STATE OF GEORGIA

BEFORE THE
GEORGIA PUBLIC SERVICE COMMISSION

In Re:

Georgia Power Company's 2025 Integrated Resource Plan	))	**Docket No. 56002**
Georgia Power Company's 2025 Application for the Certification, Decertification, and Amended Demand-Side Management Plan	))))	**Docket No. 56003**

DIRECT TESTIMONY OF

MATTHEW RICHWINE

ON BEHALF OF NATURAL RESOURCES DEFENSE COUNCIL (NRDC),

THE SIERRA CLUB, AND

THE SOUTHERN ALLIANCE FOR CLEAN ENERGY (SACE)

MAY 2, 2025

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I. INTRODUCTION AND PURPOSE OF COMMENTS

Q PLEASE STATE YOUR NAME, POSITION, AND BUSINESS ADDRESS FOR THE RECORD.

A My name is Matthew P. Richwine. I am a Founding Partner at Telos Energy, Inc., located at 475 Broadway, Unit 6, Saratoga Springs, NY 12866.

Q PLEASE DESCRIBE TELOS ENERGY.

A Telos Energy, Inc. is a power systems analytics and engineering consulting firm specializing in power system planning, grid modeling, and analytics. Founded in 2019, Telos Energy provides detailed modeling, analysis, industry reports, and expert testimony for clients including utilities, grid operators, developers, public interest groups, and researchers, on the topics of power system planning, renewable integration, electric power reliability, resource adequacy, and electric power markets.

Q PLEASE SUMMARIZE YOUR PROFESSIONAL AND EDUCATIONAL QUALIFICATIONS.

A I am a founding partner of Telos Energy and have spent my career focused on power systems engineering, power electronic controls, system stability, and the integration of inverter-based resources like wind, solar and battery into grids large and small. Prior to Telos Energy, I had worked for General Electric in its Energy Consulting department as the Senior Manager of the Renewables and Controls team. I have been active in professional associations, including as Chair of the Institute of Electrical and Electronics Engineers (IEEE) Renewable Energy Machines and Systems

Subcommittee and contributing member of the North American Electric Reliability Corporation (NERC) Inverter-Based Resource Performance Working Group. I earned my Bachelor's and Master's degrees from Cornell University in Electrical and Computer Engineering and Systems Engineering with a focus on power systems. My professional experience and education is summarized in my resume, provided as Exhibit MR-1.

Q HAVE YOU PREVIOUSLY TESTIFIED AS AN EXPERT WITNESS BEFORE THE GEORGIA PUBLIC SERVICE COMMISSION?

A No, I have not.

Q HAVE YOU TESTIFIED BEFORE OTHER PUBLIC SERVICE COMMISSIONS IN OTHER JURISDICTIONS?

A Yes, I have:

- testified before the Michigan Public Service Commission in the matter of the application of DTE Electric Company in proceeding U-21193,
- provided subject matter expert commentary in Xcel Minnesota's 2020-2034 Upper Midwest Integrated Resource Plan, Docket No. E002/RP-19-368, and
- provided subject matter expert commentary in the matter of Minnesota Power's Application for Approval of its 2021-2035 Integrated Resource Plan, PUC Docket No. E015/RP-21-33.

Q ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS CASE?

A I am testifying on behalf of the Natural Resources Defense Council (NRDC), the Sierra Club, and the Southern Alliance for Clean Energy (SACE).

Q ARE YOU SPONSORING ANY EXHIBITS WITH YOUR TESTIMONY?

A Yes. I am sponsoring 16 exhibits in my testimony, listed in Table 1.

Table 1. List of Exhibits

Exhibit #	Title	Confidential
MR-1	Resume of Matthew Richwine	Public
MR-2	Company response to Staff discovery request STF-DEA-2-4	Public
MR-3	Company response to Staff discovery request STF-DEA-2-5	Public
MR-4	Company response to Staff discovery request STF-PIA-1-10	Trade Secret
MR-5	Company response to Staff discovery request STF-PIA-5-16	Trade Secret
MR-6	Company response to Staff discovery request STF-DEA-2-2	Trade Secret
MR-7	Rebuttal Testimony Georgia Power in response to Michael Goggin, regarding proactively building 500 kV lines. (2023 IRP Update Rebuttal Testimony - Main Panel - Public Disclosure Docket 55378, p.51)	Public
MR-8	ATC Load Interconnection Guide Revision 12	Public
MR-9	MISO Load Interconnection Whitepaper	Public
MR-10	Georgia Power IRP Rebuttal Testimony Grubb, Mallard, Robinson, Weathers June 8, 2022, page 38 (GPC 2022 Integrated Resource Plan Rebuttal Testimony 6-8-2022)	Public
MR-11	Company response to Staff discovery request STF-DEA-4-8	Public
MR-12	Company response to Staff discovery request STF-DEA-4-9	Public
MR-13	Company response to Staff discovery request STF-DEA-4-6	Public
MR-14	MISO Planning Modeling Manual Version 4.4	Public
MR-15	Company response to Staff discovery request STF-GS-1-4	Trade Secret
MR-16	FERC Order 827	Public

Q WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A I am testifying on behalf of NRDC, SACE, and Sierra Club regarding my analysis of the Transmission Plan put forth by Georgia Power Company ("GPC" or the "Company") in its 2025 Integrated Resource Plan ("IRP").

Q HOW IS THE REMAINDER OF YOUR TESTIMONY ORGANIZED?

A The remainder of my testimony is organized as follows:

- Transmission System Analysis Performed
- Impact of Large Loads on GPC's Strategic Transmission Projects
- Impact of Centralized Generation on GPC's Strategic Transmission Projects
- Impact of Variable Renewable Energy and Battery Storage on GPC's Strategic Transmission Projects
- Recommendations for the Commission

II. SUMMARY OF TESTIMONY AND KEY CONCLUSIONS

Q PLEASE SUMMARIZE YOUR TESTIMONY.

A My testimony evaluates GPC's transmission analysis as presented in its 2025 IRP, with a focus on the interaction between large loads, centralized generation, renewable energy, battery storage, and the Company's proposed Strategic Transmission Projects. My analysis finds that:

- Several proposed transmission projects are driven by large, location-specific load additions. If these large load additions fail to materialize, then several of the identified strategic transmission investments will be under-utilized in the ten-year planning horizon used for evaluation.

- Several Strategic Transmission Projects proposed by GPC in its 2025 IRP provide reinforcements needed to enable the retirement of the Bowen and Scherer plants. These transmission projects are expected to be completed by 2030 in GPC's plan, clearing the transmission constraint for the retirement of these plants after 2030.
- The interconnection of variable renewable generation projects, which tend to be dispersed across the transmission system, do not stress the transmission system as much as the interconnection of large, new, centralized generation projects. Several of the Strategic Transmission Projects enhance northbound transmission flows, enabling the interconnection of renewable generation in South and Central Georgia.
- GPC's modeling of solar and battery storage resources is unduly conservative and misaligned with industry best practices, understating their ability to support the grid and potentially overestimating transmission needs.

My testimony recommends that the Commission require greater transparency in transmission project justification, improved modeling of clean energy and storage resources, and conditional approval frameworks tied to actual system developments to ensure that transmission investments are both necessary and cost-effective.

III. TRANSMISSION SYSTEM ANALYSIS PERFORMED

Q WHAT IS THE REASON FOR PERFORMING THESE ANALYSES?

A These analyses are performed to evaluate how GPC's proposed Strategic Transmission Projects are being utilized by new large loads, planned generation upgrades, and planned generation growth in southern Georgia, which are anticipated to be mostly solar projects. By computing how much of each transmission project's capacity is needed to serve the additions of load and generation, the analysis helps identify which Strategic Transmission Projects are serving to benefit which load and generation additions. With this information, the Commission can better understand which transmission investments are low-risk, cost-effective, and appropriately aligned with system needs and which transmission projects risk being under-utilized if the anticipated load or generation projects fail to move forward or are delayed. It also supports a more transparent understanding of what changes to the system are driving transmission costs, and whether the proposed upgrades provide broader reliability or operational benefits to the grid.

Q WHAT IS THE SOURCE OF THE DATA YOU USED FOR THE TRANSMISSION ANALYSIS?

A The transmission analysis presented in this testimony is underpinned by data and modeling information provided by GPC as part of its 2025 IRP. The data sources include Technical Volume 3 – Transmission Planning[1] of GPC's 2025 IRP, which provides a high-level summary of transmission planning methodologies and descriptions of Strategic Transmission Projects[2]. In addition, detailed power flow cases for future planning years were also utilized for the transmission analysis[3]. These datasets form the technical foundation for Telos Energy's evaluation of how large loads, generation expansions, and solar resources utilize the transmission system. By drawing directly from GPC's power flow data and planning assumptions,

[1] Ga. Power Co., 2025 IRP Technical Appendix Volume 3 Transmission Plan.
[2] Ga. Power Co., 2025 IRP Technical Appendix Volume 3 Transmission Plan, Georgia Projects at 171.
[3] Ga. Power Co., 2025 IRP Technical Appendix Volume 3 Transmission Plan, Appendix H2.

Telos Energy's analysis complements and, where needed, challenges the Company's narrative regarding transmission development priorities in this IRP.

Q HOW WOULD YOU SUMMARIZE THE MODEL FILES PROVIDED BY GPC?

A As part of its 2025 IRP transmission analysis, GPC provided a set of power flow model files under a Critical Energy Infrastructure Information (CEII) non-disclosure agreement ("NDA"). These include base cases developed for system performance evaluation during peak and shoulder periods, as described in the 2024 Summer Operating Study[4]. The important cases, which Telos examined in its analysis, include "S" (Summer Peak) cases and "D" (Shoulder Load) cases. These represent the load and generation dispatch expected under typical summer peak and off-peak operating conditions across the Georgia transmission system. Each base case is built with full system topology, an economic but non-security-constrained generator dispatch, forecasted load levels, and regional transfers[5]. For each case, GPC includes representation of two power flow transfer directions external to the Southern Company territory and two resource operation modes to capture system variation. These cases serve as the foundation for both GPC's internal reliability assessments and the evaluation performed by Telos Energy, including assessments of how

[4] Ga. Power Co., 2025 IRP Technical Appendix Volume 3 Transmission Plan, 2024 Summer Operation Study at 95.
[5] Discovery Responses STF-DEA-2-4, STF-DEA-2-5.

Strategic Transmission Projects are utilized by new large loads and new generation. Each case included all of Southern Company territory and its neighbors.

Q HOW WOULD YOU DESCRIBE THE ANALYSIS THAT YOU PERFORMED?

A The analysis performed was a steady-state power flow analysis, which is used to evaluate power flow under a range of grid operating conditions, considering contingencies (a sudden loss of any element of the transmission system), to identify violations (or exceedances) of the transmission planning criteria. These violations fall into two broad groups: thermal violations and voltage violations. Thermal violations are those in which the power (current) carried by a transmission line or transformer exceeds its design limit. Voltage violations are those in which a specific location on the grid (like a substation) has a voltage outside of the range deemed acceptable by GPC for operating the grid in a reliable manner.

Telos Energy conducted its analysis using a subset of the GPC 2025 IRP model files, examining the "S" (Summer Peak) cases and "D" (Shoulder Load) cases. These represent the load and generation dispatch expected under typical summer peak and off-peak operating conditions across the Georgia transmission system. The analysis looked specifically at the beginning (2025) and ending (2034) study years to evaluate changes to the system over the ten-year planning period. The analysis focused on evaluating how Strategic Transmission Projects are impacted by different system conditions and drivers.

A Distribution Factor (DFAX) analysis was performed to measure how power flows over each transmission line in the grid when power is injected at one location on the grid and the same power is absorbed in another location. Three power transfer scenarios were evaluated:

- GPC All Generation → GPC Large Loads
- GPC Renewable Generation → GPC All Loads
- GPC Key Centralized Generators → GPC All Loads

GPC Large Loads, GPC Renewable Generation and GPC Key Generators are listed in Tables 2-4 below.

In these studies, the Strategic Transmission Projects identified in the IRP were specifically monitored to evaluate their loading under each scenario for both N-0 and N-1 system conditions. Renewable resources were assessed as a collective block, while Key Centralized Generators and Large Loads were evaluated individually. The analysis was limited to the 10-year planning horizon case (2034) to assess the highest forecasted loading conditions. Two operating conditions were used:

- Summer Peak – SNWE and NSWE variants
- Shoulder Load – SNWE and NSWE variants

These cases were selected to provide insight into the system's behavior under both peak and off-peak conditions, without simulating generator outages. This methodology provides a focused assessment of how GPC's proposed transmission projects perform under a range of realistic, stressed conditions, and how they are impacted by the major drivers of transmission system use in the IRP: large load customers, solar integration, and conventional generation.

Q CAN YOU IDENTIFY THE INDIVIDUAL LARGE LOADS, KEY CENTRALIZED GENERATORS, AND RENEWABLE GENERATION?

A Yes. The following Tables 2, 3, and 4 list the 29 GPC Large Loads, 41 GPC Key Generators and 58 GPC Renewable Generation Projects used for the DFAX analysis. The large loads evaluated included any specific load modeled that is greater than 100 MW included in the 2034 power flow cases but not included in the 2025 power flow cases provided by GPC. The renewable generation was any generator with a machine ID of S1, S2, or S3 in the power flow cases provided by GPC. The values in the tables were generated from the 2034 power flow cases.

Table 2: GPC Large Loads Analyzed in the DFAX Analysis

PSSE Bus Number	PSSE Bus Name	PSSE Bus Voltage	Load MW
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]

PSSE Bus Number	PSSE Bus Name	PSSE Bus Voltage	Load MW
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
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[redacted]	[redacted]	[redacted]	[redacted]
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[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]

Table 3: GPC Renewable Generation Projects Analyzed in the DFAX analysis

PSSE Bus Name	PSSE Bus Number	PSSE Generator ID	Generator Max MW
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
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[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]

PSSE Bus Name	PSSE Bus Number	PSSE Generator ID	Generator Max MW
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
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[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]

PSSE Bus Name	PSSE Bus Number	PSSE Generator ID	Generator Max MW
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]

Table 4: Centralized GPC Generation Analyzed in the DFAX analysis

PSSE Bus Name	PSSE Bus Number	PSSE Generator ID	Generator Max MW
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
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[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]

PSSE Bus Name	PSSE Bus Number	PSSE Generator ID	Generator Max MW
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
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[redacted]	[redacted]	[redacted]	[redacted]

Q WHAT ARE THE LIMITATIONS OF THE ANALYSIS?

A While the transmission analysis conducted by Telos Energy provides valuable insights into how GPC Large Loads, GPC Renewable Generation, and GPC Key Generators interact with Georgia Power's Strategic Transmission Projects, there are several important limitations and considerations that should be acknowledged when interpreting the results.

Limited Number of Cases Analyzed: The analysis was based on a focused subset of Georgia Power's 2034 power flow models. Specifically, the review included the Summer Peak and Shoulder Load cases under SNWE and NSEW transfer scenarios.

These cases represent stressed and off-peak operating conditions but do not capture the full range of system states or operational variability that could occur across the year. Importantly, Telos reviewed the transmission violations listed in GPC's Technical Volume 3 Appendix H Identified Problems and Solutions and found that the majority of reported violations occurred in the summer peak and shoulder cases. As such, these cases were selected as the most relevant for focused analysis, given that they reflect the most binding system conditions identified by Georgia Power itself.

Assumed Contingency Set: Telos applied a standard set of N-1 contingencies, assuming single-element outages within and tying into the state of Georgia and monitored facilities across the Southern Company system at 100 kV and above. While this is a reasonable industry-standard assumption, some utility-specific contingency definitions or protection schemes may not be reflected in the analysis.

Only Post-Project System Conditions Modeled: The 2034 power flow cases utilized for analysis already included the full set of Strategic Transmission Projects in service, meaning that Telos did not assess "before and after" system conditions. Consequently, the analysis did not evaluate how the system would perform in the absence of these projects, nor was it able to determine whether alternate solutions (e.g., non-wires alternatives or staging strategies) might have been sufficient.

In summary, while the analysis offers a credible evaluation of how Georgia Power's proposed transmission infrastructure functions under key scenarios, it should be viewed as a complement—not a substitute—for a comprehensive system planning study. The results are most useful in identifying trends, sensitivities, and project utilization patterns under peak and off-peak conditions, but should not be interpreted as an exhaustive assessment of all potential system behaviors or needs.

IV. IMPACT OF LARGE LOADS ON GPC'S STRATEGIC TRANSMISSION PROJECTS

Q HOW WOULD YOU DESCRIBE THE REPRESENTATION OF NEW LARGE LOADS IN GPC'S TRANSMISSION PLANNING MODEL?

A As stated in GPC's 2025 IRP, the Company is forecasting an unprecedented level of large load growth over the next decade. Specifically, 7.3 GW of committed large loads have formally requested service from GPC as of June 2024, and the Company's broader long-term large load economic development pipeline totals approximately 22.8 GW of potential additional load.[6] Table 5 shows the list of these large loads and compares the power flow case locations provided by GPC with data from the 2034 power flow cases[7]. As shown in Table 5, 6,239 MW of large load power flow locations were provided by GPC. In the 2034 power flow cases used for the DFAX analysis and provided by GPC, there were 9,862 MW of loads that were 100 MW or greater, of which 9,365 MW did not appear in the 2025 cases. This leaves 3,623 MW of new large loads modeled in the 2034 cases that were not identified by GPC Discovery Response PIA-5-16. This difference in modeled large

[6] Discovery Response PIA-1-10
[7] Discovery Response PIA-5-16

loads by 2034 is significant and would increase the stress on the transmission system and therefore the transmission reinforcement needs.

Table 5: Table of Large Loads Provided by GPC and Compared to Power Flow Cases

PIA-1-10 Project Name	City	County	Project Stage	PSSE Bus Number	PSSE Bus Name	PIA-1-10 Announced Load MW	PIA-5-16 MW	PSSE Case MW
[redacted]	[redacted]	[redacted]	Contract for Electric Service	[redacted]	[redacted]	1,429	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	Technical Review	[redacted]	[redacted]	1,280	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	Technical Review	[redacted]	[redacted]	1,000	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	Technical Review	[redacted]	[redacted]	780	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	Request for Electric Service	[redacted]	[redacted]	720	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	Technical Review	[redacted]	[redacted]	717	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	Request for Electric Service	[redacted]	[redacted]	693	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	Technical Review	[redacted]	[redacted]	656	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	Technical Review	[redacted]	[redacted]	651	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	Technical Review	[redacted]	[redacted]	650	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	Technical Review	[redacted]	[redacted]	600	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	Technical Review	[redacted]	[redacted]	533	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	Request for Electric Service	[redacted]	[redacted]	502	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	Technical Review	[redacted]	[redacted]	500	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	Technical Review	[redacted]	[redacted]	500	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	Technical Review	[redacted]	[redacted]	481	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	Technical Review	[redacted]	[redacted]	460	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	Technical Review	[redacted]	[redacted]	455	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	Technical Review	[redacted]	[redacted]	432	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	Request for Electric Service	[redacted]	[redacted]	432	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	Technical Review	[redacted]	[redacted]	365	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	Technical Review	[redacted]	[redacted]	335	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	Contract for Electric Service	[redacted]	[redacted]	324	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	Technical Review	[redacted]	[redacted]	321	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	Technical Review	[redacted]	[redacted]	311	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	Technical Review	[redacted]	[redacted]	300	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	Request for Electric Service	[redacted]	[redacted]	300	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	Request for Electric Service	[redacted]	[redacted]	285	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	Technical Review	[redacted]	[redacted]	271	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	Technical Review	[redacted]	[redacted]	250	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	Technical Review	[redacted]	[redacted]	250	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	Technical Review	[redacted]	[redacted]	250	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	Technical Review	[redacted]	[redacted]	245	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	Technical Review	[redacted]	[redacted]	243	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	Contract for Electric Service	[redacted]	[redacted]	240	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	Request for Electric Service	[redacted]	[redacted]	240	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	Contract for Electric Service	[redacted]	[redacted]	216	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	Technical Review	[redacted]	[redacted]	216	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	Contract for Electric Service	[redacted]	[redacted]	202	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	Technical Review	[redacted]	[redacted]	200	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	Technical Review	[redacted]	[redacted]	200	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	Contract for Electric Service	[redacted]	[redacted]	200	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	Technical Review	[redacted]	[redacted]	192	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	Contract for Electric Service	[redacted]	[redacted]	182	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	Request for Electric Service	[redacted]	[redacted]	180	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	Contract for Electric Service	[redacted]	[redacted]	180	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	Technical Review	[redacted]	[redacted]	180	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	Request for Electric Service	[redacted]	[redacted]	180	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	Technical Review	[redacted]	[redacted]	163	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	Technical Review	[redacted]	[redacted]	162	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	Technical Review	[redacted]	[redacted]	151	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	Technical Review	[redacted]	[redacted]	150	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	Contract for Electric Service	[redacted]	[redacted]	150	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	Contract for Electric Service	[redacted]	[redacted]	145	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	Technical Review	[redacted]	[redacted]	144	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	Technical Review	[redacted]	[redacted]	135	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	Technical Review	[redacted]	[redacted]	130	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	Technical Review	[redacted]	[redacted]	130	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	Contract for Electric Service	[redacted]	[redacted]	126	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	Technical Review	[redacted]	[redacted]	115	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	Technical Review	[redacted]	[redacted]	115	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	Request for Electric Service	[redacted]	[redacted]	105	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	Request for Electric Service	[redacted]	[redacted]	90	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	Technical Review	[redacted]	[redacted]	80	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	Request for Electric Service	[redacted]	[redacted]	79	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	Technical Review	[redacted]	[redacted]	60	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	Technical Review	[redacted]	[redacted]	53	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	Contract for Electric Service	[redacted]	[redacted]	52	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	Technical Review	[redacted]	[redacted]	50	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	Technical Review	[redacted]	[redacted]	49	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	Not Listed	[redacted]	[redacted]	Not Listed	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	Not Listed	[redacted]	[redacted]	Not Listed	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	Not Listed	[redacted]	[redacted]	Not Listed	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	Not Listed	[redacted]	[redacted]	Not Listed	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	Not Listed	[redacted]	[redacted]	Not Listed	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	Not Listed	[redacted]	[redacted]	Not Listed	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	Not Listed	[redacted]	[redacted]	Not Listed	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	Not Listed	[redacted]	[redacted]	Not Listed	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	Not Listed	[redacted]	[redacted]	Not Listed	[redacted]	[redacted]
					Totals	22,763	6,239	9,862
					Additional Load in PSSE Case			3,623

Q HOW DOES GPC DESCRIBE THE STRATEGIC TRANSMISSION PROJECTS FOR SERVING LARGE LOADS?

A In reviewing the IRP[8], several of the Strategic Transmission Projects are designed to address forecasted load growth. A list of strategic projects with forecasted load growth justification is provided in Table 6.

Table 6: Strategic Transmission Project with Forecasted Load Growth Justification

Strategic Transmission Project Name	GPC Justification
GTC: East Walton 500/230kV Area Project	[redacted]
Ashley Park - Wansley 500kV Line	[redacted]
GTC: Tenaska - Wansley 500kV Line	[redacted]
Cavender Drive - Tributary 230kV Line	[redacted]
GTC: Cavender Drive 500/230kV Area Project Cavender Drive - Villa Rica 500kV Cavender Drive - Union City 500kV	[redacted]
Farley (APC) - Tazewell 500kV Line	[redacted]

[8] Ga. Power Co., 2025 IRP Technical Appendix Volume 3 Transmission Plan, Georgia Projects at 255.

Strategic Transmission Project Name	GPC Justification
	[redacted]
Hatch - Wadley 500kV Line	[redacted]
McGrau Ford - Middle Fork 500kV Line	[redacted]

The IRP describes the Ashley Park–Wansley project as a major transmission enhancement designed to address "the evolving dynamics within the Georgia Integrated Transmission System (ITS), primarily driven by the changes in generation and forecasted load growth."[9] This line, approximately 30 miles in length, is positioned to enhance transfer capacity and alleviate thermal constraints in West Georgia, an area experiencing significant commercial and industrial development.

GPC's Metro West Working Group Study report[10] states that "the Metro West Working Group was established to find an area solution for the Lithia Springs and Villa Rica area loads." This report recommends four transmission projects to accommodate the Lithia Springs and Villa Rica area loads. Two of these projects, Cavender Drive - Tributary 230kV Line and GTC: Cavender Drive - Buzzard Roost 230kV Line, are in the Strategic Transmission Project list in the 2025 IRP.

[9] Ga. Power Co., 2025 IRP Technical Appendix Volume 3 Transmission Plan, Georgia Projects at 442.
[10] Discovery Request STF-DEA-2-2.

Q WHAT DOES YOUR ANALYSIS SHOW FOR LARGE LOADS?

A The DFAX analysis shows whether and to what extent each large load impacted the utilization of the strategic projects in GPC's transmission model. In Table 7, the top row shows the large loads considered in the analysis and the first column shows the Strategic Transmission Projects. The numbers in the table correspond to a percentage of flow increase based on a load increase at the large load location. Darker red values represent an increase in line loading while darker blue values represent a decrease in line loading.

Table 7: DFAX Analysis on GPC Large Loads for 2034 Shoulder NSEW NUO Case Considering N-1 Contingencies

[redacted]

Our analysis confirmed that several projects described in the IRP as driven by forecasted load growth are in fact actively utilized by large loads in the 2034 summer and shoulder peak power flow cases, including two projects that were recommendations of the Metro West Working Group Study. This result affirms

GPC's assertion that the line serves a reliability function tied to emerging large load customer demand in west and central Georgia.

In addition, the analysis identified two other Strategic Transmission Projects that, although not explicitly attributed to load growth in the IRP, show strong operational connections to large loads in the model. All projects identified in the DFAX analysis are included in Table 8 and the cost of these projects make up 16% of the total cost for all Strategic Transmission Projects. The substations are provided with the zone name to give a geographical reference to the project location. The zone names can be found in Figure 1.

Table 8: Strategic Transmission Projects with Zone and GPC Justification

Strategic Transmission Project Name	**Zones**	**GPC Justification**
Ashley Park - Wansley 500kV Line	Metro South/ Northwest	[redacted]
GTC: Tenaska - Wansley 500kV Line	West/ Northwest	[redacted]
Cavender Drive - Tributary 230kV Line	Metro West	[redacted]
GTC: Cavender Drive 500/230kV Area Project Cavender Drive - Villa Rica 500kV Cavender Drive - Union City 500kV	Metro South/ Northwest	[redacted]
GTC: Cavender Drive - Buzzard Roost 230kV Line	Metro West	[redacted]

		[redacted]
GTC: Big Smarr - Tomochichi 500kV Line	Central/ West	[redacted]

Figure 1: Map of GPC Zone Names by Geography[11]

Each of these lines demonstrated material DFAX sensitivity or contingency-related stress associated with one or more of the major new large loads included in the IRP's future case modeling. Their operational response under peak and shoulder scenarios

[11] Ga. Power Co., 2025 IRP Technical Appendix Volume 3 Transmission Plan, Georgia ITS at 23.

supports the inference that these projects play a key role in serving Georgia Power's forecasted large load additions, even though that role is not explicitly described in the IRP narrative. Figure 2 shows the location of the strategic projects in relation to the large loads and key centralized generators. The strategic projects are in green while the large loads are the small blue circles and key centralized generators are larger purple circles.

[redacted]

Figure 2: Map of Strategic Transmission Projects, Large Centralized Generators, and New Large Loads

Conversely, other Strategic Transmission Projects listed in the IRP did not show strong electrical linkage or sensitivity to the modeled large loads under the scenarios tested. As such, their justification appears more strongly tied to other drivers such as generation dispatch, system transfers, or broader reliability support. This analysis confirms that two projects beyond what GPC states as justification should be recognized as key elements in Georgia Power's strategy to accommodate new demand. For example, the Big Smarr to Tomochichi 500 kV line is presented as part of the long-term backbone reinforcement strategy but is not tied in the IRP to specific large load additions. However, without a direct statement in the IRP, the analysis presented intends to better link any Strategic Transmission Projects to the large loads.

Q WHAT IS THE COST OF THE STRATEGIC TRANSMISSION PROJECTS THAT ARE MOST CLOSELY RELATED TO SERVING NEW LARGE LOADS?

A The cost of the projects tied to load can be found in Table 9[12]. The table includes the total project cost and the GPC portion of the total cost.

Table 9: Summary of Costs of Strategic Transmission Projects Associated with New Large Loads

Strategic Transmission Project	GPC Cost	Total Cost
Ashley Park to Wansley 500 kV line	[redacted]	[redacted]
GTC: Tenaska – Wansley 500 kV Line	[redacted]	[redacted]

[12] Ga. Power Co., 2025 IRP Technical Appendix Volume 3 Transmission Plan, Georgia Projects Table 8 at 209.

Strategic Transmission Project	GPC Cost	Total Cost
Cavender Drive – Tributary 230 kV Line	[redacted]	[redacted]
GTC: Cavender Drive 500/230 kV Area Project	[redacted]	[redacted]
GTC: Cavender Drive – Buzzard Roost 230 kV Line	[redacted]	[redacted]
GTC: Big Smarr – Tomochichi 500 kV Line	[redacted]	[redacted]
Total	[redacted]	[redacted]

Q WHAT ARE THE IMPLICATIONS FOR GPC'S STRATEGIC TRANSMISSION PROJECTS IF ONE OR MORE LARGE FORECASTED LOADS DO NOT MATERIALIZE AS EXPECTED?

A There is a risk that one or more of the new Strategic Transmission Projects identified in Table 9 may be significantly under-utilized in the 10-year planning horizon if the new large load projects fail to move forward or are delayed, which is a significant possibility according to Witness Stenclik because "...much of this projected load growth is highly speculative at this stage."[13] Furthermore, GPC has not performed its transmission planning analysis considering a scenario with a lower level of load growth. Witnesses Fagan and Frayer point out that "Specifically, LEI is concerned that in its 2024 GA ITS Ten-Year Plan, GPC did not test any sensitivities relative to its load growth forecast, particularly a lower load forecast to reflect the substantial uncertainty associated with prospective large load customers, including whether they will materialize at all, or at the scale or timing that GPC projects. Running a lower

[13] Direct Testimony of Derek Stenclik, Section IV.

load forecast sensitivity would enable GPC to identify which transmission projects could potentially be deferred, ultimately reducing the [redacted] price tag allocated to GPC in the 2024 GA ITS Ten-Year Plan.[14]"

Q DOES GPC TREAT POTENTIAL NEW LOAD PROJECTS THE SAME AS POTENTIAL NEW GENERATION PROJECTS WHEN IT COMES TO PROACTIVELY PLANNING 500KV TRANSMISSION PROJECTS?

A No. As part of GPC's 2023 IRP Rebuttal Testimony, GPC claimed, in response to proactively building 500kV transmission lines for interconnecting potential future generation, that "...Georgia Power builds transmission as needed to deliver power from facilities that have been sited, financed, and have initiated the process of interconnecting to the System. Georgia Power's integrated approach ensures interconnections actually occur and minimizes transmission investments based upon speculation."[15] This statement from GPC's 2023 IRP Rebuttal Testimony indicates that GPC avoids planning 500kV transmission projects for connecting speculative independent power producer (IPP) generation. However, this approach is in contrast to GPC's 2025 IRP, where GPC plans to build several 500kV transmission lines as part of supporting the potential but still uncertain interconnection of future large loads.

Q WHICH LARGE LOAD LOCATIONS POSE THE GREATEST RISK?

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[14] Direct Testimony of Marie Fagan and Julia Frayer, Section III, Docket No. 56002.
[15] Rebuttal Testimony of Georgia Power in response to Michael Goggin at 51, regarding proactively building 500 kV lines, Docket No. 55378.

A From Table 7 that shows the DFAX matrix linking the Strategic Transmission Projects to the large loads, the list of large loads most responsible for driving specific transmission projects is shown in Table 10.

Table 10: Summary Table of Transmission Projects Supporting New Large Loads

Strategic Transmission Project	Large Load PSSE Bus Number:Name	DFAX Value	GPC Cost
Ashley Park - Wansley 500kV Line	[redacted]	[redacted]	[redacted]
GTC: Tenaska - Wansley 500kV Line	[redacted]	[redacted]	[redacted]
Cavender Drive - Tributary 230kV Line	[redacted]	[redacted]	[redacted]
GTC: Cavender Drive 500/230kV Area Project Cavender Drive - Villa Rica 500kV	[redacted]	[redacted]	[redacted]
GTC: Cavender Drive 500/230kV Area Project Cavender Drive - Union City 500kV	[redacted]	[redacted]	
GTC: Cavender Drive - Buzzard Roost 230kV Line	[redacted]	[redacted]	[redacted]
GTC: Big Smarr - Tomochichi 500kV Line	[redacted]	[redacted]	[redacted]

Q IF ONE OR MORE OF THE SPECIFIC LARGE LOAD PROJECTS SHOULD BE WITHDRAWN OR DELAYED, SHOULD THE NEED FOR THE RELATED STRATEGIC TRANSMISSION PROJECTS BE REEVALUATED?

A Yes, if one or more of the large loads identified as a driver of one or more of the Strategic Transmission Projects is to be delayed, reduced, or withdrawn, then it would impact the necessity and timing of one or more of GPC's Strategic Transmission Projects. As identified in GPC's 2025 IRP, a substantial portion of projected load growth is associated with industrial and commercial developments that are still in the early stages of commitment or interconnection.[16]

Q ARE THERE OTHER CONSIDERATIONS OR PRACTICES FOR PLANNING TRANSMISSION WITH LARGE NEW LOADS?

A If new large loads do not materialize as planned, the transmission system may not experience the expected increase in stress, congestion, or voltage limitations, thereby calling into question the immediate need or scale of some of the proposed transmission projects that GPC is proposing in this IRP.

It is important to recognize that transmission infrastructure takes many years to plan, permit, and construct. Projects intended to support large loads cannot wait until the moment those loads are operational. Therefore, a balance must be struck between planning ahead for expected growth and ensuring that those assumptions are grounded in verifiable commitments. Planning discipline is critical, not to delay necessary infrastructure, but to ensure that transmission investments are right-sized, timely, and responsive to evolving system conditions.

To this end, best practices include:

- Clearly identifying which transmission projects are primarily justified by new large loads;
- Developing trigger-based frameworks, where final project approvals or timing are contingent on measurable progress—such as site selection,

[16] Ga. Power Co., 2025 IRP Main Document, Section 5 – Load and Energy Forecast, p. 70

interconnection agreements, or construction milestones—from the large customers driving the need;

- Continue requiring quarterly updates on large loads and add to update requirements as necessary.

This approach would protect ratepayers from unnecessary or premature investments, while still allowing sufficient lead time to construct transmission infrastructure that supports reliability and economic development. In the Midcontinent Independent System Operator (MISO) region, utilities and transmission planners are increasingly required to provide load-dependent justifications. An example of this can be found in ATC's Load Interconnection Guide[17] where a Best Value Planning process is followed that develops a report that describes the justification for projects necessary for a load interconnection along with alternatives considered, scope of work, cost and schedule of implementing the projects. MISO's recent Load Interconnection Whitepaper outlines a structured approach to integrating large loads into transmission planning, emphasizing flexibility, system impact transparency, and coordination across utility and planning entities to reduce the risk of stranded investment.[18] In summary, Strategic Transmission Projects closely tied to large load additions should be treated as conditionally justified, time-sensitive infrastructure, with a planning framework that enables re-evaluation if load assumptions change materially.

[17] American Transmission Company, Load Interconnection Guide (Jan. 11, 2023), available at: https://www.atcllc.com/wp-content/uploads/load-interconnection-guide-rev.-12.pdf

[18] Midcontinent Independent System Operator, MISO Load Interconnection Whitepaper (July 2023), available at: https://cdn misoenergy.org/MISO%20Load%20Interconnection%20Whitepaper629693.pdf.

V. IMPACT OF CENTRALIZED GENERATION ON GPC'S STRATEGIC TRANSMISSION PROJECTS

Q WHAT CENTRALIZED GENERATION DID GPC CONSIDER FOR RETIREMENT AND WHAT CHANGED IN THE 2024 ITS REGARDING PROJECTS REQUIRED TO ALLOW UNIT RETIREMENT?

A In the 2025 IRP, GPC continued to evaluate the retirement of several major generation units, consistent with the Company's economic planning process and long-term resource transition objectives. Specifically, the units considered for retirement in the 2024 ITS planning process included Wansley Units 1 and 2, Bowen Units 1 through 4, and Scherer Units 1 through 3.[19] Previously, GPC had stated that "Although studies that reflect a deferred retirement of Plant Bowen Unit 1 or 2 have not been completed, projects identified for the retirement of both units are still likely to be needed even with only one unit retiring."[20] Now, the 2024 ITS reflects several key changes related to transmission infrastructure needed to support these retirements:

- In the 2025 IRP, GPC states that no transmission projects were included nor were any transmission projects excluded in the 2025 IRP as a result of the extension of the Scherer, Gaston[21], and Bowen[22] units.
- Instead of proposing new projects, the 2024 ITS[23] reflects a 1- to 3-year delay in the in-service dates of several transmission upgrades that were already

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[19] Ga. Power Co., 2025 IRP Technical Appendix Volume 3 Transmission Plan, ITS at 298.
[20] Rebuttal Testimony of Georgia Power, Grubb, Mallard, Robinson, Weathers (June 8, 2022) at 38.
[21] Discovery Response STF-DEA-4-8.
[22] Discovery Response STF-DEA-4-9.
[23] Ga. Power Co., 2025 IRP Technical Appendix Volume 3 Transmission Plan, ITS at 303.

- included in the 2021 Unit Retirement Analysis. These shifts in schedule likely reflect updated load forecasts, evolving system conditions, and project development timelines.
- Corn Crib - Lagrange Primary 115kV Reconductor, Eufala - George Dam (COE) - Webb 115kV, and Klondike Switch Replacement, three of the required transmission projects identified in the earlier analysis have already been completed, reducing the remaining infrastructure needs required to accommodate planned retirements.

The latest in-service date for any remaining retirement-related transmission project is now 2029[24], which defines the outer bound of infrastructure that must be in place before all retirements under consideration can be executed without compromising system reliability. This updated outlook indicates that while GPC continues to move toward retiring its legacy units, the transmission backbone necessary to support those retirements will be in place by 2029, with no major new projects required. This trend supports the view that generation transition planning has matured significantly since the 2021 IRP, and that transmission constraints are no longer a major barrier to retiring these aging fossil units on a schedule that aligns with reliability and cost considerations.

VI. IMPACT OF VARIABLE RENEWABLE ENERGY AND BATTERY STORAGE ON GPC'S STRATEGIC TRANSMISSION PROJECTS

Q PLEASE PROVIDE AN OVERVIEW OF THE REPRESENTATION OF RENEWABLE RESOURCES IN GPC'S TRANSMISSION MODEL.

A GPC's transmission model considers a total (new and existing) of 9800 MW of solar resources planned to be installed by 2030. This same renewable MW amount was also included in the 2034 cases. This is represented among 81 individual projects

[24] Ga. Power Co., 2025 IRP Technical Appendix Volume 3 Transmission Plan, ITS Table 41 at 303.

connecting to the HV transmission system at kV levels of greater than 100kV. GPC's transmission model assumed that of the 9800 MW installed capacity of solar, that 5800 MW of generation is available in the summer peak cases and for the shoulder cases that assumed renewable generation was online. This results in a capacity factor of 61%. The majority of renewables are assumed to be in the South, West, and Central Zones, as summarized in Figure 1 and Table 11.

Table 11: Renewables Project Summary by Location and Size

Zone	Number of Renewable Projects	Total MW in Zone
CENTRAL	21	2085
COASTAL	3	161
EAST	9	987
N. EAST	4	248
N. WEST	1	200
SAVANNAH	1	16
SOUTH	27	3597
WEST	15	2470

Q WHICH OF GPC'S STRATEGIC TRANSMISSION PROJECTS ARE IMPACTED BY MODELED RENEWABLE ENERGY INJECTIONS?

A Georgia Power's 2025 IRP identifies some of its Strategic Transmission Projects as supporting the integration of future renewable energy generation projects. My analysis confirms that several of the proposed projects play a critical role in facilitating the delivery of solar generation to load centers. Because the majority of utility-scale solar resources modeled in the IRP are located in South Georgia, and the primary demand centers—particularly the Atlanta metropolitan area—are located in North Georgia, solar injections generally increase south-to-north power flows on the transmission system. This directional power movement places loading and reliability significance on certain transmission corridors, particularly those that link southern generation zones to northern load. This is indicated by the distribution factors in Table 12.

Table 12: DFAX Analysis Results for New Renewable Generation Projects to All Loads in GPC

	DFAX for Each Case			
MonitoredFacility	D34_NSEW	D34_SNWE	S34_NSEW	S34_SNWE
[redacted]	0.04468	0.03348	0.03369	0.03301
[redacted]	0.04255	0.04255	0.04128	0.04128
[redacted]	0.03334	0.03334	0.02974	0.02974
[redacted]	0.01422	0.01422	0.01467	0.01467
[redacted]	0.05796	0.05796	0.05769	0.05769
[redacted]	0.06218	0.06218	0.06171	0.06171
[redacted]	0.03755	0.03755	0.03176	0.03176
[redacted]	0.00625	0.00625	0.00588	0.00588
[redacted]	0.01475	0.01475	0.01419	0.01419
[redacted]	0.01577	0.01577	0.01579	0.01579
[redacted]	-0.03894	-0.03894	-0.03992	-0.03992
[redacted]	-0.05852	-0.05852	-0.05967	-0.05967
[redacted]	0.0425	0.0425	0.04246	0.04246
[redacted]	0.01695	0.01695	0.01705	0.01705
[redacted]	0.02231	0.02231	0.02245	0.02245
[redacted]	0.01147	0.01147	0.01125	0.01125
[redacted]	0.00581	0.00581	0.00571	0.00571
[redacted]	0.06696	0.06696	0.0636	0.0636
[redacted]	0.00913	0.00913	0.00899	0.00899
[redacted]	0.01693	0.01693	0.01604	0.01604
[redacted]	0.07034	0.07034	0.06933	0.06933
[redacted]	0.01693	0.01693	0.01604	0.01604
[redacted]	0.00595	0.00595	0.00502	0.00502
[redacted]	0.00595	0.00595	0.00502	0.00502
[redacted]	0.10132	0.10132	0.10032	0.10032
[redacted]	0.10132	0.10132	0.10032	0.10032
[redacted]	0.00462	0.00462	0.0044	0.0044
[redacted]	0.0425	0.0425	0.04246	0.04246
[redacted]	0.0098	0.0098	0.00958	0.00958
[redacted]	0.0147	0.0147	0.01223	0.01223
[redacted]	0.024	0.024	0.02041	0.02041
[redacted]	0.06296	0.06296	0.06309	0.06309
[redacted]	0.00817	0.00817	0.00764	0.00764
[redacted]	0.01475	0.01475	0.01419	0.01419
[redacted]	0.01768	0.01768	0.01721	0.01721

Based on DFAX analysis using Georgia Power's 2034 summer and shoulder peak power flow cases, the following Strategic Transmission Projects were identified as being most impacted by solar injections, Table 13. The projects are provided with the zones to give a geographical reference to the project location. The zone names can be found in Figure 1.

Table 13: Strategic Transmission Projects Identified as Supporting Future Renewables Projects

Strategic Transmission Project Name	**Zones**	**GPC Justification**
Butler - Thomaston 230kV Line Conversion	West	[redacted]
Farley (APC) - Tazewell 500kV Line	APC/West	[redacted]
GTC: Big Smarr - Tomochichi 500kV Line	Central/ West	[redacted]
GTC: Talbot #2 - Tazewell 500kV Line	West	[redacted]
GTC: Rockville - Tiger Creek - Warthen 500kV Line	Central	[redacted]
GTC: Tiger Creek - Rockville - North Spa 230kV Line	Central/ Northeast	[redacted]

These lines exhibited the highest DFAX sensitivities under modeled solar injection conditions, indicating that they are key conduits for renewable energy delivery, even if not formally designated as such in the IRP. While GPC's planning documents refer broadly to south-to-north flow enhancements as part of the system's overall transmission strategy[25], these findings provide quantitative evidence that solar generation materially contributes to the utilization of these specific projects. Accordingly, these projects should be recognized not only for their reliability benefits but also for their role in enabling the clean energy transition and supporting the integration of 7250 MW[26] of new solar generation as proposed in the IRP. Figure 2 shows the location of the strategic projects in the state of Georgia in green. Several of these lines are oriented south to north, which support the integration of renewables and is confirmed by this analysis.

A few of these lines were also listed as being impacted by large loads. If a renewable generator or large load is connected close to one of these projects, it will be impacted by that load or generation. If the line also has a south to north orientation, it will be used as a path for moving renewable energy to the load center. For example, GTC: Big Smarr - Tomochichi 500 kV Line project was listed as impacted in both DFAX scenarios. This line has a large load and also has a south to north orientation, meaning it will be supporting load growth in the Metro Zones as well as renewable generation in the Central and South Zones.

[25] Discovery Response STF-DEA-4-6.
[26] Ga. Power Co., 2025 IRP Main Document at 89.

Q WHAT DO THE DFAX RESULTS INDICATE ABOUT THE IMPACT OF THE RENEWABLES PROJECTS ON THE TRANSMISSION SYSTEM?

A From the DFAX analysis, the impact of utility-scale solar resources on GPC's Strategic Transmission Projects was found to be modest. To further confirm the modest impact of renewables on the rest of the Georgia Transmission System, another DFAX analysis was performed monitoring all 100kV and above transmission lines to find any other transmission lines that are more greatly impacted by the renewable resources. This analysis shown in Table 14 found that the overall impact of the renewables on the transmission lines did not go above the 0.1, or 10%, seen on the Talbot - Tazewell 500kV lines.

Table 14: Analysis for All Transmission Lines in Georgia Loaded Above 50% in the Shoulder 2034 Case NSEW Considering N-1 Contingencies, for New Solar projects to All Loads in Georgia

MonitoredFacility	DFAX D34_NSEW
[redacted]	0.10138
	0.0927
	0.08985
	0.08985
	0.08648
	0.08648
	0.08469
	0.08204
	0.08166
	0.06356
	0.06218
	0.05796
	0.046
	0.04426
	0.04426
	0.04276
	0.0425
	0.0425
	0.03974
	0.03755
	0.03633
	0.03589
	0.03371
	0.03371
	0.03108
	0.03108
	0.03108
	0.03108
	0.02989
	0.0293
	0.02908
	0.02908
	0.02866
	0.02546
	0.02475
	0.02475
	0.02475
	0.02456
	0.024
	0.02384
	0.02281
	0.02281
	0.02281
	0.02166
	0.02063
	0.02058

Q WHY DO THE MODELED RENEWABLES PROJECTS HAVE A MODEST IMPACT ON THE TRANSMISSION SYSTEM?

A The modest impact is primarily due to the dispersed nature of the solar resources modeled in Georgia Power's 2025 IRP. Rather than being concentrated at a few centralized locations, the solar additions each have a low MW rating (relative to the centralized key generation projects) and they are spread across many sites in southern Georgia, which helps distribute their injection across the transmission system and reduces localized stress. However, due to the geographic separation between the primary solar resource areas in South Georgia and the major load center in the Atlanta metropolitan area, solar generation does influence south-to-north transmission flows. This effect is most notable during periods of high solar output, such as midday shoulder hours or sunny summer afternoons, when power is flowing northward from generation-rich zones to serve the concentrated demand in North Georgia. In GPC's transmission planning documentation[27], the Company emphasizes the need to improve power transfer from South to North Georgia, referencing this directional flow as part of its justification for several Strategic Transmission Projects.

The DFAX analysis confirms that several Strategic Transmission Projects identified in Table 13 support the northbound transfer of power and indirectly support the deliverability of solar energy to load centers. Furthermore, the broad geographic distribution of many smaller solar resources reduces stress on the transmission system, and as a result, their direct impact on individual Strategic Transmission Projects is limited compared to large loads or major dispatchable generation.

[27] Ga. Power Co., 2025 IRP Main Document, Section 11.3 at 112.

Q ARE THERE OTHER TRANSMISSION PROJECTS SUPPORTING RENEWABLES IN GEORGIA?

A Yes. This list of strategic transmission projects identified in Table 12 is not an exhaustive list of transmission projects helping deliver power from renewables projects to load in Georgia. Power from renewables projects can flow on many other lines in the system, in varying degrees based on the location of the lines in the network, the impedance of those lines, and the dispatch of the system. This goes for lines internal to GPC as well as interregional transmission lines that interconnect Georgia with its neighbors. As Witness Stenclik describes in Section VII of his direct testimony, interregional transmission "[e]nables access to lower-cost renewable energy, particularly wind resources from regions such as the Midwest and Texas, which are not available at scale within GPC's service territory but could be accessed through transmission investment."[28]

Q DID YOU IDENTIFY ANY CONCERNS WITH HOW GPC REPRESENTED SOLAR PROJECTS IN THEIR TRANSMISSION MODEL?

A Yes. In the power flow cases reviewed as part of GPC's 2025 IRP, I found that solar generation projects are represented in the transmission model as fully online or fully offline. Specifically, a portion of the modeled solar resources is dispatched at 100% of nameplate capacity, while the remaining solar resources are assumed to be offline entirely, contributing neither real power nor reactive power (voltage support) to the

[28] Direct Testimony of Derek Stenclik, Section VII,

Georgia transmission system. This modeling approach does not reflect actual operating conditions for utility-scale solar resources and it may result in the model showing overloaded transmission lines or transformers that would not be overloaded in reality. In practice, solar facilities operate across a range of real power outputs depending on the time of day, weather conditions, and inverter capabilities, and they typically provide voltage regulation and reactive power support when online. By modeling a large portion of solar resources as fully offline, GPC's cases likely underestimate the voltage support that solar can provide to the transmission system—particularly in areas with high PV saturation and during periods when solar is known to be contributing meaningfully to net load reduction.

Q HOW CAN SOLAR RESOURCES BE MODELED MORE REALISTICALLY AND CAN YOU PROVIDE EXAMPLES IN INDUSTRY OF GOOD PRACTICES FOR MODELING SOLAR RESOURCES?

A Yes. To more accurately represent system conditions, all solar resources should be online in a case representing daytime operations and dispatched at realistic aggregate output levels based on seasonal expected output. One example of an established industry approach to modeling solar plants is from the Midcontinent Independent System Operator (MISO), and is documented in their MISO Planning Modeling Manual, Version 4.4.[29] In Section 4.4.4.3, MISO describes the modeling of solar generators in the development of system-wide base case models for use in steady-

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[29] Midcontinent Independent System Operator, MISO Planning Modeling Manual, Reliability Data Requirements & Reporting Procedures Version 4.4, 10-31-2024, available at: https://cdn.misoenergy.org/MISO%20Planning%20Modeling%20Manual%20v4.4105063.pdf.

state and dynamics analysis. Table 4-5 of this section details the "Required Solar Output" for each planning case, where each solar plant is modeled at a partial dispatch in accordance with its capacity credit for the case (e.g., 48% for Summer Shoulder, 10% for Spring Light Load, etc.). This modeling approach is more reflective of the way solar plants operate on the system, where power injection is dispersed across all solar plants and reflects that even when solar plants are operating at partial power, they are still providing voltage support in accordance with FERC Order 827.[30] Applying a similar methodology in Georgia would improve the realism of the transmission loading and voltage profiles, more accurately identify locations where solar generation contributes to or alleviates system stress and ensure that each solar project's voltage support capabilities are appropriately captured in contingency analyses. In summary, Georgia Power's current solar modeling assumptions appear overly conservative and limit the analytical visibility of the true operational impact of solar generation projects. A more representative dispatch treatment would support better-informed planning decisions and align with practices used in other regions.

[30] Federal Energy Regulatory Commission, 18 CFR Part 35, Docket No. RM16-1-000; Order No. 827, Reactive Power Requirements for Non-Synchronous Generation, Issued June 16, 2016 at Paragraphs 34 and 37.

Q HOW DID GPC REPRESENT BATTERY ENERGY STORAGE SYSTEMS (BESS) IN THEIR TRANSMISSION MODEL?

A The GPC transmission model[31] contains 9 BESS projects totaling about 1000 MW in the year 2034. The 9 projects are spread across the Coastal, Northeast, Northwest, South, and West zones. The summer peak case has these BESS resources modeled as offline. The shoulder cases have scenarios where BESS resources are either modeled as offline or it has four projects dispatched to about 530 MW charging, with the other five projects modeled as offline. Finally, the winter peak case has the BESS resources dispatched at 530 MW charging.

Q DO YOU HAVE ANY CONCERNS WITH HOW GPC REPRESENTED THE BESS?

A Yes. Based on Telos Energy's review of the power flow cases provided in GPC's 2025 IRP, BESS are not modeled in a way that captures their operational flexibility or their ability to alleviate transmission congestion. As confirmed by the GPC response[32] and observed in the 2034 summer and shoulder power flow cases, BESS are either:

- Offline, contributing no real or reactive power support to the transmission grid, or
- Online at full charging, meaning they were modeled as load, increasing the net demand on the system rather than alleviating.

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[31] Ga. Power Co., 2025 IRP Technical Appendix Volume 3 Transmission Plan, Appendix H2.

[32] Discovery Response STF-GS-1-4

This modeling approach is problematic for three reasons.

- First, it fails to represent the critical role that storage can play during peak load periods or contingency events—when storage is most likely to be discharging to support the system.
- Second, it artificially increases system stress by modeling batteries as fully charging, which inflates flows on transmission lines and potentially overstates the need for certain infrastructure upgrades.
- Third, even when not dispatched, BESS would be online and providing valuable voltage support and voltage regulation capability that would not be considered in a model where the resource is set as completely offline. The historical data provided by GPC for one of their battery plants shows that the storage plant is providing voltage support even when active power provision is essentially zero.[33]

A more accurate approach would model BESS based on expected dispatch during stressed conditions, where they are typically discharging at or near their rated capacity, providing both real power injection and reactive support. This would align with the real-world operational strategy of storage assets, particularly in systems with increasing levels of variable renewable energy. This approach also aligns with the recorded data provided by GPC in their response to STF-GS-1-4 in which the BESS was discharging during the morning peak hour. For comparison, MISO has established a methodology for modeling battery energy storage systems in transmission planning studies, as outlined in the MISO Planning Modeling Manual, Version 4.4[34]. In MISO's approach, storage is modeled as online and providing grid

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[33] Discovery Response STF-GS-1-4.

[34] Midcontinent Independent System Operator, MISO Planning Modeling Manual, Reliability Data Requirements & Reporting Procedures Version 4.4, 10-31-2024, available at: https://cdn.misoenergy.org/MISO%20Planning%20Modeling%20Manual%20v4.4105063.pdf.

support in all scenarios, with real power dispatch determined based on an economic tiering system. This method allows storage to contribute meaningfully during stressed conditions, such as summer peak periods, without assuming it is always dispatched or relied upon in every case. This more flexible and realistic modeling framework better aligns with historical operational data and ensures that the impact of BESS on system reliability and transmission loading is accurately represented. Given GPC's own plans to significantly expand battery storage in its IRP, a more representative storage dispatch framework should be adopted. Doing so would provide greater insight into how storage can mitigate congestion, defer or reduce the need for specific transmission upgrades, and contribute to voltage and thermal stability during peak and contingency conditions. In summary, the current modeling treatment of BESS in the IRP's transmission cases does not reflect the real-world reliability and congestion relief benefits that these resources provide. GPC should adopt a more realistic dispatch framework to fully capture the system value of energy storage in transmission planning.

VII. RECOMMENDATIONS FOR THE COMMISSION

Q WHAT ARE YOUR RECOMMENDATIONS?

A I have the following recommendations for the Commission:

Require Transparent Attribution of Transmission Project Drivers

- Direct GPC to clearly attribute transmission project justifications to their primary drivers, be it large loads, solar integration, reliability reinforcement, or generation retirements, so the Commission and stakeholders can evaluate cost causation and system benefit. In addition, it would be beneficial for all Strategic

Transmission Projects to include detailed descriptions similar to the one provided for the Ashley Park – Wansley 500 kV Line[35]. These descriptions help clarify the specific drivers, objectives, and system benefits associated with each project. For example, it would be helpful if projects such as the North Spa 230 kV Area Project were accompanied by comparable detail regarding their justification, geographic relevance, and role in supporting reliability, load growth, or resource integration.

- Provide clarity on the certainty threshold required for future interconnection projects to be considered in planning new systemic (500kV) transmission investments. Ensure the project certainty threshold is consistent for generation interconnection requests as well as load interconnection requests.

Tie Transmission Approvals to Large Load Commitments

- Require Georgia Power to identify which Strategic Transmission Projects are directly driven by new large load additions.
- Condition the approval, timing, or phasing of load-driven transmission projects on measurable customer commitments (e.g., executed interconnection agreements, construction milestones).
- Continue to require quarterly updates from GPC on the status of large load developments tied to transmission needs and update this requirement with additional information as necessary.

Improve the Representation of Battery Storage and Solar in Transmission Planning

- Direct GPC to revise its modeling assumptions for BESS to reflect real-world operations—specifically, their ability to discharge during peak and contingency conditions and provide voltage support.
- Require GPC to update how solar PV is represented in transmission models. Current assumptions that treat many solar resources as either fully on or fully off are unrealistic and may distort transmission loading results.

[35] Technical Volume 3, p. 272

- Recommend adopting practices similar to MISO, where planning case assumptions for storage and solar are based on seasonal capacity expectations and duration characteristics from the Capacity, Demand, and Reserve Report.
- Acknowledge that GPC's plan includes approximately 6 GW of solar generation, largely dispersed across South Georgia. This geographic dispersion reduces stress on local transmission infrastructure compared to centralized generation and enables flexible, lower-cost interconnection.
- Recognize the value that several Strategic Transmission Projects (e.g., Big Smarr–Tomochichi, Rockville–Tiger Creek–Warthen) play a critical role in enabling south-to-north power transfers, supporting both system reliability and solar integration.
- Recognize the value that interregional transmission offers to Georgia in supplying lower-cost renewable energy from regions that have renewable energy resources to offer

Q DOES THIS CONCLUDE YOUR TESTIMONY?

A Yes.

MR-1:

Resume of Matthew Richwine

TELOS ENERGY

Matthew P. Richwine

Founding Partner

Saratoga Springs, NY

M.Eng. Systems Engineering, Cornell University
B.S. Electrical and Computer Engineering, Cornell University

Matthew Richwine is a founding partner of Telos Energy and is an industry leader in power systems engineering, power electronic controls, and system stability. For the past sixteen years, he has been designing, testing, and analyzing thermal and renewable power generation equipment and studying the stability of power systems ranging from megawatts to tens of gigawatts.

Matthew draws on his in-depth understanding of inverter-based resources and conventional synchronous generation equipment to model and analyze power systems to draw out meaningful conclusions and explore a large variety of mitigation measures to address challenges. He brings a passion for technology and for helping clients to understand new technologies in the context of their system.

He's played a leadership role in industry working groups, including Chair of the IEEE Renewable Energy Machines and Systems Subcommittee, contributing member of the NERC Inverter-Based Resource Performance Task Force and Power Plant Modeling and Validation Task Force, and IEEE P2800 Standard Drafting Committee on Inverter-Based Resources for Transmission Systems. As such, he's delivered dozens of presentations, drafted reliability guidelines and written many peer-reviewed papers on renewable generation technologies, modeling, and system stability.

Prior to founding Telos Energy, Matthew worked for General Electric for ten years in its Energy Consulting department as the Senior Manager of the Renewables and Controls team. In that role, he led a team in the development of new control systems for power converters and transmission planning models for GE's Renewables business. His experience also includes grid code compliance testing, transmission and interconnection studies for markets around the world, including North America, Ireland, UK, Australia.

Matthew holds bachelors and masters degrees from Cornell University in Electrical and Computer Engineering and Systems Engineering.

He resides in Saratoga Springs, New York with his wife and son, and he enjoys catamaran sailing, skiing, and restoring his 1965 Mustang.

Matthew P. Richwine

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SHORT BIO

Matthew Richwine is a founding partner of Telos Energy and is an industry leader in power systems engineering, power electronic controls, and system stability. For the past fourteen years, he has been designing, testing, and analyzing thermal and renewable power generation equipment and studying the stability of power systems.

EXPERIENCE

2019-Present — Founding Partner, *Telos Energy*

- Leads a team of power systems engineers in the formulation of new analytical approaches and the execution of complex studies
- Generates new business opportunities and strengthens existing business relationships across dozens of clients, including project developers, utilities, system operators, and research organizations

2017-2019 — Senior Engagement Manager, *GE Energy Consulting*

- Led a team of 10+ in the formulation of scope and execution of internal and external customer objectives, delivering $2.7MM with impact of $1B+ to GE businesses
- Supported GE equipment design teams, utilities, grid operators

2013-2017 — Consultant & Senior Consultant, *GE Energy Consulting*

- Developed a new wind turbine power plant control to coordinate multiple wind plants in a region of the electric power grid
- Modeled and simulated power systems in Hawaii, Barbados, and Honduras to evaluate the impact of increasing wind and solar generation on system stability
- Conducted testing of thermal and renewable power plants and validated models for external customers for NERC requirements

2009-2013 — Design Engineer, Electric Machinery and Systems, *GE Renewables*

- Characterized doubly-fed induction generator behavior during fault conditions through testing, data analysis, and modeling of leakage saturation
- Specified a new inverter-fed induction generator design through cross-functional trade-off studies to define mechanical and electrical requirements for an optimized system

EDUCATION

May 2009 — M.Eng. Systems Engineering, *Cornell University*

- Concentration: Controls and Power Systems

May 2008 — B.S. Electrical and Computer Engineering, *Cornell University*

- Honors: Eta Kappa Nu, Magna Cum Laude

EXPERTISE

Power Systems and Equipment Expertise:

- Powerflow and dynamics modeling and simulation
- Renewable integration and power system stability analysis
- Grid code compliance analysis and model validation testing
- Torsional dynamics analysis for sub-synchronous oscillations
- Power electronic controls design and analysis

Computer Skills

- Microsoft Office, Python, C, MATLAB, PSCAD, DIgSILENT PowerFactory, GE PSLF, Siemens PTI PSS/E, ATP, ETAP)

AWARDS

- M. Richwine, 2024 Excellence Award of the Electric System Integration Group (ESIG) for advancements in stability study methods applied to high IBR systems.
- M. Richwine, 2019 Excellence Award of the Electric System Integration Group (ESIG) for his work related to advances in planning and analysis for low inertia grids.
- M. Richwine, D. Stenclik, 2016 Next Generation Network Paper Competition, 1st Place, CIGRE-US National Committee.

PUBLICATIONS

- **M. Richwine**, I. Anselmo, P. Cicilio and A. Francisco, "Grid-Forming Inverter Batteries for Enhanced System Stability in Alaska's Islanded Railbelt Electric Grid," 2024 IEEE Power & Energy Society General Meeting (PESGM), Seattle, WA, USA, 2024, pp. 1-5
- **M. Richwine**, et al, Power System Stability Analysis & Planning Using Impedance-Based Methods, 22nd Wind & Solar Integration Workshop, Copenhagen, Denmark, 26 – 28 September 2023
- **M. Richwine**, D. Stenclik, Coordination of Distributed Resources in the Provision of Essential Reliability Services for Active Power Management, CIGRE C2/C6 PS3 Centennial 2021.
- **M. Richwine**, D. Stenclik, Analysis and Impact of Autonomous Fast Frequency Response Relative to Synchronous Machine Sources on Oahu, CIGRE-US Grid of the Future, Reston, 2018.
- D. Stenclik, **M. Richwine**, C. Cox, To Shift or Not to Shift? An Energy Storage Analysis from Hawaii, Hybrid Power Systems Workshop, Tenerife, May 2018.
- D. Stenclik, **M. Richwine**, N. Miller, The Role of Fast Frequency Response in Low Inertia Power Systems, CIGRE Session, Paris, 2018.
- **M. Richwine**, D. Stenclik, Analysis of Grid Strength for Inverter-Based Generation Resources on Oahu, CIGRE-US Grid of the Future, Cleveland, 2017.
- **M. Richwine**, D. Stenclik, An Integrated Approach to Analyzing the Impact of Increasing Distributed PV Generation on Dynamic Stability in Oahu, CIGRE-US Grid of the Future, Philadelphia, 2016.
- **M. Richwine**, J. Sanchez-Gasca, N. Miller, Validation of a Second-Generation Type 3 Generic Wind Model, IEEE PES General Meeting, 2014.

MR-2:

Company response to Staff discovery request

STF-DEA-2-4

Georgia Power Company
Docket Nos. 56002 & 56003
2025 Integrated Resource Plan and 2025 Demand-Side Management Application
STF-DEA Data Request Set No. 2

STF-DEA-2-4

Question:

Please refer to p. 10 of the "TRANSMISSION PLANNING DESCRIPTION & PROCESS" of "2025 IRP Volume 3 PUBLIC DISCLOSURE", regarding the use of economic dispatch in creating load flow base cases. Please identify and describe the specific steps that are taken to create "unit-off" and area max cases with an economic dispatch tool.

Response:

Python scripts are applied to the Company's base cases for pre-defined unit off and area max scenarios. An economic dispatch tool will dispatch the remaining units, based on economics, to balance the remaining available generation with the existing load. Generation units are dispatched to meet the load obligations of the Georgia Integrated Transmission System ("ITS") Participants. For details on Generation Scenario Cases, please refer to Section B, Table 16 (p. 269) of the 2024 GA ITS Ten-Year Plan in Technical Appendix Volume 3.

MR-3:

Company response to Staff discovery request
STF-DEA-2-5

Georgia Power Company
Docket Nos. 56002 & 56003
2025 Integrated Resource Plan and 2025 Demand-Side Management Application
STF-DEA Data Request Set No. 2

STF-DEA-2-5

Question:

Please refer to p. 33 of the "TRANSMISSION PLANNING DESCRIPTION & PROCESS" of "2025 IRP Volume 3 PUBLIC DISCLOSURE", regarding the Economic Dispatch Program.

a. When the Economic Dispatch Program is used by planners, is a security-constrained economic dispatch methodology employed?

b. It is said that "the most economical dispatch is obtained by operating all on-line units at the same incremental cost". Explain how this methodology is applied to create unit-off and area max load flow cases.

Response:

a. No, a security-constrained economic dispatch methodology is not employed.

b. The units specified by the Unit Off or Area Max cases being applied are committed and dispatched to the output levels defined by those Unit Off/Area Max definitions, and the remainder of the needed generation is dispatched economically. Please refer to the Company's response to STF-DEA-2-4. For details on Generation Scenario Cases, refer to Section B, Table 16 (p. 269) of the 2024 GA ITS Ten-Year Plan in Technical Appendix Volume 3.

MR-4:

Company response to Staff discovery request STF-PIA-1-10

STF-PIA-1-10

Question:

[1]**In the 2025 IRP Main Document on page 1:** *Georgia Power's risk-adjusted load forecast from the winter of 2024/2025 through the winter of 2030/2031 reflects approximately 8,200 MW of load growth, representing an increase of more than 2,200 MW compared to load growth projections in the 2023 IRP Update for the same period.*

a. For the 8200 MW of load growth identify the specific customers, customers' location, load ramp (loads and dates), final load (MW), the customers' Request For Service agreement, the customers' Contract For Electric Service agreement, and the customers' location inside or outside Georgia Power service territory.

b. If specific customers do not account for the entire 8200 MW then identify how the remaining load growth was developed.

Response:

a. Large load customers account for much of the increase to the load forecast. For a detailed list of the large load economic development pipeline assumed in the load forecast used in the 2025 IRP, including location, announced load ramp, and whether the project is inside or outside Georgia Power Territory, please refer to Georgia Power's Q2 2024 Large Load Economic Development Report filed on August 16, 2024. The Excel file from this report that contains the details listed above is provided as STF-PIA-1-10 Attachment Y TRADE SECRET.

   Due to the size and differing levels of progress of each project, the Company continues to utilize the Load Realization Model ("LRM") developed for the 2023 IRP Update. This model uses a probabilistic approach to evaluate the range and likelihood of future potential outcomes of load growth from new committed and prospective large load customers. The model accounts for the size and various progress stages of individual projects in Georgia Power's large load economic development pipeline. The LRM assesses the risk associated with announced loads being realized by assigning lower likelihoods than to committed customers. As such, all projects are included in the load forecast but at different levels of materialization.

   For the requested Request for Service agreements please refer to the following attachments:

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[1] For purposes of this filing, the winter of two years that are listed together refers to the period from December of the first year through February of the following year. For example, the winter of 2030/2031 refers to the period from December 2030 through February 2031.

STF-PIA-1-10 Attachment A TRADE SECRET
STF-PIA-1-10 Attachment B TRADE SECRET
STF-PIA-1-10 Attachment C TRADE SECRET
STF-PIA-1-10 Attachment D TRADE SECRET
STF-PIA-1-10 Attachment E TRADE SECRET
STF-PIA-1-10 Attachment F TRADE SECRET
STF-PIA-1-10 Attachment G TRADE SECRET
STF-PIA-1-10 Attachment H TRADE SECRET
STF-PIA-1-10 Attachment I TRADE SECRET
STF-PIA-1-10 Attachment J TRADE SECRET
STF-PIA-1-10 Attachment K TRADE SECRET
STF-PIA-1-10 Attachment L TRADE SECRET

For the requested Contracts for Electric Service agreements please refer to the following attachments:

STF-PIA-1-10 Attachment M TRADE SECRET
STF-PIA-1-10 Attachment N TRADE SECRET
STF-PIA-1-10 Attachment O.1 TRADE SECRET
STF-PIA-1-10 Attachment O.2 TRADE SECRET
STF-PIA-1-10 Attachment O.3 TRADE SECRET
STF-PIA-1-10 Attachment P TRADE SECRET
STF-PIA-1-10 Attachment Q.1 TRADE SECRET
STF-PIA-1-10 Attachment Q.2 TRADE SECRET
STF-PIA-1-10 Attachment Q.3 TRADE SECRET
STF-PIA-1-10 Attachment Q.4 TRADE SECRET
STF-PIA-1-10 Attachment R TRADE SECRET
STF-PIA-1-10 Attachment S TRADE SECRET
STF-PIA-1-10 Attachment T TRADE SECRET
STF-PIA-1-10 Attachment U.1 TRADE SECRET
STF-PIA-1-10 Attachment U.2 TRADE SECRET
STF-PIA-1-10 Attachment V TRADE SECRET
STF-PIA-1-10 Attachment W TRADE SECRET
STF-PIA-1-10 Attachment X.1 TRADE SECRET
STF-PIA-1-10 Attachment X.2 TRADE SECRET

b. The load forecast is developed by combining two components: the organic forecast and external adjustments. The organic forecast estimates the load growth of existing lines of business based on historical data. External adjustments account for the forecasted load from new customers and new lines of business that are not part of the historical data. Together, these two components form the total company forecast, which accounts for the entire 8,200

MW of load growth. In summary, a significant portion of the 8,200 MW comes from large load customers, while the remainder is derived from the organic forecast.

These files have been redacted in their entirety.

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These files have been redacted in their entirety.

These files have been redacted in their entirety.

These files have been redacted in their entirety.

These files have been redacted in their entirety.

Project Name	*City*
REDACTED	**REDACTED**
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REDACTED	REDACTED
REDACTED	REDACTED
REDACTED	REDACTED
REDACTED	REDACTED
REDACTED	REDACTED

*Announced load as of 2037

County	*GPS Coordinates*	*Class*	*Segment*
REDACTED	**REDACTED**	Industrial	Manufacturing
REDACTED	**REDACTED**	Commercial	Data Center
REDACTED	**REDACTED**	Commercial	Data Center
REDACTED	**REDACTED**	Commercial	Data Center
REDACTED	**REDACTED**	Commercial	Data Center
REDACTED	**REDACTED**	Commercial	Data Center
REDACTED	**REDACTED**	Commercial	Data Center
REDACTED	**REDACTED**	Commercial	Data Center
REDACTED	**REDACTED**	Commercial	Data Center
REDACTED	**REDACTED**	Commercial	Data Center
REDACTED	**REDACTED**	Commercial	Data Center
REDACTED	**REDACTED**	Commercial	Data Center
REDACTED	**REDACTED**	Commercial	Data Center
REDACTED	**REDACTED**	Industrial	Clean Energy Tech
REDACTED	**REDACTED**	Commercial	Data Center
REDACTED	**REDACTED**	Commercial	Data Center
REDACTED	**REDACTED**	Industrial	Other
REDACTED	**REDACTED**	Industrial	Clean Energy Tech
REDACTED	**REDACTED**	Commercial	Data Center
REDACTED	**REDACTED**	Commercial	Data Center
REDACTED	**REDACTED**	Commercial	Data Center
REDACTED	**REDACTED**	Commercial	Data Center
REDACTED	**REDACTED**	Commercial	Data Center
REDACTED	**REDACTED**	Commercial	Data Center
REDACTED	**REDACTED**	Commercial	Data Center
REDACTED	**REDACTED**	Commercial	Data Center
REDACTED	**REDACTED**	Commercial	Data Center
REDACTED	**REDACTED**	Commercial	Data Center
REDACTED	**REDACTED**	Commercial	Data Center
REDACTED	**REDACTED**	Industrial	Other
REDACTED	**REDACTED**	Commercial	Data Center
REDACTED	**REDACTED**	Industrial	Other
REDACTED	**REDACTED**	Commercial	Data Center
REDACTED	**REDACTED**	Industrial	Clean Energy Tech
REDACTED	**REDACTED**	Industrial	Manufacturing
REDACTED	**REDACTED**	Commercial	Data Center
REDACTED	**REDACTED**	Commercial	Data Center
REDACTED	**REDACTED**	Industrial	Manufacturing
REDACTED	**REDACTED**	Industrial	Other
REDACTED	**REDACTED**	Commercial	Data Center
REDACTED	**REDACTED**	Commercial	Data Center
REDACTED	**REDACTED**	Commercial	Data Center
REDACTED	**REDACTED**	Industrial	Clean Energy Tech
REDACTED	**REDACTED**	Industrial	Manufacturing
REDACTED	**REDACTED**	Industrial	Manufacturing
REDACTED	**REDACTED**	Commercial	Data Center

REDACTED	**REDACTED**	Commercial	Data Center
REDACTED	**REDACTED**	Commercial	Data Center
REDACTED	**REDACTED**	Industrial	Clean Energy Tech
REDACTED	**REDACTED**	Commercial	Data Center
REDACTED	**REDACTED**	Industrial	Manufacturing
REDACTED	**REDACTED**	Industrial	Clean Energy Tech
REDACTED	**REDACTED**	Commercial	Data Center
REDACTED	**REDACTED**	Commercial	Data Center
REDACTED	**REDACTED**	Commercial	Data Center
REDACTED	**REDACTED**	Industrial	Clean Energy Tech
REDACTED	**REDACTED**	Industrial	Other
REDACTED	**REDACTED**	Commercial	Data Center
REDACTED	**REDACTED**	Commercial	Data Center
REDACTED	**REDACTED**	Commercial	Data Center
REDACTED	**REDACTED**	Commercial	Data Center
REDACTED	**REDACTED**	Commercial	Data Center
REDACTED	**REDACTED**	Commercial	Data Center
REDACTED	**REDACTED**	Commercial	Data Center
REDACTED	**REDACTED**	Commercial	Data Center
REDACTED	**REDACTED**	Commercial	Data Center
REDACTED	**REDACTED**	Commercial	Data Center
REDACTED	**REDACTED**	Commercial	Data Center
REDACTED	**REDACTED**	Commercial	Data Center
REDACTED	**REDACTED**	Commercial	Data Center

Territory	*Project Stage*	*Announced Load**	*Initial Service Date*
Outside	Contract for Electric Service	52	Q2 2024
Inside	Request for Electric Service	720	Q2 2027
Outside	Request for Electric Service	180	Q2 2026
Inside	Technical Review	300	Q2 2026
Inside	Technical Review	780	Q2 2026
Inside	Request for Electric Service	693	Q4 2025
Inside	Technical Review	481	Q4 2025
Inside	Technical Review	651	Q2 2027
Inside	Technical Review	365	Q4 2025
Inside	Technical Review	144	Q2 2026
Inside	Contract for Electric Service	182	Q2 2026
Inside	Contract for Electric Service	216	Q2 2026
Inside	Contract for Electric Service	324	Q2 2026
Inside	Technical Review	60	Q2 2026
Inside	Technical Review	311	Q4 2024
Inside	Technical Review	243	Q2 2027
Inside	Technical Review	200	Q1 2025
Outside	Contract for Electric Service	202	Q2 2024
Inside	Technical Review	163	Q2 2025
Inside	Technical Review	200	Q2 2027
Inside	Technical Review	455	Q4 2025
Inside	Technical Review	130	Q4 2024
Inside	Technical Review	500	Q2 2026
Outside	Contract for Electric Service	200	Q1 2025
Inside	Contract for Electric Service	240	Q1 2025
Inside	Technical Review	162	Q2 2028
Outside	Technical Review	130	Q2 2029
Multiple Sites	Technical Review	192	Q2 2030
Inside	Contract for Electric Service	180	Q4 2025
Multiple Sites	Technical Review	135	Q4 2024
Inside	Technical Review	150	Q2 2027
Multiple Sites	Technical Review	245	Q2 2026
Multiple Sites	Technical Review	250	Q2 2026
Inside	Technical Review	80	Q4 2024
Multiple Sites	Technical Review	53	Q4 2025
Inside	Technical Review	500	Q2 2027
Inside	Technical Review	151	Q2 2027
Multiple Sites	Technical Review	1,280	Q2 2029
Inside	Technical Review	115	Q2 2026
Inside	Technical Review	180	Q2 2025
Inside	Technical Review	656	Q2 2026
Multiple Sites	Technical Review	460	Q4 2025
Outside	Technical Review	250	Q2 2026
Outside	Technical Review	50	Q2 2026
Inside	Request for Electric Service	105	Q2 2025
Inside	Technical Review	216	Q2 2026

Inside	Technical Review	250	Q2 2026
Inside	Technical Review	1,000	Q4 2025
Inside	Technical Review	717	Q3 2025
Inside	Technical Review	335	Q2 2027
Outside	Request for Electric Service	79	Q2 2025
Inside	Request for Electric Service	90	Q3 2024
Inside	Technical Review	432	Q2 2027
Outside	Contract for Electric Service	1,429	Q2 2024
Outside	Technical Review	115	Q4 2025
Inside	Contract for Electric Service	126	Q3 2023
Inside	Technical Review	49	Q2 2026
Inside	Technical Review	650	Q2 2026
Inside	Request for Electric Service	432	Q2 2026
Inside	Technical Review	321	Q4 2024
Outside	Request for Electric Service	240	Q2 2025
Inside	Request for Electric Service	300	Q2 2027
Inside	Technical Review	600	Q2 2027
Inside	Request for Electric Service	285	Q2 2027
Inside	Request for Electric Service	180	Q2 2026
Inside	Contract for Electric Service	150	Q2 2024
Inside	Technical Review	533	Q2 2026
Inside	Request for Electric Service	502	Q4 2025
Inside	Technical Review	271	Q2 2027
Inside	Contract for Electric Service	145	Q2 2028

Load Ramp

2023	*2024*	*2025*	*2026*	*2027*	*2028*	*2029*	*2030*
	16	52	52	52	52	52	52
			0	90	285	510	695
	0	0	40	110	175	180	180
			100	200	300	300	300
			15	195	390	585	780
		2	10	87	173	260	347
		14	118	261	404	481	481
				74	149	223	307
		5	125	245	365	365	365
			36	72	108	144	144
			72	128	182	182	182
0	0	0	30	90	150	216	216
0	0	0	94	159	213	256	324
			30	60	60	60	60
	2	10	104	208	311	311	311
				39	63	115	167
		25	200	200	200	200	200
	60	113	144	162	192	197	202
		5	80	163	163	163	163
				40	80	160	200
		5	95	185	275	365	455
	5	5	68	130	130	130	130
			75	150	250	350	450
		10	30	60	90	130	180
		10	30	60	100	140	190
					50	100	162
						30	80
							35
		2	60	60	120	120	180
	25	25	135	135	135	135	135
				75	150	150	150
			85	85	245	245	245
			125	250	250	250	250
	5	5	40	40	80	80	80
		15	15	53	53	53	53
				500	500	500	500
				126	151	151	151
						10	50
			48	97	115	115	115
		15	45	90	180	180	180
			52	126	209	304	353
		140	300	460	460	460	460
			250	250	250	250	250
			50	50	50	50	50
		5	91	105	105	105	105
			36	108	180	216	216

			75	150	200	250	250
		5	15	250	500	750	1,000
		5	5	5	540	717	717
				134	268	335	335
		26	47	47	64	64	64
	61	90	90	90	90	90	90
				72	216	288	360
	81	400	768	975	1,054	1,429	1,429
		22	30	90	95	115	115
10	50	73	87	95	106	115	126
			12	12	49	49	49
			120	191	247	303	359
			60	108	216	324	432
	3	25	120	209	301	321	321
		15	155	240	240	240	240
				75	150	225	300
				150	300	600	600
				100	200	285	285
0	0	0	36	108	180	180	180
	20	140	150	150	150	150	150
			10	107	213	320	427
		24	63	119	184	253	309
0	0	0	0	33	48	79	97
					97	104	145

2031	*2032*	*2033*	*2034*	*2035*	*2036*	*2037*
52	52	52	52	52	52	52
720	720	720	720	720	720	720
180	180	180	180	180	180	180
300	300	300	300	300	300	300
780	780	780	780	780	780	780
433	520	606	693	693	693	693
481	481	481	481	481	481	481
419	530	642	651	651	651	651
365	365	365	365	365	365	365
144	144	144	144	144	144	144
182	182	182	182	182	182	182
216	216	216	216	216	216	216
324	324	324	324	324	324	324
60	60	60	60	60	60	60
311	311	311	311	311	311	311
208	243	243	243	243	243	243
200	200	200	200	200	200	200
202	202	202	202	202	202	202
163	163	163	163	163	163	163
200	200	200	200	200	200	200
455	455	455	455	455	455	455
130	130	130	130	130	130	130
500	500	500	500	500	500	500
200	200	200	200	200	200	200
240	240	240	240	240	240	240
162	162	162	162	162	162	162
130	130	130	130	130	130	130
70	105	140	175	192	192	192
180	180	180	180	180	180	180
135	135	135	135	135	135	135
150	150	150	150	150	150	150
245	245	245	245	245	245	245
250	250	250	250	250	250	250
80	80	80	80	80	80	80
53	53	53	53	53	53	53
500	500	500	500	500	500	500
151	151	151	151	151	151	151
1,280	1,280	1,280	1,280	1,280	1,280	1,280
115	115	115	115	115	115	115
180	180	180	180	180	180	180
407	461	503	536	581	623	656
460	460	460	460	460	460	460
250	250	250	250	250	250	250
50	50	50	50	50	50	50
105	105	105	105	105	105	105
216	216	216	216	216	216	216

250	250	250	250	250	250	250
1,000	1,000	1,000	1,000	1,000	1,000	1,000
717	717	717	717	717	717	717
335	335	335	335	335	335	335
79	79	79	79	79	79	79
90	90	90	90	90	90	90
432	432	432	432	432	432	432
1,429	1,429	1,429	1,429	1,429	1,429	1,429
115	115	115	115	115	115	115
126	126	126	126	126	126	126
49	49	49	49	49	49	49
415	471	527	583	650	650	650
432	432	432	432	432	432	432
321	321	321	321	321	321	321
240	240	240	240	240	240	240
300	300	300	300	300	300	300
600	600	600	600	600	600	600
285	285	285	285	285	285	285
180	180	180	180	180	180	180
150	150	150	150	150	150	150
533	533	533	533	533	533	533
387	441	480	502	502	502	502
140	179	233	255	271	271	271
145	145	145	145	145	145	145

New Project?	*Change in Announced Load*	*Load Ramp*	*Project Stage*
		Y	Y
		Y	
		Y	
Y			
Y			
	Y	Y	Y
	Y	Y	
Y			
	Y	Y	
		Y	
		Y	Y
		Y	
	Y	Y	
		Y	Y
Y			
Y			
Y			
	Y	Y	
Y			
Y			
		Y	
Y			
	Y	Y	
Y			
Y			
	Y	Y	

Y			
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	Y	Y	
Y			
	Y	Y	
		Y	
	Y	Y	
		Y	
Y			
		Y	
	Y	Y	
	Y	Y	
Y			
		Y	
	Y	Y	Y

Initial Service Date
Y
Y
Y
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Y

Y

Y
Y

2C7D8C3077B37D1C68CC9B55A8DA97B0.xlsx **PUBLIC DISCLOSURE**

Project Name	*Q2 2024*	*Q1 2024*	*Change*
REDACTED	693	983	-290
REDACTED	481	1,110	-629
REDACTED	365	245	120
REDACTED	60	120	-60
REDACTED	180	120	60
REDACTED	115	260	-145
REDACTED	105	110	-5
REDACTED	717	552	165
REDACTED	79	78	1
REDACTED	1,429	1,492	-63
REDACTED	300	150	150
REDACTED	285	200	85
REDACTED	145	115	30

Project Name	*Q2 2024* *2023*	*2024*	*2025*	*2026*
REDACTED		16	52	52
REDACTED				0
REDACTED		0	0	40
REDACTED			2	10
REDACTED			14	118
REDACTED			5	125
REDACTED				36
REDACTED	0	0	0	30
REDACTED	0	0	0	94
REDACTED				30
REDACTED		60	113	144
REDACTED			2	60
REDACTED				
REDACTED				48
REDACTED			5	91
REDACTED			5	5
REDACTED			26	47
REDACTED				
REDACTED		81	400	768
REDACTED				60
REDACTED			15	155
REDACTED				
REDACTED				
REDACTED				10
REDACTED				

2027	2028	2029	2030	2031	2032	2033	2034
52	52	52	52	52	52	52	52
90	285	510	695	720	720	720	720
110	175	180	180	180	180	180	180
87	173	260	347	433	520	606	693
261	404	481	481	481	481	481	481
245	365	365	365	365	365	365	365
72	108	144	144	144	144	144	144
90	150	216	216	216	216	216	216
159	213	256	324	324	324	324	324
60	60	60	60	60	60	60	60
162	192	197	202	202	202	202	202
60	120	120	180	180	180	180	180
500	500	500	500	500	500	500	500
97	115	115	115	115	115	115	115
105	105	105	105	105	105	105	105
5	540	717	717	717	717	717	717
47	64	64	64	79	79	79	79
72	216	288	360	432	432	432	432
975	1,054	1,429	1,429	1,429	1,429	1,429	1,429
108	216	324	432	432	432	432	432
240	240	240	240	240	240	240	240
75	150	225	300	300	300	300	300
100	200	285	285	285	285	285	285
107	213	320	427	533	533	533	533
	97	104	145	145	145	145	145

2C7D8C3077B37D1C68CC9B55A8DA97B0.xlsx **PUBLIC DISCLOSURE**

			Q1 2024				
2035	*2036*	*2037*	*2023*	*2024*	*2025*	*2026*	*2027*
52	52	52	0	0	16	25	52
720	720	720	0	0	0	0	70
180	180	180	0	0	40	110	175
693	693	693	0	78	480	650	820
481	481	481	0	0	0	3	58
365	365	365	0	0	5	65	125
144	144	144	0	0	36	72	108
216	216	216	0	0	30	60	100
324	324	324	0	0	0	94	159
60	60	60	0	0	60	120	120
202	202	202	0	63	116	147	165
180	180	180	0	60	120	120	120
500	500	500	0	0	0	500	500
115	115	115	0	0	0	60	200
105	105	105	0	0	70	110	110
717	717	717	0	0	5	5	5
79	79	79	0	0	27	52	52
432	432	432	0	0	0	72	216
1,429	1,429	1,429	0	65	321	578	677
432	432	432	0	0	0	108	216
240	240	240	0	0	20	180	240
300	300	300	0	0	0	75	150
285	285	285	0	0	0	0	100
533	533	533	0	2	10	107	213
145	145	145	0	0	0	0	0

2028	*2029*	*2030*	*2031*	*2032*	*2033*	*2034*	*2035*	*2036*
52	52	52	52	52	52	52	52	52
285	510	695	720	720	720	720	720	720
180	180	180	180	180	180	180	180	180
983	983	983	983	983	983	983	983	983
376	702	1041	1110	1110	1110	1110	1110	1110
185	245	245	245	245	245	245	245	245
144	144	144	144	144	144	144	144	144
140	216	216	216	216	216	216	216	216
213	256	292	313	324	324	324	324	324
120	120	120	120	120	120	120	120	120
192	197	202	202	202	202	202	202	202
120	120	120	120	120	120	120	120	120
500	500	500	500	500	500	500	500	500
230	260	260	260	260	260	260	260	260
110	110	110	110	110	110	110	110	110
540	552	552	552	552	552	552	552	552
78	78	78	78	78	78	78	78	78
288	360	432	432	432	432	432	432	432
740	812	884	956	1028	1100	1172	1239	1271
324	432	432	432	432	432	432	432	432
240	240	240	240	240	240	240	240	240
150	150	150	150	150	150	150	150	150
200	200	200	200	200	200	200	200	200
320	427	533	533	533	533	533	533	533
97	104	115	115	115	115	115	115	115

	Change							
2037	*2023*	*2024*	*2025*	*2026*	*2027*	*2028*	*2029*	*2030*
52	-	16	36	27	-	-	-	-
720	-	-	-	-	20	-	-	-
180	-	-	(40)	(70)	(65)	(5)	-	-
983	-	(78)	(478)	(640)	(733)	(810)	(723)	(636)
1110	-	-	14	115	203	28	(221)	(560)
245	-	-	-	60	120	180	120	120
144	-	-	(36)	(36)	(36)	(36)	-	-
216	-	-	(30)	(30)	(10)	10	-	-
324	-	-	-	-	-	-	-	32
120	-	-	(60)	(90)	(60)	(60)	(60)	(60)
202	-	(3)	(3)	(3)	(3)	-	-	-
120	-	(60)	(118)	(60)	(60)	-	-	60
500	-	-	-	(500)	-	-	-	-
260	-	-	-	(12)	(103)	(115)	(145)	(145)
110	-	-	(65)	(19)	(5)	(5)	(5)	(5)
552	-	-	-	-	-	-	165	165
78	-	-	(1)	(5)	(5)	(14)	(14)	(14)
432	-	-	-	(72)	(144)	(72)	(72)	(72)
1492	-	16	79	190	298	314	617	545
432	-	-	-	(48)	(108)	(108)	(108)	-
240	-	-	(5)	(25)	-	-	-	-
150	-	-	-	(75)	(75)	-	75	150
200	-	-	-	-	-	-	85	85
533	-	(2)	(10)	(97)	(106)	(107)	(107)	(106)
115	-	-	-	-	-	-	-	30

2031	2032	2033	2034	2035	2036	2037
-	-	-	-	-	-	-
-	-	-	-	-	-	-
-	-	-	-	-	-	-
(550)	(463)	(377)	(290)	(290)	(290)	(290)
(629)	(629)	(629)	(629)	(629)	(629)	(629)
120	120	120	120	120	120	120
-	-	-	-	-	-	-
-	-	-	-	-	-	-
11	-	-	-	-	-	-
(60)	(60)	(60)	(60)	(60)	(60)	(60)
-	-	-	-	-	-	-
60	60	60	60	60	60	60
-	-	-	-	-	-	-
(145)	(145)	(145)	(145)	(145)	(145)	(145)
(5)	(5)	(5)	(5)	(5)	(5)	(5)
165	165	165	165	165	165	165
1	1	1	1	1	1	1
-	-	-	-	-	-	-
473	401	329	257	190	158	(63)
-	-	-	-	-	-	-
-	-	-	-	-	-	-
150	150	150	150	150	150	150
85	85	85	85	85	85	85
-	-	-	-	-	-	-
30	30	30	30	30	30	30

Project Name	*Q2 2024*
REDACTED	Contract for Electric Service
REDACTED	Request for Electric Service
REDACTED	Contract for Electric Service
REDACTED	Contract for Electric Service
REDACTED	Contract for Electric Service

Q1 2024

Request for Electric Service

Technical Review

Request for Electric Service

Request for Electric Service

Request for Electric Service

Project Name	*Q2 2024*
REDACTED	Q2 2024
REDACTED	Q2 2026
REDACTED	Q4 2025
REDACTED	Q4 2025
REDACTED	Q4 2025
REDACTED	Q2 2026
REDACTED	Q2 2026
REDACTED	Q2 2026
REDACTED	Q4 2024
REDACTED	Q1 2025
REDACTED	Q1 2025
REDACTED	Q4 2025
REDACTED	Q4 2024
REDACTED	Q4 2024
REDACTED	Q4 2025
REDACTED	Q2 2027
REDACTED	Q4 2025
REDACTED	Q3 2024
REDACTED	Q2 2027
REDACTED	Q4 2025
REDACTED	Q2 2027
REDACTED	Q2 2026
REDACTED	Q4 2025

Q1 2024	*Change (Months)*
Q2 2025	-12
Q3 2025	9
Q2 2024	18
Q2 2026	-6
Q2 2025	6
Q1 2025	15
Q3 2025	9
Q2 2025	12
Q2 2024	6
Q2 2025	-3
Q2 2025	-3
Q2 2024	18
Q2 2024	18
Q2 2024	18
Q2 2025	18
Q2 2026	12
Q2 2025	6
Q2 2024	3
Q2 2026	12
Q2 2025	6
Q2 2026	12
Q1 2024	27
Q1 2025	9

2C7D8C3077B37D1C68CC9B55A8DA97B0.xlsx **PUBLIC DISCLOSURE**

Project Name	*Announced Load (MW) in 1Q Update*
REDACTED	150
REDACTED	200
REDACTED	66
REDACTED	433
REDACTED	630
REDACTED	86
REDACTED	50
REDACTED	100
REDACTED	700
REDACTED	180

Note
Load now falls below 110 MW threshold for Commercial Large Load Customer.

Reason for Removal
Project Cancelled
See Note
Project Cancelled
Project Delayed Indefinitely
Project Cancelled
Selected Alternative State
Project Delayed Indefinitely
Project Delayed Indefinitely
Project Cancelled
Project Cancelled

MR-5:

Company response to Staff discovery request
STF-PIA-5-16

STF-PIA-5-16

<u>Question:</u>

Please provide the assumed interconnection bus (location) and ratings (Pload and Qload) for each new large load assumed in the IRP.

<u>Response:</u>

Please refer to STF-PIA-5-16 Attachment TRADE SECRET.

Station Name	PSSE Bus Number	Customer Name	Bus Name	Zone	TEAMS Project Number	2025 MW	2025 MVar	2026 MW	2026 MVar	2027 MW	2027 MVar	2028 MW	2028 MVar	2029 MW	2029 MVar	2030 MW	2030 MVar	2031 MW	2031 MVar	2032 MW	2032 MVar	2033 MW	2033 MVar	2034 MW	2034 MVar	2035 MW	2035 MVar
TWO RUN RANCH	REDACTED	REDACTED	REDACTED	REDACTED	20175	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
GREAT VALLEY	REDACTED	REDACTED	REDACTED	REDACTED	20031	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
TRAE LANE	REDACTED	REDACTED	REDACTED	REDACTED	19962	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
SHUGART FARMS	REDACTED	REDACTED	REDACTED	REDACTED	18736	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
MIDWAY	REDACTED	REDACTED	REDACTED	REDACTED	18996	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
HYUNDAI MOTORS	REDACTED	REDACTED	REDACTED	REDACTED	19523	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
ALIGNED - WINSTON (BAGGETT)	REDACTED	REDACTED	REDACTED	REDACTED	20769	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
BULLARD ROAD	REDACTED	REDACTED	REDACTED	REDACTED	20134	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
TRAMMEL CROW - WALDRUP FARMS	REDACTED	REDACTED	REDACTED	REDACTED	20770	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
SUMMER LAKE	REDACTED	REDACTED	REDACTED	REDACTED	19433	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
AWS BUTTS COUNTY (TOWALIGA)	REDACTED	REDACTED	REDACTED	REDACTED	20716	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
TILFORD YARDS	REDACTED	REDACTED	REDACTED	REDACTED	19590	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
CENTENNIAL YARDS	REDACTED	REDACTED	REDACTED	REDACTED	19411	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
DC BLOX (FARMER RD)	REDACTED	REDACTED	REDACTED	REDACTED	20463	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
SOUTHMEADOW	REDACTED	REDACTED	REDACTED	REDACTED	19432	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
TA REALTY - ELLENWOOD	REDACTED	REDACTED	REDACTED	REDACTED	20518	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
T5 SHUGART	REDACTED	REDACTED	REDACTED	REDACTED	20993	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
TA REALTY (RED OAK)	REDACTED	REDACTED	REDACTED	REDACTED	20851	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
STONEWALL TELL ROAD (CUSTOMER OWNED)	REDACTED	REDACTED	REDACTED	REDACTED	20216	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
VANTAGE DC (MALLORY RD)	REDACTED	REDACTED	REDACTED	REDACTED	20633	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
BOULDER PARK	REDACTED	REDACTED	REDACTED	REDACTED	20581	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
CHARLES (CUSTOMER OWNED)	REDACTED	REDACTED	REDACTED	REDACTED	19904	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
CREOLA (CUSTOMER OWNED)	REDACTED	REDACTED	REDACTED	REDACTED	19904	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
DOWNRANGE	REDACTED	REDACTED	REDACTED	REDACTED	20223	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED

MR-6:

Company response to Staff discovery request STF-DEA-2-2

PUBLIC DISCLOSURE
Georgia Power Company
Docket Nos. 56002 & 56003
2025 Integrated Resource Plan and 2025 Demand-Side Management Application
STF-DEA Data Request Set No. 2

STF-DEA-2-2

Question:

Please refer to the 2025 IRP Main Document, p. 113, Table 11.3.

a. For any Strategic Projects not included in Appendix C of the "2024 GA ITS Ten-Year Plan," provided in Technical Appendix Vol. 3 document titled "2025 IRP Volume 3 PUBLIC DISCLOSURE," please provide Background and Problem Descriptions, Study Assumptions, Discussion of Alternatives, and Conclusions and Recommendations. This includes, but may not be limited to, the following projects.

b. Butler – Thomaston 230kV Line Conversion

c. Cavender Drive – Tributary 230kV Line

d. North Spa 230kV Area Project

e. Goshen Area 230kV Area Project

Response:

a. For the project details, refer to Section D1.IV, Analysis Results of the 2024 GA ITS Ten-Year Plan and Section H1, Identified Problems and Solutions in Technical Appendix Volume 3.

b. The conversion of the Butler – Thomaston 230kV line aims to address the evolving dynamics within the Georgia Integrated Transmission System ("ITS"), primarily driven by the changes in generation and forecasted load growth. This project involves rebuilding the radial Thomaston - Butler 115kV line to 230kV network operation. Additionally, supplemental projects include the conversion of the Wesley substation from 115kV to 230kV, upgrades and accommodations at Butler and Thomaston substations. The decision to undertake this project stems from the necessity to enhance available transmission capacity that will help with future Georgia Power generation requests for proposals ("RFP") solicitations. This project provides a REDACTED reduction of loading on the Bonaire Primary-Butler 230kV line, provides a new network connection (South to North), and increases the available capacity on this line from REDACTED (Summer B rating) to REDACTED (Summer B rating).

Refer to Technical Appendix Volume 3 Section H1.A, Thermal Problems and Solutions Report (SHOTD) and Section H2 for load flow files.

c. Please refer to STF-DEA-2-2 Attachment A TRADE SECRET for the Metro West Working Group Study report.

d. The North Spa 230kV Strategic Project, in conjunction with the GTC: Tiger Creek – Rockville – North Spa 230kV project, aims to address the evolving dynamics within the Georgia ITS, primarily driven by the changes in generation and forecasted load growth. This project involves building a new 230kV switching station and looping in the East Social Circle - Oasis (White) 230kV line. Additionally, this project builds a new 230kV line to Cornish Mountain from North Spa and terminates the new 230kV line from Rockville 230kV station to the North Spa station. The decision to undertake this project stems from the necessity to enhance available transmission capacity and mitigate thermal limits resulting from 230 kV contingencies under NERC TPL-001-5. This project will reduce loading and increase available capacity on various circuits, thereby alleviating or reducing thermal constraints on critical circuits under contingency scenarios. In addition, it provides an additional 230kV corridor from the Central region into the Metro East area and minimizes outage impacts to the transmission system. This project reduces loading on the following circuits:

Facility Name	Facility Rating (MVA)	Loading Reduction
Branch – Eatonton #2 230kV	**REDACTED**	**REDACTED**
Branch – Oasis 230kV	**REDACTED**	**REDACTED**
Branch – Glenwood Springs 230kV	**REDACTED**	**REDACTED**
Branch – Tiger Creek (White) 230kV	**REDACTED**	**REDACTED**
Branch – Tiger Creek (Black) 230kV	**REDACTED**	**REDACTED**
East Walton 500/230kV auto-transformer	**REDACTED**	**REDACTED**
Bostwick - East Walton 230kV	**REDACTED**	**REDACTED**
East Walton – Jack Creek 230kV	**REDACTED**	**REDACTED**

PUBLIC DISCLOSURE
Georgia Power Company
Docket Nos. 56002 & 56003
2025 Integrated Resource Plan and 2025 Demand-Side Management Application
STF-DEA Data Request Set No. 2

Refer to Technical Appendix Volume 3 Section H1.A, Thermal Problems and Solutions Report (SHOTD) and Section H2 for load flow files.

e. Please refer to STF-DEA-2-2 Attachment B TRADE SECRET for the Goshen Area Working Group Study report.

MR-7:

Rebuttal Testimony Georgia Power in response to Michael Goggin,

regarding proactively building 500 kV lines. (2023 IRP Update

Rebuttal Testimony - Main Panel - Public Disclosure Docket

55378, p.51)

the solutions proposed in the 2023 IRP Update and supplemental filings could complement future 500kV development.

Further, simply proposing to build more 500kV lines in the state misunderstands how transmission planning is coordinated with generation resource planning in Georgia and would result in very expensive infrastructure investment with no guarantee to alleviate known or anticipated transmission constraints. In deregulated markets, transmission owners build large transmission lines across states hoping that they have sited the infrastructure where independent power producers will seek to interconnect. In contrast, Georgia Power builds transmission as needed to deliver power from facilities that have been sited, financed, and have initiated the process of interconnecting to the System. Georgia Power's integrated approach ensures interconnections actually occur and minimizes transmission investments based upon speculation. Further, Witness Goggin's testimony seems to ignore the integrated nature of the transmission system in Georgia whereby Georgia Power jointly plans and operates the networked transmission system with the other Georgia ITS participants in the state: Georgia Transmission Corporation ("GTC") and the Municipal Electric Authority of Georgia ("MEAG").

In addition, adding or upgrading existing line voltage to 500 kV is not as simple as swapping out the line on existing structures. The Company requires additional rights of way access for larger voltage lines, the acquisition of which adds substantial time and cost to the process of rebuilding or retrofitting a line. Finally, Witness Goggin seems to gloss over the significant costs and time requirements associated with changing the voltage level of existing facilities, which would be additional costs borne by Georgia Power customers.

MR-8:

ATC Load Interconnection Guide Revision 12

Revision 12.0

Load Interconnection Guide

Energizing Your Future

AMERICAN TRANSMISSION COMPANY

Load Interconnection Guide

Revision 12.0
January 11, 2023

American Transmission Company
W234 N2000 Ridgeview Pwky. Court
Waukesha, WI 53188-1022

American Transmission Company (ATC) plans, constructs, owns, operates and maintains the high-voltage electric transmission system (69 kV and above) to provide adequate and reliable transmission of electric power in portions of Wisconsin, Michigan, Minnesota and Illinois. ATC is a member of the Midcontinent Independent System Operator (MISO) regional transmission organization, and provides nondiscriminatory service to all customers, supporting effective competition in energy markets without favoring any market participant. ATC owns more than 10,081 miles of transmission lines and 582 substations. ATC presently maintains more than 700 load interconnections with municipalities, cooperatives, and investor-owned utilities (Customers). For more information about ATC, visit our Web site at www.atcllc.com.

In general, ATC accommodates a Customer's new or modified load interconnections according to the requirements of a Distribution – Transmission Interconnection Agreement (D-T IA) between ATC and the Customer.[1] ATC will collaborate with the Customer in the development and implementation of the appropriate interconnection solution in response to the Customer's requested need. It is important to note that ATC provides no retail services. The direct interconnection of retail customers to ATC's transmission facilities is governed in part by requirements of the local distribution company or Customer in whose service territory the interconnection is requested.

The Customer is directed to ATC's Web site (https://www.atcllc.com/customer-engagement/connecting-to-the-grid/) for formal submittal of a load interconnection request for each of the following types of projects:

1 New load interconnections or,

2 Modifications to existing load interconnection facilities.

Any questions or requests for additional information concerning load interconnections to the ATC Transmission System should be directed to:

T-DLIRFS@atcllc.com
ATC Interconnection Solutions

[1] It is important to note that the phrase "load interconnection" is synonymous to "distribution-transmission interconnection." Capitalized Terms not defined in this Load Interconnection Guide have the meaning set forth in Attachment FF-ATCLLC of the MISO Open Access Transmission, Energy and Operating Reserve Markets Tariff.

Table of Contents

1 Introduction

1.1 Purpose

This Load Interconnection Guide is intended to be a single resource for a Customer working with ATC on a new or modified load interconnection. ATC is committed to working collaboratively with the Customer to effectively plan, develop and implement a safe and reliable new or modified load interconnection. This document provides ATC's minimum requirements and guidance to enable development and completion of load interconnections that consistently satisfy the needs of both ATC and its Customers. The minimum facility requirements described herein are consistent with the Facility Interconnection Requirements promulgated in Mandatory Reliability Standard FAC-001 Requirement R1 (as modified from time-to-time).

This guide generally applies to proposed new load interconnections. ATC will work with the Customer to apply this guide to modifications of an existing interconnection as appropriate, but also while respecting previous interconnection requirements, limitations, and other factors on a case-specific basis. This Guide may also apply to new load interconnections associated with the provision of auxiliary power to generation facilities when the auxiliary power interconnection facilities are a separate interconnection to the ATC Transmission System.

1.2 Legal and Regulatory Requirements

1.2.1 FERC

Throughout the interconnection process, ATC adheres to the FERC Standards of Conduct[2] as well as the rules relating to critical energy infrastructure information. If the LDC (Local Distribution Company) is a new customer of ATC's, a new Distribution – Transmission Interconnection Agreement (D-T IA) will need to be filed with FERC before the facility is energized. A Standards of Conduct Agreement (SOCA) will also be needed between the parties.

1.2.2 State

The states in which ATC operates have their own requirements for siting and construction. This guide is not intended to describe those requirements. The Customer will be responsible for compliance with the specific state requirements and processes. Further information regarding these requirements and processes is available from the pertinent state regulatory agency:

- Public Service Commission of Wisconsin - http://www.psc.wi.gov/
- Michigan Public Service Commission - http://www.michigan.gov/mpsc/
- Minnesota Public Utilities Commission - http://www.mn.gov/puc//
- Illinois Commerce Commission - http://www.icc.illinois.gov/

[2] Order No. 888, 61 FR 21540 (May 10, 1996)

1.2.3 NERC

ATC is registered as a Transmission Owner, Transmission Operator, and Transmission Planner with both the Midwest Reliability Organization (MRO) and Reliability*First* Corporation (RFC) under the requirements of the electric reliability organization, the North American Electric Reliability Corporation (NERC).

2 Load Interconnection Process

This section describes the process that ATC will follow in working with the Customer on a Load Interconnection or Distributed Energy Resource (DER) projects. See Appendix B for a high-level process overview diagram. ATC works with its Customers to accommodate all requests for load or DER interconnections utilizing the concept of Best Value Planning (BVP)[3]. The BVP process collaboratively establishes a consistent means of assessing an interconnection project that considers various project alternatives, including their costs, as well as issues relating to system performance, construction, maintenance, environmental impacts and regulatory requirements in relation to the requested in-service date. *See Also,* Attachment FF-ATCLLC of the Mid-continent Independent Transmission Operator (MISO) FERC Electric Tariff. Section 2.2 of this document further describes the Best Value Planning (BVP) process.

2.1 Process Initiation

As part of ATC's ongoing planning process, ATC maintains close working relationships with existing interconnected Customers in order for both parties to best understand both ATC and the Customer's present and future needs. ATC's planning processes and mechanisms are formally filed at FERC as part of the Midcontinent ISO tariff.[4]

ATC encourages Customers to share their knowledge of proposed interconnections and load forecasts as soon as possible and especially through regular interaction and meetings with ATC. However, ATC will formally develop a potential new or modified load or DER interconnection only after the Customer submits a Load Interconnection Request Form (LIRF) or DER Request Form (DERRF) to ATC. Upon submittal of a LIRF/DERRF, ATC will post updates on the status of the interconnection project on ATC's Distribution -Transmission (D-T) Interconnection Queue.[5]

Additionally, all existing ATC Customers are required to annually provide ATC with their respective 11-year load forecasts[6] that reflect expected load growth, modified and proposed new load interconnections to be used in the Ten-Year Assessment. ATC administers these potential modified or new interconnections reflected in the load forecasts via its D-T Interconnection Queue and includes all proposed interconnection projects that have completed the BVP process in ATC's annual system planning used for the 10-Year Assessment. These projects are also then listed in the appropriate MISO Transmission Expansion Planning (MTEP) report that is published in December of each year.

2.1.1 Load Interconnection Request

The first step in more specifically working with ATC to develop a new load interconnection requires the Customer to submit a completed Load Interconnection Request Form (LIRF) to ATC. An example of the LIRF template is included in Appendix D.

2.1.1.1 Scenarios Requiring a LIRF Submittal

[3] See BVP definition in Appendix A.1

[4] See Attachment FF-ATCLLC of the MISO FERC Electric Tariff.

[5] See http:// http://www.atcllc.com/customer-engagement/connecting-to-the-grid/

[6] See http://www.atc10yearplan.com/ for a complete description of the ATC Planning Ten Year Assessment.

The Customer should submit a LIRF to ATC for any additions or modifications to the distribution system that may be reasonably anticipated to have a potential impact on the Transmission System, including the scenarios shown in Table 1.

Table 1: Scenarios Requiring LIRF Submittal		
1	**New Distribution Interconnections**	New interconnections made via either a new or existing substation.
2	**Modifications to Existing Distribution Interconnections**	Modification of an existing load interconnection (e.g. replacement or addition of an interconnection transformer, capacitors).
3	**Un-forecasted Load**	The notable change of any load not included in the Customer's last 10-year load forecast to ATC.
4	**Power Quality**	Addition or modification of any loads or equipment that may affect power quality.
5	**Reliability Needs – Customer Request to Improve Interconnection Performance**	Customer requests ATC review transmission service reliability at the Point of Interconnection.

2.1.1.2 Distributed Energy Resource (DER) Request (DERRF)

The first step in more specifically working with ATC to develop a new DER interconnection requires the Customer to submit a completed DER Request Form (DERRF) to ATC. An example of the DERRF template is included in Appendix D.

The Customer should submit a DERRF to ATC when addition of, change to or removal of any generating capacity interconnected to a distribution system that's part of an existing load interconnection where the resulting aggregate DER generating capacity is greater than or equal to 1 MW (including battery storage system(s)). A DERRF submittal is also recommended for each additional 500 KW (after the previous DER BVP assessment) and for any equipment changes that modifies an existing DER's ability to isolate for transmission faults. Refer to the ATC DER Planning Guide for more information on protection requirements for DERs.[7]

2.1.1.3 Timing of a LIRF/DERRF Submittal

To enable ATC to meet the needs of the Customer, a LIRF/DERRF must be received sufficiently in advance of the Customer's requested in-service date for the new or modified load or DER interconnection. This will allow sufficient time for the following:

[7] See the footnote on page 41 for additional guidance.

- Effective BVP,
- Satisfaction of any necessary regulatory requirements and/or permitting,
- Complete design of necessary facilities,
- Order of long-lead time materials, and
- Safe and effective construction.

However, ATC is also mindful of the possibility of being counterproductive if a LIRF/DERRF is submitted prematurely and before the Customer can commit [more] firmly to certain project details. Therefore, ATC provides the following guidance for the Customer to consider with respect to when to submit a LIRF/DERRF. Ultimately, as part of BVP, ATC and the Customer will develop a mutually agreeable schedule for meeting both parties' needs with respect to the project in-service date.

The following discussion represents typical schedule requirements of ATC's project development and implementation process. Ultimately the ATC and Customer implementation team will establish a project-specific schedule that may deviate from the timelines noted below based upon project-specific details.

1. **Best Value Planning (6-18 months):**
   BVP between ATC and the Customer can typically take anywhere from 6 to 18 months, dependent upon extent of anticipated scope of work for both parties. At the outset of BVP, ATC and the Customer will agree on a specific development/BVP schedule.

2. **Construction Lead Time (18-60 months):**

   a. **12 months**
   Construction (after receipt of the appropriate project documentation[8]) will take 12 months for DER interconnections (any voltage) requiring only transmission line arrester upgrades.

   b. **18 months**
   Construction (after receipt of the appropriate project documentation) will take 18 months for load interconnections (any voltage) requiring transmission line extensions of less than 500 feet.

   c. **24 months**
   Construction (after receipt of the appropriate project documentation) will take 24 months for load interconnections at all voltages with transmission line extensions of 500 feet or greater, but less than 1 mile.

   d. **36-54 months**
   Construction (after receipt of the appropriate project documentation) will take 36-54 months for load interconnections requiring transmission line extensions greater than 1 mile at any transmission voltage.

   e. **54-60 months**
   Construction (after receipt of the appropriate project documentation) will take 54-60 months for load interconnections that potentially involve gas-insulated substations, underground transmission, other major

[8] The appropriate project documentation may consist of any one of these documents, a signed Best Value Plan Report, a signed Capital Work Letter, a Minimal Capital Work Letter, a signed Project Commitment Agreement, or a signed Facility Construction Agreement. It is the responsibility of both ATC and the Customer to determine the appropriate documentation to use for communicating the agreed upon project documentation to both Parties involved in the Project.

Transmission System reinforcements, or appropriate State Regulatory Approvals such as a Certificate of Public Convenience and Necessity (CPCN).

2.1.1.4 LIRF/DERRF Receipt Notice

Within 10 business days of the receipt of a LIRF/DERRF, ATC will acknowledge the receipt of the LIRF/DERRF with written communication back to the Customer (typically via e-mail) and indicate whether the LIRF/DERRF is complete or if additional information is required. If ATC indicates that the LIRF/DERRF is not complete, ATC still needs certain information from the Customer in order to effectively conduct its initial cross-functional evaluation and prepare for planning analyses.

ATC will typically respond to the Customer that a LIRF or DERRF is complete when the information provided in Table 2 or Table 3 has been received.

Table 2: LIRF Information Required in order to be "Complete"	
1	**Requestor Information –** contact information for the Customer
2	**Load Interconnection Information –** substation location (prospective geographic/physical location(s), especially for a new substation or expansion of an existing substation) and load characteristics
3	**10-Year Load Forecast –** supply a new load forecast if loads shifted or peak outside of typical summer peaking hours or indicate that the last forecast is still accurate
4	**One-line Diagram –** required for modified load interconnections, not necessarily required for new load interconnections
5	**Scope and Justification –** distribution scope of work and justification for the project

Table 3: DERRF Information Required in order to be "Complete"	
1	**Requestor Information –** contact information for the Customer
2	**DER Interconnection Information –** requested ATC point of interconnection, DER generator information, MISO Market participation, DER modeling information (including short circuit) and protective system/anti islanding capabilities
3	**Inverter Certification Information –** IEEE requirements and UL certifications
4	**One-line Diagram –** required for modified load interconnections, not necessarily required for new load interconnections
5	**Scope –** distribution scope of work for the DER project

ATC can only effectively coordinate with the Customer on a schedule to meet a requested in-service date after **all** information listed above has been included in a LIRF/DERRF. If all required information is not available at the time the LIRF/DERRF is submitted, the Customer should contact ATC as soon as possible to jointly determine what developmental work can be performed until the missing information becomes available.

2.1.1.5 Notification of Initial LIRF/DERRF Review

Within 20 business days of the LIRF/DERRF being deemed complete, ATC will communicate to the Customer one of the following:

1. ATC's initial assessment indicates that there are minimal or no anticipated upgrades to ATC's network Transmission System or Interconnection Facilities necessary for ATC to accommodate the proposed new or modified load or DER interconnection.

2. ATC's initial assessment indicates that it is likely that significant upgrades to ATC's network Transmission System and/or Interconnection Facilities will be required to accommodate the proposed new or modified load or DER interconnection. ATC will also seek a collaborative scoping conversation with the Customer to determine a schedule for Best Value Planning (BVP).

2.1.1.6 LIRF Revisions

If the Customer makes changes to the project that result in changes to LIRF/DERRF information (e.g. a delay in in-service date, scope of work revision, load forecast changes, etc.), ATC requests that the Customer submit a revised LIRF/DERRF to ATC to enable project development and/or implementation to continue. ATC will process the LIRF/DERRF in a manner similar to the original LIRF/DERRF submittal. If the only change is a change in in-service date, written communication, such as email or meeting notes, is adequate. Should the project change after the appropriate project documentation is issued, ATC and the Customer will work together to revise or amend the appropriate project documentation.

2.1.2 Un-Forecasted Load Interconnection Requests

In developing load interconnection requests related to un-forecasted load, ATC and the Customer will collaborate to assess the preliminary best value interconnection solution. This collaboration may include preliminary feasibility and/or system impact studies by ATC relating to the un-forecasted load interconnection request given that the proposed load interconnection request has not been accounted for in the annual 10-year load forecast. The preliminary feasibility and/or system impact studies help to determine if the addition of the un-forecasted load would have an adverse impact on the ATC Transmission System. Un-forecasted load interconnection requests may cause ATC and its Customer to consider additional issues such as aggressive in-service dates, significant transmission system upgrades outside of the load interconnection, regulatory timelines, and outage schedules while jointly developing a solution to satisfy the un-forecasted load interconnection request. Please refer to the ATC Economic Development Projects Guide GD-1801 for additional information. Contact ATC Interconnection Solutions for a copy of this Guide.

Once a LIRF is submitted, ATC will typically perform formal studies related to a *single* preferred interconnection location (as mutually agreed to by ATC and the Customer). Should the Customer request the formal study of additional interconnection locations related to the same load interconnection need, ATC reserves the right to charge the cost of such additional studies to the Customer in accordance with ATC's Elective Interconnection Facilities Business Practice. The Customer will be responsible to pay for the estimated cost of any additional studies prior to ATC beginning the additional study work. ATC retains discretion to waive this requirement on a case-by-case basis, as determined by ATC in a non-discriminatory and non-preferential manner.

2.2 Project Development

ATC and the Customer will employ BVP in order to determine the most effective solution to meet the Customer's load interconnection request.

BVP describes ATC and the Customer's collaborative development of the requested load interconnection project and determination of the best value solution. Steps within the BVP process include:

1. ATC and the Customer agree on the study schedule, study milestones, needs analysis, alternatives (both transmission and distribution) to consider, the forms of communication to be used while working together, and formal documentation.
2. ATC will coordinate with the customer to determine the appropriate project documentation.
3. The Customer documents needs/project justification and its part of a draft BVP matrix including alternatives considered; all in support of the Customer's analysis.
4. ATC documents needs/project justification and its part of a draft BVP matrix including alternatives considered; all in support of ATC's analysis.
5. ATC and the Customer complete a formal BVP report.
6. ATC and the Customer acquire management approvals as required before moving the project formally to implementation.

ATC and the Customer will formally document their BVP collaboration and conclusions in a BVP Project Scoping Report[9].

BVP takes into account such factors as:

1. Customer justification or need drivers behind the requested load interconnection.
2. Distribution and transmission system performance assessment including; power flow impact (voltage and thermal limitations), short circuit changes, protection/coordination concerns, operational concerns/limitations and asset management/maintenance concerns.
3. ATC stakeholder impact.
4. Construction as well as operating costs (for both transmission and distribution facilities),
5. Environmental issues,
6. Siting requirements, including land acquisition and permits, and
7. Ongoing operations and maintenance considerations, including reliability impacts on the transmission system.

[9] The collaborative review / analysis and BVP documentation of an interconnection project is governed in part by NERC Standard FAC-002-3 requirements R1, Parts 1 1-1 4, and the requirements of ATC's Local Planning under Attachment FF-ATCLLC of the Midcontinent ISO Tariff ATC and the Customer are required to retain the documentation of the reliability impact of the new facilities in accordance with NERC Standard FAC-002-3 Additionally, it is required that the Customer ensure that the load associated with the interconnection project is included within the metered boundaries of a Balancing Authority in accordance with NERC Standard FAC-001-3 requirement 3 3

To facilitate consistent analysis, review, documentation, and resource allocation for a given load interconnection project; Appendix C describes four different reporting levels of BVP activities and the responsibilities of both ATC and its Customer. The complexity of the assessment associated with the BVP Project Scoping Report is dependent on the size and cost of the proposed load interconnection project. Once ATC and its Customer determines the best value solution to meet ATC and the Customer's needs, ATC and the Customer prepare the BVP Project Scoping Report that sets forth the solution to meet the Customer's load interconnection request.

Once the BVP process is completed, the next implementation step is to develop the appropriate project documentation which may consist of a Best Value Plan Report, a Capital Work Letter (CWL), a Minimal Capital Work Letter, a No Capital Work Letter, a Project Commitment Agreement (PCA), or a Facilities Construction Agreement (FCA). The agreed upon project documentation sets forth for both parties the scope of construction activities and the proposed construction schedule[10] in order to construct the facilities necessary to interconnect the new load or modify the existing load interconnection facilities. For more information, the process included in BVP, please refer to the BVP white paper located at – https://www.atcllc.com/customer-engagement/connecting-to-the-grid/. Please also refer to Attachment FF-ATCLLC of the MISO Tariff for additional information.

2.3 Project Implementation

Once ATC and the Customer agree on the best value solution and formally publish a BVP Project Scoping Report, as appropriate, ATC will provide the Customer with the appropriate project documentation. A brief description of the project documentation documents are shown in the next section.

2.3.1 Project Documentation

At the conclusion of the Best Value Planning process, ATC will work with the Customer to develop the appropriate project documentation. This documentation may consist of any one of the documents described below:

At a minimum, the Best Value Plan Report will typically include:

- A review of the alternatives considered,
- Scope of work for both ATC & Customer,
- Anticipated ATC Cost,
- Schedule estimate.

The Capital Work Letter will typically include:

- Scope of work for both ATC & Customer,

The Minimal Capital Work Letter will typically include:

- Scope of work for both ATC & Customer,

The No Capital Work Letter will typically include:

- Scope of O&M work for both ATC & Customer,

At a minimum, the PCA will typically include the items in Table 3.

[10] Only the BVP report, PCA and FCA contain proposed construction schedules

Table 3: Required PCA Contents		
1	**BVP Project Scoping Report**	Provides the justification that supports the decision for the facilities to be constructed.
2	**Non-Typical Planning Studies**	Indication of any remaining studies, aside from the typical planning studies. (Examples may include power quality studies, special protection assessments, etc.)
3	**Project Schedule**	An estimated project schedule, including a timeline for any necessary regulatory approvals and the expected completion date of the project.
4	**High-Level Scope of Work**	Including a one-line diagram, project location or map.
5	**Applicable Business Practices**	Indication of other applicable ATC Business Practices associated with the project.

At a minimum the Facility Construction Agreement will typically include:
- Scope of work for both ATC & Customer,
- Anticipated ATC Cost,
- Schedule estimate.

The determination of what type of project documentation is required for a given project is made based upon the BVP solution for the given project. ATC will work with the Customer to define which form of project documentation is appropriate for each Load Interconnection Project. Examples of the project documentation documents are available upon request[11] to the ATC Interconnection Solutions Group.

Additionally, an example of the PCA template can be seen at: https://www.atcllc.com/customer-engagement/connecting-to-the-grid/.

2.3.2 Distribution - Transmission Interconnection Agreement

ATC requires execution of a Distribution – Transmission Interconnection Agreement (D-T IA) before ATC will commence any regulatory proceedings (if applicable) or otherwise begin design engineering on any project associated with a load interconnection request. If the request is from a Customer that has an existing D-T IA, the new interconnection substation will be included in the Entity Ownership Records (EOR) through the EOR Business Practice.

2.3.3 Regulatory Approvals

In the event that the load interconnection request requires regulatory approvals or filings, ATC and the Customer shall cooperate in seeking any regulatory or other approvals by providing the necessary information and

[11] See the footnote on page 41 for additional guidance.

participating in any regulatory proceeding or process to demonstrate need for the project, if requested to do so by either ATC or the Customer.

Examples of regulatory approvals or filings include, but are not limited to:

State Public Service Commissions for[12]:

- Construction Authorization filings,
- Certificates of Public Convenience and Necessity filings,
- Affiliated Interest filings

Federal Energy Regulatory Commission for:

- D-T IA filings

NERC (together with Midwest Reliability Organization and Reliability*First* Corporation) for:

- Reliability filings / reports associated with interconnection facilities at voltages greater than or equal to 100 kV.

Please note; NERC compliance is the responsibility of both ATC and the Customer. Under NERC requirements, ATC is a registered:

- Transmission Owner,
- Transmission Operator,
- Transmission Planner, and a
- Distribution Provider

<u>IMPORTANT NOTE:</u> ATC does not assume any NERC reliability responsibilities aside from those listed above. The D-T IA between ATC and its Customers is not a delegation of, nor the transfer of either party's NERC functional responsibilities from one party to the other.

Additional requirements applicable to both parties' substations are set forth in state electrical and administrative codes. ATC should be consulted on matters relative to the guidelines and requirements contained in this guide, but Customers are advised to consult directly with appropriate code enforcement authorities for matters that pertain to requirements of other applicable governing codes and/or with the specific requirements set forth in contracts concluded with ATC. Likewise, the regulatory filings listed above are for ATC requirements only, the Customer may have regulatory filings that may also be needed as determined by the Customer.

[12] Note: Regulatory requirements vary from state to state and need to be coordinated between ATC and its Customer for a given project.

2.3.4 ATC's relationship to the wholesale electric market

ATC owns, operates, maintains and plans the transmission system over which MISO provides transmission service in conjunction with its FERC Electric Tariff. ATC is not a Market Participant in the MISO Energy and Operating Reserve Markets.

3 Interconnection Facility Requirements

3.1 Overview

These design guidelines apply predominantly to new load interconnections and modifications to existing interconnections. ATC will work with the Customer to apply these guidelines as appropriate and feasible for modifications to existing load interconnections. Some proposed load interconnections may also require necessary network upgrades to ATC's Transmission System, beyond the interconnection facilities themselves. This guide does not govern those additional ATC Transmission System modifications that may be required. Any upgrades needed to the ATC transmission system will be identified within the BVP Project Scoping Report and used when assessing alternatives.

By following the process guidelines in the previous section of this document, ATC and its Customers work together to develop an interconnection project design in response to a Customer's interconnection request. This section of the document offers an overview of technical design guidelines to assist ATC and its Customers when developing a project solution for a load interconnection request.

It is important to note that ATC design standards apply to ATC Transmission System facilities and that the Customer's design standards apply to the Customer's facilities unless otherwise specifically noted in the following sections.

In the event that such ATC design guides, standards or specifications do not address a particular item or issue, ATC requires that the Customer and ATC agree on the use of nationally-recognized standards, guides or specifications to ensure that the Customer's Interconnection Facilities are designed in accordance with Good Utility Practice and any applicable Mandatory Reliability Standards (for example FAC-001). In the event that there is a conflict between any mandatory standard, guide or specification and ATC's design guides, standards and material/construction specifications, the more restrictive design guides, standards and specifications will apply.

3.2 ATC and Customer Responsibility

The requirements in this guide are part of the requirements necessary to protect ATC's transmission facilities and to maintain transmission system reliability consistent with the NERC Mandatory Reliability Standards. The Customer is responsible for the reliability, availability and the protection of its own facilities. All facilities constructed to meet a Customer's load interconnection request will be designed, installed, operated and maintained in accordance with Good Utility Practice, the National Electrical Code (Article 90), National Electrical Safety Code, equipment manufacturer's requirements, approved North American Electric Reliability Corporation and Regional Entity reliability standards, any applicable independent system operator or ATC planning criteria [13] and guidelines, and all other applicable laws, rules and regulations.

3.2.1 Customer Submittals Prior to Design Work

[13] See ATC planning criteria at http://www.atc10yearplan.com/about/planning-criteria-and-tools/

The Customer shall submit the following information after the LIRF has been accepted and the planning analysis performed, including any BVP, and prior to ATC initiating design work:

- A substation three-line diagram that includes substation phasing,
- A general arrangement diagram,
- Proposed modifications to Common Facilities,
- The power transformer nameplate drawing and the manufacturer's performance specification or test report, if it's available,
- A detailed description of the protection scheme to be used on the Customer's power transformer(s), and
- An executed PCA or, as necessary, an executed Facilities Construction Agreement if ATC's Elective Interconnection Facilities Business Practice applies.[14]
  Customer shall coordinate with ATC Legal to determine whether any FPA section 203 prior authorizations (acquisitions/dispositions of FERC-jurisdictional facilities) or FPA section 205 prior authorizations (for provision of services by a public utility) are required and, if so, cooperate in obtaining same.

3.2.2 Customer Submittals During Design Work

The Customer shall also provide the information listed below to ATC for review and approval prior to completion of required design work. The information can be submitted electronically (.pdf format for example) or as printed copies of drawings, whichever is convenient. *Please allow three weeks for ATC's review of the submitted information and at least three weeks for the Customer's consideration of ATC comments or modifications prior to the start of project construction:*

- As available, current transformer ("CT") ratio correction curves and excitation curves for any CTs that may be used in ATC protection schemes.
- A Customer-owned line conductor terminal structure design.
- If the interconnection is to a substation bus protected by an ATC bus differential relay; the Customer must provide AC schematics showing proposed changes and additions to the current inputs to the ATC bus differential relay and DC schematics showing tripping and breaker failure functionality.
- If interconnection is to a substation bus tripped by an ATC bus lockout relay; the Customer must provide DC schematics showing Customer breaker failure relay trip outputs, test switches, and connection to the ATC protective devices.

3.2.3 Elective Facilities

The Customer may request interconnection facilities beyond those facilities that ATC would normally determine as appropriate for a given interconnection request. The cost responsibilities for the incremental facilities will be determined during the BVP process. ATC may agree to provide such facilities provided that the following conditions are satisfied:

- The Customer agrees to finance and pay the construction cost difference (including any applicable taxes) between the Customer-requested facilities and those facilities ATC determines appropriate.
- The Customer-requested facilities meet all regulatory and reliability standards requirements and pose no additional risks or obligations for ATC's operations or maintenance of ATC's facilities.
- ATC can obtain all necessary permits and approvals.

Please consult ATC Business Practice, Elective Interconnection Facilities for additional information. See the ATC website: www.atcllc.com/customer-engagement/business-practices/.

[14] For any Elective Facilities transaction ≥ $ 250,000 with an ATC affiliate please contact the ATC Legal Department for a determination of the appropriate regulatory actions

3.3 Procedures for Coordinated Joint Studies of New Facilities and Their Impacts on the Interconnected Transmission Systems

Please refer to Sections 2.1 and 2.2 above for additional details on notifying ATC of an interconnection request and the assessment completed during BVP.

3.4 Procedures for Notification of New or Modified Facilities to Others (Those Responsible for the Reliability of the Interconnected Transmission Systems) as soon as Feasible

Please refer to Section 2.1 above for additional details on notifying ATC of an interconnection request.

3.5 Design of Common Facilities

Depending on the substation's ownership, ATC or the Customer may own facilities that are used by multiple parties at that substation. However, ATC will not share a joint substation or any common facilities with an end-use customer for load interconnections made directly from transmission facilities to an end-use customer's facilities.

For further information regarding Common Facilities, please consult ATC's Joint-use Substations -- Common Facilities Business Practice[15] for more details on how ATC and the Customer should coordinate the design, addition or modification of common facilities. All Common Facilities will be designed to meet ATC Design Criteria, all applicable national and state electrical and safety codes, and all applicable NERC, Federal, State, MRO (or Reliability*First*) and MISO standards and policies for Transmission Owner interconnection service to a Local Distribution Company. Any differences or conflicts between the Customer's standards and ATC standards will be addressed in the design of the Common Facilities. The Customer shall provide a common facilities design proposal for ATC review and comment prior to any construction.

3.6 Interconnection Configuration

The configuration of interconnection facilities will take into account both the immediate and future plans for the new or modified substation. Where economically advantageous, future requirements of the Customer and ATC will be incorporated into the immediate substation design associated with the load interconnection request. ATC strongly advocates three-phase interconnections with balanced load between all three phases. ATC may consider exceptions to this configuration on a case-by-case basis.

The interconnection facility configuration is considered by ATC to be a joint development effort. In addition to meeting the Customer's needs, ATC's design requirements are intended to facilitate ongoing maintenance and the required reliability of the transmission system, with minimal dependence on Customer load switching and/or load bridging[16]. ATC's facilities design will endeavor to include the most effective and least-cost design of both transmission and distribution facilities in order to minimize the frequency and duration of Customer interruptions. The jointly agreed to electric facilities design will be documented in the BVP Report. Examples of typical interconnection configurations can be found in Appendix F. It should be noted that Configurations H and I in

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[15] See ATC Business Practice "Joint Use Substations – Cost Responsibility For Common Facilities" http://www atcllc com/customer-engagement/business-practices/

[16] Please refer to the ATC Business Practice Load Bridging for Transmission Related Work http:// www.atcllc.com/customer-engagement/business-practices/.

Appendix F will be determined by a transmission network need. These are not typical configurations, nor driven by the Customer.

3.6.1 Line Topology, Line Sectionalizing

ATC prefers to design its new facilities to sectionalize the affected transmission line's[17] load in a way that provides the greatest reliability for ATC's facilities as well as the Customer's. Sectionalizing the affected transmission lines may include load-break switches, remote-controlled motor-operated disconnect switches, auto-sectionalizers, or breakers. The consideration of the appropriate sectionalizing method and equipment choice will be made on a case-by-case basis subject to the approval of ATC Operations, Maintenance and Engineering groups. The following criteria may be used in designing and sectionalizing transmission lines, unless ATC and the Customer determine that other criteria should apply:

3.6.1.1 Sectionalizing Guidelines - 30 MW

When the new request affects a transmission line's load[18] to be greater than or equal to 30 MW, then ATC will split the load on the existing line by adding breakers per Section 3.21.3 at an appropriate location to maximize transmission line performance. When 30 MW is forecasted between breakers in the LDC load forecast at an existing substation without line breakers, two (2) line breakers will be installed. When a substation has two distribution transformers with 30 MW of load realized at the substation, a bus tie breaker will be installed.

3.6.1.2 Sectionalizing Guidelines - 300 MW-miles

Another factor to be considered is the product of line length (in miles) and the load (in MW) on the transmission line. If this product is equal to or greater than 300 MW-miles, then ATC in collaboration with the Customer will consider determining the most appropriate manner to sectionalize the affected transmission line.

3.6.1.3 Reliability Considerations

Some load interconnections may require consideration of other guidelines in those instances when it is anticipated that the transmission lines may not perform adequately or reliably because of the load interconnection. (See Sections 3.6.1.4 and 3.6.1.5 below). ATC may consider other criteria in order to sectionalize the affected transmission lines in a reasonable and reliable manner.

3.6.1.4 ATC Reliability Performance Metrics

ATC monitors transmission system reliability performance as related to load interconnection (delivery) points using a performance metric. The ultimate goal is to understand the ongoing performance of an integrated transmission and distribution system, but at very specific interconnection points. This performance metric is significantly affected by not only the transmission system performance, but also the design and performance of the interconnected distribution system. For example, a local distribution company's ability to bridge distribution loads (especially automatically) will have substantial impact on ATC's delivery point metric which in part measures the number of end-use customers impacted by outages.

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[17] A transmission line is defined as a segment of the ATC Transmission System found between two circuit breakers.

[18] The term "load" as used here is the maximum forecast load as discussed in Section 2 1 of this Guide

When considering the line sectionalizing requirements for any load interconnection, ATC may consider the performance of the existing transmission line affected by the new load interconnection request relative to ATC's other lines' delivery point metrics performance. ATC may determine not to sectionalize an affected transmission line if doing so would decrease its performance reliability based upon the performance metrics measured by ATC.

3.6.1.5 Distribution Change-Over

Transmission line sectionalizing may not be necessary if the distribution facilities incorporate bridging capability.

3.6.1.6 Number of Taps

Multiple taps between breakers may; 1) affect Customer service reliability, 2) complicate load bridging and operations, and 3) increase response time to isolate disturbances. Therefore, the number of existing taps on the transmission line affected by the new load interconnection request is a factor that ATC will consider when determining the effective line sectionalizing design. However, in general for lines with three or more taps (new plus existing), ATC will consider the design of line sectionalizing as set forth in Section 3.21.4 and Appendix F below. At a minimum, a new interconnection will have load break switches if there is another distribution tap without load break switches on the transmission line.

3.6.1.7 Number of End-Use Customers: The number of end-use customers normally connected to the local distribution system could be a factor that should be considered when considering effective transmission line sectionalization. However, in general, for transmission lines that support more than 3,000 end-use customers ATC will design line sectionalizing as already provided for in Section 3.21.4.

3.6.1.8 Underground Transmission Lines

Substations served with underground transmission lines require additional consideration and will be handled on a case-by-case basis because of the risk of long-term outages resulting from underground cable failure. ATC Operations, Maintenance and Engineering groups may be required to participate in the facilities design with Planning.

3.6.1.9 Sectionalizing Device Ratings/Capability

Aside from the guidance derived from the line sectionalizing design guidelines discussed above, load break capability, line charging interruption and short circuit current interruption requirements of the transmission line under consideration may require installation of line sectionalizing devices that are designed to withstand high current applications. This will be accounted for in the Sectionalizing Device Matrix seen in Appendix F.

When disconnect switches will be used for the sectionalizing device, picking up charging current is considered to be an acceptable application for the device and should not be accounted for within the Appendix F selection matrix. The proper switch type for these substation applications will be determined during design with guidance provided by GDE-4500, the Substation Disconnect Switch design guide.

While these guidelines are specific, in some exceptional cases, the BVP study and analysis may need to be sensitive to case-specific considerations not otherwise addressed in these guidelines.

ATC and its Customers will coordinate the application and use of sectionalizing devices as part of the development of the interconnection project.

3.6.2 Line Topology – Radial versus Loop-through Connections

ATC and its Customer will jointly decide on the optimum means of connecting a new substation to the ATC Transmission System. To encourage efficient land usage for load interconnections, ATC will provide a straight bus (loop feed) substation for any new load interconnection substation with an ultimate configuration of two or more transformers.

When modifying an existing load interconnection substation with one transformer that is radially fed where Customer load growth subsequently calls for two or more transformers, ATC and the Customer will utilize the BVP process to determine on a case-by-case basis if the substation should be converted to a loop-through substation instead of establishing a second radial feed into the substation. Land availability, substation proximity to the transmission line, the need for line breakers, load bridging capability of the distribution system and other related issues will be jointly considered. Additional information on determining the interconnection configuration is included in the Bus Configuration Flow Chart in Appendix F.

If the Customer submits a request for ATC to construct transmission facilities to connect a spare, de-energized transformer or other similar modification for load bridging, ATC will consider that scope elective facilities. However, if the Customer has specific distribution planning criteria that provides justification for the request, ATC's scope, through the BVP process, would be deemed standard facilities.

Please consult ATC Business Practice, Elective Interconnection Facilities for additional information. See the ATC website: www.atcllc.com/customer-engagement/business-practices/.

3.6.3 Phase Rotation

ATC phase rotation is ABC (counter-clockwise). The Customer will exercise careful coordination with ATC to match this phase rotation to the Customer's specific phase designations. For new interconnections, the LDC typically specifies the phase rotation for the interconnection facility. When ATC was formed, it was recognized that the phase rotation configurations vary from contributor –to- contributor. Table 4 below highlights the phase rotation conventions used by the various Balancing Authorities interconnecting to the ABC phasing of the ATC Transmission System.

Table 4

Balancing Areas		Phase to Phase		
Wisconsin Public Service Corporation		C	A	B
Wisconsin Power and Light Company		A	B	C
Madison Gas and Electric		A	B	C
Wisconsin Electric Power Company		A	B	C
Upper Peninsula Power Company		A	B	C
Edison Sault Electric Light Company		A	B	C
Cloverland / Edison Sault (West)	(See Note 2)	A	B	C
Cloverland / Edison Sault (East)	(See Note 3)	C	A	B
General Notes:				
Note 1. All systems have A – B – C rotation				
Note 2. Cloverland / Edison Sault Substations; West of Hiawatha Substation				
Note 3. Cloverland / Edison Sault Substations; Hiawatha Substation and East				

3.7 Voltage Level and MW and MVAR Capacity or Demand at the Point of Interconnection

3.7.1 Voltage Level

The design of the new interconnections must effectively address the voltage requirements of both this Section and in Section 3.13 (Voltage, Reactive Power & Power Factor). ATC operates transmission facilities predominantly at nominal system voltages of 69, 138, 345 kV, which is further detailed in ATC Design Criteria. For the purposes of this guide, any reference to 138kV voltage levels shall also encompass interconnections to ATC's 115 kV system. ATC will discuss with the Customer on a case-by-case basis the requirements associated with interconnections to the relatively small amount of 161 and 230 kV facilities owned and operated by ATC.

The service voltage will depend on 1) the location of Customer Facilities relative to ATC's existing facilities and 2) the present and future load the Customer intends to serve. The Customer shall consult with ATC on how these issues will affect service voltage selection.

3.7.2 MW and MVAR Capacity or Demand at the Point of Interconnection

ATC and the Customer will work together in the design of the Interconnection Facilities to provide sufficient MW and MVAR capacity at the Point of Interconnection for both current and future needs of both parties as determined by the collaborative BVP process.

3.8 Breaker Duty and Surge Protection

3.8.1 Fault Current

Customer Interconnection Facilities connected to ATC's Transmission System can be subjected to fault levels that are largely the product of system characteristics and interconnection impedance. The design of the Customer's Interconnection Facilities must possess sufficient fault interrupting and momentary withstand ratings to meet the maximum expected fault current, with appropriate margin for future system growth (See also Section 3.15.4 Circuit Breakers).

3.8.2 Continuous Current Ratings

ATC will endeavor to design facilities for the maximum continuous load that the Customer forecasts in the interconnection request or the next highest ATC standard rating for equipment beyond the maximum continuous rating of the Customer's transformer. The minimum continuous rating for new ATC substation facilities will be 2,000 A. The minimum continuous rating for new ATC transmission line tap switches will be 1,200 A. Any consideration of planned or emergency overloads are to be provided for in the LIRF.

3.8.3 Transient and Fault Duty Ratings

Customer facilities are to be designed to include sufficient fault interrupting and momentary withstand ratings to meet the maximum expected transmission system requirements, with appropriate margin for future system growth. Equipment fault ratings will be determined for each interconnection as part of the project development process.

3.8.4 Shielding, Grounding & Surge Protection

ATC's requirements for substation shielding, grounding, and surge protection are addressed in *ATC Substation Site Design* Criteria – CR-0060. Surge protection for Customer-owned equipment shall be designed and incorporated to be independent of ATC's surge protection for ATC's equipment.

All Interconnection Facility equipment must be adequately designed to meet surge protection and shielding requirements. ATC and the Customer will coordinate with each other in a manner that will provide the necessary data at the request of either party.

3.9 System Protection and Coordination

3.9.1 Protection and Control Guidelines

To minimize disturbances to the ATC system, the Customer must design its interconnection facilities to protect its transformer with a Customer-owned protective scheme utilizing a circuit breaker, or circuit switcher as appropriate for the primary tripping device. ATC may contact the Customer to facilitate coordination of protection schemes between systems, including addition of current transformers (CTs) to accommodate bus differential scheme changes.

If a fuse is used for high-side protection of a distribution transformer (permissible on 69 kV interconnections only), the fuse must be able to operate for all transformer faults during an N-1 transmission event for the available fault current.

Examples of situations that may require additional review by the ATC System Protection Department include (but are not limited to):

- Any generation normally connected to the local distribution system where the distributed energy resource is ≥ 1/3 of the minimum load at the substation or transformer,
- Normally-closed distribution voltage bus tie breaker(s) between at least two separate transmission sources,
- Situations that include the use of distribution transfer trip or direct transfer trip protection schemes, and
- Load interconnections to end-use customers directly to the Transmission System.

3.9.2 Control Circuit Practices

The specifics of the protection requirements design will be dictated by several factors, such as available communication facilities, line length and construction, interconnection on a blackstart path, mutual coupling effects, available fault currents, critical clearing times, circuit breaker characteristics, etc. However, in general the requirements in the following sub-sections will apply.

3.9.3 General Requirements

ATC's protective relay systems for transmission facilities are generally designed to provide some level of redundancy. ATC installs two relay protection schemes for line and bus protection. The schemes will use separate AC current and voltage sources, separate DC control circuits, and separate circuit breaker trip coils. Redundant batteries are generally not required.

ATC's preferred bus protection scheme design utilizes two (2) bus differentials, connected to two (2) separate sets of CTs. Determination of the required number of CTs, the location of the CTs, the CT ratio and accuracy class for both new interconnections and replacements of existing distribution transformers must be made in conjunction with ATC system protection on a project specific basis, considering both the existing configuration and future plans for the substation.

ATC requires engineering review of any modifications to its protective relay or control circuits. This review should take place during the engineering phase of the project.

When designing and installing protective relay systems, the Customer is encouraged to install equipment with replaceable indicating lamps or other obvious indicators that clearly show the operating status of the Customer's transformer protective device and ATC's equipment.

3.9.4 Instrument Transformers

ATC includes instrument transformers as part of its protective relay design.

3.9.5 Distributed Energy Resources

In those situations where there are distributed energy resource facilities associated with the Customer's distribution system, care must be taken to protect the ATC Transmission System from fault currents. The Customer's protective system design must include provisions for separating from ATC's system. The Customer shall provide the protective system design for ATC's review. ATC recommends that any generation without sufficient synchronizing capabilities be disconnected before reconnecting the Customer to ATC's transmission system. The Customer must have adequate protection to sense all transmission faults and disconnect from the transmission system in the event of a transmission fault. Consistent with the Distribution – Transmission Interconnection Agreement (D-T IA), it is the responsibility of the LDC to ensure that this protection is in place. Additional information about DER can be seen in the *ATC Distributed Energy Resource –*

Protection and Insulation Coordination Guide GD-1701. Contact ATC Interconnection Solutions for a copy of the Guide.[19]

In addition to how the DER is assessed through the DERRF process, ATC also reviews how these units should be modeled and forecasted. Additional information on modeling and load forecast implication of distributed energy resources can be seen in the ATC Generator Modeling Decision Methodology found on: https://www.atcllc.com/customer-engagement/connecting-to-the-grid/

3.9.5.1 Distributed Energy Resource Reliability and Safety Related Issues

Delta-wye transformer configurations are the preferred means of interconnecting load to the ATC Transmission System. When the nature of a load interconnection changes due to the addition of DER (for both changes to existing as well as new load interconnections) it is important for ATC to assess the potential for adverse impacts to the ATC Transmission System. This is especially true when the name plate rating of the accumulative DER is greater than or equal to (≥) 1/3 of the minimum load at the substation or transformer. The reliability and safety related design issues that need to be reviewed includes (but are not limited to):

- Transmission system network impact,
- System protection requirements to mitigate back-feed into a fault on the ATC transmission system,
- Insulation coordination of substation and line equipment (including arrestors and voltage transformers (VTs)). (See Sections 3.7.1.1 and 3.12 also)

It is requested that ATC be advised of all new and existing distributed energy resources at a load interconnection point with a cumulative capacity greater than 1 MW. The information may be submitted to ATC via a DERRF. It will then be assessed within ATC to determine the impact and if additional analysis and/or system upgrades are needed. A DERRF submittal is also recommended for each additional 500 KW (after the previous DER BVP assessment).

Typically, if VTs are required to support the Customer's protection systems to separate the distribution system from the ATC Transmission System, the VTs should be installed on the Customer side of the disconnecting device and owned by the Customer. If BVP and/or substation space limitations result in the VTs being installed on the ATC side of the Customer's disconnecting device, then it is appropriate for ATC to own and maintain the VTs consistent with the D-T IA. The addition of Voltage Transformers to the ATC side of the high-side breaker in these instances will be consistent with ATC design practices.

Determination of the appropriate voltage class for ATC-owned VTs will be determined as part of the design of the Interconnection Facilities.

3.9.5.2 Distributed Energy Resources Synchronizing Requirements

The Customer is responsible to ensure that the design of the Customer's distribution system provides for the synchronization of the Distributed Energy Resource Facility to the Customer's distribution system.

3.9.6 Reclosing

ATC's transmission line reclosing practice after a breaker has opened during an operation is to reclose the transmission line one or more seconds after a line breaker has tripped open. The Customer is responsible for

[19] See the footnote on page 41 for additional guidance..

designing its distribution system to isolate all sources of back-feed from the distribution line prior to any ATC reclose attempts. This includes any Customer-owned throw-over schemes. ATC will address timing considerations with its Customer on a project-specific basis.

3.9.7 Breaker Failure

Scenario 1. - Customer equipment connected to an ATC transmission bus that has a conventional bus differential / lockout protection scheme.

In the event of a bus fault or breaker failure condition on the transmission system, ATC will send a trip signal to the Customer to trip their high-side interrupting device.

ATC's practice is to receive two (2) separate trip outputs from the Customer's high-side interrupting device breaker failure relay. One of these outputs will be wired to trip the interconnecting bus lockout and the other will trip the interconnecting bus relay which will direct trip the breakers on the interconnecting bus. If the Customer is unable to provide two (2) separate breaker failure trip output contacts, the single contact will be used to trip the interconnecting bus lockout.

Test switches should be installed in the same control house as the Customer's breaker failure relay. The required test switches will be placed such that they allow for operation of lockout relays, while preventing breaker failure operations and / or tripping of the Interconnection Facilities.

Scenario 2. - Customer equipment connected to an ATC transmission line, or a bus with no conventional bus differential that is protected by the line protection scheme.

If the Customer-owned equipment could be a source into a line fault (such as networked distribution), the Customer's protective scheme design shall be capable of recognizing a fault condition and isolating the source of the fault from the transmission line. For a radial connection, Customer-owned high side protective device failure presents a risk to both the Customer and ATC. Customer-owned equipment is at risk of catastrophic failure due to a sustained fault. The Customer is responsible for mitigating these high side protective device failure risks in the Customer's design of its protective systems.

3.9.7.1 Test Switches

Each Party's protective relay design shall incorporate the necessary test switches to perform the tests required for the pre- and post- in-service testing discussed in Section 3.19. The required test switches will be placed such that they allow operation of lockout relays while preventing breaker failure operations and/or tripping of the Interconnection Facilities.

3.9.8 Substation Electrical Service

The Customer will consult with appropriate ATC personnel for the design of substation AC and DC systems that will be connected to ATC equipment.

Additional information on control circuit practices can be discussed with ATC as part of the development of the interconnection project. (See also ATC Business Practice "Transmission Related Station Power Use at Substations" which can be found on the ATC website httphttp://www.atcllc.com/customer-engagement/business-practices/.

3.10 Metering and Telecommunications

3.10.1 Communications

ATC will install the communications facilities determined by ATC to be necessary at networked connected load interconnection substations. The communication facilities may be utilized for protection, control or metering applications as appropriate. ATC will design communication facilities for their use to match existing methods employed on the existing line. The communication methods may include, but are not limited to, telephone circuits, fiber optic networks, or other technologies as appropriate. ATC will identify for the Customer the space requirements necessary to accommodate ATC's communication requirements in the Interconnection Facilities.

3.10.2 SCADA / RTU

ATC encourages Customers to control distribution lines that are interconnected to ATC substations remotely via SCADA for potential emergencies including, but not limited to, system restoration activities following a blackout or reduction and/or control of loadings for other unanticipated events.

3.10.3 Revenue Metering

Since the Customer and ATC will both monitor metering data, they shall together determine the design requirements for interconnection revenue metering on a project-specific basis. Primary instrument transformers/devices will be revenue class, preferably wound-type current transformers, and voltage transformers that are accessible to the Customer and ATC.

3.10.4 Balancing Area Metering

Consult ATC's Coordination of Balancing Authority Business Practice for guidance on the design and installation of appropriate Balancing Authority Area (BAA) facilities for any load interconnection project that impacts a BAA boundary. In addition, the ATC Guide for LBA Transmission Load Interconnection is included in Appendix G. In general ATC does not install instrument transformers associated with any required BAA metering. For BAA metering at any existing load interconnection substations, the Customer will install, own, and maintain any cables necessary to connect to any ATC transmission-connected instrument transformers.

3.11 Grounding and Safety

As set forth in the D-T IA, the Customer and ATC must agree to operate their respective facilities considering the ratings and capabilities of the facilities of the other party and shall not operate their system in a manner that would result in exceeding the operating limits or equipment ratings of the other party. This includes the coordination and use of appropriately sized grounding equipment as part of the Interconnection Facilities' design.

3.11.1 Effective Grounding

ATC maintains effective grounding on its transmission system facilities, as defined by the National Electrical Safety Code (NESC). All Customer facilities connected to the ATC Transmission System must be designed to be effectively grounded per the NESC requirement. The Customer must meet the effective grounded system criterion independent of the ATC Transmission System.

3.11.2 Grounding System

The Customer is responsible for the appropriate grounding of their equipment. At the Point of Interconnection, the Customer's grounding equipment must be compatible with ATC's grounding equipment. The Customer shall submit the grounding system study and design for ATC review prior to construction. The ground grid design must comply with IEEE 80 and properly address site extremes. Site tests should be completed to determine soil resistivity prior to ground grid design. Post-construction grid resistance testing should be performed to verify design assumptions and that the installation was completed per the ground grid design. ATC grounding standards are available upon request[20].

3.11.3 Safety Issues

All personnel working on or in proximity to the Interconnection Facility as well as personnel performing switching on lines associated with the Interconnection Facility will comply with all safety policies, manuals and procedures of the Customer and ATC along with all applicable OSHA safety laws and federal, state, and local rules and regulations.

The Customer and ATC will agree to work together to develop appropriate switching procedures to be utilized at the Interconnection Facilities.

All Customer equipment must be designed physically and electrically to allow for the attachment of properly sized working grounds as specified in IEEE 1246, *Guide for Temporary Protective Grounding Systems Used in Substations.*

3.12 Insulation and Insulation Coordination (Basic Insulation Level)

The substation equipment and bus systems shall be designed for the voltage ratings shown below. Substations designed for 230kV and 161kV shall be dealt with as an exception. New substations energized at 115kV shall be built to 138kV ratings in accordance with Table 5. Additions to existing substations energized at 115kV or 138kV, with 550kV BIL construction shall be continued similar to their original design and in all other cases consideration shall be given to the existing substation design.

Table 5: Equipment Voltage Ratings

Nominal Operating Voltage (phase-to-phase)	**138 kV**	**69 kV**
Nominal Phase-to-Phase Voltage	138 kV	69 kV
Nominal Phase-to-Ground Voltage	80 kV	40 kV
Maximum Phase-to-Phase Voltage	145 kV	72.5 kV
Maximum Phase-to-Ground Voltage	84 kV	42 kV
Basic Insulation Level (BIL)	650 kV[1]	350 kV
1. In some remote locations and transformers a 550 kV BIL may be acceptable.		

[20] See the footnote on page 41 for additional guidance.

ATC and the Customer must ensure that all equipment is adequately protected from excessive system over-voltages. This includes selection of equipment Basic Insulation Level (BIL) and protective devices (e.g., surge arresters) to achieve proper insulation coordination across the distribution – transmission interconnection.

ATC designs its transmission facilities for the BILs shown in Table 5. Interconnections at 230kV or 161kV will be reviewed on an exception basis. New substations energized at 115kV will be built to 138kV ratings in accordance with 138 kV standards. Additions to existing substations energized at 115kV or 138kV, with 550kV BIL construction will be continued similar to their original design. In all other cases consideration will be given to the existing substation design.

3.13 Voltage, Reactive Power, and Power Factor Control

3.13.1 Steady State Voltage Range

The Customer should expect a normal transmission operating voltage range of +/- 5% from nominal. During system contingency or emergency operation, ATC permits operating voltages to vary up to +/- 10% from nominal. The Customer's equipment should be designed appropriately to operate and maintain adequate voltage under these conditions.

Refer to ATC's Planning Criteria (see current 10-Year Assessment, - About section under Planning Criteria, Practices and Tools - https://www.atc10yearplan.com/) for additional guidance related to voltage ratings.

3.13.2 Transmission Line Reactive Capability

All interconnections will be designed to be reactive compensated pursuant to Good Utility Practice to ensure proper operation of the interconnection. The Customer must provide their own reactive support for their Interconnection Facilities.

3.13.3 Load Interconnection Power Factor Guidelines

ATC's Customers should plan, design and maintain their load interconnection facilities in order to maintain a power factor at the low side of the load interconnection transformer that is greater than 95% lagging when the load is greater than 85% of maximum forecast load at that load interconnection.

Customer reactive resources should be designed with the ability to be switched off during light loading periods. This applies to any load interconnection where transmission system BVP indicates a need for transmission system power factor improvement at that load interconnection.

For cost allocation purposes, if the Customer load interconnection power factor derived from the Customer's most recent load forecast is below 95% lagging, the Customer will be responsible to bring the power factor up to the 95% level and ATC will be responsible to bring the power factor up to the level identified in the BVP. Costs will be allocated between ATC and the Customer based upon a ratio of the Customer capacitor banks installed. If the load interconnection power factor is already above the 95% lagging level and additional transmission system power factor improvement is identified in the BVP to address the transmission system need, then ATC will reimburse the

Customer(s) for the additional Customer capacitor banks identified in the BVP consistent with its Capacitor Bank Business Practice[21].

The Customer is responsible for maintaining the 95% (or greater) lagging power factor at the load interconnection regardless of previous capacitor bank contributions requested by ATC. If Customer capacitor banks are removed it is required that the Customer maintain a power factor according to these guidelines.

3.14 Power Quality Impacts

3.14.1 Voltage Flicker and Harmonics

The energization and operation of any facilities on the Customer's side of the interconnection facilities must be consistent with ATC's Planning Criteria[22] and Operating Instructions (available upon request[23]) regarding permissible voltage deviations, harmonics, flicker and distortion.

3.14.2 Frequency and Frequency Control

The Customer should expect a normal transmission operating voltage range of +/- 5% from nominal. During system contingency or emergency operation, ATC permits operating voltages to vary up to +/- 10% from nominal. The Customer's equipment should be designed appropriately to operate and maintain adequate frequency under these conditions. For DER, energy delivered into the ATC Transmission System must be 60 Hz sinusoidal alternating current as a standard frequency. In accordance with Applicable Reliability Standards, the Customer will design and install both control and protective relaying equipment necessary to maintain proper transmission system frequency.

3.15 Substation Equipment Ratings

The Customer and ATC must agree on the applicable substation/transmission/protection design guides, standards, and specifications to be used, for the design of and procurement for the interconnection of the Customer's facility (or facilities). Both Parties will be afforded the opportunity to confirm the overall Interconnection Facility capabilities and identify the limiting transmission element within the Interconnection Facility.

As set forth in the D-T IA, the Customer and ATC will be obligated to operate their respective facilities considering the ratings and capabilities of the facilities of the other party and shall not operate their respective systems in a manner that would result in exceeding the operating limits or equipment ratings of the other party. This includes the coordination of the topics discussed in Sections 3.15.1 through 3.15.6 below.

3.15.1 Voltage and BIL Levels

See Section 3.12 above.

3.15.2 Current Ratings

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[21] See ATC Business Practice 0302 entitled "Capacitor Bank Installations on Distribution Systems for Transmission Benefit" which can be found at: https://www atcllc com/customer-engagement/business-practices/

[22] See ATC planning criteria at https://www.atc10yearplan.com/about/planning-criteria-and-tools-2/

[23] See the footnote on page 41 for additional guidance.

ATC and the Customer shall coordinate Interconnection Facility equipment current ratings with each other during the design of the Interconnection Facilities.

3.15.3 Bus Spacing and Clearances

ATC substation and bus systems shall be designed to match existing layouts when applicable, but at a minimum, new equipment shall maintain clearances and spacing consistent with the current ATC design standards, available upon request. ATC and the Customer shall coordinate substation and bus clearances and spacing with each other during the design of the Interconnection Facilities.

3.15.4 Circuit Breakers

ATC and its Customers will coordinate the application and use of dead-tank circuit breakers as part of the development of the interconnection project. It is understood that when ATC installs line breakers at 100 kV and above on greenfield sites, it is expected that the LDC also will install breakers to protect their transformers. The LDC-owned breakers should meet all project requirements and be equipped with LDC required accessories.

The ATC power circuit breakers at the substations are expected to be SF6 gas-insulated, dead-tank type that conform to applicable ANSI-C37 standards. ATC will provide expected short circuit currents to the Customer to assist them in selecting the appropriate circuit breaker ratings during the design of the Interconnection Facilities.

CTs should fit the specific project requirements and be designed and tested to the most recent revision of IEEEC57.13. A fault study can be requested by the LDC during the scoping of the project. If a high impedance differential is installed on a bus, all CTs should be connected at the same, full ratio. A good reference is ATC's own breaker application guide, GDE-4000. A current copy can be found on the ATC standards website.

3.15.5 Disconnect Switches

ATC disconnect switches are expected to be three-phase, gang operated, horizontal-mounted, with station post insulators that conform to ANSI-29.9 as outlined in ATC's substation switch design guide GDE-4500. ATC and the Customer shall coordinate the application of disconnect switches with each other during the design of the Interconnection Facilities.

3.15.6 Voltage Transformers (VTs & CCVTs)

Wound voltage transformers (VTs) are preferred for all 138 kV and lower bus voltage sensing and non-power line carrier applications on ATC Transmission System facilities. Voltage transformers will conform to IEEE C57.13. Coupled Capacitor Voltage Transformers (CCVTs) will conform with ANSI C93.1. ATC and the Customer shall coordinate the application of these VTs and CCVTs with each other during the design of the Interconnection Facilities.

3.16 Synchronizing of Facilities

3.16.1 Synchronism

The Customer is responsible to ensure that the design of the Customer's distribution system provides for the synchronization of the Distributed Energy Resource Facility to the Customer's distribution system.

ATC and the Customer shall coordinate the application of these devices during the design of the Interconnection Facilities.

3.16.2 Phase Rotation

The ATC Transmission System phase rotation is ABC counter-clockwise. The Customer should verify phase rotation with ATC before purchasing any equipment and proceeding with the Interconnection Facility construction. See Section 3.7.2 of this guide for additional information.

3.17 Maintenance Coordination

3.17.1 Maintenance Notification

The Customer must notify ATC or Midcontinent ISO as provided for in the applicable Midcontinent ISO ASM Tariff and the D-T IA of any unusual conditions including, but not limited to the following:

1. Partial operating capability due to equipment limitations.

2. Scheduled outage periods and return to service expectations. Return to service notification must be updated daily to reflect the recent progress or the lack of progress.

3.17.2 Maintenance

Interconnection equipment owned by the Customer should be maintained and inspected according to manufacturer recommendations, NERC, and/or industry standards. Procedures must be established for visual and operational inspections. Provisions should be established for equipment maintenance and testing as part of the Interconnection Facilities design.

ATC maintains the right to review the maintenance, calibration, and operation data of all protective equipment for protecting ATC facilities, ATC Customers, and other Interconnected Parties. The Customer is responsible for providing the necessary test accessories (such as relay test plugs, instruction manuals, wiring diagrams, etc.) required to test these protective devices. Verification testing may include the tripping of the interconnection breaker, as appropriate.

If ATC performs work on the premises of the Customer, ATC operating personnel may inspect the work area. If ATC personnel deem working conditions to be hazardous, the Customer must correct the unsafe conditions before ATC personnel will perform their work.

3.18 Operational Issues (Abnormal Frequency and Voltages)

3.18.1 Abnormal Frequency and Voltages

As part of the Interconnection Facilities design, ATC and the Customer will work together to establish appropriate procedures, protocols and operating guides (if necessary) to account for and manage abnormal frequency, voltages or other operating limits on either party's system in accordance with all appropriate industry standards, Mandatory Reliability Standards, and Good Utility Practice.

3.18.2 Power System Restoration Design Considerations

ATC is required to maintain a power system restoration plan in accordance with NERC Standard EOP-005, including provisions for supplying cranking power to target facilities and off-site power to nuclear plants. If the proposed Customer interconnection impacts the ATC restoration plan, as determined by ATC, additional design requirements may be identified, such as, requiring interconnection to a different transmission facility, where available. If the ATC restoration plan will be impacted, the Customer will be required to install and maintain SCADA control of the Customer owned high side disconnecting devices. Alternatively, ATC will install a ring bus interconnection configuration to ensure appropriate clearing of distribution equipment in a timely manner.

3.19 Inspection Requirements for Existing or New Facilities

3.19.1 Acceptance Testing, Inspection and Commissioning

ATC requires all Customers proposing to interconnect to the ATC Transmission System comply with the applicable testing and/or performance requirements as part of the Interconnection Facilities design.

3.19.2 General

Prior to energizing the interconnection equipment with the ATC Transmission System, the Customer and ATC will work together to ensure that all pertinent contracts (such as the D-T IA) are signed and that all equipment modifications have been completed. The Customer is required to demonstrate the correct operation of all interface protective and control devices to ATC. ATC shall define and witness but is not responsible for performing this demonstration.

The Customer must provide detailed information on the protective relaying, metering, and control (including sync-check) equipment that will interface with the ATC Transmission System.

Scheduling of demonstration testing should be coordinated through ATC with a minimum of fifteen business days notice. Any outage of ATC protection equipment must be requested and approved in accordance with ATC's System Operation Approval Procedure for System Protection Equipment and Communication Channel Outages. This procedure is available upon request[24].

[24] See the footnote on page 41 for additional guidance.

ATC commissioning specifications and documentation requirements are available upon request[25] and provide the specific criteria that ATC uses for ensuring its electrical equipment is properly tested and checked out. Inspection and approval by ATC does not constitute a warranty or relieve the Customer of responsibility for the operating condition or installation of the equipment and may not be relied upon by the Customer for that purpose. Once interconnected, ATC will retain the right to inspect the Interconnection Facilities at ATC's discretion.

3.19.3 Demonstration

The Customer and ATC shall adhere to the following steps in assuring that the Interconnection Facilities have been adequately tested both prior to and after energization and interconnection to the ATC Transmission System:

- Construction testing documentation review,
- Demonstration tests,
- Post in-service tests.

Details on the specific testing requirements are to be coordinated between ATC and the Customer as part of the commissioning process.

3.19.4 Future Changes In Requirements

From time-to-time new requirements for testing, reporting, equipment and/or performance are established by NERC or Regional Entity for interconnections. The Customer should take the appropriate actions, so it is notified of any requirement changes by the applicable entity.

3.19.5 Performance of Tests

The Customer must test all wire, cable, electrical equipment, and systems installed by the Customer or connected by the Customer to assure proper installation, adjustment, setting, connection, and functioning. Details on the performance of specific testing requirements are to be coordinated between ATC and the Customer as part of the commissioning process.

3.19.6 Test Equipment

The Customer must provide all equipment necessary to perform the tests required by ATC. Details on the specific testing equipment requirements are to be coordinated between ATC and the Customer prior to preforming tests.

3.19.7 ATC Supplied Equipment

Any ATC supplied equipment that is factory calibrated (transducers, pressure switches, tuners, etc.) shall be tested to verify calibration consistent with ATC testing practices. The use of ATC supplied equipment shall be coordinated with the appropriate ATC personnel prior to performing tests.

3.19.8 Final Design / Final "Draft" As-Built Documents

The Customer must at the time of demonstration testing have a complete set of construction drawings and documentation available. ATC and the Customer will coordinate together what information is required prior to demonstration testing. ATC shall be provided a duplicate copy of this documentation at least fifteen business days

[25] See the footnote on page 41 for additional guidance.

prior to demonstration testing. A coordination meeting with ATC should be held to clarify any questions on documentation or testing requirements at least one week before demonstration testing begins.

3.20 Communications and Procedures During Normal and Emergency Operating Conditions

ATC and the Customer will design the Interconnection Facilities to function properly under both Normal and Emergency Operating Conditions. General guidelines will be stated below, but any specific guidelines will be defined in the D-T IA between ATC and the Customer.

The Customer shall operate within the applicable guidelines of this document and any other specific requirements as stated in the D-T IA, if applicable.

3.20.1 Normal Conditions

The Customer must have twenty-four-hour support available and operate according to the instructions and approval given by the ATC system control center personnel:

3.20.2 Abnormal Conditions

ATC reserves the right to open the interconnection disconnecting device for any of the following reasons:

1. ATC line maintenance work on ATC Transmission System.
2. ATC Transmission System emergency.
3. Inspection of a Customer's substation equipment and protective equipment reveals a hazardous condition.
4. Failure of the Customer to provide maintenance and testing reports when required.
5. Customer's Interconnection Facilities interfere with other ATC customers, other Interconnection Parties, or with the operation of the ATC Transmission System.
6. Customer has modified the Interconnection Facilities that affects ATC equipment without the knowledge and approval of ATC or has not installed ATC required protective devices.
7. Personnel or public safety are threatened.
8. Customer fails to comply with applicable OSHA Safety Tagging and Lockout requirements or ATC Hold Card Procedures.

Changes to the ATC Transmission System or the addition of other ATC Customer Interconnection Party's facilities, loads, or generators in the vicinity of the Customer's Interconnection Facilities may require modifications to the Customer's and ATC's interconnection protective devices. If such changes are required, the Customer may be subject to future charges for these modifications as described in the D-T IA.

3.21 Transformers

3.21.1 Transformer Connections

The Customer shall clearly designate the proposed transformer connection scheme and provide drawings and test reports submitted to ATC. ATC prefers delta-grounded wye for the Customer's transformer connection scheme. ATC shall review other transformer configurations on a project specific basis depending on the circumstances.

3.21.2 Transformer Protection

The Customer shall install, own and maintain transformer protective equipment[26], including surge protection devices on the Customer side of the Point of Interconnection. For straight bus applications, the Customer may design transformer protection using one of four options. The Customer will determine the most appropriate option by considering the transmission connection, available fault current[27] and the Customer's standard practices. These options are:

- Option 1. - A circuit breaker in series with a source-side disconnect switch installed at the load interconnection substation,
- Option 2. - A circuit switcher or transrupter with an integral visible air-break switch can be utilized in existing substations where space is constrained. This configuration is not recommended for new interconnections, (see Section 3.21.4 for additional information on disconnect switches)
- Option 3. - A circuit switcher or transrupter **without** an integral visible air-break switch and an air-break switch in series with the circuit switcher or transrupter,
- Option 4. - Fuses in series with an air-break switch (with the switch must have the capability to break Customer transformer magnetizing current and the fuse must interrupt for all transformer faults). Fuses can only be used on 69 kV interconnections.

When the interconnection is made to a ring bus or breaker-and-a-half substation configuration, the Customer does not necessarily need to install a transformer high-side interrupting device – only a disconnect switch capable of breaking transformer magnetizing current. Customer-owned transformer relaying will trip ATC-owned circuit breakers in these configurations. Please see ATC High Voltage Underground Line Design Guide (GDE-0260) Section 4.3 a discussion on riser structures for underground connections at substations.

Additional design considerations include:

- The Customer's interrupting device shall not be designed to depend upon AC power, including capacitive trip devices, for tripping.
- ATC will provide expected short circuit currents for a specific location upon request[28].
- For options 1-4, the Customer's interconnection will contain current transformers sufficient for supporting an ATC bus differential protection scheme if necessary. All interconnections to breakered substations must meet this requirement. ATC has specific CT requirements for differential protection. See Section 3.9.3 for specific CT requirements.

ATC and its Customers will coordinate the application and use of transformer protection as part of the development and design of the interconnection project. As discussed in Sections 3.2.1 & 3.2.2 the Customer must submit the transformer manufacturer's test report prior to ATC initiating the design work and the CT ratio curves to ATC as a part of the engineering review package, specified in section 3.9.3 of this guide.

ATC and its Customers will coordinate the application and use of circuit breakers as part of the development of the interconnection project. It is understood that when ATC installs line breakers at 100 kV and above on greenfield sites, it is expected that the LDC also installs circuit breakers to protect their transformers.

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[26] Note: All of the interconnection configuration drawings in Appendix F use a breaker symbol (with interrupting device "i d " designation) to represent the general requirement of a customer-owned protective device per this section ATC prefers utilizing a breaker in this application, however a circuit switcher or a fuse may be a viable alternative Consult previous sections in this guide for recommended devices The demarcation point (change of ownership point) is at the source-side terminal of the customer–owned disconnecting device

[27] Note: The high voltage device must be capable of interrupting the worst-case fault current (from ATC) and not rely on bus tie breakers or line circuit breakers as low-cost method for protecting for high current faults

[28] See the footnote on page 41 for additional guidance.

For existing substations with transformer additions and/or replacements it is expected that the LDC installs circuit breakers as transformer protection if any one of the following situations is true:

- A bus outage that the LDC transformer is located on violate an Interconnection Reliability Operating Limit.
- There are concerns with NERC TPL-001 P2-P7 contingencies.
- There is 30 MWs or more of non-consequential load loss. Substations with multiple transformers will be addressed in the following way:
    - In a substation with transmission bus-tie breaker – load served by failed equipment is not counted
    - In a substation without transmission bus-tie breaker – load served by failed equipment is counted
    - Assumes multiple transformer substations have capacity for transformer failure
- There are more than three transmission network elements (ATC transformers are included; capacitor banks are not included unless if the outage of the capacitor bank or banks behind a single breaker results in a limitation of ATC's Planning Criteria).

3.21.3 Circuit Breakers

If transmission circuit breakers are required in the Interconnection Facilities design (typically when 30 MW of load is forecasted within the 10-year planning horizon, or the sectionalizing guidelines are applied), ATC will install a breaker on each of the line terminals at a straight bus load interconnection substation. The application of a bus-tie breaker will be considered when 30 MW of substation load is achieved. ATC may also elect to install breakers in any position deemed appropriate for reliable design when the subject interconnection substation includes more than two transmission line elements and/or a generation interconnection(s).

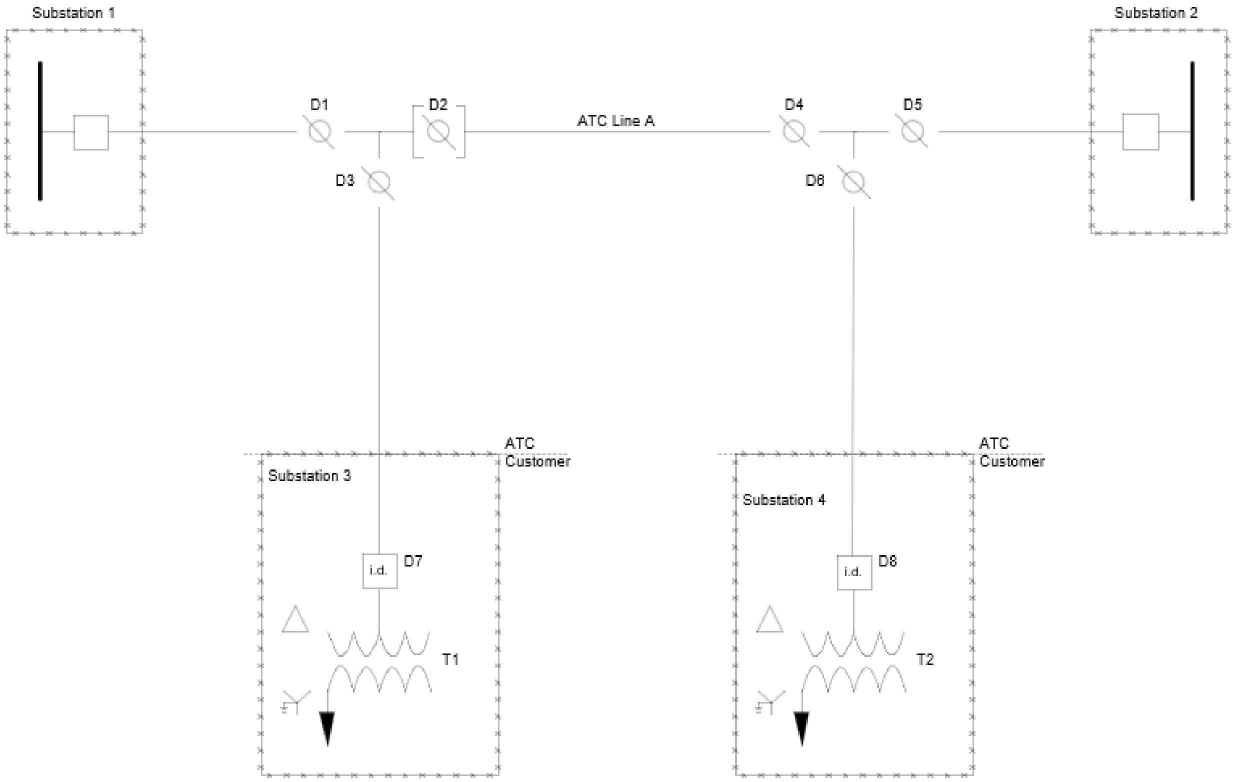
If a Customer-owned circuit breaker is installed, CT requirements for ATC bus differential protection should be evaluated as needed. See Section 3.9.3 for specific CT requirements.

3.21.4 Disconnect Switches

Load interconnection facilities shall include disconnect switches located in appropriate places which are summarized here.

All line disconnect switches shall be installed on steel structures. Installation on wood structures is not acceptable (unless installation is temporary, i.e. scheduled to be removed within two years).

Since the configuration drawings in Appendix F provide details for any single load interconnection, Figure 1 is provided to show the minimum installation of mainline switches for a typical line with multiple radial load interconnections.



* ATC and its Customer will work together to determine if a radial connection is the most appropriate design for any single interconnection.

Figure 1: Typical switch installation on a line with multiple radial taps[29]

ATC will apply switches with load-break, and/or line-charging current break capability as necessary, after considering the proper current breaking capability of all proposed and existing disconnect switches on the transmission line(s) affected by the proposed interconnection.

Motor-operators and RTUs are elective facilities for the convenience of the Customer and are paid for by the Customer. The exception to this statement is when the use of this equipment is determined to be appropriate per Section 3.6.1 of this Guide. ATC reserves the right to approve the design and equipment to be installed for these purposes since these devices directly impact the reliability of the switch installation.

For load interconnection requests that are on 69 kV lines, ATC will use phase-over-phase switch installations. In addition, ATC may install a 3-way switch to facilitate construction and coordinate outages most effectively.[30] For load interconnection requests that are on 138 kV lines, ATC will use horizontal mounted switches.

3.22 Physical Design Guidelines

[29] A symbology key is available in Appendix F

[30] Phase-over phase switch installation is only acceptable for 69 kV applications or where physical space in an existing right-of-way does not accommodate a horizontal mount installation Hydraulic motor-operators are not permitted for phase-over-phase switch installations, since experience has demonstrated insufficient hydraulic pressure often results in switch contact not closing properly

3.22.1 Site Selection

One of the most critical factors in the design of a substation is its location. It is important that the site selected have sufficient space to accommodate the present and future Customer and/or ATC's use. The Customer should review all potential substation sites with ATC prior to purchasing property.

The preparation of the site should follow ATC Design Criteria. The Customer shall submit soil borings and resistivity reports to ATC for review and use in the design of ATC's transmission facilities.

The Customer should consider the following factors when siting a load interconnection substation:

- Environmental considerations, including previous site usage or possible permitting issues,
- Sufficient size to accommodate the ultimate interconnection configuration requirements,
- Ingress/egress, including proximity to all-weather roads and/or railroad siding for (heavy) equipment installation and removal,
- Proximity to existing transmission lines and other utilities,
- The availability of suitable right-of-way and access to the substation site for transmission lines,
- Proximity to potential contaminants (such as highway salt),
- Site maintenance requirements including repair, landscaping, and storage, and
- The ATC communication methods presently employed on the existing line to be tapped, including the availability or feasibility of other methods (microwave, fiber, power line carrier, leased phone-lines, and point-to-point radio). If a substation requires underground interconnection, the cost for an underground load interconnection will be borne by the Customer, unless the interconnection is to be made to an existing ATC underground transmission line. The Customer should consult with ATC for design details regarding the feasibility of underground transmission facilities with respect to the location siting decision. Consult ATC Business Practice, Elective Undergrounding for additional details.

3.22.2 Space Requirements

When reasonably possible, the Customer will provide sufficient physical space to accommodate not only ATC and the Customer's present but also anticipated future use of the substation (see Appendix F for typical space requirements of each substation configuration). Such additional ATC requirements, beyond those outlined in the ATC Design Guide, may include transmission capacitor banks and/or additional ATC-owned elements (e.g. lines). Space required for an ATC capacitor bank is detailed in ATC Guide. The Customer should also consider its requirements for connection of a mobile substation as a means for load bridging under emergency outage circumstances.

The Customer shall also provide sufficient clearance from energized equipment to satisfy the NESC and ATC Design Criteria. To facilitate maintenance access, ATC prefers to maintain a horizontal clearance between the substation fence and bus support structures or equipment consistent with the Safety Clearance Zone specifications consistent with the NESC Section 110.A.2. Please refer to the ATC Design Criteria CR-0060 entitled "*Substation Site Design*", Section 4.3. The Customer shall discuss exceptions with ATC as part of the design review process.

3.22.3 Ownership Demarcation

The Point of Interconnection will be where the Customer interconnection facilities connect to the ATC Transmission System.

3.22.3.1 Radial Connections

The point of interconnection between ATC and Customer-owned high-voltage facilities will be at the Customer end of the jumper connected the to the ATC-owned line insulator connection at the Customer's dead-end structure. For an overhead ATC-owned transmission tap conductor terminated at a Customer-owned dead-end structure, the Customer will include provisions on that structure to accommodate the installation of surge arresters by either party, if necessary. Through the project team, ATC and its Customer will select an appropriate connector and coordinate responsibility for furnishing and installing the connectors as well as completing the final connection of the jumpers to the Customer-owned facilities.

3.22.3.2 Network Connections

The Customer's connection at the high-voltage bus side terminal of the Customer-owned disconnecting device will be the physical point of transmission facilities ownership demarcation between ATC and Customer-owned facilities. Through the project team, ATC and its Customer will select an appropriate connector and coordinate responsibility for furnishing and installing the connectors as well as completing the final connection of the jumpers to the Customer-owned facilities.

The default Point Of Interconnection for interconnected bus differential relaying is located at the terminal of the Customer-owned CTs on the Customer-owned breaker or transformer. ATC owns all of the cables up to the Customer-owned CTs on the Customer-owned breaker or transformer.

3.22.4 Land Rights

3.22.4.1 Customer-Owned or Leased Substation Lands

The Customer shall furnish at no cost to ATC any necessary access, easements, licenses, and/or rights-of-way upon, over, under, and across lands owned by the Customer and/or its affiliated interests for the construction, operation and maintenance of necessary lines, substations, and other equipment to accomplish the requested interconnection. ATC will be responsible for obtaining land rights from third parties. The Customer will be responsible for obtaining all of the appropriate permits for the substation.

3.22.4.2 ATC-Owned Substation Lands

ATC will furnish at no cost to the Customer any necessary access, easements, licenses, and/or rights of way upon, over, under, and across lands owned by ATC and/or its affiliated interests for the construction, operation and maintenance of the Customer's facilities. The Customer will be responsible for obtaining any land rights from third parties. ATC will be responsible for obtaining all of the appropriate permits for the substation.

3.22.5 Clearances

Clearances to ATC substation facilities shall satisfy ATC Design Criteria.

3.22.6 Line Termination Structures

The Customer and ATC shall carefully coordinate the substation design of the last span of wire between the last ATC transmission tower and the substation overhead line terminal structure(s). ATC and the Customer together will arrange the orientation of the substation in relation to ATC's incoming transmission line(s) to minimize line angles, turning towers, and crossings.

ATC will typically design the last full-tension tap span to terminate into an ATC-owned structure outside the Customer's radially fed load interconnection substation. However, where physical constraints dictate, and ATC-owned transmission lines terminate at a Customer-owned terminal (dead-end) structure, the Customer will design the structure to support the loads identified for ATC's equipment provided by ATC's Design Engineering Department and those outlined in ATC Design Criteria.

3.22.6.1 Site Preparation

Examples of the common facilities requirements that are applicable to Customer-owned substations containing ATC equipment can be found in the ATC Business Practice BP 0403 entitled Joint-Use Substation Cost Responsibility for Common Facilities.

3.22.6.1.1 Greenfield Interconnection Substation

The Customer is responsible for providing a suitable site for the load interconnection substation. When appropriate, the Customer will be required to convey to ATC all necessary easements, in a form acceptable to ATC, over all property owned, leased or otherwise controlled by the Customer, including easements for ingress and egress to permit ATC access to all of the ATC Interconnection Facilities and Network Upgrades, which are on the property of the Customer. Additionally, the site that the Customer provides to ATC must be sufficiently large enough to accommodate the present and future uses of ATC and meet the rough grading requirements of ATC for the substation pad. ATC design expectations and review of rough grading are listed in ATC Construction Standard Specification Manual – section 31.10.10., available upon request[31] The specific real estate requirements will be determined during the detailed design.

The Customer will be responsible for obtaining all necessary zoning, building, and environmental, permits or approvals required for the load interconnection substation. This includes permits for impacts to waterways, wetlands, floodplains, or endangered resources and any compensatory mitigation associated with such permits. The specific permits required will depend on the characteristics of the site and the local jurisdiction. When appropriate, copies of all environmental permits obtained shall be provided to ATC in order to ensure that ATC's construction of the substation meets all permit requirements.

The Customer is responsible to design, obtain permits and install all storm water management facilities for the load interconnection substation and the overall Customer property. The Customer will be responsible for establishing final grade, revegetation, and any necessary landscaping of the portion of their property. When appropriate, the Customer's storm water management permit shall allow for ATC's construction activities to build the substation and bring it to final grade. Long-term maintenance and inspections of all storm water management facilities are the responsibility of the Customer. If ATC's construction activities disturb areas where the Customer has completed final grading and re-vegetation, ATC will repair the disturbance in a timely manner.

3.22.6.1.2 Existing Interconnection Substation

If the Customer chooses to modify or expand an existing load interconnection substation that results in the need for environmental permits/approvals, ATC and the Customer (and landowner if other than ATC or Customer) will coordinate to determine which entities will be responsible for obtaining the necessary permits/approvals.

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[31] See the footnote on page 41 for additional guidance.

3.22.6.2 Control Enclosures

The Customer will design control enclosures (buildings) that contain ATC relaying with sufficient space for convenient access to control panels - with at least 36 inches of clear space behind the panels and unobstructed access to substation batteries. Please review ATC Design Guide or refer to the latest version of the NESC for additional guidance.

3.22.6.3 Security / Access

The Customer will design, install, own, and maintain the substation fence.

The Customer will make provisions at both the substation gate and the control enclosure for an ATC lock, thereby enabling ATC access by an ATC-owned key or other electronic means.

The Customer will design the substation outdoor lighting system to provide adequate illumination for security, emergency ingress/egress, and position indication of disconnect switchblades. ATC does not require lighting for nighttime maintenance operations.

Substations interconnected to the ATC transmission system above 100 kV may need additional security and access included in the design. This will be determined by the design team during the project.

3.22.6.4 Conduit / Raceway

The Customer will install, own, and maintain substation cable conduit and/or raceway systems.

3.22.6.5 Signs and identification

The following requirements apply to all substations containing ATC equipment.

- For maximum effectiveness, the Customer will place security and identification signs at eye level (less than six feet and more than four feet above grade or floor level).
- On Customer-owned dead-end and/or switch structures, the Customer will provide phase identification signs on A, B, and C phases to indicate ATC standard phase rotation next to the termination device for each interconnection point.

3.22.6.6 References

The following documents[32] provide additional guidance for use in the development of load interconnection facilities between ATC and its Customers:

- ATC Business Practice, Coordination of Local Balancing Authority Metering Boundary Modifications (See the ATC website https://www.atcllc.com/customer-engagement/business-practices/).
- ATC Business Practice, Capacitor Bank Installations on Distribution Systems for Transmission Benefit (See the ATC website https://www.atcllc.com/customer-engagement/business-practices/).

[32] Internal ATC references/documentation are available upon request to existing customers and entities with a signed non-disclosure agreement with ATC. Please contact ATC Interconnection Solutions (T-DLIRFS@atcllc.com) for additional information and guidance.

- ATC Business Practice, Elective Interconnection Facilities for additional information (See the ATC website https://www.atcllc.com/customer-engagement/business-practices/).
- ATC Business Practice; Elective Undergrounding (See the ATC website https://www.atcllc.com/customer-engagement/business-practices/).
- ATC Business Practice, Joint-use Substations -- Common Facilities (See the ATC website https://www.atcllc.com/customer-engagement/business-practices/).
- ATC Business Practice; Load Bridging for Transmission Related Work (https://www.atcllc.com/customer-engagement/business-practices/).
- ATC Construction Standard Specification Manual (Available upon request).
- ATC Criteria CRT-0060, Substation Site Design (Available upon request).
- ATC Guide GDE-8000; Substation Capacitor Bank (Available upon request).
- ATC Guide GD-2300; Substation Control House (Available upon request).
- ATC Guide GDE-4500, Substation Disconnect Switch (Available upon request).
- ATC Distributed Energy Resource Guide GD-1701 (Available upon request).
- ATC Best Value Planning White Paper (See the ATC website: http://www.atcllc.com).
- ATC Planning Criteria (See the ATC website: https://www.atc10yearplan.com/about/planning-criteria-and-tools-2/)
- Midcontinent ISO Tariff - Open Access Transmission, Energy and Operating Reserve Markets Tariff (ASM Tariff) - Midcontinent ISO FERC Electric Tariff, First Revised Vol. No. 1.
- National Electrical Code.
- National Electrical Safety Code.
- IEEE Standard 1246 "Guide for Temporary Protective Grounding systems used in Substations"
- IEEE Standard 1547 "IEEE Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power System Interfaces"
- NERC Reliability Standard FAC-002-3
- NERC Reliability Standard FAC-001-3.3

Revision History

Revision Information

Revision	Author	Date	Section	Description
12.0	Kaylin Schueler	1/11/23	Various	• Section 3 6 2 Line Topology – Radial versus Loop-through Connections • Updates to links and functional area names • Updates to Appendix B and C
11.0	Kaylin Schueler	12/10/21	Various	• Added reference to DER Request Form • Removal of all language and diagrams related to 2 way switches • Updates to LIG diagrams – Appendix B • Updates to Load Interconnection Configurations – Appendix F
10.0	Kaylin Schueler	12/18/20	Various	• DCG terminology/definition updated to DER • Additions of MCW, NCW and CW definitions • Added Site Preparation language • Removal of MCW $ threshold • Update to Interconnection Configuration Diagrams & Figure 1 Disconnect Switches
9.0	John Raisler	12/20/19	3.9.5.1	• Clarified that the installation of VTs will be to ATC design specifications
8.0	John Raisler	12/20/18	Various	• Updated various links and document references • Added Battery Storage to DCG definition • Added appropriate project documentation definition and description to reflect updated project commitment practice • Replaced circuit switcher symbol with breaker symbol to represent interrupting device (i d) in all Appendix F substation configuration diagrams and Figures in the document • Clarified language in various sections for readability
7.0	John Raisler	12/15/2017	3	• Clarified language in the two breaker failure scenarios
6.0	Heather Andrew	12/21/2016	Various	• Updated reference to FAC-001 • Updated one-lines • Added SOCA reference • Updated BA Metering reference
5.0	Heather Andrew	12/16/2015	Various	• Updated Appendix F, • Added Appendix G, • Removed Planning Coordinator role • Updated transformer protection section • Updated power factor section • Removed Index • Removed copies of LIRF and PCA
4.01	Heather Andrew	10/09/2014	Appendix F	• Updated the Flowchart

4.0	Heather Andrew	6/16/2014	All	• Changed MISO's name to Midcontinent Independent System Operator • Section 2 1 2 – Last Paragraph, changed "will be responsible to pay…" to "may be responsible to pay…" • Updated Sections 3 3 and 3 4 with the correct reference sections • Section 3 6 – added a statement clarifying when a ring bus would be implemented • Section 3 6 1 1 – updated to reflect what load level drives line breakers and a bus tie breaker • Section 3 6 3 – corrected the phasing table for Cloverland/Edison Sault • Section 3 9 1 – removed fuses for an option for new substation and the footnote Added a statement about fuses at existing locations • Section 3 9 5 – added a reference to the new Planning Guideline for distribution connected generation • Section 3 15 4 – added a statement about when circuit breakers are recommended for LDC transformer protection Also added a paragraph as to the CT requirements • Section 3 21 2 – added a statement about integral circuit breaker/switch configurations for existing and new interconnections • Section 3 21 3 – added two clarifying statements about when breakers are considered • Appendix B – Updated the CA threshold reference in the box on lower right corner • Appendix B – Updated the BVP process map • Appendix C – updated the table to reflect the new BVP Assessment Types per the new Queue layout • Appendix F – Added a bus configuration decision tree • Appendix F – Configurations J and K became I and J because there was no I previously
3.0	John Raisler	1/21/2013	All	
2.0	John Raisler	08-24-11	All	Rearranged & added sections to align with FAC-001 requirements ordering of topics. Added Expanded Distribution Connected Generation discussion in 3.10.5 Added BVP Process Flow Diagram Appendix B Updated BVP Responsibilities Matrix Appendix C Updated LIRF example Added Revision History

1.0	John Raisler	10-09-09	All	New - Includes review by: System Protection, Operations, Commissioning, Safety, Substation Services, Environmental, Maintenance, Metering, Planning, Legal and Interconnection Services.

Appendix A.1 – Glossary of Terms

Any capitalized terms not defined herein will have the meanings set forth in the Midcontinent ISO Tariff.

ATC Design Criteria, ATC Guide: are terms used to reference a series of design criteria documents and guides used internally at ATC to document specifications for various transmission facilities. (See Section 3.4 references) The documents are available upon request.

ATC Transmission System: the facilities owned by ATC subject to the administration of the Midcontinent ISO that are used to provide energy market, transmission, energy, and ancillary reserves market, interconnection services or Wholesale Distribution Service under the Midcontinent ISO ASM Tariff.

Balancing Authority: an entity responsible for managing an electric system area (a Balancing Authority Area) bounded by interconnection metering and telemetry; and capable of controlling generation to maintain its interchange schedule with other Balancing Authority Areas and contributing to frequency regulation and which has received certification by NERC or a Regional Reliability Council of NERC.

Best Value Planning (BVP): means the consideration of, or evaluation of, one or more alternatives to the proposed construction of new, or the modification of existing, transmission facilities which have been identified in a planning process to determine whether an alternative or alternatives exists that may include the construction of new, or the modification of the existing, distribution facilities or transmission facilities owned by others that is/are less costly or which may provide greater enhancement to the reliability, capability or integrity of ATC's transmission facilities and such interconnected transmission or distribution facilities when compared to the estimated cost of the construction and capability of the proposed new, or the proposed modification of, ATC's transmission facilities, while taking into account the environmental considerations, regulatory approvals and the ability to construct the proposed distribution or transmission facilities in a timely and appropriate manner.

Best Value Planning Project Scoping Report: the report jointly developed by ATC and its Customer that documents the decisions leading to the recommended project solution for a given load interconnection request. Once this report signed by both ATC and the Customer, it is then used to document the commitment to proceed with the project, support project approvals, project schedules, project budgets and regulatory requirements.

Capital Work (CW) : A D-T project in which ATC's scope drives the need for a full project team and the associated spend is considered capital. Examples may include but not limited to a new substation, adding a transformer and installing sectionalizing device(s).

Capital Work Letter: A signed Capital Work Letter summarizes and commits ATC and the Customer to the agreed upon scope of work.

Common Facilities: those facilities, installed at a joint-use substation, which are substantially used and useful to more than one entity at such substation.

Customer[33]: any authorized distribution utility that proposes a new or modified load interconnection with ATC's Transmission System at a nominal voltage level of ≥ 50 kV. For purposes of this Guide, Customers that serve load are Local Distribution Companies (LDCs) that include Investor-Owned Utilities, Municipal Utilities and Rural Electric Cooperatives. The LDCs may or may not be functionally NERC registered as Distribution Providers (DPs).

Customer's Interconnection Facilities: all facilities and equipment, as identified in the D-T IA, that are located between customer load(s) 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 load to the Transmission System.

Distributed Energy Resources (DER): is defined as "any resource located on the distribution system, any subsystem thereof or behind a customer meter." These resources may include, but are not limited to, resources that are in front of and behind the customer meter, electric storage resources, intermittent generation, distributed generation, demand response, energy efficiency, thermal storage, and electric vehicles and their supply equipment – as long as such a resource is "located on the distribution system, any subsystem thereof or behind a customer meter.".[34]

Distribution – Transmission Interconnection Agreement (D-T IA): the form of the interconnection agreement. ATC utilizes an ATC developed Distribution – Transmission Interconnection Agreement template which is files at FERC and made part of the Midcontinent ISO ASM Tariff once it is fully executed.

Existing Substation: any substation other that the new interconnection substation at which any single new load interconnection is proposed.

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[33] Any references to "customer(s)" are intended to include either the distribution utility, their end-use customer that is directly-connected to the transmission system, or both in the sense that the end-use customer's relationship with ATC must be coordinated through the responsible distribution utility.

[34] DER as defined in FERC 18 CFR Part 35 – Docket No RM18-9-000; Order No. 2222 (pg. 91). Issued September 17, 2020 - https://www.ferc.gov/sites/default/files/2020-09/E-1_0.pdf

Facility Construction Agreement: A signed FCA establishes a commitment by both ATC and the Customer to support the Project. An FCA is typically used to document elective facilities chosen by the Customer in support of the project.

FERC: the Federal Energy Regulatory Commission or its successor.

Good Utility Practice: 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, including those practices required by Federal Power Act Section 215(a)(4). Good Utility Practice includes compliance with Mandatory Reliability Standards.

Guide: this ATC published document entitled "Load Interconnection Guide."

Interconnection Facilities: the physical plant and equipment required to facilitate the transfer of electric energy between two or more entities; including communication equipment, substations and transmission lines.

Joint-use Substations: substations in which both the Customer and ATC own facilities.

Load: a customer's projected normal peak demand load forecast (in both MW & MVAR) for a minimum 10 years, used by ATC for sizing interconnection facilities.

Load Interconnection: the interconnection service provided by ATC at a voltage level ≥ 50 kV to a Customer for transformation and/or utilization.

D-T Interconnection Queue: ATC maintains a listing of load and DER interconnection requests from its Customers for the benefit of both ATC and its Customers. The D-T Interconnection Queue is available on the ATC Web site at http://www.atcllc.com/customer-engagement/connecting-to-the-grid/ look for the link to the ATC queue towards the bottom of the webpage.

Mandatory Reliability Standards: those standards promulgated and approved by NERC as the Electric Reliability Organization (ERO), or any Regional Entity authorized to do so, as ratified and approved by the FERC that are applicable to ATC and the Customer.

Minimal Capital Work (MCW) : a D-T project that results in minimal ATC scope and capital spend for minor equipment replacements and/or interconnection modifications. Examples may include work to support a mobile sub, high side protection upgrades & upgrades to surge arresters.

MISO: the Midcontinent Independent Transmission System Operator, Inc., the Regional Transmission Organization that administers the tariff and provides transmission and energy market services over the transmission facilities of its transmission-owning members in interstate commerce.

MISO Tariff: the MISO FERC Electric Tariff under the terms of which open access transmission, energy and operating reserves market and interconnection services are offered, as filed with the FERC, and as amended or supplemented from time to time, or any successor tariff. Used interchangeably with Tariff.

NERC: the North American Electric Reliability Corporation or its successor organization.

Network Connection: an interconnection configured with multiple transmission connections into the load interconnection substation. In addition to the Customer's load, transmission network power may flow through the interconnection facility.

New Interconnection Substation: any existing or new substation at which a new load interconnection is proposed.

No Capital Work (NCW) : a D-T project in which the ATC scope and costs are considered O&M. There are two types of NCW projects: **LDC support** & **LDC only**. If an LDC scope drives the need for system protection to review and update drawings and/or if there is commissioning work to support the project, the project is considered LDC support. If the LDC scope does not result in any ATC support work, but may require the LDC to submit updated documentation, like a transformer test report, it is considered LDC only.

Planning Authority: MISO is the responsible entity that coordinates and integrates transmission facility and service plans, resource plans and protection systems associated with the ATC Transmission System.

Point of Change of Ownership (PCO): the point, as set forth in Appendix A to the D-T Interconnection Agreement, where the Customer's Interconnection Facilities connect to the ATC Interconnection Facilities.

Project Commitment Agreement (PCA): the Project Commitment Agreement establishes the commitments by ATC and the Customer when significant resources are required to site, engineer, design, permit, procure, and build the planned interconnection facilities. The PCA will also include any remaining study requirements, the timeline for any necessary regulatory approvals, cost estimates and the preliminary construction schedule.

Radial Tap Connection: an interconnection configured with a single transmission connection into the load interconnection substation.

Tariff: the MISO Tariff through which open access transmission service and interconnection service are offered, as filed with the FERC, and as amended or supplemented from time to time, or any successor tariff. Used interchangeably with MISO Tariff.

Transmission Facilities: for the purpose of this Guide, means electric lines and related facilities that are operated at 50 kV and above.

Transmission Operator: ATC is the entity responsible for the reliability of the ATC Transmission System. ATC is also the entity that operates or directs the operations of the ATC Transmission System.

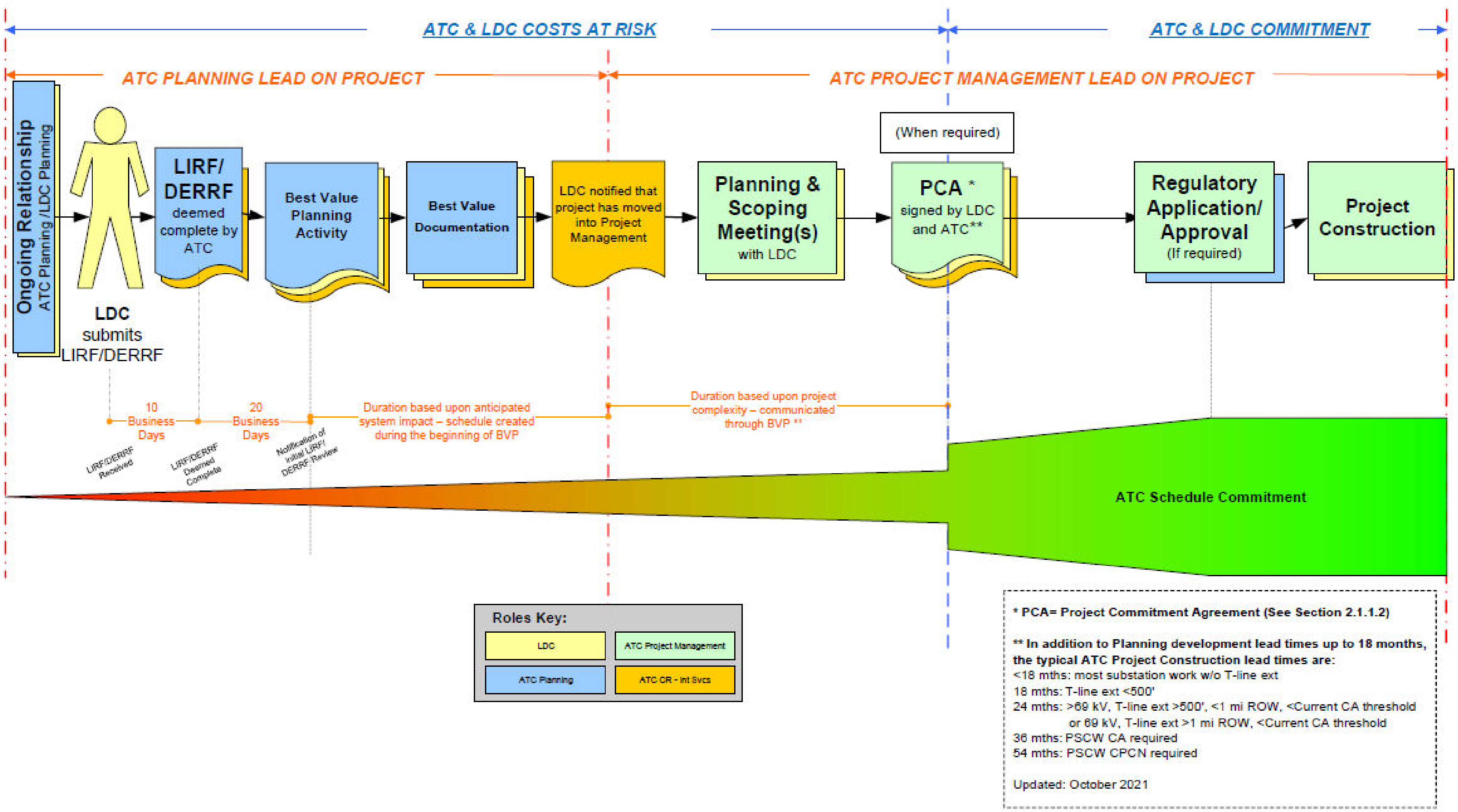
Transmission Owner: ATC is the entity that owns and maintains the ATC-owned Transmission Facilities.

Transmission Planner: ATC is the entity that develops a long-term (generally one year & beyond) plan for the reliability (adequacy) of the interconnected bulk electric transmission systems within its portion of the Planning Authority Area.

Transmission System: the facilities owned by ATC subject to the administration of the Midcontinent ISO that are used to provide energy market, transmission service or wholesale distribution service under the Tariff.

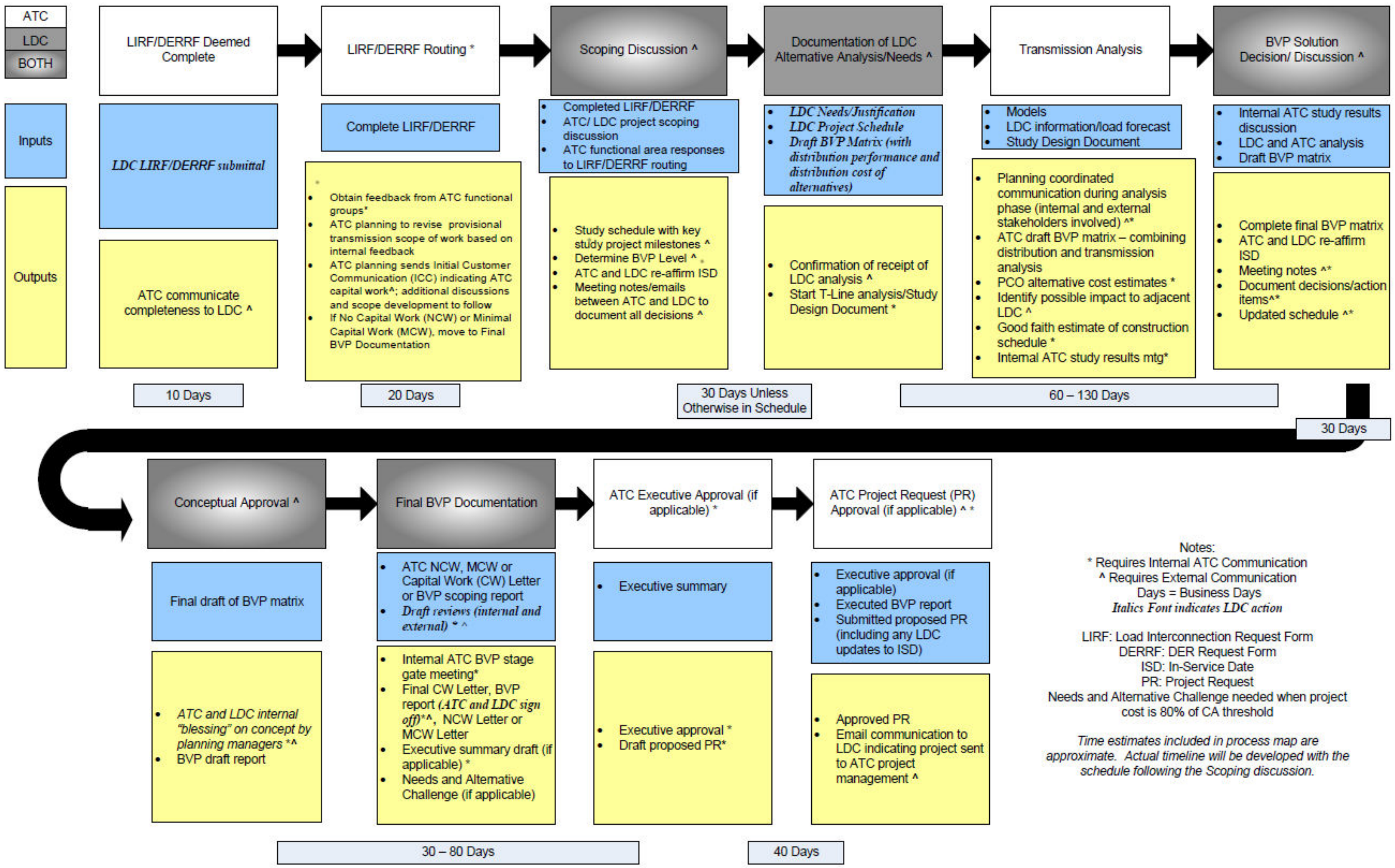
Appendix B – Load Interconnection Process Overview

SUMMARY - LDC & ATC LOAD INTERCONNECTION PROJECT COMPONENTS



Appendix B – Load Interconnection Process Overview (continued) -*Additional detail showing Best Value Planning Process Map*

Best Value Planning Process Map Updated 11/2022



Notes:
* Requires Internal ATC Communication
^ Requires External Communication
Days = Business Days
Italics Font indicates LDC action

LIRF: Load Interconnection Request Form
DERRF: DER Request Form
ISD: In-Service Date
PR: Project Request
Needs and Alternative Challenge needed when project cost is 80% of CA threshold

Time estimates included in process map are approximate. Actual timeline will be developed with the schedule following the Scoping discussion.

Appendix C - Best Value Plan Documentation Descriptions

Best Value Planning Assessment Type

BVP Assessment Type*	Explanation**	LDC Information (minimum)	Transmission Analysis	ATC Documentation
NCW	No ATC Capital Work and no transmission analysis	Completed LIRF/DERRF	No planning analysis – internal ATC routing only	NCW letter stating assessment completed
MCW	Minimal ATC Capital Work and no transmission analysis	Completed LIRF/DERRF	No planning analysis – internal ATC routing only	MCW letter stating assessment completed
Alternative Assessment	May include a transmission alternative interconnecting load to the transmission line currently serving the local load or assessment of multiple substation configurations	Completed LIRF/DERRF and LDC distribution assessment (as listed in guidelines in Appendix B)	Potential for planning analysis of alternatives including a difference analysis (compared to the base case model) including Category B and C contingencies and possibly different transmission system network and load configurations – amount determined by engineering judgment and team meetings	Letter stating assessment completed or BVP Scoping Report – describing the pertinent assumptions and assessment that was performed
System Study	ATC Executive approval needed or ATC Needs and Alternatives challenge is needed (ATC project cost of 80% of the CA threshold) or multiple transmission alternatives. If applicable –ATC to file a Certificate of Authority (CA) or Certificate of Public Convenience and Necessity (CPCN) with the PSCW	Completed LIRF/DERRF and LDC distribution assessment (as listed in guidelines in Appendix B) with at least one viable distribution alternative (see Project Alternatives in Appendix B)	Modeling analysis for at least two alternatives including a difference analysis (compared to the base case model) including Category B and C contingencies with different transmission system network and load configurations. Modeling will encompass at least a 10-year planning horizon	BVP Scoping Report and if applicable - support for CPCN or CA filing documentation

*BVP assessment type and high-level schedule will be developed after Scoping Meeting with Customer as seen in Appendix B
**These are typical explanations of BVP types however any given project may change during BVP if the scope of work changes

Appendix D – Example Load Interconnection Request Form & Distributed Energy Resource Request Form

The LIRF and DERRF can be found at:
https://www.atcllc.com/customer-engagement/connecting-to-the-grid/

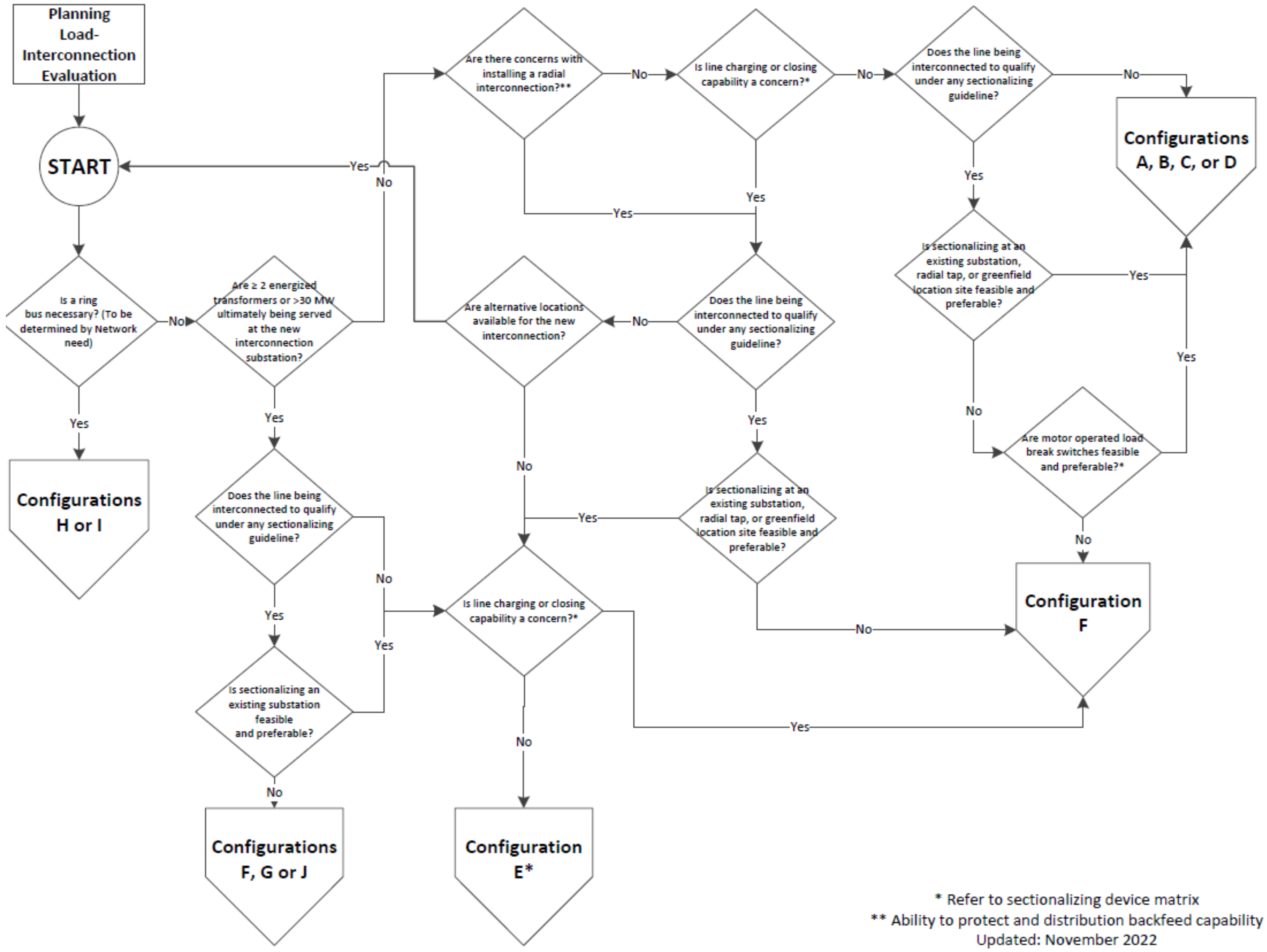
Appendix E – Example Project Commitment Agreement

The Project Commitment Agreement template can be found at:

https://www.atcllc.com/customer-engagement/connecting-to-the-grid/

Appendix F – Interconnection Configurations

Figure 2 Bus Configuration Decision Flow Chart



Note: When the proposed substation has two transformers and the load is < 30 MW, it is acceptable to not include line breakers in the original substation design

Sectionalizing Device Risk Matrix

Updated 11/5/21		Decision Characteristics										
Bus Configuration	Device	Line Charging Interruption[1]	Closing Capability (Load Pickup) [2 & 4]	Load Break Capability[3]	Is there an adjacent tap with load break capabilities?	Is Communication available?	Is AC Power available?	Is a Battery available?	Space	Response Time	Decision
A, B, C, D or E	Disconnect Switch	Is it 69 kV: line charging > 5 Amps, Is it 138 kV: line charging > 3.5 Amps? Yes - move down. No - continue moving to the right.	Is the line flow at closing > 100 amps? Yes - Move down. No continue moving to the right.	Not applicable	Yes - continue moving to the right. No - move down.	No Concern	No Concern	No Concern	If there is not enough right-of-way for horizontal 138 kV switches - move down.	If the closest responding line crew is 1 hour or more away - move down.	Install this device.
	Load Break Switch	Is line charging > 70 Amps? Yes - move down. No - continue moving to the right.	Is the line flow at closing > 100 amps? Yes - Move down. No continue moving to the right.	Is Line Flow > 2000 Amps? Yes - move down. No - continue moving right.	No Concern	No Concern	No Concern	No Concern	If there is not enough right-of-way for horizontal 138 kV switches - move down.	If the closest responding line crew is 1 hour or more away - move down.	Install this device.
	Remote controlled Motor Operated Load Break Switch on Line (typically with a long radial tap or just on the T-line for sectionalizing)	Is line charging > 70 Amps? Yes - move down. No - continue moving to the right.	Is the line flow at closing > 100 amps? Yes - Move down. No continue moving to the right.	Is Line Flow > 2000 Amps? Yes - move down. No - continue moving right.	No Concern	Yes - continue moving to the right. No - move down.	If unable to use nearby distribution service for power supply - move down.	If unable to located at the switch pole or secure the new equipment - move down.	If there is not enough right-of-way for horizontal 138 kV switches - move down.	No Concern	Install this device.
	Remote controlled Motor Operated Load Break Switch in Sub or on T-line within 500' of sub	Is line charging > 300 Amps? Yes - move down. No - continue moving to the right.	Is the line flow at closing > 100 amps? Yes - Move down. No continue moving to the right.	Is Line Flow > 2000 Amps? Yes - move down. No - continue moving right.	No Concern	Yes - continue moving to the right. No - move down.	If unable to use substation power supply - move down.	If unable to use substation battery - move down.	If there is not enough right-of-way for horizontal 138 kV switches - move down.	No Concern	Install this device.
F, G, H or J	Circuit Breaker	No Concern	No Concern	No Concern	No Concern	No Concern	No Concern	No Concern	No Concern	No Concern	Install this device.

1. ATC recommends using a design margin of double the charging current for the interruption device (exp. 4 amps of charging current requires a device that can interrupt 8 amps). For further guidance please refer to GDE-4500, Section 4.11.

2. Rule of thumb value to ensure longevity of the switch as switches are not designed to pick up load. Picking up limited amounts of charging current is a frequent application for line switches and should not be accounted for with this selection matrix. Refer to section 3.6.1.9 Sectionalizing Device Ratings/Capability in the Load Interconnection Guide for additional information.

3. Assumes a 2000 amp rated switch.
4. Lines with only one tap do not require additional consideration for closing capability for switches.

Instructions:
Start on the first row, first column and work you way right and down as you answer questions.

Other Notes:
MOD Gear mechanism can be exercised without an outage. Additional research is being done on MOD mechanisms. Need to ensure alignment of switch after operation due to slow operation.
Installations with switches will experience a sustained outage for switching. Load break switches with MOD's will experience a sustained outage in the substation and a momentary outage on the transmission line.
Disconnect and load break switches will need an outage to maintain them.

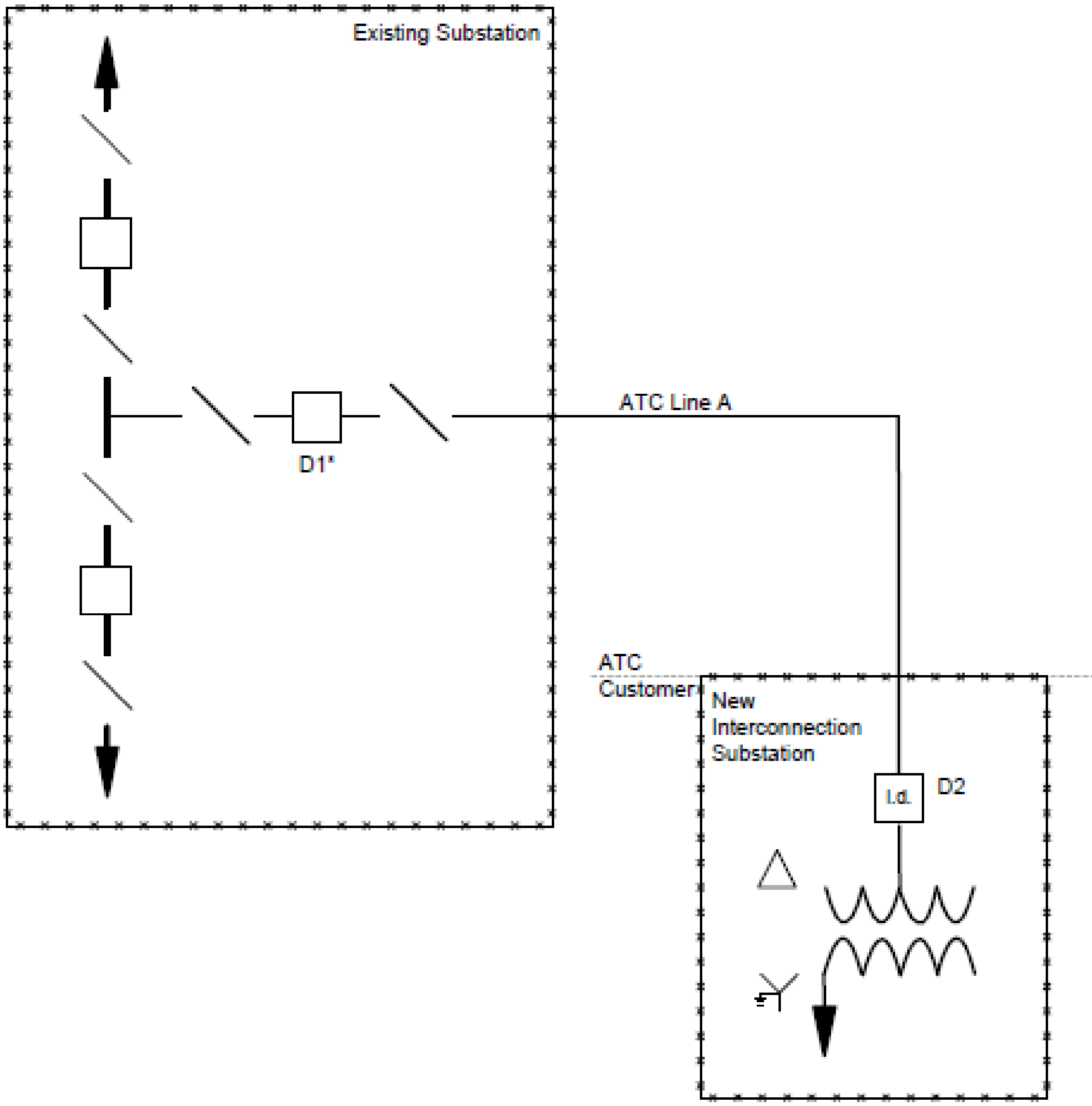
	Existing	Proposed for present or ultimate installation	Space for future (>10 yrs) installation
Circuit breaker			
Disconnect switch (switch with horns typical).			
Disconnecting device with sufficient capability to break line charging current (switch with whips typical).			
Disconnect switch with sufficient capability for loop-splitting on network lines or load-breaking on radial lines (switch with interrupter typical).			
Interrupting device sufficient for power transformer protection[1].	i.d.	i.d.	i.d.
Power transformer			

Figure 3 Load Interconnection Configurations Symbology Key

1. ATC recommends customers utilize breakers for the interrupting device, however it is recognized that the ultimate decision on the interrupting device remains with the customer See Section 3 21 2 of this Guide for additional information For 69 kV applications, if the interrupting device is a fuse, a series switch capable of breaking transformer magnetizing current is needed and low voltage device(s) is(are) needed for breaking load Fuses must be capable of clearing all transformer faults For additional discussion on transformer protection issues please see Section 3 2 1 2

Appendix F – Interconnection Configurations (Continued)

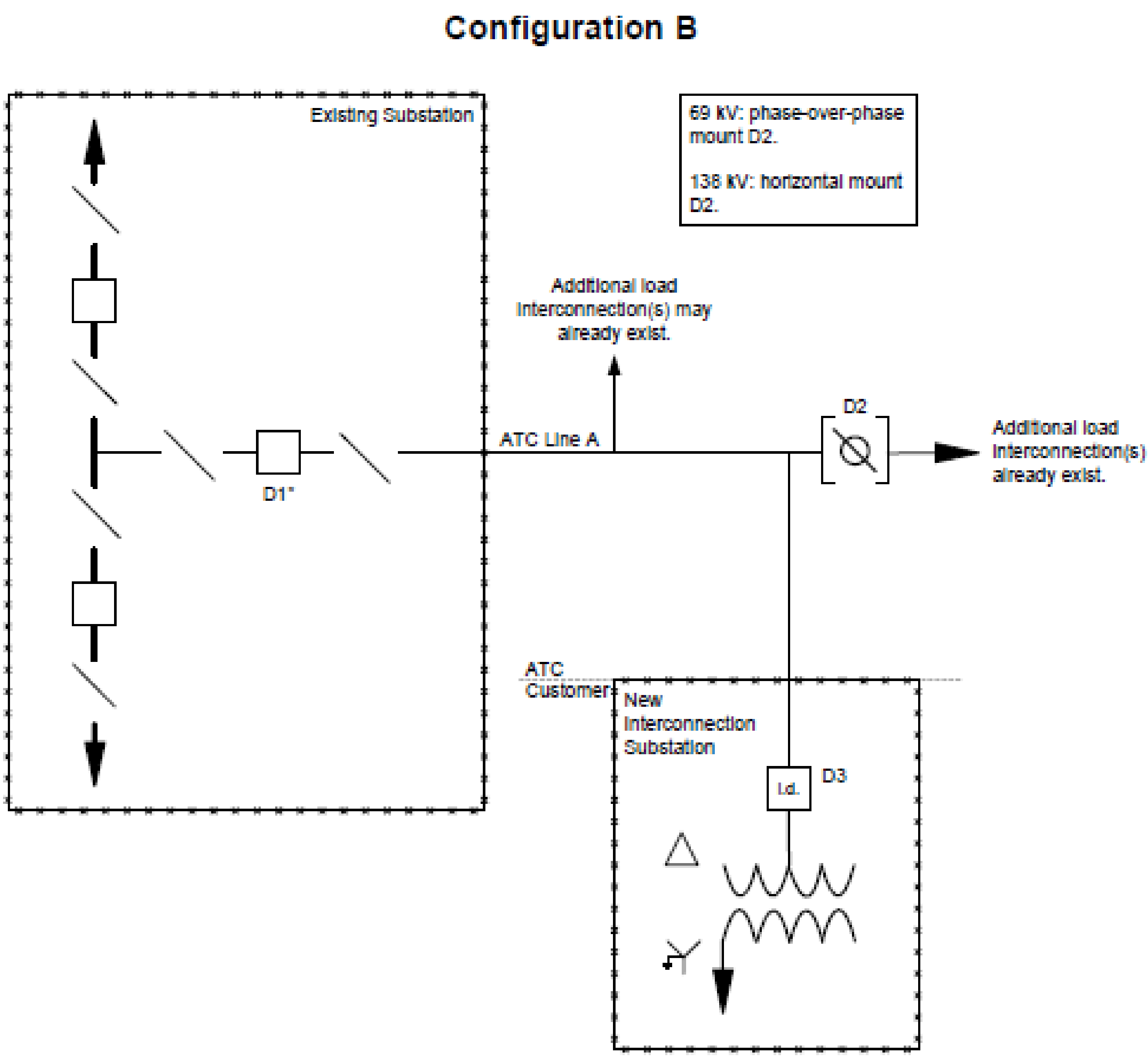
Configuration A



* This line terminal breaker is not necessarily required if either of the following is true:
1) The radial line is terminated into a ring bus or breaker-and-a-half configuration.
2) The length of the tap from the mainline to the load interconnection substation is short enough that transmission exposure is minimal and the Customer's transformer protective device is sufficient by itself.

Figure F.4: Load Interconnection Configuration A

Appendix F – Interconnection Configurations (Continued)



* This line terminal breaker is not necessarily required if the radial line is terminated into a ring bus or breaker-and-a-half configuration.
Note: Switch D2 is needed only if it is greater than 1 mile to the next substation. Customer disconnect switch (D3) must be visible from the tap.

Figure F.5: Load Interconnection Configuration B

Appendix F – Interconnection Configurations (Continued)

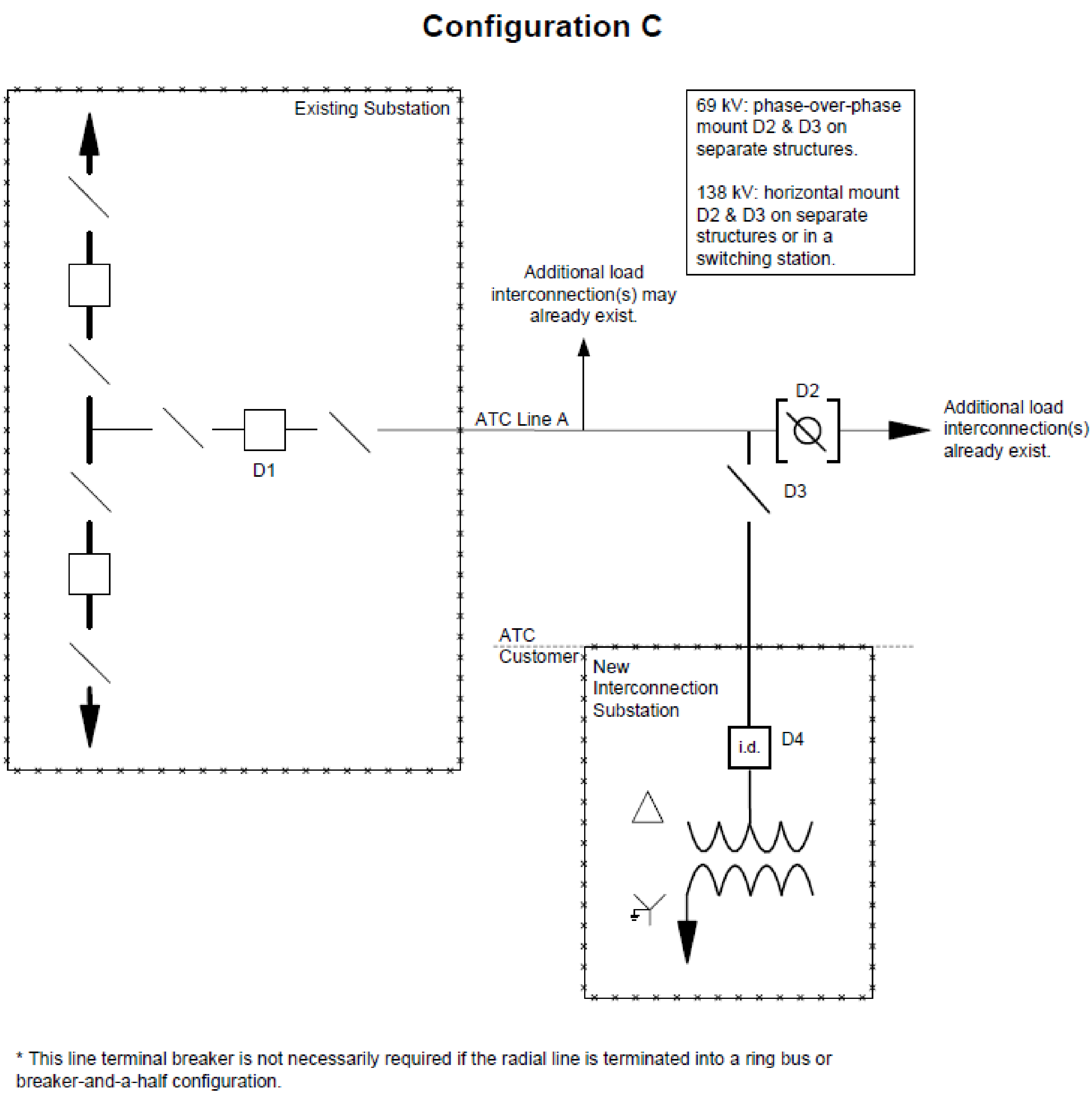


Figure F.6: Load Interconnection Configuration C

Appendix F – Interconnection Configurations (Continued)

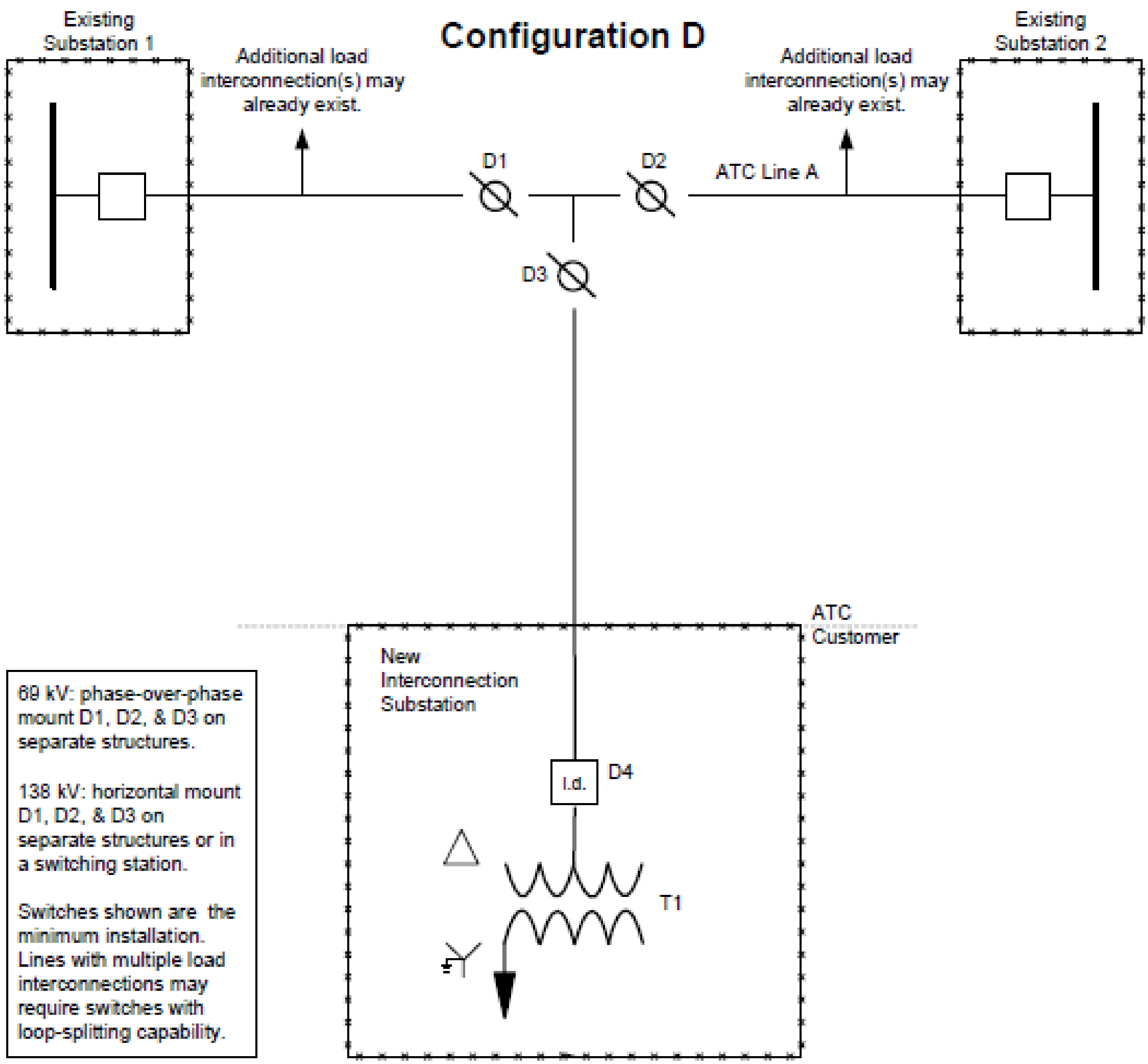


Figure F.7: Load Interconnection Configuration D

Appendix F – Interconnection Configurations (Continued)

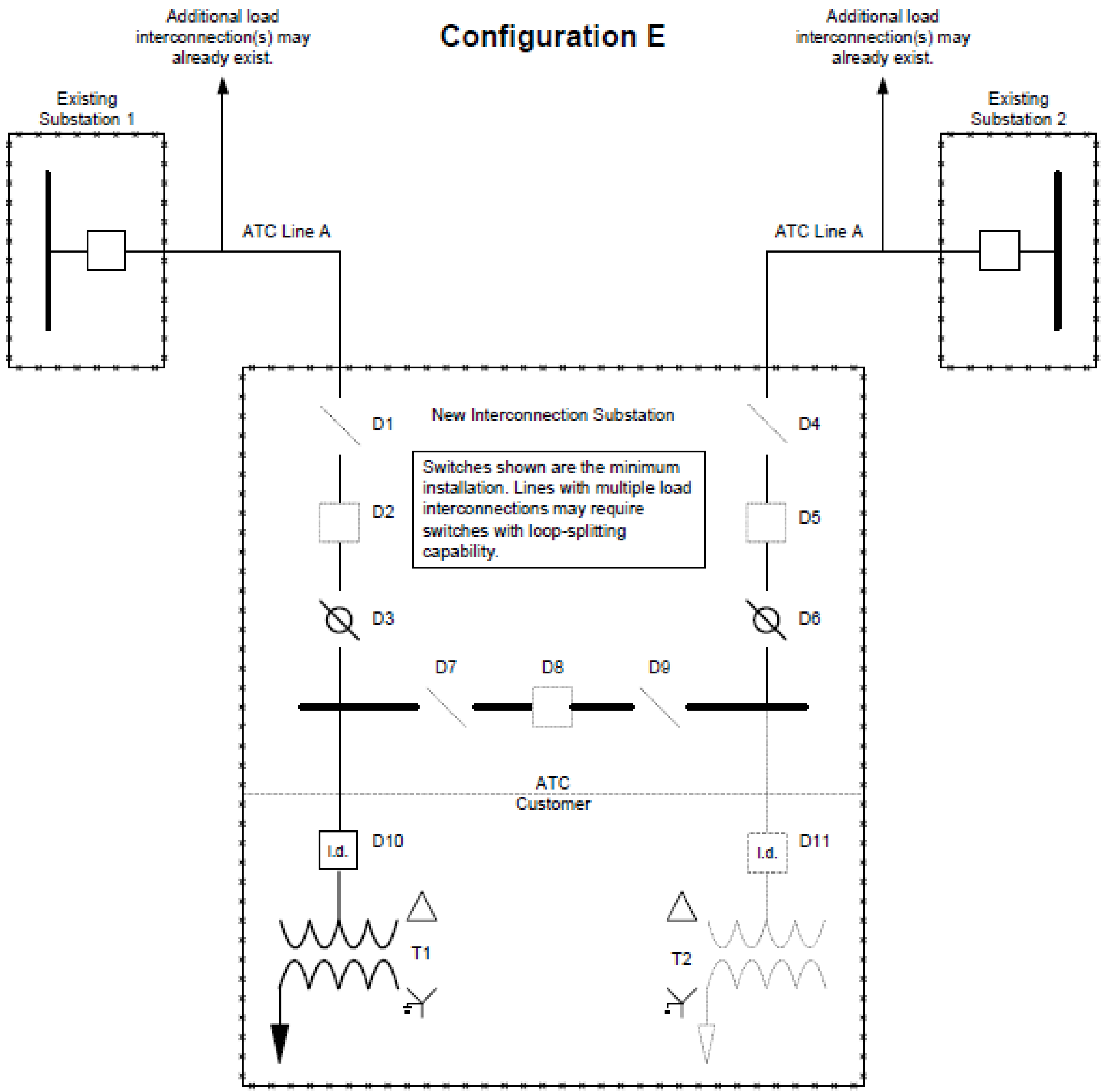


Figure F.8: Load Interconnection Configuration E

Note: For Switches D1 and D4, if only one D-T interconnection is on the line segment, sectionalizing could be done with remote circuit breakers, but ATC still recommends switches with load break capability in case other D-T interconnections are added at a later date
Note: If total substation load is less than 30 MW, it is acceptable to not install breakers D2 and D5 until such time the substation load is ≥ 30 MW If both T1 and T2 are installed, then also install switches D7 and D9

Appendix F – Interconnection Configurations (Continued)

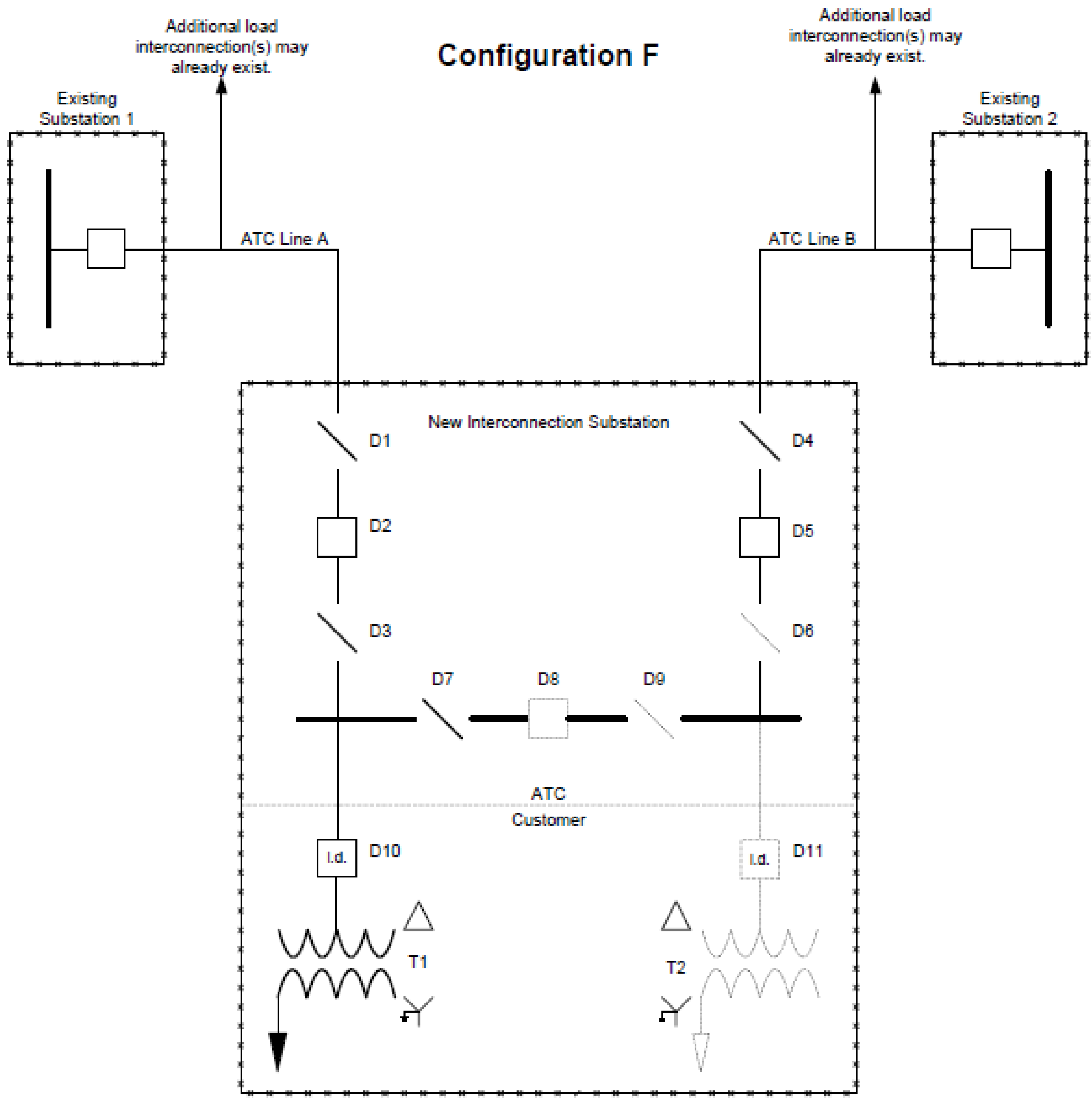
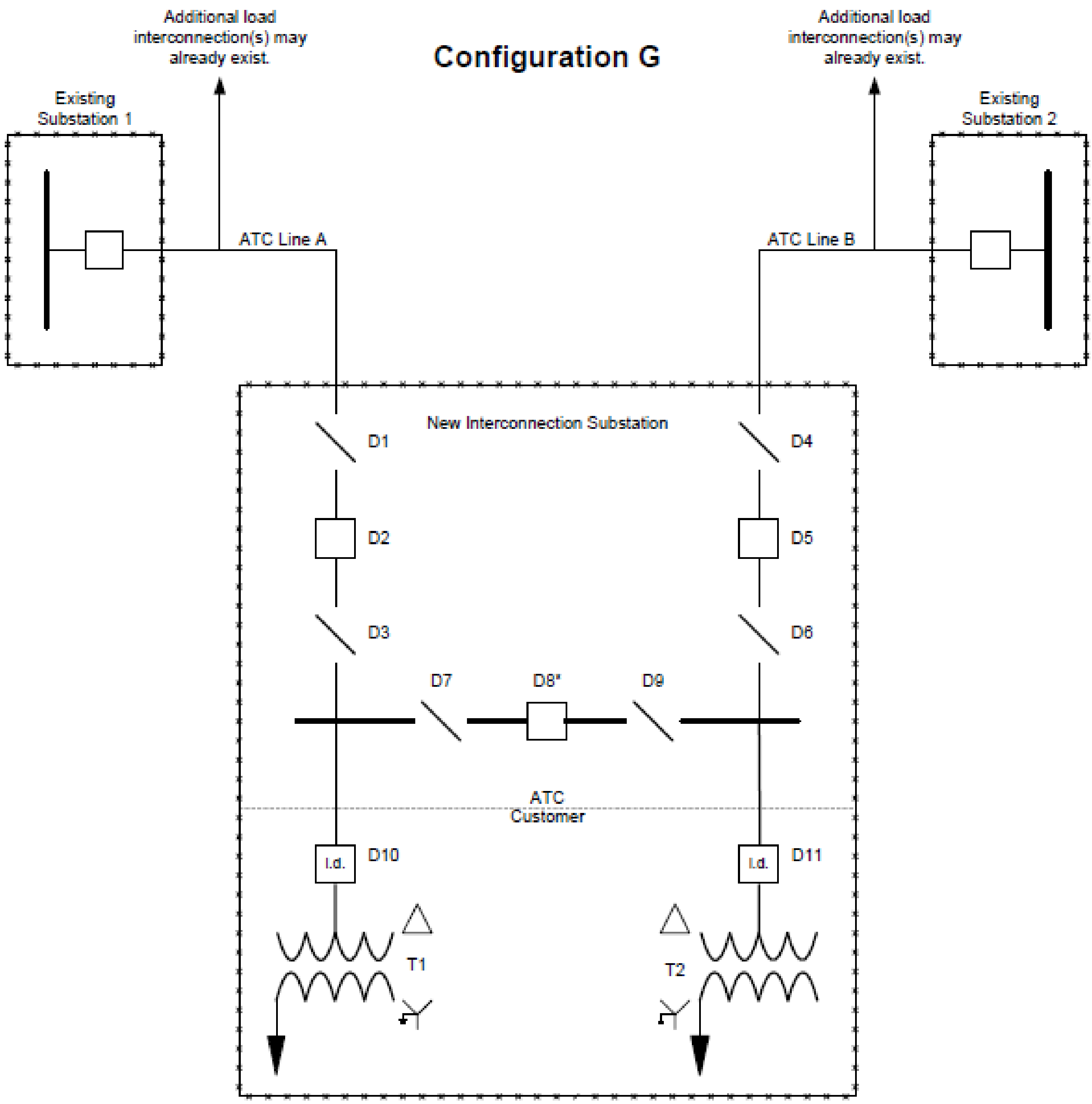


Figure F.9: Load Interconnection Configuration F

Note: For Switches D7 and D9, two switches are to be installed between transformers unless the customer can demonstrate load bridging capability in order to maintain a single switch with both transformers out of service

Appendix F – Interconnection Configurations (Continued)



* If multiple transformers are part of the ultimate design, but only one will be installed presently, the bus-tie breaker (D8) may be installed at the time an additional transformer is installed. Both maintenance switches (D7 and D9) associated with the bus-tie breaker will be installed as part of the present design.

Figure F.10: Load Interconnection Configuration G

Appendix F – Interconnection Configurations (Continued)

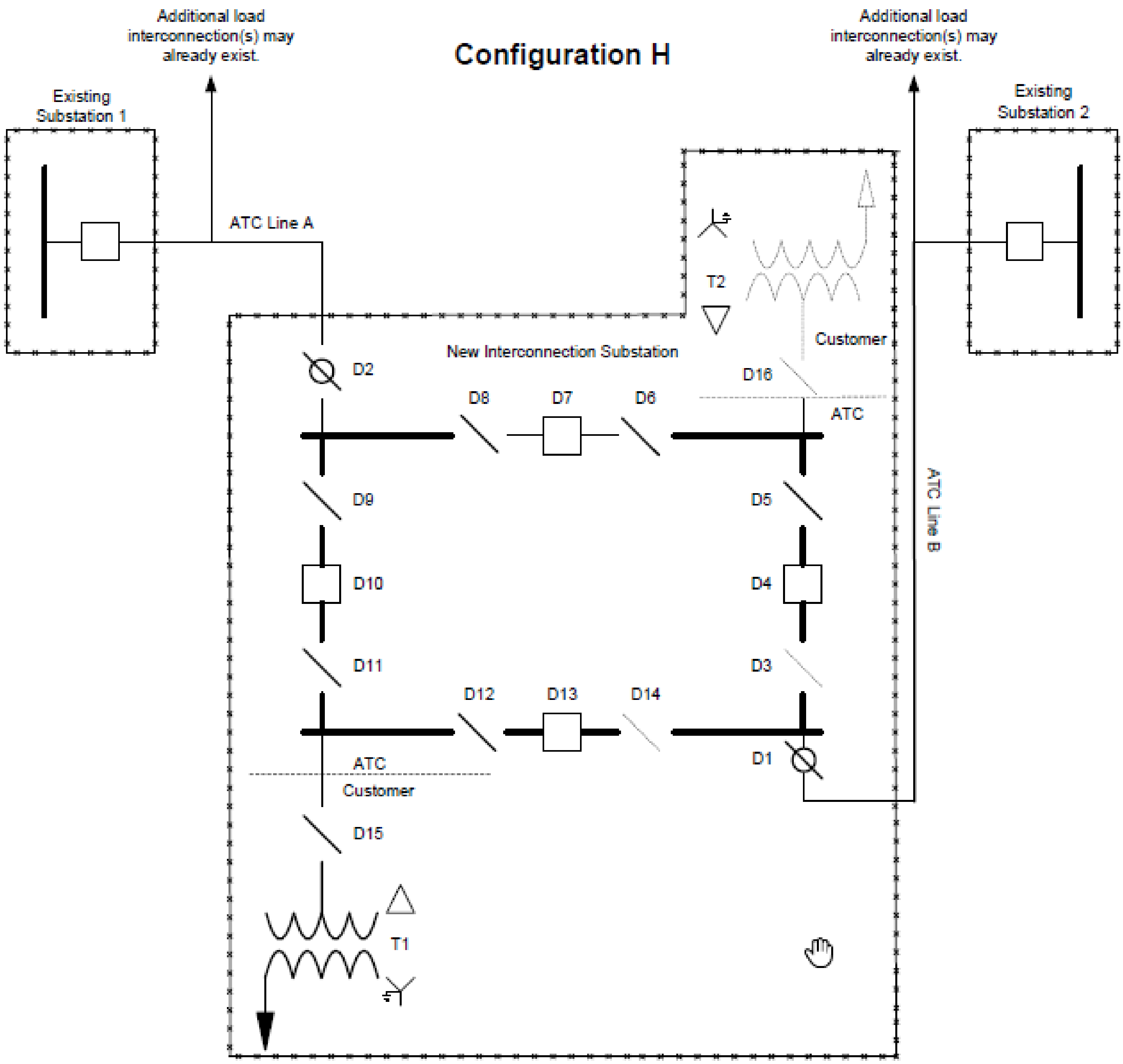


Figure F.11: Load Interconnection Configuration H

Appendix F – Interconnection Configurations (Continued)

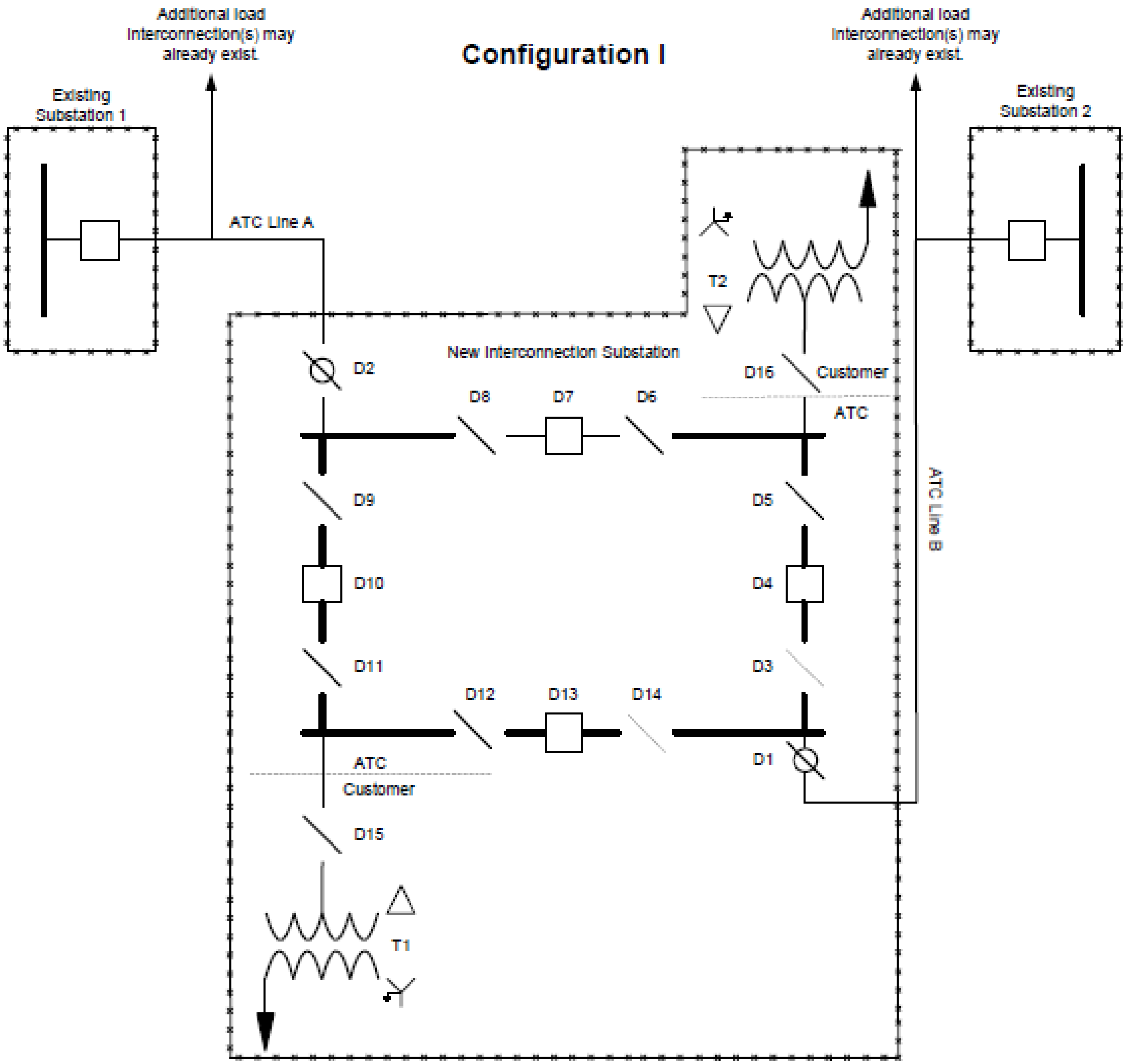
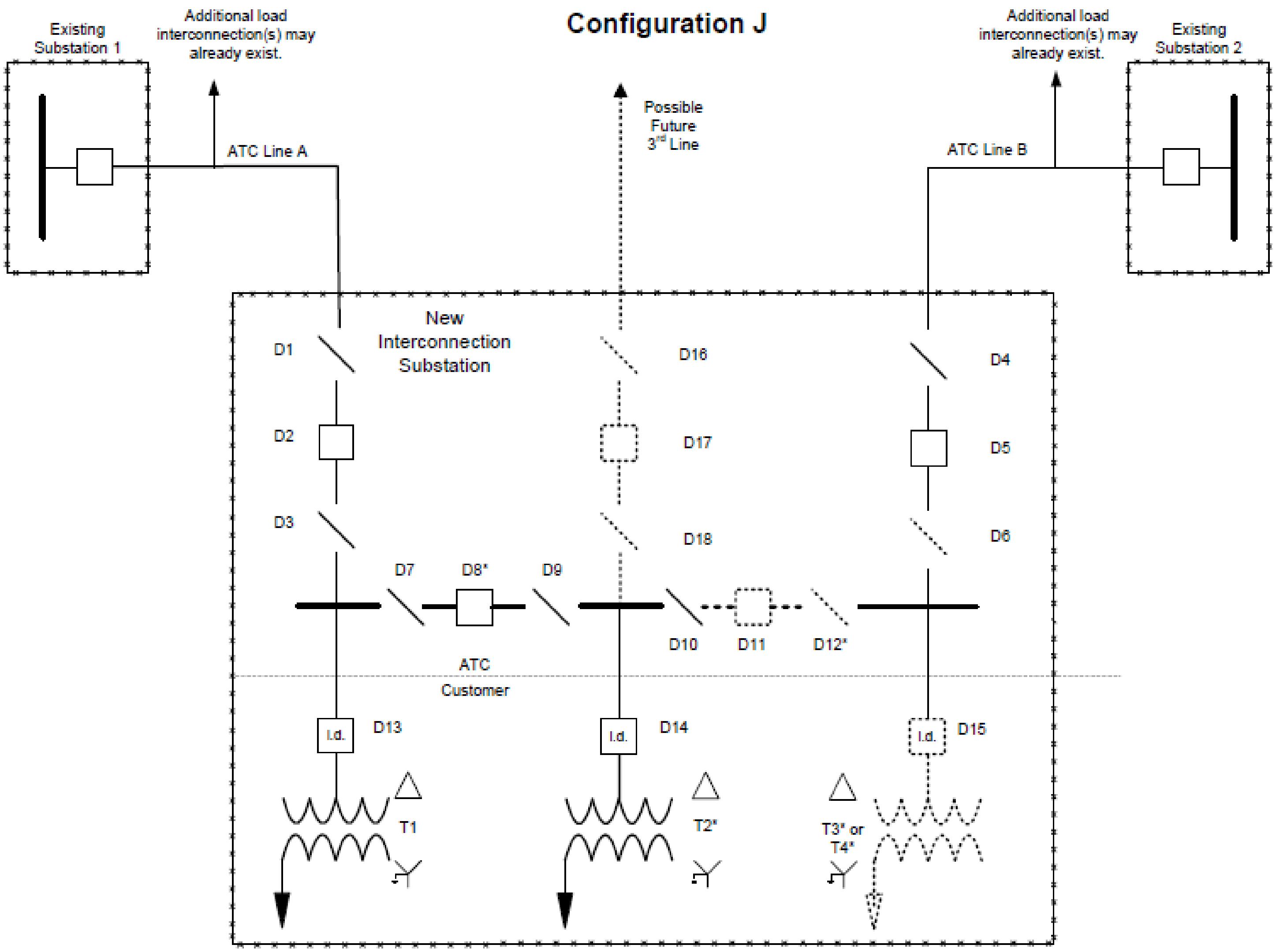


Figure F.12: Load Interconnection Configuration I

Appendix F – Interconnection Configurations (Continued)



* A third line source is recommended. For a three transformer substation, the BVP will determine the ultimate substation configuration. It is incumbent upon both ATC and the LDC to fully vet this substation configuration for optimal design and system resiliency.

Figure F.13: Load Interconnection Configuration J

Note: The BVP will determine the ultimate substation configuration It is incumbent upon both ATC and the Customer to fully vet this substation configuration for optimal design and resiliency

Appendix G –

ATC Guide for LBA Transmission Load Interconnections

Purpose: When a new load interconnection is requested or there is a change in LBA, the Interconnected Entity shall contact American Transmission Co, through the appropriate Regional Manager. The Regional Manager shall then follow the steps below. For projects that involve capital work, please refer to the Coordination of LBA Metering Boundary Modifications Business Practice (found at: https://www.atcllc.com/customer-engagement/business-practices/). The intent of this document is to provide the same structure for non-construction projects.

1. ATC Regional Account Manager shall contact the LBA as soon as possible and schedule a meeting with all parties to discuss the metering needs, costs and schedule; to ensure everyone is working together with the same plan and timelines.
    - For existing interconnection locations with no ATC Capital Work, notification to the LBA should be accomplished no later than six (6) prior to the intended LBA Area Metering Boundary change.
    - For new interconnections or modifications to existing interconnection facilities, ATC will establish a Project Team to define the ATC scope of Work and coordinate with the LBA via the Project team,
2. The LBA Project Team will consist of representatives from ATC Customer Engagement and Subject Matter Experts (SME) (as appropriate), the affected Local Balancing Authority (LBA), Interconnected Entity (IE) and/or any known affected entity.
3. ATC, the IE and the LBA will review the ATC System one-line drawings to see if existing Intertie and/or LBA metering is being affected by the project. ATC, the IE and LBA will also review the project scope to see if new LBA metering or new Intertie metering is required.
4. The IE shall enter into appropriate agreements with the affected LBA.
5. The LBAs are responsible for providing LBA metering and RTU specifications and will be coordinated with ATC if applicable.
6. The IE and the LBA is responsible for providing ATC and each other notice when the metering and RTU equipment is ready to be energized. Any changes to the energization schedule by any party should be communicated to the Project Team in a timely fashion.
7. ATC will coordinate with MISO, as well as the affected LBA, any modeling issues and/or updates that may result from system modifications.
8. Responsibility for any cost incurred for the design, purchase, installation, and/or relocation of the LBA metering equipment associated with an Interconnection project is outlined in Section 2.4 of the Scope and Applicability Section of the Coordination of LBA Metering Boundary Modifications Business Practice.
9. It is the responsibility of the Project Team ATC member to ensure the ATC System one-line drawings are updated to include any changes to the LBA and/or Intertie metering information that was made due to the project.

MR-9:

MISO Load Interconnection Whitepaper

MISO Load Interconnection Whitepaper

July 2023

Version 0.1

Table of Contents

1. Introduction

The purpose of this document is to provide more information about the process of interconnecting new loads to the Transmission System, while describing related roles and responsibilities of load owners, Transmission Owners/Operators, Load Serving Entities, and MISO. Connecting loads to the Transmission System may cause reliability impacts, so MISO and its Transmission Owners must help ensure the reliability of the Transmission System is maintained.

The studies that MISO conducts to determine reliability impacts are performed in accordance with NERC Reliability Standards TPL-001-5 and FAC-002-2, which describe Transmission System Planning Performance Requirements and Facility Interconnection Studies respectively. All studies, and the mitigation of reliability issues a new load may create, are also done in accordance with MISO's Transmission Expansion Planning Protocol (Tariff Attachment FF) and as detailed in MISO's Transmission Planning Business Practice Manual (BPM-020).

2. Overview of Responsibilities

2.1 Responsibilities of the Load Owner

The entity seeking to interconnect its load to the MISO Transmission System should first contact and collaborate with the appropriate Transmission Owner (TO) and Load Serving Entity (LSE) to develop a load interconnection agreement. It is required that the TO, LSE, and the load owner have an interconnection agreement. The TO must perform its own assessment to determine whether the load can physically and reliably connect to its transmission system. The load owner will be expected to supply all necessary technical data needed to perform reliability analysis studies. To help guide a load owner through this process, many of MISO's transmission-owning members have publicly available reference guides or help documents for new interconnection customers[1]. The Load Serving Entity is responsible for including any new loads in the forecasts provided to MISO for development of its system planning scenarios.

2.2 Responsibilities of the MISO Transmission Owner

The Transmission Owner will conduct its own studies to determine whether the load can reliably and physically connect to the transmission system and then develop an interconnection agreement with the LSE and/or load owner. The TO will lead the reliability impact study of any interconnection request that it receives based upon its own planning criteria. The TO may perform steady state, dynamic, or other analysis per its interconnection requirements. If there are consequential

[1]For example, the following is provided by American Transmission Company: https://www.atcllc.com/customer-engagement/connecting-to-the-grid/

reliability impacts, the TO will work with the load owner to provide the appropriate mitigation acceptable to the Transmission Owner and MISO. Such transmission upgrades should be submitted to MISO as an MTEP project to be studied along with the additional load amount. All transmission upgrades as described in MISO's BPM -020 that are required by new load interconnections must be submitted through MISO's annual MTEP cycle to facilitate an open and transparent stakeholder process. The transmission owner is also expected to coordinate with the LSE in submitting demand and load data to MISO for its annual planning model development process. If the Transmission Owner has determined that no transmission upgrades are required to reliably connect and serve the load interconnection then that request is not required to be included in MISO MTEP process but still must be coordinated with MISO's planning and operational groups.

2.3 Responsibilities of MISO

The Transmission Owner, load owner, and LSE should coordinate to provide MISO with any necessary data needed to review all load interconnection studies. All load interconnections that have been identified through the Transmission Owners study process as requiring transmission upgrades will be independently reviewed by MISO to determine the reliability impacts on the MISO system. MISO will collaborate with the TO, load owner, and LSE to review the results of the analysis and determine if any mitigations are required to address reliability impacts. Any modification to the transmission system based on those mutually developed mitigation solutions will be presented to stakeholders through the annual MTEP process , such as a Subregional Planning Meeting or Technical Study Task Force. If the Transmission Owners studies do not show a need for transmission upgrades then MISO may defer performing an independent assessment and not require an MTEP project be submitted to account for the project. MISO planning and operational staff will work to approve the change through the appropriate procedures as defined in it's various BPMs.

3. Frequently Asked Questions

Question: *How do I know if my load is connecting to part of MISO's Transmission System?*

Answer: MISO's Transmission System is defined as the transmission facilities owned or controlled by Transmission Owners that have conveyed functional control to MISO. The Transmission Owner will have this information. However, lists of transferred transmission facilities (TTF) are also posted on the Legal section of MISO's public website: https://www.misoenergy.org/legal/transferred-transmission-facilities/

Question: *Does the size (MW) of new load matter with respect to the process it should follow?*

> **Answer**: No, the same process applies for any load interconnecting to the Transmission System regardless of the amount of energy being withdrawn.

Question: *My load will be co-located at the same site as existing generation and served only by that generation, not withdrawing from the grid. Do I still need to go through MISO's transmission planning process?*

> **Answer**: Yes, the load should still go through the process described above and is independent from MISO's generation interconnection process. It is not permissible to de-rate or lower existing generation injection amounts to account for the new load's withdrawal. The load must go through the process(es) described in this document and be studied for reliability impacts.

Question: *The load is from a new energy storage facility that will be charging from the transmission system. Which MISO process should I follow, transmission planning or generation interconnection?*

> **Answer**: The load of batteries charging from the Transmission System is studied through MISO's generation interconnection process. New storage projects, assuming they will also discharge or inject energy into the transmission system, should be submitted through MISO's generation interconnection queue and not as standalone load through the transmission planning process.

4. Definitions (per Module A)

Load: A term that refers to either an end-user of Energy, net of system losses, or the amount of Energy (MWh) consumed by such end-user within the Transmission Provider Region.

Load Serving Entity (LSE): Any entity that has undertaken an obligation to serve Load for end-use customers by statute, franchise, regulatory requirement or contract for Load located within or attached to the Transmission System, including but not limited to purchase-selling entities and retail power marketers with the obligation to serve Load. Where a distribution cooperative or a municipal distribution system otherwise covered by the prior sentence is a wholesale customer of a generation and transmission cooperative or a municipal Joint Action Agency, the generation and transmission cooperative, a state or federal agency or municipal Joint Action Agency may act as the Load Serving Entity for such distribution cooperative or municipal distribution system. Where retail Load switching occurs in a state, the entity with the obligation to serve Load is the LSE.

Transmission Owner(s): Each member of the ISO whose transmission facilities (in whole or in part) make up the Transmission Provider Transmission System. An ITC is not a Transmission Owner as defined herein. Those Transmission Owners or ITC Participants that are not public utilities under the Federal Power Act shall not become subject to Commission regulation by virtue of their status as Transmission Owners or ITC Participants under this Tariff; provided, however, that by transferring functional responsibility of their facilities classified as transmission and covered by this Tariff, those Transmission Owners or ITC Participants that are not public utilities under the Federal Power Act have agreed to participate in an ITC and/or the ISO in accordance with the terms of the ITC Participant Transfer Agreement. An ITC Participant is not, by virtue of participation in an ITC, a Transmission Owner as defined herein.

Transmission Provider Region: The Transmission System and Region that: (i) function as a centrally coordinated system and (ii) operate, subject to the single set of Dispatch Targets and Setpoint Instructions determined and issued by the Transmission Provider.

Transmission System: The transmission facilities owned or controlled by Transmission Owners that have conveyed functional control to the Transmission Provider, and are used to provide Transmission Service under Module B of this Tariff. The Transmission System includes transmission facilities owned or controlled by Transmission Owners, the functional control of which has been transferred to the Transmission Provider subject to Commission approval under Section 203 of the Federal Power Act. In addition, the Transmission System includes other transmission facilities owned or controlled by the Transmission Owner that are booked to transmission accounts and are not controlled or operated by the Transmission Provider but are facilities that the Transmission Owners, by way of the Agency Agreement, have allowed the Transmission Provider to use in providing service under this Tariff. While not part of the Transmission System, service over Distribution Facilities is available through the execution of a Service Agreement pursuant to Schedule 11 of this Tariff. The term Transmission System shall include the Transmission System (Michigan).

5. References and Related Documents

- MISO Business Practice Manual 015 – Generation Interconnection
- MISO Business Practice Manual 020 – Transmission Planning
- MISO Planning Modeling Manual v4.1

6. Revision History

Date	Version	Description	Author(s)
07/18/2023	0.1	Initial draft	MISO Planning Staff

MR-10:

Georgia Power IRP Rebuttal Testimony Grubb, Mallard, Robinson,

Weathers June 8, 2022, page 38 (GPC 2022 Integrated Resource

Plan Rebuttal Testimony 6-8-2022)

working groups, stakeholder engagement through SERTP with regional transmission planning entities, and eastern interconnection coordination and planning through the Eastern Interconnection Planning Cooperative ("EIPC"). Additional stakeholder involvement would impede the Company's ability to jointly plan transmission projects with ITS Participants to support the timely transition of the generation fleet to more economical and cleaner resources. Updating Commission staff on a semi-annual basis to provide updates on strategic North-South transmission projects is a more efficient approach to ensure these projects are completed in a timely manner.

Q. HAS THE COMPANY ALREADY IDENTIFIED PROJECTS THAT ARE NEEDED FOR ITS PROPOSED UNIT RETIREMENTS THROUGH 2028?

A. Yes. These projects are listed in Technical Appendix Volume 1, Selected Supporting Information, Transmission Retirement Projects.

Q. ARE TRANSMISSION PROJECTS FOR PLANT BOWEN UNITS 1-2 STILL NEEDED IF THE COMMISSION DEFERS THE RETIREMENT OF ONE OF THE UNITS TO 2035?

A. Yes. Although studies that reflect a deferred retirement of Plant Bowen Unit 1 or 2 have not been completed, projects identified for the retirement of both units are still likely to be needed even with only one unit retiring. Therefore, projects should commence without delay to maintain the option of retirement at the earliest possible date in case of additional future environmental pressure. The Company will continue studying and identifying strategic transmission projects necessary for the eventual retirements of all units at Plant Bowen and the continued addition of renewable resources in south Georgia. As previously stated, the time required to build greenfield transmission projects is between six and eight years. Accordingly, the currently identified transmission projects related to the retirement of Plant Bowen Units 1-2 should still begin as soon as possible, regardless of whether retirement is delayed.

MR-11:

Company response to Staff discovery request STF-DEA-4-8

Georgia Power Company
Docket Nos. 56002 & 56003
2025 Integrated Resource Plan and 2025 Demand-Side Management Application
STF-DEA Data Request Set No. 4

STF-DEA-4-8

Question:

Please refer to the Direct Testimony of Jeffrey R. Grubb, J. Randy Hubbert, M. Brandon Looney, Michael B. Robinson, and Francisco Valle, Section V: Supply-Side Strategy, A. Resource Extensions & Continued Operation, pp. 27. With the 2025 IRP, the Company has requested to extend the operation of six generating units: Plant Scherer Unit 3, Plant Gatson Units 1-4 and A.

a. Please explain in detail how these extensions are modeled online or offline in the 2025 IRP Technical Appendix Volume 3 Transmission Plan Section H. Appendix item 2 – Load Flow Data Files.

b. Were any transmission projects included in the 2025 IRP as a result of extending the operation of these units? If so, please provide a list of those transmission projects, a description of each, and the associated costs.

c. Were any transmission projects excluded from the 2025 IRP as a result of extending the operation of these units? If so, please provide a list of those transmission projects, a description of each, and the associated costs.

Response:

a. The referenced units are modeled online and are dispatched economically. Refer to responses STF-DEA-2-4 and STF-DEA-2-5, in Docket Nos. 56002 and 56003.

b. No.

c. No.

MR-12:

Company response to Staff discovery request STF-DEA-4-9

Georgia Power Company
Docket Nos. 56002 & 56003
2025 Integrated Resource Plan and 2025 Demand-Side Management Application
STF-DEA Data Request Set No. 4

STF-DEA-4-9

Question:

Please refer to the Direct Testimony of Jeffrey R. Grubb, J. Randy Hubbert, M. Brandon Looney, Michael B. Robinson, and Francisco Valle, Section V: Supply-Side Strategy, A. Resource Extensions & Continued Operation, pp. 27. With the 2025 IRP, the Company has requested to extend the operation of Bowen Units 1-4 beyond 2034.

a. Please explain in detail how these extensions are modeled online or offline in the power flow cases.

b. Were any transmission projects included in the 2025 IRP as a result of extending the operation of these units? If so, please provide a list of those transmission projects, a description of each, and the associated costs.

c. Were any transmission projects excluded from the 2025 IRP as a result of extending the operation of these units? If so, please provide a list of those transmission projects, a description of each, and the associated costs.

Response:

a. Refer to response STF-DEA-4-8 (a), in Docket Nos. 56002 & 56003.

b. Refer to response STF-DEA-4-8 (b), in Docket Nos. 56002 & 56003.

c. Refer to response STF-DEA-4-8 (c), in Docket Nos. 56002 & 56003.

MR-13:

Company response to Staff discovery request STF-DEA-4-6

STF-DEA-4-6

Question:

Please refer to the Direct Testimony of Jeffrey R. Grubb, J. Randy Hubbert, M. Brandon Looney, Michael B. Robinson, and Francisco Valle, Section VI: Transmission and Innovative Solutions, 'A. Strategic Transmission', Pg.38/44, Lines 5-16. The Company states that the projects listed in Table 11.3 of the IRP Main Document were "identified and selected to improve power transfer from South Georgia to North Georgia." Please respond to the following questions:

a. Have all the projects shown within Table 11.3 been evaluated to increase the power transfer capability from South Georgia to North Georgia? If so, please describe the nature of the study that confirmed this and provide study results.

b. How will the identified transmission projects contribute to reducing grid congestion and ensuring grid resilience during peak load conditions? Provide case studies, historical data comparisons, or system simulations that justify these improvements.

c. What specific load forecasting models and assumptions were used to determine the necessity of projects listed in Table 11.3? Provide supporting study results that validate the assumptions made in the planning process.

d. Were any alternative transmission routing or non-wire alternatives (NWAs) evaluated before finalizing the project list in Table 11.3? If so, provide an evaluation summary of these alternatives and the reasons for their rejection.

Response:

a. The projects that increase the power transfer capabilities from South to North are listed below. For additional details on these projects, please refer to Section VI.C (p 163-168) of the of the 2022 GA ITS Ten-Year Plan in Docket 44160, Section VI.C (p 272-297) of the 2024 GA ITS Ten Year Plan in Technical Appendix Volume 3,and Sections H1A and H1B of Technical Appendix Volume 3.

Project Number	Project Name	Need Date	Reference Information
16887	Butler - Thomaston 230kV Line Conversion	6/1/2029	Refer to STF-DEA-2-2 TRADE SECRET in Docket No. 56002.
19950	GTC: Dresden - Talbot 500kV Line	6/1/2029	Refer to Section VI.C (p 163-168) of the of the 2022 GA ITS

			Ten-Year Plan in Docket 44160.
21063	Farley (APC) - Tazewell 500kV Line	6/1/2030	Refer to Section VI.C (p 277-280) of the of the 2024 GA ITS Ten-Year Plan in Docket 56002.
21076	GTC: Talbot #2 - Tazewell 500kV Line	6/1/2030	Refer to Section VI.C (p 277-280) of the of the 2024 GA ITS Ten-Year Plan in Docket 56002.
20756	Hatch - Wadley 500kV Line	6/1/2031	Refer to Section VI.C (p 281-284) of the of the 2024 GA ITS Ten-Year Plan in Docket 56002.
09661	McGrau Ford - Middle Fork 500kV Line	6/1/2033	Refer to Section VI.C (p 285-297) of the of the 2024 GA ITS Ten-Year Plan in Docket 56002.

b. The transmission projects address multiple thermal overloads identified as part of the Georgia Integrated Transmission System ("ITS") transmission planning processes in compliance with NERC TPL-001-5. The planning processes, along with applicable compliance scenarios, are outlined in Section III.A, Table 6 (p 29) of the 2024 GA ITS Ten Year Plan and Section B2 (p 1) of the ITS Planning Procedure #9. Results of the transmission planning processes are noted in the thermal and voltage problem reports provided in Sections H1A and H1B of Technical Appendix, Volume 3.

c. Please refer to Table 5 (p 26) 2024 GA ITS Ten-Year Plan in Technical Appendix Volume 3 for the load forecast. Please also refer to Sections H1A and H1B of Technical Appendix Volume 3.

d. Please refer to response STF-DEA-2-10 (d).

MR-14:

MISO Planning Modeling Manual Version 4.4

MISO Planning Modeling Manual

Reliability Data Requirements & Reporting Procedures

Version 4.4

10-31-2024

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Contents

1

Introduction

1.1 Purpose

The purpose of this document is to outline data reporting procedures needed to support the development of base case models that realistically simulate steady state and dynamic behavior of the MISO transmission system. MISO develops a series of power flow and dynamics simulation models which MISO and its members utilize to perform reliability and economic planning studies needed to fulfill various NERC and Tariff compliance obligations.

Pursuant to requirement R1 of MOD-032-1, MISO as a NERC Planning Coordinator (PC), and its NERC Transmission Planners (TPs) have jointly established a set of common procedures for submitting data needed for developing planning models as described in this document.

Pursuant to requirement R1.3 of MOD-032-1, this Requirements and Reporting Procedures manual is posted on the MISO website at the following location: https://www.misoenergy.org/planning/planning-modeling/

MISO TPs may elect to utilize the PC Reporting Procedures described herein to gather the required information from the MISO Model On Demand (MOD) application. Data owners should check with any TPs they are involved with to determine if a different reporting procedure exists for the TP.

The PC is also responsible for submitting models for its planning area to the Electric Reliability Organization (ERO) or its designee to support creation of the Interconnection-wide cases that include the Planning Coordinator's planning area per requirement R4 of MOD-032-1.

1.2 Process Overview

Figure 1-1 provides a high-level overview of the modeling process. Additional details on the modeling process are outlined in Sections 4 & 0.

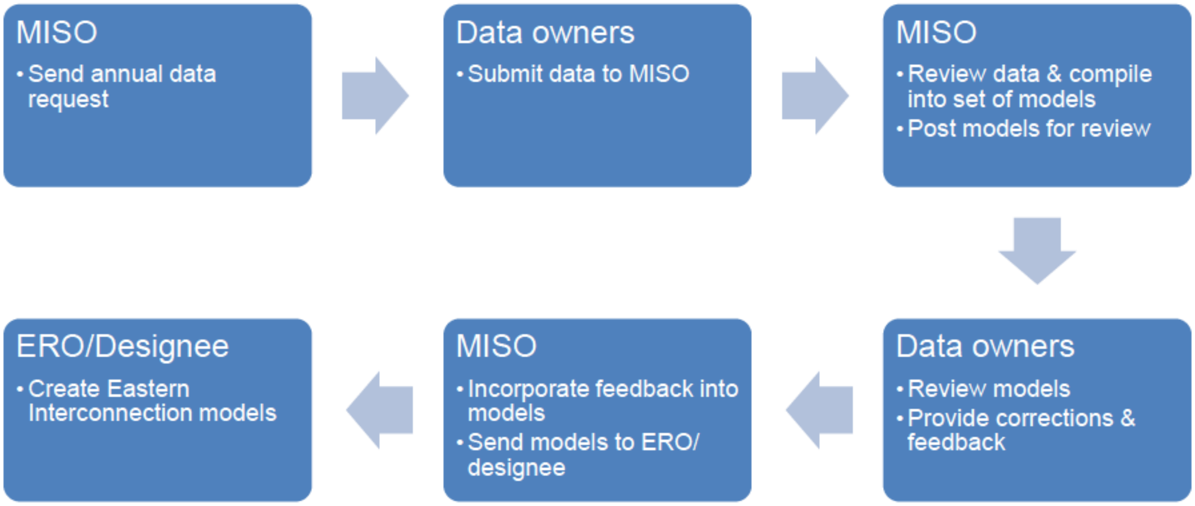

Figure 1-1: Modeling Process Overview

1.3 Responsible Entities

Pursuant to requirements R2 of MOD-032-1, identified data owners are responsible for providing the data necessary to model their assets to its Transmission Planner(s) and Planning Coordinator(s) as described in this document. Transmission Planners may notify data owners that they do not want the data and that it should only be sent to the Planning Coordinators. Applicable data owners and their respective data submission responsibilities include:

- Generator Owners (GO) are responsible for submitting modeling data for their existing and future generating facilities with a signed interconnection agreement and removing units that are retired per MISO's Attachment Y process.
- Load Serving Entities (LSE)[1] are responsible for providing their load forecasts corresponding to the scenarios developed.
- Resource Planners (RP) are responsible for submitting modeling data for future generating facilities with a signed interconnection agreement if the GO is not listed in the NERC NCR Active Entity list and is in the RP Plan.
- Transmission Owners (TO) are responsible for submitting data for modeling their existing and approved future transmission facilities.
- Transmission Service Providers (TSP) are responsible for providing long-term firm OASIS information to the Planning Coordinator used in preparation of the area interchange schedules.

[1] MISO recognizes that LSE is no longer a functional entity under NERC. However, the MOD-032-1 standard has not yet been updated to reassign the LSE function. MISO will coordinate all updates to this document to meet the standard language.

- Balancing Authorities (BA) currently do not have any data submittal requirements since they don't own facilities.

1.4 Data Submittal Delegation Options

1.4.1 Generator Owners

GOs will coordinate with their interconnected TO in order to ensure that their data is consistent with the TO-submitted topology. The Generator Owner may request assistance from the Transmission Owner in ensuring the equipment is modeled in the format requested. The Transmission Owner will let the Generator Owner know if they are willing to assist. GOs may submit their data directly to MOD/MISO or work with their interconnected TO to submit the data to MOD/MISO on their behalf. GOs are expected to submit directly to MOD/MISO unless they have made arrangements with their interconnected Transmission Owner to submit data on their behalf. If arrangements have been made, the MOD-032 Letter of Notice of Data Submittal Duty form must be completed and submitted to MISO at PlanningModeling@misoenergy.org. Once submitted, this Notice remains in effect until notification is provided to MISO to suspend the Notice. The form can be found at https://www.misoenergy.org/planning/planning-modeling/

1.4.2 Load Serving Entities

Load serving entities (LSE) will coordinate with their interconnected TO in order to ensure that their data is consistent with the TO submitted topology. In alignment with MISO BPM-011 Section 3.2, each LSE is responsible to work with applicable Electric Distribution Companies (EDC) to coordinate the submission of EDC demand and energy forecast data that are subject to retail choice. The LSE may request assistance from the Transmission Owner in ensuring the loads and equipment are modeled in the format requested. The Transmission Owner will let the LSE know if they are willing to assist LSEs are required to submit directly to MOD/MISO unless they have made arrangements with their interconnected Transmission Owner to submit data on their behalf. If arrangements have been made, the MOD-032 Letter of Notice of Data Submittal Duty must be submitted to MISO at PlanningModeling@misoenergy.org. Once submitted, this Notice remains in effect until notification is provided to MISO to suspend the Notice. The form can be found at https://www.misoenergy.org/planning/planning-modeling/

1.4.3 Transmission Owner Submittal of Unregistered Entities

As a best modeling practice, MISO requests that TOs also submit modeling data at their disposal for unregistered entities in their footprint, as this will produce higher-quality models and ensure more accurate planning analyses.

2

Data Submission Requirements

Modeling data to be submitted is organized by responsible entity below. These data requirements are defined by MOD-032-1 Attachment 1 which is included in Section 10 of this document for reference. MISO as a PC will send a message confirming an entity's participation in fulfilling their modeling obligation/compliance with MOD-032-1 at the end of the model building cycle.

2.1 Load Serving Entity[2]

In coordination with their interconnected TO, the LSE shall provide the aggregate demand levels for each of the scenarios specified in Section 4.2. The LSE shall use the bus numbers assigned to them by the interconnecting Transmission Owner from their MMWG[3]-assigned bus ranges. Table 2-1 provides a summary of the data required to be submitted by the LSE.

Table 2-1: Data to be submitted by the LSE

Steady-State
Aggregate demand on a bus level
Location of new expected loads
Dynamics
Load Composition or Characteristics
Sequence Network[4]
Load
Grounding Designation[5]

2.2 Generator Owner

In coordination with their interconnected TO, the GO shall provide the necessary data to model their generating facilities. The Generator Owner shall use bus numbers assigned to them by the interconnecting Transmission Owner from their MMWG-assigned bus ranges. Table 2-2 provides a summary of the data required to be submitted by the GO.

Data for existing and planned generators with executed interconnection agreements should be submitted. Units that have been retired per MISO's Attachment Y process should be removed from Model On Demand accordingly. Actual dispatch will be determined based on study needs.

[2] MISO recognizes that LSE is no longer a functional entity under NERC. However, the MOD-032-1 standard still lists this as an applicable function entity. MISO will coordinate all updates to this document to meet the standard language.
[3] Mulit-Regional Modeling Working Group
[4] If applicable and not supplied by the Transmission Owner
[5] Whether or not the load is grounded. Activate option in PSS®E

Table 2-2: Data to be submitted by the GO

Steady-State
Generator parameters
Generator step-up (GSU) transformer data
Seasonal output capabilities
Station Service[6] Load
Reactive Power Compensation[7]
Inverter-based resource (IBR) Collector System
Dynamics
Generator
Excitation System
Turbine-Governor
Power System Stabilizer
Protection Relays
Frequency Response
Geomagnetically induced current (GIC)
Substation data
GIC transformer data
GIC branch data
Fixed shunt data
Sequence Network
Generator
Branch
Generator Step-up Transformer
Station Service Load
Induction Machine

2.3 Resource Planner

The entity designated as Resource Planner (RP) for future planned resource(s) being constructed as a part of their resource plan shall assume the responsibility of providing necessary data for that resource(s) to MISO, given the data is available to the Resource Planner (see Section 2.4 for guidance when this information is not available). The standards and data requirements should follow what is outlined and described in section 2.2 under "Generator Owner".

2.4 Transmission Owner

The TO is responsible for providing the necessary data to model the items listed in Table 2-3. In the event a Resource Planner is unable to provide the necessary information for future planned

[6] Refer to Section 4.4.6.1 for submittal requirements
[7] Additional reactive power support equipment (such as a switched shunt) used to maintain an acceptable power factor at the Point of Interconnection

resources, the TO will need to be notified that bus numbers will need to be provided to MISO to allow for proper modeling of the facilities.

Table 2-3: Data to be submitted by the TO

Steady-State
System Topology
Buses
AC transmission lines
HVDC transmission facilities
Transformers
Reactive Power Compensation
Static VAR Systems (SVS)
Initial Generator Output in MOD (to be submitted by the TO whose model control area the unit is located within)[8]
Aggregate demand on a bus level
Location of new expected loads
Dynamics
Static VAR Systems
HVDC Facilities
FACTS Devices
Protection Relays
Geomagnetically induced current (GIC)
Substation data
GIC transformer data
GIC branch data
Fixed shunt data
Sequence Network
Non-transformer Branch
Mutual Branch
Transformer
Switched Shunt
Fixed Shunt

[8] Applicable to generation which has a signed delegation agreement for data submittal by the Transmission Owner on file with MISO. In the circumstance where the model Control Area is not a Transmission Owner, then the LBA may submit the data instead of the control area Transmission Owner if MISO is notified via email by both parties to PlanningModeling@misoenergy.org

3 Model On Demand (MOD) Training & Access

3.1 MOD Access Levels

A brief description of the different access levels in MOD is provided below:

- **Market Participant** – Ability to access the MOD Base case only
- **Ratings Only** – View and submit equipment ratings only
- **User** – Create and submit modeling data in MOD (applies to majority of MOD users)
- **Local Process Manager** – Review, approve and may submit information to MISO Process Manager
- **MISO Process Manager** – Reviews and accepts submittals (limited to MISO staff)
- **MOD Administrator** – Sets roles of MOD users (limited to MISO staff)

Data submitters will require “User” level access in order to submit the necessary data. The diagram below shows the sequence of data from their submission to MOD through their implementation in models.

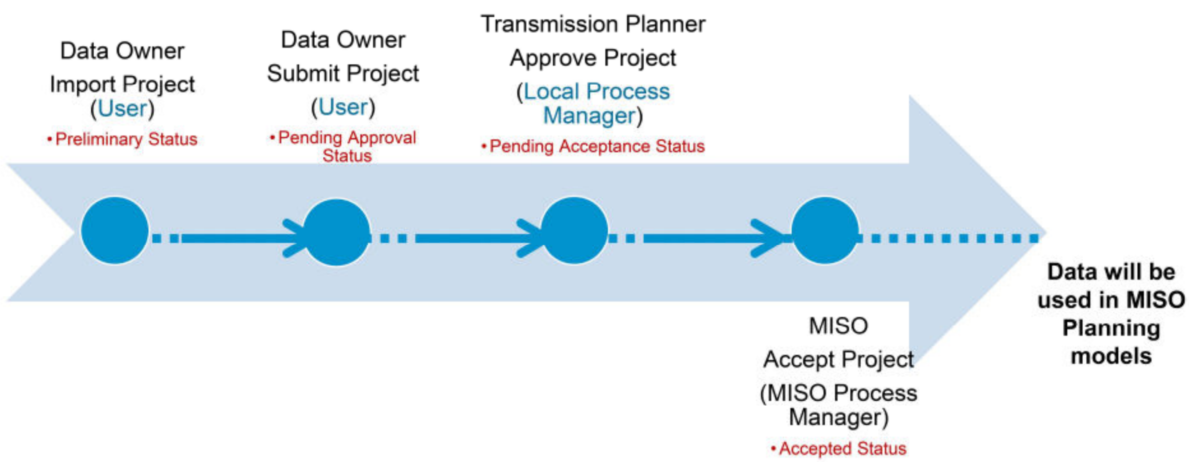

Figure 3-1: Sequence of MOD Data Submission

3.2 Obtaining Access to MOD

In order to gain access to MOD, each company must have a Universal NDA on file with MISO and each individual user is required to sign a Critical Energy Infrastructure Information (CEII) NDA. MISO Client Relations can assist in completing or verifying the NDAs. MISO Client Services and Readiness can be contacted at the MISO Help Center.

Once the appropriate NDAs are in place, the company should complete one of the following MOD access request forms:

For access allowing submission of modeling data:

- Model on Demand TO/GO Request Form

For access allowing read-only of MOD base case (does not have ability to submit data to MOD):

- Model on Demand Market Participant ONLY Request

3.3 MOD Case Build Information Order

Data submitted into MOD is hierarchical, meaning that information needs to be submitted in the correct files and profiles in order to take effect and not be overwritten. Below in Figure 3-2 this hierarchy is visualized, where "Base Case Information" is the starting point.

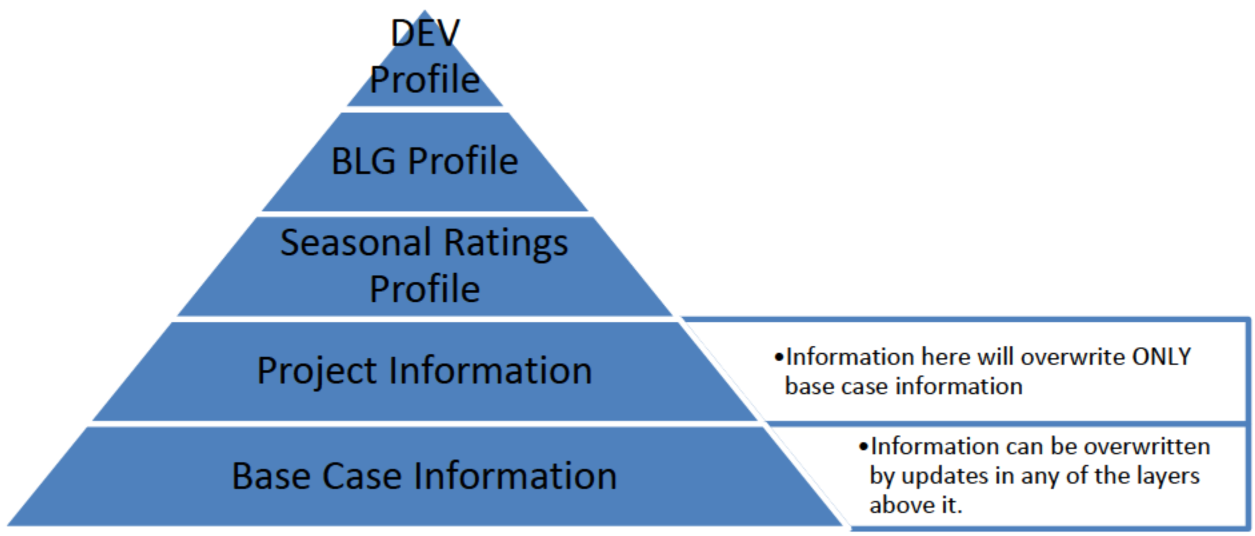

Figure 23-2

3.4 MOD Training

MISO will generally conduct training on how to submit data through MOD annually in the Fall. Additional training sessions may be scheduled as needed. There are three general locations where MOD training materials are located.

1. Customer Learning Center on the MISO Learning Management System (LMS).
    - Current MOD training materials are found here.
    - The process to access the Customer Learning Center is located on the MISO Help Center.
    - The MOD Modules are located under Customer Training/Transmission Generation and Resource Planning/System Modeling.
2. MOD – Archived Cases section
    - Additional MOD Training
    - Recordings of previously MISO conducted training
3. MISO MTEP Sharefile

- https://misoenergy.sharefile.com/home/shared >MTEP>MOD-032>Model On Demand file examples
- MOD file examples found here are to aid in how to submit data

4

Power Flow Model Development

4.1 Data Format

Power Flow model data is to be submitted to MISO via MISO's Model on Demand (MOD) Tool in the MOD format as explained ahead. Models are developed using the Siemens PTI PSS®E software program. Data submitted should be compatible with the MOD and PSS®E versions currently specified by MISO. The formal data request submitted to members will provide the correct version information. Modeling data requests and notifications are sent to the Modeling User Group mailing list. Instructions on how stakeholders can subscribe to the list are located at the following location: MISO Mailing Lists

4.2 Scenarios

For each annual planning cycle MISO will develop a set of power flow cases as shown in Table 4-1. The scenarios developed could change from year to year based on MISO and member needs. However, at a minimum those needed for TPL and MOD-032-1 compliance will be included. General descriptions of the scenarios are provided below:

- **Winter Peak Load (WIN)** – is defined as the winter peak demand expected to be served.
- **Spring Light Load (SLL)** - is defined as a typical early morning load level, modeling near minimum load conditions.
- **Spring Minimum Load (SML)** - is defined as the lowest net load level typically seen or expected to be seen during spring load conditions
- **Summer Peak Load (SUM)** - is defined as the summer peak demand expected to be served.
- **Summer Shoulder Load (SSH)** - is defined as 70% to 80% of summer peak load conditions. The Summer Shoulder shall represent a typical summer day peak value, not the shoulder values of a peak day.
- **Fall Peak Load (FAL)** - is defined as typical fall peak load conditions.

Table 4-1: Scenarios to be developed

Model Year	Spring Light Load	Spring Minimum Load	Spring	Summer Shoulder	Summer Peak	Fall	Winter Peak
0					X	X	X
1	X		X		X		X
2	X				X		X
5	X	X		X	X		X
10					X		X

As indicated in Table 4-1, modeling data is collected for years 0, 1, 2, 5 & 10. For example, for the 2020 model series the model years would be 2020, 2021, 2022, 2025, 2030.

4.3 Schedule

The annual schedule power flow model development schedule is shown in Table 4-2. Specific dates will be supplied with the annual data request.

Table 4-2: Power flow Development Schedule

Task	Estimated Completion
Steady State Data Request sent to TO, GO, LSE	August
Pass 1 models posted for review	August
Initial Data Request Information Due	September
Post Pass 2 models for review	October
Pass 2 data updates due for inclusion in Pass 3 including list of planned outages	November
Post Pass 3 models for review	December
Members submit final updates/corrections to MOD	January
Submit planned outages for inclusion in final pass	January
Post Final MISO models	March
Request Updates prior to MMWG submittal	April
Send final models to ERO (*Actual timeframe to be determined based on ERO schedule)	June*

4.4 Level of Detail

On at least an annual basis each data owner is required to submit the following model data to MISO's MOD database:

1. Transmission projects intended to be approved by MISO (moved to MTEP Appendix A) in the upcoming MTEP cycle; to be submitted by Transmission Owners
    a. This includes the projects that are submitted to MISO's MTEP Project Database by member companies by September 15 of each year.
    b. Section 10 contains NERC MOD-032-1 Attachment 1 detailing the minimum information that is required to effectively model the interconnected transmission system.
2. Generators with executed Generator Interconnection Agreements (GIA) & associated network upgrades. At a minimum, all generators with a nameplate capacity greater than 20 MVA or a facility with an aggregated nameplate capacity greater than 75 MVA must be modeled in detail including the gross generator values, station service loads[9], and generator step-up transformers (except for those meeting the exclusion criteria as specified in the NERC BES definition). Additionally, Blackstart Resources, as defined by NERC, identified in the Transmission Operator's restoration plan must be modeled in detail. Generation which meets the exclusion criteria as defined by NERC in the BES definition is not required to provide detailed model information but is recommended to do so. Units that have been retired are to be removed from MOD. Generators with a CP Node should be added to MOD with an in-service date that matches the Commercial

[9] Refer to section 4.4.6.1 for representation threshold

Operations Modeling date of the unit(s), generally in in alignment with the date and terms outlined in the executed GIA. Units that have not yet retired and have an approved Attachment Y should remain in MOD until the retirement date, however, a MOD project may be submitted preemptively to remove the unit on its Attachment Y retirement date as long as the unit has a publicly announced retirement.

3. Bus/Load/Generation and Device Control Profiles, which include:
    a. Bus information (such as status, voltage magnitude, voltage angle) is not recommended to be included in Bus/Load/Generation profiles, as they are overwritten as part of the solution methodology.
    b. Load forecast for each scenario at the bus level representing a forecasted 50/50 coincident relative to the company peak; to be submitted by TO or designated entity.
    c. Corresponding generation limits and level for each scenario in the model list (Pmin, Pmax, Qmin, Qmax, Pgen); Generation limits/capabilities to be submitted by Generation Owner. Generator Owner shall submit generator capabilities (Pmax/Qmax) that correspond to a point in the reactive capability curve, Generation output to be coordinated between Transmission Owners and Generator Owners.
    d. Settings on regulating equipment such as transformers, switched shunts and HVDC data; to be submitted by data owner.
4. Updates and/or corrections to approved future generation and transmission projects including planned maintenance equipment outages. Scheduled outages submitted to MISO via the CROW system with duration of greater than 6 months will be incorporated in the Pass 3 and final pass cases.
5. Any corrections that need to be made to existing system modeling in the MOD Base Case. Data owners shall provide facility retirement updates.
6. Non-Tier Order workbook information detailing the fuel type and capability within each modeled DER and other non-tier ordered resources, whether represented as a machine or as a negative load.

If the data has not changed since the last submission, a written confirmation that the data has not changed is sufficient. Such confirmation should be sent to MISO as the Planning Coordinator and the appropriate Transmission Planner. MISO correspondence should be sent by email to PlanningModeling@misoenergy.org.

The data submitted must be sufficient to perform reliability and economic studies on the bulk electric system (BES) as defined by NERC[10]. To that extent, relevant data associated with sub-100 kV facilities may also need to be provided.

4.4.1 MOD Naming Conventions

Files submitted to MOD (projects, profiles, etc.) must follow naming conventions specified in the following sub-sections.

10 http://www.nerc.com/pa/RAPA/BES%20DL/bes_phase2_reference_document_20140325_final_clean.pdf

4.4.1.1 *MOD MTEP Project Files*
MOD project files are used to make transmission system topology changes. MTEP project submissions are first created within MISO's MTEP Project Database with a numerical Project ID. Filenames should contain the company name acronym, the MTEP Project ID (MTEP_PRJID), and lastly the project name (PROJECT_NAME) as in the example below:

Example: ITC-MTEP_PRJID-PROJECT_NAME.prj

4.4.1.2 *Expedited Project Review Project Files*
MOD project files that are representative of items that have been identified in the expedited project review process. File names should contain the same information as company name acronym, an "Expedited" indicator, and project name as in the example below:

Example: ITC-EXPEDITED-PROJECT_NAME_prj

4.4.1.3 *Generator Project Files*
Generator project files are used to make generation additions, deletions, and modifications including any topology modification required for interconnection. Submissions to the Generation Interconnection Agreement (GIA) queue process are given a DPP Study Project ID. Filenames should contain the company name acronym, and the DPP Study Project ID (GXXX/JXXX/RXXX), and lastly the project name (PROJECT_NAME) as in the example below:

Example: ITC-JXXX-PROJECT_NAME.prj

4.4.1.4 *Bus/Load/Generation (BLG) Profiles*
BLG profiles contain load and generation information for each scenario. Each BLG profile name should contain the specific scenario, the MISO Series cycle, and lastly the company name acronym as in the example below:

Example for 2022 Summer Peak BLG profile: 2022SUM-MISO20-XEL-BLG.raw

4.4.1.5 *Device Control Profiles*
Device profiles contain information about settings on regulating equipment such as transformers, switched shunts and DC data. Each DEV profile name should contain the specific scenario, the MISO Series cycle, and lastly the company name acronym as in the example below:

Example for 2022 Summer Peak DEV profile: 2022SUM-MISO20-ATC-DEV.raw

4.4.2 Definitions

4.4.2.1 *Profile Types*
Commonly abbreviated in communication as BLG and DEV respectively, MOD Profiles contain load, generation and device control information for each model scenario within the MISO Series. During model building, Profiles are applied over the most recent Monthly Base Case models and over approved Projects thus overwriting data for seasonal changes. Profiles created for previous MISO Series cycles are not utilized again. They are re-created every cycle and cannot be used to modify transmission topology.

- **Bus Profiles**: Bus profiles update bus information. As such, this section of the BLG should not be populated as the information overwrites reviewed topology from Projects. The only MOD-defined data fields that are used by MISO during the model building process are (along with data fields they point to in PSS®E):
    - IDE – "Code"
    - VM – "Voltage"
- VA – "Angle" **Load Profiles**: Load profiles reflect the expected load values associated with a specific year/case/sensitivity. All load identifiers within the Load Profile shall be capitalized to exactly match the load designation within the power flow case. Load data from these profiles are validated against the values submitted through the Module E process.
- **Generation Profiles**: Generation profiles reflect the expected output of generation associated with a specific year/case/sensitivity to meet the Load profile. Generation shall not have a Pmax=Pmin=Pgen=0 as it effectively removes the generation from dispatch. Generation shall not have a Pmin=Pmax=Pgen; this restricts the unit from modifying its output based on sensitivity criteria. Exceptions must be documented and confirmed with MISO.
- **Device Profiles**: Device profiles reflect the transformer taps and control settings; generator scheduled voltage, regulating bus, and RMPCT; switched shunt control mode, status, and initial output; and the DC line schedules. All transformer winding voltages must be aligned with the correct tap positions. All transformer winding voltages must be aligned with the correct bus. Provide all DC dispatch profiles to realistically represent the season or sensitivity as specified. Device profiles should only be submitted for taps and settings that are changed on a seasonal basis as no profiles are re-used after their respective models have been built. Fixed settings should be submitted as a Non-MTEP MISO project as below.

4.4.2.2 *Project Types*

- **MTEP Appendix B**: Projects that are demonstrated to be a potential solution to an identified reliability, economic, or policy need.
- **MTEP Appendix A**: Projects that have been justified to be the preferred solution to an identified reliability, economic, or policy need, and have been reviewed and approved by the MISO Board of Directors.
- **Non-MTEP MISO**: Projects submitted by MISO members that represent facilities for which functional control has not been transferred to MISO and that don't fall under the jurisdiction of the MTEP process, as detailed in the Transmission Planning BPM under Section 4.2.3 (Project Reporting Guidelines).
- **Non-MISO Network**: Projects submitted by Non-MISO members/Non-MISO electric system
- **Base Case Change**: Projects submitted to make changes to the MOD Base Case
- **Generator**: Projects submitted to add generators with approved interconnection service, including all Network Upgrades identified in the Generator Interconnection Agreement.

4.4.2.3 *Project Statuses*

- **Target MTEP A:** Projects that are proposed that are desired to be approved by the MISO Board of Directors in the current planning cycle
- **Conceptual**: Conceptual or vision plans
- **Alternative**: Alternatives to preferred projects in MTEP Appendix B
- **Proposed**: Projects that require additional review and are subject to change
- **Planned**: Projects that have completed the TO planning process and that the TO intends to permit and construct
- **In Service**: In Service Generator
- **Correction**: Base case change to be submitted for correction of MOD Base Case

4.4.3 Modeling Criteria

Criteria for inclusion of MOD projects into the base models are shown in Table 4-3.

Table 4-3: Project Inclusion Criteria

Project Type	Target MTEP A	Planned	Proposed	Alternative	Conceptual	In Service	Base Case Options *
MTEP Appendix A		IN MODELS					
MTEP Appendix B	IN TA MODELS	NOT IN MODELS	NOT IN MODELS	NOT IN MODELS			
Non-MTEP MISO		IN MODELS					
Non-MISO Network		IN MODELS					
Base case Change							IN MODELS
Generator		IN MODELS			NOT IN MODELS	IN MODELS	

*Base Case Options include Correction, Error Correction, Field Change, As Built, Emergency Upgrade, and Facility Addition.

4.4.4 Modeling of Generators

MISO recommends that any generating resource currently represented in the MISO Commercial and/or Network Model in the form of a GEN/ESR node be included in the Planning Models as alignment is driven between the Operations and Planning models. For any generators that meet a BES exclusion, no additional information needs to be provided to supplement what is seen in the Operations model should that generator be included in the Planning model. We encourage owners of this data to review these representations and provide updates as they fit.

4.4.4.1 *Synchronous Generators*

Data must be submitted to model the synchronous machine components explicitly

- Point of Interconnection Transformer and Transmission Line (Medium to High voltage)

- Generator step-up transformer (Low to Medium voltage)
- Reactive Compensation
- Station Service Loads (if greater than 1 MW)
- Machine ID synchronized with unit ID
- MOD Project Name shall include the MISO interconnection queue study number for any generation improvements including installation or uprate
- Generator Bus name shall include MISO interconnection queue designation
    - For example, "JXXXX Gen" (bus name limited to 12 characters)

4.4.4.2 *Wind Farms*

Data shall be submitted to allow wind farms to be modeled as a single equivalent machine with at least the following:

- Point of Interconnection Transformer and Transmission Line (Medium to High voltage)
- Equivalent generator step-up transformer (Low to Medium voltage)
- Collector System Equivalent (transmission lines representing the equivalent impedance of the collector system)
- Reactive Compensation
- Wind-free reactive status with new reactive limits
    - Unit Online
    - PGEN=0
    - Updated MVAR limits or updated Reactive assets nearby
- Wind-free Collector System Fixed Shunt
    - Unit Offline
    - PGEN=0, Machine In-Service (Status)=0, then Fixed shunt is online (1). Otherwise the shunt is offline (0).
    - Fixed Shunt on low side of POI transformer with B sized to negate collector system Charging.
    - Recommended Shunt ID of 'NP'
- Wind Turbine Generator modeled at the appropriate low voltage (i.e. 690 V)
- WMOD[11] and WPF[12] populated with an appropriate non-zero value. If WMOD 2 or 3 is selected and units have differing leading and lagging power factors, please submit the more conservative value.
- Machine ID using a "W" character
- MOD Project Name shall include the MISO interconnection queue study number for any generation improvements including installation or uprate
- Generator Bus name shall include MISO interconnection queue designation
    - For example, "JXXXX Wind" (bus name is limited to 12 characters)

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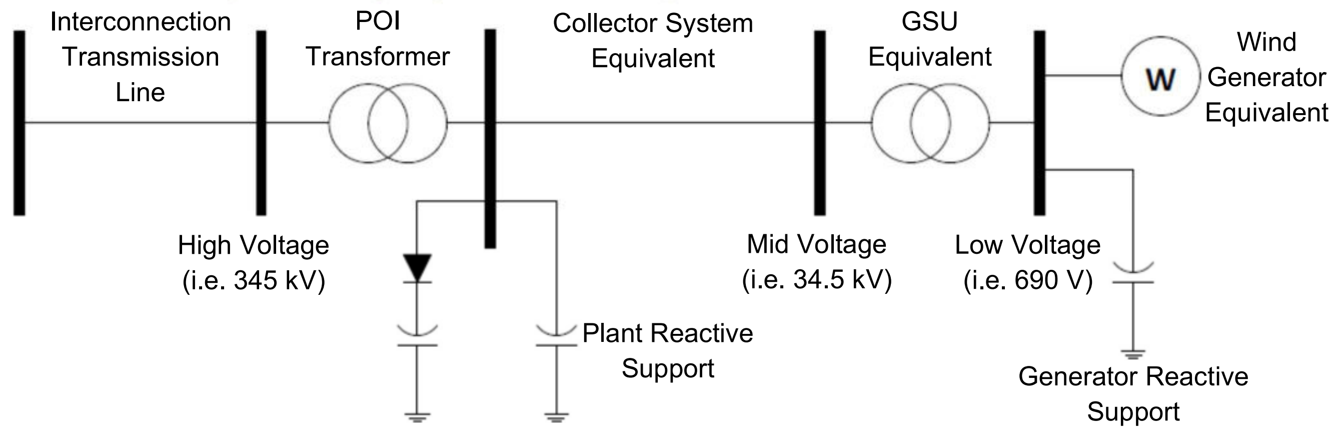
[11] Machine Control Mode
[12] Renewable Machine Power Factor

Figure 4-1: Single equivalent machine representation for wind farm



Modeling multiple equivalent machines for a single wind farm is acceptable when trying to model:

- Different turbine types/manufacturers
- Geographic diversity
- Explicit ownership
- Different development phases

Bus numbers for buses shown in Figure 4-1 should be coordinated with the interconnecting TO. Specific wind output levels are required to be specified for the various scenarios in the BLG profile, as shown in Table 4-4.

Table 4-4: Required Wind Output

Scenario	Wind Level	Wind Unit Output (%)*
Summer Peak	Capacity Credit Wind	Capacity Credit**
Fall, Spring	Off-Peak Average Wind	28.5%
Winter Peak, Light Load, Minimum Load	Average Wind	67%
Summer Shoulder	Average Wind	27%
Summer Shoulder	High Wind	72%
Light Load	High Wind	83%
Light Load	No Wind	0%

* Will be reviewed and updated periodically
** Wind Capacity Credit as assigned in the annual MISO Wind and Solar Capacity Credit Report

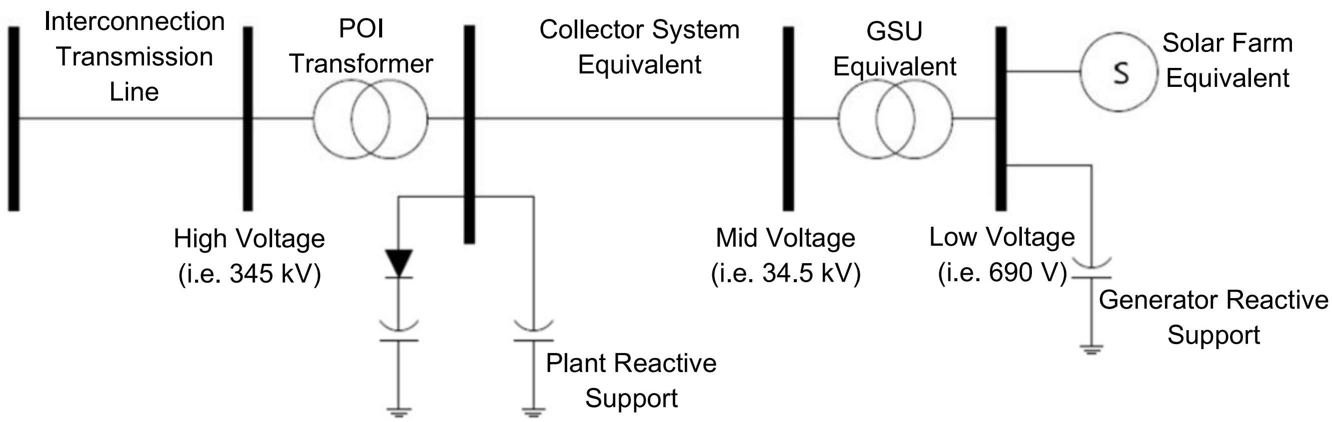
4.4.4.3 *Solar Farms*

Data shall be submitted to allow solar farms to be modeled as a single equivalent machine with at least the following:

- Point of Interconnection Transformer and Transmission Line (Medium to High voltage)
- Equivalent generator step-up transformer (Low to Medium voltage)
- Collector System Equivalent (transmission lines representing the equivalent impedance of the collector system)
- Reactive Compensation
- Sun-free reactive status with new reactive limits
    - Unit Online
    - PGEN=0
    - Updated MVAR limits or updated Reactive assets nearby
- Sun-free Collector System Fixed Shunt
    - Unit Offline
    - PGEN=0, Machine In-Service (Status)=0, then Fixed shunt is online (1). Otherwise the shunt is offline (0).
    - Fixed Shunt on low side of POI transformer with B sized to negate collector system Charging.
    - Recommended Shunt ID of 'NP'
- Solar Modules modeled at the appropriate low voltage (i.e. 690 V)
- WMOD[13] and WPF[14] populated with an appropriate non-zero value. If WMOD 2 or 3 is selected and units have differing leading and lagging power factors, please submit the more conservative value.
- Machine ID using a "PV" or "S" characters
- MOD Project Name shall include the MISO interconnection queue study number for any generation improvements including installation or uprate
- Generator Bus name shall include MISO interconnection queue designation
    - For example "JXXXX Solar" (bus name is limited to 12 characters)

[13] Machine Control Mode
[14] Renewable Machine Power Factor

Figure 4-2: Single equivalent machine representation for solar farm



Specific solar output levels are required to be specified for the various scenarios in the BLG profile, as shown in Table 4-5.

Table 4-5: Required Solar Output

Scenario	Solar Unit Output (%)*
Summer Peak, Spring Peak, Fall Peak	Capacity Credit**
Light Load (No Wind, Average Wind), Minimum Load, Winter Peak	0%
Summer Shoulder (Average Wind)	48%
Summer Should (High Wind)	47%
Spring Light Load (High Wind)	10%

* Will be reviewed and updated periodically
**Solar Capacity Credit as assigned in the annual MISO Wind and Solar Capacity Credit Report

4.4.4.4 *Energy Storage*

Data shall be submitted to allow Energy Storage devices to be modeled as a single equivalent machine with at least the following:

- Point of Interconnection Transformer and Transmission Line (Medium to High voltage)
- Equivalent generator step-up transformer (Low to Medium voltage)
- Collector System Equivalent (transmission lines representing the equivalent impedance of the collector system)
- Reactive Compensation

- WMOD[15] and WPF[16] populated with an appropriate value (WMOD =1 or WMOD = 2).
- Machine ID using an “ES” or “E” characters
- MOD Project Name shall include the MISO interconnection queue study number for any generation improvements including installation or uprate
- Generator Bus name shall include installation MISO interconnection queue designation
    - For example, ”JXXX_ENSTOR1”
- Pmin in alignment with maximum charge rate, not facility storage size; Pmax in alignment with maximum discharge rate, not facility storage size

Table 4-6: Required Energy Storage Output

MODE	MW Output	WMOD	QT, QB Limits	Scenario
SATOA**	0%	1	Full Load MVAR Range	All Scenarios
Market Participant	Economic Tier Order	1	Full Load MVAR Range	All Scenarios

Storage Requires two Economic Tier Orders for Standby and Discharging
**Storage As Transmission Only Asset

4.4.4.5 *Hybrid Generation*

For modeling of plants with a shared interconnection, comprising of more than one fuel type, each fuel type shall be explicitly modeled as a machine whether AC or DC coupled.

4.4.4.6 *Generator Replacement Project*

A Generator Replacement project will interconnect a new generator at the same site as an existing generator.

Replacement generators shall be modeled on a new bus with, a new bus number, that has a common transmission interconnection as the unit(s) it is replacing. This bus shall be named with the replacement project number (RXXXX).

Both generators shall be represented in the model until the old unit is physically retired. Dispatch of the legacy and replacement generator will be dictated by the anticipated replacement date of the Generator Interconnection Agreement.

4.4.5 Distributed Energy Resources (DER)

A Distributed Energy Resource (DER) is an electricity supply resource that is either behind the meter on a customer premise or connected to a utility distribution system.

15 Machine Control Mode
16 Renewable Machine Power Factor

MISO recommends that existing inverter-based DER be explicitly represented within the power flow models. As an example, solar gardens or battery storage may have a significant aggregate impact on the transmission system at individual transmission-distribution interface buses.

Additional non-inverter-based DER are not expected to be explicitly represented at this time.

4.4.5.1 *Responsible Entities for Data Submission*

The Transmission Owners (TO) shall coordinate with Load Serving Entities (LSE) in order to enable representation of these resources at the Transmission-Distribution (T-D) boundary. As LSEs are the owners of the information below the T-D boundary, their involvement in the process will be instrumental to success in implementation of DER representation.

To avoid misrepresentation of data, for each piece of information only one entity shall submit the DER information to MISO. MISO recommends the current method of load reporting be utilized.

4.4.5.2 *Required Information*

Information required to adequately represent DER in a Power Flow environment include:

- Interconnection location (PSS®E Bus Number)
  - TOs shall aid LSEs in identifying where DER is represented, in a manner similar to current Load Modeling practices
- Fuel Types and Nameplate Capacity at each interconnection location (Solar/Wind/Battery/Thermal/Other)
  - Single aggregate representation of the DER as a unit or load at each interconnection location
  - LSEs shall provide and designated entity shall report what fuel types are represented at each interconnection location
  - LSEs shall provide and designated entity shall collect and report the total capabilities (Real & Reactive) by fuel type for each interconnection location
- No additional T-D Transformers should be added to the models. Existing load locations shall be utilized.
  - TOs shall generalize the T-D transformer impact into the Machine or Load representation of the reported DER, if needed

MISO recommends leveraging existing processes, such as local interconnection agreements, to populate DER information.

4.4.5.3 *Representation in Power Flow Models*

DER representation in power flow models shall be represented as either a machine or as a distinct distributed resource within the load record.

- Machine Record
  - Recommended for non-aggregate units, such as non-zero marginal cost generation (ex. Thermal)
  - To be represented and treated similarly to Synchronous Generators (194.4.4.1)

- Distributed Resource on a Distinct Load
    - Recommended for aggregate units, such as zero marginal cost generation (ex. Wind/Solar/Geothermal/etc)
    - This option allows for the best available information to be utilized in the Composite Load Model (CMLD)
    - No more than one DER should exist at a single bus, aggregation from multiples to a single node is required
    - Load ID should be 'DR'
    - Load values shall not net out the impact of the reported DER

      Reported Load = Forecasted Load + reported DER

4.4.5.4 *Non-Tier Order Workbook*

MISO shall distribute a workbook for data collection of the above information to facilitate DER representation and dispatch as part of the initial data request. This workbook will publish the current MISO Series dispatch for inverter-based units that are not part of economic tier order dispatch[17]. Additionally, DER machines, behind-the-meter generation (BTMG) and negative loads that are non-inverter based are labeled as "As Is" within the workbook where dispatch will remain as is submitted through BLG Profiles. Dispatch of DER will be handled with the same ruleset that governs BES generation[18]. Additional items to be collected via the Non-Tier Order workbook are solar or wind farms that have enabled Sun-free/Wind-free, where the machine is online at zero real power but is capable of producing/consuming reactive power for voltage support. If this scenario is used then the new maximum and minimum values of reactive power are to be specified when in this particular mode of operation. A different scenario to be supplied is if the plant has capability to reduce/control the charging of the collector system when the plant is not providing real power. In this case the correct way to model is to have a fixed shunt at the low side of the POI transformer, as shown in Figure 4-1 or 4-2, which when in service will negate the charging seen by the collector system. The bus number (where the shunt is modeled) and fixed shunt ID would be supplied in the Non-Tier Order Workbook. MISO recommends that a shunt ID of 'NP' be used, meaning "No Power."

MISO shall contact assets owners about mapping inquiries where further information is needed.

4.4.6 Load Modeling

MISO's general policy is that loads be created at all buses where step-down transformers take Energy from the Transmission System and supply the distribution system. Transmission Owners are responsible to populate the transmission/distribution boundaries with loads. Load Serving Entities/Designated Submitters are responsible for populating the loads with forecast MW/MVAR values through the BLG profiles. Additionally, the scalable load should also be

[17] Economic tier order dispatch is described in Section 4.4.14 (Dispatch)
[18] Inverter-based resource dispatch rules are defined in sections 4.4.4.2 (Wind), 4.4.4.3 (Solar) and 4.4.4.4 (Energy Storage)

easily identifiable. Therefore, the scalable load field should be populated as 1 if it is scalable (conforming) and 0 if it is not scalable (non-conforming).

The external area Load is modeled as represented in the NERC series models or the neighboring coordinated system used to develop the MOD base models.

4.4.6.1 *Station Service*

Bulk Electric System generators with station service load greater than 1 MW are required to model their station service load explicitly. In order to maintain a consistent naming convention associated with station service load, MISO recommends that all station service load have a load ID of SS. If there is more than 1 generator at a bus the station service load shall have a load ID of S1, S2, S3, etc. associated with the correct generator ID. If a legacy station service load ID is being used please communicate that to MISO via email to: PlanningModeling@misoenergy.org.

Nuclear generation station service loads are not required to adhere to the SS load identification recommendation above. Station service loads not directly connected to the generation bus are not required to adhere to the SS load identification recommendation above. The GO is responsible to inform MISO of the generator-station service association as part of their data submittal.

Station Service loads should be enabled or disabled based on the generator status within the year/case/sensitivity unless MISO is notified of special considerations. Station Service loads shall be positive values.

4.4.6.2 *Interruptible Load Modeling*

Loads that are interruptible should be modeled as such, indicated with INTRPT = 1 in MOD, which will flag the “Interruptible” field in PSSE. The full MW value that is interruptible should modeled. If a portion of the entire load is interruptible, two loads should be modeled. The uninterruptible portion of the load should have INTRPT either set to 0 or be left blank; the interruptible portion of the load should have INTRPT set to 1.

4.4.6.3 *Load Forecast Expectations*

The general expectation for load forecasts is that they should be inclusive of natural load growth as well as new loads coming online and any load retirements. As a general quality assurance practice, MISO will perform some checks for each submitted load profile:

1. Comparison of current year load value to previous year load value for variances greater than 10%
2. Comparison of current year load value as a percent of previous year Module E value for YoY variances greater than 10%
3. Comparison of current year load value as a percent of previous year real-time peak load value for YoY variances greater than 10%

Load profiles provided must also adhere to the prescribed year/season/sensitivity scenario. Generally, MISO will use the following ratios as a reasonability check for submitted load profiles and looking at the entire MISO footprint, understanding each TO will not necessarily fall into these ratios for each scenario due to footprint diversity:

1. Summer Peak 100% of Summer Peak
2. Summer Shoulder 70-80% of Summer Peak
3. Fall 75-90-% of Summer Peak
4. Spring 75-90% of Summer Peak
5. Light Load 45-65% of Summer Peak
6. Minimum Load30-50% of Summer Peak
7. Winter Peak 100% of Winter Peak

These comparisons will not include non-firm loads such as station service, Qualifying Facilities, etc. Any variances outside the bounds observed in the checks listed above (for example a large industrial load comes online) will be flagged by the MISO Planning Modeling team for requiring justification (i.e. new large industrial load included, unmodeled DERs now represented, inclusion of new units/loads due to acquisition, etc.). If the methodology changes for load forecasting, MISO should be notified of this as well.

4.4.7 Area Interchange

Area interchange will be set to model firm and expected inter- and intra-MISO transactions. An Area Interchange Transaction workbook will be utilized to determine Area Interchange. Data needed to model transactions will include the source and sink areas, transaction MW amount, applicable model scenarios, start/end dates and an OASIS reference (Transmission Service Reservation) number or a Grandfathered Agreement (GFA) number if applicable (Expected transfers may not have OASIS or GFA information). This data is required to be provided by TOs in collaboration with their Balancing Authority. The LBA may submit the data instead of the control area Transmission Owner if MISO is notified via email by both parties to PlanningModeling@misoenergy.org

Transactions need to be confirmed by both transacting parties. MISO will post a workbook to the MISO MTEP Sharefile for review, edits, additions and deletions. Final cases are solved by enabling the PSS®E “ties + loads” interchange function.

Method to collect transaction level data will be accomplished through a workbook.

4.4.8 Tie Lines

MISO will maintain a tie-line workbook for its members’ ties with external (non-MISO) entities. The workbook format will be determined by the ERO/designee. The Power Flow Coordinator maintains a Master Tie Line Database. A tie line will not be represented in a particular power flow base case model unless both parties have agreed to include it. Tie lines between MISO entities need to be coordinated between both parties. MISO can facilitate dialogue between its members if that is desired.

All existing and future planned tielines modeled in MOD must have matching representation for bus numbers and circuit ID in the ERAG MMWG and MISO MOD cases and must be linked to the ERAG Master Tie Line Database. For tie-lines not owned by a MISO member but connecting to a MISO member bus, the MISO member must submit a MOD project to connect the external and internal areas. All tie-lines must be represented within the MISO models regardless of normal operational status.

4.4.9 Ratings

Data owners are responsible for maintaining the ratings data for their facilities in MOD as per the FAC-008-3 standard. While creating cases, facility ratings are selected as indicated below:

- Rate 1=Normal
- Rate 2=STE (Emergency Rating, the rating used in contingency analysis)
- Rate 3=LTE (Long-Term Emergency Rating, not required)

4.4.10 Branch Modeling

AC line modeling must include the following characteristics:

- From Bus Number
- To Bus Number
- Ckt ID
- Line Resistance (R) in pu
- Line Reactance (X) in pu
- Charging (B) in pu
- Whether it is Metered on the From end
- Ratings (Refer to section 4.4.9 for rating guidance)
- Owner

If the line is a zero-impedance line the Ckt ID must start with a Z.

AC Line Name – this is an optional field that can be filled out. This field does require unique entries across the entire case. In order to assure unique entries, MISO recommends the following naming conventions:

1. For lines that are not inter-area ties (non-area ties), please have the corresponding area number or area name followed by a colon preceding the unique name (this keeps uniqueness within each area and under each area's control).
2. It is recommended to avoid the use of underscore; if a duplicate entry occurs, an _# will be appended to the end (this will allow for easy parsing out for the data owner if a duplicate happens).
3. For area ties, include both areas separated by forward slash followed by a dash preceding the unique name. The order should be From bus area/To bus area.

   Example:

   Non-area tie: 207-161kV line from XXX to XXX
   Non-area tie: 217-ARPT DTWN
   Area tie: 207/210-345kV tieline

4.4.11 Transformer Modeling

Transformer modeling must include the following characteristics:

- Owner
- Nominal voltages of each winding
- Winding ratings (Refer to section 4.4.9 for rating guidance)
- Regulated Bus
- Tap ratios
- Number of tap positions
- Tap position limits (Min. and Max.)
- Control Mode
- From/To/Last Bus Numbers and Circuit ID
- Proper Vector Group[19]
- Impedance data (R and X)

In addition, three-winding transformers shall be modeled in the following configuration:
Winding 1 – Highest KV – Highest MVA Rating
Winding 2 – 2nd Highest KV – 2nd Highest MVA Rating
Winding 3 – Lowest KV – Lowest MVA Rating

Data submitters may utilize a different winding configuration so long as the configuration is uniform throughout the submitter's area(s).

Transformer Name: This is an optional field that can be filled out. This field does require unique entries across the entire case. In order to assure unique entries, MISO recommends the following naming conventions.

1. For lines that are not inter-area ties (non-area tie), please have the corresponding area number or name followed by a colon preceding the unique name (this keeps uniqueness within each area and under each areas control).
2. It is recommended to avoid the use of underscore; if a duplicate entry occurs, an _# will be appended to the end (this will allow for easy parsing out for the data owner).
3. For area tie transformers, include both areas separated by forward slash followed by a dash preceding the unique name. The order should be From bus area/To bus area.

   Example:
   Non-area tie: 207-asdf GSU
   Area tie: 207/210-asdf Phase Shifter

4.4.12 Voltage Limits

Data owners are responsible for maintaining the bus level voltage limits for their facilities in MOD. Data owners must provide:

- Normal maximum voltage (pu)
- Normal minimum voltage (pu)
- Emergency (N-1) maximum voltage (pu)
- Emergency (N-1) minimum voltage (pu)

[19] Only required for transformers to be included in GIC analysis. Please refer to Section 9.

4.4.13 Standard Case Effective Dates

Effective dates are cutoffs that are used to identify projects that are applied to the corresponding model scenario as noted in Table 4-7. Therefore, all projects that have their expected in-service date specified to be on or before the effective date are included in the corresponding model.

Table 4-7: Standard Effective Dates

Season	Standard Case Effective Date (MM-DD)
Spring Peak, Spring Light Load, and Spring Minimum Load	04-15
Summer Peak and Summer Shoulder	07-15
Fall Peak	10-15
Winter Peak	01-15

4.4.14 Dispatch

MISO uses a combination of generation dispatches for its NERC TPL analyses. Most models that are used for steady state analysis contain a control area level Network Resource dispatch. For implementing this dispatch, wind and solar resources are dispatched at set percentages first to meet the needs of the case definition, reflecting what would be seen in an operating scenario. Network Resources in each control area are then dispatched in economic tier order to meet the load, loss, and interchange level. MISO maintains generation tiered merit order information in the Tier Order Workbook.The Non-Tier Order workbook contains the dispatch information needed for all non-tier order resources. Interchange level is determined from the Area Interchange Transaction workbook which is gathered at the control area level.

5

Dynamics Model Development

5.1 Data Format

Dynamics modeling data needs to be submitted in the form of a Siemens PTI PSS®E Dyre (.dyr) file. Dyre file submittals can be of just changes to your system from the existing .dyr or of an entire representation of only your system in a .dyr. Models are developed using the PSS®E software program and DSA Tools TSAT program. Data submitted must be compatible with the PSS®E and DSA Tools TSAT versions currently specified by MISO.

Standard library models should be used to represent all active elements (generators, static VAR compensators, etc) whenever possible. If a user-written model (UDM) is being submitted, documentation and a .dll file must be submitted along with the .dyr file. The documentation must include the characteristics of the model including block diagrams, values and names for all model parameters, and a list of all state variables as stated in Section 6 of this document.

Modeling data requests and notifications are sent to the Modeling User Group mailing list. Individuals can subscribe to the list at the following location: https://www.misoenergy.org/Pages/ListsSignup.aspx.

5.2 Scenarios

For each annual planning cycle, MISO will develop a single dynamics data set to be used with the associated power flow models list in Table 5-1. The scenarios developed could change from year to year based on MISO and member needs. However, at a minimum those needed for TPL and MOD-032-1 compliance will be included.

Table 5-1: Power flow Scenarios Used for Dynamics

Model Year	Light Load	Summer Peak	Summer Shoulder	Fall Peak	Winter Peak
1		X			
5	X	X	X		
10		X*			

*Will be built **if** proposed material generation additions or changes occur in between years 5&10. If year 10 Summer Peak is required to be submitted to ERO designee and MISO has no material generation additions/changes, MISO will submit +5 Summer Peak dynamics.

5.3 Schedule

The annual schedule for dynamics model development is shown in Table 5-2. Specific dates will be supplied with the annual data request.

Table 5-2: Dynamics Development Schedule

Task	Estimated Completion
MISO requests updated Dynamic data (.dyr updates)	April
Create Initialized Pass 1 Dynamics Package	April - May
Post Initialized Pass 1 Dynamics Package & provide output of sample set of disturbances	May
Data owners review and provide corrections	June
Incorporate updates and develop Final Dynamics Package	June
Post Final Dynamics Package	July
Dynamics Data submitted to ERO or its Designee	August (Actual timeframe to be determined based on ERO schedule)

5.4 Level of Detail

Dynamics simulations analyze the transient response of the power system following a disturbance. These simulations are in a timeframe of 0 to 20 seconds with a typical time step of ¼ cycle. As such it is necessary to develop a model that sufficiently represents the automatic response of all active elements to a disturbance on the power system.

On an annual basis each data owner is required to submit the following model data:

- Dynamic models to represent approved future active elements such as generators, FACTS devices, or fast switching shunts
- Updates to existing dynamic models

GOs and LSEs are expected to submit directly to MISO unless they have made arrangements with the interconnecting Transmission Owner to submit data on their behalf. If arrangements have been made, it must be communicated in writing to MISO at PlanningModeling@misoenergy.org

If the data has not changed since the last submission, a written confirmation that the data has not changed is sufficient. Such confirmation should be sent to MISO as the Planning Coordinator and the appropriate Transmission Planner. MISO correspondence should be sent by email to PlanningModeling@misoenergy.org.

5.4.1 Power Flow Representation

The dynamics model will use a power flow model consistent with the steady-state model outlined in Section 4. If changes are required to the power flow data for dynamics, they should be reflected in the steady-state power flow cases and the appropriate changes entered in MOD.

5.4.2 Dynamics Representation

5.4.2.1 *Generators*

At a minimum, all generators with a nameplate greater than 20 MVA or a facility with an aggregated nameplate greater than 75 MVA must be modeled in detail (except for those meeting the exclusion criteria as specified in the NERC BES definition) and additionally Blackstart Resources identified in the Transmission Operator's restoration plan. A detailed model of a generator must include:

- Generator Model
- Excitation System Model
  - May be omitted if unit is operated under manual excitation control
- Turbine-Governor Model
  - May be omitted if unit doesn't regulate frequency
- Power System Stabilizer Model
  - May be omitted if device is not installed or not active
- Reactive Line Drop Compensation Model
  - May be omitted if device is not installed or not active
- Frequency Response
  - Responsive *Generator is operated to be fully frequency responsive*
  - Squelched *Generator is frequency responsive but load controller will override after some time*
  - Non-Responsive *Generator does not regulate frequency*

Generators with detailed modeling must use a dynamic model from the Standard Generator Component Model List, specified in Section 6. If a suitable model is not on the standard list the data submitter may request a model be added to the standard list by providing MISO with a technical justification for doing so. Additions and subtractions to the standard list will be handled on a case by case basis.

Several legacy models have been omitted from the Standard Generator Component Model List since they can be directly converted to newer dynamic models with minimal effort and without changes to simulation results. The recommended conversions from a particular legacy model to a newer model are listed in Section 6.

In instances where detailed dynamic modeling is unavailable, generic data may be used. Generators without detailed modeling will be netted with the load (set as a negative load).

5.4.2.2 *Static VAR Systems & Synchronous Condensers*

Static VAR Systems (SVS) and synchronous condensers are reactive power devices that can vary the amount of reactive power supplied or absorbed within the simulated timeframe (0-20 seconds). These devices must be modeled in sufficient detail in order to simulate its expected behavior.

If the reactive power device is modeled as a generator (for example a synchronous condenser) it should follow the guidelines in Section 5.4.2.1.

5.4.2.3 *HVDC*

All HVDC transmission facilities must be represented with a sufficiently detailed model to simulate its expected behavior. For future HVDC transmission facilities where exact design specifications are not known generic HVDC models should be used (such as CDC6).

5.4.2.4 *Load*

The dynamic behavior of load must be modeled in sufficient detail to meet NERC TPL compliance obligations. The dynamic behavior of load can be specified on an aggregate (area/zone/owner) or individual bus level. Providing a specific dynamic load characteristic model or the motor load composition is acceptable.

Loads with detailed characteristic modeling must use a dynamic model from the Standard Component Model List, specified in Section 6. If a desired model is not on the standard list the data submitter may request a model be added to the standard list by providing MISO with a technical justification for doing so. Additions to the standard list will be handled on a case by case basis.

If a specific dynamic load characteristic model is not provided, the motor load composition of the load on a bus/area/zone or owner level is required in order to determine the appropriate dynamic representation. The composition of the load shall be defined as:

- Motor A – Small 3-Phase (i.e. compressor motors used in large air-conditioners and refrigerators)
- Motor B – Large 3-Phase (i.e. Fan Motor)
- Motor C – Medium 3-Phase (i.e. Pump Motor)
- Motor D – 1-Phase Air Conditioner Compressor Motor
- Electronic Load – Voltage Dependent Load
- Static Load – Frequency & Voltage Dependent Load

Based on the composition of the load an appropriate dynamic representation will be developed using the composite load model (CMLD). Additional details on how the composite load model parameters will be developed are specified in Section 7. A walkthrough of how to determine the motor load composition based on the Residential/Commercial/Industrial/Agricultural composition of the load is also detailed in Section 7.1.

5.4.2.5 *Protection Relays*

Generic protection relays are applied during the simulation that scan for bus voltages, out-of-step conditions, and against generic protection zones for transmission lines. These generic protection relays only monitor system conditions. Table 5-3 shows the generic relay settings.

Table 5-3: Generic Relay Settings

Generic Relay	Monitored Condition
Generic Transient Voltage Monitoring	$0.7 \le V_{bus} \le 1.2$ (12 cycles following the initiating event)
Generic Out-of-Step Monitoring	Apparent Impedance > Line Impedance
Generic Distance Relay	Circle A = 1.00 x Line Impedance Circle B = 1.25 x Line Impedance Circle C = 1.50 x Line Impedance

Equipment-specific detailed protection relay models shall be submitted for:

- Voltage and frequency ride through relay settings of BES resources
    - In support of PRC-006-5 and MISO's underfrequency load shedding analysis, frequency trip settings of resources that meet the gross nameplate criteria as stipulated in PRC-006-5, Requirements R4.1 through R4.6 as shown below.

      4.1. Underfrequency trip settings of individual generating units greater than 20 MVA (gross nameplate rating) directly connected to the BES that trip above the Generator Underfrequency Trip Modeling curve in PRC-006-5 - Attachment 1.
      4.2. Underfrequency trip settings of generating plants/facilities greater than 75 MVA (gross aggregate nameplate rating) directly connected to the BES that trip above the Generator Underfrequency Trip Modeling curve in PRC-006-5 - Attachment 1.
      4.3. Underfrequency trip settings of any facility consisting of one or more units connected to the BES at a common bus with total generation above 75 MVA (gross nameplate rating) that trip above the Generator Underfrequency Trip Modeling curve in PRC-006-5 - Attachment 1.
      4.4. Overfrequency trip settings of individual generating units greater than 20 MVA (gross nameplate rating) directly connected to the BES that trip below the Generator Overfrequency Trip Modeling curve in PRC-006-5 — Attachment 1.
      4.5. Overfrequency trip settings of generating plants/facilities greater than 75 MVA (gross aggregate nameplate rating) directly connected to the BES that trip below the Generator Overfrequency Trip Modeling curve in PRC-006-5 — Attachment 1.
      4.6. Overfrequency trip settings of any facility consisting of one or more units connected to the BES at a common bus with total generation above 75 MVA

- Automatic action of Special Protection Schemes (SPS)

5.5 Dynamics Data Checks

Once the dynamic models are created, a set of data checks to flag potential issues with the data submitted will be performed. Section 11.2 provides a list of the data quality checks performed. In addition to the data checks, a sample set of disturbances are run to assist in model review. Data owners are required to submit corrected model data in the time window specified in the model review request/notification.

5.6 Distributed Energy Resources

MISO recommends that dynamics data be provided for any DERs that are represented in the power flow models. The representation that is provided can either be a generic model or a user-defined model (UDM), depending on the resource and complexity of modeling the DER. Guidelines for UDMs can be found in Section 6.

6

Standard Generator & Load Component Model List

MISO recognizes the NERC Acceptable Model List posted at:
https://www.nerc.com/pa/RAPA/ModelAssessment/Documents/Dynamic%20Modeling%20Recommendations.pdf.

Note that MISO, in addition to the models listed in the NERC Acceptable Model List, does not accept the additional models listed in Appendix 3. The recent Acceptable Model List change published by NERC is not inclusive of models MISO has previously not accepted. MISO no longer accepts governor models that are unable to model deadband even though they are acceptable to NERC. For example, TGOV1 is currently an acceptable NERC model but since deadband is not modeled it is no longer acceptable to MISO. Also note that MISO does not accept user defined models (UDM) unless they meet the following conditions.

- The specific performance features of the user-defined modeling are necessary for proper representation and simulation of inter-Data Submitting Entity dynamics, and
- Standard PSS®E dynamic models cannot adequately approximate the specific performance features of the dynamic device being modeled.
- The User Written Model must be table driven, not CONET or CONEC based.
- When user-defined modeling is used in the MMWG cases, written documentation shall be supplied explaining the dynamic device performance characteristics, detailed block diagrams, model ICONs, CONS, and Variables. The documentation for all MMWG user-defined models shall be posted on the MMWG Internet site as a separate document. Any benign warning messages that are generated by the model code at compilation time should also be documented. This documentation must be continuous updated to demonstrate that new standard library models do not meet the necessary performance features.
- .dll files or source code and object file(s) shall be provided for all User Models. Source code shall be submitted in FORTRAN or the FLECS language of the PSS®E version currently specified by MISO.
- If a PSS®E UDM is supplied, then a DSA Tools TSAT UDM must be created and maintained as well.

Please note that TSAT may not have a standard library model for all PSS®E or PSLF dynamic component models but still has the ability to automatically read and convert them into the appropriate TSAT format. Some models will be listed as “UDM” for TSAT, however; this should not be confused with the term “user-written model” or “UDM” used in the context of PSS®E or PSLF. Models must be provided which are usable within both the DSA Tools TSAT and PSS®E application.

7

Composite Load Model

The composite load model was developed through industry collaboration led by the efforts of the NERC Load Modeling Working Group (LMWG). The composite load model has since been implemented into the various commercially available software tools. Figure 7-1 provides a diagram of the composite load model. Please refer to the WECC Report "Composite Load Model for Dynamic Simulations"[20] for additional information about the composite load model.

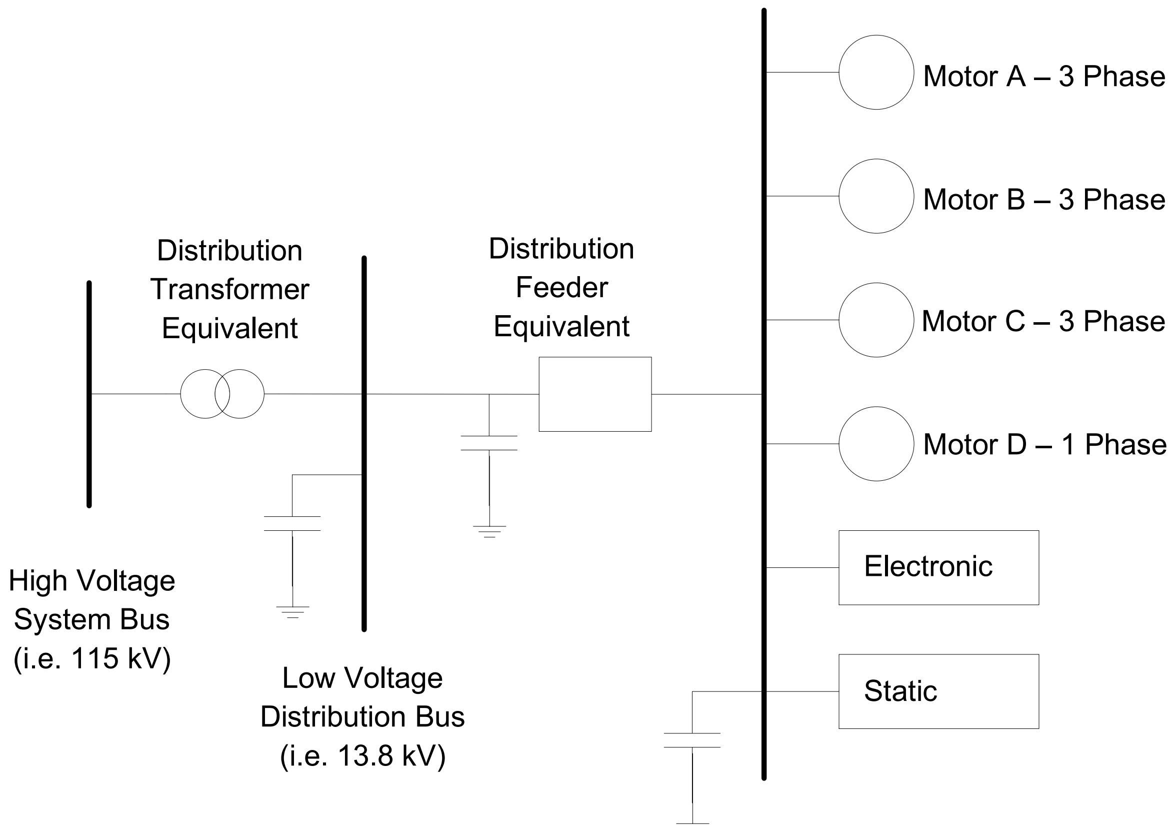


Figure 7-1: Composite Load Model

20 https://www.wecc.org/_layouts/15/WopiFrame.aspx?sourcedoc=/Reliability/WECC%20MVWG%20Load%20Model%20Report%20ver%201%200.pdf&action=default&DefaultItemOpen=1

7.1 Parameter Derivation Based on Load Composition

The composite load model has 133 different parameters. The majority of these parameters are used to define the characteristics and behavior of the 6 main components of the model, which are listed below:

- Motor A – Small 3-Phase (i.e. compressor motors used in large air-conditioners and refrigerators)
- Motor B – Large 3-Phase (i.e. Fan Motor)
- Motor C – Medium 3-Phase (i.e. Pump Motor)
- Motor D – 1-Phase Air Conditioner Compressor Motor
- Electronic Load – Voltage Dependent Load
- Static Load – Frequency & Voltage Dependent Load

Table 7-1-1 provides example percentages of load composition for different components of load.

Table 7-1-1: Sample Summer Peak Load Composition Based on R/C/I/A

	Residential	Commercial	Industrial	Agricultural
Motor A	8%	12%	13%	10%
Motor B	7%	10%	22%	20%
Motor C	2%	4%	16%	22%
Motor D	34%	25%	0%	8%
Electronic	15%	18%	27%	10%
Static	34%	31%	22%	30%

Table 7-1-2: Sample Shoulder Load Composition Based on R/C/I/A

	Residential	Commercial	Industrial	Agricultural
Motor A	8%	12%	13%	10%
Motor B	7%	10%	22%	20%
Motor C	2%	4%	16%	22%
Motor D	25%	20%	0%	8%
Electronic	19%	23%	27%	10%
Static	39%	31%	22%	30%

Table 7-1-3: Sample Light Load Composition Based on R/C/I/A

	Residential	Commercial	Industrial	Agricultural
Motor A	10%	12%	13%	10%
Motor B	8%	10%	22%	20%
Motor C	2%	4%	16%	25%
Motor D	0%	5%	0%	5%
Electronic	40%	38%	27%	10%
Static	40%	31%	22%	30%

Table 7-1-4: Sample Minimum Load Composition Based on R/C/I/A

	Residential	Commercial	Industrial	Agricultural
Motor A	10%	12%	13%	10%
Motor B	8%	10%	22%	20%
Motor C	2%	4%	16%	25%
Motor D	0%	5%	0%	5%
Electronic	40%	38%	27%	10%
Static	40%	31%	22%	30%

Table 7-1-5: Sample Winter Peak Composition Based on R/C/I/A

	Residential	Commercial	Industrial	Agricultural
Motor A	10%	12%	13%	15%
Motor B	7%	10%	22%	20%
Motor C	2%	4%	16%	15%
Motor D	0%	0%	0%	0%
Electronic	35%	34%	27%	10%
Static	46%	40%	22%	40%

Since load components are defined as fractions of the total load, mixtures of Residential/Commercial/Industrial/Agricultural are handled by summing the weighted fraction as shown in Equation 7-2.

Equation 7-2: Derivation of Load Composition Based on R/C/I/A in Table 7-1-1

$$\begin{bmatrix} F_{ma}\text{: Motor A Fraction} \\ F_{mb}\text{: Motor B Fraction} \\ F_{mc}\text{: Motor C Fraction} \\ F_{md}\text{: Motor D Fraction} \\ F_{el}\text{: Motor A Fraction} \end{bmatrix} = \begin{bmatrix} \text{CON}(J+18) \\ \text{CON}(J+19) \\ \text{CON}(J+20) \\ \text{CON}(J+21) \\ \text{CON}(J+22) \end{bmatrix} = \begin{bmatrix} 0.08 & 0.12 & 0.13 & 0.10 \\ 0.07 & 0.10 & 0.22 & 0.18 \\ 0.02 & 0.04 & 0.16 & 0.22 \\ 0.34 & 0.25 & 0.00 & 0.10 \\ 0.15 & 0.18 & 0.27 & 0.10 \end{bmatrix} \times \begin{bmatrix} Residential \\ Commercial \\ Industrial \\ Agricultural \end{bmatrix}$$

7.2 Example Composite Load Model Based on Load Composition

The PSS®E dyre entry for composite load model has the following structure:

```
I, 'USRLOD', LID, 'CMLDxxU2', 12, IT, 2, 133, 27, 146, 48, 0, 0, CON(J) to CON(J+132) /
```

Where:

Model suffix "XX"	Corresponding "IT" Description	Corresponding "I" Description
BL	**1**	Bus number
OW	**2**	Owner number
ZN	**3**	Zone number
AR	**4**	Area number
AL	**5**	0 (All)

Below is an example of how the composite load fractions will be calculated based on a provided load composition.

Given the load composition for area 1 is:

- Residential – 40%
- Commercial – 30%
- Industrial – 20%
- Agricultural – 10%

Thus:

$$\begin{bmatrix} F_{ma} \\ F_{mb} \\ F_{mc} \\ F_{md} \\ F_{el} \end{bmatrix} = \begin{bmatrix} \mathrm{CON(J+18)} \\ \mathrm{CON(J+19)} \\ \mathrm{CON(J+20)} \\ \mathrm{CON(J+21)} \\ \mathrm{CON(J+22)} \end{bmatrix} = \begin{bmatrix} 0.08 & 0.12 & 0.13 & 0.10 \\ 0.07 & 0.10 & 0.22 & 0.18 \\ 0.02 & 0.04 & 0.16 & 0.22 \\ 0.34 & 0.25 & 0.00 & 0.10 \\ 0.15 & 0.18 & 0.27 & 0.10 \end{bmatrix} \times \begin{bmatrix} 0.40 \\ 0.30 \\ 0.20 \\ 0.10 \end{bmatrix} = \begin{bmatrix} \mathbf{0.104} \\ \mathbf{0.120} \\ \mathbf{0.074} \\ \mathbf{0.221} \\ \mathbf{0.178} \end{bmatrix}$$

The DYR entry would be:

```
1  'USRLOD'    *          'CMLDARU2'       12         4  2  133  27  146  48
                   0              0
                  -1              0         0.02       0.02          1
                   0              1            1          1        0.9
                 1.1        0.00625            1       1.02        999
                   5              0            0      0.104       0.12
               0.074          0.221        0.178          1       0.72
                0.52              1            2        0.5          1
                 0.5              0            2          1          1
                   0             -1            3        0.8       0.01
                 3.1         0.1384        0.121     0.1028     0.0028
                 0.1              0          0.7       0.05        0.3
                   1           9999          0.6       0.02        0.7
                   1          99999            3        0.8      0.005
                   4          0.185         0.16        0.8     0.0044
                 0.5              2          0.7       0.05        0.3
                   1           9999          0.6       0.02        0.5
                0.75           0.25            3        0.8       0.01
                 3.1          0.185         0.16       0.35     0.0036
                0.15              2          0.7       0.05        0.3
                   1           9999          0.6       0.02        0.5
                0.75           0.25        9999*        0.3      0.025
                0.05              1         0.98       0.45        0.1
                 0.1              0            0          1          6
                   2             12          3.2         11        2.5
                0.86            0.2         0.95          1       -3.3
                 0.5            0.4          0.6        0.5         15
                 0.7            1.9          0.1        0.6       0.02
                   0           9999          0.5          /
```

* *The blue highlighted parameter is the Tstall value for motor D.*

- *To disable motor stalling, use the value 9999.*
- *If the motor is set to stall, a commonly used value is 0.03*

8

Short Circuit Model Development

In support of the TPL-007 harmonic analysis requirements, MISO Transmission Owners (TO) and Generator Owners (GO) are required to provide MISO the following positive, negative*, and zero sequence network information:

1. Generator
2. Load
3. Non-Transformer Branch
4. Mutual Branch
5. Transformer
6. Switched Shunt
7. Fixed Shunt
8. Induction Machine

Sequence network data shall be submitted to MISO using MOD project files. *Negative sequence data is automatically recognized by PSS®E as the negative of the positive sequence data. All formatting shall follow the currently applicable version of PSS®E within MOD. Topology must be consistent with MISO power flow model representation, i.e. designated 6-digit bus numbers and consistent transformer modeled windings.

MOD project filenames should contain the company name acronym followed by SEQNET and any other identifying information determined by the entity.

Example: ATC-SEQNET-345kV system

Data shall be submitted for all elements meeting any of the following criteria:

- NERC BES defined elements (excluding Blackstart resources with a point of interconnection less than 200 kV)
- 200 kV and higher MISO transferred transmission facilities
- Transformers interconnecting to the above facilities at 100 kV or higher via at least two terminals

Do not submit equivalized representation of neighboring networks represented within a TO/GO model.

MISO will be performing the harmonic analysis on the 5-year Summer Peak and 5-year Summer Shoulder, Average Wind models. For equipment not yet in service, provide short circuit information based on best engineering practices.

9

GIC Model Development

Additional data to supplement an AC power flow model is required to develop Geomagnetic Induced Current (GIC) system models in accordance with R2 of TPL-007. These models require system details related to the path of GIC through the system similar to DC modeling. MISO is requiring data on facilities that include power transformer(s) with a high side, wye-grounded winding with terminal voltage greater than 200 kV in accordance with the TPL-007 standard. Additional data beyond the required scope of TPL-007 will be accepted.

Details and examples of the data being requested are referenced in section 9.2. For brevity, only the data being requested is listed in sections 449.1. Data will be received by MISO through the submission of an Excel Spreadsheet attached to a GIC Model Data Request.

9.1 Required GIC Data:

9.1.1 Substation and Bus Data

A new data construct which supports the calculation of GIC is the Substation. This is a one-to-many relationship between a group of power system Buses within a Substation. Data required of the substation is:

- Substation number
    - The substation number should be the lowest Bus number of the highest voltage present within the substation. Substations numbers must be selected from the utilities' allocated bus numbers which can be found in the MMWG model building manual, located at:
        - https://rfirst.org/ProgramAreas/ESP/ERAG/MMWG/Pages/MMWG.aspx
- Substation summer ground resistance
- Latitude and Longitude of Substation
- Earth model to be applied
    - Either utilizing the acronym identifying the United States Geological Survey (USGS) Earth model or detailed parameters with additional Earth model input as part of section 9.1.5
- The bus data which correlates buses to the substation in which they are located

9.1.2 Transmission Line Data

MISO requires two categories of data be submitted for line data. Lines which are installed underground at greater than 200 kV or have implicit shunts with ground paths must be reported in data submissions. Underground lines require an indication of no induced current (Vp and Vq) be indicated with 0.0 entries. Line shunts are entered as a resistance correlated to the end of the branch which it is installed.

MISO will not require utilities to include DC conductor resistance inputs for each line and will run calculations with program approximated DC value. Any submission of this data will be accepted and applied by MISO.

9.1.3 Transformer Data

Transformers require the most data of any transmission system element to be submitted. It is highly recommended to utilize the three-winding model within power flow tools instead of modeling the transformer as three two-winding transformers. The following information must be submitted:

- If present, the winding that a DC blocking device may be installed on
- Transformer DC winding resistances
- The transformer Vector Group
    - Alternatively, this may be submitted to Model on Demand within the AC power flow model data
- Transformer Core Construction, <u>or</u> K-factor if known
- If present, the size and location of grounding resistors
- Phase shifting transformers may require special consideration

9.1.4 Fixed Shunt Data (Reactors)

Reactors may offer a path to ground and are required within the GIC model where grounding exists. The below data fields are required for equipment at greater than 200 kV:

- Bus Number
- Shunt ID
- DC Ohms/phase of the reactors
- Grounding Resistor (if present)

9.1.5 Earth Model Data

If a model submitting entity has more comprehensive data on the Earth resistivity model, they may enter the data within the Earth Model Data.

9.1.6 Switched Shunt Data (Reactors)

Similar to Fixed and Line associated Shunts, Switched Shunts can offer a path(s) to ground. The below data fields are required for equipment at greater than 200 kV:

- Bus Number
- DC Ohms/phase of the reactors
- Grounding Resistor (if present)
- Block Number and Size
- Step Number

To date, simulation software allows for the entry of one DC resistance value for all represented paths. MISO will be collecting the "*blocks*" and "*steps*" to correlate this information to the switching status of the devices within the AC power flow model.

9.1.7 Load, DC Line Data, VSC and Facts Devices

Multiple devices may contain applicable transformers implicitly within the power flow model element. These devices are likely to be two winding wye-delta or delta-wye. For grounded wye transformers 200 kV and higher, data is required with the following information collected:

- Line name (only for DC devices)
- Bus Number
- ID
- DC Winding Resistance
- Grounding Resistor if present
- Transformer Core Construction, or K-factor if known

For loads which may represent lower voltage systems and have alternative transformer construction than grounded wye-delta, total winding resistance to ground should be used.

9.1.8 Use of Default or Estimated Data

The use of default or estimated data GIC models should be utilized as an exception. When parameters are estimated, a description of the estimate must be reflected in the comments along with plans to determine the required data.

9.1.9 Updating the AC Power Flow Model

Topology changes may be required to accurately represent GIC information. These topology changes are required to be submitted to MOD as Base Case Change, Facility Addition. The use of calculated equivalents in the GIC data will only be accepted with written permission from MISO and detailed documentation retained to describe the calculations utilized. For example: additional buses are required to be modeled when there are transformers that span two different substations and when substations have different ground grid resistances. Projects submitted to MOD for this purpose should include the syntax “GIC Update” in the project file name.

9.2 Reference Papers

- *Geomagnetic Disturbance Modeling Examples from the MISO system* – a confidential MISO reference document
- *Modeling and Evaluation of Geomagnetic Storms in the Electric Power System* (Krishat Patil, Siemens USA)
- MISO GIC Data Request Spreadsheet

9.3 Schedule

The annual request for GIC data will be communicated to members after the completion of the Dynamics Model series, usually during the June timeframe. Specific dates will be supplied with the annual data request.

10

MOD-032-1 – Attachment 1

The table below indicates the information that is required to effectively model the interconnected transmission system for the Near-Term Transmission Planning Horizon and Long-Term Transmission Planning Horizon. Data must be shareable on an interconnection-wide basis to support use in the Interconnection-wide cases. A Planning Coordinator may specify additional information that includes specific information required for each item in the table below. Each functional entity1 responsible for reporting the respective data in the table is identified in the right column, adjacent to and following each data item. The data reported shall be as identified by the bus number, name, and/or identifier that is assigned in conjunction with the PC, TO, or TP.

Data	Functional Applicability
Steady-state *(Items marked with an asterisk indicate data that vary with system operating state or conditions. Those items may have different data provided for different modeling scenarios*	
1. Each bus a. nominal voltage b. area, zone and owner	TO
2. Aggregate Demand[21] a. real and reactive power* b. in-service status*	LSE
3. Generating Units[22] a. real power capabilities - gross maximum and minimum values b. reactive power capabilities - maximum and minimum values at real power capabilities in 3a above c. station service auxiliary load for normal plant configuration (provide data in the same manner as that required for aggregate Demand under item 2, above). d. regulated bus* and voltage set point* (as typically provided by the TOP) e. machine MVA base f. generator step up transformer data (provide same data as that required for transformer under item 6, below) g. generator type (hydro, wind, fossil, solar, nuclear, etc) h. in-service status*	GO, RP (for future planned resources only)
4. AC Transmission Line or Circuit a. impedance parameters (positive sequence) b. susceptance (line charging) c. ratings (normal and emergency)* d. in-service status*	TO
5. DC Transmission systems	TO

[21] For purposes of this item, aggregate Demand is the Demand aggregated at each bus under item 1 that is identified by a Transmission Owner as a load serving bus. A LSE is responsible for providing this information, generally through coordination with the Transmission Owner.
[22] Including synchronous condensers and pumped storage.

Data	Functional Applicability
6. Transformer (voltage and phase-shifting) a. nominal voltages of windings b. impedance(s) c. tap ratios (voltage or phase angle)* d. minimum and maximum tap position limits e. number of tap positions (for both the ULTC and NLTC) f. regulated bus (for voltage regulating transformers)* g. ratings (normal and emergency)* h. in-service status*	TO
7. Reactive compensation (shunt capacitors and reactors) a. admittances (Mvar) of each capacitor and reactor b. regulated voltage band limits* (if mode of operation not fixed) c. mode of operation (fixed, discrete, continuous, etc.) d. regulated bus* (if mode of operation not fixed) e. in-service status*	TO
8. Static Var Systems a. reactive limits b. voltage set point* c. fixed/switched shunt, if applicable d. in-service status*	TO
9. Other information requested by the Planning Coordinator or Transmission Planner necessary for modeling purposes.	BA, GO, LSE, TO, TSP
Dynamics *(If a user-written model(s) is submitted in place of a generic or library model, it must include the characteristics of the model, including block diagrams, values and names for all model parameters, and a list of all state variables)*	
10. Generator	GO, RP (for future planned resources only)
11. Excitation System	GO, RP (for future planned resources only)
12. Governor	GO, RP (for future planned resources only)
13. Power System Stabilizer	GO, RP (for future planned resources only)
14. Demand	LSE
15. Wind Turbine Data	GO
16. Photovoltaic systems	GO
17. Static Var Systems and FACTS	GO, TO, LSE
18. DC system models	TO
19. Other information requested by the Planning Coordinator or Transmission Planner necessary for modeling purposes.	BA, GO, LSE, TO, TSP
Short circuit	
20. Provide for all applicable elements in column “steady-state” a. Positive Sequence Data b. Negative Sequence Data c. Zero Sequence Data	GO, RP, TO
21. Mutual Line Impedance Data *	TO, GO*
22. Other information requested by the Planning Coordinator or Transmission Planner necessary for modeling purposes.	BA, GO, LSE, TO, TSP
Geomagnetically induced current (GIC)	
23. Substations a. associated bus(es) b. geophysical location (lat, long degrees) c. grounding resistance (ohms)	TO, GO
24. GIC branch data a. dc resistance (ohms/phase) b. if no GIC coupling: underground/water cable	TO, GO

Data	Functional Applicability
25. GIC transformer data a. dc resistances (ohms/phase) b. blocking device status c. vector group d. core design: phases, shell/core, legs e. K factor: a factor to calculate transformer reactive power loss from GIC flowing in its winding (Mvar/Amp) f. grounding resistances g. dc network model: T model for PARs	TO, GO
26. Fixed shunt a. dc resistance (ohms/phase) b. grounding dc resistance (ohms)	TO, GO
27. [Optional: alternative earth model]	TO, GO

11

Data Checks

Once the power flow models are created, a set of data checks to flag potential issues with the data submitted will be performed by MISO. In addition to the data checks shown below, a sample N-1 DC contingency screen is performed to assist with model review. Results of the data checks and sample contingency screens will be included along with each model posting. Data owners are required to submit corrected data in the time window specified in the model review request/notification.

11.1 Power Flow Data Checks

Name	Data Checked	Conditions Flagged
Bus Voltage	Buses	Existing TO planning criteria
Blank Voltage Fields	Buses	Blank BASKV field
Machines on Code 1 Buses	Buses; Generators	Generator at bus with IDE = 1
Online Machines on Code 4 Buses	Buses; Generators	Machine with STATUS = 1 at bus with IDE = 4
Code 2 Buses Without Machines	Buses; Generators	No generator at bus with IDE = 2
Unrealistic PMAX and PMIN	Generators Including off-line generators	PMAX < PMIN, PMAX > 2000, PMIN < -1000
Unrealistic QMAX and QMIN	Generators Including off-line generators	QMAX < QMIN, QMAX > 1000, QMAX < -1000
PGEN Outside Range	Generators with STAT = 1 & Bus IDE=2 or 3	PGEN > PMAX, PGEN < PMIN
Non-positive RMPCT	Generators	RMPCT ≤ 0
GTAP Out Of Range	Generators	GTAP > 1.1, GTAP < 0.9
CNTB Errors	Switched Shunts; Generators; Transformers with COD1 = 1	Conflicting voltage objectives
Small Voltage Band Shunts	Switched Shunts	VSWHI – VSWLO < 0.0005
Missing Block 1 Steps	Switched Shunts	Missing Block 1 steps
Transformer MAX below MIN	2-Winding Transformers with COD1 ≠ 0	VMA1 ≤ VMI1, RMA1 ≤ RMI1
Transformer Default R	2-Winding Transformers with COD1 ≠ 0	RMA1 = 1.5 and RMA2 = 0.51
Transformer Default V	2-Winding Transformers with COD1 ≠ 0	VMA1 = 1.5 and VMA2 = 0.51
Small Voltage Band Transformer	All Transformers with COD1 = 1	VMA – VMI < 2.0 × Step Size
Small Transformer Step Size	Transformers	0.015625 < Step Size < 0.00625

Name	Data Checked	Conditions Flagged
Max or Min at 0	2-Winding Transformers with COD1 ≠ 0	RMA1 = 0, RMI1 = 0, VMA1 = 0, VMI1 = 0
Branch Issues	Branches; 2-Winding Transformers	Branches: R > |X| Transformers: R1-2 > |X1-2| High/Low Reactance, Charging Issues
Rating Errors	Branches; Transformers	RATEB < RATEA, RATEA = 0, RATEB = 0
3 Winding Rating Errors	3-Winding Transformers[3]	RATEB < RATEA, RATEA = 0, RATEB = 0
Branch Overloads	Branches; Transformers	Branch loading above 100% of RATEA or RATEB
Islands	Buses	Buses with IDE 1 or 2 not connected to a bus with IDE = 3
Unrealistic MBASE	Generators	MBASE < PMAX, MBASE = 100
Unrealistic ZSOURCE	Generators	RSOURCE = 0 & XSOURCE = 1, RSOURCE = 1 & XSOURCE = 1, RSOURCE > XSOURCE
Machines Missing GSU	Machines at buses ≥ 50 kV	Implicit GSU not specified
Open ended branches	Branches, Transformers	Branch with STATUS = 1 connected to bus with IDE = 4
Branches to different bus voltages	Branches, Transformers	Branches between buses with different bus voltages
Wind units modeled at high voltage buses	Generators	Wind units that are modeled on buses 10kV or higher
Ensure WMOD is populated for wind units modeled with library models	WMOD	

11.2 Dynamics Data Checks

Models Checked	Data Checked	Conditions Flagged
All Gen Model with inertia defined as H	H	H = 0
All Gen Model with S(1.0)	S(1.0)	S(1.0) <0
All Gen Model with S(1.2)	S(1.2)	S(1.2) <0
All Gen Model with S(1.0) and S(1.2)	S(1.0)	S(1.0) > S(1.2)
All Gen/Exciter Model with S(E1)	S(E1)	S(E1) < 0
All Gen/Exciter Model with S(E2)	S(E2)	S(E2) < 0
All Gen/Exciter Model with S(E1) and S(E2)	S(E1)	S(E1) > S(E2) if E1 < E2
All Gen/Exciter Model with S(E1) and S(E2)	S(E1)	S(E1) < S(E2) if E1 > E2
All Gen Models with reactance/transient reactance defined as Xd and X'd in D axis	Xd	Xd <= X'd
All Gen Models with transient reactance/sub-transient reactance defined as X'd and X"d in D axis	X'd	X'd <= X"d
All Gen Models with sub-transient reactance/leakage reactance defined as X"d and XL in D axis	X"d	X"d <= XL
All Gen Models with reactance/transient reactance defined as Xq and X'q in Q axis	Xq	Xq <= X'q
All Gen Models with transient reactance/sub-transient reactance defined as X'q and X"q in Q axis	X'q	X'q <= X"d (X"d=X"q)
All Gen Models with reactance/transient reactance defined as X and X'	X	X <= X'
All Gen Models with transient reactance/sub-transient reactance defined as X' and X"	X'	X' <= X" if X"/=0 and T"/=0
All Gen Models with sub-transient reactance/leakage reactance defined as X" and XL	X"	X" <= XL if X"/=0 and T"/=0
All Gen Models with transient reactance/leakage reactance defined as X' and XL	X'	X' <= XL if X"=0 or T'=0

12

Entity Lists

Detailed list of NERC Compliance Registry is available at:

https://www.nerc.com/pa/comp/Pages/Registration.aspx

MISO membership listing is available at:

https://cdn.misoenergy.org/Current%20Members%20by%20Sector95902.pdf

Appendix 1

Transmission Planner Compliance

Pursuant to requirement R1 of MOD-032-1, MISO as a NERC Planning Coordinator (PC), and its NERC Transmission Planners (TPs) have jointly developed modeling data requirements and reporting procedures for MISO's planning area. Transmission Planners that have participated in the development of this document are as follows:

Transmission Planner	Transmission Planner Participant
ALLETE, Inc. (for its operating division Minnesota Power)	Ruth R. Pallapati
Ameren Services Company	Jason Genovese
American Transmission Company, LLC	Kerry Marinan Robert Krueger
Big Rivers Electric Corporation	Tim Curtis
Cedar Falls Utilities	Ken Kagy
Central Iowa Power Cooperative	Ethan Tellier Jacob Lampi Alex Kloiber
City Of Ames Electric Services	Lyndon Cook
City of Columbia, MO	Armin Karabegovic
City of Lansing by its Board of Water and Light	Jamal Ahmed Robert Tidd
City Water, Light & Power (Springfield, Illinois)	Chris Daniels Steve Rose
Cleco Power LLC	Terry Whitmore Chris Thibodeaux Ian Gray
Consumers Energy	Jeff Chilson Jeff Swan
Dairyland Power Cooperative	Steve Porter
Duke Energy Corporation	Phillip C. Briggs
East Texas Electric Cooperative, Inc.	Claudiu Cadar John Chiles Jason Shook (GDS Associates)
Entergy	William Hamilton Peng Yu
Great River Energy	Patrick Quinn
GridLiance Heartland	Rachael Ibuado
Henderson Municipal Power and Light	
Hoosier Energy Rural Electric Cooperative, Inc.	Sara Ostrander Mike Dicks
Indianapolis Power & Light Company	Mark Kemper Robert Grubb Brad Williams
International Transmission Company (d/b/a ITC Transmission)	

Transmission Planner	Transmission Planner Participant
	Angeliki Dimopulos Cody Rorick Jeffrey Taylor
ITC Midwest	Angeliki Dimopulos Cody Rorick Jeffrey Taylor (ITC Holdings Corp.)
Lafayette Utilities System	Hunter Boudreaux
Michigan Electric Transmission Company, LLC	Angeliki Dimopulos Cody Rorick Jeffrey Taylor (ITC Holdings Corp.)
MidAmerican Energy Company	Daniel Rathe
Minnkota Power Cooperative	Will Lovelace
Missouri River Energy Services	Andrew Berg Jesse Kreutzfeldt
Muscatine Power & Water (Board Of Water, Electric & Communications)	Lewis Ross Nick Lorenz Greg Slonka
Montana Dakota Utilities	Brian Giggee Maxx Snell
Northern Indiana Public Service Company	Lynn A. Schmidt
Otter Tail Power Company	Denise Keys
Prairie Power, Inc.	Karl Kohlrus
Republic Transmission	Diwakar Tewari Joshua York
Rochester Public Utilities	Scott Nickels
Cooperative Energy	Jason Goar
Southern Illinois Power Cooperative	Jeff Jones
Southern Indiana Gas & Electric Company (Vectren)	Larry Rogers Mark Rose
Southern Minnesota Municipal Power Agency	Patrick Egan Rick Koch
Wabash Valley Power Association	Susan Sosbe Tom Imel
Wolverine Power Supply Cooperative, Inc.	Tyler Bruning
Xcel Energy	Craig Wrisley Dylan Kohl

Appendix 2 MISO 2025 Model List

Study Cycle	Type of Model	Calendar Year	Scenario	Study Requiring Model	Profile	Year	Load Level	Topology	Gen dispatch	Wind dispatch	Solar Dispatch	MISO N/S Flow Limit
2025	Powerflow	0	2025 Summer Peak	ECON, QOL, PRA	2025SUM-MISO25	2025	SUM	TA	LBA	CapCred	CapCred	1K
2025	Powerflow	0	2025 Fall Peak	Base Model (Maintenance Margin), PRA	2025FAL-MISO25	2025	FAL	TA	LBA	28.5%	CapCred	1K
2025	Powerflow	0	2025/2026 Winter Peak	Base Model (ERAG for CSA), PRA	2025WIN-MISO25	2025/2026	WIN	TA	LBA	40%	0.0%	1K
2025	Powerflow	1	2026 Spring Peak	Base Model (Maintenance Margin), PRA	2026SPR-MISO25	2026	SPR	TA	LBA	28.5%	CapCred	1K
2025	Powerflow	1	2026 Summer Peak	Base (ERAG,GI,LOLE and CIL/CEL,MM,CSA,Mock, UFLS)	2026SUM-MISO25	2026	SUM	TA	LBA	CapCred	CapCred	1K
2025	Powerflow	1	2026 Summer Shoulder (High Wind)	SSR	2026SHHW-MISO25	2026	SH	TA	LBA	83%	10%	1K
2025	Powerflow	1	2026 Spring Light Load	ERAG	2026SLL-MISO25	2026	SLL	TA	LBA	40.0%	0%	1K
2025	Powerflow	1	2026 Fall Peak	CIL/CEL	2026FAL-MISO25	2026	FAL	TA	LBA	28.5%	CapCred	1K
2025	Powerflow	1	2026/2027 Winter Peak	ERAG, CIL/CEL	2026WIN-MISO25	2026/2027	WIN	TA	LBA	67%	0%	1K
2025	Powerflow	2	2027 Spring Peak	CIL/CEL	2027SPR-MISO25	2027	SPR	TA	LBA	28.5%	CapCred	1K
2025	Powerflow	2	2027/2028 Winter Peak	ERAG	2027WIN-MISO25	2027/2028	WIN	TA	LBA	67%	0%	1K
2025	Powerflow	2	2027 Summer Shoulder (High Wind)	SSR	2027SHHW-MISO25	2027	SH	TA	LBA	83%	10%	1K
2025	Powerflow	5	2030 Spring Minimum Load (Average Wind)	ERAG	2030SMLAW-MISO25	2030	SML	TA	LBA	27%	0%	1K
2025	Powerflow	10	2035/2036 Winter Peak	ERAG	2035WIN-MISO25	2035/2036	WIN	TA	LBA	67%	0%	1K
2025	Powerflow	1	2026 Summer Shoulder (Average Wind)	SSR	2026SHAW-MISO25	2026	SH	TA	LBA	27%	48%	2.5/3K
2025	Powerflow	2	2027 Summer Shoulder (Average Wind)	SSR	2027SHAW-MISO25	2027	SH	TA	LBA	27%	48%	2.5/3K
2025	Powerflow	10	2035 Summer Shoulder (Average Wind)	SSR	2035SH-MISO25	2035	SH	TA	LBA	27%	48%	2.5/3K
2025	Powerflow	2	2027 Spring Light Load	TPL & Project Review	2027SLL-MISO25	2027	SLL	AA	LBA	0%	0%	1K
2025	Powerflow	2	2027 Summer Peak	TPL & Project Review	2027SUM-MISO25	2027	SUM	AA	LBA	CapCred	CapCred	1K
2025	Powerflow	5	2030 Spring Light Load (High Wind)	TPL & Project Review	2030SLLHW-MISO25	2030	SLL	AA	LBA	83%	10%	1K
2025	Powerflow	5	2030 Summer Peak	TPL & Project Review	2030SUM-MISO25	2030	SUM	AA	LBA	CapCred	CapCred	1K
2025	Powerflow	5	2030 Summer Shoulder (Average Wind)	TPL & Project Review	2030SHAW-MISO25	2030	SH	AA	LBA	27%	48%	1K
2025	Powerflow	5	2030 Summer Shoulder (High Wind)	TPL & Project Review	2030SHHW-MISO25	2030	SH	AA	LBA	72%	47%	1K
2025	Powerflow	5	2030/2031 Winter Peak (North Flow for MH)	Project Review	2030WINNF-MISO25	2030/2031	WIN	AA	LBA	67%	0%	1K
2025	Powerflow	10	2035 Summer Peak	TPL & Project Review	2035SUM-MISO25	2035	SUM	AA	LBA	CapCred	CapCred	1K
2025	Powerflow	2	2027 Spring Light Load	TPL & Project Review	2027SLL-MISO25	2027	SLL	TA	LBA	0%	0%	1K
2025	Powerflow	2	2027 Summer Peak	TPL & Project Review	2027SUM-MISO25	2027	SUM	TA	LBA	CapCred	CapCred	1K
2025	Powerflow	5	2030 Spring Light Load (High Wind)	TPL & Project Review	2030SLLHW-MISO25	2030	SLL	TA	LBA	83%	10%	1K
2025	Powerflow	5	2030 Summer Peak	TPL & Project Review, LOLE, GI, SSR, CIL/CEL	2030SUM-MISO25	2030	SUM	TA	LBA	CapCred	CapCred	1K
2025	Powerflow	5	2030 Summer Shoulder	TPL & Project Review	2030SHAW-MISO25	2030	SH	TA	LBA	27%	48%	1K
2025	Powerflow	5	2030 Summer Shoulder	TPL & Project Review, GI, SSR	2030SHHW-MISO25	2030	SH	TA	LBA	72%	47%	1K
2025	Powerflow	5	2030/2031 Winter Peak (North Flow for MH)	TPL & Project Review	2030WINNF-MISO25	2030/2031	WIN	TA	LBA	67%	0%	1K
2025	Powerflow	5	2030/2031 Winter Peak (South Flow for MH)	TPL & Project Review, ERAG	2030WINSF-MISO25	2030/2031	WIN	TA	LBA	67%	0%	1K
2025	Powerflow	10	2035 Summer Peak	TPL & Project Review	2035SUM-MISO25	2035	SUM	TA	LBA	CapCred	CapCred	1K

Appendix 3

Additional Unaccepted Dynamics Models

In addition to the dynamics model types listed in the NERC Unacceptable Model List, MISO does not accept the following models:

Model Description	Siemens PSS/E	GE PSLF
Round Rotor Generator Model (IEEE Std 1110 §5.3.2 Model 2.2)	GENROU	genrou
Round Rotor Generator Model (IEEE Std 1110 §5.3.2 Model 2.2)	GENROE	--
Salient Pole Generator Model (IEEE Std 1110 §5.3.1 Model 2.1)	GENSAE	--
Third Order Generator Model	CGEN1	--
GE Frame 6, 7, and 9 Gas Turbine Model	--	gegt1
Hydro Turbine-Governor Model	HYGOV2	--
1981 IEEE Type 1 General Steam Turbine-Governor Model	IEEEG1	ieeeg1
1973 IEEE General Steam Non-Reheat	IEESGO	--
Steam Turbine-Governor Model w/ Fast Valving	TGOV2	--
1973 Modified IEEE Type 1 General Steam Turbine-Governor Model w/ Fast Valving	TGOV3	tgov3
Modified IEEE Type 1 General Steam Turbine-Governor Model w/ PLU and EVA	TGOV4	--
Modified IEEE Type 1 General Steam Turbine-Governor Model w/ Boiler Controls	TGOV5	--
WECC GP Hydro Turbine-Governor Model	WSHYGP	gpwscc

Appendix 4

Document Version History

Version	Date	Comment
1.1	2016-07-16	
1.2 DRAFT	2016-10-16	Amended to include GIC modeling practices
2.0	2017-07-21	Finalized GIC sections
2.1	2017-09-29	Updated Standard Dynamics List
2.2	2018-08-07	Updated Introduction, Generator modeling
3.0	2019-12-05	Updated Load Section Added Profiles Section Updated Short Circuit Data Requirements for TPL-007 Harmonic Analysis Distributed Energy Resource representation requirements Updated hyperlinks
3.1	2020-08-21	Distributed Energy Resource Update Transformer Modeling added Branch Modeling added Dynamic Protection Relays New Appendix 2
	2020-10-28	Update tables to reflect new wind and solar dispatch levels as approved by PSC and PAC
4.0	2021-08-13	Changed Document Name Reordered multiple sections Added Voltage Limits section Updated language in multiple sections Updated hyperlinks Updated in-document cross-reference links
4.1	2022-08-11	Wind Farms – wind-free reactive status & description Solar Farms – sun-free reactive status & description Energy Storage – dispatch update Generator Replacement Project added Tie-line Modeling Update
4.3	2023-08-09	Inclusion of Resource Planner as having data requirements MOD Base Case Hierarchy added Generator in-service date guidance Expideited project review file naming convention Bus Profile clarification Shunt setting guidance Solar/wind reactive power for voltage support guidance Modeling of Generators guidance provided DER Modeling guidance updated Load forecast expectations and MISO variance analysis checks added

Version	Date	Comment
4.4	2024-xx-xx	Update to Resource Planner and Transmission Owner for GIA data Storage Resource Pmax and Pmin requirements Inclusion of Interruptible Load guidance Effective date guidance updated for new generators Update to general load modeling ratios for the MISO footprint Update renewable dispatch percentages to be in line with Expansion Planning TPL Expectations

MR-15:

Company response to Staff discovery request STF-GS-1-4

Georgia Power Company
Docket Nos. 56002 & 56003
2025 Integrated Resource Plan and 2025 Demand-Side Management Application
STF-GS Data Request Set No. 1

STF-GS-1-4

Question:

Please see Table 14 (Base Case Definitions) on page 260 in Section D (Ten Year Transmission Expansion Plan) of the Volume 3 Technical Appendix.

a. Please confirm that the Company assumes that battery resources are off in studies of summer peak and charging at full capacity in studies of winter peak.

b. Does this assumption potentially overstate the need for grid upgrades by ignoring how batteries can discharge to help meet load during peak conditions?

c. Are the same battery charging and discharging assumptions also used for interconnection studies? If not, please provide the battery dispatch assumptions used for interconnection studies.

d. Please provide data showing the actual dispatch (charging and discharging) of the Company's operating batteries during summer and winter peak conditions for the last three years.

Response:

a. For Southern Company's base case models, battery resources are modeled off in summer peak. Winter peak is a little more nuanced. Batteries are expected to be discharging during winter peak and charging within four hours between peaks, which is estimated to be approximately 90% of winter peak load. Since a 90% winter peak load case does not currently exist, batteries are modeled as charging for winter in the off-the-shelf base cases.

b. No, this assumption does not overstate the need for grid upgrades. If appropriately sized and available for that purpose, a local battery could be discharged to push back on an identified constraint. In summer peak cases, modeling the battery in the off state initially allows planners to see any overloads without unintentionally creating small pockets of must-run generation, which may not be sized and/or be suitable for the purpose of alleviating transmission constraints long term. Similarly, if constraints are identified for charging at winter peak, planners can determine whether that is a scenario that requires a project.

c. No. While existing batteries will be modeled in the stated configuration in the base cases, interconnection studies consider only discharging of the battery in any transmission delivery screens. From an interconnection perspective, all necessary network upgrades required for the facility to safely and reliability interconnect to the Southern Company Transmission System are captured for the facility regardless of its charging or discharging state. A separate Transmission Service Request is required for both discharging and charging from a battery. The transmission service studies are performed, and any resulting service is offered, separately from the interconnection study process. Please refer to Southern Companies' Generator Interconnection Business Practices, Section 2.9.4. ESR Grid Charging available at, which is publicly available on OASIS.

d. Georgia Power has one battery resource currently online, Mossy Branch Battery Energy Storage System, which achieved commercial operation in October 2024. As such, actual dispatch data is only available for winter peak 2025. Please see STF-GS-1-4 Attachment TRADE SECRET for charging and discharging data for the winter peak on January 22, 2025.

PUBLIC DISCLOSURE

Table 1: Real Time Data of Mossy Branch BESS on 1/22/2025 (Winter Peak)

Date/Time	Mossy Branch (MW)	Mossy Branch (MVAR)	Southern BA Total Load (MW)
01/22/2025 00:00:00	**REDACTED**	**REDACTED**	**REDACTED**
01/22/2025 00:30:00	**REDACTED**	**REDACTED**	**REDACTED**
01/22/2025 01:00:00	**REDACTED**	**REDACTED**	**REDACTED**
01/22/2025 01:30:00	**REDACTED**	**REDACTED**	**REDACTED**
01/22/2025 02:00:00	**REDACTED**	**REDACTED**	**REDACTED**
01/22/2025 02:30:00	**REDACTED**	**REDACTED**	**REDACTED**
01/22/2025 03:00:00	**REDACTED**	**REDACTED**	**REDACTED**
01/22/2025 03:30:00	**REDACTED**	**REDACTED**	**REDACTED**
01/22/2025 04:00:00	**REDACTED**	**REDACTED**	**REDACTED**
01/22/2025 04:30:00	**REDACTED**	**REDACTED**	**REDACTED**
01/22/2025 05:00:00	**REDACTED**	**REDACTED**	**REDACTED**
01/22/2025 05:30:00	**REDACTED**	**REDACTED**	**REDACTED**
01/22/2025 06:00:00	**REDACTED**	**REDACTED**	**REDACTED**
01/22/2025 06:30:00	**REDACTED**	**REDACTED**	**REDACTED**
01/22/2025 07:00:00	**REDACTED**	**REDACTED**	**REDACTED**
01/22/2025 07:05:54	**REDACTED**	**REDACTED**	**REDACTED**
01/22/2025 07:30:00	**REDACTED**	**REDACTED**	**REDACTED**
01/22/2025 08:00:00	**REDACTED**	**REDACTED**	**REDACTED**
01/22/2025 08:30:00	**REDACTED**	**REDACTED**	**REDACTED**
01/22/2025 09:00:00	**REDACTED**	**REDACTED**	**REDACTED**
01/22/2025 09:30:00	**REDACTED**	**REDACTED**	**REDACTED**
01/22/2025 10:00:00	**REDACTED**	**REDACTED**	**REDACTED**
01/22/2025 10:30:00	**REDACTED**	**REDACTED**	**REDACTED**
01/22/2025 11:00:30	**REDACTED**	**REDACTED**	**REDACTED**
01/22/2025 11:30:00	**REDACTED**	**REDACTED**	**REDACTED**
01/22/2025 12:00:00	**REDACTED**	**REDACTED**	**REDACTED**
01/22/2025 12:30:00	**REDACTED**	**REDACTED**	**REDACTED**
01/22/2025 13:00:00	**REDACTED**	**REDACTED**	**REDACTED**
01/22/2025 13:30:00	**REDACTED**	**REDACTED**	**REDACTED**
01/22/2025 14:00:00	**REDACTED**	**REDACTED**	**REDACTED**
01/22/2025 14:30:00	**REDACTED**	**REDACTED**	**REDACTED**
01/22/2025 15:00:00	**REDACTED**	**REDACTED**	**REDACTED**
01/22/2025 15:30:00	**REDACTED**	**REDACTED**	**REDACTED**
01/22/2025 16:00:00	**REDACTED**	**REDACTED**	**REDACTED**
01/22/2025 16:30:00	**REDACTED**	**REDACTED**	**REDACTED**
01/22/2025 17:00:00	**REDACTED**	**REDACTED**	**REDACTED**
01/22/2025 17:30:00	**REDACTED**	**REDACTED**	**REDACTED**
01/22/2025 18:00:00	**REDACTED**	**REDACTED**	**REDACTED**

PUBLIC DISCLOSURE

01/22/2025 18:30:00	**REDACTED**	**REDACTED**	**REDACTED**
01/22/2025 19:00:00	**REDACTED**	**REDACTED**	**REDACTED**
01/22/2025 19:30:00	**REDACTED**	**REDACTED**	**REDACTED**
01/22/2025 20:00:00	**REDACTED**	**REDACTED**	**REDACTED**
01/22/2025 20:30:00	**REDACTED**	**REDACTED**	**REDACTED**
01/22/2025 21:00:00	**REDACTED**	**REDACTED**	**REDACTED**
01/22/2025 21:30:00	**REDACTED**	**REDACTED**	**REDACTED**
01/22/2025 22:00:00	**REDACTED**	**REDACTED**	**REDACTED**
01/22/2025 22:30:00	**REDACTED**	**REDACTED**	**REDACTED**
01/22/2025 23:00:00	**REDACTED**	**REDACTED**	**REDACTED**
01/22/2025 23:30:00	**REDACTED**	**REDACTED**	**REDACTED**

MR-16:

FERC Order 827

155 FERC ¶ 61,277
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

18 CFR Part 35

[Docket No. RM16-1-000; Order No. 827]

Reactive Power Requirements for Non-Synchronous Generation

(Issued June 16, 2016)

AGENCY: Federal Energy Regulatory Commission.

ACTION: Final rule.

SUMMARY: The Federal Energy Regulatory Commission (Commission) is eliminating the exemptions for wind generators from the requirement to provide reactive power by revising the *pro forma* Large Generator Interconnection Agreement (LGIA), Appendix G to the *pro forma* LGIA, and the *pro forma* Small Generator Interconnection Agreement (SGIA). As a result, all newly interconnecting non-synchronous generators will be required to provide reactive power at the high-side of the generator substation as a condition of interconnection as set forth in their LGIA or SGIA as of the effective date of this Final Rule.

EFFECTIVE DATE: This Final Rule will become effective **[Insert date 90 days after publication in the FEDERAL REGISTER]**.

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SUPPLEMENTARY INFORMATION:

155 FERC ¶ 61,277
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Reactive Power Requirements for Non-Synchronous Generation — Docket No. RM16-1-000

ORDER NO. 827

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UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Reactive Power Requirements for Non-Synchronous Generation | Docket No. RM16-1-000

ORDER NO. 827

FINAL RULE

(Issued June 16, 2016)

1. The Federal Energy Regulatory Commission (Commission) is eliminating the exemptions for wind generators from the requirement to provide reactive power by revising the *pro forma* Large Generator Interconnection Agreement (LGIA), Appendix G to the *pro forma* LGIA, and the *pro forma* Small Generator Interconnection Agreement (SGIA). Under this Final Rule, newly interconnecting non-synchronous generators that have not yet executed a Facilities Study Agreement as of the effective date of this Final Rule will be required to provide dynamic reactive power within the range of 0.95 leading to 0.95 lagging at the high-side of the generator substation. This Final Rule revises the *pro forma* LGIA and *pro forma* SGIA to establish reactive power requirements for non-synchronous generation. Specifically, the *pro forma* LGIA will include the following (the *pro forma* SGIA will include similar language):[1]

> **Non-Synchronous Generation**. Interconnection Customer shall design the Large Generating Facility to maintain a

[1] See Section IV of this Final Rule, *Compliance and Implementation*, for the specific changes to the *pro forma* LGIA and *pro forma* SGIA.

> composite power delivery at continuous rated power output at the high-side of the generator substation at a power factor within the range of 0.95 leading to 0.95 lagging, unless the Transmission Provider has established a different power factor range that applies to all non-synchronous generators in the Control Area on a comparable basis. This power factor range standard shall be dynamic and can be met using, for example, power electronics designed to supply this level of reactive capability (taking into account any limitations due to voltage level, real power output, etc.) or fixed and switched capacitors, or a combination of the two. This requirement shall only apply to newly interconnecting non-synchronous generators that have not yet executed a Facilities Study Agreement as of the effective date of the Final Rule establishing this requirement (Order No. 827).

2. Section 35.28(f)(1) of the Commission's regulations requires every public utility with an open access transmission tariff (OATT) on file to also have on file the *pro forma* LGIA and *pro forma* SGIA "required by Commission rulemaking proceedings promulgating and amending such interconnection procedures and agreements."[2] As a result of this Final Rule, all newly interconnecting non-synchronous generators will be required to provide reactive power as a condition of interconnection pursuant to the *pro forma* LGIA and *pro forma* SGIA. These reactive power requirements will apply to any new non-synchronous generator seeking to interconnect to the transmission system that has not yet executed a Facilities Study Agreement as of the effective date of this Final Rule.

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[2] 18 C.F.R. § 35.28(f)(1) (2015).

3. The existing *pro forma* LGIA and *pro forma* SGIA both require, as a condition of interconnection, an interconnecting generator to design its Generating Facility[3] "to maintain a composite power delivery at continuous rated power output at the Point of Interconnection at a power factor[4] within the range of 0.95 leading to 0.95 lagging"[5] (the reactive power requirement).

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[3] The *pro forma* LGIA defines "Generating Facility" as an "Interconnection Customer's device for the production of electricity identified in the Interconnection Request," excluding the Interconnection Customer's Interconnection Facilities. The *pro forma* LGIA further defines "Large Generating Facility" as a "Generating Facility having a Generating Facility Capacity of more than 20 MW." The *pro forma* SGIA defines "Small Generating Facility" as an "Interconnection Customer's device for the production and/or storage for later injection of electricity identified in the Interconnection Request," excluding the Interconnection Customer's Interconnection Facilities. For purposes of this Final Rule, unless otherwise noted, "Generating Facility" refers to both a Large Generating Facility and a Small Generating Facility.

[4] The power factor of an alternating current transmission system is the ratio of real power to apparent power. Reliable operation of a transmission system requires system operators to maintain a tight control of voltages (at all points) on the transmission system. The ability to vary the ratio of real power to apparent power (i.e., adjust the power factor) allows system operators to maintain scheduled voltages within allowed for tolerances on the transmission system and maintain the reliability of the transmission system. The Commission established a required power factor range in Order No. 2003 of 0.95 leading to 0.95 lagging, but allowed transmission providers to establish different requirements to be applied on a comparable basis. *See Standardization of Generator Interconnection Agreements and Procedures*, Order No. 2003, FERC Stats. & Regs. ¶ 31,146, at P 542 (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), *cert. denied*, 552 U.S. 1230 (2008).

[5] Section 9.6.1 of the *pro forma* LGIA and section 1.8.1 of the *pro forma* SGIA.

4. As discussed below, however, wind generators have been exempt from the general requirement to provide reactive power absent a study finding that the provision of reactive power is necessary to ensure safety or reliability. The Commission exempted wind generators from the uniform reactive power requirement because, historically, the costs to design and build a wind generator that could provide reactive power were high and could have created an obstacle to the development of wind generation.[6] Due to technological advancements, the cost of providing reactive power no longer presents an obstacle to the development of wind generation.[7] The resulting decline in the cost to wind generators of providing reactive power renders the current absolute exemptions unjust, unreasonable, and unduly discriminatory and preferential. Further, the growing penetration of wind generators on some systems increases the potential for a deficiency in reactive power.[8]

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[6] *Interconnection for Wind Energy*, Order No. 661, FERC Stats. & Regs. ¶ 31,186, at P 51, *order on reh'g*, Order No. 661-A, FERC Stats. & Regs. ¶ 31,198 (2005).

[7] *See, e.g.*, *Payment for Reactive Power*, Commission Staff Report, Docket No. AD14-7, app. 2, at 1-3 (Apr. 22, 2014).

[8] *See, e.g.*, *PJM Interconnection, L.L.C.*, 151 FERC ¶ 61,097, at P 7 (2015); CAISO Comments at 2-3 (explaining that, in 2014, CAISO had over 11,000 MW of interconnected variable energy resources, the majority of which are non-synchronous generators, but expects to have over 20,000 MW of such resources interconnected by 2024).

5. Given these changes, the Commission finds under section 206 of the Federal Power Act (FPA)[9] that wind generators should not have an exemption from the reactive power requirement which is unavailable to other generators. While we find that requiring non-synchronous generators to provide dynamic reactive power is now reasonable, we recognize that distinctions between non-synchronous and synchronous generators still exist and that these differences justify requiring non-synchronous generators to provide dynamic reactive power at a different location than synchronous generators: non-synchronous generators will be required to provide dynamic reactive power at the high-side of the generator substation, as opposed to the Point of Interconnection. The reactive power requirements we adopt here for newly interconnecting non-synchronous generators provide just and reasonable terms, which recognize the technical differences of non-synchronous generators from synchronous generators. These requirements also benefit customers by ensuring that reliability is protected without adding unnecessary obstacles to further development of non-synchronous generators.

I. Background

6. Transmission providers require reactive power to control system voltage for efficient and reliable operation of an alternating current transmission system. At times, transmission providers need generators to either supply or consume reactive power.

[9] 16 U.S.C. § 824d-e (2012).

Starting with Order No. 888,[10] which included provisions regarding reactive power from generators as an ancillary service in Schedule 2 of the *pro forma* OATT, the Commission issued a series of orders intended to ensure that sufficient reactive power is available to maintain the reliability of the bulk power system.

7. Starting with Order No. 2003, the Commission adopted standard procedures and a standard agreement for the interconnection of Large Generating Facilities (the *pro forma* LGIA), which included the reactive power requirement.[11] Under this requirement, large generators must design their Large Generating Facilities to provide 0.95 leading to 0.95 lagging reactive power at the Point of Interconnection. Synchronous generators have met this requirement by providing dynamic reactive power at the Point of Interconnection, utilizing the inherent dynamic reactive power capability of synchronous generators. The Commission recognized in Order No. 2003-A that the *pro forma* LGIA was "designed around the needs of large synchronous generators and that generators relying on newer technologies may find that either a specific requirement is inapplicable or that it calls for a slightly different approach" because such generators "may have

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[10] *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, FERC Stats. & Regs. ¶ 31,036 (1996), *order on reh'g*, Order No. 888-A, FERC Stats. & Regs. ¶ 31,048, *order on reh'g*, Order No. 888-B, 81 FERC ¶ 61,248 (1997), *order on reh'g*, Order No. 888-C, 82 FERC ¶ 61,046 (1998), *aff'd in relevant part sub nom. Transmission Access Policy Study Group v. FERC*, 225 F.3d 667 (D.C. Cir. 2000), *aff'd sub nom. New York v. FERC*, 535 U.S. 1 (2002).

[11] Order No. 2003, FERC Stats. & Regs. ¶ 31,146 at PP 1, 542.

unique electrical characteristics."[12] Therefore, the Commission exempted wind generators from this reactive power requirement.[13]

8. In June 2005, the Commission issued Order No. 661,[14] establishing interconnection requirements in Appendix G to the *pro forma* LGIA for large wind generators.[15] Recognizing that, unlike traditional synchronous generators, wind generators had to "install costly equipment" to maintain reactive power capability, the Commission in Order No. 661 preserved the exemption for large wind generators from the reactive power requirement unless the transmission provider shows, through a System Impact Study, that reactive power capability is required to ensure safety or reliability.[16] The Commission explained that this qualified exemption from the reactive power

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[12] Order No. 2003-A, FERC Stats. & Regs. ¶ 31,160 at P 407 & n.85.

[13] *Id.* Article 9.6.1 of the *pro forma* LGIA provides: "Interconnection Customer shall design the Large Generating Facility to maintain a composite power delivery at continuous rated power output at the Point of Interconnection at a power factor within the range of 0.95 leading to 0.95 lagging, unless Transmission Provider has established different requirements that apply to all generators in the Control Area on a comparable basis. The requirements of this paragraph shall not apply to wind generators."

[14] *Interconnection for Wind Energy*, Order No. 661, FERC Stats. & Regs. ¶ 31,186, Appendix B (Appendix G – Interconnection Requirements for a Wind Generating Plant), *order on reh'g*, Order No. 661-A, FERC Stats. & Regs. ¶ 31,198 (2005).

[15] *Id*. P 1.

[16] *Id.* PP 50-51. Appendix G states: "A wind generating plant shall maintain a power factor within the range of 0.95 leading to 0.95 lagging, measured at the Point of Interconnection as defined in this LGIA, if the Transmission Provider's System Impact Study shows that such a requirement is necessary to ensure safety or reliability."

requirement for large wind generators would provide certainty to the industry and "remove unnecessary obstacles to the increased growth of wind generation."[17]

9. In May 2005, the Commission issued Order No. 2006,[18] in which it adopted standard procedures and a standard agreement for the interconnection of Small Generating Facilities (*pro forma* SGIA).[19] In Order No. 2006, the Commission completely exempted small wind generators from the reactive power requirement.[20] The Commission reasoned that, similar to large wind generators, small wind generators would face increased costs to provide reactive power that could create an obstacle to the development of small wind generators. Additionally, the Commission reasoned that small wind generators would "have minimal impact on the Transmission Provider's

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[17] *Id.* P 50.

[18] *Standardization of Small Generator Interconnection Agreements and Procedures*, Order No. 2006, FERC Stats. & Regs. ¶ 31,180, Attachment F (Small Generator Interconnection Agreement), *order on reh'g*, Order No. 2006-A, FERC Stats. & Regs. ¶ 31,196 (2005), *order granting clarification*, Order No. 2006-B, FERC Stats. & Regs. ¶ 31,221 (2006).

[19] *Id*. P 1.

[20] *Id.* P 387. Section 1.8.1 of the *pro forma* SGIA states: "The Interconnection Customer shall design its Small Generating Facility to maintain a composite power delivery at continuous rated power output at the Point of Interconnection at a power factor within the range of 0.95 leading to 0.95 lagging, unless the Transmission Provider has established different requirements that apply to all similarly situated generators in the control area on a comparable basis. The requirements of this paragraph shall not apply to wind generators."

electric system" and therefore the reliability requirements for large wind generators that were eventually imposed in Order No. 661 were not needed for small wind generators.[21]

10. Since the Commission provided these exemptions from the reactive power requirement for wind generators, the equipment needed for a wind generator to provide reactive power has become more commercially available and less costly, such that the cost of installing equipment that is capable of providing reactive power is comparable to the costs of a traditional generator.[22] Recognizing these factors, the Commission recently accepted a proposal by PJM Interconnection, L.L.C. (PJM), effectively removing the wind generator exemptions from the PJM tariff.[23] Specifically, the Commission granted PJM an "independent entity variation" from Order No. 661 in accepting PJM's proposal to require interconnection customers seeking to interconnect non-synchronous generators,[24] including wind generators, to use "enhanced inverters" with the capability to provide reactive power.[25] The Commission observed that, "[a]lthough there are still

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[21] *Id.* P 24.

[22] *See, e.g.*, *Payment for Reactive Power*, Commission Staff Report, Docket No. AD14-7, app. 1, at 6, app. 2, at 4-5 (Apr. 22, 2014).

[23] *PJM Interconnection, L.L.C.*, 151 FERC ¶ 61,097 at P 28.

[24] Non-synchronous generators are "connected to the bulk power system through power electronics, but do not produce power at system frequency (60 Hz)." They "do not operate in the same way as traditional generators and respond differently to network disturbances." *Id.* P 1 n.3 (citing Order No. 661, FERC Stats. & Regs. ¶ 31,198 at P 3 n.4). Wind and solar photovoltaic generators are two examples of non-synchronous generators.

[25] *Id.* PP 1, 6.

technical differences between non-synchronous generators [such as wind generators] and traditional generators, with regard to the provision of reactive power, those differences have significantly diminished since the Commission issued Order No. 661."[26] The Commission agreed with PJM "that the technology has changed both in availability and in cost since the Commission rejected [the California Independent System Operator's] proposal in 2010," such that "PJM's proposal will not present a barrier to non-synchronous resources."[27]

II. <u>Need for Reform</u>

11. Based upon this information, on November 19, 2016, the Commission issued a Proposal to Revise Standard Generator Interconnection Agreements (NOPR) that proposed to eliminate the exemptions for wind generators from the requirement to provide reactive power as contained in the *pro forma* LGIA, Appendix G to the *pro forma* LGIA, and the *pro forma* SGIA.[28] In the NOPR, the Commission sought comment on: whether to remove the exemptions for wind generators from the reactive power requirement; whether the current power factor range of 0.95 leading to 0.95 lagging, as set forth in the existing *pro forma* LGIA and *pro forma* SGIA, is reasonable given the technology used by non-synchronous generators; whether newly

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[26] *Id.* P 28.

[27] *Id.*

[28] *Reactive Power Requirements for Non-Synchronous Generation*, Notice of Proposed Rulemaking, 80 Fed Reg. 73,683 (Nov. 25, 2015), FERC Stats. & Regs. ¶ 32,712 (2015).

interconnecting non-synchronous generators should only be required to produce reactive power when the generator's real power output is greater than 10 percent of nameplate capacity; and whether the existing methods used to determine reactive power compensation are appropriate for wind generators and, if not, what alternatives would be appropriate.[29]

12. In response to the NOPR, 24 entities submitted comments,[30] most of which generally support the proposed elimination of the exemptions. However, some commenters seek clarification of various issues that fall into six broad categories: (1) comments regarding where the reactive power requirement should be measured (the Point of Interconnection, the generator terminals, or elsewhere); (2) comments contesting the proposal to require fully dynamic reactive power capability; (3) comments contesting the proposal to require non-synchronous generators to maintain the required power factor range only when the generator's real power output exceeds 10 percent of its nameplate capacity; (4) comments on compensation methods for reactive power; (5) comments seeking clarification as to which non-synchronous resources the Final Rule will apply; and (6) comments on the need for regional flexibility.

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[29] *Id.* P 18.

[30] *See* Appendix A for a list of entities that submitted comments and the shortened names used throughout this Final Rule to describe those entities.

III. Discussion

13. The Commission finds that, given the changes to the cost of providing reactive power by non-synchronous generators, as well as the growing penetration of such generators, the reactive power requirements in the *pro forma* LGIA and *pro forma* SGIA are no longer just and reasonable and are unduly discriminatory and preferential and, thus, need to be revised. We have determined in this Final Rule to apply comparable reactive power requirements to non-synchronous generators and synchronous generators. We recognize technological differences between non-synchronous and synchronous generators still remain. Because of the configuration and means of producing power of synchronous generators, these generators provide dynamic reactive power at the Point of Interconnection. Many commenters point out, however, that the advancements in technology do not permit some non-synchronous generators to provide dynamic reactive power at reasonable cost at the Point of Interconnection. Recognizing the differences between the two categories of generation, we have determined to require non-synchronous generators to provide dynamic reactive power at the high-side of the generator substation.[31]

[31] This measurement point is different from Order No. 2003 requirement, which measures the power factor at the Point of Interconnection. As an example, the generator substation would be the substation for a wind generator that separates the low-voltage collector system from the higher voltage elements of the Interconnection Customer Interconnection Facilities that bring the generator's energy to the Point of Interconnection. Both the *pro forma* Large Generator Interconnection Procedures and the *pro forma* Small Generator Interconnection Procedures require interconnecting

(continued ...)

14. The requirements adopted by this Final Rule are intended to ensure that all generators, both synchronous and non-synchronous, are treated in a not unduly discriminatory or preferential manner, as required by sections 205 and 206 of the FPA, and to ensure sufficient reactive power is available on the bulk power system as more non-synchronous generators seek to interconnect and more synchronous generators retire.

15. We discuss below the issues raised in the comments.

A. Reactive Power Requirement for Non-Synchronous Generators

1. NOPR Proposal

16. In the NOPR, the Commission proposed to eliminate the exemptions for wind generators from the reactive power requirement, and thereby to require that all newly interconnecting non-synchronous generators provide reactive power as a condition of interconnection.[32]

2. Comments

17. Most commenters agree that the current exemptions for wind generators from the reactive power requirement are unjust, unreasonable, and unduly discriminatory and preferential due to increases in the number and size of non-synchronous generators, and

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generators to provide a simplified one-line diagram of the plant and station facilities, which will be appended to the interconnection agreement.

[32] NOPR, FERC Stats. & Regs. ¶ 32,712 at P 12.

advances in non-synchronous generator technology.[33] Commenters contend that operation and planning of the bulk power system requires adequate levels of voltage support, and that exempting wind generators from the reactive power requirement may inhibit the proper operation of the bulk power system.[34] Specifically, commenters assert that non-synchronous generators are increasingly replacing synchronous generators, which is resulting in a decrease in the amount of dynamic reactive power available to the transmission system.[35] Commenters also contend that the inverters used by most non-synchronous generators today are manufactured with the inherent capability to produce reactive power.[36] Therefore, commenters generally support the Commission's proposal to create comparable reactive power requirements for non-synchronous and synchronous generators.[37] While the Public Interest Organizations support the removal of the

[33] EEI Comments at 5; Indicated NYTOs Comments at 2-3; ISO/RTO Council Comments at 4; ISO-NE Comments at 9-10; MISO Comments at 2.

[34] CAISO Comments at 2-5; ISO/RTO Council Comments at 5; ISO-NE Comments at 9; NERC Comments at 5-6; Six Cities Comments at 3-4.

[35] CAISO Comments at 2-3; EEI Comments at 4-5; ITC Comments at 1-2; SCE Comments at 2; SDG&E Comments at 2.

[36] CAISO Comments at 3; ISO/RTO Council Comments at 5; MISO Comments at 2-3; NaturEner Comments at 2; NERC Comments at 9; SCE Comments at 2.

[37] CAISO Comments at 3; EEI Comments at 6-7; EPSA Comments at 3; Idaho Power Comments at 1; Indicated NYTOs Comments at 2; ISO/RTO Council Comments at 4; ISO-NE Comments at 7-8; ITC Comments at 1; Lincoln Comments at 1-2; MISO Comments at 1-2; NEPOOL Initial Comments at 6; SCE Comments at 2; SDG&E Comments at 3.

exemptions for wind generators from the reactive power requirement, they ask that the Commission not impose unduly burdensome requirements on non-synchronous generators.[38]

18. Commenters argue that it is more effective to have a standard reactive power requirement for wind generators than requiring transmission providers to show through a System Impact Study the need for reactive power from an interconnecting wind generator on a case-by-case basis because a System Impact Study may not reflect the future needs of the transmission system.[39] CAISO explains that deficiencies in reactive power support may only become apparent when there are high levels of variable energy resources and low demand, or when certain transmission infrastructure or synchronous generators are out of service.[40] Because System Impact Studies do not study all conditions, CAISO contends they may not capture these deficiencies before a wind generator interconnects to the transmission system.[41] Therefore, CAISO, as well as the ISO/RTO Council, assert that transmission providers may need to remedy deficiencies in reactive power support

[38] Public Interest Organizations Comments at 1.

[39] CAISO Comments at 4-5; EEI Comments at 5-6; ISO/RTO Council Comments at 5; ISO-NE Comments at 2.

[40] CAISO Comments at 4.

[41] *Id.*

that were not identified through a System Impact Study through authorization and development of transmission infrastructure upgrades.[42]

19. Commenters argue that relying on transmission system upgrades after a wind generator interconnects, or relying on more recently interconnected generation resources, to meet reactive power deficiencies may shift the cost of providing reactive power from one interconnection customer to another. Specifically, if a System Impact Study does not show that an earlier interconnecting wind generator needs to provide reactive power, but, as a result of the combination of existing and new wind generators, a System Impact Study for a later interconnecting wind generator does make that showing, the newer interconnecting wind generator would have the entire burden of supplying reactive power instead of sharing equally with the other wind generators creating the need for reactive power.[43] Further, commenters assert that requiring transmission providers to show through a System Impact Study the need for reactive power from interconnecting wind generators leads to delays and increased costs in processing interconnection requests.[44] Commenters argue that a uniform reactive power requirement for non-synchronous generators may result in reduced costs for wind development by allowing standardization

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[42] CAISO Comments at 4; ISO/RTO Council Comments at 5.

[43] ISO/RTO Council Comments at 5; Union of Concerned Scientists Comments at 4-5.

[44] ISO-NE Comments at 2, 4, 10; NEPOOL Initial Comments at 5.

of components and equipment.[45] Additionally, ISO-NE argues that the difficulty in demonstrating a need for reactive power through a System Impact Study has resulted in some wind generators not being required to install reactive power equipment and, consequently, not being able to deliver real power during certain system conditions as a result of insufficient reactive power capability.[46] According to ISO-NE, this situation has resulted in transmission system operators needing to curtail wind generators as a result of unstudied real-time system characteristics.[47]

20. Several independent system operators (ISOs) and regional transmission organizations (RTOs) have been developing new reactive power requirements and procedures to address deficiencies in the current method of requiring transmission providers to show through a System Impact Study that reactive power from an interconnecting wind generator is necessary to ensure safety or reliability.[48]

3. Commission Determination

21. Based on the comments filed in response to the NOPR, and the record in the PJM and ISO-NE proceedings accepting PJM's and ISO-NE's reactive power requirements for

[45] Indicated NYTOs Comments at 2; Joint NYTOs Comments at 2.

[46] ISO-NE Comments at 5.

[47] *Id*. at 6.

[48] CAISO Comments at 1-2; ISO-NE Comments at 6; NEPOOL Initial Comments at 4.

non-synchronous generators,[49] the Commission adopts in this Final Rule reactive power requirements for newly interconnecting non-synchronous generators, as discussed in greater detail below. We find the continued exemptions from the reactive power requirement in the *pro forma* LGIA and the *pro forma* SGIA for newly interconnecting wind generators to be unjust, unreasonable, and unduly discriminatory and preferential.

22. Non-synchronous generators other than wind generators currently are not exempt from the reactive power requirement in the *pro forma* LGIA and *pro forma* SGIA,[50] although the Commission has treated other types of non-synchronous generators in the same manner as wind generators on a case-by-case basis.[51] We proposed in the NOPR[52]

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[49] On April 15, 2016, after issuing the NOPR and receiving comments, the Commission approved ISO-NE's proposal to eliminate the exemptions for wind generators from the reactive power requirement. *ISO New England Inc.*, 155 FERC ¶ 61,031 (2016). The Commission previously accepted PJM's similar proposal. *See PJM Interconnection, L.L.C.*, 151 FERC ¶ 61,097 (2015).

[50] Order Nos. 2003, 661, and 2006 explicitly exempted only wind generators from the reactive power requirement. *See* Order No. 661, FERC Stats. & Regs. ¶ 31,186 at P 106 ("While we are not applying the Final Rule Appendix G to non-wind technologies, we may do this in the future, or take other generic or case-specific actions, if another technology emerges for which a different set of interconnection requirements is necessary.").

[51] *See Nevada Power Co.*, 130 FERC ¶ 61,147, at P 27 (2010) ("[C]onsistent with our requirements for all wind facilities in Order No. 661, the Commission will require based on the facts of this case, that, before Nevada Power may require El Dorado's solar facility to be capable of providing reactive power, Nevada Power must show, through a system impact study, that such a requirement is necessary to ensure the safety or reliability of the grid."); *id.* P 24 ("We agree . . . that this is not the appropriate proceeding in which to make a generic determination on whether to extend to solar generators wind power's exemption from the requirement to provide reactive power support.").

to apply the Final Rule to all *non-synchronous* generators, and received no adverse comments. This Final Rule will apply to all newly interconnecting non-synchronous generators that have not yet executed a Facilities Study Agreement as of the effective date of this Final Rule.

23. Older wind turbine generators consumed reactive power, but, because they did not use inverters like other non-synchronous generators, they lacked the capability to produce and control reactive power without the use of costly equipment.[53] Based on technological improvements since the Commission created the exemptions for wind generators, requiring newly interconnecting wind generators to provide reactive power is not the obstacle to the development of wind generation that it was when the Commission issued Order Nos. 2003, 661, and 2006.[54] In particular, the wind turbines being installed today are generally Type III and Type IV inverter-based turbines,[55] which are capable of producing and controlling dynamic reactive power, which was not the case in 2005 when

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[52] *E.g.*, NOPR, FERC Stats. & Regs. ¶ 32,712 at P 17.

[53] Order No. 661, FERC Stats. & Regs. ¶ 31,186 at PP 50-51.

[54] As discussed above, in exempting wind generators from the reactive power requirement, the Commission sought to avoid creating an obstacle to the development of wind generation. For example, in Order No. 661, the Commission was concerned with "remov[ing] unnecessary obstacles to the increased growth of wind generation." *Id.* P 50.

[55] A Type III wind turbine is a non-synchronous wound-rotor generator that has a three phase AC field applied to the rotor from a partially-rated power-electronics converter. A Type IV wind turbine is an AC generator in which the stator windings are connected to the power system through a fully-rated power-electronics converter. Both Type III and Type IV wind turbines have inherent reactive power capabilities.

the Commission exempted wind generators from the reactive power requirement in Order No. 661.[56]

24. We therefore conclude that improvements in technology, and the corresponding declining costs for newly interconnecting wind generators to provide reactive power, make it unjust, unreasonable, and unduly discriminatory and preferential to exempt such non-synchronous generators from the reactive power requirement when other types of generators are not exempt. Further, requiring all newly interconnecting non-synchronous generators to design their Generating Facilities to maintain the required power factor range ensures they are subject to comparable requirements as other generators.[57]

25. The Commission also is concerned that, as the penetration of non-synchronous generators continues to grow, exempting a class of generators from providing reactive power could create reliability concerns, especially if those generators represent a substantial amount of total generation in a particular region, or if many of the resources that currently provide reactive power are retired from operation. In addition, as noted above, maintaining the exemptions for wind generators places an undue burden on synchronous generators to supply reactive power without a reasonable technological or

[56] *Id.* PP 50-51.

[57] *See*, *e.g.*, *Sw. Power Pool, Inc*., 119 FERC ¶ 61,199, at P 29 ("Providing reactive power within the [standard power factor range] is an obligation of a generator, and is as much an obligation of a generator as, for example, operating in accordance with Good Utility Practice."), *order on reh'g*, 121 FERC ¶ 61,196 (2007).

cost-based distinction between synchronous and non-synchronous generators.[58] Therefore, the Commission concludes that the continued exemptions from the reactive power requirement for newly interconnecting wind generators are unjust, unreasonable, and unduly discriminatory and preferential. For these reasons, the Commission revises the *pro forma* LGIA, Appendix G to the *pro forma* LGIA, and the *pro forma* SGIA to eliminate the exemptions for wind generators from the reactive power requirement.[59]

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[58] *See PJM Interconnection, L.L.C.*, 151 FERC ¶ 61,097 at P 7; *Payment for Reactive Power*, Commission Staff Report, Docket No. AD14-7, app. 1 (Apr. 22, 2014).

[59] The Final Rule does not revise any regulatory text. The Final Rule revises the *pro forma* LGIA and *pro forma* SGIA in accordance with section 35.28(f)(1) of the Commission's regulations, which provides: "Every public utility that is required to have on file a non-discriminatory open access transmission tariff under this section must amend such tariff by adding the standard interconnection procedures and agreement and the standard small generator interconnection procedures and agreement required by Commission rulemaking proceedings promulgating and amending such interconnection procedures and agreements, or such other interconnection procedures and agreements as may be required by Commission rulemaking proceedings promulgating and amending the standard interconnection procedures and agreement and the standard small generator interconnection procedures and agreement." 18 C.F.R. § 35.28(f)(1) (2015). *See Integration of Variable Energy Resources*, Order No. 764, FERC Stats. & Regs. ¶ 31,331, at PP 343-345 (adopting this regulatory text effective September 11, 2012), *order on reh'g and clarification*, Order No. 764-A, 141 FERC ¶ 61,232 (2012), *order on clarification and reh'g*, Order No. 764-B, 144 FERC ¶ 61,222 (2013). While not revising regulatory text, the Commission is using the process provided for rulemaking proceedings, as defined in 5 U.S.C. § 551(4)-(5) (2012).

B. Power Factor Range, Point of Measurement, and Dynamic Reactive Power Capability Requirements

1. NOPR Proposal

26. The Commission proposed in the NOPR as part of the reactive power requirements for non-synchronous generators to require all newly interconnecting non-synchronous generators to design their Generating Facilities to maintain a composite power delivery at continuous rated power output at the Point of Interconnection at a power factor within the range of 0.95 leading to 0.95 lagging.[60] Further, the Commission proposed to require that the reactive power capability installed by non-synchronous generators be dynamic.[61]

2. Comments

27. Several commenters support the Commission's proposal to measure the reactive power requirement at the Point of Interconnection.[62] Commenters note that measuring the reactive power requirement at the Point of Interconnection is consistent with the current requirement in the *pro forma* LGIA for measuring the reactive power requirement where a transmission provider's System Impact Study shows the need for reactive power from an interconnecting wind generator.[63] Midwest Energy argues that transmission

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[60] NOPR, FERC Stats. & Regs. ¶ 32,712 at P 16.

[61] *Id.* P 14.

[62] CAISO Comments at 6; EEI Comments at 8; Indicated NYTOs Comments at 4; Midwest Energy Comments at 9; NERC Comments at 9.

[63] CAISO Comments at 6; EEI Comments at 7.

providers are only concerned with power factor and voltage at the Point of Interconnection.[64] CAISO asserts that measuring the reactive power requirement at the Point of Interconnection gives interconnection customers flexibility in how they design their generator projects to meet the reactive power requirement.[65] CAISO states that inverter manufacturers informed CAISO that current inverters used by most non-synchronous generators are capable of producing 0.95 leading and 0.95 lagging reactive power at full real power output at the generator's Point of Interconnection.[66] NextEra acknowledges that the common approach within ISOs/RTOs is to measure reactive power at the Point of Interconnection, but suggests that if reactive power is measured at the Point of Interconnection, then the Commission should maintain the flexibility for non-synchronous generators to meet that requirement using static reactive power devices if agreed to by the transmission provider, as provided for in Appendix G to the *pro forma* LGIA.[67] NaturEner asserts that, depending on the length of the collector system, transformer substation characteristics, and the length of the Interconnection Customer Interconnection Facilities from the generator terminals to the Point of Interconnection, it may not be possible for non-synchronous generators to meet the 0.95 leading to

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[64] Midwest Energy Comments at 9.

[65] CAISO Comments at 6.

[66] *Id*. at 3.

[67] NextEra Comments at 10-11.

0.95 lagging reactive power requirement at the Point of Interconnection without installing additional equipment.[68]

28. On the other hand, some commenters disagree with the NOPR proposal and argue that the reactive power requirement should be measured at the generator terminals rather than at the Point of Interconnection for non-synchronous generators. They assert that measuring at the Point of Interconnection would result in significantly higher costs for non-synchronous generators than measuring at the generator terminals. They also argue that, because of the often significant distance between non-synchronous generator terminals and the Point of Interconnection, measuring the reactive power requirement for non-synchronous generators at the generator terminals would result in a reactive power requirement that is comparable to measuring at the Point of Interconnection for synchronous generators.[69] AWEA and LSA contend that synchronous and non-synchronous generators are not similarly situated due to the fact that non-synchronous generators are typically located geographically and electrically farther from the Point of Interconnection than synchronous generators.[70] Therefore, AWEA and LSA request that non-synchronous generators have the option to meet the reactive power requirement at the generator terminals, even if the requirement at that point is more stringent

[68] NaturEner Comments at 3.

[69] AWEA and LSA Comments at 12; Joint NYTOs Comments at 3-4; Public Interest Organizations Comments at 2; Union of Concerned Scientists Comments at 3.

[70] AWEA and LSA Comments at 12.

(e.g., 0.95 leading to 0.90 lagging) than at the Point of Interconnection.[71] AWEA and LSA note that they supported the independent entity variation from Order No. 661 in PJM in part because the reactive power requirement is measured at the generator terminals.[72]

29. Some commenters argue that, due to the configuration of typical non-synchronous generators, additional investment is required to supplement the inherent dynamic reactive power capability of the generators to meet the reactive power requirement at the Point of Interconnection; therefore, they assert that requiring measurement at the Point of Interconnection would reset the costs for non-synchronous generators to a level higher than that which the Commission considered in approving PJM's independent entity variation.[73] In addition to equipment investment, AWEA and LSA contend that, in many situations, providing excess reactive power at the generator terminals to meet the reactive power requirement at the Point of Interconnection would result in a large decrease in real power output, and accompanying lost opportunity costs and lost zero-emission, zero-fuel cost energy.[74] Similarly, NaturEner argues that the proposed power factor range of 0.95 leading to 0.95 lagging is only reasonable if the reactive power requirement is measured

[71] *Id*. at 10, 12-13.

[72] *Id*. at 10-11.

[73] AWEA and LSA Comments at 10-12; NextEra Comments at 9; Union of Concerned Scientists Comments at 3-4.

[74] AWEA and LSA Comments at 11.

at the generator terminals.[75] NaturEner contends that measuring the reactive power requirement at the generator terminals will result in sufficient voltage control at the Point of Interconnection.[76] Alternatively, NaturEner also suggests that it would be reasonable to require a power factor range of 0.95 leading to 0.95 lagging at the generator substation.[77] Finally, NaturEner argues that any additional reactive power needs could be determined in a System Impact Study.[78]

30. While CAISO allows synchronous generators to provide reactive power at the generator terminals, CAISO does not support providing this option to non-synchronous generators. CAISO argues that measuring the reactive power requirement at the generator terminals is inappropriate for non-synchronous generators because non-synchronous generators often use multiple transformers, collection circuits, and substations to transmit real power across lengthy Interconnection Customer Interconnection Facilities from the generator terminal to the Point of Interconnection, reducing the amount of reactive power that reaches the transmission system. In contrast, CAISO explains that the configuration of synchronous generators typically involves a single transformer and short Interconnection Customer Interconnection Facilities from

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[75] NaturEner Comments at 3.

[76] *Id*. at 3-4.

[77] *Id*. at 3.

[78] *Id*. at 4; *see also* Midwest Energy Comments at 10.

the generator terminal to the Point of Interconnection, making measuring the reactive power requirement at the generator terminals for synchronous generators appropriate for ensuring that sufficient reactive power is provided to the transmission system.[79]

31. As to the Commission's proposal to require fully dynamic reactive power capability, commenters in support argue that requiring dynamic reactive power capability allows generators to operate across a broader range of operating conditions than allowing static reactive power devices.[80] ISO-NE asserts that requiring fully dynamic reactive power capability is consistent with the historic requirement that synchronous generators provide dynamic reactive power.[81] ISO-NE contends that generators are more effective at providing dynamic reactive power compared to transmission infrastructure.[82]

32. Conversely, other commenters disagree with the proposal to require fully dynamic reactive power capability. SDG&E contends that such a requirement is not necessary and that allowing non-synchronous generators to use static reactive power devices to meet the reactive power requirement will provide flexibility to generator developers and keep costs at a reasonable level.[83] SDG&E suggests that the dynamic reactive power

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[79] CAISO Comments at 6-7.

[80] EEI Comments at 8; ISO-NE Comments at 8.

[81] ISO-NE Comments at 8.

[82] *Id.* at 9.

[83] SDG&E Comments at 3-4.

capability requirement only be for 0.985 leading to 0.985 lagging reactive power capability.[84] Other commenters assert that the existing *pro forma* LGIA and *pro forma* SGIA neither define “dynamic” reactive power capability, nor specify a mix of static versus dynamic reactive power capability that a generator must maintain, and that the Commission should not specify such a mix in this proceeding.[85] Rather, AWEA and LSA argue that it would be discriminatory to require non-synchronous generators to maintain fully dynamic reactive power capability because their configuration results in significant loss of dynamic reactive power from the generator terminal to the Point of Interconnection. Instead, AWEA and LSA argue that static reactive power devices are necessary and effective to supplement the dynamic reactive power capability of the generator to provide reactive power at the Point of Interconnection.[86]

33. NextEra argues that if the proposed reactive power requirement is for fully dynamic reactive power capability, then measuring the requirement at the generator terminals for non-synchronous generators is required to ensure comparable treatment to synchronous generators.[87] NextEra contends that the cost of providing reactive power is manageable at the Point of Interconnection if the flexibility provided in section 9.6.1 of

[84] *Id*. at 4.

[85] AWEA and LSA Comments at 8; EEI Comments at 8; Midwest Energy Comments at 5; NextEra Comments at 6.

[86] AWEA and LSA Comments at 9; *see also* Midwest Energy Comments at 6.

[87] NextEra Comments at 9-10.

the *pro forma* LGIA is maintained and the reactive power requirement can be met with static reactive power devices, but that the requirement could be cost-prohibitive if non-synchronous generators are required to install dynamic reactive power devices.[88] Commenters request that the Commission clarify that it did not intend to specify that a non-synchronous generator must meet the reactive power requirement with only dynamic reactive power capability.[89] Specifically, NextEra argues that the Commission should not remove paragraph A.ii of Appendix G to the *pro forma* LGIA because it provides important provisions regarding the types of devices that can be used to meet the reactive power requirement.[90]

3. <u>Commission Determination</u>

34. We will require the reactive power requirements in the *pro forma* LGIA and *pro forma* SGIA for non-synchronous generators to be measured at the high-side of the generator substation. Newly interconnecting non-synchronous generators will be required to design their Generating Facilities to maintain a composite power delivery at continuous rated power output at the high-side of the generator substation. At that point, the non-synchronous generator must provide dynamic reactive power within the power factor range of 0.95 leading to 0.95 lagging, unless the transmission provider has

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[88] *Id.* at 9; NextEra Supplemental Comments at 4.

[89] AWEA and LSA Comments at 9; Midwest Energy Comments at 6; NextEra Comments at 7.

[90] NextEra Comments at 8.

established a different power factor range that applies to all non-synchronous generators in the transmission provider's control area on a comparable basis.[91] To ensure there is no undue discrimination, we clarify that the ability of a transmission provider to establish different requirements is limited to establishing a different power factor range, and not to the other reactive power requirements.

35. Non-synchronous generators may meet the dynamic reactive power requirement by utilizing a combination of the inherent dynamic reactive power capability of the inverter, dynamic reactive power devices (e.g., Static VAR Compensators), and static reactive power devices (e.g., capacitors) to make up for losses. In developing this reactive power requirement for non-synchronous generators, the Commission is balancing the costs to newly-interconnecting non-synchronous generators of providing reactive power with the benefits to the transmission system of having another source of reactive power.

36. Although the Commission in the NOPR considered measuring the reactive power requirements for non-synchronous generators at the Point of Interconnection, we are persuaded by commenters' arguments that requiring fully dynamic reactive power

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[91] Under these provisions, transmission providers may establish a different power factor range for synchronous or non-synchronous generators as long as the requirement applies to all generators in each class on a comparable basis. *See* Order No. 2003, FERC Stats. & Regs. ¶ 31,146 at P 542 ("We adopt the power factor requirement of 0.95 leading to 0.95 lagging because it is a common practice in some NERC regions. If a Transmission Provider wants to adopt a different power factor requirement, Final Rule LGIA Article 9.6.1 permits it to do so as long as the power factor requirement applies to all generators on a comparable basis.").

capability at the Point of Interconnection may result in significantly increased costs for non-synchronous generators in meeting the reactive power requirements.[92] These added costs will ultimately be borne by customers, whether through reactive power payments in regions that compensate for reactive power capability, or through elevated prices for capacity or energy in regions that do not compensate for reactive power capability. In contrast, measuring the reactive power requirements at the high-side of the generator substation, rather than at the Point of Interconnection, will be less expensive for non-synchronous generators because a greater amount of the inherent dynamic reactive power capability of the inverters associated with non-synchronous generators will be available at the high-side of the generator substation than at the Point of Interconnection.

37. In adopting the Point of Interconnection as the point of measurement for large wind plants in Order No. 661, the Commission balanced the case-by-case reactive power requirement with the needs of the transmission system.[93] Here, we remove the case-by-case approach, and require that all newly interconnecting non-synchronous generators provide reactive power as a condition of interconnection. By requiring *all* newly interconnecting non-synchronous generators to provide reactive power, we are increasing the amount of reactive power available to meet transmission system needs, and, at the

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[92] *See, e.g.*, NaturEner Comments at 3 ("Based on the above technological and cost-based reasons, NaturEner believes the +/- 0.95 requirement is reasonable if the Proposed Rule is refined to measure the requirement at the wind turbine terminals (or as an alternative at the wind farm substation), and not at the Point of Interconnection.").

[93] Order No. 661, FERC Stats. & Regs. ¶ 31,186 at P 59.

same time, balancing the costs to non-synchronous generators of providing that reactive power by measuring the requirements at the high-side of the generator substation.

38. Similarly, in Order No. 661, the Commission was not convinced that dynamic reactive power capability was needed from every wind generator, and so adopted the case-by-case approach.[94] However, with the increasing penetration of wind generation and retirement of traditional synchronous generators, which provided dynamic reactive power capability to the transmission system, we now find it is necessary to require dynamic reactive power capability from all new generators. The dynamic reactive power capability may be achieved at the high-side of the generator substation at lower cost compared to dynamic reactive power at the Point of Interconnection by systems using a combination of dynamic capability from the inverters plus static reactive power devices to make up for losses. Therefore, this Final Rule gives non-synchronous generators the flexibility to use static reactive power devices to make up for losses that occur between the inverters and the high-side of the generator substation, so long as the generators maintain 0.95 leading to 0.95 lagging dynamic reactive power capability at the high-side of the generator substation.

39. While measuring the reactive power requirements at the Point of Interconnection would provide the greatest amount of reactive power to the transmission system, the costs associated with providing that level of reactive power do not justify the added benefit to

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[94] *Id.* P 66.

the transmission system.[95] In fact, one of the reasons for undertaking this rulemaking proceeding was the Commission recognized that the cost of providing reactive power may no longer present an obstacle to the development of wind generation. On the other hand, measuring the reactive power requirements at the Generating Facilities would likely result in very little reactive power being provided to the transmission system but would be relatively inexpensive to implement for the non-synchronous generator. The high-side of the generator substation represents a middle ground. It is located beyond the low voltage collector systems where significant reactive power losses occur, resulting in more reactive power provided to the transmission system than a requirement at the Generating Facilities, while being less expensive to implement than a requirement at the Point of Interconnection. We find that measuring the reactive power requirements at the high-side of the generator substation reasonably balances the need for reactive power for the transmission system with the costs to non-synchronous generators of providing reactive power.

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[95] *See ISO New England Inc.*, Tariff Filing, Transmittal Letter, Docket No. ER16-946-000, at 17 (filed Feb. 16, 2016) ("[T]he proposed requirements provide for the reactive capability to be measured at the high-side of the station transformer rather than at the Point of Interconnection to account for the long generator leads through which many wind generators are interconnecting to the New England system – as long as approximately 50-80 miles between the generator collector transformer and the Point of Interconnection. There is no benefit to the generator, and little benefit to the system, to force the generator to provide voltage support all the way to a Point of Interconnection that is very remote, and it is not necessarily even achievable to effectively transfer such quantities of reactive power over such distances."); *see also* NextEra Supplemental Comments at 3-4.

40. We find establishing dynamic reactive power requirements at the high-side of the generator substation preferable to the suggestion in the comments that, at relative equal cost, reactive power could be provided at the Point of Interconnection as long as the inherent dynamic reactive power produced by the generator can be enhanced with static reactive power capability. By establishing dynamic reactive power requirements at the high-side of the generator substation, non-synchronous generators will be able to provide faster responding and more continuously variable reactive power capability than if they provide static reactive power capability at the Point of Interconnection. In addition, requiring dynamic reactive power capability allows generators to operate across a broader range of operating conditions than allowing static reactive power enhancements.[96]

C. Real Power Output Level

1. NOPR Proposal

41. The NOPR proposed to require newly interconnecting non-synchronous generators to design their Generating Facilities to maintain the required power factor range only when the generator's real power output exceeds 10 percent of its nameplate capacity.[97]

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[96] EEI Comments at 8; ISO-NE Comments at 8; *see also ISO New England Inc.*, Tariff Filing, Transmittal Letter, Docket No. ER16-946-000, at 19 (filed Feb. 16, 2016) ("[I]n New England's experience, the implementation of the reactive power exemption has disadvantaged wind generators seeking to interconnect, putting burdens on the study process not experienced for conventional generators and compromising their ability to operate through various system conditions once interconnected, a situation that leads system operators to curtail wind farm output for system reliability reasons.").

[97] NOPR, FERC Stats. & Regs. ¶ 32,712 at P 15 (citing Order No. 661, FERC Stats. & Regs. ¶ 31,186 at P 46).

The proposed *pro forma* LGIA would state: "Non-synchronous generators shall only be required to maintain the above power factor when their output is above 10 percent of the Generating Facility Capacity."[98] The Commission stated its understanding that the inverters used by non-synchronous generators were not capable of producing reactive power when operating below 10 percent of nameplate capacity.[99]

2. <u>Comments</u>

42. Several commenters support the 10 percent exemption given current inverter technology.[100] EEI notes that the Commission uses both "generator nameplate capacity" and "Generator Facility Capacity" in reference to the 10 percent exemption, and requests that the Commission clarify that the correct term is "Generator Facility Capacity."[101] The ISO/RTO Council states that its ISO/RTO members do not uniformly agree that the 10 percent exemption is appropriate and want to be able to establish rules based on their individual situations.[102] Similarly, the Indicated NYTOs support the Commission allowing regional variation on the 10 percent exemption within a reasonable range based

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[98] *Id.* P 16. The Commission proposed similar revisions to the *pro forma* SGIA: "Non-synchronous generators shall only be required to maintain the above power factor when their output is above 10 percent of the generator nameplate capacity." *Id.*

[99] *Id*. P 15 (citing Order No. 661, FERC Stats. & Regs. ¶ 31,186 at P 46).

[100] EEI Comments at 9; NaturEner Comments at 4; NERC Comments at 10; SCE Comments at 3; NextEra Comments at 11.

[101] EEI Comments at 9-10.

[102] ISO/RTO Council Comments at 3.

on existing regional requirements (up to an exemption for below 25 percent real power output).[103]

43. AWEA and LSA and the Joint NYTOs argue that the 10 percent exemption should be increased to 25 percent, consistent with what the Commission approved in PJM.[104] AWEA and LSA assert that the ability of non-synchronous generators to provide reactive power can be reduced when individual generators within the plant are not producing real power, such that the 10 percent operating threshold is insufficient.[105]

44. Other commenters oppose the 10 percent exemption, arguing that it is not necessary given the technology available to non-synchronous generators.[106] These commenters contend that some inverters can produce reactive power at zero real power output.[107] Additionally, ISO-NE argues that requiring non-synchronous generators to be capable of providing reactive power at all output levels will further technological development and advancement.[108] ISO-NE asserts that if the Commission adopts the 10 percent exemption, it should limit the exemption to only wind generators because non-

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[103] Indicated NYTOs Comments at 4.

[104] AWEA and LSA Comments at 13; Joint NYTOs Comments at 3.

[105] AWEA and LSA Comments at 13.

[106] ISO-NE Comments at 13; Midwest Energy Comments at 9; MISO Comments at 3.

[107] ISO-NE Comments at 14; NaturEner Comments at 4.

[108] ISO-NE Comments at 14.

synchronous generators other than wind generators have not had an exemption from the reactive power requirement and it is inappropriate to create a new exemption for these generators.[109]

45. MISO requests that non-synchronous generators be required to produce reactive power at low and zero-voltage conditions to ensure the robustness of the transmission system.[110] Similarly, Midwest Energy argues that the Commission has not fully considered the high levels of reactive power generated by lightly loaded interconnection facilities associated with non-synchronous generators.[111] Midwest Energy explains that its largest events of excess reactive power production have occurred when non-synchronous generators are producing less than 10 percent of their nameplate capacity. Midwest Energy asserts that it may be necessary for non-synchronous generators to install static inductors to absorb reactive power in these situations. Therefore, according to Midwest Energy, requiring non-synchronous generators to provide reactive power at all levels of real power output would prevent potential high voltage reliability concerns.[112]

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[109] *Id*. at 14-15.

[110] MISO Comments at 3.

[111] Midwest Energy Comments at 2-3.

[112] *Id*. at 8.

46. AWEA and LSA request clarification regarding the proposal in the NOPR that non-synchronous generators be required to maintain a "composite power delivery at continuous rated power output at the Point of Interconnection at a power factor within the range of 0.95 leading to 0.95 lagging."[113] AWEA and LSA argue that this language can be interpreted as either requiring non-synchronous generators to provide reactive power proportionate to the actual output of the generator, or to provide reactive power within the full power factor range based on the maximum output of the generator no matter the actual output of the generator.[114] AWEA and LSA contend that the first interpretation—a reactive power requirement proportionate to actual output—is the most reasonable interpretation.[115] NERC asserts that the second interpretation is correct.[116]

3. Commission Determination

47. We will not adopt the 10 percent exemption proposed in the NOPR in this Final Rule and will instead require all newly interconnecting non-synchronous generators to design their Generating Facilities to meet the reactive power requirements at all levels of

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[113] AWEA and LSA Comments at 5; NOPR, FERC Stats. & Regs. ¶ 32,712 at P 16.

[114] AWEA and LSA Comments at 5-7 (explaining that the first interpretation will result in a triangular PQ curve, while the latter will result in a rectangular PQ curve); *see also* NERC Comments at 9.

[115] AWEA and LSA Comments at 6.

[116] NERC Comments at 9.

real power output, as is already required of synchronous generators.[117] Although several commenters support the 10 percent exemption,[118] and some commenters support increasing that threshold to 25 percent,[119] we find, on balance, that requiring non-synchronous generators to provide reactive power at all levels of real power output appropriately recognizes the capabilities of existing non-synchronous generation technologies and creates requirements that are comparable to the existing requirement for synchronous generators. Additionally, by maintaining the reactive power requirement at all output levels, non-synchronous generators will mitigate potential over-voltage concerns on lightly loaded Interconnection Customer Interconnection Facilities of a non-synchronous generator when operating at low real power output.

48. While some commenters argue that technical limitations exist that prevent non-synchronous generators from providing adequate reactive power at lower levels of real power output, and note that the Commission approved a 25 percent exemption in PJM, several commenters indicate that non-synchronous generators *are* capable of providing reactive power at all levels of real power output.[120] Although the Commission approved

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[117] Section 9.6.1 of the *pro forma* LGIA and section 1.8.1 of the *pro forma* SGIA.

[118] EEI Comments at 9; NaturEner Comments at 4; NERC Comments at 10; SCE Comments at 3; NextEra Comments at 11.

[119] AWEA and LSA Comments at 13; Joint NYTOs Comments at 3.

[120] ISO-NE Comments at 13; Midwest Energy Comments at 9; MISO Comments at 3.

a 25 percent exemption in PJM, that was pursuant to a section 205 filing with broad stakeholder support. We now act on a more comprehensive record and take action generically to apply to all transmission providers.[121] Moreover, while not all non-synchronous generators are currently designed to maintain reactive power capability at all levels of real power output, modern inverters can be designed to provide this capability. We agree with ISO-NE's comments that imposing this requirement will help encourage further technological development, such that the bulk power system will ultimately receive higher quality and more reliable reactive power service from all generators.

49. As for AWEA and LSA's and NERC's requested clarifications, we clarify that the amount of reactive power required from non-synchronous generators should be proportionate to the actual output of the generator, such that a 100 MW generator would be required to provide approximately 33 MVAR of reactive power when operating at maximum output (100 MW), and approximately 3.3 MVAR when operating at 10 MW, and so on. This addresses some commenters' concerns that sometimes not all non-synchronous generators at a particular location are operating at a given time (e.g., only 50 of 100 wind turbines are actually spinning or 1/3 of solar panels are covered by clouds), without creating an unnecessary exemption for non-synchronous generators.

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[121] As discussed below, to the extent an ISO or RTO seeks to maintain an existing exemption, it can include such a request in its compliance filing as an independent entity variation and the Commission will consider the request at that time based on the arguments provided.

D. Compensation

1. NOPR Proposal

50. The Commission stated in the NOPR that non-synchronous generators are eligible for the same payments for reactive power as all other generators, consistent with the compensation provisions of the *pro forma* LGIA and *pro forma* SGIA.[122] The Commission proposed that any compensation for such non-synchronous generators would be based on the cost of providing reactive power, but noted that the cost to a wind generator of providing reactive power may not be easily estimated using existing methods that are applied to synchronous generators.[123] Therefore, the Commission sought comment on whether these existing methods are appropriate for wind generators and, if not, what alternatives would be appropriate.[124]

2. Comments

51. Several commenters support the Commission's proposal to require transmission providers to compensate non-synchronous generators for reactive power on a comparable basis as synchronous generators, provided that non-synchronous generators provide

[122] NOPR, FERC Stats. & Regs. ¶ 32,712 at P 12 (citing Order No. 2003-A, FERC Stats. & Regs. ¶ 31,160 at P 416); *see also* sections 9.6.3 and 11.6 of the *pro forma* LGIA and sections 1.8.2 and 1.8.3 of the *pro forma* SGIA.

[123] NOPR, FERC Stats. & Regs. ¶ 32,712 at P 12 (citing *Payment for Reactive Power*, Commission Staff Report, Docket No. AD14-7, app. 2 (Apr. 22, 2014)).

[124] *Id.* P 18 (citation omitted).

comparable reactive power service.[125] Other commenters seek clarification, or ask that the Commission outline principles for compensation.[126] Other commenters argue that the Commission should not mandate a uniform approach to reactive power compensation.[127] Finally, while some commenters ask that the Commission address the issue of reactive power compensation, they assert that addressing reactive power compensation in this rulemaking is outside the scope of the proceeding.[128]

3. Commission Determination

52. We will not change the Commission's existing policies on compensation for reactive power. Sections 9.6.3 and 11.6 of the currently-effective *pro forma* LGIA and sections 1.8.2 and 1.8.3 of the currently-effective *pro forma* SGIA provide that the transmission provider must compensate the interconnecting generator for reactive power service when the transmission provider requests that the interconnecting generator operate outside of the specified reactive power range. These sections also provide that if the transmission provider compensates its own or affiliated generators for reactive power

[125] CAISO Comments at 9; EEI Comments at 10; ISO/RTO Council Comments at 7; MISO Comments at 3-4.

[126] ISO/RTO Council Comments at 7; SDG&E Comments at 4-5; AWEA and LSA Comments at 2-5; Public Interest Organizations Comments at 2-3; NextEra Comments at 14.

[127] Indicated NYTOs Comments at 4; ISO/RTO Council Comments at 7; SDG&E Comments at 4; CAISO Comments at 8-9; Joint NYTOs Comments at 4; SCE Comments at 3; Six Cities Comments at 2, 5-6.

[128] EPSA Comments at 6; NextEra Comments at 14.

service within the specified reactive power range, it must compensate all generators for this service, and at what rate such compensation should be provided. While the Commission asked for comments on principles for compensating non-synchronous generators for reactive power, the comments, aside from noting that the current *AEP* methodology[129] does not translate to non-synchronous generation, did not provide a sufficient record for determining a new method. Therefore, any non-synchronous generator seeking reactive power compensation would need to propose a method for calculating that compensation as part of its filing. We note, however, that Commission staff is convening a workshop to explore reactive power compensation issues in the markets operated by ISOs/RTOs on June 30, 2016.[130]

E. Application of the Final Rule

1. NOPR Proposal

53. As a transition mechanism, the Commission proposed in the NOPR to apply the reactive power requirements in this Final Rule to all newly interconnecting non-synchronous generators that, as of the effective date of this Final Rule, either: (1) have not executed an interconnection agreement; or (2) requested that an interconnection agreement be filed unexecuted that is still pending before the Commission. The

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[129] *See Am. Elec. Power Serv. Corp.*, Opinion No. 440, 88 FERC ¶ 61,141, at 61,456-57 (1999).

[130] *See Reactive Supply Compensation in Markets Operated by Regional Transmission Organizations and Independent System Operators*, Notice of Workshop, Docket No. AD16-17-000 (issued Mar. 17, 2016).

Commission also proposed to apply the reactive power requirements to all existing non-synchronous generators making upgrades that require new interconnection requests after the effective date of the Final Rule. The Commission stated that it did not believe it would be reasonable or necessary to require all existing wind generators to provide reactive power because not all such generators are capable of providing reactive power without incurring substantial costs to install new equipment. However, the Commission proposed to require existing wind generators that make upgrades that require new interconnection requests to conform to the new reactive power requirements.[131]

2. <u>Comments</u>

54. CAISO and MISO support the Commission's proposed application of the new reactive power requirements to new and existing non-synchronous generators.[132] CAISO contends that interconnection customers should be required to adhere to the conditions of interconnection at the time they execute an interconnection agreement. CAISO states that, in its own reactive power stakeholder initiative, it proposed to apply a new reactive power requirement to its April 2016 interconnection queue cluster and to all future clusters. CAISO explains that, depending on the timing of the Final Rule, the new reactive power requirements would apply to this same group of interconnecting generators because they will not execute their interconnection agreements for at least one

[131] NOPR, FERC Stats. & Regs. ¶ 32,712 at P 17.

[132] CAISO Comments at 5-6; MISO Comments at 5-6.

year after the study process begins. CAISO states that applying reactive power requirements to these interconnecting generators would ensure these generators do not lean on existing generators to provide reactive power.[133]

55. In contrast, some commenters argue that the Commission should not apply the new reactive power requirements to generators that have begun or have already received their System Impact Study, depending on the requirements of the Final Rule.[134] AWEA and LSA contend that applying the proposed reactive power requirements to non-synchronous generators that have begun their System Impact Study, or that have been in the interconnection queue for some period of time without starting their System Impact Study, may result in sizable costs and fundamental unfairness. AWEA and LSA argue that such non-synchronous generators may not have been designed to meet the new reactive power requirements and, therefore, may incur substantial equipment costs to meet those requirements.[135]

56. NextEra argues that the proposed application of the Final Rule to non-synchronous generators that have not yet executed an interconnection agreement is unreasonable if the Commission requires fully dynamic reactive power capability measured at the Point of

[133] CAISO Comments at 5-6.

[134] AWEA and LSA Comments at 14; NextEra Comments at 13.

[135] AWEA and LSA Comments at 14-15.

Interconnection.[136] NextEra asserts that requiring fully dynamic reactive power capability at the Point of Interconnection would be a significant change to the status quo and would render some investments made by non-synchronous generators that have already received the results of their System Impact Study, but have not yet executed an interconnection agreement, useless. According to NextEra, such a major shift could also impose delays and additional costs related to the redesign, purchase, and installation of additional equipment.[137] NextEra contends that if the Commission allows for the use of static reactive power devices to supplement the dynamic reactive power capability of non-synchronous generators at the Point of Interconnection, the Commission would merely be formalizing what is already common practice, and, therefore, that the proposed application of the Final Rule would be reasonable. However, if the Commission requires fully dynamic reactive power capability at the Point of Interconnection, NextEra asks that the Final Rule not apply to non-synchronous generators that have received their System Impact Study.[138]

57. Some commenters also oppose the Commission's proposal to apply the reactive power requirements to existing non-synchronous generators making upgrades that require

[136] NextEra Comments at 11.

[137] *Id*. at 12-13.

[138] *Id*. at 12.

new interconnection requests.[139] AWEA and LSA assert that most upgrades do not involve fundamental changes to the original technology, or to the hardware, but instead simply involve software upgrades.[140] Lincoln argues that applying the new reactive power requirements to wind generators making upgrades could result in financial detriment to entities that have previously entered into binding contracts to purchase wind generation by exposing those entities to unforeseen expenses not contemplated when they entered into the contracts.[141] AWEA and LSA request that the new reactive power requirements only apply to upgrades on a case-by-case basis, depending on the outcome of the relevant interconnection study, and only to the incremental capacity requested through the upgrade.[142] AWEA and LSA also request that the Commission clarify what constitutes a "Material change" to a generator that would trigger a new interconnection study.[143]

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[139] AWEA and LSA Comments at 14; Lincoln Comments at 2.

[140] AWEA and LSA Comments at 14.

[141] Lincoln Comments at 2.

[142] AWEA and LSA Comments at 14-15.

[143] *Id*. at 15.

58. SDG&E requests that the Commission clarify that the proposed reactive power requirements would apply to *all* non-synchronous generators and not to just wind generators.[144]

3. Commission Determination

59. We will apply the requirements of this Final Rule to all newly interconnecting non-synchronous generators that have not yet executed a Facilities Study Agreement[145] as of the effective date of this Final Rule. We will not apply the requirements of this Final Rule to existing non-synchronous generators making upgrades to their Generating Facilities that require new interconnection requests. However, such a generator may be required to provide reactive power if a transmission provider determines through that generator's System Impact Study that a reactive power requirement is necessary to ensure safety or reliability. The transition mechanism we establish in this Final Rule allows non-synchronous generators currently in the process of interconnecting to complete the interconnection process without unreasonable delay or expense.

a. Newly Interconnecting Non-Synchronous Generators

60. While the Commission proposed in the NOPR to apply the requirements of the Final Rule to all newly interconnecting non-synchronous generators that have not yet

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[144] SDG&E Comments at 1, 3.

[145] The *pro forma* Large Generator Interconnection Procedures contain a standard "Interconnection Facilities Study Agreement" as Appendix 4. Similarly, the *pro forma* Small Generator Interconnection Procedures contain a standard "Facilities Study Agreement" as Attachment 8.

executed an interconnection agreement as of the effective date of the Final Rule, or requested that one be filed unexecuted that is still pending, we agree with AWEA and LSA, and NextEra,[146] that applying the Final Rule as proposed may unduly burden non-synchronous generators that have completed their System Impact Study. Such non-synchronous generators may have already purchased equipment needed to interconnect prior to executing an interconnection agreement (or requesting that one be filed unexecuted that is still pending).[147] We are especially concerned with applying new reactive power requirements to non-synchronous generators that have advanced in the interconnection process in light of our decision to measure the reactive power requirements at the high-side of the generator substation, rather than at the Point of Interconnection. Because the Point of Interconnection has been the industry standard under Appendix G to the *pro forma* LGIA, non-synchronous generators that have completed their System Impact Study may have relied on that standard in designing their Generating Facilities, thereby creating an undue burden on such generators.[148]

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[146] AWEA and LSA Comments at 14; NextEra Comments at 13.

[147] AWEA and LSA explain that many non-synchronous generators will have already chosen their collector array cable and transformer or inverter before receiving an interconnection agreement. Rather than being able to choose equipment that could reduce reactive losses, the only compliance option for non-synchronous generators that are "significantly advanced" in the interconnection process to meet the requirements of the Final Rule would be to install potentially expensive reactive power devices. AWEA and LSA Comments at 15.

[148] NextEra Comments at 12-13.

61. To avoid these undue burdens, we will apply the requirements of this Final Rule to all newly interconnecting non-synchronous generators that have not yet executed a Facilities Study Agreement as of the effective date of this Final Rule. Pursuant to the *pro forma* Large Generator Interconnection Procedures and to the *pro forma* Small Generator Interconnection Procedures, and simultaneous with the delivery of the System Impact Study, the transmission provider provides a draft Facilities Study Agreement to an interconnecting generator.[149] The executing of the Facilities Study Agreement immediately follows the completion of the System Impact Study. The execution of the Facilities Study Agreement, and the subsequent completion of the Facilities Study, represents the time in the interconnection process when the transmission provider and generator developer agree to the general technical requirements that will be needed for the generator to reliably interconnect to the transmission system.[150] This point in the

[149] Section 8.1 of the *pro forma* Large Generator Interconnection Procedures state that, simultaneous with the delivery of the System Impact Study, the transmission provider must provide the interconnection customer with an Interconnection Facilities Study Agreement. Likewise, section 3.5 of the *pro forma* Small Generator Interconnection Procedures state that a transmission provider must provide an interconnection customer a Facilities Study Agreement along with the completed System Impact Study report.

[150] Section 7.3 of the *pro forma* Large Generator Interconnection Procedures explains that the System Impact Study will "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," along with "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

(continued ...)

interconnection process is early enough in the development of a generation project such that the project developer likely has not purchased equipment to interconnect their project because they have not yet reached an agreement with the transmission provider on the interconnection requirements of the project, which occurs after the completion of the System Impact Study. In choosing to apply the reactive power requirements of this Final Rule to projects that have not executed a Facilities Study Agreement, the Commission is ensuring that a majority of newly interconnecting non-synchronous generators are subject to the requirements of this Final Rule without subjecting projects to additional costs after the interconnection requirements of the project have been established.[151] Further, as discussed in the Commission's determination in Section III.B, *Power Factor Range, Point of Measurement, and Dynamic Reactive Power Capability Requirements*, the new reactive power requirement for non-synchronous generators will be measured at the high-side of the generator substation and should not result in the increased costs of providing

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construct." Section 5.0 of the System Impact Study Agreement attached to the *pro forma* Small Generator Interconnection Procedures as Attachment 7 provides the same.

[151] *See, e.g.*, *Neptune Regional Transmission Sys., LLC v. PJM Interconnection, L.L.C.*, 110 FERC ¶ 61,098, at P 23 ("Each customer knows that subsequent cost allocations will be determined by circumstances that are known as of the time its System Impact Study is conducted. Projects may drop out of the queue and customers may move up the queue, but the cost allocation system insulates an interconnection customer from costs arising from events occurring after its System Impact Study is completed, other than costs arising from changes from higher-queued generators. . . . If an interconnection customer were to be held financially responsible for the costs of events occurring after its System Impact Study is completed it would be impossible for the customer to make reasoned business decisions."), *order on reh'g*, 111 FERC ¶ 61,455 (2005), *aff'd sub nom. Pub. Serv. Elec. and Gas Co. v. FERC*, 485 F.3d 1164 (D.C. Cir. 2007).

dynamic reactive power at the Point of Interconnection that would substantially affect the financial viability of a non-synchronous generator in the interconnection queue that AWEA and LSA raise in their comments.

62. In addition, using the execution of a Facilities Study Agreement as the point in the interconnection process for transitioning to the requirements of this Final Rule represents a clearly defined point to avoid confusion in applicability. To further ensure clarity for newly interconnecting non-synchronous generators, we include in the revisions to section 9.6.1 to the *pro forma* LGIA and section 1.8.1 to *pro forma* SGIA this transition mechanism,[152] which we require transmission providers to adopt, as part of their compliance with this Final Rule.[153]

63. We also amend Appendix G to the *pro forma* LGIA, which public utility transmission providers are required to adopt, as part of their compliance with this Final Rule. Appendix G to the *pro forma* LGIA applies only to wind generators.[154] Those newly interconnecting wind generators that have executed a Facilities Study Agreement

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[152] *See infra* P 74 (providing the amended text of section 9.6.1 to the *pro forma* LGIA and section 1.8.1 to the *pro forma* SGIA).

[153] In *West Deptford Energy, LLC v. FERC*, 766 F.3d 10, 20 (D.C. Cir. 2014), the court explained that the tariff provisions in effect at the time an interconnection agreement is executed apply to that interconnection customer, "unless the amended tariff has a grandfathering provision."

[154] *See* Order No. 661, FERC Stats. & Regs. ¶ 31,186, Appendix B (Appendix G – Interconnection Requirements for a Wind Generating Plant).

as of the effective date of this Final Rule will be subject to the amended Appendix G.[155] If Appendix G is not applicable to any newly interconnecting wind generators, the public utility transmission provider or RTO/ISO should remove Appendix G from its LGIA as part of its compliance filing. When all newly interconnecting wind generators that have executed Facilities Study Agreements as of the effective date of this Final Rule finalize their LGIAs and Appendix G is no longer necessary, we encourage the public utility transmission providers and RTOs/ISOs to file, or to include as part of, an FPA section 205 filing a proposal to remove Appendix G from their LGIA.

b. Upgrades to Existing Non-Synchronous Generators

64. Some commenters raise concerns with applying the requirements of this Final Rule to existing non-synchronous generators making upgrades that require new interconnection requests.[156] Generally, such generators would otherwise be exempt from the reactive power requirement. Lincoln argues that the proposed application of the new reactive power requirements to existing non-synchronous generators making upgrades could expose entities with existing power purchase agreements to unforeseen expenses.[157] As noted by AWEA and LSA, most upgrades that require new interconnection requests

[155] *See infra* P 74 (providing the amended text of paragraph A.ii of Appendix G to the *pro forma* LGIA).

[156] AWEA and LSA Comments at 14; Lincoln Comments at 2.

[157] Lincoln Comments at 2.

do not involve fundamental changes to the original technology, or to the hardware, but instead simply involve software upgrades.[158]

65. We recognize that there are a variety of triggering points for a new interconnection request in the various transmission provider regions, and the fact that an existing non-synchronous generator making an upgrade may not be installing new equipment. We also acknowledge, as the Commission did in the NOPR, that not all existing wind generators are capable of providing reactive power without incurring substantial costs to install new equipment.[159] Therefore, we will not apply the requirements of this Final Rule to existing non-synchronous generators making upgrades that require new interconnection requests.[160] Rather, we will maintain the existing approach in Appendix

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[158] AWEA and LSA Comments at 14.

[159] NOPR, FERC Stats. & Regs. ¶ 32,712 at P 17.

[160] Given our determination not to adopt the NOPR proposal, we find moot AWEA and LSA's request that the Commission clarify what constitutes a "Material change" to a generator that would trigger a new interconnection study. We note that, on May 13, 2016, Commission staff held a technical conference on generator interconnection issues, exploring triggers for restudies, among other things. *See Review of Generator Interconnection Agreements and Procedures*, Supplemental Notice of Technical Conference, Docket Nos. RM16-12-000, RM15-21-000 (issued May 4, 2016); *Review of Generator Interconnection Agreements and Procedures*, Notice Inviting Post-Technical Conference Comments, Docket Nos. RM16-12-000, RM15-21-000 (issued June 3, 2016) (Question 1.10: "Should interconnection procedures be more specific about what constitutes a material modification to a generator interconnection request? Is it clear to interconnection customers what types of modifications to their interconnection requests would and would not affect their place in the queue? Do transmission owners and RTO/ISOs exercise any level of discretion in determining whether a customer has made a material modification? What is the range and nature of that discretion? Please reference provisions in interconnection procedures, as applicable, in your answer.").

G to the *pro forma* LGIA for existing non-synchronous generators making upgrades to their Generating Facilities that require new interconnection requests after the effective date of this Final Rule, meaning that those upgrades will be exempt from the requirement to provide reactive power unless the transmission provider's System Impact Study shows that provision of reactive power by that generator is necessary to ensure safety or reliability.

66. We decline AWEA and LSA's request that the reactive power requirement apply only to the incremental capacity that results from an upgrade in the event the System Impact Study shows the need for reactive power.[161] If a transmission provider's System Impact Study shows the need for reactive power as a result of an upgrade, the transmission provider should have the flexibility to require reactive power capability consistent with the needs identified in the study, including the ability to apply the reactive power requirements of this Final Rule to all of the generator's capacity. Otherwise, allowing a transmission provider to apply the reactive power requirements only to the incremental capacity that results from an upgrade would undermine the Commission's goal of ensuring adequate reactive power support for the transmission system.[162] Therefore, we will give transmission providers the flexibility to apply the reactive power

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[161] AWEA and LSA Comments at 14-15.

[162] NOPR, FERC Stats. & Regs. ¶ 32,712 at P 11 (explaining the Commission's concern that the growing penetration of wind generators increases the potential for a deficiency in reactive power, and resulting local reliability issues).

requirements to all of an existing non-synchronous generator's capacity when that generator makes an upgrade that requires a new interconnection request, and the System Impact Study shows the need for reactive power.[163]

67. We require transmission providers to propose, as part of their compliance with this Final Rule, tariff revisions implementing the transition mechanism laid out above for existing non-synchronous generators making upgrades to their Generating Facilities that require new interconnection requests.

F. Regional Flexibility

68. Multiple commenters request that the Commission recognize independent entity variations for ISOs/RTOs and regional differences for transmission providers outside of ISOs/RTOs in evaluating compliance with the Final Rule.[164]

69. We apply here all three of the methods for proposing variations adopted in Order No. 2003: (1) variations based on Regional Entity reliability requirements; (2) variations that are "consistent with or superior to" the Final Rule; and (3) "independent entity

[163] As with the existing approach, should an existing non-synchronous generator disagree with the transmission provider that the System Impact Study shows a need for reactive power as a result of the upgrade, it may challenge the transmission provider's conclusion through dispute resolution or appeal to the Commission. *See* Order No. 661, FERC Stats. & Regs. ¶ 31,186 at P 51.

[164] EEI Comments at 11; Indicated NYTOs Comments at 3; ISO-NE Comments at 11-12; ISO/RTO Council Comments at 3; Joint NYTOs Comments at 3; NEPOOL Initial Comments at 6; NEPOOL Supplemental Comments at 3-4.

variations" from ISOs/RTOs.[165] If a transmission provider seeks to justify variations from the requirements of this Final Rule, it may do so in its compliance filing. A transmission provider may propose to include standards developed by NERC or a Regional Entity in its own standard interconnection agreement. The Commission is mindful of the work being done by these organizations in developing standards for the interconnection of non-synchronous generators, and we strongly encourage all interested parties to continue to participate in developing these standards.

G. <u>Miscellaneous Comments</u>

70. CAISO argues that the Commission should allow transmission providers to propose additional technical requirements for interconnecting non-synchronous generators related to voltage support, such as requiring automatic voltage control.[166] Transmission providers may propose additional technical requirements, to the extent they believe those are necessary, in a separate filing pursuant to section 205 of the FPA.

71. MATL requests clarification that the Commission will continue to accept tariff arrangements that require customers on merchant transmission lines to self-supply ancillary services. MATL specifically requests that this clarification be included in the final rule compliance obligation, and in similar future proceedings.[167] We clarify that

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[165] Order No. 2003, FERC Stats. & Regs. ¶ 31,146 at PP 824-827; *see also* Order No. 661, FERC Stats. & Regs. ¶ 31,186 at P 109.

[166] CAISO Comments at 8.

[167] MATL Comments at 5.

merchant transmission lines that have received exemptions from providing ancillary services will not be affected by this Final Rule. Therefore, those entities that do not have reactive power requirements in their Commission-approved OATTs will not need to submit a compliance filing in response to this Final Rule.

72. SCE requests that the Commission expand the scope of the rulemaking proceeding to include low voltage ride-through requirements for synchronous and non-synchronous Generating Facilities smaller than 20 MW.[168] We decline to expand the scope of the rulemaking proceeding to include low voltage ride-through requirements for synchronous and non-synchronous Generating Facilities smaller than 20 MW. We note that the Commission has issued a Notice of Proposed Rulemaking, *Requirements for Frequency and Voltage Ride Through Capability of Small Generating Facilities*, to consider these issues.[169]

73. AWEA and LSA request that the Commission limit the reactive power requirements to a specific range of voltage at the Point of Interconnection.[170] NERC also recommends that the Commission clarify the reactive power requirements by providing a

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[168] SCE Comments at 4.

[169] *See Requirements for Frequency and Voltage Ride Through Capability of Small Generating Facilities*, Notice of Proposed Rulemaking, 81 Fed. Reg. 15,481 (Mar. 23, 2016), 154 FERC ¶ 61,222 (2016).

[170] AWEA and LSA Comments at 7 (explaining the range of voltage and providing a proposed Q-V curve).

reactive capability versus voltage characteristic diagram.[171] We find the request to specify a voltage range for the reactive power requirements to be outside the scope of this proceeding. The existing *pro forma* LGIA and *pro forma* SGIA do not specify a voltage range for the reactive power requirement for synchronous generators, and the Commission does not have a sufficient record on which to create such a requirement.

IV. Compliance and Implementation

74. Section 35.28(f)(1) of the Commission's regulations requires every public utility with a non-discriminatory OATT on file to also have on file the *pro forma* LGIA and *pro forma* SGIA "required by Commission rulemaking proceedings promulgating and amending such interconnection procedures and agreements."[172] The Commission hereby revises section 9.6.1 of the *pro forma* LGIA to read:

> **9.6.1 Power Factor Design Criteria**
>
> **9.6.1.1 Synchronous Generation**. Interconnection Customer shall design the Large Generating Facility to maintain a composite power delivery at continuous rated power output at the Point of Interconnection at a power factor within the range of 0.95 leading to 0.95 lagging, unless the Transmission Provider has established different requirements that apply to all synchronous generators in the Control Area on a comparable basis. ~~The requirements of this paragraph shall not apply to wind generators.~~
>
> **9.6.1.2 Non-Synchronous Generation**. Interconnection Customer shall design the Large Generating Facility to maintain a composite power delivery at continuous rated power output at the high-side of the generator substation at a power factor within the range of 0.95 leading to 0.95 lagging, unless the Transmission Provider has established a different power

[171] NERC Comments at 9-10.

[172] 18 C.F.R. § 35.28(f)(1) (2015).

> factor range that applies to all non-synchronous generators in the Control Area on a comparable basis. This power factor range standard shall be dynamic and can be met using, for example, power electronics designed to supply this level of reactive capability (taking into account any limitations due to voltage level, real power output, etc.) or fixed and switched capacitors, or a combination of the two. This requirement shall only apply to newly interconnecting non-synchronous generators that have not yet executed a Facilities Study Agreement as of the effective date of the Final Rule establishing this requirement (Order No. 827).

The Commission similarly revises section 1.8.1 of the *pro forma* SGIA to read:

> 1.8.1 Power Factor Design Criteria
>
> 1.8.1.1 Synchronous Generation. The Interconnection Customer shall design its Small Generating Facility to maintain a composite power delivery at continuous rated power output at the Point of Interconnection at a power factor within the range of 0.95 leading to 0.95 lagging, unless the Transmission Provider has established different requirements that apply to all similarly situated synchronous generators in the control area on a comparable basis. ~~The requirements of this paragraph shall not apply to wind generators.~~
>
> 1.8.1.2 Non-Synchronous Generation. The Interconnection Customer shall design its Small Generating Facility to maintain a composite power delivery at continuous rated power output at the high-side of the generator substation at a power factor within the range of 0.95 leading to 0.95 lagging, unless the Transmission Provider has established a different power factor range that applies to all similarly situated non-synchronous generators in the control area on a comparable basis. This power factor range standard shall be dynamic and can be met using, for example, power electronics designed to supply this level of reactive capability (taking into account any limitations due to voltage level, real power output, etc.) or fixed and switched capacitors, or a combination of the two. This requirement shall only apply to newly interconnecting non-synchronous generators that have not yet executed a Facilities Study Agreement as of the effective date of the Final Rule establishing this requirement (Order No. 827).

In addition, the Commission revises paragraph A.ii of Appendix G to the *pro forma* LGIA, "Technical Standards Applicable to a Wind Generation Plant," as follows:[173]

> The following reactive power requirements apply only to a newly interconnecting wind generating plant that has executed a Facilities Study Agreement as of the effective date of the Final Rule establishing the reactive power requirements for non-synchronous generators in section 9.6.1 of this LGIA (Order No. 827). A wind generating plant to which this provision applies shall maintain a power factor within the range of 0.95 leading to 0.95 lagging, measured at the Point of Interconnection as defined in this LGIA, if the Transmission Provider's System Impact Study shows that such a requirement is necessary to ensure safety or reliability. The power factor range standard can be met by using, for example, power electronics designed to supply this level of reactive capability (taking into account any limitations due to voltage level, real power output, etc.) or fixed and switched capacitors if agreed to by the Transmission Provider, or a combination of the two. The Interconnection Customer shall not disable power factor equipment while the wind plant is in operation. Wind plants shall also be able to provide sufficient dynamic voltage support in lieu of the power system stabilizer and automatic voltage regulation at the generator excitation system if the System Impact Study shows this to be required for system safety or reliability.[174]

[173] The full text of the *pro forma* LGIA will be posted on the Commission's internet page at: http://www.ferc.gov/industries/electric/indus-act/gi/stnd-gen.asp. The full text of the *pro forma* SGIA will be posted on the Commission's internet page at: http://www.ferc.gov/industries/electric/indus-act/gi/small-gen.asp.

[174] Section A.ii of Appendix G to the *pro forma* LGIA.

75. As in Order Nos. 2003[175] and 661,[176] the Commission is requiring all public utility[177] transmission providers to adopt the requirements of this Final Rule as revisions (as discussed above) to the LGIA and SGIA in their OATTs within 90 days after the publication of this Final Rule in the Federal Register.[178] Transmission providers that are not public utilities also must adopt the requirements of this Final Rule as a condition of maintaining the status of their safe harbor tariff or otherwise satisfying the reciprocity requirement of Order No. 888.[179] As discussed above, we are not requiring changes to interconnection agreements already in effect, but are applying the requirements of this Final Rule to newly interconnecting non-synchronous generators that have not yet executed a Facilities Study Agreement. The requirements of this Final Rule also do not

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[175] Order No. 2003, FERC Stats. & Regs. ¶ 31,146 at P 910.

[176] Order No. 661, FERC Stats. & Regs. ¶ 31,186 at P 121.

[177] For purposes of this Final Rule, a public utility is a utility that owns, controls, or operates facilities used for transmitting electric energy in interstate commerce, as defined by the FPA. *See* 16 U.S.C. § 824(e) (2012). A non-public utility that seeks voluntary compliance with the reciprocity condition of an OATT may satisfy that condition by filing an OATT, which includes the *pro forma* LGIA and *pro forma* SGIA.

[178] MISO requests that the Commission extend the requirements of this Final Rule to the MISO *pro forma* Generator Interconnection Agreement and not just to the Commission's *pro forma* LGIA and *pro forma* SGIA. MISO Comments at 4-6. As stated, each public utility transmission provider subject to this Final Rule is directed to adopt the requirements of this Final Rule as revisions to the standard interconnection agreements in its OATT.

[179] Order No. 888, FERC Stats. & Regs. ¶ 31,036 at 31,760-63.

apply to existing non-synchronous generators making upgrades to their Generating Facilities that require new interconnection requests.

76. In some cases, public utility transmission providers may have provisions in the currently effective LGIAs and SGIAs in their OATTs related to the provision of reactive power by non-synchronous generators that the Commission has deemed to be consistent with or superior to the *pro forma* LGIA and *pro forma* SGIA. Where the relevant provisions of the *pro forma* LGIA and *pro forma* SGIA are modified by this Final Rule, public utility transmission providers must either comply with this Final Rule or demonstrate that their previously-approved LGIA and SGIA variations continue to be consistent with or superior to the *pro forma* LGIA and *pro forma* SGIA as modified by this Final Rule.

77. In addition, some ISOs/RTOs may have provisions in the currently effective LGIAs and SGIAs in their OATTs related to the provision of reactive power by non-synchronous generators that the Commission has accepted as an independent entity variation to the *pro forma* LGIA and *pro forma* SGIA. Where the relevant provisions of the *pro forma* LGIA and *pro forma* SGIA are modified by this Final Rule, ISOs/RTOs must either comply with this Final Rule or demonstrate that their previously-approved LGIA and SGIA variations continue to justify an independent entity variation from the *pro forma* LGIA and *pro forma* SGIA as modified by this Final Rule.

V. <u>Information Collection Statement</u>

78. The following collection of information contained in this Final Rule is subject to review by the Office of Management and Budget (OMB) regulations under section

3507(d) of the Paperwork Reduction Act of 1995.[180] OMB's regulations require approval of certain information collection requirements imposed by agency rules.[181] Upon approval of a collection of information, OMB will assign an OMB control number and expiration date. Respondents subject to the filing requirements of this Final Rule will not be penalized for failing to respond to this collection of information unless the collection of information displays a valid OMB control number.

79. The reforms adopted in this Final Rule revise the Commission's *pro forma* LGIA and *pro forma* SGIA in accordance with section 35.28(f)(1) of the Commission's regulations.[182] This Final Rule requires each public utility transmission provider to revise its *pro forma* LGIA and *pro forma* SGIA to: (1) eliminate the exemptions for wind generators from the requirement to provide reactive power; and (2) require that all newly interconnecting non-synchronous generators that have not yet executed a Facilities Study Agreement provide reactive power as a condition of interconnection as set forth in their LGIA or SGIA as of the effective date of this Final Rule. The reforms adopted in this Final Rule require filings of *pro forma* LGIAs and *pro forma* SGIAs with the Commission. The Commission anticipates the revisions required by this Final Rule, once implemented, will not significantly change currently existing burdens on an ongoing

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[180] 44 U.S.C. § 3507(d) (2012).

[181] 5 C.F.R. § 1320.11 (2015).

[182] 18 C.F.R. § 35.28(f)(1) (2015).

basis. With regard to those public utility transmission providers that believe that they already comply with the revisions adopted in this Final Rule, they can demonstrate their compliance in the filing required 90 days after the effective date of this Final Rule. The Commission will submit the proposed reporting requirements to OMB for its review and approval under section 3507(d) of the Paperwork Reduction Act.[183]

80. While the Commission expects the revisions adopted in this Final Rule will provide significant benefits, the Commission understands that implementation can be a complex and costly endeavor. The Commission solicited comments on the accuracy of provided burden and cost estimates and any suggested methods for minimizing the respondents' burdens. The Commission did not receive any comments concerning its burden or cost estimates. Therefore, the Commission retains the estimates proposed in the NOPR, with minor changes to reflect updated estimates.

Burden Estimate: The Commission believes that the burden estimates below are representative of the average burden on respondents. The estimated burden and cost for the requirements adopted in this Final Rule follow.[184]

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[183] 44 U.S.C. § 3507(d) (2012).

[184] Commission staff estimates that industry is similarly situated in terms of hourly cost (wages plus benefits). Based on the Commission's average cost (wages plus benefits) for 2015, \$72/hour is used.

FERC 516B revisions in Final Rule in RM16-1					
	No. of Respondents[185] (1)	Annual No. of Responses Per Respondent (2)	Total No. of Responses (1)*(2)=(3)	Average Burden (Hrs.) & Cost ($) Per Response (4)	Total Annual Burden Hrs. & Total Annual Cost ($) (3)*(4)=(5)
Conforming LGIA changes to incorporate revisions	132	1	132	7.5 $540	990 hours $71,280
Conforming SGIA changes to incorporate revisions	118	1	118	7.5 $540	885 hours $63,720
Total			250	15 hours $1,080	1,875 hours $135,000

Cost to Comply: The Commission has projected the total cost of compliance as follows:[186]

- Year 1: $135,000 ($1,080/utility)
- Year 2: $0

After implementation in Year 1, the revisions adopted in this Final Rule would be complete.

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[185] Number of Applicable Registered Entities.

[186] The costs for Year 1 consist of filing revisions to the *pro forma* LGIA and *pro forma* SGIA with the Commission within 90 days of the effective date of this Final Rule plus initial implementation. The Commission does not expect any ongoing costs beyond the initial compliance in Year 1.

Title: FERC-516B, Electric Rate Schedules and Tariff Filings.

Action: Revisions to an information collection.

OMB Control No.: TBD

Respondents for this Rulemaking: Businesses or other for profit and/or not-for-profit institutions.

Frequency of Information: One-time during Year 1.

Necessity of Information: The Commission adopts revisions in this Final Rule to the *pro forma* LGIA and *pro forma* SGIA to improve the reliability of the bulk power system by requiring all newly interconnecting non-synchronous generators to provide reactive power as a condition of interconnection, and to ensure that all generators are being treated in a not unduly discriminatory or preferential manner.

Internal Review: The Commission has reviewed the requirements in this Final Rule and has determined that such revisions are necessary. These requirements conform to the Commission's need for efficient information collection, communication, and management within the energy industry. The Commission has assured itself, by means of internal review, that there is specific, objective support for the burden estimates associated with the information collection requirements.

81. Interested persons may obtain information on the reporting requirements by contacting the following: Federal Energy Regulatory Commission, 888 First Street, NE, Washington, DC 20426 [Attention: Ellen Brown, Office of the Executive Director], e-mail: DataClearance@ferc.gov, phone: (202) 502-8663, fax: (202) 273-0873.

82. Comments on the collection of information and the associated burden estimates in this Final Rule should be sent to the Commission in this docket and may also be sent to the Office of Information and Regulatory Affairs, Office of Management and Budget, 725 17th Street, NW, Washington, DC 20503 [Attention: Desk Officer for the Federal Energy Regulatory Commission], at the following e-mail address: oira_submission@omb.eop.gov. Please reference the docket number of this rulemaking in your submission.

VI. Regulatory Flexibility Act Certification

83. The Regulatory Flexibility Act of 1980 (RFA)[187] generally requires a description and analysis of rules that will have significant economic impact on a substantial number of small entities. The RFA does not mandate any particular outcome in a rulemaking. It only requires consideration of alternatives that are less burdensome to small entities and an agency explanation of why alternatives were rejected.

84. The Small Business Administration (SBA) revised its size standards (effective January 22, 2014) for electric utilities from a standard based on megawatt hours to a standard based on the number of employees, including affiliates. Under SBA's standards, some transmission owners will fall under the following category and

[187] 5 U.S.C. § 601-12 (2012).

associated size threshold: electric bulk power transmission and control, at 500 employees.[188]

85. The Commission estimates that the total number of public utility transmission providers that would have to modify the LGIAs and SGIAs within their currently effective OATTs is 132. Of these, the Commission estimates that approximately 43 percent are small entities (approximately 57 entities). The Commission estimates the average total cost to each of these entities will be minimal, requiring on average 15 hours or $1,080. According to SBA guidance, the determination of significance of impact "should be seen as relative to the size of the business, the size of the competitor's business, and the impact the regulation has on larger competitors."[189] The Commission does not consider the estimated burden to be a significant economic impact. As a result, the Commission certifies that the revisions adopted in this Final Rule will not have a significant economic impact on a substantial number of small entities.

VII. Environmental Analysis

86. The Commission is required to prepare an Environmental Assessment or an Environmental Impact Statement for any action that may have a significant adverse effect

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[188] 13 C.F.R. § 121.201, Sector 22 (Utilities), NAICS code 221121 (Electric Bulk Power Transmission and Control) (2015).

[189] U.S. Small Business Administration, *A Guide for Government Agencies How to Comply with the Regulatory Flexibility Act*, at 18 (May 2012), https://www.sba.gov/sites/default/files/advocacy/rfaguide_0512_0.pdf.

on the human environment.[190] As we stated in the NOPR, the Commission concludes that neither an Environmental Assessment nor an Environmental Impact Statement is required for the revisions adopted in this Final Rule under section 380.4(a)(15) of the Commission's regulations, which provides a categorical exemption for approval of actions under sections 205 and 206 of the FPA relating to the filing of schedules containing all rates and charges for the transmission or sale of electric energy subject to the Commission's jurisdiction, plus the classification, practices, contracts and regulations that affect rates, charges, classifications, and services.[191] The revisions adopted in this Final Rule update and clarify the application of the Commission's standard interconnection requirements to non-synchronous generators. Therefore, this Final Rule falls within the categorical exemptions provided in the Commission's regulations, and as a result neither an Environmental Impact Statement nor an Environmental Assessment is required.

VIII. Document Availability

87. In addition to publishing the full text of this document in the Federal Register, the Commission provides all interested persons an opportunity to view and/or print the contents of this document via the Internet through the Commission's Home Page (http://www.ferc.gov) and in the Commission's Public Reference Room during normal

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[190] *Regulations Implementing National Environmental Policy Act of 1969*, Order No. 486, FERC Stats. & Regs. ¶ 30,783 (1987).

[191] 18 C.F.R. § 380.4(a)(15) (2015).

business hours (8:30 a.m. to 5:00 p.m. Eastern time) at 888 First Street, NE, Room 2A, Washington, DC 20426.

88. From the Commission's Home Page on the Internet, this information is available on eLibrary. The full text of this document is available on eLibrary in PDF and Microsoft Word format for viewing, printing, and/or downloading. To access this document in eLibrary, type the docket number of this document, excluding the last three digits, in the docket number field.

89. User assistance is available for eLibrary and the Commission's website during normal business hours from the Commission's Online Support at (202) 502-6652 (toll free at 1-866-208-3676) or email at ferconlinesupport@ferc.gov, or the Public Reference Room at (202) 502-8371, TTY (202) 502-8659. E-mail the Public Reference Room at public.referenceroom@ferc.gov.

IX. Effective Date and Congressional Notification

90. The Final Rule is effective [**INSERT DATE 90 days from publication in FEDERAL REGISTER**]. However, as noted above, the requirements of this Final Rule will apply only to newly interconnecting non-synchronous generators that have not yet executed a Facilities Study Agreement. The Commission has determined, with the concurrence of the Administrator of the Office of Information and Regulatory Affairs of OMB, that this Final Rule is not a "major rule" as defined in section 351 of the Small Business Regulatory Enforcement Fairness Act of 1996. This Final Rule is being submitted to the Senate, House, Government Accountability Office, and Small Business Administration.

List of subjects in 18 C.F.R. Part 35
Electric power rates; Electric utilities; Non-discriminatory open access transmission tariffs

By the Commission.

(S E A L)

Kimberly D. Bose,
Secretary.

Appendix A

List of Commenters (RM16-1-000)

AWEA and LSA	American Wind Energy Association and Large-scale Solar Association
CAISO	California Independent System Operator Corporation
EEI	Edison Electric Institute
EPSA	Electric Power Supply Association
Idaho Power	Idaho Power Company
Indicated NYTOs	Consolidated Edison Company of New York, Inc.; Niagara Mohawk Power Corporation d/b/a National Grid; and Orange and Rockland Utilities, Inc.
ISO/RTO Council	ISO/RTO Council
ISO-NE	ISO New England Inc.
ITC	International Transmission Company d/b/a ITC Transmission; Michigan Electric Transmission Company, LLC; ITC Midwest LLC; and ITC Great Plains, LLC
Joint NYTOs	New York Power Authority; New York State Electric and Gas; Rochester Gas and Electric; and Central Hudson Gas and Electric
Lincoln	City of Lincoln, Nebraska d/b/a Lincoln Electric System
MATL	MATL LLP
Midwest Energy	Midwest Energy, Inc.
MISO	Midcontinent Independent System Operator, Inc.
NaturEner	NaturEner USA, LLC and its subsidiaries
NEPOOL	New England Power Pool Participants Committee
NERC	North American Electric Reliability Corporation
NextEra	NextEra Energy, Inc.
PG&E	Pacific Gas and Electric Company
Public Interest Organizations	Center for Rural Affairs; Clean Wisconsin; Great Plains Institute; Natural Resources Defense Council; Sierra Club; Sustainable FERC Project; Western Grid Group; Wind on the Wires
SCE	Southern California Edison Company
SDG&E	San Diego Gas and Electric Company
Six Cities	Cities of Anaheim, Azusa, Banning, Colton, Pasadena, and Riverside, California
Union of Concerned Scientists	Union of Concerned Scientists