performance of additional analyses and/or studies. If the TCR is determined to have no adverse effect on electrical parameters or performance, then the TCR will not be considered a Material Modification, but rather will be deemed a Permissible Technological Advancement.

If the Transmission Provider determines that additional analyses and/or studies are required, Transmission Provider's studies may include steady-state, reactive power, short circuit, stability analysis and any other appropriate studies that the Transmission Provider deems necessary based on the Transmission Provider's engineering judgement.

These additional studies and/or analyses will determine whether the technological advancement results in electrical performance that is equal to or better than the electrical performance expected prior to the TCR and be deemed a Permissible Technological Advancement, or if the technological advancement is deemed a

Material Modification. Transmission Provider shall complete the evaluation as soon as practical but no later than thirty (30) Calendar Days after the receipt of the completed TCR.

Transmission Provider will produce a report that will state if the technological change is permissible. If the proposed technology fails to meet the definition of a Permissible Technological Advancement, then the TCR is deemed to be a Material Modification. In such cases, the study report shall provide an explanation regarding why the technological change is a Material Modification. The Interconnection Customer can choose to abandon the request and retain its queue position or choose to proceed with the request and reenter the queue with a new queue position.

If the study determines that the proposed technology meets the definition of a Permissible Technological Advancement, the modification is approved and will be incorporated into the Interconnection Request. Study reports may be updated if appropriate. Once the Permissible Technological Advancement is approved and incorporated into the Interconnection Request, a new TCR would be required for the Interconnection Customer to revert back to the original equipment or to make additional modifications to equipment.

Transmission Provider shall either refund any overage or charge for any shortage for costs of the study that exceed the deposit amount. The studies associated with the TCR shall be billed separately from other Interconnection Studies.

Section 6. Procedures for Interconnection Requests Submitted Prior to Effective Date of Standard Large Generator Interconnection Procedures.

6.1 Queue Position for Pending Requests.

6.1.1 Any Interconnection Customer assigned a Queue Position prior to the effective date of this LGIP shall retain that Queue Position.

6.1.1.1 If an Interconnection Study Agreement has not been executed as of the effective date of this LGIP, then such Interconnection Study, and any subsequent Interconnection Studies, shall be processed in accordance with this LGIP.

6.1.1.2 If an Interconnection Study Agreement has been executed prior to the effective date of this LGIP, such Interconnection Study shall be completed in accordance with the terms of such agreement, except where Transmission Provider initiates a transition to a Definitive Interconnection Study Process as prescribed in Section 7.

6.1.1.3 If an LGIA has been submitted to FERC for approval before the effective date of the LGIP, then the LGIA would be grandfathered.

6.2 New Transmission Provider.

If Transmission Provider transfers control of its Transmission System to a successor Transmission Provider during the period when an Interconnection Request is pending, the original Transmission Provider shall transfer to the successor Transmission Provider any amount of the deposit or payment with interest thereon that exceeds the cost that it incurred to evaluate the request for interconnection. Any difference between such net amount and the deposit or payment required by this LGIP shall be paid by or refunded to the Interconnection Customer, as appropriate. The original Transmission Provider shall coordinate with the successor Transmission Provider to complete any Interconnection Study, as appropriate, that the original Transmission Provider has begun but has not completed. If Transmission Provider has tendered a draft LGIA to Interconnection Customer but Interconnection Customer has not either executed the LGIA or requested the filing of an unexecuted LGIA with FERC, unless otherwise provided, Interconnection Customer must complete negotiations with the successor Transmission Provider.

Section 7. Transition Procedures for Definitive Interconnection Study Process.

Where the Transmission Provider publicizes its intent to transition to the Definitive Interconnection Study Process prescribed in Section 10 by posting notice to the OASIS website (the date of posting to be known as the "Cluster Study transition notice date"), such notice not to be published until after approval of the revised LGIP by FERC, an Interconnection Customer that has received a Queue Number but has not executed an Interconnection Agreement with the Transmission Provider prior to the Cluster Study transition notice date may elect to be studied under the Transition Procedures set forth in this section by executing a transitional study agreement (as applicable under Section 7.2) and meeting the requirements to enter the Transition Procedures study process. An Interconnection Customer electing to complete the study process under this section must notify the Transmission Provider and meet all Transitional readiness milestone requirements within sixty (60) Calendar Days of the delivery of notice of the Transmission Provider's transition to the Definitive Interconnection Study Process, such notice to be provided by the Transmission Provider in writing. If an Interconnection Customer elects to continue with a Transitional Serial Interconnection Facilities Study or a Transitional Cluster Study as described below, Transmission Provider shall retain the current study deposits, and Interconnection Customer shall be responsible for the entire cost of all studies pursuant to Sections 7.1, Section 7.2, and Section 11. An Interconnection Customer that does not meet the Transition Procedure requirements shall be deemed withdrawn pursuant to the Transition Procedures set forth in this section and then may submit a new Interconnection Request to be studied under the Definitive Interconnection Study Process.

7.1 Transitional Serial Process.

An Interconnection Customer that has a) a final System Impact Study Report that identifies the Interconnection Facilities and any Network Upgrades required to feasibly interconnect the proposed Generating Facility, and b) an Interconnection Facilities Study Agreement executed by the Interconnection Customer prior to the Cluster Study transition notice date, may opt to continue with the serial Facilities Study process if the Interconnection Customer provides notice in writing to the Transmission Provider and meets each of the following requirements that demonstrate readiness within the timeframe prescribed in Section 7.

a) Execute a Transitional Serial Interconnection Facilities Study Agreement, as provided in Appendix 8-1;

b) Provide security equal to one hundred percent (100%) of the costs identified for Transmission Provider's Interconnection Facilities and Network Upgrades in the System Impact Study Report. The security shall be in the form of (a) cash; (b) an irrevocable letter of credit in a form reasonably acceptable to Transmission Provider; or (c) for amounts exceeding the potential Withdrawal Penalty to be assigned under this Section, other forms of security provided for in Section 11.5 of the LGIA (such as a surety bond) in a form reasonably acceptable to Transmission Provider. If the Interconnection Customer withdraws prior to executing an LGIA, the Transmission Provider shall be entitled to use the security as payment for (a) the final invoice for study costs and (b) the Withdrawal Penalty, after which any remaining amount of security shall be returned to Interconnection Customer. If the Interconnection Customer does not withdraw and executes an LGIA, the amount of security shall be increased or decreased as needed in order to reflect the cost estimate for Transmission Provider's Interconnection Facilities and Network Upgrades set forth in Appendix B to the LGIA. Once the LGIA is fully executed, the terms of the LGIA shall govern such security.

c) Demonstrate exclusive Site Control for the entire Generating Facility and any Interconnection Customer's Interconnection Facilities.

d) Interconnection Customer shall provide one of the following:

i. A contract, binding upon the parties to the contract, for sale of the Generating Facility's energy, or the entire constructed Generating Facility, where the term of sale is not less than five (5) years, or

ii. Reasonable evidence that the Generating Facility is included in a Resource Planning Entity's Resource Plan or has received a contract award in a Resource Solicitation Process, or

iii. An executed Provisional Large Generator Interconnection Agreement filed with FERC. Such an agreement shall not be suspended and shall include a commitment to construct the Generating Facility.

The Transmission Provider shall complete the Transitional Serial Facilities Study pursuant to Section 11 except that the Readiness Milestone 4 requirement Section 11.2 shall not apply.

All LGIA negotiations shall be completed and the LGIA executed (or filed unexecuted) within sixty (60) Calendar Days of the publication of the final Interconnection Facilities Study Report or the Interconnection Request shall be deemed withdrawn pursuant to Section 4.7 unless extended by mutual agreement of Transmission Provider and Interconnection Customer. A change in the Commercial Operation Date shall not delay the construction of facilities if such delay negatively affects lower or equal queued projects.

If the Interconnection Customer elects to proceed under this Transitional Serial Process and subsequently withdraws its Interconnection Request or the Generating Facility otherwise does not reach Commercial Operation, a Withdrawal Penalty equal to nine (9) times the Interconnection Request's total study cost is imposed and the collected amount shall be distributed to fund future Cluster Study costs pursuant to Section 4.7.1.2, unless the Transmission Provider determines consistent with Good Utility Practice that a Withdrawal Penalty should not be assigned pursuant to Section 4.7.1.

7.2 Transitional Cluster Process.

7.2.1 Transitional Cluster Eligibility Requirements.

An Interconnection Customer with an assigned Queue Position prior to the Cluster Study transition notice date, may opt to enter the transitional cluster study ("Transitional Cluster Study") if the Interconnection Customer meets the requirements detailed below pursuant to the process established in Section 7. All Interconnection Customers who enter the Transitional Cluster Study shall be considered to have an equal Queue Position, and identified Network Upgrade costs shall be allocated according to Section 10.4 of this LGIP. The Transitional Cluster Study costs shall be allocated according to the method described in Section 10.3.

A Transitional Cluster Study general informational meeting open to all eligible Interconnection Customers shall be held within thirty (30) Calendar Days of the Cluster Study transition notice date. To join the Transitional Cluster Study, the Interconnection Customer must meet all of the following requirements within the timeframe prescribed in Section 7:

a) Execute a Transitional Cluster Study Agreement, as provided in Appendix 8-2;

b) Request either Energy Resource Interconnection Service or Network Resource Interconnection Service; provided, however, any Interconnection Customer requesting Network Resource Interconnection Service may also request that it be concurrently studied for Energy Resource Interconnection Service prior to Section 7.2.4 Transitional Cluster Facilities Study but must designate either ERIS or NRIS no later than five business days after the Transitional Cluster Phase 2 Report is issued;

c) Make a supplemental Interconnection Request study deposit in cash, if necessary, to increase the Interconnection Customer's total study deposit to equal the amount required under Section 4.1.2 of the LGIP;

d) Demonstrate that Interconnection Customer has exclusive Site Control for the entire Generating Facility and all required Interconnection Facilities to the Point of Interconnection to the Transmission Provider's System. Interconnection Customer may provide a cash deposit equal to $20,000 plus $500/MW in lieu of Site Control to enter Transitional Cluster Study Phase 1. A deposit in lieu of Site Control is not accepted for later Phases of the Transitional Cluster Study Process; and

e) Interconnection Customer shall provide one of the following:

   i. Executed term sheet (or comparable evidence) related to a contract, binding upon the parties to the contract, for sale of the Generating Facility's energy, or the entire constructed Generating Facility, where the term of sale is not less than five (5) years, or

   ii. Reasonable evidence that the Generating Facility is included in an Resource Planning Entity's Resource Plan or Resource Solicitation Process, or

   iii. An executed Provisional Large Generator Interconnection Agreement filed with FERC that is not in suspension with 1) a commitment to construct the facility, 2) a Commercial Operation Date no later than 2024 and 3) a security deposit in addition to amount required under Section 4.1.2 where the total security deposit represents a reasonable estimation of the potential costs that could be ultimately allocated to the project in the Transitional Cluster Study, or

iv. Security equal to three million dollars ($3,000,000). The security shall be in the form of (a) cash; or (b) an irrevocable letter of credit in a form reasonably acceptable to Transmission Provider. If the Interconnection Customer withdraws prior to executing an LGIA, the Transmission Provider shall be entitled to use the security as payment for (a) the final invoice for study costs and (b) the Withdrawal Penalty, after which any remaining amount of security shall be returned to Interconnection Customer. If the Interconnection Customer does not withdraw and executes an LGIA, the amount of security shall be increased or decreased as needed in order to reflect the cost estimate for Transmission Provider's Interconnection Facilities and Network Upgrades set forth in Appendix B to the LGIA. Once the LGIA is fully executed, the terms of the LGIA shall govern such security.

7.2.2 Transitional Cluster Expedited Customer Engagement Process and Phase 1. If one or more valid requests are received into the Transitional Cluster Study, the Transmission Provider shall undertake an expedited thirty (30) Calendar Day customer engagement process as provided for in Section 10.1 and shall then initiate a Phase 1 study under the procedures prescribed in Section 10.8 ("Transitional Cluster Study Phase 1") to evaluate the impact of the proposed interconnection(s) within the Transitional Cluster Study on the reliability of the Transition Provider's System. The Transmission Provider shall use Reasonable Efforts to complete the Transitional Cluster Study Phase 1 consisting of a power flow and voltage analysis within ninety (90) Calendar Days. The Transitional Cluster Study Phase 1 Report shall identify the Interconnection Facilities and Network Upgrades that are expected to be required as a result of the Interconnection Request(s) and provide a non-binding good-faith indicative estimate of cost responsibility and a non-binding good-faith estimated time to construct. The Transmission Provider will host a meeting to discuss the results of Transitional Cluster Study Phase 1 within ten (10) Calendar Days of issuing the Transitional Cluster Study Phase 1 Report.

An Interconnection Customer that withdraws the Interconnection Request from the Transitional Cluster during the Phase 1 study or within thirty (30) Calendar Days of the Transmission Provider's publication of the Transitional Cluster Study Phase 1 Report shall be assigned its allocated Phase 1 Study Costs calculated pursuant to Section 10.3 and shall not be allocated a Withdrawal Penalty. At any time after Phase 2 commences, the Interconnection Customer shall be subject to the Withdrawal Penalty identified in Section 7.2.6 and the collected amount shall be distributed to fund Transitional Cluster Study or future Cluster Study costs pursuant to Section 4.7.1.2, unless the Transmission Provider determines consistent with Good Utility Practice that a Withdrawal Penalty should not be assigned pursuant to Section 4.7.1. If the Interconnection Customer withdraws its Interconnection Request or the Generating Facility otherwise does not reach Commercial Operation, the deposit(s) required by Section 7.2.3 are fully refundable once the final invoice for study costs and Withdrawal Penalty is settled.

7.2.3 Transitional Cluster Study Phase 2.
Within thirty (30) Calendar Days of the Transmission Provider's publication of the Transitional Cluster Study Phase 1 Report, each Interconnection Customer electing to proceed with Phase 2 of the Transitional Cluster Study must meet all of the following requirements:

a) Provide security equal to three million dollars ($3,000,000) inclusive of any security previously required by Section 7.2.1(e.). The security shall be in the form of (a) cash; (b) an irrevocable letter of credit in a form reasonably acceptable to Transmission Provider; or (c) for amounts exceeding the potential Withdrawal Penalty to be assigned under Section 7.2.6, other forms of security provided for in Section 11.5 of the LGIA (such as a surety bond) in a form reasonably acceptable to Transmission Provider. If the Interconnection Customer withdraws prior to executing an LGIA, the Transmission Provider shall be entitled to use the security as payment for (a) the final invoice for study costs and (b) the Withdrawal Penalty, after which any remaining amount of security shall be returned to Interconnection Customer. If the Interconnection Customer does not withdraw and executes an LGIA, the amount of security shall be increased or decreased as needed in order to reflect the cost estimate for Transmission Provider's Interconnection Facilities and Network Upgrades set forth in Appendix B to the LGIA. Once the LGIA is fully executed, the terms of the LGIA shall govern such security.

b) Demonstrate exclusive Site Control for the entire Generating Facility and all required Interconnection Facilities to the Point of Interconnection on the Transmission Provider's Transmission System.

c) Interconnection Customer shall provide one of the following:

   i. A contract binding upon the parties to the contract, for sale of the Generating Facility's energy, or the entire constructed Generating Facility, where the term of sale is not less than five (5) years, or

   ii. Reasonable evidence that the Generating Facility is included in an Resource Planning Entity's Resource Plan and, if required, has filed an application for a Certificate of Public Convenience and Necessity to construct the Generating Facility or has been selected in a Resource Solicitation Process, or

   iii. An executed Provisional Large Generator Interconnection Agreement filed with FERC that is not in suspension with 1) a commitment to construct the Generating Facility, 2) a Commercial Operation Date no later than 2024 and 3) a security deposit in addition to amount required under Section 4.1.2 where the total security deposit represents a reasonable estimation of the potential costs that could be ultimately allocated to the project in the transitional cluster study, or

   iv. Provide additional security equal to two million dollars ($2,000,000). The security shall be in the form of (a) cash; (b) an irrevocable letter of credit in a form reasonably acceptable to Transmission Provider; or (c) for amounts exceeding the potential Withdrawal Penalty to be assigned under Section 7.2.6, other forms of security provided for in Section 11.5 of the LGIA (such as a surety bond) in a form reasonably acceptable to Transmission Provider. If the Interconnection Customer withdraws prior to executing an LGIA, the Transmission Provider shall be entitled to use the security as payment for (a) the final invoice for study costs and (b) the Withdrawal Penalty, after which any remaining amount of security shall be returned to Interconnection Customer. If the Interconnection Customer does not withdraw and executes an LGIA, the amount of security shall be increased or decreased as needed in order to reflect the cost estimate for Transmission Provider's Interconnection Facilities and Network Upgrades set forth in Appendix B to the LGIA. Once the LGIA is fully executed, the terms of the LGIA shall govern such security.

Once Transitional Cluster Study Phase 2 commences, the Transmission Provider shall complete an updated power flow/voltage analysis (if necessary), stability analysis and short circuit analysis for the Generating Facilities remaining in the Transitional Cluster Study pursuant to the procedures in Section 10.8(c.). The Transmission Provider shall use Reasonable Efforts to complete the Phase 2 analysis within one hundred fifty (150) Calendar Days. The results of this analysis shall identify the Interconnection Facilities and Network Upgrades expected to be required to reliably interconnect the Generating Facilities proceeding in the Transitional Cluster Study and shall provide a non-binding good-faith estimate of cost responsibility and a non-binding good-faith estimated time to construct. The Phase 2 Report shall identify each Interconnection Customer's estimated allocated costs for the Interconnection Facilities and Network Upgrades that would be borne by the Interconnection Customer under a future Interconnection Agreement.

If the Interconnection Customer withdraws the Interconnection Request at any time after Phase 2 commences, the Interconnection Customer shall be subject to the Withdrawal Penalty identified in Section 7.2.6 and the collected amount shall be distributed to fund future Cluster Study costs pursuant to Section 4.7.1.2, unless the Transmission Provider determines consistent with Good Utility Practice that a Withdrawal Penalty should not be assigned pursuant to Section 4.7.1.

7.2.4 Transitional Cluster Facilities Study.

If any Interconnection Customer within the Transitional Cluster Study withdraws its Interconnection Request after the Phase 2 Report is issued, the withdrawing Interconnection Customer shall be subject to the Withdrawal Penalty identified in Section 7.2.6 and the collected amount shall be distributed to fund re-study or future Cluster Study costs pursuant to Section 4.7.1.2, unless the Transmission Provider determines consistent with Good Utility Practice that a Withdrawal Penalty should not be assigned pursuant to Section 4.7.1. The Transmission Provider shall determine whether re-study of the Transitional Cluster Generating Facilities is required pursuant to Section 10.10 prior to executing the Facilities Study Agreement and returning it to the Interconnection Customers.

The Transmission Provider shall complete the Facilities Study for all Generating Facilities in the Transitional Cluster Study within one hundred fifty (150) Calendar Days pursuant to Section 11 except that the Readiness Milestone 4 requirement in Section 11.2 shall not apply to Interconnection Customers participating in the Transitional Cluster Study.

7.2.5 Transitional Cluster LGIA.

After the Facility Study Report is published, the remaining process shall proceed according to Section 14 of this LGIP with the exception of the security required in item (b) of Section 14.4 (posting Readiness Milestone 5), which shall not apply. If the Interconnection Customer withdraws its Interconnection Request or if the Generating Facility otherwise does not reach Commercial Operation, the security is fully refundable once the final invoice for study costs and Withdrawal Penalty is settled.

All LGIA negotiations shall be completed and the LGIA executed (or filed unexecuted) within sixty (60) Calendar Days of the tender of the draft LGIA or the Interconnection Request is deemed withdrawn unless extended by mutual agreement of Transmission Provider and Interconnection Customer. A change in the Commercial Operation Date shall not delay the construction of Transmission Provider's Interconnection Facilities or Network Upgrades if such delay negatively affects lower or equal queued projects. The Withdrawal Penalty for Interconnection Customers participating in the Transitional Cluster Process that have executed an LGIA is listed in Section 7.2.6, and the collected amount shall be distributed to fund future Cluster Study costs pursuant to Section 4.7.1.2, unless the Transmission Provider determines consistent with Good Utility Practice that a Withdrawal Penalty should not be assigned pursuant to Section 4.7.1. If the Interconnection Customer withdraws its Interconnection Request or its Generating Facility or otherwise does not reach Commercial Operation, the deposit is fully refundable once the final invoice for study costs and Withdrawal Penalty is settled.

7.2.6 Transitional Cluster Withdrawal Penalty.

The Withdrawal Penalty for Interconnection Customers electing to proceed to Phase 2 of the Transitional Cluster Study is equal to nine (9) times the Interconnection Request's total study cost is imposed.

Section 8. Serial Interconnection Feasibility Study.

A Transmission Provider shall administer a Serial Interconnection Study Process under Section 8 (Feasibility Study), Section 9 (System Impact Study), and Section 11 (Facilities Study), unless and until the Transmission Provider has elected to transition to the Definitive Interconnection Study Process as described in Section 10. A Transmission Provider will provide notice on OASIS upon transitioning to the Definitive Interconnection Study Process pursuant to the process described in Section 7.

8.1 Serial Interconnection Feasibility Study Agreement.

Where a Transmission Provider administers the Serial Interconnection Study Process, Transmission Provider shall provide to Interconnection Customer an Interconnection Feasibility Study Agreement in the form of Appendix 4 simultaneously with the acknowledgement of a valid Interconnection Request. The Interconnection Feasibility Study Agreement shall specify that Interconnection Customer is responsible for the actual cost of the Interconnection Feasibility Study. Within five (5) Business Days following the Scoping Meeting Interconnection Customer shall specify for inclusion in the attachment to the Interconnection Feasibility Study Agreement the Point(s) of Interconnection and any reasonable alternative Point(s) of Interconnection. Within five (5) Business Days following Transmission Provider's receipt of such designation, Transmission Provider shall tender to Interconnection Customer the Interconnection Feasibility Study Agreement signed by

Transmission Provider, which includes a good faith estimate of the cost for completing the Interconnection Feasibility Study. Interconnection Customer shall execute and deliver to Transmission Provider the Interconnection Feasibility Study Agreement along with a $10,000 deposit no later than thirty (30) Calendar Days after its receipt.

On or before the return of the executed Interconnection Feasibility Study Agreement to Transmission Provider, Interconnection Customer shall provide the technical data called for in Appendix 4, Attachment A.

If the Interconnection Feasibility Study uncovers any unexpected result(s) not contemplated during the Scoping Meeting, a substitute Point of Interconnection identified by either Interconnection Customer or Transmission Provider, and acceptable to the other, such acceptance not to be unreasonably withheld, will be substituted for the designated Point of Interconnection specified above without loss of Queue Position, and Re-studies shall be completed pursuant to Section 8.4 as applicable. For the purpose of this Section 8.1, if Transmission Provider and Interconnection Customer cannot agree on the substituted Point of Interconnection, then Interconnection Customer may direct that one of the alternatives as specified in the Interconnection Feasibility Study Agreement, as specified pursuant to Section 4.1.1, shall be the substitute.

If Interconnection Customer and Transmission Provider agree to forgo the Serial Interconnection Feasibility Study, Transmission Provider will initiate a Serial Interconnection System Impact Study under Section 9 of this LGIP and apply the $10,000 deposit towards the Interconnection System Impact Study.

8.2 Scope of Serial Interconnection Feasibility Study.

The Interconnection Feasibility Study shall preliminarily evaluate the feasibility of the proposed interconnection to the Transmission System.

The Interconnection Feasibility Study will consider the Base Case as well as all generating facilities (and with respect to (iii), any identified Network Upgrades) that, on the date the Interconnection Feasibility Study is commenced: (i) are directly interconnected to the Transmission System; (ii) are interconnected to Affected Systems and may have an impact on the Interconnection Request; (iii) have a pending higher queued Interconnection Request to interconnect to the Transmission System; and (iv) have no Queue Position but have executed an LGIA or requested that an unexecuted LGIA be filed with FERC. The Interconnection Feasibility Study will consist of a power flow and short circuit analysis. The Interconnection Feasibility Study will provide a list of facilities and a non-binding good faith estimate of cost responsibility and a non-binding good faith estimated time to construct.

8.3 Serial Interconnection Feasibility Study Procedures.

Transmission Provider shall utilize existing studies to the extent practicable when it performs the study. Transmission Provider shall use Reasonable Efforts to complete the Interconnection Feasibility Study no later than forty-five (45) Calendar Days after Transmission Provider receives the fully executed Interconnection Feasibility Study Agreement. At the request of Interconnection Customer or at any time Transmission Provider determines that it will not meet the required time frame for completing the Interconnection Feasibility Study, Transmission Provider shall notify Interconnection Customer as to the schedule status of the Interconnection Feasibility Study. If Transmission Provider is unable to complete the Interconnection Feasibility Study within that time period, it shall notify Interconnection Customer and provide an estimated completion date with an explanation of the reasons why additional time is required. Upon request, Transmission Provider shall provide Interconnection Customer supporting documentation, workpapers and relevant power flow, short circuit and stability databases for the Interconnection Feasibility Study, subject to confidentiality arrangements consistent with Section 16.1.

Transmission Provider shall study the Interconnection Request at the level of service requested by the Interconnection Customer, unless otherwise required to study the full Generating Facility Capacity due to safety or reliability concerns.

8.3.1 Meeting with Transmission Provider.
Within ten (10) Business Days of providing an Interconnection Feasibility Study report to Interconnection Customer, Transmission Provider and Interconnection Customer shall meet to discuss the results of the Interconnection Feasibility Study.

8.4 Re-Study.
If Re-Study of the Interconnection Feasibility Study is required due to a higher queued project dropping out of the queue, or a modification of a higher queued project subject to Section 5.4, or re-designation of the Point of Interconnection pursuant to Section 8.1 Transmission Provider shall notify Interconnection Customer in writing. Such Re-Study shall take no longer than forty-five (45) Calendar Days from the date of the notice. Any cost of Re-Study shall be borne by the Interconnection Customer being re-studied.

Section 9. Serial Interconnection System Impact Study.

9.1 Serial Interconnection System Impact Study Agreement.
Unless otherwise agreed, pursuant to the Scoping Meeting provided in Section 4.4.6, simultaneously with the delivery of the Interconnection Feasibility Study to Interconnection Customer, Transmission Provider shall provide to Interconnection Customer a Serial Interconnection System Impact Study Agreement in the form of Appendix 5 to this LGIP. The Serial Interconnection System Impact Study Agreement shall provide that Interconnection Customer shall compensate Transmission Provider for the actual cost of the Serial Interconnection System Impact Study. Within three (3) Business Days following the Interconnection Feasibility Study results meeting, Transmission Provider shall provide to Interconnection Customer a non-binding good faith estimate of the cost and timeframe for completing the Interconnection System Impact Study.

9.2 Execution of Serial Interconnection System Impact Study Agreement.
Interconnection Customer shall execute the Serial Interconnection System Impact Study Agreement and deliver the executed Serial Interconnection System Impact Study Agreement to Transmission Provider no later than thirty (30) Calendar Days after its receipt along with demonstration of Site Control, and a $50,000 deposit.

If Interconnection Customer does not provide all such technical data when it delivers the Serial Interconnection System Impact Study Agreement, Transmission Provider shall notify Interconnection Customer of the deficiency within five (5) Business Days of the receipt of the executed Serial Interconnection System Impact Study Agreement and Interconnection Customer shall cure the deficiency within ten (10) Business Days of receipt of the notice, provided, however, such deficiency does not include failure to deliver the executed Serial Interconnection System Impact Study Agreement or deposit.

If the Serial Interconnection System Impact Study uncovers any unexpected result(s) not contemplated during the Scoping Meeting and the Interconnection Feasibility Study, a substitute Point of Interconnection identified by either Interconnection Customer or Transmission Provider, and acceptable to the other, such acceptance not to be unreasonably withheld, will be substituted for the designated Point of Interconnection specified above without loss of Queue Position, and restudies shall be completed pursuant to Section 9.6 as applicable. For the purpose of this Section 9.2, if Transmission Provider and Interconnection Customer cannot agree on the substituted Point of Interconnection, then Interconnection Customer may direct that one of the alternatives as specified in the Interconnection Feasibility Study Agreement, as specified pursuant to Section 4.1.1, shall be the substitute.

9.3 Scope of Serial Interconnection System Impact Study.

The Serial Interconnection System Impact Study shall evaluate the impact of the proposed interconnection on the reliability of the Transmission System. The Serial Interconnection System Impact Study will consider the Base Case as well as all generating facilities (and with respect to (iii) below, any identified Network Upgrades associated with such higher queued interconnection) that, on the date the Serial Interconnection System Impact Study is commenced: (i) are directly interconnected to the Transmission System; (ii) are interconnected to Affected Systems and may have an impact on the Interconnection Request; (iii) have a pending higher queued Interconnection Request to interconnect to the Transmission System; and (iv) have no Queue Position but have executed an LGIA or requested that an unexecuted LGIA be filed with FERC.

The Serial Interconnection System Impact Study will consist of a short circuit analysis, a stability analysis, and a power flow analysis. The Serial Interconnection System Impact Study will state the assumptions upon which it is based; state the results of the analyses; and provide the requirements or potential impediments to providing the requested interconnection service, including a preliminary indication of the cost and length of time that would be necessary to correct any problems identified in those analyses and implement the interconnection. For purposes of determining necessary Interconnection Facilities and Network Upgrades, the System Impact Study shall consider the level of Interconnection Service requested by the Interconnection Customer, unless otherwise required to study the full Generating Facility Capacity due to safety or reliability concerns. The Serial Interconnection System Impact Study will provide a list of facilities that are required as a result of the Interconnection Request and a non-binding good faith estimate of cost responsibility and a non-binding good faith estimated time to construct.

9.4 Serial Interconnection System Impact Study Procedures.

Transmission Provider shall coordinate the Serial Interconnection System Impact Study with any Affected System that is affected by the Interconnection Request pursuant to Section 4.6 above. Transmission Provider shall utilize existing studies to the extent practicable when it performs the study. Transmission Provider shall use Reasonable Efforts to complete the Serial Interconnection System Impact Study within ninety (90) Calendar Days after the receipt of the Serial Interconnection System Impact Study Agreement or notification to proceed, study payment, and technical data.

At the request of Interconnection Customer or at any time Transmission Provider determines that it will not meet the required time frame for completing the Serial Interconnection System Impact Study, Transmission Provider shall notify Interconnection Customer as to the schedule status of the Serial Interconnection System Impact Study. If Transmission Provider is unable to complete the Serial Interconnection System Impact Study within the time period, it shall notify Interconnection Customer and provide an estimated completion date with an explanation of the reasons why additional time is required. Upon request, Transmission Provider shall provide Interconnection Customer all supporting documentation, workpapers and relevant pre-Interconnection Request and post-Interconnection Request power flow, short circuit and stability databases for the Serial Interconnection System Impact Study, subject to confidentiality arrangements consistent with Section 16.1.

9.5 Meeting with Transmission Provider.
Within ten (10) Business Days of providing an Serial Interconnection System Impact Study report to Interconnection Customer, Transmission Provider and Interconnection Customer shall meet to discuss the results of the Interconnection System Impact Study.

9.6 Re-Study.
If Re-Study of the Serial Interconnection System Impact Study is required due to a higher queued project dropping out of the queue, or a modification of a higher queued project subject to Section 5.4, or re-designation of the Point of Interconnection pursuant to Section 9.2, Transmission Provider shall notify Interconnection Customer in writing. Such Re-Study shall take no longer than sixty (60) Calendar Days from the date of notice. Any cost of Re-Study shall be borne by the Interconnection Customer being re-studied.

Section 10. Definitive Interconnection Study Process.

For a Transmission Provider that has transitioned to the Definitive Interconnection Study Process under the procedure described in Section 7, the Transmission Provider shall annually administer a Definitive Interconnection System Impact Cluster Study Process as provided for in this Section. The diagram attached as Appendix 6-1 provides an overview and timeline of initiation of a Definitive Interconnection Study: the DISIS Request Window, Customer Engagement Window, and Phase 1 of the DISIS.

Interconnection Customers may initially elect to obtain an Informational Interconnection Study, as provided for under Section 3, prior to submitting an Interconnection Request and proceeding into the Definitive Interconnection Study Process. Interconnection Customers that elect to withdraw from the Definitive Interconnection Study Process may be subject to a Withdrawal Penalty, as further addressed in Section 4.7.1.

10.1 Initiation of a Definitive Interconnection System Impact Study Cluster.
The Transmission Provider shall accept Interconnection Requests during the “DISIS Request Window.” A DISIS Request Window shall open annually on January 1 and shall remain open for 180 Calendar Days or the following Business Day if the 180th day falls on a weekend or NERC recognized holiday.

If one or more valid Interconnection Requests are received, for sixty (60) Calendar Days following the close of the DISIS Request Window (the “Customer Engagement Window”), the Transmission Provider shall work with applicable Interconnection Customers to build models, verify data, hold stakeholder meetings (including Scoping Meetings, as appropriate), cure any deficiencies in the Interconnection Request(s) as described in Section 4.4.5, and generally prepare for the start of the Definitive Interconnection System Impact Study. Notwithstanding the preceding sentence and upon written consent of all Interconnection Customers within a specific Cluster, the Transmission Provider may shorten the "Customer Engagement Window" in order to start the Definitive Interconnection System Impact Study earlier. Within the first ten (10) Business Days following the close of the DISIS Request Window, the Transmission Provider shall post on its OASIS site a list of Interconnection Requests for that Cluster, identifying for each Interconnection Request: (i) the location by county and state; (ii) the transmission substation or transmission line or lines where the interconnection will be made; (iii) cluster being requested; and (iv) the type of Generating Facility to be constructed including fuel type such as wind, natural gas, coal, or solar.

Prior to the close of the Customer Engagement Window, each Interconnection Customer shall i) execute a DISIS Agreement pursuant to Section 10.6; ii) provide initial security equal to 1 times the Section 4.1.2 study deposit amount to enter the DISIS; and iii) provide evidence satisfactory to the Transmission Provider of either an initial Readiness Milestone ("M1"), as described in Section 10.11.1, or additional security in the form of an irrevocable letter of credit or cash in lieu of the M1 Readiness Milestone equal to one times the Study Deposit required in Section 10.11.6.

At the end of the Customer Engagement Window, all Interconnection Requests meeting the foregoing readiness requirements and that have an executed DISIS Agreement shall be included in that DISIS Cluster. Any Interconnection Requests not deemed sufficient pursuant to Section 4.4.5 or that are undergoing dispute resolution pursuant to Section 16.6 at the close of the Customer Engagement Window shall not be included in the commencing DISIS Cluster. Immediately following the Customer Engagement Window, the Transmission Provider shall initiate the Definitive Interconnection System Impact Study process described in more detail in Section 10.

10.2 Initiation of a Resource Solicitation Cluster.

At any time, and upon request of a Resource Planning Entity, a Transmission Provider may initiate a Resource Solicitation Cluster. Within ten (10) Business Days of receipt of a request to perform a Resource Solicitation Cluster that includes valid Interconnection Requests as described in Section 4.4, Transmission Provider and Resource Planning Entity shall meet to determine a mutually agreeable scope of study and timeframe to initiate the Resource Solicitation Cluster.

The Transmission Provider may administer the Resource Solicitation Cluster either separately or as part of a Definitive Interconnection System Impact Study Cluster initiated pursuant to Section 10.2. Where the Resource Solicitation Cluster is studied separately from the Definitive Interconnection System Impact Study Cluster, the Resource Solicitation Cluster shall respect Queue Position and shall be studied as its own Cluster based upon a Resource Planning Entity-designated Queue Number where the Resource Planning Entity acts as authorized representative for Interconnection Customer(s) in connection with a Resource Solicitation Cluster and the Transmission Provider shall Study the Cluster based upon the Queue Number of the Resource Solicitation Cluster relative to the Queue Position of all other Interconnection Requests/Clusters.

The Transmission Provider shall publicize the scope of study and timeframe to initiate the Resource Solicitation Cluster. The timeline shall indicate the close of the Customer Engagement Window for that Resource Solicitation Cluster. Where the Transmission Provider is administering the Resource Solicitation Cluster as part of a Definitive Interconnection System Impact Study Cluster the Definitive Interconnection System Impact Study shall proceed as described in Section 10.

After Transmission Provider completes the Definitive Interconnection System Impact Studies for the requested combinations, the results will be provided (Phase 1 Report, Phase 2 Report, Phase 3 Report, etc.; as applicable under Section 10.8) to the Resource Planning Entity for use in the Resource Solicitation Process. The results will be posted on Transmission Provider's OASIS consistent with the posting of other study results.

A Generating Facility that initially is associated with a Queue Position through the Resource Solicitation Process may also reserve a later Queue Position separate from the Resource Solicitation Cluster. In either case, the Interconnection Customer must meet all requirements associated with maintaining each Queue Position for the Generating Facility. In the event a Generating Facility has multiple Queue Positions, it shall not be double counted in the study models.

After receipt of the Phase 2 Report, the Resource Planning Entity must select one of the studied combinations in the Resource Solicitation Process prior to the commencement of any Facilities Study associated with Generating Facilities selected in the Resource Solicitation Process. Prior to the completion of the Facilities Study for the combination of Generating Facilities selected, the Resource Planning Entity may replace Interconnection Customers, subject to any necessary Re-Study pursuant to Sections 10.8(e.) or 10.10. While conducting the Definitive Interconnection Study Process, the Transmission Provider may suspend further action on the Interconnection Requests in the Resource Solicitation Process that are not included in the selected combination. Once a Generating Facility is rejected in a Resource Solicitation Cluster Process administered separately from a Definitive Interconnection System Impact Study Cluster, the Generating Facility shall lose the Queue Position it held as part of the Resource Solicitation Process. If a Generating Facility is selected by the Resource Planning Entity at the conclusion of the Resource Solicitation Process, the Generating Facility may no longer maintain more than one Queue Position

10.3 Definitive Interconnection Study Process Study Cost Allocation.
The administering Transmission Provider shall determine each Interconnection Customer's share of the costs of completing the DISIS Cluster Study (including general queue administration costs and overheads) by allocating: (1) ten percent (10%) of the applicable study costs to Interconnection Customers on a per capita basis based on number of Interconnection Requests included in the applicable Cluster; and (2) ninety percent (90%) of the applicable study costs to Interconnection Customers on a pro-rata basis based on requested megawatts included in the applicable Cluster. If an Interconnection Customer exits the Cluster prior to the Transmission Provider commencing Phase 2 pursuant to Section 10.8(c.) (including where the Transmission Provider determines through Phase 1 that a distribution-level System Impact Study should be completed for one or more distribution-level Interconnection Customers in lieu of being evaluated through Phase 2), then the Transmission Provider shall determine each Interconnection Customer's costs of preparing for and completing the DISIS prior to commencing Phase 2 and shall then separately determine each remaining Interconnection Customer's costs for the remainder of the DISIS.

If a Phase 3 restudy or general restudy is required pursuant to Sections 10.8(e) or 10.10, then Transmission Provider shall allocate the costs of the restudy as provided for in this section amongst the Interconnection Customers included in the restudy. If an Interconnection Customer proposes non-material changes to its Interconnection Request requiring limited restudy, the costs of the limited restudy shall be directly assigned to the requesting Interconnection Customer. The Facilities Study for a Transmission Provider administering the Definitive Interconnection Study Process is an individual study and the costs for each Facilities Study is directly assigned to the Interconnection Customer associated with such study.

10.4 Transmission Provider's Interconnection Facilities and Network Upgrade Cost Allocation.

The Transmission Provider shall calculate each Interconnection Customer's share of Upgrades and Interconnection Facilities costs identified in Cluster Studies in the following manner:

a) Station equipment Network Upgrades, including all switching stations, shall be allocated based on the number of Generating Facilities interconnecting at an individual station on a per capita basis (i.e. on a per Interconnection Request basis). If multiple Interconnection Customers are connecting to the Transmission Provider's Transmission System through shared Interconnection Facility(ies), those Interconnection Customers shall be considered one Interconnection Customer for the per capita calculation described in the preceding sentence. Shared Interconnection Facilities shall be allocated based on the number of Generating Facilities sharing that Interconnection Facility on a per capita basis.

b) All Network Upgrades other than those identified in Section 10.8(a.) shall be allocated based on the proportional impact of each individual Generating Facility in the Cluster Studies on such Network Upgrades. The proportional impact of such Network Upgrades shall be calculated as follows. All transmission lines and transformers identified as Network Upgrades shall be allocated using distribution factor analysis. Voltage support related Network Upgrades shall be allocated using a voltage impact analysis which will identify each Generating Facility's contribution to the voltage violation. Network Upgrades associated with upgrading existing breakers due to short circuit current exceeding breaker capability shall be allocated proportionally based on the short circuit current contribution of each request.

c) Costs of Distribution Upgrades shall be allocated or assigned to each Interconnection Customer based upon the proportional impact of each individual Generating Facility in the Cluster Study based upon the need for the Distribution Upgrade. Distribution line work (e.g., reconductoring) shall be allocated to Generating Facilities contributing to the Upgrade on a per MW basis, based upon location (% of Upgrade). All other Distribution Upgrades shall be allocated on a per capita basis (i.e. on a per Interconnection Request basis) based upon the number of projects on the feeder or substation contributing to the need for the Upgrade.

d) Costs of Transmission Provider's Interconnection Facilities are directly assigned to the Interconnection Customer(s) using such facilities.

Interconnection Customer funding of Network Upgrades are eligible for credits as provided in Article 11 of the LGIA.

10.5 Definitive Interconnection System Impact Study Agreement.
Unless otherwise agreed, pursuant to the Scoping Meeting provided for in Section 4.4.7, within thirty (30) Calendar Days of the Transmission Provider's acknowledgement of a valid Interconnection Request requesting that a Definitive Interconnection System Impact Study be performed, the Transmission Provider shall provide to the Interconnection Customer a DISIS Agreement in the form of Appendix 6-3 to this LGIP. The DISIS Agreement shall provide that Interconnection Customer shall compensate the Transmission Provider for the actual cost of the DISIS. At least seven (7) Calendar Days before the close of a Customer Engagement Window, the Transmission Provider shall provide to each Interconnection Customer proposing to enter the DISIS Cluster a non-binding updated good faith estimate of the cost and timeframe for completing the Definitive Interconnection System Impact Study.

10.6 Execution of Definitive Interconnection System Impact Study Agreement.
The Interconnection Customer shall execute the DISIS Agreement and deliver the executed DISIS Agreement to Transmission Provider no later than the close of the Customer Engagement Window or its Interconnection Request shall be deemed withdrawn by Transmission Provider.

10.7 Scope of Definitive Interconnection System Impact Study.
The Definitive Interconnection System Impact Study shall evaluate the impact of the proposed interconnection(s) within the Cluster on the reliability of the Transmission System. The Definitive Interconnection System Impact Study will consider the Transmission Provider's Base Case as well as all Generating Facilities (and with respect to (iii) below, any identified Network Upgrades associated with such higher queued requests) that, on the date the DISIS Request Window closes: (i) are existing and directly interconnected to the Transmission System; (ii) are existing and interconnected to Affected Systems and may have an impact on the Interconnection Request; (iii) have a pending Interconnection Request to interconnect to the Transmission System with a higher queue position than the DISIS Cluster, either individually under Section 5.2 or included in a higher queued Cluster Study; and (iv) have executed an LGIA or requested that an unexecuted LGIA be filed with FERC.

As set forth in more detail in Section 10.8 below, the Definitive Interconnection System Impact Study is a phased study under which the first phase (Phase 1) consists of a power flow and voltage analysis that is followed by a second phase (Phase 2) that consists of a short circuit analysis and a stability analysis. Any DISIS re-studies (Phase 3) shall consist of a power flow/voltage analysis, a short circuit analysis, and/or a stability analysis, as needed. The Definitive Interconnection System Impact Study report shall state the assumptions upon which it is based; state the results of the analyses; and provide the requirements or potential impediments to providing the requested interconnection, including a preliminary indication of the cost and length of time that would be necessary to correct any problems identified in those analyses and implement the interconnection. The Definitive Interconnection System Impact Study shall provide a list of facilities that are required as a result of the Interconnection Request and a non-binding good faith estimate of cost responsibility and a nonbinding good faith estimated time to construct.

For purposes of clustering Interconnection Requests, the Transmission Provider may make reasonable changes to the requested Point(s) of Interconnection as part of the DISIS to facilitate the efficient and reliable interconnection of Interconnection Customers at common Points of Interconnection. The Transmission Provider shall notify Interconnection Customers in writing of any intended changes to the requested Point(s) of Interconnection and the Point(s) of Interconnection shall only change upon mutual agreement. Where the Interconnection Customer agrees to a Transmission Provider's proposal to change the Point of Interconnection and the change results in a loss of Site Control, the Interconnection Customer shall have 150 days to provide affirmation and reasonable documentation, if requested by the Transmission Provider, that Site Control to the new Point of Interconnection has been obtained or the Interconnection Customer shall be required to post the additional security required by Section 10.11.6 to continue to proceed through the Definitive Interconnection Study process.

Where an Interconnection Customer is proposing to interconnect a Generating Facility to the Distribution System and has been determined through Phase 1 not to cause or contribute to the need for Network Upgrades requiring further study in Phase 2, the Transmission Provider shall complete a Distribution level System Impact Study, as further discussed in Section 10.8(a.) below.

10.8 Definitive Interconnection System Impact Study Procedures.

Transmission Provider shall coordinate the Definitive Interconnection System Impact Study with any Affected System that is affected by the Interconnection Request pursuant to Section 4.6 above. Transmission Provider shall utilize existing studies to the extent practicable when it performs the DISIS. Interconnection Requests for DISIS may be submitted only within the DISIS Request Window and Transmission Provider shall initiate the Definitive Interconnection Study Process pursuant to Section 4.4.2 and 10.1.

The diagrams attached as Appendix 6-2 provides an overview and timeline of the Definitive Interconnection Study Process, including the Phases and milestones associated with the Definitive Interconnection System Impact Study.

a. The DISIS Cluster shall consist of all eligible Interconnection Requests that have (i) executed a DISIS Agreement pursuant to Section 10.6; (ii) provided initial security equal to 1 times the Section 4.1.2 study deposit amount to enter the DISIS in the form of an irrevocable letter of credit or cash; and (iii) provided evidence satisfactory to the Transmission Provider of either an initial Readiness Milestone ("M1"), as described in Section 10.11.1, or additional security in the form of an irrevocable letter of credit or cash in lieu of the M1 Readiness Milestone equal to one times the study deposit required in Section 10.11.6 before the close of the Customer Engagement Window pursuant to Section 10.1. The Transmission Provider shall use Reasonable Efforts to complete the first phase (Phase 1) consisting of a power flow and voltage analysis within ninety (90) Calendar Days. The Phase 1 Report shall identify the Transmission Provider's Interconnection Facilities and Transmission Provider's Network Upgrades that are expected to be required as a result of the Interconnection Request(s) and a non-binding good-faith indicative level estimate of cost responsibility and a non-binding good-faith estimated time to construct. After issuing the Phase 1 Report, the Transmission Provider shall hold a second thirty (30) Calendar Day Customer Engagement Window and will host an open meeting ("Phase 1 Report Meeting") with Interconnection Customer(s) and identified Affected System Operators within ten (10) Business Days of publishing the DISIS Phase 1 results on the Transmission Provider's OASIS site.

Where the Transmission Provider determines through the initial Phase 1 study that a proposed distribution-level Interconnection Customer will not cause or contribute to the need for Network Upgrades, the Transmission Provider shall notify the Interconnection Customer in writing during the post-Phase 1 Customer Engagement Window that the Transmission Provider shall complete an individual Distribution-level System Impact Study for the proposed Generating Facility within fifty (50) Business Days. Upon issuance of the individual Distribution-level System Impact Study Report, the Interconnection Customer would then proceed immediately to the Section 11 Facilities Study process. Interconnection Customers that are studied for distribution level impacts only must continue to meet all Readiness Milestone requirements (or provide security in lieu of the Readiness Milestone) to proceed to Facilities Study under Section 11.

b. Within twenty (20) Calendar Days of the Phase 1 Report Meeting, all Interconnection Customers proceeding in the DISIS to Phase 2 are required to satisfy the requirements of Readiness Milestone 2 ("M2") as described in Section 10.11.2. Interconnection Customers that do not provide the Readiness Milestone (or provide additional security in lieu of the Readiness Milestone described in Section 10.11.6) by the required date shall be deemed withdrawn from the Queue and subject to a Withdrawal Penalty pursuant to Section 4.7.1.

c. Interconnection Customers who satisfy the M2 readiness requirements or provide the required security by the Transmission Provider shall continue in to the second phase ("Phase 2") of the Definitive Interconnection System Impact Study. Phase 2 consists of an updated power flow/voltage analysis (if necessary), stability analysis and short circuit analysis for the Interconnection Customers remaining in the DISIS Cluster. The Transmission Provider shall use Reasonable Efforts to complete the Phase 2 analysis within one hundred fifty (150) Calendar Days. The results of this analysis shall identify the Interconnection Facilities and Network Upgrades expected to be required to reliably interconnect the Generating Facilities in that DISIS Cluster. The Phase 2 Report shall provide non-binding estimates of the costs of required Network Upgrades and Interconnection Facilities allocated to each Interconnection Customer within the Cluster. The Transmission Provider shall hold a third thirty (30) Calendar Day Customer Engagement Window and will host an open meeting ("Phase 2 Report Meeting") with Interconnection Customer(s) and identified Affected System Operators within ten (10) Business Days of publishing the DISIS Phase 2 results on the Transmission Provider's OASIS site.

d. Within twenty (20) Calendar Days of the Phase 2 Report Meeting, each Interconnection Customer with an Interconnection Request in the Cluster is required to provide Readiness Milestone 3 ("M3") as described in Section 10.11.3. Interconnection Customers that do not provide the Readiness Milestone (or provide security *in lieu* of the Readiness Milestone described in Section 10.11.6) by the required date shall be deemed withdrawn from the Queue pursuant to Section 4.7.1.

   i. If all Interconnection Customers in the Cluster provide M3 and no Interconnection Customers withdraw from the Queue at this stage, the Definitive Interconnection Study Process shall advance to the Facilities Study (Section 11). The Transmission Provider shall notify Interconnection Customers in the Cluster in writing that Phase 3 is not required and simultaneously provide the Facilities Study Agreement in the form of Appendix 7.

ii. If one or more Interconnection Customer(s) withdraws from the Cluster, the Transmission Provider shall determine if a full System Impact Re-study is necessary. If the Transmission Provider determines a re-study is not necessary and Phase 3 is not required, the Transmission Provider shall provide an updated Phase 2 Report within thirty (30) Calendar Days of such determination and the Definitive Interconnection Study Process advances to the Interconnection Facilities Study (Section 11). When the updated Phase 2 report is issued, the Transmission Provider shall notify Interconnection Customers in the Cluster in writing that Phase 3 is not required and simultaneously provide the Facilities Study Agreement in the form of Appendix 7.

iii. If one or more Interconnection Customers withdraws from the Cluster and the Transmission Provider determines a full System Impact Re-study is necessary, the Transmission Provider will continue with System Impact restudies ("Phase 3") until the Transmission Provider determines that no further re-studies are required. If Interconnection Customer withdraws its Interconnection Request after the Phase 3 restudy described in Section 10.8(e) or during the Facilities Study and the Transmission Provider determines system impact level studies are necessary, the Cluster shall be restudied under the terms of Phase 3. Transmission Provider shall notify Interconnection Customers in the Cluster in writing and post on OASIS that a re-study is required.

e. If required by the Transmission Provider under Section 10.8(d.) (iii.), Interconnection Requests shall continue with the third phase ("Phase 3") of the Definitive Interconnection System Impact Study. Phase 3 may consist of updated power flow/voltage analysis, stability analysis, and/or short circuit analysis if necessary for the Interconnection Requests remaining in the Cluster. The Transmission Provider shall use Reasonable Efforts to complete the Phase 3 analysis within one hundred fifty (150) Calendar Days. The results of this analysis shall identify the Transmission Provider's Interconnection Facilities and Transmission Provider's Network Upgrades expected to be required to reliably interconnect the Generating Facilities in that Cluster and shall provide non-binding estimates for the required upgrades. The Phase 3 Report shall identify each Interconnection Request's estimated allocated costs for Interconnection Facilities and Network Upgrades. The Transmission Provider shall hold a fourth thirty (30) Calendar Day Customer Engagement Window and will host an open meeting ("Phase 3 Report Meeting") with Interconnection Customer(s) and identified Affected System Operators within ten (10) Business Days of publishing the DISIS Phase 3 results on the Transmission Provider's OASIS site. The Transmission Provider shall notify Interconnection Customers in the Cluster in writing when no further re-studies are required and simultaneously provide the Interconnection Customer(s) a Facilities Study Agreement in the form of Appendix 7. If additional restudies are required before moving to Facilities Study, within twenty (20) Calendar Days of the Phase 3 Report Meeting (or Phase 3 Updated Report Meeting), all Interconnection Customers are required to provide an updated Readiness Milestone 3 ("M3") as described in Section 10.11.3 . Interconnection Customers that do not provide the Readiness Milestone (or provide security in lieu of the Readiness Milestone described in Section 10.11.6) by the required date shall be deemed withdrawn from the Queue pursuant to Section 4.7. Transmission Provider shall notify Interconnection Customers in the Cluster in writing when no further re-studies are required and simultaneously provide the Interconnection Facilities Agreement in the form of Appendix 7.

f. Within thirty (30) Calendar Days of the notice that no System Impact restudies are needed and delivery of a Facilities Study Agreement by the Transmission Provider, each

Interconnection Customer with an Interconnection Request in the Cluster that has completed the DISIS process is required to (i) return an executed Facilities Study Agreement in the form of Appendix 7 (completed and including all required data identified therein); and (ii) provide Readiness Milestone 4 ("M4") as described in Section 10.11.4 (or provide additional security in lieu of the Readiness Milestone described in Section 10.11.6). Interconnection Customers that do not provide the executed Facilities Study Agreement and Readiness Milestone 4(or provide security in lieu of the Readiness Milestone 4 described in Section 10.11.6) by the required date shall be deemed withdrawn from the Queue and subject to a Withdrawal Penalty pursuant to Section 4.7.1.

At the request of an Interconnection Customer or at any time the Transmission Provider determines that it will not meet the indicated timeframe for completing the DISIS, the Transmission Provider shall notify Interconnection Customer(s) in writing as to the schedule status of the DISIS Cluster. If the Transmission Provider is unable to complete the DISIS within the time period, it shall notify Interconnection Customer(s) and provide an estimated completion date with an explanation of the reasons why additional time is required. Upon request, Transmission Provider shall provide Interconnection Customer all supporting documentation, workpapers, and relevant pre-Interconnection Request and post-Interconnection Request power flow, short circuit and stability databases for the DISIS, subject to confidentiality arrangements consistent with Section 16.1.

10.9 Post-DISIS Report Meeting.

Within ten (10) Business Days of furnishing a final DISIS study report to Interconnection Customer(s) with an Interconnection Request in the Cluster and posting the report on OASIS, the Transmission Provider shall convene an open meeting to discuss the study results. The Transmission Provider shall, upon request, also make itself available to meet with individual Interconnection Customers after the study report is provided.

10.10 Re-Study.

If Re-Study of the Definitive Interconnection System Impact Study other than the re-study described above in 10.8(e.) is required due to a higher or equal priority queued Interconnection Request dropping out of the Queue, or a modification of a higher queued Interconnection Request subject to Section 5.4, Transmission Provider shall notify Interconnection Customer(s) in writing. The Transmission Provider shall make Reasonable Efforts to ensure such Re-Study take no longer than one hundred fifty (150) Calendar Days from the date of notice. Any cost of Re-Study shall be borne by Interconnection Customer(s) being re-studied.

10.11 Readiness Milestones.

Satisfaction of the requirements of Readiness Milestones 1, 2, 3, and 4 are required throughout the Definitive Interconnection Study Process to demonstrate the readiness of the Interconnection Customer to develop the Generating Facility. Satisfaction of the requirements of Readiness Milestones 1, 2, 3 are required during the Definitive Interconnection System Impact Study Process. Readiness Milestone 4 is required after the Definitive Interconnection System Impact Study Process has concluded, but before the Facilities Study commences. Satisfaction of the requirements of Readiness Milestone 5 is required after the LGIA is executed as described in Section 10.11.5. An Interconnection Customer who does not satisfy the requirements of an applicable Readiness Milestone (or provide additional security in lieu thereof described in Section 10.11.6) is subject to withdrawal of its Interconnection Request from the queue and payment of a withdrawal penalty pursuant to Section 4.7.1.

10.11.1 Readiness Milestone 1 ("M1").

M1 is satisfied by the Interconnection Customer providing one of the three options below. M1 may also be satisfied by providing additional security described in Section 10.11.6 in lieu of demonstrating readiness.

a) Executed term sheet (or comparable evidence) related to a contract, binding upon the parties to the contract, for sale of (i) the constructed Generating Facility, (ii) the Generating Facility's energy, or (iii) the Generating Facility's ancillary services if the Generating Facility is an electric storage resource; where the term of sale under (ii) or (iii) is not less than five (5) years.

b) Reasonable evidence the Generating Facility has been selected by a Resource Planning Entity in a Resource Plan or is offering to sell its output through a Resource Solicitation Process; or

c) Provisional Large Generator Interconnection Agreement accepted for filing at FERC. Such an agreement shall not be suspended and shall include a commitment to construct the Generating Facility.

10.11.2 Readiness Milestone 2 ("M2").

M2 is satisfied by the Interconnection Customer providing one of the three options below. M2 may also be satisfied by providing additional security as described in Section 10.11.6 in lieu of demonstrating readiness.

a) Executed term sheet (or comparable evidence) related to a contract, binding upon the parties to the contract, for sale of (i) the constructed Generating Facility, (ii) the Generating Facility's energy, or (iii) the Generating Facility's ancillary services if the Generating Facility is an electric storage resource; where the term of sale under (ii) or (iii) is not less than five (5) years.

b) Reasonable evidence that the Project has been selected by a Resource Planning Entity in a Resource Plan or is offering to sell its output through a Resource Solicitation Process; or

c) Provisional Large Generator Interconnection Agreement accepted for filing at FERC. Such an agreement shall not be suspended and shall include a commitment to construct the Generating Facility.

10.11.3 Readiness Milestone 3 ("M3").

M3 is satisfied by the Interconnection Customer providing one of the three options below. M3 may also be satisfied by providing additional security described in Section 10.11.6 in lieu of demonstrating readiness.

a) Executed contract, binding upon the parties to the contract, for sale of (i) the constructed Generating Facility, (ii) the Generating Facility's energy, or (iii) the Generating Facility's ancillary services if the Generating Facility is an electric storage resource; where under (ii) or (iii) the term of sale is not less than five (5) years.

b) Reasonable evidence that the project has been selected by a Resource Planning Entity in a Resource Plan or is offering to sell its output through a Resource Solicitation Process; or

c) An unsuspended Provisional Large Generator Interconnection Agreement accepted for filing by FERC with reasonable evidence that the Generating Facility and Interconnection Facilities have commenced design and engineering.

10.11.4 Readiness Milestone 4 ("M4").

M4 is satisfied by the Interconnection Customer providing one of the three options below. M4 may also be satisfied by providing security as described in Section 10.11.6 in lieu of demonstrating readiness.

a) Executed contract, binding upon the parties to the contract, for sale of (i) the constructed Generating Facility, (ii) the Generating Facility's energy, or (iii) the Generating Facility's ancillary services and capacity if the Generating Facility is an electric storage resource; where under (ii) or (iii) the term of sale is not less than five (5) years;

b) Reasonable evidence that the project has been selected by a Resource Planning Entity in a Resource Plan and, if required, has filed an application for a Certificate of Public Convenience and Necessity to construct the Generating Facility or has been selected in a Resource Solicitation Process; or

c) An unsuspended Provisional Large Generator Interconnection Agreement accepted for filing by FERC with reasonable evidence that the Generating Facility and Interconnection Facilities have commenced construction.

10.11.5 Readiness Milestone 5 ("M5").

All Interconnection Customers are required to provide security in order to satisfy Readiness Milestone 5 (M5) when the LGIA is executed as described in Section 14.4. The amount of security required for M5 is equal to nine (9) times the Interconnection Customer's share of the Definitive Interconnection Study Process study costs. If this amount is not known, the Transmission Provider shall use the Section 4.4.2 study deposit amount as an estimate of study cost until such amounts are known. If initially estimated, M5 shall be updated when the final invoice for actual study costs is issued. As this M5 amount is the total security required to satisfy Readiness Milestone 5, any security previously provided pursuant to Sections 10.11.1, 10.11.2, 10.11.3, 10.11.4, or 10.11.6 shall be applied towards the Readiness Milestone 5 amount when the LGIA is executed. The Interconnection Customer shall only be responsible to provide the incremental amount of security to the Transmission Provider and any excess security provided shall be refunded to the Interconnection Customer. Transmission Provider shall refund all security provided under this section to the Interconnection Customer upon achieving Commercial Operation.

10.11.6 Security Requirements.

A table showing the security required in each milestone is provided in Appendix 6-2. The security amount is dependent on if the Interconnection Customer provided a Readiness Milestone and the study phase the Interconnection Customer is entering. All security shall be in the form of (a) cash or (b) an irrevocable letter of credit in a form reasonably acceptable to Transmission Provider. If the Interconnection Customer withdraws prior to executing an

LGIA, the Transmission Provider shall be entitled to use the financial security as payment for (a) the final invoice for study costs and (b) the Withdrawal Penalty, after which any remaining amount of security shall be returned to Interconnection Customer. If the Interconnection Customer does not withdraw and executes an LGIA, the amount of security shall be increased or decreased as needed in order to reflect the cost estimate for Transmission Provider's Interconnection Facilities and Network Upgrades set forth in Appendix B to the LGIA. Once the LGIA is fully executed, the terms of the LGIA shall govern such security.

Prior to the close of the Customer Engagement Window, all Interconnection Customers must provide initial security equal to the Section 4.1.2 study deposit amount as described in Section 10.1 and 10.8(a.). The security provided in Section 10.8(a.) will be applied towards the amount of security required for M5.

An Interconnection Customer may opt to provide security *in lieu* of providing Readiness Milestones 1 through 4, as described above in Sections 10.11.1, 10.11.2, 10.11.3, and 10.11.4. The security provided is applied towards the security amount required for each successive milestone if the Interconnection Customer does not withdraw from the Definitive Interconnection Study Process. For example, the security provided for M2 is applied to the amount of security required for M3. If an Interconnection Customer is initially required to provide increased security under this Section 10.11.6 because it cannot satisfy the requirements of a Readiness Milestone, but subsequently does satisfy those requirements prior to the next Readiness Milestone, its security should be reduced accordingly.

In lieu of providing a demonstration of readiness for Milestones 1 through 4, the amount of security required is a multiple of the study deposit described in Section 4.1.2 and is in addition to the initial security required for all Interconnection Customers under Section 10.1 and 10.8(a.). The additional amount of security required for each milestone for Interconnection Customers that do not provide a demonstration of readiness is:

M1 = 1 times the Section 4.1.2 study deposit amount
M2 = 2 times the Section 4.1.2 study deposit amount
M3 = 4 times the Section 4.1.2 study deposit amount
M4 = 6 times the Section 4.1.2 study deposit amount

For clarity, the total (i.e. inclusive of the security required under Section 10.8(a.) amount of security required for each milestone for Interconnection Customers that do not provide a demonstration of readiness is:

M1 = 2 times the Section 4.1.2 study deposit amount
M2 = 3 times the Section 4.1.2 study deposit amount
M3 = 5 times the Section 4.1.2 study deposit amount
M4 = 7 times the Section 4.1.2 study deposit amount

If the Interconnection Customer withdraws prior to executing an LGIA, the Transmission Provider shall be entitled to use the security as payment for (a) the final invoice for study costs and (b) the Withdrawal Penalty, after which any remaining amount of security shall be returned to Interconnection Customer. If the Interconnection Customer does not withdraw and executes an LGIA, the amount of financial security shall be increased or decreased as needed in order to reflect the cost estimate for Transmission Provider's Interconnection

Facilities and Network Upgrades set forth in Appendix B to the LGIA. Once the LGIA is fully executed, the terms of the LGIA shall govern such security.

Section 11. Interconnection Facilities Study.

11.1 Serial Interconnection Study Process – Interconnection Facilities Study Agreement. Simultaneously with the delivery of the Interconnection System Impact Study to Interconnection Customer, Transmission Provider shall provide to Interconnection Customer an Interconnection Facilities Study Agreement in the form of Appendix 7 to this LGIP. The Interconnection Facilities Study Agreement shall provide that Interconnection Customer shall compensate Transmission Provider for the actual cost of the Interconnection Facilities Study. Within three (3) Business Days following the Interconnection System Impact Study results meeting, Transmission Provider shall provide to Interconnection Customer a non-binding good faith estimate of the cost and timeframe for completing the Interconnection Facilities Study. Interconnection Customer shall execute the Interconnection Facilities Study Agreement and deliver the executed Interconnection Facilities Study Agreement to Transmission Provider within thirty (30) Calendar Days after its receipt, together with the required technical data and the greater of $100,000 or Interconnection Customer's portion of the estimated monthly cost of conducting the Interconnection Facilities Study.

11.1.1 Transmission Provider shall invoice Interconnection Customer on a monthly basis for the work to be conducted on the Interconnection Facilities Study each month. Interconnection Customer shall pay invoiced amounts within thirty (30) Calendar Days of receipt of invoice. Transmission Provider shall continue to hold the amounts on deposit until settlement of the final invoice.

11.2 Definitive Interconnection Study Process – Facilities Study Agreement. Simultaneously with the notice to Interconnection Customer(s) that Phase 3 is complete or not required, Transmission Provider shall provide to Interconnection Customer an Interconnection Facilities Study Agreement in the form of Appendix 7 to this LGIP. Within five (5) Business Days following the open DISIS results (Phase 2 or Phase 3) meeting, Transmission Provider shall provide to Interconnection Customer a non-binding good faith estimate of the cost and timeframe for completing the Interconnection Facilities Study. The Interconnection Facilities Study Agreement shall provide that Interconnection Customer shall compensate Transmission Provider for the actual cost of the Interconnection Facilities Study. Interconnection Customer shall execute the Interconnection Facilities Study Agreement and deliver the executed Interconnection Facilities Study Agreement to Transmission Provider, together with the required technical data, and Readiness Milestone 4 as described in Section 10.11.4. Interconnection Customers that do not provide the Readiness Milestone (or additional security *in lieu* of the Readiness Milestone) by the required date shall be deemed withdrawn from the Queue pursuant to Section 4.7.

11.3 Scope of Interconnection Facilities Study. The Interconnection Facilities Study shall specify and provide a non-binding estimate of the cost of the equipment, engineering, procurement and construction work needed to implement the conclusions of the final Phase 2 or Phase 3 Report (as appropriate) in the Definitive Interconnection Study Process and the System Impact Study in the Serial Interconnection Study Process in accordance with Good Utility Practice to physically and electrically connect the Interconnection Facilities to the Transmission System. The Interconnection Facilities

Study shall also identify the electrical switching configuration of the connection equipment, including, without limitation: the transformer, switchgear, meters, and other station equipment; the nature and estimated cost of any Transmission Provider's Interconnection Facilities and Network Upgrades necessary to accomplish the interconnection; and an estimate of the time required to complete the construction and installation of such facilities.

The Interconnection Facilities Study will also identify any potential control equipment for requests for Interconnection Service that are lower than the Generating Facility Capacity.

11.4 Interconnection Facilities Study Procedures.

a. Transmission Provider shall coordinate the Interconnection Facilities Study with any Affected System pursuant to Section 4.6 above. Transmission Provider shall utilize existing studies to the extent practicable in performing the Interconnection Facilities Study.

Transmission Provider shall use Reasonable Efforts to complete the study and issue a draft Interconnection Facilities Study report to Interconnection Customer within ninety (90) Calendar Days where Transmission Provider is administering the Serial Interconnection Study Process, and within one hundred fifty (150) Calendar Days for all Interconnection Customers within the Cluster where the Transmission Provider is administering the Definitive Interconnection Study Process.

b. At the request of Interconnection Customer or at any time Transmission Provider determines that it will not meet the required time frame for completing the Interconnection Facilities Study, Transmission Provider shall notify Interconnection Customer as to the schedule status of the Interconnection Facilities Study. If Transmission Provider is unable to complete the Interconnection Facilities Study and issue a draft Interconnection Facilities Study report within the time required, it shall notify Interconnection Customer and provide an estimated completion date and an explanation of the reasons why additional time is required.

c. Interconnection Customer may, within thirty (30) Calendar Days after receipt of the draft Interconnection Facilities Study report, provide written comments to Transmission Provider, which Transmission Provider shall consider in completing the final Interconnection Facilities Study report. Transmission Provider shall issue the final Interconnection Facilities Study report within fifteen (15) Business Days of receiving Interconnection Customer's comments or promptly upon receiving Interconnection Customer's statement that it will not provide comments. Transmission Provider may reasonably extend such fifteen (15) Business Day period upon notice to Interconnection Customer if Interconnection Customer's comments require Transmission Provider to perform additional analyses or make other significant modifications prior to the issuance of the final Interconnection Facilities Study report. Upon request, Transmission Provider shall provide Interconnection Customer supporting documentation, workpapers, and databases or data developed in the preparation of the Interconnection Facilities Study, subject to confidentiality arrangements consistent with Section 16.1.

11.5 Meeting with Transmission Provider.
Within ten (10) Business Days of providing a draft Interconnection Facilities Study report to Interconnection Customer, Transmission Provider and Interconnection Customer shall meet to discuss the results of the Interconnection Facilities Study.

11.6 Serial Interconnection Study Process Facilities Study Re-Study.
If Re-Study of the Interconnection Facilities Study is required due to a higher or equal priority queued project dropping out of the Queue or a modification of a higher queued project pursuant to Section 5.4, Transmission Provider shall so notify Interconnection Customer in writing. The Transmission Provider shall make Reasonable Efforts to ensure such Re-Study shall take no longer than sixty (60) Calendar Days from the date of notice. Re-Studies that require rerunning the system impact study analysis make take longer than sixty days. Any cost of Re-Study shall be borne by the Interconnection Customer(s) being re-studied.

11.7 Definitive Interconnection Study Process Facilities Study Re-Study.
If Re-Study of the Interconnection Facilities Study is required due to a higher or equal priority queued project dropping out of the Queue or a modification of a higher queued project pursuant to Section 5.4, Transmission Provider shall so notify Interconnection Customer in writing. The Transmission Provider shall make Reasonable Efforts to ensure such Re-Study shall take no longer than sixty (60) Calendar Days from the date of notice, unless the Transmission Provider DISIS Phase 3 re-study is required. Re-Studies that require rerunning the DISIS analysis make take longer than sixty days. Any cost of Re-Study shall be borne by the Interconnection Customer(s) being re-studied pursuant to Section 10.3.

Section 12. Engineering & Procurement ("E&P") Agreement.

Prior to executing an LGIA, an Interconnection Customer may, in order to advance the implementation of its interconnection, request and Transmission Provider shall offer the Interconnection Customer, an E&P Agreement that authorizes Transmission Provider to begin engineering and procurement of long lead-time items necessary for the establishment of the interconnection. However, Transmission Provider shall not be obligated to offer an E&P Agreement if Interconnection Customer is in Dispute Resolution as a result of an allegation that Interconnection Customer has failed to meet any milestones in the Serial Interconnection Study Process, Readiness Milestones in the Definitive Interconnection Study Process, or comply with any prerequisites specified in other parts of the LGIP. The E&P Agreement is an optional procedure and it will not alter the Interconnection Customer's Queue Position or In-Service Date. The E&P Agreement shall provide for Interconnection Customer to pay the cost of all activities authorized by Interconnection Customer and to make advance payments or provide other satisfactory security for such costs.

Interconnection Customer shall pay the cost of such authorized activities and any cancellation costs for equipment that is already ordered for its interconnection, which cannot be mitigated as hereafter described, whether or not such items or equipment later become unnecessary. If Interconnection Customer withdraws its application for interconnection or either Party terminates the E&P Agreement, to the extent the equipment ordered can be canceled under reasonable terms, Interconnection Customer shall be obligated to pay the associated cancellation costs. To the extent that the equipment cannot be reasonably canceled, Transmission Provider may elect: (i) to take title to the equipment, in which event Transmission Provider shall refund Interconnection Customer any amounts paid by Interconnection Customer for such equipment and shall pay the cost of delivery of such equipment, or (ii) to transfer title to and deliver such equipment to Interconnection Customer, in which event Interconnection Customer shall pay any unpaid balance and cost of delivery of such equipment.

Section 13. Serial Interconnection Study Process- Optional Interconnection Study.

13.1 Optional Interconnection Study Agreement.

On or after the date when Interconnection Customer receives Interconnection System Impact Study results, Interconnection Customer may request, and Transmission Provider shall perform a reasonable number of Optional Studies. The request shall describe the assumptions that Interconnection Customer wishes Transmission Provider to study within the scope described in Section 13.2. Within five (5) Business Days after receipt of a request for an Optional Interconnection Study, Transmission Provider shall provide to Interconnection Customer an Optional Interconnection Study Agreement in the form of Appendix 9.

The Optional Interconnection Study Agreement shall: (i) specify the technical data that Interconnection Customer must provide for each phase of the Optional Interconnection Study, (ii) specify Interconnection Customer's assumptions as to which Interconnection Requests with earlier queue priority dates will be excluded from the Optional Interconnection Study case and assumptions as to the type of interconnection service for Interconnection Requests remaining in the Optional Interconnection Study case, and (iii) Transmission Provider's estimate of the cost of the Optional Interconnection Study. To the extent known by Transmission Provider, such estimate shall include any costs expected to be incurred by any Affected System whose participation is necessary to complete the Optional Interconnection Study. Notwithstanding the above, Transmission Provider shall not be required as a result of an Optional Interconnection Study request to conduct any additional Interconnection Studies with respect to any other Interconnection Request.

Interconnection Customer shall execute the Optional Interconnection Study Agreement within ten (10) Business Days of receipt and deliver the Optional Interconnection Study Agreement, the technical data and a $10,000 deposit to Transmission Provider.

13.2 Scope of Optional Interconnection Study.

The Optional Interconnection Study will consist of a sensitivity analysis based on the assumptions specified by Interconnection Customer in the Optional Interconnection Study Agreement. The Optional Interconnection Study will also identify Transmission Provider's Interconnection Facilities and the Network Upgrades, and the estimated cost thereof, that may be required to provide transmission service or Interconnection Service based upon the results of the Optional Interconnection Study. The Optional Interconnection Study shall be performed solely for informational purposes. Transmission Provider shall use Reasonable Efforts to coordinate the study with any Affected Systems that may be affected by the types of Interconnection Services that are being studied. Transmission Provider shall utilize existing studies to the extent practicable in conducting the Optional Interconnection Study.

13.3 Optional Interconnection Study Procedures.

The executed Optional Interconnection Study Agreement, the prepayment, and technical and other data called for therein must be provided to Transmission Provider within ten (10) Business Days of Interconnection Customer receipt of the Optional Interconnection Study Agreement. Transmission Provider shall use Reasonable Efforts to complete the Optional Interconnection Study within a mutually agreed upon time period specified within the

Optional Interconnection Study Agreement. If Transmission Provider is unable to complete the Optional Interconnection Study within such time period, it shall notify Interconnection Customer and provide an estimated completion date and an explanation of the reasons why additional time is required. Any difference between the study payment and the actual cost of the study shall be paid to Transmission Provider or refunded to Interconnection Customer, as appropriate. Upon request, Transmission Provider shall provide Interconnection Customer supporting documentation and workpapers and databases or data developed in the preparation of the Optional Interconnection Study, subject to confidentiality arrangements consistent with Section 16.1.

Section 14. Standard Large Generator Interconnection Agreement (LGIA).

14.1 Tender.

Interconnection Customer shall tender comments on the draft Interconnection Facilities Study Report within thirty (30) Calendar Days of receipt of the report. Within thirty (30) Calendar Days after the comments are submitted or after the Interconnection Customer notifies Transmission Provider in writing that it will provide no comments, Transmission Provider shall tender a draft LGIA, together with draft appendices. The draft LGIA shall be in the form of Transmission Provider's FERC-approved standard form LGIA, which is in Appendix 10. Interconnection Customer shall return the completed draft appendices and execute the LGIA within thirty (30) Calendar Days unless the sixty (60) Calendar Day negotiation period under Section 14.2 has commenced.

14.2 Negotiation.

Notwithstanding Section 14.1, at the request of Interconnection Customer Transmission Provider shall begin negotiations with Interconnection Customer concerning the appendices to the LGIA at any time after Interconnection Customer executes the Interconnection Facilities Study Agreement. Transmission Provider and Interconnection Customer shall negotiate concerning any disputed provisions of the appendices to the draft LGIA for not more than sixty (60) Calendar Days after tender of the final Interconnection Facilities Study Report. If Interconnection Customer determines that negotiations are at an impasse, Interconnection Customer may request termination of the negotiations at any time after tender of the draft LGIA pursuant to Section 14.1 and request submission of the unexecuted LGIA with FERC or initiate Dispute Resolution procedures pursuant to Section 16.6. If Interconnection Customer requests termination of the negotiations, but within sixty (60) Calendar Days thereafter fails to request either the filing of the unexecuted LGIA or initiate Dispute Resolution, it shall be deemed to have withdrawn its Interconnection Request. Unless otherwise agreed by the Parties, if Interconnection Customer has not executed the LGIA, requested filing of an unexecuted LGIA, or initiated Dispute Resolution procedures pursuant to Section 16.6 within sixty (60) Calendar Days of tender of draft LGIA, it shall be deemed to have withdrawn its Interconnection Request. Transmission Provider shall provide to Interconnection Customer a final LGIA within fifteen (15) Business Days after the completion of the negotiation process.

14.3 Serial Interconnection Study Process – Execution and Filing.

Within fifteen (15) Business Days after receipt of the final LGIA, Interconnection Customer shall provide Transmission Provider (A) reasonable evidence that continued Site Control or (B) posting of $250,000, non-refundable additional security, which shall be applied toward future construction costs. At the same time, Interconnection Customer also shall provide reasonable evidence that one or more of the following milestones in the development of the Large Generating Facility, at Interconnection Customer election, has been achieved: (i) the execution of a contract for the supply or transportation of fuel to the Large Generating Facility; (ii) the execution of a contract for the supply of cooling water to the Large Generating Facility; (iii) execution of a contract for the engineering for, procurement of major equipment for, or construction of, the Large Generating Facility; (iv) execution of a contract for the sale of electric energy or capacity from the Large Generating Facility; or (v) application for an air, water, or land use permit.

Interconnection Customer shall either: (i) execute two originals of the tendered LGIA and return them to Transmission Provider; or (ii) request in writing that Transmission Provider file with FERC an LGIA in unexecuted form. As soon as practicable, but not later than ten (10) Business Days after receiving either the two executed originals of the tendered LGIA (if it does not conform with a FERC-approved standard form of interconnection agreement) or the request to file an unexecuted LGIA, Transmission Provider shall file the LGIA with FERC, together with its explanation of any matters as to which Interconnection Customer and Transmission Provider disagree and support for the costs that Transmission Provider proposes to charge to Interconnection Customer under the LGIA. An unexecuted LGIA should contain terms and conditions deemed appropriate by Transmission Provider for the Interconnection Request. If the Parties agree to proceed with design, procurement, and construction of facilities and upgrades under the agreed-upon terms of the unexecuted LGIA, they may proceed pending FERC action.

14.4 Definitive Interconnection Study Process – Execution and Filing.
Within fifteen (15) Business Days after receipt of the final LGIA, Interconnection Customer shall (a) provide reasonable evidence that continued Site Control exists as defined in Section 1 and (b) post Readiness Milestone 5 (security equal to nine (9) times that Interconnection Customer's share of the Definitive Interconnection Study Process study costs as described in Section 10.11.5). If the actual study costs are not known at the time, study costs shall be estimated as the study deposit described in Section 4.1.2, and the M5 amount shall be updated when the study costs are known. If the Interconnection Customer does not reach Commercial Operation, upon payment of any final invoice, including any Withdrawal Penalty, Readiness Milestone 5 shall be refunded to the Interconnection Customer, including any accumulated interest, if applicable. If the Interconnection Customer reaches Commercial Operation, Readiness Milestone 5 is refunded to the Interconnection Customer including any accumulated interest, if applicable. Within fifteen (15) Business Days after receipt of the final LGIA, Interconnection Customer also shall provide reasonable evidence that one or more of the following milestones in the development of the Large Generating Facility, at Interconnection Customer election, has been achieved: (i) the execution of a contract for the supply or transportation of fuel to the Large Generating Facility (not applicable for wind or solar resources); (ii) the execution of a contract for the supply of cooling water to the Large Generating Facility (not applicable for wind or solar resources); (iii) execution of a contract for the engineering for, procurement of major equipment for, or construction of, the Large Generating Facility; (iv) execution of a contract (or comparable evidence) for the sale of electric energy or capacity from the Large Generating Facility; or (v) application(s) for applicable air, water, or land use permit(s).

Interconnection Customer shall either: (i) execute two originals of the tendered LGIA and return them to Transmission Provider; or (ii) request in writing that Transmission Provider file with FERC an LGIA in unexecuted form. As soon as practicable, but not later than ten

(10) Business Days after receiving either the two executed originals of the tendered LGIA (if it does not conform with a FERC-approved standard form of interconnection agreement) or the request to file an unexecuted LGIA, Transmission Provider shall file the LGIA with FERC, together with its explanation of any matters as to which Interconnection Customer and Transmission Provider disagree and support for the costs that Transmission Provider proposes to charge to Interconnection Customer under the LGIA. An unexecuted LGIA should contain terms and conditions deemed appropriate by Transmission Provider for the Interconnection Request. If the Parties agree to proceed with design, procurement, and construction of facilities and upgrades under the agreed-upon terms of the unexecuted LGIA, they may proceed pending FERC action.

14.5 Commencement of Interconnection Activities.
If Interconnection Customer executes the final LGIA, Transmission Provider and Interconnection Customer shall perform their respective obligations in accordance with the terms of the LGIA, subject to modification by FERC. Upon submission of an unexecuted LGIA, Interconnection Customer and Transmission Provider shall promptly comply with the unexecuted LGIA, subject to modification by FERC.

Section 15. Construction of Transmission Provider's Interconnection Facilities and Network Upgrades.

15.1 Schedule.
Transmission Provider and Interconnection Customer shall negotiate in good faith concerning a schedule for the construction of Transmission Provider's Interconnection Facilities and the Network Upgrades.

15.2 Construction Sequencing.

15.2.1 General.
In general, the In-Service Date of an Interconnection Customers seeking interconnection to the Transmission System will determine the sequence of construction of Network Upgrades. Construction Sequencing may also apply to shared Transmission Provider’s Interconnection Facilities in a similar manner as described below for Network Upgrades.

15.2.2 Advance Construction of Network Upgrades That are an Obligation of an Entity Other Than Interconnection Customer.
An Interconnection Customer with an LGIA, in order to maintain its In-Service Date, may request that Transmission Provider advance to the extent necessary the completion of Network Upgrades that: (i) were assumed in the Interconnection Studies for such Interconnection Customer, (ii) are necessary to support such In-Service Date, and (iii) would otherwise not be completed, pursuant to a contractual obligation of an entity other than Interconnection Customer that is seeking interconnection to the Transmission System, in time to support such In-Service Date. Upon such request, Transmission Provider will use Reasonable Efforts to advance the construction of such Network Upgrades to accommodate such request; provided that Interconnection Customer commits to pay Transmission Provider: (i)any associated expediting costs and (ii) the cost of such Network Upgrades.

Transmission Provider will refund to Interconnection Customer both the expediting costs and the cost of Network Upgrades, in accordance with Article 11.4 of the LGIA. Consequently, the entity with a contractual obligation to construct such Network Upgrades shall be obligated to pay only that portion of the costs of the Network Upgrades that Transmission Provider has not refunded to Interconnection Customer. Payment by that entity shall be due on the date that it would have been due had there been no request for advance construction. Transmission Provider shall forward to Interconnection Customer the amount paid by the entity with a contractual obligation to construct the Network Upgrades as payment in full for the outstanding balance owed to Interconnection Customer. Transmission Provider then shall refund to that entity the amount that it paid for the Network Upgrades, in accordance with Article 11.4 of the LGIA.

15.2.3 Advancing Construction of Network Upgrades That are Part of an Expansion Plan of the Transmission Provider.

An Interconnection Customer with an LGIA, in order to maintain its In-Service Date, may request that Transmission Provider advance to the extent necessary the completion of Network Upgrades that: (i) are necessary to support such In-Service Date and (ii) would otherwise not be completed, pursuant to an expansion plan of Transmission Provider, in time to support such In-Service Date. Upon such request, Transmission Provider will use Reasonable Efforts to advance the construction of such Network Upgrades to accommodate such request; provided that Interconnection Customer commits to pay Transmission Provider any associated expediting costs. Interconnection Customer shall be entitled to transmission credits, if any, for any expediting costs paid.

15.2.4 Amended Interconnection System Impact Study.

An Interconnection System Impact Study will be amended to determine the facilities necessary to support the requested In-Service Date. This amended study will include those transmission and Large Generating Facilities that are expected to be in service on or before the requested In-Service Date.

Section 16. Miscellaneous.

16.1 Confidentiality.

Confidential Information shall include, without limitation, all information relating to a Party's technology, research and development, business affairs, and pricing, and any information supplied by either of the Parties to the other prior to the execution of an LGIA.

Information is Confidential Information only if it is clearly designated or marked in writing as confidential on the face of the document, or, if the information is conveyed orally or by inspection, if the Party providing the information orally informs the Party receiving the information that the information is confidential.

If requested by either Party, the other Party shall provide in writing, the basis for asserting that the information referred to in this Article warrants confidential treatment, and the requesting Party may disclose such writing to the appropriate Governmental Authority. Each Party shall be responsible for the costs associated with affording confidential treatment to its information.

16.1.1 Scope.

Confidential Information shall not include information that the receiving Party can demonstrate: (1) is generally available to the public other than as a result of a disclosure by the receiving Party; (2) was in the lawful possession of the receiving Party on a non-confidential basis before receiving it from the disclosing Party; (3) was supplied to the receiving Party without restriction by a third party, who, to the knowledge of the receiving Party after due inquiry, was under no obligation to the disclosing Party to keep such information confidential; (4) was independently developed by the receiving Party without reference to Confidential Information of the disclosing Party; (5) is, or becomes, publicly known, through no wrongful act or omission of the receiving Party or Breach of the LGIA; or (6) is required, in accordance with Section 16.1.6, Order of Disclosure, to be disclosed by any Governmental Authority or is otherwise required to be disclosed by law or subpoena, or is necessary in any legal proceeding establishing rights and obligations under the LGIA.

Information designated as Confidential Information will no longer be deemed confidential if the Party that designated the information as confidential notifies the other Party that it no longer is confidential.

16.1.2 Release of Confidential Information.
Neither Party shall release or disclose Confidential Information to any other person, except to its Affiliates (limited by the Standards of Conduct requirements), employees, consultants, or to parties who may be or considering providing financing to or equity participation with Interconnection Customer, or to potential purchasers or assignees of Interconnection Customer, on a need-to-know basis in connection with these procedures, unless such person has first been advised of the confidentiality provisions of this Section 16.1 and has agreed to comply with such provisions. Notwithstanding the foregoing, a Party providing Confidential Information to any person shall remain primarily responsible for any release of Confidential Information in contravention of this Section 16.1.

16.1.3 Rights.
Each Party retains all rights, title, and interest in the Confidential Information that each Party discloses to the other Party. The disclosure by each Party to the other Party of Confidential Information shall not be deemed a waiver by either Party or any other person or entity of the right to protect the Confidential Information from public disclosure.

16.1.4 No Warranties.
By providing Confidential Information, neither Party makes any warranties or representations as to its accuracy or completeness. In addition, by supplying Confidential Information, neither Party obligates itself to provide any particular information or Confidential Information to the other Party nor to enter into any further agreements or proceed with any other relationship or joint venture.

16.1.5 Standard of Care.
Each Party shall use at least the same standard of care to protect Confidential Information it receives as it uses to protect its own Confidential Information from unauthorized disclosure, publication or dissemination. Each Party may use Confidential Information solely to fulfill its obligations to the other Party under these procedures or its regulatory requirements.

16.1.6 Order of Disclosure.
If a court or a Government Authority or entity with the right, power, and apparent authority to do so requests or requires either Party, by subpoena, oral deposition, interrogatories, requests for production of documents, administrative order, or otherwise, to disclose

Confidential Information, that Party shall provide the other Party with prompt notice of such request(s) or requirement(s) so that the other Party may seek an appropriate protective order or waive compliance with the terms of the LGIA. Notwithstanding the absence of a protective order or waiver, the Party may disclose such Confidential Information which, in the opinion of its counsel, the Party is legally compelled to disclose. Each Party will use Reasonable Efforts to obtain reliable assurance that confidential treatment will be accorded any Confidential Information so furnished.

16.1.7 Remedies.
The Parties agree that monetary damages would be inadequate to compensate a Party for the other Party's Breach of its obligations under this Section 16.1. Each Party accordingly agrees that the other Party shall be entitled to equitable relief, by way of injunction or otherwise, if the first Party Breaches or threatens to Breach its obligations under this Section 16.1, which equitable relief shall be granted without bond or proof of damages, and the receiving Party shall not plead in defense that there would be an adequate remedy at law. Such remedy shall not be deemed an exclusive remedy for the Breach of this Section 16.1, but shall be in addition to all other remedies available at law or in equity. The Parties further acknowledge and agree that the covenants contained herein are necessary for the protection of legitimate business interests and are reasonable in scope. No Party, however, shall be liable for indirect, incidental, or consequential or punitive damages of any nature or kind resulting from or arising in connection with this Section 16.1.

16.1.8 Disclosure to FERC, its Staff, or a State.
Notwithstanding anything in this Section 16.1 to the contrary, and pursuant to 18 CFR section 1b.20, if FERC or its staff, during the course of an investigation or otherwise, requests information from one of the Parties that is otherwise required to be maintained in confidence pursuant to the LGIP, the Party shall provide the requested information to FERC or its staff, within the time provided for in the request for information. In providing the information to FERC or its staff, the Party must, consistent with 18 CFR section 388.112, request that the information be treated as confidential and non-public by FERC and its staff and that the information be withheld from public disclosure. Parties are prohibited from notifying the other Party prior to the release of the Confidential Information to FERC or its staff. The Party shall notify the other Party to the LGIA when it is notified by FERC or its staff that a request to release Confidential Information has been received by FERC, at which time either of the Parties may respond before such information would be made public, pursuant to 18 CFR section 388.112. Requests from a state regulatory body conducting a confidential investigation shall be treated in a similar manner, consistent with applicable state rules and regulations.

16.1.9 Subject to the exception in Section 16.1.8, any information that a Party claims is competitively sensitive, commercial or financial information ("Confidential Information") shall not be disclosed by the other Party to any person not employed or retained by the other Party, except to the extent disclosure is (i) required by law; (ii) reasonably deemed by the disclosing Party to be required to be disclosed in connection with a dispute between or among the Parties, or the defense of litigation or dispute; (iii) otherwise permitted by consent of the other Party, such consent not to be unreasonably withheld; or (iv) necessary to fulfill its obligations under this LGIP or as a transmission service provider or a Control Area operator including disclosing the Confidential Information to an RTO or ISO or to a subregional, regional or national reliability organization or planning group. The Party asserting confidentiality shall notify the other Party in writing of the information it claims is confidential. Prior to any disclosures of the other Party's Confidential Information under this subparagraph, or if any third party or Governmental Authority makes any request or demand for any of the information described in this subparagraph, the disclosing Party agrees to promptly notify the other Party in writing and agrees to assert confidentiality and cooperate with the other Party in seeking to protect the Confidential Information from public disclosure by confidentiality agreement, protective order or other reasonable measures.

16.1.10 This provision shall not apply to any information that was or is hereafter in the public domain (except as a result of a Breach of this provision).

16.1.11 Transmission Provider shall, at Interconnection Customer's election, destroy, in a confidential manner, or return the Confidential Information provided at the time of Confidential Information is no longer needed.

16.2 Delegation of Responsibility.
Transmission Provider may use the services of subcontractors as it deems appropriate to perform its obligations under this LGIP. Transmission Provider shall remain primarily liable to Interconnection Customer for the performance of such subcontractors and compliance with its obligations of this LGIP. The subcontractor shall keep all information provided confidential and shall use such information solely for the performance of such obligation for which it was provided and no other purpose.

16.3 Serial Interconnection Study Process – Obligation for Study Costs.
Transmission Provider shall charge and Interconnection Customer shall pay the actual costs of the Interconnection Studies. Any difference between the study deposit and the actual cost of the applicable Interconnection Study shall be paid by or refunded, except as otherwise provided herein, to Interconnection Customer or offset against the cost of any future Interconnection Studies associated with the applicable Interconnection Request prior to beginning of any such future Interconnection Studies. Any invoices for Interconnection Studies shall include a detailed and itemized accounting of the cost of each Interconnection Study. Interconnection Customer shall pay any such undisputed costs within thirty (30) Calendar Days of receipt of an invoice therefor. Transmission Provider shall not be obligated to perform or continue to perform any studies unless Interconnection Customer has paid all undisputed amounts in compliance herewith.

16.4 Definitive Interconnection Study Process – Obligation for Study Costs and Withdrawal Penalty.
Transmission Provider shall charge and Interconnection Customer shall pay the actual costs of the Interconnection Studies and the Withdrawal Penalty, as applicable. Any difference between the study deposit and the actual cost of the applicable Interconnection Study shall be paid by or refunded, except as otherwise provided herein. Any invoices for Interconnection Studies shall include a detailed and itemized accounting of the cost of each Interconnection Study as well as the Withdrawal Penalty, if applicable. Interconnection Customer shall pay any such undisputed costs within thirty (30) Calendar Days of receipt of an invoice. Transmission Provider shall not be obligated to perform or continue to perform any studies unless Interconnection Customer has paid all undisputed amounts in compliance herewith. If invoices are not paid within thirty (30) Calendar Days of receipt of an invoice, Transmission Provider shall draw upon the security provided under this LGIP to settle all accounts, which shall include any offsets of amounts due and owing by Transmission Provider. After the final

invoice is paid and all accounts are settled, Transmission Provider shall refund all remaining security.

16.5 Third Parties Conducting Studies.

If (i) at the time of the signing of an Interconnection Study Agreement there is disagreement as to the estimated time to complete an Interconnection Study, (ii) Interconnection Customer receives notice pursuant to Sections 3.3, 7.1, 7.2, 8.3, 9.4, 10.8, 11.4, or 13.3 that Transmission Provider will not complete an Interconnection Study within the applicable timeframe for such Interconnection Study, or (iii) Interconnection Customer receives neither the Interconnection Study nor a notice under Sections 3.3, 7.1, 7.2, 8.3, 9.4, 10.8, 11.4, or 13.3 within the applicable timeframe for such Interconnection Study, then Interconnection Customer may require Transmission Provider to utilize a third party consultant reasonably acceptable to Interconnection Customer and Transmission Provider to perform such Interconnection Study under the direction of Transmission Provider. At other times, Transmission Provider may also utilize a third party consultant to perform such Interconnection Study, either in response to a general request of Interconnection Customer, or on its own volition.

In all cases, use of a third party consultant shall be in accord with Article 26 of the LGIA (Subcontractors) and limited to situations where Transmission Provider determines that doing so will help maintain or accelerate the study process for Interconnection Customer's pending Interconnection Request and not interfere with Transmission Provider's progress on Interconnection Studies for other pending Interconnection Requests. In cases where Interconnection Customer requests use of a third party consultant to perform such Interconnection Study, Interconnection Customer and Transmission Provider shall negotiate all of the pertinent terms and conditions, including reimbursement arrangements and the estimated study completion date and study review deadline. Transmission Provider shall convey all workpapers, data bases, study results and all other supporting documentation prepared to date with respect to the Interconnection Request as soon as soon as practicable upon Interconnection Customer's request subject to the confidentiality provision in Section 16.1. In any case, such third party contract may be entered into with either Interconnection Customer or Transmission Provider at Transmission Provider's discretion. In the case of (iii) Interconnection Customer maintains its right to submit a claim to Dispute Resolution to recover the costs of such third party study. Such third party consultant shall be required to comply with this LGIP, Article 26 of the LGIA (Subcontractors), and the relevant Tariff procedures and protocols as would apply if Transmission Provider were to conduct the Interconnection Study and shall use the information provided to it solely for purposes of performing such services and for no other purposes. Transmission Provider shall cooperate with such third party consultant and Interconnection Customer to complete and issue the Interconnection Study in the shortest reasonable time.

16.6 Disputes.

16.6.1 Submission.

In the event either Party has a dispute, or asserts a claim, that arises out of or in connection with the LGIA, the LGIP, or their performance, such Party (the "disputing Party") shall provide the other Party with written notice of the dispute or claim ("Notice of Dispute"). Such dispute or claim shall be referred to a designated senior representative of each Party for resolution on an informal basis as promptly as practicable after receipt of the Notice of Dispute by the other Party. In the event the designated representatives are unable to resolve the claim or dispute through unassisted or assisted negotiations within thirty (30) Calendar Days of the other Party's receipt of the Notice of Dispute, such claim or dispute may, upon mutual agreement of the Parties, be submitted to arbitration and resolved in accordance with the arbitration procedures set forth below. In the event the Parties do not agree to submit such claim or dispute to arbitration, each Party may exercise whatever rights and remedies it may have in equity or at law consistent with the terms of this LGIA. Where the Transmission Provider is administering a Definitive Interconnection Study Process as prescribed in Section 10 and an Interconnection Customer initiates a dispute pursuant to this Section, the disputing Interconnection Customer shall have the option to either withdraw from the Cluster and be studied as part of the next Cluster or to continue being evaluated as part of the Cluster provided that it complies with all Readiness Milestones and other requirements of the Section 10 Definitive Interconnection System Impact Study.

16.6.2 External Arbitration Procedures.
Any arbitration initiated under these procedures shall be conducted before a single neutral arbitrator appointed by the Parties. If the Parties fail to agree upon a single arbitrator within ten (10) Calendar Days of the submission of the dispute to arbitration, each Party shall choose one arbitrator who shall sit on a three-member arbitration panel. The two arbitrators so chosen shall within twenty (20) Calendar Days select a third arbitrator to chair the arbitration panel. In either case, the arbitrators shall be knowledgeable in electric utility matters, including electric transmission and bulk power issues, and shall not have any current or past substantial business or financial relationships with any party to the arbitration (except prior arbitration). The arbitrator(s) shall provide each of the Parties an opportunity to be heard and, except as otherwise provided herein, shall conduct the arbitration in accordance with the Commercial Arbitration Rules of the American Arbitration Association ("Arbitration Rules") and any applicable FERC regulations or RTO rules; provided, however, in the event of a conflict between the Arbitration Rules and the terms of this Section 16, the terms of this Section 16 shall prevail.

16.6.3 Arbitration Decisions.
Unless otherwise agreed by the Parties, the arbitrator(s) shall render a decision within ninety (90) Calendar Days of appointment and shall notify the Parties in writing of such decision and the reasons therefor. The arbitrator(s) shall be authorized only to interpret and apply the provisions of the LGIA and LGIP and shall have no power to modify or change any provision of the LGIA and LGIP in any manner. The decision of the arbitrator(s) shall be final and binding upon the Parties, and judgment on the award may be entered in any court having jurisdiction. The decision of the arbitrator(s) may be appealed solely on the grounds that the conduct of the arbitrator(s), or the decision itself, violated the standards set forth in the Federal Arbitration Act or the Administrative Dispute Resolution Act. The final decision of the arbitrator must also be filed with FERC if it affects jurisdictional rates, terms and conditions of service, Interconnection Facilities, or Network Upgrades.

16.6.4 Costs.
Each Party shall be responsible for its own costs incurred during the arbitration process and for the following costs, if applicable: (1) the cost of the arbitrator chosen by the Party to sit on the three member panel and one half of the cost of the third arbitrator chosen; or (2) one half the cost of the single arbitrator jointly chosen by the Parties.

16.6.5 Non-binding dispute resolution procedures. If a Party has submitted a Notice of Dispute pursuant to Section 16.6.1, and the Parties are unable to resolve the claim or dispute through unassisted or assisted negotiations within the thirty (30) Calendar Days provided in that section, and the Parties cannot reach mutual agreement to pursue the Section 16.6.2 arbitration process, a Party may request that Transmission Provider engage in Nonbinding Dispute Resolution pursuant to this section by providing written notice to Transmission Provider ("Request for Non-binding Dispute Resolution"). Conversely, either Party may file a Request for Non-binding Dispute Resolution pursuant to this section without first seeking mutual agreement to pursue the Section 16.6.2 arbitration process. The process in Section 16.6.5 shall serve as an alternative to, and not a replacement of, the Section 16.6.2 arbitration process. Pursuant to this process, a transmission provider must within 30 days of receipt of the Request for Non-binding Dispute Resolution appoint a neutral decision-maker that is an independent subcontractor that shall not have any current or past substantial business or financial relationships with either Party. Unless otherwise agreed by the Parties, the decision-maker shall render a decision within sixty (60) Calendar Days of appointment and shall notify the Parties in writing of such decision and reasons therefore. This decision-maker shall be authorized only to interpret and apply the provisions of the LGIP and LGIA and shall have no power to modify or change any provision of the LGIP and LGIA in any manner. The result reached in this process is not binding, but, unless otherwise agreed, the Parties may cite the record and decision in the non-binding dispute resolution process in future dispute resolution processes, including in a Section 16.6.2 arbitration, or in a Federal Power Act section 206 complaint. Each Party shall be responsible for its own costs incurred during the process and the cost of the decision-maker shall be divided equally among each Party to the dispute.

16.7 Local Furnishing Bonds.

16.7.1 Transmission Providers That Own Facilities Financed by Local Furnishing Bonds. This provision is applicable only to a Transmission Provider that has financed facilities for the local furnishing of electric energy with tax-exempt bonds, as described in Section 142(f) of the Internal Revenue Code ("local furnishing bonds"). Notwithstanding any other provision of this LGIA and LGIP, Transmission Provider shall not be required to provide Interconnection Service to Interconnection Customer pursuant to this LGIA and LGIP if the provision of such Transmission Service would jeopardize the tax-exempt status of any local furnishing bond(s) used to finance Transmission Provider's facilities that would be used in providing such Interconnection Service.

16.7.2 Alternative Procedures for Requesting Interconnection Service. If Transmission Provider determines that the provision of Interconnection Service requested by Interconnection Customer would jeopardize the tax-exempt status of any local furnishing bond(s) used to finance its facilities that would be used in providing such Interconnection Service, it shall advise the Interconnection Customer within thirty (30) Calendar Days of receipt of the Interconnection Request.

Interconnection Customer thereafter may renew its request for interconnection using the process specified in Article 5.2(ii) of the Transmission Provider's Tariff.

Public Staff Levitas Cross-Exhibit No. 3

I/A

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Duke Energy Carolinas, LLC,	)	
Duke Energy Florida, LLC, and	)	Docket No. ER21-___-000
Duke Energy Progress, LLC	)	

DIRECT TESTIMONY
OF

KENNETH J. JENNINGS

DIRECT TESTIMONY OF KENNETH JENNINGS

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**DIRECT TESTIMONY OF
KENNETH JENNINGS**

Summary of Testimony

Mr. Jennings discusses Duke Energy Carolinas, LLC's ("DEC"), Duke Energy Progress, LLC's ("DEP" and with DEC, the "Duke Carolinas Utilities"), and Duke Energy Florida, LLC's (collectively, the "Duke Southeast Utilities" or "Duke Transmission Providers" or "Duke") proposed revisions to its Large Generator Interconnection Procedures ("LGIP") contained in Attachment J to the Duke Energy Joint Open Access Transmission Tariff (the "Joint OATT"). Mr. Jennings also discusses the stakeholder process used to help develop these proposed revisions. Mr. Jennings provides an overview of the proposed revised LGIP, which reflects a move from a first-come, first-served approach to a first-ready, first-served approach. Mr. Jennings will explain how the various components of the revised LGIP are designed to address the challenges currently facing the Duke Transmission Providers in administering their respective interconnection queues in order to ensure that Duke is able to efficiently and fairly provide interconnection service. Mr. Jennings discusses Duke's proposal to determine readiness and other related concepts which are central to the revised LGIP. Mr. Jennings provides a description of the various aspects of the proposal that provide Interconnection Customers with information so that they can ensure that a project is ready prior to entering the generation interconnection queue. Mr. Jennings also describes the proposed queue reform transition process that facilitates the transition of current Interconnection Customers requesting interconnection service under Duke's current LGIP to the revised LGIP.

I. INTRODUCTION AND EXPERIENCE

Q. Please state your name and business address.

A. My name is Kenneth J. Jennings. My business address is 411 Fayetteville Street, Suite NC16, Raleigh, NC 27601.

Q. By whom are you employed and what is your position?

A. I am employed by Duke Energy Carolinas, LLC ("DEC"), a wholly owned subsidiary of Duke Energy Corporation ("Duke Energy"), as General Manager of Renewable Integration and Operations.

Q. Please describe Duke Energy.

A. Duke Energy is a public utility holding company with, among other subsidiaries, six wholly-owned, vertically integrated public utility operating company subsidiaries: in the Southeast -- Duke Energy Carolinas, LLC ("DEC"), Duke Energy Progress, LLC ("DEP" with DEC, "Duke Carolinas Utilities"), and Duke Energy Florida, LLC ("DEF") ("Duke Southeast Utilities" or "Duke"); in the Midwest -- Duke Energy Indiana, LLC ("DEI"), Duke Energy Kentucky, Inc. ("DEK"), and Duke Energy Ohio, Inc. ("DEO") ("Duke Midwest Utilities") (collectively, the "Duke Operating Utilities").

Q. On whose behalf are you testifying?

A. I am testifying on behalf of the Duke Southeast Utilities with respect to their filing with the Federal Energy Regulatory Commission ("FERC" or "Commission") of proposed revisions to the Large Generator Interconnection Procedures ("LGIP") (including the Large Generator Interconnection Agreement ("LGIA")) contained in Attachment J to the Joint Open Access Transmission Tariff ("Joint OATT" or "Tariff") to which each Duke Southeast Utility is a party. The tariff changes address many issues that have arisen with the "first-come, first-served" serial generator interconnection queue process established under the Commission's *pro forma* LGIP process adopted in Order No. 2003.[1] The Duke Carolinas Utilities propose to move to a "first-ready, first-served" cluster approach in order to facilitate interconnection of new generation.

Each Duke Southeast Utility that is a party to the Joint OATT will have the option to elect on an individual transmission provider basis whether to move to the cluster approach. While DEC and DEP plan to move immediately to a "first ready, first served" cluster study approach, DEF will continue its implementation of the serial generator interconnection process and the retain flexibility to transition to a clustered generator interconnection process in the future. The Duke Midwest Utilities are not parties to the Joint OATT and therefore the changes to the Joint OATT do not apply to them. DEI is a member of the Midcontinent Independent System Operator, Inc. ("MISO") and subject to its tariff. MISO has already filed and received Commission authorization for several iterations of queue reform to move to a first-ready, first-served approach in order to address issues similar to those faced by generation projects proposing to interconnect to DEC and DEP. DEK and DEO are members of PJM Interconnection, L.L.C. ("PJM") and subject to its tariff. PJM has also filed and received Commission authorization for several iterations of queue reform.

The Duke Southeast Utilities are not in a regional transmission organization ("RTO") like PJM or MISO. The issues faced by the generators seeking to interconnect

[1] *Standardization of Generator Interconnection Agreements and Procedures,* Order No. 2003, FERC Stats. & Regs. ¶ 31,146 (2003), *order on reh'g*, Order No. 2003-A, FERC Stats. & Regs. ¶ 31,160, *order on reh'g*, Order No. 2003-B, FERC Stats. & Regs. ¶ 31,171 (2004), order on reh'g, Order No. 2003-C, FERC Stats. & Regs. ¶ 31,190 (2005), *aff'd sub nom. Nat'l Ass'n of Regulatory Util. Comm'rs* v. FERC, 475 F.3d 1277 (D.C. Cir. 2007) (collectively, "Order No. 2003").

to the DEC and DEP systems and the transmission functions are different than those faced by generators and transmission owners in MISO or PJM.

Q. Please explain your duties and responsibilities.

A. As the General Manager of Renewable Integration and Operations, my responsibilities include supervising interconnection account managers for the 6 Duke Operating Utilities, overseeing interconnection related agreements with third parties, MISO, and PJM, and resolving wholesale customer interconnection service concerns. I am responsible for day-to-day management of interconnection operations, including compliance and administration of the state jurisdictional interconnection procedures and the FERC-jurisdictional large and small generator interconnection procedures across all 6 state jurisdictions of the Duke Operating Utilities.

Q. Please briefly describe your background, including your education and experience in the electric utility business.

A. I received an A.A.S. in Manufacturing Technology, and a B.S. in Manufacturing from Northern Kentucky University in 1991 and 1993, respectively. I also completed a Master's Degree in Business Administration. I began working for Cinergy Corporation, now a subsidiary of Duke Energy Corp. in 1999 working in the Engineering and Construction Group of Cinergy Generation Resources, LLC. I have held positions such as Manager of Business Analysis; Station Performance Engineer at Miami Fort Station in North Bend, Ohio; Technical Analysis Engineer in the Business Development Support Group; and Condition Based Maintenance Team Lead over thermal performance of all Cincinnati Gas & Electric generation facilities in Cincinnati. In April of 2006, Cinergy Corporation was acquired by Duke Energy Corp., at which time I was promoted to the position of Director of RTO Market Services. In that role I was designated as the Duke Energy PJM member's committee representative with voting rights in the PJM stakeholder processes.

In 2014, Duke Energy divested its control of its Midwest Commercial assets, at which point I accepted the position of North Carolina Distributed Energy Strategy and Policy Director. In this role, I supported Duke as a subject matter expert in its North Carolina renewable energy program development efforts and stakeholder processes. I also developed and designed renewable energy products and tariffs for compliance under state statutory requirements. In February of 2019, I was promoted to my current position.

Q. Have you previously filed testimony before the Federal Energy Regulatory Commission?

A. No. I have participated in a number of FERC regulatory proceedings as the Duke business subject matter expert but have not formerly provided testimony before the Commission. However, I have testified numerous times before state utility commissions in proceedings which range from fuel adjustment clause proceedings in Indiana to interconnection complaints in North Carolina. I also served as the expert witness in both Ohio and Kentucky when DEO sought state regulatory approval to transfer functional control over its transmission system from MISO to PJM.

II. PURPOSE AND SUMMARY

Q. What is the purpose of your testimony?

A. The purpose of my testimony is provide an overview of the rationale and mechanics for the Duke Southeast Utilities' amendments to their interconnection procedures in Attachment J to the Joint OATT consisting of its (a) *pro forma* LGIP and (b) *pro forma*

LGIA. The revised LGIP provides a transparent process enabling each Duke Transmission Provider to elect to move from a first-come, first-served model under the Commission's Order No. 2003 *pro forma* tariff study process to a first-ready, first-served cluster study model. DEC and DEP will elect to do so immediately after Commission approval of the Joint OATT revisions, whereas DEF will refrain from doing so for the time being and continue processing interconnection requests on a serial basis. Finally, I also discuss how Duke developed its queue reform proposal and the stakeholder process that informed Duke's queue reform work.

Q. What are the goals Duke is seeking to achieve with these tariff changes?

A. The ultimate goal is to improve the efficiency, predictability, and fairness of the generator interconnection process for all customers. To meet that goal, Duke must be able to administer the process in a timely manner. To that end, Duke's proposed tariff changes address the huge backlog of interconnection requests in the Carolinas and create a more efficient and streamlined process. In addition to the ultimate goal, there are several related goals as well. First, Duke expects that the revised LGIP will better accommodate ready or near-ready projects entering the queue by (1) providing a process where developers can proactively obtain specific interconnection information prior to entering the queue and (2) dis-incentivizing developers from prematurely entering the queue or from submitting interconnection requests for speculative or non-viable projects. Second, Duke believes the revised LGIP will address the current delays in the multi-step study process associated with contingent upgrades and the potential for cascading restudies that could result from projects being withdrawn from the queue. Third, Duke will streamline the study process by merging the interconnection Feasibility Study and the System Impact Study (now separate under the FERC *pro forma* LGIP and currently effective Duke LGIP), thus creating a single, multi-phased Definitive Interconnection System Impact Study ("DISIS"). Fourth, DEC and DEP will transition from the serial study process to a clustered study process in an orderly manner consistent with Commission precedent, allowing only ready projects (and not speculative projects) to advance by establishing a one-time transitional serial process and a one-time transitional cluster process before fully implementing the DISIS Cluster process going forward. Finally, Duke will address the growing interdependencies between FERC-jurisdictional and state-jurisdictional interconnection requests by harmonizing the new LGIP Definitive Interconnection Study Process with consistent cluster study processes approved by the North Carolina Utilities Commission ("NCUC") and Public Service Commission of South Carolina ("PSCSC").

Q. When does Duke propose the revised LGIP to be effective?

A. Duke proposes that the revised LGIP be effective June 1, 2021, 62 days after this filing. If accepted as of that effective date, DEC and DEP would each publicize its intent to transition to the Definitive Interconnection Study Process by (a) posting on their respective OASIS sites in July 2021 that the first DISIS Cluster process will be initiated and first annual DISIS Request Window will open on January 1, 2022 and (b) deliver written notice of the Transmission Provider's transition to the Definitive Interconnection Study Process to all current Interconnection Customers to inform them of their options under the transitional process, as described in LGIP § 7.

Q. Please summarize the proposed tariff changes.

A. The proposed revisions to the Joint OATT include:

- The creation of an Informational Interconnection Study ("IIS") to provide information to Interconnection Customers prior to entering the generator interconnection queue. (LGIP § 3).
- The creation of a Definitive Interconnection Study Process, whereby the LGIP process moves from a first-come, first-served serial study process to a first-ready, first-served cluster study process. (LGIP § 10).
- The creation of Readiness Milestones and Withdrawal Penalties into the Definitive Interconnection Study process to ensure that projects are ready or near-ready to interconnect, including "at risk" financial milestones, which will dis-incentivize projects from proceeding through the queue if they are not ready to do so. (LGIP § 10.11; LGIP § 4.7.1).
- The creation of two transitional processes to facilitate the transition of Interconnection Customers from the current LGIP to the revised LGIP. (LGIP § 7).
- Proposed changes to the LGIA that align with the Definitive Interconnection Study. (LGIP Appendix 10)

Q. Can you please introduce the other witnesses sponsoring testimony in support of the Duke Southeast Utilities' tariff revisions?

A. Yes. Duke witness Mr. Dewey S. Roberts III, General Manager, Transmission Planning and Operations Strategy for Duke Energy Corporation, describes Duke, the state of the current Duke Interconnection queue and the events prompting the need for queue reform. Also, Ms. Kendal C. Bowman, Vice President Regulatory Affairs and Policy North Carolina addresses the Duke Southeast Utilities' harmonization of proposed LGIP modifications with the recently approved modifications to the North Carolina Interconnection Procedures and South Carolina Generator Interconnection Procedures.

III. DEVELOPMENT OF QUEUE REFORM PROPOSAL

Q. Please describe the Duke Southeast Utilities' development of the queue reform proposal.

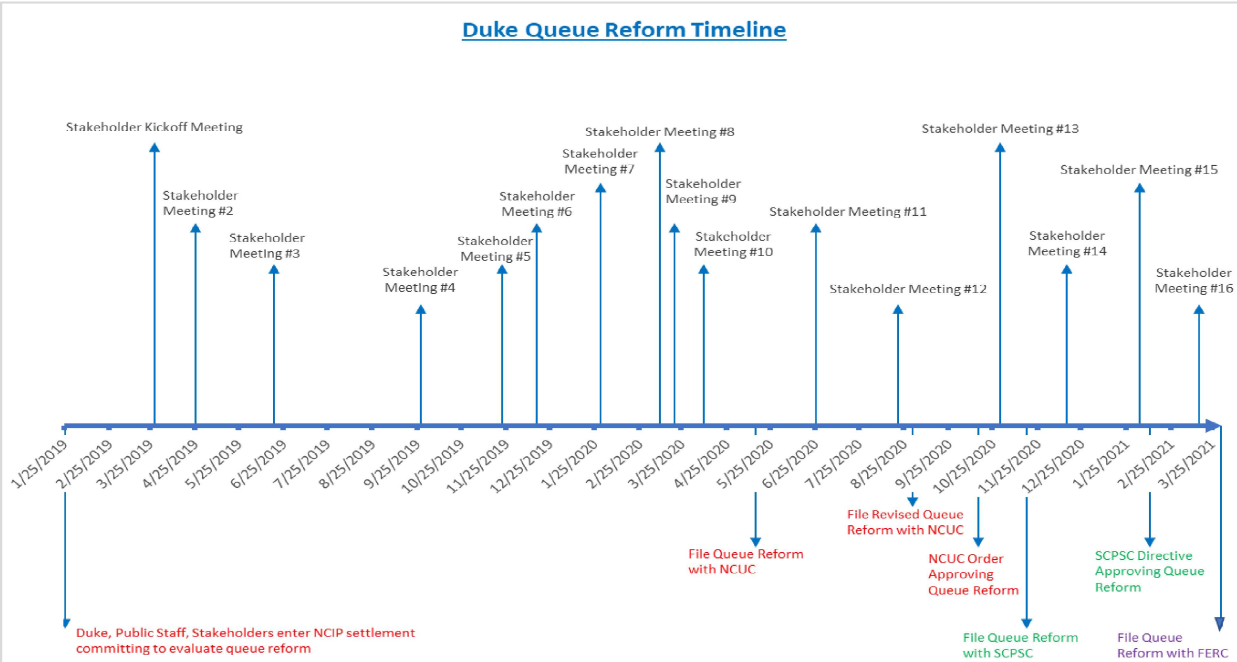
A. The process began by first reviewing the Commission's guidance on queue reform[2] as well as surveying other queue reform efforts throughout the country proposed by public utilities within and outside of RTOs. Shortly after Duke held its initial stakeholder meetings, the NCUC issued an order directing the Duke Carolinas Utilities to "establish a stakeholder process within the first quarter of 2019 to discuss the process of transitioning their North Carolina queues to a grouping study process and that the Duke Utilities shall report to the Commission no later than July 31, 2019, as to the status of that stakeholder process."[3] In response to this NCUC directive to move their North Carolina state-jurisdictional generator interconnection queues from a serial to a cluster study process, the Duke Carolinas Utilities commenced a multi-year stakeholder engagement and coordination process. The Duke Carolinas Utilities also recognized that they must harmonize any generator interconnection procedures established for their North Carolina state-jurisdictional generator queues with their (a) South Carolina state-jurisdictional generator queues and (b) FERC-jurisdictional queues, in order to effectively model and study all generator Interconnection Requests in their BAAs on a clustered basis.

[2] *See, e.g., Interconnection Queuing Practices*, 122 FERC ¶ 61,252 (2008) ("2008 Technical Conference Order").

[3] Order Approving Revised Interconnection Standard and Requiring Reports and Testimony, at 61, North Carolina Utilities Commission, Docket No. E-100, Sub 101 (Jun. 14, 2019). The Duke Carolinas Utilities' initiation of the queue reform stakeholder process prior to the NCUC's issuance of a final order was, in part, based on a partial stipulation entered into with NCUC Public Staff and certain other stakeholders in January 2019.

At that time, PSCo was the utility that had most recently developed a queue reform proposal known as the "Definitive Interconnection Study Process" and was working through its stakeholder process. The Duke Carolinas Utilities' significantly modeled their queue reform proposal on PSCo's Definitive Interconnection Study Process proposal and began honing it through stakeholder engagement. Through this work, Duke sought to identify solutions implemented by similarly situated public utilities and to identify what additional modifications could be made to Duke's LGIP that would incorporate lessons learned from the experiences of others. After this research was completed, Duke developed and initial conceptual queue reform framework and drafted proposed changes to the LGIP. Utilizing this proposed revised LGIP as a starting point, Duke then undertook a robust stakeholder process to solicit feedback from interested parties on the preferred approach to implement queue reform for both FERC-jurisdictional and state-jurisdictional Interconnection Customers. This feedback was considered and, where possible, incorporated into a modified proposal that was followed by a detailed review of draft LGIP tariff language. As presented in Figure 1 below, this process extended over an approximately two-year period, finally culminating in Duke's proposed revised LGIP submitted in this filing.

FIGURE 1



Q. Please describe the survey work Duke performed.

A. Because many public utilities have already undertaken queue reform efforts, Duke believed that incorporating that experience and leveraging the associated learnings would play a vital role in the development of Duke's own proposal. In particular, Duke evaluated similarly situated non-RTO transmission providers to examine whether, and how, those utilities moved forward with queue reform, and what lessons could be learned from their work. In addition, the Commission's 2008 Technical Conference Order in Docket No. AD08-2-000 served as an important starting point to help ensure that any queue reform proposal would be consistent with Commission guidance.[4] Duke reviewed the many iterations of queue reform performed in MISO (which administers the generator interconnection queue for DEI), PJM (which administers the generator interconnection

[4] *See generally* 2008 Technical Conference Order.

queue for DEO), as well as queue reform undertaken by the California Independent System Operator Corporation ("CAISO"), the sole RTO in the Western Interconnection, the Electric Reliability Council of Texas ("ERCOT"), and other RTOs to determine what structural changes have been tested throughout the country, as well as the results of the tariff changes.

Q. What were the results of Duke's survey work?

A. Duke identified Public Service of Colorado ("PSCO") as a similarly situated utility that had undertaken queue reform to address issues similar to those faced by Duke. PSCO's queue reform appeared to be the most recent and the most comprehensive non-RTO queue reform proposal accepted by the Commission at the time Duke was contemplating queue reform.[5] The Commission authorized PSCO to transition its interconnection queue from a first-come, first-served model to a first-ready, first-served model in Docket No. ER19-2774. In light of such Commission approval, Duke utilized the PSCO revisions to its LGIP as a starting point for its own queue reform efforts.

I note that Public Service Company of New Mexico ("PNM")[6], Arizona Public Service Company ("APS"), Nevada Power Company ("NV Energy")[7], and El Paso Electric Services Co. ("El Paso Electric") were also non-RTO member public utilities whose queue reform efforts were approved by the Commission.[8] While the queue reforms of PNM, APS, NV Energy, and El Paso Electric were beneficial for those non-

[5] *Pub. Serv. Co. of Colo.,* 169 FERC ¶ 61,182 (2019).

[6] *Pub. Serv. Co. of N.M.*, 136 FERC ¶ 61,231 (2011).

[7] *Ariz. Pub. Serv. Co.*, 137 FERC ¶ 61,099 (2011).

[8] *Id.; NV Energy, Inc.*, 142 FERC ¶ 61,165 (2013) (joint filing with affiliate Sierra Pacific Power Company); *El Paso Elec. Servs. Co.*, 137 FERC ¶ 61,101 (2011).

independent transmission providers and provide useful precedent, Duke determined that the reforms undertaken by these utilities, on their own, would be insufficient to address the issues confronting the Duke queues. More recently, in 2020, the Commission also approved queue reform initiatives for PacifiCorp[9] and Tri-State Generation & Transmission Association, Inc.[10] Similar to the other non-RTO transmission providers identified above, Duke took learnings from these recent proceedings but, ultimately, determined that the PSCo model (modified in certain respects to meet Duke's needs and stakeholders' preferences) was the most appropriate model for the Duke Southeast Utilities to follow.

Q. Please describe PSCO and PSCO's queue reform filing.

A. PSCO is a vertically integrated franchised public utility with approximately 8,453 MW of peak load in its Balancing Area Authority ("BAA") as of 2017. PSCO generates, transmits and distributes electric power and energy throughout portions of the State of Colorado. Since there is no RTO serving Colorado, PSCO is the Transmission Provider for the PSCO Transmission System.

In a series of filings with FERC in 2018 and 2019,[11] PSCo sought approval of a comprehensive queue reform proposal to address its queue backlog and create a more effective set of interconnection procedures by transitioning to a first-ready, first-served

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[9] *PacifiCorp,* 171 FERC ¶ 61,112 (2020) (accepting queue reform tariff revisions subject to compliance filing). *PacifiCorp*, delegated letter order in Docket No. ER20-924 (Dec. 29, 2020) (accepting compliance filing).

[10] *Tri-State Generation and Trans. Assoc., Inc.,* 173 FERC ¶ 61,231 (2020).

[11] PSCo initially petitioned FERC for approval of queue reform revisions to its tariff in November 2018, which FERC denied by an order issued January 31, 2019. *Pub. Serv. Co. of Colo.*, 166 FERC ¶ 61,076 (2019), *reh'g denied*, 167 FERC ¶ 61,141 (2019). PSCo subsequently refiled its queue reform tariff revisions with FERC in September 2019 in FERC Docket No. ER19-2774, et al. *Pub. Serv. Co. of Colo.,* 169 FERC ¶ 61,182 (2019) (accepting OATT revisions subject to compliance filing) ("PSCo Order Approving Queue Reform"). *Pub. Serv. Co. of Colo.*, delegated letter order in Docket No. ER19-2774-002 (March 2, 2020) (accepting compliance filing).

Cluster Study approach called the "Definitive Interconnection Study Process." [12] Among other things, PSCo proposed: (1) to provide Interconnection Customers with the option of receiving informational interconnection studies (rather than submit an interconnection request in order to obtain such information); (2) to replace the *pro forma* serial study process with a cluster-based Definitive Interconnection Study Process and to administer a multi-phase Definitive Interconnection System Impact Study or "DISIS;" (3) to require Interconnection Customers participating in the DISIS to comply with increasing non-financial "Readiness Milestones" to show that their projects are making progress toward commercial operation, or, alternatively, to provide increasing financial security in lieu of demonstrating readiness; (5) to impose withdrawal penalties on customers that exit the Definitive Interconnection Study Process and cause harm to other customers within the DISIS cluster study; (6) to clarify existing Site Control requirements, and (7) to adopt transition procedures for processing PSCo's existing backlog of requests by establishing a transitional serial process for later stage projects that have executed a Facilities Study Agreement and a transitional cluster process for earlier stage projects.

Q. Has the Commission approved PSCO's queue reform filing?

A. Yes. In December 2019, the Commission issued its Order approving PSCo's transition to the proposed DISIS process.[13] The Commission specifically found that PSCo had demonstrated that its proposed study deposits and cost allocation methodologies were consistent with or superior to the *pro forma* LGIP,[14] noting that the increased study

[12] *See generally* PSCo Order Approving Queue Reform.

[13] *Id.*

[14] As background, Order No. 2003 (which establishes FERC's *pro forma* LGIP) requires that interconnection customers pay the actual costs of their studies; FERC agreed with PSCo and commenters that the proposed study deposit amounts were reasonable for obtaining and keeping a queue position and complied with Order No 2003. *Id.*

deposit amounts and increasing readiness requirements resulted from a comprehensive stakeholder process and were reasonable for obtaining and keeping a queue position.[15] The Commission also found the proposed financial security requirement reasonable by increasing Interconnection Customers' demonstration to obtain and keep a queue position, while at the same time, not being so high as to deter interested projects from initiating interconnection requests.[16] In addition, the Commission approved PSCo's proposed non-financial readiness milestones and alternative financial security option in lieu of the readiness milestones, finding that the "readiness milestones should help make the interconnection process more efficient for Interconnection Customers with projects that are ready to proceed through the queue, i.e., first-ready, first-served approach, and PSCo's proposed options will provide Interconnection Customers with the flexibility to employ a variety of business models."[17] Finally, the Commission found that the imposing incrementally increasing withdrawal penalties for Interconnection Customers exiting the Definitive Interconnection Study Process and using the withdrawal penalty revenue to fund restudy costs is reasonable given that it increases requirements to keep queue position and would offset the significant cost of restudies for other customers caused by a customer's withdrawal.[18]

at P 36 (citing Order No. 2003, 104 FERC ¶ 61,103 at P 37 (2003)). FERC's reasoning was supported by its 2008 Technical Conference Order which was issued in response to concerns about the effectiveness of queue management and suggested that increasing the requirements for obtaining and keeping queue position, such as increasing deposit amounts, assisted in speeding up queue processing was consistent with the goals of Order No. 2003. *See* 2008 Technical Conference Order at P 3.

[15] PSCo Order Approving Queue Reform at P 36.

[16] *Id.* at PP 49-51.

[17] *Id.* at P 50.

[18] *Id.* at P 51.

Q. Did Duke discuss PSCO's queue reform with PSCO and other stakeholders?

A. Yes. Duke personnel met virtually with PSCO personnel several times to better understand the impact and effectiveness of PSCO's queue reform. PSCO provided useful technical and policy information related to its revised LGIP as well as data related to its interconnection studies. The discussions with PSCO were extremely helpful, and Duke is appreciative of PSCO's assistance. As is discussed further in my testimony, Duke shared information received from PSCO with stakeholders to facilitate the development of the revised LGIP proposal included in the instant filing.

Q. Are there differences between the PSCO queue and the current Duke queue that affected Duke's analysis?

A. There are always differences. Obviously, the attributes of the systems are very different. A key difference is that state policies promulgated in North Carolina and, to a lesser extent, South Carolina, to encourage PURPA and establish favorable standard contract terms for Qualifying Facilities ("QFs") created the climate in which a high volume of solar projects entered the Duke Carolinas Utilities' queues.

Since 2014, DEC and DEP have processed, studied and interconnected over 560 utility scale generating facilities totaling 5,693 MW. Of the 5,693 MW, 35% or 1,988 MW are connected to the distribution systems of DEC and DEP. This relatively significant percentage of distribution-connected generating facilities becomes even more significant when viewed based on the relative percentage of generating facilities interconnected versus on an installed capacity basis. Of the 560 new interconnected generating facilities connected since 2014, 83% or 464 of them are connected to a DEC or DEP distribution circuit.

A second, related, difference is the power flow and loading impacts that the high penetration of generating facilities installed on the DEC and DEP distribution systems is having on the bulk electric system. Analysis completed in 2020 identified that, in DEP, 100 out of 408 substation banks, or 24.5%, are backfeeding into the transmission system due to distribution-connected generation. This significant backflow of power from distribution connected generation onto the DEP, and to a lesser extent, DEC transmission systems has contributed to much of the congestion that now exists in the Duke queues. Due to the impacts that distribution requests are imposing on the DEC and DEP transmission systems, it has become essential that both DEC and DEP simultaneously study distribution interconnection requests with transmission interconnection requests in order to also allow the distribution requests to share in the cost of transmission network upgrades when they impact the transmission systems.

Q. Please describe how Duke initiated the stakeholder process.

A. In February 2019, Duke engaged Navigant Consulting to support and facilitate stakeholder meetings as an independent party to advance the progression of the queue reform effort. They were selected primarily due to their experience working with the CAISO on queue reform as well as the work they had performed to support the early stages of the PSCO queue reform effort. After Navigant was engaged, the Duke Southeast Utilities notified all Duke Interconnection Customers and other interested parties via email that a "queue reform kick-off meeting" would be held on March 28, 2019. The notice was posted on the Duke Southeast Utilities' Open Access Same-Time Information System ("OASIS") sites. [19]

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[19] *Available at* https://www.oasis.oati.com/woa/docs/DUK/DUKdocs/Meeting_1_email.pdf.

Q. Was the first stakeholder meeting held as scheduled?

A. Yes. The first stakeholder meeting was held at Duke's offices in Raleigh, NC on March 28, 2019. Prior to the meeting, draft presentations and a meeting agenda were posted to OASIS. Topics discussed at the stakeholder meeting included Duke's current queue process and the issues Duke faced, the attendant need for queue reform, and Duke's proposed timeline. Most attendees participated through a web conferencing application (link provided by Duke) as it was intended to be a kick-off meeting to set expectations, communicate the future timeline, and begin the process.

Q. Were there additional stakeholder meetings?

A. Yes. Duke held a total of 16 broadly attended stakeholder meetings over a 2-year period as part of its effort to assemble a robust and well-vetted proposal. Duke received feedback from stakeholders during the meetings, but also received hundreds of questions, comments, suggestions and proposals outside of the meetings from stakeholders as well.

Q. Please describe Duke's stakeholder meetings.

A. Duke's stakeholder meetings were not just an opportunity for Duke to share with stakeholders the queue reform proposals but encompassed working sessions which provided an opportunity for stakeholders to contribute to the final design. A list of the 16 stakeholder meetings and the main topics of each is as follows:

- March 28, 2019 – Stakeholder Kickoff Meeting
- April 25, 2019 – Stakeholder Meeting (Interconnection queue: Current State, -Overview queue Reform: National Trends and Emerging Best Practices, and queue Reform: Framework processing, timeline, milestones, cost allocation.)
- June 18, 2019 – Stakeholder Meeting (DISIS framework and transition processes)
- September 27, 2019 – Stakeholder Meeting (proposed October 2019 filing with NCUC and transition process)

- November 22, 2019 – Stakeholder Meeting (cost allocation, cluster study process timeline)
- December 16, 2019 – Stakeholder Meeting (PSCO queue reform process)
- January 29, 2020 – Stakeholder Meeting (DISIS study process, Customer Engagement Window, deposits, cost allocation, withdrawal penalty and the transition process)
- March 10, 2020 – Stakeholder Meeting (North Carolina Interconnection Procedures)
- March 20, 2020 – Stakeholder Meeting (North Carolina Interconnection Procedures)
- April 9, 2020 – Stakeholder Meeting (North Carolina Interconnection Procedures)
- May 15, 2020 – Duke Carolinas Utilities file queue reform proposal with NCUC
- June 25, 2020 – Stakeholder Meeting (federal queue reform trends, cluster study process, cost, security and the readiness milestone allocation, withdraw penalties and the overall transition process)
- August 21, 2020 – Stakeholder Meeting (modifications to the North Carolina Interconnection Procedures based on comments filed by intervening parties in North Carolina Utilities Commission Docket No. E-100, Sub 101)
- August 31, 2020 – Duke Carolinas Utilities file revised queue reform proposal with NCUC
- October 15, 2020 – NCUC issues order approving queue reform proposal[20]
- October 30, 2020 – Stakeholder Meeting (South Carolina Generator Interconnection Procedures)
- November 17, 2020 – Duke Carolinas Utilities file queue reform proposal with South Carolina Public Service Commission (“SCPSC”)
- December 15, 2020 – Stakeholder Meeting (draft of LGIP and LGIA)
- February 3, 2021 – Stakeholder Meeting (revised draft of LGIP and LGIA, including supporting visuals)
- February 10, 2021 – SCPSC issues Commission Directive approving queue

[20] Order Approving Queue Reform, North Carolina Utilities Commission, Docket No. E-100, Sub 101 (Oct. 15, 2020) (“NCUC Order”).

reform proposal[21]

- March 16, 2021 – Stakeholder Meeting (final draft of LGIP and LGIA)
- March 31, 2021 – Duke Southeast Utilities file queue reform proposal with FERC

Q. Was there robust participation and active engagement in the stakeholder meetings?

A. Yes. Duke strived to make the stakeholder meetings inclusive and accessible. First, we made it clear that all stakeholder meetings were open to all interested parties. With respect to accessibility, Duke arranged for call-in numbers and WebEx connections in order to facilitate participation by those parties who could not attend in person. Upon the onset of COVID-19, WebEx became the exclusive means of meeting. Additionally, in order to facilitate informed and productive sessions, all meeting materials were posted on OASIS prior to the meetings. Duke maintained an open-door policy for stakeholders who could not participate in meetings by accepting written and verbal comments and following up with parties individually, as necessary.

Once the high-level process changes had been vetted with stakeholders for nearly a year, Duke began by drafting revisions to the North Carolina state jurisdictional procedures which align with aspects of the FERC revisions proposed. Multiple review sessions were held where Duke shared the revisions and received stakeholder feedback. As a result of the constructive discussion and deliberation at these meetings, and additional stakeholder comments following the meetings, Duke refined and modified its proposal. Again, the materials from the stakeholder process were made available to stakeholders and remain posted on Duke's OASIS.

[21] Public Service Commission of South Carolina, Commission Directive, Docket No. 2019-326-E (Feb. 10, 2021) ("PSCSC Directive").

After nearly five months of stakeholder review of state jurisdictional procedure revisions, Duke finalized on a nearly uncontested consensus proposal heavily based on PSCo's queue reform initiative, which DEC and DEP filed with the NCUC on May 15, 2020. Duke continued working with stakeholders after the filing was made on a handful of remaining issues and reached full consensus with stakeholders in September 2020 and obtained NCUC approval of the North Carolina queue reform procedures in October of 2020.

Duke then turned to drafting revisions to the South Carolina Generator Interconnection Procedures and the LGIP. Duke dedicated considerable time for "page turn" meetings with stakeholders, during which revised versions of Duke's proposed LGIP reforms were reviewed page-by-page and stakeholder feedback was, again, solicited. These page-turn sessions occurred on December 15, 2020, February 10, 2021 and March 16, 2021. Duke also met with any interested party who requested a meeting. These meetings provided another avenue for Duke to obtain feedback and craft a proposal that could obtain stakeholder support. During this time period, Duke then received approval on revisions to the South Carolina Generator Interconnection Procedures from the SCPSC via a directive issued on February 10, 2021.

By the end of the 2-year long stakeholder meetings, Duke had developed a consensus queue reform proposal that was supported by stakeholders and approved by state regulators in North Carolina and South Carolina in two different proceedings. There are numerous areas where stakeholder suggestions were included in the final LGIP proposal being filed with the Commission today.

Q. Did Duke accept written comments to its proposed LGIP revisions in addition to the stakeholder meetings?

A. Yes. As I noted above, Duke received numerous pages of comments throughout the stakeholder process. Duke sought (and received) comments from stakeholders who were unable to attend the meetings, but we also encouraged those stakeholders who did participate in the meetings to provide written comments as the LGIP revisions evolved. To ensure that all stakeholders could benefit from the comments of others, as well as Duke's responses to those comments, all comments received were posted on OASIS in a timely manner.

Q. **Does Duke's queue reform proposal reflect the stakeholder feedback received?**

A. Yes. The goal of Duke's queue reform is to have a process that the Duke Transmission Providers can successfully implement and that also works for Duke's Interconnection Customers by making it feasible for commercially ready projects to obtain interconnection service in a timely and efficient manner. The stakeholder process was invaluable for Duke to learn about the commercial realities of its current and prospective Interconnection Customers, to obtain crucial feedback on how to improve the LGIP, to learn from developer experiences in North Carolina, and South Carolina, and Florida as well as other regions, and to make the interconnection study process workable for those who use it. Many of Duke's customers have experience with other transmission provider's processes, and so brought a uniquely valuable perspective regarding how we could leverage best practices while recognizing the unique realities of developing generation in the Southeast, particularly in North Carolina and South Carolina where the number of interdependent transmission and distribution-level, FERC and state-jurisdictional interconnection requests is unparalleled in the southeast, and, in many respects, across the entire country. Consequently, Duke's proposed revisions to its LGIP submitted in this filing evolved substantially over the course of the stakeholder process, and reflect the significant value gleaned during the stakeholder process.

Additionally, it was important for Duke to seek to achieve reasonable consensus in order to have "buy in" from our Interconnection Customers and stakeholders. Achieving stakeholder consensus should help ease the transition into the revised LGIP and mitigate issues that will inevitably arise. That said, Duke's stakeholders can, and sometimes did, have differing points of view about the best way to implement queue reform. For instance, there was not full consensus on the issue of full readiness to enter the transition serial process, or a grandfathering structure for all interconnection requests currently in the queue (some of which have been in the queue for a considerable length of time). Duke encountered these differences of opinion during the stakeholder process and endeavored to accommodate these differing opinions wherever possible.

Q. Please describe some of the main aspects of the queue reform proposal that Duke was able to obtain consensus from stakeholders.

A. For the proposed Transitional Cluster Study Process, Duke was urged by its stakeholders to delay the higher level of readiness and security until the Phase 1 Study results are known in order to allow Interconnection Customers to make a decision based on knowledge gained from the Phase 1 power flow analysis. Stakeholders claimed that without some basis for interconnection costs, it was difficult to make contractual commitments to off-takers; furthermore, financial commitments and the risk of penalties made these hurdles to enter Phase 1 of the Transitional Cluster Study likely insurmountable. Therefore, Duke decided to make entry into the Transitional Cluster process much more like the DISIS process. Duke has reduced the security to enter the Transitional Cluster Study from $5 million required by PSCO to $3 million. If an interconnection achieves readiness following the Phase 1 portion of the cluster process, then they may proceed to Phase 2 without additional security. If they are not capable of securing the readiness milestones prior to the end of Phase 1 and prior to entering Phase 2, they may still proceed to Phase 2 by providing an additional $2 million in security. Interconnection Customers withdrawing after Phase 1, will only be required to pay actual study costs and will not be subject to penalties. All deposits and security will be trued up and funds greater than the amount necessary to cover study costs will be refunded to the Interconnection Customer. Any Interconnection Customer withdrawing beyond the Phase 2 Customer Engagement Window will be obligated to pay withdrawal penalties defined under Section 7.2.6 (unless exempted as provided for in DISIS), and all funds not necessary to fund study costs or penalties or any other administrative costs associated with performing the interconnection study process will be refunded to the withdrawing Interconnection Customer.

The downside to this approach is that we believe that this flexibility provided to Interconnection Customers is much more likely to result in restudy; however, it is also much more likely to result in sharing of network upgrades and the successful interconnection of additional resources progressing to LGIA and subsequent commercial operation through the Transitional Cluster. It was these degrees of compromise that has resulted in overwhelming consensus with stakeholders and support for filings made with state Commissions in North Carolina and South Carolina.

Q. Assuming the revised LGIP is approved, do you propose revisiting these issues in the next few years to evaluate the effectiveness of the proposal?

A. Yes. Duke proposes an evaluation of the revised LGIP after two years of experience, in order to determine whether the proposed tariff revisions are achieving the goals of providing an interconnection process that is efficient and fair. Duke makes this commitment to the Commission as part of its effort to achieve stakeholder consensus in light of various comments made during the stakeholder process. Importantly, this will allow Duke to identify lessons learned through both the Transition Process as well as the initial annual DISIS Cluster. Duke also plans to undertake a similar assessment in North Carolina and to report to the NCUC.

IV. DESCRIPTION OF PROPOSED TARIFF REVISIONS

A. INFORMATIONAL INTERCONNECTION STUDY AND OTHER AVENUES FOR INFORMATION

Q. Please describe the Informational Interconnection Study.

A. Duke is proposing that potential Interconnection Customers be permitted to evaluate interconnection feasibility by means of a fully customizable Informational Interconnection Study prior to entering into the Definitive Interconnection Study Process and accepting a queue Position.

Once a Duke Transmission Provider transitions to the Definitive Interconnection Study Process, the Informational Interconnection Study, included in LGIP Section 3, will be offered to prospective Interconnection Customers and will replace the "Optional Study" from the Order No. 2003 *pro forma* LGIP. The Optional Study process, now in

Section 13 of the LGIP, will remain for Duke Transmission Providers that continue to administer a serial interconnections Study process.

The Informational Interconnection Study is designed to meet an Interconnection Customers' informational needs when deciding whether to participate in the Definitive Interconnection Study Process in two important ways. First, an Interconnection Customer can request that Duke perform an Informational Interconnection Study at any time. Second, an Interconnection Customer can determine the scope of the study, meaning that the study can be tailored to the customer's particular needs and objectives.

Consequently, the Informational Interconnection Study enables the prospective Interconnection Customer to study almost any interconnection scenario, including the evaluation of location, voltage, and size of potential generation. The process may evaluate a single project in isolation, or it may evaluate the impact of other clustered generation on a specific interconnection request. The Informational Interconnection Study may be limited much like a traditional Energy Resource Interconnection Service ("ERIS") Feasibility Study or may be similar to a full NRIS System Impact Study that includes power-flow, voltage, stability, and short-circuit analysis.

Q. What are some of the benefits of this new Informational Interconnection Study?

A. The IIS provides greater flexibility to the Interconnection Customer in several different ways. The first benefit is that the new study process provides an avenue for developers to obtain and evaluate interconnection-related information for their projects before entering the queue. In doing so, this study work does not adversely affect the queue or preclude other ready projects from advancing through the Definitive Interconnection Study Process.

Informational Interconnection Studies are for informational purposes only and are not queued studies. Since the Interconnection Customer is not committing to entering the queue through this study process, the Interconnection Customer is able to avoid the at-risk payments associated with the new Definitive Interconnection Study Process and may withhold or refine its prospective interconnection request until the Interconnection Customer is truly ready to move forward with a project.

The first benefit of the Informational Interconnection Study relates to its flexible scoping. The scope of work will be proposed by the Interconnection Customer to suit the Interconnection Customer's business needs and Duke will work with the customer to refine the scope of work. In this way, the IIS should facilitate the Interconnection Customer's understanding of potential interconnection related costs for their project prior to entering the project into the Definitive Interconnection Study Process.

The second benefit is that the results of the IIS could form the basis of a potential Provisional Large Generator Interconnection Agreement ("Provisional LGIA"), which as discussed below can satisfy a Readiness Milestone needed to advance in the queue.

Q. What costs will be charged to Interconnection Customers?

A. Because of the varied scope of these Informational Interconnection Studies, the actual costs may widely vary. Duke proposes to require a $10,000 deposit for the Informational Interconnection Study, which will be reconciled against the actual study costs when the study is complete. This standardized Informational Interconnection Study deposit amount is the same as PSCo.

Q. Are there additional avenues available to Interconnection Customers who wish to obtain information before significant commitments are required?

A. Yes. Interconnection Customers have other avenues to obtain additional information before significant at-risk financial deposits are made. Two of these are: (1) the Customer Engagement Window following the filing of an interconnection request and prior to entering the queue; and (2) Phase 1 of the Definitive Interconnection Study Process, which provides Interconnection Customers with reasonable estimation of interconnection construction costs before moving to subsequent phases of the Definitive Interconnection Study Process increased levels of commitment. I will discuss each of these in greater detail below as part of my description of the Definitive Interconnection Study Process. Each of these steps in the process enables the Interconnection Customer to refine its understanding of interconnection costs as part of its determination of readiness.

In addition, the Commission's directives in Order No. 845 already requires Duke to post study models and assumptions on OASIS.[22] This enables customers to study different points of interconnection and alternative project sizes and configurations for themselves, thus further enhancing a developer's ability to obtain valuable interconnection information without having to prematurely enter the queue.

Q. Rather than undertake the Informational Interconnection Study process and risk a lower queue position in the future, why wouldn't an Interconnection Customer simply submit a speculative project in the queue and obtain needed interconnection information while maintaining a higher queue position?

[22] *Reform of Generator Interconnection Procedures and Agreements*, Order No. 845, 163 FERC ¶ 61,043 at P 558 (2018) ("Order No. 845").

A. The proposed queue reform is intended to allow near-ready projects to enter the queue while also dis-incentivizing the submission of speculative projects. That said, under Duke's proposal, Interconnection Customers may request interconnection for speculative projects, but the design does not encourage those projects to stay in the queue if they are not viable. The revised LGIP provides stepwise increasing requirements and reasonable off ramps for such projects before requiring significant demonstrations of readiness. Specifically, after requesting interconnection, customers may be part of the study process though Phase 1 with little financial risk.

Q. What risks are there for Interconnection Customers prior to this Phase 1?

A. I discuss the Definitive Interconnection Study Process and its various phases later in my testimony. There is some risk and additional requirements that encourage only ready or at least near-ready projects to enter the Definitive Interconnection Study Process. For instance, although the study deposits are refundable during the Customer Engagement Window, the $5,000 application fee is not. In order to enter the Definitive Interconnection Study, in addition to other things, the Interconnection Customer must provide (1) Site Control for its facility, (2) a term sheet related to the sale of the Generating Facility or its output, evidence it is selected in a resource plan, or a Commission filed Provisional Large Generator Interconnection Agreement, (3) a study deposit as defined in Section 4.1.2 and in Figure 2 below, **[and][or]** (4) cash or a letter of credit for security to cover withdraw penalties defined in Section 10.11.6.

FIGURE 2

Size of Project Associated with Interconnection Request	Amount of Deposit
< 20 MW	$20,000 + $1/kW

≥ 20 MW< 50 MW	\$35,000 + \$1/kW
≥ 50 MW< 80MW	\$50,000 + \$1/kW
≥ 80 MW < 200 MW	\$150,000
≥ 200 MW	\$250,000

The first 3 tiers up to 80 MW align with the state-jurisdictional study deposits approved by the NCUC[23] and PSCPSC.[24] The proposed study deposit amounts for projects entering the DISIS Cluster that are 80 MW or greater are the same as PSCo's study deposit amounts, while the study deposit amounts for projects entering the DISIS Cluster that are less than 80 MW are lower than the initial deposit amounts required under the PSCo Definitive Interconnection Study Process. However, they are designed to reasonably encourage customers to exercise discipline in determining which projects are ready to request interconnection and proceed through Phase 1 of the Definitive Interconnection Study Process. Part of the security for the Financial Readiness option becomes at-risk after Phase 1. Therefore, after Phase 1—and increasingly after Phase 2—Duke expects speculative projects will exit the queue if they are not economically viable.

Q. Why have developers submitted speculative projects into the Duke Transmission Providers' queues in the past?

A. As discussed in more detail in the Testimony of Mr. Roberts, Duke believes developers have historically submitted interconnection requests for speculative projects and placed them in the queue because (1) it was the only avenue for developers to obtain detailed interconnection related information on the Duke systems, (2) entering the queue allowed developers to obtain priority rights to available transmission capacity as they evaluated

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[23] NCUC Order at 3.

[24] PSCSC Directive at 1.

development and off-take options, (3) there has been little risk or cost for Interconnection Customers to advance non-viable projects and subsequently withdraw from the queue during system impact study or facilities study, and (4) as a business process, Interconnection Customers could complete the interconnection process and suspend their project (without penalty) for up to 3 years while they worked to make their project commercially viable.

Duke addresses each of these three items in its revised LGIP. First, the Information Interconnection Study and the Customer Engagement Window provide the information a developer may need to inform readiness. Second, the Cluster Study process eliminates the incentive to submit an interconnection request to obtain priority rights to transmission capacity from being "first in." Third, Duke proposes a series of Readiness Milestones and Site Control provisions in the new Definitive Interconnection Study Process, so advancing through the interconnection process is no longer viewed as a free option. Fourth, when faced with a more certain and efficient interconnection process, developers may move the interconnection request to later in their development process.

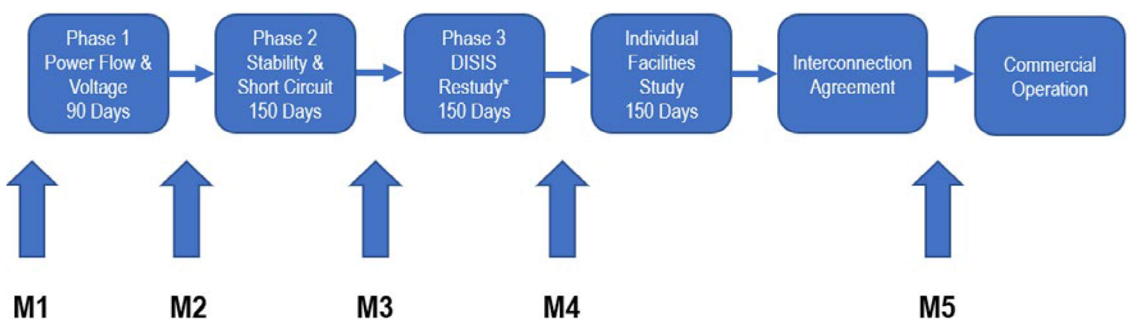
B. DEFINITIVE INTERCONNECTION STUDY PROCESS

Q. What is the Definitive Interconnection Study Process?

A. The Definitive Interconnection Study Process is a multi-phase interconnection study process that culminates in an LGIA under which the Interconnection Customer will take Interconnection Service. As shown in the figure below, the Definitive Interconnection Study Process has four main phases (Phase 1, Phase 2, Phase 3, and Phase 4), which consist of a multiphase clustered Definitive Interconnection System Impact Study

("DISIS") (Phases 1–3) followed by an individual Interconnection Facilities Study for each interconnection request (Phase 4). As noted above, and discussed further below, Interconnection Customers must meet certain Readiness Milestones that demonstrate increasing readiness over the course of the process in order to advance to a successive phase. More specifically, Readiness Milestone 1 ("M1") must be satisfied before moving to Phase 1, Readiness Milestone 2 ("M2") must be satisfied before moving to Phase 2, Readiness Milestone 3 ("M3") must be satisfied before moving to Phase 3 and Readiness Milestone 4 ("M4") must be satisfied before moving to the next phase which is execution of the LGIA, and Readiness Milestone 5 ("M5") is required at that time.

FIGURE 3



*Phase 3 Re-Study will occur only if required

The revised LGIP provides Interconnection Customers with the flexibility to withdraw from the queue in the early phases with little risk if the projected interconnection costs, or some other issue, results in the project not being ready to move forward with interconnection. The demonstration of readiness required will rise with each successive phase, such that only Interconnection Customers with sufficiently developed projects are advancing through the study process.

Q. Is Duke providing a process diagram for the Definitive Interconnection Study Process?

A. Yes. Appendix 6-1 to the revised LGIP presents an overview and timeline of initiation of a DISIS Cluster, including the interconnection request Window, Customer Engagement Window, and Phase 1 of the DISIS. Appendix 6-2 also provides an overview and timeline of the Definitive Interconnection Study Process, including the Phases and Readiness Milestones associated with the Definitive Interconnection System Impact Study. As described in more detail below, the Definitive Interconnection Study Process may be shortened under a variety of circumstances, and so the timeline for the first DISIS Cluster is approximate.

1. CLUSTERED STUDY PROCESS

Q. Why is Duke proposing to use a clustered study process?

A. As Mr. Roberts describes in his Direct Testimony, Duke has found that the serial nature of the current interconnection process has, despite Duke's good faith and reasonable efforts, led to significant delays in the interconnection process due to, among other things: (1) the sheer volume of interconnection requests and (2) the risk of (and increasing occurrence of) cascading restudies when a higher queued project withdraws from the queue or modifies its request (e.g., changing from NRIS to ERIS). Because each study in the current serial process is dependent on all higher queued studies, a change in a higher queued request can, for instance, result in the need for Duke to restudy dozens of lower queued requests, which results in material uncertainty for many (if not most) Interconnection Customers and substantial delays in moving Interconnection Customers through the process.

In response to this current challenge, Duke proposes to group multiple interconnection requests submitted within a specific request window into a single cluster. This means that instead of running, for instance, one hundred separate feasibility and system impact studies, Duke might run four increasingly detailed studies based on regionally interdependent clusters of interconnection requests as part of the DISIS. In conjunction with the change to a cluster process, because of the change to the first-ready, first-served design, Duke also expects the total number of projects to decrease significantly as the requests will be limited to ready projects. This clustering vastly decreases the volume of studies, resulting in a more manageable process which, in turn, improves the processing times for our Interconnection Customers. Although cascading restudies may still be an issue when using cluster studies, the use of cluster studies mitigates the problem to a more manageable level, as the studies will be grouped together in clusters and thus fewer separate restudies would be required.

Q. Is Duke proposing two different types of clusters?

A. Yes. Interconnection Customers may enter the queue through either an annual Definitive Interconnection System Impact Study Cluster ("DISIS Cluster") or a Resource Solicitation Cluster. Both of these cluster types follow the same study process but are initiated in a different way. To be clear, once either type of Cluster is formed, it proceeds along the same timeline and is processed in the same manner and in queue order.

Q. How does an Interconnection Customer enter a DISIS Cluster?

A. To be considered in the DISIS Cluster, Interconnection Customers are required to submit a valid interconnection request into a request window that recurs on an annual basis. The

DISIS Request Window will open for a 180-day period every year with the window opening on January 1.

Q. How does an Interconnection Customer enter a Resource Solicitation Cluster?

A. A Resource Planning Entity, as the authorized agent, submits all interconnection requests on behalf of the Interconnection Customers whom the Resource Planning Entity is seeking to interconnect as part of its Resource Solicitation Process. A Resource Planning Entity may submit these requests at any time but must submit all relevant requests at the same time. Within 10 Business Days of submitting the requests, the Transmission Provider and Resource Solicitation Entity meet to determine a mutually agreeable timeline to start the DISIS for the Resource Solicitation Cluster, including the timeline of the Customer Engagement Window.

Q. Why is a Resource Solicitation Cluster needed separate from the DISIS Cluster?

A. A resource solicitation cluster does not need to be separate as long as the resource solicitation is intentionally coordinated to coincide with the timing of the annual cluster process. However, the separate resource solicitation cluster allows Duke to study market participants competing in the resource solicitation on a timeline that differs from the annual DISIS Cluster, if needed to meet the objectives of the resource solicitation. This alternative resource solicitation cluster will provide important flexibility to DEC, DEP, and DEF as the resource planning entities, and aligns with a similar resource solicitation cluster study option approved for PSCo.

Q. Please describe the "Customer Engagement Window."

A. After Interconnection Customer(s) submit an interconnection request during the DISIS Request Window, the Interconnection Customer(s) enter a 60-day "Customer Engagement Window" during which time Duke will work with applicable Interconnection Customers to build models, verify data, hold stakeholder meetings (including scoping meetings, as appropriate), work with requestors to cure any deficiencies in the interconnection request, and generally prepare for the start of the DISIS. Scoping meetings are held within this initial Customer Engagement Window.

Q. Is there also a Customer Engagement Window for the Resource Solicitation Cluster?

A. Yes, there is a Customer Engagement Window for the Resource Solicitation Cluster.

Q. What benefits does an Interconnection Customer gain from the Customer Engagement Window?

A. The Customer Engagement Window is an important time for Interconnection Customers to determine whether they are ready and truly want to enter the DISIS. Customers learn an important piece of information during the Customer Engagement Window—namely, information regarding the number, size and location of other projects requesting interconnection in the particular Cluster.

This information is valuable to Interconnection Customers because the upgrade costs for interconnection are influenced by the other requests in a specific Cluster. For instance, a 2,000 MW Cluster may require significantly more Network Upgrades than a 200 MW Cluster. Likewise, knowing if there are other projects proposing to interconnect at the same location could prove relevant or even dispositive in determining whether an Interconnection Customer chooses to proceed. For instance, two generators proposing to interconnect in a similar location (e.g., the same substation) may share the upgrade costs instead of bearing all of the costs themselves. Interconnection Customers who submit interconnection requests during the DISIS Request Window are, therefore, able to learn what other projects are seeking interconnection in that Cluster, and so are able to refine their estimate of the potential scope of upgrade costs. In the stakeholder process, developers underscored the importance of this phase of project development and expressed support for a process that would position them to better understand their upgrade costs sooner, thereby facilitating more transparency thus a more informed decision earlier in the process.

The length of the Customer Engagement Window is appropriate because an Interconnection Customer may use this time to evaluate a number of “what if” scenarios. For example, they can evaluate what may happen if certain other requests do not move forward in the DISIS process.

During the Customer Engagement Window, Interconnection Customers may not yet have signed the DISIS Study Agreement and any study deposit or security provided with the interconnection request (except for the application fee) is fully refundable and comes with no penalty. By the end of the Customer Engagement Window, Duke will include all Interconnection Customers with a completed interconnection request (including all necessary technical information), a signed DISIS Agreement, and initial M1 security into the study phase (i.e., the DISIS) of that Cluster.

2. STUDY PHASES

Q. You mentioned earlier that the Definitive Interconnection Study Process has four main phases. Please describe these phases.

A. After the Customer Engagement Window, the Definitive Interconnection Study Process is generally divided into four phases: *Phase 1*, a high-level feasibility study that consists of a power flow and voltage analysis; *Phase 2*, a full system impact study that adds the stability and short circuit analysis; *Phase 3*, system impact restudies, if necessary. The last phase is an individual Interconnection Facilities Study for each of the projects in the Cluster.

Both the DISIS Cluster and the Resource Solicitation Cluster are studied in this same manner. Phase 1 of the DISIS is a high-level power-flow and voltage study that is similar to a Feasibility Study in the FERC *pro forma* LGIP, which generally determines most of the Interconnection Facilities and Network Upgrades required for interconnection. Phase 2 completes the traditional System Impact Study by adding a stability and short circuit analysis to the power-flow analysis from the first phase. To the extent required, for instance if interconnection requests were withdrawn from the Cluster before Phase 2, the power-flow and voltage analysis may be updated in Phase 2.

If, following the publication of the Phase 2 Study Report, the Cluster is stable (*e.g.*, no changes to the modeling assumptions occur such as the withdrawal of an interconnection request), then the Cluster Study will skip the Phase 3 study and will move directly to the last phase, the Interconnection Facilities Study.

By contrast, if such modeling changes (*e.g.* one or more Interconnection Customers withdraw) create a need to restudy the Cluster, then the modified Cluster undergoes a system impact re-study (*i.e.*, the power-flow, voltage, stability, and short-circuit analyses are repeated for the modified Cluster). This re-study is Phase 3 and the restudies are repeated until the Cluster is stable. I note that one goal of prioritizing ready projects is to reduce, or even eliminate, the need for the Phase 3 Re-study.

Once the Cluster is deemed stable, each of the interconnection requests in the Cluster advances to the last phase which comprises individual Interconnection Facilities Studies based off of the results of the Phase 2 or Phase 3 study, as appropriate. The Interconnection Facilities Study is followed by LGIA negotiation and execution.

The various phases of the Definitive Interconnection Study Process are depicted in Appendices 6-1 and 6-2 to the LGIP.

C. TIMING OF STUDIES

Q. What are the timing considerations for these study phases?

A. Duke expects to complete Phase 1 relatively quickly and will use reasonable efforts to complete the study within 90 days. The Phase 2 analysis is more complicated and time consuming, and Duke will use reasonable efforts to complete Phase 2 in 150 calendar days. If no restudies are required, Phase 3 is skipped. If the Cluster requires restudy, Duke will use reasonable efforts to complete each restudy in 150 days. The restudies in Phase 3 are repeated until the Cluster is deemed stable. Therefore, the total length of Phase 3 depends on the degree and number of re-studies required, if any. If any of the studies are completed in less than the relevant time frame, Duke will publish the study report early and thereby accelerate the overall study process timeline.

For each of Phases 1 through 3, Duke will hold a report meeting within 10 business days of publishing the applicable phased study report and Interconnection Customers must commit to stay in the study process within 20 calendar days of the report meeting by providing the next applicable Readiness Milestone.

For the Interconnection Facilities Study, Duke will use reasonable efforts to issue a draft Interconnection Facilities Study Report to the individual Interconnection Customer within 150 days after acceptance of the Interconnection Facilities Agreement and satisfaction of Readiness Milestone 4. Following receipt of the draft Interconnection Facilities study report, just as it is for the FERC *pro forma* LGIP, the Interconnection Customer has 30 days to provide written comments on the report and Duke must issue the final report within 15 days of receiving Interconnection Customers comments or promptly upon notice from Interconnection Customer that it will not be providing comments.

In sum, Duke anticipates that the study portions (not including customer engagement periods) of the interconnection study process will be just over one year (90 days + 150 days + 150 days = 390 days), if no restudies are required. Each restudy adds approximately five months to the timeline. Although this timeline is longer than the current timeline set forth in the *pro forma* LGIP (45 days + 90 days + 90/180 days = 225/315 days), Duke's proposed process is an improvement over the current process because: (1) the Customer Engagement Window ensures data is sufficient and studies start promptly, (2) interconnection requests are not waiting indefinitely until higher queued projects drop out and thus they can be studied far sooner, (3) the Cluster study evaluates multiple interconnection requests simultaneously, and (4) the first-ready approach limits restudies and delays in the projected timelines. Said differently, while the timelines in the proposed LGIP are somewhat longer than the study timeliness in the current LGIP, more projects will actually move through the interconnection process under the revised LGIP in the same time period thereby leading to a more efficient interconnection process for all affected Interconnection Customers.

Q. What are Duke's expectations for meeting the timelines to complete the study phases?

A. As a general matter Duke believes that it will be able to process the interconnection requests in a timely fashion and in accordance with the timeline set forth in the revised LGIP. After experience with performing Cluster Studies as part of the Definitive Interconnection Study Process, Duke proposes to lengthen or shorten study process timelines described in the revised LGIP as part of its two-year review.

D. ALLOCATION OF COSTS

1. STUDY COSTS

Q. How then will actual study costs be allocated within a given Cluster?

A. For the clustered DISIS portion of the Definitive Interconnection Study Process, study costs are allocated as follows: (1) 10% of the applicable study costs to Interconnection Customers on a per capita basis based on number of Interconnection Requests included in the applicable Cluster; and (2) 90% of the applicable study costs to Interconnection Customers on a pro-rata basis based on requested megawatts included in the applicable Cluster. PSCo utilized a similar approach to allocating study costs; however instead of applying a 90%/10% allocation, PSCo determined each Interconnection Request's share of the costs of completing the DISIS Cluster Study (including general queue administration costs and overheads) by allocating: (1) fifty percent (50%) of the applicable study costs to Interconnection Requests on a per capita basis based on number of Interconnection Requests included in the applicable Cluster; and (2) fifty percent

(50%) of the applicable study costs to Interconnection Requests on a pro-rata basis based on requested megawatts included in the applicable Cluster.

Recognizing that both large generators and small generators requesting NRIS, as well as state-jurisdictional Interconnection Customers will be subject to the same allocation methodology, Duke Southeast Utilities elected to apply the 90-10 allocation to provide a more balanced and equitable study cost allocation, based on a relatively simple cost causation principle. TJE 90-10 approach aligns well with study deposits that would be submitted based on varying assumptions around the number and size of projects submitted into the cluster process. The Duke Southeast Utilities structured these two study cost allocations to reflect the Commission's cost causation principle of allocating costs "to those [that] cause the costs to be incurred and reap the resulting benefits."[25]

Q. What study costs does an Interconnection Customer pay at the end of the study process?

A. Consistent with the FERC *pro forma* LGIP, Duke proposes to retain the requirement that Interconnection Customers pay actual study costs. The actual cost will be reconciled with the study deposit at the end of the study process.

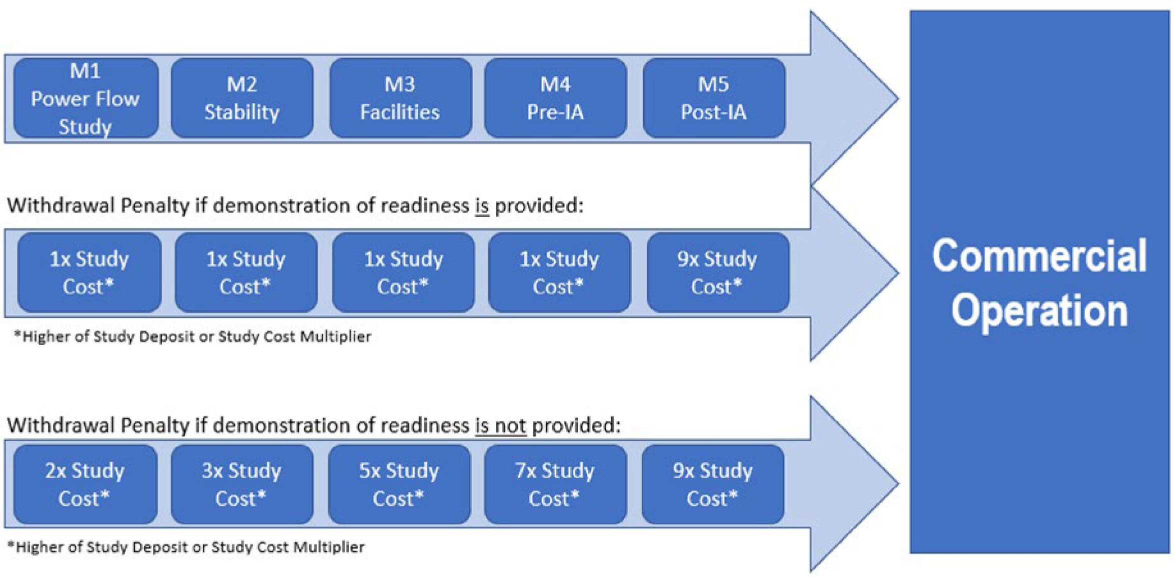
Q. What costs does an Interconnection Customer pay if it withdraws from the queue?

A. In addition to requiring payment by each Interconnection Customer for actual study costs incurred while performing studies associated with their Generating Facilty(ies), the

[25] The Commission recently reiterated its cost causation principle in FERC Order No. 845-A, explaining that its cost causation principle "generally requires that costs 'are to be allocated to those [that] cause the costs to be incurred and reap the resulting benefits.'" FERC Order No. 845-A at P 78 (citing *S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d at 87 (quoting *Nat'l Assoc. of Regulatory Util. Comm'rs v. FERC*, 475 F.3d at 1285).

proposed Definitive Interconnection Study Process may impose a Withdrawal Penalty on Interconnection Customers exiting the queue and causing harm to other Interconnection Customers. Duke's proposed Withdrawal Penalty structure depicted in Figure 6 below is based upon the PSCo Definitive Interconnection Study Process and is designed to balance the legitimate interests of all Interconnection Customers to have the ability to make the business decision to withdraw from the study process while providing redress for other Interconnection Customers that are adversely impacted by an Interconnection Customer's withdrawal.[26] Calculation of the Withdrawal Penalty amount is dependent on (1) whether a demonstration of readiness was provided, and (2) the phase of the Definitive Interconnection Study Process that the Interconnection Customer is in at the time of withdrawal.

FIGURE 6



[26] The Withdrawal Penalty concept and structure is closely modeled on the PSCo process. *See* PSCo Order Approving Queue Reform at PP 44-46, 51.

Q. Will all Interconnection Customers participating in the proposed Definitive Interconnection Study Process be subject to a Withdrawal Penalty?

A. There are a number of circumstances where a Withdrawal Penalty would not be imposed under Section 4.7.1. If an Interconnection Customer reaches commercial operation, there is obviously no Withdrawal Penalty. Similarly, if the Interconnection Customer's withdrawal does not harm other customers within the Cluster (such as by requiring restudy or shifting costs to other customers), then there is no Withdrawal Penalty. There would also be no Withdrawal Penalty imposed where (1) the cost responsibility identified for an Interconnection Customer in the current study report associated with new Network Upgrades to the Transmission Provider's System increased by more than twenty-five percent (25%) compared to the costs identified in the previous report or (2) if the customer withdraws after the Interconnection Facilities Study report is published and before providing M5, and the cost responsibility for that Interconnection Customer identified in the Interconnection Facilities Study report increases by more than one hundred percent (100%) compared to the Phase 2 report. More simply, an Interconnection Customer is subject to a Withdrawal Penalty if it elects to withdraw from the interconnection process and the withdrawal has a negative impact on other Interconnection Customers and where the withdrawing Interconnection Customer's assigned System Upgrade costs did not increase significantly between phases of the DISIS or over the Definitive Interconnection Study Process.

Q. How will withdrawal penalties be distributed?

A. Withdrawal Penalty revenue will be distributed to Interconnection Customers in a specific Custer in a similar way as study costs are allocated. This distribution will appear as a bill credit on the Interconnection Customers' study invoice but will not exceed the study amount for which the customer is responsible and will not be distributed to the withdrawing customer. To the extent there are additional Withdrawal Penalty revenues after funding not-yet-invoiced studies (e.g. restudies) for other customers in the same cluster, the Withdrawal Penalty revenue will be distributed to not-yet-invoiced studies for subsequent clusters.

2. ALLOCATION OF COSTS ASSOCIATED WITH TRANSMISSION FACILITIES

Q. Are study cost allocations distinguishable from facilities cost assignment for transmission facilities within a Cluster?

A Yes. It is important to distinguish study deposits, study cost allocation, and queue withdrawal penalties on the one hand, from transmission facilities cost assignment on the other. As a general matter, with regard to transmission facilities cost assignment, Duke follows the FERC *pro forma* LGIP funding policy set forth in Order No. 2003, and Duke is not proposing to change its funding policy. In Order No. 2003, the Commission stated that, where the Transmission Provider is not an RTO/ISO, it is appropriate for the Interconnection Customer to "be solely responsible for the costs of Interconnection Facilities" but Network Upgrades are ultimately paid by Transmission Customers.[27] Interconnection Customers are responsible for the costs of two types of transmission facilities: Interconnection Customer's Interconnection Facilities ("ICIF") and Transmission Provider's Interconnection Facilities ("TPIF"). Although Interconnection Customers may initially fund Network Upgrades associated with generation

[27] Order No. 2003 at P 676; *pro forma* LGIP Article 11.3.

interconnection, the costs of Network Upgrades are ultimately borne by Duke network transmission customers and Duke retail customers.

Q. How is cost assignment for transmission facilities proposed to be allocated among the various Clusters?

A. As in the current serial study process, queue position dictates cost assignment. Interconnection requests contained in subsequent Clusters are lower queued than interconnection requests in earlier Clusters, so available transmission capacity or new upgrades will be allocated to the Cluster that first uses or needs the available or newly installed capacity. In this fashion, certain Clusters may take advantage of any available transmission capacity. Conversely, if transmission capacity is limited, a new Cluster may require additional facilities to be constructed in order for that Cluster to interconnect.

Q. Are there any additional considerations regarding transmission facilities cost allocation within a given Cluster?

A. Yes. Duke proposes to allocate the costs of facilities required for interconnection in a manner similar to what was approved for PSCO. This allocation separates out the allocation for facilities required to directly interconnect the generators such as new substations or additional breakers and meters in a substation with other Network Upgrades. Section 10.4 of the revised LGIP sets forth the allocation in more detail, but I describe it generally below.

Because all requests in a cluster are equally queued, all requests equally require the substation or additional breakers to be built. For instance, if two generators require a substation to be built, both generators are equally responsible for the need of that substation, and the substation will be designed to accommodate both generators.

Therefore, it is reasonable to allocate such facilities on a per capita basis. For the other Network Upgrades, Duke will allocate the costs of those Network Upgrades on the individual Interconnection Customer's impact on those new Network Upgrades. The impact will be determined during the study process utilizing distribution factors.

This allocation of costs is mainly used to determine the Security Readiness Milestone and initial funding requirements because Duke's transmission customers, not Duke's Interconnection Customers, are ultimately responsible for Network Upgrades.

Q. Have stakeholders reviewed the cost allocation methodology described above?

A. Yes. Duke fully reviewed the cost allocation methodology for Interconnection Facilities and Network Upgrades with stakeholders during the 2-year long stakeholder engagement process. The topic was discussed with stakeholders at multiple meetings, and Duke led a "deep dive" discussion on this topic during 2 particular meetings. The stakeholders were ultimately agreeable to the cost methodology, which the state regulatory commissions approved the methodology as part of the revised state-jurisdictional generator interconnection procedures.

Q. Are there any additional details or examples of how the Duke Carolinas Utilities would apply the cost allocation methodology?

A. Yes. As part of the filing that Duke is submitting with the Commission, Duke has included an exhibit which tracks very closely to the exhibit that PSCo file as part of its queue reform filing with the Commission. The exhibit provides more details about the cost allocation methodology, as well as examples of how the cost methodology is applied and how it aligns with Commission-approved cost allocation methodologies.

E. READINESS MILESTONES AND SITE CONTROL

Q. Duke is implementing a series of Readiness Milestones and mandating Site Control in the Definitive Interconnection Study Process to incentivize customers to not prematurely enter the queue. Will the Readiness Milestones similarly allow viable projects to advance to completion?

A. Duke has developed its proposed Readiness Milestones and Site Control provisions with the goal of creating an effective process that allows viable projects to move through the queue, while also providing developers with the flexibility to demonstrate their readiness in a variety of ways. The purpose of the Readiness Milestones and Site Control provisions is to require an Interconnection Customer to demonstrate that a specific project is ready to move forward with interconnection so that it is less likely to withdraw from the queue and harm other Interconnection Customers. The Readiness Milestone and Site Control requirements helps prioritize ready projects, which is the basis of a first-ready, first-served approach. After starting with PSCO's milestones and further consulting with our stakeholders regarding various ways that readiness may be demonstrated, Duke proposes to offer both financial and non-financial readiness demonstration options. These are described in Section 10.11 of the revised LGIP and described in more detail below.

Q. Are Readiness Milestones the same thing as study deposits?

A No. It is important to distinguish study deposits and Readiness Milestones. Readiness Milestones are used during the study process to demonstrate readiness to interconnect while study deposits are used to pay the Transmission Provider's costs of implementing the study process.

Q. How did Duke determine the Readiness Milestones?

A. Duke used the Readiness Milestones approved for PSCO as a starting point. During the stakeholder process, Duke, in concert with stakeholders, refined the Readiness Milestones. Readiness Milestones were one of the most deliberated topics in the stakeholder process. Stakeholders were sometimes divided on what forms of readiness could be considered as meaningful at certain points in the Definitive Interconnection Study Process. More rigorous demonstrations of readiness result in more certainty in the interconnection process, which is especially important later in the Definitive Interconnection Study Process. Stakeholders' understanding of the generation development business and their experience in other regions, including PSCo, helped guide the ultimate choices of Readiness Milestones.

Q. What Readiness Milestones are proposed in Duke's revised LGIP?

A. As is defined in Section 10.11 of the LGIP Duke requires the following:

<u>Readiness Milestone 1 ("M1") (required pre-Phase 1 per LGIP § 10.1)</u>.

M1 is satisfied by the Interconnection Customer providing one of the 4 options below.

1) Executed term sheet (or comparable evidence) related to a contract, binding upon the parties to the contract, for sale of (i) the constructed Generating Facility, (ii) the Generating Facility's energy, or (iii) the Generating Facility's ancillary services if the Generating Facility is an electric storage resource; where the term of sale under (ii) or (iii) is not less than five (5) years;
2) Reasonable evidence the Generating Facility has been selected by a Resource Planning Entity in a Resource Plan or is offering to sell its output through a Resource Solicitation Process;

3) Provisional Large Generator Interconnection Agreement accepted for filing at FERC. Such an agreement shall not be suspended and shall include a commitment to construct the Generating Facility; or

4) Additional security in lieu of readiness equal to one (1) times the Interconnection Customer's share of the Definitive Interconnection Study Process study costs. If this amount is not known, the Transmission Provider shall use the Section 4.4.2 study deposit amount as an estimate of study cost until such amounts are known.

Readiness Milestone 2 ("M2") (required pre-Phase 2 per LGIP § 10.8(b)).

M2 is satisfied by the Interconnection Customer providing one of the options below.

1) Executed term sheet (or comparable evidence) related to a contract, binding upon the parties to the contract, for sale of (i) the constructed Generating Facility, (ii) the Generating Facility's energy, or (iii) the Generating Facility's ancillary services if the Generating Facility is an electric storage resource; where the term of sale under (ii) or (iii) is not less than five (5) years;

2) Reasonable evidence that the Project has been selected by a Resource Planning Entity in a Resource Plan or is offering to sell its output through a Resource Solicitation Process;

3) Provisional Large Generator Interconnection Agreement accepted for filing at FERC. Such an agreement shall not be suspended and shall include a commitment to construct the Generating Facility; or

4) Additional security in lieu of readiness in the amount of two (2) times the Interconnection Customer's share of the Definitive Interconnection Study Process study costs. If this amount is not known, the Transmission Provider shall use the

Section 4.4.2 study deposit amount as an estimate of study cost until such amounts are known.

Readiness Milestone 3 ("M3") (required within 20 Calendar Days of the Phase 2 Report Meeting per LGIP § 10.8(d)).

1) Executed contract, binding upon the parties to the contract, for sale of (i) the constructed Generating Facility, (ii) the Generating Facility's energy, or (iii) the Generating Facility's ancillary services if the Generating Facility is an electric storage resource; where under (ii) or (iii) the term of sale is not less than five (5) years;
2) Reasonable evidence that the project has been selected by a Resource Planning Entity in a Resource Plan or is offering to sell its output through a Resource Solicitation Process;
3) An unsuspended Provisional Large Generator Interconnection Agreement accepted for filing by FERC with reasonable evidence that the Generating Facility and Interconnection Facilities have commenced design and engineering; or
4) Additional security in lieu of readiness in the amount of four (4) times the Interconnection Customer's share of the Definitive Interconnection Study Process study costs. If this amount is not known, the Transmission Provider shall use the Section 4.4.2 study deposit amount as an estimate of study cost until such amounts are known.

Readiness Milestone 4 ("M4") (required within 30 Calendar Days of Facility Study Agreement delivery per LGIP § 10.8(f)).

1) Executed contract, binding upon the parties to the contract, for sale of (i) the constructed Generating Facility, (ii) the Generating Facility's energy, or (iii) the

Generating Facility's ancillary services and capacity if the Generating Facility is an electric storage resource; where under (ii) or (iii) the term of sale is not less than five (5) years;

2) Reasonable evidence that the project has been selected by a Resource Planning Entity in a Resource Plan and, if required, has filed an application for a Certificate of Public Convenience and Necessity to construct the Generating Facility or has been selected in a Resource Solicitation Process;

3) An unsuspended Provisional Large Generator Interconnection Agreement accepted for filing by FERC with reasonable evidence that the Generating Facility and Interconnection Facilities have commenced construction; or

4) Additional security in lieu of readiness in the amount of six (6) times the Interconnection Customer's share of the Definitive Interconnection Study Process study costs. If this amount is not known, the Transmission Provider shall use the Section 4.4.2 study deposit amount as an estimate of study cost until such amounts are known.

<u>Readiness Milestone 5 ("M5") (required within 15 Business Days of final LGIA delivery per LGIP § 14.4).</u>

All Interconnection Customers are required to provide security in order to satisfy Readiness Milestone 5 (M5) when the LGIA is executed as described in Section 14.4. The amount of security required for M5 is equal to nine (9) times the Interconnection Customer's share of the Definitive Interconnection Study Process study costs. If this amount is not known, the Transmission Provider shall use the Section 4.4.2 study deposit amount as an estimate of study cost until such amounts are known. If initially estimated, M5 shall be updated when the final invoice for actual study costs is issued. As this M5 amount is the total security required to satisfy Readiness Milestone 5, any security previously provided pursuant to Sections 7.1, 7.2, 10.11.1, 10.11.2, 10.11.3, 10.11.4, or 10.11.6 shall be applied towards the Readiness Milestone 5 amount when the LGIA is executed.

Q. Why is it important to include both financial and non-financial readiness options?

A. By allowing multiple options to satisfy the Readiness Milestone requirements, Duke's proposal affords the Interconnection Customer the flexibility to employ a variety of business models in the Duke region and enables developers to pursue multiple business opportunities for a single Generating Facility. Duke believes that providing customers with multiple options for demonstrating readiness (both financial and non-financial) will maximize flexibility while still providing certainty to Interconnection Customers through a vastly improved interconnection process.

1. SECURITY READINESS MILESTONE

Q. Please describe the initial M1 Security Readiness Milestone.

A. The Security Readiness Milestone requires all Interconnection Customers to demonstrate their commitment to developing a project by posting an amount of security that is significant enough to encourage developers to enter only ready or near-ready projects into the queue for study in DISIS Phase 1. The amount of security required becomes at-risk and increases as the project progresses though the study phases, requiring an Interconnection Customer to demonstrate its continued and increasing commitment to construct the generating facility. The security-in-lieu-of-readiness option demonstrates the Interconnection Customer's readiness commitment.

Q. What are the security amounts for each phase?

A. Prior to the close of the Customer Engagement Window, all Interconnection Customers must provide initial security equal to the Section 4.1.2 study deposit amount as described in Section 10.1 and 10.8(a.). The security provided in Section 10.8(a.) will be applied towards the amount of security required for M5.

The security amounts for each phase (M1-M5) are set forth in Figure 6 below. The top row shows the security amounts due for projects that can demonstrate readiness, and the bottom row shows the higher security amounts due for projects that cannot demonstrate readiness.

FIGURE 6

Readiness?	M1- Due by close of 60 CD Cust. Eng. Window	M2- Due within 20 CDs of Phase 1 Rpt Mtg	M3- Due within 20 CDs of Phase 2 Rpt Mtg	M4- Due within 30 CDs of FSA delivery	M5- Due within 15 BDs of final LGIA delivery
Yes	1x Study Deposit	1x Study Deposit	1x Study Deposit	1x Study Deposit	9x Study Deposit
No	2x Study Deposit	3x Study Deposit	5x Study Deposit	7x Study Deposit	9x Study Deposit

An Interconnection Customer may opt to provide security in lieu of providing Readiness Milestones 1 through 4, as identified in Sections 10.11.1, 10.11.2, 10.11.3, and 10.11.4 and prescribed in Section 10.11.6. The security provided is applied towards the security amount required for each successive milestone if the Interconnection Customer does not withdraw from the Definitive Interconnection Study Process. For example, the security provided for M2 is applied to the amount of security required for M3. If an Interconnection Customer is initially required to provide increased security under this Section 10.11.6 because it cannot satisfy the requirements of a Readiness Milestone, but subsequently does satisfy those requirements prior to the next Readiness Milestone, its security should be reduced accordingly.

All security shall be in the form of (a) cash or (b) an irrevocable letter of credit in a form reasonably acceptable to Transmission Provider. If the Interconnection Customer withdraws prior to executing an LGIA, the Transmission Provider shall be entitled to use the security as payment for (a) the final invoice for study costs and (b) the Withdrawal Penalty, after which any remaining amount of security shall be returned to Interconnection Customer. If the Interconnection Customer does not withdraw and executes an LGIA, the amount of security shall be increased or decreased as needed in order to reflect the cost estimate for Transmission Provider's Interconnection Facilities and Network Upgrades set forth in Appendix B to the LGIA. Once the LGIA is fully executed, the terms of the LGIA shall govern such security.

Q. Are these security amounts cumulative?

A. No, the above tables represent the total amount of security required at each milestone; therefore, the incremental amount necessary to maintain good standing in order to continue proceeding through the DISIS process is the difference between the security required at the current milestone versus the security required at the most recent milestone. For example, an Interconnection Customer progressing to M4 who has a security requirement equal to 7 times the study deposit amount and who had already met the M3 requirement of 5 times the study deposit amount, will only be required to support an additional 2 times the study deposit amount in order to progress to the M4 study process. Section 10.11.6 seeks to clarify this point for Interconnection Customers.

Q. How are these financial security amounts different than those accepted for PSCO?

A. As depicted in Figure 7 below, there are no differences between the security multipliers proposed and those accepted for PSCO. While the security multipliers are the same, as discussed previously, Duke's 5-tiered study deposit approach differs from PSCo's 3-tiered approach by offering more intermediate tiers to balance the burden of requiring a higher upfront study deposit to establish an Interconnection Request with the recognition that larger Interconnection Customers are obligated to pay a more significant portion of the Transmission Provider's actual costs of implementing the Definitive Interconnection Study Process. The proposed study deposit amounts for projects entering the DISIS Cluster that are 80 MW or greater are also the same as PSCo's study deposit amounts, while the study deposit amounts for projects entering the DISIS Cluster that are less than 80 MW are lower than the initial deposit amounts required under the PSCo Definitive Interconnection Study Process.

FIGURE 7

Financial Security Requirements and Withdrawal Penalties in DISP: Comparison of Duke to PSCo

Utility	Readiness?	M1	M2	M3	M4	M5
PSCo	Yes	1x Study Deposit	1x Study Deposit	1x Study Deposit	1x Study Deposit	9x Study Deposit
Duke	Yes	1x Study Deposit	1x Study Deposit	1x Study Deposit	1x Study Deposit	9x Study Deposit
PSCo	No	2x Study Deposit	3x Study Deposit	5x Study Deposit	7x Study Deposit	9x Study Deposit
Duke	No	2x Study Deposit	3x Study Deposit	5x Study Deposit	7x Study Deposit	9x Study Deposit

Q. If an Interconnection Customer withdraws from the queue, are there any circumstances under which security would be refunded?

A. Yes, there are two. Duke proposes to fully refund or otherwise release the Security Readiness Milestone under two limited circumstances: (1) if the withdrawal does not negatively affect equal or lower queued projects and (2) if the cost of the upgrades assigned to the Interconnection Customer significantly increases from Duke's initial or prior estimates.

The first exception reflects the fact that if the withdrawal does not affect other interconnection requests, the withdrawal will not harm other Interconnection Customers or the study process itself, and so it is reasonable to refund the security in that instance.

The second exception reflects the fact that the upgrade costs assigned to an Interconnection Customer might change and increase significantly during the interconnection process, through no fault of the Interconnection Customer. As discussed above, the Definitive Interconnection Study Process is a phased process in which Interconnection Customers must show continued commitment by providing each successive Readiness Milestone based on a projection of final interconnection costs as calculated in the most recent study report. The commitment to move forward with the study process is based partially on the cost for interconnection, and costs could fluctuate at each phase based on numerous factors. Duke agreed with stakeholders that a greater than 25% increase in interconnection costs could make a specific project uneconomic and so result in a previously "ready" project withdrawing from the queue. Stakeholders also wanted to ensure that customers could withdraw if there was a significant increase in allocation costs over the process, and not just between successive phases. To address this desire, Duke proposes to refund the security if the allocated cost of interconnection increases by more than 100% between the Phase 2 results and the Phase 4 results.

These circumstances—which are consistent with withdrawal penalty exemptions provided for by PSCo—make it reasonable to not refund the security in all other instances. In all other instances, the security is "at-risk" and will not be returned to the Interconnection Customer.

Q. How does Duke propose to allocate any security amounts that are forfeited as a result of withdrawing from the queue?

A. Where an Interconnection Customer withdraws from the queue or otherwise terminates its request and forfeits its security as a withdrawal penalty, Duke proposes to use the non-refunded security to benefit all similarly queued (i.e., from the same Cluster) or lower queued (i.e., in a subsequent Cluster) Interconnection Customers by funding some or all of their study costs.

Duke proposes to allocate withdrawal penalties in the same manner as study costs: (1) 10% on a per customer basis based on number of interconnection requests in the applicable Cluster; and (2) 90% to Interconnection Customers on a pro-rata basis based on requested megawatts included in the applicable Cluster. Duke's proposed 10%/90% allocation approach is designed to allocate a relatively greater percentage of study costs and withdrawal penalty revenues to larger Interconnection Customers within the Cluster and a relatively smaller percentage of such costs to smaller Interconnection Customers consistent with the allocation of study costs paid by Interconnection Customers. The Duke Southeast Utilities structured these allocations to reflect the Commission's cost causation principle of allocating costs for the same reasons that I discussed previously for allocating study costs. The Duke Southeast Utilities also believe that this allocation structure is more equitable to all Interconnection Customers.

2. CONTRACT FOR SALE OPTION

Q. What are the non-financial demonstrations of readiness options?

A. As I mentioned above, it is important that Duke provide multiple options to satisfy the Readiness Milestone requirements, including both financial and non-financial options, which affords the Interconnection Customer the flexibility to employ a variety of business models in a Duke region and enables developers to pursue multiple business opportunities for a single planned generating facility. To this end, Duke has developed, in concert with stakeholders, the following three non-financial Readiness Milestone options: (1) the contract for sale option; (2) inclusion in a Resource Plan; and (3) Provisional Interconnection Service. Site Control is considered separately from these three options because a demonstration of Site Control is required at every phase of the study process, regardless of what form of financial or non-financial demonstration of readiness a developer wishes to provide.

Also, I note that these non-financial options are available only for the first four Readiness Milestones because security equivalent to 9 times study costs is required at M5 for all requests. Furthermore, like security Readiness Milestones described above, each of these non-financial Readiness Milestones becomes increasingly stringent in their requirements as the interconnection request progresses through the study process.

Q. Please describe the contract for sale option.

A. Duke's proposal would give Interconnection Customers the option to demonstrate increasing readiness through the study process by means of an executed term sheet for the first two milestones (M1 and M2) and by means of an executed contract for the next two milestones (M3 and M4). The term sheet or contract may be for sale of: (i) the constructed generating facility, (ii) the generating facility's energy, or (iii) the generating facility's ancillary services and capacity if the generating facility is an electric storage resource; where the term of sale is not less than 5 years.

Q. Why is it reasonable and appropriate to include this option as a demonstration of readiness?

A. It is Duke's opinion that if a generating facility has a confirmed off taker or a purchaser, it is likely to complete the interconnection process absent some materially unexpected increase in costs. Duke believes that this contract for sale option provides developers flexibility to enter into contracts for the generating facilities and/or energy and other products produced by the generating facility.

3. INCLUSION IN A RESOURCE PLAN OPTION

Q. Please describe the inclusion in a Resource Plan option.

A. Duke's proposal would allow Interconnection Customers the option to demonstrate increasing readiness by means of being included in a Resource Plan for the first three milestones (M1, M2, and M3) and by means of having been selected by a Resource Planning Entity in a Resource Plan and, if required, has filed an application for a Certificate of Public Convenience and Necessity to construct the generating facility in the final milestone. (M4).

Q. In what way does this readiness milestone option provide flexibility to developers?

A. Duke is mindful that regulatory approval to procure or construct a new generating facility is often proceeding in parallel with the interconnection study process, so Duke's proposal requires only inclusion in a Resource Plan up until the Facility Study Phase. The next milestone, Readiness Milestone 4 (M4), would require that the resources have filed an application for a Certificate of Public Convenience and Necessity to construct the generating facility.

4. PROVISIONAL INTERCONNECTION SERVICE OPTION

Q. Please describe the Provisional Interconnection Service option.

A. Duke's proposal considers generating facilities with Provisional Interconnection Service as ready projects. Provisional Interconnection Service is intended for projects that commit to interconnect before the final interconnection study is complete. Again, Duke proposes increasing demonstration of readiness in which the first two milestones (M1 and M2) require the Provisional Interconnection Service Agreement to be filed with the Commission, at Milestone 3 (M3) reasonable evidence that the generating facility and Interconnection Facilities have commenced design and engineering, and for Milestone 4 (M4) requires evidence that the facilities have commenced construction.

Q. Could Interconnection Customers use this option to circumvent the security requirements or other non-financial Readiness Milestones?

A. To ensure that the use of the Provisional Interconnection Service option is an accurate demonstration of readiness to proceed, Duke is requiring that Interconnection Customers that use a Provisional LGIA to demonstrate readiness commit to fully fund the estimated upgrade costs associated with their projects

Duke's inclusion of this option is consistent with the Commission's recent directives in Order No. 845 that "Interconnection Customers with provisional agreements must still assume all risk and liabilities associated with the required interconnection facilities and network upgrades for their interconnection."[28]

5. SITE CONTROL

Q. How does Duke propose to handle site control as part of the Definitive Interconnection Study Process?

A. As part of the Definitive Interconnection Study Process, the Duke Southeast Utilities proposes to adopt the (a) definition of site control and (b) site control requirements document attached as Exhibit D, each as was approved in the PSCo proceeding. While PSCo's proposal involved escalating percentages of site control required during the Definitive Interconnection Study Process, the Duke Southeast Utilities propose to require full site control through the Definitive Interconnection Study Process. This proposed approach to site control required as part of the Definitive Interconnection Study Process is consistent the site control required as part of the current FERC-approved serial interconnection study process. Additionally, the proposed site control approach has been approved as part of Duke's queue reform filings in North Carolina and South Carolina.[29] Over the course of the almost two-year stakeholder engagement process, stakeholders have viewed the proposed approach to site control as acceptable, and Duke Southeast Utilities have not received provided negative feedback indicating otherwise.

F. TRANSITIONAL PROCESS

Q. What is the goal of Duke's transition proposal?

[28] Order No. 845 at P 425.

[29] NCUC Order at 3. PSCSC Directive at 1.

A. In the current serial study process, projects that are lower in the queue cannot be studied and definitively assigned upgrades until higher queued projects withdraw from the queue or terminate their Interconnection Agreements. Duke believes that speculative, non-viable projects with higher queue Positions are barring lower queued ready projects from being studied or from advancing to interconnection and may be leading to inaccurate study results.

Therefore, if those higher queued projects were allowed to retain their queue position during the transition to the new cluster study process, the same problems that have given rise to this queue reform proposal would continue. Thus, the goal of Duke's transition proposal is to transition only ready projects (and not speculative projects) so that Duke would be able to study and interconnect those Interconnection Customers in a timely and effective manner.

Q. Why is it important for Duke's queue reform to include an effective transition mechanism?

A. Duke's objective of reforming the queue will not be successful unless speculative or non-ready projects are given a reasonable opportunity to demonstrate readiness and commitment to interconnection. If they cannot, they need to be removed from the queue so as not to impede other ready projects. Even if an Interconnection Customer first entered the Duke queue with a business model that assumed that it would not need to decide whether to interconnect for years into the future, because of the current and pressing issues with the Duke Carolinas Utilities' interconnection queue challenges summarized above and in the accompanying testimony of Mr. Roberts, it is unjust and unreasonable to allow these Interconnection Customers to harm ready projects by creating a barrier to interconnection. I note also that the entire proposed redesign assumes that the transitional projects are ready to go forward and that, at least for later stage projects transitioning under the transitional serial process, none will withdraw. If this assumption proves false, then cascading restudies and inaccurate study results will undermine the entire queue reform proposal. For these reasons and for this one-time transition only, Duke proposes to ensure that transitioned projects are truly ready to proceed by imposing additional requirements on interconnection projects already in the queue.

Q. Please describe Duke's proposed transitional process.

A. Duke proposes an expedited process for ready projects that have been delayed in Duke's current queue. Duke has established three options for projects in the current Duke queue: (1) the transitional serial process; (2) the transitional cluster process; and (3) withdrawal from the queue and reenter the queue in a DISIS Cluster. In order to enter either the transitional serial or the transitional cluster processes, a project must successfully demonstrate readiness. If a currently queued Interconnection Customer elects not to transition using either the transitional serial or transitional cluster process, then that Interconnection Customer may notify the Duke Transmission Provider of its intent to withdraw (or shall be deemed withdrawn after the 60-day election period) and may then reenter the queue through a future DISIS Cluster.

1. TRANSITIONAL SERIAL PROCESS

Q. What projects qualify to participate in the transitional serial process?

A. An Interconnection Customer may opt to enter the transitional serial process provided that the Interconnection Customer has both (a) a final System Impact Study Report that identifies the interconnection request is feasible and identifies facilities required to interconnect and (b) an Interconnection Facilities Study Agreement that was executed prior to the Cluster Study transition notice date. The transitional serial process essentially allows ready projects in the Interconnection Facilities Study process to continue with that study, enter into an LGIA, and interconnect. The only material difference between the current and proposed process for these transitional serial projects is that they are truly ready to interconnect and will thus not negatively impact the subsequent transition cluster or subsequent DISIS clusters.

Q. How does an Interconnection Customer in the transitional serial process demonstrate that it is truly ready to interconnect?

A. To join the Transitional Serial Process, the Interconnection Customer must meet all of the following requirements within the timeframe prescribed in Section 7:

a) Execute a Transitional Serial Interconnection Facilities Study Agreement, as provided in Appendix 8-1;

b) Provide security equal to one hundred percent (100%) of the costs identified for Transmission Provider's Interconnection Facilities and Network Upgrades in the System Impact Study Report. The security shall be in the form of (a) cash; (b) an irrevocable letter of credit in a form reasonably acceptable to Transmission Provider; or (c) for amounts exceeding the potential Withdrawal Penalty to be assigned under this Section, other forms of security provided for in Section 11.5 of the LGIA (such as a surety bond) in a form reasonably acceptable to Transmission Provider. If the Interconnection Customer withdraws prior to executing an LGIA, the Transmission Provider shall be entitled to use the security as payment for (a) the final invoice for study costs and (b) the Withdrawal Penalty, after which any remaining amount of security shall be returned to Interconnection Customer. If the Interconnection Customer does not withdraw and executes an LGIA, the amount of security shall be increased or decreased as needed in order to reflect the cost estimate for Transmission Provider's Interconnection Facilities and Network Upgrades set forth in Appendix B to the LGIA. Once the LGIA is fully executed, the terms of the LGIA shall govern such security.

c) Demonstrate exclusive Site Control for the entire Generating Facility and any Interconnection Customer's Interconnection Facilities.

d) Interconnection Customer shall provide one of the following:

   i. A contract, binding upon the parties to the contract, for sale of the Generating Facility's energy, or the entire constructed Generating Facility, where the term of sale is not less than five (5) years, or

   ii. Reasonable evidence that the Generating Facility is included in a Resource Planning Entity's Resource Plan or has received a contract award in a Resource Solicitation Process, or

   iii. An executed Provisional Large Generator Interconnection Agreement filed with FERC. Such an agreement shall not be suspended and shall include a commitment to construct the Generating Facility.

2. TRANSITIONAL CLUSTER PROCESS

Q. What projects qualify to participate in the transitional cluster process?

A. To enter the Transitional Cluster Study, Interconnection Customers must (1) have an assigned Queue Position prior to the Cluster Study transition notice date; (2) meet the Transitional Cluster readiness or security requirements prescribed in Section 7.2.1, and (3) execute a Transitional Cluster Study Agreement. All Interconnection Requests that opt for this path will be considered to have an equal Queue Position and be studied in a single Transitional Cluster. The costs of the study and the identified facilities will be allocated in the same manner as costs are allocated for DISIS Clusters pursuant to Section 10.4 of the Revised LGIP.

Q. Is the Duke transitional cluster process the same as PSCo's transitional cluster process?

A. No. The transitional cluster study process was an area of significant stakeholder interest and is one area that has evolved significantly from the PSCo Definitive Interconnection Study Process. Through the stakeholder process, many stakeholders expressed concerns about mandating significant readiness requirements to enter the transitional cluster without information from the Duke Transmission Providers about their potentially assigned Network Upgrades. This lack of information is in part due to the fact that these early-stage projects have not completed System Impact Study under the existing serial study process and in part due to the fact that the Duke Transmission Providers cannot identify system impacts and provide preliminary Network Upgrade cost estimates without knowing which projects will enter the transitional cluster. In an effort to address these concerns, Duke, with input from stakeholders, has significantly restructured the transitional cluster study process from a "significant financial readiness to enter, single study" transitional cluster, similar to PSCo, to a "lower readiness to enter, multi-phased" transitional cluster process more similar to DISIS. The transitional cluster will unquestionably take longer than the PSCo transitional cluster and, potentially, will require some amount of restudy as Interconnection Customers exit after the transitional cluster phase 1 study; however, Duke supports this proposal as just and reasonable and responsive to stakeholder feedback.

The Duke Southeast Utilities have also adjusted the definitive readiness requirements in response to stakeholder feedback to provide current Interconnection Customers that desire to enter the transitional cluster and believe their project to be "near-ready" but not capable of demonstrating readiness an alternative security-in-lieu-of-project-readiness path to both enter and proceed through the transitional cluster. The Duke Transmission Providers found this deviation from PSCo (which mandated all projects demonstrate definitive project readiness to enter the transitional cluster) to be reasonable and appropriate to accommodate stakeholder feedback and to address concerns about mandating definitive project readiness at the outset of the multi-phased transitional cluster.

Q. How does an Interconnection Customer in the transitional cluster process demonstrate that it is truly ready to connect?

A. To join the Transitional Cluster Study, the Interconnection Customer must meet all of the following requirements within the timeframe prescribed in Section 7:

a) Execute a Transitional Cluster Study Agreement, as provided in Appendix 8-2;

b) Choice of requesting either ERIS or NRIS;

c) Make a supplemental interconnection request study deposit in cash, if necessary, to increase the Interconnection Customer's total study deposit to equal the amount required under Section 4.1.2 of the LGIP;

d) Demonstrate that Interconnection Customer has exclusive Site Control for the entire generating facility and all required interconnection facilities to the point of interconnection to the transmission provider's system. Interconnection Customer may provide a cash deposit equal to $20,000 plus $500/MW in lieu of Site Control to enter Transitional Cluster Study Phase 1. A deposit in lieu of Site Control is not accepted for later phases of the Transitional Cluster Study Process; and Interconnection Customer shall provide one of the following:

i. Executed term sheet (or comparable evidence) related to a contract, binding upon the parties to the contract, for sale of the generating facility's energy, or the entire constructed generating facility, where the term of sale is not less than 5 years, or

ii. Reasonable evidence that the generating facility is included in a Resource Planning Entity's Resource Plan or Resource Solicitation Process, or

iii. An executed Provisional Large Generator Interconnection Agreement filed with FERC that is not in suspension with 1) a commitment to construct the facility, 2) a Commercial Operation Date no later than 2024 and 3) a security deposit in addition to amount required under Section 4.1.2 where the total security deposit represents a reasonable estimation of the potential costs that could be ultimately allocated to the project in the Transitional Cluster Study, or

iv. Security equal to $3,000,000. The security shall be in the form of (a) cash or (b) an irrevocable letter of credit in a form reasonably acceptable to Transmission Provider. If the Interconnection Customer withdraws prior to executing an LGIA, the Transmission Provider shall be entitled to use the security as payment for (a) the final invoice for study costs and (b) the Withdrawal Penalty, after which any remaining amount of security shall be returned to Interconnection Customer. If the Interconnection Customer does not withdraw and executes an LGIA, the amount of security shall be increased or decreased as needed in order to reflect the cost estimate for Transmission Provider's Interconnection Facilities and Network Upgrades set forth in Appendix B to the LGIA. Once the LGIA is fully executed, the terms of the LGIA shall govern such security.

At Phase 2 of the Transitional Cluster Study process, the readiness requirements increase: Within 30 Calendar Days of the transmission provider's publication of the Transitional Cluster Study Phase 1 Report, each Interconnection Customer electing to proceed with Phase 2 of the Transitional Cluster Study must meet all of the following requirements:

a) Provide security equal to three million dollars ($3,000,000) inclusive of any security previously required by Section 7.2.1(e.). The security shall be in the form of (a) cash; (b) an irrevocable letter of credit in a form reasonably acceptable to Transmission Provider; or (c) for amounts exceeding the potential Withdrawal Penalty to be assigned under Section 7.2.6, other forms of security provided for in Section 11.5 of the LGIA (such as a surety bond) in a form reasonably acceptable to Transmission Provider. If the

Interconnection Customer withdraws prior to executing an LGIA, the Transmission Provider shall be entitled to use the security as payment for (a) the final invoice for study costs and (b) the Withdrawal Penalty, after which any remaining amount of security shall be returned to Interconnection Customer. If the Interconnection Customer does not withdraw and executes an LGIA, the amount of security shall be increased or decreased as needed in order to reflect the cost estimate for Transmission Provider's Interconnection Facilities and Network Upgrades set forth in Appendix B to the LGIA. Once the LGIA is fully executed, the terms of the LGIA shall govern such security.

b) Demonstrate exclusive Site Control for the entire generating facility and all required interconnection facilities to the point of interconnection on the transmission provider's transmission system.

c) Interconnection Customer shall provide one of the following:

i. A contract binding upon the parties to the contract, for sale of the generating facility's energy, or the entire constructed generating facility, where the term of sale is not less than 5 years, or

ii. Reasonable evidence that the generating facility is included in a Resource Planning Entity's Resource Plan and, if required, has filed an application for a Certificate of Public Convenience and Necessity to construct the generating facility or has been selected in a Resource Solicitation Process, or

iii. An executed Provisional Large Generator Interconnection Agreement filed with FERC that is not in suspension with 1) a commitment to construct the generating facility, 2) a Commercial Operation Date no later than 2024 and 3) a security deposit in addition to amount required under Section 4.1.2 where the total security deposit represents a reasonable estimation of the potential costs that could be ultimately allocated to the project in the transitional cluster study, or

iv. Provide additional security equal to two million dollars ($2,000,000). The security shall be in the form of (a) cash; (b) an irrevocable letter of credit in a form reasonably acceptable to Transmission Provider; or (c) for amounts exceeding the potential Withdrawal Penalty to be assigned under Section 7.2.6, other forms of security provided for in Section 11.5 of the LGIA (such as a surety bond) in a form reasonably acceptable to Transmission Provider. If the Interconnection Customer withdraws prior to executing an LGIA, the Transmission Provider shall be entitled to use the security as payment for (a) the final invoice for study costs and (b) the Withdrawal Penalty, after which any remaining amount of security shall be returned to Interconnection Customer. If the Interconnection Customer does not withdraw and executes an LGIA, the amount of security shall be increased or decreased as needed in order to reflect the cost estimate for Transmission Provider's Interconnection Facilities and Network Upgrades set forth in

Appendix B to the LGIA. Once the LGIA is fully executed, the terms of the LGIA shall govern such security.

Q. Under what circumstances is the $3-$5 million deposit refundable?

A. If the Interconnection Customer withdraws from the queue prior to Phase 2 of the Transition Cluster Study, the Interconnection Customer will be fully refunded the deposit and will only be obligated to pay the study costs allocated to them. However, if an Interconnection Customer elects to proceed to Phase 2 and then subsequently withdraws from the queue, the Interconnection Customer will be subject to the provisions under Section 7.2.6 unless the withdrawal does not negatively affect the cost or timing of any other interconnection requests in the Transitional Cluster Study or the first DISIS Cluster. Any refund will be net of the Interconnection Customer's study costs related to the transitional cluster study as well as the withdraw penalty which is equal to 9 times the study cost as defined in Section 7.2.6.

Q. How did Duke determine that a $3 - $5 million deposit would be reasonable to demonstrate readiness for the purpose of the transitional cluster process?

A. To ensure that such Interconnection Customers are truly ready to move forward, projects in the transitional cluster must make a deposit on Transmission Provider Interconnection Facilities and Network Upgrades that are required for interconnection. However, since Duke does not yet know how many projects will enter the transitional cluster and has not yet completed the transitional cluster study that would identify the Transmission Provider Interconnection Facilities and Network Upgrades and the cost responsibility for such facilities, Duke must estimate the potential costs. Through the stakeholder process, Duke has established $3-$5 million as a reasonable deposit for the Transmission Provider

Interconnection Facilities and Network Upgrades cost that might be allocated to an Interconnection Customer, although \$3-\$5 million is likely on the low end of the potential cost.

There are numerous reference points that support the reasonableness of a \$3-\$5 million deposit. Duke's estimated Transmission Provider Interconnection Facilities costs for transmission level interconnections range between \$2.3 and \$14 million per interconnection request, excluding real estate or right-of-way costs. The range is primarily dependent on the voltage level of the interconnection and typically includes the cost to tap the transmission line, build the new breaker station, and install the protection scheme. Generating facilities that require tap lines longer than 500 feet may also receive additional estimates around \$2 million per mile. Furthermore, Network Upgrade cost estimates identified on the Duke system have ranged between \$500,000 for line switches at the point-of-interconnection to \$280 million for an upgrade requiring over 90 miles of upgraded conductor and structures.

If there are a significant number of requests in the transitional cluster, Duke expects a significant number of network facilities to be required for interconnecting the cluster. In addition to the per project TPIF cost discussed here, there are over \$500 million of network upgrades that have been previously identified through serial study of prior-queued projects.

Therefore, Duke believes that \$3-\$5 million represents a reasonable deposit on TPIF and Network Upgrades that may be allocated to any specific generator in the transitional cluster study process. The \$3-\$5 million is security on the facilities the Interconnection Customer will fund. When the study is complete, the \$3-\$5 million will be reconciled to an amount equal 100% of the allocated upgrade costs identified in the Transitional Cluster Study upon execution of the LGIA (i.e., Readiness Milestone 5). Because we expect that the projects and identified transmission upgrades will have a commercial operation date or in-service date in the near future, we also expect that the LGIA will require full funding (100%) of the identified facilities in the LGIA Milestones shortly after execution of the LGIA.

Q. How many projects does Duke anticipate will enter the transitional cluster?

A. At this time, Duke does not know for certain how many projects are ready and will opt to enter the transitional cluster. If we consider the number of projects currently in the NC and SC state-jurisdictional queues along with those in the FERC-jurisdictional queues, the numbers could be very high, at least 50 for each utility (DEC and DEP). That would also total over 8,000 MW in each of the utilities. However, with close evaluation and assuming the population of projects will focus on renewables and battery storage, one could estimate that the MW amount might be less than half of that and on the order of about 3,000 MW in each utility. It is clear that not all projects will ultimately request to be studied in the transitional cluster. It is also clear that some late-stage projects that have been assigned network upgrades may withdraw and re-enter the queue so that the upgrades can be reallocated across multiple projects.

3. TIMING CONSIDERATIONS

Q. How long does an Interconnection Customer have to enroll in either the transitional serial or transitional cluster process?

A. Upon a Duke Transmission Provider giving notice of its intent to transition to the Definitive Interconnection Study Process, any Interconnection Customer that has received a Queue Number but has not executed an Interconnection Agreement prior to the Cluster Study transition notice date may elect to be studied under the Transition Procedures by meeting the requirements to enter either the Transitional Serial study process or Transitional Cluster study process. An Interconnection Customer electing to complete the transitional process must notify the interconnecting Duke Transmission Provider and meet all applicable transitional process readiness requirements within 60 Calendar Days of the Cluster Study transition notice date.

If a currently queued Interconnection Customer elects not to transition using either the transitional serial or transitional cluster process, then that Interconnection Customer will be withdrawn from the queue and will have the option to reenter the queue through a future DISIS Cluster. The first DISIS Request Window will open soon after the transition study processes get underway. Assuming timely approval of the Companies' queue reform proposal to become effective June 2, 2021, as requested, the Duke Carolinas Utilities plan to issue the Cluster Study transition notice and initiate the 60-day transition window soon thereafter resulting in the 30-day expedited transitional cluster customer engagement process being completed on or before October 1 2020, and the 90-day transitional cluster Phase 1 study commencing thereafter. The first DISIS Request Window will be from January 1, 2022 through June 30, 2022. This DISIS Request Window is followed by a 60-day Customer Engagement Window, which means that the Phase 1 study will start on or about August 30, 2022. This timeline means that the first DISIS Cluster Study will commence at about the same time that the transitional cluster phase 2 study process is reaching completion. Transitional serial projects will be considered higher queued than the transitional cluster and the first DISIS Cluster. The transitional cluster will be considered higher queued compared to the first DISIS Cluster. The transitional Cluster will utilize a somewhat expedited study process for the currently queued ready projects and is expected to be complete by fall 2022.

V. <u>CONCLUSION</u>

Q. Please summarize your recommendations.

A. I recommend that the Commission approve DEC, DEF and DEP's requested proposed revisions to Attachment J to the Joint OATT effective June 1, 2021, as proposed.

Q. Does this conclude your testimony?

A. Yes.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Duke Energy Carolinas, LLC,	)	
Duke Energy Florida, LLC, and	)	Docket No. ER21-___-000
Duke Energy Progress, LLC	)	

AFFIDAVIT

Mr. Kenneth J. Jennings, being duly sworn, deposes and states: that the Direct Testimony of Mr. Kenneth J. Jennings was prepared by me or under my direct supervision, and that the statements contained therein are true and correct to the best of my knowledge and belief.

Mr. Kenneth J. Jennings

PEGGY HOLTON
NOTARY
PUBLIC
WAKE COUNTY, NC

Subscribed and sworn me this 31st day of March 2021.

Peggy Holton
Notary Public
My commission expires: 12/22/2021

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Duke Energy Carolinas, LLC	)	
Duke Energy Florida, LLC	)	Docket No. ER21-1579-000
Duke Energy Progress, LLC	)	

COMMENTS IN SUPPORT
OF PINE GATE RENEWABLES, LLC

Pursuant to Rules 212 and 214 of the Rules of Practice and Procedure[1] of the Federal Energy Regulatory Commission ("Commission"), Pine Gate Renewables, LLC ("Pine Gate") hereby submits these comments in the above-captioned proceeding.[2]

I. BACKGROUND

On April 1, 2021, Duke Energy Carolinas, LLC ("DEC"), Duke Energy Progress, LLC ("DEP"), and Duke Energy Florida, LLC ("DEF") (collectively, the "Duke Southeast Utilities") submitted a filing with the Commission in the above-captioned proceeding ("Queue Reform Filing").[3] The Queue Reform Filing contains modifications to the Duke Southeast Utilities' *pro forma* Large Generator Interconnection Procedures and Large Generator Interconnection Agreement attached as Attachment J to their Joint Open Access Transmission Tariff.

In the Queue Reform Filing, the Duke Southeast Utilities propose the ability to elect on an individual transmission provider basis whether to move from a first-come, first-served serial generator interconnection process to a first-ready, first-served clustered interconnection process. The Duke Southeast Utilities state in the Queue Reform Filing that DEC and DEP plan to

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[1] 18 C.F.R. §§ 385.212, 385.214 (2020).

[2] Pine Gate previously filed a timely doc-less Motion to Intervene in this proceeding. *See* Doc-Less Motion to Intervene of Pine Gate Renewables, LLC, Docket No. ER21-1579-000 (Apr. 12, 2021).

[3] Revisions to Attachment J (Large Generator Interconnection Procedures) to Joint OATT of Duke Energy Carolinas, LLC, Duke Energy Progress, LLC, and Duke Energy Florida, LLC, Docket No. ER21-1579-000 (Apr. 12, 2021).

immediately elect to move to a first-ready, first-served cluster process whereas DEF will not immediately elect to do so.

The Commission issued a Notice of Filing in this proceeding setting a deadline of April 22, 2021 for public comments in this docket.

II. COMMENTS

Pine Gate is a utility-scale solar and storage developer based in Asheville, North Carolina. While Pine Gate is active in many states, its largest market to date has been the DEC and DEP service territories, where Pine Gate and its affiliates have more than 250 megawatts ("MW") of solar facilities in operation and under construction, almost 1,000 additional MW under contract, and more than 1,500 additional MW under development. Pine Gate has been extensively involved in stakeholder processes and negotiations with DEC and DEP regarding its proposed queue reform before both the state regulatory commission and FERC. Pine Gate appreciates the significant modifications the Duke Southeast Utilities have made to their proposals to address concerns raised by Pine Gate and other solar developers.

Pine Gate supports the Duke Southeast Utilities' Queue Reform Filing, both with respect to (a) the prospective Definitive Interconnection Study Process for new requests under the first-ready, first-served cluster process as well as (b) the transition process that will apply to Interconnection Customers currently in an interconnection queue where a Duke Energy Southeast Utility elects to move from serial generator interconnection processing to clustered processing.

Pine Gate recognizes and appreciates the challenges that the Duke Southeast Utilities have faced in recent years with respect to managing increasingly large interconnection queues on a serial basis. Pine Gate believes that the proposed queue reforms filed in this proceeding will help resolve the significant delays and inefficiencies experienced in the serial interconnection process due to, among other things, (1) the sheer volume of interconnection requests, (2) the need for significant grid upgrades required to facilitate interconnections, and (3) the potential for substantial restudies under the current serial process. The inevitable delays and inefficiencies that result from managing increasingly large interconnection queues on a serial basis do not provide benefit to any parties involved. Pine Gate itself has many projects that have been on hold for extended periods of time due to the inherent problems with the current serial study process and plans to advance those projects through the proposed transitional study process once it is approved. For these reasons, Pine Gate supports the Queue Reform Filing, which represents a necessary evolution of the Duke Southeast Utilities' generator interconnection processes in order to permit higher penetrations of new generation resources (often renewable energy resources and distributed energy resources), while continuing to ensure emerging technical and equity issues are purposefully addressed.

III. COMMUNICATIONS

All communications related to this proceeding should be addressed to:

Steven Levitas
Senior Vice President, Regulatory & Government Affairs
Pine Gate Renewables, LLC
130 Roberts Street
Asheville, NC 28801
919-749-2953
slevitas@pgrenewables.com

Brett White
Director, Regulatory Affairs
Pine Gate Renewables, LLC
130 Roberts Street
Asheville, NC 28801
919-880-4879
bwhite@pgrenewables.com

IV. SERVICE OF FILING

This filing will be served electronically on the official service list in this proceeding.

V. CONCLUSION

For the reasons set forth above, Pine Gate hereby respectfully requests that the Commission consider its comments in this proceeding.

Respectfully submitted,

/s/ Steven Levitas
Steven Levitas
Senior Vice President, Regulatory & Government Affairs
Pine Gate Renewables, LLC
130 Roberts Street
Asheville, NC 28801
919-749-2953
slevitas@pgrenewables.com

Dated: April 19, 2021

CERTIFICATE OF SERVICE

In accordance with 18 C.F.R. § 385.2010(f)(2), I hereby certify that the foregoing document was served electronically today upon each person designated on the official service lists compiled by the Secretary in these proceedings.

Dated: April 19, 2021

/s/ Brett White

Brett White
Director, Regulatory Affairs
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Document Content(s)

Public Staff Levitas Cross Exhibit 5

I/A

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Edgecombe Solar Energy LLC Complainant, v. Duke Energy Progress, LLC, Duke Energy Carolinas, LLC, and Duke Energy Florida, LLC, Respondents.	)))))))))	Docket No. EL21-73-000

MOTION FOR LEAVE TO ANSWER AND ANSWER OF THE NORTH CAROLINA UTILITIES COMMISSION TO EDGECOMBE SOLAR ENERGY LLC'S ANSWER

Pursuant to Rules 212 and 213 of the Rules of Practice and Procedure of the Federal Energy Regulatory Commission ("Commission" or "FERC"), the North Carolina Utilities Commission ("NCUC"), an intervenor in this docket, respectfully moves for leave to answer and answers ("Answer") the Answer of Edgecombe Solar Energy LLC ("Edgecombe") filed on June 16, 2021 ("Edgecombe Answer"). In its Complaint, Edgecombe seeks an order of the Commission directing Duke Energy Progress, LLC, Duke Energy Carolinas, LLC, and Duke Energy Florida, LLC (collectively, the "Duke Companies") to revise their template Affected System Operating Agreement ("ASOA") to provide for reimbursement of Network Upgrades that the Duke Companies construct as an Affected System Operator. Edgecombe argues that this result is required by Order No. 2003.[1]

The NCUC takes no position on the merits of Edgecombe's Complaint. However, the Edgecombe Answer filed in response to the Answer and Motion to Dismiss of the Duke Companies

[1] *See, e.g.*, Edgecombe Complaint at 2-3, citing *Standardization of Generator Interconnection Agreements and Procedures*, Order No. 2003, 68 Fed. Reg. 49,845 (Aug. 19, 2003), FERC Stats. & Regs. P 31,146 (2003), *order on reh'g*, Order No. 2003-A, 69 Fed. Reg. 15,932 (2004), FERC Stats. & Regs., P 31,160 (2004), *order on reh'g*, Order No. 2003-B, 70 Fed. Reg. 265 (2005), FERC Stats & Regs. P 31,171 (2004), Order No. 2003-C, FERC Stats. & Regs., P 31,190(2005), *aff'd sub nom. Nat'l Ass'n of Regulatory Util. Comm'rs v. FERC*, 475 F.3d 1277 (D.C. Cir. 2007).

incorrectly paraphrases certain arguments of the Duke Companies in a way that introduces – presumably unintentionally – inaccurate statements about North Carolina law and supposed policies of the NCUC. Therefore, in the event these matters inform the Commission's determination of the issues in this proceeding, this Answer ensures that the Commission has accurate information.

I. Motion for Leave to Answer

Answers to answers are only permitted when allowed by the decisional authority, pursuant to Rule 213 of the Commission's Rules of Practice and Procedure. [2] Good cause exists to grant the NCUC's motion because its Answer clarifies and corrects incorrect and misleading statements and thereby provides the Commission with information that may assist in its decision-making process.[3]

II. Answer

The NCUC is a regulatory body organized and existing under the laws of the State of North Carolina.[4] Its purpose, *inter alia*, is to regulate rates and charges for the sale or distribution of electricity in the State. No entity may begin construction of an electric generating facility without first obtaining from the NCUC a certificate that public convenience and necessity requires, or will require, such construction (a "CPCN").[5] In considering whether to grant a CPCN, the Commission is required to consider the costs to construct the new generation.[6]

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2 18 C.F.R. § 385.213(a)(2)(2020).

3 *See, e.g., Potomac-Appalachian Transmission Highline, LLC*, 140 F.E.R.C. ¶61,229, P102 (2012); *Southern Minnesota Municipal Power Agency v. Northern States Power Company (Minnesota); Northern States Power Company (Minnesota) v. Southern Minnesota Municipal Power Agency*, 57 F.E.R.C. ¶61,136, 61,494 (1991).

4 N.C. GEN. STAT. § 62.2 *et seq.* (2108).

5 N.C. GEN. STAT. § 62.110.1(a)(2018).

6 N.C. GEN. STAT. § 62.110.1(e)(2018).

A. The Public Staff Is Independent of the NCUC and Is Not a Decision-Making Body.

The North Carolina Utilities Commission – Public Staff ("Public Staff") operates independently of the NCUC. By statute, the Public Staff "shall not be subject to the supervision, direction or control of the [NCUC], the chairman [of the NCUC], or members of the [NCUC]."[7] The Public Staff's role and purpose differs from the NCUC and the NCUC staff. Intervention of the Public Staff in proceedings before the Commission is authorized by North Carolina law, and in those proceedings the Public Staff represents the using and consuming public.[8] The Public Staff does not have decision-making authority; rather, the Public Staff participates in proceedings before the Commission as a party intervenor.[9] North Carolina law separately provides for the role of the NCUC and allows the NCUC to retain its own staff as necessary to discharge its responsibilities and duties.[10]

In addressing arguments of the Duke Companies, Edgecombe's Answer mistakenly attributes the positions and actions of the independent Public Staff to the NCUC Staff.[11] As a result, the NCUC seeks to correct this misunderstanding.

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7 N.C. GEN. STAT. § 62-15(b)(2018).

8 *Id.*

9 N.C. GEN. STAT. § 62-15(d)(3)(2018).

10 N.C. GEN. STAT. § 62-14(2018).

11 For instance, in characterizing the position of the Duke Companies, Edgecombe states that "customers may have incentive to agree to forego reimbursement in light of the North Carolina Utilities Commission ('NCUC') staff recommendations to condition state permits required for construction of the generation project on the generator's agreeing to accept direct assignment of Network Upgrade costs. Edgecombe Answer at 2. *See also* Edgecombe Answer at 7-8, paraphrasing the Duke Companies' Answer by referring to the Public Staff as "state commission staff."

B. The NCUC Has Not Adopted Any Rule or Policy Conditioning Issuance of a CPCN on the Allocation of Network Upgrade Costs.

Edgecombe's Answer references the "NCUC's preference and policy effectively denying state permits to generators whose interconnections would result in load reimbursing for generator upgrade costs[,]" suggesting the existence of such a preference or policy. [12] To be clear, no such preference and policy exists. To the contrary, the NCUC has not adopted any rule, guidance, or practice that would require denial of a CPCN simply because the costs of network upgrades would be allocated in part to retail customers.

The Edgecombe Answer refers to the "*Friesian* proceeding challenging a state commission order denying a project's CPCN based on its policy of conditioning the permit on acceptance of direct assigned interconnection costs." [13] The NCUC's rules and orders speak for themselves. However, to the extent the *Friesian* Order is relevant it demonstrates that the NCUC's interest is in determining the all-in, *total* cost of a project – whether they be site costs, permitting and regulatory costs, construction costs, operating costs, interconnection costs, system upgrade costs, or any other category – as one of the many factors to be weighed when determining whether a generating resource is needed and is appropriately sited at the location proposed by the CPCN applicant.[14]

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12 Edgecombe Answer at 7-8.

13 Edgecombe Answer at 8 n. 21.

14 Order Denying Certificate of Public Convenience and Necessity for Merchant Generating Facility, *In the Matter of Application of Friesian Holdings, LLC, for a certificate of Public Convenience and Necessity to Construct a 70-MW Solar Facility in Scotland County, North Carolina*, Docket No. EMP-105, Sub 0 at 16-25 (N.C.U.C. June 11, 2020)(attached as Exhibit 1).

CONCLUSION

For the reasons stated herein, the Commission should grant the NCUC's motion to answer Edgecombe's Answer, in order to provide the Commission with information that may assist in its decision-making process.

Dated this the 30th day of June, 2021.

Respectfully submitted,

NORTH CAROLINA UTILITIES COMMISSION
By Its Attorneys,

Louis S. Watson, Jr.
Jennifer Harrod
Derrick Mertz
North Carolina Utilities Commission
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By: /s/
Jennifer Harrod

CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing document upon each person designated on the official service list compiled by the Secretary in this proceeding.

Dated at this 30th day of June, 2021.

/s/

Jennifer Harrod

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. EMP-105, SUB 0

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Application of Friesian Holdings, LLC, for a Certificate of Public Convenience and Necessity to Construct a 70-MW Solar Facility in Scotland County, North Carolina	))))	ORDER DENYING CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR MERCHANT GENERATING FACILITY

HEARD: Wednesday, December 18, 2019, at 10:00 a.m., in Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

BEFORE: Chair Charlotte A. Mitchell, Presiding; and Commissioners ToNola D. Brown-Bland, Lyons Gray, Daniel G. Clodfelter, Kimberly W. Duffley, and Jeffrey A. Hughes.

APPEARANCES:

For Friesian Holdings, LLC:

Karen M. Kemerait, Fox Rothschild, LLP, 434 Fayetteville Street, Suite 2800, Raleigh, North Carolina 27601

Steven J. Levitas, Kilpatrick Townsend & Stockton, LLP, 4208 Six Forks Road, Suite 1400, Raleigh, North Carolina 27609

For Duke Energy Progress, LLC:

Jack E. Jirak, Associate General Counsel, Duke Energy Corporation, P.O. Box 1551 / NCRH 20, Raleigh, North Carolina 27602

For North Carolina Sustainable Energy Association:

Peter Ledford and Benjamin Smith, North Carolina Sustainable Energy Association, 4800 Six Forks Road Suite 300, Raleigh, North Carolina 27609

For North Carolina Clean Energy Business Alliance:

Benjamin L. Snowden, Kilpatrick Townsend & Stockton, LLP, 4208 Six Forks Road, Suite 1400, Raleigh, North Carolina 27609

For the Using and Consuming Public:

Tim R. Dodge and Layla Cummings, Public Staff - North Carolina Utilities Commission, 4326 Mail Service Center, Raleigh, North Carolina 27699-4300

BY THE COMMISSION: On November 7, 2016, in Docket No. SP-8467, Sub 0, the Commission issued Friesian Holdings, LLC (Friesian or the Applicant), a certificate of public convenience and necessity (CPCN) pursuant to N.C. Gen. Stat. § 62-110.1(a) and Commission Rule R8-64 for the construction of a 75-MW solar photovoltaic electric generating facility to be located on Leisure Road near Academy Road, Laurinburg, in Scotland County, North Carolina (the Facility). In addition, the Commission accepted the registration of the Facility as a new renewable energy facility pursuant to Commission Rule R8-66.

On August 2, 2018, Friesian filed a request to amend the CPCN previously issued for the Facility.

On May 15, 2019, in both Docket Nos. SP-8467, Sub 0 and EMP-105, Sub 0, Friesian filed a statement requesting that the Commission (1) allow Friesian to withdraw the requested amendment; and (2) consider a new application for a CPCN pursuant to Commission Rule R8-63 in Docket No. EMP 105, Sub 0, for this same facility (the Application). The Commission treated this filing as a request to cancel the previously issued CPCN in Docket No. SP-8467, Sub 0. And, on June 14, 2019, the Commission issued an order allowing withdrawal of the requested amendment, canceling the previously issued CPCN, and closing the docket.

Also on May 15, 2019, Friesian prefiled the direct testimony and exhibits of Brian C. Bednar, Friesian's Manager and Authorized Agent, as well as President of Birdseye Renewable Energy, LLC (Birdseye), an affiliate of Friesian. The testimony explained that Friesian seeks approval to build a 70-MW solar PV facility beginning in the summer of 2023, and that the Facility would interconnect with the electric transmission system owned by Duke Energy Progress, LLC (DEP or Duke).

On May 31, 2019, the Public Staff filed a Notice of Completeness stating that it had reviewed the application as required by Commission Rule R8-63(d) and considered the Application to be complete. In addition, the Public Staff requested that the Commission issue a procedural order.

On June 13, 2019, the Commission issued an Order that, *inter alia*, scheduled hearings, established a procedural schedule for the filing of petitions to intervene and of testimony, and directed Friesian to publish notice of the public hearing once a week for four consecutive weeks, beginning at least 30 days prior to July 26, 2019.

On June 21, 2019, the North Carolina Electric Membership Corporation (NCEMC) filed a petition to intervene, which the Commission granted on July 2, 2019. On July 18, 2019, NCEMC filed comments.

On July 18, 2019, Friesian filed the final, executed confidential Power Purchase Agreement (PPA) to replace the draft, confidential PPA that was originally filed as Confidential Exhibit No. 7 with the Application on May 15, 2019.

On July 23, 2019, DEP filed a petition to intervene, which the Commission granted on August 2, 2019.

On July 29, 2019, the North Carolina Sustainable Energy Association (NCSEA) filed a petition to intervene, which the Commission granted on August 20, 2019.

On August 1, 2019, the Public Staff filed a motion identifying and asking that the Commission consider several prehearing legal issues and seeking the establishment of a date for the filing of prehearing briefs and the suspension of the schedule for the filing of expert witness testimony. The intervention of the Public Staff is recognized pursuant to N.C.G.S. § 62-15(d) and Commission Rule R1-19(e).

On August 5, 2019, the North Carolina Clean Energy Business Alliance (NCCEBA) filed a petition to intervene, which the Commission granted on August 16, 2019.

On August 5, 2019, the Commission issued an Order suspending the procedural schedule previously established and allowing the parties to file briefs addressing the following legal issues:

> (1) The appropriate standard of review for the Commission to apply in determining the public convenience and necessity for a certificate to construct a merchant generating facility pursuant to N.C.[G.S.] § 62-110.1 and Commission Rule R8-63;
>
> (2) Whether the Commission has authority under state and federal law to consider as part of its review of the Application the costs associated with the approximately $227 million dollars in transmission network upgrades and interconnection facilities necessary to accommodate the FERC jurisdictional interconnection of the merchant generating facility, and the resulting impact of those network costs on retail rates in North Carolina; and
>
> (3) Whether the allocation of costs associated with interconnecting the Friesian project and any resulting additional capacity made available that is then utilized by State-jurisdictional interconnection projects is consistent with the Commission's guidance provided in the Commission's June 14, 2019, Order Approving Revised Interconnection Standard and Requiring Reports and Testimony, issued in Docket No. E-100, Sub 101, in which the Commission directed the utilities as follows: "to the greatest extent possible, to continue to seek to recover from Interconnection Customers all expenses . . . associated with supporting the generator interconnection process under the NC Interconnection Standard."

On August 26, 2019, Friesian, the Public Staff, DEP, and NCCEBA each filed briefs; on September 9, 2019, Friesian, the Public Staff, DEP, and NCCEBA and NCSEA (jointly) each filed reply briefs.

On October 3, 2019, the Commission issued an Order scheduling oral argument whereat the parties were to address the issues noted in the Commission's August 5 Order, and, additionally, the question of whether and, if so, how the July 14, 2017 decision of the U.S. Court of Appeals for the D.C. Circuit in *Orangeburg v. FERC*, 862 F.3d 1071 (2017), applies to the issues noted in the Commission's August 5 Order.

On October 21, 2019, this matter came on for oral argument as scheduled.

On October 25, 2019, the Commission issued an interlocutory order notifying the parties of the Commission's preliminary decision on the legal issues addressed by the parties' prehearing briefs and at oral argument. In sum, the Commission "agree[d] with the arguments of DEP and the Public Staff that the Commission may consider the costs for future network upgrades that are required to accommodate a proposed electric generating facility when considering an application for a CPCN pursuant to N.C.G.S. § 62-110.1 and Commission Rule R8-63," and noted that "[t]he Commission's final order on the merits of the CPCN application [would] include the Commission's full discussion and conclusions relevant to these issues . . . ." The Commission further ordered the procedural schedule resumed, setting a hearing for the purpose of receiving expert witness testimony for December 18, 2019, at 10:00 a.m., and allowing for the timely filing of supplemental direct testimony and exhibits.

On November 26, 2019, Friesian filed the supplemental direct testimony and corresponding exhibits of three witnesses: Charles Askey, Senior Project Manager in the Power Engineering & System Planning Group at Timmons Group; Brian Bednar; and Rachel Wilson, Principal Associate with Synapse Energy Economics, Inc. (Synapse).

On December 6, 2019, the Public Staff filed the joint testimony and exhibits of Evan Lawrence and Dustin Metz, both engineers in the Electric Division.

Also on December 6, 2019, and in lieu of testimony, DEP filed statement of position letters from Stephen De May, North Carolina President of Duke Energy, and Jack E. Jirak, Associate General Counsel for Duke Energy Corporation. These filings were unsworn and have not been subjected to cross-examination.

Statements of position letters were also filed in this docket by Helen Livingston in her individual capacity; Maggie Clark, Senior Manager of State Affairs, Solar Energy Industries Association (SEIA), on behalf of SEIA; James McDougald, Economic Development Director for the Town of Maxton; Ray Britt, Chairman of the Bladen County Board of Commissioners; and Bob Davis, Chair of the Scotland County Board of Commissioners.

On December 12, 2019, Friesian filed the rebuttal testimony and exhibits of witnesses Askey, Bednar, and Wilson.

This matter came on for hearing on December 18, 2019. Friesian presented the testimony and exhibits of witnesses Askey, Bednar, and Wilson, who testified as a panel. The Public Staff presented the testimony and exhibits of witnesses Lawrence and Metz, who also testified as a panel. None of the other intervenors, including DEP and NCEMC, presented witnesses or testimony, or offered any exhibits.

On December 20, 2019, the Public Staff filed a copy of the presentation given by the National Renewable Energy Laboratory (NREL) on its Carbon-free Resource Integration Report on the Duke System given to the Carbon Reduction Stakeholder Group hosted by the North Carolina Department of Environmental Quality (DEQ) at the Nicholas Institute on December 11, 2019, as a late-filed exhibit.

On January 8, 2020, DEP filed a response to a Commission question related to the increase in the cost of the network upgrades as a late-filed exhibit.

On February 10, 2020, Friesian, the Public Staff, and NCSEA separately filed proposed orders and briefs.

On April 16, 2020, DEP filed a supplemental late-filed exhibit.

On April 20, 2020, Friesian filed a Motion for Expedited Consideration of its Application.

On April 21, 2020, the Commission issued a Notice of Decision.

Based upon consideration of the pleadings, testimony, and exhibits received into evidence, the items upon which the Commission takes judicial notice, and the record as a whole, the Commission makes the following

FINDINGS OF FACT

1. Friesian is a limited liability company registered to do business in the State of North Carolina. Friesian is an affiliate of Birdseye Renewable Energy, LLC.

2. Friesian's Application for a CPCN authorizing the construction of a 70-MW solar photovoltaic electric generating facility to be located on approximately 544 acres in Scotland County, North Carolina (the Facility), was filed pursuant to N.C.G.S. § 62-110.1 and Commission Rule R8-63.

3. The Application has sufficiently completed State Clearinghouse Review.

4. While the Facility would be located in DEP service territory, the output from the Facility would be wheeled by DEP to NCEMC pursuant to a power purchase agreement (PPA) between Friesian and NCEMC for the sale of the output and renewable energy certificates (RECs) generated by the Facility. Friesian fails to sufficiently establish that the Facility's output is necessary to meet any of NCEMC's Renewable Energy and Energy Efficiency Portfolio Standard (REPS) compliance requirements to be given substantial weight in support of the Application.

5. Friesian fails to support the beneficial economic impacts that it asserts would flow to Scotland County with either sufficient detail or specific attribution to the Facility to be given substantial weight in support of the Application.

6. In its determination of need the Commission may consider factors other than Friesian's plan for the output of the Facility, including the long-term energy and capacity needs in the State and region, as well as system reliability concerns.

7. It is undisputed that the energy and capacity provided by the Facility are not otherwise needed to support any immediate or future load growth in the DEP East Balancing Area or the southeastern region of the State.

8. The placement of additional uncontrolled solar generating capacity in a region of the DEP system that currently contains significant existing solar generation may increase and exacerbate system operational issues already being faced by DEP's system operators and would provide minimal contribution to meeting winter peak load conditions.

9. The Facility proposes to interconnect with DEP's transmission network and begin commercial operation in December 2023. Friesian and DEP executed a Large Generator Interconnection Agreement (LGIA) in June 2019. Capacity on the transmission lines to which the Facility would connect is currently constrained, and load flow models indicate that additional generating capacity cannot be added in the pertinent portion of DEP's service territory without requiring substantial upgrades, including the construction of a proposed new 34.5-kV collector station and 230-kV breaker station, and the reconductoring of 63 miles of DEP transmission lines.

10. The generating plant of the Facility is estimated to cost $100 million to construct. The transmission network upgrades required to support the Facility (Network Upgrades) are estimated to cost $223.5 million to construct.

11. It is appropriate for the Commission to consider the total construction costs of a facility, including the cost to interconnect and to construct any necessary transmission network upgrades, when determining the public convenience and necessity of a proposed new generating facility.

12. The use of the levelized cost of transmission (LCOT) provides a benchmark as to the reasonableness of the transmission network upgrade cost associated with interconnecting a proposed new generating facility.

13. The potential for the Network Upgrades to lead to additional proposed generating capacity to be placed in service is too uncertain and speculative to be given substantial weight in support of the Application.

14. The Synapse Report does not provide sufficient evidence that either the Facility or the associated Network Upgrades would provide quantifiable ratepayer savings, emission reductions, or other environmental or health benefits.

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

16. Given the uncertainties stated in Findings of Fact Nos. 13, 14, and 15, more deliberate and comprehensive planning is the appropriate method, at this time, to identify and plan for upgrades to the system that are in the public interest.

17. The General Assembly, in enacting House Bill 589 (HB589), intended to establish a process to identify and support the location of additional renewable generation in the State in a manner that is most cost-effective to ratepayers.

18. Reform of the North Carolina Interconnection Procedures to involve the clustering of projects for interconnection study purposes is consistent with N.C.G.S. § 62-110.1(b) and is appropriate to help ensure that interconnection customers are receiving appropriate pricing signals to locate their projects in the most cost-effective interconnection locations, as well as to reduce congestion that otherwise results when the need for significant upgrades is identified.

APPLICABLE LEGAL STANDARD

Article 6 of Chapter 62 provides, in relevant part, that

> no public utility or other person shall begin the construction of any . . . facility for the generation of electricity to be directly or indirectly used for the furnishing of public utility service . . . without first obtaining from the Commission a certificate that public convenience and necessity requires, or will require, such construction.

N.C.G.S. § 62-110.1(a). In considering whether to approve a facility proposed under this statute the Commission must focus upon an element of public need for the facility and emphasize a policy that favors the orderly expansion of electric generating capacity that both creates a reliable and economical power supply *and* prevents the costly overbuilding of generation resources. *See State ex rel. Utils. Comm'n v. Empire Power*, 112 N.C. App. 265, 279-80, 435 S.E.2d 553, 561 (1994); *State ex rel. Utils. Comm'n v. High Rock Lake*

Ass'n, 37 N.C. App. 138, 140-41, 245 S.E.2d 787, 790, *disc. rev. denied*, 295 N.C. 646, 248 S.E.2d 257 (1978).

That said, the North Carolina Supreme Court has long recognized the flexibility of the public convenience and necessity standard, requiring that the distinct facts of each case be considered:

> In our opinion, these statutes give the Commission not only the authority but impose upon it the duty to pass upon [the matter] and to determine whether or not it is in the public interest . . . .
>
> The doctrine of convenience and necessity has been the subject of much judicial consideration. No set rule can be used as a yardstick and applied to all cases alike. This doctrine is a relative or elastic theory rather than an abstract or absolute rule. The facts in each case must be separately considered and from those facts it must be determined whether or not public convenience and necessity require [the action].

State ex rel. Utils. Comm'n v. Casey, 245 N.C. 297, 302, 96 S.E.2d 8, 12 (1957) (citation and quotation marks omitted).

Finally, the decision of whether to grant or deny a CPCN must rest upon substantive evidence; it cannot rest on speculation or sentiment. *Cf. Howard v. City of Kinston*, 148 N.C. App. 238, 246, 558 S.E.2d 221, 227 (2002). The burden is on the applicant to provide this substantive evidence and demonstrate that the CPCN should be granted.

The Commission has carefully considered and weighed all the evidence and arguments presented in this proceeding, and concludes that Friesian has failed to show that the Application is in the public interest and that public convenience and necessity requires that the Application be granted.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 1-3

These findings of fact are informational, procedural, and jurisdictional in nature and are not in dispute.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 4-8

The evidence supporting these findings of fact is found in the Application; the testimony of Friesian witnesses Askey, Bednar, and Wilson; and the joint testimony of Public Staff witnesses Lawrence and Metz.

Witness Bednar testified that Friesian entered into a power purchase agreement (PPA) with NCEMC on July 15, 2019, under which NCEMC will purchase all of the Facility's output. Witness Bednar also stated that the Facility will provide a significant number of renewable energy certificates (RECs) for use by NCEMC to comply with North Carolina's Renewable Energy and Energy Efficiency Portfolio Standard (REPS or Senate Bill 3), which among other things requires rural electric cooperatives and municipal electric suppliers to meet a 10% REPS requirement. Witness Bednar testified that these plans for the sale of the Facility's energy and capacity demonstrate its need. Tr. vol. 2, 21-22. Witness Bednar further offered the economic development impact to the communities of Scotland County, and other Tier 1 counties, as an additional reason to support granting the CPCN. Tr. vol. 2, 37.

In their joint testimony, Public Staff witnesses Lawrence and Metz asserted that having an executed PPA does not in-and-of-itself sufficiently demonstrate that a merchant generating facility is entitled to a CPCN; need is instead to be evaluated on a case-by-case basis. Tr. vol. 3, 116. They testified that the Commission had previously held that it is reasonable to require substantial evidence of the need for a merchant generating facility, and that a flexible standard for demonstrating need was appropriate, but that an executed PPA or other contractual agreement was not necessary. *Id.* at 114. Witnesses Lawrence and Metz further stated that the Public Staff has previously recommended approval of CPCN applications in the absence of a signed PPA. Tr. vol. 3, 165. They acknowledged that they were not aware of any prior case in which the Public Staff has taken the position that it is taking in the present case, that the PPA contract itself is not a sufficient demonstration of need. *Id.* at 174. They further acknowledged that they were not aware of any Commission precedent to this effect. *Id.* at 165.

Public Staff witnesses Lawrence and Metz also acknowledged that DEP's integrated resource plan (IRP) indicates a capacity need over the planning period but argued that "one cannot assume that any generation resource can be added to, and complement, the existing system just because reserve margins fall below a particular threshold," noting that the IRP is a capacity expansion model used to solve for multiple constraints and scenarios to help determine the generation resources needed to meet long-term load in the most economical manner. *Id.* at 117-18. They further testified that the DEP system is winter peaking and winter planning, and while DEP's IRP demonstrates a need for dependable capacity to meet winter peak loads, the addition of intermittent, non-dispatchable renewable solar facilities will provide minimal contribution to winter morning peak loads and limited value to grid operators. *Id.* at 118-19.

Witnesses Lawrence and Metz also testified that DEP had not previously identified the transmission lines in question as needing upgrades due to reliability issues in any of the reports issued by the NC Transmission Planning Collaborative (NCTPC). Witness Metz acknowledged that transmission in the area where the Facility is proposed to be located has been identified as constrained, meaning that it has limited ability to accommodate new generating resources, but argued that being constrained was not necessarily disadvantageous. He noted that constrained areas can occur throughout a utility's system, and the NERC standards require transmission planners to evaluate risk in order to target critical areas in the electrical grid for investments. Tr. vol. 4, 22-23.

Friesian witness Askey offered the results of an analysis conducted by the Timmons Group of the system impact study developed by DEP to evaluate the impacts to the system of adding the Friesian capacity at the proposed location. He interpreted the study to show that multiple line segments are loaded at over 95% or 100% of their contingency ratings, triggering the need for upgrades. He further noted that, even without additional generating capacity being added, the system is within five to ten percent of the contingency loading levels under the scenarios modeled, indicating that the system in that area is at the upper end of its operational range. Tr. vol. 2, 67-70.

Witness Askey stated that DEP's system is technically NERC-compliant but he believes that deferral of the Network Upgrades will leave the transmission system in southeastern North Carolina in a "maxed-out state" and could leave the grid more vulnerable to disruption than it would be if the Network Upgrades are constructed. *Id.* at 79-83.

Discussion and Conclusions

Commission Rule R8-63(b)(3) requires an applicant for a CPCN for a merchant plant to provide "a description of the need for the facility in the state and/or region, with supporting documentation." Additionally, before the Commission can award a CPCN for a generating facility, N.C.G.S. § 62-110.1(d) requires the Commission to consider the "applicant's arrangement with other electric utilities for interchange of power, pooling of plant, purchase of power and other methods for providing reliable, efficient, and economical electric service." Thus, a sufficient demonstration of need for a proposed new generating facility is fundamental to the Commission's decision of whether public convenience and necessity requires granting the CPCN.

As noted above, that demonstration generally is to focus on dual concerns: the orderly expansion of generation and capacity, and the prevention of costly overbuilding. And the required demonstration of need may also differ depending on whether the CPCN is sought for a generating facility by a regulated utility, a small power producer seeking to sell its output to the utility as a qualifying facility (QF), or a merchant generating facility.[1]

[1] For example, an electric public utility under Rule R8-61(b)(1) must, in addition to demonstrating need for a facility in its IRP, submit additional information supporting the need for the facility related to resource and fuel diversity, information on energy and capacity forecasts, and an explanation of how the proposed facility meets the identified energy and capacity needs. For QFs, the Commission has previously stated that federal law has essentially established a "public need" for their construction, based on the obligations established under the Public Utility Regulatory Policies Act of 1978 (PURPA) requiring a utility to purchase the output from a QF at its avoided cost rates. *See* Order on Motion to Dismiss*, Application of Empire Power Company for a Certificate of Public Convenience and Necessity Pursuant to G.S. 62-110.1(a),* No. SP-91, Sub 0 (N.C.U.C. Apr. 23, 1992). Because of the federally mandated purchase of the output of QFs, when Friesian first applied for a CPCN to develop and operate the Facility as a QF, the Commission did not consider the need for the Facility because the federal mandate takes the place of (or amounts to) need.

Similarly, considerations relating to the total costs of the Friesian project, discussed at greater length later in this order, were not operative in the Commission's determination of Friesian's application in Docket No. SP 8467, Sub 0. PURPA directs that for a QF which will sell its energy and capacity to a regulated utility, the total costs

To this end, the flexibility of the CPCN standard necessarily includes analyzing the need for the merchant generating facility to be placed not just within the State but a certain region, as well as evaluating whether the applicant has accurately assessed and met wholesale market needs. All said, it is "the duty [of the Commission] to pass upon [the project] and to determine whether or not it is in the public interest ." *Casey*, 245 N.C. at 302, 96 S.E.2d at 12; *see also* Order Granting Certificate*, Application of Rowan Generating Company, LLC, for a Certificate of Public Convenience and Necessity to Construct a Generating Facility in Rowan County, North Carolina*, No. EMP-3, Sub 0, 8 (N.C.U.C. Oct. 12, 2001) (stating that the Commission is "mindful that issues regarding the appropriate amount of merchant plant generation in the State remain to be decided.").

Friesian witness Bednar testified that the PPA with NCEMC is dispositive on the issue of need. As it traditionally has, the Commission affords some weight to the existence of the PPA as a demonstration of need. But the Commission agrees with Public Staff witnesses Metz and Lawrence that while having "[a]n executed PPA does demonstrate at least in part the potential [financial] viability of the project, [it] is not, in and of itself, a sufficient criterion on which to base a recommendation for approval or disapproval of a CPCN." Tr. vol. 3, 116. Rather, the existence of a PPA or other plans for sale of energy and capacity from the facility must be balanced against other existing factors that may be considered when determining the overall need for the Facility. As evidenced by prior Commission orders, the question may include the facility's compliance with State or federal laws,[2] the provision of lower-cost, economic power alternatives,[3] or whether the generation addition helps address reliability and service quality issues.[4]

Friesian witness Bednar also testified that the Facility would provide a significant number of renewable energy credits (RECs) for use by NCEMC to comply with North Carolina's Renewable Energy and Energy Efficiency Portfolio Standards (REPS).

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for the QF's project are immaterial so long as the price the regulated utility will pay to the QF for energy and capacity do not exceed the utility's own "avoided cost." If the total costs of the project cannot be recouped by the QF from charges that are calculated based on the purchasing utility's avoided cost, then any resulting loss is essentially invisible when viewed from the perspective of the total electricity generation, transmission, and distribution system.

[2] *See, e.g.,* Order Granting Certificate and Accepting Registration of New Renewable Facility, *Application of Atlantic Wind, LLC, for a Certificate of Public Convenience and Necessity*, No. EMP-49, Sub 0 (N.C.U.C. May 3, 2011; Order Granting Certificate of Public Convenience and Necessity with Conditions, *Application of Duke Energy Carolinas, LLC, for Approval of a Solar Photovoltaic Distributed Generation Program*, No. E-7, Sub 856 (N.C.U.C. Dec. 31, 2008).

[3] *See, e.g.,* Order Issuing Certificate of Public Convenience and Necessity with Conditions, *Application of Duke Energy Carolinas, LLC, for a Certificate of Public Convenience and Necessity to Construct a 402-MW Natural Gas-Fired Combustion Turbine Generating Facility in Lincoln County, North Carolina*, No. E-7, Sub 1134 (N.C.U.C. Dec. 7, 2017).

[4] *See, e.g.,* Order Granting Certificate with Conditions, *Application of Duke Energy Progress, LLC, for a Certificate of Public Convenience and Necessity to Construct a Microgrid Solar and Battery Storage Facility in Haywood County, North Carolina*, No. E-2, Sub 1127 (N.C.U.C. Apr. 6, 2017); Order Granting Certificate of Public Convenience and Necessity with Conditions, *Application of Duke Energy Progress, LLC for A Certificate of Public Convenience and Necessity to Construct a Microgrid Solar and Battery Storage Facility in Madison County, North Carolina*, No. E-2, Sub 1185 (N.C.U.C. May 10, 2019).

Friesian witness Wilson similarly stated that "NCEMC likely analyzed its . . . renewable generation supply needed for REPS compliance . . . and concluded that contracting with Friesian was a cost-effective way to meet those needs." But neither witness Bednar nor witness Wilson provided any corroborating evidence that the RECs that would be procured by NCEMC from Friesian are necessary for this purpose or that NCEMC has an actual need for RECs.

Relatedly, on July 18, 2019, NCEMC filed an unsworn comment in this docket, stating that "the [Friesian] Project — specifically, the parties' execution of the Project PPA — will simultaneously advance NCEMC's pursuit of BEF [a set of 'strategic business objectives' called 'A Brighter Energy Future'] and further its ability to achieve REPS compliance." But the letter filed by NCEMC is merely a restatement of NCEMC's three business objectives. It does not set out a specific, or even a general, strategy for attaining "A Brighter Energy Future," it contains no programs, policies, goals, objectives, or metrics, and it does not speak at all to NCEMC's targets for REPS compliance. In short, neither NCEMC nor Friesian presented sufficient evidence supporting the general assertion that the RECs generated by the Facility will facilitate NCEMC's compliance with its REPS obligations or meet its business objectives. *See* N.C.G.S. § 62-65(a).

Moreover, an examination of both NCEMC's most recent, verified NC REPS Compliance Plan, filed August 29, 2019, in Docket No. E-100, Sub 163, and the database in the North Carolina Renewable Energy Tracking System (NC-RETS) — both of which the Commission took judicial notice, *see* Tr. vol. 3, 78 — show that NCEMC has fully satisfied its RECs requirements without the Facility and, thus, does *not* need the Facility's RECs to achieve or maintain compliance for the near future. Indeed, the Friesian PPA, which was executed in June of 2019, is not referenced or identified in NCEMC's REPS Compliance Plan. Based on the foregoing, the Commission is not persuaded that the generation by the Facility of a significant number of RECs for use by NCEMC for REPS compliance demonstrates a need for the Facility in the region.

Friesian witness Bednar testified that the construction of the Facility will result in the creation of jobs and tax revenue in Scotland County. However, when the Commission pressed witness Bednar to provide support for the economic impact calculations, he was unable to do so. *See* Tr. vol. 3, 87-89.

On the topic of general need for new generating facilities in this region, the Commission notes that **[BEGIN CONFIDENTIAL]**

[END CONFIDENTIAL].

To this end, the Commission recognizes, as testified to by Public Staff witnesses Lawrence and Metz, that DEP's IRP indicates a capacity need over the planning period. However, the Commission also notes the Public Staff's testimony that "one cannot assume that *any* generation resource can be added to, and complement, the existing system just because reserve margins fall below a particular threshold[.]" *Id.* at 117 (emphasis added). Rather, the IRP involves a capacity expansion model that solves for multiple system constraints and scenarios ultimately to determine the generation resources needed to meet load projections over the planning period. As Public Staff witness Metz and Lawrence testified, and as Friesian witness Askey acknowledged on cross-examination, the DEP system is winter peaking and winter planning at this time, and while DEP's IRP demonstrates a need for additional capacity to meet winter peak loads, the addition of uncontrolled, intermittent solar generation will provide minimal contribution to winter morning peak loads and limited value to grid operators. *Id.*; *see also* Tr. vol. 2, 176-79. Thus, the Commission is persuaded by the Public Staff that the capacity need identified in DEP's IRP does not support a determination of need for the Facility.

Importantly, the Applicant has identified no reliability or service quality concerns necessitating the Facility. To the contrary, Friesian witness Bednar acknowledged that DEP states that the continued addition of solar generation in the DEP East Balancing Area would instead exacerbate existing reliability challenges and increase the potential for NERC compliance issues. *See* Tr. vol. 2, 165-67. He also acknowledged that DEP's growing experience in managing operationally excess energy and increasingly steep ramping requirements as additional unscheduled and uncontrolled solar generation is integrated into the system will increase the likelihood of emergency curtailments of solar generation in DEP. *Id.* at 167-69.

In sum, while the Commission gives some weight to the PPA as support for the need for the Facility, the Commission balances this evidence against the Applicant's failure to substantiate either the need for RECs generated by the Facility or its economic impacts, that the Facility is not likely to satisfy the capacity need identified in the DEP IRP, and that the Facility is not proposed to address reliability or service quality concerns and may actually exacerbate existing reliability and service quality issues being experienced in the DEP East Balancing Area. Based on the weight of the evidence, the Commission concludes that the Applicant has failed to demonstrate a need for the Facility.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 9-12

The evidence supporting these findings of fact is found in the Application and the testimony of Friesian witnesses Bednar and Wilson, and the joint testimony of Public Staff witnesses Lawrence and Metz.

According to the Application and as Friesian witness Bednar testified, the Facility would be constructed on approximately 544 acres in Scotland County, North Carolina, southwest of Laurinburg. The Facility would interconnect with the DEP transmission grid through a newly constructed 34.5-kV collector station directly adjacent to the DEP

Laurinburg-Bennettsville 230-kV transmission line. *See also* Application Exhibit 5. Witness Bednar testified that the Facility is expected to have a useful life of approximately 20 years and that the estimated construction costs for the generating plant are approximately $100 million. Tr. vol. 2, 19-21.

Witness Bednar also described the factors that Birdseye uses to identify the lowest cost sites for solar development in the State, including the Facility. He listed several favorable attributes present in the southeastern region of the State, including the abundance of open, flat land, low population density, proximity to transmission infrastructure, and favorable geology for the low-cost installation of solar foundations. Given these attributes, the region has already attracted significant solar development and is now severely constrained, with no new generation resources able to be added without substantial upgrades to DEP's transmission system. Tr. vol. 2, 24-34.

Public Staff witnesses Lawrence and Metz testified that under the Large Generator Interconnection Agreement (LGIA) executed between DEP and Friesian in June 2019 (*see* Public Staff's August 26, 2019 Prehearing Brief, Exhibit 1), the Facility requires approximately $4 million in Interconnection Facilities that are directly attributable to the Facility, including a new 230-kV breaker station. In addition, the Facility will also require extensive transmission network upgrades (Network Upgrades). The Network Upgrades are currently estimated to cost $223.5 million, and include reconductoring 63 miles, and uprating 10 miles, of DEP transmission lines. *Id.; see also* Tr. vol. 3, 122.

Witnesses Lawrence and Metz explained that the LGIA obligates Friesian to pay for the Interconnection Facilities, to provide DEP with security for the associated Network Upgrades, and to pay DEP's invoices for costs incurred to construct the Network Upgrades. Upon commercial operation and under Duke's Open Access Transmission Tariff (OATT), however, Friesian would be entitled to receive repayment from DEP of the entire balance of the Network Upgrades cost plus interest at the monthly interest rates posted by FERC. Under the LGIA, specifically, DEP must repay Friesian via lump sum cash repayment by the earlier of either DEP's next North Carolina general rate case or by December 31, 2027, with interest.

DEP then would seek to include approximately 30% of the costs in its FERC formula rates charged to its wholesale customers, resulting in an increase in transmission rates of approximately 10% above the average annual rate on a pro-rata basis across all of DEP's wholesale transmission customers. *Id.* at 101, 124-25. At the retail level, the remaining 70% of the costs would be recovered from DEP's retail customers through base rates, with 60% recovered through North Carolina base rates and 10% recovered through South Carolina base rates. Based on calculations completed by DEP, this cost recovery would result in an order of magnitude increase in retail rates for DEP's North Carolina retail customers of approximately 0.5% per year on a pro-rata basis. *Id.* at 124-26.

Public Staff witnesses Lawrence and Metz stated that the Public Staff generally evaluates interconnection and system upgrade costs in other merchant and utility CPCN proceedings. In several of those proceedings Public Staff noted some concerns regarding certain transmission-related costs but did not ultimately recommend denial of the CPCNs. Witnesses Lawrence and Metz also testified that for a number of these previously reviewed merchant generating facilities, however, several were proposed to be sited in the service territory of Dominion Energy North Carolina (DENC). *Id.* at 126-28.

Public Staff witnesses Lawrence and Metz argued that a levelized cost of transmission (LCOT) analysis provides a tool to evaluate the reasonableness of the upgrade costs associated with certain generating technologies. They cited to a 2019 study by Lawrence Berkeley National Laboratory (LBNL Study) that reviewed interconnection cost studies for renewable energy facilities on a nationwide basis, doing so by calculating LCOT value. Witnesses Lawrence and Metz explained that LCOT value is calculated by dividing the annualized cost of the required new transmission assets over the typical transmission asset lifetime by the expected annual generator output in MWh, with the outputs presented in a $/MWh value. The LBNL Study compiled transmission upgrade costs for 303 projects in the MISO region (amounting to a total of 49 GW); 338 projects in PJM (amounting to a total of 64 GW); and another 2,399 projects from various locations as reported to EIA. *Id.* at 129-30*; see also* Lawrence/Metz Exhibit 2.

In terms of solar generating facilities, the LBNL Study found that network upgrade costs for solar projects in MISO averaged $56/kW, with an LCOT value of $1.56/MWh; in PJM they averaged $116/kW, with an LCOT value of $3.22/MWh; and in the other locations (from the EIA data) they averaged $103/kW, with an LCOT value of $2.21/MWh. Witnesses Lawrence and Metz testified that, by comparison, the cost of the Network Upgrades is $3,186/kW, with an LCOT value of $62.94/MWh. Lawrence and Metz also compared the LCOT value for Friesian with that of other merchant generators in North Carolina for which the Commission had issued CPCNs. The LCOT values for the NTE Kings Mountain (Docket No. EMP-76, Sub 0) and NTE Reidsville (Docket No. EMP-92, Sub 0) facilities were significantly lower than the LCOT value projected for Friesian at $0.33/MWh and $0.92/MWh respectively. Tr. vol. 3, 130-33.

In rebuttal, Friesian witness Wilson testified that the LCOT analysis conducted by the Public Staff compared an individual project to average values presented by total volumes of renewable generation derived from large data sets. She further indicated that the Public Staff's calculation of LCOT for Friesian should be adjusted to include all of the projects that are behind Friesian in the interconnection queue and thus the Public Staff should have summed the total number of MW associated with those projects into its analysis, as well as the transmission costs associated with those projects. Witness Wilson testified that, if an additional 1,561 MW of projects that are interdependent on the Network Upgrades were included in the calculation, the cost of the Network Upgrades would fall within the range of the LBNL Study. Tr. vol. 2, 113-16.

Witness Wilson also testified that the Regional Energy Deployment System (ReEDS), developed by the National Renewable Energy Laboratory (NREL), considers generation and transmission capacity costs in its capacity-expansion model in order to minimize busbar and system-level costs for electric-sector planning purposes. Based on the 2018 Standard Scenarios presented by the ReEDS model, North Carolina in an optimized scenario could add another 900 MW of solar above current levels and associated transmission necessary for integration by 2022. *Id.*

Likewise, Friesian witness Askey testified that the Public Staff's LCOT analysis failed to consider additional generation that would use and benefit from the Network Upgrades. Witness Askey also stated that there are significant differences in LCOT calculations for Friesian compared to those for regional transmission organizations (RTOs) like MISO and PJM, which are regulated by FERC and outside of any state regulatory compact. In the context of RTOs, costs associated with transmission upgrades to accommodate new generation may be evaluated as part of system-wide baseline upgrades, as network improvements, and as directly assigned costs, and that the cost allocation may vary as a result of the different assignment of costs. Therefore, he concluded, it is difficult for any entity other than the RTO itself to determine the LCOT for a generating facility interconnecting to the grid. Witness Askey thus testified that comparing the LCOT for the Network Upgrades provides little discernable value. Tr. vol. 2, 91-92.

Upon questioning, however, witness Askey acknowledged that the largest transmission network upgrade that a merchant facility has accepted responsibility for within PJM was $125 million and that the project involved a gas-fired facility. Witness Askey indicated that a solar facility within PJM would not accept financial responsibility for network upgrades in the range of $425 million even under the model that subsequent projects coming online would contribute to the cost. Tr. vol 3, 83-84.

Discussion and Conclusions

The Commission may consider all costs that are required to construct a proposed electric generating facility, including the cost to construct the generating plant as well as the cost to construct interconnection facilities and network upgrades, when considering an application for a CPCN pursuant to N.C.G.S. § 62-110.1 and Commission Rule R8-63. To this end, the Commission, when evaluating whether public convenience and necessity requires granting the CPCN in this case, will consider the total construction cost of the Facility, which includes the cost of the generating plant, the interconnection facilities, and the Network Upgrades.

The plain language of N.C.G.S. § 62-110.1 authorizes the Commission to consider all costs associated with the construction of the proposed generating facility. Specifically, the statue provides that, "[a]s a condition for receiving a certificate, the applicant shall file an estimate of *construction costs in such detail as the Commission may require . . .* and no certificate shall be granted unless the Commission has approved the estimated construction costs *and* made a finding that construction will be consistent with the Commission's plan for expansion of electric generating capacity." N.C.G.S. § 62-110.1(e) (emphases added). When the language of a statute is clear and unambiguous it must be given its plain and definite meaning. *Carolina Power & Light Co. v. City of Asheville [(CP&L I)]*, 358 N.C. 512, 518, 597 S.E.2d 717, 722 (2004).

Nothing in the statute delineates or otherwise limits which costs that the Commission may consider when evaluating an application for a CPCN. *See Midrex Techs., Inc., v. N.C. Dep't of Revenue*, 369 N.C. 250, 258, 794 S.E.2d 785, 792 (2016) (courts must "give effect to the words actually used in a statute and should neither delete words used nor insert words not used ") (citation and quotation marks omitted). Thus, the Commission may consider all costs of a proposed facility, including those necessary to interconnect to the system and transmit the energy produced by the generating facility, i.e., all costs that are necessary to make useful operation of the facility at the outset. *See High Rock Lake Ass'n*, 37 N.C. App. at 140-41, 245 S.E.2d at 790 (the statute "directs the Utilities Commission to consider . . . the construction costs *of the project* before granting a certificate of public convenience and necessity for a new facility") (emphasis added).

The CPCN statute also obligates the Commission to analyze "the long-range needs for expansion of facilities including its estimate of the probable future growth of the use of electricity, the probable needed generating reserves, the extent, size, mix and general location of generating plants and arrangements for pooling power to the extent not regulated by the Federal Energy Regulatory Commission and other arrangements with other utilities and energy suppliers to *achieve maximum efficiencies for the benefit of the people of North Carolina* " N.C.G.S. § 62-110.1(c) (emphasis added); *see also State ex rel. Utilities Com'n v. Carolina Power & Light Co. [(CP&L II)]*, 359 N.C. 516, 522, 614 S.E.2d 281, 285 (2005). And, "[i]n acting upon any petition for the construction of any facility for the generation of electricity, the Commission shall take into account the applicant's arrangements with other electric utilities for interchange of power, pooling of plant, purchase of power and other methods for providing *reliable, efficient, and economical electric service*." N.C.G.S. § 62-110.1(d) (emphasis added). Without consideration of the total construction cost of a proposed generating facility, the Commission cannot ensure that any build-out will represent maximum efficiencies and provide cost-effective electric service for citizens and other ratepayers. *See CP&L II*, 359 N.C. at 522, 614 S.E.2d at 285.

Additionally, assuming *arguendo* that the language of the CPCN statute is ambiguous, the Commission concludes that the legislature must have intended that the Commission would consider all costs triggered by the siting of a generating plant. The "best indicia of that intent" includes "what the act seeks to accomplish." *Diaz v. Div. of Soc. Servs.*, 360 N.C. 384, 387, 628 S.E.2d 1, 3 (2006) (citation omitted); *accord CP&L I*, 358 N.C. at 518, 597 S.E.2d at 722 ("the reviewing court must construe the statute in an attempt not to defeat or impair the object of the statute "). The very reason the CPCN statute was enacted was to stop the costly overexpansion of facilities to serve areas that did not need them. *See High Rock Lake Ass'n*, 37 N.C. App. at 140-41, 245 S.E.2d at 790; *see also State ex rel. Utils. Comm'n v. Empire Power*, 112 N.C. App. 265, 280, 435 S.E.2d 553, 561 (1994).

This conclusion is further informed when reading "[the CPCN] standard *in pari materia* with N.C.G.S. § 62-2 which contains ten [now twelve] specific policies " *Empire Power*, 112 N.C. App. at 274, 435 S.E.2d at 557. Several of these policies support that the legislature intends the Commission to encourage cost-efficient siting of generation facilities, and thus that the Commission has the authority to consider all costs borne as a result of that siting decision.

Friesian and intervenors NCCEBA and NCSEA have argued that even if the Commission has the statutory authority to consider the transmission upgrade costs, any such consideration is preempted by the Federal Power Act, 16 U.S.C.S § 791a, et seq. (FPA or the Act), and FERC's jurisdiction under that Act. In brief, these parties contend that because FERC has sole jurisdiction to determine the manner in which the costs of the Network Upgrades will be paid and then assigned to various parties and interests, the Commission is thereby forbidden to consider both *the fact* that the Facility will cause such costs to be incurred and the *magnitude* of such costs in themselves or proportionally.

It is well-established that states have traditionally assumed jurisdiction and authority over the generation of electricity, and thus over decisions addressing the need for and the siting of all necessary facilities. *See Pacific Gas & Elec. Co. v. State Energy Resources Conservation and Development Comm'n*, 461 U.S. 190, 194, 75 L. Ed. 2d 752, 760 (1983); *see also FERC v. Elec. Power Supply Ass'n [(EPSA)]*, 577 U.S. ___, ___, 193 L. Ed. 2d 661, 668 (2016). Similarly, "states have traditionally assumed all jurisdiction [over the approval or denial of] permits for the siting and construction of electric transmission facilities." *Piedmont Environmental Council v. FERC*, 558 F.3d 304, 310 (4th Cir. 2009), *cert. denied*, 558 U.S. 1147, 175 L. Ed. 2d 972 (2010); *see also Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, Order No. 888, 75 F.E.R.C. ¶ 61,080, P.433 n.543, 61 Fed. Reg. 21,540, 21,626 n.543 (1996) ("Among other things, Congress left to the States authority to regulate generation and transmission siting."). Indeed, the FPA only gives FERC the authority to interfere with this jurisdiction — i.e., delegates to FERC federal jurisdiction which preempts state jurisdiction — when the transmission both falls inside a national interest corridor and one of five "carefully drawn" circumstances applies. *See* 16 U.S.C.S. § 824p(b)(1); *see also Piedmont*, 558 F.3d at 313-14.

Even in a traditionally state-occupied realm, however, Congress may supersede state or local action either explicitly or implicitly. *See generally Pacific Gas*, 461 U.S. at 203-04**,** 75 L. Ed. 2d at 765; *see also New York v. FERC*, 535 U.S. 1, 18, 152 L. Ed. 2d 47, 62 (2002); *Anderson v. Sara Lee Corp.*, 508 F.3d 181, 191 (4th Cir. 2007). There, State action is preempted only to the extent that it: "actually conflicts with federal law"; makes compliance with both federal and state law impossible; or "stands as an obstacle to the accomplishment and execution of the full purposes and objectives of Congress." *Pacific Gas*, 461 U.S. at 204, 75 L. Ed. 2d at 765 (citations and quotation marks omitted). And on review there is no "presumption one way or the other." *New York*, 535 U.S. at 18, 152 L. Ed. 2d at 63.

The FPA gives FERC the

> exclusive authority to regulate the sale of electric energy at wholesale in interstate commerce . . . [and] assigns to FERC responsibility for ensuring that "[a]ll rates and charges made, demanded, or received by any public utility for or in connection with the transmission or sale of electric energy subject to the jurisdiction of the Commission . . . shall be just and reasonable ."

Hughes v. Talen Energy Marketing, LLC, 578 U.S.__,__,194 L. Ed. 2d 414, 419-20 (2016); *see also* 16 U.S.C. § 824(b)(1). "This statutory text unambiguously authorizes FERC to assert jurisdiction over two separate activities — transmitting and selling [the power in the wholesale market]." *New York*, 535 U.S. at 19-20, 152 L. Ed. 2d at 63; *see also* 16 U.S.C. § 824(a).

The FPA also gives FERC jurisdiction over "any rate, charge, or classification, demanded, observed, charged, or collected by any public utility for any transmission or sale subject to the jurisdiction of [FERC]" as well as "any rule, regulation, practice, or contract affecting such rate, charge, or classification." 16 U.S.C. § 824e(a). Admittedly, this jurisdiction might well encompass allocating the cost of transmission facilities to retail ratepayers once those facilities have been constructed. *See S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d 41, 63-64 (D.C. Cir. 2014) (finding that this "does not interfere with the traditional state authority that is preserved by Section 201" of the FPA); *see also Standardization of Generator Interconnection Agreements and Procedures,* Order No. 2003, 104 F.E.R.C. ¶ 61,103 (2003).

But nothing in the FPA extends this jurisdiction over, and precludes, the States' consideration of the cost of required transmission network upgrades when determining the most prudent and cost-effective locations for generating facilities to be placed or whether the generation is needed in the first instance. *See Virginia Uranium, Inc. v. Warren*, 139 S. Ct. 1894, 1907, 204 L. Ed. 2d 377, 389 (2019) (typically, "any '[e]vidence of pre-emptive purpose,' whether express or implied, must be 'sought [and found] in the text and structure of the statute at issue.'"); *see also id.* at 1900, 204 L. Ed. 2d at 381 (". . . it is our duty to respect not only what Congress wrote but, as importantly, what it didn't write."). Nor do any of FERC's regulations or orders decidedly extend the same. *See generally Hillsborough County v. Automated Med. Labs., Inc.*, 471 U.S. 707, 717, 85 L. Ed. 2d 714, 724 (1985) ("We are even more reluctant to infer pre-emption from the comprehensiveness of [agency] regulations than from the comprehensiveness of statutes ").

Rather, "the law places beyond FERC's power, and leaves to the States alone . . . control over in-state facilities used for the generation of electric energy." *Hughes*, 578 U.S. at_, 194 L. Ed. 2d at 420 (citations omitted). This authority includes deciding *where* to site those generation facilities and "[t]here is little doubt that state public utility commissions or similar bodies are empowered to make the initial decision regarding the need for power." *Pacific Gas*, 461 U.S. at 205-06, 75 L. Ed. 2d at 760 (citations omitted); *see also Conn. Dep't of Pub. Util. Control v. FERC*, 569 F.3d 477, 481 (D.C. Cir. 2009) ("State and municipal authorities retain the right to forbid new entrants from providing new capacity . . . to limit new construction to more expensive, environmentally-friendly units, or to take any other action in their role as regulators of generation facilities without direct interference from the Commission"; it is the "consumer-constituents of state commissions . . . [that] will appropriately bear the costs of that decision, including paying more for system reliability from older and less efficient units."). This authority thus necessarily includes consideration of all the information that might impact that siting decision — including the construction of transmission system upgrades required to accommodate that additional generation.

FERC implicitly recognized the same in Order No. 888. *See* Order No. 888, 61 Fed. Reg. at 21,626 n.543. FERC further declared that its Final Rule "[was] not [to] affect or encroach upon state authority in such traditional areas as the authority over local service issues, including reliability of local service . . . [and] utility generation and resource portfolios." *Id.* at n.544 (cited in *New York*, 535 U.S. at 24, 152 L. Ed. 2d at 66).

Later, FERC issued Order No. 1000 in an effort to manage electric transmission grids on a regional level. *See Transmission Planning & Cost Allocation by Transmission Owning & Operating Pub. Utils.*, Order No. 1000, 136 F.E.R.C. ¶ 61,051 (2011). Therein, FERC recognized that States could continue to regulate electric transmission lines, explicitly stating:

> We acknowledge that there is longstanding state authority of certain matters that are relevant to transmission planning and expansion, such as matters relevant to siting, permitting, and construction. However, nothing in this Final Rule involves an exercise of siting, permitting, and construction authority. The transmission planning and cost allocation requirements of this Final Rule . . . are associated with the processes used to identify and evaluate transmission system needs and potential solutions to those needs. In establishing these reforms, the Commission is simply requiring that certain processes be instituted. This in no way involves an exercise of authority over those specific substantive matters traditionally reserved to the states, including integrated resource planning, or authority over such transmission facilities. For this reason, we see no reason why this Final Rule should create conflicts between state and federal requirements.

Order No. 1000 at ¶ 107; *see also MISO Transmission Owners v. FERC*, 819 F.3d 329, 336 (7th Cir. 2016) (it was a "proper goal" for FERC "to avoid intrusion on the traditional role of the States in regulating the siting and construction of transmission facilities"), *cert. denied*, 137 S. Ct. 1223, 197 L. Ed. 2d 463 (2017). It makes little sense then that the Commission would continue to have authority over the siting, permitting, and construction of all generation and transmission facilities — including for integrated resource planning purposes — but would not have the authority to consider all information that might impact the propriety of siting and constructing those facilities.

That conclusion is also consistent with and supported by language in the Supreme Court's decision in *Nantahala Power & Light Co. v. Thornburg*, 476 U.S. 953, 90 L. Ed. 2d 943 (1986). Though the question now before the Commission presents in a different procedural guise than the ratemaking proceedings that were at issue in *Nantahala*, Justice O'Connor's discussion of the distinction between a decision to purchase power and the price at which such power is purchased is nevertheless pertinent. In holding that this Commission impermissibly invaded FERC's exclusive jurisdiction when it attempted to establish retail rates that did not recognize and accept the FERC-determined allocation of low-cost "entitlement power," the Court noted that such a case was *not* the same as an unconstrained decision whether or not to enter into a transaction involving the purchase of power in the first instance, stating:

> Without deciding this issue, we may assume that a particular *quantity* of power procured by a utility from a particular source could be deemed unreasonably excessive if lower-cost power is available elsewhere, even though the higher-cost power actually purchased is obtained at a FERC-approved, and therefore reasonable, *price*.

Id. at 972, 90 L. Ed. 2d at 958 (emphasis in original). In other words, because the utilities in *Nantahala* were bound by FERC's allocation of available low-cost "entitlement power," they were not free to purchase a greater amount of such low-cost power, in preference to higher cost power from other wholesale suppliers, and consequently this Commission was likewise bound by such allocation in setting retail rates for such utilities.

The important distinction between the facts in *Nantahala* and those presented to the Commission here is that the decision posed to the utilities in *Nantahala* — that is, whether, and how much power, to purchase — was constrained by FERC determinations. In this case, however, the question to be decided is not so constrained. FERC has not ordered, directly or indirectly, that the Friesian facility be constructed, that it be sited at any particular location in the state, that its energy and capacity be sold to any particular purchaser, that such energy and capacity be sold at any particular price, or any other of the numerous other details of the Friesian project. Whether it is in the public convenience and necessity that Friesian be constructed at all is conceptually the same type of decision as that embodied in the above-quoted passage from *Nantahala*.

Two years after the *Nantahala* decision, in *Mississippi Power & Light Co. v. Mississippi ex rel. Moore*, 487 U.S. 354, 101 L. Ed. 2d 322 (1988), the Supreme Court reiterated that distinction, quoting from *Nantahala* and elaborating thus:

> Appellees seek to characterize this case as falling within facts distinguished in *Nantahala*. Without purporting to determine the issue, we stated in *Nantahala*: "[W]e may assume that a particular *quantity* of power procured by a utility from a particular source could be deemed unreasonably excessive if lower-cost power is available elsewhere, even though the higher-cost power actually purchased is obtained at a FERC-approved, and therefore reasonable, *price* . . . ." As we assumed, it might well be

> unreasonable for a utility to purchase unnecessary quantities of high-cost power, even at FERC-approved rates, if it had the legal right to refuse to buy that power. But if the integrity of FERC regulation is to be preserved, it obviously cannot be unreasonable for MP & L to procure the particular quantity of high-priced Grand Gulf power that FERC has ordered it to pay for. Just as Nantahala had no legal right to obtain any more low-cost TVA power than the amount allocated by FERC, it is equally clear that MP & L may not pay for less Grand Gulf power than the amount allocated by FERC.

Mississippi Power, 487 U.S. at 373-74, 101 L. Ed. 2d at 340 (internal citation omitted). Once again, the utility's decision whether, and how much power, to purchase was legally constrained by FERC's determination of the wholesale power allocation and the wholesale rates. Thus, in both *Nantahala* and *Mississippi Power* the matter of whether the affected utility would or would not, or should or should not, enter into an arrangement or agreement governed by FERC-established rules and orders had already been decided before the state regulatory bodies considered those arrangements in ratemaking proceedings.

The two cases stand for the proposition that a state cannot, through its retail ratemaking, attempt to nullify or vary an action taken or cost incurred by the regulated utility in consequence of and in compliance with FERC rules and determinations. By contrast, the question now before this Commission is, in substance, the same as would have been the case if the Mississippi Public Service Commission, cognizant of likely or anticipated FERC policy and practice, had decided that a CPCN should not be granted to permit Mississippi Power & Light Co. to participate in the joint construction of the Grand Gulf nuclear power plant.[5] And, accordingly, both *Nantahala* and *Mississippi Power* support the determination that whether or not power shall be procured at all — in this case by means of the construction of a new generating facility — is not limited by FERC's jurisdiction to determine the price of such power or the assignment of the costs of procuring it.

That said, no party disputes that southeastern North Carolina exhibits many attributes favorable for the development of solar generating facilities and that those attributes have resulted in significant solar development in that region. As a result, however, the transmission infrastructure in that portion of the DEP system is approaching a tipping point where additional generation in certain portions of the system will require significant upgrades to the network. The Commission shares the concern of the Public Staff regarding the appropriateness of siting additional generation in this region, in this

[5] It is of interest that the Mississippi Public Service Commission had originally granted a CPCN to Mississippi Power & Light Co. to participate in the Grand Gulf nuclear plant development before any of the matters in controversy in the case took place. This fact was noted by the Supreme Court as part of the factual background for the case, *see Mississippi Power*, 487 U.S. at 358-59, 364, 101 L. Ed. 2d at 330-31, 333-34, but there is nothing in the Court's decision to suggest that the Mississippi commission would have been intruding on FERC's jurisdiction had it simply chosen to deny the CPCN due to uncertainties or concerns about the ultimate costs that would have been incurred by or assigned to Mississippi Power & Light Co.

manner, and at this time, given the significant cost implications for the provision of electric service in North Carolina.

This concern is especially prudent given a comparison of the cost of comparable new solar energy facilities. To this end, the Commission views the LCOT analysis performed by the Public Staff as a benchmark of the reasonableness of the Network Upgrades relative to other similar transmission investments made to interconnect generating facilities in North Carolina.[6] And the LCOT analysis performed by the Public Staff shows just how unprecedented the cost of the Network Upgrades are to costs realized on a national basis. To that end, the Commission accepts that the calculated LCOT value of the Network Upgrades is $62.94 MWh, and far surpasses — it is 19.5 times higher than — the next highest mean range value reported by the Study for solar generating facilities calculated in MISO, PJM, or more broadly by EIA.[7]

The Commission has also reviewed the other North Carolina merchant plant projects discussed by Public Staff witnesses Lawrence and Metz, as well as the cost estimates for other Duke transmission projects as reported by the North Carolina Transmission Planning Collaborative (NCTPC) for the last 14 years — of which the Commission took judicial notice at the hearing. *See* Tr. vol. 3, 77-78. During those 14 years, the typical Duke transmission project had a mean cost in the range of $20 to $42 million, and the two most expensive Duke transmission projects were estimated to cost $85 million (Richmond to Fort Bragg Woodruff Street 230 kV line) and $95 million (Orchard Tie 230/100 kV tie station). The NTE Reidsville combined cycle plant's interconnection costs were estimated at $53 million. At an estimated construction cost of $223.5 million, the Network Upgrades would far and away be the single costliest transmission project in North Carolina in recent times, perhaps the most expensive ever.

No party through the time of the hearing — or any time prior to the filing of the parties' proposed orders — challenged the accuracy of the estimated $223.5 million plus

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[6] The Commission notes that the LBNL Study specifically states that the cost information in the report is generalized and should be used to inform high-level decisions and directives. LBNL Study at 27.

[7] The Commission also rejects, as Friesian argues, that uncertain future generation must be included when calculating the Friesian Facility's LCOT value. To the contrary, the LCOT analysis provides a useful comparison of actual incurred costs with the proposed transmission upgrade costs associated with specific generation resources. The LCOT analysis does not evaluate the loading of existing lines and whether they are fully subscribed, but instead provides a high-level comparison of costs that have been incurred around the nation to interconnect solar facilities. To assume that those lines can, or will certainly, accommodate additional generation resources goes beyond the scope of the LBNL Study. Insofar as the Commission were to accept DEP's estimate that the Network Upgrades will facilitate another 1,000 MW of generator interconnections (for a total of 1,070 MW) — which, as discussed further below, is uncertain — the cost would still be a relatively high $208/kW, still close to double the highest average cost of any of the groupings studied.

Likewise, the Commission agrees with the Public Staff that DEP's estimate overlooks the likelihood that these future projects will themselves require additional costly upgrades. Without studying the future projects comprehensively as part of a group or cluster, however, how much additional generation would be able to interconnect, and whether additional upgrade costs could impact the LCOT calculations, is uncertain.

interest.[8] Further, no party presented a witness, such as a Duke transmission expert, who could credibly address the potential that the actual cost for the Network Upgrades could be substantially more or less than $223.5 million, let alone be cross-examined. As such, the Commission accepts this estimate for the purposes of its decision making.

Also, the Commission is concerned about the potential for the Network Upgrades cost to increase further. Witness Bednar admitted this possibility. He discussed that labor competition for high voltage transmission and station work might well drive various costs even higher. *See* Tr. vol. 2, 39 (noting a "dramatic increase in interconnection costs"), 41-42 ("from 2017 to today, my sources within the [Engineering, Procurement, and Construction] community [state] that it's not unusual for high voltage and transmission costs to have risen 30 to 40 percent broadly, nationwide, based . . . upon shortages of general construction capacity "), 44-45. So too might an increase in material costs — witness Bednar candidly testified to a "5 to 10 percent increase on [the price of] cable and wire" every six months for "a cumulative in two and a half years of [a] 35 percent" cost increase. *Id.* at 45. He also acknowledged that each of Birdseye's other projects had seen their estimated interconnection costs increase. *Id.* at 46.

As such the Commission believes that the current estimated cost — already significant — could be understated. This belief also rests upon the scale and complexity of the upgrades in question, which, according to witness Bednar, includes crossing the

[8] On January 8, 2020, DEP filed a late-filed exhibit. That filing describes the basis for the almost doubling of costs from the initial estimate of $116 million: "a more detailed understanding of the scope and . . . developed using the Company's [recently] updated cost and scheduling systems." DEP also indicates therein that already-experienced increases in labor costs and costs due to environmental compliance factored into the $223.5 million estimate. In addition, a contingency of approximately $39.5 million was included in that estimate. January 8, 2020 DEP Late-Filed Exhibit, 1.

On April 16, 2020, DEP filed a supplemental late-filed exhibit. That filing sought to revise DEP's earlier estimate from $223.5 million to $187.3 million. The filing explains the basis for the $37.1 million reduction as driven primarily by: lowered vendor rates; material assumption variances, and the use of a wood product matting in lieu of a composite material in some locations; and reduction of the earlier contingency amount — which was itself $39.5 million.

But neither of these late-filed exhibits were subject to examination nor is it clear through what witness they might be introduced. Indeed, not only did no party, including DEP, choose to call an appropriate witness at the hearing to explain the bases for these now three estimates, the late-filed exhibits themselves are merely letters from Duke's Associate General Counsel, who was neither a witness in this case nor was ever likely to be one. Rather than assuage the Commission, the various swings in the estimated cost of the transmission network upgrades raise further concern.

Appendix B of the LGIA indicates that Duke will provide Friesian with "Class III Estimates" of the project's costs; the January 8, 2020 DEP Late-Filed Exhibit, however, describes its estimate as a "Class 4 estimate"; and the April 16, 2020 DEP Supplemental Late-Filed Exhibit describes its estimate as a Class 3 Estimate. It is the Commission's understanding that no matter whether the current estimate is a Class 3 or 4 type estimate, these types of estimates have low accuracy. Even the lower of the two most recent estimates allows, as a Class 3 Estimate, for the possibility that actual costs could be understated as much as 30 percent. In other words, the most recent estimate could still increase another $56 million — i.e., more than the most recent downward adjustment, and to a number higher still than the accepted $223.5 million estimate.

All said, whether $187.3 million, $223.5 million, or more, the Commission's analysis and ultimate conclusion would remain the same.

Cape Fear River four times, *see id.* at 40 & 47; the work having to occur during 12 weeks each year when the existing transmission lines in question can be taken out of service, where a single weather event, such as a hurricane or late snow or ice storm, has the potential to substantially delay the work, *id.* at 66-68, 124; and the short window — by the 2023 in-service date — in which to complete the upgrades. Each concern risks driving the cost higher.

The Commission recognizes and acknowledges the jurisdiction of the FERC with respect to the allocation of the costs associated with interconnecting a merchant generating facility such as the Facility. Nevertheless, the cost of the Network Upgrades dwarfs the costs of the generating plant, and the scale of the costs associated with the Facility relative to the size and projected revenue from the Facility raises concerns regarding economic viability of the project. Indeed, as witness Bednar admitted, the Homer and Fair Bluff projects — proposed generating facilities in the interconnection queue behind, and thus interdependent with, the Facility — would not be viable were they responsible for paying for the Network Upgrades. *See* Tr. vol. 2, 137-38.

For these reasons, the Commission concludes that siting the Facility in this region of the State and at the particular point of interconnection is not consistent with the requirements of N.C.G.S. § 62-110.1(d) for the provision of “reliable, efficient and economical electric service.”

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 13-15

The evidence supporting these findings of fact is found in the testimony of Friesian witnesses Askey, Bednar, and Wilson, and the joint testimony of Public Staff witnesses Lawrence and Metz.

Friesian witness Bednar testified that he expects “that the Friesian upgrades will be utilized by a minimum of 1,000 MW of later queued generation in the constrained area” of DEP’s system in which the Facility proposes to interconnect. Tr. vol. 2, 42. Witness Bednar further testified that he believes the Network Upgrades are necessary to support significant addition of solar generation resources in North Carolina due to the importance of the constrained area to further solar development in the State. Tr. vol. 2, 45. He stated that the Network Upgrades represent the only “immediately-actionable” proposal to address transmission-related constraints in this region of the State. Tr. vol. 2, 43-44.

Friesian witness Askey testified that data request responses from Duke identified approximately 1,561 MW that is currently interdependent on the Network Upgrades and that DEP stated that the “Friesian upgrades will at least partially facilitate the interconnection of more than 1,000 MW of additional generation.” Tr. vol. 2, 171-72. He conceded, however, that there may well be additional transmission network upgrades that are required to interconnect those other projects.

Friesian witness Wilson testified that the LCOT analysis conducted by the Public Staff is deficient in that it fails to take into consideration all of the projects that are behind

Friesian in the interconnection queue. Witness Wilson testified that, if an additional 1,561 MW of projects that are interdependent on the Network Upgrades were included in the calculation, the cost of the Network Upgrades would fall within the range of the LBNL Study. Tr. vol. 2, 113-16. Friesian witness Askey similarly testified that the Public Staff's LCOT analysis failed to consider additional generation that would use and benefit from the Network Upgrades. Tr. vol. 2, 91-92.

With respect to transmission constraints, Friesian witness Askey testified that, based on information provided by DEP, substantial transmission network upgrades will be needed to accommodate any new generating resources that are planned for the southeastern region of North Carolina. He testified that one of DEP's two 1235-MW combined cycle plants that are being evaluated for siting in Cumberland County is interdependent on and would benefit from the Network Upgrades. Tr. vol. 2, 266. He also stated that even if the DEP facilities being studied are not built, the Network Upgrades will be required to connect new generation resources in the State. *Id.* at 175.

In their joint testimony, Public Staff witnesses Lawrence and Metz acknowledged that Q399, the queue position of the second proposed combined cycle plant under consideration by DEP, is interdependent upon a significant portion of the Network Upgrades, as well as upon other significant transmission upgrades that may be required. The Public Staff refused to assign significant weight to the potential for the Network Upgrades to reduce the upgrade costs associated with future planned generation, however, because such an analysis is "heavily dependent upon future IRPs showing a continued need for additional capacity, contingencies such as the completion of the [Atlantic Coast Pipeline], as well as DEP demonstrating that [the] Q399 [project] is in the public interest in a CPCN application, as opposed to other resource alternatives." Tr. vol. 3, 132-33.

Friesian witness Wilson testified that a substantial buildout of new renewable energy resources is in the public interest for North Carolina ratepayers, notwithstanding the cost upon those ratepayers of the $223.5 million in Network Upgrades needed to support the Facility. In her direct testimony, witness Wilson cited a study in which she was a primary author entitled *North Carolina's Clean Energy Future: An Alternative to Duke's Integrated Resource Plan* (Synapse Report), included in her testimony as Exhibit RW-1. In support of her argument, witness Wilson testified that the type of generating portfolio recommended by the Synapse Report results in least cost energy and has additional benefits in the form of reduced air emissions and improved public health. Tr. vol. 2, 98. The Synapse Report was previously presented in Docket No. E-100, Sub 157 in response to the Commission's solicitation of comments on the 2018 IRPs submitted by DEP and Duke Energy Carolinas (collectively, Duke). The Synapse Report presents a "Clean Energy scenario" that models a significant addition of solar and storage resources to the Duke portfolio over the 15-year IRP planning horizon. *Id.* at 99-100. In the Clean Energy scenario, by 2033, there are 14 gigawatts (GW) of solar capacity and almost 6 GW of battery capacity added in the Duke service territories. *Id.* at 120.

Witness Wilson stated that the Clean Energy scenario represents a savings of almost $8 billion in terms of the net present value of revenue requirements over the duration of the 15-year planning period. Witness Wilson calculated that the health benefits of the Clean Energy scenario range from $195 to $440 million by 2024, due to avoided emissions of sulfur dioxide, oxides of nitrogen, and particulate matter. *Id.*

Witness Wilson also admitted that the Synapse Clean Energy scenario does not include the costs of any new transmission or upgrades to existing transmission required to interconnect renewables, including the Friesian project. *Id.* at 104, 120; *see also* Tr. vol. 3, 22-23. Further, she stated:

> My study is an economic one, and it looks at the least cost resource alternative to a comparison portfolio, which in this case is Duke's 2018 IRP, and determines that additional solar and storage resources are to the benefit of ratepayers. *It doesn't look at where those renewables are sited, [or] costs that it might take to integrate them*, and those costs are going to change over time, certainly.

Tr. vol. 3, at 25-26 (emphasis added).

Public Staff witnesses Lawrence and Metz explained that Governor Cooper's Executive Order 80 (EO80) states that North Carolina will strive to reduce greenhouse gas emissions (GHG) by 40% below 2005 levels by 2025. *Id.* at 133. EO80 further required DEQ to develop a Clean Energy Plan for the State. The Clean Energy Plan set a goal to reduce electric sector GHG emissions by 70% below 2005 levels by 2030 and obtain carbon neutrality by 2050. The Plan states that "NC's values such as electricity affordability, equity, and reliability should be fully considered." *Id.* at 134-35.

Friesian witness Wilson stated that achieving the goals of the DEQ Clean Energy Plan to reduce carbon emissions by 70% from 2005 levels by 2030 will be difficult if no additional solar resources can be interconnected in the areas dependent on the Network Upgrades. Tr. vol. 2, 108. She also testified that in order to achieve the types of emissions reductions that are being contemplated by the State of North Carolina, projects like Friesian must move forward. Tr. vol. 3, 26.

However, witnesses Lawrence and Metz testified that the Clean Energy Plan stated that the State is already on track to meet the goals of EO80. Regarding the current trend in the State's emissions, the report states:

> NC has already reduced significant amounts of GHG emissions from the electric power sector. The State's Clean Smokestacks Act, REPS, PURPA and market drivers have decarbonized the electric power sector at a faster pace than many other states. According to the most recent statewide inventory, GHG emissions from the electric power sector have declined 34% relative to 2005 levels. These reductions have been achieved in the absence of explicit carbon policies in the State. DEQ estimates that with full

> implementation of HB589, the GHG reduction level from the electric power sector will reach roughly 50% by 2025 and remain at this level out to 2030.

Id. at 134.[9]

Witness Metz also testified that DEP is working with the National Renewable Energy Laboratory (NREL) to determine the quantity of renewables that can interconnect to the system. Tr. vol. 4, 83. Witness Metz explained that there are two phases of the study:

> Phase 1 scope quantify the amount of carbon free electricity, estimate a curtailment[, ramping,] and system flexibility limits, evaluate its shifts, and daily seasonal net load timing supply. There's another phase coming because Phase 1 did not consider unit commitment and economic dispatch[,] system stability cost[,] or transmission impacts. Phase 2 will address those concerns.

Id. at 104.

Discussion and Conclusions

The Commission has carefully considered the evidence presented by the Applicant as to secondary benefits that would follow the construction of the Facility and concludes that, at this time, those benefits are too speculative and uncertain to support a determination that granting the CPCN is in the public interest.

Friesian asserts that the Network Upgrades would enable significant, additional future generating capacity to interconnect to the DEP network. Friesian points to a data request response received from Duke as support that the Network Upgrades would enable the interconnection of more than 1,000 MW of additional solar generation in the southeastern portion of North Carolina and the northeastern portion of South Carolina. *See* Tr. vol. 2, 122-23, 170-71; Tr. vol. 3, 136. The Duke data request response also states that "[b]ased on the assessment completed by DEP for interconnection requests received through September 30, 2017, there are 108 interconnection requests totaling 1,561 MW that have been identified as being interdependent on the upgrades assigned to Friesian." Friesian witness Wilson also testified that the Network Updates might facilitate the interconnection of an additional 900 MW of future solar generation as well. *See* Tr. vol. 2, 114-15.

But whether the additional generation will be developed and placed in service is subject to many variables in addition to interconnection cost. And there is nothing in the record from which the Commission can conclude that any one of the proposed generating facilities, much less all of them, will actually be constructed and placed in service. Without

[9] *See also* Tr. vol. 3, Official Exhibits, Public-Staff Frisian Panel Cross Examination Exhibit 7, DEQ Clean Energy Plan, at 267.

more, the Commission concludes that whether the Network Upgrades are or will be needed to enable significant, additional future generation is too uncertain to be given significant evidentiary weight by the Commission.

Friesian's assertion also includes that the Network Upgrades would facilitate and reduce the cost of DEP-owned proposed generating capacity. While the Load, Capacity, and Reserves Tables in DEP's 2018 IRP and 2019 IRP Update indicate the addition of two facilities with approximately 1,300 MW of combined cycle capacity in 2025 and 2027, these resources are undesignated at this time. DEP has not yet taken steps to determine resource alternatives to meet the undesignated need shown in the IRP, such as issuing a request for proposals (RFP) or filing a CPCN application for the facilities. DEP itself did not cite this benefit in its December 6, 2019 letters to the Commission, and DEP did not provide a witness in this proceeding to explain whether the Network Upgrades would benefit any planned DEP facilities.

Further, DEP's interconnection queue report dated January 27, 2020, shows that 12 interconnection requests are pending for a total of 14,560 MW of new, DEP-owned gas-fired generating plants, while DEP's IRP shows that the Company plans to build a much smaller amount of new gas-fired generation, 7,852 MW, through 2034. DEP does not have a CPCN granted or an application for a CPCN or any such plant pending. After reviewing the queue report, the Commission concludes that DEP has as yet no firm plans to build a gas-fired generator in Cumberland County but is instead studying several alternative sites throughout its territory, including sites in Wake, Wilson, Person, and Johnston Counties. The Commission therefore concludes that whether the Network Upgrades are or will be needed in the near term for any planned or proposed DEP generating facilities to provide service to DEP customers is likewise too uncertain to be given significant evidentiary weight by the Commission.

Friesian next calls upon the Synapse Report. But its Clean Energy scenario does not model the Friesian Facility or the Network Upgrades at all, making it of limited relevance. Also, the Report's Clean Energy scenario calls for the addition of more than 14 GW of solar generating capacity and almost 6 GW of battery capacity in the DEP and DEC territories over the next 15 years. Yet, insofar as the Commission were to accept DEP's estimate, the Network Upgrades would only *partially*[10] facilitate a small fraction, some 1,000 MW, of the solar generating capacity necessary to achieve the benefits claimed by the Synapse Report. For purposes of this proceeding, witness Wilson did not quantify the estimated benefits along these narrower, more pertinent, lines. More concerning, her Clean Energy scenario fails to include the cost of transmission network upgrades in its model. If these upgrades had been contemplated, the model likely would have produced different, and less favorable, results regarding the benefits to ratepayers. For each of these reasons, the Commission must afford limited evidentiary weight to the benefits included in the Synapse Report and discussed by witness Wilson.

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[10] *See* Tr. vol. 2, 56, 171 ("partial facilitation means that it will address the interdependencies, but there may be additional upgrades associated with those projects that [are required] to allow them to also interconnect").

Friesian's reliance on the DEQ Clean Energy Plan exhibits similar shortcomings. As the Public Staff notes, the Clean Energy Plan contains several recommendations to ensure the addition of reliable and affordable energy resources. These goals are statewide goals. Importantly, according to DEQ, the State's electricity sector is currently *on pace* to meet the Governor's EO80 emissions reduction target in 2025.

The Clean Energy Plan also contains several recommendations for stakeholder processes and comprehensive planning tools to achieve its goals to add cost-effective, affordable clean energy resources to North Carolina's generating portfolio. Specifically, it states:

> DEQ will enlist assistance from academic institutions to deliver a report to the Governor by December 31, 2020, that recommends carbon reduction policies and the specific design of those policies to best advance core values—including a significant and timely decline in greenhouse gas emissions, affordable electricity rates, expanded clean energy resources, compliance flexibility, equity, and grid reliability. The report will evaluate policy designs for the following: (1) accelerated coal retirements, (2) a market-based carbon reduction program, (3) clean energy policies such as an updated REPS, an EERS Short term and clean energy standard, and a (4) a combination of these policy options.

Tr. vol. 3, Official Exhibits, Clean Energy Plan, Public Staff-Friesian Panel Cross-Examination Exhibit No. 7, 213. Relatedly, Duke is also currently working with NREL to develop a Carbon-free Resource Integration Study to analyze and quantify the impact of new renewables on the DEP and DEC systems. *See* December 20, 2020 Public Staff Late-Filed Exhibit No. 1.

In sum, the Commission concludes that the benefits alleged by the Applicant to follow the construction of the Facility are too speculative and uncertain to support a determination that granting the CPCN is in the public interest.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 16-18

The evidence supporting these findings of fact is found in the prehearing brief of the Public Staff, the testimony of Friesian witness Bednar, and the joint testimony of Public Staff witnesses Lawrence and Metz.

Public Staff witnesses Lawrence and Metz testified regarding the need for comprehensive system planning, including the IRP process, the integrated systems operation planning (ISOP) process being developed by the utilities, distribution system planning, and competitive bidding processes like the CPRE Program or short-term market solicitations, rather than individual CPCN applications. The Public Staff believes that as rate pressures on electric customers continue to increase, comprehensive system planning will produce more efficient, cost-effective results than the piece-meal planning and construction approach currently being used. Tr. vol. 3, 137-38.

In its prehearing brief, the Public Staff noted that, in its June 14, 2019 Order Approving Revised Interconnection Standard and Requiring Reports and Testimony, in Docket No. E-100, Sub 101 (2019 Sub 101 Order), the Commission directed the utilities, "to the greatest extent possible, to continue to seek to recover from Interconnection Customers all expenses (including reasonable overhead expenses) associated with supporting the generator interconnection process under the NC Interconnection Standard." Prehearing brief at 11-12, quoting from 2019 Sub 101 Order at 18. The Public Staff noted the Commission's recognition of the arguments raised by Duke and others that the current serial study process was not sustainable and that comprehensive queue reform was necessary to better align the NC Interconnection Standard and Duke's FERC OATT with regard to studying projects, assigning upgrade costs, and collecting the costs of those projects. As such, the Commission found that the commitment by Duke to implement a stakeholder process to develop a group study proposal was reasonable and appropriate. *Id.*

Also in its prehearing brief, the Public Staff noted that a significant portion of the additional generating capacity that would benefit from the Network Upgrades would not be responsible for any of the network upgrade costs and that this disparity highlights the need for the queue reform measures proposed by Duke. *Id.*

Friesian witness Bednar acknowledged the benefits of comprehensive system planning but believed that deferral of the Network Upgrades is "ill-advised," noting that the timing of the IRP and ISOP processes creates risks of bringing new generation online, will result in additional study costs, and will increase the cost of the upgrades when they are ultimately constructed. Tr. vol. 2, 43. He cited the statements of position filed by Duke Energy, in which Duke stated that the need for the upgrades would not go away, and that "if the Friesian Network Upgrades are not constructed at this time, there will be a further substantial delay of any additional generating facilities in this area of DEP." *Id.* at 44, quoting from December 6, 2019, letter from Jack Jirak on behalf of DEP.

Witness Bednar testified that the Application involves unique circumstances and that the construction of the Network Upgrades will provide substantial benefits to the DEP transmission system and the State as a whole. Regarding the potential impacts of the Network Upgrades on the current queue reform efforts underway by Duke, witness Bednar testified that the Network Upgrades would minimize short-term challenges associated with Duke's queue reform plans, as well as allow for the interconnection of a substantial amount of renewable resources in the region. Tr. vol. 2, 46-47.

On cross-examination, Public Staff witness Metz stated that the Public Staff is generally supportive of a transition from the current serial queue to a grouping study model, and stated that on a going-forward basis, the grouping study approach would help to address some of the concerns raised in this proceeding. Witness Metz conceded that the transition process will be complex and that such a transition could be further delayed if the Network Upgrades are not approved. But he further stated that the transmission network upgrades required by the Facility are substantial and represent a tipping point. Tr. vol. 4, 42-47.

Discussion and Conclusions

The circumstances presented by the Facility illustrate the significant issues related to the continued development of renewable energy, as well as the implications for the electric systems, in North Carolina. As previously discussed in the Commission's 2019 Sub 101 Order, North Carolina has achieved nation-leading success in the siting and development of renewable energy generating facilities over the past decade, and the majority of the capacity added utilized existing transmission and distribution capacity on the DEP, DEC, and DENC systems. However, this success has come at a cost with the transmission system constraints in southeastern North Carolina and the system operational challenges that the utilities have begun to experience. In enacting HB589, the General Assembly both recognized these challenges and accordingly encouraged the siting of renewable energy resources in locations where the system could most efficiently accommodate them. *See* N.C.G.S. § 62-110.8(c).

The Commission recognizes the activities underway to consider and address the issues highlighted by the Facility. Both the DEQ Carbon Reduction Stakeholder Group and Phase 2 of the NREL Carbon-Free Resources Integration Study intend to analyze and quantify the impact of new renewables on the DEP and DEC systems and both are likely to result in recommendations. Similarly, there exists the promise of future queue reform that seeks to enable Duke to perform a cluster study process. *See* Order Requiring Queue Reform Proposal and Comments, *Petition for Approval of Revisions to Generator Interconnection Standards*, Docket No. E-100, Sub 101 (N.C.U.C. August 27, 2019). Each of these activities, in addition to the IRP and ISOP processes, can inform or support various long-term options being evaluated and provide a framework to identify the most cost-effective solutions. *See* N.C.G.S. § 62-110.1(d).

The Commission is unable to find sufficient support in the record for witness Bednar's assertion that the Network Upgrades are inevitable and that any delay in their construction will only result in increased costs to customers. To the contrary, the Commission instead credits the testimony of Public Staff witnesses Metz and Lawrence that the potential to defer costs may provide benefits to customers, depending on the carrying cost of capital, changes in commodity prices, and labor rates. Tr. vol. 3, 216-20. Additionally, due to technological changes, there also may be other alternatives identified that ultimately help to defer, minimize, or avoid altogether, the need for costly future network upgrades. *Id.* at 137. More importantly, the Commission sees value in deferring any decision related to upgrade of the system in the southeastern region of the State, pending the outcome of the activities underway.

Relatedly, in its October 23, 2019 Order Granting Motion to Delay in Docket No. E-100, Sub 101 (October 23 Order), the Commission specifically directed Duke to (1) file an updated version of its queue reform proposal as modified based on feedback from stakeholders, along with a redline version of the North Carolina Interconnection Procedures, or (2) notify the Commission that no modifications are needed. The October 23 Order also established a further procedural schedule, which was subsequently extended by order of the Commission in response to request by the parties, requiring parties to file comments on Duke's proposal and for Duke to file reply comments. Duke filed its proposal on May 15, 2020. The Commission recognizes the significance of the transition period in this process.

In sum, the Commission concludes that it is prudent to await the results of the work being undertaken in North Carolina on these issues and to consider the results of these studies and proposals in the context of the IRP process. The IRP process is the more appropriate forum to consider benefits associated with upgrades to the system, in addition to and in the context of reliability, resilience, and affordability.

CONCLUSION

After having carefully considered and weighed the evidence and arguments presented in this proceeding, the Commission concludes that Friesian has failed to persuade the Commission that granting the Application is in the public interest and required by public convenience and necessity and, therefore, denies Friesian's Application.

IT IS, THEREFORE, SO ORDERED.

ISSUED BY ORDER OF THE COMMISSION.

This the 11th day of June, 2020.

NORTH CAROLINA UTILITIES COMMISSION

Janice H. Fulmore, Deputy Clerk

Commissioner Lyons Gray did not participate in this decision.

Document Content(s)

Public Staff Miller Cross Exhibit 1

I/A

Transitional Cluster Phase 1
Customer Engagement Meeting

November 29, 2021



DUKE ENERGY.

Agenda

DUKE ENERGY

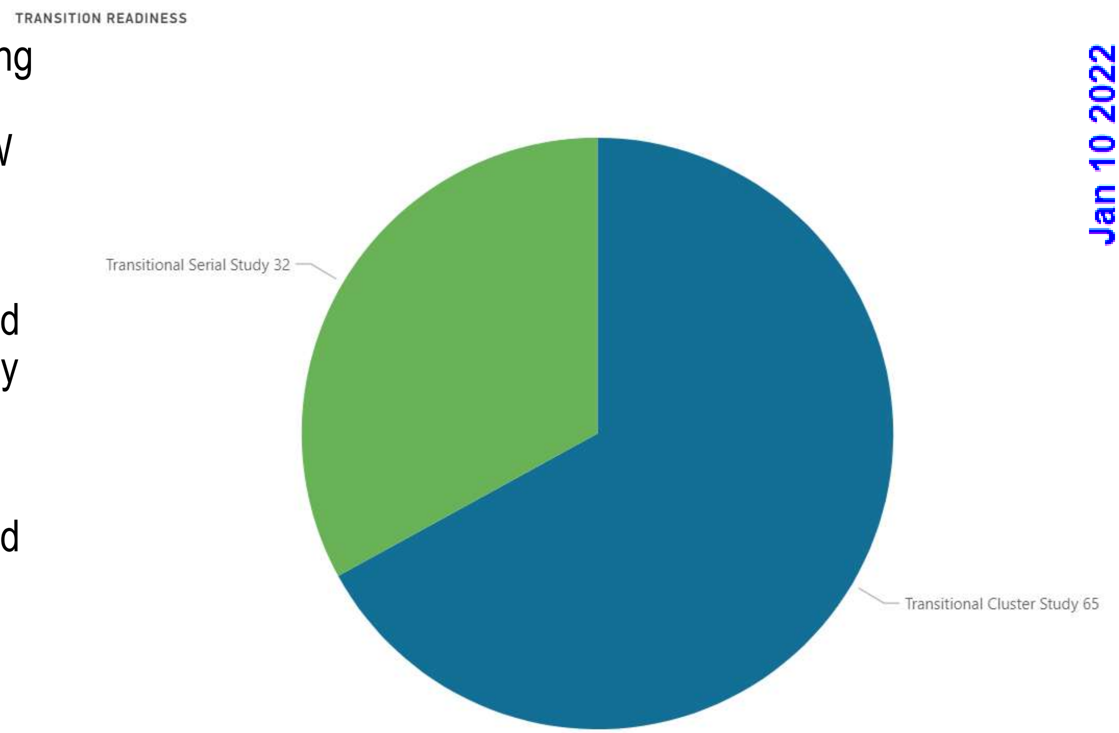
- Introduction and Safety
- Summary of Elections and Readiness Demonstration
- Projects Included in Transition Cluster Phase 1
- Allocation of Phase 1 Study Costs
- Summary of Base Case
- Timing and Next Steps
- Q&A

DEC and DEP Transitional Readiness

- Out of the 268 eligible DEC and DEP Interconnection Customers, 97 established readiness required for entering the Transition Serial and Transitional Cluster Study Processes representing 5,854.9 MW of the 19,385.5 MW eligible.

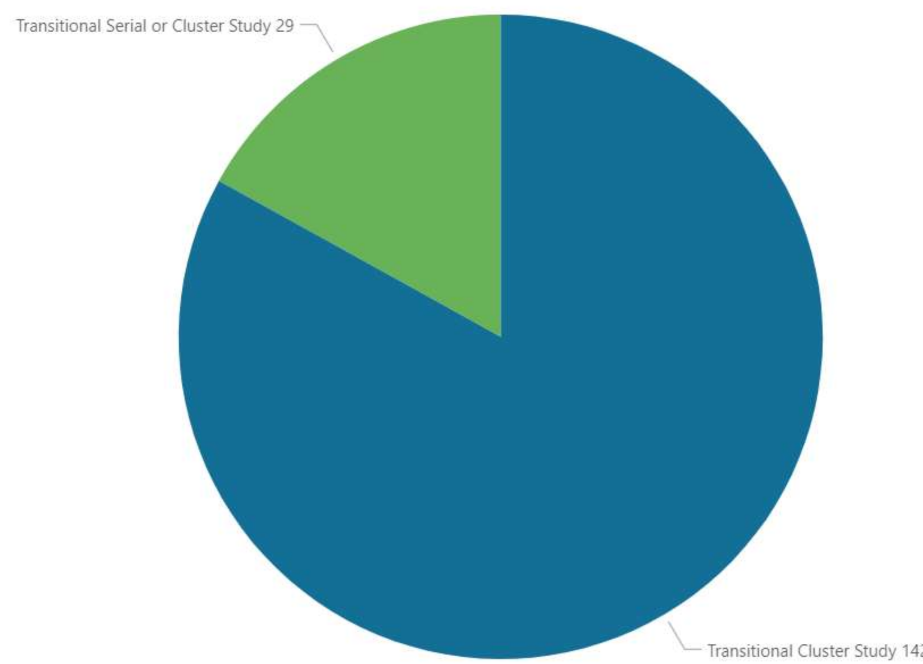
- 65 DEC and DEP Interconnection Customers established readiness required to enter the Transitional Cluster Study Process representing 5,241.1 MW.

- 32 DEC and DEP Interconnection Customers established readiness required to enter the Transitional Serial Study Process representing 613.8 MW.



DEC and DEP Transitional Withdrawals

- During the 60-day transition period (Sept 1 to Oct 31), 171 out of the 268 eligible DEC and DEP Interconnection Customers did not establish required readiness and voluntarily withdrew or were deemed withdrawn from DEC and DEP interconnection queues- representing 13,530.6 MW out of the 19,385.5 MW.



Current Transitional Cluster Metrics-OPCO, Jurisdiction, & Energy Type

	FERC Count	FERC MW	NC Count	NC MW	SC Count	SC MW
Transitional Cluster						
DEC						
Battery	1	50	1	3	-	-
CC	2	2244	-	-	-	-
PV	-	-	2	104	9	438
DEP						
Battery	3	74	-	-	-	-
PV	5	735	17	796	19	505
Transitional Serial						
DEC						
PV	1	20	4	184	2	77
DEP						
Battery	3	128	-	-	-	-
CT Uprate	5	101	-	-	-	-
PV	-	-	5	43	12	61

List of DEC Transitional Cluster Projects

Unique ID	Queue Number	D or T	State /FERC	OPCO	Facility State	Energy Source Type	Installed Capacity MW AC	Substation Name	Feeder Name	Facility County	Transmission Line	% Study Cost DEC
016298	SC2017-01133	Transmission	State	DEC	SC	Solar	39			Chester	Chester 100 kV Black	1.90
021177	180305_1522	Transmission	FERC	DEC	SC	Natural Gas	741	Riverview		Cherokee		24.16
023506	2018-10-09 03:35:00	Transmission	State	DEC	SC	Solar	74			Union	Jordan 100 kV	3.01
041456	2019-08-05 14:31:00	Distribution		DEC	NC	Battery	2.75	Reames Rd Ret 2408		Mecklenburg		0.75
048968	2017-11-21 00:00:00	Transmission	State	DEC	SC	Solar	69.75			Chester	Landsford 100 kV	2.88
062756	2017-11-15 14:36:00	Transmission	State	DEC	SC	Solar	32			Greenwood	Wilsons Creek 44 kV	1.68
065312	2018-06-26 15:18:00	Transmission	State	DEC	NC	Solar	69			Rowan	Albemarle 100 kV White	2.85
066052	2016-04-29 00:01:00	Transmission	State	DEC	SC	Solar	74.5			Chester	Landsford B and W	3.03
073054	2019-07-15 11:59:00	Transmission	FERC	DEC	NC	Natural Gas	1503			Davidson	Tyro 230kV	48.31
126062	2020-03-09 22:02:00	Transmission	State	DEC	NC	Solar	35			Alamance	Melville 44 kV	1.78
126066	2020-03-09 22:01:00	Transmission	State	DEC	SC	Solar	34			Greenwood	Thrush 100 kV	1.74
126078	2020-03-09 22:21:00	Transmission	State	DEC	SC	Solar	40			Laurens	Clinton B 100 kV	1.93
164382	2020-03-06 10:21:00	Transmission	State	DEC	SC	Solar	37.5			Laurens		1.86
165980	2020-03-06 10:27:00	Transmission	State	DEC	SC	Solar	37.5			Laurens		1.86
186466	2021-07-06 15:28:00	Transmission	FERC	DEC	NC	Battery	50			Gaston		2.25

List of DEP Transitional Cluster Projects (page 1)

DUKE ENERGY

Unique ID	Queue Number	D or T	State/ FERC	OPCO	Facility State	Energy Source Type	Installed Capacity MW AC	Substation Name	Feeder Name	Facility County	Transmission Line	% Study Cost DEP
002115	CHKLIST-8586	Distribution		DEP	NC	Solar	4.998	WEATHERSPOON 230KV	SEVENTH STREET 23KV	Robeson		0.440
002156	CHKLIST-8626	Distribution		DEP	NC	Solar	4.999	WEATHERSPOON 230KV	SEVENTH STREET 23KV	Robeson		0.441
004484	SC2015-00027	Distribution		DEP	SC	Solar	2	DILLON 115KV	INDUSTRIAL 23KV	Dillon		0.313
004538	SC2015-00047	Distribution		DEP	SC	Solar	10	DILLON 115KV	INDUSTRIAL 23KV	Dillon		0.654
004540	SC2015-00048	Distribution		DEP	SC	Solar	8.8	MCCOLL 230KV	INDUSTRIAL 23KV	Marlboro		0.603
005037	NC2016-02789	Distribution		DEP	NC	Solar	1.998	WHITEVILLE 115KV	BRUNSWICK 23KV	Columbus		0.313
005703	Q381	Transmission	State	DEP	NC	Solar	75			Montgomery	Blewett Plt-Tillery Plt 115KV	3.427
008286	NC2016-02928	Distribution		DEP	NC	Solar	4.992	WADESBORO BOWMAN SCHOOL 230KV	ANSONVILLE 23KV	Anson		0.440
010586	Q387	Transmission	State	DEP	NC	Solar	75			Caswell	Marion-Whiteville 230kV	3.427
016227	SC2017-01134	Distribution		DEP	SC	Solar	1.98	HARTSVILLE SEGARS MILL 230KV	FOXHOLLOW 24KV	Darlington		0.312
016257	SC2017-01144	Distribution		DEP	SC	Solar	1.98	HARTSVILLE SEGARS MILL 230KV	PINERIDGE 23KV	Darlington		0.312
016321	Q426	Transmission	State	DEP	SC	Solar	74.5			Chesterfield	Pageland 115kV Tap Line	3.405
016326	SC2017-01185	Distribution		DEP	SC	Solar	2	MCCOLL 230KV		Marlboro		0.313
016327	SC2017-01186	Distribution		DEP	SC	Solar	2	MCCOLL 230KV		Marlboro		0.313
016328	SC2017-01180	Distribution		DEP	SC	Solar	2	MCCOLL 230KV		Marlboro		0.313

List of DEP Transitional Cluster Projects (page 2)

Unique ID	Queue Number	D or T	State/ FERC	OPCO	Facility State	Energy Source Type	Installed Capacity MW AC	Substation Name	Feeder Name	Facility County	Transmission Line	% Study Cost DEP
017658	Q437	Transmission	State	DEP	SC	Solar	80	Marion 230-kV tie station		Marion	N/A	3.640
019139	SC2017-01153	Distribution		DEP	SC	Solar	2	MULLINS 115KV	MULLINS 23KV	Dillon		0.313
019170	SC2017-01178	Distribution		DEP	SC	Solar	2	MCCOLL 230KV		Marlboro		0.313
019176	SC2017-01183	Distribution		DEP	SC	Solar	2	MCCOLL 230KV		Marlboro		0.313
019261	NC2018-03096	Distribution		DEP	NC	Solar	6.201	LAURINBURG 230KV	AIR BASE 23KV	Scotland		0.492
019397	2018-10-09 04:07:00	Transmission	State	DEP	SC	Solar	75			Florence	Florence DuPont - SCPSA Hemingway 115kV	3.427
020832	SC2018-01271	Distribution		DEP	SC	Solar	2	MULLINS 115KV	MULLINS 23KV	Marion		0.313
021764	2018-10-09 04:09:00	Transmission	State	DEP	NC	Solar	8	Kinston DuPont 115kV		Lenoir	Kinston Dupont 115kV	0.569
021772	2018-10-09 04:10:00	Transmission	State	DEP	NC	Solar	8	Kinston DuPont 115kV		Lenoir	Kinston Dupont 115kV	0.569
021892	SC2018-01293	Distribution		DEP	SC	Solar	2	MULLINS 115KV	ACADEMY STREET 23KV	Marion		0.313
022128	2018-10-09 04:11:00	Transmission	State	DEP	NC	Solar	79.8			Lenoir	Lee-Wommack 230kV North	3.631
024078	2018-10-09 04:08:00	Transmission	State	DEP	SC	Solar	79.8			Kershaw	Robinson-Camden Jct 115kV	3.631
030708	2019-02-25 17:04:00	Transmission	State	DEP	NC	Solar	78.32			Nash	Person-Rocky Mount 230KV	3.568
032986	2016-07-07 00:00:00	Transmission	State	DEP	NC	Solar	80			Bladen	Cumberland -Whiteville 230KV	3.640
067146	2020-06-17 11:13:00	Transmission	State	DEP	SC	Solar	80			Darlington	Robinson Plant - Florence 230KV	3.640

List of DEP Transitional Cluster Projects (page 3)

DUKE ENERGY

Unique ID	Queue Number	D or T	State/ FERC	OPCO	Facility State	Energy Source Type	Installed Capacity MW AC	Substation Name	Feeder Name	Facility County	Transmission Line	% Study Cost DEP
119904	2020-06-23 12:46:00	Transmission	FERC	DEP	NC	Battery	20	Fort Bragg Longstreet Rd 230 kV		Cumberland		1.080
126008	2020-03-09 23:03:00	Transmission	State	DEP	NC	Solar	75			Wilson	Rocky Mount - Wilson 230	3.427
138340	2020-12-02 12:28:00	Transmission	State	DEP	NC	Solar	74			Robeson		3.384
169712	2021-05-18 09:35:00	Transmission	State	DEP	NC	Solar	80			Montgomery		3.640
169716	2021-05-13 11:25:00	Transmission	State	DEP	NC	Solar	80			Bladen	Cumberland - Delco 230 kV	3.640
170274	2021-04-09 10:35:00	Transmission	FERC	DEP	NC	Solar	275			Richmond		11.958
177122	2021-08-17 09:00:00	Transmission	FERC	DEP	NC	Solar	69.9			Scotland		3.209
179866	2021-06-08 11:29:00	Transmission	FERC	DEP	SC	Solar	150			Williamsburg	Florence - Kingstree 230 kV	6.626
179996	2021-06-08 11:30:00	Transmission	FERC	DEP	SC	Solar	74.9			Williamsburg	Kingstree - Sumter 115 kV	3.422
186310	2021-07-06 15:24:00	Transmission	FERC	DEP	NC	Battery	23.3			Durham		1.221
187960	2021-07-29 12:47:00	Transmission	FERC	DEP	SC	Solar	165			Darlington		7.266
191894	2021-08-18 14:35:00	Transmission	FERC	DEP	NC	Battery	30.5			Buncombe		1.528
200482	2020-03-06 15:10:00	Transmission	State	DEP	NC	Solar	60			Richmond		2.787
205718	2020-03-06 10:47:00	Transmission	State	DEP	SC	Solar	74.9			Marlboro		3.422

Allocation of Phase 1 Study Costs

DUKE ENERGY

Pre-Phase 1 costs

- Direct charged costs and overhead allocations (11/1/2021 – 11/30/2021)

Phase 1 study costs

- Direct charged costs and overhead allocations (12/1/2021 – end of Phase 1)

Projects withdrawn prior to 12/1 will be allocated their percentage of pre-phase 1 costs

Projects not withdrawn prior to 12/1 will be allocated their percentage of pre-phase 1 costs plus phase 1 study costs

Summary of Base Cases – DEC & DEP

DUKE ENERGY

- Transitional Cluster Base Case
  - Summer 2025 model
  - Winter 2025/26 model
  - Include existing and planned transmission
  - Include existing generation, those with Interconnection Agreements, and those still active in the Transitional Serial Process
- Transitional Cluster Study Case
  - Add Transitional Cluster interconnection requests
    - Summer model
      - All requests at full summer MW output
    - Winter model
      - All dispatchable (e.g. combined cycle plants, stand-alone batteries) at full winter MW output
      - Full battery-only output of solar/battery hybrid plants
      - Solar-only requests turned off

DEC/DEP Distribution

Substation	Feeder	Clustered Projects	Queued Ahead DER on Feeder (MW)	Total DER on Feeder (MW)	Existing Generation on Substation (MW)	Total Generation on Substation (MW)	Substation ONAN Rating (MVA)
Reames Rd Ret	01522408	2019-08-05 14:31:00 - 2.75MW	0	2.75	0	2.75	20
DILLON 115KV	T2750B04	SC2015-00027 - 2MW	6.2	18.2	6.2	18.2	30
		SC2015-00047 - 10MW					
HARTSVILLE SEGARS MILL 230KV	T3665B04	SC2017-01144 - 1.98MW	8.9	10.88	10.9	14.86	30
	T3665B05	SC2017-01134 - 1.98MW	0	1.98			
LAURINBURG 230KV	T2200B23	NC2018-03096 - 6.201MW	6.999	13.2	6.999	13.2	15
MCCOLL 230KV	T3760B01	SC2017-01186 - 2MW	0	6	8.9	27.2	15
		SC2017-01185 - 2MW					
		SC2017-01178 - 2MW					
	T3760B02	SC2015-00048 - 8.8MW	8.9	21.7			
		SC2017-01180 - 2MW					
		SC2017-01183 - 2MW					
MULLINS 115KV	T3030B01	SC2017-01153 - 2MW	2	6	2	8	30
		SC2018-01271 - 2MW					
	T3030B04	SC2018-01293 - 2MW	0	2			
WADESBORO BOWMAN SCHOOL 230KV	T1672B03	NC2016-02928 - 4.992MW	7.192	12.19	12.198	17.19	15
WEATHERSPOON 230KV	T2631B03	CHKLIST-8586 - 4.998MW	6.997	16.994	26.288	36.285	30
		CHKLIST-8626 - 4.999MW					
WHITEVILLE 115KV	T6670B03	NC2016-02789 - 1.998MW	6.997	8.995	16.947	18.945	30

Timing and Next Steps

- Phase 1 Starts December 1, 2021
- Phase 1 Ends February 28, 2022
- Phase 2 Readiness/Customer Engagement Window Starts March 1, 2022
- Phase 1 Report and Results Meeting by March 10, 2022
- Phase 2 Readiness/Customer Engagement Window Ends March 30, 2022
- Phase 2 Study Starts March 31, 2022

Certain pages are marked confidential but they were deemed NONCONFIDENTIAL during the hearing. ktm

Public Staff Miller Cross Exhibit 2

I/A

Juno Solar, LLC

Responses to Public Staff Data Request No. 2
Docket No. EMP-116, Sub 0
Date Sent: September 23, 2021
Requested Due Date: October 4, 2021

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Please provide any available responses electronically. If in Excel format, include all working formulas.

Topic: Miller Supplemental Testimony and Power Flow Analysis Filed on 9/14/2021

1. Ms. Miller states on p. 1 of her supplemental testimony that Juno's interconnection request is on hold due to interdependency in Duke's Transmission Interconnection queue. Please provide a list with the name, MW capacity, and query date for each project that Juno is interdependent with.

   Birch Creek has not been provided with a list of specific projects with which Juno is interdependent. However, it is Birch Creek's understanding that all new generator interconnection requests in the southeastern region of Duke Energy Progress's ("DEP") territory were listed as status "On hold – interdependency" at the time of Juno's initial interconnection request due to the network upgrade requirements associated with Friesian Holdings.

   Per Duke's queue reform, all projects that have an assigned queue position prior to August 20, 2021 are eligible to enter the Transitional Cluster Process. All the projects that are participating in the Transitional Cluster Process are interdependent with each other as they will be studied together as part of a "cluster" of projects. At this point in time, it has not yet been determined which projects are going to be part of the Transitional Cluster until after October 31, 2021 when the application period closes, or by extension which projects will have specific electrical interdependencies with one another.

2. On p. 1 of Ms. Miller's supplemental testimony she states that Juno performed a steady state power flow analysis. Please answer the following questions regarding the power flow analysis:
   a. When did Duke provide Juno the system representation (p. 1 ln 21)?

      DEP provided the base case models and auxiliary files on 6/7/2021.

      i. Define system representation.
         The system representation is defined as the configuration of the network, load, and generation in an electrical control area and neighboring systems as it is forecasted to be for the study year. This is also referred to as a base case model.

   b. Did Duke provide any other peak studies; seasonal or yearly? If so, please provide copies.

      No.

   c. Why did the Company choose Summer Peak 2024?

      The study year represents the year in which the request wants to be in service or earliest realistic in-service year. Due to significant solar generation in DEP, the primary study hour for generation interconnection studies is 1pm on a summer peak day, with customer load at 90% of peak and solar generation at 100%. Juno Solar chose to use the summer peak 2024 model to produce the most conservative scenario appropriate to the nature of the interconnection request, following DEP interconnection study guidelines as provided by DEP.

   d. Why didn't the Company choose a shoulder season or winter peak for the power flow analysis or even a different year such as 2023?

      Refer to the answer provided above.

   e. Please provide Juno's assumptions of what projects were or were not included in the power flow analysis.

      All of the state and federal projects that have firm transmission commitments, executed interconnection agreements, and have met financial obligations were considered in the model. Additionally, Juno Solar included all state and federal transmission interconnection requests that are active in the queue. Juno Solar excluded from the analysis projects that have been withdrawn, cancelled, or suspended from the queue. The rationale for their removal was to account for the uncertainty of these projects being brought back into the Transitional Cluster. Juno Solar decided it was appropriate to work with the best available information it had at the time the study was conducted. Refer to the Transmission Queue spreadsheet attached for the complete list of projects considered in the analysis.

i. For example, did Juno solar assume that all previous state and federal queue projects would be interconnected?

   Refer to the answer provided above.

   1. Please list the amount of MWs per queue and per service territory that are assumed in Juno's analysis.

      Refer to the Transmission Queue Report spreadsheet.

ii. Did Juno assume that the network upgrades from Friesian Holdings (Docket No. EMP-105) would be completed prior to the power flow analysis? Note: the reason for specifying EMP-105 in this question is because it is the most current individual project that could trigger a large transmission upgrade and is known to have contingent projects.

   Juno did not assume that the network upgrades from Fresian Holdings, LLC ("Friesian Holdings") would be completed prior to the analysis. However, the output of Fresian Holdings was accounted for in the model.

iii. Please include a list of state (North Carolina and South Carolina) and federal interconnection projects, their respective MW capacity, and node/substation injection point that Juno assumed in the power flow analysis.

Refer to the Transmission Queue Report Spreadsheet attached.

iv. Did Juno assume that all Duke Energy projects in the federal interconnection queue would be interconnected?

Refer to the answer provided in part e. of question number 2.

v. Did Juno remove Duke Energy's place holder projects?

Juno Solar does not understand what the Public Staff means by a "place holder project."

vi. Did Juno remove projects that were in a suspended state (state and federal interconnection queues)? If so, please list the projects and the rationale for their removal.

Refer to the answer in part e. of question number 2.

3. Did Juno exclude any other projects from the power flow analysis? If so, please provide a list of projects that it excluded.

   Additional projects that were excluded from the analysis were projects that did not have a Point of Interconnection assigned in the Transmission Queue Report. Refer to the Transmission Queue Report Spreadsheet.

4. Did Juno's power flow analysis and subsequent $16.84M in network upgrade costs assume that all projects before Juno interconnected and paid their respective system/network upgrade costs?

   The $16.84M assumed the mitigation of pre-existing overloads identified in the power flow analysis that are further exacerbated by the individual project's output, as well as new constraints triggered by the Interconnection Request solely. The power flow analysis considered network upgrades for projects with executed Interconnection Agreements and firm transmission commitments only.

5. Please define what Ms. Miller classifies as “transmission facilities” and “transmission system” on page 2, lines 8 through 10.

   A “transmission facility” includes any individual structure or equipment (line, transformer, breaker) that is used to facilitate the movement of electrical energy from a generation resource across the transmission system. The “transmission system” is referred to as the collective group of transmission facilities connected at 69 kV or above in Duke Energy Progress and neighboring control areas that facilitate the movement of electrical energy.

6. Please describe the parts of the system that Juno’s $16.84M will upgrade and describe the components in the study area.

   The $16.94M assumed that approximately 17 miles of the 115 kV circuit from DEP’s Fayetteville 115 kV Substation to DEP’s Fayetteville DuPont 115kV Substation and a segment of 115 kV line towards St Paul 115 kV Substation would have to be re-built using higher ampacity conductor and replacing all existing structures.

7. What class or level of estimate would Juno consider the $16.84M estimate?
   a. What is the tolerance range of that estimate?

      This is a “planning” or budgetary class estimate based on reasonable assumptions in line with utility practice and industry standards. This estimate is estimated to have a -20%/+100% variation.

8. Please confirm if the $16.84M is for the total upgrade costs and not Juno’s pro-rata or weighted share.

   The $16.84M assumed the mitigation of pre-existing overloads identified in the power flow analysis that are further exacerbated by the individual project’s output, as well as new constraints triggered by the Interconnection Request solely. Juno will only be responsible for a fraction of this amount that will ultimately be determined by the project’s individual distribution factors and MW impact on the limiting elements subject to the total MW impact on the limiting elements caused by other projects subject to cost allocation in the Transitional Cluster.

9. On page 1, Ms. Miller states that Juno is planning to participate in the Transition Cluster. What transmission study year is Juno assuming the Transition Cluster going to use?

    a. If applicable, please explain why Juno's power flow analysis did not use the same time period as the Transition Cluster.
    Birch Creek expects that projects in the Transitional Cluster window will use 2024 as a base year for studies.

10. Is it Juno's position that an LCOT greater than $4/MWh is unjust and unreasonable?

    Juno Solar is not taking any position about whether a LCOT value greater than $4/MWH is just and reasonable. An LCOT value greater than $4/MWh has not been proposed for the Juno Solar project, and it would be inappropriate for Juno Solar to opine about the reasonableness of an LCOT value that has not been proposed. That being said, Juno Solar has proposed a just and reasonable LCOT value that it believes should not result in any objection or concern from the Public Staff or the Commission.

    a. If so, please describe what factors would make it unjust and unreasonable and explain why?

    Please see Juno Solar's response to question 10 above.

    b. If not, what LCOT would be unjust and unreasonable, and please explain why.

    The Public Staff has repeatedly acknowledged that the Commission cannot deny CPCNs for all FERC-jurisdictional projects because of the reimbursement required by FERC's crediting policy, but instead must have a rational basis for denial in specific cases. In the Friesian docket, the Public Staff made it clear that LCOT is the appropriate test for evaluating such projects and supported its position with testimony that the Commission should utilize LCOT as the appropriate test. The Commission adopted the Public Staff's position and recommendation in its Order denying Friesian's CPCN. The Public Staff has acknowledged that CPCNs should be issued where the LCOT is within the range of appropriate market benchmarks. Juno Solar believes that $4.00/MWh is currently a reasonable amount that should not result in any objection or concern from the Commission or the Public Staff. While this question does not provide the Public Staff's position about what an unjust and unreasonable LCOT value might be, in the event that the Public Staff were to take the position that an LCOT of some amount above $4.00 is unreasonable, any such position would not be relevant to this case and would be based upon speculation about future upgrade costs for other projects.

11. On. p. 3 of Ms. Miller's supplemental testimony, she testifies that subsequent to the Friesian Holdings CPCN proceeding, transmission costs have general risen, due to 1) increasing materials and labor costs, and 2) tendency of these costs to increase with increased solar penetration. Please answer the following questions:

    a. Please provide all examples of transmission for solar facilities that Ms. Miller is referencing in her testimony that have met either of the two points listed above.

        i. For each of the examples, please provide the following: location, cost, MW capacity, year of study, year of expected commercial operation at the time of study, its LCOT, status of power purchase agreement, and if it has signed/agreed to the commercial terms to pay for the engineering and construction of the transmission line upgrades.

        The statement that interconnection costs have risen is based on industry observation and is not one that can be readily demonstrated on a project-to-project basis, as each project has its own unique interconnection requirements. Birch Creek has, however, observed systematically underestimated interconnection costs from the point of System Impact Study ("SIS") to Facilities Study ("FS"), where it is not unusual of late to see FS cost estimates roughly doubling the corresponding estimates made during the SIS phase, including project studied by DEP and DEC.

        Rising hard costs and labor costs across the nation presumably impact all interconnection costs. The Employment Cost Index maintained by the Bureau of Labor Statistics reflected a year-over-year increase of 2.6% as of the last quarter, and many commodity costs have risen steadily since early 2020, with steel commodity costs in particular seeing an over 200% price increase since March 2020 and contributing substantially to rising costs of electrical infrastructure.

        Furthermore, in the Friesian docket, DEP filed a late filed exhibit on January 8, 2020 to explain the reason for the increase in cost estimate for the network upgrades from $116 million (Initial Estimate) to $224.4 (IA Estimate). DEP provided information that the increase in costs is not applicable to just the Friesian project, but applies generally to transmission projects. DEP provided the following information:

- Labor costs – As was discussed extensively during the hearing, there has been an increase in labor costs for this type of work. This updated labor cost information was then used to develop a more refined estimate of the per mile labor costs that led to the updated estimate.

- Environmental costs – Similarly, the Company continues to experience increased costs for environmental compliance and such increased costs were factored into the IA Estimate. For instance, the Company's experience with more recent projects has demonstrated that matting costs (a significant cost item) were often far greater than initial estimates.

12. P. 4 of Ms. Miller's supplemental testimony contains a Q&A on other utility systems that need to be studied in which Ms. Miller references PJM. Has Juno considered other utilities other than PJM and the need to evaluate system impacts, i.e. Duke Energy Carolinas, LLC (DEC), or other utilities in South Carolina?

    a. Please provide documentation that ensures that this project is not triggering any affected utility studies.

    Through the course of Birch Creek's injection study, all tie lines to neighboring utilities were monitored for potential overloads and none were found due to Juno's power flowing into adjacent systems, other than PJM. It should further be noted that these potential violations delivering power into PJM are triggered by three natural gas projects amounting to 4,050 MW within a 5-bus radius of an area tie line between DEP and Dominion Virginia Power in PJM, with Juno minimally contributing to, but not causing, the potential violations.

    b. How many miles away from the applicant's point of interconnection is the nearest transmission node/point/interchange to DEC?

    Juno interconnects to the Richmond - Laurinburg 230 kV circuit between Laurell Hill and Richmond 500/230 kV Substation. Richmond Substation has a 500 kV area tie line between DEP and DEC that terminates at DEC's Newport 500 kV Substation. Approximately 75 miles separates the plant from the Newport substation.

c. Does Juno expect that DEP will notify Juno in the event that there is a potential affected utility?

Yes, the Juno project and broader system of identification and notification of affected system study requirements has been discussed with DEP on multiple occasions, and DEP has assured Birch Creek that it will be notified of affected system study needs identified through the interconnection and transmission study process.

13. On p. 5 of Ms. Miller's supplemental testimony she states that Juno will seek to contract with **[BEGIN ~~CONFIDENTIAL~~]** a PJM counterparty. Please answer the following questions:

a. Explain why this information is ~~confidential.~~

This is a unique offtake strategy for a project in the DEP footprint, and is thus commercially sensitive.

b. Explain the electrical wheeling charges from Juno solar to a delivery point in PJM.

Juno Solar will reserve firm transmission rights over the DEP system to a delivery point in PJM. Tariff rates for monthly firm transmission service are currently $1,859 per megawatt-month.

c. Provide Juno's estimated total wheeling charges for this facility on a monthly and annual basis.

Juno will reserve long-term firm point-to-point transmission which has a minimum increment of one year, so all calculations of charges are annual. These calculations are provided in ~~Confidential~~ Attachment A – Wheeling Charge Calculations.

d. Provide the source material and calculations with intact formulas for the wheeling charges.

These are provided in the attachment discussed in response to 13(c) and based on DEP's OASIS-posted projected transmission rates.

e. Will Juno's wheeling charges include the electric utilities total cost of transmission assets? If not, please explain why not.

Utilities cost of transmission assets are included in the Formula Rate used to calculate the Annual Transmission Revenue Requirement, and consequently the OASIS-posted transmission rates to which Juno will be subject in its wheeling costs.

f. For purposes of the wheeling charges calculation, provide the point of delivery in PJM in which the Applicant is hypothetically assuming.

Energy delivered from DEP to the PJM border is settled at the PJM “SOUTH” node (formerly “SOUTHIMP” for imports). The transmission “wheel” or wheels purchased will have a physical path of CPLE to PJM.

g. If DEP’s transmission costs increased, would the wheeling charges would also increase? **[END ~~CONFIDENTIAL]~~**

Wheeling charges would increase for future transmission purchases but not for transmission already reserved.

~~CONFIDENTIAL~~ - Entire Sheet

Firm PTP Purchase	*MW*	175

		2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
DEP Projected Cost	*$/MW-month*	2011	2092	2175	2262	2307	2353	2400	2448	2497	2547	2598	2650	2703
Annual Transmission Cost	*$000*	-	-	381	4,750	4,845	4,942	5,041	5,142	5,245	5,349	5,456	5,566	5,677

		2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
DEP Projected Cost	*$/MW-month*	2757	2813	2869	2926	2985	3044	3105	3167	3231	3295	3361	3428	3497	3567	3638
Annual Transmission Cost	*$000*	5,790	5,906	6,024	6,145	6,268	6,393	6,521	6,651	6,784	6,920	7,059	7,200	7,344	7,491	7,640

		2051	2052	2053	2054	2055	2056	2057	2058	2059	2060	2061	2062	2063	2064	2065
DEP Projected Cost	*$/MW-month*	3711	3785	3861	3938	4017	4097	4179	4263	4348	4435	4524	4614	4707	4801	4897
Annual Transmission Cost	*$000*	7,793	7,949	8,108	8,270	8,436	8,604	8,776	8,952	9,131	9,314	9,500	9,690	9,884	10,081	9,426

DEP Projected Rates
Escalated Rates
Partial Year