Georgia Power Company
Docket Nos. 56002 & 56003
2025 Integrated Resource Plan and 2025 Demand-Side Management Application
STF-DEA Data Request Set No. 1

STF-DEA-1-44

Question:

Referring to the Large Load Realization Model, please explain if the Company has updated any of the model assumptions since the 2023 IRP Update. If not, why not?

Response:

Since the 2023 IRP Update, the Company has updated customer information to reflect the latest available data as of Q2 2024, which was used in preparing the Budget 2025 projections that support the 2025 IRP. However, the underlying assumptions of the Load Realization Model, such as correlations, load realization percentages, and standard delays, have remained unchanged.

Contact: Francisco Valle

STATE OF GEORGIA

BEFORE THE

GEORGIA PUBLIC SERVICE COMMISSION

In Re:	)	
	)	
Georgia Power Company's 2025 Integrated Resource Plan	)	Docket No. 56002
-and-		
Georgia Power Company's 2025 2025 Application for the Certification, Decertification and Amended Demand-Side Management Plan	)	Docket No. 56003
	)	*** Volume 1 of 3 ***

Hearing in Room 110
244 Washington Street
Atlanta, Georgia

Tuesday, March 25, 2025

The Session was called to order, pursuant to Notice at 9:30 a.m.

PRESENT WERE:

JASON SHAW, Chairman
TIM ECHOLS, Vice-Chairman
FITZ JOHNSON, Commissioner
LAUREN "BUBBA" MCDONALD, Commissioner
TRICIA PRIDEMORE, Commissioner (By Zoom)

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Athens, Georgia 30601
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they move forward with it or not, they have done a lot of work. So it's not something that they just haphazardly sign. And it's driven the customer choice market and been that standard for -- for decades.

Q. But the pipeline that's being modeled here doesn't just include those committed customers; isn't that right?

A. (Witness Valle) That is correct. It's a mix of -- of committed and prospective customers.

A. (Witness Grubb) And that's no different than any load forecast we've ever had. So if you think about a load forecast ten years ago that had a projected growth, that doesn't mean that those commercial and residential customers had already located in the state. There's always that projection of load that's in the forecast.

Q. Now, in addition to adding customers to the pipeline, is -- is there a process then also for removing customers from the pipeline or the portfolio if the project status stalls out for an extended period of time?

A. (Witness Valle) Yes, yes. So the company has been very diligent in tracking all the activity. And so part of the activity is to monitor the projects that get removed from the -- from the pipeline, as well as those that have been added to the pipeline.

So for the year 2024 for the fourth quarter

quarterly reports, we've been tracking really well in terms of the projects removed. So for every project that has been removed, over two customers have been added to the pipeline.

For every megawatt that has been removed, 3 megawatts have been added to the pipeline. And that's why, if you look at the size of the pipeline over time, it continues to grow. So we have cancellations, but we also have additions that more than offset any -- any cancellations so far. Excuse me.

CHAIRMAN SHAW: And I think Commissioner Pridemore has a question, too. Yeah.

COMMISSIONER PRIDEMORE: Thank you. Is my audio working?

CHAIRMAN SHAW: Yes.

MR. VALLE: Yes.

COMMISSIONER PRIDEMORE: Okay. So for the purposes of the record, and my question is for Mr. Robinson. So we hear and, of course, read a lot of stories about the grid nationally and the need to build out transmission. And I know that Georgia has this licked and is doing it better than anyone else, in my opinion. And we're able to get projects on faster, we're able to build transmission that's not redundant. It's safe,

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-2-10

Question:

Please refer to Table 2, p. 7-20 of the "2024 GA ITS Ten-Year Plan" within "2025 IRP Volume 3 TRADE SECRET".

a. Please provide an identical table of projects that were first identified in the 2024 ten-year planning process and not identified in any prior years.

b. Please provide a similar table of projects identified in the 2025 IRP that are not included in the 10 Year Plan Projects.

c. Please identify all projects that include non-wire alternatives (NWAs) and grid-enhancing technologies (GETs) as part of their scope.

d. Are there any projects not identified where NWAs or GETs were considered as a solution, but not ultimately selected? If so, please identify these projects, which technologies were considered, and why these technologies were not selected as part of the final project scope.

Response:

a. Please refer to Section 4, Analysis Results of the 2024 GA ITS Ten-Year Plan (Section D1 of Technical Appendix Volume 3), which identifies changes from previous Ten-Year Plan for all 2024 Ten Year Plan projects.

b. All transmission projects identified in the 2025 IRP are listed in Section D1 (2024 GA ITS Ten-Year Plan) and Section F (GPC Distribution Substation Projects & Forecast) of Technical Appendix Volume 3.

c. Please refer to STF-DEA-2-10 Attachment.

d. For specific details on Alternative Solutions, please refer to Sections H1A and H1B of Technical Appendix Volume 3. Rebuild/reconductors were selected for the projects listed below due to Power Flow Controllers limiting or increasing system flows on a line rather than increasing capacity. Power flow controllers are leveraged as a bridge to long-term solutions to address thermal constraints.

Contact: Mike Robinson

TEAMS Number	Project Name	Sections H1A and H1B Report Title	Sections H1A and H1B Page Number	NWAs/ GETs Considered as Alternatives
20764	Atkinson – Northside Drive 115kV Rebuild	ATKINSON – NORTHSIDE DRIVE 115KV	1-2	Power Flow Controllers
20761	Atkinson – Northwest 115kV Rebuild	ATKINSON – NORTHWEST 115KV	2	Power Flow Controllers
18960	Blankets Ck-Woodstock 115kV line Rebuild (Woodstk-Little Rvr)	BLANKETS CREEK – WOODSTOCK 115KV	3-4	Power Flow Controllers
20506	GTC: Switch Way – Thornton Road 230kV Line Reconductor	SWITCH WAY – THORNTON ROAD 230KV	6	Power Flow Controllers
20024	Dyer Road – East Roanoke 115kV Rebuild	DYER ROAD - EAST ROANOKE (APC) 115 KV	13-14	Power Flow Controllers
10222	Blakely Primary – Huckleberry 115kV Rebuild	BLAKELY PRIMARY - HUCKLEBERRY 115KV	64-65	Power Flow Controllers
20285	Lower River – Webb (APC) 115kV Reconductor	LOWER RIVER ROAD - WEBB (APC) 115 KV	69-70	Power Flow Controllers

Contact: Mike Robinson

Table 1: 2024 TYP Projects with Non-Wire Alternatives or Grid Enhancing Technologies

TEAMS Number	Project Name	NWAs or GETs
20466	EATONTON PRIMARY SMART VALVE INSTALLATION	Power Flow Controllers
20326	ANTHONY SHOALS STATCOM SYSTEM	STATCOM
21069	SMART VALVES AT EAST VILLA RICA SWITCHING STATION	Power Flow Controllers
20067	SAV: DEPTFORD - MAGNOLIA 115KV RECONDUCTOR	Advanced Conductor
20066	SAV: BOULEVARD - DEPTFORD 115KV RECONDUCTOR	Advanced Conductor
19676	ADAMSVILLE - JACK MCDONOUGH 230KV LINE REBUILD	Advanced Conductor
18889	JEFFERSON STREET#3 - NORTHWEST (WHITE) 115 KV RECONDUCTOR	Advanced Conductor
20152	CC - CASS PINE- HILL VIEW 230 KV LINE- CC IMPROVEMENTS	Advanced Conductor
20018	CC - QTS FAYETTEVILLE TRANSMISSION NEEDS	Advanced Conductor
19597	ADAMSVILLE - BUZZARD ROOST 230KV REBUILD AND JUMPER UPGRADE	Advanced Conductor
18960	BLANKETS CREEK – WOODSTOCK 115KV LINE REBUILD	Advanced Conductor
20216	CC - STONEWALL TELL ROAD (TA REALTY) (GPC OWNED)	Advanced Conductor
18679	DU: EAST DALTON - OOSTANAULA 115KV REBUILD	Advanced Conductor
19618	GORDON-N DUBLIN 115KV (GORDON-ENGL MCI J) REBUILD	Advanced Conductor
21139	GRADY - MORROW (WHITE) 115KV REBUILD	Advanced Conductor

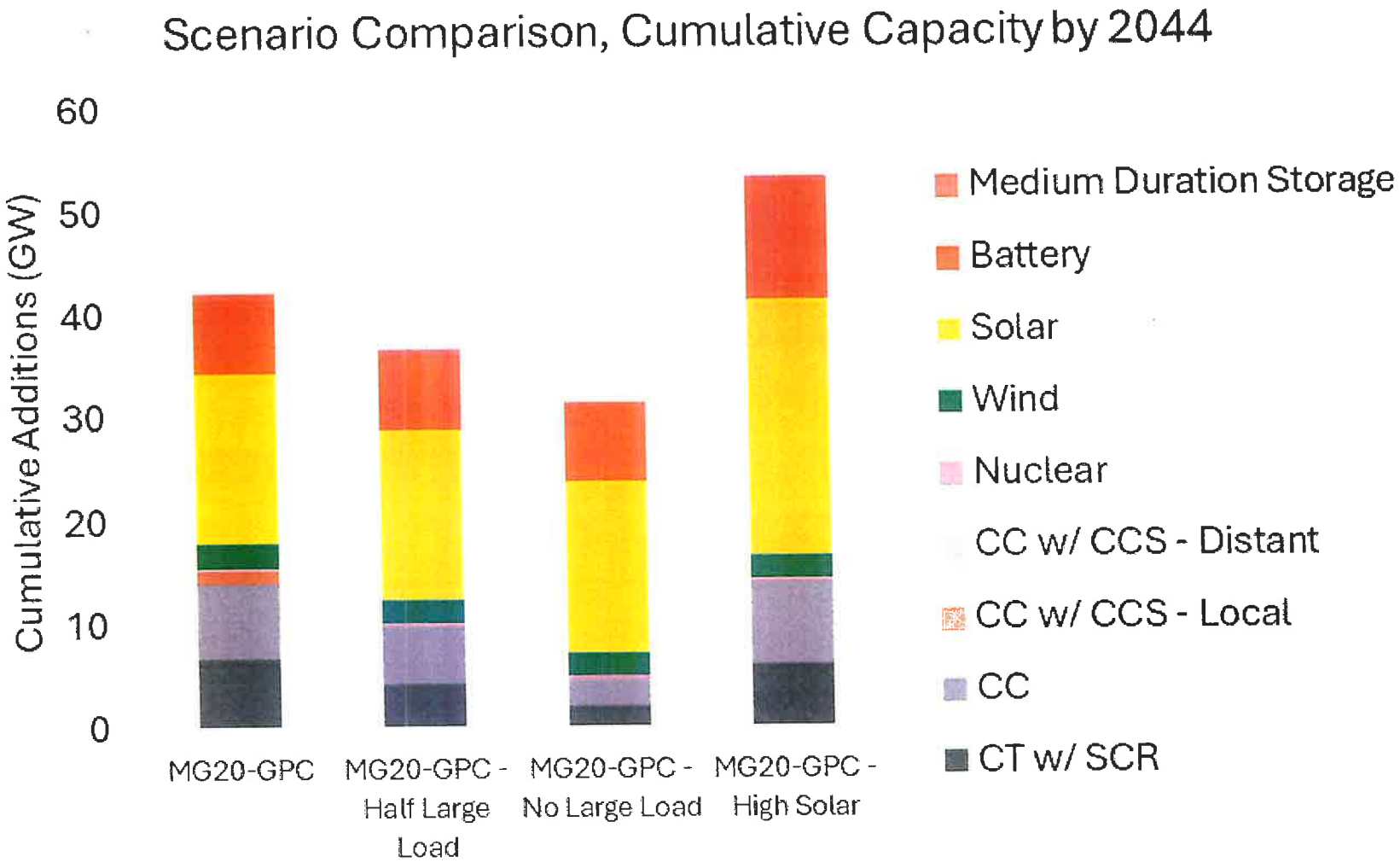
TEAMS Number	Project Name	NWAs or GETs
19636	HAMMOND - WEISS DAM 115KV LINE REBUILD	Advanced Conductor
20277	SAV: MCINTOSH - PURRYSBURG 230KV REACTORS	Advanced Conductor
17900	UNION CITY - YATES 230 KV WHITE LINE REBUILD	Advanced Conductor
20223	CC - PROJECT PAYTON BAINBRIDGE	Advanced Conductor
19287	GRADY-WEST END 115KV REBUILD	Advanced Conductor
19363	MORROW - MOUNTAIN VIEW 115 KV REBUILD	Advanced Conductor
19635	GTC: HICKORY LEVEL - VILLA RICA 230KV LINE RECONDUCTOR	Advanced Conductor
19601	MORROW - YATES COMMON 115KV LINE UPGRADE	Advanced Conductor
15879	POSSUM BRANCH - YATES COMMON 115KV REBUILD (YATES TO CLEM)	Advanced Conductor
20781	CC - SUMMER LAKE - VILLA RICA 230KV REBUILD (CC IMPROVMNT)	Advanced Conductor
20736	CC - TA REALTY ELLENWOOD NETWORK IMPROVEMENTS	Advanced Conductor
20858	GTC: ADAMSVILLE - BUZZARD ROOST 230KV REBUILD	Advanced Conductor
20776	GTC: DOUGLASVILLE - VILLA RICA 230KV REBUILD (CC NET IMPRVT)	Advanced Conductor
09662	GTC: EAST WALTON 500/230KV PROJECT	Advanced Conductor
20505	GTC: GARRETT RD - V. RICA 230KV LINE RECONDUCTOR (CC NET IM)	Advanced Conductor
20506	GTC: SWITCH WAY - THORNTON ROAD 230KV LINE REBUILD	Advanced Conductor

TEAMS Number	Project Name	NWAs or GETs
10143	LAWRENCEVILLE - WINDER 115KV LINE REBUILD	Advanced Conductor
10481	LAWRENCEVILLE - WINDER PRIMARY 230KV LINE REBUILD	Advanced Conductor
20785	SAV: GOSHEN (SAV) - KRAFT 115KV LINE REBUILD	Advanced Conductor
20150	CC - HILL VIEW & GRASSY HOLLOW SUB - CC IMPROVEMENTS	Advanced Conductor
19997	AULTMAN ROAD-PERRY 115KV LINE REBUILD	Advanced Conductor
21048	FITZGERALD - PITTS 115 KV LINE REBUILD	Advanced Conductor
08458	GTC: BARNESVILLE - SOUTH GRIFFIN 230KV PROJECT	Advanced Conductor
20503	GTC: BARNEYVILLE - EAST MOULTRIE 115KV NEW LINE	Advanced Conductor
19629	MEAG: BRUMBLEY CREEK - SOUTH BAINBRIDGE 115KV REBUILD	Advanced Conductor
20482	PITTMAN ROAD - WEST POINT DAM (USA) 115KV REBUILD	Advanced Conductor
20783	SAV: COLEMAN - DEAN FOREST 115KV LINE REBUILD	Advanced Conductor
20407	SAV: MAGNOLIA - TRUMAN PARKWAY 115KV REBUILD	Advanced Conductor
20274	UNION CITY - YATES 230KV (BLACK) LINE REBUILD	Advanced Conductor
13166	FIRST AVENUE - NORTH COLUMBUS 115KV LINE REBUILD	Advanced Conductor
10222	BLAKELY PRIMARY - HUCKLEBERRY 115KV REBUILD	Advanced Conductor
21047	BROADWAY - ECHECONNEE 115 KV LINE REBUILD	Advanced Conductor

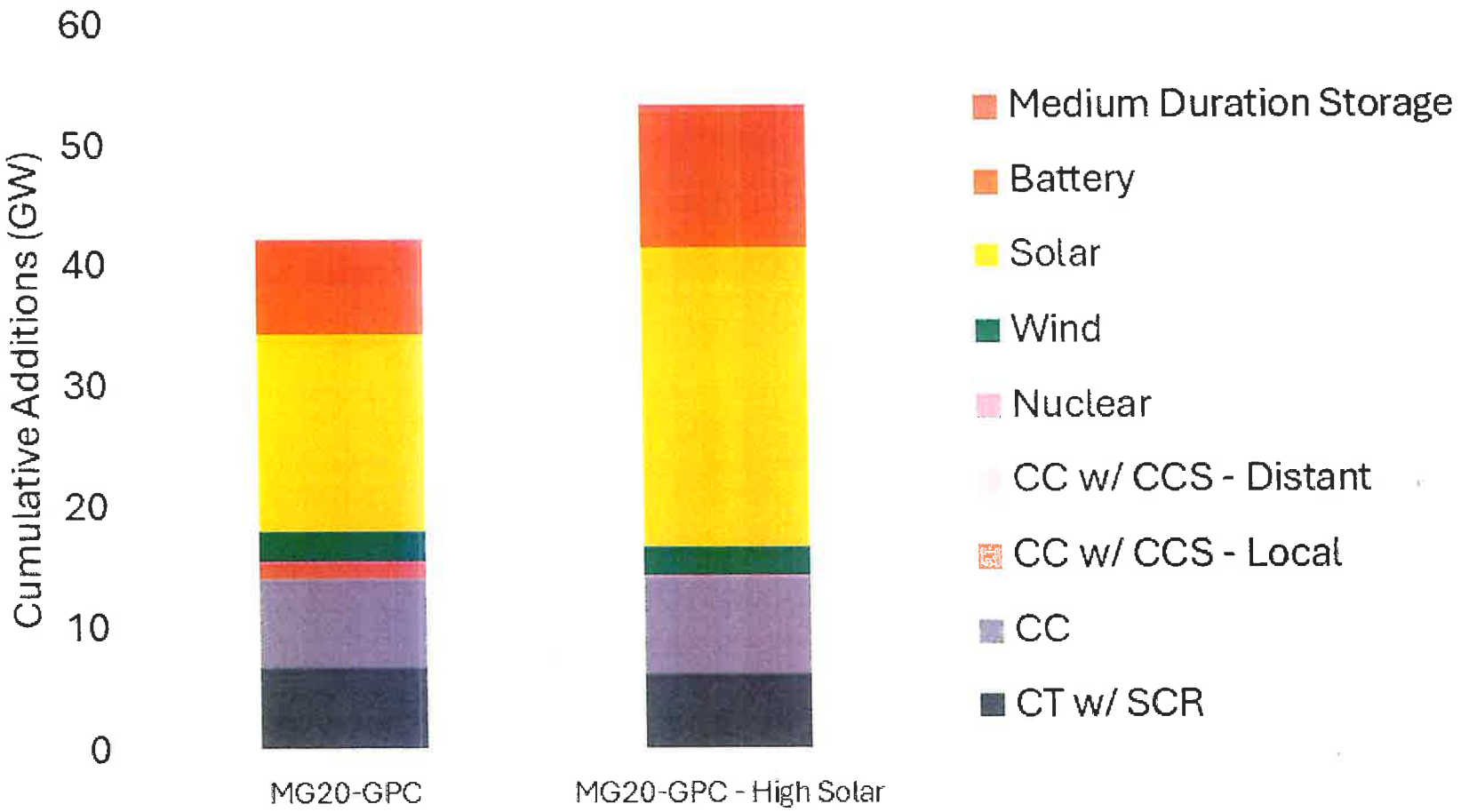
TEAMS Number	Project Name	NWAs or GETs
21036	BUZZARD ROOST - FACTORY SHOALS 230KV NEW LINE	Advanced Conductor
21142	CONYERS - KLONDIKE 230 KV SECOND LINE	Advanced Conductor
21112	GTC: BARNESVILLE PRIMARY - THOMASTON 230KV (PLACEHOLDER)	Advanced Conductor
21140	GTC: BONAIRE PRIMARY - EASTMAN PRIMARY 115 KV LINE REBUILD	Advanced Conductor
20849	GTC: CLIFTONDALE - LINE CREEK 230KV LINE	Advanced Conductor
21141	LLOYD SHOALS - PORTERDALE PRIMARY 115KV REBUILD	Advanced Conductor
20285	LOWER RIVER - WEBB (APC) 115KV RECONDUCTOR	Advanced Conductor
19621	MCEVER ROAD - SHOAL CREEK 115KV REBUILD	Advanced Conductor
20346	MCMANUS - WEST BRUNSWICK 115KV REBUILD	Advanced Conductor
17706	MEAG: AULTMAN ROAD - FORT VALLEY #1 115 KV REBUILD	Advanced Conductor
20757	NORCROSS - NORTH DRUID HILLS 115KV REBUILD	Advanced Conductor
21006	SAV: BOULEVARD - MAGNOLIA 115 KV LINE REBUILD	Advanced Conductor
21023	SAV: DEAN FOREST - LITTLE OGEECHEE 230 KV REBUILD	Advanced Conductor
13628	SOUTH BAINBRIDGE - SINAI (FPL) 115KV LINE RECONDUCTOR	Advanced Conductor
20248	BAY CREEK - CONYERS 230KV REBUILD	Advanced Conductor
21129	ANNISTON - HAMMOND 230KV LINE	Advanced Conductor

TEAMS Number	Project Name	NWAs or GETs
20764	ATKINSON - NORTHSIDE DRIVE 115KV REBUILD	Advanced Conductor
20761	ATKINSON - NORTHWEST 115KV REBUILD	Advanced Conductor
21130	CC - NORTH GEORGIA DATA NETWORK UPGRADES (GPC)	Advanced Conductor
10478	CORNELIA - TALLULAH LODGE 115KV REBUILD	Advanced Conductor
18669	DU: DAWSON CROSSING - NELSON (WHITE) 115 KV REBUILD	Advanced Conductor
21097	EAST POINT - TRIBUTARY 230KV REBUILD	Advanced Conductor
20480	EAST POINT - UNION CITY 230KV BLACK LINE RECONDUCTOR	Advanced Conductor
19627	ECHECONNEE-WELLSTON 115KV LINE REBUILD	Advanced Conductor
12120	GAINESVILLE #2 - MCEVER ROAD 115 KV REBUILD	Advanced Conductor
20298	GLENWOOD SPRINGS - LAKE OCONEE 115KV LINE REBUILD	Advanced Conductor
21014	GTC: BUZZARD ROOST - CAVENDER DRIVE 230KV NEW LINE	Advanced Conductor
21113	GTC: HARTWELL ENERGY - MIDDLE FORK 230KV LINE	Advanced Conductor
21131	GTC: POND FORK - MIDWAY 115KV LINE	Advanced Conductor
20789	JEFFERSON ROAD - WINDER PRIMARY 115KV REBUILD	Advanced Conductor
20284	KETTLE CREEK PRIMARY - PINE GROVE PRIMARY 115KV REBUILD	Advanced Conductor
20857	NEW CAVENDER DRIVE - TRIBUTARY 230KV LINE	Advanced Conductor

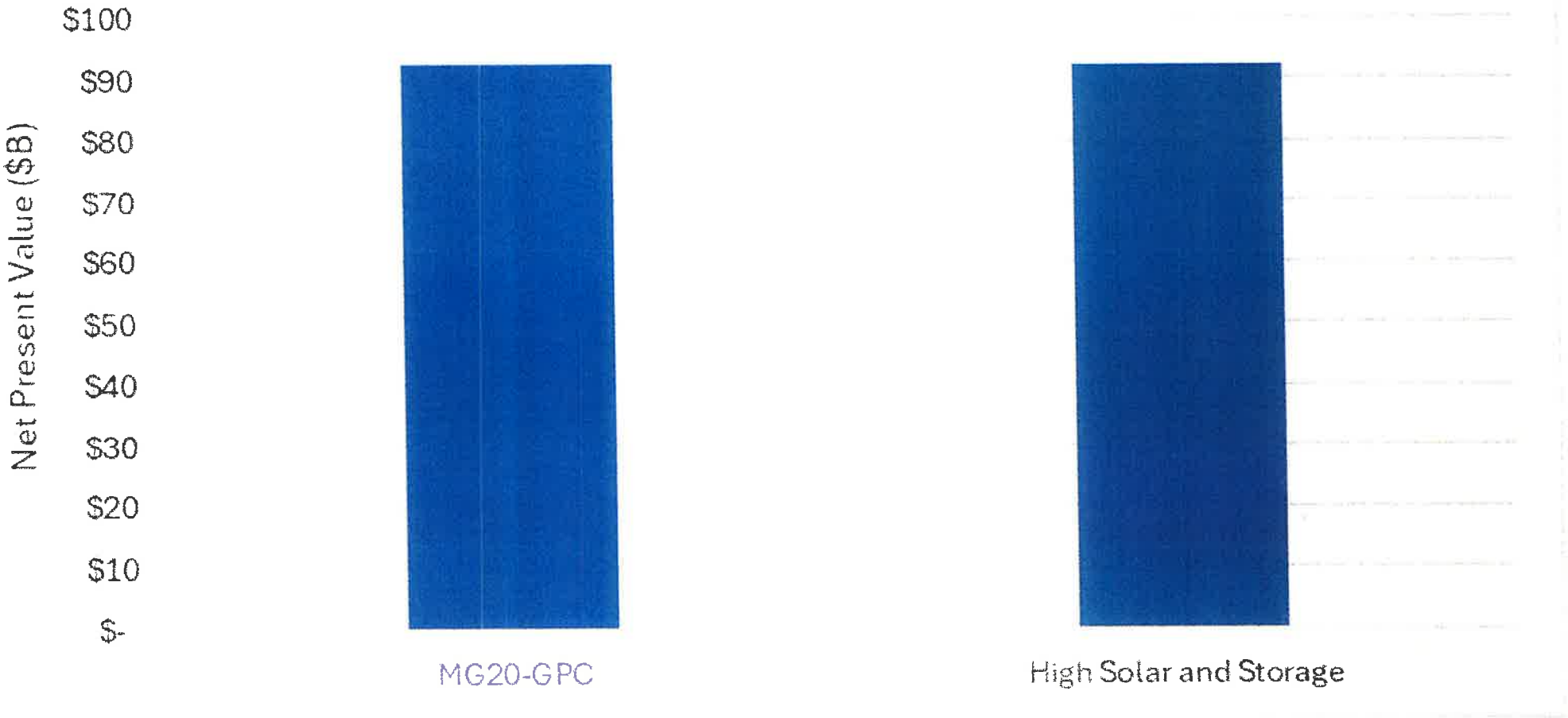
TEAMS Number	Project Name	NWAs or GETs
21098	TRIBUTARY - THORNTON RD 230KV REBUILD	Advanced Conductor
20690	EAST POINT - UNION CITY (WHITE) 230KV REBUILD	Advanced Conductor
20784	SAV: COLEMAN - MELDRIM 115KV LINE REBUILD	Advanced Conductor
20793	EVANS PRIMARY - THURMOND DAM (USA) #5 115KV REBUILD	Advanced Conductor
20794	EVANS PRIMARY - THURMOND DAM (USA) #6 115KV REBUILD	Advanced Conductor
12217	GTC: CENTER PRIMARY - CLARKSBORO 230 KV REBUILD	Advanced Conductor
20773	GTC: CLARKSBORO - WINDER PRIMARY 230KV REBUILD	Advanced Conductor
20791	GTC: SHOAL CREEK - SOUTH HALL 230KV REBUILD	Advanced Conductor
21053	MCEVER ROAD - SHOAL CREEK 115KV REBUILD	Advanced Conductor
10487	PINE GROVE PRIMARY - WEST VALDOSTA 115 KV RECONDUCTOR	Advanced Conductor
17993	EVANS PRIMARY - THOMSON PRIMARY 115KV REBUILD	Advanced Conductor


Scenario Comparison, Cumulative Capacity by 2044
Cumulative Additions (GW)
60
50
40
30
20
10
0
MG20-GPC
MG20-GPC - Half Large Load
MG20-GPC - No Large Load
MG20-GPC - High Solar
Medium Duration Storage
Battery
Solar
Wind
Nuclear
CC w/ CCS - Distant
CC w/ CCS - Local
CC
CT w/ SCR

Scenario Comparison, Cumulative Capacity by 2044



Net Present Value of Core Scenarios



Georgia Power Company
Docket No. 56002 & 56003
2025 Integrated Resource Plan and 2025 Demand-Side Management Application
STF-JKA Data Request Set 3

STF-JKA-3-8

Question:

Please provide all analysis, notes, and calculations produced by the Company or Astrape in relation to the seasonal ELCC values and seasonal resource accreditation associated with latest reliability studies. Explain if the increase in summer reserve margin has or would have a corresponding increase in ELCC value for summer peak resources, such as solar.

Response:

As explained on page 16 of the 2024 Reserve Margin Study provided in Technical Appendix Volume 1, Section 2, an aggregate economic load carrying capability ("ELCC") value was calculated for demand side, solar, and wind resources. For the winter season, the aggregate ELCC for these resources was 21%. For the summer season, the aggregate ELCC was 44%. These aggregate values resulted in the recognized capacity values shown in Table I-5 on page 17 of the 2024 Reserve Margin Study. An increase in the summer target reserve margin is not expected to have a notable impact on summer ELCC values. The Company will reevaluate ELCC values in 2025 incorporating the recommendations from the 2024 Reserve Margin Study.

Contact: Brandon Looney

Battery Capacity Values for B25 IRP

Suggested from IRP

FINAL

Winter

Total	Avg Trended	Avg Trended Rounded	Incremental	FINAL with 39.7GW of Solar	FINAL Aurora Tranches
1,000	99%	100%	1,000	99%	
2,000	99%	100%	1,000	98%	95%
3,000	96%	95%	1,000	90%	
4,000	92%	90%	1,000	81%	
5,000	88%	90%	1,000	72%	75%
6,000	84%	85%	1,000	65%	
7,000	80%	80%	1,000	58%	
8,000	77%	75%	1,000	52%	50%
9,000	73%	75%	1,000	45%	
10,000	70%	70%	1,000	38%	
11,000	66%	65%	1,000	30%	
12,000	63%	65%	1,000	22%	25%
13,000	59%	60%	1,000	19%	
14,000	56%	55%	1,000	19%	
15,000	54%	55%	1,000	18%	

Summer

Total	Avg Trended	Avg Trended Rounded	Incremental	FINAL with 39.7GW of Solar	FINAL Aurora Tranches
1,000	98%	100%	1,000	98%	
2,000	98%	100%	1,000	98%	100%
3,000	100%	100%	1,000	100%	
4,000	100%	100%	1,000	100%	
5,000	100%	100%	1,000	100%	100%
6,000	100%	100%	1,000	100%	
7,000	100%	100%	1,000	100%	
8,000	96%	95%	1,000	72%	75%
9,000	92%	90%	1,000	54%	
10,000	86%	85%	1,000	39%	
11,000	81%	80%	1,000	30%	
12,000	77%	75%	1,000	28%	30%
13,000	73%	75%	1,000	28%	
14,000	70%	70%	1,000	27%	
15,000	67%	65%	1,000	26%	

Assumptions:
- Values were simulated with an additional 30GW (39.7GW total) of diverse solar

These values are incremental to an embedded BESS amount of 809 MW

Unit Name		Winter	Summer	
Battery_2022_IRP_MCGRAU_FORD	265	100%	100%	
Battery_2028_IRP_Exp_Generic	300	100%	100%	
Battery_Moody	49.5	90%	35%	**Hybrid Facility has a total 100% capacity value as a percentage of the POI, solar and BESS portions listed separately in the ledger
Battery_MOSSY_BRANCH_DEMO	65	100%	100%	
Battery_MPC Walnut Grove	1 285	100%	100%	
Battery_Robins	128	90%	25%	**Hybrid Facility has a total 100% capacity value as a percentage of the POI, solar and BESS portions listed separately in the ledger

SREA EXHIBIT AP-1:

Alejandro Palomino Curriculum Vitae (CV)

Alejandro Palomino, PhD, Senior Consultant

Energy Strategies | 111 E Broadway STE 1200, Salt Lake City, UT 84111 | apalomino@energystrat.com

PROFESSIONAL EXPERIENCE

Energy Strategies, Salt Lake City, UT, *Senior Consultant*, Jan 2024 – Present; *Consultant*, Aug 2024 – Jan 2024

- Conducted long-term capacity expansion modeling (Aurora) to provide technical support in utility-integrated resource planning intervention across 3 states and 5 utilities
- Developed 8760 price-taker optimal battery dispatch model (Pyomo)
- Built PostgreSQL geospatial database to support distribution system infrastructure with automated updates from utility APIs
- Lead open-source, probabilistic study to evaluate the influence of regional coordination (WRAP) on utility resource adequacy
- Presented findings from "Assessing Resource Adequacy in Montana" to the Montana Energy and Telecommunications Interim Committee
- **Skills**: Aurora · PLEXOS · PostgreSQL · Pyomo · Google Maps API

Duke Energy Commercial Renewables, Charlotte, NC, *SCADA Engineer*, Feb 2016 – Apr 2017

- Managed 7 utility scale (> 5 MW) solar SCADA retrofit projects with a budget of greater than $70,000 each.
- Authored first SCADA controls user manuals in support of operational training needs.
- Supported the operation of 32 solar sites and 12 wind sites by troubleshooting SCADA and networking issues
- Authored standard 3rd Party Vendor Interface Specification to ensure consistent, reliable integration of legacy equipment into the Duke control center
- Saved approximately $13k by performing in house work to synchronize field controllogix PLCs with central SCADA Logix5000 server
- Troubleshot PI interface issues between active sites and Duke control center and documented strategies to improve operations' response to future issues

Siemens Energy, Orlando, FL, *Process and Controls Engineer*, Jul 2013 – Feb 2016; Electrical Engineer, Jan 2013 – Jul 2013; Manufacturing Process Engineer, Jun 2012 – Dec 2012

- Lead I&C design engineer for 800MW combined cycle power plant
- Reviewed P&IDs in building 4000 I/O point database
- Designed cabinet hardware and managed $1.5M budget in purchasing
- Drafted custom motor control circuit diagrams to customer requirements
- Drafted single line diagram for a 3x0 cogeneration gas fired power plant for Royal Dutch Shell

- Participated in electrical design and led early stage electrical proposal for Royal Dutch Shell power control centers and motor control centers
- Authored HW/SW specification for IEC61850 infrastructure upgrade at an existing power plant
- Initialized 20 7SJ Siprotec relays for IEC61850 over TCP/IP motor control center for 2x1 power
- Remote opened and closed a MV circuit breaker using an IEC61850 client simulator (Triangle MicroWorks) via a fiber optic network
- Managed coil shape validation process including a team of 4 operators
- Developed Polyworks computer macros to increase validation efficiency and ease of use for users
- Designed novel clamp set up for pressing process

EDUCATION

The University of Utah, Salt Lake City, UT
Ph.D. in Electrical Engineering, 2022
Dissertation: *Cyber-Secure Utilization of Electric Vehicle Charging Flexibility in Distribution Networks*
Masters of Science in Electrical Engineering, 2020
Thesis: *Probabilistic Analysis of Electric Vehicle Loading on Distribution Infrastructure*

The University of Florida, Gainesville, FL
Bachelors of Science in Mechanical Engineering, 2012
Thesis: *Temperature Monitoring System for High Voltage/High Current Electrical Equipment*

PUBLICATIONS

- Gridlab with Keegan Moyer, **Alex Palomino**, and Zoe Fehlau. "*Assessing Resource Adequacy in Montana*." Available at https://gridlab.org/portfolio-item/assessing-resource-adequacy-in-montana/
- Energy Systems Integration Group with Keegan Moyer, John Muhs, and **Alex Palomino**. "*Modeling the Effects of Distributed Generation on Transmission Infrastructure Investment: A Western Case Study.*" Available at https://www.esig.energy/distributed-generation- impact-on-transmission/
- Parvania, Masood, Jairo Giraldo, and **Alejandro Palomino**. "*Security systems, methods, storage medium for increasing security of devices utilizing a communication channel*." U.S. Patent Application No. 18/156,985.
- **Palomino, Alejandro**. *Cyber-Secure Utilization of Electric Vehicle Charging Flexibility in Distribution Networks*. Diss. The University of Utah, 2022.
- **Palomino, Alejandro**, Jairo Giraldo, and Masood Parvania. "*Graph-based interdependent cyber-physical risk analysis of power distribution networks*." IEEE transactions on power delivery 38.3 (2022): 1510-1520.
- **Palomino, Alejandro**, Masood Parvania, and Regan Zane. "*Impact of covid-19 on mobility and electric vehicle charging load*." *2021 IEEE Power & Energy Society General Meeting (PESGM)*. IEEE, 2021.
- **Palomino, Alejandro**, and Masood Parvania. "*Bayesian hierarchical model for characterizing electric vehicle charging flexibility*." 2020 IEEE Power & Energy Society General Meeting (PESGM). IEEE, 2020.

- Ebrahimi, Mehrdad, Mohammad Rastegar, Mohammad Mohammadi, **Alejandro Palomino** & Masood Parvania. "*Stochastic charging optimization of V2G-capable PEVs: A comprehensive model for battery aging and customer service quality.*" *IEEE Transactions on Transportation Electrification* 6.3 (2020): 1026-1034.
- Khan, Mohammed Masum Siraj, **Alejandro Palomino**, Jonathon Brugman, Jairo Giraldo, Sneha Kumar Kasera, and Masood Parvania. "*The cyberphysical power system resilience testbed: Architecture and applications.*" *Computer* 53.5 (2020): 44-54.
- **Palomino, Alejandro**, and Masood Parvania. "*Data-driven risk analysis of joint electric vehicle and solar operation in distribution networks*." *IEEE Open Access Journal of Power and Energy* 7 (2020): 141-150.
- Bagherinezhad, Avishan, **Alejandro D. Palomino**, Bosong Li, and Masood Parvania. "*Spatio-temporal electric bus charging optimization with transit network constraints*." *IEEE Transactions on Industry Applications* 56.5 (2020): 5741-5749.
- **Palomino, Alejandro**, and Masood Parvania. "*Advanced charging infrastructure for enabling electrified transportation*." *The Electricity Journal* 32.4 (2019): 21-26.
- **Palomino, Alejandro**, and Masood Parvania. "*Probabilistic impact analysis of residential electric vehicle charging on distribution transformers*." *2018 North American Power Symposium (NAPS)*. IEEE, 2018.

INTERVENTION WORK

- Iowa Utilities Commission (Docket No. M-0156): Technical Modeling Support of Environmental Law and Policy Center intervention in the 2024 MidAmerican Resource Evaluation Study
- Iowa Utilities Commission (Docket No. RPU-2021-0003): Technical Modeling Support of the Environmental Law and Policy Center intervention in the 2025 Interstate Power & Light Resource Evaluation Study
- Arizona Corporation Commission (Docket No. E-99999A-22-0046): Technical Modeling Support of Western Resource Advocates' Amended Notice of Filing Comments on the 2021, 2022, and 2023 Integrated Resource Plans of Arizona Public Service Company
- Arizona Corporation Commission (Docket No. E-99999A-22-0046): Western Resource Advocates' Notice of Filing Comments on the 2021, 2022, and 2023 Integrated Resource Plans of Tucson Electric Power Company

SREA EXHIBIT AP-2:

Telos Energy, Winter Storm Elliot: An Independent Review of Southern Company's Performance During the Historic Events of December 22 – 25, 2022 (2024)

Winter Storm Elliott

An independent review of Southern Company's performance during the historic events of December 22-25, 2022.

TELOS ENERGY

SOUTHERN RENEWABLE ENERGY ASSOCIATION

Prepared by Telos Energy for the Southern Renewable Energy Association.

Foreword

Winter Storm Elliott was a historic and sobering event, testing the reliability of our power system against extreme weather, high loads, gas supply disruptions, and generator outages.

From December 22 to December 25, 2022, extreme cold gripped much of the country, even extending into the Southeast, pushing grid operators and utilities to their limits. Utilities across the region called for energy emergencies and at times involuntary load shedding occurred.

In the aftermath of the event, FERC and NERC conducted a detailed post-mortem to evaluate root causes of the event. While this report provided valuable insights for each balancing area in the Southeast, it did not include a detailed overview of Southern Company's generator performance, nor did it look at the timeframe most important for Southern Company.

To fill this gap, Telos Energy, on behalf of the Southeast Renewable Energy Association, conducted an independent review of generator performance within Southern Company's footprint during this storm. Our goal was simple: to better understand what worked, what didn't, and what we can learn to improve future grid planning and reliability.

Before diving into the report, we want to recognize the operators who managed the power system during this storm. They no doubt worked tirelessly to maintain service for their customers and their communities. Southern Company managed to avoid rolling blackouts during the extreme weather—while neighbors could not.

Operators made decisions under immense pressure, ensuring customers had heat, preventing property damage and even saving lives.

This report is not about second-guessing those efforts. Instead, it aims to shed light on generator performance and planning processes, helping ensure our future systems can withstand similar events.

What this storm highlighted is that no resource is perfect and all resources - whether natural gas, coal, hydro, wind, or solar - are affected by the weather. Robust and fair accreditation of all resources is essential not just to make informed investment decisions, but to ensure reliability.

This starts with accrediting natural gas and coal resources using effective load carrying capability similar to what is being done for solar and battery storage. It also extends to interregional transmission, which can also be treated as a capacity resource. Together, proper accreditation can enable a diversified portfolio that strengthens the grid.

Transparency is another cornerstone of effective planning. Much of our analysis relied on data from Georgia Power Company's (GPC) regulatory filings, but gaps remained, requiring us to piece together a fuller picture using publicly available sources like EPA and EIA datasets.

At times we had to use generation during EEA events as a proxy for availability and outages. No doubt there are small errors or omissions in this analysis, and we look forward to additional data to help correct these. Transparency matters—not just for analysts like us, but for regulators, planners, and stakeholders who need accurate information to make informed decisions.

We hope this report serves as a constructive step toward greater understanding of past events and enables more robust planning. Together, let's continue building a grid that's ready to meet the reliability challenges ahead.

Introduction

Winter Storm Elliott created severe stress on the electric grid from December 21 - 26, 2022. The storm brought extreme cold, high winds, and snow, leading to a dramatic surge in electricity demand coupled with widespread outages caused by freezing equipment and disrupted fuel supplies.

Many utilities, including those in regions managed by the Tennessee Valley Authority (TVA), PJM (Pennsylvania-New Jersey-Maryland Interconnection), Duke Energy, and Southern Company, faced challenging conditions and implemented emergency procedures to maintain grid stability. The North American Electric Reliability Corporation (NERC) and the Federal Energy Regulatory Commission (FERC) subsequently released reports[1] detailing the storm's impact on utilities and highlighted region-wide deficiencies in both electric-gas coordination and preparedness for extreme weather. These reports underscored the urgency of enhancing reliability frameworks to address correlated failures across energy and fuel networks.

Post-storm scrutiny focused on the severe impacts in TVA, PJM, and the Carolinas where there was involuntary load shedding. However, Southern Company and its subsidiaries—Georgia Power, Alabama Power, Mississippi Power, and Southern Power—also faced substantial operational challenges.

On December 24, 2022, Southern Company issued an Energy Emergency Alert Level 2 (EEA 2), signaling the need to manage load through voluntary reductions. Unlike TVA and other utilities that implemented controlled outages, Southern Company managed to avoid EEA 3 measures which would have triggered involuntary load shedding, or "rolling blackouts."

During this time, the thermal generating fleet across the eastern interconnection experienced widespread outages, fuel supply disruptions, and unavailability. Figure 1 below shows a timeline of hourly electricity demand from the Southern Pool with callouts for key periods identified in this analysis. Additionally, yellow bars indicate approximate times when neighboring regions were under EEA 1 to EEA 2 and orange bars represent regions where EEA 1 to EEA 3 conditions occurred in relation to Southern. Periods of EEA for non-Southern regions represent approximate times any EEA was in effect.

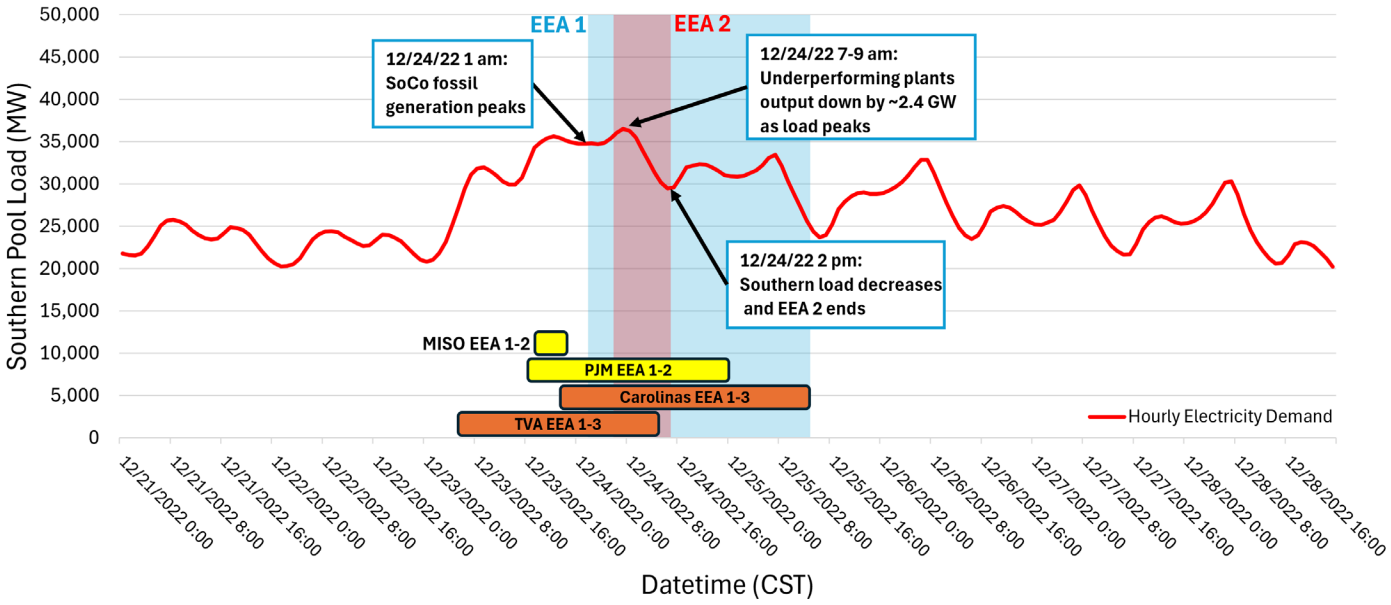


Figure 1. Summary timeline for Southern Company generator performance during Winter Storm Elliott

1 *FERC, NERC, & Regional Entity Staff. (2023, October). Inquiry into bulk-power system operations during December 2022 Winter Storm Elliott. Retrieved from https://www.ferc.gov/news-events/news/ferc-nerc-release-final-report-lessons-winter-storm-elliott*

The EEA declaration underscores the significant strain on its system, prompting an examination of the company's resource preparedness, load forecasting accuracy under extreme conditions, and planning processes to mitigate risks to system reliability and control costs for ratepayers. It also highlights the importance of including these types of weather events – and the corresponding generator performance – in long-term planning.

This report evaluates Southern Company's performance in key areas during Winter Storm Elliott, including generator performance, load forecasting accuracy, and both bilateral and SEEM market transactions. Key findings explore how well Southern Company anticipated and mitigated cold weather risks, the extent of generator derates or outages during the event, and the performance of renewable resources under extreme conditions.

Transparency remains a key challenge: although power purchases increased significantly during Southern Company's EEA 2 event, limited information is available, particularly regarding price formation, leaving ratepayers to bear unclear emergency costs.

The company's forecasting and planning for winter peak loads appear insufficient for managing high-impact, low-frequency events without resorting to extreme measures, and further assessment is needed to ensure Southern Company is accounting for winter outage risks across its generation fleet.

As a vertically integrated utility operating in a non-organized market, Southern Company lacks the standardized post-event reporting and market transparency seen in regulated regions like PJM and MISO. This limited transparency restricts a full evaluation of Southern Company's operational decisions and financial impact on ratepayers. Consequently, stakeholders lack critical insights into the company's efficiency, resource planning efficacy, and the true costs of emergency power.

This report addresses these gaps using limited data available from Georgia Power dockets, EPA data on large fossil-fuel plant operations, and grid operation data from the Energy Information Administration (EIA), seeking to answer critical questions on Southern Company's performance during Winter Storm Elliott.

This report seeks to address four primary questions:

- **Winter Load Forecasting:** How well does Southern Company predict winter peak load events, and did actual risks during the storm align with utility expectations?
- **Generator Performance:** How did all generation resources perform during severe conditions, and how effectively does Southern Company account for cold weather outage risks in its planning?
- **Emergency Power Purchases and Costs:** From where did emergency power originate, and at what cost? How did these costs compare to those in nearby regional markets?
- **Southeast Energy Exchange Market (SEEM) Performance:** How was the Southeast Energy Exchange Market (SEEM) leveraged during Winter Storm Elliott, and how has it been used in subsequent winter peak load events in 2023 and 2024?

"Transparency remains a key challenge: although power purchases increased significantly during Southern Company's EEA 2 event, limited information is available, particularly regarding price formation, leaving ratepayers to bear unclear emergency costs."

This report aims to inform Southern Company stakeholders and regulatory authorities on the overall performance of the generation fleet, how well winter risk is characterized, and opportunities for increased transparency during and after emergency events, and recommendations on how to better incorporate these challenges in long-term planning.

Winter Load Forecasting

The Southern Company region operates as a dual-peaking system, with high loads and tight reserve margins both in summer, due to air conditioning demands, and in winter, due to electric heating needs.

Every year, the Southern Balancing Authority (SBA), comprising Southern Company subsidiaries like Georgia Power, Alabama Power, and Mississippi Power, develops both a base winter peak load (50/50 load forecast) and an extreme peak load (90/10 load forecast) to prepare for severe weather scenarios. For the 2022-2023 winter season, SBA's extreme winter peak load forecast was 45,462 MW, slightly under the all-time winter peak of 45,887 MW[2].

To meet these forecasted loads, SBA projected resource availability based on its planning criteria, estimating 53,759 MW of resource capacity. After accounting for planned and unplanned outages and demand response, total capacity available was 52,133 MW. Under the 90/10 extreme peak forecast, the SBA projected reserve capacity of 6,671 MW, indicating a 15% reserve margin.

Given these assumptions, SBA anticipated sufficient resources to cover demand even during challenging weather like Winter Storm Elliott. However, on December 24, despite actual peak load remaining slightly below the 90/10 forecast at 45,153 MW, the SBA entered both EEA 1 and EEA 2 conditions, signaling that actual resource availability was below expectations during this high-demand period.

Table 1 shows the winter reliability expectations going into Winter Storm Elliott from the NERC/FERC inquiry.

2022-2023 Winter Reliability Load and Resource Summary	Southern
50/50 Winter Forecast (MW)	41,300
90/10 Winter Forecast (MW)	45,462
Winter Storm Elliot Peak (MW)	45,153
Expected Available Resources (MW)[3]	52,133
Expected Reserves to 50/50	26.2%
Expected Reserves to 90/10	14.7%
Expected Reserves to Actual Peak	15.5%

Table 1. Southern Winter Reliability Summary from NERC and FERC Inquiry into Winter Storm Elliott.

Evaluating Operational Forecast Accuracy and Error Margins

Reviewing the 2022 resource adequacy assessments for the Southern Pool (Georgia Power, Mississippi Power, and Alabama Power) reveals significant forecasting challenges for December peak loads. The historical data shown in Table 2 *(page 5, top)* shows that high forecast error exists even 1-hour ahead of peak load in December. For Winter Storm Elliott, the average error leading up to peak load would be 271 – 455 MW, depending on how far ahead the forecast is made. Assuming that the standard deviation is for a normal distribution, there was a 16% probability that December peak load could have been more than 3,600 MW above the forecasted peak load based on historical forecast error.

This high variability in forecast winter peak load means grid operators face high levels of uncertainty during extreme cold weather. Even though going into the event it appeared that adequate reserves were available, and peak load would be within the 90/10 forecast, clearly risks developed that prompted emergency procedures.

More insight into the specific decision-making steps from normal operations to EEA 1, 2, and potentially EEA 3 would help contextualize the risks of Winter Storm Elliott. Post-event analysis reports are commonplace in regions with markets, like PJM, MISO, and SPP, since market transparency builds trust and creates accountability for remedial actions.

2 Federal Energy Regulatory Commission (FERC) and North American Electric Reliability Corporation (NERC), FERC, NERC Release Final Report on Lessons from Winter Storm Elliott (2023), available at https://www.ferc.gov/news-events/news/ferc-nerc-release-final-report-lessons-winter-storm-elliott.

3 Expected available resources includes 53,759 MW of capacity, 2,510 MW of demand response, and -4,136 MW of expected planned and forced outages.

Historical Peak Load Forecast Error	Peak Load	4-hour mean error	1-hour mean error	4-hour std dev	1-hour std dev
December Error		1.0%	0.6%	10.4%	8.0%
Winter Storm Elliott Risk	45,153 MW	455 MW	271 MW	4,696 MW	3,612 MW

Table 2. 2022 Georgia Power Reserve Margin Study Historical Dispatchers' December Peak Load Forecast Error

Greater transparency in Southern's decision-making framework could clarify whether improvements are needed in forecasting accuracy, resource adequacy modeling, or operational protocols.

Suggestions to Improve Confidence in Winter Planning

Though Winter Storm Elliott brought conditions close to the 90/10 forecast, the region experienced emergency conditions not anticipated by existing plans. Despite projected reserves, the system escalated to EEA 2 conditions, where voluntary load reductions were employed.

This raises questions about whether Southern is making appropriate assumptions on generator availability during extreme, but anticipated, winter weather.

As winter reliability grows increasingly critical, Southern Company's strategies and readiness for low-frequency, high-impact events like Winter Storm Elliott require further scrutiny, particularly given the challenges of electric-gas coordination and growing electricity demand from data centers and electric vehicles.

The following actions are recommended to improve winter peak planning and transparency for stakeholders:

- Improvements to mitigate volatility in winter peak load are needed. These could include more advanced demand side management strategies, improved home efficiency programs, or virtual power plants to mitigate winter peak load risk while mitigating transmission system constraints.
- Evaluate load diversity and peak load risks for neighbors outside of SERC to enable more robust interregional support during high impact low probability events.

Generator Performance

The following analysis reviews how generators and different fuel types across Southern Company's footprint performed during Winter Storm Elliott.

Given the scale and severity of the event, units were expected to maintain or increase output to meet peak demand, especially as the region moved into EEA 1 and EEA 2. However, after reviewing generation data, significant drops in capacity or availability during this period are assumed to indicate operational challenges. The period used to evaluate generator performance is referred to as the "emergency window" which extends from December 24th at 7 am – 9 am. This three-hour window surrounding the peak load hour is used to represent the hours of greatest risk across the region.

Unfortunately, actual operational data was only provided by Georgia Power. Data transparency limitations make it challenging to assess performance throughout the broader balancing authority. This results in substantial gaps for Mississippi Power, Alabama Power, and Southern Power. This lack of detail underscores the need for Southern Company to provide comprehensive post-event analyses for their entire footprint. This practice aligns with other regions and supports transparent planning for system reliability and ensures accountability.

Overall Southern Company Fossil Fleet Performance by Fuel Type

The performance of Southern Company's fossil-fuel fleet, broken down by fuel type, is illustrated in Figure 2 *(below).* Total generation is from EPA's Continuous Emissions Monitoring System (CEMS) data, discounted by 2-7% based on technology type to approximate auxiliary loads. The gap in the data represents the remaining amount of demand served by nuclear, hydro, solar, and external power purchases.

Fossil-fuel generation in Southern Company's territory declined throughout the EEA 2 period when risks were highest, despite calls for voluntary load reductions. Fossil-fuel generation declined 2.4% in the hours before, 3.3% during, and 6% in the hours following peak load. Load shown in the figure represents the total reported generation from Georgia Power for all Southern Company entities.

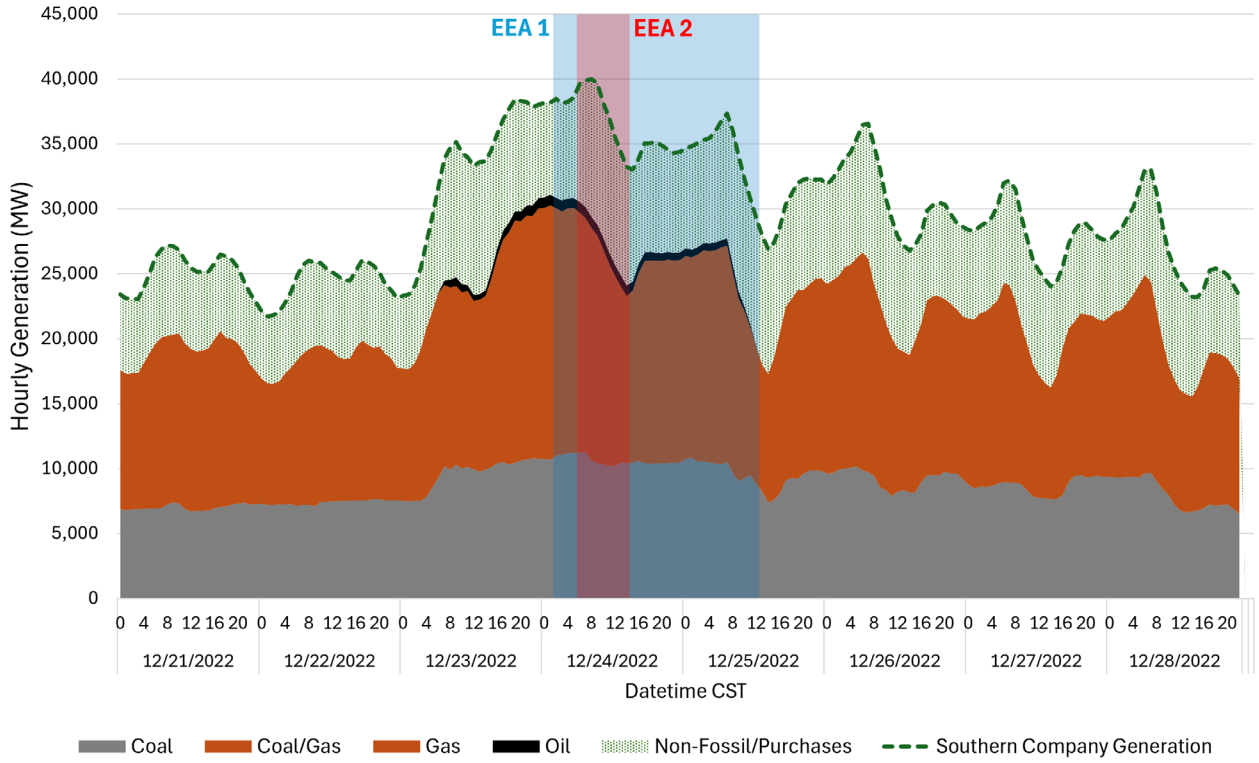


Figure 2. Southern Company Fossil Generation by Fuel Type during Winter Storm Elliott.

The data indicates that fossil generation peaked approximately 5 hours before peak load with numerous outages occurring when the capacity was needed most.

The fleetwide capacity factor for each fossil fuel type during EEA 2 is shown in Figure 3 *(below)*. Notably, coal and natural gas generation decreased by 7.5% and 8.1% relative to their maximum leading up to the emergency window.

While no load shedding occurred as the fleets experienced outages during EEA 1 and EEA 2 periods, the effects of cold weather on outage rates warrants further evaluation due to the volatility in winter demand described in the Winter Load Forecasting section.

Based on the emergency window of 7 am – 9 am on December 24, there were 22 plants (including aggregated one) that had either known outages reported by GPC, or had substantial deviations in the EPA data, or simply did not generate at all during the event.

These plants' winter ratings total 15,816 MW; however, average generation across these units was 8,084 MW, meaning that during the most extreme hours of the storm these units were only operating at 51% capacity factor across the fleet 51%.

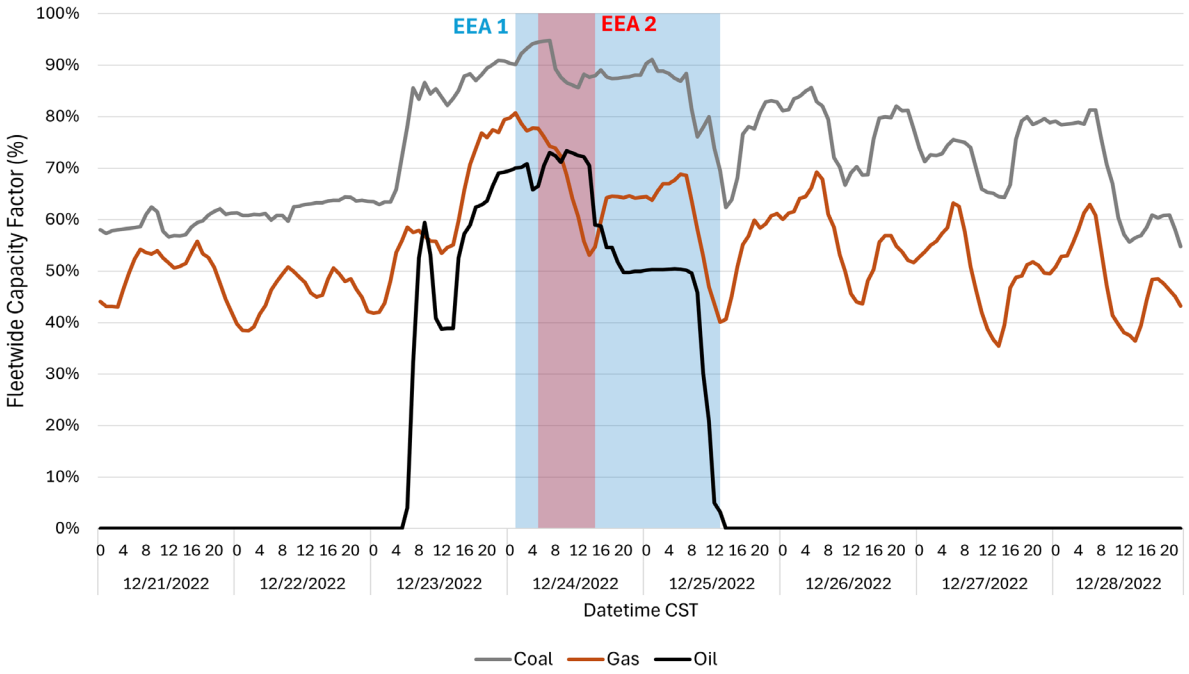


Figure 3. Southern Company Fossil Fleet Capacity Factors during Winter Storm Elliott.

Not all the unavailability exhibited by these plants can be attributed to forced outages without additional information. But the fact remains that these plants either had generators on some type of outage or were experiencing derates due to fuel supply availability during the emergency window. Figure 4 *(page 8, top)* shows the plants identified as underperformers and their average generation during the emergency window.

Generators that were GPC power purchase agreements were aggregated if they were less than 100 MW. Undispatched capacity represents the delta between the generation during the emergency window and the plants winter ratings.

In some cases, units were completely unavailable, in others output had been decreasing since the EEA 1 period was declared, or sharp drops in generation were observed in at least one of the emergency window hours.

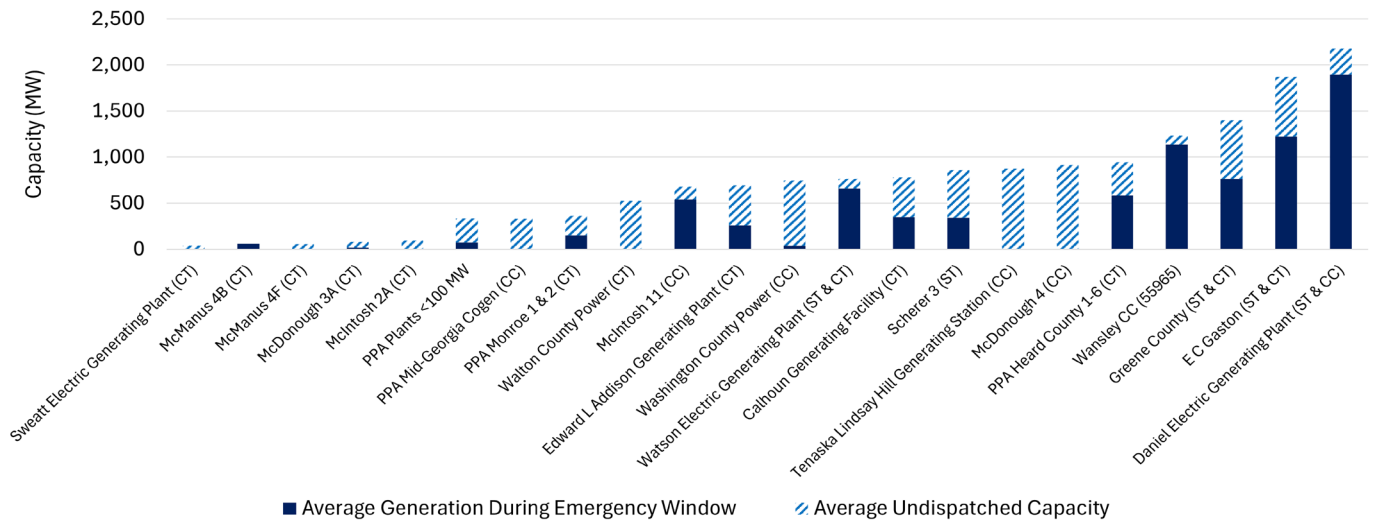


Figure 4. Southern Company known and potential unavailable capacity due to outages on 12/24/2022 hours 7am - 9am CST.

Known Georgia Power Plant Outages

This section provides a review of available hourly generation data for plants that experienced known outages as reported by Georgia Power. More information on the entire company's performance is needed to accurately determine where and when cold weather affects power plant outages although further sections provide estimates of unavailable capacity by Southern Company subsidiary and PPA resources.

Georgia Power Company owned plants where known outages occurred on December 24, 2022, from 1 am – 1 pm are:

- McDonough Unit 4 – 808 MW Combined Cycle
- McIntosh Unit 11 – 294 MW Combined Cycle
- McDonough CT 3B – 40 MW Combustion Turbine
- McIntosh CT 2 – 94 MW Combustion Turbine
- McManus CT 4B – 55 MW Combustion Turbine
- McManus CT 4F – 55 MW Combustion Turbine
- Scherer 3 – 644 MW Coal Steam Turbine

Including a planned derate of 71 MW at the Hatch nuclear plant, a total of 2,061 MW of GPC owned resources out of 14,092 MW of capacity resources (15%) were on outage during Southern Company's highest risk period during the storm.

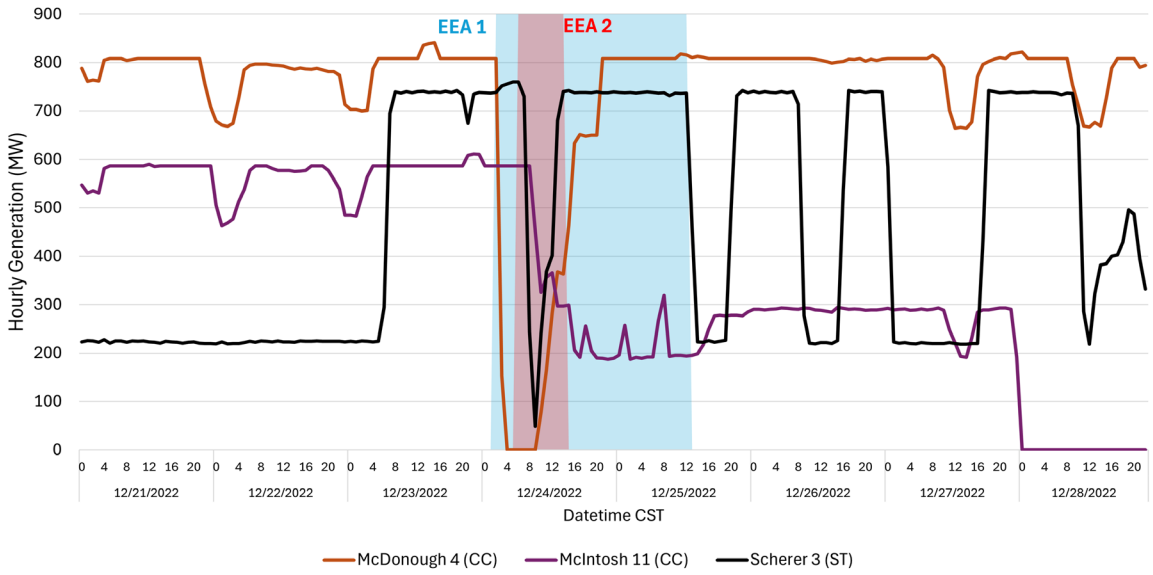


Figure 5. Hourly Generation for Large GPC Units with Outages During Winter Storm Elliott.

Figure 5 *(page 8)* shows the operations for McDonough Unit 4, McIntosh 11 and Scherer 3 based on GPC provided hourly generation data.

The timing of outages for each of the three units shown above varies, but the most significant impact is what the total amount of generation was on outage during the peak load hour. Based on Energy Information Administration winter ratings for these three units had 1,622 MW of reduced output during peak load. The worst-case level of reduced output for these three plants was 1,952 MW, one hour after peak load.

Figure 6 *(below)* shows the smaller unit outages during this period. Notably, McManus appears to have returned to service in time for the EEA 2 event. Both McDonough 3A, and McIntosh 2A, and McManus 4F were either unavailable during the EEA 2 event or unable to operate at their maximum rating.

The total amount of these plants operating below their rating during the peak load was 212.6 MW, one hour after peak load.

It is not unreasonable for power plant outages to occur during extreme weather conditions. Additional information provided by GPC indicated that the 2,061 MW of outages GPC experienced resulted in 15% of their total capacity resources on outage during the storm.

In addition to the GPC owned resources on outage, a total of 1,031 MW of GPC Capacity PPA resources were on outage during the storm. These units were not identified but represented 25% of GPCs capacity PPA resources. In total, 14.5% of the GPC owned and GPC PPA fleet experienced a forced outage during Winter Storm Elliott[4].

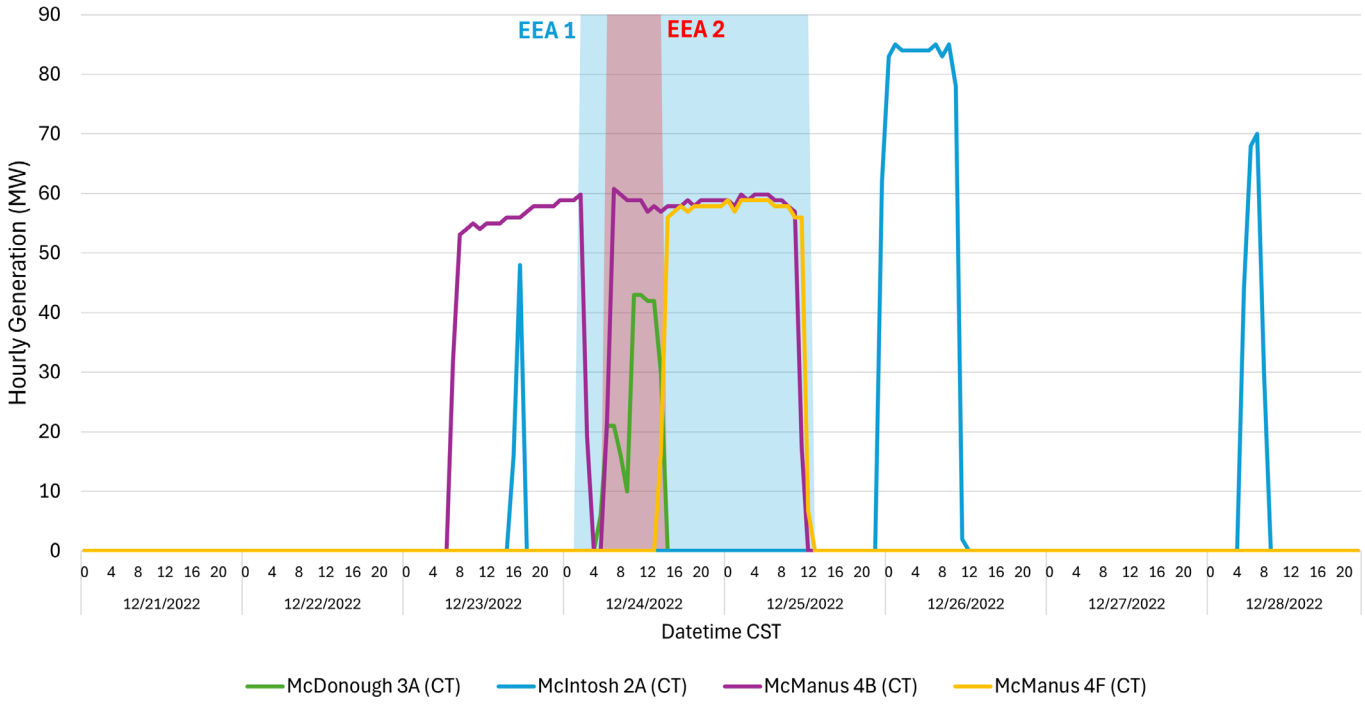


Figure 6. Hourly Generation for Small GPC Units with Outages During Winter Storm Elliott.

Performance of Non-Georgia Power Generators

The previous section only reviewed Georgia Power generators because the unit-specific data was made available in regulatory filings. To augment this data, a review of other Southern Company resources was conducted using publicly available data from the EPA CEMS database. All owned or PPA resources from Alabama Power, Mississippi Power, and Southern Power that were equipped with emissions monitoring systems were reviewed.

While only gross generation data is available, power plants that showed substantially low output or significant deviations during the emergency window (7 am to 9 am) were deemed potential outages.

4 Docket No. 55378, Georgia Power Company's 2023 Integrated Resource Plan Update – Hearing Request Set Number 1 (HR-1-1)

This assumes that the resources would have been utilized further, if available, to avoid EEA 2 and xpensive market purchases.

Performance of Alabama Power Generators

Review of Alabama Power fossil fueled generation showed three dual fuel gas/oil power plants with declining output or substantially reduced output. Figure 7 *(below)* shows the total plants hourly generation as a percentage of their winter rating based on EPA CEMS and EIA 860 data. These plants stand out because due to overall lower generation than might be expected during the event considering emergency purchases were required.

The three plants shown here are:

- 1,400 MW Greene County (owned by Alabama Power and Mississippi Power)
- 1,872 MW E C Gaston plant (owned by Alabama Power and Georgia Power), and
- 80 MW Calhoun Generating Facility.

During the emergency window, Greene County output was 318 MW lower than the maximum during EEA 1. E C Gaston output was 20 MW lower, but overall output was limited to only 65% of its capacity. Calhoun Generating Facility output was 255 MW lower. This behavior may be indicative of unit outages or fuel supply disruptions and a sign of correlated cold weather outages. In total, these three plants had reduced output of approximately 1,881 MW at their worst hour during the emergency window.

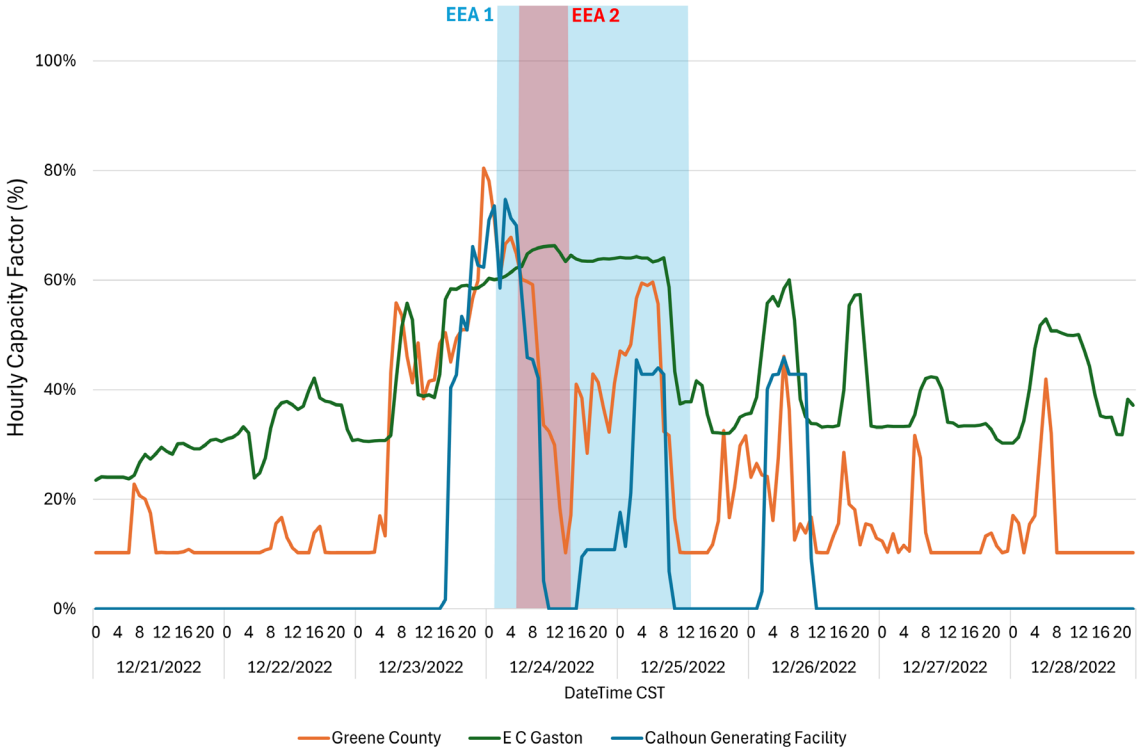


Figure 7. Alabama Power generation identified as having potential outages during Winter Storm Elliott.

In addition to the fossil fueled plants, Unit 1 at the 1,791 MW Joseph M Farley nuclear plant in Houston, AL was offline until the EEA event occurred. This unit represents 895 MW of capacity unavailable to the system due to a planned refueling outage. Typically, refueling outages aren't notable because they are scheduled in the shoulder season where risk is lower.

However, in 2022 the refueling outage for Farley 1 started on 9/18/2022 and didn't end until 12/22/2022 when the unit started slowing increasing output. This represents a 95 day outage for the unit. Typically refueling outages are between 30-45 days indicating the system faced higher risk in the winter due to the extended outage at the unit.

Figure 8 *(below)* shows the daily power reactor status report for Farley 1 from 12/21/2022 – 12/28/2022. Data is interpolated for each day since the reactor reports status at the beginning of each day. The squares on the chart represent the daily power reactor status report percentage of power output.

By the time of the EEA 1 and EEA 2 declaration Farley 1 was estimated to be between 18-30% of its rating, meaning an additional 638.4 - 733.9 MW had yet to ramp up. The extended refueling outage timeline exacerbated risks in December which is a highly volatile winter month.

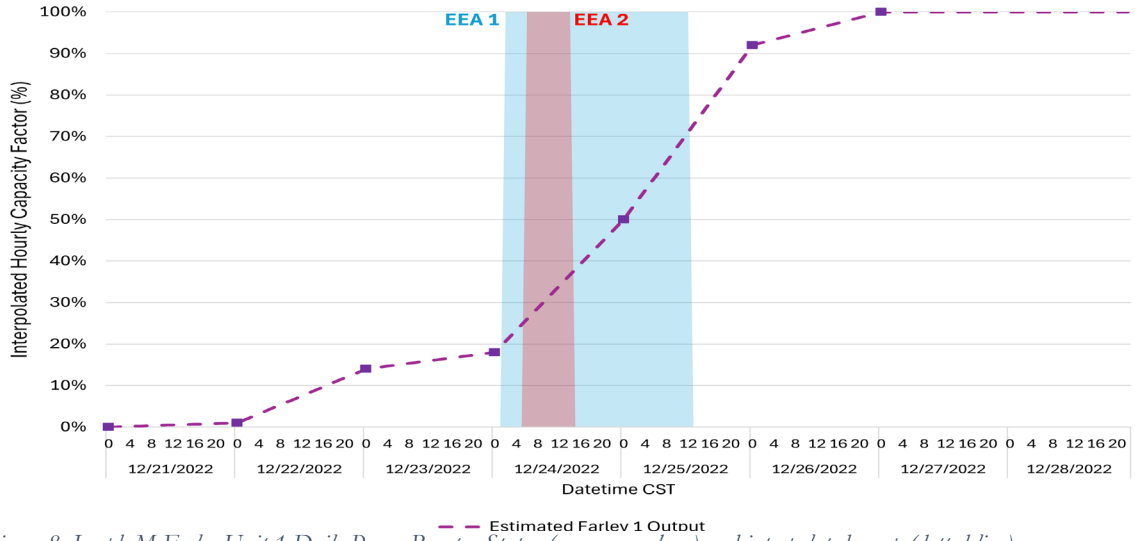


Figure 8. Joseph M Farley Unit 1 Daily Power Reactor Status (square markers) and interpolated ramp (dotted line)

Performance of Mississippi Power Generators

Review of Mississippi Power fossil fueled generation showed three plants where output leading up to the peak load hour was declining or well below its winter rating. Figure 9 *(page 12, top)* shows the total plants hourly generation as a percentage of their winter rating based on EPA CEMS and EIA 860 data.

These plants stand out because of substantial deviations in generation during the emergency window due to overall lower generation than might be expected during the event considering emergency purchases were required.

The three plants identified as having potential outages or were the:

- 41 MW Sweatt Electric Generating Plant
- 762 MW Watson Electric Generating Plant, and
- 2,180 MW Daniel Electric Generating Plant.

The Sweatt Electric Generating Plant appears to have been offline or unavailable throughout the entire period. This may indicate an extended outage that started before the storm.

This unit was flagged because no operations were found at any point during the EEA 2 period.

During emergency window, the Watson Electric Generating Plant output was 163 MW lower than its maximum during the EEA 1 period that morning. The Daniel Electric Generating Plant output was 436 MW lower. This behavior may be indicative of unit outages or fuel supply disruptions and a sign of correlated cold weather outages.

In total, these two plants' output during the emergency window was lower by 598 MW. Including Sweatt in the total brings it to 639.5 MW.

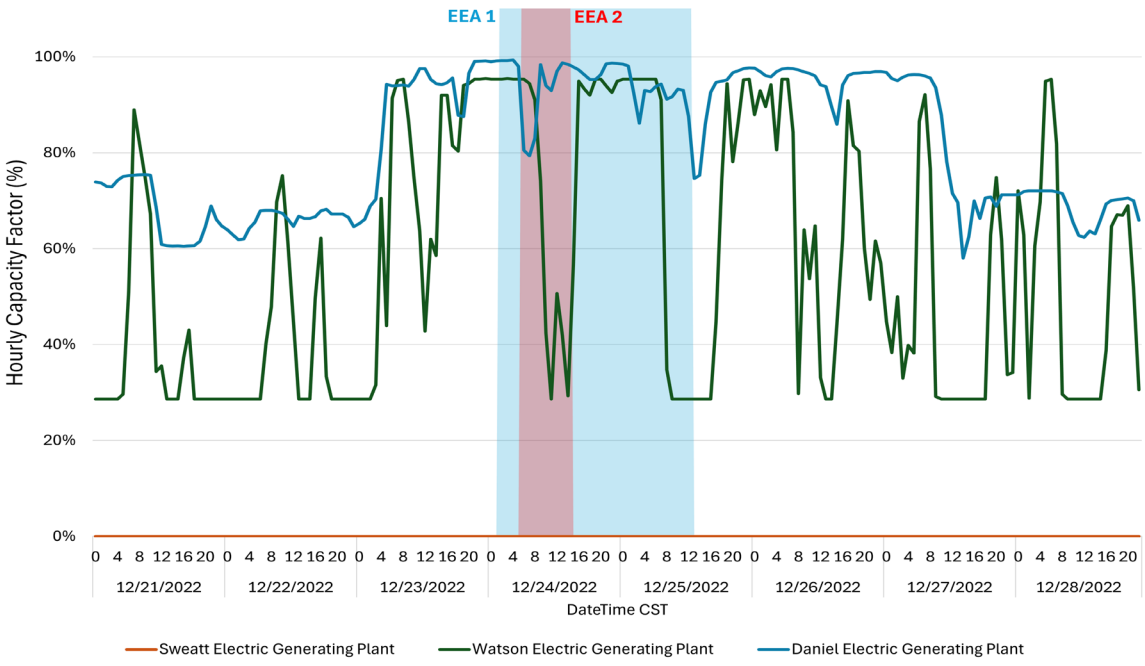


Figure 9. Mississippi Power generation identified as having potential outages during Winter Storm Elliott.

Performance of Southern Power Generators

Review of Southern Power fossil fueled generation showed two plants where output leading up to the peak load hour was declining or well below its winter rating. Figure 10 *(below)* shows the total plants hourly generation as a percentage of their winter rating based on EPA CEMS and EIA 860 data. These plants stand out because of substantial deviations in generation after EEA 1 and EEA 2 were declared and due to overall lower generation than might be expected during the event considering emergency purchases were required.

The two plants identified as having potential outages or derates during the EEA period were the 693 MW Edward L. Addison Generating Plant and the 1,233 MW Wansley Combined Cycle.

During the emergency window, the Edward L. Addison Generating Plant output was lower by 275 MW relative to the EEA 1 hours prior. The Wansley Combined Cycle output was 209 MW lower. This behavior may be indicative of unit outages or fuel supply disruptions and a sign of correlated cold weather outages. In total, these two plants' output during the emergency window was lower by 483 MW.

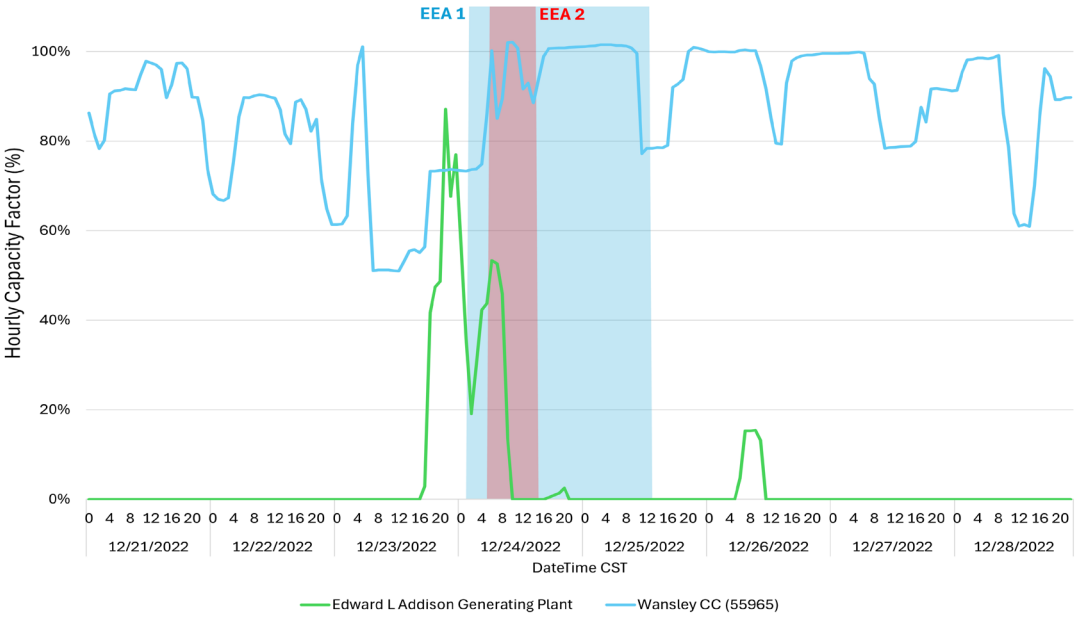


Figure 10. Southern Power generators identified as having potential outages during Winter Storm Elliott.

Performance of PPA Generators

In addition to utility owned assets, Southern Company and its subsidiaries also procure capacity and energy via PPAs.

These types of resources use a variety of fuels, including gas, landfill gas, oil, and biomass. EPA data is not available for non-utility generating units, nor units that are less than 25 MW in size. Due to this limitation, only those PPA units that are known to contract with Southern Company subsidiaries and met the size threshold or those that Georgia Power provided data on were reviewed in this section. Generation by plant for different fuel types is reviewed in the following subsections.

Biomass PPA Generator Performance

Data was only available for biomass generators reported in the Georgia Power IRP and provided in the docket request. Review of these units' output leading up to and during the peak load hour shows a general underperformance relative to the size of the PPA.

Figure 11 *(below)* shows the five plants that had zero output during the peak load hour. The hourly data shown also indicates little to no generation for these plants during the entire EEA 1 and 2 period. The total capacity unavailable during the emergency window was 230 MW out of 302 MW of biomass PPA resources.

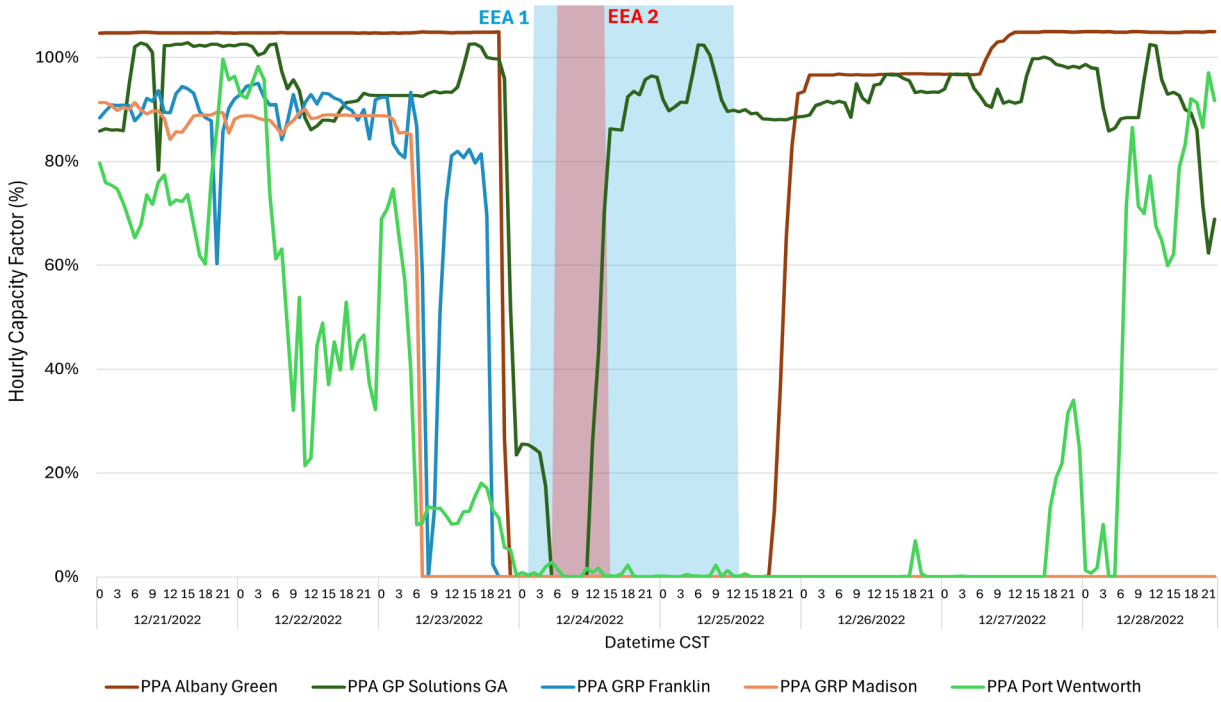


Figure 11. Georgia Power Biomass PPA generators identified as having potential outages during Winter Storm Elliot.

Landfill Gas (LFG) PPA Generator Performance

Data was only available for landfill gas generators reported in the Georgia Power IRP and provided in the docket request. Review of these units' output leading up to and during the peak load hour shows a general underperformance relative to the size of the PPA.

Figure 12 *(page 14, top)* shows that all five plants had zero output during the peak load hour. The hourly data shown also indicates no generation for these plants from 12/23/2022 to until the morning of 12/27/2022. The total capacity unavailable during the peak load hour was 32.3 MW and 100% of the LFG PPA resources.

Gas PPA Generator Performance

Several larger gas generators that are not owned by Southern Company also serve load via PPAs. A review of both the EPA CEMS data and data provided by Georgia Power shows that six plants had potential outages or derates leading up to the peak hour.

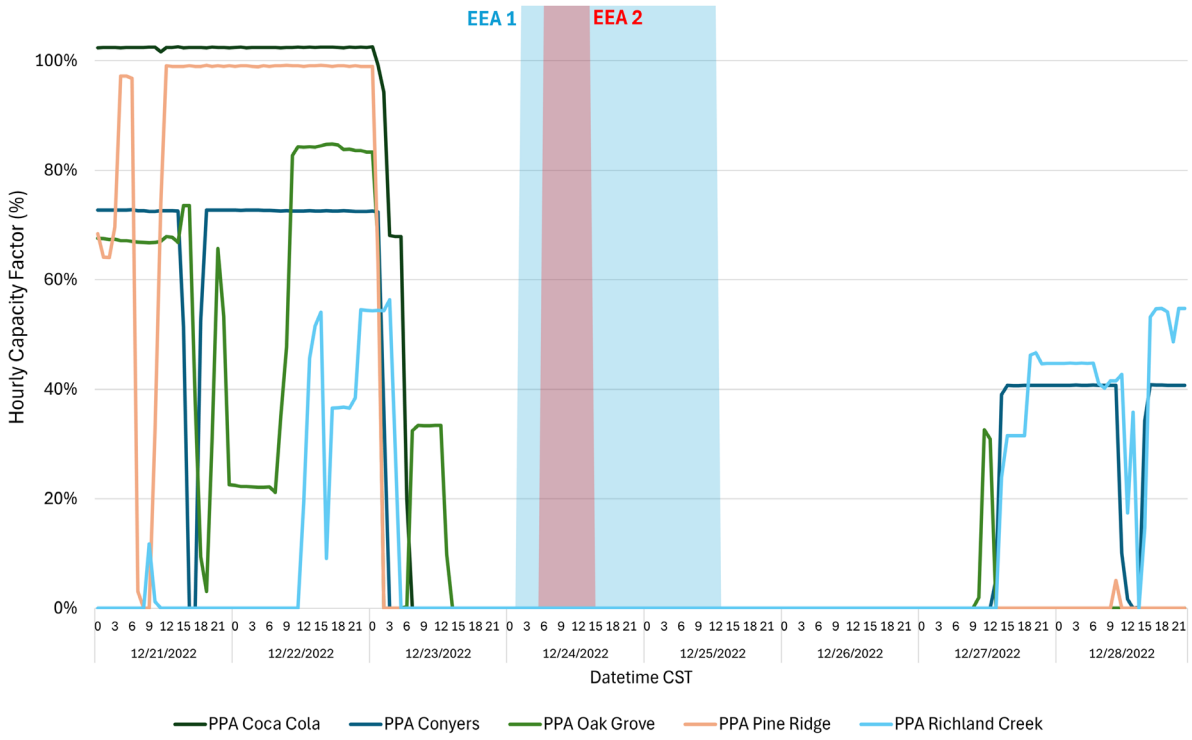


Figure 12 Georgia Power LFG PPA generators identified as having potential outages during Winter Storm Elliott.

Figure 13 (below) shows the hourly generation data for the plants using EPA CEMS data. These three units shown indicate likely low resource availability that is likely not attributable to Winter Storm Elliott except for potentially Washington County Power which sees a reduction in outFigure 13. Additional Southern Company PPA generators identified as put going into the EEA 1 period. Relative to their winter capacity ratings, the lack of generation totals 2,044 MW.

Additional information based on monthly net generation for each of the facilities in 2022 and 2021 indicate that there may have been extended outages at all three plants since monthly net generation was either 0 or substantially reduced in October, November, and December relative to the same months in 2021.

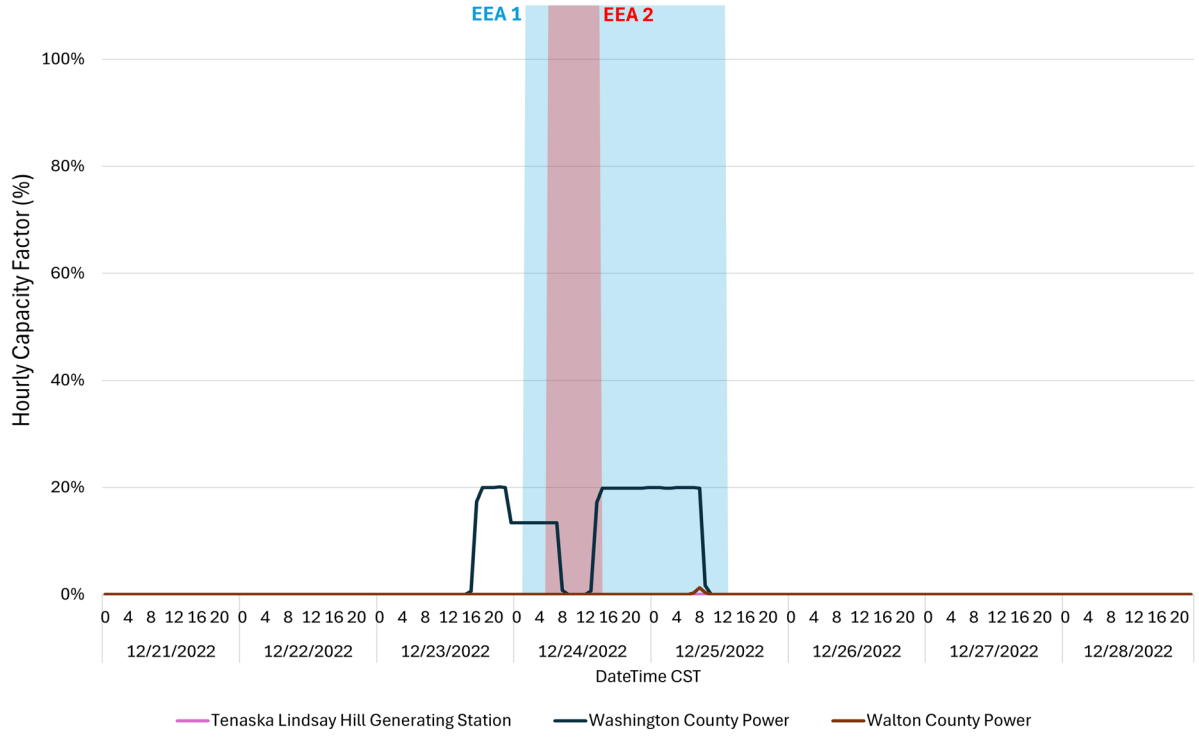


Figure 13. Additional Southern Company PPA generators identified as unavailable during Winter Storm Elliott based on EPA CEMS data.

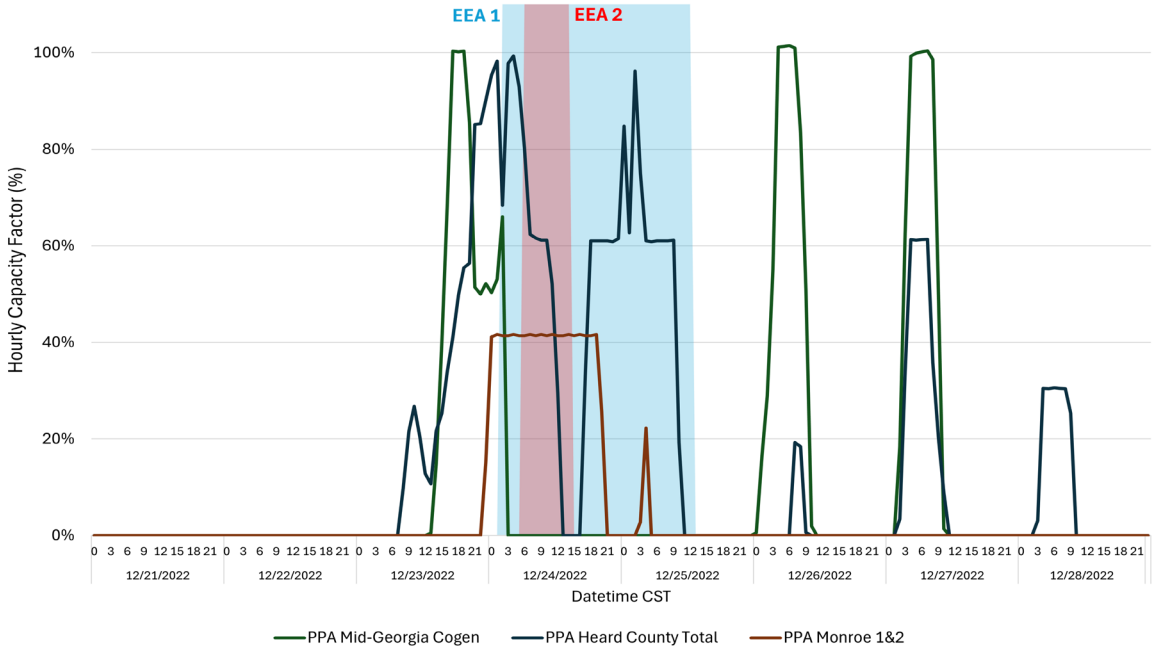


Figure 14. Additional Southern Company PPA generators identified as unavailable during Winter Storm Elliott based on Georgia Power data.

Figure 14 *(above)* shows the hourly generation data for additional PPA plants using Georgia Power provided data. The three plants are the 945 MW Exelon Heard facility (also called Tenaska Georgia Generating Station), the 300 MW Mid-Georgia Cogen, and the 360 MW Monroe plant (also called MPC Generating).

The data shown indicates that all three plants faced decreased generating capability during the emergency window. The Mid-Georgia Cogen plant has a noticeable drop in generation down to 0.

The Heard County plant has a similar trajectory where the plant is at full output prior to the event and eventually drops to 62% output during the peak load hour. Lastly, the Monroe facility was operating only at 41% output due to no generation from Monroe unit 2 during the EEA period. In total, these plants provided 727 MW of output during the emergency window relative to their total 1,635 MW winter ratings.

Evaluating Incremental Cold Weather Outages

In their 2022 IRP, Georgia Power shared the Southern Pool's assumptions on incremental cold weather outages for Southern Company resources. Their recognition that cold weather increases the probability of generators going on outage is a best practice; however, the data provided is highly aggregated, assuming all unit types are affected equally, and only shown at the pool level.

Risks will vary by fuel type and by region in the pool and should be communicated as such.

Additionally, Southern Company assumed in their analysis that actions they took reduced cold weather outage risks in the future relative to the historical period. This is shown by the shift down and to the left of the orange line (assumed improvements) relative to the blue line (historical performance) in Figure 15

Considering Winter Storm Elliott and upcoming IRPs, these assumptions should be re-evaluated to ensure they are valid. The results of applying these assumptions to their modeling process should be documented in more detail to show the magnitude of additional outages that can occur as temperatures drop. Reporting the worst-case fleet availability level rather than just the incremental effect would go a long way in properly communicating what cold weather risks look like for the generation fleet.

Based on the data from the 2022 Georgia Power IRP, the fleetwide incremental cold weather outages are shown in Figure 15 *(page 16, top).* Based on Figure 15 and an average temperature of 7 degrees F during the morning of 12/24/2022 across Southern Company the improved incremental outage rate was 2.77%. The original incremental cold weather outage rate was 5.28%.

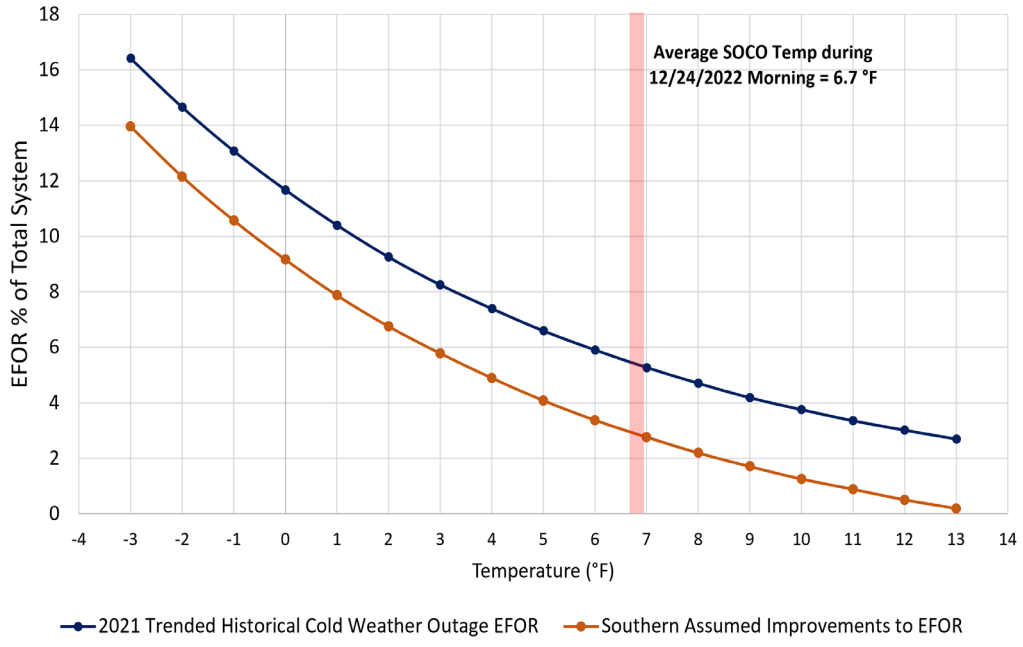


Figure 15. Incremental Equivalent Forced Outage Rate (EFOR) at the Total Southern Company System.

Given that Georgia Power alone experienced a 15% reduction in capacity due forced outages during the storm, the assumed incremental outage rates of 2.77% discussed above appear to significantly underrepresent winter outage risks for the system. Therefore, these assumptions should be revisited and results of the analysis should be transparent for stakeholders.

The challenges due to cold weather outages reinforce the need for all resources to be evaluated for their firm capacity contribution using probabilistic methods just like wind, solar, and battery storage.

As discussed, another issue is that the company-wide risk due to cold weather outages remains unclear since reported data is missing for Alabama, Mississippi, and Southern Power owned units and PPAs during the event. This report has estimated the performance of these plants, but actual detailed information is needed.

Furthermore, Georgia Power only provided information on outages that occurred on the peak load day of December 24, 2022. Extreme cold weather affected the entire region prior, during, and after the worst day while temperatures were still low, and the effects of cold weather outages could have occurred on other days than the peak day.

Performance of Renewable Resources

Figure 16 *(below)* illustrates the total generation from solar resources within the Southern Company balancing authority footprint during the storm. As expected, solar resources did contribute to meeting demand throughout the day, but in the early morning hours output was limited. Compared to other winter peak events, solar performance was generally stable, but its role in peak support remains constrained due to the lack of irradiance at critical morning and and

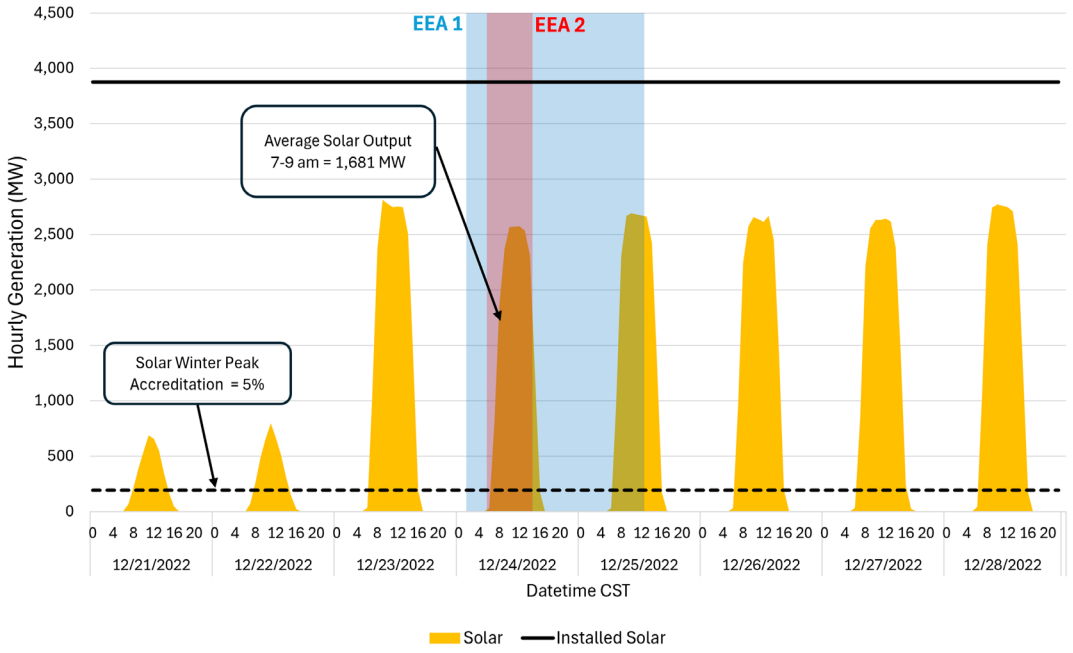


Figure 16. Solar generation for the entire Southern Company Balancing Authority during Winter Storm Elliott.

Month-Year	Peak Load Hour	Peak Load (MW)	Solar Capacity Factor at Peak
January 2019	1/30/19 6:00	40,450	1%
January 2020	1/22/20 6:00	40,410	1%
February 2021	2/17/21 6:00	40,922	4%
December 2022	12/24/22 7:00	45,131	21%
December 2023	12/20/23 7:00	37,890	23%
January 2024	1/17/24 6:00	47,368	2%

Table 3. Southern Company Balancing Authority solar capacity factor during historical peak load hours based on EIA data.

evening peaks. This shows that while solar production was low on the days leading up to the extreme cold event, production was high in the day prior to, and during, the event. This suggests that in the future, with increased battery storage resources, solar resources can improve reliability even if they are unavailable during the early morning peak load hours.

Table 3 *(above)* shows historical peak load and solar output relative to installed capacity for the 2019-2024 winter peak load events in the Southern Company Balancing Authority according to EIA 930 and EIA 860 data. Solar resources are not expected to contribute to winter peak load and utilities plan for this accordingly.

For example, the 2022 Georgia Power IRP evaluated the capacity accreditation for solar resources and determined their winter accreditation is 0-10% depending on the type of solar array and the penetration on the system[5]. Results in Table 3 and Figure 16 indicate that solar performed well above it's expected contribution during Winter Storm Elliott.

Other historical peak loads show performance can vary widely, largely driven by whether peak loads occur between 6-7 am based on the data shown. While solar generation during winter peak loads can vary, if battery storage resources are added alongside solar then greater utilization can be achieved, especially for early morning peak load hours in the wintertime. Currently, battery storage deployment is limited in Southern Company.

It is clear though that prior to the extreme events occurring on December 24, 2022, that storage resources could have been charged in advance to mitigate the hours of highest peak load enhancing resilience by rapidly offsetting unexpected generator outages and increasing system flexibility. Furthermore, solar, storage, and wind resources create portfolio effects that can boost the total renewable systems capacity accreditation. These effects should be evaluated and accreditation refined over time.

Recommendations to Improve Planning for Cold Weather Outages

The following are recommendations on how Southern Company and its subsidiaries can provide greater clarity on how the generation fleet performs under cold weather conditions and how to better represent the risks that all generation faces when planning for new generation resources to meet demand or replace retirements:

1. **Conduct transparent evaluation of how increases to power plant outages due to cold weather. Current information is from the Georgia Power 2022 IRP and only provides fleetwide incremental outages.**
2. **Assess whether assumed cold weather outage improvements in 2021 have been effective.**
3. **Assess all future resource addition options based on every resource type and its effective load carry capability (ELCC) like how wind, solar, and battery storage is assessed. This necessitates including cold weather outages in the assessment.**
4. **Provide transparency on the current capacity accreditation assumed for all resources. Historical accreditation using incremental capacity equivalent (ICE) is redacted in previous full IRP filings.**

5 2022 GPC IRP, Study of Renewable Capacity Values using the ELCC Methodology in the Southern Company System, December 2021.

Emergency Power Purchases and Costs

One key reliability feature of the bulk power system is the ability to import power from neighboring regions to alleviate stress during extreme events.

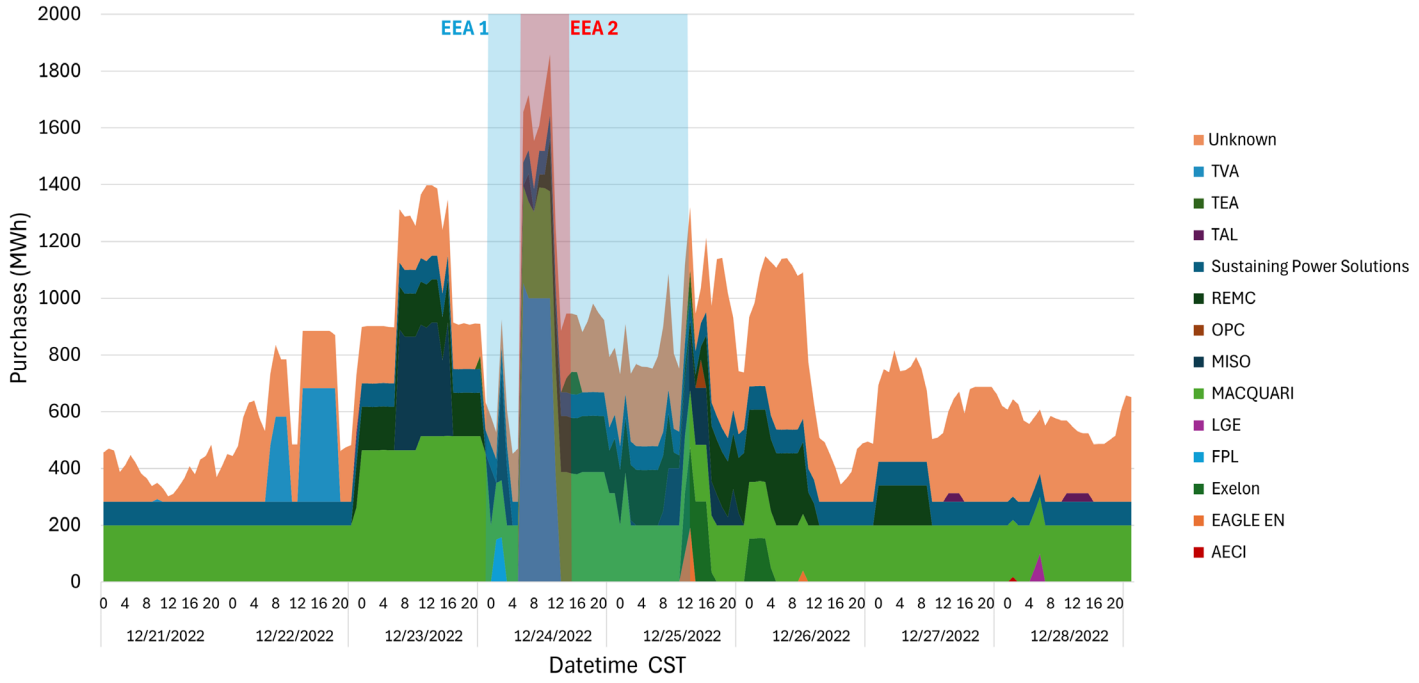


Figure 17. Winter Storm Elliott - Southern Company Known and Estimated Purchases by Source.

Even in vertically integrated areas like the Southeast, energy exchanges play a crucial role in balancing supply and demand and ensuring system reliability, especially during emergencies such as Winter Storm Elliott.

However, these regions typically lack transparency about where emergency power originates and its cost to customers, limiting public oversight of emergency spending and raising questions about planning for reliable external support an ensuring that prices are based in some transparent fashion.

In response to regulatory data requests, some data for Georgia Power was released, though comprehensive data for the full Southern Company system remains unavailable. By matching resource IDs and timestamps from Georgia Power with anonymized data from other Southern Company entities, it was possible to estimate the source, magnitude, and cost of emergency power for the broader system.

However, only Georgia Power Company transactions are shown with complete information regarding the source and price of power, while non-GPC transactions are based on estimations.

Figure 17 *(above)* displays all purchases by source including estimated and unidentified purchases for all Southern Company entities.

Note that outside of known balancing authorities, the exact power plants and owners are uncertain so additional tracking to what kind of units are providing the power is difficult to accomplish.

Price Variability by Seller and Estimated Costs

Throughout Winter Storm Elliott, prices varied significantly depending on the seller. This variation is expected during extreme events as regions experience fluctuating spare capacity. Figure 18 *(below)* illustrates the known and estimated costs of power purchased by Southern Company by seller, with unknown purchases estimated based on the average price for known purchases during each hour. In total, emergency purchases cost $51 million, or $350/MWh.

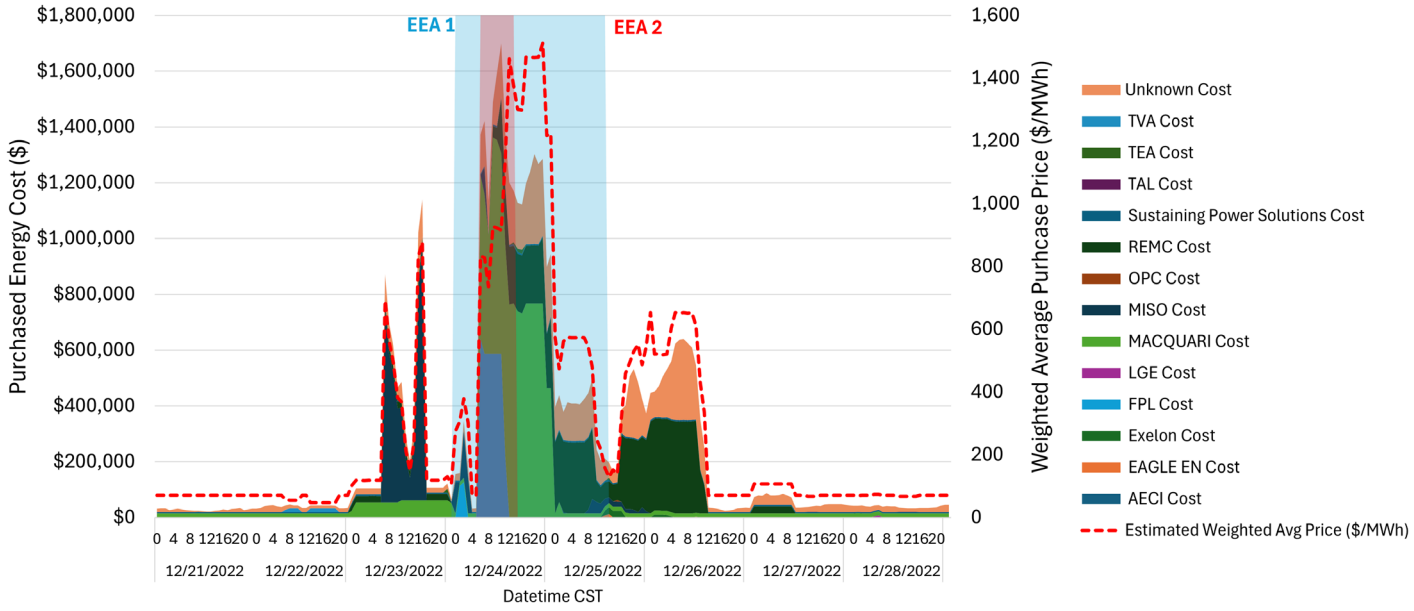


Figure 18. Winter Storm Elliot - Southern Company Estimated Cost by Source.

Table 4 *(page 20)* provides a summary of purchase data available via Georgia Power's discovery request, including estimates for all Southern Company purchases matched with GPC resource IDs, where prices for matched sellers were set to the GPC rate. For transactions labeled "unknown," no GPC resource ID was available for matching.

This summary highlights several points: while energy costs generally track with total MWh purchased, certain sellers exhibited disproportionately high prices. For instance, purchases from REMC, MISO, and FPL accounted for a much higher percentage of total costs compared to MWh purchased.

Specifically, REMC transactions represented only 9.9% of the total MWh but contributed 24.3% of total costs due to elevated prices that persisted well after EEA 1 and EEA 2 conditions had ended.

The price formation for non-market regions like MISO lack transparency, making it difficult to determine the reasons behind these elevated rates. It is expected that prices across the region will be high during the event.

But the reason some prices were $400/MWh versus $4,000/MWh is worth providing more detail on.

Other sellers also contributed to high overall costs, notably Macquarie and FPL. FPL provided 6,736 MWh at an average price of $599/MWh, reaching a peak of $1,000/MWh. Macquarie, supplying roughly 33% of Southern Company's total purchased MWh during the event, averaged $330/MWh, with some purchases reaching as high as $4,000/MWh during EEA 2.

Such data points suggest the potential for substantial savings if lower-cost alternatives were available and less market power given to emergency purchases by planning for a more resilient system.

Seller Name	Total MWh	% of Total MWh	Total Cost ($)	% of Total Cost	Average Price ($/MWh)	Max Price ($/MWh)
AECI	18	0.0%	$946	0.002%	$53	$54
EAGLE EN	331	0.2%	$22,015	0.04%	$67	$70
Exelon	2,045	1.4%	$160,005	0.31%	$78	$85
FPL	6,736	4.6%	$4,033,643	7.85%	$599	$1,000
LGE	146	0.1%	$12,182	0.02%	$83	$96
MACQUARI	48,596	33.2%	$16,053,050	31.24%	$330	$4,000
MISO	6,909	4.7%	$5,246,666	10.27%	$764	$2,832
OPC	100	0.1%	$6,000	0.01%	$60	$60
REMC	14,498	9.9%	$12,518,350	24.36%	$863	$1,300
Sustaining Power Solutions	15,936	10.9%	$987,235	1.92%	$62	$62
TAL	270	0.2%	$8,730	0.02%	$32	$36
TEA	357	0.2%	$56,714	0.11%	$159	$303
TVA	3,909	2.7%	$128,399	0.25%	$33	$44
Unknown*	46,633	31.8%	$12,118,397	23.58%	$260	$1,081
Total Purchases	146,484	100%	$51,382,333	100%	$351	$4,000

Table 4. Summary data by Southern Company during Winter Storm Elliott based on GPC Data (12/21/2022 - 12/28/2022).

Implications of Non-Transparent Price Setting

This review of emergency power purchases underscores the wide range of prices paid by Georgia Power to different sellers during Winter Storm Elliott, revealing challenges inherent in a system without transparent locational marginal pricing (LMP) for transactions in vertically integrated regions like the Southeast.

In contrast, neighboring regions impacted by Winter Storm Elliott, such as MISO, provide LMP data that reflects both energy production and transportation costs, including information on transmission congestion and losses.

Notably, MISO provides real-time price data at its interface with Southern Company in Mississippi, updated on a five-minute basis. This level of pricing transparency allows stakeholders to verify that prices reflect actual market conditions.

For Southern Company customers, the lack of similar transparency represents a challenge, particularly in the context of high emergency costs.

Currently, neither Georgia Power's public data nor the Southeast Energy Exchange Market (SEEM), reviewed in detail in the next section, offers information on price formation, especially under stress conditions.

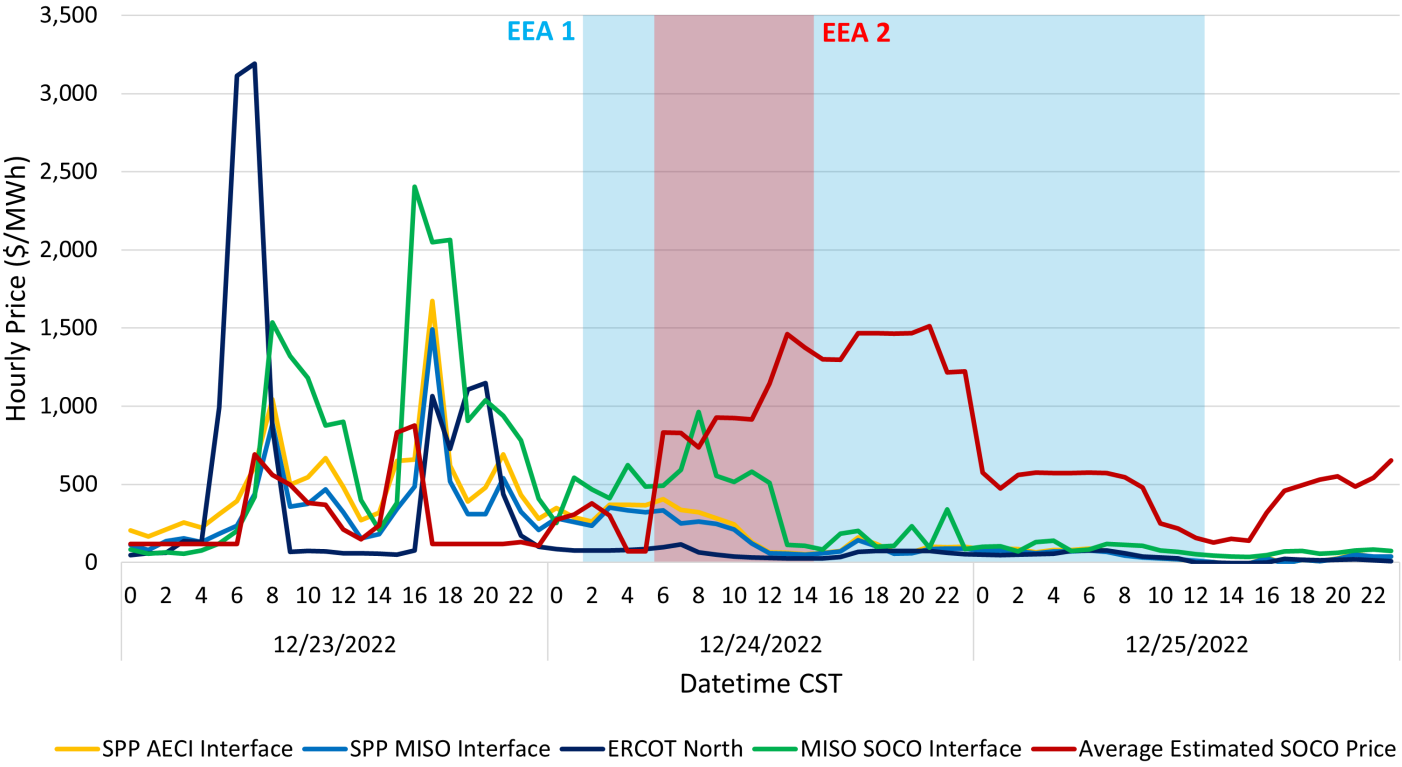


Figure 19. Average Known Southern Company Purchase Price vs Nearby Market LMP ($/MWh)

This limitation prevents customers from understanding the rationale behind emergency prices and assessing whether costs could have been mitigated through better planning or interregional coordination.

Opportunities for Interregional Transmission to Improve Reliability and Reduce Costs

Reviewing LMPs for nearby regions highlights potential cost savings and reliability benefits that increased imports from neighboring regions could provide if transmission were available.

Enhanced interregional transmission connections with transparent pricing could offer more reliable access to affordable external resources.

Figure 19 *(above)* shows that prices in ERCOT, SPP, and MISO (at the Southern Company interface) were considerably lower than GPC purchase prices on December 24 and 25, when generation weighted known prices averaged over $1,000/MWh.

Leveraging interregional transfers could thus help Southern Company meet peak demands more cost-effectively during future extreme events, while offering customers clearer insights into price formation.

Southeast Energy Exchange Market Performance

The Southeast Energy Exchange Market (SEEM) began operations in November 2022, just one month before Winter Storm Elliott stressed power systems across the Southeastern United States. SEEM was designed to facilitate voluntary bilateral energy trade across the region, providing participants with a way to exchange surplus energy efficiently.

However, during the critical hours of December 24th, 2022, when the Southern region declared EEA 1 and EEA 2 energy emergencies, publicly available data shows that no exchanges occurred among SEEM participants. This absence of trades highlights questions about SEEM's role in supporting reliability during peak demand events and the broader applicability of its platform under emergency conditions.

While SEEM data is anonymized, the platform generally shows transaction volumes across different periods, allowing observers to see broad trends without detailed participant information. Analysis of SEEM's transaction volumes during Winter Storm Elliott suggests low utilization by market participants at a time when system operators were under significant stress to maintain grid stability. This could be attributed, in part, to SEEM's novelty or uncertainty about the available capacity and pricing under extreme conditions.

However, low activity in SEEM during the storm aligns with the independent market auditor's reports[6], which indicate that SEEM transactions were limited during cold weather events, potentially due to limited availability of surplus energy and participant hesitancy during tight grid conditions. Despite SEEM's low trading volume during Winter Storm Elliott, bilateral transactions outside SEEM were still active across the region. Southern Company, for example, engaged in multiple direct purchases during this period, reflecting a preference for more established bilateral agreements rather than SEEM exchanges under emergency circumstances.

This trend indicates that SEEM's structure may not yet fully align with participant needs during stress events, when timely and cost-effective energy transactions are most critical.

SEEM Performance in Subsequent Winter Peak Events

Since Winter Storm Elliott, SEEM has continued operating through subsequent winter peak load events, but its performance under these conditions has similarly shown limited market activity during peak demand periods. This ongoing trend suggests that SEEM, while potentially valuable for regular trading, has not become a resource for emergency support during peak conditions such as those that occurred during Winter Storm Heather[7].

Furthermore, the anonymized structure of SEEM data limits participants and stakeholders from understanding price formation or the dynamics of energy exchanges during tight conditions, in contrast to organized markets like MISO or PJM, where locational marginal pricing (LMP) provides detailed price signals reflecting supply and demand fluctuations in real time.

In summary, SEEM's first significant test under Winter Storm Elliott highlighted critical limitations in the platform's ability to facilitate energy exchanges during emergencies.

Its low utilization during peak load events like Winter Storm Elliott and Winter Storm Heather calls into question its ability to aid the system in matching economic transactions during reliability events. As a result, SEEM may not yet be equipped to provide meaningful support for system operators or offer cost-effective, transparent solutions for ratepayers during critical grid conditions.

6 Potomac Economics, Monthly Audit Report on the Southeast Energy Exchange Market - December 2022, January 31, 2023.
7 Potomac Economics, Monthly Audit Report on the Southeast Energy Exchange Market - January 2024, February 29, 2024.

Conclusion and Recommendations

This report examined Southern Company's generation fleet performance, load forecasting accuracy, and market transactions during Winter Storm Elliott. While Southern Company successfully managed the event without resorting to involuntary load shedding, the system operated under tight conditions, revealing areas where improvements in resource reliability, forecasting, and market transparency could enhance resilience against future weather-related stress.

Additionally, the Southeast Energy Exchange Market (SEEM), which had launched only a month earlier, showed minimal trading activity, highlighting opportunities for enhancements to support reliability during emergencies. Questions remain regarding how the system might have performed if demand had been higher, such as on a non-holiday weekday when electricity use is typically greater.

These considerations underscore the need for a deeper examination of how risk is evaluated in system planning and how potentially high-value opportunities to mitigate risk from extreme weather (such as by improving energy efficiency and increasing access to interregional resources) are assessed. This is of particular importance for extreme winter events which have high uncertainty on both generator outages and electricity demand.

To address these challenges, the following actions would benefit both Southern Company and stakeholders in improving transparency and ensuring reliability.

1. **Enhance Thermal Resource Evaluation:** Future grid planning should improve methods for evaluating the capacity contribution of thermal resources. Rather than discounting by average forced outage rates, planning should reflect the real correlated outage risk of these resources during extreme events. Consistent with the evaluation approach for wind and solar resources, this revised methodology would provide a more accurate picture of available capacity during winter peak demands and extreme weather events.

2. **Reassess Incremental Cold Weather Outages:** Southern Company should re-evaluate incremental cold weather outage assumptions, disaggregating data by fuel type rather than applying fleet-wide assumptions. Analyzing outage probabilities by fuel type could highlight distinct vulnerabilities and more accurately inform resource adequacy planning for cold weather conditions.

3. **Increase Transparency:** Southern Company should establish more transparent mechanisms for purchased power and emergency cost formation. Adopting some form of locational marginal pricing (LMP) across the Southern Company territory would align emergency prices with real-time market conditions, offering regulators and customers a clearer understanding of cost drivers during emergencies as they relate to both the price of energy and the cost of transmission.

4. **Enhance SEEM Functionality and Transparency:** Based on SEEM's limited use during Winter Storm Elliott, improvements should be considered to enhance its role in reliability. The platform could incorporate faster price signaling or offer day-ahead market signals to increase utilization during peak events. Recommendations already exist from the SEEM independent auditor to improve performance. Current reviews of SEEM by FERC also offer a chance to improve operations during emergencies, particularly with external regions into SEEM.

5. **Evaluate interregional transmission opportunities to mitigate winter reliability risks by accessing low cost and uncorrelated resources in external regions.** It is well documented that interregional transmission can provide substantial resource adequacy and resilience benefits. Long-term and multi-value transmission planning should be adopted in the region.

6. **Evaluate targeted energy efficiency opportunities to reduce load and volatility during cold weather events, including building envelope efficiency improvements and more efficient heating programs to mitigate winter load volatility.**

By implementing these recommendations, Southern Company and its stakeholders can strengthen reliability, ensure resource adequacy, and reduce costs under extreme weather conditions. A focus on accurate resource evaluation, refined forecasting, and transparent pricing mechanisms will better equip the region to manage future winter peak events effectively.

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SREA EXHIBIT AP-3:

J. Michael Hagerty, Peter Heller & Evan Bennett, Modernizing Southeast Grid Investments: How Enhanced Regional Transmission Planning Supports a Growing Economy, Brattle, (2025)

Modernizing Southeast Grid Investments: How Enhanced Regional Transmission Planning Supports a Growing Economy

PREPARED BY

J. Michael Hagerty

Peter Heller

Evan Bennett

APRIL 2, 2025

Brattle

PREPARED FOR

CCEBA Carolinas Clean Energy Business Association

CEBA Clean Energy Buyers Association

SOUTHERN RENEWABLE ENERGY ASSOCIATION

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Executive Summary

Southeast Must Invest in Regional Transmission to Cost-Effectively Meet Growing Demand and Maintain Reliability

Facing unprecedented load growth and increasing reliability risks, Southeast utilities need to invest in their regional transmission systems to improve reliability and reduce costs.

- **4x Increase in Transmission Costs over Last 20 years:** Spending on utility-specific upgrades increased during a period of moderate load growth due to aging infrastructure and new generation capacity needs
- **20 GW of Load Growth in Next 10 Years:** Serving the rapid 25% increase in load cost-effectively requires identifying opportunities for regional projects to supplement local upgrades and reduce system costs
- **80 GW of New Generation to Serve Load:** New generation (gas, solar, and storage) faces cost & schedule risks due to limited transmission capacity, which can be mitigated by proactive regional upgrades
- **Increasing Severity & Frequency of Winter Storms:** Winter storms have created new reliability risks over last 5 years that drive a need for both regional and interregional upgrades

Recent national studies find a significant need for new regional transmission across the Southeast.

Yet, all recent Southeast transmission upgrades are based on utility-specific local transmission planning* that has not considered the benefits of supplementing local upgrades with larger, more cost-effective regional and interregional transmission projects.

*In some portions of the Southeast (e.g., GA, NC, and SC), utilities within the same state collaborate on "local" reliability-driven transmission planning for their service territories.

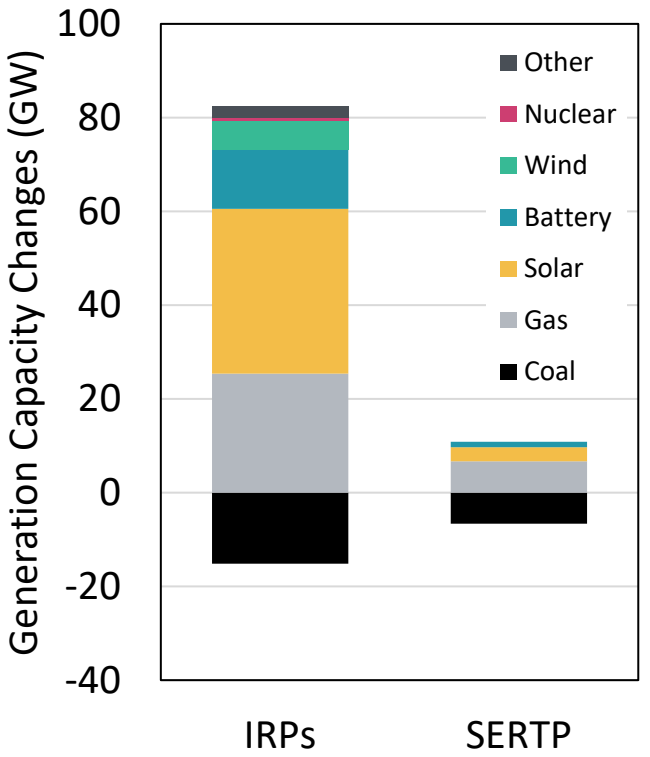
Existing Regional Planning Process Results in Insufficient Investment in the Regional Transmission Network

Southeastern Regional Transmission Planning (SERTP) completes an annual "bottom-up" regional planning process that has several limitations for identifying beneficial regional upgrades.

- **Limited Scope**: SERTP aggregates local planning studies and confirms regional reliability for a single future load scenario, failing to utilize scenarios developed in Sponsors' resource planning studies
- **Inconsistent with IRPs**: SERTP studies include just 12% of the 80 GW of new generation identified as needed by the most recent IRP studies
- **Lack of Transparency:** SERTP provides limited information on transmission costs, violations, or alternatives studied to meet needs
- **No Regional Projects Approved**: SERTP analyzes regional alternatives based on a limited set of system needs, resulting in no regional upgrades in 11 years of SERTP regional planning studies

Existing SERTP planning process will not identify and approve the most cost-effective transmission infrastructure to reliably serve future load

IRP vs SERTP 2035 Generation Changes
(TVA, Duke, LG&E/KU, GPC)



Recommendations to Enhance SERTP Regional Planning that will Reduce Costs and Increase Reliability of the Southeast Grid

Exhibit AP-3

SERTP can leverage industry-wide experience over the past 20 years by implementing proven practices to reduce long-term system costs and risks, including the MISO LRTP and CTPC/Duke MVST planning processes

I. Improve Existing Planning Process

1. **Increase transparency** of study assumptions, approach, and results
2. **Engage state commissions and energy agencies** to participate in process and ensure results reduce costs and address state policies
3. Expand solutions studied to reflect **least-cost transmission "loading order"** that maximizes existing grid, upgrades existing lines, and builds new lines where necessary

II. Expand SERTP Planning Capabilities

4. Develop **multiple scenarios based on recent IRPs** to plan for a range of load and generation portfolios
5. Accurately identify congestion and quantify cost savings of regional upgrades via **region-wide production cost model**
6. Develop guidelines to evaluate a **comprehensive set of cost savings and other benefits** when analyzing regional upgrades

III. Implement Comprehensive & Proactive Planning Process

7. Implement **multi-driver approach to identifying regional & interregional needs** and candidate solutions
8. Estimate cost savings and other benefits of solutions **over the entire useful life of the assets**
9. Establish regional cost allocation that reflects **beneficiaries pays and cost causation principles**

Case Study: SERTP-Identified Upgrades Reduce Costs

To demonstrate the value for regional transmission, we performed a high-level analysis of three 500 kV upgrades SERTP identified in its 2024 process based on historical data.

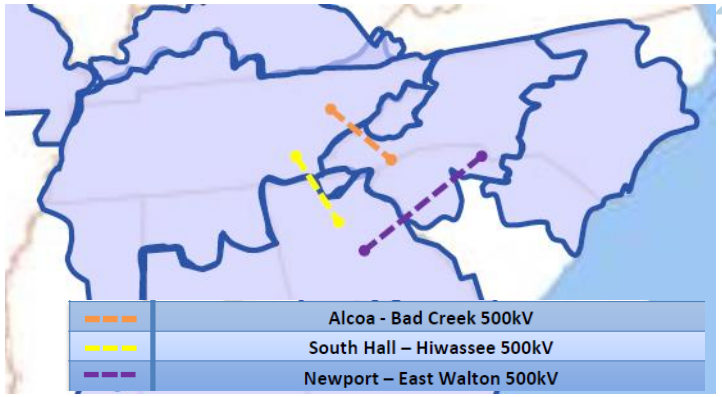
We estimated $8 billion of benefits compared to $5 billion in costs, resulting in at least $3 billion of net benefits

- Production cost savings: $2.9 billion (*range*: $2.0–3.6 billion)
- Load diversity cost savings: $3.3 billion (*range*: $0.9–6.0 billion)
- Resilience benefits: $1.6 billion (*range*: $0.7–2.3 billion)
- Additional potential benefits: avoided reliability and interconnection upgrade costs, greater production cost savings with increased solar/wind additions and reduced generation costs

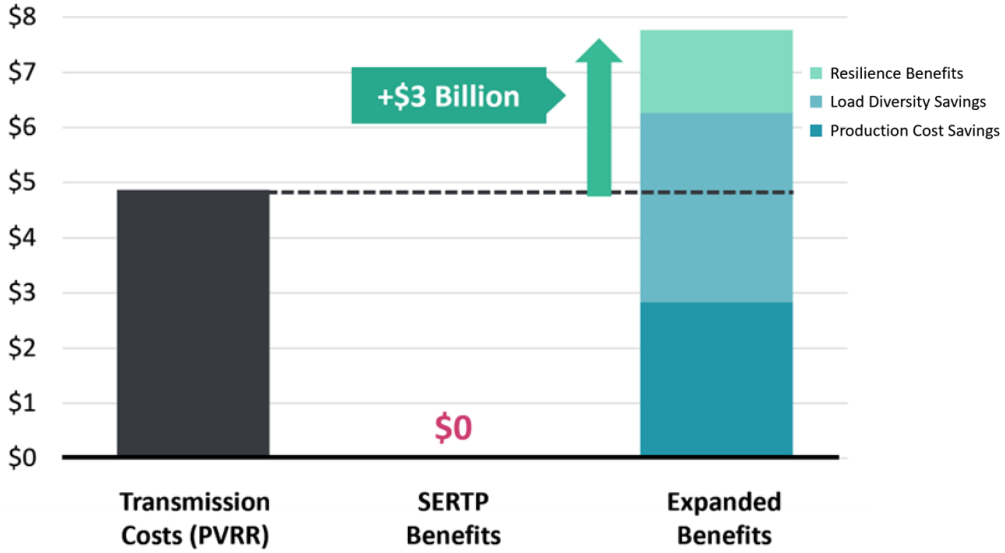
Regional transmission can reduce system costs when a broader scope of cost savings and other benefits are analyzed

By contrast, SERTP's very narrow view of benefits based solely on avoided local transmission costs identified no cost savings

SERTP-Identified Regional Projects



Estimated Net Benefits of Regional Projects



Order 1920 Provides Southeast Opportunity in 2025 to Enhance its Regional Transmission Planning Process

- **Southeast is the only major U.S. region that has not pursued significant regional transmission projects over the past decade**
- **The lack of proactive regional transmission planning process results in higher costs, lower reliability, and delays in serving growing load due to insufficient grid infrastructure**
- **FERC issued Order No. 1920 last year that requires SERTP to implement a proactive, long-term, multi-value regional planning process, presenting a pivotal opportunity for the Southeast to align its regional transmission planning with industry best practices developed over the past 10–20 years**
- **The Southeast should embrace this opportunity in 2025 to modernize SERTP's regional transmission planning to build a stronger, more efficient grid that supports economic growth, energy affordability, and long-term resilience**

Report Contents

I. The Southeast Must Invest in Regional Transmission to Cost-Effectively Meet Growing Demand and Maintain Reliability

II. SERTP Regional Transmission Planning Process Is Insufficient to Meet Future System Needs

III. Recommendations to Enhance SERTP Regional Transmission Planning

IV. Why the Southeast Needs to Modernize Its Regional Planning Process Now to Reduce Costs and Increase Reliability

I. The Southeast Must Invest in Regional Transmission to Cost-Effectively Meet Growing Demand and Maintain Reliability

Southeast Needs to Invest in its Transmission Infrastructure

Facing unprecedented load growth and increasing reliability risks, Southeast utilities need to invest in their transmission systems to **improve reliability** and **reduce cost**.

Local Reliability Needs Increased Transmission Investment by 4x

- Local reliability projects are increasing due to load growth, new generation, and aging infrastructure
- In-kind replacements will miss opportunities to more cost-effectively expand system capabilities
- No investment in regionally-planned transmission projects

Load Growth Increases Need for Regional Transmission Investment

- Growth being driven by commercial and industrial activity will increase needs for infrastructure
- Proactive transmission upgrades can increase system capacity and allow new loads to interconnect more quickly

Insufficient Regional Capacity Increases Winter Risks and Customer Costs

- Regional transmission capacity increases resilience to extreme weather events and reduces likelihood of outages
- Regional projects can reduce total annual system costs, including production costs, capacity costs, local transmission costs, etc.

Proactive Planning De-Risks Generation Needed to Serve Load

- New load requires additional generation resources to enter the system that are currently limited by lack of capacity
- Proactive regional planning can build out upgrades prior to need and reduce new resource development timelines to efficiently meet IRP needs

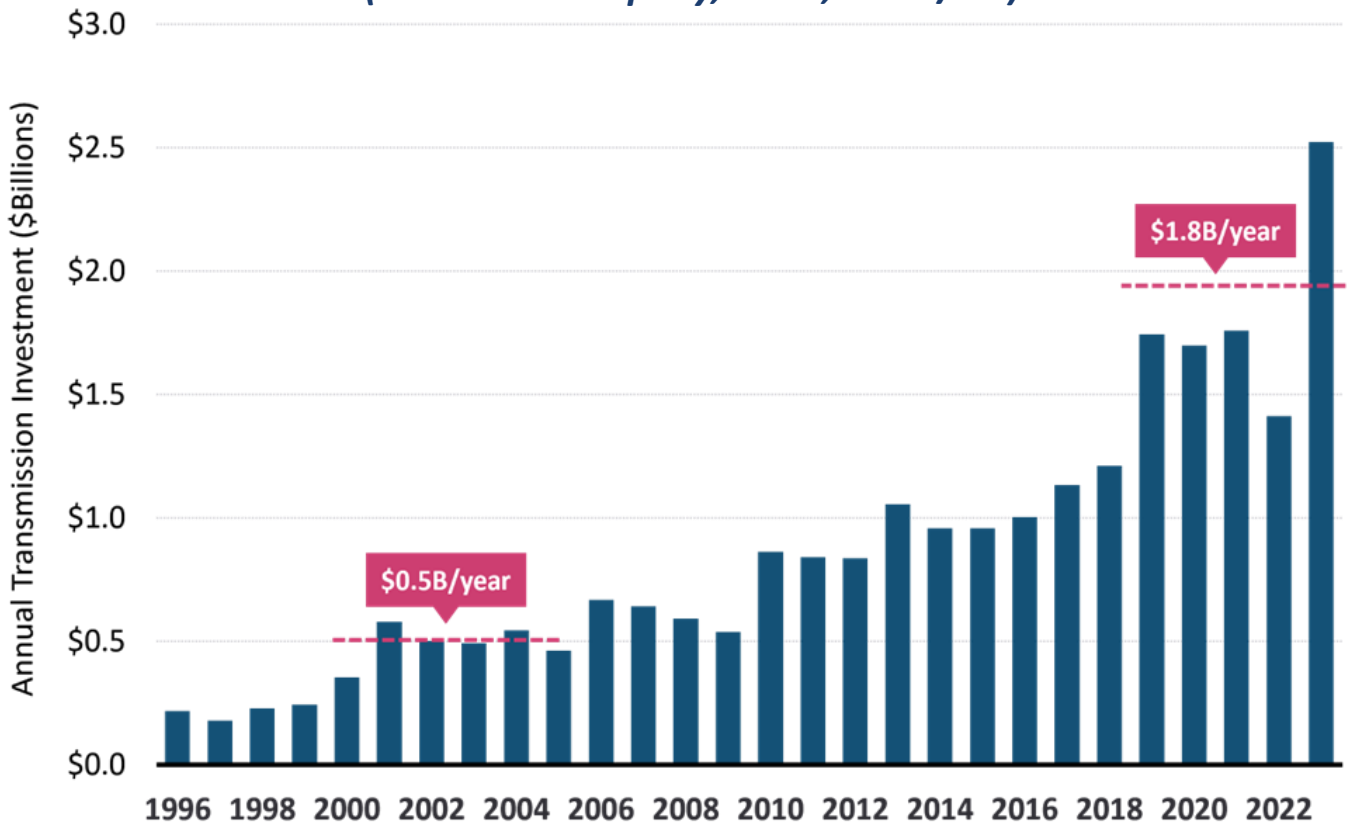
4x Increase in Reliability-Driven Local Transmission Needs

Transmission investment of three major utilities in the Southeast increased from **$0.5 billion per year in the early 2000s to $1.8 billion per year in the past 5 years**.

- Increased transmission costs in the Southeast (and across the U.S.) have been driven by utility-specific projects* to support limited load growth, replace aging infrastructure, and interconnect new generation, driving up transmission rates
- Southeast utilities risk inefficiently investing in lower-value projects in the absence of a regional forward-looking strategy to maximize the value of its future grid investments

*In some portions of the Southeast (e.g., GA, NC, and SC), utilities within the same state collaborate on "local" reliability-driven transmission planning for their service territories.

Annual Transmission Investment in SERTP Region
(Southern Company, Duke, LG&E/KU)



Source: Analysis of FERC Form 1 Data

Transmission Needed to Serve 21 GW of Load Growth

Southeast utilities are projecting **21 GW (+25%) of load growth by 2035** in their resource planning studies due to new data centers and manufacturing facilities, equivalent to adding twice New York City's power demand in 10 years.

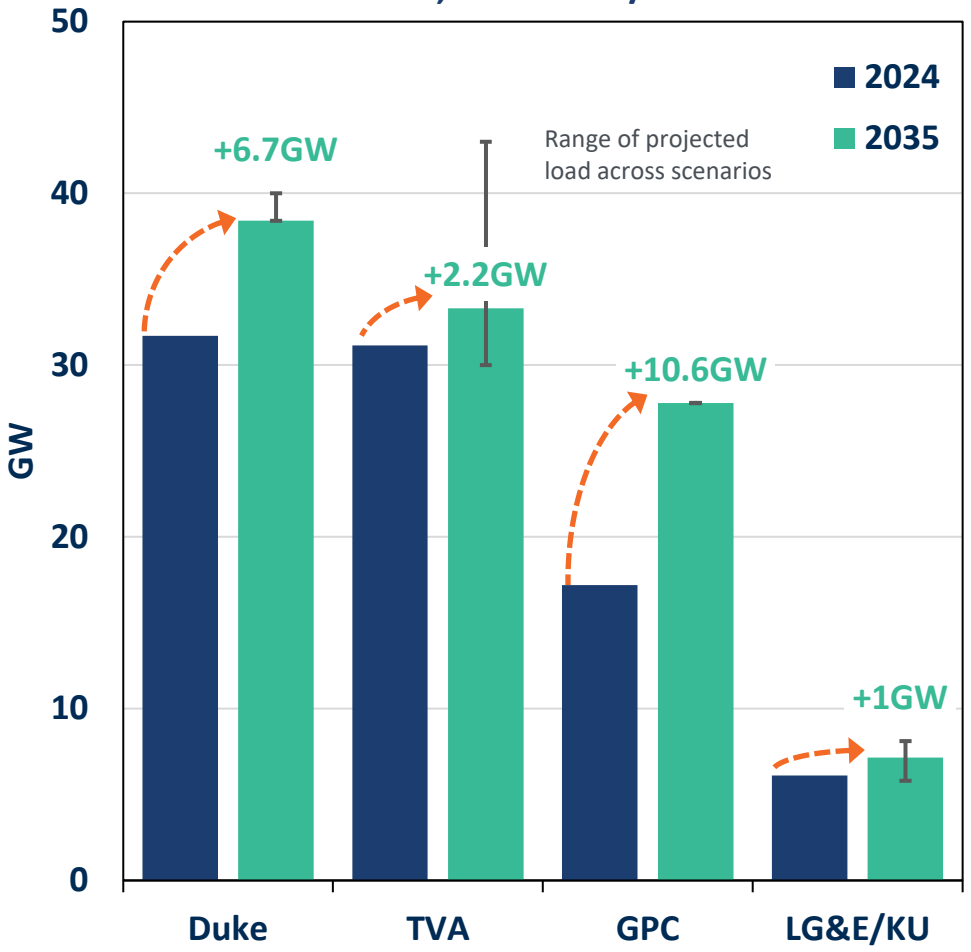
- Duke Energy: +7 GW to +9 GW
- TVA: +1 to +12 GW (base: 2 GW)
- Georgia Power (GPC): +11 GW

Combining utility-specific local planning with improved regional planning will support utilities in meeting the significant increase in load at lower total costs and allow for efficient interconnection of new loads.

Transmission studies recently identified large-scale regional upgrades needed for cost-effectively supporting large load additions in Texas ($32 billion) and Mid-Atlantic ($6 billion).

Sources: ERCOT 2024 Regional Transmission Plan (RTP) 345-kV Plan and Texas 765-kV Strategic Transmission Expansion Plan Comparison; PJM Board Approves New Transmission Projects To Support Grid Reliability

Projected Load Growth by 2035 in Duke, TVA, GPC, and LG&E/KU



Sources: Duke 2023 2023 Carolinas Resource Plan Supplemental Planning Analysis; TVA 2025 Draft IRP; Georgia Power Company 2025 IRP; LG&E/KU 2024 IRP Volume I

Transmission Upgrades De-Risk New Generation Additions

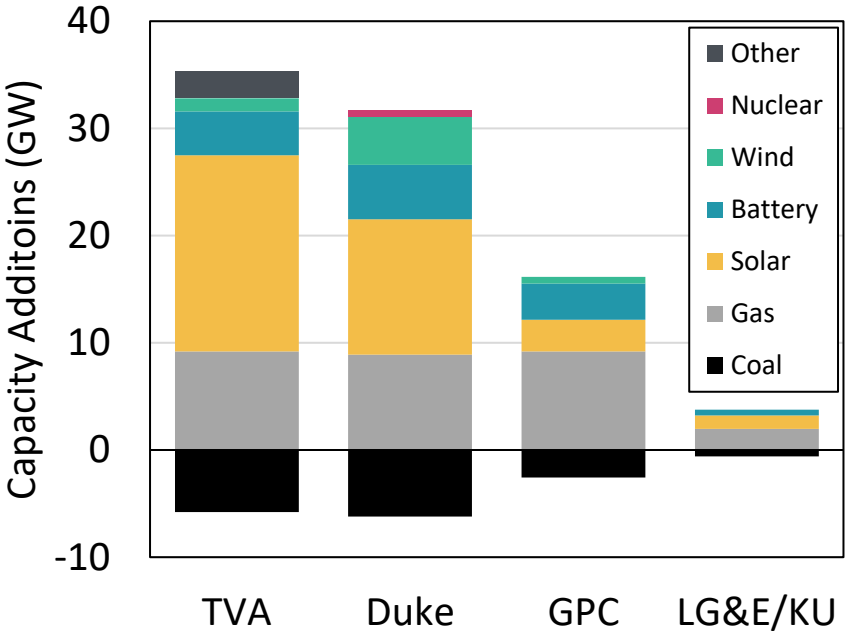
Southeast utilities' resource planning studies demonstrate the need to build and interconnect **more than 80 GW of new generation capacity** by 2035, or 8 GW per year.

- For context, the new Vogtle nuclear units added 3 GW to the grid
- New generation requires significant time to identify and construct network upgrades prior to interconnection
- Changing generation types and locations are shifting flows across the grid and increasing regional transmission needs

Without a stronger regional grid, new generation could face delays that increase energy prices and slow economic growth.

Yet Southeast utilities do not study regional upgrades to support the future generation mix; instead, higher-cost network upgrades will be identified on a just-in-time basis through generator interconnection studies.

New Generation Additions in Recent IRPs



Sources: TVA 2025 Draft IRP; Duke 2023 2023 Carolinas Resource Plan Supplemental Planning Analysis; Georgia Power Company 2025 IRP Technical Appendix Vol II ("Resource Mix Study"), Capacity Expansion Plans; LG&E/KU 2024 IRP Volume I

Regional Transmission Reduces Risks of Extreme Weather

In addition to load growth and new generation, recent extreme weather events have stressed the Southeast grid and lead to reliability events that could have been avoided with increased regional and interregional capacity.

Winter Storm Elliott in December 2022 demonstrated the need for access to additional import capacity to maintain grid reliability in the Southeast, as several utilities were forced to order firm load shedding:

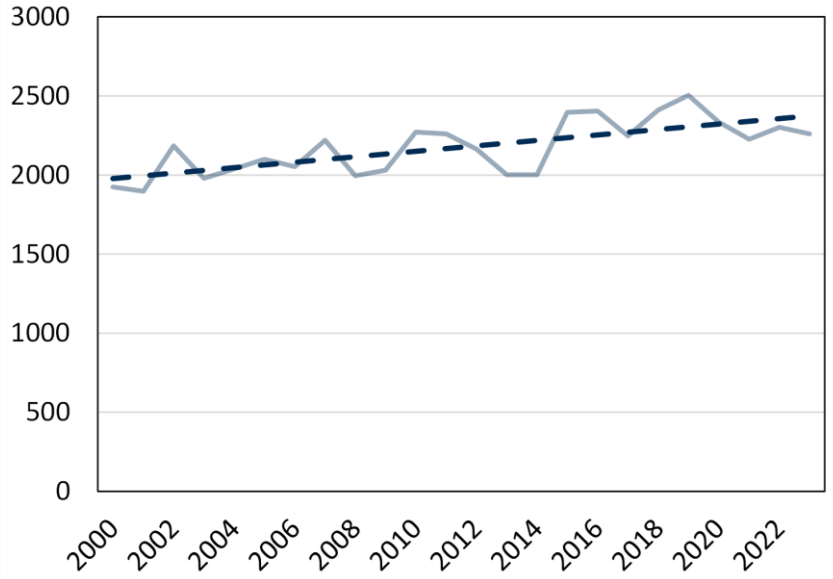
- DEC and DEP: Approximately 5,000 MWh over four hours
- TVA: Approximately 19,000 MWh over seven hours
- LG&E/KU: Approximately 1,200 MWh over four hours

Despite similar outages, Georgia Power avoided firm load shedding through imports from Florida; similarly, PJM avoided outages by relying on regional and interregional capacity with MISO to maintain system reliability.

As summers get warmer and winters storm increase, regional planners need to consider extreme conditions in future planning.

Regional and interregional transmission is an insurance policy against future extreme conditions, such as winter storms, heat waves, and renewable droughts, etc., providing access to a wider set of generation to serve load that increases reliability and reduces cost risks for customers.

Change in Cooling Degree Days for the South Atlantic Division



Sources & Notes: EIA Monthly Energy Review, January 2025. Population-weighted degree days are used by the EIA to model and forecast energy consumption.

Source: FERC, NERC and Regional Entity Staff Report, Inquiry into Bulk-Power System Operations During December 2022 Winter Storm Elliott, October 2023.

Investing in Regional Transmission Reduces Total System Costs

Regional transmission can significantly reduce costs across the power system in excess of the incremental costs of the transmission solutions, resulting in lower total costs of serving demand.

The most significant drivers of cost savings from regional transmission projects include:

- **Production cost savings**: Reduce operational costs by increasing access to lower cost, more efficient generation resources, especially during heat waves, major generation and transmission outages, etc.
- **Lower energy losses**: Reduce operational costs by offloading highly utilized lines and reducing energy losses, and reduce capacity costs due to lower on-peak energy losses
- **Local transmission and interconnection cost savings**: Reduce costs of lower voltage local reliability projects needed for serving load, replacing aging infrastructure, or interconnecting new generation when regional plans are effectively developed and implemented
- **Generation capacity cost savings**: Reduce costs of new capacity to meet reserve requirements by taking advantage of load diversity between utilities across the region

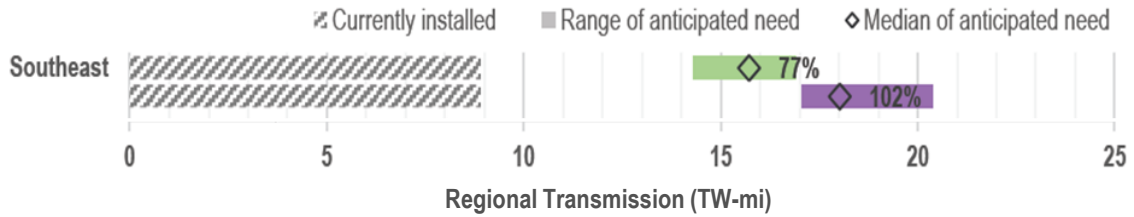
In the past 3 years, MISO approved $33 billion of regional projects that will **reduce net system costs by $50–125 billion** over the life of the assets based on a broad view of transmission cost savings.

Source: MISO, Long Range Transmission Planning, accessed February 2025.

Southeast Transmission Needs Highlighted in National Studies

National Transmission Needs Study (2023)

Summarizes 300 future scenarios and sensitivities from 6 independent studies for 2030, 2035, and 2040. By 2035, Southeast will need **7 TW-miles of new within-region transmission** and significant expansion of interregional transmission, ranging from **5.1 – 39.9 TW-miles with neighboring regions**.

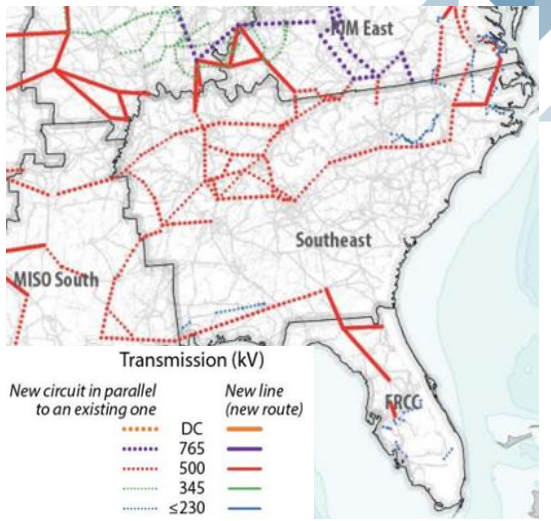


Range of new transmission need for future scenarios with moderate load and high clean energy growth (green, top for each region) and high load and high clean energy growth (purple, bottom). Median % growth compared to 2020 system shown.

Source: National Transmission Needs Study

National Transmission Planning Study (2024)

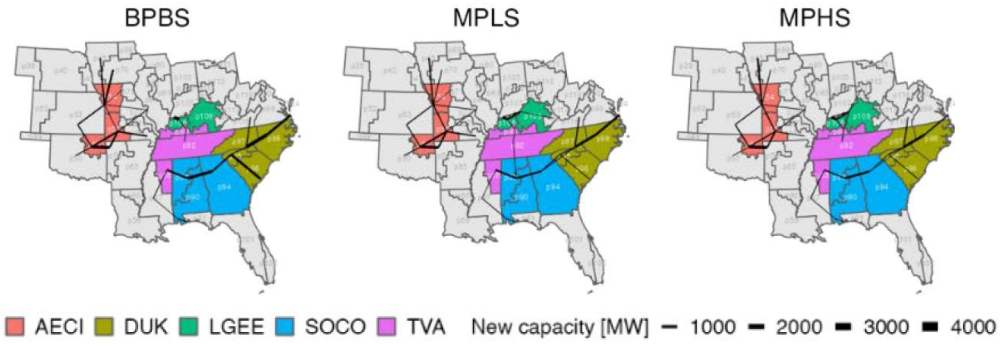
Conducted zonal capacity expansion and RA modeling through 2050 under 96 scenarios. Mid-demand, 90% emissions reduction AC scenario **strengthens existing 500 kV networks and connects SERTP to the Midwest and Plains through 345 kV and 500 kV lines** to enable flows across north-south and west-east interfaces to key load centers.



Source: National Transmission Planning Study

NREL/LBNL Solar and Storage Integration Study (2024)

Investigates higher levels of solar and storage on transmission needs by 2035 and benefits of increased operational coordination among utilities. In lower-solar scenarios, **transmission additions added east-west regional capacity.**



Source: Solar and Storage Integration in the Southeastern United States

NERC Interregional Transfer Capability Study (2024)

Analyzed transfer capability between neighboring regions and recommended "prudent" interregional additions to maintain reliability. Identifies 4.1 GW of transmission into SERC-E (NC/SC) from other Southeast regions and PJM by 2033 **justifiable based on reliability alone** to alleviate resource deficiencies.

Table ES.1: Recommended Prudent Additions Detail

Transmission Planning Region	Weather Years (WY) / Events	Resource Deficiency Hours	Maximum Deficiency (MW)	Additional Transfer Capability (MW)	Interface Additions (MW)
SERC-E	Winter Storm Elliott (WY2022)	9	5,849	4,100	SERC-C (300) SERC-SE (2,200) PJM-W (1,600)
SERC-Florida	Summer WY2009 and Winter WY2010	6	1,152	1,200	SERC-SE (1,200)
MISO-S	WY2009 and WY2011 summer events	4	629	600	ERCOT (300) SERC-SE (300)

Source: Interregional Transfer Capability Study (ITCS)

Southeast Can Build on Order 1920 to Improve Regional Planning

In 2024, the Federal Energy Regulatory Commission (FERC) issued Order No. 1920 to improve long-term regional transmission planning and cost allocation by proactively planning for regional grid needs based on industry-wide best practices implemented across the country.

Southeast utilities will need to update their regional planning process to meet Order 1920 requirements:

- Complete a comprehensive long-term (20+ year) planning process every 5 years that considers at least 7 drivers of transmission needs plus asset refurbishment and generator interconnection needs
- Develop at least 3 plausible and diverse scenarios, including at least 1 “stress test” sensitivity
- Quantify at least 7 benefits metrics for upgrades that meet long-term regional needs
- Consider a broader set of solutions including grid-enhancing technologies (GETs), upsizing existing lines
- Develop default or state-sponsored cost allocation mechanisms
- Engage regional state entities through the transmission planning process

Order No. 1920 provides the Southeast an opportunity in 2025 to implement a new regional transmission planning process that will modernize its transmission network.

II. SERTP Regional Transmission Planning Process Is Insufficient to Meet Future System Needs

Who Is SERTP?

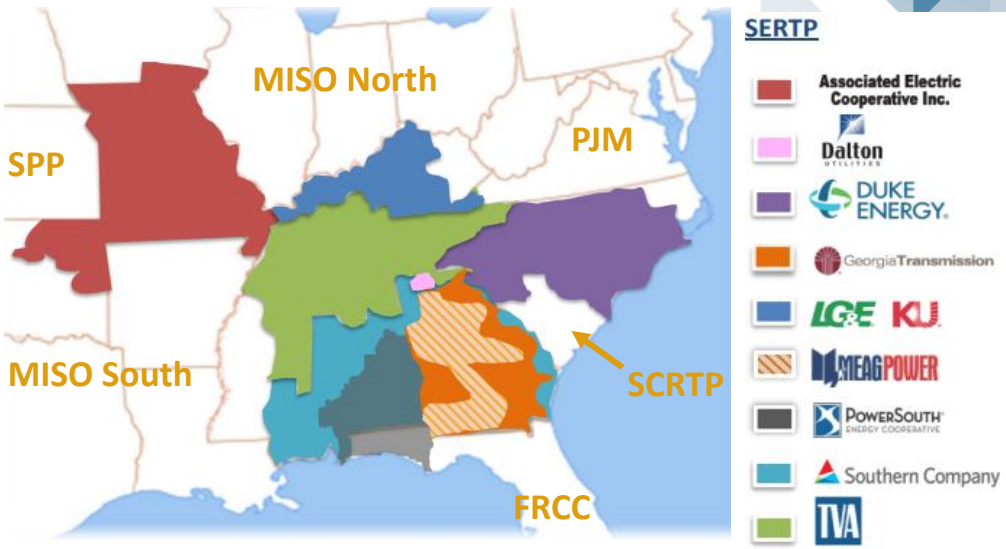
The Southeast Regional Transmission Planning (SERTP) was formed in 2007 to comply with FERC Order No. 890 by Southeast transmission providers (or "Sponsors").

- There are currently 10 Sponsors spanning 12 states
- South Carolina Regional Transmission Planning (SCRTP) members expected to join SERTP in 2025
- SERTP process was updated in 2015 to meet Order 1000 regional/interregional planning requirements

SERTP is a forum for Sponsors to collaborate on regional planning and cost allocation and has no independent SERTP staff beyond the utility Sponsors.

SERTP produces a Regional Transmission Plan each year that primarily reflects the aggregated 10-year local transmission plans provided by each Sponsor.

SERTP Regional Footprint



SERTP Sponsors' Peak Demand

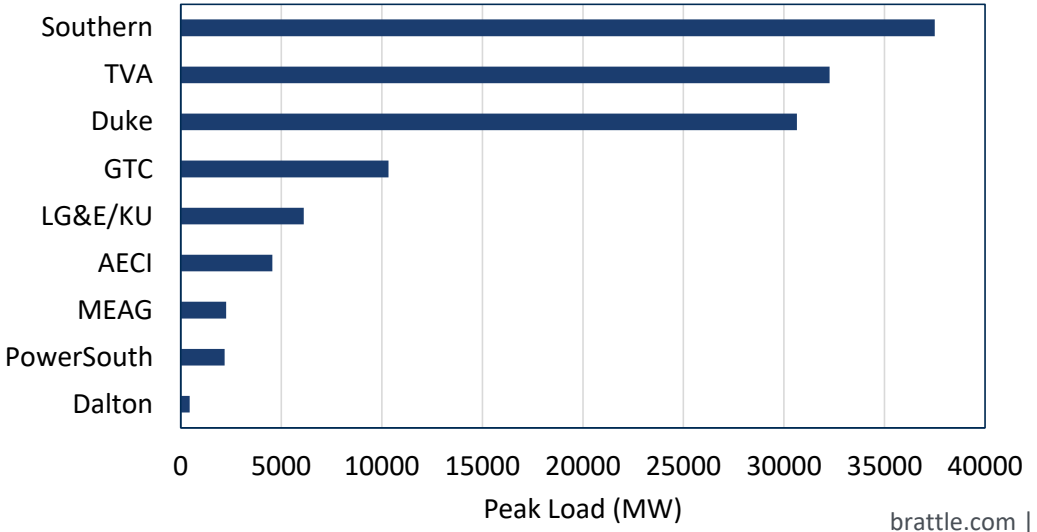


Image Source: SERTP - 1st Quarter Meeting (southeasternrtp.com). March 19th, 2024.

SERTP Produces an Annual 10-Year Regional Transmission Plan

In the annual regional planning process, SERTP Sponsors aggregate local plans into a preliminary expansion plan and assess whether regional projects meet reliability criteria at lower cost than local projects.

- SERTP hosts 4 meetings in each annual planning cycle to present their progress and allow for stakeholder input
- Stakeholders can request SERTP to study regional "economic" and "policy" needs and identify required upgrades

(1) Sponsors' Local Transmission Plans (Feb.–Jun.)

- Developed by each Sponsor or load serving entities (LSEs) in the 7 BAAs

(2) SERTP Preliminary Expansion Plan (Apr.–Jun.)

- "Bottom-Up Reliability Study Process" based on local transmission plans to identify any regional reliability constraints
- Evaluation of stakeholder-submitted public policy requirements

(3) SERTP Regional Planning Analyses (Sep.–Nov.)

- Evaluation stakeholder-requested economic planning studies
- Analysis of regional projects identified to be potentially more efficient or cost effective

(4) SERTP 10-Yr Regional Transmission Plan (Oct.–Dec.)

- "Snapshot" of transmission plan presented at the Annual Transmission Planning Summit

Source: 2024 2nd Quarter SERTP Meeting Presentation (southeasternrtp.com)

Regional Transmission Planning vs. Local Planning and IRPs

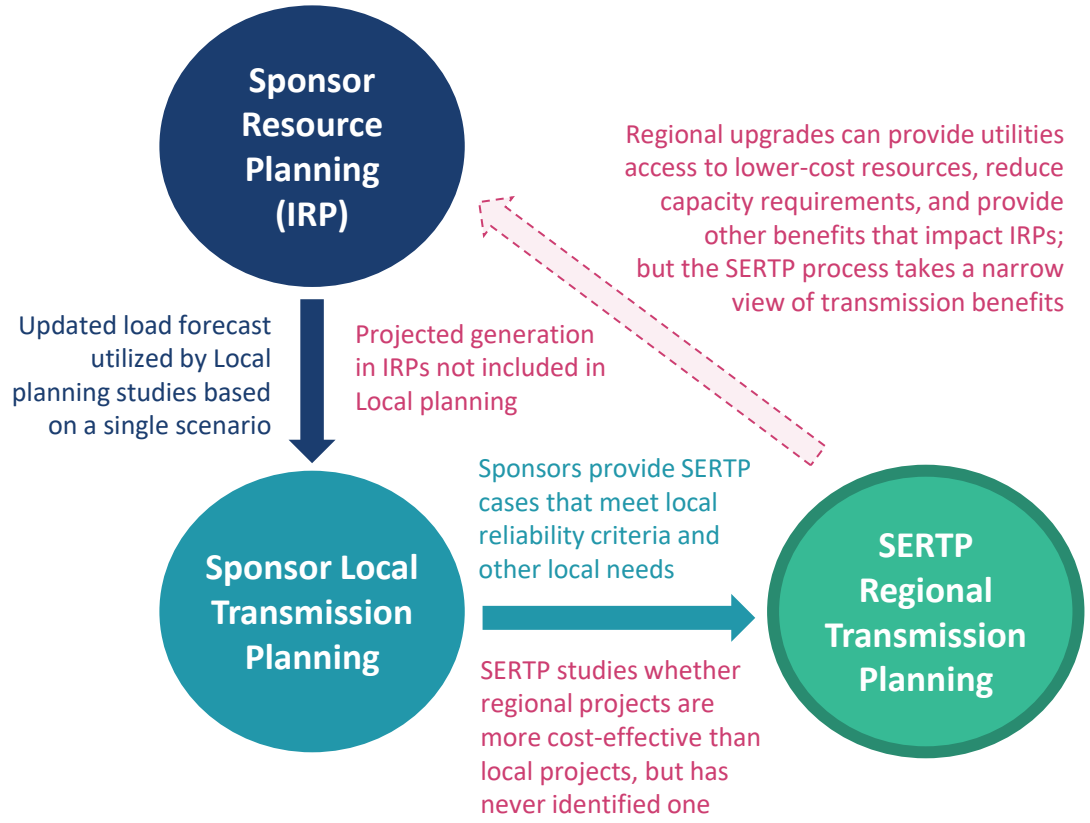
SERTP's planning models reflect system conditions studied in each Sponsor's local transmission planning study, not a consistent regional view of future system conditions.

- Each Sponsor completes local transmission planning studies that incorporate the latest load forecast but only a limited set of new generation resources and retirements
- Sponsors identify local upgrades to resolve reliability violations based on NERC criteria* and provide those cases to SERTP

SERTP planning does not account for the full set of new generation identified in recent IRPs, limiting SERTP from identifying least-cost upgrades to support new resources.

Regional planning can identify upgrades that provide utilities access to a broader set of resources in their IRPs and for dispatching generation more efficiently (see figure).

Coordination across Resource Planning and Transmission Planning Studies



* Duke recently began studying several future scenarios and multi-value upgrades via the CTPC MVST local planning process (as summarized later in the slides), but has not yet completed it first MVST study.

SERTP Assumptions Not Aligned with Local Resource Planning

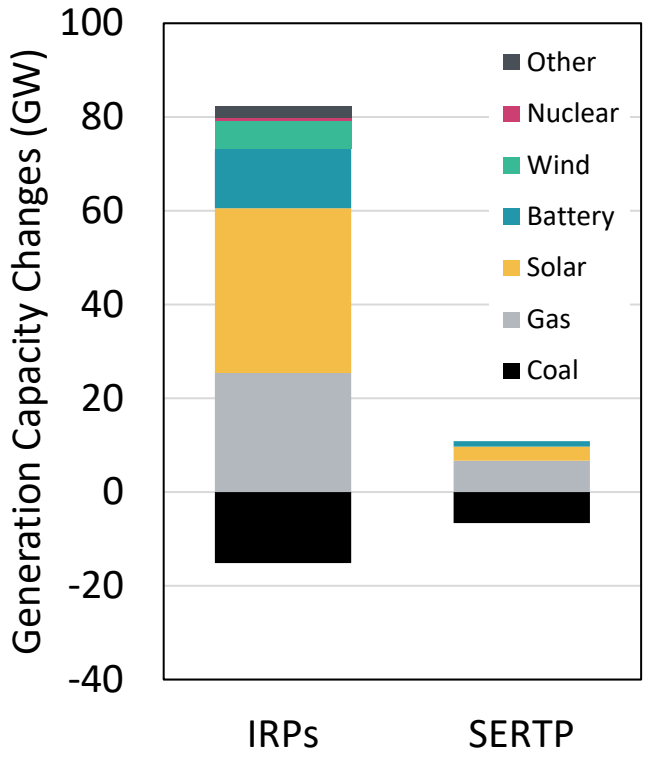
SERTP models regional system conditions for a single future scenario based on Sponsor-specific assumptions that are not aligned with the Sponsors' own resource planning studies.

Significant discrepancies exist between the projected generation resources in Sponsor IRPs and the SERTP planning models.

- SERTP model only includes 10 GW of the 80 GW of new generation resources identified in the latest IRPs by 2035 (12%), including just 8% of solar additions, 27% of gas additions, and 41% of coal retirements
- In some cases, utilities are not including resources that they already requested approval from its state commissions for construction
- In some regions, SERTP includes hypothetical "proxy units" to ensure there are sufficient resources to meet load, instead of utilizing IRP portfolios

SERTP's single future scenario does not utilize the future scenarios developed in each Sponsor's resource planning studies to assess how the regional system could adapt to uncertainties in future changes (e.g., high growth scenarios or alternative generation resource mixes).

IRP vs SERTP 2035 Generation Changes
(TVA, Duke, LG&E/KU, GPC)



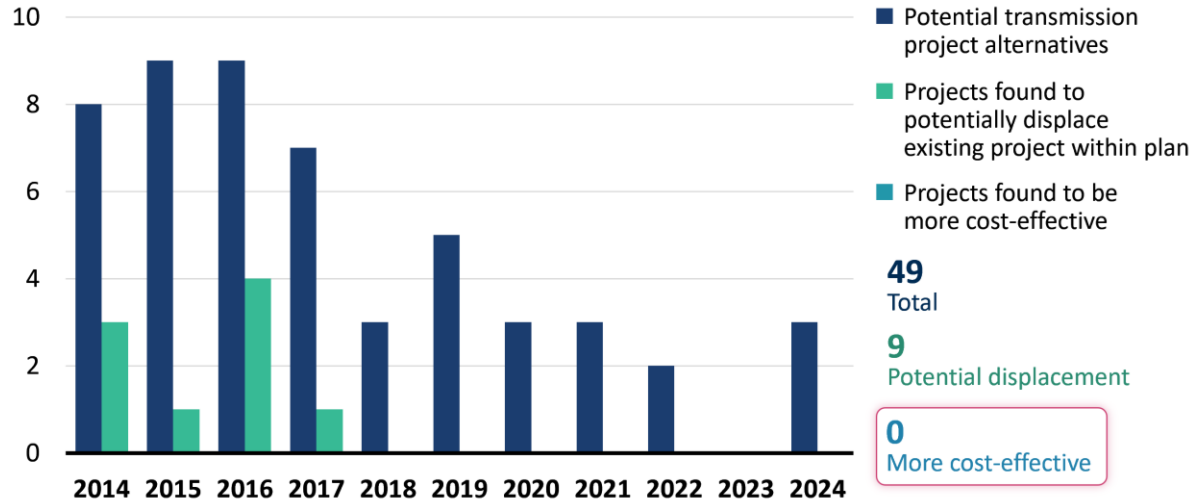
SERTP Has Not Identified Cost-Effective Regional Projects

Based on Sponsor-provided plans, SERTP conducts a reliability study to determine if regional projects could provide a more cost-effective solution than proposed local upgrades based on the following criteria:

- Ability to resolve reliability violations based on NERC criteria
- Project feasibility (i.e., viability of constructing and tying in the proposed project by the in-service date)
- Avoided local transmission costs
- Ability to reduce real power losses

SERTP **has never identified a more efficient or cost-effective regional project** to include in its annual regional plan, despite studying 49 alternative projects due to the limited scope of benefits analyzed.

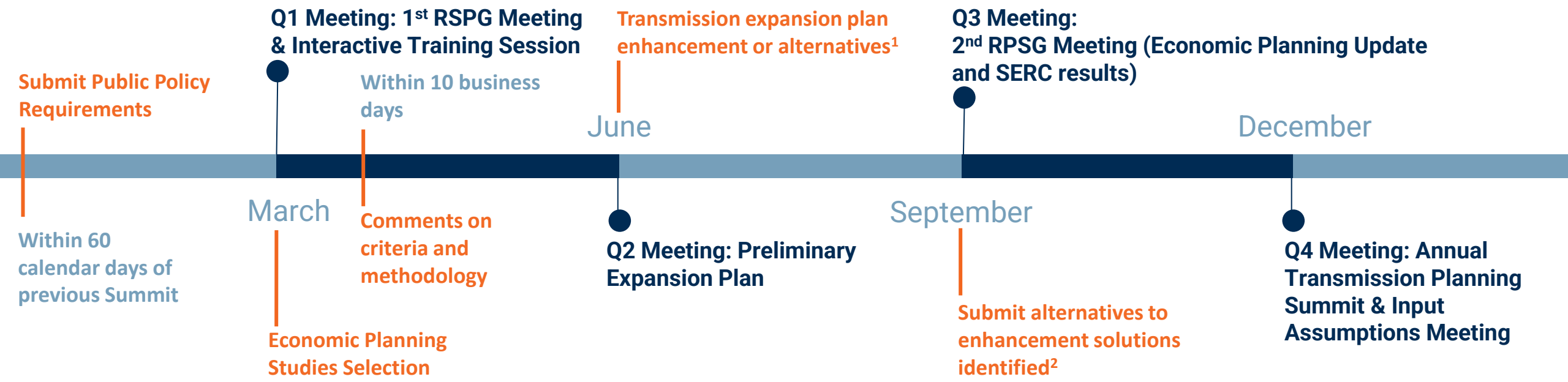
Potential Transmission Project Alternatives Evaluated by SERTP



SERTP Stakeholders Can Request Economic & Policy Studies

SERTP completes economic planning studies and an assessment of public policy requirements (PPRs) submitted by stakeholders in the Regional Planning Stakeholder Group (RPSG)

- SERTP may review up to 5 economic studies each year; stakeholders responsible for costs of additional studies
- Stakeholders can provide additional comments to SERTP at several points of the process, as noted below



[1] Preliminary transmission expansion plan will be posted on the **secure/CEII area** of the Regional Planning Website at least 10 calendar days prior to the Preliminary Expansion Plan meeting. Gaining access to the secure/CEII information is a process requiring background checks, $280 in fees, and executing a restrictive NDA.

[2] Preliminary economic planning study results posted 10 calendar days prior to the 2nd RPSG meeting. Stakeholders have 30 calendar days after the meeting to submit alternatives.

Source: Duke Joint OATT, Attachment N-1. Joint_OATT.pdf (duke-energy.com)

Economic Requests for <4 GW Identify Limited Regional Needs

SERTP economic studies analyze stakeholder requests for regional bulk power transfers and identify the least-cost upgrades required to enable those transfers while maintaining reliability.

- SERTP economic studies do not represent a commitment to proceeding with recommended enhancements
- Studies provide costs to entities seeking service across SERTP, which informs their decisions to pursue regional transfers, but does not consider a broader set of cost savings to SERTP customers

Amongst requests for 500 MW - 4,000 MW of transfers, SERTP identified limited upgrades (<$100 million), demonstrating that there is available capacity to accommodate incremental regional flows in this range.

2023 and 2024 SERTP Economic Study Results

Project No.	Year & Load Level	Source	Sink	Transfer Amount *MW*	Costs *$ Million*	*$/kW*
1	2028 - Winter Peak	MISO	TVA	2900	$21.5	$7.4
2	2028 - Summer Peak	South Georgia	North Georgia	1600	$95.9	$59.9
3	2028 - Summer Peak	TVA	North Georgia	1600	$56.5	$35.3
4	2028 - Summer Peak	MISO	LG&E/KU	1242	$83.5	$67.3
5	2033 - Summer Peak	SOCO	DEC	500	$0.0	$0.0
6	2029 - Summer Peak	MISO South/FRCC	SOCO	4000	$1.9	$0.5
7	2026 - Summer Peak	PJM	DEC/DEP	2000	$7.0	$3.5
8	2034 - Summer Peak	MISO North	SOCO	10000	$4,607.9	$460.8
9	2029 - Summer Peak	SPP/MISO North	AECI	2500	$0.0	$0.0
10	2034 - Winter Peak	DEC/SOCO	Santee Cooper	2400	$24.3	$10.1

Sources: SERTP 2024 Economic Planning Study Final Results
SERTP 2023 Economic Planning Study Final Results

2023 and 2024 SERTP Economic Study Requests

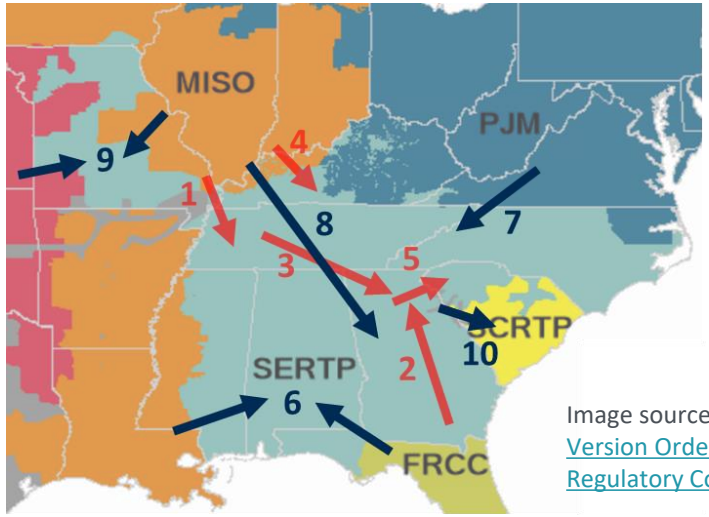


Image source: Regions Map Printable Version Order No. 1000 | Federal Energy Regulatory Commission (ferc.gov)

Major Regional Upgrades Identified for 10 GW Request

Stakeholders in 2024 requested SERTP to study a 10 GW transfer from MISO North to SOCO that resulted in SERTP identifying $4.6 billion of regional upgrades between TVA, Duke, and SOCO.

- Request triggered 139 violations and identified the need for seven new 500 kV lines and 40 other upgrades

SERTP selected three 500 kV lines for their analysis of more efficient and more cost-effective regional upgrades but identified no avoided local upgrade costs and considered no other cost savings or benefits.

10 GW Economic Request Reliability Violations

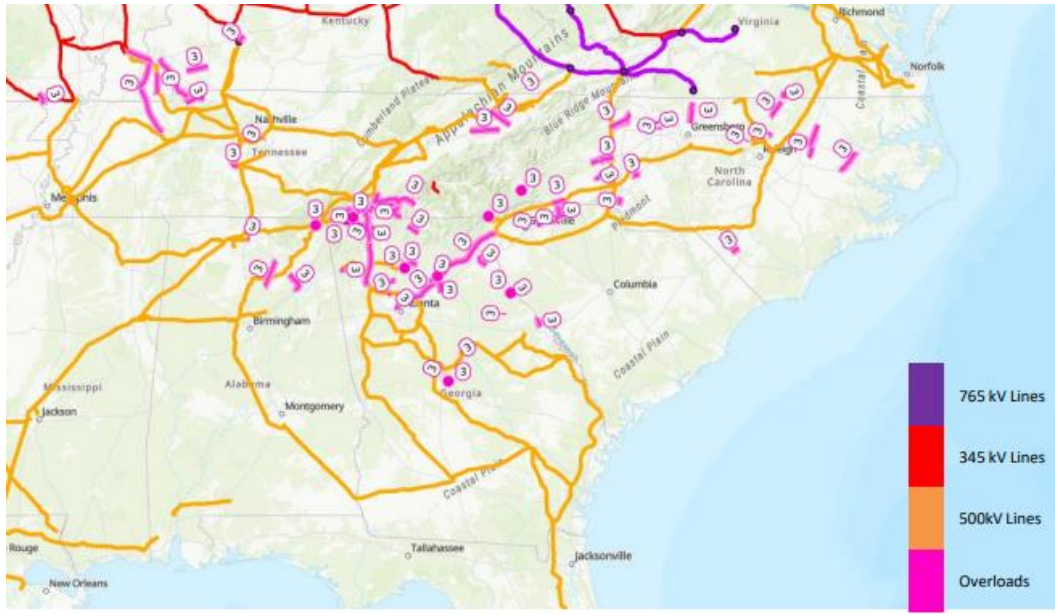


Image Source: SERTP 2024 SERTP 3rd Quarter Meeting Presentation, slide 25.

Regional Projects for Additional Analysis

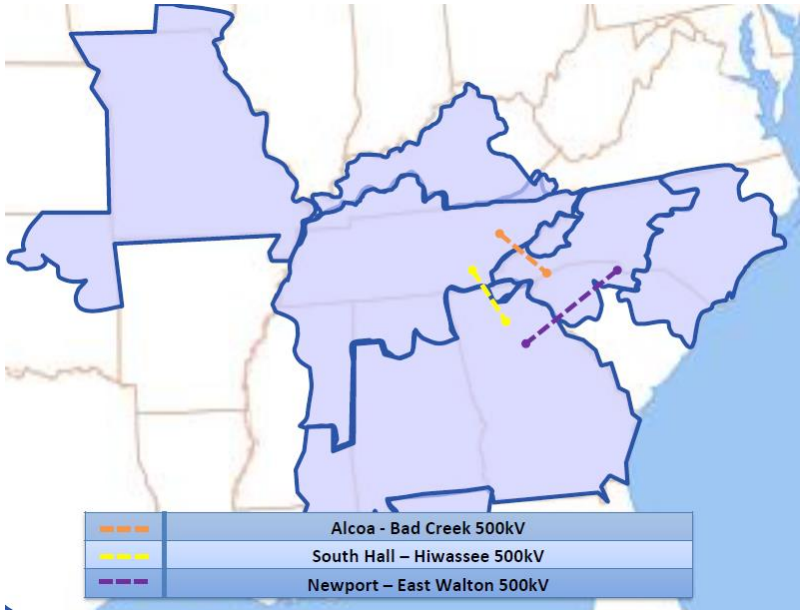


Image Source: SERTP 2024 SERTP 3rd Quarter Meeting Presentation, slide 49.

SERTP Has Not Studied Regional Public Policy Needs

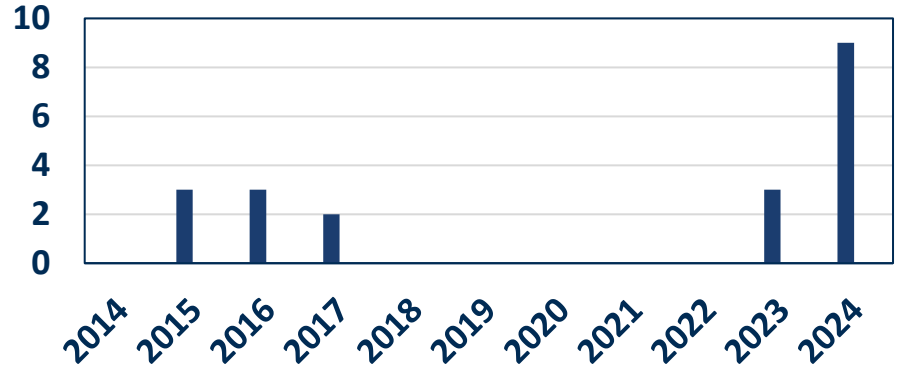
Stakeholders may propose transmission needs driven by Public Policy Requirements (PPRs) for SERTP to assess if the requests meet the following criteria:

1. Is the PPR an enacted local, state, or federal law(s) and/or regulation(s)?
2. Does the PPR drive a transmission need(s)?
3. Is the transmission need already addressed or otherwise being evaluated in the then-current planning cycle?

SERTP has never evaluated a regional transmission needs for a PPR

- The narrow scope of a PPR excludes Sponsors' Board commitments and SERTP's reliance on local transmission plans means that state laws can be considered as addressed in Sponsors' local plans
- For example, SERTP responded to a 2024 PPR request to study the North Carolina Carbon Plan by noting that the needs are already being considered in the CTPC local planning process, and so "no additional transmission needs for the proposed PPR have been identified"
- In doing so, SERTP fails to consider the potential for regional capacity to reduce the costs of satisfying policy requirements across the Southeast

SERTP Public Policy Requirements Proposals for Transmission Needs since 2014



Sources: SERTP Archive Documents, Transmission Needs Driven by Public Policy Requirements (2014–2024).

Key Shortcomings in the SERTP Regional Planning Process

Local Transmission Plans

- Sponsors' local transmission plans are developed with little transparency and do not account for multiple drivers of transmission needs
- Local transmission planning studies are not closely integrated with future planned generation additions based on Sponsors' IRPs, limiting scope of system needs identified in SERTP studies

Preliminary Expansion Plan

- Preliminary SERTP expansion plan is an aggregation of local plans to confirm simultaneous feasibility under all applicable reliability standards
- Only one future scenario is modeled based on local plan assumptions, failing to account for the role of regional projects to more efficiently address future outcomes given high levels of uncertainty

Regional Planning Analyses

- Limited scope of scenarios and regional cost savings of transmission quantified in SERTP planning studies
- Economic and policy studies do not provide reasonable opportunity to identify the most beneficial projects
- Study design results in SERTP never identifying a need for any regional projects in its 10-year Plan

Regional Transmission Plan

- SERTP regional transmission plan mimics the local planning results, failing to identify sufficient cost savings and other benefits to identify a regional transmission need and provide low-cost options for accessing a wider range of resources in IRPs and generation dispatch
- Stakeholder engagement does not incorporate meaningful recommendations and does not include active state participation.

SERTP Transmission Planning Results in Higher Total Costs

Current SERTP regional planning does not yield the most valuable and cost-effective transmission infrastructure for the following reasons:

- Reactive, reliability-driven planning results in piecemeal, higher-cost transmission solutions
- Failure to evaluate full range of plausible futures that explicitly account for long-term uncertainties results in higher-cost outcomes when the future deviates from base case planning assumptions
- Lack of consideration of multiple benefits of transmission does not result in the selection of the highest-value projects that reduce system-wide costs; currently only reliability and losses considered

Maximizing the value of regional upgrades may require SERTP Sponsors to modify their approaches to resource planning and market transactions to efficiently utilize the existing and planned regional transmission capacity.

FERC Order No. 1920 presents a critical opportunity for SERTP to enhance coordination, optimize investments, and ensure cost-effective solutions that benefit both utilities and customers.

III. Recommendations to Enhance SERTP Regional Planning

Framework for Improved SERTP Regional Planning Process

Experience across the electric power industry over the past 10–20 years provides proven planning practices that can reduce total system costs and risks:

- Proactively and holistically plan for future generation and load by incorporating realistic projections of all needs: anticipated generation mix and load levels over the lifespan of the transmission investments; critical to avoid siloed, incremental planning processes
- Account for the full range of transmission needs and use multi-value planning to comprehensively identify investments that cost-effectively address all categories of needs and benefits
- Address uncertainties and high-stress grid conditions explicitly through scenario-based planning that accounts for all transmission needs for a broad range of plausible long-term futures as well as real-world system conditions, including challenging weather events
- Use comprehensive transmission network portfolios to address system needs and cost allocation more efficiently and less contentiously than a project-by-project approach
- Jointly plan interregional projects across neighboring systems to recognize regional interdependence, increase system resilience, and take full advantage of scale economics and geographic diversification

Source: Brattle & Grid Strategies Report: Transmission Planning for the 21st Century: Proven Practices that Increase Value and Reduce Costs, October 2021.

Recommendations to Enhance SERTP Regional Planning

SERTP can leverage industry-wide experience over the past 20 years by implementing proven practices to reduce long-term system costs and risks, including the MISO LRTP and CTPC/Duke MVST planning processes.

I. Improve Existing Planning Process

1. **Increase transparency** of study assumptions, approach, and results
2. **Engage state commissions and energy agencies** to participate in process and ensure results reduce costs and address state policies
3. Expand solutions studied to reflect **least-cost transmission "loading order"** that maximizes existing grid, upgrades existing lines, and builds new lines where necessary

II. Expand SERTP Planning Capabilities

4. Develop **multiple scenarios based on recent IRPs** to plan for a range of load and generation portfolios
5. Accurately identify congestion and quantify cost savings of regional upgrades via **region-wide production cost model**
6. Develop guidelines to account for **comprehensive set of cost savings and other benefits** when analyzing regional upgrades

III. Implement Comprehensive & Proactive Planning Process

7. Implement **multi-driver approach to identifying regional & interregional needs** and candidate solutions
8. Estimate cost savings and other benefits of solutions **over the entire useful life of the assets**
9. Establish regional cost allocation that reflects **beneficiaries pays and cost causation principles**

1. Increase SERTP Planning Transparency

SERTP process lacks transparency, restricting the ability of stakeholders and state utility commission to review study assumptions, approach, and results and provide feedback to SERTP on ways to improve regional planning.

- Modeling approaches and costs of Sponsors' local upgrade projects, the only regional benefit considered by SERTP, are opaque with CEII clearance required to access information that is not restricted in other planning regions
- Even with CEII access, stakeholders lack cost information and only receive raw power flow cases, not study details and results

Greater Access to Input Assumptions

- In 2024, SERTP identified changes in the resource mix by type and utility
- Provide more clarity and consistency in resource updates across utilities
- More granular information on load forecasts between BAAs, including coincident peak analysis

More Information on Study Results

- Provide more detailed results, including:
  1. Limiting element that triggers violation
  2. Alternative solutions studied
  3. Basis for selecting solution
- Include individual solution estimated costs in the preliminary and final regional transmission plan

Expand Results of Regional Project Analyses

- Detail the selection process of each regional project that is selected for analysis: what motivated the selection of the line(s), how many years of the 10-year study are their benefits analyzed for, etc.

Longer Time Windows for Stakeholder Interaction

- Lengthen window that stakeholders have to submit comments on criteria and method used in planning process beyond only 10 business days
- Ensure documents are posted more than 10 days prior to meetings to give ample time to review

2. Engage State Commissions and Energy Agencies

State agencies and commissions should be actively engaged in the SERTP process to incorporate the perspectives and priorities of regulators and energy agencies into regional transmission planning.

By having insight into regional planning, regulators can ensure that customers are paying for an efficient power system that meets state policy goals and provides reliable electric service.

SPP Regional State Committee (RSC)

- Comprised of state commissioners from 12 states within SPP
- **RSC maintains Federal Power Act 205 rights** to file proposals with FERC to modify rules and tariffs
- Decision making is shared between SPP Board and RSC; RSC has primary responsibility for resource adequacy and cost allocation

Organization of PJM State Inc. (OPSI)

- Collaborative body representing 14 regulatory agencies within PJM
- Facilitates communication and coordination among members, **allowing states to collectively address** PJM operations and market rules
- Ensures that **state interests and policies are considered** in regional decision-making processes

NorthernGrid Enrolled Parties and States Committee (EPSC)

- Participate in development of regional study scope and provide comments on draft regional plans
- Enables **state agencies to participate actively in transmission planning** and **ensures that state-specific concerns and objectives are addressed** within the regional planning framework

Other state organizations participating in regional planning include Organization of MISO States (OMS) and New England States Committee (NESCOE). The California Public Utilities Commission and New York Public Service Commission play an active role in regional planning within their respective single-state RTOs.

3. Expand Solutions to Reflect a Least-Cost Loading Order

SERTP should expand the solutions considered in its studies to include grid-enhancing technologies (GETs), advanced transmission technologies (ATTs), and remedial action schemes (RAS) that maximize the utilization of the existing grid to accommodate new load and generation in the near-term.

By studying potential solution alternatives, SERTP can "stack" solutions by estimated cost and schedule to identify the most beneficial solutions to providing a reliable and efficient grid.

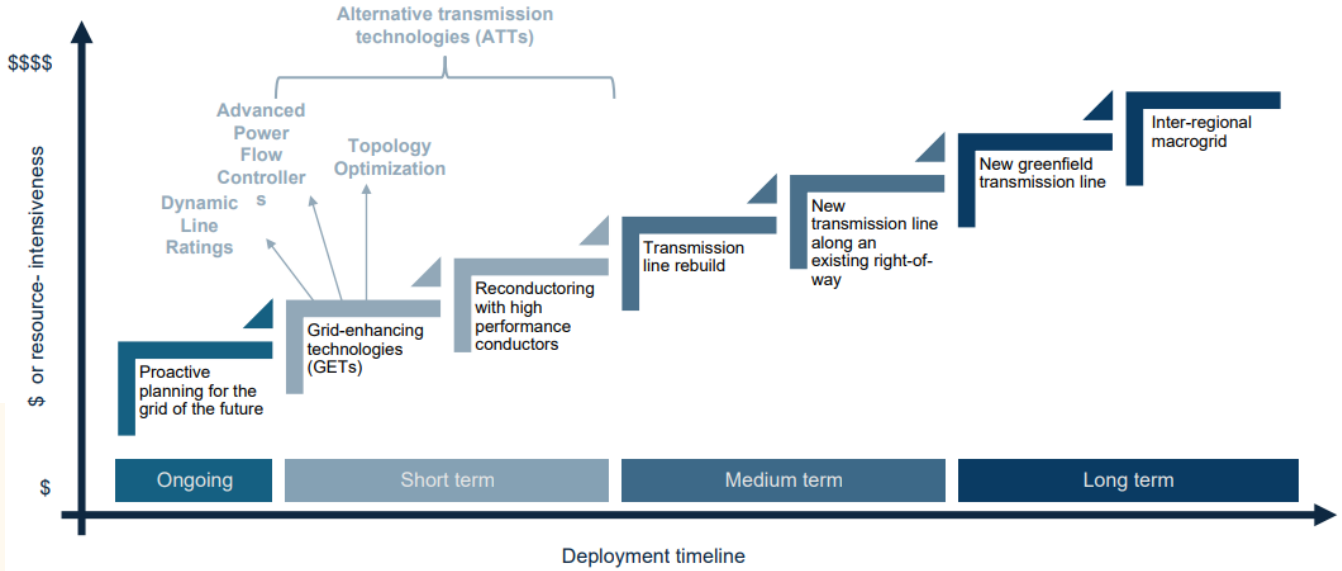
Southeast examples:

- Georgia Power relied on operating guidelines and ATTs in its most recent IRP to resolve reliability-driven system needs
- Duke's MVST will consider GETs, advanced conductors, RAS, and battery storage as well as greenfield transmission and ROW optimization

Further Examples:

- CAISO use of RAS to create 15 GW of headroom
- Priority order required by the German "NOVA Principle"
- MA CETWG Report: "Loading Order" recommendations

Proposed Transmission Solution Loading Order



Source: Sarah Toth (RMI), Alternative Transmission Technologies in Order 1920 and PJM, September 6, 2024.

4. Develop Multiple Future Scenarios Based on IRPs

Scenario-based planning is a process first developed in the 1940s and 1950s as a tool for **integrating uncertainties into long-term strategic planning**.

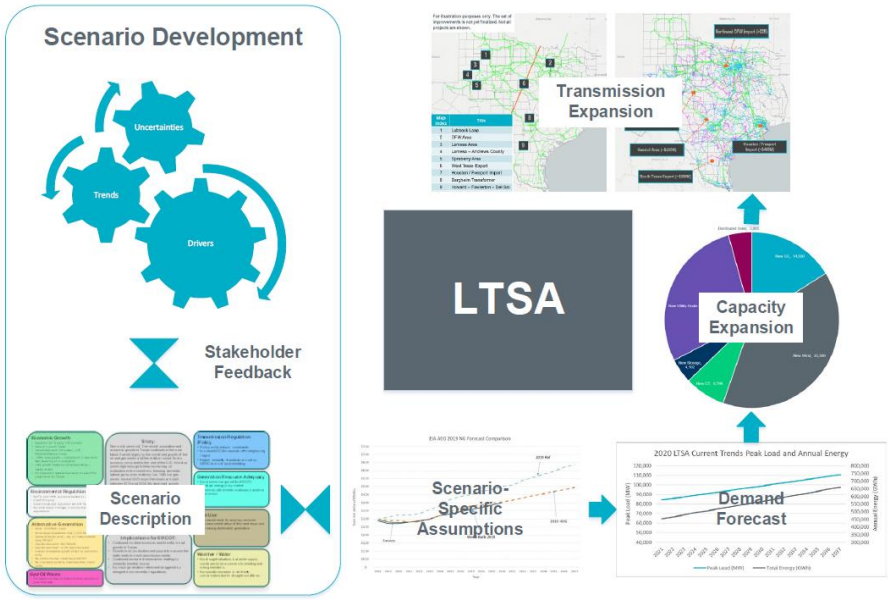
- Used by Shell since the 1970s for long-term planning under large uncertainties
- Assists planners to think in advance about the many ways the future may unfold and how to respond effectively and flexibly as the future becomes reality
- Scenario = one fully-defined, plausible view of what the future may look like

Examples of scenario-based planning approaches used in regional transmission planning include:

- ERCOT's Long-Term System Assessment Process (LTSA)
- MISO's Long Range Transmission Planning (LTRP)
- SPP's recent Integrated Transmission Plan (ITP)

SERTP should leverage the range of future outlooks for demand and generation resources already completed by Sponsor utilities in their IRP studies, similar to Duke's use of the Carolinas Resource Plan to study three scenarios in the MVST process.

ERCOT LTSA Process



5 & 6. Study Comprehensive Set of Cost Savings and Benefits

SERTP can take advantage of the best practices developed across the industry over the past 20 years to estimate transmission benefits.

- Analytical approaches for quantifying transmission benefits have been documented in a report submitted to FERC cited in Order 1920
- Planners have implemented these analyses to justify major investments in regional transmission

Critical for SERTP to develop a detailed nodal production cost model of its region to accurately capture congestion to identify needs and estimate cost savings of transmission solutions.

New approaches continue to be developed to accurately account for the benefits of transmission:

- Use weather-reflective (rather than weather-normalized) production cost and long-term expansion planning simulations (e.g., for 20–30 weather years)
- Production cost simulations with both day-ahead and real-time cycles to capture unpredictable real-time challenges and associated value

Transmission Cost Savings and Benefits Quantified by Planners

Benefit Category	Transmission Benefit
1. Traditional Production Cost Savings	Adjusted Production Cost (APC) savings as currently estimated in most planning processes
2. Additional Production Cost Savings	i. Impact of generation outages and A/S unit designations
	ii. Reduced transmission energy losses
	iii. Reduced congestion due to transmission outages
	iv. Reduced production cost during extreme events and system contingencies
	v. Mitigation of typical weather and load uncertainty, including the geographic diversification of uncertain renewable generation variability
	vi. Reduced cost due to imperfect foresight of real-time system conditions, including renewable forecasting errors and intra-hour variability
	vii. Reduced cost of cycling power plants
	viii. Reduced amounts and costs of operating reserves and other ancillary services
	ix. Mitigation of reliability-must-run (RMR) conditions
	x. More realistic "Day 1" market representation
3. Reliability and Resource Adequacy Benefits	i. Avoided/deferred cost of reliability projects (including aging infrastructure replacements) otherwise necessary
	ii. (a) Reduced loss of load probability or (b) reduced planning reserve margin
4. Generation Capacity Cost Savings	i. Capacity cost benefits from reduced peak energy losses
	ii. Deferred generation capacity investments
	iii. Access to lower-cost generation resources
5. Market Facilitation Benefits	i. Increased competition
	ii. Increased market liquidity
6. Environmental Benefits	i. Reduced expected cost of potential future emissions regulations
	ii. Improved utilization of transmission corridors
7. Public Policy Benefits	Reduced cost of meeting public policy goals
8. Other Project-Specific Benefits	Examples: increased storm hardening and wild-fire resilience, increased fuel diversity and system flexibility, reduced cost of future transmission needs, increased wheeling revenues, HVDC operational benefits

Source: Brattle & Grid Strategies Report: Transmission Planning for the 21st Century: Proven Practices that Increase Value and Reduce Costs, October 2021.

5 & 6. Planners Approved Upgrades based on Cost Savings

SERTP should review industry experience analyzing a comprehensive set of cost savings and other benefits and develop planning guidelines for estimating transmission benefits in future regional studies

SPP 2016 RCAR, 2013 MTF

Quantified

1. **Production cost savings***
   - Value of reduced emissions
   - Reduced ancillary service costs
2. Avoided transmission project costs
3. Reduced transmission losses provide capacity and energy benefit*
4. Lower transmission outage costs
5. Value of reliability projects
6. Value of mtg public policy goals
7. Increased wheeling revenues

Not quantified

8. Reduced cost of extreme events
9. Reduced reserve margin
10. Reduced loss of load probability
11. Increased competition/liquidity
12. Improved congestion hedging
13. Mitigation of uncertainty
14. Reduced plant cycling costs
15. Societal economic benefits

(SPP Regional Cost Allocation Review Report for RCAR II, July 11, 2016. SPP Metrics Task Force, *Benefits for the 2013 Regional Cost Allocation Review*, July, 5 2012.)

MISO MVP Analysis

Quantified

1. **Production cost savings** *
2. Reduced operating reserves
3. Reduced planning reserves
4. Reduced transmission losses*
5. Reduced renewable generation investment costs
6. Reduced future transmission investment costs

Not quantified

7. Enhanced generation policy flexibility
8. Increased system robustness
9. Decreased natural gas price risk
10. Decreased CO_2 emissions output
11. Decreased wind generation volatility
12. Increased local investment and job creation

(Proposed Multi Value Project Portfolio, Technical Study Task Force and Business Case Workshop August 22, 2011)

CAISO TEAM DPV2 Analysis

Quantified

1. **Production cost savings*** and reduced energy prices from societal and customer perspective
2. Mitigation of market power
3. Insurance value for high-impact low-probability events
4. Capacity benefits due to reduced gen investment costs
5. Operational benefits (RMR)
6. Reduced transmission losses*
7. Emissions benefit

Not quantified

8. Facilitation of the retirement of aging power plants
9. Encouraging fuel diversity
10. Improved reserve sharing
11. Increased voltage support

(CPUC Decision 07-01-040, January 25, 2007, Opinion Granting a Certificate of Public Convenience and Necessity)

NYISO AC Upgrades Analysis

Quantified

1. **Production cost savings*** (includes savings not captured by normalized simulations)
2. Capacity resource cost savings
3. Reduced refurbishment costs for aging transmission
4. Reduced costs of achieving renewable and climate policy goals

Not quantified

5. Protection against extreme market conditions
6. Increased competition and liquidity
7. Storm hardening and resilience
8. Expandability benefits

(Newell, et al., Benefit-Cost Analysis of Proposed New York AC Transmission Upgrades, September 15, 2015)

* Fairly consistent across RTOs

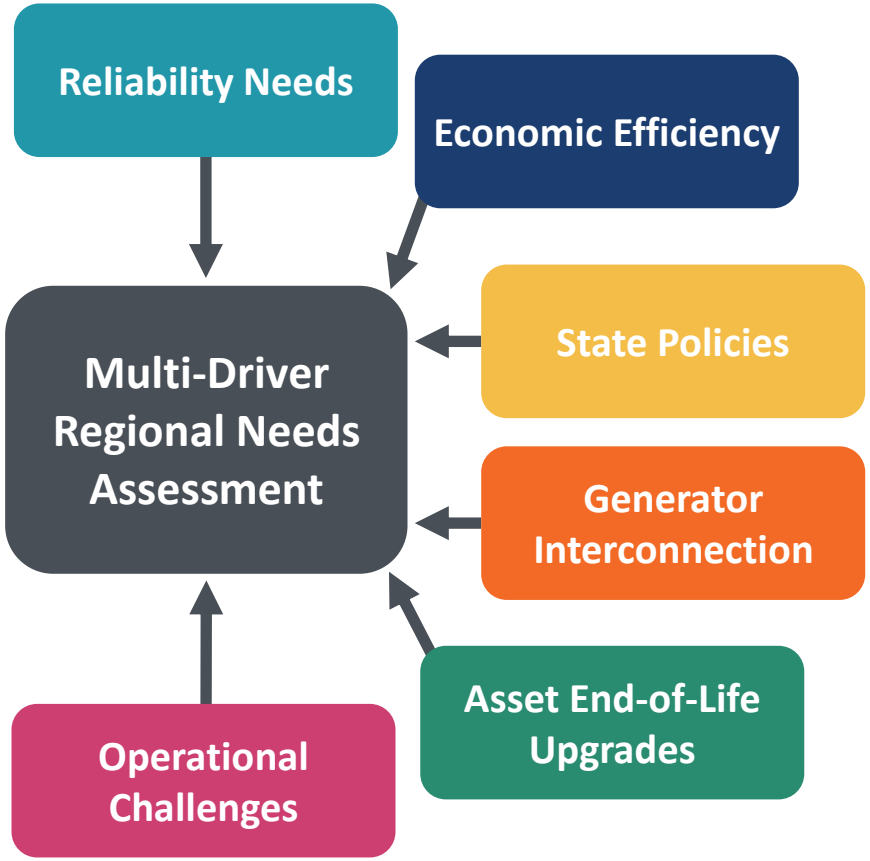
7. Multi-Driver Needs Assessment to Identify Solutions

Implementing a multi-driver approach to identifying regional transmission needs will allow regional transmission planners to identify overlapping concerns and develop cost-effective, right-sized solutions that can provide a broad range of benefits.

- Regional transmission can provide multiple benefits, but regional planners often focus solely on identifying the least-cost solutions for single drivers, e.g., reliability, economic efficiency, generator interconnection, or public policy needs, through a siloed process
- Siloed regional planning misses the broader benefits of regional projects that address multiple needs simultaneously, leading to higher overall electricity costs

MISO's LTRP process includes identifying reliability, economic, and policy needs based on several long-term future scenarios.

SPP completes a five-part needs assessment that reviews (1) economic, (2) reliability, (3) public policy, (4) persistent operational, and (5) winter weather needs.



8. Estimate Benefits & Costs over Entire Asset Life

SERTP should evaluate candidate solutions for an expanded set of cost savings and other benefits based on the guidelines it develops with stakeholders over **the full useful life of the solutions**.

For example, **we estimate the potential cost savings of 1 GW of regional transmission** between BAAs within the SERTP region over a 50-year life of a new transmission asset for three benefit metrics.

Production Cost Savings

Regional transmission could provide **$2.8 billion in fuel and congestion cost savings** by increasing transfer capability between major utilities by 1 GW over 50 years.

Transmission BAA Pair	50-year NPV	
	$0/MWh Hurdle	$8/MWh Hurdle
	$ Millions	*$ Millions*
TVA and DUKE	$1,261	$994
SOCO and TVA	$1,244	$963
SOCO and DUKE	$1,138	$871

Load Diversity Savings

By increasing transfer capability for sharing resources between BAAs that take advantage of temporal differences of peak load, SERTP Sponsors could save on avoided generation capacity costs.

Using historical differences in independent system peaks, regional transmission could **reduce costs of achieving resource adequacy requirements by $1.26 billion** by increasing transmission between each of the neighboring SERTP BAAs by 1 GW.

Resiliency Benefits

With additional interregional capability to access generation during Winter Storm Elliot, 1 GW of regional transmission capacity to support customers across the Southeast could have avoided 10 GWh of total load shed.

At a VOLL of $10,000/MWh, **1 GW of regional transmission would avoid $668 million of customer costs due to unserved load,** assuming a similar event occurred every 5 years.

9. Develop Cost Allocation for Approved Portfolios

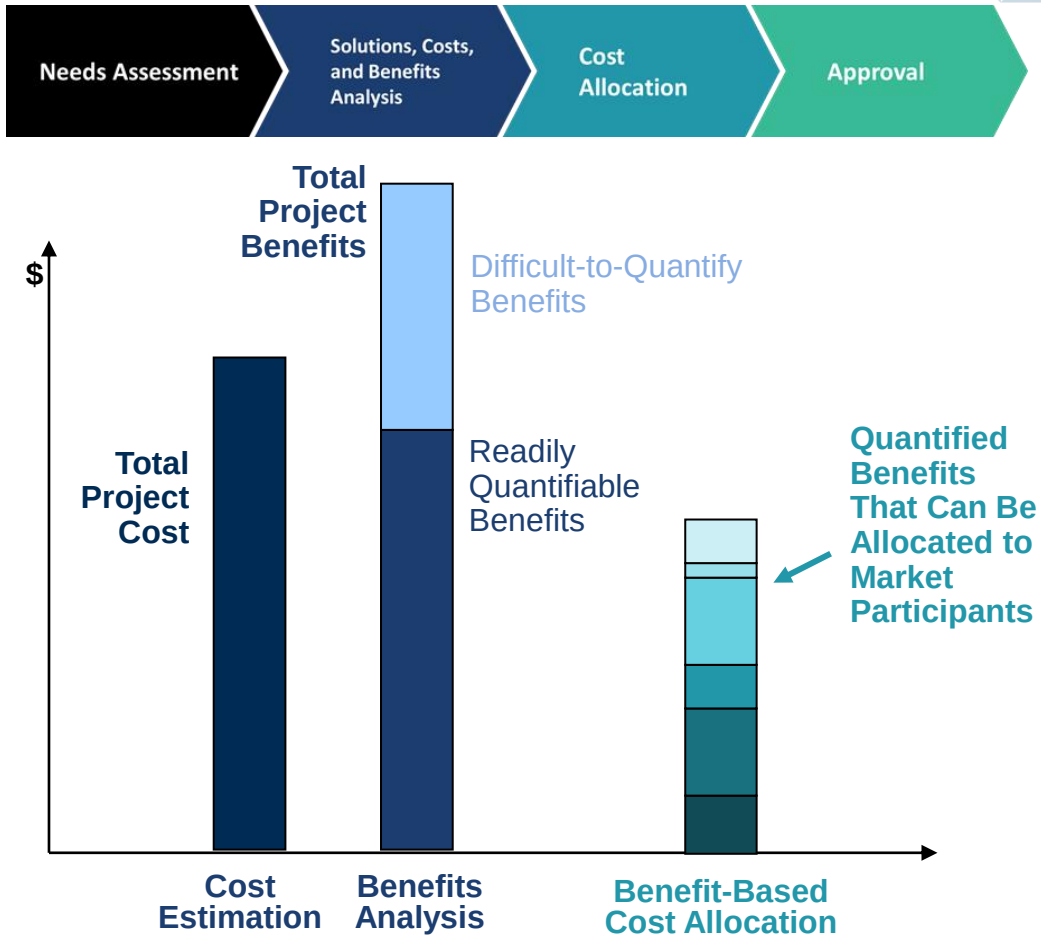
Important for SERTP to develop a regional cost allocation approach that ensures regional customer transmission costs are roughly commensurate with their benefits

To ensure beneficial projects are approved and costs are fairly allocated, recommend a 2-step approach:

1. SERTP determines whether projects are beneficial overall based on a broad set of benefits over the life of the asset
2. Evaluate how to allocate the costs of a portfolio of projects based on their joint distribution of benefits

This approach will tend to reduce issues related to cost allocation, as a broad set of benefits quantified for a portfolio of projects tends to be more stable over time and be distributed more uniformly.

SERTP should weigh the tradeoffs of an overly formulaic approach to cost allocation versus a simpler load-ratio-share approach for Sponsors with demonstrated benefits.



IV. Why the Southeast Needs to Modernize Its Regional Planning Process Now to Reduce Costs and Increase Reliability

Regional Upgrades Are Providing Benefits Across U.S.

Every region across the U.S. other than the Southeast has taken proactive steps to build out its regional grid in order to lower electricity costs, improve reliability, and support economic growth.

The following regional projects pursued in the past few years represents $117 billion of investments:

- MISO LRTP Tranche 1 and Tranche 2.1 Portfolios: $33 billion (see following slides)
- ERCOT 2025 Upgrades to Serve Load Growth: $32 billion
- Southwest Power Pool 2024 Integrated Transmission Planning (ITP) Portfolio: $11 billion
- California ISO 2022/23 and 2023/24 Policy Projects: $10 billion
- PacifiCorp Energy Gateway and Boardman-to-Hemingway Projects: $8 billion
- Champlain Hudson Power Express and NECEC to Access Canadian Hydro: $8 billion
- PJM 2024 RTEP Data Center-Driven Regional Upgrades: $6 billion

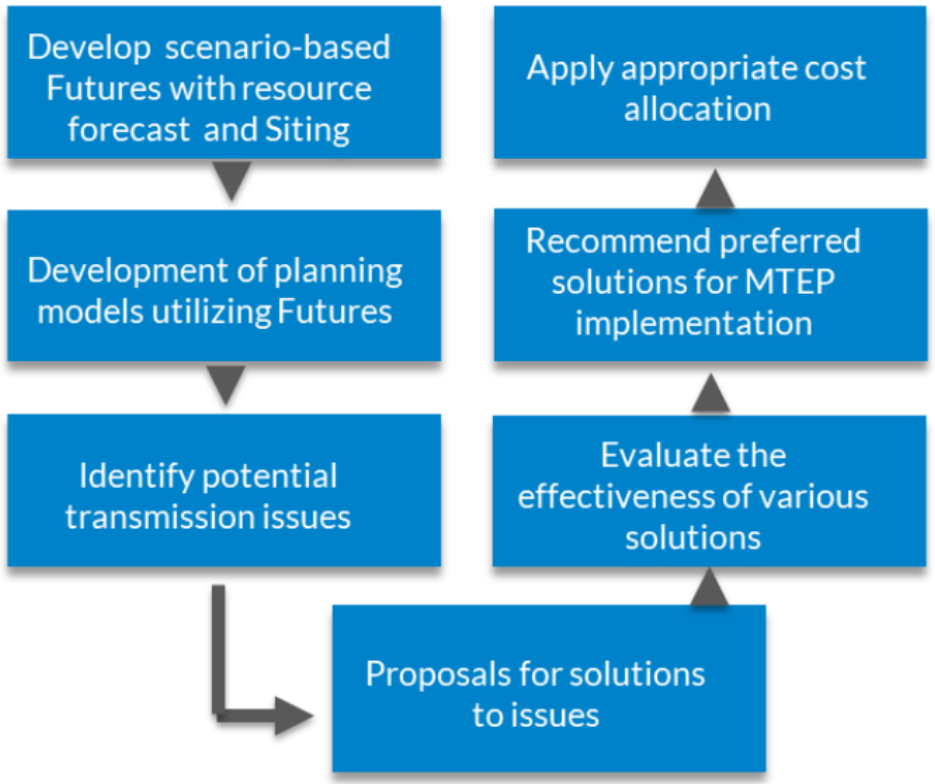
Similar system needs that led transmission planners across the country to embrace proactive regional transmission planning also apply to the Southeast and SERTP as demonstrated by national studies.

MISO and the Carolinas Transmission Planning Collaborative (CTPC) provide clear examples of proactive transmission planning approaches that SERTP should consider for enhancing its regional planning process.

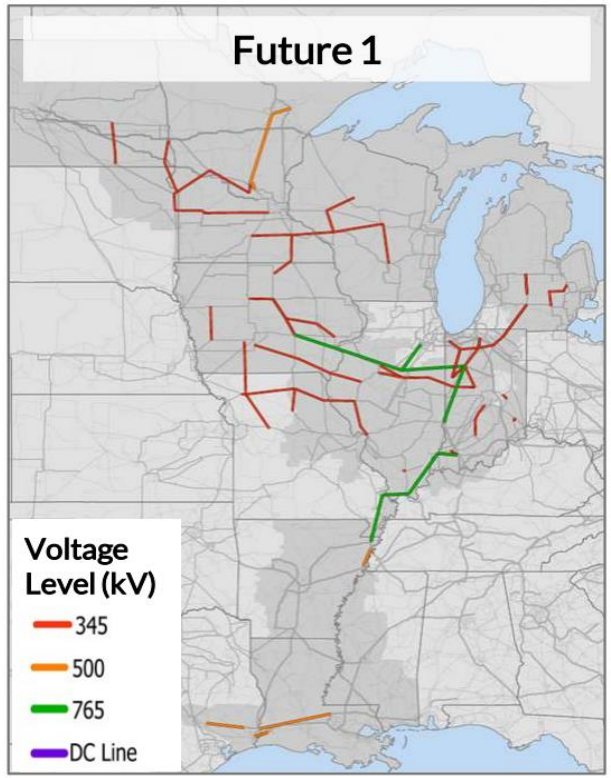
MISO Long Range Transmission Planning Process

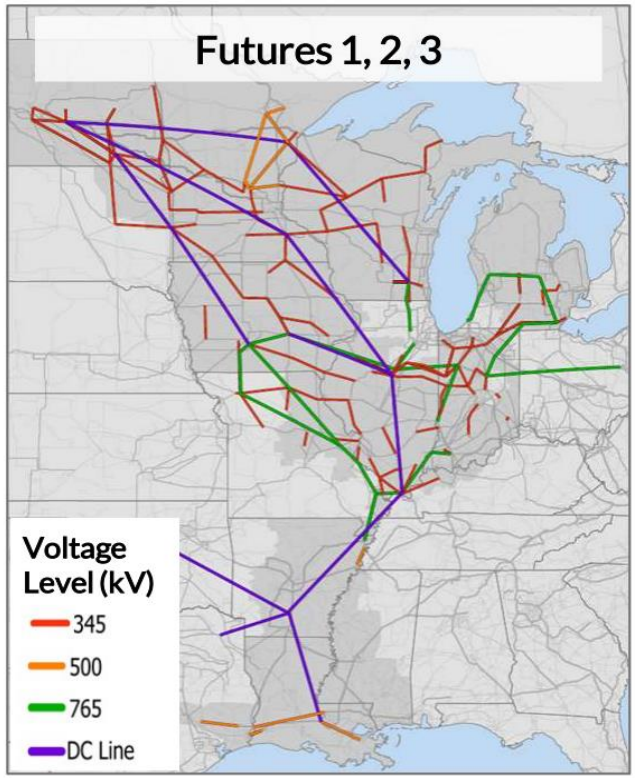
MISO's LRTP Tranche 1 and Tranche 2.1 evaluated 20-year reliability, economic, and policy needs for three plausible "Futures" scenarios that accounted for uncertainty in load growth and generation.

MISO' LRTP Process



MISO's Identified Long-Term Transmission Needs





Source: MISO LRTP Roadmap March 2021

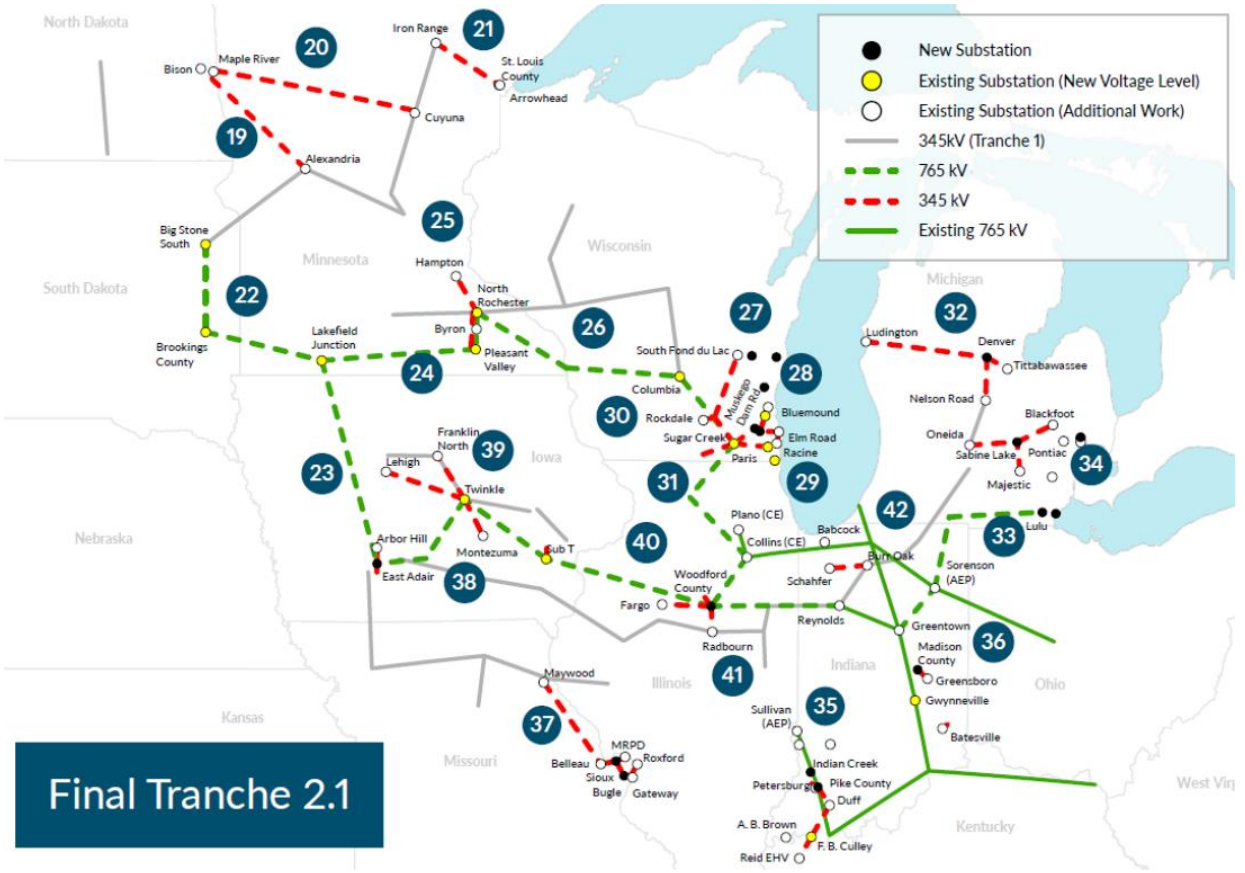
MISO Long-Range Transmission Planning Results

MISO completed the first two tranches of its LRTP multi-value planning process, which resulted in $33 billion of regional transmission investment to modernize its grid.

MISO LRTP RESULTS

- Tranche 1 results:
  - $10 billion portfolio of new 345 kV projects
  - Supports interconnection of 53 GW of renewable resources
  - Reduces system costs by $37–70 billion
- Tranche 2.1 results:
  - $22 billion portfolio of new 345 kV and 765 kV projects and substations
  - Reduces system costs by $34–62 billion
- Portfolios of LRTP projects designed to benefit each zone within MISO's Midwest Subregion with costs allocated on a postage-stamp (per-MWh) basis to customers in MISO Midwest

MISO LRTP Tranche 1 and Tranche 2.1 Projects



Source: https://www.misoenergy.org/planning/long-range-transmission-planning/

CTPC/Duke Multi-Value Strategic Transmission (MVST) Study

Carolinas Transmission Planning Collaborative (CTPC) completes local transmission planning for utilities in North and South Carolina, including Duke Energy (DEC/DEP), ElectriCities, and NCEMC

CTPC identified **$503 million of Public Policy upgrades** in its 2023 Annual Plan to support solar additions based on upgrades identified in multiple interconnection cluster studies.

CTPC added to its local planning process a **proactive, scenario-based, multi-driver process to identify Multi-Value Strategic Transmission (MVST) projects;** implementing its first MVST study in 2024–2025.

Key Aspects of CTPC Multi-Value Strategic Transmission Process

IRP-based Scenarios

Identify reliability and economic needs for future scenarios based on Duke's projected load and IRP-developed generation portfolios

Alternative Solutions

Consider GETs, advanced conductors, Remedial Action Schemes (RAS), and storage as potential solutions as well as existing lines upgrades and greenfield transmission

Portfolio Evaluation

Evaluate a portfolio of transmission solutions over the life of the assets to resolve identified needs

Benefits Analysis

Quantify (1) avoided capacity costs, (2&3) capacity cost and energy cost savings from reduced losses, (4) congestion and fuel cost savings, (5) avoided customer outages, and (6) avoided transmission costs

Case Study: Assessing Benefits of SERTP Regional Projects

To demonstrate the value of Southeast regional transmission, we performed a high-level analysis of three 500 kV upgrades SERTP identified in its 2024 regional planning process (see map).

The analysis evaluated the potential cost savings and other benefits of the regional projects based on an expanded set of benefits utilizing recent historical market data:

- **Production cost savings** based on historical 2015–2023 system lambdas reported by SERTP Sponsors as a proxy
- **Load diversity benefits** based on historical 2011–2023 load shapes, accounting for capacity cost savings from imports
- **Resilience benefits** during extreme weather conditions, such as Winter Storm Elliott

Regional Projects Evaluated in 2024 SERTP Regional Plan

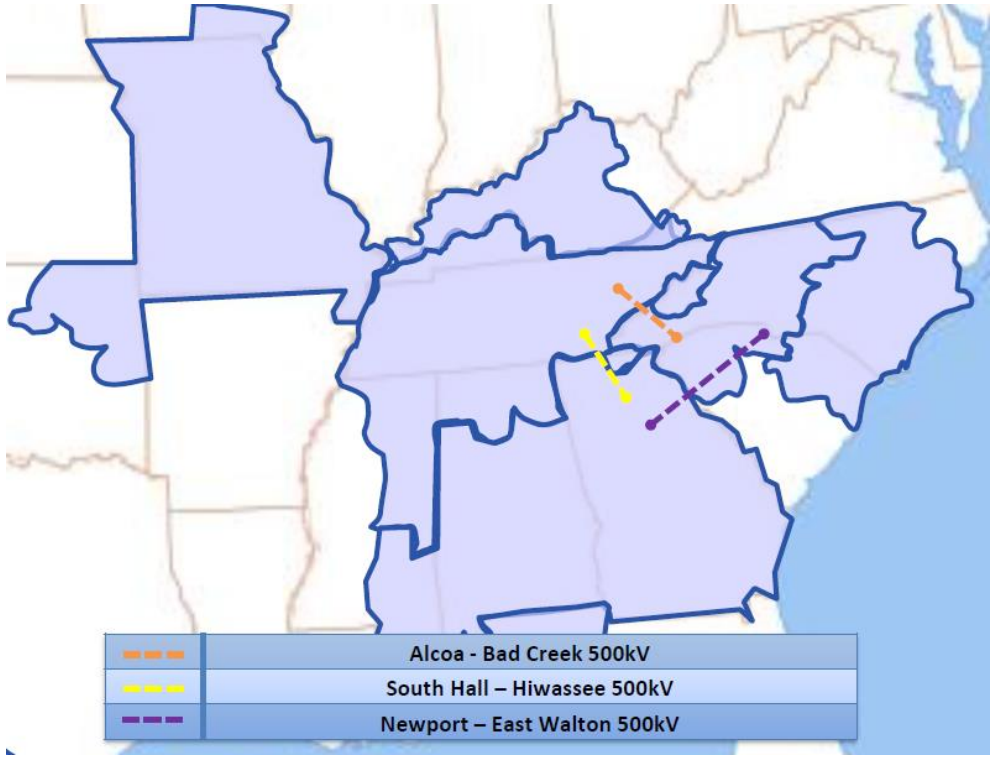


Image Source: SERTP 2024 SERTP 3rd Quarter Meeting Presentation, slide 49.

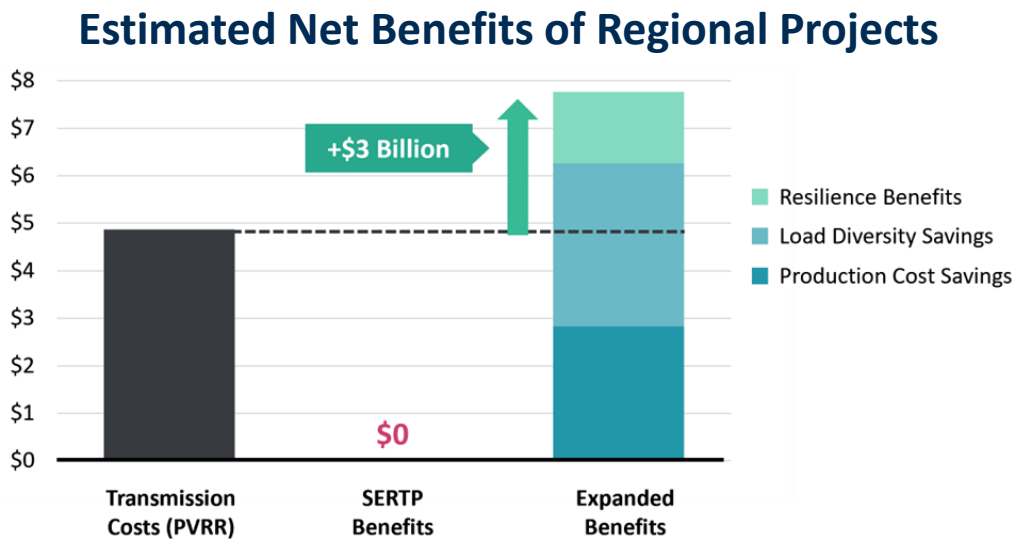
Expanded Scope of Cost Savings Identifies Cost-Effective Upgrades

Using an expanding set of benefits, we estimated $8 billion of cost savings and other benefits for these proposed regional lines, resulting in $3 billion of net benefits for customers in the Southeast over the life of the assets.

- Production cost savings: $2.8 billion (range: $2.0–3.6 billion)
- Load diversity cost savings: $3.3 billion (range: $0.9–6.0 billion)
- Resilience benefits: $1.6 billion (range: $0.7–2.3 billion)
- *Note: A more detailed study is likely to identify additional benefits not quantified in this high-level analysis, including avoided reliability and interconnection upgrades, greater production cost savings with increased solar/wind, and reduced generation costs*

Regional transmission can reduce system costs when a broader scope of cost savings and other benefits are analyzed

By contrast, SERTP's very narrow view of benefits based solely on avoided local transmission costs identified **no cost savings**.



Note: Detailed results included in the appendix slides. Load diversity savings were capped at 1 GW of potential value, as we assumed the new lines would be limited to about 1 GW of capacity.

Order 1920 Provides Southeast Opportunity in 2025 to Enhance Its Regional Transmission Planning Process

- **Southeast is the only major U.S. region that has not pursued significant regional transmission projects over the past decade**
- **Every year without a proactive regional transmission planning process in the Southeast results in higher electricity bills, increased blackout risks, and lost business investment over the long term due to insufficient grid infrastructure**
- **FERC issued Order No. 1920 last year that requires SERTP to implement a proactive, long-term, multi-value regional planning process, presenting a pivotal opportunity for the Southeast to align its regional transmission planning with industry best practices developed over the past 10–20 years**
- **The Southeast should embrace this opportunity in 2025 to modernize SERTP's regional transmission planning to build a stronger, more efficient grid that supports economic growth, energy affordability, and long-term resilience**

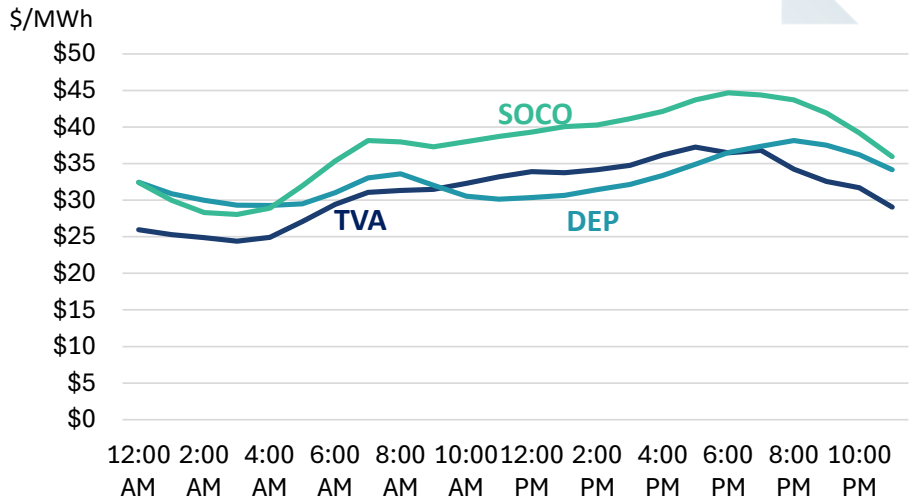
Appendix: Case Study Detailed Analysis

Estimated Production Cost Savings

Using historical system lambdas, we estimate the potential value of 1 GW of transfer capability for pairs of our case study balancing authorities

- Methodology for Estimating Production Cost Savings:
  - System lambdas represent an approximation of marginal unit cost in an hour and are directly reported by each utility to FERC
  - We assume the new transmission will optimize flows by sending power from the BA with a lower price to the BA with a higher price every hour when the price separation exceeds a specific "hurdle" (representing trading costs like wheeling charges and other frictions)[1]
  - Resulting flow and price separation estimate value of new transmission upgrades
- Production Cost Savings Results:
  - With a trading hurdle of $8/MWh, the regional upgrades provide $2.8 billion in production cost savings
  - Average price separation between BAs is $8 - $10/MWh, but there is significant value in periods of high price separation

2019-2023 Average Marginal Cost of Energy



Estimated 2019 – 2023 Value of 1 GW of New Transmission

Transmission BAA Pair	Average Annual 2019-2023 Value			50 Year NPV of 1,000 MW (at 7% Discount Rate)		
	$0/MWh Hurdle	$8/MWh Hurdle	$15/MWh Hurdle	$0/MWh Hurdle	$8/MWh Hurdle	$15/MWh Hurdle
	$ Millions	*$ Millions*	*$ Millions*	*$ Millions*	*$ Millions*	*$ Millions*
TVA and DUKE	$91	$72	$55	$1,261	$994	$758
SOCO and TVA	$90	$70	$49	$1,244	$963	$671
SOCO and DUKE	$82	$63	$43	$1,138	$871	$596
			Total Savings	$3,643	$2,828	$2,025

[1] The selection of $8/MWh and $15/MWh hurdle rates mimics the low-coordination and high-coordination scenarios in the Southeast from Kahrl, Fredrich, et al., *Solar and Storage Integration in the Southeastern United States: Economics, Reliability, and Operations.* Lawrence Berkeley National Laboratory and National Renewable Energy Laboratory, 2024.

Load Diversity Savings Value

Interregional transmission unlocks a planning benefit to utilities that we call 'load diversity savings' which is: The value of capacity avoided by one region by relying on capacity in another region that is enabled by transmission

- Utilities plan their generation fleet to meet their own annual peak load, not considering that a balancing authority near them may have spare capacity at the same time due to regional diversity in load shapes
  - *Duke for example may experience peak load at 6pm EST while TVA may peak at 7pm EST, or in different months entirely*
- **This savings value is calculated by determining how much lower the combined coincident peak of two balancing authorities is compared to their own independent annual peak loads**
  - By planning for one combined coincident peak, you can avoid capacity costs in one or both balancing authorities
  - This benefit **is only reliable if you have expanded interregional transmission** that allows you to rely on capacity from another balancing authority during peak load periods
- **The next three slides walk through how we estimate this metric historically**

Load Diversity Benefits of Regional Upgrades

Potential capacity savings exist from the diversity of peak load in the Southeast

- **Potential capacity savings**: Comparison of two BAAs **independent peaks** and their BAA peak under the pair's **joint coincident peak**
- **Existing transmission capacity:** EIA historic 95th percentile and maximum transmission flows between the BAAs
- Potential savings vs. EIA 95th percentile historic (2015-2023) transfer limits

At an avoided capital cost of $833/kW, the potential capital cost savings using the sum of the average potential savings **would be $1,256 million**

- *Based on 2025 AEO Tennessee Gas-CT capital cost*
- *Cost savings are higher once you include operating cost of the gas plant and cost of capital*
- *Would be even higher for avoided storage*

Potential Load Diversity Benefits of Transmission Expansion (MW)

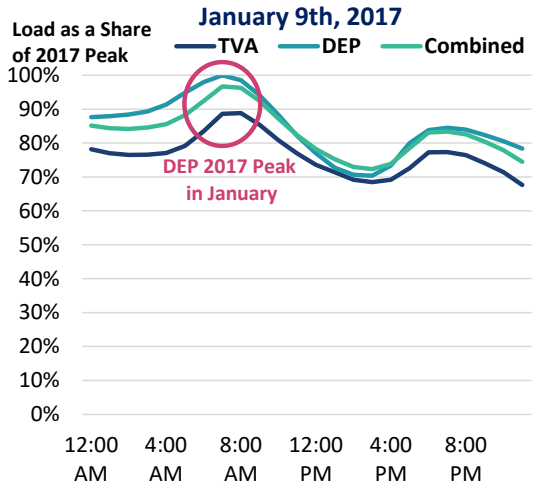
BAA Pair		Potential Peak Savings from TX		EIA Historic Transfer Limits	Potential Savings - EIA Limits	
BAA Pair	BAA	2011-2023 Average Potential Savings	2011-2023 Maximum Potential Savings	EIA Implied Transfer Limit	Average Potential Savings - EIA Transfer Limit	Maximum Potential Savings - EIA Transfer Limit
TVA <> AECI	TVA	28	205	325		
	AECI	461	1,459	38	**423**	**1,421**
TVA <> SOCO	TVA	446	2,170	1,546		**624**
	SOCO	127	670	1,802		
TVA <> DEC	TVA	221	1,133	154	**67**	**979**
	DEC	658	1,597	323	**335**	**1,274**
TVA <> DEP	TVA	118	906	68	**50**	**838**
	DEP	737	2,380	104	**633**	**2,276**
DEP <> SOCO	DEP	604	1,932	1,501		**431**
	SOCO	106	934	1,692		
DEC <> SOCO	DEC	287	885	502		**383**
	SOCO	199	1,515	1,163		**352**

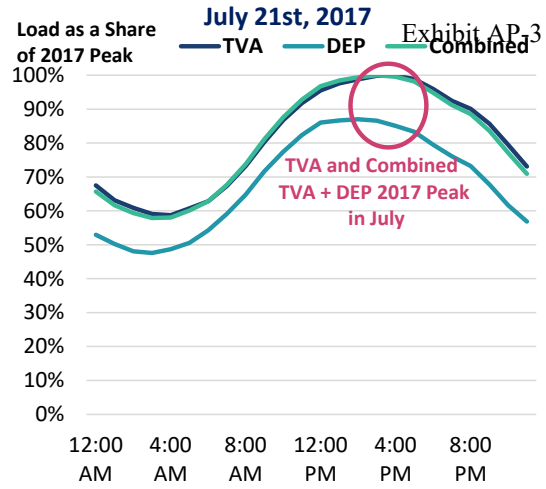
Load Diversity Savings Value

As an example, DEP peaks independently in January 2017 while TVA is 3.4 GW below its own 2017 peak that it planned its system to meet

TVA and DEP's load diversity savings calculation is shown on the right

- The independent gross peak is each BAs annual peak on their own
- The coincident peak is each BAs load during the joint TVA + DEP peak during the year
- The potential load diversity savings is the difference between a BA's gross peak and load during the coincident peak
- **This is then compared in our summary table in the previous slide to the existing transfer capacity** to see if this diversity value can be captured via existing transmission already





Load Diversity Savings Calculation Example for TVA and DEP

	Tennessee Valley Authority			Duke Energy Progress LLC		
Year	Independent Gross Peak	Peak During TVA + DEP Coincident Peak	Potential Load Diversity Savings from TX	Independent Gross Peak	Peak During TVA + DEP Coincident Peak	Potential Load Diversity Savings from TX
	MW	*MW*	*MW*	*MW*	*MW*	*MW*
2011	36,765	36,627	138	16,244	15,861	383
2012	36,696	36,696	0	16,095	15,989	106
2013	33,897	33,897	0	15,278	14,649	630
2014	39,355	39,355	0	17,342	17,170	172
2015	38,646	38,646	0	18,994	17,713	1,281
2016	35,192	35,192	0	16,224	16,224	0
2017	35,281	35,235	46	17,731	15,351	2,380
2018	38,361	37,454	906	18,933	17,969	964
2019	34,891	34,891	0	16,676	15,533	1,143
2020	34,139	34,111	27	16,144	16,144	0
2021	35,883	35,553	329	15,916	15,666	250
2022	39,442	39,355	86	17,181	15,538	1,643
2023	37,578	37,578	0	15,825	15,202	622
Average Peak Saving			**118**			**737**
Maximum Peak Saving			**906**			**2,380**

Load Diversity Savings Value

Potential load diversity savings between our four case-study examples from 2011 – 2023 average over $900 million, mostly between TVA and Duke

- Average avoided capacity cost denotes the 2011 – 2023 average annual load diversity savings vs. the maximum which denotes the highest year of possible savings
- Maximum avoided capacity savings are nearly $6 billion across the four BAAs for up to 2.3 GW of transmission
- These savings are likely to increase in the future as it does not include projected load growth

BAA Combinations for 2011 – 2023 Potential Load Diversity Savings

Metric			TVA - DEP		TVA - DEC		TVA - SOCO		SOCO - DEP		SOCO - DEC		
Metric	Unit	Col.	TVA	DEP	TVA	DEC	TVA	SOCO	SOCO	DEP	SOCO	DEP	
Average Load Diversity Savings	MW	[1]	118	737	221	658	446	127	106	604	199	287	
Maximum Load Diversity Savings	MW	[2]	906	2,380	1,133	1,597	2,170	670	934	1,932	1,515	885	
EIA Implied Import Capacity	MW	[3]	68	104	154	323	1,546	1,802	1,692	1,501	1,163	502	
Avg. Savings - Import Capacity	MW	[4]	50	633	67	335	-	-	-	-	-	-	
Max. Savings - Import Capacity	MW	[5]	838	2,276	979	1,274	624	-	-	431	352	383	
Avg. Avoided Capacity Cost	$ Millions	[6]	$42	$527	$56	$279	-	-	-	-	-	-	$904 million savings
Max. Avoided Capacity Cost	$ Millions	[7]	$698	$1,896	$816	$1,061	$520	-	-	$359	$293	$319	$5,962 million savings

Notes: [1] & [2] include 2011 – 2023 hourly load data from EIA calculated for each BAA pair. [3] is the 95th percentile of historic 2015 – 2023 EIA transfers between BAAs. [4] is [1] – [3] when [1] > [3]. [5] is [2] – [3] when [2] > [3]. [6] and [7] multiply [4] and [5] by $833/kW, our assumed cost of peaking capacity from the EIA's 2025 AEO Gas-CT cost for Tennessee.

Resilience Benefits from Transmission

Additional customer savings are unlocked from transmission in the form of resilience to extreme weather events like Winter Storm Elliott by allowing BAs to import power in periods of system stress

TVA, Duke, and LG&E/KU were all forced to order firm load shedding during Winter Storm Elliott

- TVA shed 19,000 MWh; Duke shed a combined 4,936 MWh; and LG&E/KU shed 1,265 MWh

Utilizing regional and interregional transmission to unlock greater access to imports during emergency events can avoid load shed and create significant cost savings resulting from lost load

- Lost load is valued somewhere between $10,000/MWh (in MISO) and $35,000/MWh (in ERCOT)
- Based on outage data from Winter Storm Elliott, 1 GW of additional transmission available to import generation across the region could have avoided between $95 million to $333 million in lost load during the event

If we assume these events happen roughly every five years, regional transmission could provide nearly $668 million to $2.3 billion in resiliency benefits of avoided lost load.

Prepared By

J. Michael Hagerty

PRINCIPAL
WASHINGTON, D.C.

Michael.Hagerty@brattle.com

+1.202.419.3323

Peter Heller

ENERGY RESEARCH ASSOCIATE
BOSTON

Peter.Heller@brattle.com

+1.617.234.5670

Evan Bennett

ENERGY SPECIALIST
WASHINGTON, D.C.

Evan.Bennett@brattle.com

+1.202.908.2640

The views expressed in this presentation are strictly those of the presenter(s) and do not necessarily state or reflect the views of The Brattle Group or its clients.

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CERTIFICATE OF SERVICE

I certify that I have served the following parties with the foregoing **Direct Testimony and Exhibits of Alejandro Palomino on Behalf of Southern Renewable Energy Association** by electronic mail, this 2nd day of May, 2025.

Whit Cox
SREA Regulatory Director

Sallie Tanner
Executive Secretary
Georgia Public Service Commission
244 Washington Street, SW
Atlanta, GA 30334
stanner@psc.ga.gov

Jamie Barber
Justin Pawluk
Robert Trokey
Chris Collado
Georgia Public Service Commission
244 Washington Street, SW
Atlanta, Georgia 30334
jbarber@psc.ga.gov
jpawluk@psc.ga.gov
rtrokey@psc.ga.gov
ccollado@psc.ga.gov

J. Pollock Incorporated
14323 South Outer 40 Road
Suite 206 N
Town and Country, MO 63017-5734
jcp@pollockinc.com

Robert B. Baker
Robert B. Baker, PC
2480 Briarcliff Road, NE, Suite 6
Atlanta, Georgia 30329
bobby@robertbaker.com

Jim Clarkson
Resource Supply Management
135 Emerald Lake Rd
Columbia, SC 29209
jclarkson@rsmenergy.com

Steven Hewitson
Brandon Marzo
Allison Pryor
Troutman Pepper Locke
Bank of America Plaza
600 Peachtree St., NE, Suite 5200
Atlanta, Georgia 30308
steven.hewitson@troutman.com
brandon.marzo@troutman.com
allison.pryor@troutman.com

Charles B. Jones, III
Lloyd Avram
Georgia Association of Manufacturers
The Hurt Building
50 Hurt Plaza, Suite 1620
Atlanta, Georgia 30303
cjones@gamfg.org
lavram@gamfg.orgJeffry C. Pollock

Jennifer Whitfield
Bob Sherrier
Amitav Kamani
Tia McGee
Southern Environmental Law Center
Ten 10th St. NW, Suite 1050
Atlanta, GA 30309
jwhitfield@selcga.org
bsherrier@selcga.org
akamani@selcga.org
tmcgee@selcga.org

Simon Mahan
Southern Renewable Energy Assoc.
11610 Pleasant Ridge Rd., Suite 103 #176
Little Rock, AR 72223
simon@southernwind.org

Jeremiah Haswell, Director
Regulatory Affairs Georgia Power Company
Bin 10230
241 Ralph McGill Boulevard, NE
Atlanta, Georgia 30308-3374
jhaswell@southernco.com

Maggie Shober
Eddy Moore
Southern Alliance for Clean Energy
P.O. Box 1842
Knoxville, TN 37901
maggie@cleanenergy.org
eddy@cleanenergy.org

Benjamin L. Snowden
Cordon M. Smart
Fox Rothschild LLP
434 Fayetteville Street, Suite 2800 Raleigh, NC 27601
BSnowden@FoxRothschild.com
CSmart@FoxRothschild.com

Gerald T. Chichester
Fox Rothschild, LLP
999 Peachtree Street, NE
Suite 1500
Atlanta, GA 30309
GChichester@FoxRothschild.com

David Nifong
City of Decatur, Department of Public Works
2635 Talley Street
Decatur, GA 30030
david.nifong@decaturga.com

Gordon Kenna
DeKalb County, Public Works
180 Sams Street
Decatur, GA 30030
hgkenna@dekalbcountyga.gov

Mike Wharton
Joey Crews
Athens-Clarke County, Sustainability Office
110 Bray Street
Athens, GA 30601
mike.wharton@accgov.com
joseph.crews@accgov.com

Peter Hubbard
Georgia Center for Energy Solutions
55 Leslie St SE
Atlanta, GA 30317
peter@georgia-ces.org

Alicia Brown
Capital Good Fund
333 Smith St.
Providence, RI 02908
aliciab@capitalgoodfund.org

Scott F. Dunbar
Keyes and Fox LLP
1580 Lincoln St.
Suite 1105
Denver, CO 80203
sdunbar@keyesfox.com

Anna Bella Korbatov
Director of Regulatory Affairs
Fermata Energy
100 10th St. NE, # 101
Charlottesville, VA 22902
annabella@fermataenergy.com

Steve Letendre, PhD
Senior Director of Regulatory Affairs
Fermata Energy
100 10th St. NE
Charlottesville, VA 22902
steve@fermataenergy.com

Zachary Fabish
Isabella Ariza
Sierra Club
50 F Street NW
8th Floor
Washington, DC 20001
zachary.fabish@sierraclub.org
Isabella.ariza@sierraclub.org

Curt Thompson
Attorney at Law
Thompson & Associated Law Firm, PC 3775
Venture Drive, D100
Duluth, GA 30096
curthbthompson@bellsouth.net

Georgia Solar Energy Industries Association,
Inc. Attn: Stephen Butler, Executive Director
2451 Cumberland Parkway, Suite 3380
Atlanta, GA 30339
steve@connectpublicaffairs.org

Kimberly (Kasey) A. Sturm Weissman PC
One Alliance Center
4th floor
3500 Lenox Road
Atlanta, Georgia 30326
kaseys@weissman.law

Jonathan Hunt
Metropolitan Atlanta Rapid
Transit Authority
2424 Piedmont Road, NE
Atlanta, Georgia 30324
jhunt@itsmarta.com

John Joseph McNutt
US Army Legal Services Agency
Office of The Judge Advocate General
9275 Gunston Road (JALS-ELD) Fort Belvoir,
Virginia 22060-5546 john.j.mcnutt.civ@army.mil

Liz Coyle
Georgia Watch
55 Marietta Street, Suite 903
Atlanta, GA 30303
lcoyle@georgiawatch.org

Heather Pohnan
Southern Alliance for Clean Energy
691 John Wesley Dobbs Ave. NE Suite C
Atlanta, Georgia 30312
heather@cleanenergy.org

Chandra Farley
John R. Seydel
City of Atlanta, Office of Sustainability and Resilience
55 Trinity Ave SW
Atlanta, GA 30303
cfarley@atlantaga.gov
jrseydel@atlantaga.gov

Steven L. Jones
Matthew P. McKagen
Taylor English Duma LLP
1600 Parkwood Circle Suite 200
Atlanta, GA 30339
sjones@taylorenglish.com
mmckagen@taylorenglish.com

Patrick King II
Luis Matinez
Amanda Levin
Maeve Sneddon
Natural Resources Defense Council
1152 15th St. NW #300
Wahington, DC 20005
pkingii@nrdc.org
lmartinez@nrdc.org
alevin@nrdc.org
msneddon@nrdc.org

Newton M. Galloway
Terri M. Lyndall
Galloway & Lyndall, LLP
406 North Hill Street
Griffin, Georgia 30223
(770) 233-6230
ngalloway@gallyn-law.com
tlyndall@gallyn-law.com

David E. Penland
One Griffin Center
100 S. Hill Street, Suite 600
Griffin, GA 30223
(770) 227-4000 telephone
(770) 229-8524 facsimile
dpenland@beckowen.com

Juan Estrada
Juan Estrada Law, LLC
3675 Crestwood Parkway, Suite 400
Duluth, Georgia 30096
Juan@JuanEstradaLaw.com

Allison Kvien
Regulatory Director Southeast
2810 Coliseum Centre Drive Suite 120,
Charlotte, NC 28217
akvien@votesolar.org

Donald Moreland
Georgia Solar Energy Association
1199 Euclid Avenue
Atlanta, GA 30307
don@solarcrowdsource.com

Mendie White
Gwinnett County, Offices of the County
Administrator 75 Langley Dr.
Lawrenceville, GA 30046
mendie.white@gwinnettcounty.com

STATE OF GEORGIA
BEFORE THE
PUBLIC SERVICE COMMISSION

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

EXHIBIT AP-1

Anjali Goel Patel
Vice President for Clean Energy
David Gardiner and Associates
2609 11th St N. • Arlington, VA 22201
anjali@dgardiner.com

EMPLOYMENT HISTORY:

David Gardiner and Associates, Clarendon, VA
Vice President for Clean Energy April 2022–present

- Provide strategic, programmatic, and management support to Americans for a Clean Energy Grid, a multi-stakeholder organization that educates and advocates for the expansion, modernization, and integration of the high-capacity transmission network to improve reliability and resilience and increase access to cleaner energy resources.
- Advocate for federal and state policies to improve corporate access to clean energy and to facilitate cost-effective and equitable transportation decarbonization initiatives.
- Educate public and private entities on energy infrastructure investment, decarbonization technologies, and tax incentives and federal funding opportunities to help advance greenhouse gas emission reductions.
- Assist with business development and supervise and manage the firm's Clean Energy team.

Office of the People's Counsel for the District of Columbia, Washington, DC
Litigation Supervisor September 2021–April 2022
Senior Assistant People's Counsel June 2018–September 2021

- Managed a complex portfolio of litigated cases, and regulatory and policy matters before PJM, state and federal agencies, and appellate courts with an emphasis on ensuring safe and reliable utility service at just and reasonable rates, promoting equity considerations, and advancing the District of Columbia (DC) government's robust decarbonization goals. Major cases include: serving as lead counsel in an electric distribution rate case in which the utility sought approval to transition to a multiyear rate plan with performance incentive mechanisms; drafting a petition to address community solar billing and metering issues; advocating for the public interest in proposed energy efficiency, transportation electrification, and infrastructure improvement programs; advocating for transparent and cost-effective market rules and policies in PJM's stakeholder processes; drafting comments to address Federal Energy Regulatory Commission (FERC) rulemaking proposals and comments and protests to FERC orders revising PJM's governing documents; serving as the Secretary of the DC Public Service Commission's Pilot Project Governance Board; participating in stakeholder meetings addressing grid modernization, energy efficiency, and electrification initiatives.
- Provided issue briefings and strategic advice to senior management and assisted in developing the agency's litigation, legislative, and policy positions.
- Supervised, mentored, and trained staff attorneys and ensured that federal, state, and court dockets pertaining to utility-related matters impacting DC consumers were staffed appropriately.
- Drafted and reviewed legal and informational materials to support the agency's mission and policies, including motions, briefs, comments, petitions, testimony, discovery, settlement agreements, public fact sheets, web articles, and press releases.
- Supervised and managed litigation teams of in- and out-of-house attorneys and technical experts.
- Managed consultant contracts and assisted the Agency's Technical Division in procurement processes.
- Conducted outreach to elected and appointed officials, civic and neighborhood associations, labor organizations, environmental and advocacy groups, and other stakeholders on pending cases and emerging issues in the energy industry.
- Served as the Freedom of Information Act (FOIA) Officer from June 2018-November 2021.

Spiegel & McDiarmid LLP, Washington, DC
Associate September 2010–May 2018

- Advocated for the interests of governmental authorities and public entities before appellate courts and federal and state agencies, including FERC, the U.S. Environmental Protection Agency, and Federal Aviation Administration, by developing litigation strategies, drafting procedural and substantive pleadings, engaging in settlement negotiations, cross-examining witnesses at hearings, drafting and reviewing discovery, reviewing and revising expert testimony, and collaborating with technical consultants. Work included: litigating gas and electric cases before state public service commissions; representing municipal utility and state agency interests in public utility merger proceedings; representing client interests in an arbitration proceeding concerning power purchase costs; representing client interests in settlement negotiations before FERC Administrative Law Judges; and drafting comments for municipal utilities on FERC's electric and merchant gas transmission policies.
- Co-founded and contributed to the public interest energy and environmental blog, consideringthegrid.com.
- Counseled clients on the application of and developments in complex regulatory and constitutional laws and policies.
- Drafted, negotiated, and interpreted contracts for municipal utilities and airport operators.
- Mentored, issued assignments to, and reviewed work product from junior associates.
- Directed and managed secretarial and paralegal support.

Law Clerk May–July 2008

Great Lakes Commission, Ann Arbor, MI
Great Lakes Commission-Sea Grant Fellow June 2009–July 2010

- Facilitated consensus building, information exchange, and policy development for the Great Lakes Wind Collaborative—a multi-sector and binational coalition dedicated to facilitating the sustainable development of onshore and offshore wind in the Great Lakes region—and the Great Lakes Panel on Aquatic Nuisance Species—a federally organized panel with binational membership dedicated to preventing the spread of new, and controlling existing, aquatic invasive species in the Great Lakes.
- Drafted resolutions, comments on proposed rulemakings, and legislative testimony on issues of regional environmental and economic significance.
- Developed grant agreements for, and addressed public comments on, the implementation of the Great Lakes Restoration Initiative, a $475 million Congressionally approved program.
- Organized and conducted regional stakeholder workshops and webinars.

Academy of Natural Sciences, Philadelphia, PA
Educator and Overnight Program Manager September 2001–June 2005

- Designed and conducted classes and teacher workshops on natural history and environmental topics.
- Created curricula, hired and managed staff, and developed and maintained an annual budget for the museum's overnight program.

EDUCATION:

The University of Michigan Law School, Ann Arbor, MI
Juris Doctor December 2008

Drexel University, Philadelphia, PA
Master of Science in Environmental Policy June 2005

Case Western Reserve University, Cleveland, OH
Bachelor of Arts in Biology and Environmental Studies, *magna cum laude* May 1999
Minors in Chemistry and English

SELECT PUBLICATIONS:

Americans for a Clean Energy Grid, *State Policies to Advance Transmission Modernization and Expansion* (2024).

David Gardiner and Associates, *Options for Decarbonizing Cold-Weather Higher Education Campus Heating Systems* (2024).

David Gardiner and Associates, *Consumer Advocates of the PJM States' Transmission Handbook*, CAPS, (2024.

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Robert A. Jablon, Anjali G. Patel, and Latif M. Nurani, Trinko *and* Credit Suisse *Revisited: The Need for Effective Agency Review and Shared Antitrust Responsibility*, 34 Energy L.J. 627 (Fall 2013).

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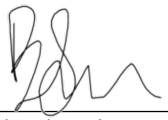
Anjali Patel, *The Role of the Great Lakes-St. Lawrence Seaway Ports in the Advancement of the Wind Energy Industry*, The Great Lakes Commission (2010).

BAR ADMISSIONS

U.S. Court of Appeals, D.C. Circuit	Admitted 2015
U.S. Court of Appeals, Second Circuit	Admitted 2018
U.S. District Court, District of Columbia	Admitted 2017
District of Columbia	Admitted 2011
Michigan	Admitted 2009

CERTIFICATE OF SERVICE

I certify that the foregoing **Direct Testimony of Anjali Patel on behalf of Georgia Interfaith Power & Light and Southface Energy Institute** was filed with the Public Service Commission in Dockets No. 56002 and 56003 by electronic delivery on the 2nd of May, 2025. An electronic copy of the same was served upon all parties listed below by electronic mail as follows:



Bob Sherrier

Sallie Tanner Executive Secretary
Georgia Public Service Commission
244 Washington Street, SW
Atlanta, Georgia 30334
stanner@psc.ga.gov

Justin Pawluk
Jamie Barber
Robert Trokey
Georgia Public Service Commission
244 Washington Street, SW
Atlanta, Georgia 30334
jpawluk@psc.state.ga.us
jpawluk@psc.ga.gov
jamieb@psc.ga.gov
rtrokey@psc.ga.gov

Chris Collado
Georgia Public Service Commission
244 Washington Street, SW
Atlanta, Georgia 30334
ccollado@psc.state.ga.us
ccollado@psc.ga.gov

Steven J. Hewitson
Brandon F. Marzo
Allison W. Pryor
Troutman Pepper Hamilton Sanders, LLP
Bank of America Plaza
600 Peachtree Street, N.E.
Suite 3000
Atlanta, Georgia 30308-2216
steven.hewitson@troutman.com
brandon.marzo@troutman.com
allison.pryor@troutman.com

Jeremiah Haswell
Georgia Power Company
241 Ralph McGill Boulevard, NE
Bin 10230
Atlanta, Georgia 30308
jhaswell@southernco.com

Cheryl Johnson
Georgia Power Company
241 Ralph McGill Boulevard, NE
Atlanta, Georgia 30308-3374
cljohnson@southernco.com

Robert B. Baker
Robert B. Baker, P.C.
Resource Supply Management
2480 Briarcliff Road, NE
Suite 6
Atlanta, Georgia 30329
bobby@robertbaker.com

Jim Clarkson
Resource Supply Management
135 Emerald Lake Road
Columbia, South Carolina 29209
jclarkson@rsmenergy.com

Charles B. Jones, III
Lloyd Avram
Georgia Association of Manufacturers
The Hurt Building
50 Hurt Plaza, Suite 1620
Atlanta, Georgia 30303
cjones@gamfg.org
lavram@gamfg.org

Jeffry C. Pollock
J. Pollock Incorporated
14323 South Outer 40 Road, Suite 206 N
Town and Country, Missouri 63017-5734
jcp@jpollockinc.com

Simon Mahan
Southern Renewable Energy Association
11610 Pleasant Ridge Rd., Suite 103 #176
Little Rock, Arkansas 72223
simon@southernwind.org

Whit Cox
Southern Renewable Energy Association
11610 Pleasant Ridge Rd., Suite 103 #176
Little Rock, Arkansas 72223
whit@southernrenewable.org

Scott F. Dunbar
Partner, Keyes & Fox LLP
1580 Lincoln St., Suite 1105
Denver, Colorado 80203
sdunbar@keyesfox.com

Alicia Zaloga
Assistant, Keyes & Fox LLP
115 Kildaire Farm Road, Ste. 202-203
Cary, North Carolina 27511
azaloga@keyesfox.com

Anna Bella Korbatov
Fermata Energy
100 10th Street NE, #101
Charlottesville, Virginia 22902
annabella@fermataenergy.com

Steve Letendre, PhD
Fermata Energy
100 10th Street NE, #101
Charlottesville, Virginia 22902
steve@fermataenergy.com

Isabella Ariza
Dorothy E. Jaffe
Zachary M. Fabish
Sierra Club
50 F Street NW, 8th Floor
Washington, DC 20001
Isabella.ariza@sierraclub.org
Dori.jaffe@sierraclub.org
Zack.fabish@sierraclub.org

Curt Thompson
Thompson & Associates Law Firm, PC
3775 Venture Drive, Dl00
Duluth, Georgia 30096
curtbthompson@bellsouth.net

Maggie Shober
Southern Alliance for Clean Energy
PO Box 1842
Knoxville, Tennessee 37901
maggie@cleanenergy.org

Heather Pohnan
Southern Alliance for Clean Energy
691 John Wesley Dobbs Ave NE, Suite C
Atlanta, Georgia 30312
heather@cleanenergy.org

Eddy Moore
Southern Alliance for Clean Energy
PO Box 1842
Knoxville, Tennessee 37901
eddy@cleanenergy.org

Bryan Jacob
Southern Alliance for Clean Energy, Inc.
1455 Hampton Hill Drive
Alpharetta, Georgia 30022
bryan@cleanenergy.org

Patrick King II
Natural Resources Defense Council
1152 15th St NW #300
Washington, DC 20005
pkingii@nrdc.org

Luis Martinez
Natural Resources Defense Council
1152 15th St NW #300
Washington, DC 20005
lrnartinez@nrdc.org

Amanda Levin
Natural Resources Defense Council
1152 15th St NW #300
Washington, DC 20005
alevin@nrdc.org

Maeve Sneddon
Natural Resources Defense Council
1152 15th St NW #300
Washington, DC 20005
msneddon@nrdc.org

Alicia Brown
Capital Good Fund
333 Smith Street
Providence, Rhode Island 02908
aliciab@capitalgoodfund.org

Kimberly ("Kasey") A. Sturm
Weissman PC
One Alliance Center, Fourth Floor
3500 Lenox Road
Atlanta, Georgia 30326
kaseys@weissman.law

Jonathan Hunt
Metropolitan Atlanta Rapid Transit Authority
2424 Piedmont Road, NE
Atlanta, Georgia 30324
jhunt@itsmarta.com

Peter J. Andrews
Metropolitan Atlanta Rapid Transit Authority
2424 Piedmont Road, NE
Atlanta, Georgia 30324
pandrews@itsmarta.com

Juan Estrada
Attorney At Law
Juan Estrada Law, LLC.
3675 Crestwood Parkway, Suite 400,
Duluth, Georgia 30096
Juan@JuanEstradaLaw.com

Liz Coyle
Georgia Watch
55 Marietta Street, Suite 903
Atlanta, Georgia 30303
lcoyle@georgiawatch.org

Peter Hubbard
Georgia Center for Energy Solutions
55 Leslie Street SE
Atlanta, Georgia 30317
peter@georgia-ces.org

John Joseph McNutt
Regulatory Law Counsel
U.S. Army Legal Services Agency
Office of The Judge Advocate General
9275 Gunston Road (JALS-ELD)
Fort Belvoir, Virginia 22060-5546
john.j.mcnutt.civ@anny.mil

Newton M. Galloway
Terri M. Lyndall
Galloway & Lyndall, LLP
406 North Hill Street
Griffin, Georgia 30223
ngalloway@gallyn-law.com
tlyndall@gallyn-law.com

David E. Penland
One Griffin Center
100 S. Hill Street, Suite 600
Griffin, Georgia 30223
dpenland@beckowen.com

Cordon M. Smart
Fox Rothschild LLP
230 N. Elm Street
Suite 1200
Greensboro, North Carolina 27401
csmart@foxrothschild.com

Benjamin L. Snowden
Fox Rothschild LLP
301 Hillsborough Street
Suite 1120
Raleigh, North Carolina 27603
BSnowden@FoxRothschild.com

Gerald T. Chichester
Fox Rothschild, LLP
999 Peachtree Street, NE
Suite 1500
Atlanta, Georgia 30309
GChichester@FoxRothschild.com

David Nifong
City of Decatur
Department of Public Works
2635 Talley Street
Decatur, Georgia 30030
david.nifong@decaturga.com

Mike Wharton
Athens-Clarke County Unified Government
Sustainability Office
110 Bray Street
Athens, Georgia 30601
Mike.Wharton@accgov.com

Joey Crews
Athens-Clarke County
Sustainability Office
110 Bray Street
Athens, Georgia 30601
joseph.crews@accgov.com

Mendie White
Gwinnett County
Offices of the County Administrator
75 Langley Drive
Lawrenceville, Georgia 30046
mendie.white@gwinnettcounty.com

Chandra Farley
John R. Seydel
City of Atlanta,
Office of Sustainability and Resilience
55 Trinity Ave SW
Atlanta, Georgia 30303
cfarley@atlantaga.gov
jrseydel@atlantaga.gov

Gordon Kenna
DeKalb County
Public Works
180 Sams Street
Decatur, Georgia 30030
hgkenna@dekalbcountyga.gov

Kathy Reed
DeKalb County Government
Department of Planning and Sustainability
178 Sams Street
Decatur, Georgia 30030
kdreed@dekalbcountyga.gov

Juan Estrada
Juan Estrada Law, LLC.
3675 Crestwood Parkway,
Suite 400
Duluth, Georgia 30096
Juan@JuanEstradaLaw.com

Kimberly Scott
Georgia WAND Education Fund, Inc.
250 Georgia Ave SE # 202
Atlanta, Georgia 30312
kim@georgiawand.org

Allison Kvien
Vote Solar
2810 Coliseum Centre Drive Suite 120
Charlotte, North Carolina 28217
akvien@votesolar.org

Stephen Butler
Georgia Solar Energy Industries
Association, Inc.
2451 Cumberland Parkway
Suite 3380
Atlanta, Georgia 30339
steve@connectpublicaffairs.org

Stephanie U. Eaton
Carrie H. Grundmann
Spilman Thomas & Battle, PLLC
110 Oakwood Drive, Suite 500
Winston-Salem, North Carolina
seaton@spilmanlaw.com
cgrundmann@spilmanlaw.com

Steven W. Lee
Spilman Thomas & Battle, PLLC
1100 Bent Creek Blvd., Suite 101
Mechanicsburg, Pennsylvania 17050
slee@spilmanlaw.com

William Bradley Carver Sr., Esq.
Hall Booth Smith, P.C.
191 Peachtree Street NE
Suite 2900
Atlanta, Georgia 30303
bcarver@hallboothsmith.com

Donald Moreland
Georgia Solar Energy Association
1199 Euclid Avenue
Atlanta, Georgia 30307
don@solarcrowdsource.com
L. Craig Dowdy
Taylor English Duma LLP
1600 Parkwood Circle
Suite 200
Atlanta, Georgia 30339
craigdowdy@taylorenglish.com

Tyler Mauldin
Microsoft Corporation
200 17th Street NW
Atlanta, Georgia
tylermauldin@microsoft.com

Taylor English Duma LLP
1600 Parkwood Circle SE
Suite 200
Atlanta, Georgia 30339
c.dowdy@taylorenglish.com
cdowdy@taylorenglish.com

STATE OF GEORGIA
BEFORE THE
PUBLIC SERVICE COMMISSION

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

EXHIBIT CH-1

ENERGY FUTURES GROUP

Chelsea Hotaling

Senior Consultant

PROFESSIONAL SUMMARY

Chelsea is a Consultant at Energy Futures Group specializing in integrated resource planning and load forecasting. Prior to joining EFG, Chelsea held a research position at Clarkson University while completing her Master's in Data Analytics and Environmental Policy & Governance. Chelsea's research focused on multi-stakeholder microgrids for resiliency. She also participated in the Reforming the Energy Vision (REV) proceedings for the Potsdam (NY) microgrid REV project. Chelsea's current work is focused on all aspects of Integrated Resource Planning including capacity expansion and production cost modeling and load forecasting. Chelsea runs the EnCompass model in support of long-term planning exercises such an IRP analyses and has critiqued IRP modeling performed using Aurora, PLEXOS, PowerSimm, and System Optimizer. Chelsea has also conducted capacity expansion, production cost, and reliability modeling using the EnCompass, Aurora, PLEXOS, and SERVM models. Chelsea has experience working with numerous software programs including Python, R, and Stata.

EXPERIENCE

2025-present: Senior Consultant, Energy Futures Group, Hinesburg, VT
2021-2024: Consultant, Energy Futures Group, Hinesburg, VT
2020-2021: Senior Analyst, Energy Futures Group, Hinesburg, VT
2019-2020: Analyst, Energy Futures Group, Hinesburg, VT
2018-2019: Intern, Sommer Energy, Canton, NY
2016-2019: Research Assistant, Clarkson University, Potsdam, NY

EDUCATION

M.S., Data Analytics, Clarkson University, 2020

M.S., Environmental Policy and Governance, Clarkson University, 2019

MBA, Concentration in Environmental Management, Clarkson University, 2012

B.S., Accounting and Economics, Elmira College, 2011

SELECTED PROJECTS

- **Clean Wisconsin.** *Performed capacity expansion and production cost modeling within PLEXOS to evaluate alternative resource portfolios to the plan put forward by Wisconsin Electric Power Company. (2024 – 2025)*

- **West Virginia Citizen Action Group, Solar United Neighbors, and Energy Efficient West Virginia.** *Reviewed the commitment and operation of the Amos, Mitchell, and Mountaineer generating units during the 2023-2024 review period. (2024) Reviewed the commitment and operation of the Harrison and Fort Martin generating units during the 2022-2023 review period. (2023)*
- **The South Carolina Coastal Conservation League and Southern Alliance for Clean Energy.** *Evaluated Santee Cooper's 2024 Annual Integrated Resource Plan Update. (2023-2024) Evaluated Dominion Energy South Carolina's 2024 Annual Integrated Resource Plan Update. (2023-2024) Performed EnCompass and SERVM modeling to evaluate a clean energy replacement portfolio for proposed coal plant retirements in the Santee Cooper 2023 IRP. (2023) Performed SERVM modeling to evaluate a clean energy replacement portfolio for proposed coal plant retirements in the Dominion Energy South Carolina 2023 IRP. (2023) Evaluation of Dominion Energy South Carolina's 2020 Integrated Resource Plan. (2020)*
- **The Ecology Center, the Environmental Law & Policy Center, the Union of Concerned Scientists, and Vote Solar.** *Performed capacity expansion and production cost modeling within EnCompass to put forward an alternate plan to DTE's preferred plan in its 2022 IRP. (2022 to 2023)*
- **GridLab.** *Performed capacity expansion and production cost modeling within EnCompass to identify resource mixes to achieve 100% emissions-free electricity by 2035 for the Public Service Company of New Mexico's electric system. (2022 to 2023)*
- **Sierra Club.** *Evaluated Louisville Gas & Electric and Kentucky Utilities 2024 Integrated Resource Plan and performed capacity expansion and production cost modeling within PLEXOS in support of those comments. (2024-2025). Performed capacity expansion and production cost modeling within EnCompass to evaluate retirement and replacement of MidAmerican's coal plants. (2022 to 2023)*
- **Minnesota Center for Environmental Advocacy.** *Evaluated Xcel Energy's 2024 Integrated Resource Plan and performed EnCompass modeling in support of that evaluation (2024). Evaluated Otter Tail Power's 2021 Integrated Resource Plan and EnCompass modeling in support of that evaluation. (2022 to 2024) Evaluated Minnesota Power's 2021 Integrated Resource Plan and performed EnCompass modeling in support of that evaluation. (2021 to 2022) Evaluated Xcel Energy's 2020 Integrated Resource Plan and performed EnCompass modeling in support of that evaluation. (2019 to 2021)*
- **Citizens Action Coalition of Indiana.** *Comments regarding Duke Energy Indiana's integrated resource plans to meet future energy and capacity needs (May 2022). Comments regarding Northern Indiana Public Service Company's integrated resource plans to meet future energy and capacity needs. (March 2022) Comments regarding Southern Indiana Gas and Electric's integrated resource*

plans to meet future energy and capacity needs (November 2020). Comments regarding Indianapolis Power and Light's integrated resource plans to meet future energy and capacity needs (April 2020). Comments regarding Indiana Michigan Power Company's integrated resource plans to meet future energy and capacity needs (December 2019).

- **Natural Resources Defense Council.** *Reviewed and provided comments on Ameren Missouri's 2023 Integrated Resource Plan. (2023)*
- **Kentucky Resources Council and Kentuckians for the Commonwealth.** *Reviewed and provided comments on Big Rivers Electric 2023 Integrated Resource Plan. (2023)*
- **Kentuckians for the Commonwealth, Kentucky Solar Energy Society, and Mountain Association.** *Reviewed and provided comments on East Kentucky Power Cooperative's 2022 Integrated Resource Plan. (2022)*
- **Kentuckians for the Commonwealth, Kentucky Solar Energy Society, Metropolitan Housing Coalition, and Mountain Association.** *Reviewed and provided comments on Louisville Gas & Electric and Kentucky Utilities' 2021 Integrated Resource Plan. (2022)*
- **The Council for the New Energy Economics.** *Reviewed and submitted comments on Evergy's IRP filing in Kansas and Missouri (2020 – 2024) Participated in Evergy's integrated resource plan stakeholder workshops and performed EnCompass modeling to evaluate coal plant retirements (2020 to 2021).*
- **The Department of Attorney General and Sierra Club.** *Reviewed and submitted testimony on the Aurora modeling Indiana Michigan Power Company performed for its 2021 Integrated Resource Plan. (2022)*
- **The Environmental Law and Policy Center, The Ecology Center, Union of Concerned Scientists, and Vote Solar.** *Performed Aurora modeling to evaluate higher levels of distributed solar for the Consumers Energy Company's 2021 Integrated Resource Plan. (2020 to 2021)*
- **Colorado Office of the Utility Consumer Advocate.** *Performed EnCompass modeling related to the Public Service Company of Colorado's 2021 Electric Resource Plan. (2021)*
- **EfficiencyOne.** *Supported EfficiencyOne's participation in Nova Scotia Power's integrated resource planning process. (2019 to 2020)*
- **Washington Electric Cooperative.** *Conducted the analysis for the 2020 Integrated Resource Plan. (2019 to 2020)*
- **Coalition for Clean Affordable Energy.** *Evaluated the Public Service Company of New Mexico's abandonment and replacement of the San Juan generating station and performed EnCompass modeling to develop an alternative replacement portfolio. (2019 to 2020)*

SELECTED PUBLICATIONS

Hotaling, C., Bird, S., & Heintzelman, M. D. (2021). Willingness to pay for microgrids to enhance community resilience. Energy Policy, 154, 112248.

Atems, B., & Hotaling, C. (2018). The effect of renewable and nonrenewable electricity generation on economic growth. Energy Policy, 112, 111-118.

Bird, S., & Hotaling, C. (2017). Multi-stakeholder microgrids for resilience and sustainability. Environmental Hazards, 16(2), 116-132.

Bird, S., Enayati, A., Hotaling, C., and Ortmeyer, T. (2017). Resilient Community Microgrids: Governance and Operational Challenges. In Energy Internet: An Open Energy Platform to Transform Legacy Power Systems into Open Innovation and Global Economic Engine, edited by Alex Q. Huang and Wencong Su. Elsevier.

EXPERT TESTIMONY

Before the Public Service Commission of Wisconsin, Docket No. 6630-CE-317. *Application of Wisconsin Electric Power Company for a Certificate of Public Convenience and Necessity to Construct and Operate the South Oak Creek Combustion Turbine Project*. On behalf of Clean Wisconsin.

Before the Public Service Commission of Wisconsin, Docket No. 6630-CE-316. *Application of Wisconsin Electric Power Company for a Certificate of Public Convenience and Necessity to Construct and Operate the Paris Reciprocating Internal Combustion Engines Project*. On behalf of Clean Wisconsin.

Before the Public Service Commission of Montana, Docket No. 2024.05.053. *NorthWestern Energy's Application to Increase Retail Electric and Natural Gas Utility Service Rates and for Approval of Service Schedules, Cost Allocation, and Rate Design*. On behalf of Montana Environmental Information Center, Human Resource Council District XI, Natural Resources Defense Council, and NW Energy Coalition ("Joint Parties").

Before the Public Service Commission of West Virginia, Case No. 24-0413-E-ENEC. *Petition to Initiate the Annual Review and to Update the ENEC Rates Currently in Effect*. On behalf of West Virginia Citizen Action Group, Solar United Neighbors, and Energy Efficient West Virginia.

Before the Georgia Public Service Commission, Docket No. 55378. *Georgia Power Company's 2023 Integrated Resource Plan Update.* On behalf of Georgia Interfaith Power & Light.

Before the Public Service Commission of West Virginia, Case No. 23-0735-E-ENEC. *Petition and General Investigation to Determine Reasonable Rates and Charges on and after January 1, 2024.* On behalf of West Virginia Citizen Action Group, Solar United Neighbors, and Energy Efficient West Virginia.

Before the South Carolina Public Service Commission, Docket No. 2023-154-E. On behalf of the South Carolina Coastal Conservation League and Southern Alliance for Clean Energy.

Before the South Carolina Public Service Commission, Docket No. 2023-9-E. On behalf of the South Carolina Coastal Conservation League, Southern Alliance for Clean Energy, and Sierra Club.

Before the Michigan Public Service Commission, Case No. U-21193. *In the Matter of the Application of DTE Electric Company for Approval of its Integrated Resource Plan Pursuant to MCL 460.6t, and for other relief,* on behalf of the Ecology Center, the Environmental Law & Policy Center, the Union of Concerned Scientists, and Vote Solar.

Before the Kentucky Public Service Commission, Case Number 2022-00387. In the Matter of Electronic Tariff Filing of Kentucky Power Company for Approval of a Special Contract with Ebon International, LLC, on behalf of Mountain Association, Kentuckians for the Commonwealth, Appalachian Citizens' Law Center, Sierra Club, and Kentucky Resources Council.

Before the Kentucky Public Service Commission, Case Number 2022-00371. In the Matter of Electronic Tariff Filing of Kentucky Utilities Company for Approval of an Economic Development Rider Special Contract with Bitiki-KY, LLC, on behalf of Kentuckians for the Commonwealth, Kentucky Solar Energy Society, Mountain Association, and Kentucky Resources Council.

Before the Iowa Utilities Board, Docket No. RPU-2022-0001. Application for a Determination of Ratemaking Principle, on behalf of Environmental Intervenors.

Before the Michigan Public Service Commission, Case No. U-21189. *In the Matter of the Application of Indiana Michigan Power Company for Approval of its Integrated Resource Plan Pursuant to MCL 460.6t, Avoided Costs and for Other Relief,* on behalf of Attorney General Dana Nessel and Sierra Club.

Before the Michigan Public Service Commission, Case No. U-21090. *In the Matter of the Application of Consumers Energy Company for Approval of its Integrated Resource Plan Pursuant to MCL 460.6t and for Other Relief*, on behalf of the Environmental Law and Policy Center, the Ecology Center, Union of Concerned Scientists, and Vote Solar.

Before the Public Utilities Commission of Colorado, Proceeding No. 21A-0141E. *In the Matter of the Application of Public Service Company of Colorado for Approval of its 2021 Electric Resource Plan and Clean Energy Plan*, on behalf of the Colorado Office of the Utility Consumer Advocate.

PUBLIC DISCLOSURE

STATE OF GEORGIA

BEFORE THE

PUBLIC SERVICE COMMISSION

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

EXHIBIT CH-2

Georgia Power's Large Load Model Assumptions

The Load Realization Model is based on a Monte Carlo simulation, which is a statistical process that helps estimate the probability of uncertain events. In this case, the Monte Carlo simulation was designed by Georgia Power to estimate the probability (likelihood) that certain amounts of load will actually be demanded by large customers on its system. Specifically, Georgia Power decided to utilize the @RISK software which performs Monte Carlo simulations on variables specified by Georgia Power to try to capture the uncertainty related to the load growth. Georgia Power's Load Realization Model is run with 100,000 simulations, with each individual simulation representing a different estimate of potential load growth based on the assumptions that Georgia Power modeled for the uncertain variables. Once the @RISK model performs 100,000 draws on these uncertain variables, the load for each potential project is added together to arrive at the portfolio level load projection each year that Georgia Power then includes as an adjustment to the baseline load forecast.

Georgia Power utilizes three different uncertain variables, or probabilities, in the load realization model: (1) "project success"; (2) metered vs. announced load; and (3) probability of a delayed commercial operation date for a project.

The first variable in the model is what Georgia Power calls the probability of "Project Success,"[1] which represents a compilation of three separate inputs:

(1) Whether the project will be located in the state of Georgia (referred to as P1)

(2) Whether Georgia Power will be selected as the electric service provider for the project (referred to as P2)

(3) The success rate of the project after the contract is signed (referred to as P3)

For P1, each project was assigned either a 100% or 50% value. For P2, each project was assigned a value of 25%, 50%, 75%, or 100%. P3 is the success rate that Georgia Power has reported for its historical projects. During the 2023 IRP, Georgia Power stated that it had a recent success rate of about 95% for projects coming online after a service contract is signed, and it used the success rate at that time for assigning the P3 variable.[2] Overall Project Success is based on the product of the

[1] 2025 Tech. Appx. 1, TS-Load and Energy Forecast at 104.
[2] Georgia Power response to STF-DEA-1-13. Docket No. 55378.

three inputs (P1 x P2 x P3). The product of these three inputs is ultimately the variable that is factored into the Monte Carlo simulations for the model. The value reported for the Project Success represents the percentage of times that the load will materialize in each simulation. For example, if a project has a success value reported at 71%, that means that out of the 100,000 combinations that are drawn in the Monte Carlo simulation, the announced load will be included in the model simulation 71% of the time—or 71,000 of the 100,000 simulated outcomes.[3]

The other two variables included to capture uncertainty in the load forecast model include the probability that the announced load for the project will be more or less than the load that actually materializes (Metered vs. Announced Load) and the probability that the announced Commercial Operation Date ("COD") of the project will be delayed. Georgia Power assigned both of these variables a triangular distribution with a low, mid, and high value.

The values assigned to some of the customer segments are shown in **Table 1**.

Customer Segment	Minimum	Most Likely	Maximum
Cryptocurrency			
Datacenter – Big Tech			
Data Centers - Developers			
Industrial Segments			

Table 11. Metered vs. Announced Load: Triangular Distribution Values[4]

Within the model, the metered vs. announced load variable is used to scale the announced load of the project according to the ramp-up schedule[5] that is also specified in the model. For example, the announced load for a project might be 300 MW, but there is some uncertainty around whether this full level of load will materialize, as it could be less than 300 MW. The model will interpret this uncertainty by pulling from the low, mid, and high values that Georgia Power has specified for the customer segments. In the example I referenced above, if the project is at 300 MW of announced load, then that project will materialize as a percentage of that announced load in the

[3] Georgia Power response to STF-DEA-1-16 subpart b. Docket No. 55378.
[4] Georgia Power workpaper named "Budget 2025 Load Realization Model TRADE SECRET".
[5] The ramp-up schedule reflects that the entire load is typically not required on Day-1 of a project. For example, if a project has an announced load of 300 MW, it might expect to need 100 MW on Day-1 and then ramp up by 50 MW each year to reach the 300 MW announced load by 2027.

Load Realization Model (i.e., if the maximum value for that customer segment is 80%, the 300 MW load will appear as 240 MW in the outputs).

Table 2 below shows the triangular distribution values for the Commercial Operation Date ("COD") delay. Based on the values specified by Georgia Power, this means that the maximum delay for any project in the model is [redacted] months, and the most likely value is [redacted] months. These values are assumed for each customer within the Load Realization Model, regardless of customer segment.

	Minimum	**Most Likely**	**Maximum**
Commercial Operation Date ("COD") Delay	[redacted]		

Table 22. COD Delay (Months): Triangular Distribution Values[6]

Once the @RISK model performs 100,000 draws on these uncertain variables, the load for each potential project is added together to arrive at the portfolio level load projection each year that Georgia Power then includes as an adjustment to the baseline load forecast.

[6] Georgia Power workpaper named "Budget 2025 Load Realization Model TRADE SECRET".

PUBLIC DISCLOSURE

STATE OF GEORGIA
BEFORE THE
PUBLIC SERVICE COMMISSION

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

EXHIBIT CH-3

Components of Present Value of Revenue Requirements ($000)

Plan	Production Cost	Fixed Costs	System Cost
GPC 111 + Uprates	[redacted]	[redacted]	$109,789,528
Alt No P50			$70,171,694
Alt Committed			$95,579,840
Alt Committed + P1A			$105,506,067
Alt Committed + P1A and Delay			$103,973,245

STATE OF GEORGIA

BEFORE THE

PUBLIC SERVICE COMMISSION

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

EXHIBIT CH-4

STF-DEA-1-8

Question:

Refer to the Trade Secret 2023 IRP Update Load and Energy Forecast, p. 18, Table 1.5.1.7-1, providing the Low, Mid, and High metered vs. announced loads.

a. Provide all workpapers and analysis supporting the values used in the analysis. Workpapers should be provided in electronic spreadsheet format with formulas intact and all source data included. Also provide any sensitivities tested by the Company.
b. Are these values consistent with the Company's historical experience with contracted large load projects? If so, provide supporting details and documentation.

Response:

a. The new large load projects that are considering Georgia Power as their electric supplier are unprecedented both in the number of projects and the size of the loads being proposed. Since Georgia Power has not experienced this sort of growth before, there is no historical data that can serve as a guide for the forecast. As a result, the Company relied on informed judgment within the Company to develop key assumptions such as the Low, Mid, and High specifications found in Table 1.5.1.7-1.

b. The Company has little historical experience with contracted large loads of the size, volume, and industry segments that are considering Georgia Power. The Company relied instead on informed judgment.

Contact: Francisco Valle

STATE OF GEORGIA

BEFORE THE

PUBLIC SERVICE COMMISSION

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

EXHIBIT CH-5

STF-DEA-1-9

Question:

Refer to the Trade Secret 2023 IRP Update Load and Energy Forecast, p. 18, Table 1.5.1.8-1, providing the Low, Mid, and High values for delays in project in-service.

a. Provide all workpapers and analysis supporting the values used in the analysis. Workpapers should be provided in electronic spreadsheet format with formulas intact and all source data included. Also provide any sensitivities tested by the Company.
b. Are these values consistent with the Company's historical experience with contracted large load projects? If so, provide supporting details and documentation.

Response:

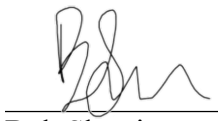
a. The new large load projects that are considering Georgia Power as their electric supplier are unprecedented both in the number of projects and the size of the loads being proposed. Since Georgia Power has not experienced this sort of growth before, there is no historical data that can serve as a guide for the forecast. As a result, the Company relied on informed judgment within the Company to develop key assumptions such as the Low, Mid, and High specifications for delays found in Table 1.5.1.8-1.

b. The Company has little historical experience with contracted large loads in the size, volume, and industry segments that are considering Georgia Power. The Company relied instead on informed judgment.

Contact: Francisco Valle

CERTIFICATE OF SERVICE

I certify that the foregoing **Direct Testimony of Chelsea Hotaling on behalf of Georgia Interfaith Power & Light and Southface Energy Institute** was filed with the Public Service Commission in Dockets No. 56002 and 56003 by electronic delivery on the 2nd of May, 2025. An electronic copy of the same was served upon all parties listed below by electronic mail as follows:



Bob Sherrier

Sallie Tanner Executive Secretary
Georgia Public Service Commission
244 Washington Street, SW
Atlanta, Georgia 30334
stanner@psc.ga.gov

Justin Pawluk
Jamie Barber
Robert Trokey
Georgia Public Service Commission
244 Washington Street, SW
Atlanta, Georgia 30334
jpawluk@psc.state.ga.us
jpawluk@psc.ga.gov
jamieb@psc.ga.gov
rtrokey@psc.ga.gov

Chris Collado
Georgia Public Service Commission
244 Washington Street, SW
Atlanta, Georgia 30334
ccollado@psc.state.ga.us
ccollado@psc.ga.gov

Steven J. Hewitson
Brandon F. Marzo
Allison W. Pryor
Troutman Pepper Hamilton Sanders, LLP
Bank of America Plaza
600 Peachtree Street, N.E.
Suite 3000
Atlanta, Georgia 30308-2216
steven.hewitson@troutman.com
brandon.marzo@troutman.com
allison.pryor@troutman.com

Jeremiah Haswell
Georgia Power Company
241 Ralph McGill Boulevard, NE
Bin 10230
Atlanta, Georgia 30308
jhaswell@southernco.com

Cheryl Johnson
Georgia Power Company
241 Ralph McGill Boulevard, NE
Atlanta, Georgia 30308-3374
cljohnson@southernco.com

Robert B. Baker
Robert B. Baker, P.C.
Resource Supply Management
2480 Briarcliff Road, NE
Suite 6
Atlanta, Georgia 30329
bobby@robertbaker.com

Jim Clarkson
Resource Supply Management
135 Emerald Lake Road
Columbia, South Carolina 29209
jclarkson@rsmenergy.com

Charles B. Jones, III
Lloyd Avram
Georgia Association of Manufacturers
The Hurt Building
50 Hurt Plaza, Suite 1620
Atlanta, Georgia 30303
cjones@gamfg.org
lavram@gamfg.org

Jeffry C. Pollock
J. Pollock Incorporated
14323 South Outer 40 Road, Suite 206 N
Town and Country, Missouri 63017-5734
jcp@jpollockinc.com

Simon Mahan
Southern Renewable Energy Association
11610 Pleasant Ridge Rd., Suite 103 #176
Little Rock, Arkansas 72223
simon@southernwind.org

Whit Cox
Southern Renewable Energy Association
11610 Pleasant Ridge Rd., Suite 103 #176
Little Rock, Arkansas 72223
whit@southernrenewable.org

Scott F. Dunbar
Partner, Keyes & Fox LLP
1580 Lincoln St., Suite 1105
Denver, Colorado 80203
sdunbar@keyesfox.com

Alicia Zaloga
Assistant, Keyes & Fox LLP
115 Kildaire Farm Road, Ste. 202-203
Cary, North Carolina 27511
azaloga@keyesfox.com

Anna Bella Korbatov
Fermata Energy
100 10th Street NE, #101
Charlottesville, Virginia 22902
annabella@fermataenergy.com

Steve Letendre, PhD
Fermata Energy
100 10th Street NE, #101
Charlottesville, Virginia 22902
steve@fermataenergy.com

Isabella Ariza
Dorothy E. Jaffe
Zachary M. Fabish
Sierra Club
50 F Street NW, 8th Floor
Washington, DC 20001
Isabella.ariza@sierraclub.org
Dori.jaffe@sierraclub.org
Zack.fabish@sierraclub.org

Curt Thompson
Thompson & Associates Law Firm, PC
3775 Venture Drive, Dl00
Duluth, Georgia 30096
curtbthompson@bellsouth.net

Maggie Shober
Southern Alliance for Clean Energy
PO Box 1842
Knoxville, Tennessee 37901
maggie@cleanenergy.org

Heather Pohnan
Southern Alliance for Clean Energy
691 John Wesley Dobbs Ave NE, Suite C
Atlanta, Georgia 30312
heather@cleanenergy.org

Eddy Moore
Southern Alliance for Clean Energy
PO Box 1842
Knoxville, Tennessee 37901
eddy@cleanenergy.org

Bryan Jacob
Southern Alliance for Clean Energy, Inc.
1455 Hampton Hill Drive
Alpharetta, Georgia 30022
bryan@cleanenergy.org

Patrick King II
Natural Resources Defense Council
1152 15th St NW #300
Washington, DC 20005
pkingii@nrdc.org

Luis Martinez
Natural Resources Defense Council
1152 15th St NW #300
Washington, DC 20005
lrnartinez@nrdc.org

Amanda Levin
Natural Resources Defense Council
1152 15th St NW #300
Washington, DC 20005
alevin@nrdc.org

Maeve Sneddon
Natural Resources Defense Council
1152 15th St NW #300
Washington, DC 20005
msneddon@nrdc.org

Alicia Brown
Capital Good Fund
333 Smith Street
Providence, Rhode Island 02908
aliciab@capitalgoodfund.org

Kimberly ("Kasey") A. Sturm
Weissman PC
One Alliance Center, Fourth Floor
3500 Lenox Road
Atlanta, Georgia 30326
kaseys@weissman.law

Jonathan Hunt
Metropolitan Atlanta Rapid Transit Authority
2424 Piedmont Road, NE
Atlanta, Georgia 30324
jhunt@itsmarta.com

Peter J. Andrews
Metropolitan Atlanta Rapid Transit Authority
2424 Piedmont Road, NE
Atlanta, Georgia 30324
pandrews@itsmarta.com

Juan Estrada
Attorney At Law
Juan Estrada Law, LLC.
3675 Crestwood Parkway, Suite 400,
Duluth, Georgia 30096
Juan@JuanEstradaLaw.com

Liz Coyle
Georgia Watch
55 Marietta Street, Suite 903
Atlanta, Georgia 30303
lcoyle@georgiawatch.org

Peter Hubbard
Georgia Center for Energy Solutions
55 Leslie Street SE
Atlanta, Georgia 30317
peter@georgia-ces.org

John Joseph McNutt
Regulatory Law Counsel
U.S. Army Legal Services Agency
Office of The Judge Advocate General
9275 Gunston Road (JALS-ELD)
Fort Belvoir, Virginia 22060-5546
john.j.mcnutt.civ@anny.mil

Newton M. Galloway
Terri M. Lyndall
Galloway & Lyndall, LLP
406 North Hill Street
Griffin, Georgia 30223
ngalloway@gallyn-law.com
tlyndall@gallyn-law.com

David E. Penland
One Griffin Center
100 S. Hill Street, Suite 600
Griffin, Georgia 30223
dpenland@beckowen.com

Cordon M. Smart
Fox Rothschild LLP
230 N. Elm Street
Suite 1200
Greensboro, North Carolina 27401
csmart@foxrothschild.com

Benjamin L. Snowden
Fox Rothschild LLP
301 Hillsborough Street
Suite 1120
Raleigh, North Carolina 27603
BSnowden@FoxRothschild.com

Gerald T. Chichester
Fox Rothschild, LLP
999 Peachtree Street, NE
Suite 1500
Atlanta, Georgia 30309
GChichester@FoxRothschild.com

David Nifong
City of Decatur
Department of Public Works
2635 Talley Street
Decatur, Georgia 30030
david.nifong@decaturga.com

Mike Wharton
Athens-Clarke County Unified Government
Sustainability Office
110 Bray Street
Athens, Georgia 30601
Mike.Wharton@accgov.com

Joey Crews
Athens-Clarke County
Sustainability Office
110 Bray Street
Athens, Georgia 30601
joseph.crews@accgov.com

Mendie White
Gwinnett County
Offices of the County Administrator
75 Langley Drive
Lawrenceville, Georgia 30046
mendie.white@gwinnettcounty.com

Chandra Farley
John R. Seydel
City of Atlanta,
Office of Sustainability and Resilience
55 Trinity Ave SW
Atlanta, Georgia 30303
cfarley@atlantaga.gov
jrseydel@atlantaga.gov

Gordon Kenna
DeKalb County
Public Works
180 Sams Street
Decatur, Georgia 30030
hgkenna@dekalbcountyga.gov

Kathy Reed
DeKalb County Government
Department of Planning and Sustainability
178 Sams Street
Decatur, Georgia 30030
kdreed@dekalbcountyga.gov

Juan Estrada
Juan Estrada Law, LLC.
3675 Crestwood Parkway,
Suite 400
Duluth, Georgia 30096
Juan@JuanEstradaLaw.com

Kimberly Scott
Georgia WAND Education Fund, Inc.
250 Georgia Ave SE # 202
Atlanta, Georgia 30312
kim@georgiawand.org

Allison Kvien
Vote Solar
2810 Coliseum Centre Drive Suite 120
Charlotte, North Carolina 28217
akvien@votesolar.org

Stephen Butler
Georgia Solar Energy Industries
Association, Inc.
2451 Cumberland Parkway
Suite 3380
Atlanta, Georgia 30339
steve@connectpublicaffairs.org

Stephanie U. Eaton
Carrie H. Grundmann
Spilman Thomas & Battle, PLLC
110 Oakwood Drive, Suite 500
Winston-Salem, North Carolina
seaton@spilmanlaw.com
cgrundmann@spilmanlaw.com

Steven W. Lee
Spilman Thomas & Battle, PLLC
1100 Bent Creek Blvd., Suite 101
Mechanicsburg, Pennsylvania 17050
slee@spilmanlaw.com

William Bradley Carver Sr., Esq.
Hall Booth Smith, P.C.
191 Peachtree Street NE
Suite 2900
Atlanta, Georgia 30303
bcarver@hallboothsmith.com

Donald Moreland
Georgia Solar Energy Association
1199 Euclid Avenue
Atlanta, Georgia 30307
don@solarcrowdsource.com
L. Craig Dowdy
Taylor English Duma LLP
1600 Parkwood Circle
Suite 200
Atlanta, Georgia 30339
craigdowdy@taylorenglish.com

Tyler Mauldin
Microsoft Corporation
200 17th Street NW
Atlanta, Georgia
tylermauldin@microsoft.com

Taylor English Duma LLP
1600 Parkwood Circle SE
Suite 200
Atlanta, Georgia 30339
c.dowdy@taylorenglish.com
cdowdy@taylorenglish.com

STATE OF GEORGIA
BEFORE THE
PUBLIC SERVICE COMMISSION

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

EXHIBIT SLS-1

ENERGY FUTURES GROUP

Stacy Sherwood
Principal

PROFESSIONAL SUMMARY

Stacy Sherwood brings over 15 years of experience in the energy industry, specializing in energy efficiency (EE), demand response (DR), automated metering infrastructure (AMI), cost recovery, and renewable energy. Stacy has testified or provided comments before the public service commissions of Kentucky, Louisiana, Maryland, and Missouri, the Kansas Corporation Commission, the Virginia State Corporation Commission, and the public utilities commissions of Maine, Pennsylvania and Rhode Island on AMI, EE, protections for cryptocurrency related load growth, and reasonableness of revenue increases. Throughout her career, Stacy has evaluated various electric and natural gas EE and DR plans; potential studies; evaluation, measurement, and verification reports; and riders for cost recovery. In particular, she has specialized in the design of low-income EE programs in Arkansas, Maryland, and Pennsylvania. Stacy has also testified in 15 cases related to the reasonableness of revenue requirements in Maine, Pennsylvania, and Rhode Island.

Since joining EFG in October 2021, Stacy has immersed herself in Connecticut's energy goals and policy and has established relationships with all stakeholders relevant to Connecticut's energy efficiency and demand response programs. She serves as the team lead and senior technical consultant on behalf of the Connecticut Energy Efficiency Board, which provides oversite of the state's energy efficiency programs. Through her work in Connecticut, Kentucky, and Maryland, she has evaluated the impacts of EE programs and other policies as it relates to environmental justice. More recently, she has begun providing support to jurisdictions on establishing a cost-benefit framework to evaluate distributed energy resources (DERs) and identifying safeguards related to large loads, such as data centers and cryptomining.

EXPERIENCE

2024-Present: Principal, Energy Futures Group, Hinesburg, VT
2021-2023: Managing Consultant, Energy Futures Group, Hinesburg, VT
2015-2021: Senior Analyst, Exeter Associates, Inc., Columbia, MD
2013-2015: Assistant Director of Energy, Analysis, and Planning Division, Maryland Public Service Commission, Baltimore, MD
2011-2013: Regulatory Economist II, Maryland Public Service Commission, Baltimore, MD
2009-2011: Regulatory Economist I, Maryland Public Service Commission, Baltimore, MD

EDUCATION

B.A., Business Administration, Economics, Accounting/Economics, McDaniel College, 2009

SELECTED PROJECTS

- ***Connecticut Energy Efficiency Board.*** *Lead Technical Consultant on the oversight of the state's electric and gas residential energy efficiency programs. Work closely with the state's utilities to develop, implement, and evaluate cost-effective program designs and goals for the Three-Year Conservation and Load Management Plan. (2021-Present)*
- ***Natural Resources Defense Council.*** *Filed testimony before the Kansas Corporation Commission to support the adoption of energy efficiency programs for the first time in the Evergy service territory. Worked with parties to negotiate program design and implementation, as well as the performance incentive mechanism. (2021-2022)*
- ***Louisiana Public Service Commission.*** *Filed testimonies evaluating the reasonableness of automated metering infrastructure implementation plans by Concordia Electric Cooperative, Inc., Southwest Louisiana Electric Membership Corporation, and Point Coupee Electric Membership Corporation. (2020-2021)*
- ***Pennsylvania Office of Consumer Advocate.*** *Reviewed and commented on potential studies utilized to develop energy efficiency and demand response targets for Phase III and IV of the Act 129 Energy Efficiency and Conservation (EE&C) Program. Provided written testimony on utility EE&C five-year plans. (2015-2021, 2023-2024)*
- ***Arkansas Attorney General's Consumer Utility Rate Advocacy Division.*** *Drafted a dedicated limited income EE program strawman implemented on a pilot basis by the electric and natural gas utilities. (2018-2020)*
- ***Arkansas Attorney General's Consumer Utility Rate Advocacy Division.*** *Participated in Parties Working Collaboratively (PWC) group regarding the electric*

and natural gas EE programs. Provided comments on three-year plans, annual progress reports, and evaluation, measurement, and verification reports. (2017-2021)

- ***Maryland Public Service Commission Staff**. Developed templates and directed work groups related to the implementation of the electric and natural gas EmPOWER Maryland EE and DR programs. Evaluated the semi-annual reports and three-year plans filed by the utilities and submitted comments regarding plan recommendations before the Maryland Public Service Commission. (2009-2015)*

EXPERT TESTIMONY

Before the Pennsylvania Public Utilities Commission, Docket No. M-2024-3048418, *Petition of UGI Utilities, Inc. – Gas Division for Approval of its Phase II Energy Efficiency and Conservation Plan*, February 2025, on behalf of the Pennsylvania Office of Consumer Advocate. Testified regarding reasonableness of proposed Plan. (Case settled prior to cross-examination.)

Before the Public Service Commission of Wisconsin, Case No. 6630-CE-317, *Application of Wisconsin Electric Power Company for a Certificate of Public Convenience and Necessity to Construct and Operate the South Oak Creek Combustion Turbine Project in the City of Oak Creek, Milwaukee County, Wisconsin*, February 2025, on behalf of Clean Wisconsin. Testified on increased need for energy efficiency in the Wisconsin Electric Power Company service territory. (Ongoing).

Before the Public Service Commission of Wisconsin, Case No. 6630-CE-316, *Application of Wisconsin Electric Power Company for a Certificate of Public Convenience and Necessity to Construct and Operate the Paris Reciprocating Internal Combustion Engines Project, Consisting of Seven Natural Gas-Fired Reciprocating Internal Combustion Engines Generating up to 128 MW Total at the Lakeshore Capacity Improvement Project Regulator Station in the Town of Paris, Kenosha County, Wisconsin*, December 2024, on behalf of Clean Wisconsin. Testified on increased need for energy efficiency in the Wisconsin Electric Power Company service territory. (Ongoing).

Before the Kentucky Public Service Commission, Case No. 2024-00115, *In the matter of Electronic Application of Kentucky Power Company For: (1) Approval to Expand its Targeted Energy Efficiency Program; (2) Approval of a Home Energy Improvement Program and a Commercial Energy Solutions Program; (3) Authority to Recover Costs and Net Lost Revenues, and to Receive Incentives Associated with the Implementation of its Demand Side Management/Energy Efficiency Programs; (4) Approval of Revised Tariff D.S.M.C.; (5) Acceptance of its Annual DSM Status Report; and (6) All Othe Required Approvals and Relief,* May 2024, on behalf of Mountain Association, Appalachian Citizens' Law

Center, Kentuckians for the Commonwealth, and Kentucky Solar Energy Society. Testified on the reasonableness of the proposed demand side management programs and cost recovery mechanism.

Before the Public Service of South Carolina Docket No. 2023-388-E, *In the matter of Application of Duke Energy Carolinas, LLC for Authority to Adjust and Increase its Electric Rates, Adjustments in Electric Rate Schedules and Tariffs, and Request for an Accounting Order,* April 2024, on behalf of the South Carolina Conservation League, Southern Alliance for Clean Energy, and Vote Solar. Testified regarding impact of rate increase on customer energy burden and the benefits of energy efficiency to offset rate impact.

Before the Commonwealth of Virginia State Corporation Commission Case No. PUR-2023-000169, *Petition of Appalachian Power Company for approval to continue a rate adjustment clause, the EE-RAC, and for approval of new energy efficiency programs pursuant to § 56-585.1 A 5 c and 56-596.2 of the Code of Virginia,* March 2024, on behalf of the Appalachian Voices. Testified regarding reasonableness of proposed Plan.

Before the Public Service Commission of the State of Missouri, File No. EO-2023-0136, *In the matter of Union Electric Company d/b/a Ameren Missouri's 4th Filing to Implement Regulatory Changes in Furtherance of Energy Efficiency as Allowed by MEEIA,* March 2024, on behalf of the National Resources Defense Council. Testified regarding reasonableness of proposed Plan.

Before the Pennsylvania Public Utilities Commission, Docket No. M-2023-3043230, *Petition of UGI Utilities, Inc. – Electric Division for Approval of its Energy Efficiency and Conservation Plan*, September 2023, on behalf of the Pennsylvania Office of Consumer Advocate. Testified regarding reasonableness of proposed Plan. (Case settled prior to cross-examination.)

Before the Commonwealth of Kentucky before the Public Service Commission, Case No. 2022-00424, *In the Matter of Electronic Tariff Filing of Kentucky Power Company for Approval of a Special Contract Under Its Economic Development Rider and Demand Response Service Tariffs with Cyber Innovation Group, LLC.,* on behalf of the Mountain Association, Kentuckians for the Commonwealth, Appalachian Citizens' Law Center, Sierra Club, and Kentucky Resources Council. Testified on the merits of providing an economic development discount rate to a proposed crypto mining facility as it relates to ratepayer risk.

Before the Commonwealth of Kentucky before the Public Service Commission, Case No. 2022-00387, *In the Matter of Electronic Tariff Filing of Kentucky Power Company for Approval of a Special Contract with Ebon International, LLC.,* on behalf of the Mountain Association, Kentuckians for the Commonwealth,

Appalachian Citizens' Law Center, Sierra Club, and Kentucky Resources Council, Inc. Testified on the merits of providing an economic development discount rate to a proposed crypto mining facility as it relates to ratepayer risk.

Before the Commonwealth of Kentucky before the Public Service Commission, Case No. 2022-00037, *In the Matter of Electronic Tariff Filing of Kentucky Utilities Company for Approval of an Economic Development Rider Special Contract with Bitiki-KY, LLC.,*on behalf of Kentuckians for the Commonwealth, Kentucky Solar Energy Society, Mountain Association, and Kentucky Resources. Testified on the merits of providing an economic development discount rate to a proposed crypto mining facility as it relates to ratepayer risk.

Before the State of Maine Public Utilities Commission, Docket No. 2022-0025 *Versant Power Request for Approval of a Distribution Rate Change – 307*, December 2022, for Maine Office of Consumer Advocate. Testified regarding the reasonableness of the overall revenue increase.

Before the Kansas Corporation Commission, Docket No. 22-EKME-254-TAR *In the Matter of the Application of Evergy Kansas Metro, Inc., Evergy Kanasas South, Inc. and Evergy Kansas Central, Inc. for Approval of its Demand-Side Management Portfolio Pursuant to the Kansas Energy Efficiency Investment Act ("KEEIA"), K.S.A. 66-1283,* June 2022, for Natural Resources Defense Council. Testified regarding reasonableness of the proposed Plan and its compliance with the KEEIA Act.

Before the Louisiana Public Service Commission, Docket No. U-35877 *Pointe Coupee Electric Membership Corporation Application to Acquire and Install an Automated Metering System and Request for Cost Recovery and Related Relief,* February 2021, for the Louisiana Public Service Commission Staff. Testified regarding the implementation of automated metering infrastructure to replace current meters. (Case settled prior to cross-examination.)

Before the Pennsylvania Public Utilities Commission, Docket No. M-2020-3020818, *Petition of Duquesne Light Company for Approval of its Energy Efficiency and Conservation Phase IV Plan*, January 2021, on behalf of the Pennsylvania Office of Consumer Advocate. Testified regarding reasonableness of the proposed Plan and its compliance with Pennsylvania Act 129. (Case settled prior to cross-examination.)

Before the Pennsylvania Public Utilities Commission, Docket No. M-2020-3020830, *Petition of PECO Energy Company for Approval of its Energy Efficiency and Conservation Phase IV Plan*, January 2021, on behalf of the Pennsylvania Office of Consumer Advocate. Testified regarding reasonableness of the proposed Plan

and its compliance with Pennsylvania Act 129. (Case settled prior to cross-examination.)

Before the Pennsylvania Public Utilities Commission, Docket No. M-2020-3020824, *Petition of PPL Electric Utilities for Approval of its Energy Efficiency and Conservation Phase IV Plan*, January 2021, on behalf of the Pennsylvania Office of Consumer Advocate. Testified regarding reasonableness of the proposed Plan and its compliance with Pennsylvania Act 129. (Case settled prior to cross-examination.)

Before the Louisiana Public Service Commission, Docket No. U-35707 Southwest Louisiana Electric Membership Corporation *Application for Approval to Acquire and Install an Automated Metering System and Request for Cost Recovery and Related Relief,* December 2020, for the Louisiana Public Service Commission Staff. Testified regarding the implementation of automated metering infrastructure to replace current meters. (Case settled prior to cross-examination.)

Before the Pennsylvania Public Utilities Commission, Docket No. R-2020-3020919 *Pennsylvania Public Utility Commission v. Audubon Water Company*, November 2020, for the Pennsylvania Office of Consumer Advocate. Testified regarding reasonableness of the overall revenue increase. (Case settled prior to cross-examination.)

Before the Pennsylvania Public Utilities Commission, Docket No. R-2020-3020256 *Pennsylvania Public Utility Commission v. City of Bethlehem – Water Department*, November 2020, for the Pennsylvania Office of Consumer Advocate. Testified regarding reasonableness of the overall revenue increase. (Case settled prior to cross-examination.)

Before the Louisiana Public Service Commission, Docket No. U-35456 Concordia Electric Cooperative Inc. *Application for Certification of a Replacement Advanced Metering System and Approval of Related Financing*, November 2020, for the Louisiana Public Service Commission Staff. Testified regarding the implementation of automated metering infrastructure to replace current meters. (Case settled prior to cross-examination.)

Before the Pennsylvania Public Utilities Commission, Docket No. R-2020-3019612 *Pennsylvania Public Utility Commission v. Reynolds Disposal Company*, October 2020, for the Pennsylvania Office of Consumer Advocate. Participated in mediation regarding reasonableness of the overall revenue increase.

Before the Pennsylvania Public Utilities Commission, Docket No. R-2019-3010955 *Pennsylvania Public Utility Commission v. City of Lancaster – Sewer Fund*,

October 2019, for the Pennsylvania Office of Consumer Advocate. Testified regarding reasonableness of the overall revenue increase.

Before the Pennsylvania Public Utilities Commission, Docket No. R-2019-3008208 *Pennsylvania Public Utility Commission v. Wellsboro Electric Company*, October 2019, for the Pennsylvania Office of Consumer Advocate. Testified regarding reasonableness of the overall revenue increase.

Before the Pennsylvania Public Utilities Commission, Docket No. R-2019-3008209 *Pennsylvania Public Utility Commission v. Valley Energy, Inc*, October 2019, for the Pennsylvania Office of Consumer Advocate. Testified regarding reasonableness of the overall revenue increase.

Before the Pennsylvania Public Utilities Commission, Docket No. R-2019-3008212, *Pennsylvania Public Utility Commission v. Citizens' Electric Company of Lewisburg, PA*, October 2019, for the Pennsylvania Office of Consumer Advocate. Testified regarding reasonableness of the overall revenue increase.

Before the Pennsylvania Public Utilities Commission, Docket No. R-2019-3009559, *Pennsylvania Public Utility Commission v. Eaton Sewer & Water Company, Inc. – Wastewater Division*, August 2019, for the Pennsylvania Office of Consumer Advocate. Participate in mediation regarding reasonableness of the overall revenue increase.

Before the Pennsylvania Public Utilities Commission, Docket No. R-2019-3009567, *Pennsylvania Public Utility Commission v. Eaton Sewer & Water Company, Inc. – Water Division*, August 2019, for the Pennsylvania Office of Consumer Advocate. Participate in mediation regarding reasonableness of the overall revenue increase.

Before the Pennsylvania Public Utilities Commission, Docket No. R-2019-3008947, *Pennsylvania Public Utility Commission v. Community Utilities of Pennsylvania Inc. Water Division*, July 2019, for the Pennsylvania Office of Consumer Advocate. Testified regarding reasonableness of the overall revenue increase. (Case settled prior to cross-examination.)

Before the Pennsylvania Public Utilities Commission, Docket No. R-2019-3008948, *Pennsylvania Public Utility Commission v. Community Utilities of Pennsylvania Inc. Wastewater Division*, July 2019, for the Pennsylvania Office of Consumer Advocate. Testified regarding reasonableness of the overall revenue increase. (Case settled prior to cross-examination.)

Before the Pennsylvania Public Utilities Commission, Docket No. R-2019-3006904, *Pennsylvania Public Utility Commission v. The Newtown Artesian Water*

Company (Supplement No. 136 to Tariff Water – Pa. P.U.C. No. 9), March 2019, for the Pennsylvania Office of Consumer Advocate. Testified regarding reasonableness of the overall revenue increase. (Case settled prior to cross-examination.)

Before the Pennsylvania Public Utilities Commission, Docket No. R-2018-3006814, *Pennsylvania Public Utility Commission v. UGI Utilities, Inc – Gas Division (Utility Code 123100, Filed Tariff Gas- Pa. P.U.C. Nos. 7 and 7S)*, January 2019, on behalf of the Pennsylvania Office of Consumer Advocate. Testified regarding reasonableness of its proposed consolidated natural gas energy efficiency plan. (Case settled prior to cross-examination.)

Before the Pennsylvania Public Utilities Commission, Docket No. M-2018-3004144, *Petition of UGI Utilities, Inc. – Electric Division for Approval of its Energy Efficiency and Conservation Plan*, August 2018, on behalf of the Pennsylvania Office of Consumer Advocate. Testified regarding reasonableness of proposed Plan. (Case settled prior to cross-examination.)

Before the Pennsylvania Public Utilities Commission, Docket No. R-2018-3001307, *Pennsylvania Public Utility Commission v. Hidden Valley Utility Services, L.P. – Wastewater (General Rate Increase Filed Pursuant to 66 PS. CS 1308, Including Answers to 52 PA. Code 53.52)*, April 2018, on behalf of the Pennsylvania Office of Consumer Advocate. Testified regarding the reasonableness of the overall revenue increase.

Before the Pennsylvania Public Utilities Commission, Docket No. R-2018-3001306, *Pennsylvania Public Utility Commission v. Hidden Valley Utility Services, L.P. – Water (General Rate Increase Filed Pursuant to 66 PS. CS 1308, Including Answers to 52 PA. Code 53.52)*, April 2018, on behalf of the Pennsylvania Office of Consumer Advocate. Testified regarding the reasonableness of the overall revenue increase.

Before the Pennsylvania Public Utilities Commission, Docket No. P-2015-2497267, *Petition of Duquesne Light Company for Approval of its Smart Meter Procurement and Installation Plan*, February 2016, on behalf of the Pennsylvania Office of Consumer Advocate. Testified regarding the inclusion of additional costs related to the Plan's implementation.

Before the Pennsylvania Public Utilities Commission, Docket No. M-2015-2477174, *Petition of UGI Utilities, Inc. – Electric Division for Approval of Phase II of its Energy Efficiency and Conservation Plan*, February 2016, on behalf of the Pennsylvania Office of Consumer Advocate. Testified regarding reasonableness of proposed Plan. (Case settled prior to cross-examination.)

Before the Pennsylvania Public Utilities Commission, Docket No. M-2015-2515642, *Petition of PPL Electric Utilities for Approval of its Energy Efficiency and Conservation Phase II Plan*, January 2016, on behalf of the Pennsylvania Office of Consumer Advocate. Testified regarding reasonableness of the proposed Plan and its compliance with Pennsylvania Act 129. (Case settled prior to cross-examination.)

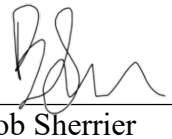
Before the Pennsylvania Public Utilities Commission, Docket No. M-2015-2515375, *Petition of Duquesne Light Company for Approval of its Energy Efficiency and Conservation Phase II Plan*, January 2016, on behalf of the Pennsylvania Office of Consumer Advocate. Testified regarding reasonableness of the proposed Plan and its compliance with Pennsylvania Act 129. (Case settled prior to cross-examination.)

Before the Public Utilities Commission of Rhode Island, Docket No. 4595, *Newport Water Division – Rate Application to Collect Additional Revenues of $1,304,595 for a Total Cost of Service of $20,151,440*, December 2015, on behalf of the Division of Public Utilities and Carriers. Testified regarding reasonableness of the overall rate revenue increase.

Before the Maryland Public Service Commission, Case No. 9311, *In the Matter of the Application of Potomac Electric Power Company for an Increase in its Retail Rates For the Distribution of Electric Energy*, April 2013, on behalf of the Maryland Public Service Commission Staff. Testified regarding the inclusion of advanced metering infrastructure meters and energy advisor and engineer positions in rates.

CERTIFICATE OF SERVICE

I certify that the foregoing **Direct Testimony of Stacy L. Sherwood on behalf of Georgia Interfaith Power & Light and Southface Energy Institute** was filed with the Public Service Commission in Dockets No. 56002 and 56003 by electronic delivery on the 2nd of May, 2025. An electronic copy of the same was served upon all parties listed below by electronic mail as follows:



Bob Sherrier

Sallie Tanner Executive Secretary
Georgia Public Service Commission
244 Washington Street, SW
Atlanta, Georgia 30334
stanner@psc.ga.gov

Justin Pawluk
Jamie Barber
Robert Trokey
Georgia Public Service Commission
244 Washington Street, SW
Atlanta, Georgia 30334
jpawluk@psc.state.ga.us
jpawluk@psc.ga.gov
jamieb@psc.ga.gov
rtrokey@psc.ga.gov

Chris Collado
Georgia Public Service Commission
244 Washington Street, SW
Atlanta, Georgia 30334
ccollado@psc.state.ga.us
ccollado@psc.ga.gov

Steven J. Hewitson
Brandon F. Marzo
Allison W. Pryor
Troutman Pepper Hamilton Sanders, LLP
Bank of America Plaza
600 Peachtree Street, N.E.
Suite 3000
Atlanta, Georgia 30308-2216
steven.hewitson@troutman.com
brandon.marzo@troutman.com
allison.pryor@troutman.com

Jeremiah Haswell
Georgia Power Company
241 Ralph McGill Boulevard, NE
Bin 10230
Atlanta, Georgia 30308
jhaswell@southernco.com

Cheryl Johnson
Georgia Power Company
241 Ralph McGill Boulevard, NE
Atlanta, Georgia 30308-3374
cljohnson@southernco.com

Robert B. Baker
Robert B. Baker, P.C.
Resource Supply Management
2480 Briarcliff Road, NE
Suite 6
Atlanta, Georgia 30329
bobby@robertbaker.com

Jim Clarkson
Resource Supply Management
135 Emerald Lake Road
Columbia, South Carolina 29209
jclarkson@rsmenergy.com

Charles B. Jones, III
Lloyd Avram
Georgia Association of Manufacturers
The Hurt Building
50 Hurt Plaza, Suite 1620
Atlanta, Georgia 30303
cjones@gamfg.org
lavram@gamfg.org

Jeffry C. Pollock
J. Pollock Incorporated
14323 South Outer 40 Road, Suite 206 N
Town and Country, Missouri 63017-5734
jcp@jpollockinc.com

Simon Mahan
Southern Renewable Energy Association
11610 Pleasant Ridge Rd., Suite 103 #176
Little Rock, Arkansas 72223
simon@southernwind.org

Whit Cox
Southern Renewable Energy Association
11610 Pleasant Ridge Rd., Suite 103 #176
Little Rock, Arkansas 72223
whit@southernrenewable.org

Scott F. Dunbar
Partner, Keyes & Fox LLP
1580 Lincoln St., Suite 1105
Denver, Colorado 80203
sdunbar@keyesfox.com

Alicia Zaloga
Assistant, Keyes & Fox LLP
115 Kildaire Farm Road, Ste. 202-203
Cary, North Carolina 27511
azaloga@keyesfox.com

Anna Bella Korbatov
Fermata Energy
100 10th Street NE, #101
Charlottesville, Virginia 22902
annabella@fermataenergy.com

Steve Letendre, PhD
Fermata Energy
100 10th Street NE, #101
Charlottesville, Virginia 22902
steve@fermataenergy.com

Isabella Ariza
Dorothy E. Jaffe
Zachary M. Fabish
Sierra Club
50 F Street NW, 8th Floor
Washington, DC 20001
Isabella.ariza@sierraclub.org
Dori.jaffe@sierraclub.org
Zack.fabish@sierraclub.org

Curt Thompson
Thompson & Associates Law Firm, PC
3775 Venture Drive, Dl00
Duluth, Georgia 30096
curtbthompson@bellsouth.net

Maggie Shober
Southern Alliance for Clean Energy
PO Box 1842
Knoxville, Tennessee 37901
maggie@cleanenergy.org

Heather Pohnan
Southern Alliance for Clean Energy
691 John Wesley Dobbs Ave NE, Suite C
Atlanta, Georgia 30312
heather@cleanenergy.org

Eddy Moore
Southern Alliance for Clean Energy
PO Box 1842
Knoxville, Tennessee 37901
eddy@cleanenergy.org

Bryan Jacob
Southern Alliance for Clean Energy, Inc.
1455 Hampton Hill Drive
Alpharetta, Georgia 30022
bryan@cleanenergy.org

Patrick King II
Natural Resources Defense Council
1152 15th St NW #300
Washington, DC 20005
pkingii@nrdc.org

Luis Martinez
Natural Resources Defense Council
1152 15th St NW #300
Washington, DC 20005
lrnartinez@nrdc.org

Amanda Levin
Natural Resources Defense Council
1152 15th St NW #300
Washington, DC 20005
alevin@nrdc.org

Maeve Sneddon
Natural Resources Defense Council
1152 15th St NW #300
Washington, DC 20005
msneddon@nrdc.org

Alicia Brown
Capital Good Fund
333 Smith Street
Providence, Rhode Island 02908
aliciab@capitalgoodfund.org

Kimberly ("Kasey") A. Sturm
Weissman PC
One Alliance Center, Fourth Floor
3500 Lenox Road
Atlanta, Georgia 30326
kaseys@weissman.law

Jonathan Hunt
Metropolitan Atlanta Rapid Transit Authority
2424 Piedmont Road, NE
Atlanta, Georgia 30324
jhunt@itsmarta.com

Peter J. Andrews
Metropolitan Atlanta Rapid Transit Authority
2424 Piedmont Road, NE
Atlanta, Georgia 30324
pandrews@itsmarta.com

Juan Estrada
Attorney At Law
Juan Estrada Law, LLC.
3675 Crestwood Parkway, Suite 400,
Duluth, Georgia 30096
Juan@JuanEstradaLaw.com

Liz Coyle
Georgia Watch
55 Marietta Street, Suite 903
Atlanta, Georgia 30303
lcoyle@georgiawatch.org

Peter Hubbard
Georgia Center for Energy Solutions
55 Leslie Street SE
Atlanta, Georgia 30317
peter@georgia-ces.org

John Joseph McNutt
Regulatory Law Counsel
U.S. Army Legal Services Agency
Office of The Judge Advocate General
9275 Gunston Road (JALS-ELD)
Fort Belvoir, Virginia 22060-5546
john.j.mcnutt.civ@anny.mil

Newton M. Galloway
Terri M. Lyndall
Galloway & Lyndall, LLP
406 North Hill Street
Griffin, Georgia 30223
ngalloway@gallyn-law.com
tlyndall@gallyn-law.com

David E. Penland
One Griffin Center
100 S. Hill Street, Suite 600
Griffin, Georgia 30223
dpenland@beckowen.com

Cordon M. Smart
Fox Rothschild LLP
230 N. Elm Street
Suite 1200
Greensboro, North Carolina 27401
csmart@foxrothschild.com

Benjamin L. Snowden
Fox Rothschild LLP
301 Hillsborough Street
Suite 1120
Raleigh, North Carolina 27603
BSnowden@FoxRothschild.com

Gerald T. Chichester
Fox Rothschild, LLP
999 Peachtree Street, NE
Suite 1500
Atlanta, Georgia 30309
GChichester@FoxRothschild.com

David Nifong
City of Decatur
Department of Public Works
2635 Talley Street
Decatur, Georgia 30030
david.nifong@decaturga.com

Mike Wharton
Athens-Clarke County Unified Government
Sustainability Office
110 Bray Street
Athens, Georgia 30601
Mike.Wharton@accgov.com

Joey Crews
Athens-Clarke County
Sustainability Office
110 Bray Street
Athens, Georgia 30601
joseph.crews@accgov.com

Mendie White
Gwinnett County
Offices of the County Administrator
75 Langley Drive
Lawrenceville, Georgia 30046
mendie.white@gwinnettcounty.com

Chandra Farley
John R. Seydel
City of Atlanta,
Office of Sustainability and Resilience
55 Trinity Ave SW
Atlanta, Georgia 30303
cfarley@atlantaga.gov
jrseydel@atlantaga.gov

Gordon Kenna
DeKalb County
Public Works
180 Sams Street
Decatur, Georgia 30030
hgkenna@dekalbcountyga.gov

Kathy Reed
DeKalb County Government
Department of Planning and Sustainability
178 Sams Street
Decatur, Georgia 30030
kdreed@dekalbcountyga.gov

Juan Estrada
Juan Estrada Law, LLC.
3675 Crestwood Parkway,
Suite 400
Duluth, Georgia 30096
Juan@JuanEstradaLaw.com

Kimberly Scott
Georgia WAND Education Fund, Inc.
250 Georgia Ave SE # 202
Atlanta, Georgia 30312
kim@georgiawand.org

Allison Kvien
Vote Solar
2810 Coliseum Centre Drive Suite 120
Charlotte, North Carolina 28217
akvien@votesolar.org

Stephen Butler
Georgia Solar Energy Industries
Association, Inc.
2451 Cumberland Parkway
Suite 3380
Atlanta, Georgia 30339
steve@connectpublicaffairs.org

Stephanie U. Eaton
Carrie H. Grundmann
Spilman Thomas & Battle, PLLC
110 Oakwood Drive, Suite 500
Winston-Salem, North Carolina
seaton@spilmanlaw.com
cgrundmann@spilmanlaw.com

Steven W. Lee
Spilman Thomas & Battle, PLLC
1100 Bent Creek Blvd., Suite 101
Mechanicsburg, Pennsylvania 17050
slee@spilmanlaw.com

William Bradley Carver Sr., Esq.
Hall Booth Smith, P.C.
191 Peachtree Street NE
Suite 2900
Atlanta, Georgia 30303
bcarver@hallboothsmith.com

Donald Moreland
Georgia Solar Energy Association
1199 Euclid Avenue
Atlanta, Georgia 30307
don@solarcrowdsource.com
L. Craig Dowdy
Taylor English Duma LLP
1600 Parkwood Circle
Suite 200
Atlanta, Georgia 30339
craigdowdy@taylorenglish.com

Tyler Mauldin
Microsoft Corporation
200 17th Street NW
Atlanta, Georgia
tylermauldin@microsoft.com

Taylor English Duma LLP
1600 Parkwood Circle SE
Suite 200
Atlanta, Georgia 30339
c.dowdy@taylorenglish.com
cdowdy@taylorenglish.com

SOUTHERN ENVIRONMENTAL LAW CENTER

Ten 10th Street NW, Suite 1050
Atlanta, GA 30309

Telephone 404-521-9900
Facsimile 404-521-9909

May 29, 2025

VIA ELECTRONIC DELIVERY

Ms. Sallie Tanner
Executive Secretary
Georgia Public Service Commission
244 Washington Street, SW
Atlanta, Georgia 30334

Re: Errata to the Direct Testimony of Chelsea Hotaling on Behalf of Georgia Interfaith Power & Light and Southface Energy Institute; Docket Nos. 56002, 56003

Dear Ms. Tanner:

Please find enclosed an electronic version of the following **Public Disclosure version of the Errata to the Direct Testimony of Chelsea Hotaling on behalf of Georgia Interfaith Power & Light and Southface Energy Institute** to be filed in Docket Nos. 56002 and 56003.

Please also find enclosed an electronic version of the Trade Secret version of the Errata to the Direct Testimony of Chelsea Hotaling on behalf of GIPL and Southface.

Respectfully submitted,

Jennifer Whitfield
Senior Attorney
Southern Environmental Law Center
Ten 10th Street NW, Suite 1050
Atlanta, Georgia 30309
404-521-9900
jwhitfield@selcga.org

Counsel for GIPL and Southface

PUBLIC DISCLOSURE

STATE OF GEORGIA
BEFORE THE
GEORGIA PUBLIC SERVICE COMMISSION

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

Errata to Chelsea Hotaling Testimony

The Southern Environmental Law Center, on behalf of intervenors Georgia Interfaith Power & Light (GIPL) and Southface Energy Institute (hereinafter collectively referred to as "Movants"), files this first errata to the May 2, 2025, direct testimony of Chelsea Hotaling.

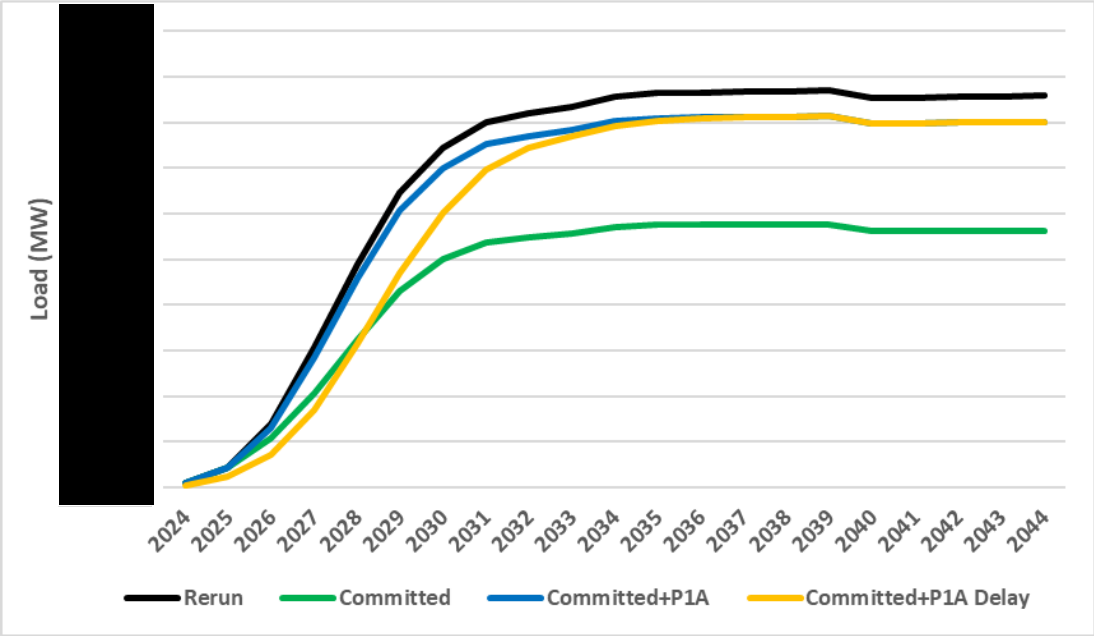
Ms. Hotaling has identified an error in Figure 1 and Figure 4. Updated Figures 1 and 4 are attached. These corrections merely correct an error discovered from creating the Figures. They do not change any of Ms. Hotaling's findings or conclusions.

Respectfully submitted on May 29, 2025.

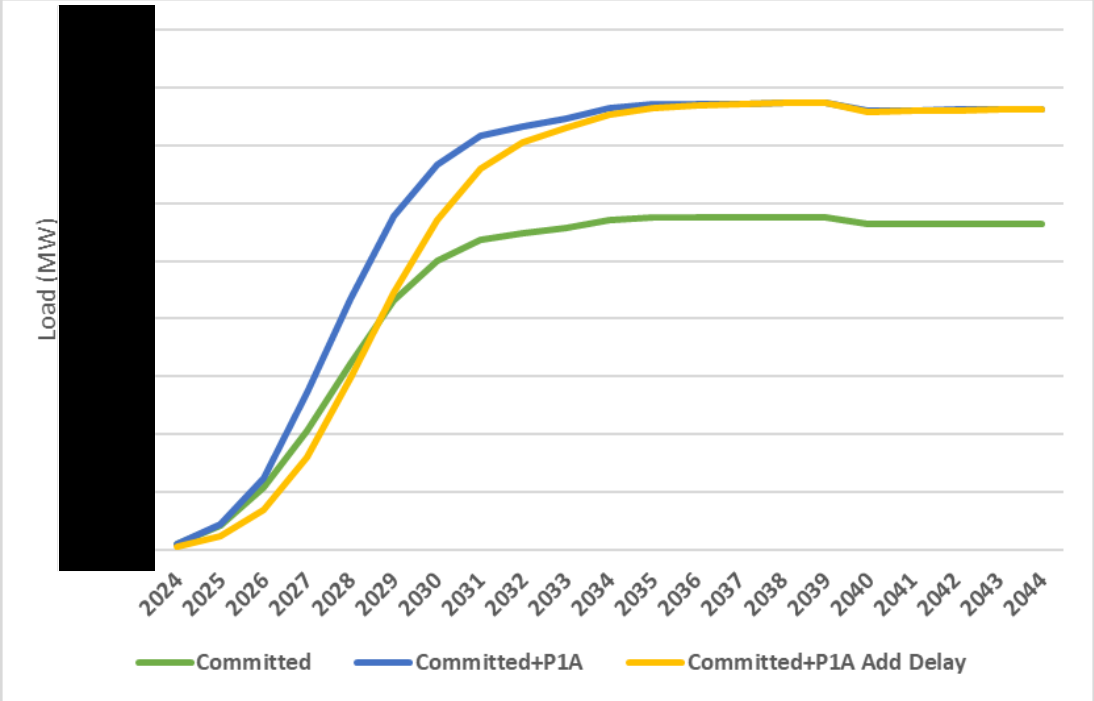
Jennifer Whitfield
Bob Sherrier
Southern Environmental Law Center
Ten 10th Street NW, Suite 1050
Atlanta, Georgia 30309
jwhitfield@selc.org
bsherrier@selc.org

ERRATA TO CHELSEA HOTALING TESTIMONY

CH Figure 1



CH Figure 4



CERTIFICATE OF SERVICE

I certify that the foregoing **Public Disclosure version of the Errata to the Direct Testimony of Chelsea Hotaling** was filed with the Public Service Commission on behalf of Georgia Interfaith Power & Light and Southface Energy Institute in Dockets No. 56002 and 56003 by electronic delivery on the 29th of May, 2025. An electronic copy of same was served upon all parties listed below by electronic mail as follows:

Jennifer Whitfield

Sallie Tanner
Executive Secretary
Georgia Public Service Commission
244 Washington Street, SW
Atlanta, Georgia 30334
stanner@psc.ga.gov

Justin Pawluk
Jamie Barber
Robert Trokey
Georgia Public Service Commission
244 Washington Street, SW
Atlanta, Georgia 30334
jpawluk@psc.state.ga.us
jpawluk@psc.ga.gov
jamieb@psc.ga.gov
rtrokey@psc.ga.gov

Chris Collado
Georgia Public Service Commission
244 Washington Street, SW
Atlanta, Georgia 30334
ccollado@psc.state.ga.us
ccollado@psc.ga.gov

Steven J. Hewitson
Brandon F. Marzo
Allison W. Pryor
Troutman Pepper Hamilton Sanders, LLP
Bank of America Plaza
600 Peachtree Street, N.E.
Suite 3000
Atlanta, Georgia 30308-2216
steven.hewitson@troutman.com
brandon.marzo@troutman.com
allison.pryor@troutman.com

Jeremiah Haswell
Georgia Power Company
241 Ralph McGill Boulevard, NE
Bin 10230
Atlanta, Georgia 30308
jhaswell@southernco.com

Cheryl Johnson
Georgia Power Company
241 Ralph McGill Boulevard, NE
Atlanta, Georgia 30308-3374
cljohnson@southernco.com

Robert B. Baker
Robert B. Baker, P.C.
Resource Supply Management
2480 Briarcliff Road, NE
Suite 6
Atlanta, Georgia 30329
bobby@robertBbaker.com

Jim Clarkson
Resource Supply Management
135 Emerald Lake Road
Columbia, South Carolina 29209
jclarkson@rsmenergy.com

Charles B. Jones, III
Lloyd Avram
Georgia Association of Manufacturers
The Hurt Building
50 Hurt Plaza, Suite 1620
Atlanta, Georgia 30303
cjones@gamfg.org
lavram@gamfg.org

Jeffry C. Pollock
J. Pollock Incorporated
14323 South Outer 40 Road, Suite 206 N
Town and Country, Missouri 63017-5734
jcp@jpollockinc.com

Simon Mahan
Southern Renewable Energy Association
11610 Pleasant Ridge Rd., Suite 103 #176
Little Rock, Arkansas 72223
simon@southernwind.org

Whit Cox
Southern Renewable Energy Association
11610 Pleasant Ridge Rd., Suite 103 #176
Little Rock, Arkansas 72223
whit@southernrenewable.org

Scott F. Dunbar
Partner, Keyes & Fox LLP
1580 Lincoln St., Suite 1105
Denver, Colorado 80203
sdunbar@keyesfox.com

Alicia Zaloga
Assistant, Keyes & Fox LLP
115 Kildaire Farm Road, Ste. 202-203
Cary, North Carolina 27511
azaloga@keyesfox.com

Anna Bella Korbatov
Fermata Energy
100 10th Street NE, #101
Charlottesville, Virginia 22902
annabella@fermataenergy.com

Steve Letendre, PhD
Fermata Energy
100 10th Street NE, #101
Charlottesville, Virginia 22902
steve@fermataenergy.com

Isabella Ariza
Dorothy E. Jaffe
Zachary M. Fabish
Sierra Club
50 F Street NW, 8th Floor
Washington, DC 20001
Isabella.ariza@sierraclub.org
Dori.jaffe@sierraclub.org
Zack.fabish@sierraclub.org

Curt Thompson
Thompson & Associates Law Firm, PC
3775 Venture Drive, Dl00
Duluth, Georgia 30096
curtbthompson@bellsouth.net

Maggie Shober
Southern Alliance for Clean Energy
PO Box 1842
Knoxville, Tennessee 37901
maggie@cleanenergy.org

Heather Pohnan
Southern Alliance for Clean Energy
691 John Wesley Dobbs Ave NE, Suite C
Atlanta, Georgia 30312
heather@cleanenergy.org

Eddy Moore
Southern Alliance for Clean Energy
PO Box 1842
Knoxville, Tennessee 37901
eddy@cleanenergy.org

Bryan Jacob
Southern Alliance for Clean Energy, Inc.
1455 Hampton Hill Drive
Alpharetta, Georgia 30022
bryan@cleanenergy.org

Patrick King II
Natural Resources Defense Council
1152 15th St NW #300
Washington, DC 20005
pkingii@nrdc.org

Luis Martinez
Natural Resources Defense Council
1152 15th St NW #300
Washington, DC 20005
lrnartinez@nrdc.org

Amanda Levin
Natural Resources Defense Council
1152 15th St NW #300
Washington, DC 20005
alevin@nrdc.org

Maeve Sneddon
Natural Resources Defense Council
1152 15th St NW #300
Washington, DC 20005
msneddon@nrdc.org

Alicia Brown
Capital Good Fund
333 Smith Street
Providence, Rhode Island 02908
aliciab@capitalgoodfund.org

Kimberly ("Kasey") A. Sturm
Weissman PC
One Alliance Center, Fourth Floor
3500 Lenox Road
Atlanta, Georgia 30326
kaseys@weissman.law

Jonathan Hunt
Metropolitan Atlanta Rapid Transit Authority
2424 Piedmont Road, NE
Atlanta, Georgia 30324
jhunt@itsmarta.com

Peter J. Andrews
Metropolitan Atlanta Rapid Transit Authority
2424 Piedmont Road, NE
Atlanta, Georgia 30324
pandrews@itsmarta.com

Juan Estrada
Attorney At Law
Juan Estrada Law, LLC.
3675 Crestwood Parkway, Suite 400,
Duluth, Georgia 30096
Juan@JuanEstradaLaw.com

Liz Coyle
Georgia Watch
55 Marietta Street, Suite 903
Atlanta, Georgia 30303
lcoyle@georgiawatch.org

Peter Hubbard
Georgia Center for Energy Solutions
55 Leslie Street SE
Atlanta, Georgia 30317
peter@georgia-ces.org

John Joseph McNutt
Regulatory Law Counsel
U.S. Army Legal Services Agency
Office of The Judge Advocate General
9275 Gunston Road (JALS-ELD)
Fort Belvoir, Virginia 22060-5546
john.j.mcnutt.civ@anny.mil

Newton M. Galloway
Terri M. Lyndall
Galloway & Lyndall, LLP
406 North Hill Street
Griffin, Georgia 30223
ngalloway@gallyn-law.com
tlyndall@gallyn-law.com

David E. Penland
One Griffin Center
100 S. Hill Street, Suite 600
Griffin, Georgia 30223
dpenland@beckowen.com

Cordon M. Smart
Fox Rothschild LLP
230 N. Elm Street
Suite 1200
Greensboro, North Carolina 27401
csmart@foxrothschild.com

Benjamin L. Snowden
Fox Rothschild LLP
301 Hillsborough Street
Suite 1120
Raleigh, North Carolina 27603
BSnowden@FoxRothschild.com

Gerald T. Chichester
Fox Rothschild, LLP
999 Peachtree Street, NE
Suite 1500
Atlanta, Georgia 30309
GChichester@FoxRothschild.com

David Nifong
City of Decatur
Department of Public Works
2635 Talley Street
Decatur, Georgia 30030
david.nifong@decaturga.com

Mike Wharton
Athens-Clarke County Unified Government
Sustainability Office
110 Bray Street
Athens, Georgia 30601
Mike.Wharton@accgov.com

Joey Crews
Athens-Clarke County
Sustainability Office
110 Bray Street
Athens, Georgia 30601
joseph.crews@accgov.com

Mendie White
Gwinnett County
Offices of the County Administrator
75 Langley Drive
Lawrenceville, Georgia 30046
mendie.white@gwinnettcounty.com

Chandra Farley
John R. Seydel
City of Atlanta,
Office of Sustainability and Resilience
55 Trinity Ave SW
Atlanta, Georgia 30303
cfarley@atlantaga.gov
jrseydel@atlantaga.gov

Gordon Kenna
DeKalb County
Public Works
180 Sams Street
Decatur, Georgia 30030
hgkenna@dekalbcountyga.gov

Kathy Reed
DeKalb County Government
Department of Planning and Sustainability
178 Sams Street
Decatur, Georgia 30030
kdreed@dekalbcountyga.gov

Juan Estrada
Juan Estrada Law, LLC.
3675 Crestwood Parkway,
Suite 400
Duluth, Georgia 30096
Juan@JuanEstradaLaw.com

Kimberly Scott
Georgia WAND Education Fund, Inc.
250 Georgia Ave SE # 202
Atlanta, Georgia 30312
kim@georgiawand.org

Allison Kvien
Vote Solar
2810 Coliseum Centre Drive Suite 120
Charlotte, North Carolina 28217
akvien@votesolar.org

Stephen Butler
Georgia Solar Energy Industries
Association, Inc.
2451 Cumberland Parkway
Suite 3380
Atlanta, Georgia 30339
steve@connectpublicaffairs.org

Stephanie U. Eaton
Carrie H. Grundmann
Spilman Thomas & Battle, PLLC
110 Oakwood Drive, Suite 500
Winston-Salem, North Carolina
seaton@spilmanlaw.com
cgrundmann@spilmanlaw.com

Steven W. Lee
Spilman Thomas & Battle, PLLC
1100 Bent Creek Blvd., Suite 101
Mechanicsburg, Pennsylvania 17050
slee@spilmanlaw.com

William Bradley Carver Sr., Esq.
Hall Booth Smith, P.C.
191 Peachtree Street NE
Suite 2900
Atlanta, Georgia 30303
bcarver@hallboothsmith.com

Donald Moreland
Georgia Solar Energy Association
1199 Euclid Avenue
Atlanta, Georgia 30307
don@solarcrowdsource.com

Tyler Mauldin
Microsoft Corporation
200 17th Street NW
Atlanta, Georgia
tylermauldin@microsoft.com

Chimera N. Thompson
K&L Gates LLP
1601 K Street, N.W.
Washington, DC 20006
chimera.thompson@klgates.com

Kimberly B. Frank
K&L Gates LLP
1601 K Street, N.W.
Washington, DC 20006
kimberly.frank@klgates.com

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]			

1

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

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

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]

1

2 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]
[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]
[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]
[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]

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]			Contract for Electric Service	[redacted]	[redacted]	1,429	[redacted]	[redacted]
			Technical Review			1,280		
			Technical Review			1,000		
			Technical Review			780		
			Request for Electric Service			720		
			Technical Review			717		
			Request for Electric Service			693		
			Technical Review			656		
			Technical Review			651		
			Technical Review			650		
			Technical Review			600		
			Technical Review			533		
			Request for Electric Service			502		
			Technical Review			500		
			Technical Review			500		
			Technical Review			481		
			Technical Review			460		
			Technical Review			455		
			Technical Review			432		
			Request for Electric Service			432		
			Technical Review			365		
			Technical Review			335		
			Contract for Electric Service			324		
			Technical Review			321		
			Technical Review			311		
			Technical Review			300		
			Request for Electric Service			300		
			Request for Electric Service			285		
			Technical Review			271		
			Technical Review			250		
			Technical Review			250		
			Technical Review			250		
			Technical Review			245		
			Technical Review			243		
			Contract for Electric Service			240		
			Request for Electric Service			240		
			Contract for Electric Service			216		
			Technical Review			216		
			Contract for Electric Service			202		
			Technical Review			200		
			Technical Review			200		
			Contract for Electric Service			200		
			Technical Review			192		
			Contract for Electric Service			182		
			Request for Electric Service			180		
			Contract for Electric Service			180		
			Technical Review			180		
			Request for Electric Service			180		
			Technical Review			163		
			Technical Review			162		
			Technical Review			151		
			Technical Review			150		
			Contract for Electric Service			150		
			Contract for Electric Service			145		
			Technical Review			144		
			Technical Review			135		
			Technical Review			130		
			Technical Review			130		
			Contract for Electric Service			126		
			Technical Review			115		
			Technical Review			115		
			Request for Electric Service			105		
			Request for Electric Service			90		
			Technical Review			80		
			Request for Electric Service			79		
			Technical Review			60		
			Technical Review			53		
			Contract for Electric Service			52		
			Technical Review			50		
			Technical Review			49		
			Not Listed			Not Listed		
			Not Listed			Not Listed		
			Not Listed			Not Listed		
			Not Listed			Not Listed		
			Not Listed			Not Listed		
			Not Listed			Not Listed		
			Not Listed			Not Listed		
			Not Listed			Not Listed		
					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.

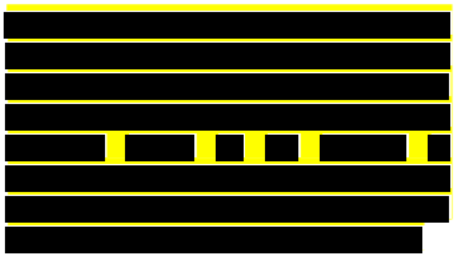
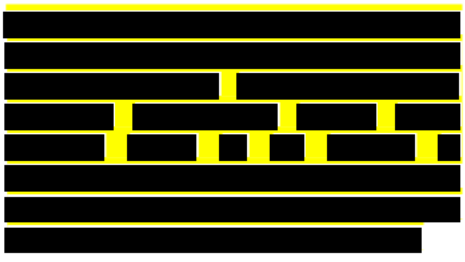
Table 7: DFAX Analysis on GPC Large Loads for 2034 Shoulder NSEW NUO Case Considering N-1 Contingencies

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	
GTC: Tenaska - Wansley 500kV Line	West/ Northwest	
Cavender Drive - Tributary 230kV Line	Metro West	
GTC: Cavender Drive 500/230kV Area Project Cavender Drive - Villa Rica 500kV Cavender Drive - Union City 500kV	Metro South/ Northwest	
GTC: Cavender Drive - Buzzard Roost 230kV Line	Metro West	

		[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.

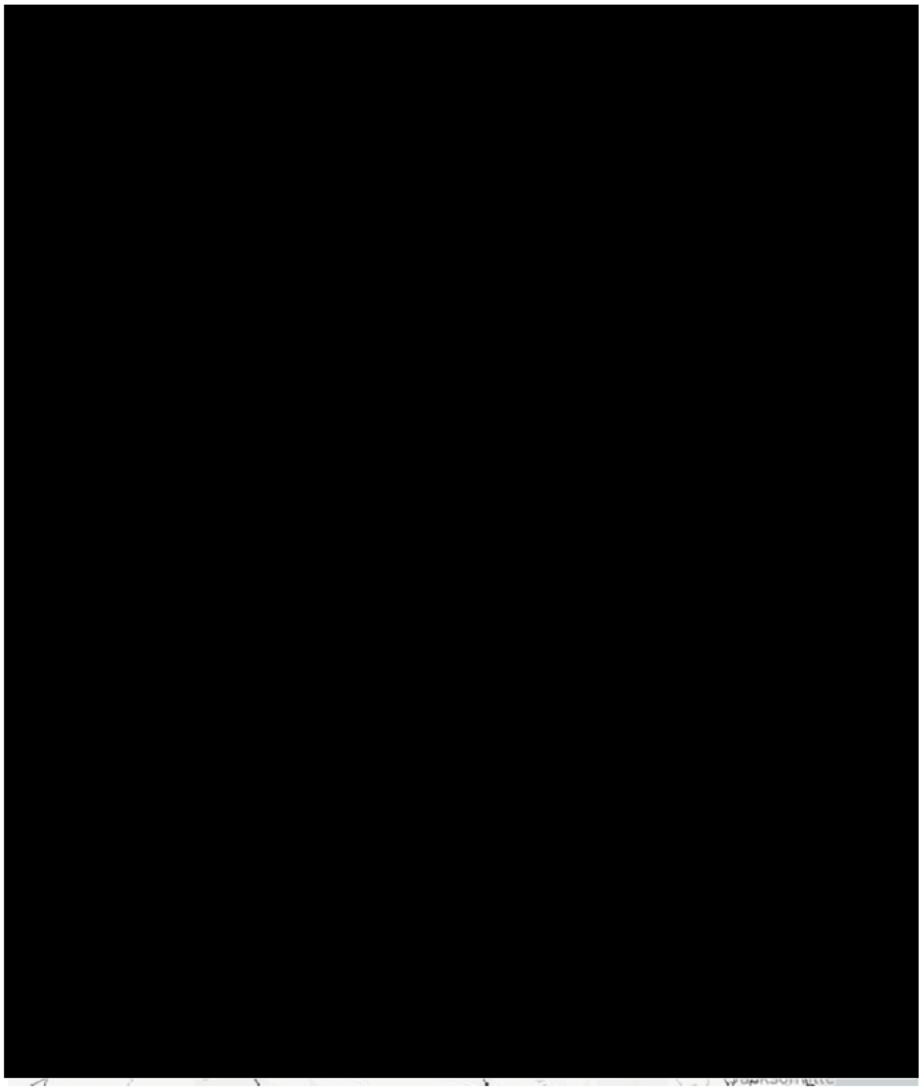


Figure 2: Map of Strategic Transmission Projects, Large Centralized Generators, and New Large Loads

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

[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
	0.04255	0.04255	0.04128	0.04128
	0.03334	0.03334	0.02974	0.02974
	0.01422	0.01422	0.01467	0.01467
	0.05796	0.05796	0.05769	0.05769
	0.06218	0.06218	0.06171	0.06171
	0.03755	0.03755	0.03176	0.03176
	0.00625	0.00625	0.00588	0.00588
	0.01475	0.01475	0.01419	0.01419
	0.01577	0.01577	0.01579	0.01579
	-0.03894	-0.03894	-0.03992	-0.03992
	-0.05852	-0.05852	-0.05967	-0.05967
	0.0425	0.0425	0.04246	0.04246
	0.01695	0.01695	0.01705	0.01705
	0.02231	0.02231	0.02245	0.02245
	0.01147	0.01147	0.01125	0.01125
	0.00581	0.00581	0.00571	0.00571
	0.06696	0.06696	0.0636	0.0636
	0.00913	0.00913	0.00899	0.00899
	0.01693	0.01693	0.01604	0.01604
	0.07034	0.07034	0.06933	0.06933
	0.01693	0.01693	0.01604	0.01604
	0.00595	0.00595	0.00502	0.00502
	0.00595	0.00595	0.00502	0.00502
	0.10132	0.10132	0.10032	0.10032
	0.10132	0.10132	0.10032	0.10032
	0.00462	0.00462	0.0044	0.0044
	0.0425	0.0425	0.04246	0.04246
	0.0098	0.0098	0.00958	0.00958
	0.0147	0.0147	0.01223	0.01223
	0.024	0.024	0.02041	0.02041
	0.06296	0.06296	0.06309	0.06309
	0.00817	0.00817	0.00764	0.00764
	0.01475	0.01475	0.01419	0.01419
	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-

[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.

[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

[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.

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]			

1

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

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

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]

1

2 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]
[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]
[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]
[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]

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]			Contract for Electric Service	[redacted]	[redacted]	1,429	[redacted]	[redacted]
			Technical Review			1,280		
			Technical Review			1,000		
			Technical Review			780		
			Request for Electric Service			720		
			Technical Review			717		
			Request for Electric Service			693		
			Technical Review			656		
			Technical Review			651		
			Technical Review			650		
			Technical Review			600		
			Technical Review			533		
			Request for Electric Service			502		
			Technical Review			500		
			Technical Review			500		
			Technical Review			481		
			Technical Review			460		
			Technical Review			455		
			Technical Review			432		
			Request for Electric Service			432		
			Technical Review			365		
			Technical Review			335		
			Contract for Electric Service			324		
			Technical Review			321		
			Technical Review			311		
			Technical Review			300		
			Request for Electric Service			300		
			Request for Electric Service			285		
			Technical Review			271		
			Technical Review			250		
			Technical Review			250		
			Technical Review			250		
			Technical Review			245		
			Technical Review			243		
			Contract for Electric Service			240		
			Request for Electric Service			240		
			Contract for Electric Service			216		
			Technical Review			216		
			Contract for Electric Service			202		
			Technical Review			200		
			Technical Review			200		
			Contract for Electric Service			200		
			Technical Review			192		
			Contract for Electric Service			182		
			Request for Electric Service			180		
			Contract for Electric Service			180		
			Technical Review			180		
			Request for Electric Service			180		
			Technical Review			163		
			Technical Review			162		
			Technical Review			151		
			Technical Review			150		
			Contract for Electric Service			150		
			Contract for Electric Service			145		
			Technical Review			144		
			Technical Review			135		
			Technical Review			130		
			Technical Review			130		
			Contract for Electric Service			126		
			Technical Review			115		
			Technical Review			115		
			Request for Electric Service			105		
			Request for Electric Service			90		
			Technical Review			80		
			Request for Electric Service			79		
			Technical Review			60		
			Technical Review			53		
			Contract for Electric Service			52		
			Technical Review			50		
			Technical Review			49		
			Not Listed			Not Listed		
			Not Listed			Not Listed		
			Not Listed			Not Listed		
			Not Listed			Not Listed		
			Not Listed			Not Listed		
			Not Listed			Not Listed		
			Not Listed			Not Listed		
			Not Listed			Not Listed		
					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.

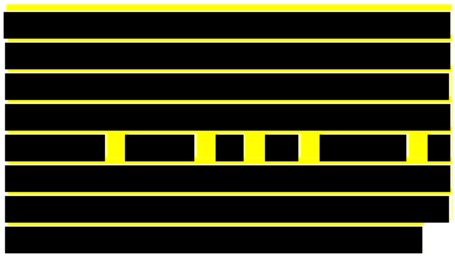
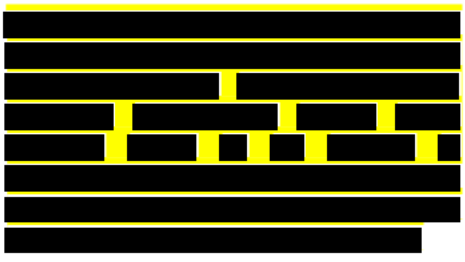
Table 7: DFAX Analysis on GPC Large Loads for 2034 Shoulder NSEW NUO Case Considering N-1 Contingencies

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	
GTC: Tenaska - Wansley 500kV Line	West/ Northwest	
Cavender Drive - Tributary 230kV Line	Metro West	
GTC: Cavender Drive 500/230kV Area Project Cavender Drive - Villa Rica 500kV Cavender Drive - Union City 500kV	Metro South/ Northwest	
GTC: Cavender Drive - Buzzard Roost 230kV Line	Metro West	

		[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.

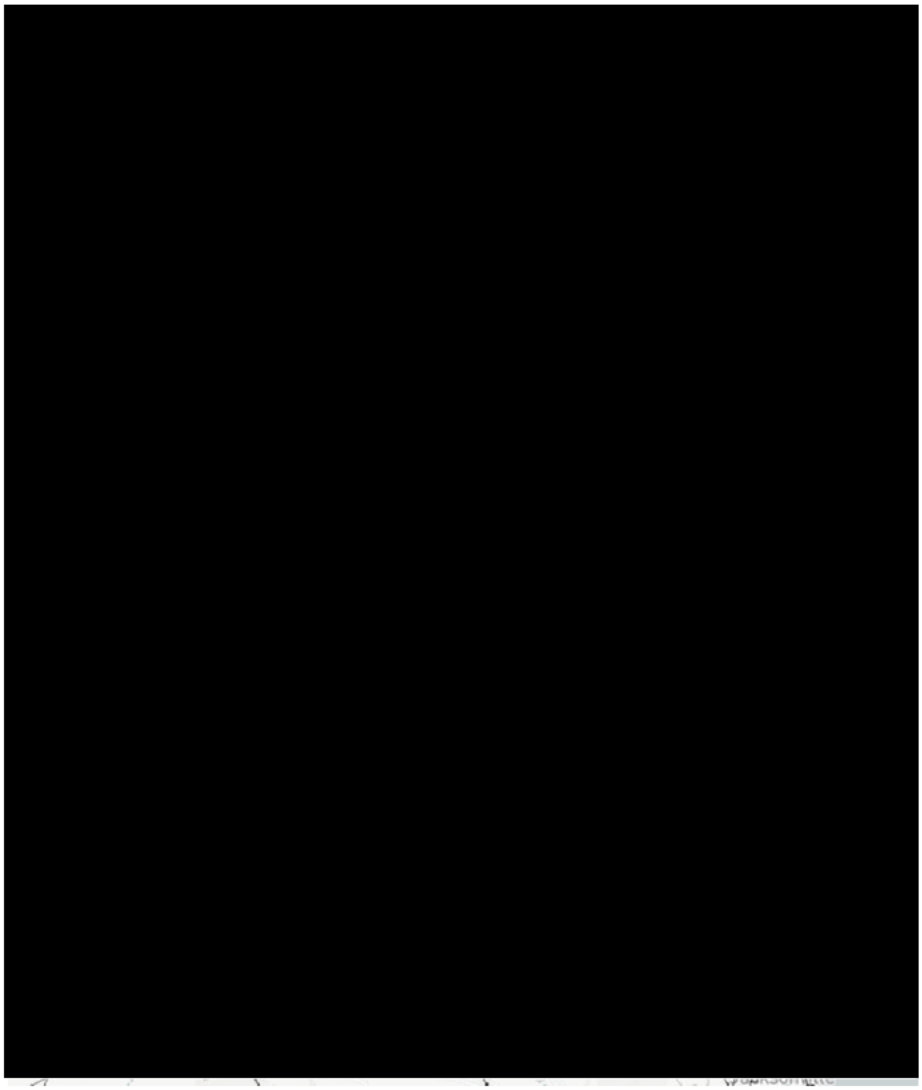


Figure 2: Map of Strategic Transmission Projects, Large Centralized Generators, and New Large Loads

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

[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
	0.04255	0.04255	0.04128	0.04128
	0.03334	0.03334	0.02974	0.02974
	0.01422	0.01422	0.01467	0.01467
	0.05796	0.05796	0.05769	0.05769
	0.06218	0.06218	0.06171	0.06171
	0.03755	0.03755	0.03176	0.03176
	0.00625	0.00625	0.00588	0.00588
	0.01475	0.01475	0.01419	0.01419
	0.01577	0.01577	0.01579	0.01579
	-0.03894	-0.03894	-0.03992	-0.03992
	-0.05852	-0.05852	-0.05967	-0.05967
	0.0425	0.0425	0.04246	0.04246
	0.01695	0.01695	0.01705	0.01705
	0.02231	0.02231	0.02245	0.02245
	0.01147	0.01147	0.01125	0.01125
	0.00581	0.00581	0.00571	0.00571
	0.06696	0.06696	0.0636	0.0636
	0.00913	0.00913	0.00899	0.00899
	0.01693	0.01693	0.01604	0.01604
	0.07034	0.07034	0.06933	0.06933
	0.01693	0.01693	0.01604	0.01604
	0.00595	0.00595	0.00502	0.00502
	0.00595	0.00595	0.00502	0.00502
	0.10132	0.10132	0.10032	0.10032
	0.10132	0.10132	0.10032	0.10032
	0.00462	0.00462	0.0044	0.0044
	0.0425	0.0425	0.04246	0.04246
	0.0098	0.0098	0.00958	0.00958
	0.0147	0.0147	0.01223	0.01223
	0.024	0.024	0.02041	0.02041
	0.06296	0.06296	0.06309	0.06309
	0.00817	0.00817	0.00764	0.00764
	0.01475	0.01475	0.01419	0.01419
	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-

[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.

[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

[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

475 Broadway #6, Saratoga Springs, NY 12866
518.396.6412 | matthew.richwine@telos.energy

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:

[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.

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.

These files have been redacted in their entirety.

Project Name	*City*
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

*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**	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			
Y			
	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
Y

Y
Y

Y

Y
Y

Y
Y

Y
Y

Y
Y

Y
Y
Y

Y

Y
Y

Y

Y

Y
Y

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

			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

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

Georgia Power Company
Docket Nos. 56002 & 56003
2025 Integrated Resource Plan and 2025 Demand-Side Management Application
STF-PIA Data Request Set No. 5

STF-PIA-5-16

Question:

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

Response:

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

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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**

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.

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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

IMPORTANT NOTE: 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

[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

[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).

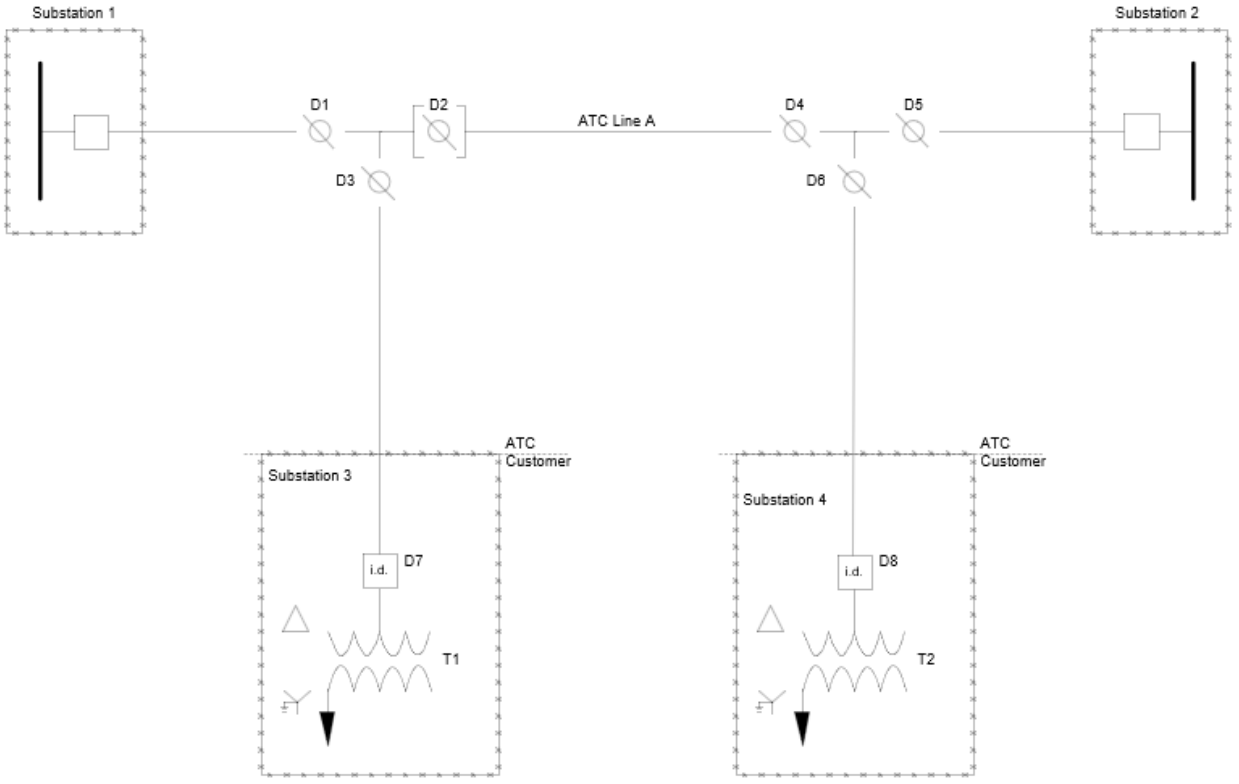
If a Customer-owned circuit breaker is installed, CT requirements for ATC bus differential protection should be evaluated as needed. See Section 3.9.3 for specific CT requirements.

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.

[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 VT's 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	Appendi x 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.

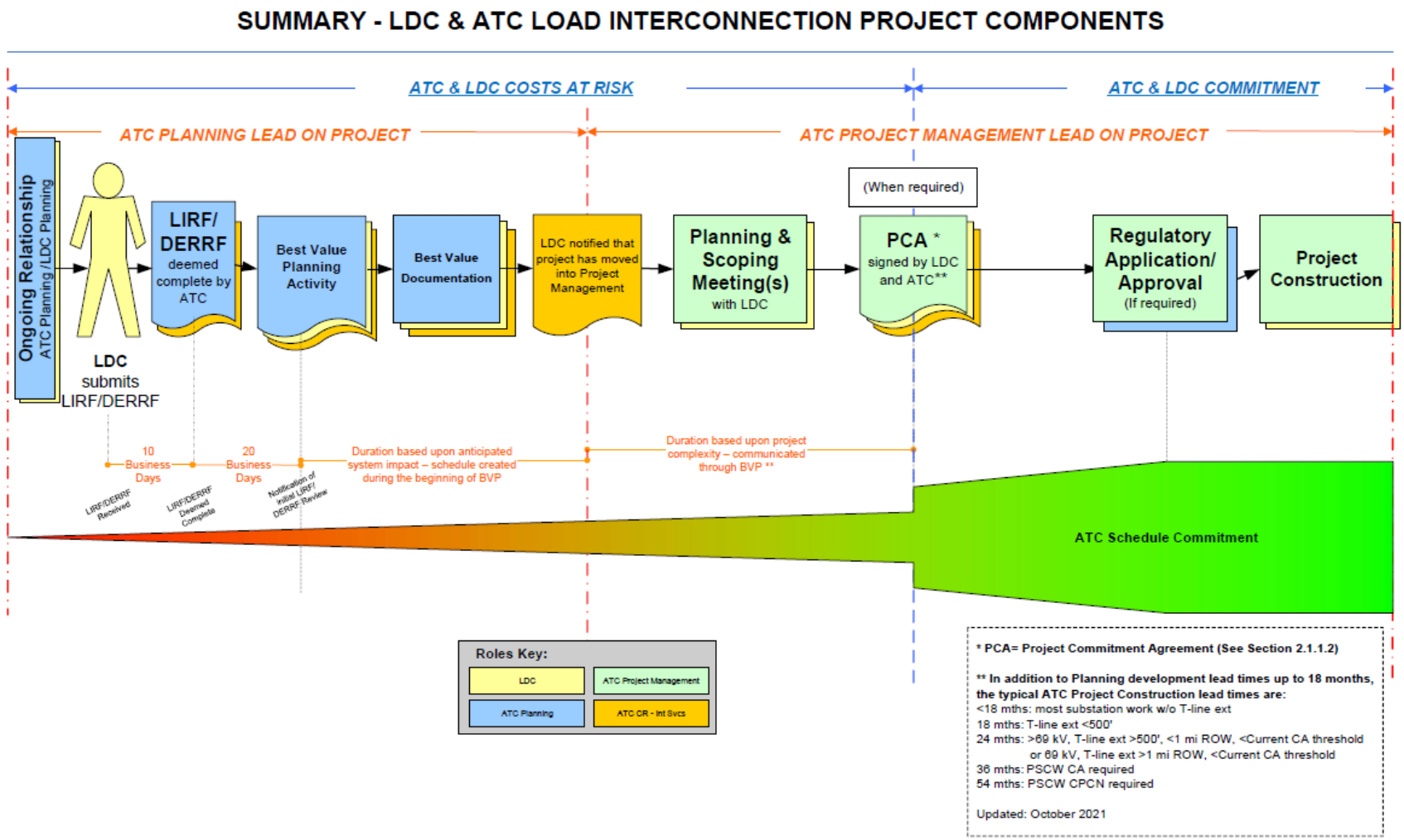
Transmission Operator: ATC is the entity responsible for the reliability of the ATC Transmission System. ATC is also the entity that operates or directs the operations of the ATC Transmission System.

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

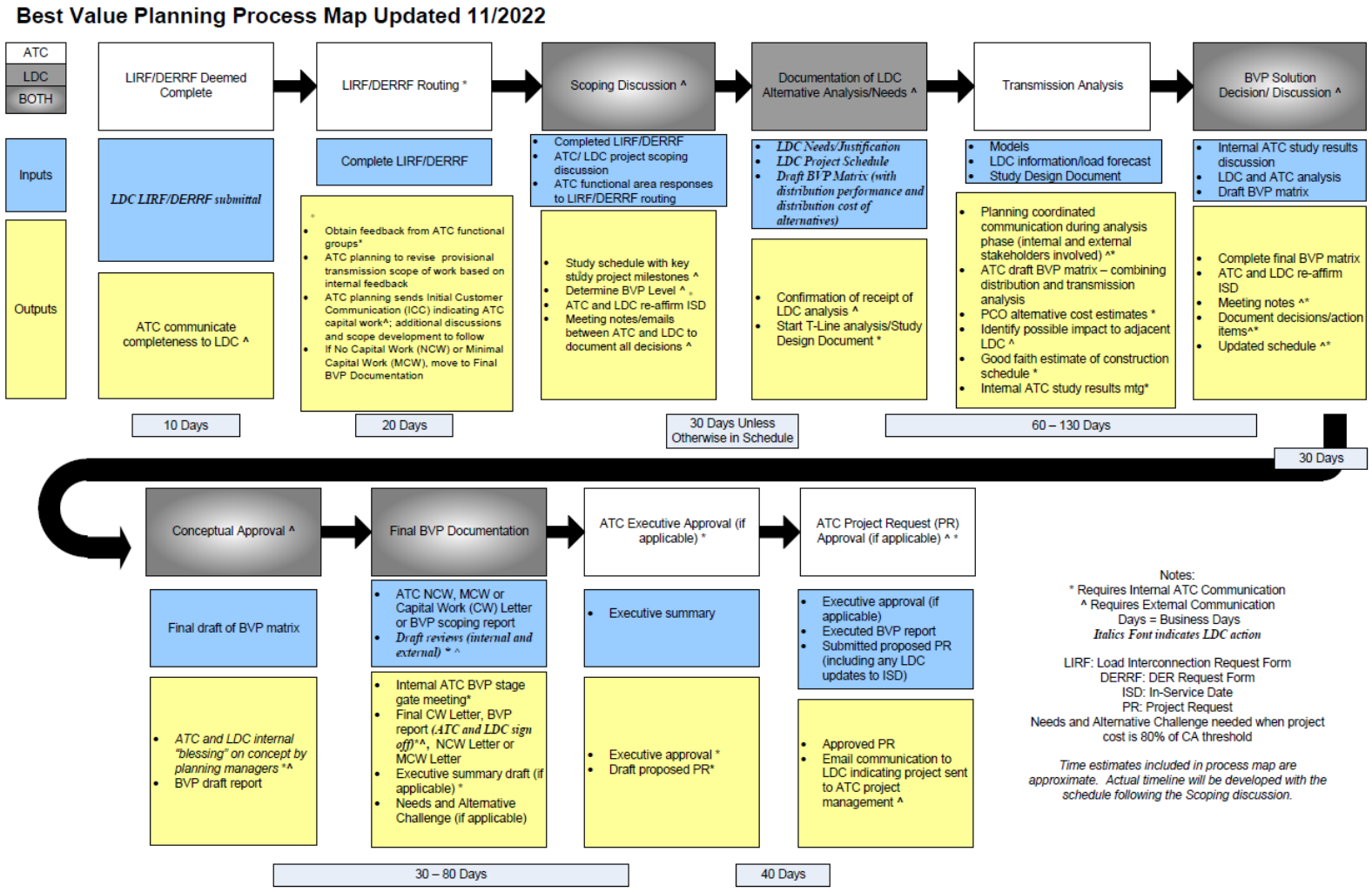
Transmission Planner: ATC is the entity that develops a long-term (generally one year & beyond) plan for the reliability (adequacy) of the interconnected bulk electric transmission systems within its portion of the Planning Authority Area.

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



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



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/

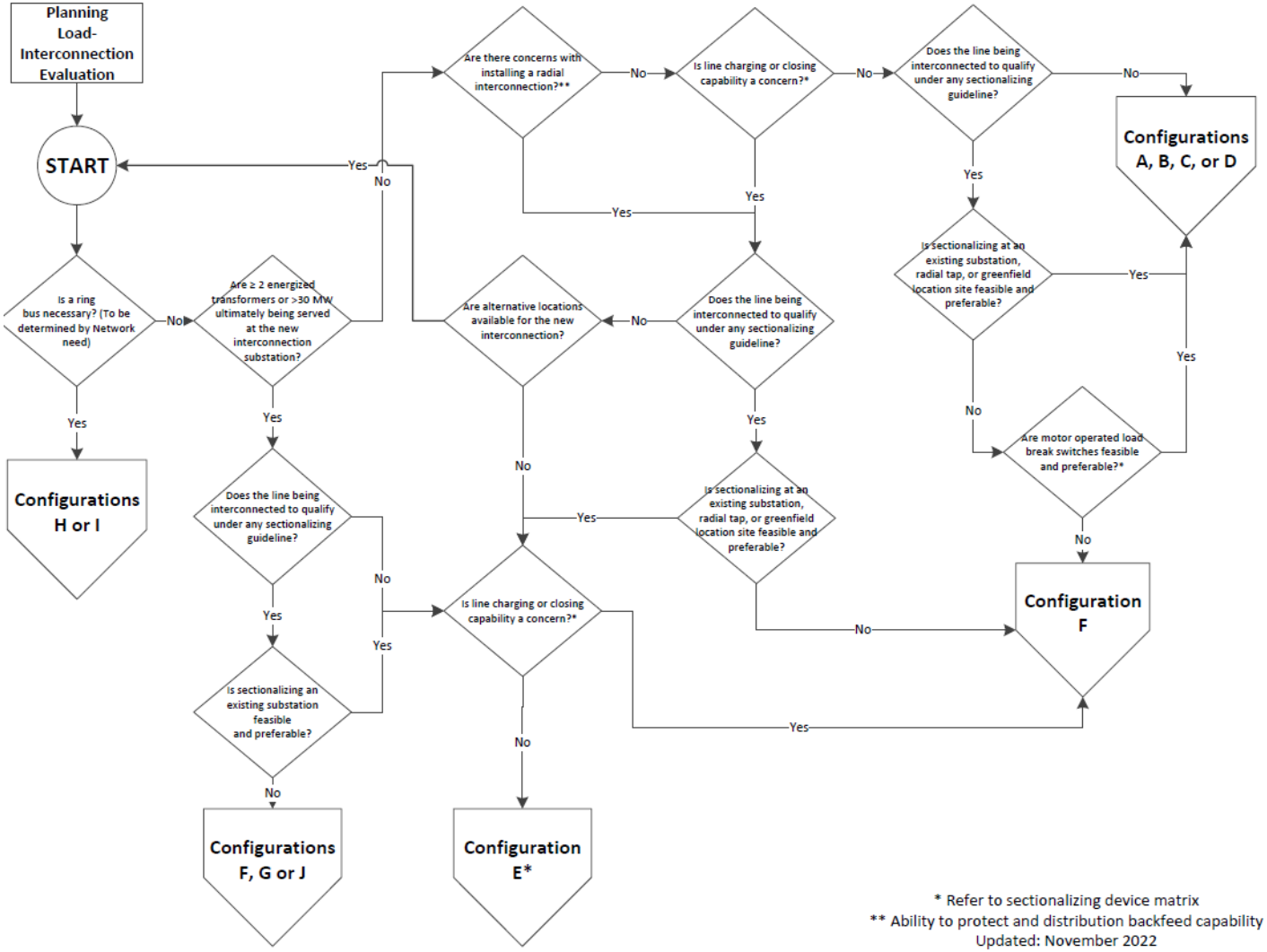
Appendix E – Example Project Commitment Agreement

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.

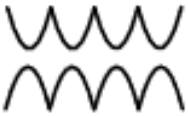
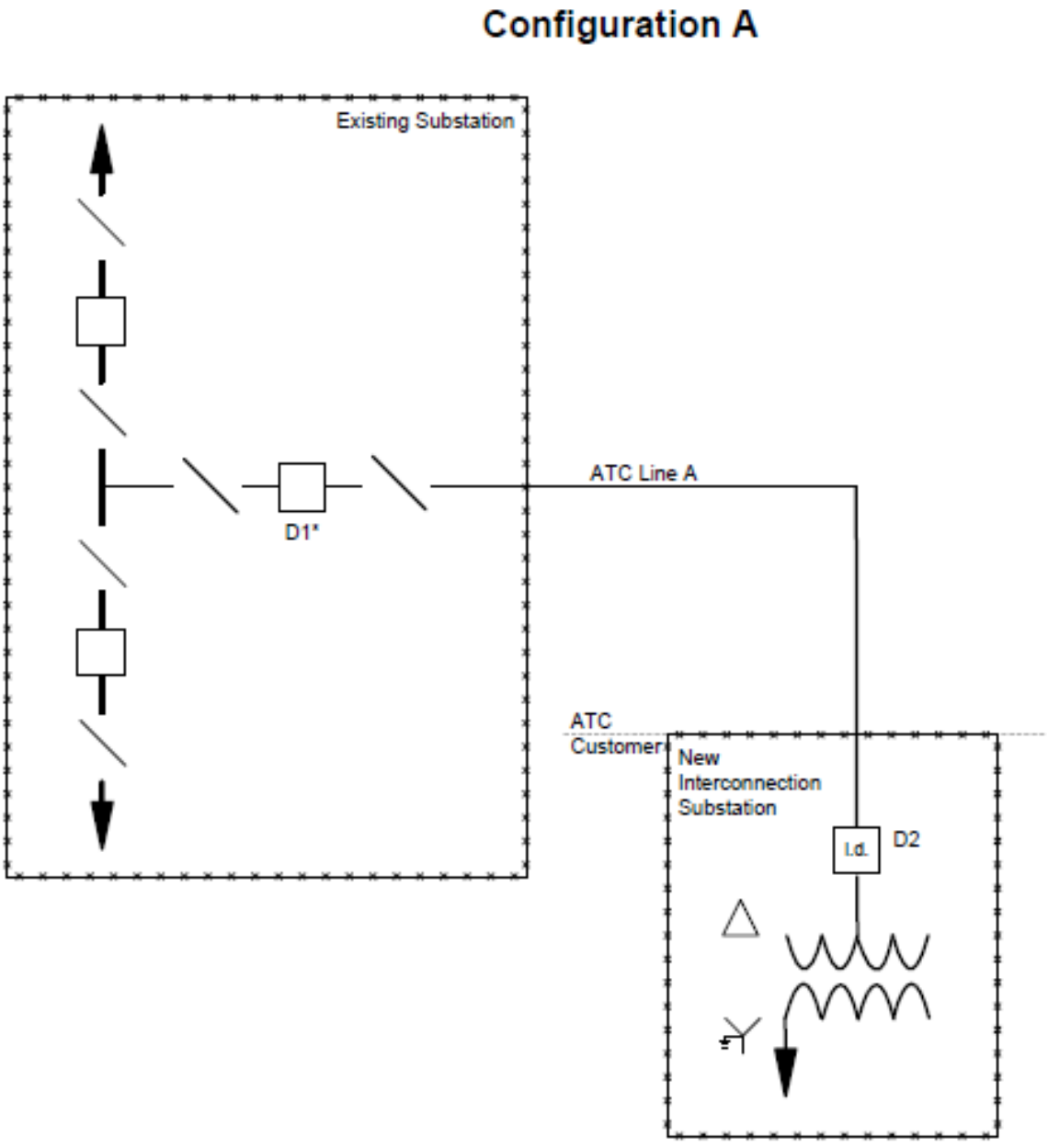
	Existing	Proposed for present or ultimate installation	Space for future (>10 yrs) installation
Circuit breaker			
Disconnect switch (switch with horns typical).			
Disconnecting device with sufficient capability to break line charging current (switch with whips typical).			
Disconnect switch with sufficient 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].			
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)



* 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)

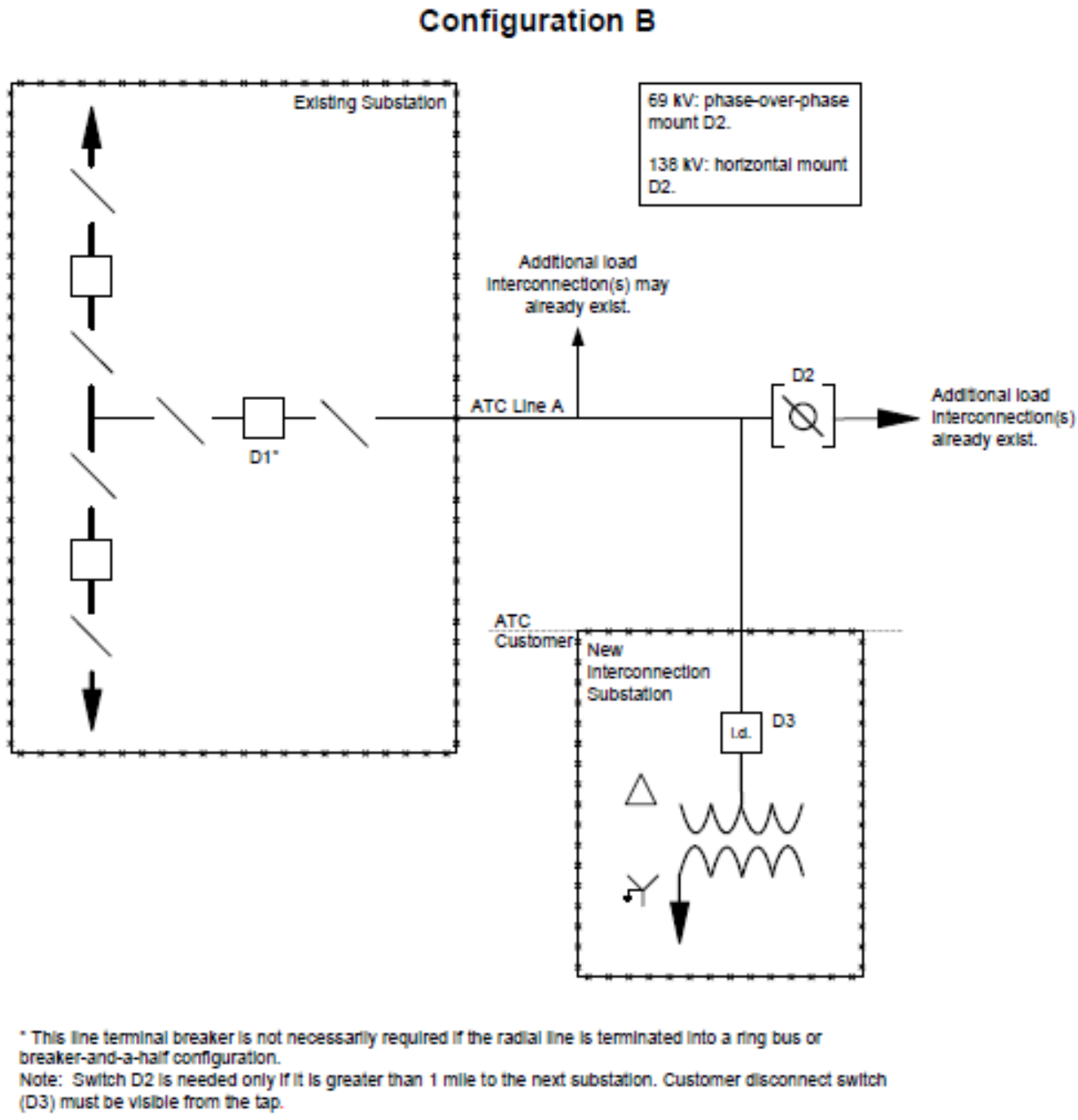


Figure F.5: Load Interconnection Configuration B

Appendix F – Interconnection Configurations (Continued)

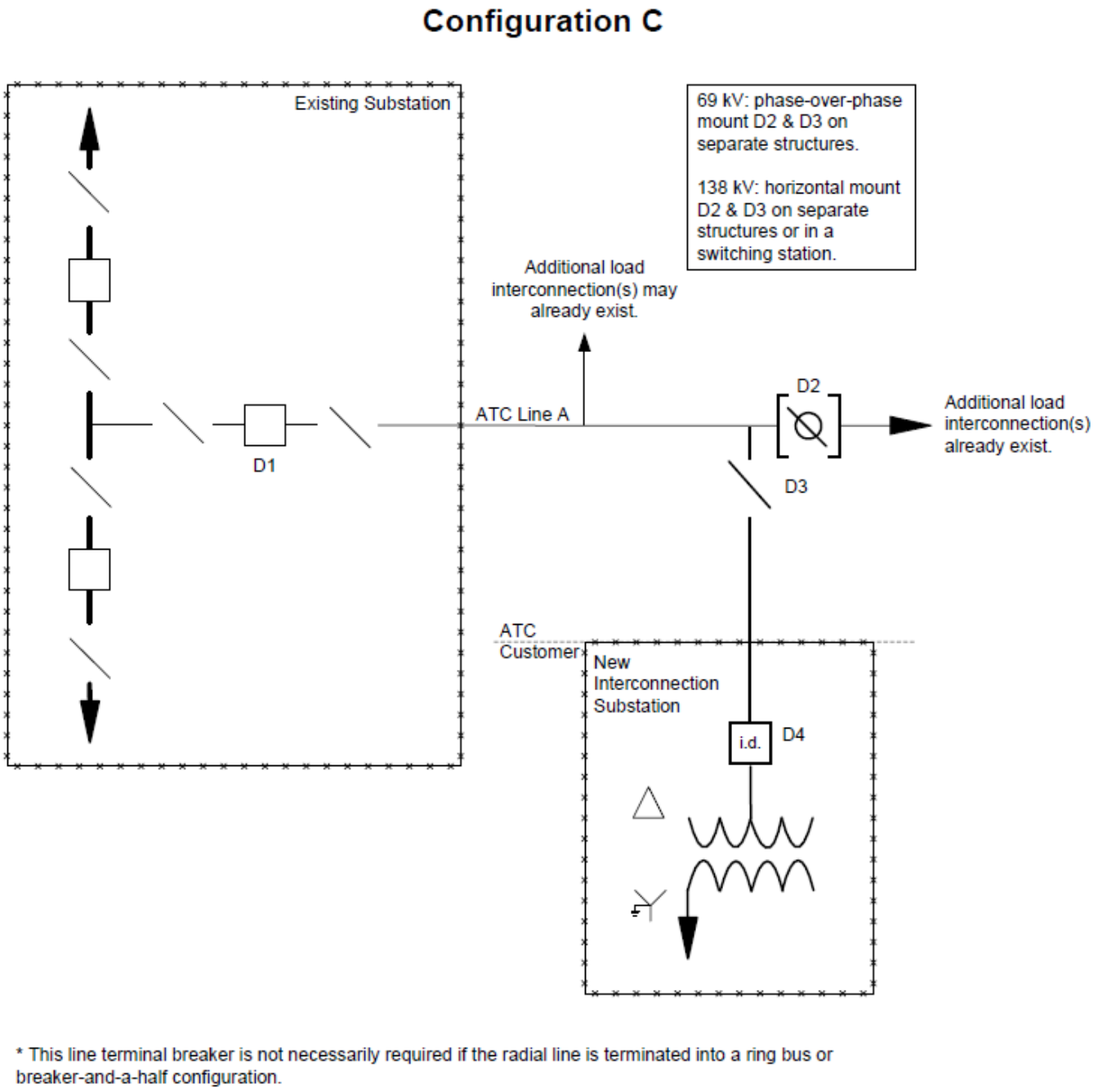


Figure F.6: Load Interconnection Configuration C

Appendix F – Interconnection Configurations (Continued)

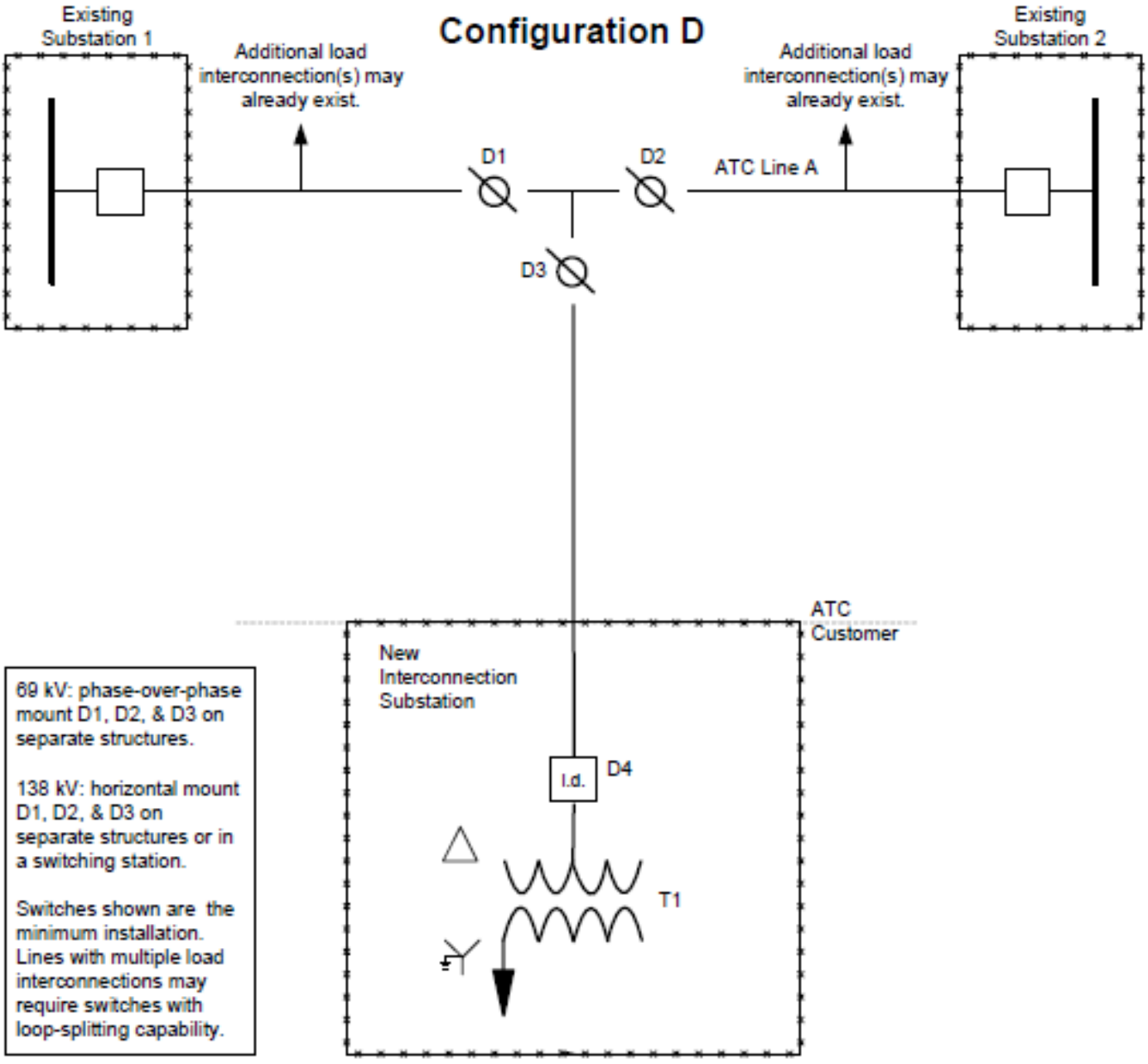


Figure F.7: Load Interconnection Configuration D

Appendix F – Interconnection Configurations (Continued)

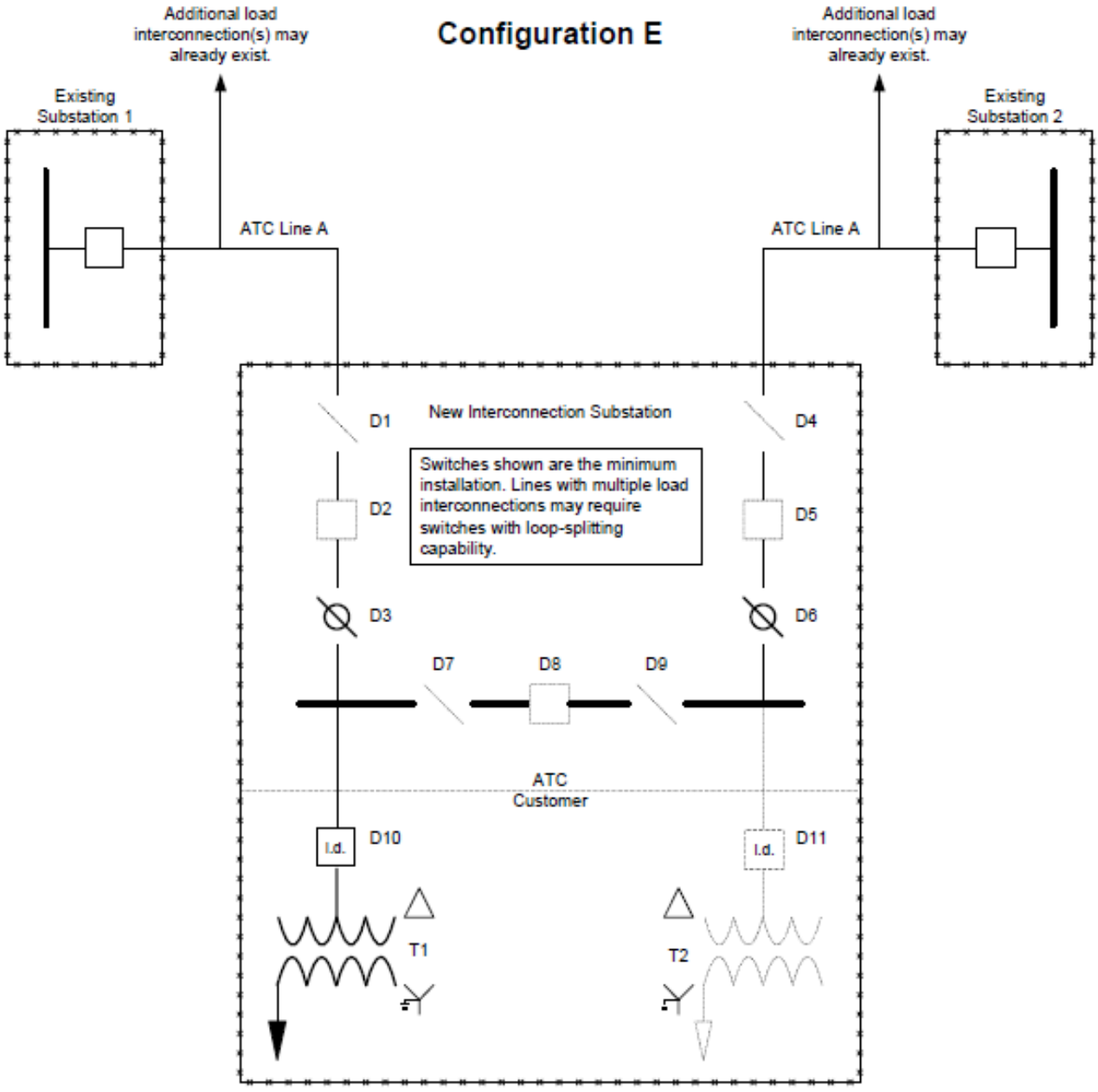


Figure F.8: Load Interconnection Configuration E

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)

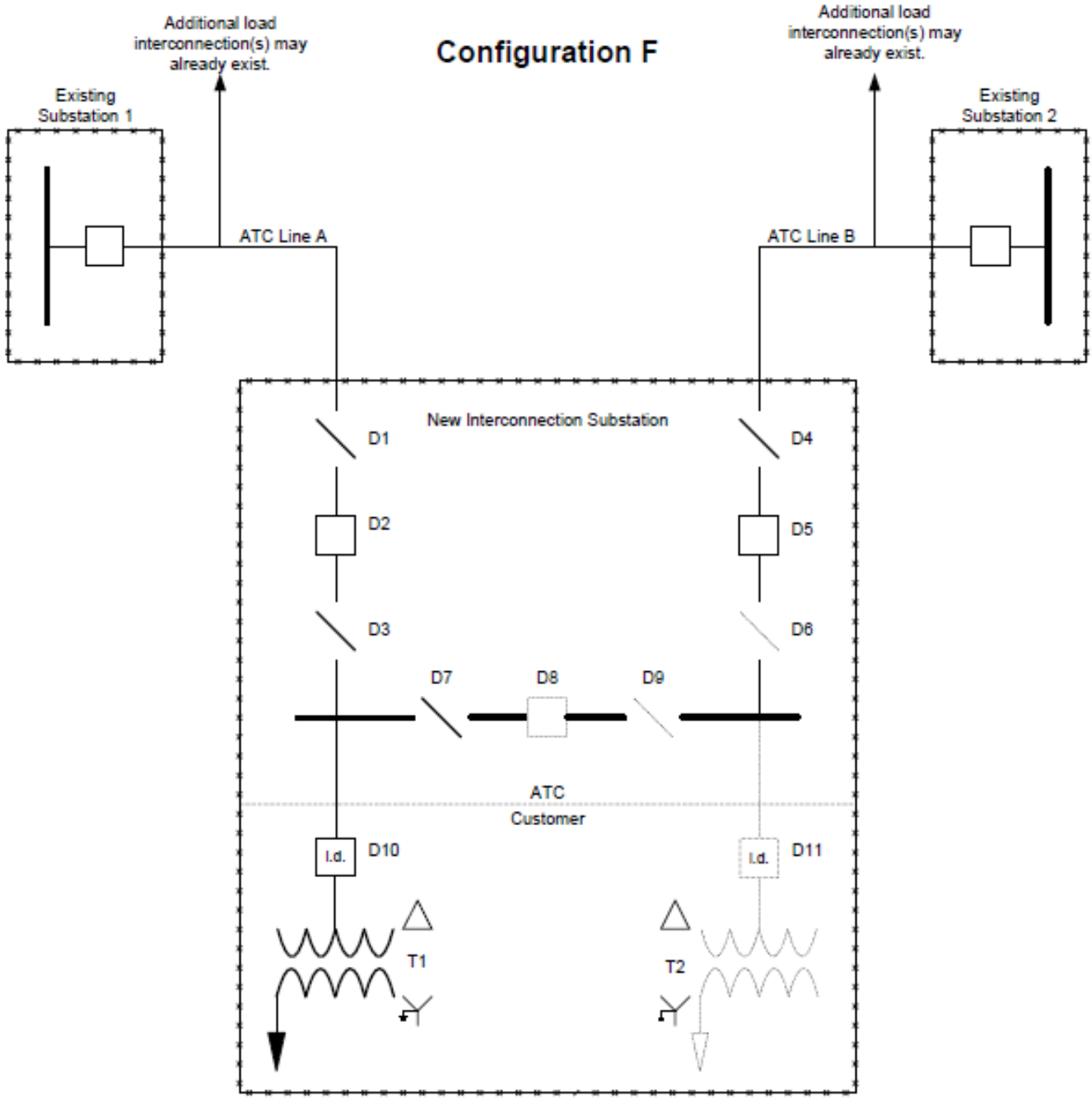
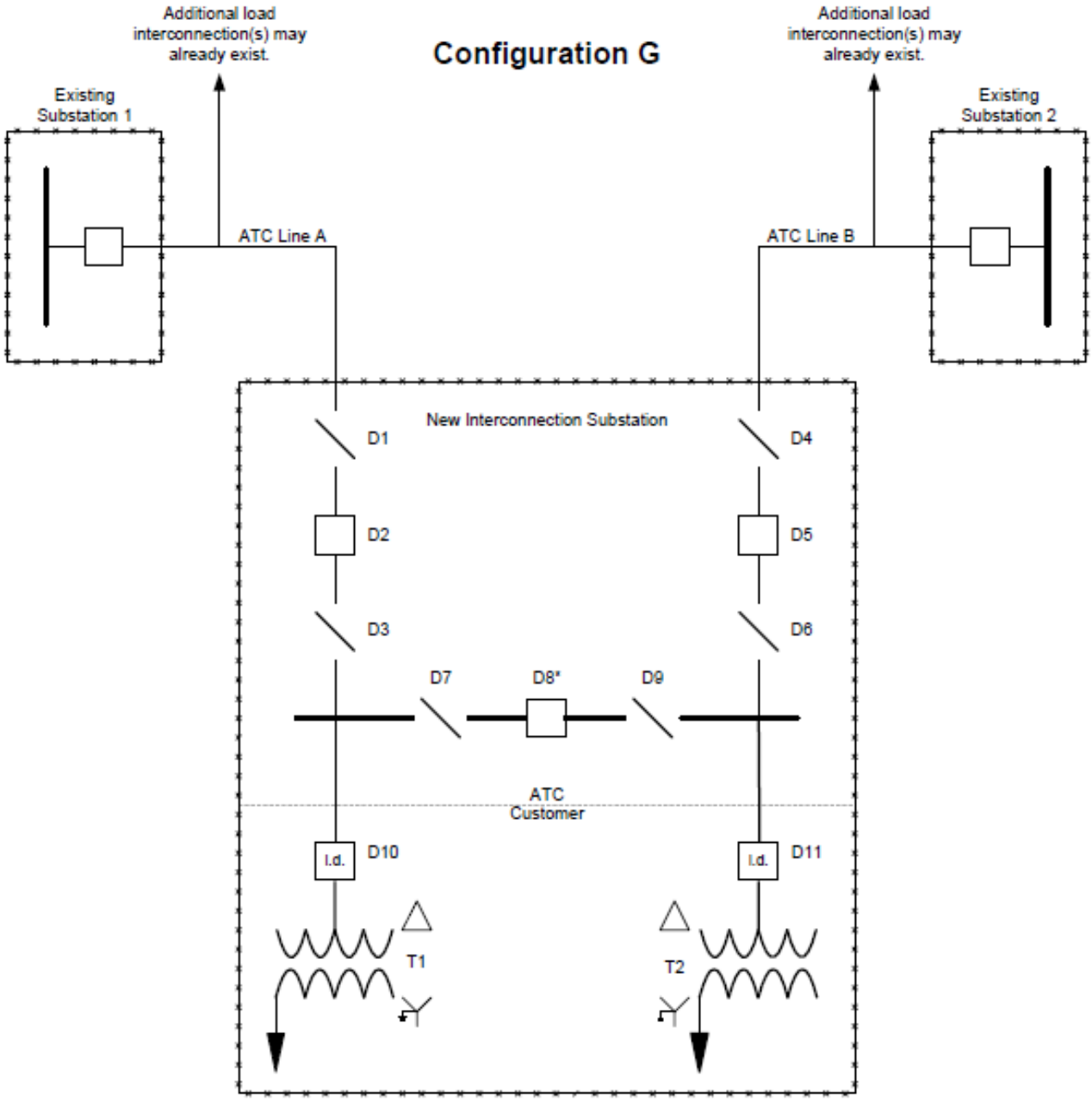


Figure F.9: Load Interconnection Configuration F

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)

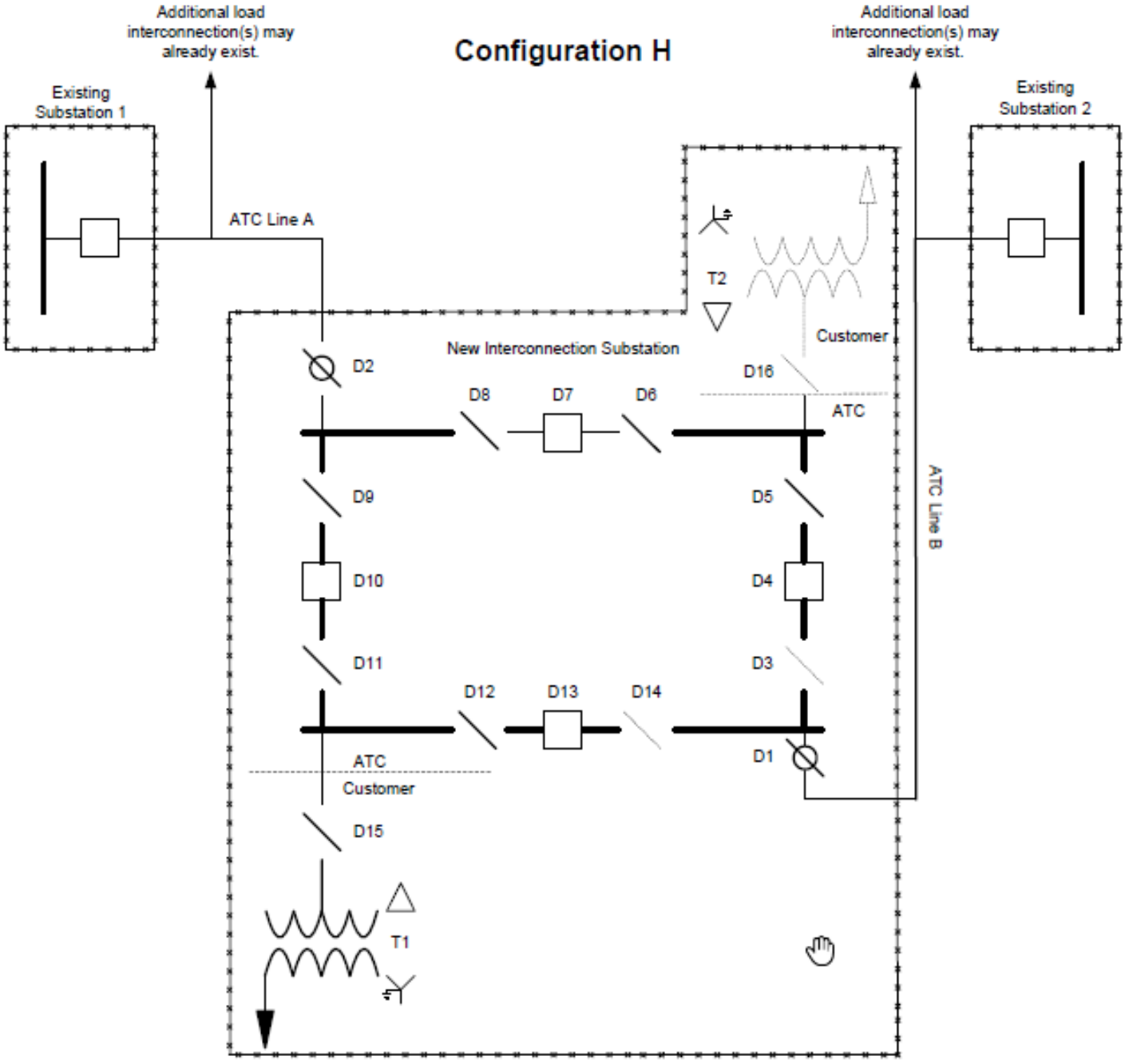


Figure F.11: Load Interconnection Configuration H

Appendix F – Interconnection Configurations (Continued)

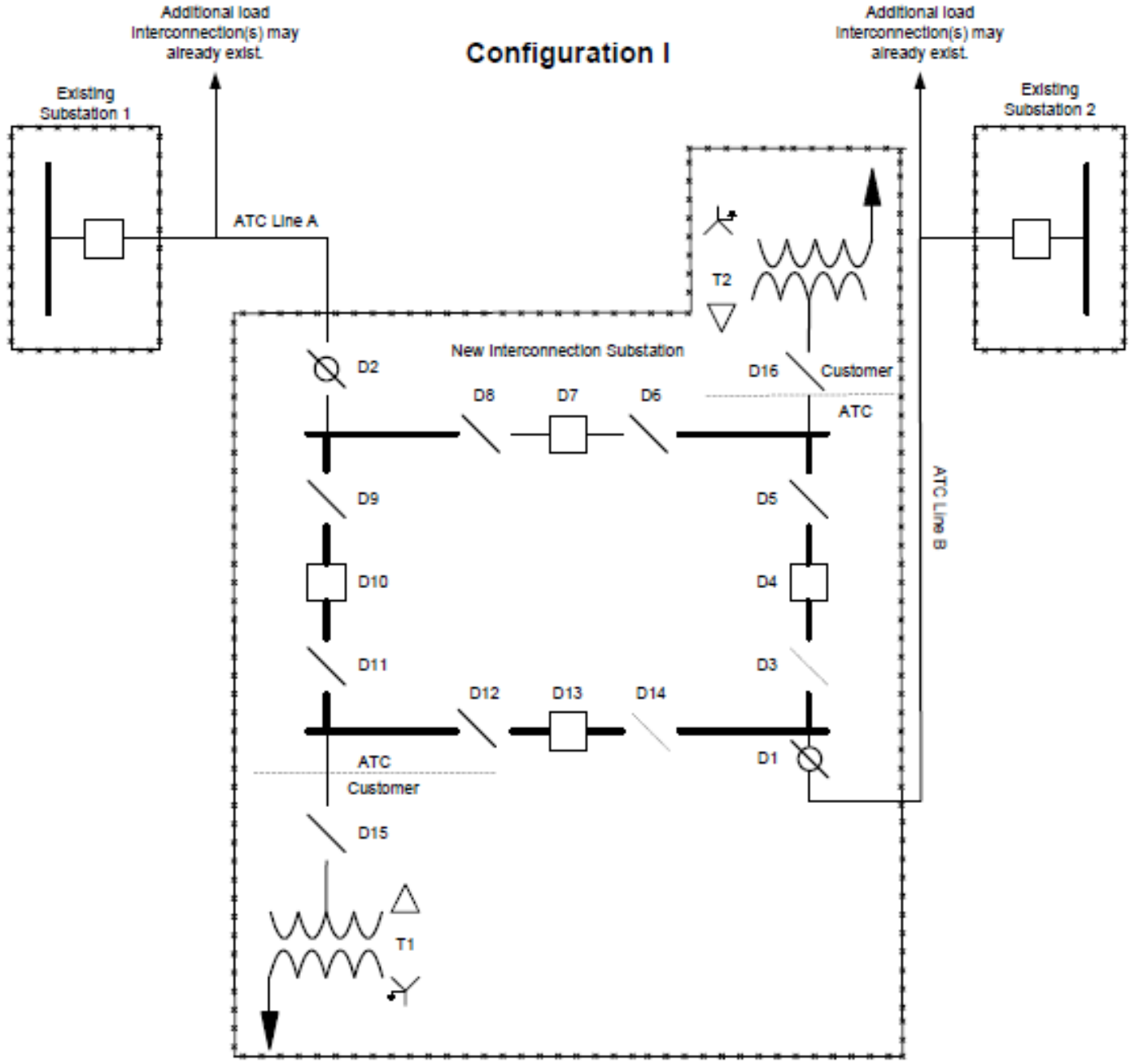
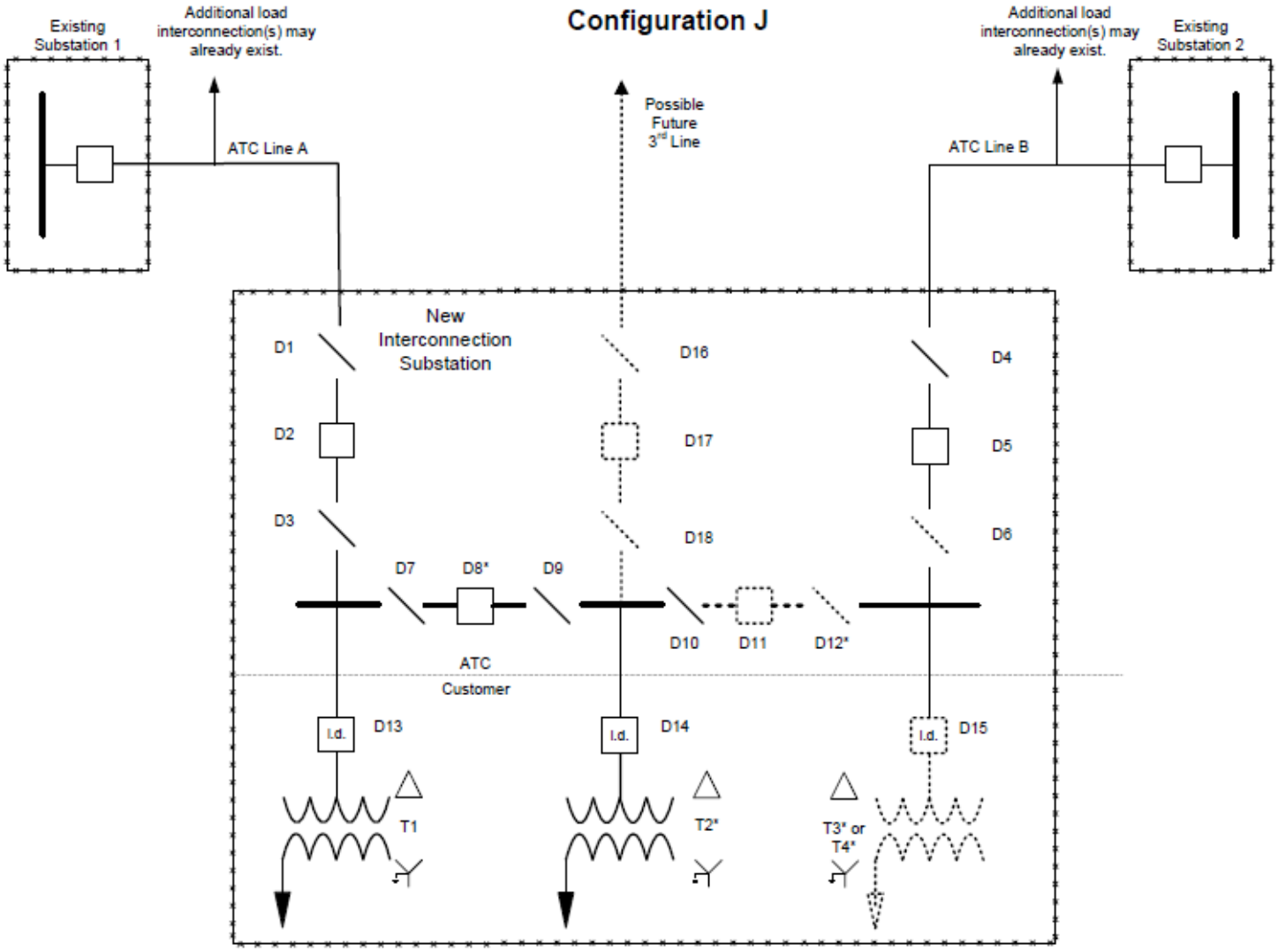


Figure F.12: Load Interconnection Configuration I

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

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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

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-4-6

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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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.

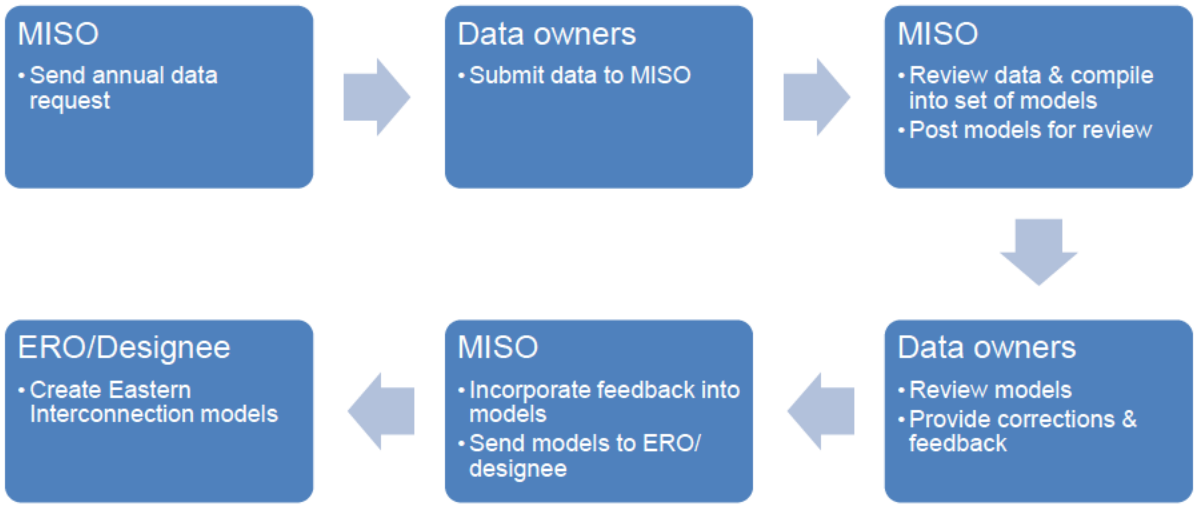


Figure 1-1: Modeling Process Overview

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.

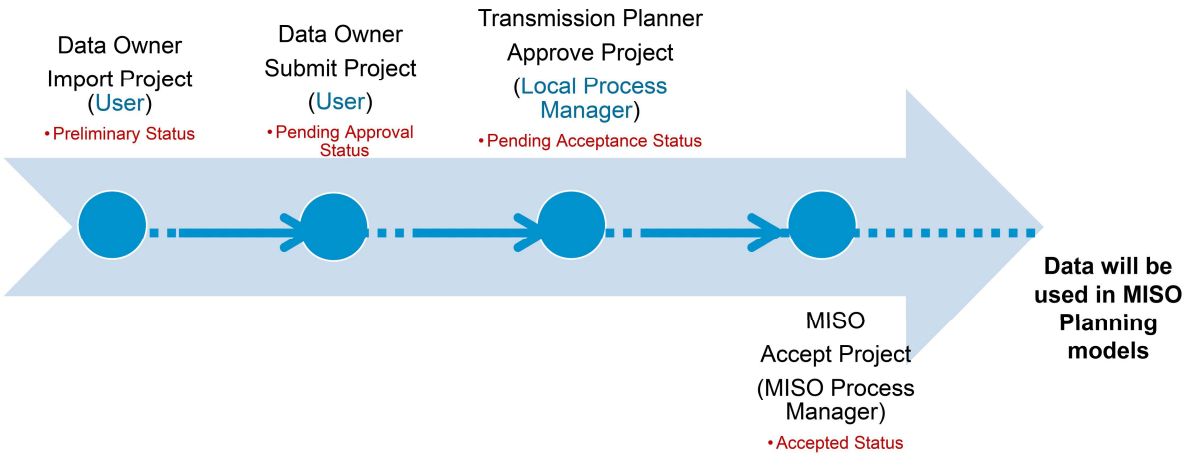


Figure 3-1: Sequence of MOD Data Submission

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.

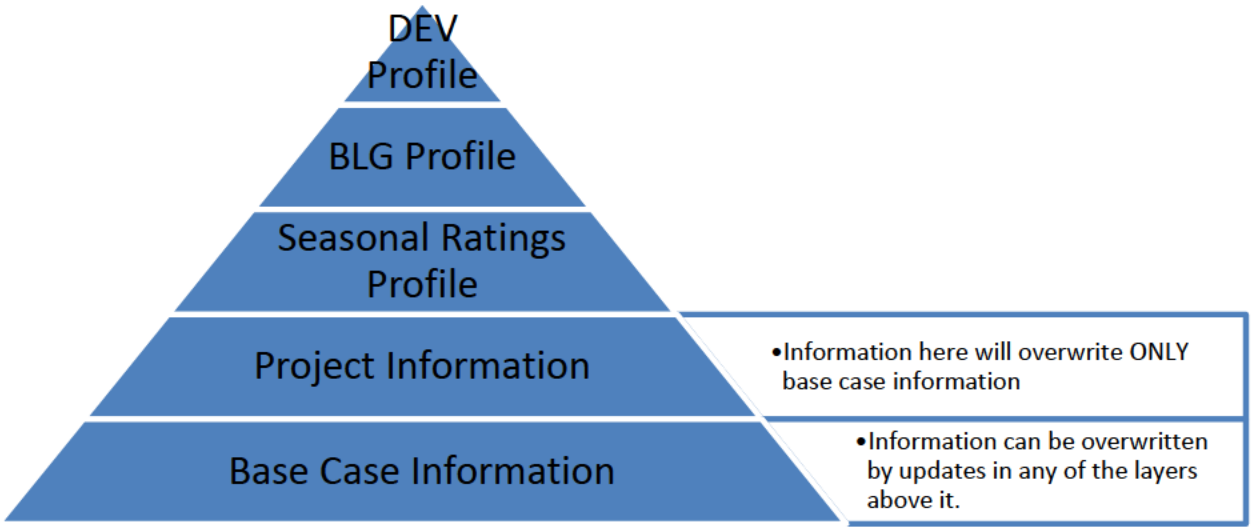


Figure 23-2

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)

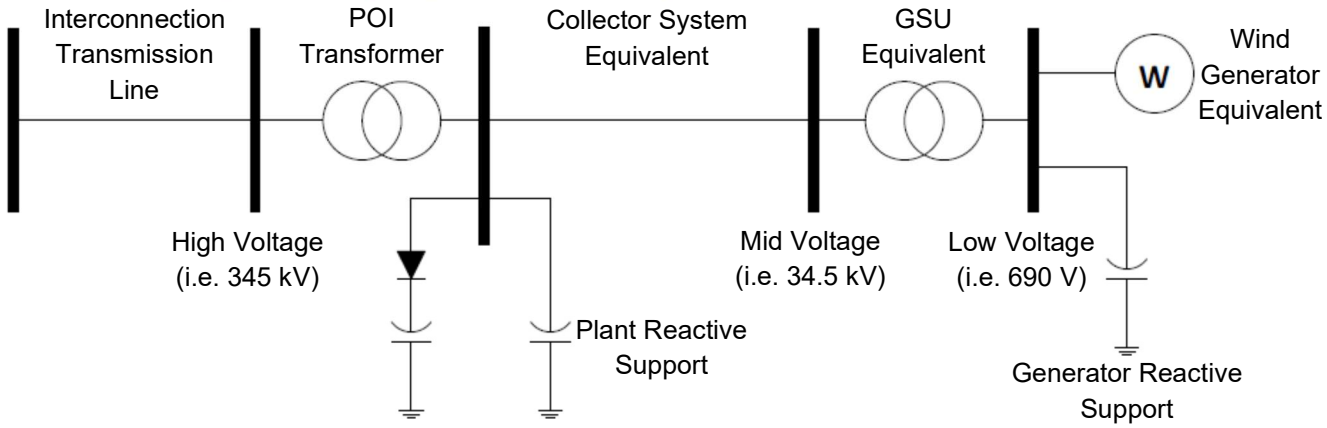
4.4.4.2 *Wind Farms*

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)

[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

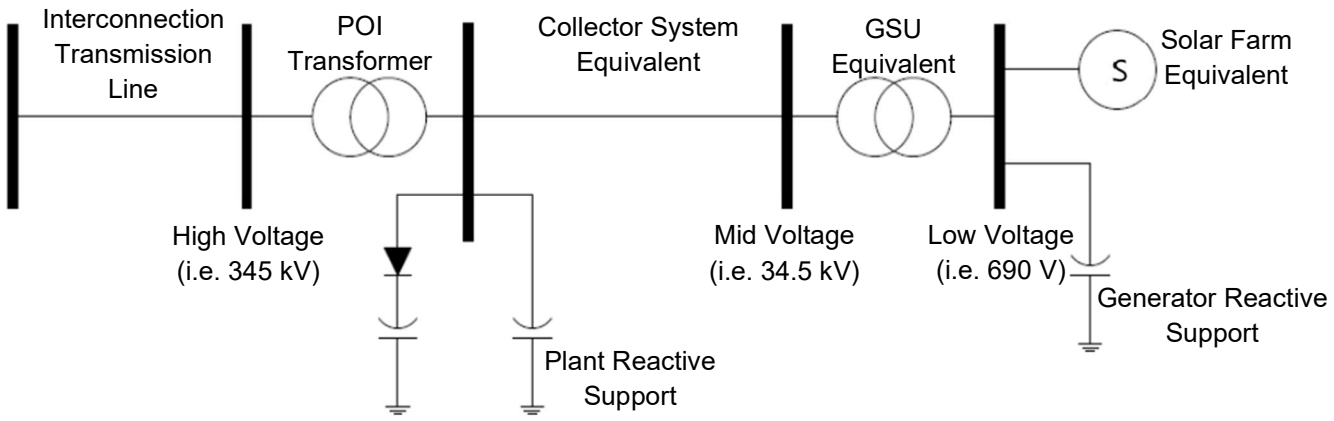
4.4.4.3 *Solar Farms*

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	$0.7 \leq V_{bus} \leq 1.2$ (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.

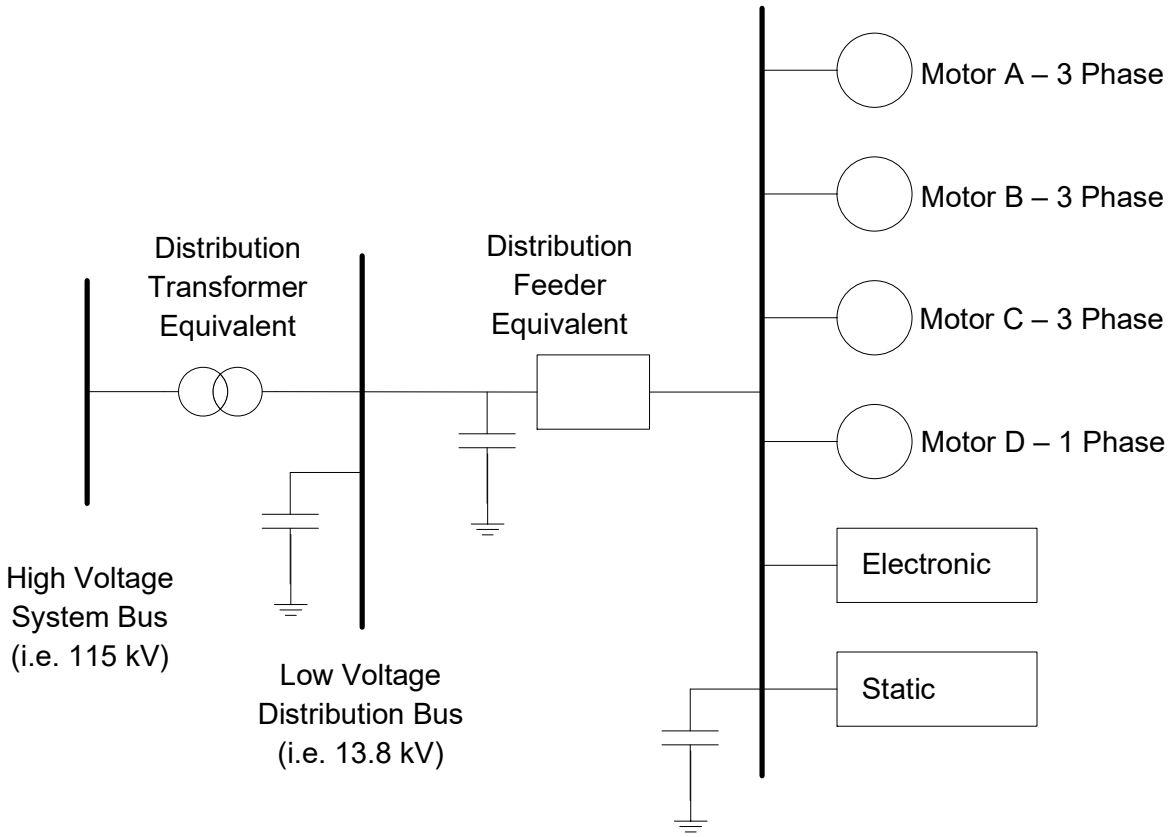


Figure 7-1: Composite Load Model

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, or 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.

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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 entity[1] 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

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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	2030SLHW-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	27%	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	2030SLHW-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]**.

FOR FURTHER INFORMATION CONTACT:

Brian Bak (Technical Information)
Office of Energy Policy and Innovation
Federal Energy Regulatory Commission

888 First Street, NE
Washington, DC 20426
(202) 502-6574
brian.bak@ferc.gov

Gretchen Kershaw (Legal Information)
Office of the General Counsel
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426
(202) 502-8213
gretchen.kershaw@ferc.gov

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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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

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.

[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).

[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]

[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

[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

[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

[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

[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. Need for Reform

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

[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.

[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

[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]

[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]

[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

[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

[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

[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

[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. Commission Determination

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

[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

[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

[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

[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.

[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]

[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. Comments

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

[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-

[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]

[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

[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

[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.

[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

[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. Comments

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]

[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

[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

[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

[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

[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. Miscellaneous Comments

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

[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

[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

[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. Information Collection Statement

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

[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]

[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.

[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

[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

[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

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

DEREK P. STENCLIK

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 QUALIFICATIONS

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

A My name is Derek Stenclik and I am a Founding Partner of Telos Energy, Inc. My business address is 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 the founding partner of Telos Energy, Inc., an analytics and engineering firm specializing in grid planning, renewable integration, and resource adequacy. I have a decade of experience helping clients across the electric power industry navigate evolving markets, adapt to rapidly changing technologies, and accelerate clean energy integration.

I specialize in production cost and resource adequacy modeling for grid planning, asset development, wind and solar integration, and battery energy storage. I am proficient in the use of spreadsheet analysis tools, as well as optimization and electricity dispatch models and resource adequacy models to conduct analyses of utility service territories and regional energy markets. I have direct experience running the PLEXOS, GE MAPS, and SERVM models, and have reviewed input and output data for several other industry models.

I am also involved in many industry groups and forums, including at the Institute of Electrical and Electronics Engineers (IEEE) and Energy Systems Integration Group (ESIG). Currently I am leading the ESIG Working Group on Redefining Resource Adequacy, which is considering novel ways to improve resource adequacy analysis and reliability planning during the power sector's transition. I am also currently participating on the Technical Advisory Panel for the Hawaiian Electric Company's Integrated Grid Planning efforts.

From 2011 to 2018, I was employed by GE Energy Consulting, most recently as the Senior Manager of Power Systems Strategy. In that role I was responsible for a team of engineers and economists that conducted economic and transmission planning studies for utilities, grid operators, and developers across North America.

I hold a master's degree in Applied Economics and Management from Cornell University and graduated with Summa Cum Laude and Phi Beta Kappa honors from State University of New York, College at Geneseo. Additional qualifications are included in my resume, Exhibit DS-1.

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

A No. This is my first time testifying as an expert witness before the Georgia Public Service Commission, but I have similar experience in other jurisdictions.

Q IN WHICH OTHER JURISDICTIONS HAVE YOU TESTIFIED BEFORE A STATE COMMISSION?

A I have testified as an expert witness before the South Carolina Public Service Commission for the Dominion Energy South Carolina Integrated Resource Planning and Avoided Cost proceedings. I have also testified as an expert witness before the Colorado Public Utilities Commission related to the Public Service Colorado Electric Resource Plan and Clean Energy Plan and the Tri-State Generation and Transmission Association, Inc's Energy Resource Plan. In addition, I regularly present in proceedings with the Hawaii Public Utilities Commission and have supported testimony for the New Mexico Public Regulation Commission.

Q ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS CASE?

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

Q ARE YOU SPONSORING ANY EXHIBITS FOR YOUR TESTIMONY?

A Yes. I am sponsoring 14 exhibits in my testimony, listed in Table 1.

Table 1. List of Exhibits

Exhibit #	Title	Confidential
DS-1	Resume of Derek P. Stenclik	Public
DS-2	Company response to Staff discovery request STF-JKA-2-32	Trade Secret
DS-3	Company response to Staff discovery request STF-PIA-5-4	Public
DS-4	Company response to Staff discovery request STF-JKA-1-11	Trade Secret
DS-5	Company response to Staff discovery request STF-GS-1-14	Public
DS-6	Company response to Staff discovery request STF-JKA-1-9	Public
DS-7	Company response to Staff discovery request STF-GS-1-15	Public
DS-8	Company response to Staff discovery request STF-GS-1-19	Public
DS-9	Company response to Staff discovery request STF-GS-1-4	Trade Secret
DS-10	SREA, Winter Storm Elliott: An independent review of Southern Company's performance during the historic events of December	Public
DS-11	Workpaper: Capacity Expansion Plans by Portfolio	Public
DS-12	Workpaper: NPV Calculations by Portfolio - Trade Secret	Trade Secret
DS-13	Workpaper: Capacity Expansion Plans - 2025 IRP - Scenario Comparisons – Stenclik.xlsx	Public
DS-14	Workpaper: Georgia Power Territorial Base Case Load vs. Capability Table - 2025 IRP – Stenclik.xlsx	Public

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

A The purpose of my testimony is to review Georgia Power Company's ("GPC" or "the Company") 2025 Integrated Resource Plan (IRP) and to evaluate and provide recommendations on topics related to the load forecast, renewable and thermal resource modeling, transmission, and power system modeling. In my testimony I also describe

modeling conducted by myself and staff at Telos Energy that provides alternative portfolios and sensitivities for the Commission to review. In preparing this testimony, I reviewed GPC's 2025 IRP filings, testimony, attachments, and responses to Public Interest Advocacy Staff's data requests.

Q HOW IS YOUR TESTIMONY ORGANIZED?

A My testimony is organized into eight sections, outlined below:

I. Introduction and Qualifications
II. Summary of Testimony and Key Conclusions
III. Independent Modeling of Alternative Portfolios
IV. Load Forecast Uncertainty and Large Loads
V. Variable Renewable Energy and Battery Storage Issues
VI. Thermal Generation Issues
VII. Transmission Modeling Issues
VIII. Final Conclusions and Alternative Portfolios
IX. Recommendations for the Commission

II. SUMMARY OF TESTIMONY AND KEY CONCLUSIONS

Q IN YOUR OPINION, DOES THE MODELING PERFORMED BY GEORGIA POWER COMPANY IN ITS 2025 IRP RESULT IN REASONABLE FUTURE RESOURCE PLANS?

A No, it does not. The Company's IRP shows an unprecedented growth in load and capacity additions. It "includes continuing the operation of Plant Bowen Units 1-4, extending the operation of approximately 1,100 MW at Plants Scherer and Gaston, [and] upgrades of up to 400 MW to nuclear and natural gas units," and "[t]hrough 2031, Georgia Power projects a capacity need of 9,000 MW."[1]

However, GPC's resource plans are based on inappropriate assumptions, including load forecasts that are too high and highly speculative, arbitrary limits on annual solar and wind builds, poorly characterized accreditation of thermal and battery storage resources, capital cost assumptions for new gas resources that are unrealistic, and a failure to fully benefit from federal subsidies available under the Inflation Reduction Act ("IRA"). This resulted in GPC portfolios that have limited fuel diversity, rely heavily on new gas resources, artificially limit lower cost and lower risk renewable energy resources, fail to capitalize on available federal subsidies which would lower costs, and place significant risk on GPC ratepayers for stranded assets that would increase rates if new large loads do not materialize as expected.

[1] Ga. Power Co., 2025 IRP Main Document at 2 [hereinafter "2025 IRP Main Document"].

My independent modeling indicates that when assumptions are revised to more realistic values, GPC's portfolios are not economically competitive as compared to alternatives that further deploy solar and storage resources and accelerate coal retirement. This approach would help balance GPC's already large reliance on natural gas and coal resources. Based on this analysis, GPC should accelerate coal retirements, increase procurement of solar and storage resources, limit new gas resource investment, and evaluate options for interregional transmission. Furthermore, new resources could be strategically located to take advantage of federal tax credits, improve reliability, and avoid new transmission. Compared to GPC's MG20 Portfolio, doing so could save GPC ratepayers 20-year net present value (NPV) of [redacted] billion (19%) from 2025-2044.

Q CAN YOU PROVIDE A BRIEF SUMMARY OF YOUR MAIN FINDINGS?

A My testimony is divided across five main topics, covering load forecast and uncertainty, variable renewable energy modeling issues, thermal resource modeling issues, transmission modeling issues, and alternative resource portfolios to consider. The following section summarizes the key findings:

Load Forecast and Uncertainty: My testimony begins by addressing the Company's load forecast, which projects unprecedented growth, largely driven by speculative large industrial and data center loads. While GPC acknowledges the uncertainty of these loads in narrative

form,[2] it fails to incorporate this uncertainty into the capacity expansion modeling in any meaningful way. The lack of a credible bookend analysis and scenarios isolating the impact of large loads leaves the IRP vulnerable to overbuilding and increased customer costs. My analysis demonstrates that isolating the impact of large load growth is essential to avoid stranded assets and ensure ratepayers are protected from speculative infrastructure development.

Variable Renewable Energy Issues: The Company imposes restrictive and unsupported annual build limits on solar and wind resources. These restrictions artificially constrain the model's ability to identify cost-effective portfolios. These constraints are binding across nearly all future years and drive the selection of new gas capacity instead of allowing the model to reflect industry trends and technological capability. I developed a High Solar and Storage scenario that relaxed these limits and demonstrated comparable or lower system costs, reduced gas reliance, and lower emissions. The IRP also fails to incorporate available federal tax credits, such as energy community bonus incentives, which would materially reduce the cost of clean energy investments.

Thermal Generation Modeling Issues: While the Company applies an effective load carrying capability (ELCC) methodology to solar, wind, and storage, it continues to assign 100% capacity credit to gas and coal resources, ignoring correlated outage risks and fuel

[2] Ga. Power Co., 2025 IRP Technical Appendix Volume 1, Load and Energy Forecast, B2025 Load and Energy Forecast at 103.

constraints—particularly during extreme winter conditions. This inconsistency inflates the reliability value of thermal resources and distorts the resource mix toward unnecessary gas additions. I presented evidence from the Company's own Reserve Margin Study and national best practices showing that cold weather events can significantly impact the reliability contribution of thermal resources. To ensure equitable and accurate modeling, the Company should adopt ELCC or PCAP-based accreditation for all resource types, including thermal. Furthermore, the Company's IRP does not reflect recent supply chain constraints driving price increases for natural gas capacity, significantly understating the costs and overstating the feasibility of its portfolios.

Transmission Modeling Issues: The Company does not evaluate interregional transmission options in its IRP, missing opportunities to access low-cost, geographically diverse resources and reducing its overall reserve margin needs. Studies I contributed to with the Energy Systems Integration Group, as well as third-party analysis by Brattle Group, show that interregional and regional transmission can significantly reduce system costs, enhance reliability, and improve resilience to extreme weather. Internally, the Company fails to model zonal transmission constraints in Aurora and fails to accurately model battery storage in transmission models, even though it proposes major transmission investments. Integrated resource and transmission planning would enable more efficient decisions, ensure the operability of proposed portfolios, and avoid unnecessary upgrades.

Recommendations and Path Forward: Throughout my testimony, I provide concrete recommendations for improving GPC's IRP and provide alternative portfolios to illustrate

and quantify the impact of these recommendations. These include modeling a broader range of load scenarios, removing arbitrary clean energy build limits, adopting consistent accreditation for all resources, and integrating transmission constraints and options into the modeling process. By adopting these reforms, the Company can produce more reliable, resilient, and cost-effective portfolios that better reflect today's energy landscape. Most importantly, these improvements will help ensure that customers are not burdened with the costs of speculative load growth or outdated planning assumptions.

III. INDEPENDENT MODELING OF ALTERNATIVE PORTFOLIOS

Q DID YOU PERFORM INDEPENDENT MODELING OF THE GPC SYSTEM TO EVALUATE ALTERNATIVE RESOURCE PORTFOLIO OPTIONS?

A Yes. To better evaluate alternative portfolio options, I independently modeled Southern Company's system using the PLEXOS production cost modeling software. First, I recreated the models and processes developed by GPC, to the closest extent reasonable, and then tested alternative portfolios to gauge the effect of changing the assumptions outlined later in this testimony, specifically, by quantifying the operating, fixed, and capital costs of the alternative portfolios.

This analysis is not meant to replace the modeling conducted by the Company. Instead, it is meant to show how the overly conservative assumptions and modeling approaches used by the Company are leaving value on the table and resulting in a more costly plan for the Company's ratepayers. The alternative portfolios show that there is an opportunity to

accelerate coal retirements, maximize federal tax credits, reduce exposure to volatile fossil fuel prices, and maintain reliability while saving ratepayers money.

Q WHY DID YOU THINK IT WAS NECESSARY TO CONDUCT YOUR OWN MODELING AND ANALYSIS?

A There are several areas where the Company's modeling used incorrect or overly conservative assumptions that overly favor new gas generation builds and coal plant retention. Most importantly, the Company failed to appropriately analyze the uncertainty around its load growth forecast in its Resource Mix Study and capacity expansion modeling, especially around large loads. The alternative portfolios I presented in this testimony provide the Commission with resource portfolios that accelerate coal retirements and limit new gas resource development in a way that is both reliable and cost effective.

Q WHAT METHODOLOGIES AND ASSUMPTIONS DID YOU USE FOR THE MODELING?

A To the extent possible, I utilized the same data and similar methods as GPC to test alternative resource portfolios. In general, I made limited changes to inputs and assumptions to allow for a more direct comparison between the Company's IRP portfolios and my results. If certain data or assumptions developed by the Company are used in my analysis, it should not be assumed that I agree with or validate the Company's approach. Instead, I tried to make the number of changes appropriately small to allow the Commission to evaluate what I feel are the most important assumptions that warrant an alternative approach.

Q CAN YOU PROVIDE AN OVERVIEW OF THE SOFTWARE YOU USED FOR YOUR ANALYSIS?

A For my analysis, I utilize the PLEXOS power system modeling software. It is similar to the Aurora model utilized by the Company and licensed by the same software developer, Energy Exemplar. Specifically, I utilized PLEXOS short-term (ST) chronological, 8,670 hour per year, production cost simulations to quantify total generation costs of each portfolio. The production cost simulations quantify fuel costs, variable operations and maintenance costs, startup costs, emissions costs, and fixed operations and maintenance costs for each portfolio. I then utilized the same financial assumptions the Company uses to calculate the NPV of each portfolio after assuming the same capital cost of new equipment, financing terms, tax credits, and project life utilized by the Company.[3]

While I used a similar production cost modeling software to the Company, I developed the PLEXOS database using the specific modeling details provided by the Company in the native Aurora file format, aligning assumptions where reasonable. I would like to thank the Company for its transparency in providing data and its modeling files, which allowed me to conduct my independent review of its system modeling.

[3] Note that NPV calculations were done for the Georgia Power Company only, inclusive of capacity additions and net interchange subject to the pooling agreement. All resource builds and costs of Mississippi Power and Alabama Power were unchanged across portfolios.

Q WHAT WAS YOUR APPROACH TO MODELING ALTERNATIVE PORTFOLIOS?

A In developing alternative portfolios for this analysis, I intentionally did not pursue a traditional least-cost optimization of new resource additions. While the software platform utilized is capable of conducting such an optimization—evaluating the most economic combination of new technologies to meet forecasted demand—my objective was to design alternative portfolios that could be more directly and transparently compared to Georgia Power Company's proposed portfolios.

To achieve this, I structured my analysis around targeted, incremental modifications to a limited number of resource decisions—such as altering the timing of retirements, adjusting the volume of renewable or storage additions, or exploring specific combinations of technologies. When changes to new resource additions or retirements were made, I confirmed that the portfolio met the reserve margin requirement in each year of the study horizon using the same load and resource workbook developed by the Company.[4]

In order to maintain consistency across modeling platforms and to mitigate the influence of any discrepancies in assumptions or modeling configurations, I also reran the Company's own portfolios (MG20) using the same modeling setup I used for my alternatives. This

[4] Ga. Power Co., Technical Appendix Volume 2, Resource Mix Study, workpaper "Georgia Power Territorial Base Case Load vs. Existing Capability Table - 2025 IRP.xlsx."

allowed for a more accurate and apples-to-apples comparison between the Company's proposed plan and the alternatives I analyzed.

Q CAN YOU EXPLAIN WHY YOU TOOK THIS APPROACH?

A This approach was chosen to enable a more direct and transparent comparison between the Company's proposed portfolios and the alternative portfolios I developed. By isolating the impact of individual resource decisions, rather than blending multiple changes into a single optimized scenario, I was able to assess the implications of each decision in a more straightforward and comprehensible manner. This transparency is particularly important when evaluating the trade-offs inherent in resource planning.

Moreover, this approach supported a more detailed and comprehensive production cost analysis. According to the Company, their modeling framework included two steps: "The results of generic expansion plan modeling are combined with the existing fleet of resources as inputs into more detailed production cost modeling to produce hourly avoided energy costs for each scenario."[5] My analysis employed the latter approach, using the Company's own generic expansion plans, and then conducting detailed 8,760-hour production cost simulation. This full-year, hourly simulation enabled a realistic assessment of unit

[5] Direct Testimony of Jeffrey R. Grubb, J. Randy Hubbert, M. Brandon Looney, Michael B. Robinson, and Francisco Valle on behalf of Georgia Power Company, Docket Nos. 56002 & 56003 at 26.

commitment and dispatch and allowed for a more accurate evaluation of portfolio reliability, operability, fuel costs, emissions, renewable curtailment, and overall system performance.

By grounding the analysis in detailed operational modeling, I was able to ensure that the alternative portfolios are not only economically reasonable but also technically viable under real-world system conditions.

Q CAN YOU PROVIDE A DISCUSSION AND SUMMARY TABLE OF THE PORTFOLIOS YOU EVALUATED IN YOUR ANALYSIS?

A Yes. In my analysis, I evaluated a range of both alternative resource portfolios ("scenarios") and post-model sensitivities to test the robustness of results under varying assumptions. The alternative portfolios involved direct modifications to the Company's proposed resource plan, including adjusting retirement dates and altering the timing or scale of gas, renewable, and storage additions. These scenario-based portfolios were designed to test the performance and operability of alternative resource mixes under detailed 8,760-hour production cost modeling.

In addition to these scenario-based portfolios, I also applied a set of sensitivities to test how key assumptions—such as capacity costs and IRA bonus credit incentives—affected the NPV of system costs. These sensitivities were applied after the production cost modeling was completed and did not affect unit dispatch or portfolio operability. Instead, they allowed me to assess the directional impact of changes in external assumptions on the relative cost-effectiveness of each portfolio.

A matrix of the evaluated portfolios and applied sensitivities is summarized in the list and Table 2. Matrix of Scenarios and Sensitivities. Each of these is discussed in more detail throughout my testimony.

- **Company Base Portfolio (MG20):** This portfolio reflects the Company's proposed resource plan as presented in the MG20 case. It aligns with the Company's assumptions for fuel prices, CO_2 prices, and load growth. It serves as the benchmark against which alternative portfolios were evaluated.
- **No Load Forecast Scenario:** This scenario removes the incremental large loads from the Company's load forecast, effectively reverting to a reference case to isolate the impact on portfolio additions, cost, and emissions attributed to large loads. Given the reduced load levels, coal plant retirements were accelerated, and new resource additions were scaled back to meet reserve margin requirements consistent with the lower forecast.
- **50% Large Load Forecast Scenario:** In this case, only half of the projected large load additions were removed from the forecast. Like the No Load Forecast scenario, coal plant retirements were accelerated, and new capacity additions were adjusted downward to reflect the resulting lower reserve margin need.
- **High Solar and Storage Portfolio:** This portfolio increases the planned annual buildout of solar resources by 50% across the planning horizon. To complement the higher solar penetration, 0.5 MW of 4-hour battery storage was added for every 1 MW of solar PV. To meet the planning reserve margin requirement, new gas capacity was reduced accordingly.

- **Combined Scenario:** This scenario combines the 50% Large Load Forecast and the High Solar and Storage Portfolio in a single scenario. It is intended to reflect a more balanced and forward-looking resource strategy that captures the benefits of multiple enhancements simultaneously.

These portfolios were tested under reference assumptions, as well as in sensitivity cases. Sensitivity cases did not adjust the capacity of the underlying portfolios, but post-processed the NPV of the portfolios with different cost assumptions. The two sensitivities were:

- **High CT/CC Costs:** This sensitivity increased the revenue requirements of combustion turbines and combined cycle technologies to reflect observed pricing increases due to increased demand and supply chain constraints. A 150% and 200% scalar was applied to the Company's revenue requirements for the five-year period from 2026-2031.
- **IRA Bonus Credits:** This sensitivity included a 10% bonus credit applied to battery energy storage systems to reflect the potential of the 10% Energy Communities Tax Credit Bonus.

Table 2. Matrix of Scenarios and Sensitivities

	Reference Assumptions	**High CT/CC Costs**	**IRA Bonus Credits**
Company Reference Portfolio (MG20)			
No Large Load Forecast			
50% Large Load Forecast			
High Solar and Storage Portfolio			
Combined Scenario			

Q WHY DID YOU SELECT MG20 AS THE REFERENCE PORTFOLIO TO COMPARE AGAINST?

A Based on my review of the IRP, it does not appear that the Company selected a single preferred portfolio for resource planning purposes. However, the Company uses the 111-MG0 scenario as its base case, which functions as a reference point throughout the Company's analysis.[6] That scenario assumes compliance with EPA's recently finalized Section 111 greenhouse gas rules.

I selected the MG20 portfolio as the primary basis for comparison. The MG20 scenario serves as a reasonable proxy for potential future environmental regulations whether the Section 111 greenhouse gas rules remain in effect over the planning period or not. The MG20 scenario shares many similarities with 111-MG0 in terms of overall resource buildout but replaces the regulatory mandate with a modeled carbon price of $20 per metric ton, increasing over the planning horizon. While there is also uncertainty surrounding the future implementation of carbon pricing, I believe that a gradually escalating CO_2 price serves as a reasonable and transparent proxy for the likelihood of future environmental regulation. It provides a policy-neutral mechanism to reflect the potential cost of carbon while still allowing for flexibility in planning assumptions.

[6] Direct Testimony of Jeffrey R. Grubb, J. Randy Hubbert, M. Brandon Looney, Michael B. Robinson, and Francisco Valle on behalf of Georgia Power Company, Docket Nos. 56002 & 56003 at 25.

Q HOW IS YOUR MODELING AND ANALYSIS USED THROUGHOUT YOUR TESTIMONY?

A Each of the scenarios was developed to test the implications of specific planning decisions and assumptions on system operations, costs, emissions, and reliability. They are discussed in greater detail in the corresponding sections of my testimony. In Section VIII, I present the combined scenario results to help summarize my findings.

IV. LOAD FORECAST UNCERTAINTY AND LARGE LOADS

The Company is understating load forecast uncertainty, especially for large loads

Q DID YOU REVIEW THE COMPANY'S LOAD FORECASTS, AND IF SO, WHAT WERE YOUR REACTIONS?

A Yes, I reviewed the Company's load forecasts as presented in the 2025 Integrated Resource Plan, and I had two principal reactions.

First, the Company is projecting significant load growth over the planning horizon. Specifically, peak demand is forecasted to increase from 17.8 GW in 2025 to 26.6 GW by the end of 2031. This represents nearly a 50% increase in peak demand over a seven-year period. This growth rate stands in sharp contrast to the Company's historical growth rates over the last several years. In my view, this is an unprecedented shift—not only for the Company, but across the utility industry more broadly.

However, my second and equally important observation is that much of this projected load growth is highly speculative at this stage. This is especially true for large industrial and data center loads ("Large Loads") which represent around 7 GW of the forecasted increase in peak demand by 2031. While it is appropriate for the Company to anticipate and plan for new sources of demand, it is critical to recognize that much of the growth embedded in the forecast lacks formal commitments or verified timelines for interconnection. Therefore, the likelihood and timing of these loads materializing remains uncertain.

The results and conclusions in the Company's IRP modeling are fundamentally dependent on the load forecast. A higher load forecast, particularly for winter peak demand, directly translates into delayed coal retirements and additional need for new capacity resources - namely medium-duration energy storage and natural gas capacity. In effect, the magnitude and composition of forecasted demand drives the resource selection outcomes, making it, in my opinion, the single most important assumption in the entire planning process.

Q IS THIS PHENOMENON UNIQUE TO THE COMPANY?

A No, the magnitude and nature of the projected load growth presented by the Company is not unique. Utilities across the country are forecasting similar increases in demand, driven by many of the same factors such as data centers, advanced manufacturing, and emerging industrial loads.

However, while the phenomenon is widespread, so too are the uncertainties that accompany it. Across jurisdictions, there is growing concern about the speculative nature of these large

new loads—particularly those tied to economic development initiatives, nascent industries, or early-stage interconnection requests. In many cases, utilities are planning around prospective load growth that lacks firm customer commitments or clear timelines for materialization.

Q DID THE COMPANY ADEQUATELY MODEL THIS UNCERTAINTY IN THE IRP?

A No, the Company did not adequately model load forecast uncertainty in its 2025 IRP. The Company describes the use of a probabilistic model, stating that "the load realization model utilizes a probabilistic approach to evaluate the range and likelihood of future potential outcomes of the load growth from large new customers. The results from this model support the external adjustment applied to the baseline Commercial and Industrial load and energy forecasts."[7]

However, this analytical approach was not meaningfully reflected in the portfolios used for capacity expansion modeling which all used essentially the same forecast, only adjusting the load forecast due to higher future prices of natural gas in Figure 1.[8] Given the amount of uncertainty inherent in the load forecast, particularly for data center demand, it is critical to evaluate a wide range of scenarios. Of the nine portfolios evaluated by the Company, only two included a variation labeled as "Standard w/ HG0 delta," and even in those cases, the difference in forecasted demand was *de minimis*.

[7] 2025 IRP Main Document at 137.
[8] 2025 IRP Main Document at 23.

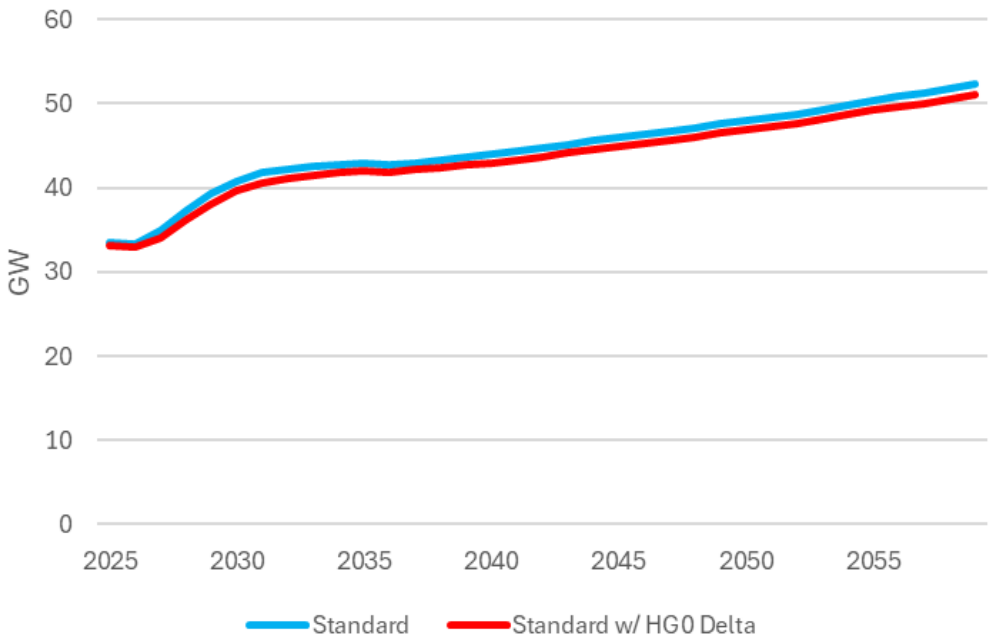

Figure 1. System Winter Peak Load[9]

In practice, the actual load forecasts used in the capacity expansion modeling were nearly identical across all scenarios. While the IRP includes sensitivities on gas prices, carbon prices, technology cost trajectories, and environmental compliance pathways under Section 111, it includes virtually no meaningful sensitivity analysis on load uncertainty, despite the Company's own acknowledgement of the unprecedented scale and volatility associated with large new commercial and industrial load additions.

The Company is facing unprecedented load growth in a short period of time, based on new industries and artificial intelligence that has never been seen historically or in other regions.

[9] 2025 IRP Main Document at 24.

And yet it offers no sensitivity analysis to evaluate different load trajectories. As a result, the modeling fails to capture the risks associated with potential overbuilding or underbuilding in the face of uncertain large load realization.

Q IF THERE IS A RISK OF ANNOUNCED LOADS NOT MATERIALIZING OR COMING ONLINE AT SLOWER OR LOWER LEVELS, HOW MIGHT THIS AFFECT THE COMPANY'S CUSTOMERS?

A The uncertainty surrounding the Company's load forecast has direct and significant implications for its customers. If the projected load does not materialize as expected, the result could be higher rates for existing customers.

This is because the Company may move forward with the procurement and construction of new resources that ultimately prove unnecessary. These resources, if built in anticipation of growth that does not occur, may see limited utilization and contribute little to system reliability or energy needs. Yet, customers would still be required to cover the fixed costs of these assets through rates.

Q ARE YOU IDENTIFYING A RISK THAT ASSETS COULD BECOME STRANDED IF THEY ARE BUILT FOR SPECULATIVE LOAD THAT DOES NOT ULTIMATELY MATERIALIZE?

A Yes. In effect, GPC's limited load forecast scenario approach creates a stranded asset risk. Ratepayers would be on the hook for infrastructure that was premised on speculative demand and may sit idle for much of their operational life. This outcome is particularly concerning

given the scale of capacity additions proposed in the IRP and the high proportion of load growth attributed to uncommitted large customers.

Q WHAT IF THE LOAD EVENTUALLY MATERIALIZES, BUT AT A SLOWER RATE OR LATER DATE?

A Even if the forecasted load ultimately materializes, a slower realization will not justify the Company proactively building resources far in advance. There are several reasons for this. First, rapid advancements in AI development and chip efficiency could significantly alter the long-term demand trajectory, making early infrastructure investments premature. Second, current supply chain constraints are elevating capital costs for new resources, meaning early procurement could lock in unnecessarily high costs. Finally, due to discounting in NPV analysis, costs incurred earlier in the IRP horizon have a disproportionate impact on total system cost, increasing the financial risk of early overbuild.

Q IS THE COMPANY DOING ENOUGH TO PROTECT CUSTOMERS AGAINST THE UNCERTAINTY WITH LARGE LOAD GROWTH?

A No, they are not, but there are ways to mitigate this risk. The first mechanism to protect customers is to avoid speculative load interconnection requests. It is my opinion that a large portion of the large load interconnection requests across the country are redundant or speculative. Now that access to transmission infrastructure has become one of the primary constraints on data center siting, developers are increasingly entering interconnection queues in multiple regions to secure optionality—even in the absence of site-specific development

plans or firm commercial commitments. This behavior is analogous to the interconnection queue congestion that has long affected renewable energy developers. As with generation queues, the accumulation of speculative load interconnection requests contributes to inefficiencies, delays, and distortions in system planning.

Q HAS THE COMPANY ACKNOWLEDGED THE POSSIBILITY THAT LARGE CUSTOMERS ARE MAKING MULTIPLE INTERCONNECTION REQUESTS TO DIFFERENT UTILITIES FOR THE SAME LOAD?

A Yes. The Company explicitly acknowledges this possibility. It states that large load "[c]ustomers often evaluate sites in multiple states before finalizing the location of a project."[10] Furthermore, the Company notes that "[a] customer may ultimately end up choosing a different state as the location of a project despite initial indications of interest in Georgia."[11]

The Company also recognizes competition within the state, adding that "there is still uncertainty due to the competitive nature of the bidding process for large load customers among electric service providers in the state, and a customer may choose an electric service provider other than Georgia Power."[12]

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[10] Ga. Power Co., 2025 IRP Technical Appendix Volume 1, Load and Energy Forecast, B2025 Load and Energy Forecast at 104.
[11] *Id.* at 103.
[12] *Id.*

This admission highlights the speculative nature of some large load interconnection requests. While the Company incorporated this uncertainty into its Load Realization Model used to inform adjustments to its organic forecast, the Company has missed an opportunity to have this uncertainty inform a robust set of large load realization alternatives in its Resource Mix Study.

Q ARE YOU SUGGESTING THAT THE COMPANY NOT SERVE NEW LARGE LOAD CUSTOMERS?

A No, I am not suggesting that the Company refuse to serve new large load customers or not prepare for their additions. Rather, I recommend that the Company better isolate the impacts of these loads on its modeling so that it can plan more effectively under conditions of uncertainty. This includes applying a wider range of load growth scenarios to assess risk and ensure the system remains reliable and cost-effective under different outcomes. Importantly, it also ensures that existing customers are not unfairly burdened with the costs of new capacity, transmission upgrades, or the increased emissions and potential reductions in resource adequacy that may result from speculative or unconfirmed large loads.

The Company should isolate the impacts of resource additions, costs, and emissions attributed to large load growth

Q CAN YOU EXPLAIN MODELING THAT THE COMPANY SHOULD HAVE CONDUCTED TO IMPROVE COST ISOLATION FOR LARGE LOADS?

A To improve cost isolation and better assess the risks associated with large load additions, the Company should have evaluated a broader and more comprehensive range of load scenarios. Specifically, the IRP would have benefited from modeling that explicitly isolates the impact of large new loads on resource portfolio decisions, system costs, and emissions outcomes.

At a minimum, the Company should have included a scenario that excludes all large new loads. Such a scenario would serve as a critical reference point—allowing for a clear comparison between a baseline system trajectory and the incremental impacts of large load growth. This would provide valuable insight into the extent to which new resource investments, particularly long-lived thermal capacity, are driven by these uncertain loads and the potential for stranded asset risk if those loads do not materialize as projected.

Furthermore, rather than relying on a narrow and largely immaterial sensitivity ("Standard w/HG0 Delta"), the Company should have conducted a comprehensive bookend analysis that captures a wider range of plausible load outcomes. This would include both low and high realization scenarios, based on the probabilistic load realization modeling referenced in the IRP. Such an approach would better reflect the inherent uncertainty surrounding large

commercial and industrial customers and provide a more robust foundation for resource planning decisions.

Q WERE OTHER SCENARIOS CONTEMPLATED BY THE COMPANY?

A Yes, alternative scenarios were contemplated by the Company as directed by the Commission. However, the Company chose not to develop scenarios that would have characterized the portfolio composition, costs, or emissions of alternative loads. According to the Company, "[t]he High Economic Growth, Low Economic Growth, No Load Growth, and Load Growth using a 20-year normal definition of weather, as stipulated in the 2019 IRP, were not modeled in Aurora. These load forecasts were developed for the Load & Energy Forecast pursuant to Commission Rule 515-3-4-.03 Energy and Demand Forecasting Requirements in the Commission's rules and regulations. This rule requires the Company to produce load forecast sensitivities for each of these forecasts but does not require the Company to run each of them through the resource mix process."[13]

Q DID YOUR MODELING AND ANALYSIS ADDRESS THIS CONCERN?

A Yes. My analysis directly addressed this concern by developing and evaluating two alternative load forecasts to illustrate how a bookend approach to large load uncertainty could be effectively conducted. These forecasts were used to construct and simulate resource

[13] Company response to STF-JKA-2-32 (a) at 2.

portfolios that reflect both the inclusion and exclusion of large new loads, thereby isolating the impact of those loads on system costs, emissions, and resource decisions.

Q WHAT ALTERNATIVE LOAD FORECASTS DID YOU CONSIDER?

A I developed two alternative load forecasts to evaluate the system impacts and planning implications of uncertainty surrounding large commercial and industrial loads. These forecasts are referred to as the "No Large Loads" forecast and the "50% Large Load Forecast."

I inferred the likely contribution of these large loads by analyzing the pronounced increase in system demand between 2026 and 2031—a growth pattern not observed in prior IRPs. Based on this timing and magnitude, I concluded that most of the increase is likely attributable to anticipated data center development and similar large load additions.

To estimate a "No Large Loads" forecast, I assumed that load growth between 2026 and 2031 followed the same compound annual growth rate (CAGR) of 1.07% that the Company applied in the more stable 2032–2040 period. This adjustment effectively removes the anomalous increase attributed to large loads. Beyond 2032, my forecast adopted the same annual growth rates as the Company's base load forecast.

The difference between the Company's Base Load Forecast and the adjusted "No Large Loads" forecast serves as an estimate of the inferred incremental data center demand, which grows from approximately 454 MW in 2026 to 7,137 MW by 2031. To convert this to annual

energy values, I applied a load factor of 90%, consistent with the high utilization characteristics typical of data centers.

The "50% Large Load Forecast" scenario assumes that only half of this inferred demand materializes over the planning horizon. The results of this analysis are presented in Figure 2. Together, these two alternative forecasts provide a useful bookend analysis that allows for a more transparent evaluation of the resource needs, cost impacts, and potential risks associated with large load uncertainty.

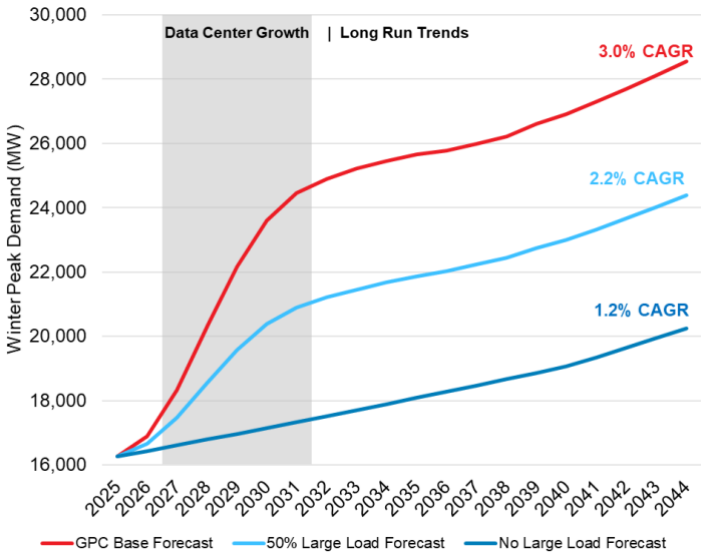

Figure 2. Alternative Demand Forecasts, Winter Peak (MW)

Q DO YOU KNOW OF OTHER UTILITIES IN SIMILAR SITUATIONS WITH ANTICIPATED LARGE LOAD GROWTH THAT HAVE TAKEN A SIMILAR APPROACH TO ANALYZING A WIDE RANGE OF LOAD GROWTH SCENARIOS?

A Yes. The Public Service of Colorado recently completed its 2024 Just Transition Solicitation. In that analysis, three load scenarios were evaluated, including a "Base" forecast, a "Low Load" forecast, and a "Lower Low Load" forecast. In these examples, the peak demand CAGR from 2023 was 4% in the Base forecast, 1.1% in the Low forecast, and 0.7% in the Lower Low forecast.[14] In other words they presented an even wider range of potential future load forecasts than the analysis I conducted.

Q HOW DID YOU ADJUST THE CAPACITY ADDITIONS WITH THE LOWER FORECAST?

A In developing alternative portfolios under the lower load forecasts, I adjusted the capacity additions from the Company's MG20 portfolio to ensure the system continued to meet the reserve margin requirements associated with the reduced demand outlook. My objective was to maintain consistency with the Company's overall planning framework while making incremental, targeted adjustments that reflected the lower system need.

[14] Colorado Public Utilities Commission, Proceeding No. 24A-0042E, 2024 Just Transition Solicitation, Hearing Exhibit 114, Supplemental Direct Testimony of John M. Goodenough at 9.

To do so, I retained most the Company's proposed capacity additions, particularly those outside of Georgia Power's service territory, and focused changes on the timing and scale of new in-state resources. Specifically, I made the following adjustments:

- Accelerated the retirement of Bowen and Scherer coal units to the end of 2031, moving them forward from the Company's proposed retirement date at the end of 2035.[15]
- Deferred new natural gas builds until such time as the reserve margin became binding under the lower load forecast.
- Reduced battery storage additions to 50% of the incremental solar capacity until reserve margin needs became binding.
- Once the reserve margin was binding, I maintained the Company's battery storage forecast and reduced new gas capacity additions to the level necessary to meet the remaining capacity need.
- Throughout, I preserved the same ratio of combined cycle to simple cycle gas turbines as proposed by the Company in its MG20 portfolio, ensuring consistency in technology mix and operational flexibility.

[15] For reference, the 2022 IRP assumed a 12/31/2027 retirement date of Bowen Units 1-2 and a 12/31/2028 retirement date for Plan Gaston Units 1-4 and Scherer Unit 3. *See* Ga. Power Co., 2023 Integrated Resource Plan Update (Docket No. 55378).

- Other resource additions proposed by the Company in the MG20 portfolio, including battery storage after 2031, solar, wind, medium duration storage, and nuclear remain unchanged.

Q WHY DID YOU CHOOSE TO ACCELERATE COAL RETIREMENTS RATHER THAN DEFER NEW GAS BUILDS?

A Under scenarios with lower load forecasts, the Company's MG20 resource portfolio becomes oversized relative to the reserve margin requirement. In these cases, there are two primary ways to rebalance the portfolio: defer new gas additions or accelerate coal retirements.

My approach prioritized accelerating coal retirements—specifically targeting retirements by the end of 2031—before deferring gas builds. This sequencing provides greater planning optionality. By preparing for earlier coal retirements, the Company can reduce reliance on older, less flexible, and higher-emitting generation. At the same time, if load materializes more quickly than expected or if clean energy deployment is delayed, the Company retains the flexibility to extend the operation of these coal units temporarily, allowing time for new resources to come online.

Q WHAT INFORMATION DOES THIS MODELING PROVIDE?

A The purpose of this modeling, particularly the "No Large Load" scenario, is not to predict the most likely future trajectory of GPC. Rather, the intent is to isolate the incremental impacts—on portfolio composition, costs, and emissions—associated with the inclusion of large, uncertain loads in the Company's planning process. By comparing the alternative load

scenarios to the Company's base forecast, this analysis provides valuable information, including:

- **Incremental resource builds**, both in terms of capacity (MW) and energy (MWh), that are required solely to serve the projected large loads.
- **Incremental system costs**, which reflect the net present value of additional generation investments, operating costs, and fuel expenses attributable to large load additions.
- **Incremental emissions impacts,** offering a more transparent view of how large load growth affects the Company's total emissions trajectory, namely CO_2.

Q WHAT WAS THE RESULT OF THE PORTFOLIO RESOURCE BUILDS?

A The results of my analysis, provided in Figure 3 of my testimony, clearly demonstrate the significant influence that large load additions, particularly data center-driven demand, in the Company's service territory have on resource development decisions.

Even with the accelerated retirement of the Bowen and Scherer coal units to the end of 2031, my modeling shows that no new natural gas capacity is required until 2032 in the No Large Loads case, assuming all other assumptions from the Company's MG20 portfolio are held constant. Moreover, the total cumulative natural gas built by 2035 is substantially reduced under the alternative load forecasts (Figure 4):

- In the Company's MG20 portfolio, cumulative new gas capacity reaches approximately 11,400 MW by 2035.

- Under the "50% Large Load Forecast," this figure falls to 7,850 MW.
- Under the "No Large Load Forecast," it is reduced further to just 2,050 MW.

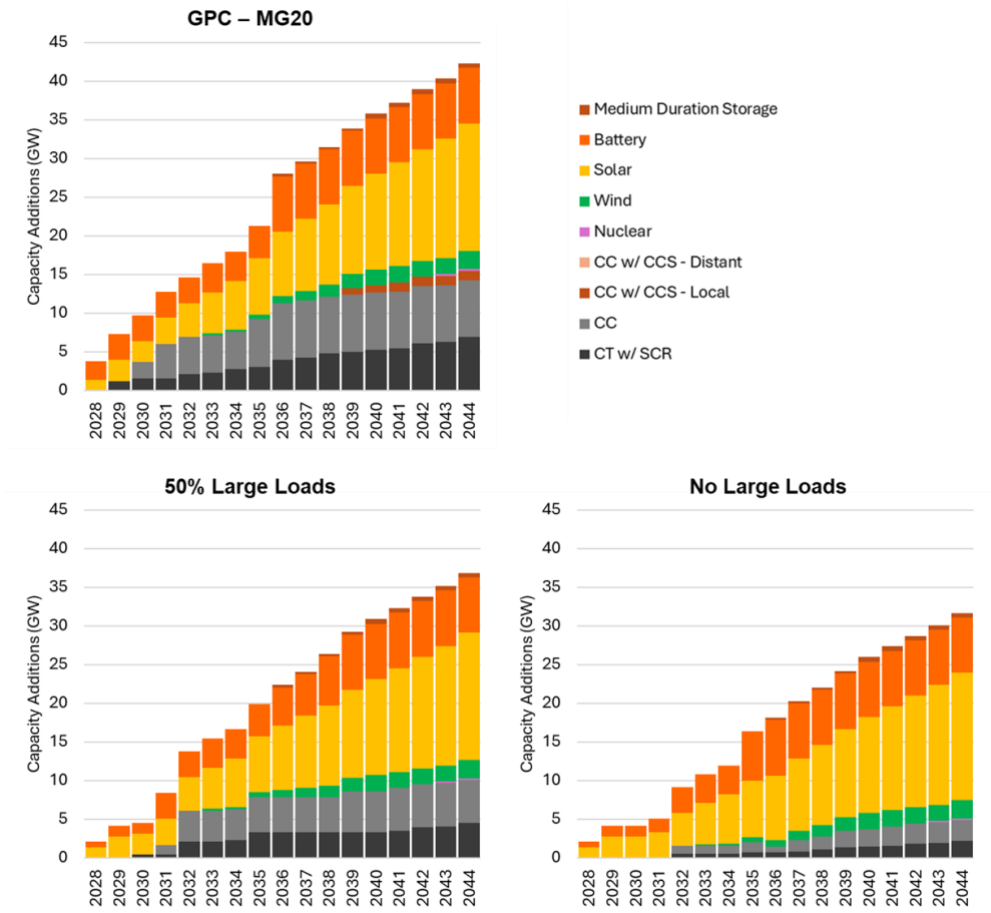

Figure 3. Cumulative Capacity Builds to 2044 by Resource Type, by Load Scenario

Note: the lower loads scenarios also assume accelerated retirement of Bowen and Scherer coal plants

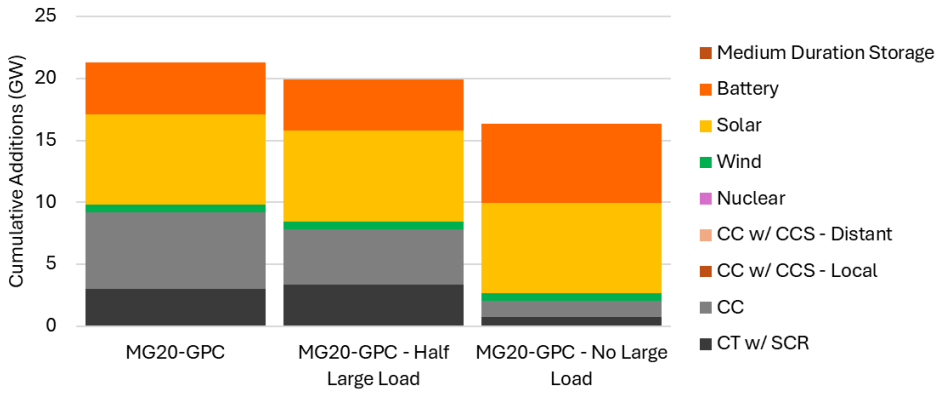

Figure 4. Scenario Comparison, Cumulative Capacity by 2035

Note: the lower loads scenarios also assume accelerated retirement of Bowen and Scherer coal plants

These results indicate that the inclusion of large, uncertain data center load in the Company's planning process is directly responsible for delaying coal retirements to 2036 and prompting up to 9,350 MW of new gas capacity additions. This finding underscores the importance of isolating large load impacts to ensure that long-term infrastructure investments are aligned with actual, realizable system needs and to minimize the risk of overbuilding and stranded assets.

Q WHAT WAS THE RESULT OF THE INCREMENTAL COST OF SERVING LARGE LOADS?

A To assess the cost implications of large new loads, each of the alternative portfolios was evaluated using a full chronological 8,760-hour per year production cost model from 2026-2044. This approach ensured that the portfolios maintained operational reliability and provided accurate estimates of fuel usage, emissions, and other system production costs. In addition, the analysis incorporated the Company's own assumptions for carbon pricing under

the MG20 CO_2 scenario, as well as the Company's stated capital cost assumptions for new resource additions, expressed in $/MW-week.

This allowed for a consistent and transparent comparison of system-level NPV across different load scenarios. The results show that the inclusion of large data center loads result in an incremental cost of [redacted] billion dollars NPV. Removing these loads from the Company's forecast results in approximately a 41% reduction in the total system cost under its MG20 portfolio (Table 3).

Table 3. 20-year NPV Comparison by Large Load Scenario

Scenario	NPV ($M)	Change in NPV ($M)	Change in NPV (%)
MG20-GPC	[redacted]	-	-
Half Large Load	[redacted]	[redacted]	-22%
No Large Load	[redacted]	[redacted]	-41%

This cost differential reflects the significant investment required to serve large, uncertain loads and includes investments that include accelerated gas capacity additions, deferred coal retirements, and higher fuel and operating costs. These findings highlight the importance of isolating and scrutinizing large load assumptions in the planning process to avoid overbuilding and to ensure cost-effective, ratepayer-aligned resource decisions.

Q WHAT WERE THE INCREMENTAL EMISSIONS IMPACTS OF LARGE LOADS?

A The emissions impacts of large new loads were also evaluated across the alternative load scenarios. As shown in Figure 5, I calculated the difference in cumulative CO_2 emissions

between the base forecast and the alternative forecasts under a consistent set of assumptions. The results show that:

- In the Company's MG20 portfolio, cumulative system-wide CO_2 emissions reach over 1,800 million tons (MT) by 2044.
- Under the "50% Large Load Forecast," this figure falls 14% to 1,573 MT.
- Under the "No Large Load Forecast," it is reduced further to just 1,334 MT, representing a 27% reduction in cumulative emissions.

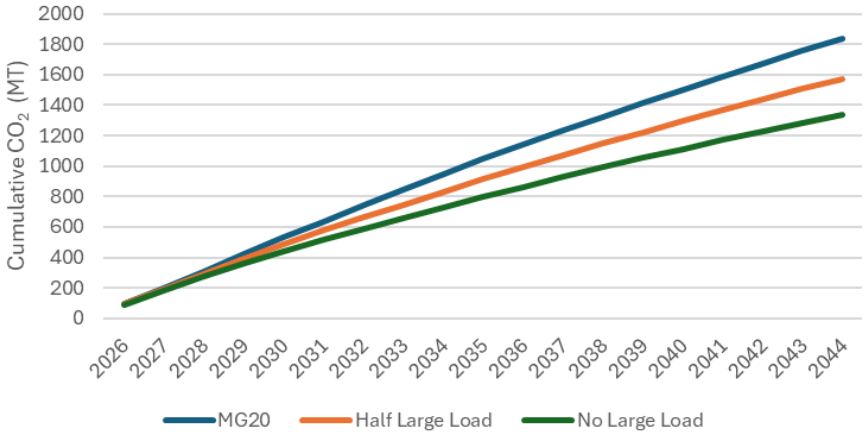

Figure 5. Cumulative, System Wide, CO2 Emissions by Load Scenario

The results indicate that the inclusion of large data center loads (absent other changes to the resource portfolio) would be responsible for a significant increase in carbon emissions over the Company's planning horizon and directly inhibit Southern Company's pathway to meet its net zero by 2050 goal. This includes both the absolute volume of additional emissions and the emissions intensity associated with serving these loads.

Q WHAT ARE THE BENEFITS OF ISOLATING LARGE LOAD GROWTH IN THIS WAY?

A The results of this comparative analysis have three important implications:

1. **Transparency** – They provide stakeholders and the Commission with clearer information about how much of the system buildout is being driven specifically by large load additions.
2. **Accountability** – They enable better tracking of the emissions associated with large loads and informs whether those customers should bear associated environmental and system costs.
3. **Cost Allocation** – They offer a sound analytical basis for developing new rate structures or interconnection terms that ensure large loads are paying their fair share of the infrastructure required to serve them.

The Company does not have appropriate rate structures in place to protect existing customers from large load growth and uncertainty

Q WHAT ARE YOUR CONCERNS ABOUT THE COMPANY'S LACK OF CUSTOMER PROTECTIONS REGARDING THE RESOURCES ADDED TO SERVE NEW LARGE LOADS?

A While new large load customers that request to interconnect to the Company's distribution or transmission system are required to pay for local upgrades, the same is not true for other system needs. Currently, I am unaware of any financial mechanism to protect customers

against the potential stranded asset risk that could arise if the Company makes resource investments or bulk transmission system upgrades to serve new large loads that may not materialize or may interconnect slower than anticipated.

Q WHAT IS THE RISK OF THE COMPANY'S CURRENT POLICIES?

A In a worst-case scenario, the Company could overbuild its system based on optimistic assumptions about load growth and then be forced to recover those costs from a smaller-than-expected customer base. This is precisely the kind of misalignment that prudent resource planning seeks to avoid.

Q WHAT STEPS SHOULD THE COMPANY AND THE COMMISSION CONSIDER TO PROTECT EXISTING CUSTOMERS FROM THE FINANCIAL RISKS OF NEW SPECULATIVE LARGE LOADS?

A While rate design itself is not necessarily within the scope of the IRP, the Company's investment decisions arising from this IRP will carry significant long-term costs. These costs must ultimately be allocated across customers, making it essential that the Commission and the Company consider how strategic directions from the IRP will have downstream impacts on rates.

The IRP, as filed, does not provide sufficient strategic direction or transparency in how the costs associated with serving large new loads will be isolated or managed relative to the costs borne by existing customers. Without additional planning or procurement mechanisms in place, existing customers could be exposed to significant financial risk if large loads fail to

materialize, develop more slowly than expected, or require different infrastructure than originally anticipated.

To mitigate these risks, the Company and Commission should prioritize procurement strategies that retain flexibility, limit large upfront commitments, and ensure that capital investments for speculative loads are more directly tied to those customers and when growth is more certain. One example of such a strategy is the Pre-Construction Development Asset (PCDA) model adopted by Xcel Energy Colorado. Under this approach, bidders can select into the PCDA process to advance to a "shovel-ready" state and access early-stage development funding at a lower cost to customers. Importantly, these projects are not committed for full construction unless qualifying events occur.[16]

For Georgia, these qualifying events could be more firm commitments as load realization goes from speculative to firm. They could also be used to hedge existing bids dropping out due to challenges with long-lead times and rising costs for equipment due to supply chain constraints. This structure helps preserve optionality and shorten future lead times, both of which will be important aspects of the Company's strategic approach to serving future data center demand without locking in costs for load that may not materialize.

[16] Colorado Public Utilities Commission, Proceeding No. 21A-0141E, Xcel Energy Colorado, Appendix G: PCDA Process, available at: https://www.xcelenergy.com/staticfiles/xe-responsive/Company/Rates%20&%20Regulations/Appendix%20G%20-%20PCDA%20Process%20(1).pdf.

There may be other models to consider, but the end goal should be a procurement strategy that shares a common goal of better aligning resource procurement with load realization while protecting existing ratepayers from cost associated with speculative investments. As the Commission considers the approval of significant amounts of new resources directly as a result of large loads, it is essential that the Company provide greater transparency on the total costs attributable to these loads and to explore resource procurement structures that mitigate stranded asset risks and protect all customers, not just the largest ones.

Q ARE OTHER UTILITIES CONSIDERING THESE OPTIONS?

A Yes. There are several utilities across the country implementing new or revised rate structures for large loads. They face similar challenges around how to manage the unprecedented levels of growth and the high level of uncertainty around load growth driven overwhelmingly by one type of demand, data centers. To this end, other regions have begun exploring innovative approaches like the one I described above. The following list, compiled from Lawrence Berkeley National Laboratory[17] and Energy Futures Group,[18] provides examples for further review by the Company and the Commission.

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[17] Andrew Satchwell et al., *Electricity Rate Designs for Large Loads: Evolving Practices and Opportunities*, Lawrence Berkeley National Laboratory (Jan. 2025), available at: https://eta-publications.lbl.gov/sites/default/files/2025-01/electricity_rate_designs_for_large_loads_evolving_practices_and_opportunities_final.pdf

[18] Stacy Sherwood, *Review of Large Load Tariffs to Identify Safeguards and Protections for Existing Ratepayer,*. Energy Futures Group, on behalf of EarthJustice (Jan. 28, 2025), available at: https://energyfuturesgroup.com/wp-content/uploads/2025/01/Review-of-Large-Load-Tariffs-to-Identify-Safeguards-and-Protections-for-Existing-Ratepayers-Report-Final.pdf.

Table 4. Regulatory Status of Large Load Tariff Examples

Source: Lawrence Berkeley National Laboratory and Energy Futures Group

Utility	Tariff	PUC Case Number	Regulatory Status (as of 1/1/2025)
Idaho Power	Brisbie Energy Services Agreement	IPC-E-21-42	Approved
Montana-Dakota Utilities	High Density Contracted Demand Response	PU-22-337	Approved
Ohio Power	New Tariffs Related to Data Centers	24-508-EL-ATA	Pending approval
NV Energy	Callisto Energy Supply Agreement	24-06014	Approved
NV Energy	Clean Transition Tariff	24-05022	Pending approval
Xcel Energy Minnesota	Google Electric Service Agreement	19-39	Approved
Black Hills Energy	Large Power Contract Service Tariff	20003-146-ET-15	Approved
Duke Energy Indiana	Special Agreements with Blocke LLC	45975	Approved
Portland General Electric	Voluntary Renewable Energy Tariff	UM 1953	Approved
Indiana Michigan Power	Industrial Power Tariff	46097	Pending approval
Entergy Mississippi	Large Power Rate	2014-UN-132	Approved
Xcel Energy Colorado	Pre-Construction Development Asset (PCDA)	C22-0559	Approved
NIPSCO	NIPSCO GenCo to serve megaload customers	Cause No. 46183	Pending

Evaluating large load flexibility could have similar reductions in resource additions and cost but was not evaluated by the Company.

Q DID THE COMPANY EVALUATE THE POTENTIAL OPPORTUNITIES THAT COULD BE REALIZED BY LOAD FLEXIBILITY OF LARGE LOADS?

A No. The Company did not evaluate or model the potential opportunities associated with load flexibility from large customers. In the Load and Energy Forecast, the Reserve Margin Study, and the Resource Mix Study, large loads were treated as firm, inflexible sources of demand. The Company states that the "high load factors and historical usage for similar [large load] customers already operating in Georgia" to justify its decision not to model large load flexibility opportunities.[19] However, the Company's decision to exclude large load flexibility due to historical operational behavior is misguided, given growing industry interest around flexible operations, and opportunities to incentivize flexibility such as innovative tariff structures that I will discuss below.

Q COULD LARGE LOAD FLEXIBILITY MITIGATE SOME OF THE UNCERTAINTY RISKS?

A Potentially, yes. This is a missed opportunity. Load flexibility from large loads could serve as a powerful tool to help mitigate system impacts and reduce the need for additional firm capacity. Allowing some degree of dispatchable or interruptible behavior from large loads

[19] Company response to Staff discovery request STF-PIA-5-4.

could reduce the Company's Target Reserve Margin (TRM) requirement and the associated cost of new firm resource additions, especially natural gas capacity.

It is unclear to what extent these large customers will be responsive to time-varying rates or demand response programs, given the capital-intensive nature of their operations and their likely preference for high utilization with limited or no price sensitivity. However, there are mechanisms the Company could explore. For example, a new tariff structure could be developed that grants accelerated interconnection in exchange for a limited degree of operational flexibility. Even a modest level of curtailment—such as 20-40 hours per year—could have significant system value and reduce the need for peaking capacity.[20]

In addition, allowing large loads to integrate onsite backup generation or energy storage, and using that as a capacity resource during tight system conditions, could further enhance flexibility without compromising customer operations.

The Company should refine both its modeling process in the IRP, and its rate structure, to quantify these potential benefits and create incentives (or requirements) to elicit this behavior.

[20] Tyler Norris et al., *Rethinking Load Growth: Assessing the Potential for Integration of Large Flexible Loads in US Power Systems*, Nicholas Institute for Energy, Environment & Sustainability, Duke University (Feb. 2025), available at: https://nicholasinstitute.duke.edu/publications/rethinking-load-growth.

Q GIVEN YOUR REVIEW AND DISCUSSION, WHAT ARE YOUR FINAL CONCLUSIONS RELATED TO THE LOAD FORECAST?

A To be clear, I am not arguing that the Company's load forecast is inherently wrong. Rather, my concern is that it does not sufficiently account for the deep uncertainty surrounding new large loads, nor does it adequately incorporate the necessary protections for existing customers or incentives for system flexibility.

Q WHAT DO YOU RECOMMEND THAT THE COMMISSION DO REGARDING LOAD FORECASTS AND NEW LARGE LOADS?

A Below is a list of recommendations for the Commission and the Company to make in this IRP.

- The Commission should require that the Company develop all-source resource procurement structures that mitigate potential upward rate pressures on existing customers due to the financial risks of speculative large loads.
- The Commission should require that the Company model a much wider and more realistic range of assumptions in the Resource Mix Study, including alternative large load realization scenarios.
- The Company should include a scenario that excludes all large new loads to isolate the costs, emissions, and resource decisions associated with speculative demand.

- The Commission should require that the Company run each requested load forecast sensitivity through the capacity expansion process, not just develop them for compliance with forecasting rules.
- The Company should evaluate options for large load flexibility, such as interruptible rates and onsite generation to reduce capacity needs.
- In the next IRP, the Company's Reserve Margin Study should evaluate potential reduction in the Target Reserve Margin that could be achieved with load flexibility from large loads.

V. VARIABLE RENEWABLE ENERGY AND BATTERY STORAGE ISSUES

The Company arbitrarily limited the amount of solar and wind added to the system which constrained the options available to meet rising load.

Q WHAT ARE YOUR CONCERNS REGARDING GPC'S ASSUMED BUILD LIMITS FOR SOLAR RESOURCES IN THE 2025 IRP?

A The Company continues to use unrealistic, unsupported constraints on solar, wind, and storage resources in its optimized Aurora modeling, specifically, limiting the annual build of solar resources to 1500 MW and wind resources to 300 MW per year across Georgia Power, Mississippi Power, and Alabama Power Companies. This is a critical assumption in the modeling as the additional wind and solar limit is hit every year from 2033 to 2044 in the

MG0, and every year from 2028-2029 and 2033 to 2044 in the MG20 portfolios.[21] In addition, the Company's Aurora files set the maximum builds for solar in [redacted] only. Absent this, it is very likely the solar build limits would have been reached in those years as well. similar constraints are seen across other portfolios. This makes any claims of an "optimized" capacity expansion meaningless, as the results are entirely driven by the Company's exogenous, arbitrary assumption limits on solar PV and wind that can be integrated in a single year.

The Company, at times, distances itself from its own analysis, stating that "[i]mportantly, generic expansion plans do not represent a resource planning decision by the Company, but rather, are indicative of what may be an economically optimal mix of resources within various scenarios."[22] But if the Company is simply evaluating economically optimal mixes of resources, why are they constraining the models most economic build decisions?

To be very clear, while the Company claims the IRP evaluated a wide range of resource candidates, they limited builds of clean energy technologies so there were no available options for the model to meet load growth and coal retirements without significant gas build.

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[21] Ga. Power Co., 2025 IRP Technical Appendix Volume 2, Resource Mix Study, workpaper "Capacity Expansion Plans - 2025 IRP.xlsx."
[22] 2025 IRP Main Document at 71.

Q IS GPC'S 1500 MW PER YEAR SOLAR LIMIT AND 300 MW PER YEAR WIND LIMIT REASONABLE?

A No, these limits are not reasonable, particularly given the purpose of modeling in an IRP. The objective of resource planning modeling is to use analysis to inform decision-making—not to constrain the analysis based on pre-determined decisions about what the utility considers reasonable or achievable. In this case, the Company is doing the opposite: it is embedding subjective decision-making assumptions into the model itself, thereby limiting the ability of the model to identify the least-cost or most prudent portfolio.

Furthermore, while GPC does not have extensive in-state wind development experience, this is not a justification for maintaining such restrictive limits. There are numerous viable opportunities to procure wind energy via interregional transmission from areas with strong wind resources. By overlooking this potential, the Company is failing to fully explore cost-effective and geographically diverse resource options that could enhance reliability and reduce costs for ratepayers. In fact, between the 2023 IRP Update and 2025 IRP, the Company reduced its annual maximum build limit for wind by 50%, and cumulative maximum build limit by 44%, and failed to provide justification for this change - despite being directly asked by Staff to directly provide a justification for any such changes in resource build limits.[23]

[23] Company response to Staff discovery request to STF-JKA-1-11.

Q WHAT DO YOU RECOMMEND FOR A BUILD LIMIT?

A At a minimum, I recommend that the Company include an unconstrained case—one in which annual build limits on solar, wind, and storage are removed entirely.[24] This would allow the model to freely select resources based on system need and relative cost-effectiveness, rather than being artificially limited by subjective judgments or assumed implementation barriers.

While an unconstrained case may produce a portfolio that could be challenging to implement in practice, the value of such an analysis is not in whether the outcome is immediately actionable, but in the insight it provides. It would allow the Commission and stakeholders to clearly see how the system would evolve if these resources were selected purely on cost and operational merit.

Moreover, I believe the results of such a case would reinforce what we see across the industry and in the Company's own modeling: that solar, wind, and battery storage are consistently among the least-regrets resources across a wide range of futures.

Q HOW DID YOU EVALUATE DIFFERENT BUILD LIMITS IN YOUR PORTFOLIO?

A To evaluate the impact of alternative build limits, I developed a scenario referred to as the "MG20 – High Solar" portfolio. In this scenario, I increased annual solar capacity additions by 50% relative to the Company's assumptions in the MG20 reference case. To ensure

[24] Capacity expansion models typically require a maximum units built in order to solve. In this case I would recommend increasing the constraint until it is no longer binding.

system reliability and capture the operational benefits of paired storage, I also added 0.5 MW of four-hour battery storage capacity for every 1 MW of incremental solar.

As expected, this higher rate of clean energy deployment resulted in a modest overshoot of the Company's target reserve margin in several years. To correct for this and maintain a balanced resource mix, I removed natural gas capacity from the plan until the reserve margin returned to target levels.

This scenario was not intended to serve as a final resource plan recommendation, but rather to quantify an illustrative example of increased solar capacity, absent the artificial annual build constraints imposed by the Company. It demonstrates the potential for clean energy resources to displace new gas capacity while still maintaining system reliability and resource adequacy.

Q HOW DID THOSE BUILD LIMITS CHANGE THE COMPOSITION OF THE OVERALL PORTFOLIO?

A The adjusted build limits in the "MG20 – High Solar" scenario resulted in a substantial shift in the composition of the overall resource portfolio, shown in Figure 6.

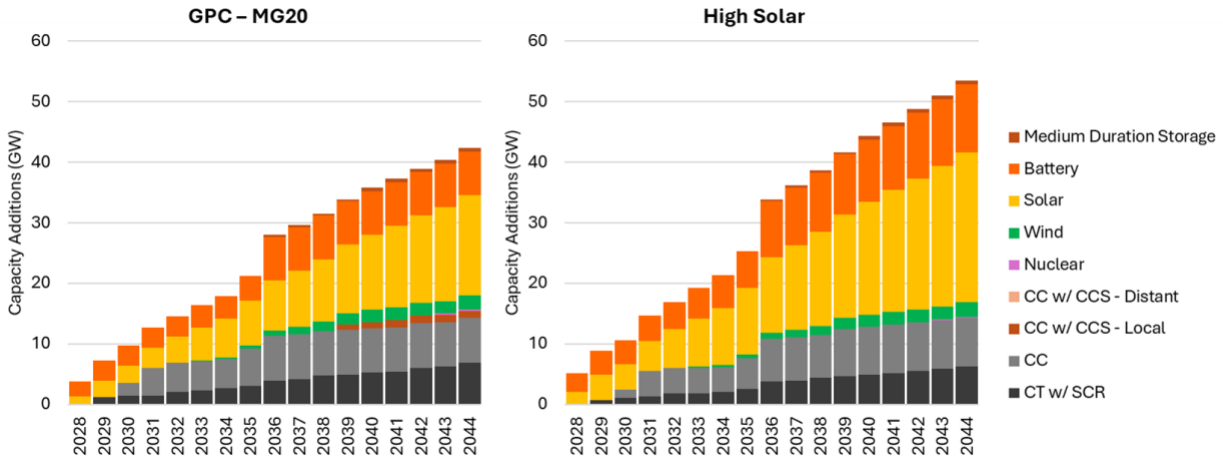

Figure 6. Cumulative Capacity Builds to 2044 by Resource Type with High Solar

Note: both scenarios assume end of 2035 retirement of Bowen and Scherer coal plants and the Company produced GPC - MG20 load forecast

By 2035, the portfolio included:

- 3.6 GW more solar capacity than the MG20 reference case,
- 1.8 GW more battery energy storage, and
- 1.5 GW less natural gas capacity.

By 2044, the impacts were even more pronounced. The portfolio reached:

- 24.7 GW of total solar capacity, representing an increase of 8.2 GW over the MG20 baseline,
- 11.3 GW of total battery storage, or 4.1 GW more than in MG20, and
- 1.1 GW less cumulative gas capacity.

These results underscore the capacity of solar and battery storage to meaningfully contribute to system reliability and energy needs when unconstrained by arbitrary build limits. The

findings also suggest that clean energy resources can significantly reduce reliance on new gas capacity while maintaining or enhancing reserve margin compliance.

Q WHAT DID YOU FIND BASED ON THOSE MODELING RUNS?

A The results of the "MG20 – High Solar" scenario were compelling. After significantly increasing the deployment of solar and battery storage resources, the NPV of GPC's total system costs was nearly identical to that of the MG20 reference case, with a slight cost savings observed in favor of the High Solar scenario. If carbon prices are removed, the "MG20 - High Solar" scenario results in almost identical NPV, just 0.07% higher. As discussed later, other factors such as higher gas capacity costs and IRA bonus tax credits available to the Company would swing the "MG20 - High Solar" portfolio to lower cost even without carbon prices.

Importantly, this scenario reflects a strategic trade-off: it replaces higher capital costs—costs that are known, fixed, and incurred upfront—with lower fuel and CO_2 costs, which are uncertain, variable, and carry long-term price risk. As such, the High Solar scenario acts as a hedge against future volatility in natural gas and CO_2 prices. It delivers long-term value to ratepayers by reducing exposure to these uncertain inputs while maintaining or improving cost performance.

The emissions benefits were also significant. The High Solar scenario resulted in 65 MT fewer CO_2 emissions (8.2%) attributable to the Company over the planning horizon

compared to the MG20 reference case. Total renewable energy generation increased to 29% in 2035 and 41% in 2044, compared to 23% and 33%, respectively, in the MG20 case.

Table 5. 20-year NPV Comparison of MG20 and High Solar and Storage Scenario

Scenario	NPV ($M)	Change in NPV ($M)	Change in NPV (%)
MG20-GPC	[redacted]	-	-
High Solar and Storage	[redacted]	[redacted]	-0.5%

Table 6. GPC Emissions Comparison of MG20 and High Solar and Storage Scenario

Scenario	Cumulative GPC Emissions (MT)	Change in Emissions (MT)	Change in Emissions (%)
MG20-GPC	798	-	-
High Solar and Storage	732	(65)	-8.2%

Taken together, these results demonstrate that a higher clean energy buildout can reduce emissions, mitigate financial risk, and offer comparable—if not lower—cost outcomes for customers. This strongly supports the inclusion of less restrictive or unconstrained clean energy build assumptions in future planning analyses.

The Company ignored possible bonus credits that could reduce capital costs of new wind, solar, and battery technologies by 10%

Q YOU HAVE MENTIONED MULTIPLE ISSUES WITH THE BUILD LIMITS AND CAPACITY CREDITS ASSIGNED TO SOLAR AND STORAGE. IN ADDITION TO THOSE ISSUES, DID THE COMPANY APPROPRIATELY CAPTURE THE FEDERAL SUBSIDIES AVAILABLE UNDER THE INFLATION REDUCTION ACT?

A No, the Company did not appropriately incorporate all opportunities and benefits associated with the IRA. According to the Company, "[a]dditional IRA bonuses for meeting the domestic content and the energy community provisions were not included for generic expansion units due to uncertainty regarding the ability to meet the requirements."[25]

The Energy Communities bonus credits provide a unique opportunity for the Company. If resources are sited in census tracts with retiring coal plants, for example, they are eligible for a 10% bonus credit to the investment tax credit (ITC) or an additional 0.26 cents/kWh production tax credit (PTC). This means that a resource located in a Designated Energy Community could increase its federal subsidy from 30% up to 40-50% of the upfront capital cost or receive an additional 20% PTC. This significantly changes the project economics of clean energy resources. Unfortunately, the Company implicitly assumed in their modeling

[25] Ga. Power Co., 2025 IRP Technical Appendix Volume 2, Resource Mix Study at 8.

that no projects could receive these bonus credits because exact siting is not known at this time.

Q ARE THERE ENERGY COMMUNITIES IN GEORGIA TODAY AND WHAT MIGHT THAT LOOK LIKE IN THE FUTURE?

A A map of the Southern Company's Designated Energy Communities is provided in Figure 7. A large portion of Georgia, Alabama, and Mississippi is available for these bonus credits. While it is unlikely that all proposed solar additions could be sited in these census tracts, it is likely that many will be. And it is entirely reasonable to assume that all standalone battery energy storage projects could be located in the census tracts to receive a 10% IRA bonus credit. It is also a real possibility that those battery projects could be sited at the same locations as the retiring Bowen and Scherer coal plants to leverage existing plant interconnection and transmission infrastructure. This would further expand the sites available for bonus tax credits.

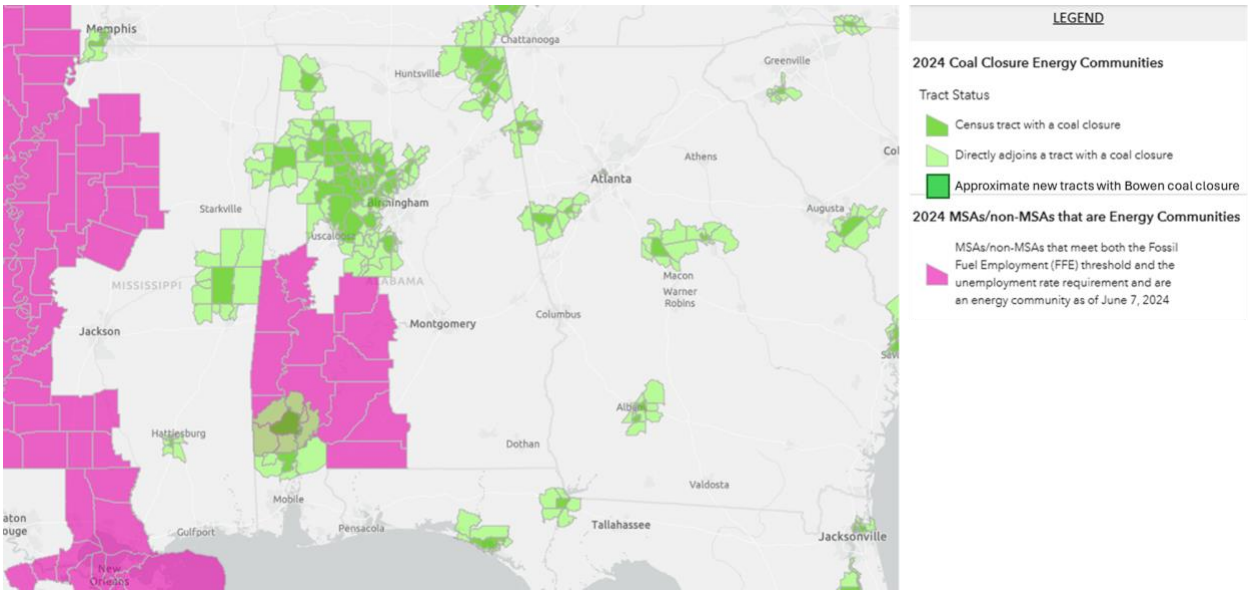

Figure 7. Map of Energy Community Tax Credit Bonus

Source: U.S. Department of Energy[26]

Finally, it is worth noting that pursuing the energy community bonus credits could generate additional benefits besides lower cost resources for the Company's ratepayers. The siting incentivized under the credits could provide jobs and tax revenue for the communities where the retiring coal plants are located, and for other communities impacted by the switch from coal to gas over the past several decades. Not only should the Company include the bonus credit in its modeling, but it should also be actively pursuing opportunities to site resources in these communities to help offset the economic impacts of coal retirements and support workforce development in new and growing industries.

[26] U.S. Dept. of Energy, National Energy Technology Laboratory, *Energy Community Tax Credit Bonus, 2024 Coal Closure Energy Communities,* availablet at: https://arcgis netl.doe.gov/portal/apps/experiencebuilder/experience/?id=a2ce47d4721a477a8701bd0e08495e1d.

Q DID YOU EVALUATE THE IMPACT OF THESE BONUS CREDITS ON THE PORTFOLIOS YOU EVALUATED?

A Yes, I did evaluate the potential impact of federal bonus tax credits on the portfolios I analyzed. The approach was intentionally straightforward to demonstrate how this type of analysis could be incorporated into the IRP process without requiring a full re-optimization of the resource portfolio.

Table 7 compares the NPV of the Company's MG20 portfolio—reproduced consistent with my modeling framework—with and without these assumed bonus credits. The results show between [redacted] and [redacted] 20-year NPV when the bonus credits are realized, reinforcing the importance of incorporating this type of sensitivity into future IRPs and my recommendation that the Company include analysis like this in future proceedings across all scenarios evaluated.

Table 7. 20-year NPV Comparison with Energy Community Bonus Tax Credits

Scenario	NPV ($M)	Change in NPV ($M)	Change in NPV (%)
MG20-GPC	[redacted]	-	-
MG20-GPC - with Bonus Credits	[redacted]	[redacted]	-0.6%
High Solar and Storage	[redacted]	-	-
High Solar and Storage - with Bonus Credits	[redacted]	[redacted]	-0.8%

The Company failed to properly model portfolio effects of solar and storage resources in capacity accreditation

Q CAN YOU DESCRIBE EFFECTIVE LOAD CARRYING CAPABILITY AND EXPLAIN HOW IT IS USED IN THE IRP?

A ELCC is a methodology used to determine the accredited capacity contribution of different resources toward meeting a system's resource adequacy needs. It reflects the amount of firm capacity a resource can be counted as contributing to the Total Reserve Margin (TRM).

ELCC is derived through probabilistic modeling, typically using a Loss of Load Expectation (LOLE) framework, which is also employed in the Company's Reserve Margin Study. These simulations evaluate the likelihood that a given resource will be available to reliably serve load during periods of highest system risk—typically during extreme weather, high demand, or unexpected outages.

In more technical terms, ELCC measures how much additional firm load the system could support after adding a resource, while maintaining the same level of reliability, as measured by the target LOLE. For example, if a solar or battery resource enables the system to serve more load without increasing reliability risk, that resource is credited with a certain level of capacity—its ELCC value.

In this IRP, GPC applies the ELCC methodology to solar, wind, and storage resources to determine how much of their nameplate capacity can be used to meet reserve margin requirements. The higher the ELCC of these resources, the more effectively they reduce the

system's net capacity requirement. As a result, higher ELCC values lead to, all other things equal, reduced reliance on thermal capacity additions and a lower overall cost for the resulting portfolio.

Q HOW DO DIFFERENT RESOURCES INTERACT WITH ONE ANOTHER WITH RESPECT TO CAPACITY ACCREDITATION?

A There are well-documented interactions in the literature that describe how different resources affect one another's accredited capacity, a phenomenon often referred to as "portfolio effects."[27,28] Capacity accreditation, particularly under an ELCC framework, is not static or intrinsic to a given resource type—it is highly dependent on the broader system context, including the overall resource mix and the shape of the load profile.

In general, a resource does not provide capacity in isolation; it provides capacity as part of an integrated system. As the composition of the system changes—whether through the addition of new resources or shifts in demand—the capacity value, or ELCC, of any given resource will also change. These interactions are often non-linear and can either diminish or enhance total portfolio capacity.

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[27] Schlag, N. *Capacity and Reliability Planning in the Era of Decarbonization,* Energy + Environmental Economics (E3), (Aug. 2020), available at: https://www.ethree.com/wp-content/uploads/2020/08/E3-Practical-Application-of-ELCC.pdf

[28] Energy Systems Integration Group, *Ensuring Efficient Reliability: New Design Principles for Capacity Accreditation,* A Report of the Redefining Resource Adequacy Task Force (Feb. 2023), available at: https://www.esig.energy/new-design-principles-for-capacity-accreditation.

There are two principal types of portfolio effects:

- **Antagonistic effects,** in which resources compete with one another to provide capacity during the same hours, leading to diminishing returns. For example, energy limited resources like demand response and battery storage can, at times, compete for the same resource adequacy risk hours.
- **Synergistic effects,** in which different resources complement each other and jointly enhance overall capacity value. In these cases, the whole is greater than the sum of the parts.

A good example of a synergistic relationship is that between solar and battery storage. Individually, each resource will experience declining ELCC at higher penetrations due to saturation effects. However, when deployed together—as modeled in the Company's Resource Mix Study—the decline in ELCC can be mitigated. Solar energy can be used to charge batteries, and the addition of solar flattens and shifts the net load curve (i.e., the load after accounting for renewables), making it more compatible with battery storage discharge patterns. This improves the reliability contribution of both technologies relative to what they could achieve in isolation.

These interactive effects are a critical consideration when assessing resource adequacy and designing portfolios and should be explicitly accounted for in modeling and planning analyses to ensure accurate and cost-effective investment decisions.

Q DID THE COMPANY TAKE INTO CONSIDERATION THE CHANGING RESOURCE MIX AND POTENTIAL PORTFOLIO EFFECTS WHEN DEVELOPING ELCC FOR SOLAR AND STORAGE RESOURCES?

A No, the Company did not. Despite well-established findings in the literature regarding the presence of portfolio effects, particularly between solar and battery storage, the Company evaluated the ELCC of solar and storage resources in isolation.

This is a significant oversight, especially given that the Company's own resource portfolios propose substantial buildouts of both solar and storage resources over the planning horizon. As a result, the Company's approach likely understates the combined capacity value these resources can provide when deployed together.

Q HOW WOULD THESE FINDINGS CHANGE THE OVERALL RESOURCE MIX DEVELOPED BY THE COMPANY IN THE IRP?

A Based on my analysis, I believe the portfolios proposed by the Company include more natural gas capacity than is necessary to meet system reliability requirements. This likely results in overbuilding the resource mix and distorts the intended balance between cost and reliability.

Had the Company appropriately considered the portfolio effects between solar and storage resources, it could have developed an ELCC "surface" or matrix that captures the interactive capacity value of these technologies when deployed together. Such an approach would reflect

the increased contribution these resources make to system reliability as a function of their joint penetration levels.

By using a static, isolated approach to ELCC, the Company underestimates the capacity contribution of solar and storage, leading to a higher modeled capacity need—primarily met by new gas resources—to satisfy reserve margin requirements.

Q WHAT DO YOU RECOMMEND THE COMPANY DO IN FUTURE IRP PROCEEDINGS TO BETTER REFLECT THE CAPACITY ACCREDITATION OF SOLAR AND STORAGE RESOURCES?

A In future IRPs, the Company should improve its Reserve Margin Study by evaluating the combined capacity contribution of solar and storage resources. Specifically, it should develop a two-dimensional ELCC matrix that shows how the capacity value of these resources changes depending on how much solar and battery storage is on the system. This is illustrated in Table 8 and Table 9 which were developed for IRPs in two neighboring Southeast utilities. This should be completed prior to GPC's proposed All-Source Capacity RFP, anticipated in the third quarter of 2025, to ensure capacity resources are evaluated on an equal playing field.[29]

[29] Direct Testimony of Jeffrey R. Grubb, J. Randy Hubbert, M. Brandon Looney, Michael B. Robinson, and Francisco Valle on behalf of Georgia Power Company, Docket Nos. 56002 & 56003 at 36.

Table 8. Duke Energy Carolinas Solar-Storage Surface Matrix[30]

		Solar MW						
	DEC	-	2,000	3,000	4,000	6,000	8,000	8,000
Battery MW	-							
	300							
	600							
	1,200							
	2,400							
	3,200							

Table 9. Dominion Energy South Carolina Solar-Storage Surface Matrix[31]

	Battery(MW)				
Solar(MW)	**100**	**150**	**400**	**650**	**900**
1,335		x	x	x	x
1,435	x	x			
1,935	x		x		
2,435	x			x	
2,935	x				x

This ELCC matrix should then be integrated into the capacity expansion model so that the planning process can reflect the real-world interactions between these resources. This would improve accuracy in identifying capacity needs and help avoid overbuilding gas resources, ensuring that ratepayers dollars support the most economic portfolio of capacity resources while minimizing stranded asset risk.

[30] Duke Energy Carolinas 2023 Integrated Resource Plan, Attachment II - 2022 ELCC Study, available at: https://www.duke-energy.com/our-company/about-us/irp-carolinas/prior-plans

[31] Dominion Energy South Carolina 2023 Integrated Resource Plan, DESC 2023 Planning Reserve Margin Study, January 27, 2023.

Q ARE THERE OTHER METHODS THAT THE COMPANY CAN USE TO ENSURE FUTURE PORTFOLIOS ARE RELIABLE AND THAT THE SYSTEM IS NOT OVERBUILDING NEW GAS RESOURCES?

A Yes. I recommend that the Company should adopt a round-trip modeling approach, also known as ex-post modeling, which tests the reliability of portfolios selected through capacity expansion modeling. This ensures that the portfolios are neither underbuilt, failing to meet resource adequacy standards, nor overbuilt with unnecessary resources.

Importantly, this approach does not rely solely on the target reserve margin and ELCC estimates to ensure resource adequacy. It tests the portfolio explicitly against the loss of load criterion (1-day-in-10-years) and across many weather years, generator outages, and load levels.

It also accounts for how ELCC values change over time with the evolving resource mix, rather than relying on static planning reserve margins. By evaluating system risk across different years and scenarios, this approach provides a clearer picture of reliability and helps avoid unnecessary gas builds while maintaining system adequacy. An example of this approach is done in Public Service of Colorado's "Reliability Rubric" which tests capacity expansion portfolios in the resource adequacy model.[32]

[32] Colorado Public Utilities Commission, Proceeding No. 24A-0442E, Public Service of Colorado, 2024 Just Transition Solicitation, Volume 2 Technical Appendix at 229.

Q CAN YOU SUMMARIZE YOUR RECOMMENDATIONS RELATED TO RENEWABLE AND BATTERY STORAGE RESOURCE MODELING IN THE IRP?

A The following list provides a set of recommendations for the Commission and the Company to improve modeling of renewable resources and battery storage in future IRPs.

- The Commission should require that the Company remove annual build limits on solar, wind, and storage in at least one unconstrained scenario to assess least-cost outcomes.
- The Commission should require that the Company justify how resource build limits were developed and explain why the Company reduced its annual maximum build limit for wind by 50% since the 2023 IRP Update.
- The Company should develop a method to incorporate the 10% IRA bonus credit for the anticipated number of projects that may be eligible to receive the energy community provisions.
- The Commission should require that the Company develop an ELCC matrix that reflects the capacity contribution of solar and battery storage resources assuming both resources are added to the model together.
- The Company should adopt round-trip modeling, also known as ex-post modeling, to verify that selected portfolios meet reliability targets without overbuilding.

VI. THERMAL GENERATION ISSUES

The Company is overstating accreditation of thermal resources by using ICAP, should transition to PCAP with ELCC accreditation.

Q EARLIER IN YOUR TESTIMONY YOU EXPRESSED CONCERNS REGARDING THE ACCREDITATION OF SOLAR AND STORAGE RESOURCES TOWARDS THE PLANNING RESERVE MARGIN. WHAT ARE YOUR CONCERNS RELATED TO THERMAL RESOURCES?

A Unlike solar, wind, and storage resources, the Company uses installed capacity (ICAP) for thermal resources, assigning 100% firm capacity credit to its portfolio, accrediting the unit's entire capacity towards the reserve margin requirement. This includes new gas generation resources included as options in the Company's build plans.

As a result, the Company places 100% of the risk of gas, coal, and other thermal generator outages into its planning reserve margin. This prevents an apples-to-apples comparison between new candidate resource types for the reliability contributions they provide when meeting the planning reserve margin requirement. This approach has been rejected by other jurisdictions because while the firm capacity value of thermal generators may be higher than other resources, they are not perfect capacity units.

A recent statement from former FERC Commissioner Clements stated that this type of capacity accreditation structure is "unduly discriminatory because it reduces the capacity accreditation of wind and solar [and storage] resources based on historically demonstrated

performance, while failing to account in any way for non-performance of other resource types."[33] Capacity accreditation can and should be used for all types of resources in a consistent manner. This ensures that resource planning models such as Aurora can properly account for the inherent limitations of all types of resources.

Q ARE THERE CORRELATED RISKS ASSOCIATED WITH NATURAL GAS AND COAL GENERATION THAT SHOULD BE REFLECTED IN THE CAPACITY ACCREDITATION?

A Yes. The risks from correlated outages and fuel supply availability are not represented for existing and candidate thermal resources in the Company's IRP portfolio related to natural gas and coal generation risks during extreme weather events. When combined with normal weather forced outage rate assumptions. accreditation of thermal resources is overstated in the Company's build plans.

The Company acknowledges this risk, stating that "the greatest reliability risk exists in the winter season due to the following drivers: (1) the narrowing of the difference between summer and winter weather-normal peak loads; (2) the distribution and duration of peak loads relative to the norm; *(3) cold weather-related unit outages*; (4) the penetration of solar resources which correlate more directly to summer peak periods; (5) *increased reliance on*

[33] Federal Energy Regulatory Commission, Commissioner Clements' Concurrence on Rehearing of Southwest Power Pool's ELCC Capacity Accreditation Proposal, March 2, 2023, Docket Nos. ER22-379-003, ER22-379-004, available at: https://www ferc.gov/news-events/news/commissioner-clements-concurrence-rehearing-southwest-power-pools-elcc-capacity.

natural gas which can be constrained in winter peak periods; and (6) market purchase availability (*emphasis added*)."[34]

It is important to note that the Company socializes these correlated outage and fuel supply risks by increasing the target reserve margin, rather than applying a lower accreditation to thermal resources. Specifically, the 2024 Reserve Margin Study does include an incremental cold weather outage curve that increases generator outage probabilities as temperatures decline and results in a higher target reserve margin. While this data is included in the Reserve Margin Study, it is not used to evaluate the actual capacity contribution provided by natural gas and coal generation in the system in a similar manner to how renewables and storage are treated. Furthermore, while the Company does include incremental cold weather outages, it also assumes that since the 2015 and 2022 cold weather events, Company owned resources have improved cold weather reliability and therefore use an adjusted incremental outage curve, shown in Figure 8.

[34] Direct Testimony of Jeffrey R. Grubb, J. Randy Hubbert, M. Brandon Looney, Michael B. Robinson, and Francisco Valle on behalf of Georgia Power Company, Docket Nos. 56002 & 56003 at 19.

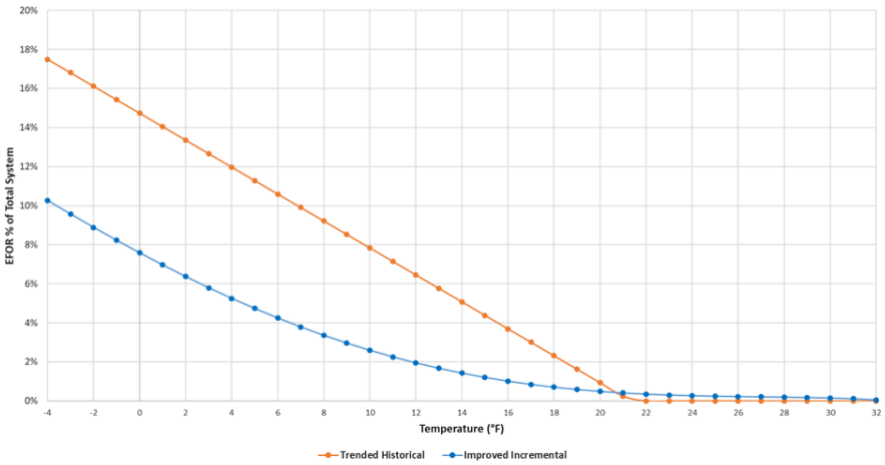

Figure 8. Cold Weather Outage Assumptions (Figure I.9 from 2024 Reserve Margin Study)

Given these recurring risks, the capacity accreditation of gas and coal resources should reflect the potential for simultaneous failures during high-risk periods. Failing to account for these correlated vulnerabilities overstates the reliability of thermal capacity and understates the system's true need for diverse and weather-resilient resources.

Q DO YOU AGREE WITH THE COMPANY'S BASIS FOR ASSUMING IMPROVED INCREMENTAL COLD WEATHER OUTAGES IN ITS 2024 RESERVE MARGIN STUDY?

A No, I believe the assumed improvements are too premature to assume the substantial performance improvements shown in Figure 8 have materialized. The Company makes several assertions that do not support the level of improvements assumed in the Reserve Margin Study. For example, in 2015, the incremental cold weather outage rate on January 8, 2015 was 7.63% and eight years later, on December 24, 2022, it was 6.67%; only a 12.5%

reduction in forced outage rates in eight years.[35] However, the assumed improved curve in Figure 8 shows for a similar system-wide temperature of 12.9 F, the incremental forced rate is <2%. These assumed improvements indicate that nearly all cold weather outage risks have been resolved since 2022. Given the extreme and rare nature of this type of cold weather on the system, the Company should not adjust cold weather reliability impacts without several examples of similar sustained cold weather conditions backing up the assumed improvements.

The Company's claims that cold weather outage rates have already improved are based on sparse data points during recent cold weather events that aren't as severe as Winter Storm Elliott in terms of both temperature and wind speed, the most recent example.[36,37,38]

Q DO YOU HAVE ANY DATA TO SUPPORT YOUR ASSERTION THAT COLD WEATHER OUTAGE RISKS AND FUEL AVAILABILITY COULD SIGNIFICANTLY IMPACT THERMAL ACCREDITATION?

A Yes, both the Company's own analysis through their external consultant Astrape Consulting and recent cold weather event data reviewed in the 2023 IRP back up the assertion that these effects should be reflected in capacity accreditation, and that assuming incremental improvements in cold weather reliability modeling is a premature action. These effects were

[35] Company response to Staff discovery request STF-GS-1-14
[36] Company response to Staff discovery request STF-JKA-1-9.
[37] Company response to Staff discovery request STF-GS-1-15.
[38] Ga. Power Co., 2023 Integrated Resource Plan Update, Docket No. 55378 HR-1-5.

reviewed in detail in my review of winter generator performance data from Docket No. 55378.[39]

Both cold weather impacts on outage rates and fuel supply availability significantly impact the 1-in-10-day LOLE planning reserve margin discussed in the 2024 Reserve Margin Study. Table 10 summarizes the change in 1-in-10-day LOLE reserve margin requirements under the Cold Weather Outage and Unlimited Natural Gas sensitivities, including how these sensitivities would impact the incremental capacity needed in 2035 due to different reserve margin levels. For comparison to the Reserve Margin Study, GPC capacity needed was calculated based on the system 25.75%, not the GPC allocation. The 2035 GPC winter peak load is used to calculate the incremental capacity need for the comparison.

Table 10. Summary Table of Georgia Power's 2024 Reserve Margin Cold Weather and Natural Gas Availability Sensitivities

Reserve Margin Study Sensitivity	Southern Company 1:10 LOLE Winter Reserve Margin	Sensitivity 1:10 LOLE Reserve Margin	GPC 2035 Incremental Capacity Need Impact
No Cold Weather Outages	25.75%	22.50%	-834 MW
Historical Cold Weather Outages	25.75%	30.25%	+1,154 MW
Unlimited Natural Gas	25.75%	20.25%	-1,411

[39] SREA, *Winter Storm Elliott: An independent review of Southern Company's performance during the historic events of December 22-25, 2022.*, (2024), available at: https://www.southernrenewable.org/uploads/1/9/8/9/19892499/winter_storm_elliott_report_southern_renewable_energy_association.pdf.

As shown, just the inclusion of cold weather outages (assuming the improved outage curve in Figure 8) increases the reserve margin by 3.25%, translating to 834 MW of additional firm capacity needed in 2035 due to their effects.

Similarly, results for historical cold weather outage performances and relaxing natural gas constraints both have substantial impacts on reserve margin targets, indicating the importance of these assumptions on system reliability. Historical cold weather outages would increase reserve margin requirements by 4.5%, which translates to 1,154 MW of additional firm capacity needed.

Lastly, the impact of natural gas constraints embedded in the Reserve Margin Study requires a higher reserve margin. The impacts of relaxing this constraint drop the requirement by 5.5%, translating to a 1,411 MW of additional firm capacity because of natural gas constraints.

These values show that risks inherent in the thermal generation fleet require higher reserve margins. Instead, the Company should accredit all resource types using a similar methodology to wind, solar, and battery storage to better reflect fleetwide contributions to firm capacity on a level field.

Q DID THE COMPANY FAIRLY REPRESENT DIFFERENT RESOURCE TYPES IN THEIR RESERVE MARGIN STUDY AND ELCC ASSUMPTIONS?

A No. While the Company applies the ELCC method to solar, wind, and battery storage, it assumes thermal resources—such as gas and coal—contribute 100% of their nameplate

capacity. This ignores the correlated risks and outage potential of thermal units, especially during extreme weather. As a result, the current approach overstates the reliability contribution of thermal resources and applies inconsistent standards across resource types. The Company asserts that "[i]ncremental cold weather forced outages were not factored into the capacity accreditation [...] because it is a weather normal analysis and [...] generator outages is accounted for in the reserve margin."[40] This shows that the Company is unfairly assessing resources using inconsistent methodologies and choosing to socialize the very real risks of correlated thermal generator outages and fuel supply constraints onto customers instead of optimizing build plans to mitigate this inherent risk.

Q HOW MIGHT THE COMPANY EVALUATE THE CAPACITY CONTRIBUTIONS OF THERMAL RESOURCES?

A While it was once common to credit thermal units at 100% of nameplate installed capacity (ICAP) similar to the Company's current approach, this is no longer standard practice. Most utilities now use unforced capacity (UCAP), which adjusts for a unit's average forced outage rate. However, UCAP has two key limitations: it doesn't account for shaft risk (the impact of losing large units) and it overlooks correlated outages, such as widespread failures during extreme cold or fuel shortages.

[40] Company response to Staff discovery request STF-GS-1-19.

To address these gaps, many utilities and system operators are moving toward perfect capacity (PCAP) or ELCC-based accreditation for all resource types, including thermal. This ensures a more accurate, risk-adjusted view of each resource's true reliability contribution.

Q DO YOU KNOW OF OTHER JURISDICTIONS THAT ACCREDIT THERMAL RESOURCES USING THE SAME METHOD AS RENEWABLE AND STORAGE RESOURCES?

A Yes, several jurisdictions that encompass a large variety of states have shifted to use more accurate accreditation methods. A non-exhaustive list of these jurisdictions include, but are not limited to, Independent System Operator of New England (CT, ME, MA, NH, RI, VT),[41] Midcontinent Independent System Operator (AR, IL, IN, IA, KY, LA, MI, MN, MO, MS, MT, ND, SD, TX, WI),[42] PJM (DL, IL, IN, KY, MD, MI, NJ, NC, OH, PA, TN, VA, WV),[43] Public Service Company of Colorado (CO), At some level, at least 31 out of the 50 states have a utility, market, or system operator recognizing the need to accredit all resources, thermal generation included, using a consistent methodology.

[41] ISO New England, *Resource Capacity Accreditation in the Forward Capacity Market*, available at: https://www.iso-ne.com/static-assets/documents/100008/a02c_mc_2024_02_06_07_rca_impact_analysis.pdf.
[42] Midcontinent Independent System Operator, *Resource Accreditation Reform,* FERC Docket ER24p-1638, available at: https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20240328-5329&optimized=false.
[43] PJM, *ELCC Class Ratings for the 2026/2027 Base Residual Auction,* available at: https://www.pjm.com/-/media/DotCom/planning/res-adeq/elcc/2026-27-bra-elcc-class-ratings.pdf.

Q HOW MIGHT A COMMON ACCREDITATION FOR ALL RESOURCE TYPES IMPACT PORTFOLIO SELECTION DECISIONS?

A These accreditation gaps overstate the reliability contribution of thermal resources while understating the value of solar and storage. The result is an overbuild of total capacity, especially natural gas additions, to meet reserve margin targets. This skews the balance between cost and reliability and leads to higher-cost portfolios than necessary.

The Company is understating the cost and timeline of new gas resources, making their near-term build plan unrealistic.

Q HOW MUCH GAS IS THE COMPANY PROPOSING BY THE END OF 2032?

A In the first five years of the IRP planning horizon where new resource additions are considered—specifically from 2028 through 2032—the Company's Resource Mix Study proposes a substantial buildout of new natural gas capacity. In the 111-MG0 scenario, the Company adds approximately 6,000 MW of gas capacity by 2032, while in the MG20 scenario, this increases to 6,900 MW by the end of 2032.

Q GIVEN SUPPLY CHAIN CONSTRAINTS, ARE YOU CONCERNED WITH THE TIMING OF THESE ADDITIONS?

A Yes, I am concerned. Even under normal conditions, the Company's proposed gas buildout between 2028 and 2032 would be considered ambitious. However, in today's constrained supply chain environment, it may be unrealistic or even infeasible.

Demand for natural gas turbines and related infrastructure has surged, particularly due to the rapid growth of AI and data center development. With only a few original equipment manufacturers (OEMs) supplying these technologies, the supply chain is currently outpaced by global demand. Industry reports indicate that the backlog for new turbine orders is now at least five years, and many OEMs require large, non-refundable deposits well in advance.

As a result, even if procurement decisions were made today, it is uncertain whether the Company could bring new gas capacity online within the proposed timeline. This raises serious questions about the feasibility of the Company's near-term gas build plans and suggests a need for greater consideration of alternative, lower-risk resource strategies that are more achievable within the current market environment.

Q ARE THERE OTHER OPTIONS AVAILABLE TO THE COMPANY THAT COULD MITIGATE THE TIMELINE AND SUPPLY CHAIN RISKS?

A Yes. There are existing resources already on the system that the Company is not considering in its Resource Mix Study but could be used to mitigate near-term reliability risks and reduce the need for new gas capacity. For example, Florida Power & Light (FPL) is a joint owner of

Scherer Unit 3 and has publicly expressed willingness to retire its stake.[44] If Georgia Power were to assume FPL's share, it could add around 200 MW of winter capacity to the Company's portfolio. There is a precedent for this type of transaction. Southern Company affiliates have executed similar asset transfers in the past, including at Plant Daniel.[45]

In addition, the Company assumes that 5,475 MW of Purchased Generating Capacity, largely made up of PPAs with third-party generators, will expire between 2028 and 2044.[46] While these PPAs are scheduled to terminate, many of the associated facilities remain technically viable beyond their current contract terms. Rather than treating these units as retired, the Company should evaluate PPA extensions or ownership transfers as viable alternatives to new construction. These options would reduce reliance on long-lead, high-cost new gas builds and provide a more flexible and timely solution to meet capacity needs.

These options would immediately defer the need for new gas resources and mitigate risks of delayed installations and supply chain constraints.

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[44] FPL's predecessor in interest as to Unit No. 3, Gulf Power Company, announced that it, too, would seek to retire Unit No. 3 as its compliance option with the ELG Rule." Complaint at 14, Fla. Power & Light Co. v. Georgia Power Co., No. 1:22-CV-1798-MLB, 2024 WL 1287025 (N.D. Ga. Mar. 26, 2024).

[45] Florida Public Service Commission, Florida Power & Light Company, Docket No. 20250011-EI, OPC's Sixth Set of Interrogatories, #138.

[46] Ga. Power Co., 2025 IRP Technical Appendix Volume 2, Resource Mix Study, workpaper "Georgia Power Territorial Base Case Load vs. Existing Capability Table - 2025 IRP.xlsx."

Q ARE YOU CONCERNED WITH THE ASSUMED COST OF THESE ADDITIONS?

A Yes, in addition to the risk of delays, I am also concerned with the Company's capital cost assumptions for new natural gas capacity. According to the Company's Resource Mix Study, the assumed capital cost for new combined cycle gas plants is [redacted] for simple cycle CTs. These values appear significantly lower than current market conditions.

Due to rising demand—particularly driven by large-scale AI and data center development—and persistent supply chain constraints, capital costs for new gas generation have increased substantially. Industry quotes for comparable combined cycle projects are now exceeding $2,000/kW, with some projects reporting even higher costs depending on location and configuration. For example, Dominion Energy South Carolina modeled new 1x1 combined cycle gas resources with a capital cost of $1,562 /kW in its 2024 IRP Update; preliminary cost estimates for its forthcoming 2025 IRP Update show 1x1 combined cycle costs increasing to $2,453/kW - a 57% increase in one year.[47] Similarly, Louisville Gas & Electric Kentucky Utilities (LG&E-KU) used a $2,121/kW nominal overnight cost assumptions for a natural gas combined cycle to go online in 2030 in its IRP filed in October of 2024.[48]

[47] Dominion Energy South Carolina IRP Advisory Group Session XVI Presentation, Tuesday, (Nov. 12, 2024), available at: https://www.desc-irp-stakeholder-group.com/Portals/0/Documents/MeetingMaterials/DESC_IRP_Stakeholder_Advisory_Group_Session_XVI.pdf.
[48] LGE-KU Integrated Resource Plan, Volume I, KPSC Case 2024-00326 (Oct. 18, 2024), available at: https://psc.ky.gov/pscecf/2024-00326/rick.lovekamp%40lge-ku.com/10182024014139/06-LGE_KU_2024_IRP_Volume_I.pdf.

If the Company proceeds with the planned 6.9 GW of new gas capacity by 2032 under these higher cost conditions, the total capital investment in gas resources could reach $17 billion, far more than is currently reflected in the IRP's portfolio cost estimates.

Q DID YOU EVALUATE THE IMPACT ON PORTFOLIO NPV WITH THESE NEW COST ESTIMATES?

A Yes. I evaluated the impact of higher gas capital costs using a method similar to the bonus credit sensitivity analysis discussed earlier. Specifically, I applied two sensitivities to the annualized revenue requirements of new gas resources, increasing them by +50% and +100%, respectively. These adjustments were made solely in the financial NPV analysis for the years 2028–2032; the capacity expansion modeling itself was not reoptimized.

Given that battery storage ELCC is already saturated in the Company's portfolios and that annual build limits for solar and wind have been reached, it is unlikely that the portfolio composition would change materially under full re-optimization. Instead, the added costs would simply result in a higher NPV to meet the same load and reserve margin requirements.

Table 11. 20-year NPV comparison of High Gas Revenue Requirements Sensitivities

Scenario	NPV ($M)	Change in NPV ($M)	Change in NPV (%)
MG20-GPC	[redacted]	-	-
MG20-GPC - 150% Gas Rev Req	[redacted]	[redacted]	2.8%
MG20-GPC - 200% Gas Rev Req	[redacted]	[redacted]	5.6%
High Solar and Storage	[redacted]	-	-
High Solar and Storage - 150% Gas Rev Req	[redacted]	[redacted]	2.4%
High Solar and Storage - 200% Gas Rev Req	[redacted]	[redacted]	4.8%

The results of this analysis show that the NPV of the MG20 portfolio increases by 2.8% and 5.6% under the higher gas capital cost assumptions. In contrast, in the portfolio with greater solar and storage additions, the NPV increase is smaller—2.4% and 4.8%—highlighting the ability of renewable resources to mitigate cost pressures associated with volatile gas infrastructure pricing. This reinforces the value of diversifying the portfolio with clean energy investments to hedge against capital cost uncertainty.

Q CAN YOU SUMMARIZE YOUR RECOMMENDATIONS RELATED TO THERMAL RESOURCE MODELING IN THE IRP?

A The list below provides a set of recommendations that the Commission and the Company can use to improve the current and future IRPs on topics related to modeling of thermal resources:

- The Company should test higher gas capital cost sensitivities in its financial analysis to capture risk exposure and provide a more realistic picture of ratepayer impacts.
- The Commission should require that the Company update its cost and timeline assumptions for new gas generators to reflect current market conditions and supply chain constraints.
- The Company should stop assigning 100% capacity credit to thermal resources and adopt a consistent accreditation methodology across all resource types.
- The Commission should require that the Company transition from an ICAP framework to a PCAP or ELCC-based accreditation method for gas, coal, and other thermal resources.

- The Company should account for correlated outage and fuel supply risks in the capacity accreditation of thermal generators, especially during extreme cold weather.

VII. TRANSMISSION MODELING ISSUES

The Company did not evaluate interregional transmission that could provide resource adequacy and access to lower cost and geographically diverse resources

Q DID THE COMPANY EVALUATE OPTIONS FOR INTERREGIONAL TRANSMISSION TO SERVE CAPACITY OR ENERGY NEEDS IN THE IRP?

A No, the Company did not evaluate interregional transmission options in the 2025 IRP. There is no evidence that the Company considered transmission expansions that would allow access to low-cost wind resources from other regions, nor did it explore how interregional transmission could improve system reliability or reduce the overall capacity need within the IRP.

The Company did include an "Unlimited Transmission" sensitivity in the 2024 Reserve Margin Study which found a reduction in reserve margin requirements. However, the Company only considers immediate neighboring balancing authorities when considering interregional transmissions impacts on the total reserve margin requirement. In essence, the Company has not fully evaluated or considered the benefit of increasing transfer capabilities beyond the SERTP/FRCC regions, leaving the analysis incomplete.

This is a significant omission, as interregional transmission has the potential to enhance resource diversity, reduce reliance on in-state gas generation, and lower the Total Reserve Margin requirement by improving system balancing across a broader geographic footprint.

Q CAN YOU CHARACTERIZE ANY BENEFITS THAT INTERREGIONAL TRANSMISSION CAN PROVIDE?

A Yes. Interregional transmission offers a range of benefits, several of which are particularly relevant to the objectives of this IRP proceeding:

- **Facilitates lower-cost energy transfers** across the Southeast and neighboring systems, allowing GPC to access surplus energy from other regions during periods of high demand or resource scarcity.
- **Enhances capacity and resource adequacy** by tapping into geographic diversity in both load and resource availability, which can reduce the overall system reserve margin requirement and improve reliability.
- **Improves resilience to extreme weather events** by expanding the geographic footprint of available resources and reducing reliance on localized generation that may be impacted by regional storms or cold weather events.
- **Enables 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.

Q CAN YOU PROVIDE AN EXAMPLE OF ANY PROPOSED TRANSMISSION PROJECTS THAT COULD PROVIDE INTERREGIONAL TRANSMISSION BENEFITS?

A Yes. There are several proposed interregional transmission projects across the country that are designed to deliver the types of benefits discussed previously—namely, improved reliability, lower reserve margin needs, and access to low-cost renewable energy.

One project particularly relevant to this proceeding is a proposed 3,000 MW transmission line that would interconnect the ERCOT with the Southern Company system, which includes GPC. This project is being developed specifically to enable large-scale energy transfers between regions, improve reliability through geographic diversity, and unlock access to low-cost wind and solar resources in Texas.[49]

Q HAVE YOU ANALYZED SIMILAR INTERREGIONAL TRANSMISSION PROJECTS FOR SOUTHERN COMPANY'S SERVICE TERRITORY?

A Yes. I have conducted studies that directly evaluate the benefits of interregional transmission for Southern Company's service territory. One study is the ESIG Multi-Benefits of Transmission Planning Study,[50] which modeled the addition of a 2,000 MW transmission line

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[49] Pattern Energy, Southern Spirit Transmission, available at: https://patternenergy.com/projects/southern-spirit-transmission/.

[50] Energy Systems Integration Group, *Multi-Value Transmission Planning for a Clean Energy Future* (June 2022), available at: https://www.esig.energy/wp-content/uploads/2022/07/ESIG-Multi-Value-Transmission-Planning-report-2022a.pdf.

between ERCOT and Southern Company. The results showed strong cost-benefit ratios of 166% and, importantly, demonstrated that even when both regions began the simulation with reliability levels below the industry standard (i.e., LOLE above 0.1 days/year), the transmission line enabled a reduction of 2,000 MW of gas capacity on each side. The added transfer capability improved resource adequacy for both ERCOT and Southern Company, making each region reliable under the planning criterion.

Q ARE YOU AWARE OF OTHER TRANSMISSION STUDIES CONDUCTED IN THE SOUTHEAST THAT SHOW SIMILAR BENEFITS OF REGIONAL COORDINATION?

A Yes. A recent study conducted by The Brattle Group, titled *Modernizing Southeast Grid Investments*, provides compelling evidence that enhanced regional transmission planning within the Southeast via SERTP can significantly reduce system costs, improve reliability, and increase resilience to extreme weather events.[51]

The report identifies critical gaps in the current Southeast Regional Transmission Planning (SERTP) process, which relies on a bottom-up aggregation of local utility plans and has not approved a single regional transmission project in over a decade due to the narrow and

[51] The Brattle Group, *Modernizing Southeast Grid Investments: How Enhanced Regional Transmission Planning Supports a Growing Economy* (April 2025), available at: https://www.brattle.com/wp-content/uploads/2025/04/Modernizing-Southeast-Grid-Investments-How-Enhanced-Regional-Transmission-Planning-Supports-a-Growing-Economy.pdf

reactive nature of Southeast transmission planning. This limited scope fails to reflect the rapid load growth forecasts developing across the region.

To demonstrate the potential benefits of a more proactive approach, Brattle evaluated three transmission upgrades identified by SERTP in 2024. The analysis shows that when using a broad set of cost and reliability metrics, total benefits were $8 billion versus $5 billion in cost. To realize these benefits, it is recommended that planners adopt scenario-based, multi-value planning aligned with FERC Order No. 1920, which would enable utilities to better evaluate long-term needs.

Taken together with the ESIG study I conducted, these findings clearly demonstrate that regional and interregional transmission planning is an underutilized tool that could provide meaningful cost and reliability benefits for the Company.

Q HOW CAN TRANSMISSION PROVIDE RESOURCE ADEQUACY?

A Interregional transmission can serve as a source of firm capacity by allowing access to surplus generation in neighboring systems that naturally arises due to diversity in weather and load. The ELCC framework used in the ESIG study is well-suited to evaluate this resource type. Just like other supply-side resources, transmission can be assessed based on its ability to reduce loss-of-load events under correlated weather and load conditions. In particular, the geographic and temporal diversity of load and renewable generation across regions makes transmission a potentially high-value resource for enhancing resource adequacy.

Properly accounting for interregional transmission within the ELCC framework would allow the Company and the Commission to weigh it alongside other capacity resources.[52,53] It would also provide greater transparency into the benefits of transmission development—particularly in light of diminishing returns from wind, solar, and storage as their penetration levels increase.

Q HOW COULD THE COMPANY EVALUATE INTERREGIONAL TRANSMISSION IN THE RESERVE MARGIN STUDY?

A The capacity contribution of interregional transmission can—and should—be evaluated in the same manner as other resources in the ELCC framework. The ELCC methodology is fundamentally designed to quantify the contribution of a resource to system reliability, and this logic applies equally to geographic diversity enabled through transmission as it does to generation or storage resources.

Assuming neighboring systems are explicitly modeled, the Company could conduct a loss-of-load expectation ("LOLE") analysis under the 0.1 days/year reliability criterion, just as it does for existing resources. Then a new transmission interface could be introduced into the model, representing firm import capability from a neighboring region. The resulting

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[52] *Id.*

[53] Astrapé Consulting, *North Plains Connector (NPC) Evaluation*, Prepared for Grid United, (May 24, 2024), available at: https://northplainsconnector.com/wp-content/uploads/2024/06/North-Plains-Connector-Evaluation_Final-Report_Astrape-Reviewed_FINAL.pdf

reduction in LOLE can then be used to calculate the ELCC of the transmission asset as additional load is added.

Q HOW MIGHT THE COMPANY INCLUDE INTERREGIONAL TRANSMISSION IN FUTURE IRPS AND ALL-SOURCE PROCUREMENTS?

A In future IRPs, the Company can and should incorporate interregional transmission as a resource option within its Reserve Margin Study and capacity expansion modeling. There are two primary ways to reflect its reliability value:

1. **Reduce the Total Reserve Margin** to reflect the added resource adequacy benefits provided by the interregional tie, or
2. **Assign a capacity credit to the transmission line,** which can then be incorporated into the Aurora capacity expansion model.

In the second approach, the transmission line would be treated as a selectable resource in the model, with assumptions about its cost, ability to buy or sell power, and associated environmental attributes. This would allow the model to economically evaluate the transmission investment alongside other local resource options, without requiring a full multi-jurisdictional transmission planning process.

A similar framework applies to all-source procurements. The transmission line could be treated like a conventional generating resource, with a defined capacity value based on expected availability during high-risk periods. This is consistent with how the Company currently uses probabilistic methods to assign ELCC values to solar, wind, and storage.

The key principle is that even without firm capacity contracts on the other side, the line itself can be reliably assigned a capacity credit based on expected import capability during periods of system stress. This enables interregional transmission to be evaluated on a level playing field with other supply-side options.

The Company's resource selection process does not incorporate internal transmission limitations, missing opportunities to strategically locate resources and mitigate transmission needs.

Q DID THE COMPANY'S MODELING INCORPORATE LOCATIONAL CONSIDERATIONS OF NEW RESOURCES OR RETIREMENTS?

A Currently, the Aurora modeling conducted by the Company does not evaluate any Southern Company transmission constraints between Georgia Power, Alabama Power, and Mississippi Power. Modeling internal zonal transmission constraints within the Company's capacity expansion, resource adequacy, and production simulations is essential for accurately reflecting the operational realities of the power grid and ensuring that resource investments are both cost-effective and reliable. Transmission plays a pivotal role in shaping resource availability, operational flexibility, and system costs, yet traditional resource planning models often oversimplify or omit these constraints. This leads to suboptimal resource portfolios that fail to account for localized congestion, inter-zonal energy flows, or critical bottlenecks.

Q WHY IS THIS APPROACH LIMITED?

A By not considering internal transmission constraints, the Company has limited insight into where new resources should be added. In addition, the Company is proposing significant transmission builds but has not evaluated whether strategic placement of generating or storage resources could defer the need for new transmission. The Company's Resource Mix Study proposes between 3,000 and 4,470 MW of battery storage by 2032 in the GPC service territory. This is a significant buildout of battery storage that could mitigate some of the transmission needs identified by the Company.

Q DO YOU THINK THE COMPANY SHOULD HAVE INCLUDED TRANSMISSION CONSIDERATIONS IN THEIR AURORA MODELING?

A Yes. Incorporating zonal, or nodal, transmission constraints in their Aurora model would enable the Company to develop resource portfolios that align better with the physical capabilities of its grid and provide valuable information to regulators and developers on best locations to site projects. Omitting zonal constraints means the interplay between transmission and generation is gone and portfolios may appear feasible on paper but encounter significant hurdles when evaluating them in transmission planning or resource adequacy studies.

Omitting modeling intra-regional transmission constraints may only be warranted if the Southern Company System truly does not experience congestion. However, if there is no transmission congestion within the Southern Company footprint, then I find it highly unusual

that the Company would also be requesting [redacted] billion of new transmission upgrades.[54] Based on the transmission system upgrades requested, there is a clear need for new transmission and these needs should be reflected in the Aurora model. As stated, representing at least some level of transmission constraints and costs to alleviate interface limits results in lower cost and more optimal planning.

Q IF THE COMPANY INCLUDED LOCATIONAL CONSIDERATIONS IN THEIR AC POWER FLOW MODELING, IS THIS SUFFICIENT?

A No, it is not sufficient. While incorporating locational considerations into AC power flow modeling is a step in the right direction, the Company's approach remains limited by the use of only a small number of snapshot analyses. This narrow scope makes it difficult to determine whether identified transmission constraints should be addressed through redispatch, operational adjustments (such as battery storage dispatch), or new transmission infrastructure.

For example, as noted in Witness Richwine's testimony, the Company's transmission analysis did not properly consider battery storage, despite nearly 5 GW of battery resources being included in the 2032 resource mix. Furthermore, the Company states that "[redacted]

[54] Ga. Power Co., 2025 IRP Volume 3 TRADE SECRET 2024 Georgia ITS Ten-Year Plan (2025-2034), Table 2 Georgia ITS 10 Year Plan Project List at 20.

[redacted] Any transmission projects supported using this type of analysis should be carefully reviewed since the default could lead to overly conservative conditions if alternative cases are not assessed based on actual expected and historical operations. If battery storage is expected to serve a meaningful share of peak demand, its operational behavior should be reflected in transmission planning models. Figure 9 are two hourly dispatch charts for summer and winter peak periods in the PLEXOS model developed for this testimony. Battery operations are identified and charged prior to the worst-case hours at lower load conditions based only on a 1-day lookahead period. The Company's current operational practices would provide sufficient lookahead forecasts to schedule storage resources to meet similar performance.

A more effective approach would involve integrated transmission and resource planning—linking the capacity expansion and production cost modeling conducted in Aurora with detailed AC power flow analysis. This would allow the Company to more holistically evaluate the most efficient combination of generation, storage, and transmission investments, ensuring that reliability and cost objectives are met in a coordinated manner.

[55] Company response to Staff discovery request STF-GS-1-4.

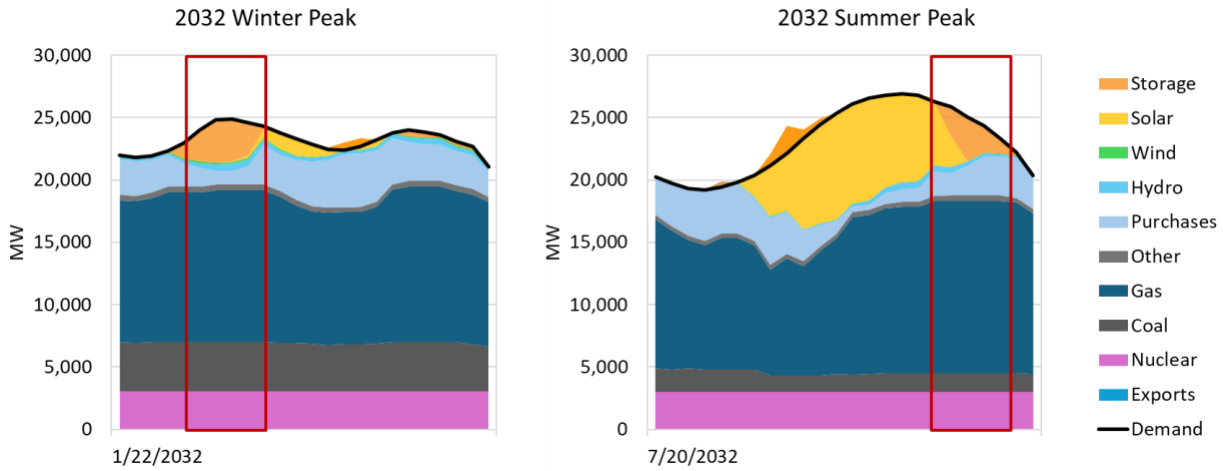

Figure 9. Hourly Dispatch for 2032 Winter (Left) and Summer (Right) Peak Load Periods

Q CAN YOU DESCRIBE HOW THE COMPANY COULD BETTER REPRESENT TRANSMISSION IN THEIR AURORA MODELING AND FUTURE RESOURCE CONSIDERATIONS?

A Yes. The Company could significantly improve the representation of transmission in its Aurora modeling by adopting a three-step zonal transmission planning approach:

1. **Cluster generation and loads by electrical proximity and interaction.** This involves grouping buses or substations into zones that reflect how power flows on the system. An example of this clustering method is discussed in Witness Richwine's testimony, with a corresponding map provided in "Figure 2: Map of Strategic Transmission Projects, Large Centralized Generators, New Large Loads."[56]

[56] Direct Testimony of Matthew Richwine.

2. **Calculate area-to-area transfer capability using AC power flow (ACPF) tools.** Once zones are defined, the Company can use power flow analysis to determine the Total Transfer Capability (TTC) between each pair of zones. This quantifies how much power can be reliably transferred across regions without violating transmission limits.
3. **Incorporate these zones and transfer limits into Aurora modeling.**

Q HOW MIGHT THIS INFORMATION BE USED TO HELP PLAN BOTH GENERATION AND TRANSMISSION RESOURCES?

A By modeling regional constraints and power transfer capabilities directly in Aurora, the Company can more accurately determine where new resources should be located to avoid triggering new transmission needs. Additionally, candidate transmission upgrades can be included as selectable options in the model, allowing the planning process to evaluate whether expanding transfer capacity would unlock lower-cost or more reliable resource portfolios.

Q WHAT ARE YOUR RECOMMENDATIONS RELATED TO TRANSMISSION MODELING IN THE IRP?

A The following recommendations will help improve integrated resource and transmission modeling in future IRPs:

- The Commission should require the Company to evaluate the ELCC of interregional transmission lines in future Reserve Margin Studies using the same ELCC framework applied to other resources.
- The Commission should require the Company to evaluate interregional transmission as a candidate resource option in its Resource Mix Study, allowing the model to select a least cost portfolio of local generating resources and interregional transmission.
- The Company should explicitly consider transmission projects like the proposed 3,000 MW ERCOT–Southern Company tie in future planning cycles.
- The Company should review findings from the ESIG and Brattle studies and apply scenario-based, multi-value transmission planning aligned with FERC Order No. 1920 and incorporate those findings into the IRP.
- The Company should improve its internal transmission modeling by representing zonal or nodal constraints in Aurora.

VIII. FINAL CONCLUSIONS AND ALTERNATIVE PORTFOLIOS

Taken together, adjustments to load, thermal modeling assumptions, and treatment of renewable energy and storage could yield a dramatically different portfolio with limited new gas builds, accelerated coal retirements and faster renewable adoption.

Q DID YOU EVALUATE HOW CHANGES TO THE LOAD FORECAST, RENEWABLE RESOURCE MODELING, AND CAPITAL COSTS OF NEW GAS RESOURCES COLLECTIVELY AFFECT THE RESOURCE SELECTION?

A Yes. While much of my testimony up to this point has focused on evaluating individual assumptions—such as load forecasts, renewable build limits, capital costs, and tax credits—in isolation, I also examined how these factors interact when applied collectively. This step is important because, while individual sensitivities provide clarity, the combined effect of these assumptions can produce even more significant changes to the resource portfolio, system costs, and emissions. For this analysis, I used the Company's MG20 portfolio as the reference case and created a "Combined Portfolio" scenario with the following modifications:

- Adjusted the load forecast to reflect the "50% Large Load Demand" scenario, which explores a middle ground if some portion of large loads do not materialize, similar to concerns raised by NRDC/SACE/Sierra Club's Witness Dr. Fagan regarding near-term load realization.

- Increased solar build limits by 50%, along with an additional 0.5 MW of 4-hour battery storage for every 1 MW of solar added, to reflect the potential for faster clean energy deployment.
- Accelerated coal retirements to 2031, aligning with reliability and cost optimization strategies discussed previously.
- Deferred new gas builds, reducing reliance on long-lead, high-cost thermal additions while still meeting the reserve margin requirement.
- Assumed 100% of battery storage additions received the 10% energy community bonus credit under the IRA.

The outcome of this analysis shows that when taken together, these changes drive a substantially different portfolio—one with lower total costs, reduced emissions, and greater flexibility in meeting long-term system needs. The exercise highlights the importance of evaluating realistic combinations of assumptions rather than relying solely on overly constrained, static inputs. This type of analysis better reflects the dynamic nature of today's energy landscape and provides the Commission with a more accurate basis for decision-making.

Q WHAT WERE THE RESULTS OF THAT ANALYSIS?

A The results of the Combined Portfolio analysis are significant and demonstrate how a more appropriate and flexible set of assumptions can produce a portfolio that has both lower cost and lower risk than any proposed by the Company. In some ways, my results show similar findings to the Company, namely that "[a]ll scenarios show substantial additions of solar and wind resources to be cost effective through the planning period."[57] But the Company could go further. As shown in Figure 10, the resulting portfolio is markedly different in composition and performance:

- Coal retirements accelerated to the end of 2031.
- Natural gas build is reduced by 6.5 GW, representing a 42% decrease by 2044 compared to the Company's MG20 portfolio.
- Solar additions increased by 8.2 GW, a 50% increase over MG20.
- Battery storage grows by 4.1 GW, or 58% more than in the Company's plan.
- The portfolio yields [redacted] billion lower NPV, a cost reduction of 19%.
- It also results in 265 million tons less cumulative CO_2 emissions, a reduction of 33% of system-wide emissions attributable to the Company.[58]

[57] 2025 IRP Main Document at 75.

[58] In this calculation, avoided CO2 emissions were quantified as the reduction in CO2 emissions for all Southern Company resources given an incremental addition of solar in the Georgia Power Company territory, regardless of which generators saw a decrease in generation.

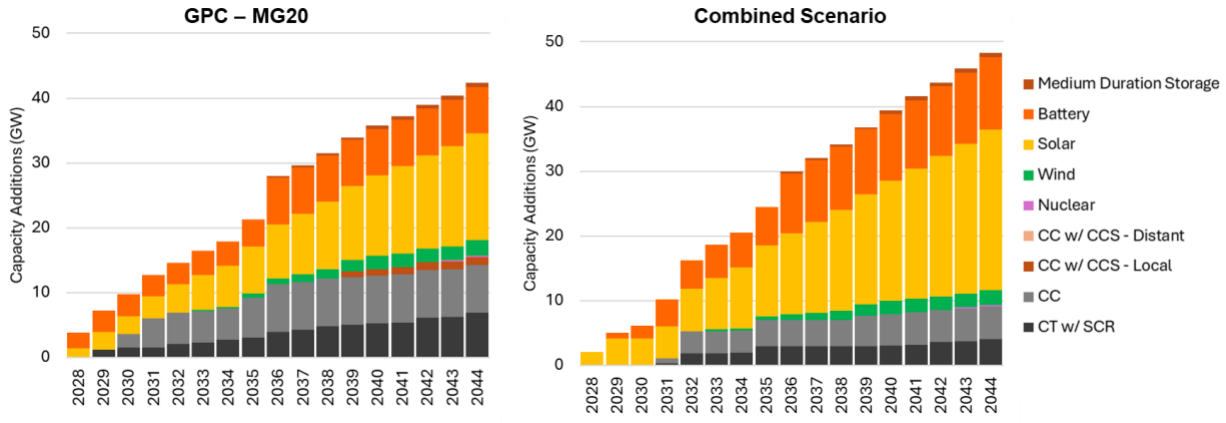

Figure 10. Cumulative Capacity Builds to 2044 by Resource Type with High Solar

Note: the Combined Scenario also assume accelerated retirement of Bowen and Scherer coal plants.

These results clearly illustrate the importance of evaluating these changes in combination. When realistic changes are made to load forecasts, renewable deployment constraints, tax credit eligibility, and gas capital costs, the system requires far less gas, retires coal earlier, and deploys more clean energy—all while lowering costs to customers and reducing emissions.

Q WHAT CONCLUSIONS CAN YOU DRAW FROM THESE RESULTS?

A The results of this analysis lead to several important conclusions about the limitations of the Company's current IRP and the opportunities for improvement.

First, the Company failed to plan for a more realistic trajectory of load growth and did not consider portfolios with higher levels of solar and battery storage that could deliver lower system costs, both in total and on a $/MWh basis.

Second, the analysis demonstrates that it is entirely possible to achieve these cost savings while maintaining the Company's target reserve margin and ensuring the same level of reliability as the Company's proposed portfolios.

Third, the findings underscore how the Company's outdated capital cost assumptions for new gas resources—when adjusted to reflect current market trends—significantly increase the cost and risk of the proposed portfolios, especially given ongoing supply chain constraints and long lead times for gas infrastructure.

Based on these findings, I recommend that the Commission require the Company to model a wider and more realistic range of assumptions, including:

- Alternative load forecasts with lower data center demand realization;
- Accelerated coal retirements;
- Higher build limits for solar, wind, and battery storage;
- Updated capital costs for new gas resources; and
- Inclusion of federal tax credits, including energy community bonus incentives.

IX. RECOMMENDATIONS FOR THE COMMISSION

My recommendations for the Commission and the Company are summarized in Table 12. The recommendations are organized by topic and prioritized by recommendations for changes that should be implemented in this IRP and others that can be addressed in future planning cycles.

Table 12. Summary of Recommendations for the Commission and the Company

Topic	Recommendation	Timing
Load Forecast	The Company should include a scenario that excludes all large new loads to isolate the costs, emissions, and resource decisions associated with speculative demand.	This IRP
Load Forecast	The Commission should consider resource procurement needs identified in the IRP that align with the uncertainty around large load realization and natural gas procurements.	This IRP
Load Forecast	The Commission should require that the Company model a much wider and more realistic range of assumptions in the Resource Mix Study, including alternative large load realization scenarios.	Future IRPs
Load Forecast	The Commission should require that the Company run each requested load forecast sensitivity through the capacity expansion process, not just develop them for compliance with forecasting rules.	Future IRPs
Load Forecast	The Company should evaluate options for large load flexibility, such as interruptible rates and onsite generation to reduce capacity needs.	Future IRPs
Load Forecast	In the next reserve margin study, the Company should evaluate potential reduction in the Target Reserve Margin that could be achieved with load flexibility from large loads.	Future IRPs
Variable Renewables & Storage	The Company should develop a method to incorporate the 10% IRA bonus credit for the anticipated number of projects that may be eligible to receive the energy community provisions.	This IRP
Variable Renewables & Storage	The Company should adopt round-trip modeling, also known as ex-post modeling, to verify that selected portfolios meet reliability targets without overbuilding.	This IRP
Variable Renewables & Storage	The Commission should require that the Company remove annual build limits on solar, wind, and storage in at least one unconstrained scenario to assess least-cost outcomes.	This IRP
Variable Renewables & Storage	The Commission should require that the Company justify how resource build limits were developed and explain any changes to annual maximum build limits for wind, solar, or battery storage.	Future IRPs
Variable Renewables & Storage	The Commission should require that the Company develop an ELCC matrix that reflects the capacity contribution of solar and battery storage resources assuming both resources are added to the model together.	Prior to Capacity IRP
Thermal Resources	The Company should test higher gas capital cost sensitivities in its financial analysis to capture risk exposure and provide a more realistic picture of ratepayer impacts.	This IRP

Thermal Resources	The Commission should require that the Company update its cost and timeline assumptions for new gas generators to reflect current market conditions and supply chain constraints.	This IRP
Thermal Resources	The Company should evaluate extending or acquiring contracts to existing resources like Scherer 3 and existing PPAs prior to building new gas resources.	This IRP
Thermal Resources	The Company should stop assigning 100% capacity credit to thermal resources and adopt a consistent accreditation methodology across all resource types.	Future IRPs
Thermal Resources	The Commission should require that the Company transition from an ICAP framework to a PCAP or ELCC-based accreditation method for gas, coal, and other thermal resources.	Future IRPs
Thermal Resources	The Company should account for correlated outage and fuel supply risks in the capacity accreditation of thermal generators, especially during extreme cold weather.	Future IRPs
Transmission	The Commission should require the Company to evaluate ELCC of interregional transmission lines in future Reserve Margin Studies using the same ELCC framework applied to other resources.	Future IRPs
Transmission	The Commission should require the Company to evaluate interregional transmission as a candidate resource option in its Resource Mix Study, allowing the model to select a portfolio of local generating resources and interregional transmission.	Future IRPs
Transmission	The Company should review findings from the ESIG and Brattle studies and apply scenario-based, multi-value transmission planning aligned with FERC Order No. 1920 and incorporate those findings into the IRP.	Future IRPs
Transmission	The Company should improve its internal transmission modeling by representing zonal or nodal constraints in Aurora.	Future IRPs

Q DOES THIS CONCLUDE YOUR TESTIMONY?

A Yes.

DS-1:

Resume of Derek P. Stenclik

TELOS ENERGY

Derek P. Stenclik

Founding Partner

Saratoga Springs, NY

M.S. Applied Economics & Management, Cornell University
B.A. International Relations, State University of New York at Geneseo

Derek Stenclik is a founding partner of Telos Energy and is an industry leader in power grid planning, operations, and reliability. He has over fifteen years of experience helping clients across the electric power industry navigate evolving markets, adapt to rapidly changing technologies, and accelerate clean energy integration. He is a recognized expert on renewable integration, resource adequacy, and grid planning.

Mr. Stenclik combines economic and engineering principles to bring a balanced perspective towards the opportunities and challenges of our current and future energy mix. He recognizes the role of a diverse resource mix and understands the need to balance affordability, reliability, and sustainability. He provides his clients unbiased, technical, and quantitative analysis by leveraging detailed power system models and simulations.

He regularly contributes to industry forums, including IEEE, CIGRE, ESIG, and peer-reviewed publications. He has authored over a dozen peer-reviewed articles and given numerous talks related to renewable integration, resource adequacy, energy storage, and ancillary market design.

Prior to founding Telos Energy, Derek spent eight years in GE Power's Energy Consulting department, most recently as the Senior Manager of Power System Strategy. In that role he supported global clients across the energy industry, including utilities, grid operators, developers, and equity investors. He also provided power market expertise across GE's portfolio of businesses, including the GE Power, Renewables and Capital divisions.

Derek graduated with an M.S. degree in Applied Economics and Management from Cornell University, with a concentration in Environmental and Natural Resource Economics. He also holds a B.A. in International Relations from the State University of New York, College at Geneseo, where he graduated Phi Beta Kappa and Summa Cum Laude.

Derek P. Stenclik

475 Broadway #6, Saratoga Springs, NY 12866
518.902.1219 | derek.stenclik@telos.energy

SHORT BIO

Derek Stenclik is a founding partner of Telos Energy and is an industry leader in power grid planning, operations, and reliability. He has over fifteen years of experience helping clients across the electric power industry navigate evolving markets and accelerate clean energy integration.

EXPERIENCE

2019-Present — Founding Partner, *Telos Energy*

- Lead business development, marketing, and finance initiatives
- Consult global clients in the electric power industry

2015-2019 — Senior Engagement Manager, *GE Energy Consulting*

- Supported utilities, grid operators, developers, governments, and NGOs
- Managed a diverse team of 11 power systems engineers and consultants

2011-2015 — Consultant & Senior Consultant, *GE Energy Consulting*

2010-2011 — Energy Analyst Intern, Office of Climate Change
New York State Energy Research and Development Authority
New York State Department of Environmental Conservation

EDUCATION

Aug. 2011 — M.S. Applied Economics & Management, *Cornell University*

- Concentration: Environmental and Natural Resource Economics
- Thesis: *Understanding Private Forest Owner Participation in Future Carbon Offset Programs in the Catskills Region: A Contingent Valuation Approach.*

May 2009 — B.A. International Relations, State University of New York at Geneseo

- Honors: Phi Beta Kappa, Summa Cum Laude

EXPERTISE

Energy Markets and Power System Planning Expertise:

- Economic dispatch and production cost modeling (GE MAPS and PLEXOS software)
- Renewable integration, integrated resource planning, and cost-benefit analysis
- Resource adequacy analysis and reliability planning
- Market design, energy and capacity market forecasting
- Financial proforma analysis, asset valuation, and tax equity investment
- Transmission congestion and curtailment risk analysis

AWARDS

- D. Stenclik, 2019 Excellence Award of the Electric System Integration Group (ESIG) for his work related to advances in PV-battery peaking plants.
- D. Stenclik, 2016 Annual Achievement Award of the Utility Variable-Generation Integration Group for the contribution to the Pan Canadian Wind Integration Study
- M. Richwine, D. Stenclik, 2016 Next Generation Network Paper Competition, 1st Place, CIGRE-US National Committee.

PUBLICATIONS & REPORTS

- **D. Stenclik**, New Resource Adequacy Criteria for the Energy Transition: Modernizing Reliability Requirements, Energy Systems Integration Group, Mar 2024
- **D. Stenclik,** et al., The Moonshot 100% clean electricity study: Assessing the tradeoffs among clean portfolios with a PNM case study, Aug 2023
- **D. Stenclik**, Ensuring Efficient Reliability: New Design Principles for Capacity Accreditation, Energy Systems Integration Group, Feb 2023
- **D. Stenclik**, et al., Beyond Expected Values, Evolving Metrics for Resource Adequacy Assessment, CIGRE Session 2022, Aug 2022.
- **D. Stenclik**, M. Welch, P. Sreedharan, Reliably Reaching California's Clean Electricity Targets, Stress Testing Accelerated 2030 Clean Portfolios,
- **D. Stenclik,** Redefining Resource Adequacy for Modern Power Systems, Energy Systems Integration Group, 2021.
- **D. Stenclik,** et al., Quantifying Risk in an Uncertain Future: The Evolution of Resource Adequacy, IEEE Power & Energy Magazine, Nov/Dec 2021.
- D. Lew, […], **D. Stenclik,** Secrets of Successful Integration, IEEE Power & Energy Magazine, Nov/Dec 2019.
- B. Zhang, **D. Stenclik**, W. Hall, Calculating the Capacity Value and Resource Adequacy of Energy Storage on High Solar Grids, CIGRE-US Grid of the Future, Reston, 2018.
- **D. Stenclik**, B. Zhang, R. Rocheleau, J. Cole, Energy Storage as a Peaker Replacement, IEEE Electrification, Vol. 6 No. 3, 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 and Impact of Autonomous Fast Frequency Response Relative to Synchronous Machine Sources on Oahu, CIGRE-US Grid of the Future, Reston, 2018.
- E. Ibanez, B. Daryanian, **D. Stenclik**, Capacity Value of Canadian Wind and the Effects of Decarbonization, 2017 Ninth Annual IEEE Green Technologies Conference (GreenTech), Denver, 2017.
- **D. Stenclik**, P. Denholm, B. Chalamala, Maintaining Balance: The Increasing Role of Energy Storage for Renewable Integration, IEEE Power and Energy Magazine, Volume: 15, Issue: 6, Nov. - Dec. 2017.
- G. de Mijolla, **D. Stenclik**, E. Ibanez, D. Lew, Regional Valuation of Regulating Reserves from Distributed Flexible Resources, CIGRE-US Grid of the Future, Cleveland, 2017.
- M. Richwine, **D. Stenclik**, Analysis of Grid Strength for Inverter-Based Generation Resources on Oahu, CIGRE-US Grid of the Future, 2017.
- M. Richwine, **D. Stenclik**, An Integrated Approach to Analyzing the Impact of Increasing Distributed PV on Dynamic Stability, CIGRE-US Grid of the Future, 2016.
- D. Woodford, B. Daryanian, **D. Stenclik**, M. Salimi, The Way to a TransCanada Electric Transmission System, CIGRE Canada Conference, Vancouver, 2016.

DS-2:

Company response to Staff discovery request STF-JKA-2-32

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

STF-JKA-2-32

Question:

Refer to page 23 of the Main Document of the IRP describing two load forecasts (Standard, Standard w/ HG0 Delta) and references to "additional load views considered in the B2025 Load & Energy Forecast in the Technical Appendix Volume 1 and the Financial Review in Technical Appendix Volume 2."

a. Please provide a list of the load forecast sensitivities produced and which were also studied in the resource mix process. Please reconcile any differences. If any load sensitivities were produced, but not studied in Aurora for an optimal expansion plan, please explain why not.

b. Refer to the list of load forecasts provided in "Table 1: List of Sensitivities for Financial Review" provided in 2025 IRP Financial Review TRADE SECRET.docx. Please reconcile the financial review sensitivities to those provided in part a.

c. Please provide a summary of any statutory requirements related to load forecasting and how GPC has complied.

d. Provide a summary of the sensitivity forecasts on an annual GWh, winter Peak, and summer peak basis (similar to Attachment 8.2-1)

Response:

a. The table below shows the loads developed as part of the Load & Energy Forecast and indicates which forecasts were modeled in Aurora for the Resource Mix Study, Financial Review, and/or Demand Side Management ("DSM") Step 9 analyses.

Load Forecast	Resource Mix Study	Financial Review	DSM Step 9
Standard	X	X	
Standard with HG Delta	X	X	
High Economic Growth			
Low Economic Growth			
No Load Growth			

High growth in large load customers		X	
Load growth with no DSM growth		X	X
Load growth with aggressive DSM growth		X	X
Load growth using a 20-year normal definition of weather, as stipulated in the 2019 IRP			
Proposed DSM			X
Capacity and Affordability DSM			X

The scenario design for the Resource Mix Study includes the standard view of load growth and an alternative view considering the effects of higher natural gas prices on the load forecast. To support previous Integrated Resource Plan ("IRP") Resource Mix Studies, the Company has considered as few as zero and as many as three alternatives to its official load forecast, which were not meaningfully different from one another from either a Resource Mix Study perspective or when used to perform resource-specific economic evaluations for both demand-side and supply-side options. The Company's scenario design strives to assemble views into scenarios that are meaningfully different from one another. For the set of scenarios analyzed in the 2025 IRP, it was determined that one alternative was sufficient, especially when combined with other key uncertainties in developing the wide range of possible futures in the nine scenarios ultimately included in the 2025 IRP.

The High Economic Growth, Low Economic Growth, No Load Growth, and Load Growth using a 20-year normal definition of weather, as stipulated in the 2019 IRP, were not modeled in Aurora. These load forecasts were developed for the Load & Energy Forecast pursuant to Commission Rule 515-3-4-.03 Energy and Demand Forecasting Requirements in the Commission's rules and regulations. This rule requires the Company to produce load forecast sensitivities for each of these forecasts but does not require the Company to run each of them through the resource mix process. All other load forecasts listed in the table above were modeled in Aurora as part of the Resource Mix Study or pursuant to Commission Rule 515-3-4.05 and are included in the Financial Review.

b. See the table in the response to subpart (a).

c. See response to subpart (a).

d. As noted, Figure 8.2-1 of Technical Appendix Volume 1 B2025 Load and Energy Forecast TRADE SECRET provides annual energy and summer and winter peak demand for the Standard and Standard with HG0 delta load forecasts. Figures 8.1-1 through 8.1-3 provide this information for the High Economic Growth, Low Economic Growth, No Load Growth, 20-Year Weather Normal, High Growth in Large Customers, No DSM, and Aggressive DSM cases. Please see STF-JKA-2-32 Attachment TRADE SECRET for the Company's summer and winter peak demand and annual energy for the Proposed and Capacity and Affordability DSM cases.

C & A

GPC

	Peak Demand (MW)		Energy (MWh)
	Summer	Winter	
2025	[redacted]		
2026			
2027			
2028			
2029			
2030			
2031			
2032			
2033			
2034			
2035			
2036			
2037			
2038			
2039			
2040			
2041			
2042			
2043			
2044			

Proposed

GPC

	Peak Demand (MW)		Energy (MWh)
	Summer	Winter	
2025	[redacted]		
2026			
2027			
2028			
2029			
2030			
2031			
2032			
2033			
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2042			
2043			
2044			

DS-3:

Company response to Staff discovery request STF-PIA-5-4

Georgia Power Company
Docket Nos. 56002 & 56003
2025 Integrated Resource Plan and 2025 Demand-Side Management Application
STF-PIA Data Request Set No. 5

STF-PIA-5-4

Question:

Please identify the assumptions that have been made regarding on-site flexibility at the large loads and their ability to reduce grid consumption during system peak hours. If there was no flexibility assumed, please explain why not and whether the utility asked the large loads about their willingness to be flexible and reduce grid consumption (potentially in return for faster interconnection and/or bill reduction)?

Response:

From a forecasting perspective, the Company is planning the system to meet the needs of our customers using our risk-adjusted framework (Load Realization Model). Given the high load factors and historical usage for similar customers already operating in Georgia, additional flexibility considerations were not modeled. The Company offers several programs large load customers can enroll in to provide value in exchange for a commitment to load flexibility. If customers enroll in these programs, their participation will be considered in the Company's planning processes.

DS-4:

Company response to Staff discovery request STF-JKA-1-11

STF-JKA-1-11

Question:

Regarding interconnection and build limits modeled for generic resources:

a. For all the modeled portfolios, provide any annual and cumulative build limits that were modeled by resource. Also, provide all workpapers used to derive the limits as used in Aurora modeling in the IRP.

b. Has Georgia Power changed any annual or cumulative build limits between the 2023 IRP Update and the 2025 IRP? Explain what has changed and why, if applicable.

c. Provide supporting industry information, justification, and support for the interconnection and/or build limit assumptions utilized.

d. Please describe any firm transportation and/or gas availability assumptions considered in the development of the limits modeled.

e. What contractual commitments or financial commitments, if any, has Georgia Power/SCS/Southern Company made to Transco for Southeast Supply Enhancement (SSE) project as of January 15, 2025?

f. What contractual commitments or financial commitments, if any, has Georgia Power/SCS/Southern Company made to SNG for South System 4 (SS4) project as of January 15, 2025?

g. What contractual commitments or financial commitments, if any, has Georgia Power/SCS/Southern Company made to Transco for FT on Station 85 receipt area (West Alabama) northeast to Georgia as of January 15, 2025?

Response:

a. See 2025 IRP Technical Appendix Vol 2 Resource Mix Study for all modeled annual and cumulative build limits. Additionally, see STF-JKA-1-11 Attachment A TRADE SECRET for derivation of the natural gas firm transportation ("FT") availability limit used for expansion CC resources.

b. Table 1 below summarizes the build limits assumed in 2025 IRP capacity expansion modeling and provides a comparison with assumptions in the 2023 IRP Update.

Table 1. Summary of Limits on Expansion Units.

Technology	2023 IRP Update	2025 IRP
CT w/SCR	• No limit	• No limit
CC	• Cumulative build limit based on annual FT availability	• Cumulative build limit based on annual FT availability
CC w/CCS	• Cumulative build limit based on annual FT availability	• Cumulative limit based on annual FT availability • Distinguishes between Local and Distant CCS • Local CCS limited to REDACTED total (**REDACTED** limit for GPC)
Solar	• Annual Max – 1,500 MW/yr	• Annual Max – 1,500 MW/yr
Wind	• Annual Max – 600 MW/yr • Cumulative Max – 8,100 MW	• Annual Max – 300 MW/yr • Cumulative Max – 4,500 MW
BESS	• Annual Max – 3,000 MW/yr • Cumulative Max – 18,000 MW	• Annual Max – 3,000 MW/yr • Cumulative Max – 18,000 MW
MDESS	• No limit	• No Limit
Nuclear	• Annual Max – 300 MW/yr	• Annual Max – 600 MW/yr

Annual Limit on CT and CC Builds

The Company used an annual maximum build limit in the 2023 IRP Update for CTs and CCs that was calculated based on the system's annual incremental capacity need. The purpose of this limit was to reduce the number of new resource options Aurora evaluates and improve runtime. Because the limit was set at or above the system's annual incremental capacity need, it did not actually limit the number of CTs or CCs that were selected by the model. For the 2025 IRP, the Company determined that having a static value that is large enough to allow Aurora to meet an entire year's capacity need with a single new resource type (if optimal), but not calculated based on annual need, simplifies the calculations required for each scenario and does not significantly increase run time.

For CTs and CC w/CCS, this limit is set to 30 blocks per year, which is equivalent to 9,000 MW (300 MW/block). For CCs, the build is limited to 3 blocks in 2029, the first year CC is allowed, and 15 blocks in 2030 to represent the estimated amount that could be constructed in that timeframe. For 2031 and beyond, the CC build limit is set to 30 blocks per year.

FT Availability Limit on CC Builds

In both the 2023 IRP Update and the 2025 IRP, the Company assumed FT used for existing units would become available to new CCs as the existing units either retired or power purchase agreement ("PPA") expired. In addition, for planning purposes, the Company assumed some additional pipeline expansion and associated FT would become available during the planning horizon. STF-JKA-1-11 Attachment B TRADE SECRET shows the resulting cumulative MW build limits that were included in the capacity expansion modeling for the 2023 IRP Update and the 2025 IRP.

Assumptions on Gas Availability for CTs

Given the current operational realities and the challenges facing the pipeline infrastructure industry, the Company assumes the most reliable operational plan for new generic expansion CTs is for them to be dual-fueled, capable of combusting either fuel oil or natural gas. For the 2023 IRP Update, the Company assumed year-round fuel oil operation for new generic CTs because the pipelines serving the Company region have become increasingly constrained and less flexible in recent years. For the 2025 IRP, this assumption was revised to only require CTs to operate on oil during the winter months (Dec-Jan-Feb) and to operate as needed on gas throughout the remainder of the year.

Local Versus Distant CC w/CCS

Areas of favorable geology for carbon storage within the Southern Company footprint are limited. For CCs that are distant from carbon storage regions, application of CCS requires that the captured CO_2 be transported by pipeline to a storage site (i.e., Distant CC w/CCS), which results in significant additional cost to construct and operate the unit. For the 2025 IRP, the Company has determined that it is reasonable to assume that only **REDACTED** of CC w/CCS could be constructed near favorable carbon storage sites (i.e., Local CC w/CCS), with significantly less cost for CO_2 transport than Distant CC w/CCS. The Company assumes REDACTED miles of pipeline for Local CC w/ CCS and REDACTED miles of pipeline for Distant CC w/ CCS. In addition, the Company assumes that only **REDACTED** of Local CC w/CCS could be constructed in the GPC service territory. Local CC w/CCS builds in the capacity expansion modeling are limited based on operating company need (e.g., if GPC is the only Operating Company with a capacity need, the build cannot exceed GPCs need for that year and cannot exceed **REDACTED**) and is limited to a system total of **REDACTED**. This limit was not included in the 2023 IRP Update modeling.

c. The Company aims to develop any generic resource limits tailored to technology deployment within its regulated service territory, rather than relying on public sources, which often cover a broader geographic scope. It is common utility practice to apply limits on generic resources in expansion plan modeling.

d. Given the challenges facing the pipeline infrastructure industry, the Company has applied a limit on the amount of new CC (including CC w/CCS) builds allowed in capacity

expansion modeling. The limit is a cumulative build constraint that is based on the amount of natural gas firm transportation ("FT") that is estimated to be available from retirement of existing resources, PPA expiration, and/or pipeline expansion. See JKA-1-11 Attachment A TRADE SECRET for derivation of the FT limits used for CC expansion resources.

e. Please see the response to STF-JKA-1-13.

f. Please see the response to STF-JKA-1-13.

g. Georgia Power/SCS/Southern Company have not made any contractual or financial commitments to Transco for new capacity with receipt points in the Station 85 area.

DS-5:

Company response to Staff discovery request STF-GS-1-14

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-1-14

Question:

At page 20 in the reserve margin study, please see the statement that "Historically, these incremental outages have materialized at system weighted temperatures of roughly 17°F and below. However, the Company has undertaken efforts to mitigate cold weather outages. Based on these efforts, it is expected that these incremental outages will not begin to materialize until the local temperatures reach approximately 10°F for retail, owned or operated resources and approximately 18°F for contracted resources."

a. Please provide the sources and assumptions that were used to determine the impact of the Company's weatherization efforts on cold weather forced outages.

b. Please provide any recent performance data used to inform or validate those assumptions regarding the impact of the Company's weatherization efforts on cold weather forced outages.

c. Please provide any evidence to support the assumption that contracted resources are less weatherized than resources owned by the Company.

d. Have gas supply or transportation constraints resulted in forced outages of Company-operated gas generators with firm gas transportation? If so, please document the generators and MW affected and the duration of each event. If so, were these outages accounted for in Astrape's analysis?

Response:

a. As of 2023, when the 2024 Reserve Margin Study cold weather assumptions were developed, Southern Company and Georgia Power plants were moving towards a design criterion of 0 degrees Fahrenheit for a 72-hour period with 25 mile per hour winds. However, this effort was still ongoing at the time of model development, so the decision was made to conservatively target 10 degrees Fahrenheit until further winterization improvements were made. The Company has since begun moving towards a by-unit Extreme Cold Weather Temperature ("ECWT") model per NERC reliability standard EOP-012-2.

b. Since 2014, there have only been two notable extreme cold weather events in the Southern Company System included in the cold weather analysis. On January 8, 2015, the system-weighted temperature dropped to 12.9°F resulting in an incremental cold weather outage rate of 7.63%. On December 24, 2022, the system-weighted temperature again dropped to 12.9°F resulting in an incremental cold weather outage rate of 6.67%. Per the cold weather outage assumptions curve on Figure I.9, page 21 of the 2024 Reserve Margin Study, the 2022 event falls slightly above the trended historical, but is an improvement over the 2015 event at the same temperature.

c. A forced outage analysis was performed at the peak load hour for Winter Storm Elliott for Power Purchase Agreement ("PPA") resources contracted by Georgia Power at the time.

	Total Capacity	**Capacity on Reserve**	**Capacity on Planned**	**Capacity on Forced**	**Available Capacity**	**Forced Outage Rate**
PPA	2,336.12	310.18	317.69	611.20	1,097.05	36%
Biomass PPA	303	-	-	267	36	88%

Per results of this analysis, the forced outage rate for PPA resources was much higher than normal. In contrast, Georgia Power resources had a total outage rate of 12% during the same hour. While this is a singular event, it offers some supporting evidence for the assertion that PPA resources might not have the same level of winterization as resources owned by the Company.

d. Per the 1980-2022 cold weather analysis for the 2024 Reserve Margin Study, no gas supply or transportation constraints resulted in forced outages of Company-operated gas generators with firm gas transportation.

DS-6:

Company response to Staff discovery request STF-JKA-1-9

STF-JKA-1-9

Question:

For a number of years, the Company has taken steps to mitigate risks of cold weather reliability. Please describe all efforts undertaken since the 2022 IRP including capital investment and O&M expense, and explain how those steps have paid off, and how the Company's Aurora and SERVM modeling assumptions have been revised since the 2022 IRP as a result of the mitigation efforts undertaken.

Response:

Since the 2022 IRP, cold weather outage assumptions in the model have been adjusted to account for the ongoing winterization improvements performed across the System. In the 2021 Reserve Margin Study, incremental cold weather-related outages for all modeled resources were anticipated to start when system-weighted temperatures fell below 13°F. In the 2024 Reserve Margin Study, this threshold was adjusted downward to 10°F but only for retail resources owned and operated by Southern Company. For contracted resources, the threshold was increased to 18°F due to fewer winterization improvements being performed on these units. In addition to the threshold, a geographic adjustment was also made at each generation site to account for differences between local temperature and the system-weighted temperature. Part I, Section I of the 2024 Reserve Margin Study provided in Technical Appendix Volume 1 details the cold weather outage modeling methodology and assumptions applied. The Aurora modeling for the Resource Mix Study applies the target reserve margin determined in the Reserve Margin Study to help identify an optimized resource expansion plan. Loads modeled in the Resource Mix Study are based on normal weather, so no incremental extreme weather outages are applied.

Southern Company is currently implementing a fleetwide winterization program with the goal of not only improving the reliability of freeze protection systems at each plant but also lowering the minimum operating temperature and freeze related parameters. This includes adding/replacing various components such as heat tracing, insulation, instrument enclosures, heated tube bundles, equipment enclosures, and other auxiliaries related to protecting components during cold weather events. Procedures have also been updated to assure compliance with NERC EOP-012-2 Extreme Cold Weather Preparedness. To date, Georgia Power has invested over $100M capital and over $7M O&M in this effort. As a result, the Georgia Power fleet winter reliability continues to improve. No unplanned generation weather related events were experienced for Company owned resources during Winter Storms Enzo and Cora.

DS-7:

Company response to Staff discovery request STF-GS-1-15

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-1-15

Question:

Please see Figure I.10 and the supporting text on page 22 of the Reserve Margin Study.

a. Please explain why the outage rate trajectory for all other regions is perfectly linear, while the trajectory for the Company's fleet curves sharply upward at low temperatures?

b. Please provide any data and assumptions used to develop or validate the curves for each region in Figure I.10.

c. Please confirm that Astrape's modeling of cold weather outages in each neighboring region using historical weather data accounts for weather/climate diversity between Southern Company and neighbors in the timing of cold weather outages.

Response:

a. The historical trend for the Company is linear in nature. However, an additional calibration was performed using historical cold weather outage time-to-repair information that was not available for the other regions. This calibration was necessary to account for the reality that a unit may not immediately recover from a cold weather outage as soon as the local temperature rises above its winterization threshold. As illustrated in Figure I.9, this resulted in a more gradual decline above approximately 8 degrees Fahrenheit, contrasting with the abrupt cutoff depicted in the historical trend curve.

b. See "Figure I.10 - Tier CWO Comparison.xlsx" provided to Commission Staff on January 31, 2025, in 2025 IRP Workpapers, Technical Appendix Volume 1, Section 2, Part I.

c. Yes, the modeling method applied by Southern Company using the historical outage versus temperature data provided by Astrapé accounts for weather/climate diversity between Southern Company and neighboring systems in the timing of cold weather outages.

DS-8:

Company response to Staff discovery request STF-GS-1-19

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-1-19

Question:

Was the cold weather-related forced outage of generators, as discussed at page 20 of the Reserve Margin Study, factored into their capacity accreditation for the generating resource selection in the Company's capacity expansion modeling?

Response:

Incremental cold weather forced outages were not factored into the capacity accreditation for the generating resources chosen during expansion modeling because it is a weather-normal analysis, and the impact of generator outages is accounted for in the reserve margin requirement included in the capacity expansion modeling.

Contact: Brandon Looney

DS-9:

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.

TRADE SECRET

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]		
01/22/2025 00:30:00			
01/22/2025 01:00:00			
01/22/2025 01:30:00			
01/22/2025 02:00:00			
01/22/2025 02:30:00			
01/22/2025 03:00:00			
01/22/2025 03:30:00			
01/22/2025 04:00:00			
01/22/2025 04:30:00			
01/22/2025 05:00:00			
01/22/2025 05:30:00			
01/22/2025 06:00:00			
01/22/2025 06:30:00			
01/22/2025 07:00:00			
01/22/2025 07:05:54			
01/22/2025 07:30:00			
01/22/2025 08:00:00			
01/22/2025 08:30:00			
01/22/2025 09:00:00			
01/22/2025 09:30:00			
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TRADE SECRET

01/22/2025 18:30:00	[redacted]
01/22/2025 19:00:00	
01/22/2025 19:30:00	
01/22/2025 20:00:00	
01/22/2025 20:30:00	
01/22/2025 21:00:00	
01/22/2025 21:30:00	
01/22/2025 22:00:00	
01/22/2025 22:30:00	
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DS-10:

SREA, Winter Storm Elliott: An independent review of Southern Company's performance during the historic events of December

Winter Storm Elliott

An independent review of Southern Company's performance during the historic events of December 22-25, 2022.

TELOS ENERGY

SOUTHERN RENEWABLE ENERGY ASSOCIATION

Prepared by Telos Energy for the Southern Renewable Energy Association.

Foreword

Winter Storm Elliott was a historic and sobering event, testing the reliability of our power system against extreme weather, high loads, gas supply disruptions, and generator outages.

From December 22 to December 25, 2022, extreme cold gripped much of the country, even extending into the Southeast, pushing grid operators and utilities to their limits. Utilities across the region called for energy emergencies and at times involuntary load shedding occurred.

In the aftermath of the event, FERC and NERC conducted a detailed post-mortem to evaluate root causes of the event. While this report provided valuable insights for each balancing area in the Southeast, it did not include a detailed overview of Southern Company's generator performance, nor did it look at the timeframe most important for Southern Company.

To fill this gap, Telos Energy, on behalf of the Southeast Renewable Energy Association, conducted an independent review of generator performance within Southern Company's footprint during this storm. Our goal was simple: to better understand what worked, what didn't, and what we can learn to improve future grid planning and reliability.

Before diving into the report, we want to recognize the operators who managed the power system during this storm. They no doubt worked tirelessly to maintain service for their customers and their communities. Southern Company managed to avoid rolling blackouts during the extreme weather—while neighbors could not.

Operators made decisions under immense pressure, ensuring customers had heat, preventing property damage and even saving lives.

This report is not about second-guessing those efforts. Instead, it aims to shed light on generator performance and planning processes, helping ensure our future systems can withstand similar events.

What this storm highlighted is that no resource is perfect and all resources - whether natural gas, coal, hydro, wind, or solar - are affected by the weather. Robust and fair accreditation of all resources is essential not just to make informed investment decisions, but to ensure reliability.

This starts with accrediting natural gas and coal resources using effective load carrying capability similar to what is being done for solar and battery storage. It also extends to interregional transmission, which can also be treated as a capacity resource. Together, proper accreditation can enable a diversified portfolio that strengthens the grid.

Transparency is another cornerstone of effective planning. Much of our analysis relied on data from Georgia Power Company's (GPC) regulatory filings, but gaps remained, requiring us to piece together a fuller picture using publicly available sources like EPA and EIA datasets.

At times we had to use generation during EEA events as a proxy for availability and outages. No doubt there are small errors or omissions in this analysis, and we look forward to additional data to help correct these. Transparency matters—not just for analysts like us, but for regulators, planners, and stakeholders who need accurate information to make informed decisions.

We hope this report serves as a constructive step toward greater understanding of past events and enables more robust planning. Together, let's continue building a grid that's ready to meet the reliability challenges ahead.

Introduction

Winter Storm Elliott created severe stress on the electric grid from December 21 - 26, 2022. The storm brought extreme cold, high winds, and snow, leading to a dramatic surge in electricity demand coupled with widespread outages caused by freezing equipment and disrupted fuel supplies.

Many utilities, including those in regions managed by the Tennessee Valley Authority (TVA), PJM (Pennsylvania-New Jersey-Maryland Interconnection), Duke Energy, and Southern Company, faced challenging conditions and implemented emergency procedures to maintain grid stability. The North American Electric Reliability Corporation (NERC) and the Federal Energy Regulatory Commission (FERC) subsequently released reports[1] detailing the storm's impact on utilities and highlighted region-wide deficiencies in both electric-gas coordination and preparedness for extreme weather. These reports underscored the urgency of enhancing reliability frameworks to address correlated failures across energy and fuel networks.

Post-storm scrutiny focused on the severe impacts in TVA, PJM, and the Carolinas where there was involuntary load shedding. However, Southern Company and its subsidiaries—Georgia Power, Alabama Power, Mississippi Power, and Southern Power—also faced substantial operational challenges.

On December 24, 2022, Southern Company issued an Energy Emergency Alert Level 2 (EEA 2), signaling the need to manage load through voluntary reductions. Unlike TVA and other utilities that implemented controlled outages, Southern Company managed to avoid EEA 3 measures which would have triggered involuntary load shedding, or "rolling blackouts."

During this time, the thermal generating fleet across the eastern interconnection experienced widespread outages, fuel supply disruptions, and unavailability. Figure 1 below shows a timeline of hourly electricity demand from the Southern Pool with callouts for key periods identified in this analysis. Additionally, yellow bars indicate approximate times when neighboring regions were under EEA 1 to EEA 2 and orange bars represent regions where EEA 1 to EEA 3 conditions occurred in relation to Southern. Periods of EEA for non-Southern regions represent approximate times any EEA was in effect.

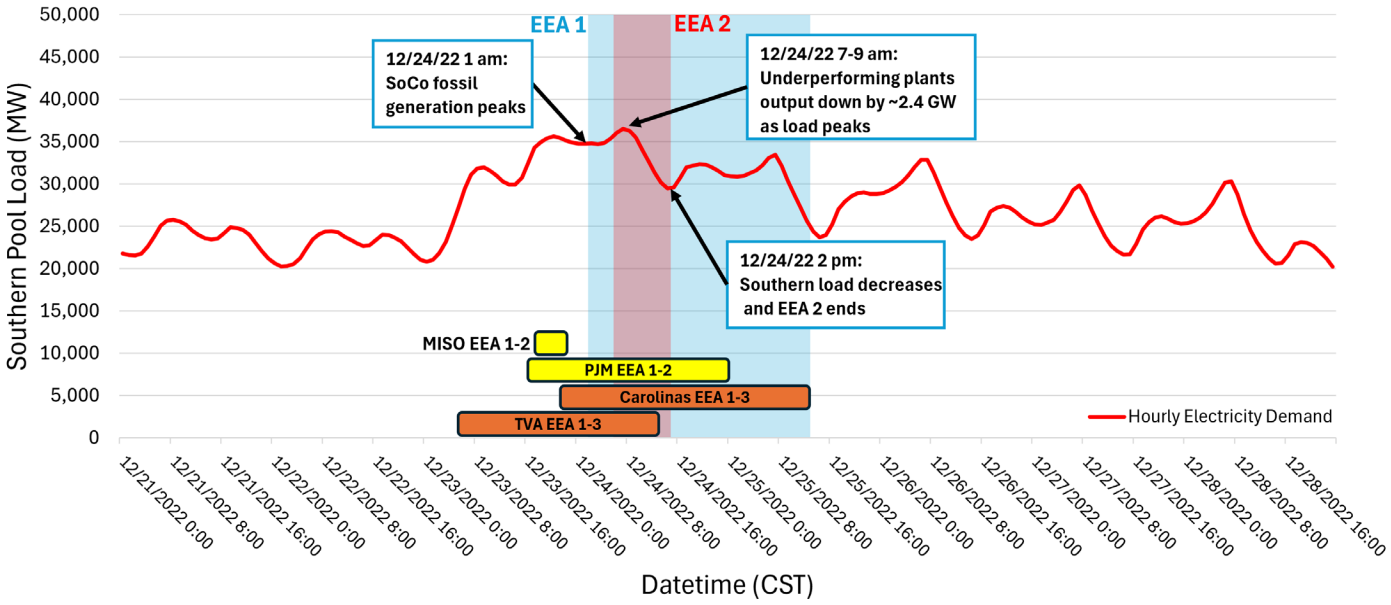

Figure 1. Summary timeline for Southern Company generator performance during Winter Storm Elliott

1 *FERC, NERC, & Regional Entity Staff. (2023, October). Inquiry into bulk-power system operations during December 2022 Winter Storm Elliott. Retrieved from https://www.ferc.gov/news-events/news/ferc-nerc-release-final-report-lessons-winter-storm-elliott*

The EEA declaration underscores the significant strain on its system, prompting an examination of the company's resource preparedness, load forecasting accuracy under extreme conditions, and planning processes to mitigate risks to system reliability and control costs for ratepayers. It also highlights the importance of including these types of weather events – and the corresponding generator performance – in long-term planning.

This report evaluates Southern Company's performance in key areas during Winter Storm Elliott, including generator performance, load forecasting accuracy, and both bilateral and SEEM market transactions. Key findings explore how well Southern Company anticipated and mitigated cold weather risks, the extent of generator derates or outages during the event, and the performance of renewable resources under extreme conditions.

Transparency remains a key challenge: although power purchases increased significantly during Southern Company's EEA 2 event, limited information is available, particularly regarding price formation, leaving ratepayers to bear unclear emergency costs.

The company's forecasting and planning for winter peak loads appear insufficient for managing high-impact, low-frequency events without resorting to extreme measures, and further assessment is needed to ensure Southern Company is accounting for winter outage risks across its generation fleet.

As a vertically integrated utility operating in a non-organized market, Southern Company lacks the standardized post-event reporting and market transparency seen in regulated regions like PJM and MISO. This limited transparency restricts a full evaluation of Southern Company's operational decisions and financial impact on ratepayers. Consequently, stakeholders lack critical insights into the company's efficiency, resource planning efficacy, and the true costs of emergency power.

This report addresses these gaps using limited data available from Georgia Power dockets, EPA data on large fossil-fuel plant operations, and grid operation data from the Energy Information Administration (EIA), seeking to answer critical questions on Southern Company's performance during Winter Storm Elliott.

This report seeks to address four primary questions:

- **Winter Load Forecasting:** How well does Southern Company predict winter peak load events, and did actual risks during the storm align with utility expectations?
- **Generator Performance:** How did all generation resources perform during severe conditions, and how effectively does Southern Company account for cold weather outage risks in its planning?
- **Emergency Power Purchases and Costs:** From where did emergency power originate, and at what cost? How did these costs compare to those in nearby regional markets?
- **Southeast Energy Exchange Market (SEEM) Performance:** How was the Southeast Energy Exchange Market (SEEM) leveraged during Winter Storm Elliott, and how has it been used in subsequent winter peak load events in 2023 and 2024?

This report aims to inform Southern Company stakeholders and regulatory authorities on the overall performance of the generation fleet, how well winter risk is characterized, and opportunities for increased transparency during and after emergency events, and recommendations on how to better incorporate these challenges in long-term planning.

"Transparency remains a key challenge: although power purchases increased significantly during Southern Company's EEA 2 event, limited information is available, particularly regarding price formation, leaving ratepayers to bear unclear emergency costs."

Winter Load Forecasting

The Southern Company region operates as a dual-peaking system, with high loads and tight reserve margins both in summer, due to air conditioning demands, and in winter, due to electric heating needs.

Every year, the Southern Balancing Authority (SBA), comprising Southern Company subsidiaries like Georgia Power, Alabama Power, and Mississippi Power, develops both a base winter peak load (50/50 load forecast) and an extreme peak load (90/10 load forecast) to prepare for severe weather scenarios. For the 2022-2023 winter season, SBA's extreme winter peak load forecast was 45,462 MW, slightly under the all-time winter peak of 45,887 MW[2].

To meet these forecasted loads, SBA projected resource availability based on its planning criteria, estimating 53,759 MW of resource capacity. After accounting for planned and unplanned outages and demand response, total capacity available was 52,133 MW. Under the 90/10 extreme peak forecast, the SBA projected reserve capacity of 6,671 MW, indicating a 15% reserve margin.

Given these assumptions, SBA anticipated sufficient resources to cover demand even during challenging weather like Winter Storm Elliott. However, on December 24, despite actual peak load remaining slightly below the 90/10 forecast at 45,153 MW, the SBA entered both EEA 1 and EEA 2 conditions, signaling that actual resource availability was below expectations during this high-demand period.

Table 1 shows the winter reliability expectations going into Winter Storm Elliott from the NERC/FERC inquiry.

2022-2023 Winter Reliability Load and Resource Summary	Southern
50/50 Winter Forecast (MW)	41,300
90/10 Winter Forecast (MW)	45,462
Winter Storm Elliot Peak (MW)	45,153
Expected Available Resources (MW)[3]	52,133
Expected Reserves to 50/50	26.2%
Expected Reserves to 90/10	14.7%
Expected Reserves to Actual Peak	15.5%

Table 1. Southern Winter Reliability Summary from NERC and FERC Inquiry into Winter Storm Elliott.

Evaluating Operational Forecast Accuracy and Error Margins

Reviewing the 2022 resource adequacy assessments for the Southern Pool (Georgia Power, Mississippi Power, and Alabama Power) reveals significant forecasting challenges for December peak loads. The historical data shown in Table 2 *(page 5, top)* shows that high forecast error exists even 1-hour ahead of peak load in December. For Winter Storm Elliott, the average error leading up to peak load would be 271 – 455 MW, depending on how far ahead the forecast is made. Assuming that the standard deviation is for a normal distribution, there was a 16% probability that December peak load could have been more than 3,600 MW above the forecasted peak load based on historical forecast error.

This high variability in forecast winter peak load means grid operators face high levels of uncertainty during extreme cold weather. Even though going into the event it appeared that adequate reserves were available, and peak load would be within the 90/10 forecast, clearly risks developed that prompted emergency procedures.

More insight into the specific decision-making steps from normal operations to EEA 1, 2, and potentially EEA 3 would help contextualize the risks of Winter Storm Elliott. Post-event analysis reports are commonplace in regions with markets, like PJM, MISO, and SPP, since market transparency builds trust and creates accountability for remedial actions.

2 Federal Energy Regulatory Commission (FERC) and North American Electric Reliability Corporation (NERC), FERC, NERC Release Final Report on Lessons from Winter Storm Elliott (2023), available at https://www.ferc.gov/news-events/news/ferc-nerc-release-final-report-lessons-winter-storm-elliott.

3 Expected available resources includes 53,759 MW of capacity, 2,510 MW of demand response, and -4,136 MW of expected planned and forced outages.

Historical Peak Load Forecast Error	Peak Load	4-hour mean error	1-hour mean error	4-hour std dev	1-hour std dev
December Error		1.0%	0.6%	10.4%	8.0%
Winter Storm Elliott Risk	45,153 MW	455 MW	271 MW	4,696 MW	3,612 MW

Table 2. 2022 Georgia Power Reserve Margin Study Historical Dispatchers' December Peak Load Forecast Error

Greater transparency in Southern's decision-making framework could clarify whether improvements are needed in forecasting accuracy, resource adequacy modeling, or operational protocols.

Suggestions to Improve Confidence in Winter Planning

Though Winter Storm Elliott brought conditions close to the 90/10 forecast, the region experienced emergency conditions not anticipated by existing plans. Despite projected reserves, the system escalated to EEA 2 conditions, where voluntary load reductions were employed.

This raises questions about whether Southern is making appropriate assumptions on generator availability during extreme, but anticipated, winter weather.

As winter reliability grows increasingly critical, Southern Company's strategies and readiness for low-frequency, high-impact events like Winter Storm Elliott require further scrutiny, particularly given the challenges of electric-gas coordination and growing electricity demand from data centers and electric vehicles.

The following actions are recommended to improve winter peak planning and transparency for stakeholders:

- Improvements to mitigate volatility in winter peak load are needed. These could include more advanced demand side management strategies, improved home efficiency programs, or virtual power plants to mitigate winter peak load risk while mitigating transmission system constraints.
- Evaluate load diversity and peak load risks for neighbors outside of SERC to enable more robust interregional support during high impact low probability events.

Generator Performance

The following analysis reviews how generators and different fuel types across Southern Company's footprint performed during Winter Storm Elliott.

Given the scale and severity of the event, units were expected to maintain or increase output to meet peak demand, especially as the region moved into EEA 1 and EEA 2. However, after reviewing generation data, significant drops in capacity or availability during this period are assumed to indicate operational challenges. The period used to evaluate generator performance is referred to as the "emergency window" which extends from December 24th at 7 am – 9 am. This three-hour window surrounding the peak load hour is used to represent the hours of greatest risk across the region.

Unfortunately, actual operational data was only provided by Georgia Power. Data transparency limitations make it challenging to assess performance throughout the broader balancing authority. This results in substantial gaps for Mississippi Power, Alabama Power, and Southern Power. This lack of detail underscores the need for Southern Company to provide comprehensive post-event analyses for their entire footprint. This practice aligns with other regions and supports transparent planning for system reliability and ensures accountability.

Overall Southern Company Fossil Fleet Performance by Fuel Type

The performance of Southern Company's fossil-fuel fleet, broken down by fuel type, is illustrated in Figure 2 *(below).* Total generation is from EPA's Continuous Emissions Monitoring System (CEMS) data, discounted by 2-7% based on technology type to approximate auxiliary loads. The gap in the data represents the remaining amount of demand served by nuclear, hydro, solar, and external power purchases.

Fossil-fuel generation in Southern Company's territory declined throughout the EEA 2 period when risks were highest, despite calls for voluntary load reductions. Fossil-fuel generation declined 2.4% in the hours before, 3.3% during, and 6% in the hours following peak load. Load shown in the figure represents the total reported generation from Georgia Power for all Southern Company entities.

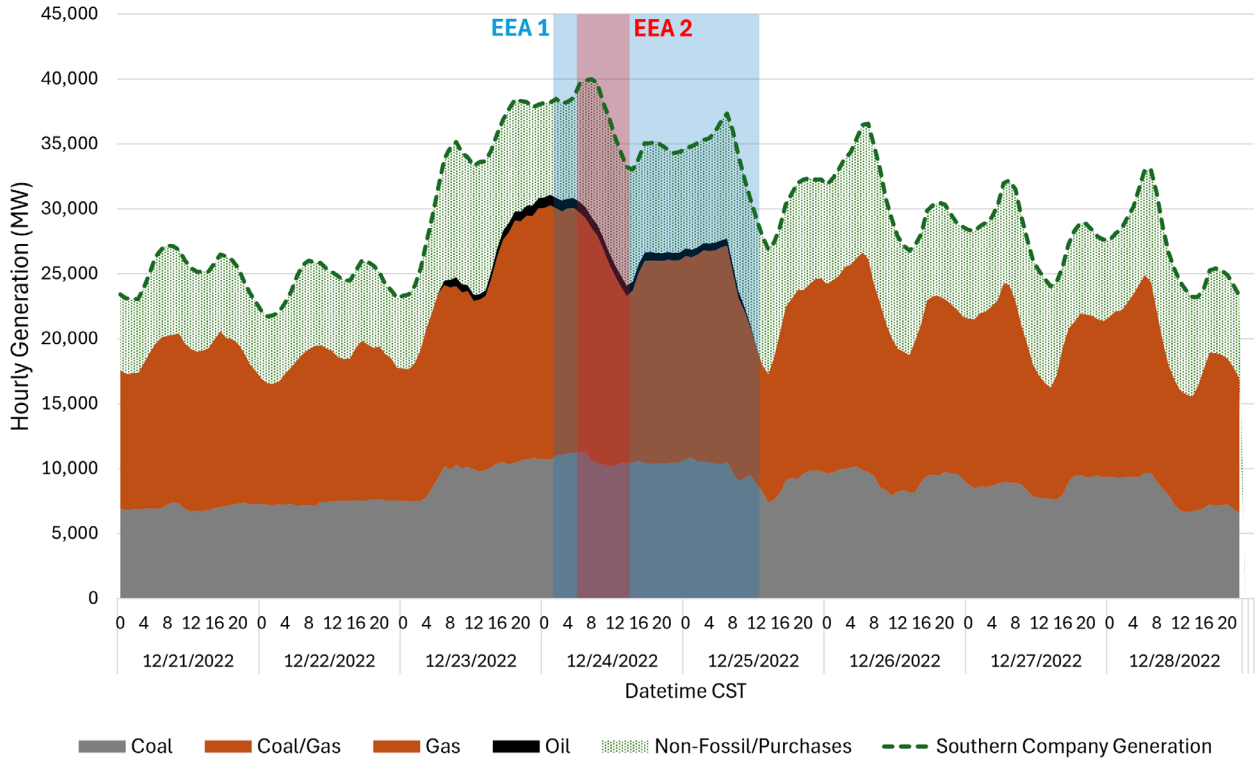

Figure 2. Southern Company Fossil Generation by Fuel Type during Winter Storm Elliott.

The data indicates that fossil generation peaked approximately 5 hours before peak load with numerous outages occurring when the capacity was needed most.

The fleetwide capacity factor for each fossil fuel type during EEA 2 is shown in Figure 3 *(below)*. Notably, coal and natural gas generation decreased by 7.5% and 8.1% relative to their maximum leading up to the emergency window.

While no load shedding occurred as the fleets experienced outages during EEA 1 and EEA 2 periods, the effects of cold weather on outage rates warrants further evaluation due to the volatility in winter demand described in the Winter Load Forecasting section.

Based on the emergency window of 7 am – 9 am on December 24, there were 22 plants (including aggregated one) that had either known outages reported by GPC, or had substantial deviations in the EPA data, or simply did not generate at all during the event.

These plants' winter ratings total 15,816 MW; however, average generation across these units was 8,084 MW, meaning that during the most extreme hours of the storm these units were only operating at 51% capacity factor across the fleet 51%.

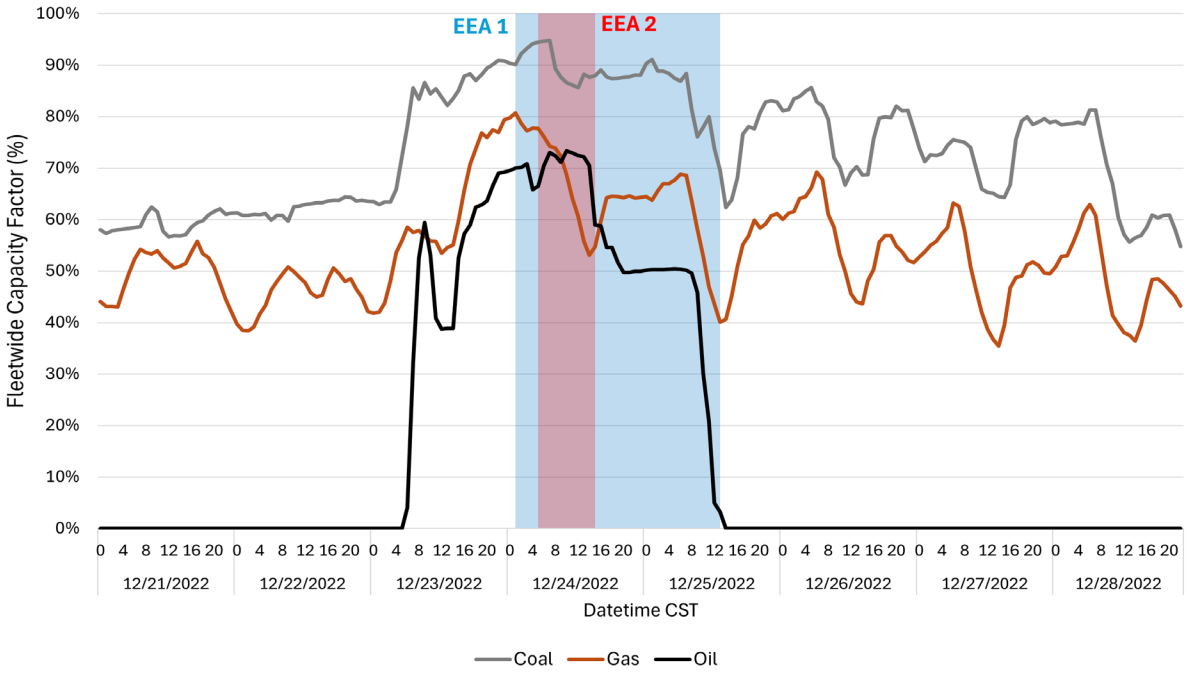

Figure 3. Southern Company Fossil Fleet Capacity Factors during Winter Storm Elliott.

Not all the unavailability exhibited by these plants can be attributed to forced outages without additional information. But the fact remains that these plants either had generators on some type of outage or were experiencing derates due to fuel supply availability during the emergency window. Figure 4 *(page 8, top)* shows the plants identified as underperformers and their average generation during the emergency window.

Generators that were GPC power purchase agreements were aggregated if they were less than 100 MW. Undispatched capacity represents the delta between the generation during the emergency window and the plants winter ratings.

In some cases, units were completely unavailable, in others output had been decreasing since the EEA 1 period was declared, or sharp drops in generation were observed in at least one of the emergency window hours.

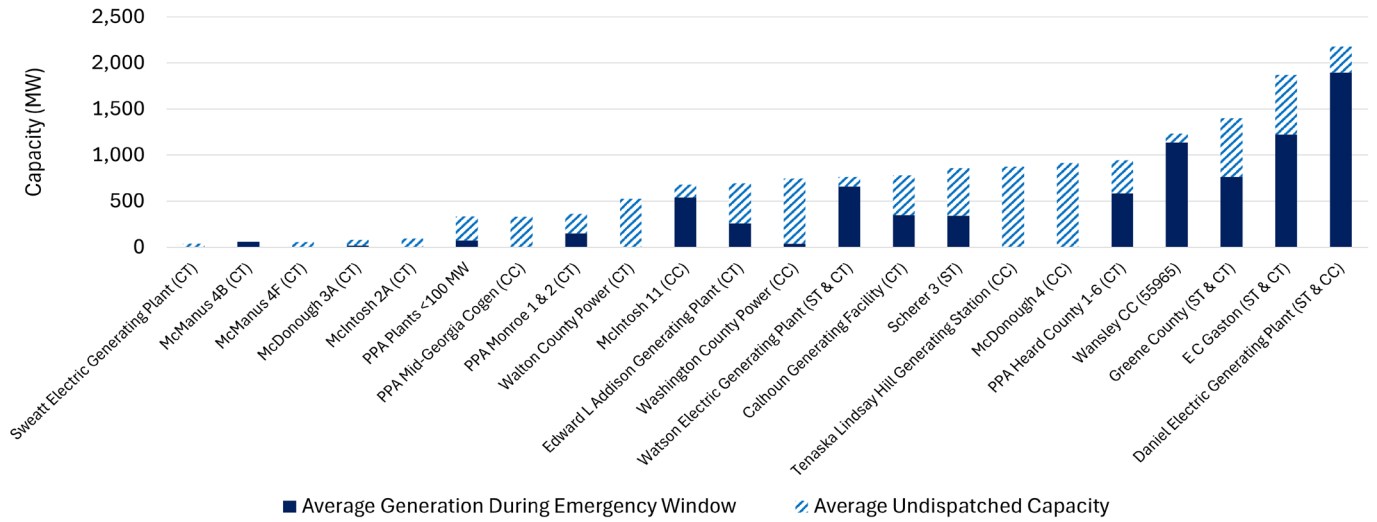

Figure 4. Southern Company known and potential unavailable capacity due to outages on 12/24/2022 hours 7am - 9am CST.

Known Georgia Power Plant Outages

This section provides a review of available hourly generation data for plants that experienced known outages as reported by Georgia Power. More information on the entire company's performance is needed to accurately determine where and when cold weather affects power plant outages although further sections provide estimates of unavailable capacity by Southern Company subsidiary and PPA resources.

Georgia Power Company owned plants where known outages occurred on December 24, 2022, from 1 am – 1 pm are:

- McDonough Unit 4 – 808 MW Combined Cycle
- McIntosh Unit 11 – 294 MW Combined Cycle
- McDonough CT 3B – 40 MW Combustion Turbine
- McIntosh CT 2 – 94 MW Combustion Turbine
- McManus CT 4B – 55 MW Combustion Turbine
- McManus CT 4F – 55 MW Combustion Turbine
- Scherer 3 – 644 MW Coal Steam Turbine

Including a planned derate of 71 MW at the Hatch nuclear plant, a total of 2,061 MW of GPC owned resources out of 14,092 MW of capacity resources (15%) were on outage during Southern Company's highest risk period during the storm.

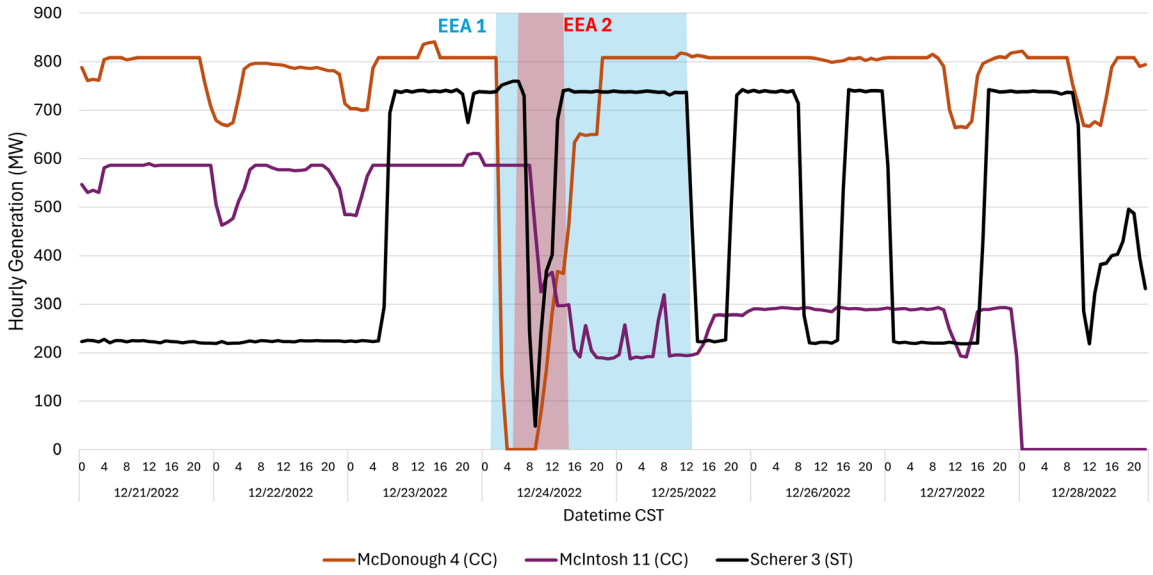

Figure 5. Hourly Generation for Large GPC Units with Outages During Winter Storm Elliott.

Figure 5 *(page 8)* shows the operations for McDonough Unit 4, McIntosh 11 and Scherer 3 based on GPC provided hourly generation data.

The timing of outages for each of the three units shown above varies, but the most significant impact is what the total amount of generation was on outage during the peak load hour. Based on Energy Information Administration winter ratings for these three units had 1,622 MW of reduced output during peak load. The worst-case level of reduced output for these three plants was 1,952 MW, one hour after peak load.

Figure 6 *(below)* shows the smaller unit outages during this period. Notably, McManus appears to have returned to service in time for the EEA 2 event. Both McDonough 3A, and McIntosh 2A, and McManus 4F were either unavailable during the EEA 2 event or unable to operate at their maximum rating.

The total amount of these plants operating below their rating during the peak load was 212.6 MW, one hour after peak load.

It is not unreasonable for power plant outages to occur during extreme weather conditions. Additional information provided by GPC indicated that the 2,061 MW of outages GPC experienced resulted in 15% of their total capacity resources on outage during the storm.

In addition to the GPC owned resources on outage, a total of 1,031 MW of GPC Capacity PPA resources were on outage during the storm. These units were not identified but represented 25% of GPCs capacity PPA resources. In total, 14.5% of the GPC owned and GPC PPA fleet experienced a forced outage during Winter Storm Elliott[4].

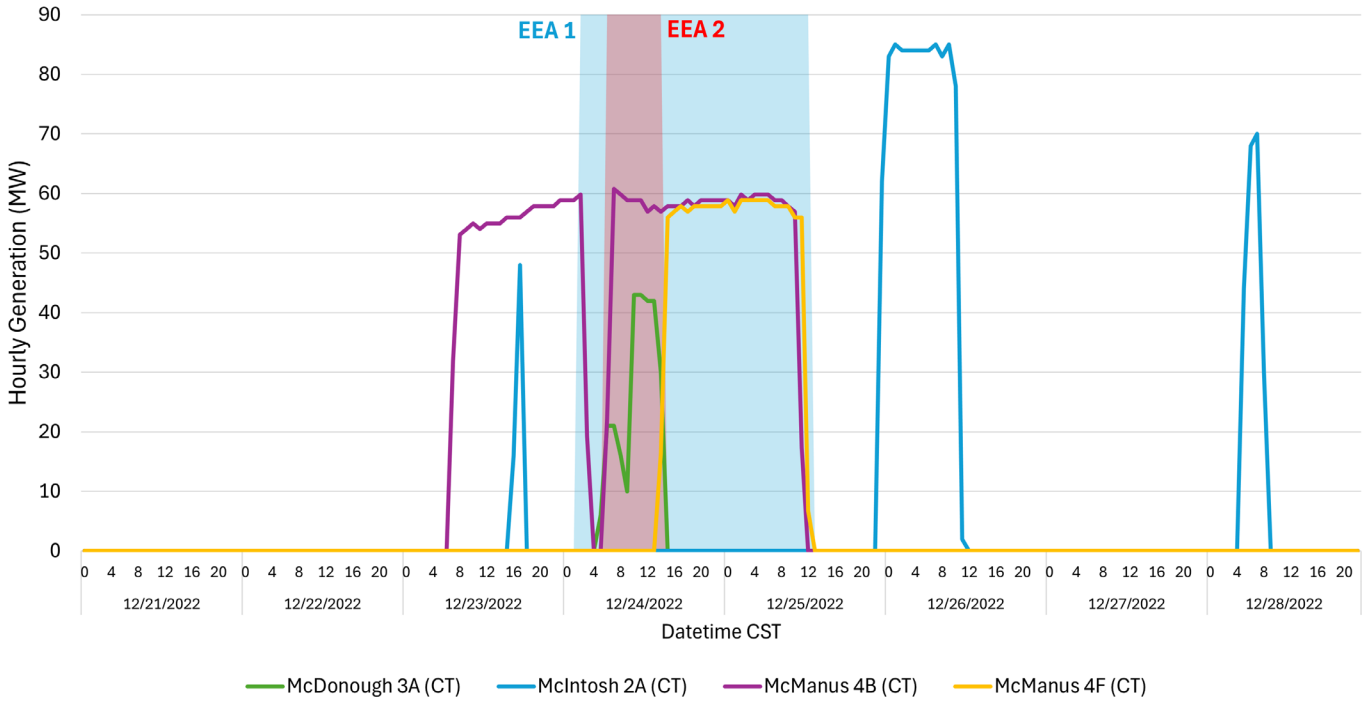

Figure 6. Hourly Generation for Small GPC Units with Outages During Winter Storm Elliott.

Performance of Non-Georgia Power Generators

The previous section only reviewed Georgia Power generators because the unit-specific data was made available in regulatory filings. To augment this data, a review of other Southern Company resources was conducted using publicly available data from the EPA CEMS database. All owned or PPA resources from Alabama Power, Mississippi Power, and Southern Power that were equipped with emissions monitoring systems were reviewed.

While only gross generation data is available, power plants that showed substantially low output or significant deviations during the emergency window (7 am to 9 am) were deemed potential outages.

4 Docket No. 55378, Georgia Power Company's 2023 Integrated Resource Plan Update – Hearing Request Set Number 1 (HR-1-1)

This assumes that the resources would have been utilized further, if available, to avoid EEA 2 and xpensive market purchases.

Performance of Alabama Power Generators

Review of Alabama Power fossil fueled generation showed three dual fuel gas/oil power plants with declining output or substantially reduced output. Figure 7 *(below)* shows the total plants hourly generation as a percentage of their winter rating based on EPA CEMS and EIA 860 data. These plants stand out because due to overall lower generation than might be expected during the event considering emergency purchases were required.

The three plants shown here are:

- 1,400 MW Greene County (owned by Alabama Power and Mississippi Power)
- 1,872 MW E C Gaston plant (owned by Alabama Power and Georgia Power), and
- 80 MW Calhoun Generating Facility.

During the emergency window, Greene County output was 318 MW lower than the maximum during EEA 1. E C Gaston output was 20 MW lower, but overall output was limited to only 65% of its capacity. Calhoun Generating Facility output was 255 MW lower. This behavior may be indicative of unit outages or fuel supply disruptions and a sign of correlated cold weather outages. In total, these three plants had reduced output of approximately 1,881 MW at their worst hour during the emergency window.

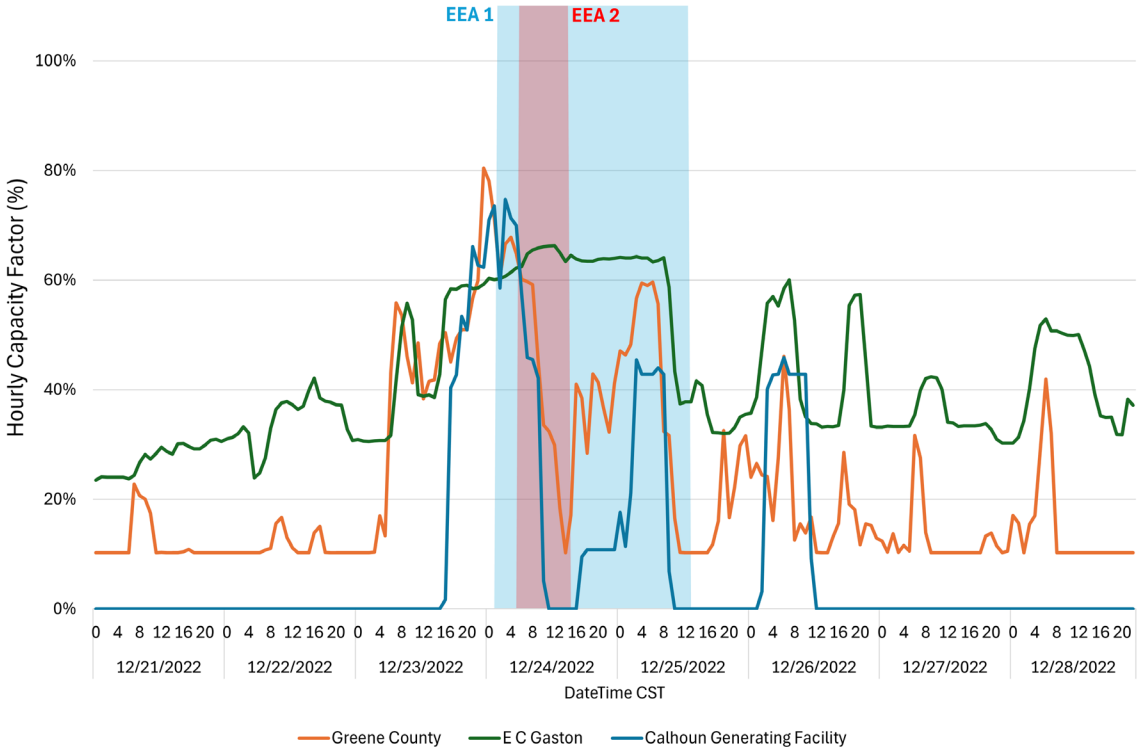

Figure 7. Alabama Power generation identified as having potential outages during Winter Storm Elliott.

In addition to the fossil fueled plants, Unit 1 at the 1,791 MW Joseph M Farley nuclear plant in Houston, AL was offline until the EEA event occurred. This unit represents 895 MW of capacity unavailable to the system due to a planned refueling outage. Typically, refueling outages aren't notable because they are scheduled in the shoulder season where risk is lower.

However, in 2022 the refueling outage for Farley 1 started on 9/18/2022 and didn't end until 12/22/2022 when the unit started slowing increasing output. This represents a 95 day outage for the unit. Typically refueling outages are between 30-45 days indicating the system faced higher risk in the winter due to the extended outage at the unit.

Figure 8 *(below)* shows the daily power reactor status report for Farley 1 from 12/21/2022 – 12/28/2022. Data is interpolated for each day since the reactor reports status at the beginning of each day. The squares on the chart represent the daily power reactor status report percentage of power output.

By the time of the EEA 1 and EEA 2 declaration Farley 1 was estimated to be between 18-30% of its rating, meaning an additional 638.4 - 733.9 MW had yet to ramp up. The extended refueling outage timeline exacerbated risks in December which is a highly volatile winter month.

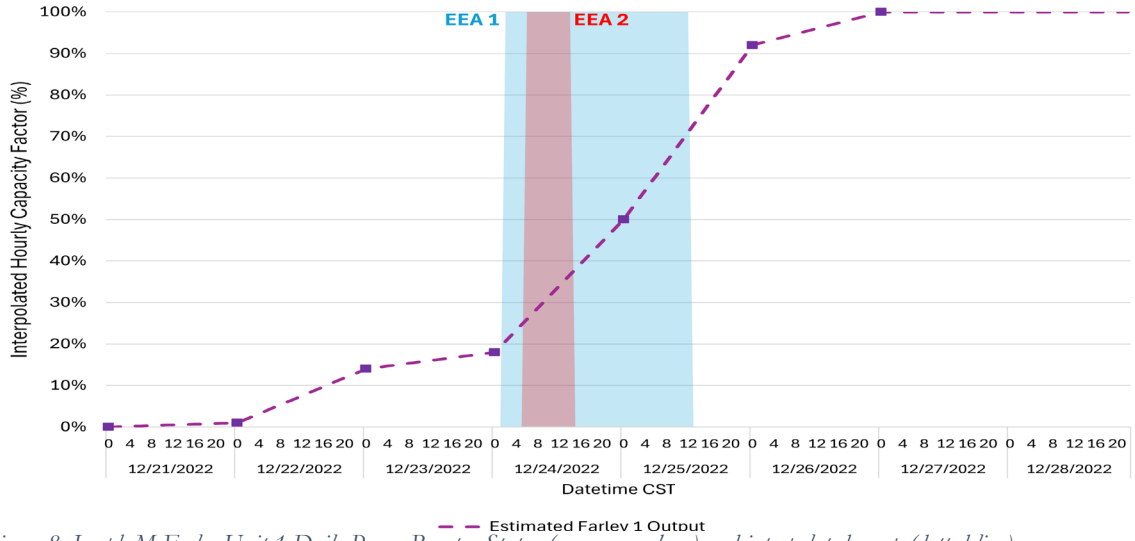

Figure 8. Joseph M Farley Unit 1 Daily Power Reactor Status (square markers) and interpolated ramp (dotted line)

Performance of Mississippi Power Generators

Review of Mississippi Power fossil fueled generation showed three plants where output leading up to the peak load hour was declining or well below its winter rating. Figure 9 *(page 12, top)* shows the total plants hourly generation as a percentage of their winter rating based on EPA CEMS and EIA 860 data.

These plants stand out because of substantial deviations in generation during the emergency window due to overall lower generation than might be expected during the event considering emergency purchases were required.

The three plants identified as having potential outages or were the:

- 41 MW Sweatt Electric Generating Plant
- 762 MW Watson Electric Generating Plant, and
- 2,180 MW Daniel Electric Generating Plant.

The Sweatt Electric Generating Plant appears to have been offline or unavailable throughout the entire period. This may indicate an extended outage that started before the storm.

This unit was flagged because no operations were found at any point during the EEA 2 period.

During emergency window, the Watson Electric Generating Plant output was 163 MW lower than its maximum during the EEA 1 period that morning. The Daniel Electric Generating Plant output was 436 MW lower. This behavior may be indicative of unit outages or fuel supply disruptions and a sign of correlated cold weather outages.

In total, these two plants' output during the emergency window was lower by 598 MW. Including Sweatt in the total brings it to 639.5 MW.

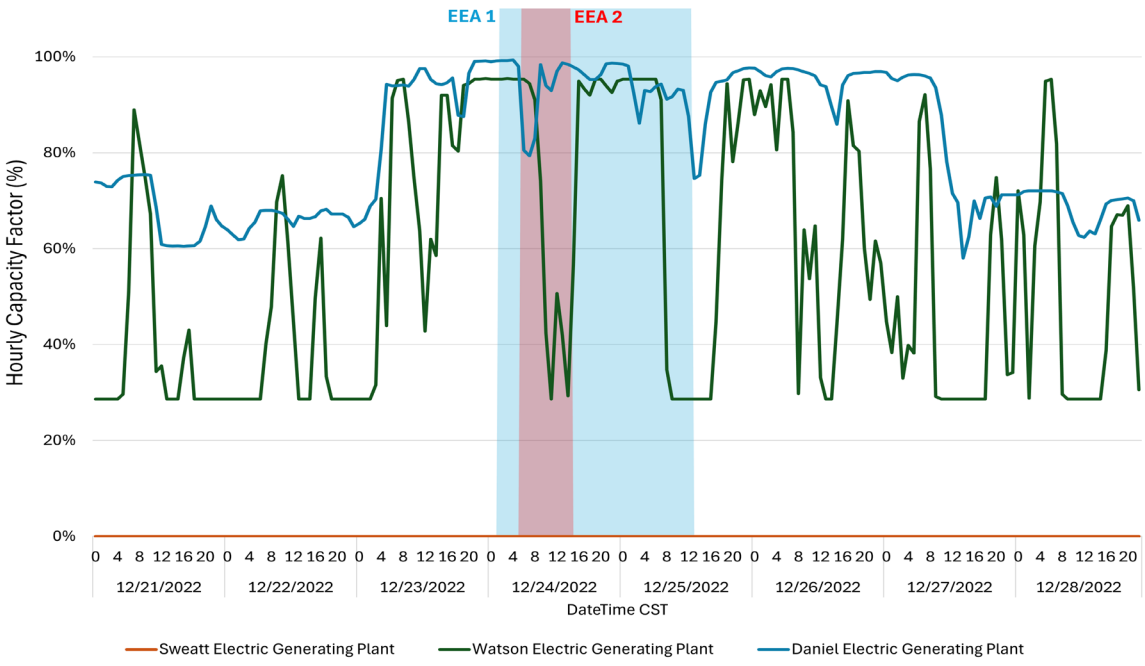

Figure 9. Mississippi Power generation identified as having potential outages during Winter Storm Elliott.

Performance of Southern Power Generators

Review of Southern Power fossil fueled generation showed two plants where output leading up to the peak load hour was declining or well below its winter rating. Figure 10 *(below)* shows the total plants hourly generation as a percentage of their winter rating based on EPA CEMS and EIA 860 data. These plants stand out because of substantial deviations in generation after EEA 1 and EEA 2 were declared and due to overall lower generation than might be expected during the event considering emergency purchases were required.

The two plants identified as having potential outages or derates during the EEA period were the 693 MW Edward L. Addison Generating Plant and the 1,233 MW Wansley Combined Cycle.

During the emergency window, the Edward L. Addison Generating Plant output was lower by 275 MW relative to the EEA 1 hours prior. The Wansley Combined Cycle output was 209 MW lower. This behavior may be indicative of unit outages or fuel supply disruptions and a sign of correlated cold weather outages. In total, these two plants' output during the emergency window was lower by 483 MW.

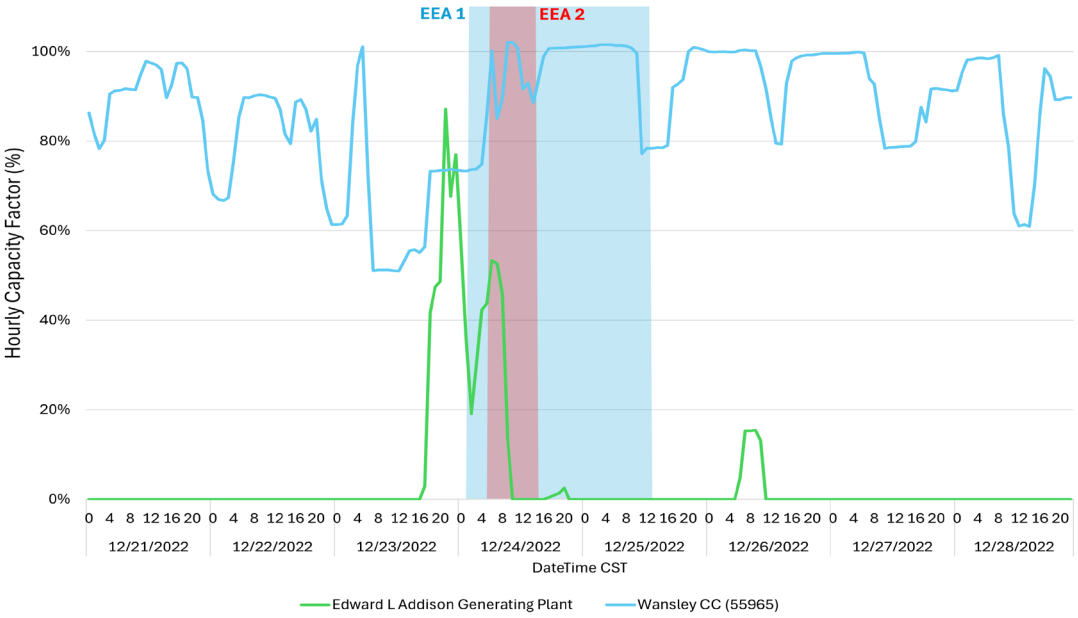

Figure 10. Southern Power generators identified as having potential outages during Winter Storm Elliott.

Performance of PPA Generators

In addition to utility owned assets, Southern Company and its subsidiaries also procure capacity and energy via PPAs.

These types of resources use a variety of fuels, including gas, landfill gas, oil, and biomass. EPA data is not available for non-utility generating units, nor units that are less than 25 MW in size. Due to this limitation, only those PPA units that are known to contract with Southern Company subsidiaries and met the size threshold or those that Georgia Power provided data on were reviewed in this section. Generation by plant for different fuel types is reviewed in the following subsections.

Biomass PPA Generator Performance

Data was only available for biomass generators reported in the Georgia Power IRP and provided in the docket request. Review of these units' output leading up to and during the peak load hour shows a general underperformance relative to the size of the PPA.

Figure 11 *(below)* shows the five plants that had zero output during the peak load hour. The hourly data shown also indicates little to no generation for these plants during the entire EEA 1 and 2 period. The total capacity unavailable during the emergency window was 230 MW out of 302 MW of biomass PPA resources.

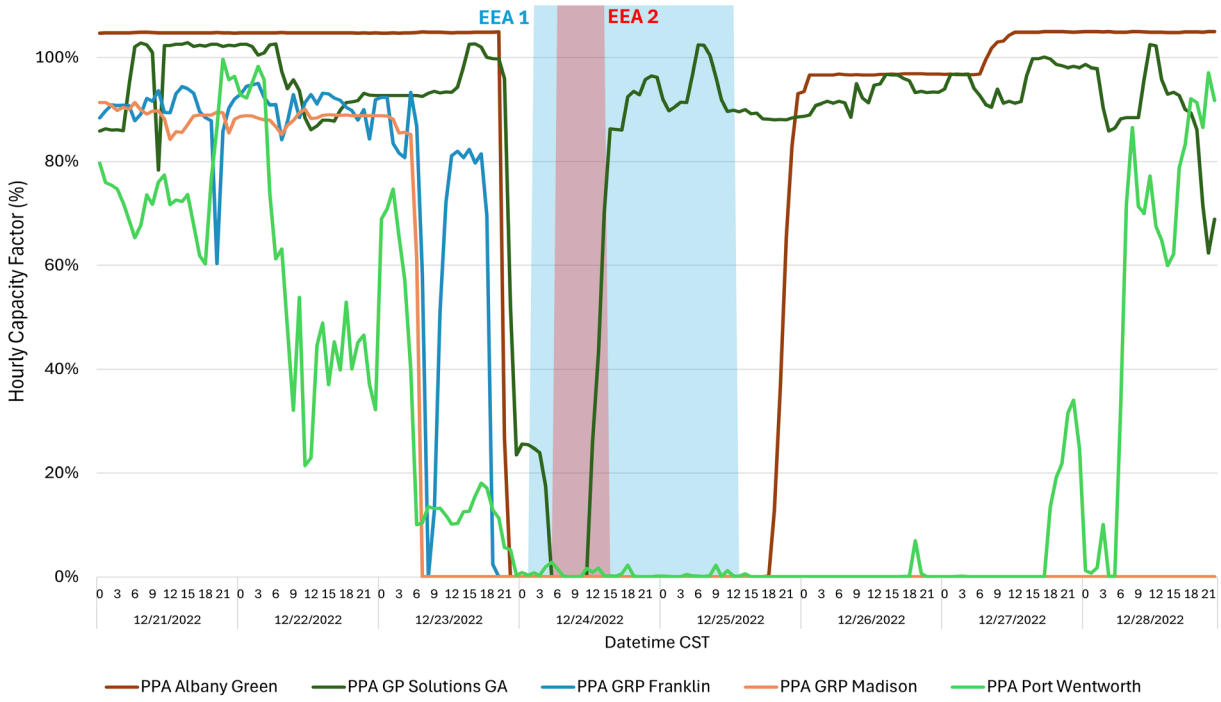

Figure 11. Georgia Power Biomass PPA generators identified as having potential outages during Winter Storm Elliot.

Landfill Gas (LFG) PPA Generator Performance

Data was only available for landfill gas generators reported in the Georgia Power IRP and provided in the docket request. Review of these units' output leading up to and during the peak load hour shows a general underperformance relative to the size of the PPA.

Figure 12 *(page 14, top)* shows that all five plants had zero output during the peak load hour. The hourly data shown also indicates no generation for these plants from 12/23/2022 to until the morning of 12/27/2022. The total capacity unavailable during the peak load hour was 32.3 MW and 100% of the LFG PPA resources.

Gas PPA Generator Performance

Several larger gas generators that are not owned by Southern Company also serve load via PPAs. A review of both the EPA CEMS data and data provided by Georgia Power shows that six plants had potential outages or derates leading up to the peak hour.

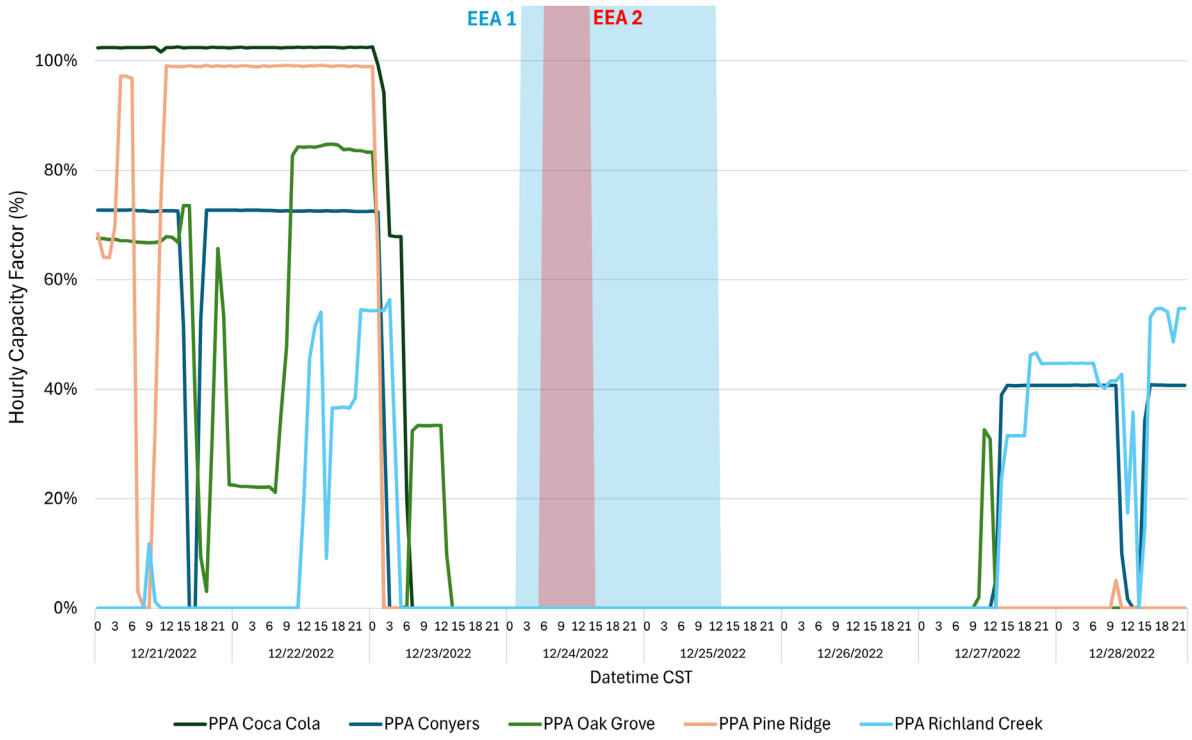

Figure 12 Georgia Power LFG PPA generators identified as having potential outages during Winter Storm Elliott.

Figure 13 (below) shows the hourly generation data for the plants using EPA CEMS data. These three units shown indicate likely low resource availability that is likely not attributable to Winter Storm Elliott except for potentially Washington County Power which sees a reduction in outFigure 13. Additional Southern Company PPA generators identified as put going into the EEA 1 period. Relative to their winter capacity ratings, the lack of generation totals 2,044 MW.

Additional information based on monthly net generation for each of the facilities in 2022 and 2021 indicate that there may have been extended outages at all three plants since monthly net generation was either 0 or substantially reduced in October, November, and December relative to the same months in 2021.

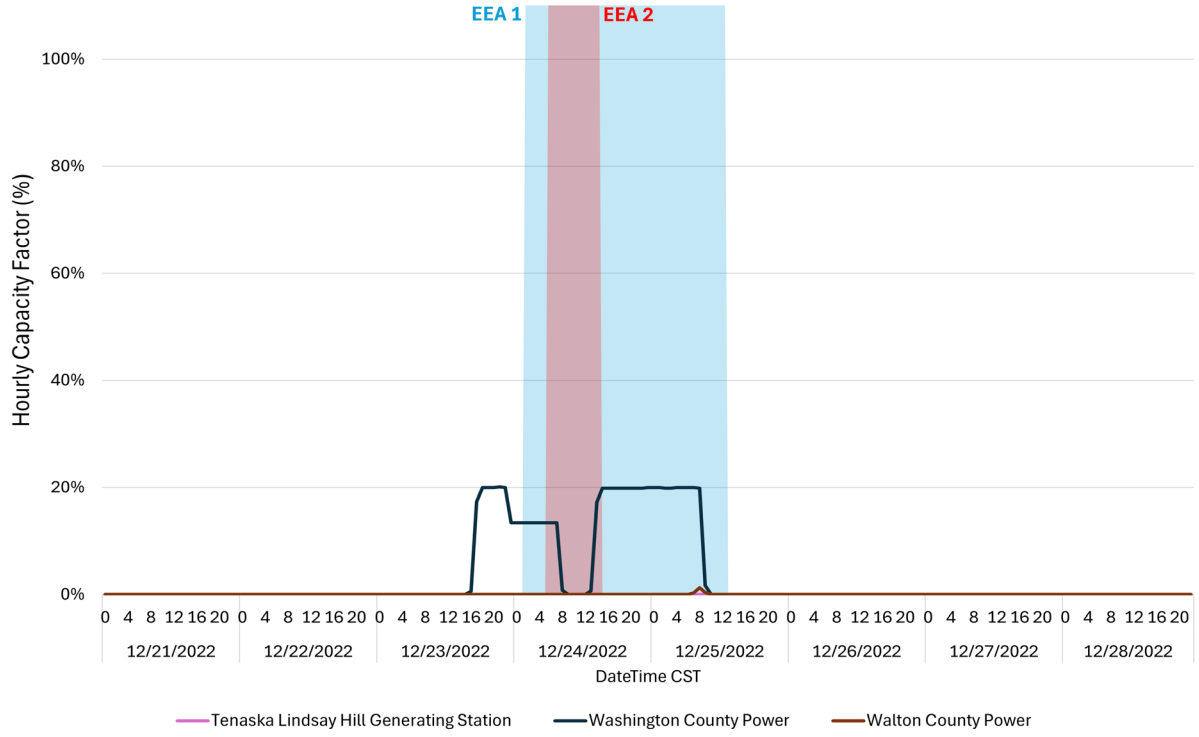

Figure 13. Additional Southern Company PPA generators identified as unavailable during Winter Storm Elliott based on EPA CEMS data.

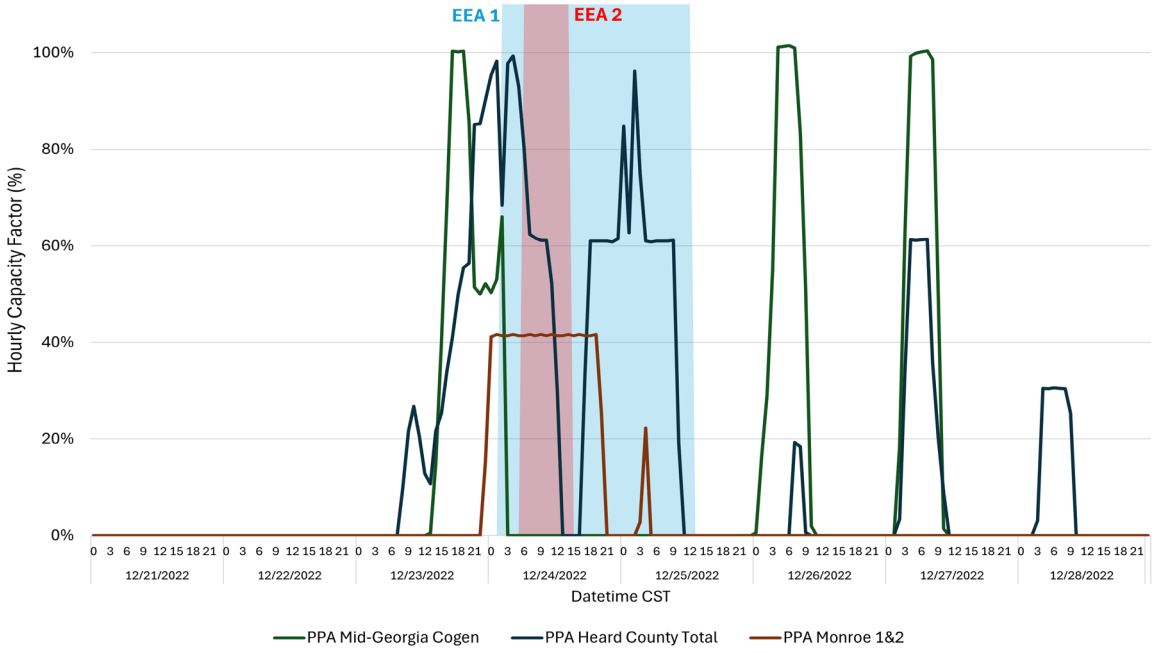

Figure 14. Additional Southern Company PPA generators identified as unavailable during Winter Storm Elliott based on Georgia Power data.

Figure 14 *(above)* shows the hourly generation data for additional PPA plants using Georgia Power provided data. The three plants are the 945 MW Exelon Heard facility (also called Tenaska Georgia Generating Station), the 300 MW Mid-Georgia Cogen, and the 360 MW Monroe plant (also called MPC Generating).

The data shown indicates that all three plants faced decreased generating capability during the emergency window. The Mid-Georgia Cogen plant has a noticeable drop in generation down to 0.

The Heard County plant has a similar trajectory where the plant is at full output prior to the event and eventually drops to 62% output during the peak load hour. Lastly, the Monroe facility was operating only at 41% output due to no generation from Monroe unit 2 during the EEA period. In total, these plants provided 727 MW of output during the emergency window relative to their total 1,635 MW winter ratings.

Evaluating Incremental Cold Weather Outages

In their 2022 IRP, Georgia Power shared the Southern Pool's assumptions on incremental cold weather outages for Southern Company resources. Their recognition that cold weather increases the probability of generators going on outage is a best practice; however, the data provided is highly aggregated, assuming all unit types are affected equally, and only shown at the pool level.

Risks will vary by fuel type and by region in the pool and should be communicated as such.

Additionally, Southern Company assumed in their analysis that actions they took reduced cold weather outage risks in the future relative to the historical period. This is shown by the shift down and to the left of the orange line (assumed improvements) relative to the blue line (historical performance) in Figure 15

Considering Winter Storm Elliott and upcoming IRPs, these assumptions should be re-evaluated to ensure they are valid. The results of applying these assumptions to their modeling process should be documented in more detail to show the magnitude of additional outages that can occur as temperatures drop. Reporting the worst-case fleet availability level rather than just the incremental effect would go a long way in properly communicating what cold weather risks look like for the generation fleet.

Based on the data from the 2022 Georgia Power IRP, the fleetwide incremental cold weather outages are shown in Figure 15 *(page 16, top).* Based on Figure 15 and an average temperature of 7 degrees F during the morning of 12/24/2022 across Southern Company the improved incremental outage rate was 2.77%. The original incremental cold weather outage rate was 5.28%.

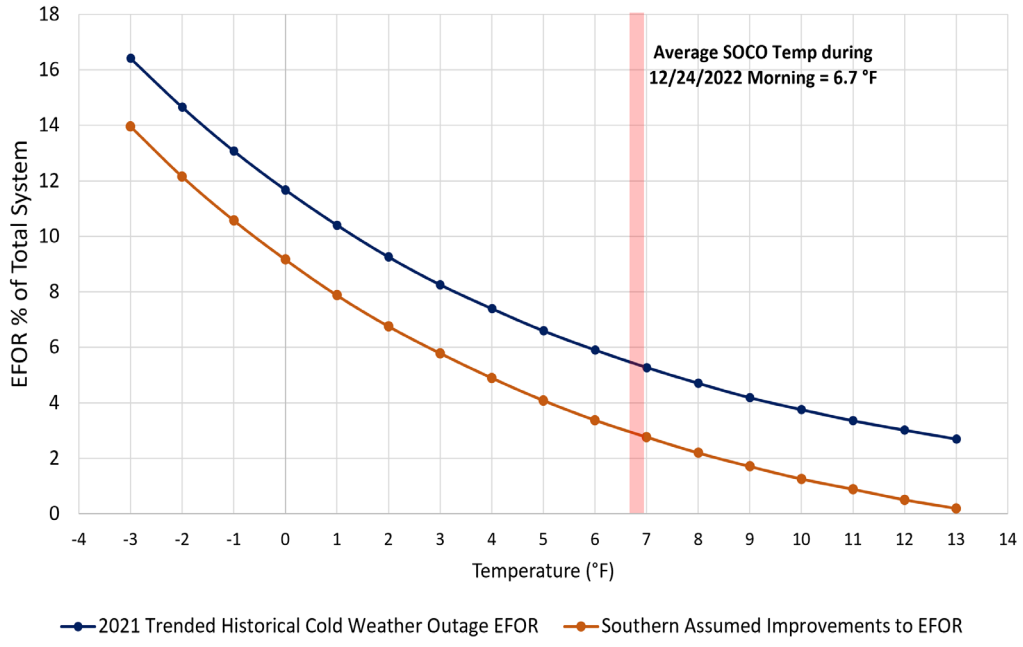

Figure 15. Incremental Equivalent Forced Outage Rate (EFOR) at the Total Southern Company System.

Given that Georgia Power alone experienced a 15% reduction in capacity due forced outages during the storm, the assumed incremental outage rates of 2.77% discussed above appear to significantly underrepresent winter outage risks for the system. Therefore, these assumptions should be revisited and results of the analysis should be transparent for stakeholders.

The challenges due to cold weather outages reinforce the need for all resources to be evaluated for their firm capacity contribution using probabilistic methods just like wind, solar, and battery storage.

As discussed, another issue is that the company-wide risk due to cold weather outages remains unclear since reported data is missing for Alabama, Mississippi, and Southern Power owned units and PPAs during the event. This report has estimated the performance of these plants, but actual detailed information is needed.

Furthermore, Georgia Power only provided information on outages that occurred on the peak load day of December 24, 2022. Extreme cold weather affected the entire region prior, during, and after the worst day while temperatures were still low, and the effects of cold weather outages could have occurred on other days than the peak day.

Performance of Renewable Resources

Figure 16 *(below)* illustrates the total generation from solar resources within the Southern Company balancing authority footprint during the storm. As expected, solar resources did contribute to meeting demand throughout the day, but in the early morning hours output was limited. Compared to other winter peak events, solar performance was generally stable, but its role in peak support remains constrained due to the lack of irradiance at critical morning and and

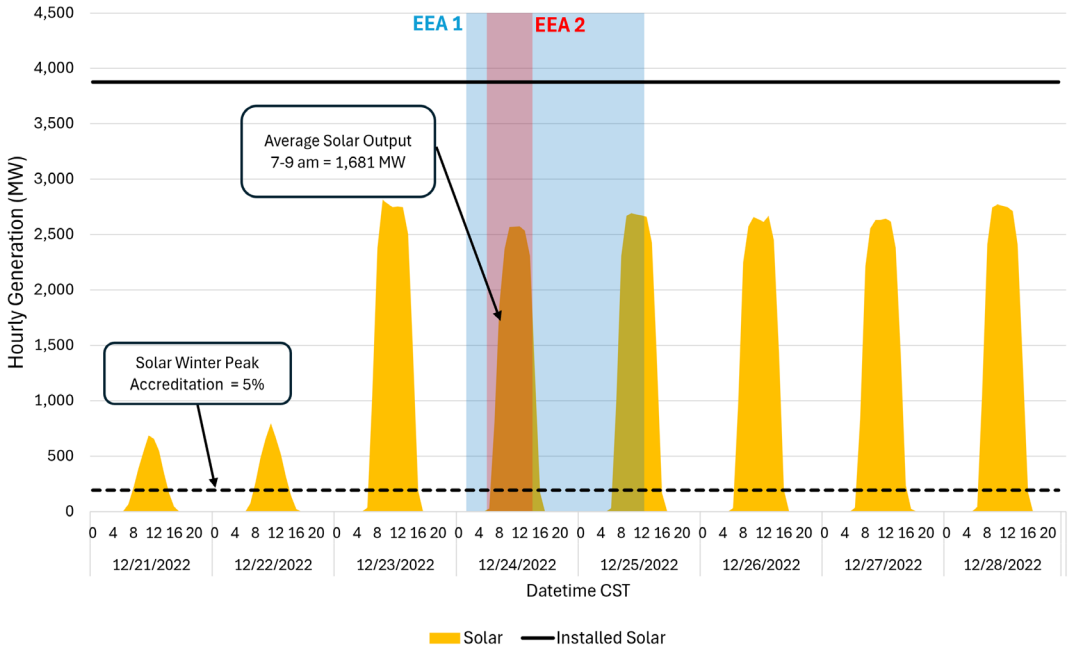

Figure 16. Solar generation for the entire Southern Company Balancing Authority during Winter Storm Elliott.

Month-Year	Peak Load Hour	Peak Load (MW)	Solar Capacity Factor at Peak
January 2019	1/30/19 6:00	40,450	1%
January 2020	1/22/20 6:00	40,410	1%
February 2021	2/17/21 6:00	40,922	4%
December 2022	12/24/22 7:00	45,131	21%
December 2023	12/20/23 7:00	37,890	23%
January 2024	1/17/24 6:00	47,368	2%

Table 3. Southern Company Balancing Authority solar capacity factor during historical peak load hours based on EIA data.

evening peaks. This shows that while solar production was low on the days leading up to the extreme cold event, production was high in the day prior to, and during, the event. This suggests that in the future, with increased battery storage resources, solar resources can improve reliability even if they are unavailable during the early morning peak load hours.

Table 3 *(above)* shows historical peak load and solar output relative to installed capacity for the 2019-2024 winter peak load events in the Southern Company Balancing Authority according to EIA 930 and EIA 860 data. Solar resources are not expected to contribute to winter peak load and utilities plan for this accordingly.

For example, the 2022 Georgia Power IRP evaluated the capacity accreditation for solar resources and determined their winter accreditation is 0-10% depending on the type of solar array and the penetration on the system[5]. Results in Table 3 and Figure 16 indicate that solar performed well above it's expected contribution during Winter Storm Elliott.

Other historical peak loads show performance can vary widely, largely driven by whether peak loads occur between 6-7 am based on the data shown. While solar generation during winter peak loads can vary, if battery storage resources are added alongside solar then greater utilization can be achieved, especially for early morning peak load hours in the wintertime. Currently, battery storage deployment is limited in Southern Company.

It is clear though that prior to the extreme events occurring on December 24, 2022, that storage resources could have been charged in advance to mitigate the hours of highest peak load enhancing resilience by rapidly offsetting unexpected generator outages and increasing system flexibility. Furthermore, solar, storage, and wind resources create portfolio effects that can boost the total renewable systems capacity accreditation. These effects should be evaluated and accreditation refined over time.

Recommendations to Improve Planning for Cold Weather Outages

The following are recommendations on how Southern Company and its subsidiaries can provide greater clarity on how the generation fleet performs under cold weather conditions and how to better represent the risks that all generation faces when planning for new generation resources to meet demand or replace retirements:

1. **Conduct transparent evaluation of how increases to power plant outages due to cold weather. Current information is from the Georgia Power 2022 IRP and only provides fleetwide incremental outages.**
2. **Assess whether assumed cold weather outage improvements in 2021 have been effective.**
3. **Assess all future resource addition options based on every resource type and its effective load carry capability (ELCC) like how wind, solar, and battery storage is assessed. This necessitates including cold weather outages in the assessment.**
4. **Provide transparency on the current capacity accreditation assumed for all resources. Historical accreditation using incremental capacity equivalent (ICE) is redacted in previous full IRP filings.**

5 2022 GPC IRP, Study of Renewable Capacity Values using the ELCC Methodology in the Southern Company System, December 2021.

Emergency Power Purchases and Costs

One key reliability feature of the bulk power system is the ability to import power from neighboring regions to alleviate stress during extreme events.

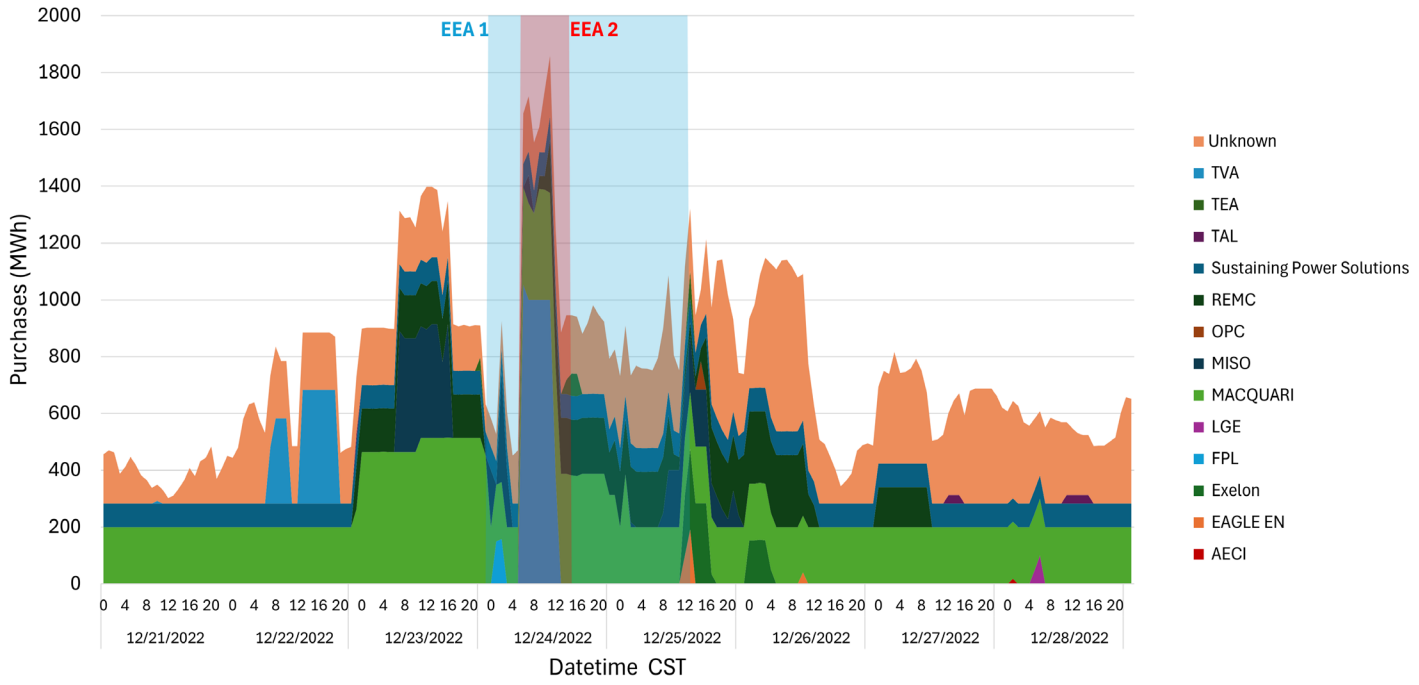

Figure 17. Winter Storm Elliott - Southern Company Known and Estimated Purchases by Source.

Even in vertically integrated areas like the Southeast, energy exchanges play a crucial role in balancing supply and demand and ensuring system reliability, especially during emergencies such as Winter Storm Elliott.

However, these regions typically lack transparency about where emergency power originates and its cost to customers, limiting public oversight of emergency spending and raising questions about planning for reliable external support an ensuring that prices are based in some transparent fashion.

In response to regulatory data requests, some data for Georgia Power was released, though comprehensive data for the full Southern Company system remains unavailable. By matching resource IDs and timestamps from Georgia Power with anonymized data from other Southern Company entities, it was possible to estimate the source, magnitude, and cost of emergency power for the broader system.

However, only Georgia Power Company transactions are shown with complete information regarding the source and price of power, while non-GPC transactions are based on estimations.

Figure 17 *(above)* displays all purchases by source including estimated and unidentified purchases for all Southern Company entities.

Note that outside of known balancing authorities, the exact power plants and owners are uncertain so additional tracking to what kind of units are providing the power is difficult to accomplish.

Price Variability by Seller and Estimated Costs

Throughout Winter Storm Elliott, prices varied significantly depending on the seller. This variation is expected during extreme events as regions experience fluctuating spare capacity. Figure 18 *(below)* illustrates the known and estimated costs of power purchased by Southern Company by seller, with unknown purchases estimated based on the average price for known purchases during each hour. In total, emergency purchases cost $51 million, or $350/MWh.

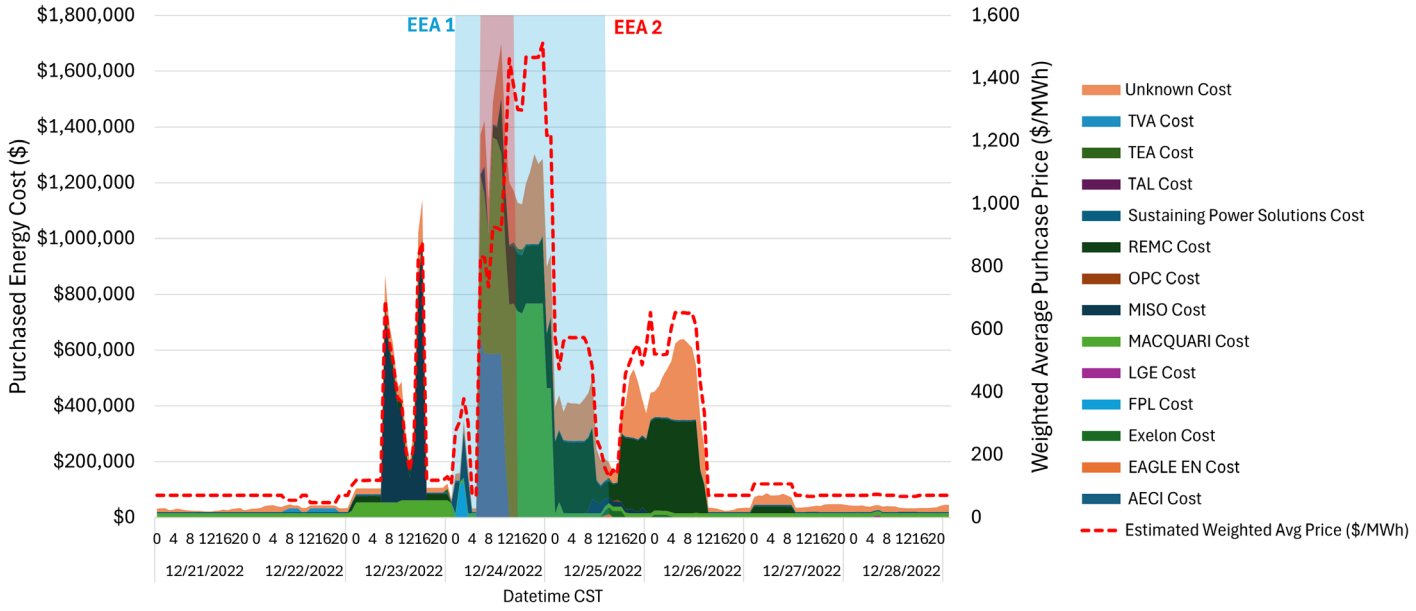

Figure 18. Winter Storm Elliot - Southern Company Estimated Cost by Source.

Table 4 *(page 20)* provides a summary of purchase data available via Georgia Power's discovery request, including estimates for all Southern Company purchases matched with GPC resource IDs, where prices for matched sellers were set to the GPC rate. For transactions labeled "unknown," no GPC resource ID was available for matching.

This summary highlights several points: while energy costs generally track with total MWh purchased, certain sellers exhibited disproportionately high prices. For instance, purchases from REMC, MISO, and FPL accounted for a much higher percentage of total costs compared to MWh purchased.

Specifically, REMC transactions represented only 9.9% of the total MWh but contributed 24.3% of total costs due to elevated prices that persisted well after EEA 1 and EEA 2 conditions had ended.

The price formation for non-market regions like MISO lack transparency, making it difficult to determine the reasons behind these elevated rates. It is expected that prices across the region will be high during the event.

But the reason some prices were $400/MWh versus $4,000/MWh is worth providing more detail on.

Other sellers also contributed to high overall costs, notably Macquarie and FPL. FPL provided 6,736 MWh at an average price of $599/MWh, reaching a peak of $1,000/MWh. Macquarie, supplying roughly 33% of Southern Company's total purchased MWh during the event, averaged $330/MWh, with some purchases reaching as high as $4,000/MWh during EEA 2.

Such data points suggest the potential for substantial savings if lower-cost alternatives were available and less market power given to emergency purchases by planning for a more resilient system.

Seller Name	Total MWh	% of Total MWh	Total Cost ($)	% of Total Cost	Average Price ($/MWh)	Max Price ($/MWh)
AECI	18	0.0%	$946	0.002%	$53	$54
EAGLE EN	331	0.2%	$22,015	0.04%	$67	$70
Exelon	2,045	1.4%	$160,005	0.31%	$78	$85
FPL	6,736	4.6%	$4,033,643	7.85%	$599	$1,000
LGE	146	0.1%	$12,182	0.02%	$83	$96
MACQUARI	48,596	33.2%	$16,053,050	31.24%	$330	$4,000
MISO	6,909	4.7%	$5,246,666	10.27%	$764	$2,832
OPC	100	0.1%	$6,000	0.01%	$60	$60
REMC	14,498	9.9%	$12,518,350	24.36%	$863	$1,300
Sustaining Power Solutions	15,936	10.9%	$987,235	1.92%	$62	$62
TAL	270	0.2%	$8,730	0.02%	$32	$36
TEA	357	0.2%	$56,714	0.11%	$159	$303
TVA	3,909	2.7%	$128,399	0.25%	$33	$44
Unknown*	46,633	31.8%	$12,118,397	23.58%	$260	$1,081
Total Purchases	146,484	100%	$51,382,333	100%	$351	$4,000

Table 4. Summary data by Southern Company during Winter Storm Elliott based on GPC Data (12/21/2022 - 12/28/2022).

Implications of Non-Transparent Price Setting

This review of emergency power purchases underscores the wide range of prices paid by Georgia Power to different sellers during Winter Storm Elliott, revealing challenges inherent in a system without transparent locational marginal pricing (LMP) for transactions in vertically integrated regions like the Southeast.

In contrast, neighboring regions impacted by Winter Storm Elliott, such as MISO, provide LMP data that reflects both energy production and transportation costs, including information on transmission congestion and losses.

Notably, MISO provides real-time price data at its interface with Southern Company in Mississippi, updated on a five-minute basis. This level of pricing transparency allows stakeholders to verify that prices reflect actual market conditions.

For Southern Company customers, the lack of similar transparency represents a challenge, particularly in the context of high emergency costs.

Currently, neither Georgia Power's public data nor the Southeast Energy Exchange Market (SEEM), reviewed in detail in the next section, offers information on price formation, especially under stress conditions.

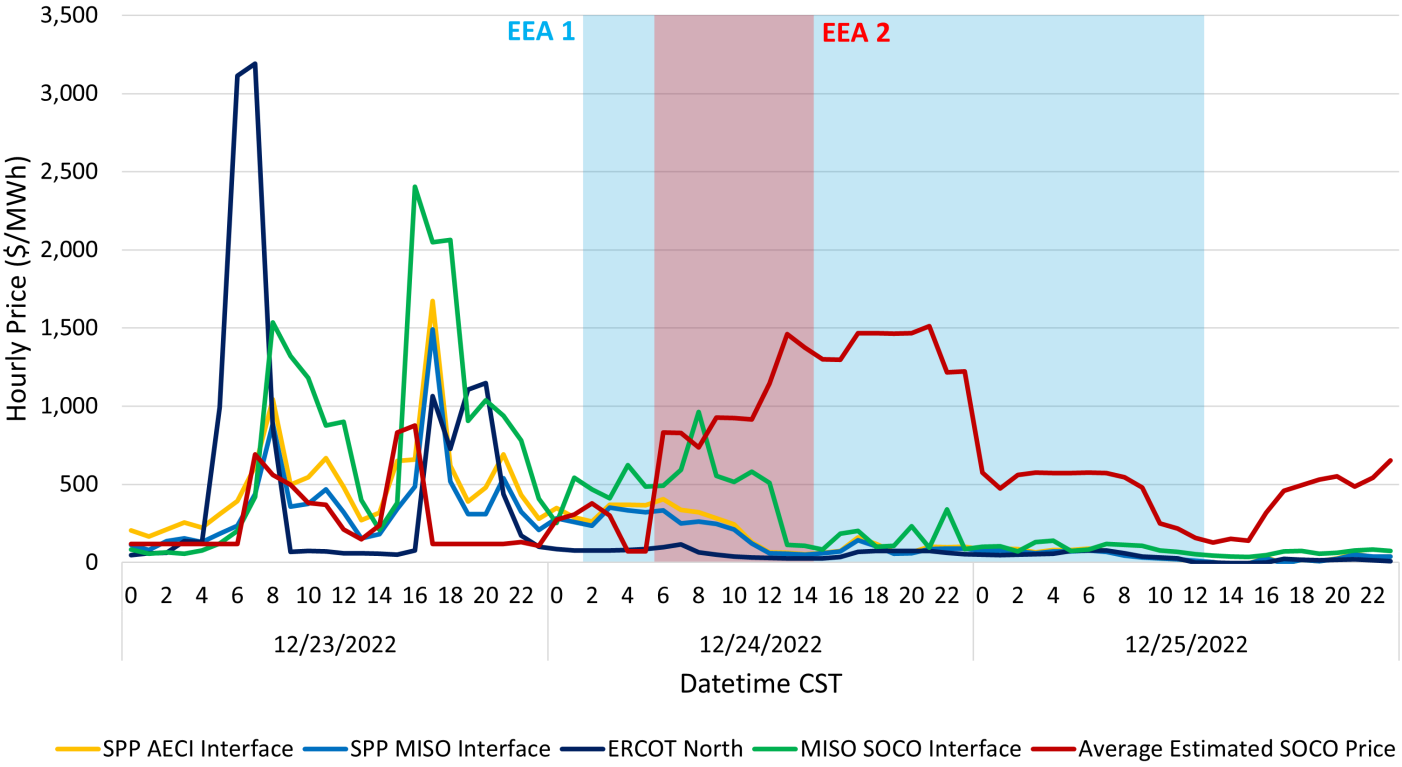

Figure 19. Average Known Southern Company Purchase Price vs Nearby Market LMP ($/MWh)

This limitation prevents customers from understanding the rationale behind emergency prices and assessing whether costs could have been mitigated through better planning or interregional coordination.

Opportunities for Interregional Transmission to Improve Reliability and Reduce Costs

Reviewing LMPs for nearby regions highlights potential cost savings and reliability benefits that increased imports from neighboring regions could provide if transmission were available.

Enhanced interregional transmission connections with transparent pricing could offer more reliable access to affordable external resources.

Figure 19 *(above)* shows that prices in ERCOT, SPP, and MISO (at the Southern Company interface) were considerably lower than GPC purchase prices on December 24 and 25, when generation weighted known prices averaged over $1,000/MWh.

Leveraging interregional transfers could thus help Southern Company meet peak demands more cost-effectively during future extreme events, while offering customers clearer insights into price formation.

Southeast Energy Exchange Market Performance

The Southeast Energy Exchange Market (SEEM) began operations in November 2022, just one month before Winter Storm Elliott stressed power systems across the Southeastern United States. SEEM was designed to facilitate voluntary bilateral energy trade across the region, providing participants with a way to exchange surplus energy efficiently.

However, during the critical hours of December 24th, 2022, when the Southern region declared EEA 1 and EEA 2 energy emergencies, publicly available data shows that no exchanges occurred among SEEM participants. This absence of trades highlights questions about SEEM's role in supporting reliability during peak demand events and the broader applicability of its platform under emergency conditions.

While SEEM data is anonymized, the platform generally shows transaction volumes across different periods, allowing observers to see broad trends without detailed participant information. Analysis of SEEM's transaction volumes during Winter Storm Elliott suggests low utilization by market participants at a time when system operators were under significant stress to maintain grid stability. This could be attributed, in part, to SEEM's novelty or uncertainty about the available capacity and pricing under extreme conditions.

However, low activity in SEEM during the storm aligns with the independent market auditor's reports[6], which indicate that SEEM transactions were limited during cold weather events, potentially due to limited availability of surplus energy and participant hesitancy during tight grid conditions. Despite SEEM's low trading volume during Winter Storm Elliott, bilateral transactions outside SEEM were still active across the region. Southern Company, for example, engaged in multiple direct purchases during this period, reflecting a preference for more established bilateral agreements rather than SEEM exchanges under emergency circumstances.

This trend indicates that SEEM's structure may not yet fully align with participant needs during stress events, when timely and cost-effective energy transactions are most critical.

SEEM Performance in Subsequent Winter Peak Events

Since Winter Storm Elliott, SEEM has continued operating through subsequent winter peak load events, but its performance under these conditions has similarly shown limited market activity during peak demand periods. This ongoing trend suggests that SEEM, while potentially valuable for regular trading, has not become a resource for emergency support during peak conditions such as those that occurred during Winter Storm Heather[7].

Furthermore, the anonymized structure of SEEM data limits participants and stakeholders from understanding price formation or the dynamics of energy exchanges during tight conditions, in contrast to organized markets like MISO or PJM, where locational marginal pricing (LMP) provides detailed price signals reflecting supply and demand fluctuations in real time.

In summary, SEEM's first significant test under Winter Storm Elliott highlighted critical limitations in the platform's ability to facilitate energy exchanges during emergencies.

Its low utilization during peak load events like Winter Storm Elliott and Winter Storm Heather calls into question its ability to aid the system in matching economic transactions during reliability events. As a result, SEEM may not yet be equipped to provide meaningful support for system operators or offer cost-effective, transparent solutions for ratepayers during critical grid conditions.

6 Potomac Economics, Monthly Audit Report on the Southeast Energy Exchange Market - December 2022, January 31, 2023.
7 Potomac Economics, Monthly Audit Report on the Southeast Energy Exchange Market - January 2024, February 29, 2024.

Conclusion and Recommendations

This report examined Southern Company's generation fleet performance, load forecasting accuracy, and market transactions during Winter Storm Elliott. While Southern Company successfully managed the event without resorting to involuntary load shedding, the system operated under tight conditions, revealing areas where improvements in resource reliability, forecasting, and market transparency could enhance resilience against future weather-related stress.

Additionally, the Southeast Energy Exchange Market (SEEM), which had launched only a month earlier, showed minimal trading activity, highlighting opportunities for enhancements to support reliability during emergencies. Questions remain regarding how the system might have performed if demand had been higher, such as on a non-holiday weekday when electricity use is typically greater.

These considerations underscore the need for a deeper examination of how risk is evaluated in system planning and how potentially high-value opportunities to mitigate risk from extreme weather (such as by improving energy efficiency and increasing access to interregional resources) are assessed. This is of particular importance for extreme winter events which have high uncertainty on both generator outages and electricity demand.

To address these challenges, the following actions would benefit both Southern Company and stakeholders in improving transparency and ensuring reliability.

1. **Enhance Thermal Resource Evaluation:** Future grid planning should improve methods for evaluating the capacity contribution of thermal resources. Rather than discounting by average forced outage rates, planning should reflect the real correlated outage risk of these resources during extreme events. Consistent with the evaluation approach for wind and solar resources, this revised methodology would provide a more accurate picture of available capacity during winter peak demands and extreme weather events.

2. **Reassess Incremental Cold Weather Outages:** Southern Company should re-evaluate incremental cold weather outage assumptions, disaggregating data by fuel type rather than applying fleet-wide assumptions. Analyzing outage probabilities by fuel type could highlight distinct vulnerabilities and more accurately inform resource adequacy planning for cold weather conditions.

3. **Increase Transparency:** Southern Company should establish more transparent mechanisms for purchased power and emergency cost formation. Adopting some form of locational marginal pricing (LMP) across the Southern Company territory would align emergency prices with real-time market conditions, offering regulators and customers a clearer understanding of cost drivers during emergencies as they relate to both the price of energy and the cost of transmission.

4. **Enhance SEEM Functionality and Transparency:** Based on SEEM's limited use during Winter Storm Elliott, improvements should be considered to enhance its role in reliability. The platform could incorporate faster price signaling or offer day-ahead market signals to increase utilization during peak events. Recommendations already exist from the SEEM independent auditor to improve performance. Current reviews of SEEM by FERC also offer a chance to improve operations during emergencies, particularly with external regions into SEEM.

5. **Evaluate interregional transmission opportunities to mitigate winter reliability risks by accessing low cost and uncorrelated resources in external regions.** It is well documented that interregional transmission can provide substantial resource adequacy and resilience benefits. Long-term and multi-value transmission planning should be adopted in the region.

6. **Evaluate targeted energy efficiency opportunities to reduce load and volatility during cold weather events, including building envelope efficiency improvements and more efficient heating programs to mitigate winter load volatility.**

By implementing these recommendations, Southern Company and its stakeholders can strengthen reliability, ensure resource adequacy, and reduce costs under extreme weather conditions. A focus on accurate resource evaluation, refined forecasting, and transparent pricing mechanisms will better equip the region to manage future winter peak events effectively.

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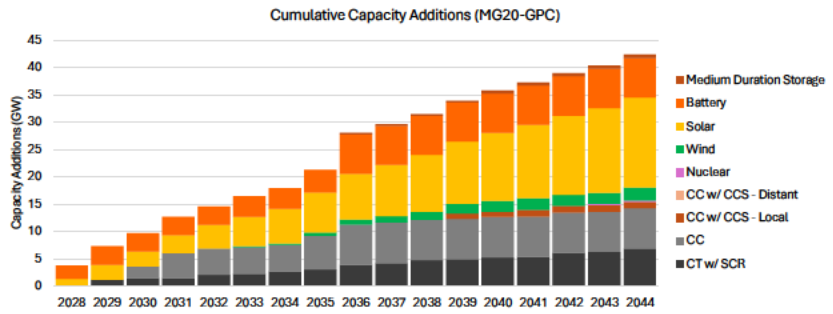
DS-11:

Workpaper: Capacity Expansion Plans by Portfolio

Scenario MG20-GPC
Title Cumulative Capacity Additions (MG20-GPC)



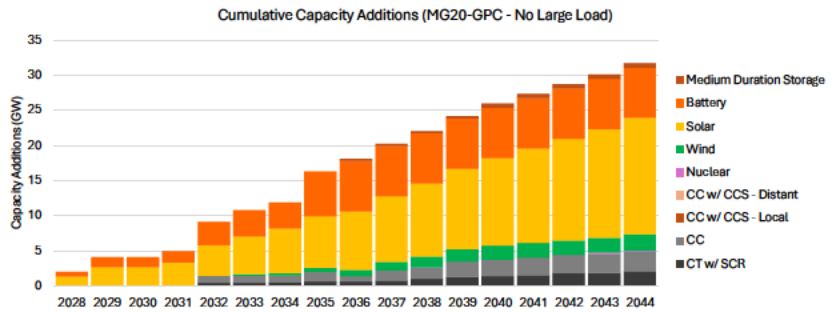
Cumulative Additions (MW)

Year	CT w/ SCR	CC	CC w/ CCS - Local	CC w/ CCS - Distant	Nuclear	Wind	Solar	Battery	Medium Duration Storage	Battery 4-hr (T1)	Battery 4-hr (T2)	Battery 4-hr (T3)	Battery 4-hr (T4)	Battery 4-hr (T1_2)	Battery 4-hr (T2_2)	Medium Duration Storage	Total Storage
2028	0	0	0	0	0	0	1370	2430	0	1530	900	0	0	0	0	0	3800
2029	1200	0	0	0	0	0	2750	3330	0	1530	1800	0	0	0	0	0	7280
2030	1500	2130	0	0	0	0	2750	3330	0	1530	1800	0	0	0	0	0	9710
2031	1500	4530	0	0	0	0	3350	3330	0	1530	1800	0	0	0	0	0	12710
2032	2100	4800	0	0	0	0	4340	3330	0	1530	1800	0	0	0	0	0	14570
2033	2310	4800	0	0	0	240	5330	3750	0	1530	2220	0	0	0	0	0	16430
2034	2730	4800	0	0	0	300	6320	3750	0	1530	2220	0	0	0	0	0	17900
2035	3030	6180	0	0	0	600	7310	4170	0	1530	2640	0	0	0	0	0	21290
2036	3930	7380	0	0	0	900	8330	7170	300	1530	2640	3000	0	0	0	300	28010
2037	4230	7380	0	0	0	1200	9350	7170	300	1530	2640	3000	0	0	0	300	29630
2038	4770	7380	0	0	0	1500	10370	7170	300	1530	2640	3000	0	0	0	300	31490
2039	4980	7380	900	0	0	1770	11390	7170	300	1530	2640	3000	0	0	0	300	33890
2040	5280	7380	900	0	0	2070	12410	7170	600	1530	2640	3000	0	0	0	600	35810
2041	5400	7380	1200	0	0	2070	13430	7170	600	1530	2640	3000	0	0	0	600	37250
2042	6090	7380	1200	0	0	2070	14450	7170	600	1530	2640	3000	0	0	0	600	38960
2043	6240	7380	1200	0	210	2070	15470	7170	600	1530	2640	3000	0	0	0	600	40340
2044	6900	7380	1200	0	210	2370	16490	7170	600	1530	2640	3000	0	0	0	600	42320
Total	**6900**	**7380**	**1200**	**0**	**210**	2370	16490	**7170**	**600**	**1530**	**2640**	**3000**	**0**	**0**	**0**	**600**	**42320**

Incremental Additions (MW)

Year	CT w/ SCR	CC	CC w/ CCS - Local	CC w/ CCS - Distant	Nuclear	Wind	Solar	Battery	Medium Duration Storage	Battery 4-hr (T1)	Battery 4-hr (T2)	Battery 4-hr (T3)	Battery 4-hr (T4)	Battery 4-hr (T1_2)	Battery 4-hr (T2_2)	Medium Duration Storage	Total Storage
2025																	
2026	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2027	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2028	0	0	0	0	0	0	1370	2430	0	1530	900	0	0	0	0	0	3800
2029	1200	0	0	0	0	0	1380	900	0	0	900	0	0	0	0	0	3480
2030	300	2130	0	0	0	0	0	0	0	0	0	0	0	0	0	0	2430
2031	0	2400	0	0	0	0	600	0	0	0	0	0	0	0	0	0	3000
2032	600	270	0	0	0	0	990	0	0	0	0	0	0	0	0	0	1860
2033	210	0	0	0	0	240	990	420	0	0	420	0	0	0	0	0	1860
2034	420	0	0	0	0	60	990	0	0	0	0	0	0	0	0	0	1470
2035	300	1380	0	0	0	300	990	420	0	0	420	0	0	0	0	0	3390
2036	900	1200	0	0	0	300	1020	3000	300	0	0	3000	0	0	0	300	6720
2037	300	0	0	0	0	300	1020	0	0	0	0	0	0	0	0	0	1620
2038	540	0	0	0	0	300	1020	0	0	0	0	0	0	0	0	0	1860
2039	210	0	900	0	0	270	1020	0	0	0	0	0	0	0	0	0	2400
2040	300	0	0	0	0	300	1020	0	300	0	0	0	0	0	0	300	1920
2041	120	0	300	0	0	0	1020	0	0	0	0	0	0	0	0	0	1440
2042	690	0	0	0	0	0	1020	0	0	0	0	0	0	0	0	0	1710
2043	150	0	0	0	210	0	1020	0	0	0	0	0	0	0	0	0	1380
2044	660	0	0	0	0	300	1020	0	0	0	0	0	0	0	0	0	1980

Scenario MG20-GPC - No Large Load
Title Cumulative Capacity Additions (MG20-GPC - No Large Load)



Cumulative Additions (MW)

Year	CT w/ SCR	CC	CC w/ CCS - Local	CC w/ CCS - Distant	Nuclear	Wind	Solar	Battery	Medium Duration Storage
2028	0	0	0	0	0	0	1370	685	0
2029	0	0	0	0	0	0	2750	1375	0
2030	0	0	0	0	0	0	2750	1375	0
2031	0	0	0	0	0	0	3350	1675	0
2032	500	1000	0	0	0	0	4340	3330	0
2033	500	1000	0	0	0	240	5330	3750	0
2034	560	1000	0	0	0	300	6320	3750	0
2035	710	1340	0	0	0	600	7310	6370	0
2036	710	710	0	0	0	900	8330	7170	300
2037	820	1430	0	0	0	1200	9350	7170	300
2038	1070	1650	0	0	0	1500	10370	7170	300
2039	1320	2200	0	0	0	1770	11390	7170	300
2040	1450	2270	0	0	0	2070	12410	7170	600
2041	1580	2510	0	0	0	2070	13430	7170	600
2042	1840	2600	0	0	0	2070	14450	7170	600
2043	1930	2660	0	0	210	2070	15470	7170	600
2044	2160	2690	0	0	210	2370	16490	7170	600
Total	**2160**	**2690**	**0**	**0**	**210**	2370	16490	**7170**	**600**

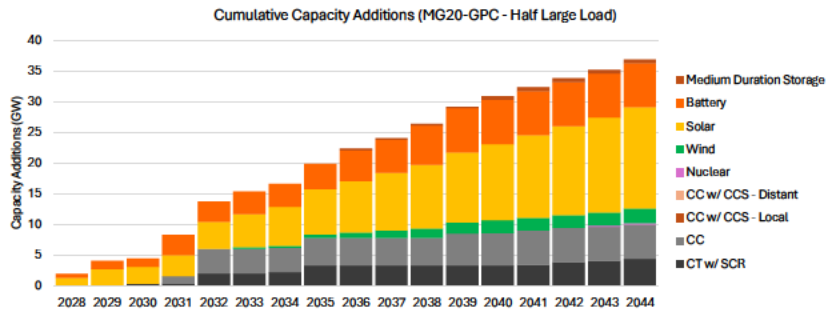
Battery 4-hr (T1)	Battery 4-hr (T2)	Battery 4-hr (T3)	Battery 4-hr (T4)	Battery 4-hr (T1_2)	Battery 4-hr (T2_2)	Medium Duration Storage	Total Storage
685	0	0	0	0	0	0	2055
1375	0	0	0	0	0	0	4125
1375	0	0	0	0	0	0	4125
1530	145	0	0	0	0	0	5025
1530	1800	0	0	0	0	0	9170
1530	2220	0	0	0	0	0	10820
1530	2220	0	0	0	0	0	11930
1530	2640	2200	0	0	0	0	16330
1530	2640	3000	0	0	0	300	18120
1530	2640	3000	0	0	0	300	20270
1530	2640	3000	0	0	0	300	22060
1530	2640	3000	0	0	0	300	24150
1530	2640	3000	0	0	0	600	25970
1530	2640	3000	0	0	0	600	27360
1530	2640	3000	0	0	0	600	28730
1530	2640	3000	0	0	0	600	30110
1530	2640	3000	0	0	0	600	31690
1530	**2640**	**3000**	**0**	**0**	**0**	**600**	**31690**

Incremental Additions (MW)

Year	CT w/ SCR	CC	CC w/ CCS - Local	CC w/ CCS - Distant	Nuclear	Wind	Solar	Battery	Medium Duration Storage
2025									
2026	0	0	0	0	0	0	0	0	0
2027	0	0	0	0	0	0	0	0	0
2028	0	0	0	0	0	0	1370	685	0
2029	0	0	0	0	0	0	1380	690	0
2030	0	0	0	0	0	0	0	0	0
2031	0	0	0	0	0	0	600	300	0
2032	500	1000	0	0	0	0	990	1655	0
2033	0	0	0	0	0	240	990	420	0
2034	60	0	0	0	0	60	990	0	0
2035	150	340	0	0	0	300	990	2620	0
2036	0	-630	0	0	0	300	1020	800	300
2037	110	720	0	0	0	300	1020	0	0
2038	250	220	0	0	0	300	1020	0	0
2039	250	550	0	0	0	270	1020	0	0
2040	130	70	0	0	0	300	1020	0	300
2041	130	240	0	0	0	0	1020	0	0
2042	260	90	0	0	0	0	1020	0	0
2043	90	60	0	0	210	0	1020	0	0
2044	230	30	0	0	0	300	1020	0	0

Battery 4-hr (T1)	Battery 4-hr (T2)	Battery 4-hr (T3)	Battery 4-hr (T4)	Battery 4-hr (T1_2)	Battery 4-hr (T2_2)	Medium Duration Storage	Total Storage
0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0
685	0	0	0	0	0	0	2055
690	0	0	0	0	0	0	2070
0	0	0	0	0	0	0	0
155	145	0	0	0	0	0	900
0	1655	0	0	0	0	0	4145
0	420	0	0	0	0	0	1650
0	0	0	0	0	0	0	1110
0	420	2200	0	0	0	0	4400
0	0	800	0	0	0	300	1790
0	0	0	0	0	0	0	2150
0	0	0	0	0	0	0	1790
0	0	0	0	0	0	0	2090
0	0	0	0	0	0	300	1820
0	0	0	0	0	0	0	1390
0	0	0	0	0	0	0	1370
0	0	0	0	0	0	0	1380
0	0	0	0	0	0	0	1580

Scenario MG20-GPC - Half Large Load
Title Cumulative Capacity Additions (MG20-GPC - Half Large Load)



Cumulative Additions (MW)

Year	CT w/ SCR	CC	CC w/ CCS - Local	CC w/ CCS - Distant	Nuclear	Wind	Solar	Battery	Medium Duration Storage
2028	0	0	0	0	0	0	1370	685	0
2029	0	0	0	0	0	0	2750	1375	0
2030	400	0	0	0	0	0	2750	1375	0
2031	420	1260	0	0	0	0	3350	3330	0
2032	2100	4000	0	0	0	0	4340	3330	0
2033	2100	4000	0	0	0	240	5330	3750	0
2034	2270	4000	0	0	0	300	6320	3750	0
2035	3350	4500	0	0	0	600	7310	4170	0
2036	3350	4500	0	0	0	900	8330	4970	300
2037	3350	4500	0	0	0	1200	9350	5370	300
2038	3350	4500	0	0	0	1500	10370	6370	300
2039	3350	5220	0	0	0	1770	11390	7170	300
2040	3350	5270	0	0	0	2070	12410	7170	600
2041	3500	5560	0	0	0	2070	13430	7170	600
2042	3930	5560	0	0	0	2070	14450	7170	600
2043	4090	5560	0	0	210	2070	15470	7170	600
2044	4480	5560	0	0	210	2370	16490	7170	600
Total	**4480**	**5560**	**0**	**0**	**210**	2370	16490	**7170**	**600**

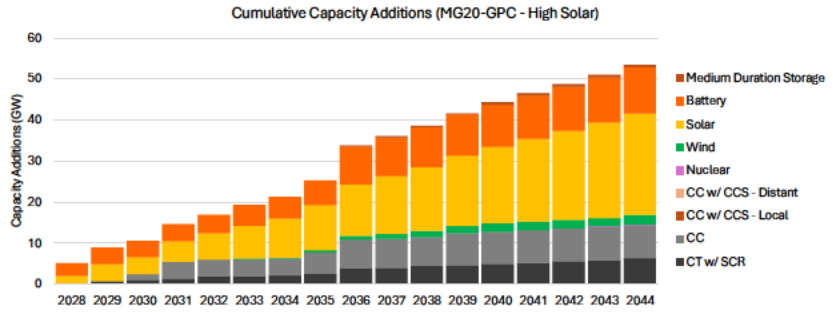
Battery 4-hr (T1)	Battery 4-hr (T2)	Battery 4-hr (T3)	Battery 4-hr (T4)	Battery 4-hr (T1_2)	Battery 4-hr (T2_2)	Medium Duration Storage	Total Storage
685	0	0	0	0	0	0	2055
1375	0	0	0	0	0	0	4125
1375	0	0	0	0	0	0	4525
1530	1800	0	0	0	0	0	8360
1530	1800	0	0	0	0	0	13770
1530	2220	0	0	0	0	0	15420
1530	2220	0	0	0	0	0	16640
1530	2640	0	0	0	0	0	19930
1530	2640	800	0	0	0	300	22350
1530	2640	1200	0	0	0	300	24070
1530	2640	2200	0	0	0	300	26390
1530	2640	3000	0	0	0	300	29200
1530	2640	3000	0	0	0	600	30870
1530	2640	3000	0	0	0	600	32330
1530	2640	3000	0	0	0	600	33780
1530	2640	3000	0	0	0	600	35170
1530	2640	3000	0	0	0	600	36880
1530	**2640**	**3000**	**0**	**0**	**0**	**600**	**36880**

Incremental Additions (MW)

Year	CT w/ SCR	CC	CC w/ CCS - Local	CC w/ CCS - Distant	Nuclear	Wind	Solar	Battery	Medium Duration Storage
2025									
2026	0	0	0	0	0	0	0	0	0
2027	0	0	0	0	0	0	0	0	0
2028	0	0	0	0	0	0	1370	685	0
2029	0	0	0	0	0	0	1380	690	0
2030	400	0	0	0	0	0	0	0	0
2031	20	1260	0	0	0	0	600	1955	0
2032	1680	2740	0	0	0	0	990	0	0
2033	0	0	0	0	0	240	990	420	0
2034	170	0	0	0	0	60	990	0	0
2035	1080	500	0	0	0	300	990	420	0
2036	0	0	0	0	0	300	1020	800	300
2037	0	0	0	0	0	300	1020	400	0
2038	0	0	0	0	0	300	1020	1000	0
2039	0	720	0	0	0	270	1020	800	0
2040	0	50	0	0	0	300	1020	0	300
2041	150	290	0	0	0	0	1020	0	0
2042	430	0	0	0	0	0	1020	0	0
2043	160	0	0	0	210	0	1020	0	0
2044	390	0	0	0	0	300	1020	0	0

Battery 4-hr (T1)	Battery 4-hr (T2)	Battery 4-hr (T3)	Battery 4-hr (T4)	Battery 4-hr (T1_2)	Battery 4-hr (T2_2)	Medium Duration Storage	Total Storage
0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0
685	0	0	0	0	0	0	2055
690	0	0	0	0	0	0	2070
0	0	0	0	0	0	0	400
155	1800	0	0	0	0	0	3835
0	0	0	0	0	0	0	5410
0	420	0	0	0	0	0	1650
0	0	0	0	0	0	0	1220
0	420	0	0	0	0	0	3290
0	0	800	0	0	0	300	2420
0	0	400	0	0	0	0	1720
0	0	1000	0	0	0	0	2320
0	0	800	0	0	0	0	2810
0	0	0	0	0	0	300	1670
0	0	0	0	0	0	0	1460
0	0	0	0	0	0	0	1450
0	0	0	0	0	0	0	1390
0	0	0	0	0	0	0	1710

Scenario MG20-GPC - High Solar
Title Cumulative Capacity Additions (MG20-GPC - High Solar)



Cumulative Additions (MW)

Year	CT w/ SCR	CC	CC w/ CCS - Local	CC w/ CCS - Distant	Nuclear	Wind	Solar	Battery	Medium Duration Storage
2028	0	0	0	0	0	0	2055	3115	0
2029	800	0	0	0	0	0	4125	4017.5	0
2030	1100	1400	0	0	0	0	4125	4017.5	0
2031	1400	4100	0	0	0	0	5025	4170	0
2032	1900	4100	0	0	0	0	6510	4415	0
2033	1900	4100	0	0	0	240	7995	5083	0
2034	2100	4100	0	0	0	300	9480	5330	0
2035	2600	5100	0	0	0	600	10965	5998	0
2036	3800	7100	0	0	0	900	12495	9253	300
2037	4000	7100	0	0	0	1200	14025	9508	300
2038	4400	7100	0	0	0	1500	15555	9763	300
2039	4700	7800	0	0	0	1770	17085	10018	300
2040	5000	7800	0	0	0	2070	18615	10273	600
2041	5200	8000	0	0	0	2070	20145	10528	600
2042	5600	8000	0	0	0	2070	21675	10783	600
2043	5900	8000	0	0	210	2070	23205	11038	600
2044	6300	8000	0	0	210	2370	24735	11293	600
Total	**6300**	**8000**	**0**	**0**	**210**	2370	24735	**11293**	**600**

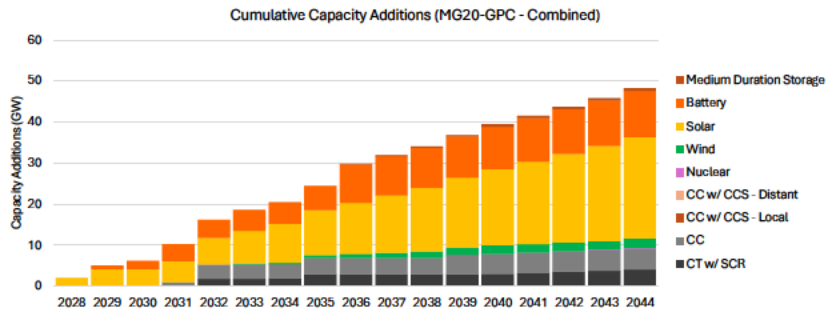
Battery 4-hr (T1)	Battery 4-hr (T2)	Battery 4-hr (T3)	Battery 4-hr (T4)	Battery 4-hr (T1_2)	Battery 4-hr (T2_2)	Medium Duration Storage	Total Storage
1530	1585	0	0	0	0	0	5170
1530	2487.5	0	0	0	0	0	8942.5
1530	2487.5	0	0	0	0	0	10642.5
1530	2640	0	0	0	0	0	14695
1530	2640	245	0	0	0	0	16925
1530	2640	913	0	0	0	0	19318
1530	2640	1160	0	0	0	0	21310
1530	2640	1828	0	0	0	0	25263
1530	2640	3000	2083	0	0	300	33848
1530	2640	3000	2338	0	0	300	36133
1530	2640	3000	2593	0	0	300	38618
1530	2640	3000	2848	0	0	300	41673
1530	2640	3000	3103	0	0	600	44358
1530	2640	3000	3358	0	0	600	46543
1530	2640	3000	3613	0	0	600	48728
1530	2640	3000	3868	0	0	600	51023
1530	2640	3000	4123	0	0	600	53508
1530	**2640**	**3000**	**4123**	**0**	**0**	**600**	**53508**

Incremental Additions (MW)

Year	CT w/ SCR	CC	CC w/ CCS - Local	CC w/ CCS - Distant	Nuclear	Wind	Solar	Battery	Medium Duration Storage
2025									
2026	0	0	0	0	0	0	0	0	0
2027	0	0	0	0	0	0	0	0	0
2028	0	0	0	0	0	0	2055	3115	0
2029	800	0	0	0	0	0	2070	902.5	0
2030	300	1400	0	0	0	0	0	0	0
2031	300	2700	0	0	0	0	900	152.5	0
2032	500	0	0	0	0	0	1485	245	0
2033	0	0	0	0	0	240	1485	668	0
2034	200	0	0	0	0	60	1485	247	0
2035	500	1000	0	0	0	300	1485	668	0
2036	1200	2000	0	0	0	300	1530	3255	300
2037	200	0	0	0	0	300	1530	255	0
2038	400	0	0	0	0	300	1530	255	0
2039	300	700	0	0	0	270	1530	255	0
2040	300	0	0	0	0	300	1530	255	300
2041	200	200	0	0	0	0	1530	255	0
2042	400	0	0	0	0	0	1530	255	0
2043	300	0	0	0	210	0	1530	255	0
2044	400	0	0	0	0	300	1530	255	0

Battery 4-hr (T1)	Battery 4-hr (T2)	Battery 4-hr (T3)	Battery 4-hr (T4)	Battery 4-hr (T1_2)	Battery 4-hr (T2_2)	Medium Duration Storage	Total Storage
0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0
1530	1585	0	0	0	0	0	5170
0	902.5	0	0	0	0	0	3772.5
0	0	0	0	0	0	0	1700
0	152.5	0	0	0	0	0	4052.5
0	0	245	0	0	0	0	2230
0	0	668	0	0	0	0	2393
0	0	247	0	0	0	0	1992
0	0	668	0	0	0	0	3953
0	0	1172	2083	0	0	300	8585
0	0	0	255	0	0	0	2285
0	0	0	255	0	0	0	2485
0	0	0	255	0	0	0	3055
0	0	0	255	0	0	300	2685
0	0	0	255	0	0	0	2185
0	0	0	255	0	0	0	2185
0	0	0	255	0	0	0	2295
0	0	0	255	0	0	0	2485

Scenario MG20-GPC - Combined
Title Cumulative Capacity Additions (MG20-GPC - Combined)



Cumulative Additions (MW)

Year	CT w/ SCR	CC	CC w/ CCS - Local	CC w/ CCS - Distant	Nuclear	Wind	Solar	Battery	Medium Duration Storage
2028	0	0	0	0	0	0	2055	0	0
2029	0	0	0	0	0	0	4125	900	0
2030	0	0	0	0	0	0	4125	2030	0
2031	260	790	0	0	0	0	5025	4170	0
2032	1820	3480	0	0	0	0	6510	4415	0
2033	1820	3480	0	0	0	240	7995	5083	0
2034	1920	3480	0	0	0	300	9480	5330	0
2035	2980	3980	0	0	0	600	10965	5998	0
2036	2980	3980	0	0	0	900	12495	9253	300
2037	2980	3980	0	0	0	1200	14025	9508	300
2038	2980	3980	0	0	0	1500	15555	9763	300
2039	2980	4660	0	0	0	1770	17085	10018	300
2040	3080	4800	0	0	0	2070	18615	10273	600
2041	3180	5040	0	0	0	2070	20145	10528	600
2042	3550	5040	0	0	0	2070	21675	10783	600
2043	3710	5040	0	0	210	2070	23205	11038	600
2044	4030	5040	0	0	210	2370	24735	11293	600
Total	**4030**	**5040**	**0**	**0**	**210**	2370	24735	**11293**	**600**

Battery 4-hr (T1)	Battery 4-hr (T2)	Battery 4-hr (T3)	Battery 4-hr (T4)	Battery 4-hr (T1_2)	Battery 4-hr (T2_2)	Medium Duration Storage	Total Storage
0	0	0	0	0	0	0	2055
900	0	0	0	0	0	0	5025
1530	500	0	0	0	0	0	6155
1530	2640	0	0	0	0	0	10245
1530	2640	245	0	0	0	0	16225
1530	2640	913	0	0	0	0	18618
1530	2640	1160	0	0	0	0	20510
1530	2640	1828	0	0	0	0	24523
1530	2640	3000	2083	0	0	300	29908
1530	2640	3000	2338	0	0	300	31993
1530	2640	3000	2593	0	0	300	34078
1530	2640	3000	2848	0	0	300	36813
1530	2640	3000	3103	0	0	600	39438
1530	2640	3000	3358	0	0	600	41563
1530	2640	3000	3613	0	0	600	43718
1530	2640	3000	3868	0	0	600	45873
1530	2640	3000	4123	0	0	600	48278
1530	**2640**	**3000**	**4123**	**0**	**0**	**600**	**48278**

Incremental Additions (MW)

Year	CT w/ SCR	CC	CC w/ CCS - Local	CC w/ CCS - Distant	Nuclear	Wind	Solar	Battery	Medium Duration Storage
2025									
2026	0	0	0	0	0	0	0	0	0
2027	0	0	0	0	0	0	0	0	0
2028	0	0	0	0	0	0	2055	0	0
2029	0	0	0	0	0	0	2070	900	0
2030	0	0	0	0	0	0	0	1130	0
2031	260	790	0	0	0	0	900	2140	0
2032	1560	2690	0	0	0	0	1485	245	0
2033	0	0	0	0	0	240	1485	668	0
2034	100	0	0	0	0	60	1485	247	0
2035	1060	500	0	0	0	300	1485	668	0
2036	0	0	0	0	0	300	1530	3255	300
2037	0	0	0	0	0	300	1530	255	0
2038	0	0	0	0	0	300	1530	255	0
2039	0	680	0	0	0	270	1530	255	0
2040	100	140	0	0	0	300	1530	255	300
2041	100	240	0	0	0	0	1530	255	0
2042	370	0	0	0	0	0	1530	255	0
2043	160	0	0	0	210	0	1530	255	0
2044	320	0	0	0	0	300	1530	255	0

Battery 4-hr (T1)	Battery 4-hr (T2)	Battery 4-hr (T3)	Battery 4-hr (T4)	Battery 4-hr (T1_2)	Battery 4-hr (T2_2)	Medium Duration Storage	Total Storage
0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	2055
900	0	0	0	0	0	0	2970
630	500	0	0	0	0	0	1130
0	2140	0	0	0	0	0	4090
0	0	245	0	0	0	0	5980
0	0	668	0	0	0	0	2393
0	0	247	0	0	0	0	1892
0	0	668	0	0	0	0	4013
0	0	1172	2083	0	0	300	5385
0	0	0	255	0	0	0	2085
0	0	0	255	0	0	0	2085
0	0	0	255	0	0	0	2735
0	0	0	255	0	0	300	2625
0	0	0	255	0	0	0	2125
0	0	0	255	0	0	0	2155
0	0	0	255	0	0	0	2155
0	0	0	255	0	0	0	2405

DS-12:

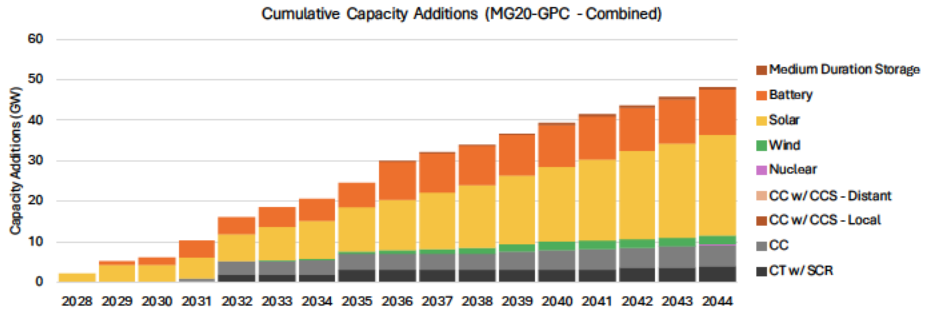
Workpaper: NPV Calculations by Portfolio - Trade Secret

File has been redacted in its entirety.

DS-13:

Workpaper: Capacity Expansion Plans - 2025 IRP - Scenario Comparisons – Stenclik.xlsx

Scenario MG20-GPC - Combined
Title Cumulative Capacity Additions (MG20-GPC - Combined)



Cumulative Additions (MW)

Year	CT w/ SCR	CC	CC w/ CCS - Local	CC w/ CCS - Distant	Nuclear	Wind	Solar	Battery	Medium Duration Storage
2028	0	0	0	0	0	0	2055	0	0
2029	0	0	0	0	0	0	4125	900	0
2030	0	0	0	0	0	0	4125	2030	0
2031	260	790	0	0	0	0	5025	4170	0
2032	1820	3480	0	0	0	0	6510	4415	0
2033	1820	3480	0	0	0	240	7995	5083	0
2034	1920	3480	0	0	0	300	9480	5330	0
2035	2980	3980	0	0	0	600	10965	5998	0
2036	2980	3980	0	0	0	900	12495	9253	300
2037	2980	3980	0	0	0	1200	14025	9508	300
2038	2980	3980	0	0	0	1500	15555	9763	300
2039	2980	4660	0	0	0	1770	17085	10018	300
2040	3080	4800	0	0	0	2070	18615	10273	600
2041	3180	5040	0	0	0	2070	20145	10528	600
2042	3550	5040	0	0	0	2070	21675	10783	600
2043	3710	5040	0	0	210	2070	23205	11038	600
2044	4030	5040	0	0	210	2370	24735	11293	600
Total	**4030**	**5040**	**0**	**0**	**210**	2370	24735	**11293**	**600**

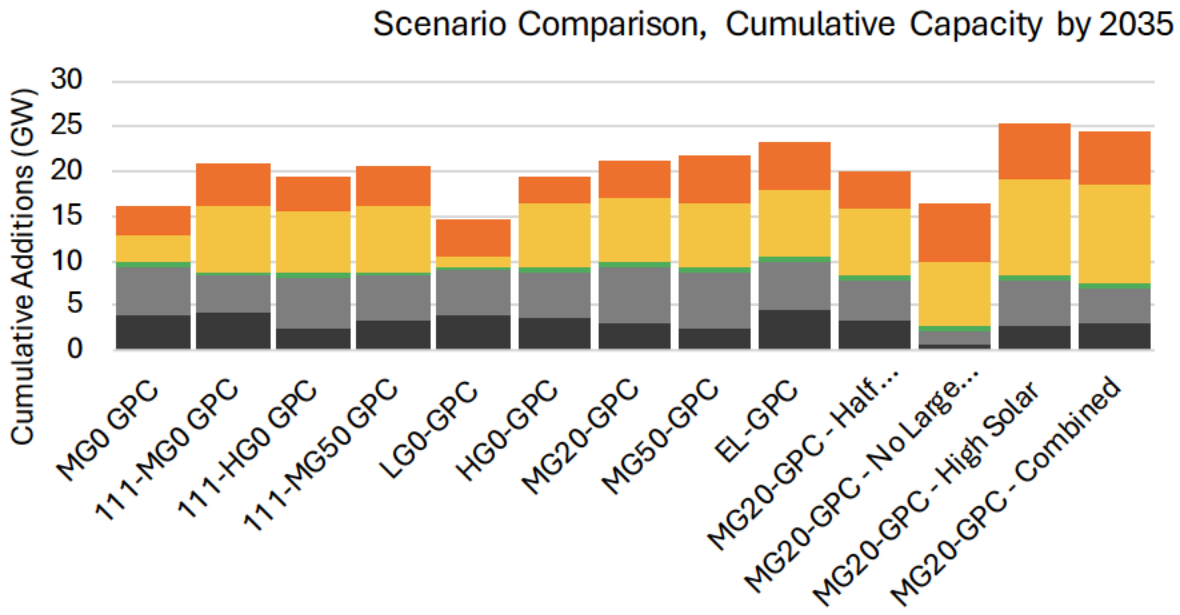
Battery 4-hr (T1)	Battery 4-hr (T2)	Battery 4-hr (T3)	Battery 4-hr (T4)	Battery 4-hr (T1_2)	Battery 4-hr (T2_2)	Medium Duration Storage	Total Storage
0	0	0	0	0	0	0	2055
900	0	0	0	0	0	0	5025
1530	500	0	0	0	0	0	6155
1530	2640	0	0	0	0	0	10245
1530	2640	245	0	0	0	0	16225
1530	2640	913	0	0	0	0	18618
1530	2640	1160	0	0	0	0	20510
1530	2640	1828	0	0	0	0	24523
1530	2640	3000	2083	0	0	300	29908
1530	2640	3000	2338	0	0	300	31993
1530	2640	3000	2593	0	0	300	34078
1530	2640	3000	2848	0	0	300	36813
1530	2640	3000	3103	0	0	600	39438
1530	2640	3000	3358	0	0	600	41563
1530	2640	3000	3613	0	0	600	43718
1530	2640	3000	3868	0	0	600	45873
1530	2640	3000	4123	0	0	600	48278
1530	**2640**	**3000**	**4123**	**0**	**0**	**600**	**48278**

Incremental Additions (MW)

Year	CT w/ SCR	CC	CC w/ CCS - Local	CC w/ CCS - Distant	Nuclear	Wind	Solar	Battery	Medium Duration Storage
2025									
2026	0	0	0	0	0	0	0	0	0
2027	0	0	0	0	0	0	0	0	0
2028	0	0	0	0	0	0	2055	0	0
2029	0	0	0	0	0	0	2070	900	0
2030	0	0	0	0	0	0	0	1130	0
2031	260	790	0	0	0	0	900	2140	0
2032	1560	2690	0	0	0	0	1485	245	0
2033	0	0	0	0	0	240	1485	668	0
2034	100	0	0	0	0	60	1485	247	0
2035	1060	500	0	0	0	300	1485	668	0
2036	0	0	0	0	0	300	1530	3255	300
2037	0	0	0	0	0	300	1530	255	0
2038	0	0	0	0	0	300	1530	255	0
2039	0	680	0	0	0	270	1530	255	0
2040	100	140	0	0	0	300	1530	255	300
2041	100	240	0	0	0	0	1530	255	0
2042	370	0	0	0	0	0	1530	255	0
2043	160	0	0	0	210	0	1530	255	0
2044	320	0	0	0	0	300	1530	255	0

Battery 4-hr (T1)	Battery 4-hr (T2)	Battery 4-hr (T3)	Battery 4-hr (T4)	Battery 4-hr (T1_2)	Battery 4-hr (T2_2)	Medium Duration Storage	Total Storage
0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	2055
900	0	0	0	0	0	0	2970
630	500	0	0	0	0	0	1130
0	2140	0	0	0	0	0	4090
0	0	245	0	0	0	0	5980
0	0	668	0	0	0	0	2393
0	0	247	0	0	0	0	1892
0	0	668	0	0	0	0	4013
0	0	1172	2083	0	0	300	5385
0	0	0	255	0	0	0	2085
0	0	0	255	0	0	0	2085
0	0	0	255	0	0	0	2735
0	0	0	255	0	0	300	2625
0	0	0	255	0	0	0	2125
0	0	0	255	0	0	0	2155
0	0	0	255	0	0	0	2155
0	0	0	255	0	0	0	2405

Year	**2035**
Title	Scenario Comparison, Cumulative Capacity by 2035



	CT w/ SCR	CC	CC w/ CCS - Local	CC w/ CCS - Distant	Nuclear	Wind	Solar
MG0 GPC	3840	5340	0	0	0	630	2970
111-MG0 GPC	4230	4140	0	0	0	420	7310
111-HG0 GPC	2490	5520	0	0	0	600	7030
111-MG50 GPC	3330	4920	0	0	0	480	7310
LG0-GPC	3870	5010	0	0	0	540	1200
HG0-GPC	3480	5130	0	0	0	630	7310
MG20-GPC	3030	6180	0	0	0	600	7310
MG50-GPC	2280	6330	0	0	0	600	7310
EL-GPC	4560	5430	0	0	0	510	7310
MG20-GPC - Half L	3350	4500	0	0	0	600	7310
MG20-GPC - No La	710	1340	0	0	0	600	7310
MG20-GPC - High	2600	5100	0	0	0	600	10965
MG20-GPC - Com	2980	3980	0	0	0	600	10965

MG0	4200	7200	0	0	0	900	4500
111-MG0	4500	5700	0	0	0	900	9900
111-HG0	2700	7500	0	0	0	900	9600
111-MG50	3600	6600	0	0	0	900	9900
LG0	4500	6600	0	0	0	900	1800
HG0	3900	6900	0	0	0	900	9900
MG20	3300	8100	0	0	0	900	9900
MG50	2700	8100	0	0	0	900	9900

EL	5400	7800	0	0	0	900	9900
MG20-GPC - Half L	3350	4500	0	0	0	600	7310
MG20-GPC - No La	710	1340	0	0	0	600	7310
MG20-GPC - High	2600	5100	0	0	0	600	10965
MG20-GPC - Com	2980	3980	0	0	0	600	10965

- Medium Duration Storage
- Battery
- Solar
- Wind
- Nuclear
- CC w/ CCS - Distant
- CC w/ CCS - Local
- CC
- CT w/ SCR

Battery	Medium Duration Storage	Total
3360	0	16140
4830	0	20930
3900	0	19540
4470	0	20510
3900	0	14520
3000	0	19550
4170	0	21290
5160	0	21680
5370	0	23180
4170	0	19930
6370	0	16330
5998	0	25263
5998	0	24523

3900	0	20700
5700	0	26700
3900	0	24600
5100	0	26100
4500	0	18300
3000	0	24600
5100	0	27300
6300	0	27900

6300	0	30300
4170	0	19930
6370	0	16330
5998	0	25263
5998	0	24523

Scenario	Property	Year	CTw/ SCR	CC
MG0	Incremental Additions (MW)	2025	0	0
MG0	Incremental Additions (MW)	2026	0	0
MG0	Incremental Additions (MW)	2027	0	0
MG0	Incremental Additions (MW)	2028	0	0
MG0	Incremental Additions (MW)	2029	1200	900
MG0	Incremental Additions (MW)	2030	300	1800
MG0	Incremental Additions (MW)	2031	900	2400
MG0	Incremental Additions (MW)	2032	300	300
MG0	Incremental Additions (MW)	2033	600	0
MG0	Incremental Additions (MW)	2034	600	0
MG0	Incremental Additions (MW)	2035	300	1800
MG0	Incremental Additions (MW)	2036	1200	2100
MG0	Incremental Additions (MW)	2037	300	0
MG0	Incremental Additions (MW)	2038	300	0
MG0	Incremental Additions (MW)	2039	300	1200
MG0	Incremental Additions (MW)	2040	900	0
MG0	Incremental Additions (MW)	2041	900	0
MG0	Incremental Additions (MW)	2042	900	0
MG0	Incremental Additions (MW)	2043	600	0
MG0	Incremental Additions (MW)	2044	300	0
MG0	Incremental Additions (MW)	Total	9900	10500
MG0 GPC	Incremental Additions (MW)	2026	0	0
MG0 GPC	Incremental Additions (MW)	2027	0	0
MG0 GPC	Incremental Additions (MW)	2028	0	0
MG0 GPC	Incremental Additions (MW)	2029	1200	0
MG0 GPC	Incremental Additions (MW)	2030	300	1500
MG0 GPC	Incremental Additions (MW)	2031	900	2190
MG0 GPC	Incremental Additions (MW)	2032	300	240
MG0 GPC	Incremental Additions (MW)	2033	420	0
MG0 GPC	Incremental Additions (MW)	2034	420	0
MG0 GPC	Incremental Additions (MW)	2035	300	1410
MG0 GPC	Incremental Additions (MW)	2036	1200	2100
MG0 GPC	Incremental Additions (MW)	2037	240	0
MG0 GPC	Incremental Additions (MW)	2038	300	0
MG0 GPC	Incremental Additions (MW)	2039	300	870
MG0 GPC	Incremental Additions (MW)	2040	810	0
MG0 GPC	Incremental Additions (MW)	2041	210	0
MG0 GPC	Incremental Additions (MW)	2042	510	0
MG0 GPC	Incremental Additions (MW)	2043	420	0
MG0 GPC	Incremental Additions (MW)	2044	210	0
MG0 GPC	Incremental Additions (MW)	Total	8040	8310
111-MG0	Incremental Additions (MW)	2026	0	0
111-MG0	Incremental Additions (MW)	2027	0	0
111-MG0	Incremental Additions (MW)	2028	0	0
111-MG0	Incremental Additions (MW)	2029	900	900

111-MG0	Incremental Additions (MW)	2030	600	1500
111-MG0	Incremental Additions (MW)	2031	900	1800
111-MG0	Incremental Additions (MW)	2032	300	300
111-MG0	Incremental Additions (MW)	2033	900	600
111-MG0	Incremental Additions (MW)	2034	0	600
111-MG0	Incremental Additions (MW)	2035	900	0
111-MG0	Incremental Additions (MW)	2036	0	300
111-MG0	Incremental Additions (MW)	2037	0	900
111-MG0	Incremental Additions (MW)	2038	300	300
111-MG0	Incremental Additions (MW)	2039	900	1500
111-MG0	Incremental Additions (MW)	2040	600	1200
111-MG0	Incremental Additions (MW)	2041	900	0
111-MG0	Incremental Additions (MW)	2042	600	600
111-MG0	Incremental Additions (MW)	2043	300	300
111-MG0	Incremental Additions (MW)	2044	300	600
111-MG0	Incremental Additions (MW)	Total	8400	11400
111-MG0 GPC	Incremental Additions (MW)	2026	0	0
111-MG0 GPC	Incremental Additions (MW)	2027	0	0
111-MG0 GPC	Incremental Additions (MW)	2028	0	0
111-MG0 GPC	Incremental Additions (MW)	2029	900	0
111-MG0 GPC	Incremental Additions (MW)	2030	600	1260
111-MG0 GPC	Incremental Additions (MW)	2031	900	1800
111-MG0 GPC	Incremental Additions (MW)	2032	300	240
111-MG0 GPC	Incremental Additions (MW)	2033	630	420
111-MG0 GPC	Incremental Additions (MW)	2034	0	420
111-MG0 GPC	Incremental Additions (MW)	2035	900	0
111-MG0 GPC	Incremental Additions (MW)	2036	0	210
111-MG0 GPC	Incremental Additions (MW)	2037	0	630
111-MG0 GPC	Incremental Additions (MW)	2038	210	210
111-MG0 GPC	Incremental Additions (MW)	2039	900	1500
111-MG0 GPC	Incremental Additions (MW)	2040	600	1200
111-MG0 GPC	Incremental Additions (MW)	2041	330	0
111-MG0 GPC	Incremental Additions (MW)	2042	390	420
111-MG0 GPC	Incremental Additions (MW)	2043	150	210
111-MG0 GPC	Incremental Additions (MW)	2044	240	420
111-MG0 GPC	Incremental Additions (MW)	Total	7050	8940
111-HG0	Incremental Additions (MW)	2026	0	0
111-HG0	Incremental Additions (MW)	2027	0	0
111-HG0	Incremental Additions (MW)	2028	0	0
111-HG0	Incremental Additions (MW)	2029	300	900
111-HG0	Incremental Additions (MW)	2030	900	2400
111-HG0	Incremental Additions (MW)	2031	300	900
111-HG0	Incremental Additions (MW)	2032	300	600
111-HG0	Incremental Additions (MW)	2033	0	1200
111-HG0	Incremental Additions (MW)	2034	600	600
111-HG0	Incremental Additions (MW)	2035	300	900
111-HG0	Incremental Additions (MW)	2036	600	600
111-HG0	Incremental Additions (MW)	2037	1200	0

111-HG0	Incremental Additions (MW)	2038	0	0
111-HG0	Incremental Additions (MW)	2039	600	600
111-HG0	Incremental Additions (MW)	2040	600	600
111-HG0	Incremental Additions (MW)	2041	900	0
111-HG0	Incremental Additions (MW)	2042	600	300
111-HG0	Incremental Additions (MW)	2043	300	600
111-HG0	Incremental Additions (MW)	2044	300	600
111-HG0	Incremental Additions (MW)	Total	7800	10800
111-HG0 GPC	Incremental Additions (MW)	2026	0	0
111-HG0 GPC	Incremental Additions (MW)	2027	0	0
111-HG0 GPC	Incremental Additions (MW)	2028	0	0
111-HG0 GPC	Incremental Additions (MW)	2029	300	0
111-HG0 GPC	Incremental Additions (MW)	2030	900	1770
111-HG0 GPC	Incremental Additions (MW)	2031	300	900
111-HG0 GPC	Incremental Additions (MW)	2032	300	600
111-HG0 GPC	Incremental Additions (MW)	2033	0	960
111-HG0 GPC	Incremental Additions (MW)	2034	390	420
111-HG0 GPC	Incremental Additions (MW)	2035	300	870
111-HG0 GPC	Incremental Additions (MW)	2036	420	420
111-HG0 GPC	Incremental Additions (MW)	2037	840	0
111-HG0 GPC	Incremental Additions (MW)	2038	0	0
111-HG0 GPC	Incremental Additions (MW)	2039	600	600
111-HG0 GPC	Incremental Additions (MW)	2040	600	600
111-HG0 GPC	Incremental Additions (MW)	2041	210	0
111-HG0 GPC	Incremental Additions (MW)	2042	300	210
111-HG0 GPC	Incremental Additions (MW)	2043	120	420
111-HG0 GPC	Incremental Additions (MW)	2044	240	420
111-HG0 GPC	Incremental Additions (MW)	Total	5820	8190
111-MG50	Incremental Additions (MW)	2026	0	0
111-MG50	Incremental Additions (MW)	2027	0	0
111-MG50	Incremental Additions (MW)	2028	0	0
111-MG50	Incremental Additions (MW)	2029	900	900
111-MG50	Incremental Additions (MW)	2030	600	1500
111-MG50	Incremental Additions (MW)	2031	300	2100
111-MG50	Incremental Additions (MW)	2032	300	900
111-MG50	Incremental Additions (MW)	2033	600	600
111-MG50	Incremental Additions (MW)	2034	300	300
111-MG50	Incremental Additions (MW)	2035	600	300
111-MG50	Incremental Additions (MW)	2036	900	300
111-MG50	Incremental Additions (MW)	2037	0	300
111-MG50	Incremental Additions (MW)	2038	0	0
111-MG50	Incremental Additions (MW)	2039	1200	300
111-MG50	Incremental Additions (MW)	2040	300	300
111-MG50	Incremental Additions (MW)	2041	0	300
111-MG50	Incremental Additions (MW)	2042	0	0
111-MG50	Incremental Additions (MW)	2043	0	600
111-MG50	Incremental Additions (MW)	2044	0	300
111-MG50	Incremental Additions (MW)	Total	6000	9000

111-MG50 GPC	Incremental Additions (MW)	2026	0	0
111-MG50 GPC	Incremental Additions (MW)	2027	0	0
111-MG50 GPC	Incremental Additions (MW)	2028	0	0
111-MG50 GPC	Incremental Additions (MW)	2029	900	0
111-MG50 GPC	Incremental Additions (MW)	2030	600	1260
111-MG50 GPC	Incremental Additions (MW)	2031	300	2100
111-MG50 GPC	Incremental Additions (MW)	2032	300	630
111-MG50 GPC	Incremental Additions (MW)	2033	420	420
111-MG50 GPC	Incremental Additions (MW)	2034	210	210
111-MG50 GPC	Incremental Additions (MW)	2035	600	300
111-MG50 GPC	Incremental Additions (MW)	2036	630	210
111-MG50 GPC	Incremental Additions (MW)	2037	0	210
111-MG50 GPC	Incremental Additions (MW)	2038	0	0
111-MG50 GPC	Incremental Additions (MW)	2039	1200	300
111-MG50 GPC	Incremental Additions (MW)	2040	300	300
111-MG50 GPC	Incremental Additions (MW)	2041	0	210
111-MG50 GPC	Incremental Additions (MW)	2042	0	0
111-MG50 GPC	Incremental Additions (MW)	2043	0	510
111-MG50 GPC	Incremental Additions (MW)	2044	0	240
111-MG50 GPC	Incremental Additions (MW)	Total	5460	6900
LG0	Incremental Additions (MW)	2026	0	0
LG0	Incremental Additions (MW)	2027	0	0
LG0	Incremental Additions (MW)	2028	0	0
LG0	Incremental Additions (MW)	2029	900	900
LG0	Incremental Additions (MW)	2030	600	1500
LG0	Incremental Additions (MW)	2031	300	3000
LG0	Incremental Additions (MW)	2032	900	0
LG0	Incremental Additions (MW)	2033	900	0
LG0	Incremental Additions (MW)	2034	600	0
LG0	Incremental Additions (MW)	2035	300	1200
LG0	Incremental Additions (MW)	2036	900	2700
LG0	Incremental Additions (MW)	2037	300	0
LG0	Incremental Additions (MW)	2038	300	0
LG0	Incremental Additions (MW)	2039	300	1200
LG0	Incremental Additions (MW)	2040	1200	0
LG0	Incremental Additions (MW)	2041	600	0
LG0	Incremental Additions (MW)	2042	1200	0
LG0	Incremental Additions (MW)	2043	300	0
LG0	Incremental Additions (MW)	2044	900	0
LG0	Incremental Additions (MW)	Total	10500	10500
LG0-GPC	Incremental Additions (MW)	2026	0	0
LG0-GPC	Incremental Additions (MW)	2027	0	0
LG0-GPC	Incremental Additions (MW)	2028	0	0
LG0-GPC	Incremental Additions (MW)	2029	900	0
LG0-GPC	Incremental Additions (MW)	2030	600	1200
LG0-GPC	Incremental Additions (MW)	2031	300	2790
LG0-GPC	Incremental Additions (MW)	2032	720	0
LG0-GPC	Incremental Additions (MW)	2033	630	0

LG0-GPC	Incremental Additions (MW)	2034	420	0
LG0-GPC	Incremental Additions (MW)	2035	300	1020
LG0-GPC	Incremental Additions (MW)	2036	900	2700
LG0-GPC	Incremental Additions (MW)	2037	240	0
LG0-GPC	Incremental Additions (MW)	2038	300	0
LG0-GPC	Incremental Additions (MW)	2039	300	870
LG0-GPC	Incremental Additions (MW)	2040	960	0
LG0-GPC	Incremental Additions (MW)	2041	0	0
LG0-GPC	Incremental Additions (MW)	2042	690	0
LG0-GPC	Incremental Additions (MW)	2043	150	0
LG0-GPC	Incremental Additions (MW)	2044	510	0
LG0-GPC	Incremental Additions (MW)	Total	7920	8580
HG0	Incremental Additions (MW)	2026	0	0
HG0	Incremental Additions (MW)	2027	0	0
HG0	Incremental Additions (MW)	2028	0	0
HG0	Incremental Additions (MW)	2029	300	900
HG0	Incremental Additions (MW)	2030	900	1500
HG0	Incremental Additions (MW)	2031	300	2700
HG0	Incremental Additions (MW)	2032	600	0
HG0	Incremental Additions (MW)	2033	600	0
HG0	Incremental Additions (MW)	2034	600	0
HG0	Incremental Additions (MW)	2035	600	1800
HG0	Incremental Additions (MW)	2036	600	2400
HG0	Incremental Additions (MW)	2037	300	0
HG0	Incremental Additions (MW)	2038	300	0
HG0	Incremental Additions (MW)	2039	300	1200
HG0	Incremental Additions (MW)	2040	900	0
HG0	Incremental Additions (MW)	2041	600	0
HG0	Incremental Additions (MW)	2042	600	0
HG0	Incremental Additions (MW)	2043	300	0
HG0	Incremental Additions (MW)	2044	300	0
HG0	Incremental Additions (MW)	Total	8100	10500
HG0-GPC	Incremental Additions (MW)	2026	0	0
HG0-GPC	Incremental Additions (MW)	2027	0	0
HG0-GPC	Incremental Additions (MW)	2028	0	0
HG0-GPC	Incremental Additions (MW)	2029	300	0
HG0-GPC	Incremental Additions (MW)	2030	900	1200
HG0-GPC	Incremental Additions (MW)	2031	300	2640
HG0-GPC	Incremental Additions (MW)	2032	540	0
HG0-GPC	Incremental Additions (MW)	2033	420	0
HG0-GPC	Incremental Additions (MW)	2034	420	0
HG0-GPC	Incremental Additions (MW)	2035	600	1290
HG0-GPC	Incremental Additions (MW)	2036	600	2400
HG0-GPC	Incremental Additions (MW)	2037	240	0
HG0-GPC	Incremental Additions (MW)	2038	300	0
HG0-GPC	Incremental Additions (MW)	2039	300	840
HG0-GPC	Incremental Additions (MW)	2040	780	0
HG0-GPC	Incremental Additions (MW)	2041	0	0

HG0-GPC	Incremental Additions (MW)	2042	300	0
HG0-GPC	Incremental Additions (MW)	2043	180	0
HG0-GPC	Incremental Additions (MW)	2044	210	0
HG0-GPC	Incremental Additions (MW)	Total	6390	8370
MG20	Incremental Additions (MW)	2026	0	0
MG20	Incremental Additions (MW)	2027	0	0
MG20	Incremental Additions (MW)	2028	0	0
MG20	Incremental Additions (MW)	2029	1200	900
MG20	Incremental Additions (MW)	2030	300	2700
MG20	Incremental Additions (MW)	2031	0	2400
MG20	Incremental Additions (MW)	2032	600	300
MG20	Incremental Additions (MW)	2033	300	0
MG20	Incremental Additions (MW)	2034	600	0
MG20	Incremental Additions (MW)	2035	300	1800
MG20	Incremental Additions (MW)	2036	900	1200
MG20	Incremental Additions (MW)	2037	300	0
MG20	Incremental Additions (MW)	2038	600	0
MG20	Incremental Additions (MW)	2039	300	0
MG20	Incremental Additions (MW)	2040	300	0
MG20	Incremental Additions (MW)	2041	300	0
MG20	Incremental Additions (MW)	2042	1200	0
MG20	Incremental Additions (MW)	2043	300	0
MG20	Incremental Additions (MW)	2044	900	0
MG20	Incremental Additions (MW)	Total	8400	9300
MG20-GPC	Incremental Additions (MW)	2026	0	0
MG20-GPC	Incremental Additions (MW)	2027	0	0
MG20-GPC	Incremental Additions (MW)	2028	0	0
MG20-GPC	Incremental Additions (MW)	2029	1200	0
MG20-GPC	Incremental Additions (MW)	2030	300	2130
MG20-GPC	Incremental Additions (MW)	2031	0	2400
MG20-GPC	Incremental Additions (MW)	2032	600	270
MG20-GPC	Incremental Additions (MW)	2033	210	0
MG20-GPC	Incremental Additions (MW)	2034	420	0
MG20-GPC	Incremental Additions (MW)	2035	300	1380
MG20-GPC	Incremental Additions (MW)	2036	900	1200
MG20-GPC	Incremental Additions (MW)	2037	300	0
MG20-GPC	Incremental Additions (MW)	2038	540	0
MG20-GPC	Incremental Additions (MW)	2039	210	0
MG20-GPC	Incremental Additions (MW)	2040	300	0
MG20-GPC	Incremental Additions (MW)	2041	120	0
MG20-GPC	Incremental Additions (MW)	2042	690	0
MG20-GPC	Incremental Additions (MW)	2043	150	0
MG20-GPC	Incremental Additions (MW)	2044	660	0
MG20-GPC	Incremental Additions (MW)	Total	6900	7380
MG50	Incremental Additions (MW)	2026	0	0
MG50	Incremental Additions (MW)	2027	0	0
MG50	Incremental Additions (MW)	2028	0	0
MG50	Incremental Additions (MW)	2029	900	900

MG50	Incremental Additions (MW)	2030	0	3000
MG50	Incremental Additions (MW)	2031	0	2700
MG50	Incremental Additions (MW)	2032	0	300
MG50	Incremental Additions (MW)	2033	300	0
MG50	Incremental Additions (MW)	2034	1200	0
MG50	Incremental Additions (MW)	2035	300	1200
MG50	Incremental Additions (MW)	2036	1800	1200
MG50	Incremental Additions (MW)	2037	0	0
MG50	Incremental Additions (MW)	2038	0	0
MG50	Incremental Additions (MW)	2039	0	0
MG50	Incremental Additions (MW)	2040	0	0
MG50	Incremental Additions (MW)	2041	0	0
MG50	Incremental Additions (MW)	2042	0	0
MG50	Incremental Additions (MW)	2043	0	0
MG50	Incremental Additions (MW)	2044	300	0
MG50	Incremental Additions (MW)	Total	4800	9300
MG50-GPC	Incremental Additions (MW)	2026	0	0
MG50-GPC	Incremental Additions (MW)	2027	0	0
MG50-GPC	Incremental Additions (MW)	2028	0	0
MG50-GPC	Incremental Additions (MW)	2029	900	0
MG50-GPC	Incremental Additions (MW)	2030	0	2340
MG50-GPC	Incremental Additions (MW)	2031	0	2700
MG50-GPC	Incremental Additions (MW)	2032	0	300
MG50-GPC	Incremental Additions (MW)	2033	270	0
MG50-GPC	Incremental Additions (MW)	2034	810	0
MG50-GPC	Incremental Additions (MW)	2035	300	990
MG50-GPC	Incremental Additions (MW)	2036	1800	1200
MG50-GPC	Incremental Additions (MW)	2037	0	0
MG50-GPC	Incremental Additions (MW)	2038	0	0
MG50-GPC	Incremental Additions (MW)	2039	0	0
MG50-GPC	Incremental Additions (MW)	2040	0	0
MG50-GPC	Incremental Additions (MW)	2041	0	0
MG50-GPC	Incremental Additions (MW)	2042	0	0
MG50-GPC	Incremental Additions (MW)	2043	0	0
MG50-GPC	Incremental Additions (MW)	2044	240	0
MG50-GPC	Incremental Additions (MW)	Total	4320	7530
EL	Incremental Additions (MW)	2026	0	0
EL	Incremental Additions (MW)	2027	0	0
EL	Incremental Additions (MW)	2028	0	0
EL	Incremental Additions (MW)	2029	900	900
EL	Incremental Additions (MW)	2030	600	4500
EL	Incremental Additions (MW)	2031	600	1500
EL	Incremental Additions (MW)	2032	900	0
EL	Incremental Additions (MW)	2033	900	0
EL	Incremental Additions (MW)	2034	1500	0
EL	Incremental Additions (MW)	2035	0	900
EL	Incremental Additions (MW)	2036	900	0
EL	Incremental Additions (MW)	2037	0	0

EL	Incremental Additions (MW)	2038	0	0
EL	Incremental Additions (MW)	2039	0	0
EL	Incremental Additions (MW)	2040	0	0
EL	Incremental Additions (MW)	2041	0	0
EL	Incremental Additions (MW)	2042	0	0
EL	Incremental Additions (MW)	2043	0	0
EL	Incremental Additions (MW)	2044	0	0
EL	Incremental Additions (MW)	Total	6300	7800
EL-GPC	Incremental Additions (MW)	2026	0	0
EL-GPC	Incremental Additions (MW)	2027	0	0
EL-GPC	Incremental Additions (MW)	2028	0	0
EL-GPC	Incremental Additions (MW)	2029	900	0
EL-GPC	Incremental Additions (MW)	2030	570	3030
EL-GPC	Incremental Additions (MW)	2031	600	1500
EL-GPC	Incremental Additions (MW)	2032	900	0
EL-GPC	Incremental Additions (MW)	2033	630	0
EL-GPC	Incremental Additions (MW)	2034	960	0
EL-GPC	Incremental Additions (MW)	2035	0	900
EL-GPC	Incremental Additions (MW)	2036	900	0
EL-GPC	Incremental Additions (MW)	2037	0	0
EL-GPC	Incremental Additions (MW)	2038	0	0
EL-GPC	Incremental Additions (MW)	2039	0	0
EL-GPC	Incremental Additions (MW)	2040	0	0
EL-GPC	Incremental Additions (MW)	2041	0	0
EL-GPC	Incremental Additions (MW)	2042	0	0
EL-GPC	Incremental Additions (MW)	2043	0	0
EL-GPC	Incremental Additions (MW)	2044	0	0
EL-GPC	Incremental Additions (MW)	Total	5460	5430
MG0	Cumulative Additions (MW)	2025	0	0
MG0	Cumulative Additions (MW)	2026	0	0
MG0	Cumulative Additions (MW)	2027	0	0
MG0	Cumulative Additions (MW)	2028	0	0
MG0	Cumulative Additions (MW)	2029	1200	900
MG0	Cumulative Additions (MW)	2030	1500	2700
MG0	Cumulative Additions (MW)	2031	2400	5100
MG0	Cumulative Additions (MW)	2032	2700	5400
MG0	Cumulative Additions (MW)	2033	3300	5400
MG0	Cumulative Additions (MW)	2034	3900	5400
MG0	Cumulative Additions (MW)	2035	4200	7200
MG0	Cumulative Additions (MW)	2036	5400	9300
MG0	Cumulative Additions (MW)	2037	5700	9300
MG0	Cumulative Additions (MW)	2038	6000	9300
MG0	Cumulative Additions (MW)	2039	6300	10500
MG0	Cumulative Additions (MW)	2040	7200	10500
MG0	Cumulative Additions (MW)	2041	8100	10500
MG0	Cumulative Additions (MW)	2042	9000	10500
MG0	Cumulative Additions (MW)	2043	9600	10500
MG0	Cumulative Additions (MW)	2044	9900	10500

MG0	Cumulative Additions (MW)	Total	9900	10500
MG0 GPC	Cumulative Additions (MW)	2026	0	0
MG0 GPC	Cumulative Additions (MW)	2027	0	0
MG0 GPC	Cumulative Additions (MW)	2028	0	0
MG0 GPC	Cumulative Additions (MW)	2029	1200	0
MG0 GPC	Cumulative Additions (MW)	2030	1500	1500
MG0 GPC	Cumulative Additions (MW)	2031	2400	3690
MG0 GPC	Cumulative Additions (MW)	2032	2700	3930
MG0 GPC	Cumulative Additions (MW)	2033	3120	3930
MG0 GPC	Cumulative Additions (MW)	2034	3540	3930
MG0 GPC	Cumulative Additions (MW)	2035	3840	5340
MG0 GPC	Cumulative Additions (MW)	2036	5040	7440
MG0 GPC	Cumulative Additions (MW)	2037	5280	7440
MG0 GPC	Cumulative Additions (MW)	2038	5580	7440
MG0 GPC	Cumulative Additions (MW)	2039	5880	8310
MG0 GPC	Cumulative Additions (MW)	2040	6690	8310
MG0 GPC	Cumulative Additions (MW)	2041	6900	8310
MG0 GPC	Cumulative Additions (MW)	2042	7410	8310
MG0 GPC	Cumulative Additions (MW)	2043	7830	8310
MG0 GPC	Cumulative Additions (MW)	2044	8040	8310
MG0 GPC	Cumulative Additions (MW)	Total	8040	8310
111-MG0	Cumulative Additions (MW)	2026	0	0
111-MG0	Cumulative Additions (MW)	2027	0	0
111-MG0	Cumulative Additions (MW)	2028	0	0
111-MG0	Cumulative Additions (MW)	2029	900	900
111-MG0	Cumulative Additions (MW)	2030	1500	2400
111-MG0	Cumulative Additions (MW)	2031	2400	4200
111-MG0	Cumulative Additions (MW)	2032	2700	4500
111-MG0	Cumulative Additions (MW)	2033	3600	5100
111-MG0	Cumulative Additions (MW)	2034	3600	5700
111-MG0	Cumulative Additions (MW)	2035	4500	5700
111-MG0	Cumulative Additions (MW)	2036	4500	6000
111-MG0	Cumulative Additions (MW)	2037	4500	6900
111-MG0	Cumulative Additions (MW)	2038	4800	7200
111-MG0	Cumulative Additions (MW)	2039	5700	8700
111-MG0	Cumulative Additions (MW)	2040	6300	9900
111-MG0	Cumulative Additions (MW)	2041	7200	9900
111-MG0	Cumulative Additions (MW)	2042	7800	10500
111-MG0	Cumulative Additions (MW)	2043	8100	10800
111-MG0	Cumulative Additions (MW)	2044	8400	11400
111-MG0	Cumulative Additions (MW)	Total	8400	11400
111-MG0 GPC	Cumulative Additions (MW)	2026	0	0
111-MG0 GPC	Cumulative Additions (MW)	2027	0	0
111-MG0 GPC	Cumulative Additions (MW)	2028	0	0
111-MG0 GPC	Cumulative Additions (MW)	2029	900	0
111-MG0 GPC	Cumulative Additions (MW)	2030	1500	1260
111-MG0 GPC	Cumulative Additions (MW)	2031	2400	3060
111-MG0 GPC	Cumulative Additions (MW)	2032	2700	3300

111-MG0 GPC	Cumulative Additions (MW)	2033	3330	3720
111-MG0 GPC	Cumulative Additions (MW)	2034	3330	4140
111-MG0 GPC	Cumulative Additions (MW)	2035	4230	4140
111-MG0 GPC	Cumulative Additions (MW)	2036	4230	4350
111-MG0 GPC	Cumulative Additions (MW)	2037	4230	4980
111-MG0 GPC	Cumulative Additions (MW)	2038	4440	5190
111-MG0 GPC	Cumulative Additions (MW)	2039	5340	6690
111-MG0 GPC	Cumulative Additions (MW)	2040	5940	7890
111-MG0 GPC	Cumulative Additions (MW)	2041	6270	7890
111-MG0 GPC	Cumulative Additions (MW)	2042	6660	8310
111-MG0 GPC	Cumulative Additions (MW)	2043	6810	8520
111-MG0 GPC	Cumulative Additions (MW)	2044	7050	8940
111-MG0 GPC	Cumulative Additions (MW)	Total	7050	8940
111-HG0	Cumulative Additions (MW)	2026	0	0
111-HG0	Cumulative Additions (MW)	2027	0	0
111-HG0	Cumulative Additions (MW)	2028	0	0
111-HG0	Cumulative Additions (MW)	2029	300	900
111-HG0	Cumulative Additions (MW)	2030	1200	3300
111-HG0	Cumulative Additions (MW)	2031	1500	4200
111-HG0	Cumulative Additions (MW)	2032	1800	4800
111-HG0	Cumulative Additions (MW)	2033	1800	6000
111-HG0	Cumulative Additions (MW)	2034	2400	6600
111-HG0	Cumulative Additions (MW)	2035	2700	7500
111-HG0	Cumulative Additions (MW)	2036	3300	8100
111-HG0	Cumulative Additions (MW)	2037	4500	8100
111-HG0	Cumulative Additions (MW)	2038	4500	8100
111-HG0	Cumulative Additions (MW)	2039	5100	8700
111-HG0	Cumulative Additions (MW)	2040	5700	9300
111-HG0	Cumulative Additions (MW)	2041	6600	9300
111-HG0	Cumulative Additions (MW)	2042	7200	9600
111-HG0	Cumulative Additions (MW)	2043	7500	10200
111-HG0	Cumulative Additions (MW)	2044	7800	10800
111-HG0	Cumulative Additions (MW)	Total	7800	10800
111-HG0 GPC	Cumulative Additions (MW)	2026	0	0
111-HG0 GPC	Cumulative Additions (MW)	2027	0	0
111-HG0 GPC	Cumulative Additions (MW)	2028	0	0
111-HG0 GPC	Cumulative Additions (MW)	2029	300	0
111-HG0 GPC	Cumulative Additions (MW)	2030	1200	1770
111-HG0 GPC	Cumulative Additions (MW)	2031	1500	2670
111-HG0 GPC	Cumulative Additions (MW)	2032	1800	3270
111-HG0 GPC	Cumulative Additions (MW)	2033	1800	4230
111-HG0 GPC	Cumulative Additions (MW)	2034	2190	4650
111-HG0 GPC	Cumulative Additions (MW)	2035	2490	5520
111-HG0 GPC	Cumulative Additions (MW)	2036	2910	5940
111-HG0 GPC	Cumulative Additions (MW)	2037	3750	5940
111-HG0 GPC	Cumulative Additions (MW)	2038	3750	5940
111-HG0 GPC	Cumulative Additions (MW)	2039	4350	6540
111-HG0 GPC	Cumulative Additions (MW)	2040	4950	7140

111-HG0 GPC	Cumulative Additions (MW)	2041	5160	7140
111-HG0 GPC	Cumulative Additions (MW)	2042	5460	7350
111-HG0 GPC	Cumulative Additions (MW)	2043	5580	7770
111-HG0 GPC	Cumulative Additions (MW)	2044	5820	8190
111-HG0 GPC	Cumulative Additions (MW)	Total	5820	8190
111-MG50	Cumulative Additions (MW)	2026	0	0
111-MG50	Cumulative Additions (MW)	2027	0	0
111-MG50	Cumulative Additions (MW)	2028	0	0
111-MG50	Cumulative Additions (MW)	2029	900	900
111-MG50	Cumulative Additions (MW)	2030	1500	2400
111-MG50	Cumulative Additions (MW)	2031	1800	4500
111-MG50	Cumulative Additions (MW)	2032	2100	5400
111-MG50	Cumulative Additions (MW)	2033	2700	6000
111-MG50	Cumulative Additions (MW)	2034	3000	6300
111-MG50	Cumulative Additions (MW)	2035	3600	6600
111-MG50	Cumulative Additions (MW)	2036	4500	6900
111-MG50	Cumulative Additions (MW)	2037	4500	7200
111-MG50	Cumulative Additions (MW)	2038	4500	7200
111-MG50	Cumulative Additions (MW)	2039	5700	7500
111-MG50	Cumulative Additions (MW)	2040	6000	7800
111-MG50	Cumulative Additions (MW)	2041	6000	8100
111-MG50	Cumulative Additions (MW)	2042	6000	8100
111-MG50	Cumulative Additions (MW)	2043	6000	8700
111-MG50	Cumulative Additions (MW)	2044	6000	9000
111-MG50	Cumulative Additions (MW)	Total	6000	9000
111-MG50 GPC	Cumulative Additions (MW)	2026	0	0
111-MG50 GPC	Cumulative Additions (MW)	2027	0	0
111-MG50 GPC	Cumulative Additions (MW)	2028	0	0
111-MG50 GPC	Cumulative Additions (MW)	2029	900	0
111-MG50 GPC	Cumulative Additions (MW)	2030	1500	1260
111-MG50 GPC	Cumulative Additions (MW)	2031	1800	3360
111-MG50 GPC	Cumulative Additions (MW)	2032	2100	3990
111-MG50 GPC	Cumulative Additions (MW)	2033	2520	4410
111-MG50 GPC	Cumulative Additions (MW)	2034	2730	4620
111-MG50 GPC	Cumulative Additions (MW)	2035	3330	4920
111-MG50 GPC	Cumulative Additions (MW)	2036	3960	5130
111-MG50 GPC	Cumulative Additions (MW)	2037	3960	5340
111-MG50 GPC	Cumulative Additions (MW)	2038	3960	5340
111-MG50 GPC	Cumulative Additions (MW)	2039	5160	5640
111-MG50 GPC	Cumulative Additions (MW)	2040	5460	5940
111-MG50 GPC	Cumulative Additions (MW)	2041	5460	6150
111-MG50 GPC	Cumulative Additions (MW)	2042	5460	6150
111-MG50 GPC	Cumulative Additions (MW)	2043	5460	6660
111-MG50 GPC	Cumulative Additions (MW)	2044	5460	6900
111-MG50 GPC	Cumulative Additions (MW)	Total	5460	6900
LG0	Cumulative Additions (MW)	2026	0	0
LG0	Cumulative Additions (MW)	2027	0	0
LG0	Cumulative Additions (MW)	2028	0	0

LG0	Cumulative Additions (MW)	2029	900	900
LG0	Cumulative Additions (MW)	2030	1500	2400
LG0	Cumulative Additions (MW)	2031	1800	5400
LG0	Cumulative Additions (MW)	2032	2700	5400
LG0	Cumulative Additions (MW)	2033	3600	5400
LG0	Cumulative Additions (MW)	2034	4200	5400
LG0	Cumulative Additions (MW)	2035	4500	6600
LG0	Cumulative Additions (MW)	2036	5400	9300
LG0	Cumulative Additions (MW)	2037	5700	9300
LG0	Cumulative Additions (MW)	2038	6000	9300
LG0	Cumulative Additions (MW)	2039	6300	10500
LG0	Cumulative Additions (MW)	2040	7500	10500
LG0	Cumulative Additions (MW)	2041	8100	10500
LG0	Cumulative Additions (MW)	2042	9300	10500
LG0	Cumulative Additions (MW)	2043	9600	10500
LG0	Cumulative Additions (MW)	2044	10500	10500
LG0	Cumulative Additions (MW)	Total	10500	10500
LG0-GPC	Cumulative Additions (MW)	2026	0	0
LG0-GPC	Cumulative Additions (MW)	2027	0	0
LG0-GPC	Cumulative Additions (MW)	2028	0	0
LG0-GPC	Cumulative Additions (MW)	2029	900	0
LG0-GPC	Cumulative Additions (MW)	2030	1500	1200
LG0-GPC	Cumulative Additions (MW)	2031	1800	3990
LG0-GPC	Cumulative Additions (MW)	2032	2520	3990
LG0-GPC	Cumulative Additions (MW)	2033	3150	3990
LG0-GPC	Cumulative Additions (MW)	2034	3570	3990
LG0-GPC	Cumulative Additions (MW)	2035	3870	5010
LG0-GPC	Cumulative Additions (MW)	2036	4770	7710
LG0-GPC	Cumulative Additions (MW)	2037	5010	7710
LG0-GPC	Cumulative Additions (MW)	2038	5310	7710
LG0-GPC	Cumulative Additions (MW)	2039	5610	8580
LG0-GPC	Cumulative Additions (MW)	2040	6570	8580
LG0-GPC	Cumulative Additions (MW)	2041	6570	8580
LG0-GPC	Cumulative Additions (MW)	2042	7260	8580
LG0-GPC	Cumulative Additions (MW)	2043	7410	8580
LG0-GPC	Cumulative Additions (MW)	2044	7920	8580
LG0-GPC	Cumulative Additions (MW)	Total	7920	8580
HG0	Cumulative Additions (MW)	2026	0	0
HG0	Cumulative Additions (MW)	2027	0	0
HG0	Cumulative Additions (MW)	2028	0	0
HG0	Cumulative Additions (MW)	2029	300	900
HG0	Cumulative Additions (MW)	2030	1200	2400
HG0	Cumulative Additions (MW)	2031	1500	5100
HG0	Cumulative Additions (MW)	2032	2100	5100
HG0	Cumulative Additions (MW)	2033	2700	5100
HG0	Cumulative Additions (MW)	2034	3300	5100
HG0	Cumulative Additions (MW)	2035	3900	6900
HG0	Cumulative Additions (MW)	2036	4500	9300

HG0	Cumulative Additions (MW)	2037	4800	9300
HG0	Cumulative Additions (MW)	2038	5100	9300
HG0	Cumulative Additions (MW)	2039	5400	10500
HG0	Cumulative Additions (MW)	2040	6300	10500
HG0	Cumulative Additions (MW)	2041	6900	10500
HG0	Cumulative Additions (MW)	2042	7500	10500
HG0	Cumulative Additions (MW)	2043	7800	10500
HG0	Cumulative Additions (MW)	2044	8100	10500
HG0	Cumulative Additions (MW)	Total	8100	10500
HG0-GPC	Cumulative Additions (MW)	2026	0	0
HG0-GPC	Cumulative Additions (MW)	2027	0	0
HG0-GPC	Cumulative Additions (MW)	2028	0	0
HG0-GPC	Cumulative Additions (MW)	2029	300	0
HG0-GPC	Cumulative Additions (MW)	2030	1200	1200
HG0-GPC	Cumulative Additions (MW)	2031	1500	3840
HG0-GPC	Cumulative Additions (MW)	2032	2040	3840
HG0-GPC	Cumulative Additions (MW)	2033	2460	3840
HG0-GPC	Cumulative Additions (MW)	2034	2880	3840
HG0-GPC	Cumulative Additions (MW)	2035	3480	5130
HG0-GPC	Cumulative Additions (MW)	2036	4080	7530
HG0-GPC	Cumulative Additions (MW)	2037	4320	7530
HG0-GPC	Cumulative Additions (MW)	2038	4620	7530
HG0-GPC	Cumulative Additions (MW)	2039	4920	8370
HG0-GPC	Cumulative Additions (MW)	2040	5700	8370
HG0-GPC	Cumulative Additions (MW)	2041	5700	8370
HG0-GPC	Cumulative Additions (MW)	2042	6000	8370
HG0-GPC	Cumulative Additions (MW)	2043	6180	8370
HG0-GPC	Cumulative Additions (MW)	2044	6390	8370
HG0-GPC	Cumulative Additions (MW)	Total	6390	8370
MG20	Cumulative Additions (MW)	2026	0	0
MG20	Cumulative Additions (MW)	2027	0	0
MG20	Cumulative Additions (MW)	2028	0	0
MG20	Cumulative Additions (MW)	2029	1200	900
MG20	Cumulative Additions (MW)	2030	1500	3600
MG20	Cumulative Additions (MW)	2031	1500	6000
MG20	Cumulative Additions (MW)	2032	2100	6300
MG20	Cumulative Additions (MW)	2033	2400	6300
MG20	Cumulative Additions (MW)	2034	3000	6300
MG20	Cumulative Additions (MW)	2035	3300	8100
MG20	Cumulative Additions (MW)	2036	4200	9300
MG20	Cumulative Additions (MW)	2037	4500	9300
MG20	Cumulative Additions (MW)	2038	5100	9300
MG20	Cumulative Additions (MW)	2039	5400	9300
MG20	Cumulative Additions (MW)	2040	5700	9300
MG20	Cumulative Additions (MW)	2041	6000	9300
MG20	Cumulative Additions (MW)	2042	7200	9300
MG20	Cumulative Additions (MW)	2043	7500	9300
MG20	Cumulative Additions (MW)	2044	8400	9300

MG20	Cumulative Additions (MW)	Total	8400	9300
MG20-GPC	Cumulative Additions (MW)	2026	0	0
MG20-GPC	Cumulative Additions (MW)	2027	0	0
MG20-GPC	Cumulative Additions (MW)	2028	0	0
MG20-GPC	Cumulative Additions (MW)	2029	1200	0
MG20-GPC	Cumulative Additions (MW)	2030	1500	2130
MG20-GPC	Cumulative Additions (MW)	2031	1500	4530
MG20-GPC	Cumulative Additions (MW)	2032	2100	4800
MG20-GPC	Cumulative Additions (MW)	2033	2310	4800
MG20-GPC	Cumulative Additions (MW)	2034	2730	4800
MG20-GPC	Cumulative Additions (MW)	2035	3030	6180
MG20-GPC	Cumulative Additions (MW)	2036	3930	7380
MG20-GPC	Cumulative Additions (MW)	2037	4230	7380
MG20-GPC	Cumulative Additions (MW)	2038	4770	7380
MG20-GPC	Cumulative Additions (MW)	2039	4980	7380
MG20-GPC	Cumulative Additions (MW)	2040	5280	7380
MG20-GPC	Cumulative Additions (MW)	2041	5400	7380
MG20-GPC	Cumulative Additions (MW)	2042	6090	7380
MG20-GPC	Cumulative Additions (MW)	2043	6240	7380
MG20-GPC	Cumulative Additions (MW)	2044	6900	7380
MG20-GPC	Cumulative Additions (MW)	Total	6900	7380
MG50	Cumulative Additions (MW)	2026	0	0
MG50	Cumulative Additions (MW)	2027	0	0
MG50	Cumulative Additions (MW)	2028	0	0
MG50	Cumulative Additions (MW)	2029	900	900
MG50	Cumulative Additions (MW)	2030	900	3900
MG50	Cumulative Additions (MW)	2031	900	6600
MG50	Cumulative Additions (MW)	2032	900	6900
MG50	Cumulative Additions (MW)	2033	1200	6900
MG50	Cumulative Additions (MW)	2034	2400	6900
MG50	Cumulative Additions (MW)	2035	2700	8100
MG50	Cumulative Additions (MW)	2036	4500	9300
MG50	Cumulative Additions (MW)	2037	4500	9300
MG50	Cumulative Additions (MW)	2038	4500	9300
MG50	Cumulative Additions (MW)	2039	4500	9300
MG50	Cumulative Additions (MW)	2040	4500	9300
MG50	Cumulative Additions (MW)	2041	4500	9300
MG50	Cumulative Additions (MW)	2042	4500	9300
MG50	Cumulative Additions (MW)	2043	4500	9300
MG50	Cumulative Additions (MW)	2044	4800	9300
MG50	Cumulative Additions (MW)	Total	4800	9300
MG50-GPC	Cumulative Additions (MW)	2026	0	0
MG50-GPC	Cumulative Additions (MW)	2027	0	0
MG50-GPC	Cumulative Additions (MW)	2028	0	0
MG50-GPC	Cumulative Additions (MW)	2029	900	0
MG50-GPC	Cumulative Additions (MW)	2030	900	2340
MG50-GPC	Cumulative Additions (MW)	2031	900	5040
MG50-GPC	Cumulative Additions (MW)	2032	900	5340

MG50-GPC	Cumulative Additions (MW)	2033	1170	5340
MG50-GPC	Cumulative Additions (MW)	2034	1980	5340
MG50-GPC	Cumulative Additions (MW)	2035	2280	6330
MG50-GPC	Cumulative Additions (MW)	2036	4080	7530
MG50-GPC	Cumulative Additions (MW)	2037	4080	7530
MG50-GPC	Cumulative Additions (MW)	2038	4080	7530
MG50-GPC	Cumulative Additions (MW)	2039	4080	7530
MG50-GPC	Cumulative Additions (MW)	2040	4080	7530
MG50-GPC	Cumulative Additions (MW)	2041	4080	7530
MG50-GPC	Cumulative Additions (MW)	2042	4080	7530
MG50-GPC	Cumulative Additions (MW)	2043	4080	7530
MG50-GPC	Cumulative Additions (MW)	2044	4320	7530
MG50-GPC	Cumulative Additions (MW)	Total	4320	7530
EL	Cumulative Additions (MW)	2026	0	0
EL	Cumulative Additions (MW)	2027	0	0
EL	Cumulative Additions (MW)	2028	0	0
EL	Cumulative Additions (MW)	2029	900	900
EL	Cumulative Additions (MW)	2030	1500	5400
EL	Cumulative Additions (MW)	2031	2100	6900
EL	Cumulative Additions (MW)	2032	3000	6900
EL	Cumulative Additions (MW)	2033	3900	6900
EL	Cumulative Additions (MW)	2034	5400	6900
EL	Cumulative Additions (MW)	2035	5400	7800
EL	Cumulative Additions (MW)	2036	6300	7800
EL	Cumulative Additions (MW)	2037	6300	7800
EL	Cumulative Additions (MW)	2038	6300	7800
EL	Cumulative Additions (MW)	2039	6300	7800
EL	Cumulative Additions (MW)	2040	6300	7800
EL	Cumulative Additions (MW)	2041	6300	7800
EL	Cumulative Additions (MW)	2042	6300	7800
EL	Cumulative Additions (MW)	2043	6300	7800
EL	Cumulative Additions (MW)	2044	6300	7800
EL	Cumulative Additions (MW)	Total	6300	7800
EL-GPC	Cumulative Additions (MW)	2026	0	0
EL-GPC	Cumulative Additions (MW)	2027	0	0
EL-GPC	Cumulative Additions (MW)	2028	0	0
EL-GPC	Cumulative Additions (MW)	2029	900	0
EL-GPC	Cumulative Additions (MW)	2030	1470	3030
EL-GPC	Cumulative Additions (MW)	2031	2070	4530
EL-GPC	Cumulative Additions (MW)	2032	2970	4530
EL-GPC	Cumulative Additions (MW)	2033	3600	4530
EL-GPC	Cumulative Additions (MW)	2034	4560	4530
EL-GPC	Cumulative Additions (MW)	2035	4560	5430
EL-GPC	Cumulative Additions (MW)	2036	5460	5430
EL-GPC	Cumulative Additions (MW)	2037	5460	5430
EL-GPC	Cumulative Additions (MW)	2038	5460	5430
EL-GPC	Cumulative Additions (MW)	2039	5460	5430
EL-GPC	Cumulative Additions (MW)	2040	5460	5430

EL-GPC	Cumulative Additions (MW)	2041	5460	5430
EL-GPC	Cumulative Additions (MW)	2042	5460	5430
EL-GPC	Cumulative Additions (MW)	2043	5460	5430
EL-GPC	Cumulative Additions (MW)	2044	5460	5430
EL-GPC	Cumulative Additions (MW)	Total	5460	5430
MG20-SYSTEM	Cumulative Additions (MW)	2026	0	0
MG20-SYSTEM	Cumulative Additions (MW)	2027	0	0
MG20-SYSTEM	Cumulative Additions (MW)	2028	0	0
MG20-SYSTEM	Cumulative Additions (MW)	2029	0	900
MG20-SYSTEM	Cumulative Additions (MW)	2030	0	1470
MG20-SYSTEM	Cumulative Additions (MW)	2031	0	1470
MG20-SYSTEM	Cumulative Additions (MW)	2032	0	1500
MG20-SYSTEM	Cumulative Additions (MW)	2033	90	1500
MG20-SYSTEM	Cumulative Additions (MW)	2034	270	1500
MG20-SYSTEM	Cumulative Additions (MW)	2035	270	1920
MG20-SYSTEM	Cumulative Additions (MW)	2036	270	1920
MG20-SYSTEM	Cumulative Additions (MW)	2037	270	1920
MG20-SYSTEM	Cumulative Additions (MW)	2038	330	1920
MG20-SYSTEM	Cumulative Additions (MW)	2039	420	1920
MG20-SYSTEM	Cumulative Additions (MW)	2040	420	1920
MG20-SYSTEM	Cumulative Additions (MW)	2041	600	1920
MG20-SYSTEM	Cumulative Additions (MW)	2042	1110	1920
MG20-SYSTEM	Cumulative Additions (MW)	2043	1260	1920
MG20-SYSTEM	Cumulative Additions (MW)	2044	1500	1920
MG20-SYSTEM	Cumulative Additions (MW)	Total	1500	1920
MG20-GPC - No Large Load	Cumulative Additions (MW)	2026	0	0
MG20-GPC - No Large Load	Cumulative Additions (MW)	2027	0	0
MG20-GPC - No Large Load	Cumulative Additions (MW)	2028	0	0
MG20-GPC - No Large Load	Cumulative Additions (MW)	2029	0	0
MG20-GPC - No Large Load	Cumulative Additions (MW)	2030	0	0
MG20-GPC - No Large Load	Cumulative Additions (MW)	2031	0	0
MG20-GPC - No Large Load	Cumulative Additions (MW)	2032	500	1000
MG20-GPC - No Large Load	Cumulative Additions (MW)	2033	500	1000
MG20-GPC - No Large Load	Cumulative Additions (MW)	2034	560	1000
MG20-GPC - No Large Load	Cumulative Additions (MW)	2035	710	1340
MG20-GPC - No Large Load	Cumulative Additions (MW)	2036	710	710
MG20-GPC - No Large Load	Cumulative Additions (MW)	2037	820	1430
MG20-GPC - No Large Load	Cumulative Additions (MW)	2038	1070	1650
MG20-GPC - No Large Load	Cumulative Additions (MW)	2039	1320	2200
MG20-GPC - No Large Load	Cumulative Additions (MW)	2040	1450	2270
MG20-GPC - No Large Load	Cumulative Additions (MW)	2041	1580	2510
MG20-GPC - No Large Load	Cumulative Additions (MW)	2042	1840	2600
MG20-GPC - No Large Load	Cumulative Additions (MW)	2043	1930	2660
MG20-GPC - No Large Load	Cumulative Additions (MW)	2044	2160	2690
MG20-GPC - No Large Load	Cumulative Additions (MW)	Total	2160	2690
MG20-GPC - No Large Load	Incremental Additions (MW)	2026	0	0
MG20-GPC - No Large Load	Incremental Additions (MW)	2027	0	0
MG20-GPC - No Large Load	Incremental Additions (MW)	2028	0	0

MG20-GPC - No Large Load	Incremental Additions (MW)	2029	0	0
MG20-GPC - No Large Load	Incremental Additions (MW)	2030	0	0
MG20-GPC - No Large Load	Incremental Additions (MW)	2031	0	0
MG20-GPC - No Large Load	Incremental Additions (MW)	2032	500	1000
MG20-GPC - No Large Load	Incremental Additions (MW)	2033	0	0
MG20-GPC - No Large Load	Incremental Additions (MW)	2034	60	0
MG20-GPC - No Large Load	Incremental Additions (MW)	2035	150	340
MG20-GPC - No Large Load	Incremental Additions (MW)	2036	0	-630
MG20-GPC - No Large Load	Incremental Additions (MW)	2037	110	720
MG20-GPC - No Large Load	Incremental Additions (MW)	2038	250	220
MG20-GPC - No Large Load	Incremental Additions (MW)	2039	250	550
MG20-GPC - No Large Load	Incremental Additions (MW)	2040	130	70
MG20-GPC - No Large Load	Incremental Additions (MW)	2041	130	240
MG20-GPC - No Large Load	Incremental Additions (MW)	2042	260	90
MG20-GPC - No Large Load	Incremental Additions (MW)	2043	90	60
MG20-GPC - No Large Load	Incremental Additions (MW)	2044	230	30
MG20-GPC - No Large Load	Incremental Additions (MW)	Total	2160	2690
MG20-GPC - Half Large Load	Cumulative Additions (MW)	2026	0	0
MG20-GPC - Half Large Load	Cumulative Additions (MW)	2027	0	0
MG20-GPC - Half Large Load	Cumulative Additions (MW)	2028	0	0
MG20-GPC - Half Large Load	Cumulative Additions (MW)	2029	0	0
MG20-GPC - Half Large Load	Cumulative Additions (MW)	2030	400	0
MG20-GPC - Half Large Load	Cumulative Additions (MW)	2031	420	1260
MG20-GPC - Half Large Load	Cumulative Additions (MW)	2032	2100	4000
MG20-GPC - Half Large Load	Cumulative Additions (MW)	2033	2100	4000
MG20-GPC - Half Large Load	Cumulative Additions (MW)	2034	2270	4000
MG20-GPC - Half Large Load	Cumulative Additions (MW)	2035	3350	4500
MG20-GPC - Half Large Load	Cumulative Additions (MW)	2036	3350	4500
MG20-GPC - Half Large Load	Cumulative Additions (MW)	2037	3350	4500
MG20-GPC - Half Large Load	Cumulative Additions (MW)	2038	3350	4500
MG20-GPC - Half Large Load	Cumulative Additions (MW)	2039	3350	5220
MG20-GPC - Half Large Load	Cumulative Additions (MW)	2040	3350	5270
MG20-GPC - Half Large Load	Cumulative Additions (MW)	2041	3500	5560
MG20-GPC - Half Large Load	Cumulative Additions (MW)	2042	3930	5560
MG20-GPC - Half Large Load	Cumulative Additions (MW)	2043	4090	5560
MG20-GPC - Half Large Load	Cumulative Additions (MW)	2044	4480	5560
MG20-GPC - Half Large Load	Cumulative Additions (MW)	Total	4480	5560
MG20-GPC - Half Large Load	Incremental Additions (MW)	2026	0	0
MG20-GPC - Half Large Load	Incremental Additions (MW)	2027	0	0
MG20-GPC - Half Large Load	Incremental Additions (MW)	2028	0	0
MG20-GPC - Half Large Load	Incremental Additions (MW)	2029	0	0
MG20-GPC - Half Large Load	Incremental Additions (MW)	2030	400	0
MG20-GPC - Half Large Load	Incremental Additions (MW)	2031	20	1260
MG20-GPC - Half Large Load	Incremental Additions (MW)	2032	1680	2740
MG20-GPC - Half Large Load	Incremental Additions (MW)	2033	0	0
MG20-GPC - Half Large Load	Incremental Additions (MW)	2034	170	0
MG20-GPC - Half Large Load	Incremental Additions (MW)	2035	1080	500
MG20-GPC - Half Large Load	Incremental Additions (MW)	2036	0	0

MG20-GPC - Half Large Load	Incremental Additions (MW)	2037	0	0
MG20-GPC - Half Large Load	Incremental Additions (MW)	2038	0	0
MG20-GPC - Half Large Load	Incremental Additions (MW)	2039	0	720
MG20-GPC - Half Large Load	Incremental Additions (MW)	2040	0	50
MG20-GPC - Half Large Load	Incremental Additions (MW)	2041	150	290
MG20-GPC - Half Large Load	Incremental Additions (MW)	2042	430	0
MG20-GPC - Half Large Load	Incremental Additions (MW)	2043	160	0
MG20-GPC - Half Large Load	Incremental Additions (MW)	2044	390	0
MG20-GPC - Half Large Load	Incremental Additions (MW)	Total	0	0
MG20-GPC - High Solar	Cumulative Additions (MW)	2026	0	0
MG20-GPC - High Solar	Cumulative Additions (MW)	2027	0	0
MG20-GPC - High Solar	Cumulative Additions (MW)	2028	0	0
MG20-GPC - High Solar	Cumulative Additions (MW)	2029	800	0
MG20-GPC - High Solar	Cumulative Additions (MW)	2030	1100	1400
MG20-GPC - High Solar	Cumulative Additions (MW)	2031	1400	4100
MG20-GPC - High Solar	Cumulative Additions (MW)	2032	1900	4100
MG20-GPC - High Solar	Cumulative Additions (MW)	2033	1900	4100
MG20-GPC - High Solar	Cumulative Additions (MW)	2034	2100	4100
MG20-GPC - High Solar	Cumulative Additions (MW)	2035	2600	5100
MG20-GPC - High Solar	Cumulative Additions (MW)	2036	3800	7100
MG20-GPC - High Solar	Cumulative Additions (MW)	2037	4000	7100
MG20-GPC - High Solar	Cumulative Additions (MW)	2038	4400	7100
MG20-GPC - High Solar	Cumulative Additions (MW)	2039	4700	7800
MG20-GPC - High Solar	Cumulative Additions (MW)	2040	5000	7800
MG20-GPC - High Solar	Cumulative Additions (MW)	2041	5200	8000
MG20-GPC - High Solar	Cumulative Additions (MW)	2042	5600	8000
MG20-GPC - High Solar	Cumulative Additions (MW)	2043	5900	8000
MG20-GPC - High Solar	Cumulative Additions (MW)	2044	6300	8000
MG20-GPC - High Solar	Cumulative Additions (MW)	Total	6300	8000
MG20-GPC - High Solar	Incremental Additions (MW)	2026	0	0
MG20-GPC - High Solar	Incremental Additions (MW)	2027	0	0
MG20-GPC - High Solar	Incremental Additions (MW)	2028	0	0
MG20-GPC - High Solar	Incremental Additions (MW)	2029	800	0
MG20-GPC - High Solar	Incremental Additions (MW)	2030	300	1400
MG20-GPC - High Solar	Incremental Additions (MW)	2031	300	2700
MG20-GPC - High Solar	Incremental Additions (MW)	2032	500	0
MG20-GPC - High Solar	Incremental Additions (MW)	2033	0	0
MG20-GPC - High Solar	Incremental Additions (MW)	2034	200	0
MG20-GPC - High Solar	Incremental Additions (MW)	2035	500	1000
MG20-GPC - High Solar	Incremental Additions (MW)	2036	1200	2000
MG20-GPC - High Solar	Incremental Additions (MW)	2037	200	0
MG20-GPC - High Solar	Incremental Additions (MW)	2038	400	0
MG20-GPC - High Solar	Incremental Additions (MW)	2039	300	700
MG20-GPC - High Solar	Incremental Additions (MW)	2040	300	0
MG20-GPC - High Solar	Incremental Additions (MW)	2041	200	200
MG20-GPC - High Solar	Incremental Additions (MW)	2042	400	0
MG20-GPC - High Solar	Incremental Additions (MW)	2043	300	0
MG20-GPC - High Solar	Incremental Additions (MW)	2044	400	0

MG20-GPC - High Solar	Incremental Additions (MW)	Total	6300	8000
MG20-GPC - Combined	Cumulative Additions (MW)	2026	0	0
MG20-GPC - Combined	Cumulative Additions (MW)	2027	0	0
MG20-GPC - Combined	Cumulative Additions (MW)	2028	0	0
MG20-GPC - Combined	Cumulative Additions (MW)	2029	0	0
MG20-GPC - Combined	Cumulative Additions (MW)	2030	0	0
MG20-GPC - Combined	Cumulative Additions (MW)	2031	260	790
MG20-GPC - Combined	Cumulative Additions (MW)	2032	1820	3480
MG20-GPC - Combined	Cumulative Additions (MW)	2033	1820	3480
MG20-GPC - Combined	Cumulative Additions (MW)	2034	1920	3480
MG20-GPC - Combined	Cumulative Additions (MW)	2035	2980	3980
MG20-GPC - Combined	Cumulative Additions (MW)	2036	2980	3980
MG20-GPC - Combined	Cumulative Additions (MW)	2037	2980	3980
MG20-GPC - Combined	Cumulative Additions (MW)	2038	2980	3980
MG20-GPC - Combined	Cumulative Additions (MW)	2039	2980	4660
MG20-GPC - Combined	Cumulative Additions (MW)	2040	3080	4800
MG20-GPC - Combined	Cumulative Additions (MW)	2041	3180	5040
MG20-GPC - Combined	Cumulative Additions (MW)	2042	3550	5040
MG20-GPC - Combined	Cumulative Additions (MW)	2043	3710	5040
MG20-GPC - Combined	Cumulative Additions (MW)	2044	4030	5040
MG20-GPC - Combined	Cumulative Additions (MW)	Total	4030	5040
MG20-GPC - Combined	Incremental Additions (MW)	2026	0	0
MG20-GPC - Combined	Incremental Additions (MW)	2027	0	0
MG20-GPC - Combined	Incremental Additions (MW)	2028	0	0
MG20-GPC - Combined	Incremental Additions (MW)	2029	0	0
MG20-GPC - Combined	Incremental Additions (MW)	2030	0	0
MG20-GPC - Combined	Incremental Additions (MW)	2031	260	790
MG20-GPC - Combined	Incremental Additions (MW)	2032	1560	2690
MG20-GPC - Combined	Incremental Additions (MW)	2033	0	0
MG20-GPC - Combined	Incremental Additions (MW)	2034	100	0
MG20-GPC - Combined	Incremental Additions (MW)	2035	1060	500
MG20-GPC - Combined	Incremental Additions (MW)	2036	0	0
MG20-GPC - Combined	Incremental Additions (MW)	2037	0	0
MG20-GPC - Combined	Incremental Additions (MW)	2038	0	0
MG20-GPC - Combined	Incremental Additions (MW)	2039	0	680
MG20-GPC - Combined	Incremental Additions (MW)	2040	100	140
MG20-GPC - Combined	Incremental Additions (MW)	2041	100	240
MG20-GPC - Combined	Incremental Additions (MW)	2042	370	0
MG20-GPC - Combined	Incremental Additions (MW)	2043	160	0
MG20-GPC - Combined	Incremental Additions (MW)	2044	320	0
MG20-GPC - Combined	Incremental Additions (MW)	Total	4030	5040
		2026	0	0
		2027	0	0
		2028	0	0
		2029	0	0
		2030	-400	0
		2031	-160	-470
		2032	-280	-520

		2033	-280	-520
		2034	-350	-520
		2035	-370	-520
		2036	-370	-520
		2037	-370	-520
		2038	-370	-520
		2039	-370	-560
		2040	-270	-470
		2041	-320	-520
		2042	-380	-520
		2043	-380	-520
		2044	-450	-520

CC w/ CCS - Local	CC w/ CCS - Distant	Solar	Wind	Battery 4-hr (T1)	Battery 4-hr (T2)	Battery 4-hr (T3)	Battery 4-hr (T4)	Battery 4-hr (T1_2)
0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0
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900	0	18000	3600	2100	3000	0	0	
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330	0	1020	0	0	0	0	0	0
240	0	1020	300	0	0	0	0	0
570	0	12150	2430	1890	2310	0	0	
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2100	0	23400	3600	2100	3000	1500	0	
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540	0	1020	120	0	0	0	0	0
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1470	0	16490	1560	1890	2460	1110	0	
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270	0	1020	0	0	0	0	0	0
540	0	1020	270	0	0	0	0	0
570	0	1020	300	0	1200	1500	0	0
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270	0	1020	30	0	0	0	0	0
540	0	1020	180	0	0	0	0	0
660	600	1020	300	0	0	600	0	0
0	0	1020	300	0	0	0	0	0
0	0	1020	0	0	0	0	0	0
0	0	1020	300	0	0	0	0	0
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0	0	1020	300	0	0	840	210	0
1470	600	16490	2340	1890	2580	2280	210	
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0	0	0	0	300	2100	0	0	0
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1200	0	1500	300	0	0	0	0	0
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990	0	1020	0	0	0	0	0	0
990	0	10380	2040	1860	2460	1890	0	
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600	0	23400	3600	2100	3000	3000	1500	
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0	0	1380	0	900	900	0	0	0
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150	0	1020	0	0	0	0	0	0
240	0	1020	300	0	0	0	0	0
390	0	16490	2430	2100	2460	2400	1080	
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0	0	1500	0	0	900	0	0	0
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2100	0	23400	3600	2100	3000	3000	0	
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900	0	1020	270	0	0	0	0	0
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1200	0	1500	300	0	0	0	0	0
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1200	0	1500	300	0	0	0	0	0
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2400	0	23400	3600	2100	3000	3000	900	
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0	0	1020	300	0	0	0	0	0
1290	0	16490	2310	1890	2430	2640	630	
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300	3300	1500	300	0	0	0	0	0
900	0	1500	300	0	0	0	0	0
300	0	1500	300	0	0	0	0	0
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900	0	1020	300	0	0	0	0	0
300	2250	1020	0	0	0	0	0	0
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1500	3450	16490	2580	1860	2550	2160	0	
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570	0	12150	2430	1890	2310	0	0	0
570	0	12150	2430	1890	2310	0	0	0
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1800	0	15900	2100	2100	3000	1500	0	0
1800	0	17400	2400	2100	3000	1500	0	0
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2100	0	20400	3000	2100	3000	1500	0	0
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0	0	8330	510	1890	2460	1110	0	0
270	0	9350	540	1890	2460	1110	0	0
810	0	10370	660	1890	2460	1110	0	0
1470	0	11390	960	1890	2460	1110	0	0
1470	0	12410	1260	1890	2460	1110	0	0
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1470	600	12410	1440	1890	2580	810	0	0
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900	0	12410	2070	1530	2640	3000	0	0
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0	0	1370	0	685	0	0	0	0
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0	0	0	0	0	0	0	0	0
0	0	1370	0	685	0	0	0	0
0	0	1380	0	690	0	0	0	0
0	0	0	0	0	0	0	0	0
0	0	600	0	155	1800	0	0	0
0	0	990	0	0	0	0	0	0
0	0	990	240	0	420	0	0	0
0	0	990	60	0	0	0	0	0
0	0	990	300	0	420	0	0	0
0	0	1020	300	0	0	800	0	0

0	0	1020	300	0	0	400	0	0
0	0	1020	300	0	0	1000	0	0
0	0	1020	270	0	0	800	0	0
0	0	1020	300	0	0	0	0	0
0	0	1020	0	0	0	0	0	0
0	0	1020	0	0	0	0	0	0
0	0	1020	0	0	0	0	0	0
0	0	1020	300	0	0	0	0	0
0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0
0	0	2055	0	1530	1585	0	0	0
0	0	4125	0	1530	2487.5	0	0	0
0	0	4125	0	1530	2487.5	0	0	0
0	0	5025	0	1530	2640	0	0	0
0	0	6510	0	1530	2640	245	0	0
0	0	7995	240	1530	2640	913	0	0
0	0	9480	300	1530	2640	1160	0	0
0	0	10965	600	1530	2640	1828	0	0
0	0	12495	900	1530	2640	3000	2083	0
0	0	14025	1200	1530	2640	3000	2338	0
0	0	15555	1500	1530	2640	3000	2593	0
0	0	17085	1770	1530	2640	3000	2848	0
0	0	18615	2070	1530	2640	3000	3103	0
0	0	20145	2070	1530	2640	3000	3358	0
0	0	21675	2070	1530	2640	3000	3613	0
0	0	23205	2070	1530	2640	3000	3868	0
0	0	24735	2370	1530	2640	3000	4123	0
0	0	24735	2370	1530	2640	3000	4123	0
0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0
0	0	2055	0	1530	1585	0	0	0
0	0	2070	0	0	902.5	0	0	0
0	0	0	0	0	0	0	0	0
0	0	900	0	0	152.5	0	0	0
0	0	1485	0	0	0	245	0	0
0	0	1485	240	0	0	668	0	0
0	0	1485	60	0	0	247	0	0
0	0	1485	300	0	0	668	0	0
0	0	1530	300	0	0	1172	2083	0
0	0	1530	300	0	0	0	255	0
0	0	1530	300	0	0	0	255	0
0	0	1530	270	0	0	0	255	0
0	0	1530	300	0	0	0	255	0
0	0	1530	0	0	0	0	255	0
0	0	1530	0	0	0	0	255	0
0	0	1530	0	0	0	0	255	0
0	0	1530	300	0	0	0	255	0

0	0	24735	2370	1530	2640	3000	4123	0
0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0
0	0	2055	0	0	0	0	0	0
0	0	4125	0	900	0	0	0	0
0	0	4125	0	1530	500	0	0	0
0	0	5025	0	1530	2640	0	0	0
0	0	6510	0	1530	2640	245	0	0
0	0	7995	240	1530	2640	913	0	0
0	0	9480	300	1530	2640	1160	0	0
0	0	10965	600	1530	2640	1828	0	0
0	0	12495	900	1530	2640	3000	2083	0
0	0	14025	1200	1530	2640	3000	2338	0
0	0	15555	1500	1530	2640	3000	2593	0
0	0	17085	1770	1530	2640	3000	2848	0
0	0	18615	2070	1530	2640	3000	3103	0
0	0	20145	2070	1530	2640	3000	3358	0
0	0	21675	2070	1530	2640	3000	3613	0
0	0	23205	2070	1530	2640	3000	3868	0
0	0	24735	2370	1530	2640	3000	4123	0
0	0	24735	2370	1530	2640	3000	4123	0
0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0
0	0	2055	0	0	0	0	0	0
0	0	2070	0	900	0	0	0	0
0	0	0	0	630	500	0	0	0
0	0	900	0	0	2140	0	0	0
0	0	1485	0	0	0	245	0	0
0	0	1485	240	0	0	668	0	0
0	0	1485	60	0	0	247	0	0
0	0	1485	300	0	0	668	0	0
0	0	1530	300	0	0	1172	2083	0
0	0	1530	300	0	0	0	255	0
0	0	1530	300	0	0	0	255	0
0	0	1530	270	0	0	0	255	0
0	0	1530	300	0	0	0	255	0
0	0	1530	0	0	0	0	255	0
0	0	1530	0	0	0	0	255	0
0	0	1530	0	0	0	0	255	0
0	0	1530	300	0	0	0	255	0
0	0	24735	2370	1530	2640	3000	4123	0
0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0
0	0	685	0	-685	0	0	0	0
0	0	1375	0	-475	0	0	0	0
0	0	1375	0	155	500	0	0	0
0	0	1675	0	0	840	0	0	0
0	0	2170	0	0	840	245	0	0

0	0	2665	0	0	420	913	0	0
0	0	3160	0	0	420	1160	0	0
0	0	3655	0	0	0	1828	0	0
0	0	4165	0	0	0	2200	2083	0
0	0	4675	0	0	0	1800	2338	0
0	0	5185	0	0	0	800	2593	0
0	0	5695	0	0	0	0	2848	0
0	0	6205	0	0	0	0	3103	0
0	0	6715	0	0	0	0	3358	0
0	0	7225	0	0	0	0	3613	0
0	0	7735	0	0	0	0	3868	0
0	0	8245	0	0	0	0	4123	0

Battery 4-hr (T2_2)	Medium Duration Storage	Nuclear	Total	Battery (Total)
0	0	0	0	0
0	0	0	0	0
0	0	0	0	0
0	0	0	1500	1500
0	0	0	4500	2400
0	0	0	2100	0
0	0	0	3300	0
0	0	0	600	0
0	0	0	2400	0
0	0	0	2400	0
0	0	0	3900	0
0	600	0	6900	1200
0	0	0	2100	0
0	300	0	2400	0
0	0	0	3300	0
0	0	0	2700	0
0	0	0	2700	0
0	0	0	2700	0
0	0	0	3000	0
0	0	0	2400	0
	900	0	48900	5100
0	0	0	0	0
0	0	0	0	0
0	0	0	1500	1500
0	0	0	3060	1860
0	0	0	1800	0
0	0	0	3090	0
0	0	0	540	0
0	0	0	1680	0
0	0	0	1470	0
0	0	0	3000	0
0	570	0	6030	840
0	0	0	1560	0
0	240	0	1860	0
0	0	0	2490	0
0	0	0	2130	0
0	0	0	1230	0
0	0	0	1530	0
0	0	0	1770	0
0	0	0	1770	0
	810	0	36510	4200
0	0	0	0	0
0	0	0	0	0
0	0	0	3000	1500
0	0	0	6000	2700

0	0	0	2100	0
0	0	0	4200	600
0	0	0	2100	0
0	0	0	3300	0
0	0	0	2400	0
0	0	0	3600	900
0	0	0	3000	900
0	0	0	3000	0
0	0	0	3000	0
0	0	600	5700	0
0	0	0	3600	0
0	0	0	3000	0
0	0	0	3000	0
0	0	0	2400	0
0	0	0	2700	0
	0	600	56100	6600
0	0	0	0	0
0	0	0	0	0
0	0	0	2870	1500
0	0	0	4470	2190
0	0	0	1860	0
0	0	0	3750	450
0	0	0	1530	0
0	0	0	2100	0
0	0	0	1470	0
0	0	0	2880	690
0	0	0	1950	630
0	0	0	1950	0
0	0	0	2100	0
0	0	600	4980	0
0	0	0	3120	0
0	0	0	1350	0
0	0	0	1830	0
0	0	0	1380	0
0	0	0	1980	0
	0	600	41570	5460
0	0	0	0	0
0	0	0	0	0
0	0	0	2400	900
0	0	0	4500	2100
0	0	0	3300	0
0	0	0	3000	900
0	0	0	2400	0
0	0	0	3000	0
0	0	0	3000	0
0	0	0	3000	0
0	0	0	3000	0
0	0	0	3300	0

0	0	0	2400	0
0	0	600	6900	2700
0	0	600	3600	0
0	0	0	2700	0
0	0	0	2700	0
0	0	0	2700	0
0	0	0	2700	0
	0	1200	54600	6600
0	0	0	0	0
0	0	0	0	0
0	0	0	2270	900
0	0	0	3500	2100
0	0	0	2670	0
0	0	0	2700	900
0	0	0	1890	0
0	0	0	2250	0
0	0	0	1800	0
0	0	0	2460	0
0	0	0	1860	0
0	0	0	2130	0
0	0	0	1830	0
0	0	600	6390	2700
0	0	420	2940	0
0	0	0	1230	0
0	0	0	1530	0
0	0	0	1560	0
0	0	0	1980	0
	0	1020	40990	6600
0	0	0	0	0
0	0	0	0	0
0	0	0	3000	1500
0	0	0	6000	2700
0	0	0	2100	0
0	0	0	4200	900
0	0	0	2700	0
0	0	0	3000	0
0	0	0	2400	0
0	0	0	2700	0
0	0	0	3300	300
0	0	600	3000	0
0	0	300	2700	0
0	0	600	6000	600
0	0	600	3000	0
0	0	600	3300	0
0	0	600	3000	0
0	0	0	3300	900
0	0	0	3600	1500
	0	3300	57300	8400

0	0	0	0	0
0	0	0	0	0
0	0	0	2870	1500
0	0	0	4470	2190
0	0	0	1860	0
0	0	0	3780	780
0	0	0	1920	0
0	0	0	1950	0
0	0	0	1470	0
0	0	0	2190	0
0	0	0	2220	210
0	0	420	1950	0
0	0	210	1950	0
0	0	600	5280	600
0	0	600	2520	0
0	0	420	1650	0
0	0	510	1830	0
0	0	0	2460	630
0	0	0	2610	1050
	0	2760	42980	6960
0	0	0	0	0
0	0	0	0	0
0	0	0	1800	1800
0	0	0	4200	2400
0	0	0	2100	0
0	0	0	3300	0
0	0	0	900	0
0	0	0	1200	0
0	0	0	1200	0
0	0	0	3600	300
0	0	0	7200	1800
0	0	0	2100	0
0	0	0	2700	600
0	0	0	3300	0
0	0	0	3000	0
0	0	0	2400	0
0	0	0	3000	0
0	0	0	2700	600
0	0	0	3900	0
	0	0	48600	7500
0	0	0	0	0
0	0	0	0	0
0	0	0	1650	1650
0	0	0	2940	2040
0	0	0	1800	0
0	0	0	3090	0
0	0	0	720	0
0	0	0	810	0

0	0	0	690	0
0	0	0	2820	210
0	0	0	6330	1410
0	0	0	1560	0
0	0	0	2100	480
0	0	0	2490	0
0	0	0	2280	0
0	0	0	1020	0
0	0	0	1710	0
0	0	0	1590	420
0	0	0	2520	0
	0	0	36120	6210
0	0	0	0	0
0	0	0	0	0
0	0	0	2700	1200
0	0	0	4500	1800
0	0	0	2400	0
0	0	0	3900	0
0	0	0	2100	0
0	0	0	2400	0
0	0	0	2400	0
0	0	0	4200	0
0	0	0	7800	3000
0	0	0	2100	0
0	0	0	2700	600
0	0	0	4200	900
0	0	0	3000	300
0	0	0	2700	300
0	0	0	3900	1500
0	0	0	2400	0
0	0	0	2400	0
	0	0	55800	9600
0	0	0	0	0
0	0	0	0	0
0	0	0	2570	1200
0	0	0	3480	1800
0	0	0	2100	0
0	0	0	3540	0
0	0	0	1530	0
0	0	0	1680	0
0	0	0	1470	0
0	0	0	3180	0
0	0	0	6780	2460
0	0	0	1560	0
0	0	0	2070	450
0	0	0	3090	630
0	0	0	2310	210
0	0	0	1230	210

0	0	0	2400	1080
0	0	0	1350	0
0	0	0	1770	0
	0	0	42110	8040
0	0	0	0	0
0	0	0	0	0
0	0	0	4500	3000
0	0	0	4500	900
0	0	0	3000	0
0	0	0	3300	0
0	0	0	2400	0
0	0	0	2700	600
0	0	0	2400	0
0	0	0	4500	600
0	300	0	7200	3000
0	0	0	2100	0
0	0	0	2400	0
0	0	0	3300	0
0	300	0	2400	0
0	0	0	3000	0
0	0	0	3000	0
0	0	300	2400	0
0	0	0	2700	0
	600	300	55800	8100
0	0	0	0	0
0	0	0	0	0
0	0	0	3800	2430
0	0	0	3480	900
0	0	0	2430	0
0	0	0	3000	0
0	0	0	1860	0
0	0	0	1860	420
0	0	0	1470	0
0	0	0	3390	420
0	300	0	6720	3000
0	0	0	1620	0
0	0	0	1860	0
0	0	0	2400	0
0	300	0	1920	0
0	0	0	1440	0
0	0	0	1710	0
0	0	210	1380	0
0	0	0	1980	0
	600	210	42320	7170
0	0	0	0	0
0	0	0	0	0
0	0	0	3000	1500
0	0	0	6000	2700

0	0	0	3000	0
0	0	0	3600	0
0	0	0	1800	0
0	0	0	2400	300
0	0	0	3300	300
0	0	0	4800	1500
0	0	0	6600	1800
0	0	600	2400	0
0	0	600	3300	900
0	0	600	3600	0
0	0	600	2400	0
0	0	600	3600	0
0	0	600	2400	0
0	0	0	1800	0
0	0	0	2100	0
	0	3600	56100	9000
0	0	0	0	0
0	0	0	0	0
0	0	0	2870	1500
0	0	0	4470	2190
0	0	0	2340	0
0	0	0	3300	0
0	0	0	1290	0
0	0	0	1770	210
0	0	0	2010	210
0	0	0	3630	1050
0	0	0	6120	1800
0	0	480	1800	0
0	0	510	2460	630
0	0	420	2550	0
0	0	600	1920	0
0	0	390	1800	0
0	0	330	1350	0
0	0	0	1020	0
0	0	0	1560	0
	0	2730	42260	7590
0	0	0	0	0
0	0	0	0	0
0	0	0	3300	1800
0	0	0	5700	2400
0	0	0	5100	0
0	0	0	3300	300
0	0	0	2700	300
0	0	0	2700	0
0	0	0	4200	900
0	0	0	3300	600
0	0	0	3900	1200
0	0	600	3900	0

0	0	600	2400	0
0	0	600	3600	0
0	0	600	6000	0
0	0	600	3300	0
0	0	600	2700	0
0	0	600	2400	0
0	0	600	2400	0
	0	4800	60900	7500
0	0	0	0	0
0	0	0	0	0
0	0	0	3020	1650
0	0	0	4320	2040
0	0	0	3600	0
0	0	0	3000	300
0	0	0	2100	210
0	0	0	1830	0
0	0	0	2580	630
0	0	0	2730	540
0	0	0	3420	1200
0	0	600	3390	0
0	0	600	1920	0
0	0	600	2820	0
0	0	420	3990	0
0	0	300	1350	0
0	0	540	1860	0
0	0	420	1710	0
0	0	480	1800	0
	0	3960	45440	6570
0	0	0	0	0
0	0	0	0	0
0	0	0	0	0
0	0	0	1500	1500
0	0	0	6000	3900
0	0	0	8100	3900
0	0	0	11400	3900
0	0	0	12000	3900
0	0	0	14400	3900
0	0	0	16800	3900
0	0	0	20700	3900
0	600	0	27600	5100
0	600	0	29700	5100
0	900	0	32100	5100
0	900	0	35400	5100
0	900	0	38100	5100
0	900	0	40800	5100
0	900	0	43500	5100
0	900	0	46500	5100
0	900	0	48900	5100

0	900	0	48900	5100
0	0	0	0	0
0	0	0	0	0
0	0	0	1500	1500
0	0	0	4560	3360
0	0	0	6360	3360
0	0	0	9450	3360
0	0	0	9990	3360
0	0	0	11670	3360
0	0	0	13140	3360
0	0	0	16140	3360
0	570	0	22170	4200
0	570	0	23730	4200
0	810	0	25590	4200
0	810	0	28080	4200
0	810	0	30210	4200
0	810	0	31440	4200
0	810	0	32970	4200
0	810	0	34740	4200
0	810	0	36510	4200
0	810	0	36510	4200
0	0	0	0	0
0	0	0	0	0
0	0	0	3000	1500
0	0	0	9000	4200
0	0	0	11100	4200
0	0	0	15300	4800
0	0	0	17400	4800
0	0	0	20700	4800
0	0	0	23100	4800
0	0	0	26700	5700
0	0	0	29700	6600
0	0	0	32700	6600
0	0	0	35700	6600
0	0	600	41400	6600
0	0	600	45000	6600
0	0	600	48000	6600
0	0	600	51000	6600
0	0	600	53400	6600
0	0	600	56100	6600
0	0	600	56100	6600
0	0	0	0	0
0	0	0	0	0
0	0	0	2870	1500
0	0	0	7340	3690
0	0	0	9200	3690
0	0	0	12950	4140
0	0	0	14480	4140

0	0	0	16580	4140
0	0	0	18050	4140
0	0	0	20930	4830
0	0	0	22880	5460
0	0	0	24830	5460
0	0	0	26930	5460
0	0	600	31910	5460
0	0	600	35030	5460
0	0	600	36380	5460
0	0	600	38210	5460
0	0	600	39590	5460
0	0	600	41570	5460
0	0	600	41570	5460
0	0	0	0	0
0	0	0	0	0
0	0	0	2400	900
0	0	0	6900	3000
0	0	0	10200	3000
0	0	0	13200	3900
0	0	0	15600	3900
0	0	0	18600	3900
0	0	0	21600	3900
0	0	0	24600	3900
0	0	0	27600	3900
0	0	0	30900	3900
0	0	0	33300	3900
0	0	600	40200	6600
0	0	1200	43800	6600
0	0	1200	46500	6600
0	0	1200	49200	6600
0	0	1200	51900	6600
0	0	1200	54600	6600
0	0	1200	54600	6600
0	0	0	0	0
0	0	0	0	0
0	0	0	2270	900
0	0	0	5770	3000
0	0	0	8440	3000
0	0	0	11140	3900
0	0	0	13030	3900
0	0	0	15280	3900
0	0	0	17080	3900
0	0	0	19540	3900
0	0	0	21400	3900
0	0	0	23530	3900
0	0	0	25360	3900
0	0	600	31750	6600
0	0	1020	34690	6600

0	0	1020	35920	6600
0	0	1020	37450	6600
0	0	1020	39010	6600
0	0	1020	40990	6600
0	0	1020	40990	6600
0	0	0	0	0
0	0	0	0	0
0	0	0	3000	1500
0	0	0	9000	4200
0	0	0	11100	4200
0	0	0	15300	5100
0	0	0	18000	5100
0	0	0	21000	5100
0	0	0	23400	5100
0	0	0	26100	5100
0	0	0	29400	5400
0	0	600	32400	5400
0	0	900	35100	5400
0	0	1500	41100	6000
0	0	2100	44100	6000
0	0	2700	47400	6000
0	0	3300	50400	6000
0	0	3300	53700	6900
0	0	3300	57300	8400
0	0	3300	57300	8400
0	0	0	0	0
0	0	0	0	0
0	0	0	2870	1500
0	0	0	7340	3690
0	0	0	9200	3690
0	0	0	12980	4470
0	0	0	14900	4470
0	0	0	16850	4470
0	0	0	18320	4470
0	0	0	20510	4470
0	0	0	22730	4680
0	0	420	24680	4680
0	0	630	26630	4680
0	0	1230	31910	5280
0	0	1830	34430	5280
0	0	2250	36080	5280
0	0	2760	37910	5280
0	0	2760	40370	5910
0	0	2760	42980	6960
0	0	2760	42980	6960
0	0	0	0	0
0	0	0	0	0
0	0	0	1800	1800

0	0	0	6000	4200
0	0	0	8100	4200
0	0	0	11400	4200
0	0	0	12300	4200
0	0	0	13500	4200
0	0	0	14700	4200
0	0	0	18300	4500
0	0	0	25500	6300
0	0	0	27600	6300
0	0	0	30300	6900
0	0	0	33600	6900
0	0	0	36600	6900
0	0	0	39000	6900
0	0	0	42000	6900
0	0	0	44700	7500
0	0	0	48600	7500
0	0	0	48600	7500
0	0	0	0	0
0	0	0	0	0
0	0	0	1650	1650
0	0	0	4590	3690
0	0	0	6390	3690
0	0	0	9480	3690
0	0	0	10200	3690
0	0	0	11010	3690
0	0	0	11700	3690
0	0	0	14520	3900
0	0	0	20850	5310
0	0	0	22410	5310
0	0	0	24510	5790
0	0	0	27000	5790
0	0	0	29280	5790
0	0	0	30300	5790
0	0	0	32010	5790
0	0	0	33600	6210
0	0	0	36120	6210
0	0	0	36120	6210
0	0	0	0	0
0	0	0	0	0
0	0	0	2700	1200
0	0	0	7200	3000
0	0	0	9600	3000
0	0	0	13500	3000
0	0	0	15600	3000
0	0	0	18000	3000
0	0	0	20400	3000
0	0	0	24600	3000
0	0	0	32400	6000

0	0	0	34500	6000
0	0	0	37200	6600
0	0	0	41400	7500
0	0	0	44400	7800
0	0	0	47100	8100
0	0	0	51000	9600
0	0	0	53400	9600
0	0	0	55800	9600
0	0	0	55800	9600
0	0	0	0	0
0	0	0	0	0
0	0	0	2570	1200
0	0	0	6050	3000
0	0	0	8150	3000
0	0	0	11690	3000
0	0	0	13220	3000
0	0	0	14900	3000
0	0	0	16370	3000
0	0	0	19550	3000
0	0	0	26330	5460
0	0	0	27890	5460
0	0	0	29960	5910
0	0	0	33050	6540
0	0	0	35360	6750
0	0	0	36590	6960
0	0	0	38990	8040
0	0	0	40340	8040
0	0	0	42110	8040
0	0	0	42110	8040
0	0	0	0	0
0	0	0	0	0
0	0	0	4500	3000
0	0	0	9000	3900
0	0	0	12000	3900
0	0	0	15300	3900
0	0	0	17700	3900
0	0	0	20400	4500
0	0	0	22800	4500
0	0	0	27300	5100
0	300	0	34500	8100
0	300	0	36600	8100
0	300	0	39000	8100
0	300	0	42300	8100
0	600	0	44700	8100
0	600	0	47700	8100
0	600	0	50700	8100
0	600	300	53100	8100
0	600	300	55800	8100

0	600	300	55800	8100
0	0	0	0	0
0	0	0	0	0
0	0	0	3800	2430
0	0	0	7280	3330
0	0	0	9710	3330
0	0	0	12710	3330
0	0	0	14570	3330
0	0	0	16430	3750
0	0	0	17900	3750
0	0	0	21290	4170
0	300	0	28010	7170
0	300	0	29630	7170
0	300	0	31490	7170
0	300	0	33890	7170
0	600	0	35810	7170
0	600	0	37250	7170
0	600	0	38960	7170
0	600	210	40340	7170
0	600	210	42320	7170
0	600	210	42320	7170
0	0	0	0	0
0	0	0	0	0
0	0	0	3000	1500
0	0	0	9000	4200
0	0	0	12000	4200
0	0	0	15600	4200
0	0	0	17400	4200
0	0	0	19800	4500
0	0	0	23100	4800
0	0	0	27900	6300
0	0	0	34500	8100
0	0	600	36900	8100
0	0	1200	40200	9000
0	0	1800	43800	9000
0	0	2400	46200	9000
0	0	3000	49800	9000
0	0	3600	52200	9000
0	0	3600	54000	9000
0	0	3600	56100	9000
0	0	3600	56100	9000
0	0	0	0	0
0	0	0	0	0
0	0	0	2870	1500
0	0	0	7340	3690
0	0	0	9680	3690
0	0	0	12980	3690
0	0	0	14270	3690

0	0	0	16040	3900
0	0	0	18050	4110
0	0	0	21680	5160
0	0	0	27800	6960
0	0	480	29600	6960
0	0	990	32060	7590
0	0	1410	34610	7590
0	0	2010	36530	7590
0	0	2400	38330	7590
0	0	2730	39680	7590
0	0	2730	40700	7590
0	0	2730	42260	7590
0	0	2730	42260	7590
0	0	0	0	0
0	0	0	0	0
0	0	0	3300	1800
0	0	0	9000	4200
0	0	0	14100	4200
0	0	0	17400	4500
0	0	0	20100	4800
0	0	0	22800	4800
0	0	0	27000	5700
0	0	0	30300	6300
0	0	0	34200	7500
0	0	600	38100	7500
0	0	1200	40500	7500
0	0	1800	44100	7500
0	0	2400	50100	7500
0	0	3000	53400	7500
0	0	3600	56100	7500
0	0	4200	58500	7500
0	0	4800	60900	7500
0	0	4800	60900	7500
0	0	0	0	0
0	0	0	0	0
0	0	0	3020	1650
0	0	0	7340	3690
0	0	0	10940	3690
0	0	0	13940	3990
0	0	0	16040	4200
0	0	0	17870	4200
0	0	0	20450	4830
0	0	0	23180	5370
0	0	0	26600	6570
0	0	600	29990	6570
0	0	1200	31910	6570
0	0	1800	34730	6570
0	0	2220	38720	6570

0	0	2520	40070	6570
0	0	3060	41930	6570
0	0	3480	43640	6570
0	0	3960	45440	6570
0	0	3960	45440	6570
0	0	0	0	
0	0	0	0	
0	0	0	700	
0	0	0	1720	
0	0	0	2290	
0	0	0	2590	
0	0	0	3130	
0	0	0	3970	
0	0	0	4900	
0	0	0	6010	
0	0	0	6490	
0	0	0	6970	
0	0	0	7510	
0	0	0	8410	
0	0	0	8890	
0	0	0	10450	
0	0	0	11740	
0	0	90	12760	
0	0	90	13480	
0	0	90	13480	
0	0	0	0	0
0	0	0	0	0
0	0	0	2055	685
0	0	0	4125	1375
0	0	0	4125	1375
0	0	0	5025	1675
0	0	0	9170	3330
0	0	0	10820	3750
0	0	0	11930	3750
0	0	0	16330	6370
0	300	0	18120	7170
0	300	0	20270	7170
0	300	0	22060	7170
0	300	0	24150	7170
0	600	0	25970	7170
0	600	0	27360	7170
0	600	0	28730	7170
0	600	210	30110	7170
0	600	210	31690	7170
0	600	210	31690	7170
0	0	0	0	0
0	0	0	0	0
0	0	0	2055	685

0	0	0	2070	690
0	0	0	0	0
0	0	0	900	300
0	0	0	4145	1655
0	0	0	1650	420
0	0	0	1110	0
0	0	0	4400	2620
0	300	0	1790	800
0	0	0	2150	0
0	0	0	1790	0
0	0	0	2090	0
0	300	0	1820	0
0	0	0	1390	0
0	0	0	1370	0
0	0	210	1380	0
0	0	0	1580	0
0	600	210	31690	7170
0	0	0	0	0
0	0	0	0	0
0	0	0	2055	685
0	0	0	4125	1375
0	0	0	4525	1375
0	0	0	8360	3330
0	0	0	13770	3330
0	0	0	15420	3750
0	0	0	16640	3750
0	0	0	19930	4170
0	300	0	22350	4970
0	300	0	24070	5370
0	300	0	26390	6370
0	300	0	29200	7170
0	600	0	30870	7170
0	600	0	32330	7170
0	600	0	33780	7170
0	600	210	35170	7170
0	600	210	36880	7170
0	600	210	36880	7170
0	0	0	0	0
0	0	0	0	0
0	0	0	2055	685
0	0	0	2070	690
0	0	0	400	0
0	0	0	3835	1955
0	0	0	5410	0
0	0	0	1650	420
0	0	0	1220	0
0	0	0	3290	420
0	300	0	2420	800

0	0	0	1720	400
0	0	0	2320	1000
0	0	0	2810	800
0	300	0	1670	0
0	0	0	1460	0
0	0	0	1450	0
0	0	210	1390	0
0	0	0	1710	0
0	0	0	36880	0
0	0	0	0	0
0	0	0	0	0
0	0	0	5170	3115
0	0	0	8942.5	4017.5
0	0	0	10642.5	4017.5
0	0	0	14695	4170
0	0	0	16925	4415
0	0	0	19318	5083
0	0	0	21310	5330
0	0	0	25263	5998
0	300	0	33848	9253
0	300	0	36133	9508
0	300	0	38618	9763
0	300	0	41673	10018
0	600	0	44358	10273
0	600	0	46543	10528
0	600	0	48728	10783
0	600	210	51023	11038
0	600	210	53508	11293
0	600	210	53508	11293
0	0	0	0	0
0	0	0	0	0
0	0	0	5170	3115
0	0	0	3772.5	902.5
0	0	0	1700	0
0	0	0	4052.5	152.5
0	0	0	2230	245
0	0	0	2393	668
0	0	0	1992	247
0	0	0	3953	668
0	300	0	8585	3255
0	0	0	2285	255
0	0	0	2485	255
0	0	0	3055	255
0	300	0	2685	255
0	0	0	2185	255
0	0	0	2185	255
0	0	210	2295	255
0	0	0	2485	255

0	600	210	53508	11293
0	0	0	0	0
0	0	0	0	0
0	0	0	2055	0
0	0	0	5025	900
0	0	0	6155	2030
0	0	0	10245	4170
0	0	0	16225	4415
0	0	0	18618	5083
0	0	0	20510	5330
0	0	0	24523	5998
0	300	0	29908	9253
0	300	0	31993	9508
0	300	0	34078	9763
0	300	0	36813	10018
0	600	0	39438	10273
0	600	0	41563	10528
0	600	0	43718	10783
0	600	210	45873	11038
0	600	210	48278	11293
0	600	210	48278	11293
0	0	0	0	0
0	0	0	0	0
0	0	0	2055	0
0	0	0	2970	900
0	0	0	1130	1130
0	0	0	4090	2140
0	0	0	5980	245
0	0	0	2393	668
0	0	0	1892	247
0	0	0	4013	668
0	300	0	5385	3255
0	0	0	2085	255
0	0	0	2085	255
0	0	0	2735	255
0	300	0	2625	255
0	0	0	2125	255
0	0	0	2155	255
0	0	210	2155	255
0	0	0	2405	255
0	600	210	48278	11293
0	0	0	0	
0	0	0	0	
0	0	0	0	
0	0	0	900	
0	0	0	1630	
0	0	0	1885	
0	0	0	2455	

0	0	0	3198	
0	0	0	3870	
0	0	0	4593	
0	0	0	7558	
0	0	0	7923	
0	0	0	7688	
0	0	0	7613	
0	0	0	8568	
0	0	0	9233	
0	0	0	9938	
0	0	0	10703	
0	0	0	11398	

DS-14:

Workpaper: Georgia Power Territorial Base Case Load vs. Capability Table - 2025 IRP – Stenclik.xlsx

Table 4.6.1c - Georgia Power Territorial Base Case Load vs. Existing Capability MG0 (Winter)

Year	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
Peak Demand (MW), (A)	16,264	16,892	18,334	20,320	22,168	23,612	24,469	24,900	25,213	25,451	25,653	25,768	25,987	26,216	26,605	26,917	27,295	27,687	28,118	28,544
Owned Generating Capacity (MW)	14,306	15,164	16,545	16,801	17,272	17,273	17,218	17,194	17,194	17,194	16,724	12,759	12,759	12,759	12,110	12,110	12,110	12,110	12,110	12,110
Purchased Generating Capacity (MW), (B)	5,913	6,012	6,242	6,503	5,723	5,830	3,787	3,787	3,732	3,729	2,412	1,830	1,763	1,414	1,414	1,054	1,034	1,031	1,028	1,028
Dispatchable DSOs (MW), (C)	649	652	656	656	659	661	665	667	670	673	675	676	681	703	711	720	728	737	748	758
Total Capacity (MW)	20,868	21,829	23,443	23,960	23,654	23,765	21,671	21,648	21,596	21,595	19,811	15,265	15,203	14,875	14,235	13,884	13,871	13,879	13,887	13,896
Capacity Required to Meet GPC Target (MW), (D)	(602)	(781)	(598)	1,467	4,086	5,783	8,948	9,511	9,954	10,252	12,290	16,980	17,316	17,930	19,057	19,799	20,284	20,768	21,299	21,822
GPC Reserve Margin (%)	28.3%	29.2%	27.9%	17.9%	6.7%	0.6%	-11.4%	-13.1%	-14.3%	-15.1%	-22.8%	-40.8%	-41.5%	-43.3%	-46.5%	-48.4%	-49.2%	-49.9%	-50.6%	-51.3%
Total Capacity with Generic Additions (MW)	20,868	21,829	23,443	26,089	27,658	30,198	30,504	31,352	31,909	32,349	32,664	32,124	32,467	32,783	33,348	33,702	34,109	34,807	35,175	35,949
Capacity Deficit (Surplus) MW	(602)	(781)	(598)	(662)	82	(651)	115	(193)	(359)	(501)	(564)	122	52	21	(56)	(19)	46	(160)	11	(231)
Reserve Margin (%)	28.3%	29.2%	27.9%	28.4%	24.8%	27.9%	24.7%	25.9%	26.6%	27.1%	27.3%	24.7%	24.9%	25.1%	25.3%	25.2%	25.0%	25.7%	25.1%	25.9%

Notes
(A) Territorial Load requirements less non-dispatchable DSOs
(B) Includes territorial and imported power purchases. Capacity does not include the Winter 2027/2028 BESS Request for Proposals (RFP) approved in the 2023 Integrated Resource Plan (IRP) Update to show total procurement needs.
(C) Values stated in combustion turbine equivalence terms
(D) Does not consider planning reserve sharing. Reflects GPC's Target Reserve Margin, resulting from a System Target Reserve Margin of 25.50% (2025-2027) and 26% (2028 and beyond).

Existing Capability

	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
Owned Generating Capacity (MW)	**14,306**	**15,164**	**16,545**	**16,801**	**17,272**	**17,273**	**17,218**	**17,194**	**17,194**	**17,194**	**16,724**	**12,759**	**12,759**	**12,759**	**12,110**	**12,110**	**12,110**	**12,110**	**12,110**	**12,110**
Nuclear	**3,049**	**3,049**	**3,049**	**3,049**	**3,049**	**3,049**	**3,049**	**3,049**	**3,049**	**3,049**	**3,049**	**3,049**	**3,049**	**3,049**	**3,049**	**3,049**	**3,049**	**3,049**	**3,049**	**3,049**
HATCH 1	451	451	451	451	451	451	451	451	451	451	451	451	451	451	451	451	451	451	451	451
HATCH 2	454	454	454	454	454	454	454	454	454	454	454	454	454	454	454	454	454	454	454	454
VOGTLE 1	560	560	560	560	560	560	560	560	560	560	560	560	560	560	560	560	560	560	560	560
VOGTLE 2	563	563	563	563	563	563	563	563	563	563	563	563	563	563	563	563	563	563	563	563
VOGTLE 3	510	510	510	510	510	510	510	510	510	510	510	510	510	510	510	510	510	510	510	510
VOGTLE 4	510	510	510	510	510	510	510	510	510	510	510	510	510	510	510	510	510	510	510	510
Coal	**4,045**	**4,045**	**4,045**	**4,045**	**4,045**	**4,045**	**3,990**	**3,965**	**3,965**	**3,965**	**3,965**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
BOWEN 1	740	740	740	740	740	740	740	740	740	740	740	-	-	-	-	-	-	-	-	-
BOWEN 2	760	760	760	760	760	760	760	760	760	760	760	-	-	-	-	-	-	-	-	-
BOWEN 3	950	950	950	950	950	950	950	950	950	950	950	-	-	-	-	-	-	-	-	-
BOWEN 4	910	910	910	910	910	910	910	910	910	910	910	-	-	-	-	-	-	-	-	-
SCHERER 1	75	75	75	75	75	75	75	75	75	75	75	-	-	-	-	-	-	-	-	-
SCHERER 2	72	72	72	72	72	72	72	72	72	72	72	-	-	-	-	-	-	-	-	-
SCHERER 3	537	537	537	537	537	537	482	458	458	458	458	-	-	-	-	-	-	-	-	-
WANSLEY 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
WANSLEY 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Combined Cycle	**4,169**	**4,169**	**4,169**	**4,169**	**4,169**	**4,169**	**4,169**	**4,169**	**4,169**	**4,169**	**4,169**	**4,169**	**4,169**	**4,169**	**4,169**	**4,169**	**4,169**	**4,169**	**4,169**	**4,169**
MCDONOUGH 4	934	934	934	934	934	934	934	934	934	934	934	934	934	934	934	934	934	934	934	934
MCDONOUGH 5	928	928	928	928	928	928	928	928	928	928	928	928	928	928	928	928	928	928	928	928
MCDONOUGH 6	930	930	930	930	930	930	930	930	930	930	930	930	930	930	930	930	930	930	930	930
MCINTOSH 10	692	692	692	692	692	692	692	692	692	692	692	692	692	692	692	692	692	692	692	692
MCINTOSH 11	685	685	685	685	685	685	685	685	685	685	685	685	685	685	685	685	685	685	685	685
Oil/Gas Steam	**1,108**	**1,108**	**1,108**	**1,108**	**1,108**	**1,108**	**1,108**	**1,108**	**1,108**	**1,108**	**648**	**648**	**648**	**648**	**-**	**-**	**-**	**-**	**-**	**-**
GASTON 1 GAS	127	127	127	127	127	127	127	127	127	127	-	-	-	-	-	-	-	-	-	-
GASTON 2 GAS	128	128	128	128	128	128	128	128	128	128	-	-	-	-	-	-	-	-	-	-
GASTON 3 GAS	102	102	102	102	102	102	102	102	102	102	-	-	-	-	-	-	-	-	-	-
GASTON 4 GAS	103	103	103	103	103	103	103	103	103	103	-	-	-	-	-	-	-	-	-	-
YATES 6 GAS	323	323	323	323	323	323	323	323	323	323	323	323	323	323	-	-	-	-	-	-
YATES 7 GAS	326	326	326	326	326	326	326	326	326	326	326	326	326	326	-	-	-	-	-	-
Combustion Turbine	**1,855**	**1,855**	**2,211**	**2,454**	**2,925**	**2,925**	**2,925**	**2,925**	**2,925**	**2,925**	**2,915**	**2,915**	**2,915**	**2,915**	**2,915**	**2,915**	**2,915**	**2,915**	**2,915**	**2,915**
GASTON A	10	10	10	10	10	10	10	10	10	10	-	-	-	-	-	-	-	-	-	-
MCDONOUGH 3A	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31
MCDONOUGH 3B	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31
MCINTOSH 1A	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95
MCINTOSH 2A	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95
MCINTOSH 3A	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95
MCINTOSH 4A	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95
MCINTOSH 5A	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95
MCINTOSH 6A	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95
MCINTOSH 7A	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95
MCINTOSH 8A	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95
MCMANUS 3A	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55

	MCMANUS 3B	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55
	MCMANUS 3C	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55
	MCMANUS 4A	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55
	MCMANUS 4B	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55
	MCMANUS 4C	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55
	MCMANUS 4D	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55
	MCMANUS 4E	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55
	MCMANUS 4F	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55
	MCMANUS DIESEL	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	WANSLEY 5A	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	WARNER ROBINS 1	93	93	93	93	93	93	93	93	93	93	93	93	93	93	93	93	93	93	93	93	93
	WARNER ROBINS 2	93	93	93	93	93	93	93	93	93	93	93	93	93	93	93	93	93	93	93	93	93
	WILSON 1A	66	66	66	66	66	66	66	66	66	66	66	66	66	66	66	66	66	66	66	66	66
	WILSON 1B	65	65	65	65	65	65	65	65	65	65	65	65	65	65	65	65	65	65	65	65	65
	WILSON 1C	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53
	WILSON 1D	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40
	WILSON 1E	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59
	WILSON 1F	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59
	WILSON DIESEL	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	YATES 10	-	-	-	200	357	357	357	357	357	357	357	357	357	357	357	357	357	357	357	357	357
	YATES 8	-	-	357	200	357	357	357	357	357	357	357	357	357	357	357	357	357	357	357	357	357
	YATES 9	-	-	-	200	357	357	357	357	357	357	357	357	357	357	357	357	357	357	357	357	357
Pump Storage		**403**	**403**	**403**	**403**	**403**	**403**	**403**	**403**	**403**	**403**	**403**	**403**	**403**	**403**	**403**	**403**	**403**	**403**	**403**	**403**	**403**
	ROCKY MTN 1 PS	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63
	ROCKY MTN 2 PS	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63
	ROCKY MTN 3 PS	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63
	WALLACE DAM 1 PS	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53
	WALLACE DAM 2 PS	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53
	WALLACE DAM 5 PS	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53
	WALLACE DAM 6 PS	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53
Hydro		**678**	**691**	**697**	**697**	**697**	**697**	**697**	**697**	**697**	**697**	**697**	**697**	**697**	**697**	**697**	**697**	**697**	**697**	**697**	**697**	**697**
	BARTLETT'S FERRY 1 HY	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17
	BARTLETT'S FERRY 2 HY	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17
	BARTLETT'S FERRY 3 HY	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17
	BARTLETT'S FERRY 4 HY	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22
	BARTLETT'S FERRY 5 HY	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60
	BARTLETT'S FERRY 6 HY	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60
	BURTON 1 HY	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
	BURTON 2 HY	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
	ESTATOAH 1 HY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	FLINT RIVER 1 HY	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
	FLINT RIVER 2 HY	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
	FLINT RIVER 3 HY	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
	GOAT ROCK 3 HY	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
	GOAT ROCK 4 HY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	GOAT ROCK 5 HY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	GOAT ROCK 6 HY	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
	GOAT ROCK 7 HY	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
	GOAT ROCK 8 HY	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
	LANGDALE 5 HY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	LANGDALE 6 HY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	LLOYD SHOALS 1 HY	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
	LLOYD SHOALS 2 HY	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
	LLOYD SHOALS 3 HY	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
	LLOYD SHOALS 4 HY	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
	LLOYD SHOALS 5 HY	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
	LLOYD SHOALS 6 HY	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
	MORGAN FALLS 1 HY	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
	MORGAN FALLS 2 HY	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
	MORGAN FALLS 3 HY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	MORGAN FALLS 4 HY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	MORGAN FALLS 5 HY	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
	MORGAN FALLS 6 HY	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
	MORGAN FALLS 7 HY	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
	NACOOCHEE 1 HY	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
	NACOOCHEE 2 HY	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
	NORTH HIGHLANDS 1 HY	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11
	NORTH HIGHLANDS 2 HY	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11
	NORTH HIGHLANDS 3 HY	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11
	NORTH HIGHLANDS 4 HY	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
	OLIVER 1 HY	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17
	OLIVER 2 HY	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17
	OLIVER 3 HY	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17
	OLIVER 4 HY	-	-	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6
	RIVERVIEW 1 HY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	RIVERVIEW 2 HY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	SINCLAIR 1 HY	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22
	SINCLAIR 2 HY	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22
	TALLULAH 1 HY	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12
	TALLULAH 2 HY	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12
	TALLULAH 3 HY	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12
	TALLULAH 4 HY	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12
	TALLULAH 5 HY	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12
	TALLULAH 6 HY	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12
	TERRORA 1 HY	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9
	TERRORA 2 HY	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9

TUGALO 1 HY	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13
TUGALO 2 HY	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13
TUGALO 3 HY	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13
TUGALO 4 HY	-	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13
WALLACE DAM 3 HY	57	57	57	57	57	57	57	57	57	57	57	57	57	57	57	57	57	57	57	57	57
WALLACE DAM 4 HY	57	57	57	57	57	57	57	57	57	57	57	57	57	57	57	57	57	57	57	57	57
YONAH 1 HY	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
YONAH 2 HY	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
YONAH 3 HY	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
Solar	**51**	**51**	**51**	**51**	**51**	**52**	**52**	**52**	**52**	**52**	**52**	**52**	**52**	**52**	**52**	**52**	**52**	**52**	**52**	**52**	**52**
COMMUNITY SOLAR - COMER	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
COMMUNITY SOLAR - GUYTON	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
COMMUNITY SOLAR - WAYNESBORO	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FALCONS	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FORT BENNING	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6
FORT GORDON	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6
FORT STEWART SOLAR	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6
FORT VALLEY STATE UNIVERSITY	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
KINGS BAY SOLAR	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6
MCINTOSH CLOSED ASH POND	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
MCLB	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6
MOODY AFB	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
RIGHT OF WAY SOLAR	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ROBINS AFB	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13
UGA SOLAR	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Unassigned Self-Build Solar	-	-	-	-	-	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
System Sales	**(1,052)**	**(206)**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
SYSTEM SALE	(1,052)	(206)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Purchased Generating Capacity (MW)	**5,913**	**6,012**	**6,242**	**6,503**	**5,723**	**5,830**	**3,787**	**3,787**	**3,732**	**3,729**	**2,412**	**1,830**	**1,763**	**1,414**	**1,414**	**1,054**	**1,034**	**1,031**	**1,028**	**1,028**
2019 IRP RENEWABLES - DGS2230	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2019 IRP RENEWABLES - DGS2330	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
2019 IRP RENEWABLES - DGS2430	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2019 IRP RENEWABLES - DGW2330	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
2019 IRP RENEWABLES - DGW2430	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
2022 IRP BIOMASS - AGE	-	-	-	-	-	35	35	35	35	35	35	35	35	35	35	35	35	35	35	35	35
2022 IRP ESS RFP	-	-	-	-	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500
2022 IRP SOLAR DG RFP 1	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
2022 IRP SOLAR DG RFP 2	-	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12
2022 IRP SOLAR US RFP 1	-	-	-	-	-	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72
2022 IRP SOLAR US RFP 2	-	-	-	-	-	-	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24
2022/2023 US - FLINT RIVER SOLAR	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
2022/2023 US - TIMBERLAND SOLAR	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7
2022/2023 US - WADLEY SOLAR	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13
2022/2023 US - WASHINGTON COUNTY SOLAR	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8
2023 IRP UPDATE BESS RFP	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
ADDISON 1 (WEST GA)	186	186	186	186	186	186	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
ADDISON 3 (WEST GA)	181	181	181	181	181	181	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
ALBANY RENEWABLE ENERGY	50	50	50	50	50	50	50	50	50	50	50	50	50	-	-	-	-	-	-	-	-
ASI CLASSIC 210 MW - DGS1320	0	0	0	0	0	0	0	0	0	-	-	-	-	-	-	-	-	-	-	-	-
ASI CLASSIC 210 MW - DGS1420	2	2	2	2	2	2	2	2	2	2	-	-	-	-	-	-	-	-	-	-	-
ASI CLASSIC 210 MW - DGS1520	6	6	6	6	6	6	6	6	6	6	6	-	-	-	-	6	-	-	-	-	-
ASI CLASSIC 210 MW - DGS1620	0	0	0	0	0	0	0	0	0	0	0	0	-	-	-	-	-	-	-	-	-
ASI CLASSIC 210 MW - DGW1420	3	3	3	3	3	3	3	3	3	-	-	-	-	-	-	-	-	-	-	-	-
ASI CLASSIC 210 MW - DGW1520	4	4	4	4	4	4	4	4	4	4	-	-	-	-	-	-	-	-	-	-	-
ASI CLASSIC 210 MW - DGW1620	0	0	0	0	0	0	0	0	0	0	0	-	-	-	-	-	-	-	-	-	-
ASI CLASSIC 210 MW - US 1: DUBLIN SOLAR CENTER - DUBLIN	1	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-
ASI CLASSIC 210 MW - US 1: RICHLAND SOLAR CENTER	5	5	5	5	5	5	5	5	5	5	5	-	-	-	-	-	-	-	-	-	-
ASI CLASSIC 210 MW - US 1: RINCON SOLAR CENTER	4	4	4	4	4	4	4	4	4	4	4	4	-	-	-	-	-	-	-	-	-
ASI CLASSIC 210 MW - US 2: BUTLER SOLAR FARM	4	4	4	4	4	4	4	4	4	4	4	4	-	-	-	-	-	-	-	-	-
ASI CLASSIC 210 MW - US 2: DECATUR COUNTY SOLAR PROJECT	5	5	5	5	5	5	5	5	5	5	5	-	-	-	-	-	-	-	-	-	-
ASI CLASSIC 210 MW - US 2: HECATE ENERGY - OLD MIDVILLE RD LLC	5	5	5	5	5	5	5	5	5	5	5	5	-	-	-	-	-	-	-	-	-
ASI CLASSIC 210 MW - US 2: SOLARGLYNN	4	4	4	4	4	4	4	4	4	4	4	4	-	-	-	-	-	-	-	-	-
ASI PRIME 525 MW - DGS1625	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	-	-	-	-
ASI PRIME 525 MW - DGS1635	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ASI PRIME 525 MW - DGS1725	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	-	-	-
ASI PRIME 525 MW - DGS1730	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
ASI PRIME 525 MW - DGS1735	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
ASI PRIME 525 MW - DGS1815	0	0	0	0	0	0	0	0	0	-	-	-	-	-	-	-	-	-	-	-	-
ASI PRIME 525 MW - DGS1820	0	0	0	0	0	0	0	0	0	0	0	0	0	0	-	-	-	-	-	-	-
ASI PRIME 525 MW - DGS1825	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	-
ASI PRIME 525 MW - DGS1835	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	-
ASI PRIME 525 MW - DGW1725	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	-	-	-	-
ASI PRIME 525 MW - DGW1730	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
ASI PRIME 525 MW - DGW1735	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ASI PRIME 525 MW - DGW1815	0	0	0	0	0	0	0	0	0	-	-	-	-	-	-	-	-	-	-	-	-
ASI PRIME 525 MW - DGW1820	0	0	0	0	0	0	0	0	0	0	0	0	0	-	-	-	-	-	-	-	-
ASI PRIME 525 MW - DGW1825	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	-	-	-
ASI PRIME 525 MW - DGW1830	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
ASI PRIME 525 MW - DGW1835	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
ASI PRIME 525 MW - US 1: BUTLER SOLAR	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25
ASI PRIME 525 MW - US 1: DECATUR PARKWAY SOLAR PROJECT	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	-	-	-	-	-
ASI PRIME 525 MW - US 1: PAWPAW SOLAR	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8
ASI PRIME 525 MW - US 2: LIVE OAK SOLAR	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
ASI PRIME 525 MW - US 2: WHITE OAK SOLAR	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15

ASI PRIME 525 MW - US 2: WHITE PINE SOLAR	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20
AXIUM US SOLAR HOLDINGS (SD&D)	0	0	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
BLUE CANYON	82	82	82	82	82	82	82	82	82	82	82	-	-	-	-	-	-	-	-	-
CCSP DG - ONLINE	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CCSP DG - REMAINING	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
COCA-COLA	6	6	6	6	6	6	6	6	6	6	6	-	-	-	-	-	-	-	-	-
CONYERS RENEWABLE ENERGY	3	3	3	3	3	3	3	3	3	3	3	3	3	-	-	-	-	-	-	-
DAHLBERG 1	-	-	-	87	87	87	87	87	87	87	87	87	87	-	-	-	-	-	-	-
DAHLBERG 10	89	88	88	88	88	88	88	88	88	88	88	-	-	-	-	-	-	-	-	-
DAHLBERG 2	88	87	87	87	87	87	87	87	87	87	87	-	-	-	-	-	-	-	-	-
DAHLBERG 3	-	-	-	87	87	87	87	87	87	87	87	87	-	-	-	-	-	-	-	-
DAHLBERG 4	87	87	87	87	87	87	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DAHLBERG 5	-	-	-	87	87	87	87	87	87	87	87	87	-	-	-	-	-	-	-	-
DAHLBERG 6	88	88	88	88	88	88	88	88	88	88	88	-	-	-	-	-	-	-	-	-
DAHLBERG 8	86	86	86	86	86	86	86	86	86	86	86	-	-	-	-	-	-	-	-	-
DAHLBERG 9	-	88	88	88	88	88	88	88	88	88	88	-	-	-	-	-	-	-	-	-
EXELON HEARD 1	158	158	158	158	158	158	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EXELON HEARD 2	158	158	158	158	158	158	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EXELON HEARD 3	158	158	158	158	158	158	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EXELON HEARD 4	158	158	158	158	158	158	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EXELON HEARD 5	158	158	158	158	158	158	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EXELON HEARD 6	158	158	158	158	158	158	-	-	-	-	-	-	-	-	-	-	-	-	-	-
GEORGIA RENEWABLE POWER FRANKLIN LLC	58	58	58	58	58	58	58	58	58	58	58	58	58	58	58	58	58	58	58	58
GEORGIA RENEWABLE POWER MADISON	58	58	58	58	58	58	58	58	58	58	58	58	58	58	58	58	58	58	58	58
GREEN POWER SOLUTIONS	29	29	29	29	29	29	29	29	29	29	29	-	-	-	-	-	-	-	-	-
HARRIS 1	668	668	668	668	668	668	-	-	-	-	-	-	-	-	-	-	-	-	-	-
HARRIS 2	690	690	690	690	690	690	690	690	690	690	-	-	-	-	-	-	-	-	-	-
INTERNATIONAL PAPER - FLINT RIVER	27	27	27	27	27	27	27	27	27	27	27	27	-	-	-	-	-	-	-	-
INTERNATIONAL PAPER - PORT WENTWORTH	30	30	30	30	30	30	30	30	30	30	30	30	-	-	-	-	-	-	-	-
LSS 50 MW - HSH PEMBROOKE	0	0	0	0	0	0	0	0	0	0	0	-	-	-	-	-	-	-	-	-
LSS 50 MW - SIMON SOLAR FARM	6	6	6	6	6	6	6	6	6	6	6	-	-	-	-	-	-	-	-	-
LSS 50 MW - SOLAR D & D CAMILLA	3	3	3	3	3	3	3	3	3	3	3	-	-	-	-	-	-	-	-	-
LSS 50 MW - SOLAR D & D CAMP (MERIWETHER COUNTY)	1	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-
MAS GEORGIA LFG - OAK GROVE	6	6	6	6	6	6	6	6	6	6	6	6	-	-	-	-	-	-	-	-
MAS GEORGIA LFG - PINE RIDGE	6	6	6	6	6	6	6	6	6	6	6	6	-	-	-	-	-	-	-	-
MAS GEORGIA LFG - RICHLAND CREEK	11	11	11	11	11	11	11	11	11	11	11	11	-	-	-	-	-	-	-	-
MID-GEORGIA COGEN	300	300	300	300	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MONROE POWER	360	360	360	360	360	360	360	360	360	360	360	360	360	360	360	-	-	-	-	-
MPC PPA	750	750	750	750	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
PIEDMONT GREEN POWER	55	55	55	55	55	55	55	55	-	-	-	-	-	-	-	-	-	-	-	-
REDI 1400 MW - C&I: DOUGHERTY COUNTY SOLAR	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12
REDI 1400 MW - C&I: TANGLEWOOD SOLAR	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6
REDI 1400 MW - DG CSS 1920	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	-	-	-	-	-
REDI 1400 MW - DG CSS 1925	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
REDI 1400 MW - DG CSS 1930	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
REDI 1400 MW - DG CSS 1935	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
REDI 1400 MW - DG CSW 1925	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	-
REDI 1400 MW - DG CSW 1930	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
REDI 1400 MW - DG CSW 1935	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
REDI 1400 MW - DGS 2030	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
REDI 1400 MW - DGS 2035	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8
REDI 1400 MW - DGW 2030	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
REDI 1400 MW - DGW 2035	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
REDI 1400 MW - US 1: QUITMAN SOLAR	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15
REDI 1400 MW - US 1: SOUTHERN OAK SOLAR	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16
REDI 1400 MW - US 1: TWIGGS COUNTY SOLAR	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20
REDI 1400 MW - US 2: COOL SPRINGS	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21
REDI 1400 MW - US 2: HICKORY PARK	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20
REDI 1400 MW - US 2: QUITMAN II	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15
REDI CS2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
SANTA ROSA	-	-	230	230	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
SUPERIOR - WASTE MANAGEMENT	6	6	6	6	6	6	6	6	6	6	6	6	6	-	-	-	-	-	-	-
WALTON COUNTY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
WANSLEY 6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
WANSLEY 7	622	622	622	622	622	622	622	622	622	622	622	-	-	-	-	-	-	-	-	-
WASHINGTON COUNTY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Dispatchable DSOs (MW)	**649**	**652**	**656**	**656**	**659**	**661**	**665**	**667**	**670**	**673**	**675**	**676**	**681**	**703**	**711**	**720**	**728**	**737**	**748**	**758**
CVR Level 1	200	202	204	204	205	207	209	210	211	212	213	214	217	227	232	236	240	245	250	255
CVR Level 2	200	202	204	204	205	207	209	210	211	212	213	214	217	227	232	236	240	245	250	255
DER Customer Program	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DPEC	92	92	92	92	92	92	92	92	92	92	92	92	92	92	92	92	92	92	92	92
RTPeDA	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
RTPeHA	124	124	124	124	124	124	124	124	124	124	124	124	124	124	124	124	124	124	124	124
Temp Check	29	29	29	29	29	29	29	29	29	29	29	29	29	29	29	29	29	29	29	29

Energy Storage	**-**	**-**	**812**	**825**	**825**	**825**	**825**	**825**	**825**	**825**	**825**	**825**	**825**	**825**	**825**	**825**	**825**	**825**	**825**	**825**
2019 IRP BESS DEMO	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2019 IRP BESS DEMO - FORT STEWART 4 HR BESS	-	-	-	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13
2022 IRP MCGRAU FORD 2 HR BATTERY	-	-	265	265	265	265	265	265	265	265	265	265	265	265	265	265	265	265	265	265
2023 IRP UPDATE - HAMMOND	-	-	58	58	58	58	58	58	58	58	58	58	58	58	58	58	58	58	58	58
2023 IRP Update - MCGRAU FORD PHASE 2	-	-	265	265	265	265	265	265	265	265	265	265	265	265	265	265	265	265	265	265
2023 IRP UPDATE - MOODY AFB	-	-	45	45	45	45	45	45	45	45	45	45	45	45	45	45	45	45	45	45
2023 IRP UPDATE - ROBINS AFB	-	-	115	115	115	115	115	115	115	115	115	115	115	115	115	115	115	115	115	115

	MOSSY BRANCH	-	-	65	65	65	65	65	65	65	65	65	65	65	65	65	65	65	65	65
Resource Additions (Nameplate MW)		-	-	3,800	7,280	9,710	12,710	14,570	16,430	17,900	21,290	28,010	29,630	31,490	33,890	35,810	37,250	38,960	40,340	42,320
	CT w/ SCR	0	0	0	1200	1500	1500	2100	2310	2730	3030	3930	4230	4770	4980	5280	5400	6090	6240	6900
	CC	0	0	0	0	2130	4530	4800	4800	4800	6180	7380	7380	7380	7380	7380	7380	7380	7380	7380
	CC w/ CCS - Local	0	0	0	0	0	0	0	0	0	0	0	0	0	900	900	1200	1200	1200	1200
	CC w/ CCS - Distant	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Solar	0	0	1370	2750	2750	3350	4340	5330	6320	7310	8330	9350	10370	11390	12410	13430	14450	15470	16490
	Wind	0	0	0	0	0	0	0	240	300	600	900	1200	1500	1770	2070	2070	2070	2070	2370
	Battery 4-hr (T1)	0	0	1530	1530	1530	1530	1530	1530	1530	1530	1530	1530	1530	1530	1530	1530	1530	1530	1530
	Battery 4-hr (T2)	0	0	900	1800	1800	1800	1800	2220	2220	2640	2640	2640	2640	2640	2640	2640	2640	2640	2640
	Battery 4-hr (T3)	0	0	0	0	0	0	0	0	0	0	3000	3000	3000	3000	3000	3000	3000	3000	3000
	Battery 4-hr (T4)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Battery 4-hr (T1_2)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Battery 4-hr (T2_2)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Medium Duration Storage	0	0	0	0	0	0	0	0	0	0	300	300	300	300	600	600	600	600	600
	Nuclear	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	210	210
Resource Additions (Effective MW)		-	-	2,129	4,004	6,434	8,834	9,704	10,313	10,754	12,854	16,859	17,264	17,909	19,113	19,818	20,238	20,928	21,288	22,053
1.0	CT w/ SCR	0	0	0	1200	1500	1500	2100	2310	2730	3030	3930	4230	4770	4980	5280	5400	6090	6240	6900
1.0	CC	0	0	0	0	2130	4530	4800	4800	4800	6180	7380	7380	7380	7380	7380	7380	7380	7380	7380
1.0	CC w/ CCS - Local	0	0	0	0	0	0	0	0	0	0	0	0	0	900	900	1200	1200	1200	1200
1.0	CC w/ CCS - Distant	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
0.0	Solar	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
0.4	Wind	0	0	0	0	0	0	0	84	105	210	315	420	525	619.5	724.5	724.5	724.5	724.5	829.5
1.0	Battery 4-hr (T1)	0	0	1453.5	1453.5	1453.5	1453.5	1453.5	1453.5	1453.5	1453.5	1453.5	1453.5	1453.5	1453.5	1453.5	1453.5	1453.5	1453.5	1453.5
0.8	Battery 4-hr (T2)	0	0	675	1350	1350	1350	1350	1665	1665	1980	1980	1980	1980	1980	1980	1980	1980	1980	1980
0.5	Battery 4-hr (T3)	0	0	0	0	0	0	0	0	0	0	1500	1500	1500	1500	1500	1500	1500	1500	1500
0.3	Battery 4-hr (T4)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
1.0	Battery 4-hr (T1_2)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
0.8	Battery 4-hr (T2_2)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
1.0	Medium Duration Storage	0	0	0	0	0	0	0	0	0	0	300	300	300	300	600	600	600	600	600
1.0	Nuclear	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	210	210

Georgia Power Territorial Base Case Load vs. Existing Capability MG0, No Large Load (Winter)

Year	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
Peak Demand (MW), (A)	16,264	16,437	16,613	16,789	16,968	17,149	17,332	17,516	17,703	17,891	18,082	18,275	18,469	18,666	18,865	19,066	19,352	19,643	19,938	20,238
Owned Generating Capacity (MW)	14,306	15,164	16,545	16,801	17,272	17,273	17,218	13,228	13,228	13,228	12,759	12,759	12,759	12,759	12,110	12,110	12,110	12,110	12,110	12,110
Purchased Generating Capacity (MW), (B)	5,913	6,012	6,242	6,503	5,723	5,830	3,787	3,787	3,732	3,729	2,412	1,830	1,763	1,414	1,414	1,054	1,034	1,031	1,028	1,028
Dispatchable DSOs (MW), (C)	649	652	656	656	659	661	665	667	670	673	675	676	681	703	711	720	728	737	748	758
Total Capacity (MW)	20,868	21,829	23,443	23,960	23,654	23,765	21,671	17,683	17,631	17,630	15,845	15,265	15,203	14,875	14,235	13,884	13,871	13,879	13,887	13,896
Capacity Required to Meet GPC Target (MW), (D)	(602)	(1,347)	(2,743)	(2,951)	(2,421)	(2,305)	17	4,236	4,522	4,758	6,782	7,603	7,908	8,483	9,372	9,974	10,345	10,702	11,063	11,429
GPC Reserve Margin (%)	28.3%	32.8%	41.1%	42.7%	39.4%	38.6%	25.0%	1.0%	-0.4%	-1.5%	-12.4%	-16.5%	-17.7%	-20.3%	-24.5%	-27.2%	-28.3%	-29.3%	-30.4%	-31.3%
Total Capacity with Generic Additions (MW)	20,868	21,829	23,443	24,611	24,960	25,071	23,233	21,987	22,333	22,413	22,639	22,864	23,107	23,353	23,608	23,862	24,219	24,577	24,945	25,319
Capacity Deficit (Surplus) MW	(602)	(1,347)	(2,743)	(3,602)	(3,727)	(3,611)	(1,545)	(67)	(181)	(25)	(12)	4	5	4	(1)	(4)	(3)	4	5	6
Reserve Margin (%)	28.3%	32.8%	41.1%	46.6%	47.1%	46.2%	34.1%	25.5%	26.2%	25.3%	25.2%	25.1%	25.1%	25.1%	25.1%	25.2%	25.2%	25.1%	25.1%	25.1%

Notes

(A) Territorial Load requirements less non-dispatchable DSOs

(B) Includes territorial and imported power purchases. Capacity does not include the Winter 2027/2028 BESS Request for Proposals (RFP) approved in the 2023 Integrated Resource Plan (IRP) Update to show total procurement needs.

(C) Values stated in combustion turbine equivalence terms

(D) Does not consider planning reserve sharing. Reflects GPC's Target Reserve Margin, resulting from a System Target Reserve Margin of 25.50% (2025-2027) and 26% (2028 and beyond).

Existing Capability

	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
Owned Generating Capacity (MW)	**14,306**	**15,164**	**16,545**	**16,801**	**17,272**	**17,273**	**17,218**	**13,228**	**13,228**	**13,228**	**12,759**	**12,759**	**12,759**	**12,759**	**12,110**	**12,110**	**12,110**	**12,110**	**12,110**	**12,110**
Nuclear	**3,049**	**3,049**	**3,049**	**3,049**	**3,049**	**3,049**	**3,049**	**3,049**	**3,049**	**3,049**	**3,049**	**3,049**	**3,049**	**3,049**	**3,049**	**3,049**	**3,049**	**3,049**	**3,049**	**3,049**
HATCH 1	451	451	451	451	451	451	451	451	451	451	451	451	451	451	451	451	451	451	451	451
HATCH 2	454	454	454	454	454	454	454	454	454	454	454	454	454	454	454	454	454	454	454	454
VOGTLE 1	560	560	560	560	560	560	560	560	560	560	560	560	560	560	560	560	560	560	560	560
VOGTLE 2	563	563	563	563	563	563	563	563	563	563	563	563	563	563	563	563	563	563	563	563
VOGTLE 3	510	510	510	510	510	510	510	510	510	510	510	510	510	510	510	510	510	510	510	510
VOGTLE 4	510	510	510	510	510	510	510	510	510	510	510	510	510	510	510	510	510	510	510	510
Coal	**4,045**	**4,045**	**4,045**	**4,045**	**4,045**	**4,045**	**3,990**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
BOWEN 1	740	740	740	740	740	740	740	-	-	-	-	-	-	-	-	-	-	-	-	-
BOWEN 2	760	760	760	760	760	760	760	-	-	-	-	-	-	-	-	-	-	-	-	-
BOWEN 3	950	950	950	950	950	950	950	-	-	-	-	-	-	-	-	-	-	-	-	-
BOWEN 4	910	910	910	910	910	910	910	-	-	-	-	-	-	-	-	-	-	-	-	-
SCHERER 1	75	75	75	75	75	75	75	-	-	-	-	-	-	-	-	-	-	-	-	-
SCHERER 2	72	72	72	72	72	72	72	-	-	-	-	-	-	-	-	-	-	-	-	-
SCHERER 3	537	537	537	537	537	537	482	-	-	-	-	-	-	-	-	-	-	-	-	-
WANSLEY 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
WANSLEY 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Combined Cycle	**4,169**	**4,169**	**4,169**	**4,169**	**4,169**	**4,169**	**4,169**	**4,169**	**4,169**	**4,169**	**4,169**	**4,169**	**4,169**	**4,169**	**4,169**	**4,169**	**4,169**	**4,169**	**4,169**	**4,169**
MCDONOUGH 4	934	934	934	934	934	934	934	934	934	934	934	934	934	934	934	934	934	934	934	934
MCDONOUGH 5	928	928	928	928	928	928	928	928	928	928	928	928	928	928	928	928	928	928	928	928
MCDONOUGH 6	930	930	930	930	930	930	930	930	930	930	930	930	930	930	930	930	930	930	930	930
MCINTOSH 10	692	692	692	692	692	692	692	692	692	692	692	692	692	692	692	692	692	692	692	692
MCINTOSH 11	685	685	685	685	685	685	685	685	685	685	685	685	685	685	685	685	685	685	685	685
Oil/Gas Steam	**1,108**	**1,108**	**1,108**	**1,108**	**1,108**	**1,108**	**1,108**	**1,108**	**1,108**	**1,108**	**648**	**648**	**648**	**648**	**-**	**-**	**-**	**-**	**-**	**-**
GASTON 1 GAS	127	127	127	127	127	127	127	127	127	127	-	-	-	-	-	-	-	-	-	-
GASTON 2 GAS	128	128	128	128	128	128	128	128	128	128	-	-	-	-	-	-	-	-	-	-
GASTON 3 GAS	102	102	102	102	102	102	102	102	102	102	-	-	-	-	-	-	-	-	-	-
GASTON 4 GAS	103	103	103	103	103	103	103	103	103	103	-	-	-	-	-	-	-	-	-	-
YATES 6 GAS	323	323	323	323	323	323	323	323	323	323	323	323	323	323	-	-	-	-	-	-
YATES 7 GAS	326	326	326	326	326	326	326	326	326	326	326	326	326	326	-	-	-	-	-	-
Combustion Turbine	**1,855**	**1,855**	**2,211**	**2,454**	**2,925**	**2,925**	**2,925**	**2,925**	**2,925**	**2,925**	**2,915**	**2,915**	**2,915**	**2,915**	**2,915**	**2,915**	**2,915**	**2,915**	**2,915**	**2,915**
GASTON A	10	10	10	10	10	10	10	10	10	10	-	-	-	-	-	-	-	-	-	-
MCDONOUGH 3A	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31
MCDONOUGH 3B	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31
MCINTOSH 1A	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95
MCINTOSH 2A	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95
MCINTOSH 3A	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95
MCINTOSH 4A	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95
MCINTOSH 5A	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95
MCINTOSH 6A	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95
MCINTOSH 7A	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95
MCINTOSH 8A	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95
MCMANUS 3A	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55

	MCMANUS 3B	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55
	MCMANUS 3C	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55
	MCMANUS 4A	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55
	MCMANUS 4B	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55
	MCMANUS 4C	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55
	MCMANUS 4D	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55
	MCMANUS 4E	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55
	MCMANUS 4F	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55
	MCMANUS DIESEL	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	WANSLEY 5A	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	WARNER ROBINS 1	93	93	93	93	93	93	93	93	93	93	93	93	93	93	93	93	93	93	93	93
	WARNER ROBINS 2	93	93	93	93	93	93	93	93	93	93	93	93	93	93	93	93	93	93	93	93
	WILSON 1A	66	66	66	66	66	66	66	66	66	66	66	66	66	66	66	66	66	66	66	66
	WILSON 1B	65	65	65	65	65	65	65	65	65	65	65	65	65	65	65	65	65	65	65	65
	WILSON 1C	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53
	WILSON 1D	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40
	WILSON 1E	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59
	WILSON 1F	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59
	WILSON DIESEL	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	YATES 10	-	-	-	200	357	357	357	357	357	357	357	357	357	357	357	357	357	357	357	357
	YATES 8	-	-	357	200	357	357	357	357	357	357	357	357	357	357	357	357	357	357	357	357
	YATES 9	-	-	-	200	357	357	357	357	357	357	357	357	357	357	357	357	357	357	357	357
Pump Storage		**403**	**403**	**403**	**403**	**403**	**403**	**403**	**403**	**403**	**403**	**403**	**403**	**403**	**403**	**403**	**403**	**403**	**403**	**403**	**403**
	ROCKY MTN 1 PS	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63
	ROCKY MTN 2 PS	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63
	ROCKY MTN 3 PS	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63
	WALLACE DAM 1 PS	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53
	WALLACE DAM 2 PS	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53
	WALLACE DAM 5 PS	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53
	WALLACE DAM 6 PS	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53
Hydro		**678**	**691**	**697**	**697**	**697**	**697**	**697**	**697**	**697**	**697**	**697**	**697**	**697**	**697**	**697**	**697**	**697**	**697**	**697**	**697**
	BARTLETT'S FERRY 1 HY	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17
	BARTLETT'S FERRY 2 HY	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17
	BARTLETT'S FERRY 3 HY	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17
	BARTLETT'S FERRY 4 HY	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22
	BARTLETT'S FERRY 5 HY	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60
	BARTLETT'S FERRY 6 HY	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60
	BURTON 1 HY	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
	BURTON 2 HY	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
	ESTATOAH 1 HY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	FLINTRIVER 1 HY	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
	FLINTRIVER 2 HY	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
	FLINTRIVER 3 HY	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
	GOATROCK 3 HY	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
	GOATROCK 4 HY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	GOATROCK 5 HY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	GOATROCK 6 HY	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
	GOATROCK 7 HY	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
	GOATROCK 8 HY	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
	LANGDALE 5 HY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	LANGDALE 6 HY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	LLOYD SHOALS 1 HY	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
	LLOYD SHOALS 2 HY	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
	LLOYD SHOALS 3 HY	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
	LLOYD SHOALS 4 HY	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
	LLOYD SHOALS 5 HY	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
	LLOYD SHOALS 6 HY	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
	MORGAN FALLS 1 HY	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
	MORGAN FALLS 2 HY	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
	MORGAN FALLS 3 HY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	MORGAN FALLS 4 HY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	MORGAN FALLS 5 HY	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
	MORGAN FALLS 6 HY	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
	MORGAN FALLS 7 HY	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
	NACOOCHEE 1 HY	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
	NACOOCHEE 2 HY	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
	NORTH HIGHLANDS 1 HY	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11
	NORTH HIGHLANDS 2 HY	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11
	NORTH HIGHLANDS 3 HY	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11
	NORTH HIGHLANDS 4 HY	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
	OLIVER 1 HY	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17
	OLIVER 2 HY	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17
	OLIVER 3 HY	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17
	OLIVER 4 HY	-	-	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6
	RIVERVIEW 1 HY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	RIVERVIEW 2 HY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	SINCLAIR 1 HY	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22
	SINCLAIR 2 HY	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22
	TALLULAH 1 HY	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12
	TALLULAH 2 HY	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12
	TALLULAH 3 HY	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12
	TALLULAH 4 HY	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12
	TALLULAH 5 HY	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12
	TALLULAH 6 HY	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12
	TERRORA 1 HY	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9
	TERRORA 2 HY	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9

TUGALO 1 HY	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13
TUGALO 2 HY	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13
TUGALO 3 HY	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13
TUGALO 4 HY	-	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13
WALLACE DAM 3 HY	57	57	57	57	57	57	57	57	57	57	57	57	57	57	57	57	57	57	57	57	57
WALLACE DAM 4 HY	57	57	57	57	57	57	57	57	57	57	57	57	57	57	57	57	57	57	57	57	57
YONAH 1 HY	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
YONAH 2 HY	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
YONAH 3 HY	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
Solar	**51**	**51**	**51**	**51**	**51**	**52**	**52**	**52**	**52**	**52**	**52**	**52**	**52**	**52**	**52**	**52**	**52**	**52**	**52**	**52**	**52**
COMMUNITY SOLAR - COMER	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
COMMUNITY SOLAR - GUYTON	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
COMMUNITY SOLAR - WAYNESBORO	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FALCONS	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FORT BENNING	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6
FORT GORDON	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6
FORT STEWART SOLAR	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6
FORT VALLEY STATE UNIVERSITY	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
KINGS BAY SOLAR	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6
MCINTOSH CLOSED ASH POND	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
MCLB	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6
MOODY AFB	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
RIGHT OF WAY SOLAR	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ROBINS AFB	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13
UGA SOLAR	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Unassigned Self-Build Solar	-	-	-	-	-	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
System Sales	**(1,052)**	**(206)**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
SYSTEM SALE	(1,052)	(206)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Purchased Generating Capacity (MW)	**5,913**	**6,012**	**6,242**	**6,503**	**5,723**	**5,830**	**3,787**	**3,787**	**3,732**	**3,729**	**2,412**	**1,830**	**1,763**	**1,414**	**1,414**	**1,054**	**1,034**	**1,031**	**1,028**	**1,028**
2019 IRP RENEWABLES - DGS2230	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2019 IRP RENEWABLES - DGS2330	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
2019 IRP RENEWABLES - DGS2430	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2019 IRP RENEWABLES - DGW2330	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
2019 IRP RENEWABLES - DGW2430	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
2022 IRP BIOMASS - AGE	-	-	-	-	-	35	35	35	35	35	35	35	35	35	35	35	35	35	35	35	35
2022 IRP ESS RFP	-	-	-	-	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500
2022 IRP SOLAR DG RFP 1	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
2022 IRP SOLAR DG RFP 2	-	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12
2022 IRP SOLAR US RFP 1	-	-	-	-	-	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72
2022 IRP SOLAR US RFP 2	-	-	-	-	-	-	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24
2022/2023 US - FLINT RIVER SOLAR	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
2022/2023 US - TIMBERLAND SOLAR	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7
2022/2023 US - WADLEY SOLAR	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13
2022/2023 US - WASHINGTON COUNTY SOLAR	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8
2023 IRP UPDATE BESS RFP	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
ADDISON 1 (WEST GA)	186	186	186	186	186	186	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
ADDISON 3 (WEST GA)	181	181	181	181	181	181	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
ALBANY RENEWABLE ENERGY	50	50	50	50	50	50	50	50	50	50	50	50	50	-	-	-	-	-	-	-	-
ASI CLASSIC 210 MW - DGS1320	0	0	0	0	0	0	0	0	0	-	-	-	-	-	-	-	-	-	-	-	-
ASI CLASSIC 210 MW - DGS1420	2	2	2	2	2	2	2	2	2	2	-	-	-	-	-	-	-	-	-	-	-
ASI CLASSIC 210 MW - DGS1520	6	6	6	6	6	6	6	6	6	6	6	-	-	-	-	6	-	-	-	-	-
ASI CLASSIC 210 MW - DGS1620	0	0	0	0	0	0	0	0	0	0	0	0	-	-	-	-	-	-	-	-	-
ASI CLASSIC 210 MW - DGW1420	3	3	3	3	3	3	3	3	3	-	-	-	-	-	-	-	-	-	-	-	-
ASI CLASSIC 210 MW - DGW1520	4	4	4	4	4	4	4	4	4	4	-	-	-	-	-	-	-	-	-	-	-
ASI CLASSIC 210 MW - DGW1620	0	0	0	0	0	0	0	0	0	0	0	-	-	-	-	-	-	-	-	-	-
ASI CLASSIC 210 MW - US 1: DUBLIN SOLAR CENTER - DUBLIN	1	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-
ASI CLASSIC 210 MW - US 1: RICHLAND SOLAR CENTER	5	5	5	5	5	5	5	5	5	5	5	-	-	-	-	-	-	-	-	-	-
ASI CLASSIC 210 MW - US 1: RINCON SOLAR CENTER	4	4	4	4	4	4	4	4	4	4	4	4	-	-	-	-	-	-	-	-	-
ASI CLASSIC 210 MW - US 2: BUTLER SOLAR FARM	4	4	4	4	4	4	4	4	4	4	4	4	-	-	-	-	-	-	-	-	-
ASI CLASSIC 210 MW - US 2: DECATUR COUNTY SOLAR PROJECT	5	5	5	5	5	5	5	5	5	5	5	-	-	-	-	-	-	-	-	-	-
ASI CLASSIC 210 MW - US 2: HECATE ENERGY - OLD MIDVILLE RD LLC	5	5	5	5	5	5	5	5	5	5	5	5	-	-	-	-	-	-	-	-	-
ASI CLASSIC 210 MW - US 2: SOLARGLYNN	4	4	4	4	4	4	4	4	4	4	4	4	-	-	-	-	-	-	-	-	-
ASI PRIME 525 MW - DGS1625	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	-	-	-	-
ASI PRIME 525 MW - DGS1635	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ASI PRIME 525 MW - DGS1725	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	-	-	-
ASI PRIME 525 MW - DGS1730	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
ASI PRIME 525 MW - DGS1735	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
ASI PRIME 525 MW - DGS1815	0	0	0	0	0	0	0	0	0	-	-	-	-	-	-	-	-	-	-	-	-
ASI PRIME 525 MW - DGS1820	0	0	0	0	0	0	0	0	0	0	0	0	0	0	-	-	-	-	-	-	-
ASI PRIME 525 MW - DGS1825	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	-	-
ASI PRIME 525 MW - DGS1835	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	-	-
ASI PRIME 525 MW - DGW1725	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	-	-	-	-
ASI PRIME 525 MW - DGW1730	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
ASI PRIME 525 MW - DGW1735	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ASI PRIME 525 MW - DGW1815	0	0	0	0	0	0	0	0	0	-	-	-	-	-	-	-	-	-	-	-	-
ASI PRIME 525 MW - DGW1820	0	0	0	0	0	0	0	0	0	0	0	0	0	-	-	-	-	-	-	-	-
ASI PRIME 525 MW - DGW1825	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	-	-	-
ASI PRIME 525 MW - DGW1830	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
ASI PRIME 525 MW - DGW1835	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
ASI PRIME 525 MW - US 1: BUTLER SOLAR	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25
ASI PRIME 525 MW - US 1: DECATUR PARKWAY SOLAR PROJECT	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	-	-	-	-
ASI PRIME 525 MW - US 1: PAWPAW SOLAR	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8
ASI PRIME 525 MW - US 2: LIVE OAK SOLAR	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
ASI PRIME 525 MW - US 2: WHITE OAK SOLAR	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15

ASI PRIME 525 MW - US 2: WHITE PINE SOLAR	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20
AXIUM US SOLAR HOLDINGS (SD&D)	0	0	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
BLUE CANYON	82	82	82	82	82	82	82	82	82	82	82	-	-	-	-	-	-	-	-	-
CCSP DG - ONLINE	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CCSP DG - REMAINING	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
COCA-COLA	6	6	6	6	6	6	6	6	6	6	6	-	-	-	-	-	-	-	-	-
CONYERS RENEWABLE ENERGY	3	3	3	3	3	3	3	3	3	3	3	3	3	-	-	-	-	-	-	-
DAHLBERG 1	-	-	-	87	87	87	87	87	87	87	87	87	87	-	-	-	-	-	-	-
DAHLBERG 10	89	88	88	88	88	88	88	88	88	88	88	-	-	-	-	-	-	-	-	-
DAHLBERG 2	88	87	87	87	87	87	87	87	87	87	87	-	-	-	-	-	-	-	-	-
DAHLBERG 3	-	-	-	87	87	87	87	87	87	87	87	-	-	-	-	-	-	-	-	-
DAHLBERG 4	87	87	87	87	87	87	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DAHLBERG 5	-	-	-	87	87	87	87	87	87	87	87	-	-	-	-	-	-	-	-	-
DAHLBERG 6	88	88	88	88	88	88	88	88	88	88	88	-	-	-	-	-	-	-	-	-
DAHLBERG 8	86	86	86	86	86	86	86	86	86	86	86	-	-	-	-	-	-	-	-	-
DAHLBERG 9	-	88	88	88	88	88	88	88	88	88	88	-	-	-	-	-	-	-	-	-
EXELON HEARD 1	158	158	158	158	158	158	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EXELON HEARD 2	158	158	158	158	158	158	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EXELON HEARD 3	158	158	158	158	158	158	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EXELON HEARD 4	158	158	158	158	158	158	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EXELON HEARD 5	158	158	158	158	158	158	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EXELON HEARD 6	158	158	158	158	158	158	-	-	-	-	-	-	-	-	-	-	-	-	-	-
GEORGIA RENEWABLE POWER FRANKLIN LLC	58	58	58	58	58	58	58	58	58	58	58	58	58	58	58	58	58	58	58	58
GEORGIA RENEWABLE POWER MADISON	58	58	58	58	58	58	58	58	58	58	58	58	58	58	58	58	58	58	58	58
GREEN POWER SOLUTIONS	29	29	29	29	29	29	29	29	29	29	29	-	-	-	-	-	-	-	-	-
HARRIS 1	668	668	668	668	668	668	-	-	-	-	-	-	-	-	-	-	-	-	-	-
HARRIS 2	690	690	690	690	690	690	690	690	690	690	-	-	-	-	-	-	-	-	-	-
INTERNATIONAL PAPER - FLINT RIVER	27	27	27	27	27	27	27	27	27	27	27	27	-	-	-	-	-	-	-	-
INTERNATIONAL PAPER - PORT WENTWORTH	30	30	30	30	30	30	30	30	30	30	30	30	-	-	-	-	-	-	-	-
LSS 50 MW - HSH PEMBROOKE	0	0	0	0	0	0	0	0	0	0	0	-	-	-	-	-	-	-	-	-
LSS 50 MW - SIMON SOLAR FARM	6	6	6	6	6	6	6	6	6	6	6	-	-	-	-	-	-	-	-	-
LSS 50 MW - SOLAR D & D CAMILLA	3	3	3	3	3	3	3	3	3	3	3	-	-	-	-	-	-	-	-	-
LSS 50 MW - SOLAR D & D CAMP (MERIWETHER COUNTY)	1	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-
MAS GEORGIA LFG - OAK GROVE	6	6	6	6	6	6	6	6	6	6	6	6	-	-	-	-	-	-	-	-
MAS GEORGIA LFG - PINE RIDGE	6	6	6	6	6	6	6	6	6	6	6	6	-	-	-	-	-	-	-	-
MAS GEORGIA LFG - RICHLAND CREEK	11	11	11	11	11	11	11	11	11	11	11	11	-	-	-	-	-	-	-	-
MID-GEORGIA COGEN	300	300	300	300	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MONROE POWER	360	360	360	360	360	360	360	360	360	360	360	360	360	360	360	-	-	-	-	-
MPC PPA	750	750	750	750	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
PIEDMONT GREEN POWER	55	55	55	55	55	55	55	55	-	-	-	-	-	-	-	-	-	-	-	-
REDI 1400 MW - C&I: DOUGHERTY COUNTY SOLAR	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12
REDI 1400 MW - C&I: TANGLEWOOD SOLAR	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6
REDI 1400 MW - DG CSS 1920	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	-	-	-	-	-
REDI 1400 MW - DG CSS 1925	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
REDI 1400 MW - DG CSS 1930	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
REDI 1400 MW - DG CSS 1935	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
REDI 1400 MW - DG CSW 1925	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	-
REDI 1400 MW - DG CSW 1930	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
REDI 1400 MW - DG CSW 1935	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
REDI 1400 MW - DGS 2030	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
REDI 1400 MW - DGS 2035	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8
REDI 1400 MW - DGW 2030	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
REDI 1400 MW - DGW 2035	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
REDI 1400 MW - US 1: QUITMAN SOLAR	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15
REDI 1400 MW - US 1: SOUTHERN OAK SOLAR	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16
REDI 1400 MW - US 1: TWIGGS COUNTY SOLAR	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20
REDI 1400 MW - US 2: COOL SPRINGS	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21
REDI 1400 MW - US 2: HICKORY PARK	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20
REDI 1400 MW - US 2: QUITMAN II	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15
REDI CS2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
SANTA ROSA	-	-	230	230	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
SUPERIOR - WASTE MANAGEMENT	6	6	6	6	6	6	6	6	6	6	6	6	6	-	-	-	-	-	-	-
WALTON COUNTY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
WANSLEY 6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
WANSLEY 7	622	622	622	622	622	622	622	622	622	622	622	-	-	-	-	-	-	-	-	-
WASHINGTON COUNTY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Dispatchable DSOs (MW)	**649**	**652**	**656**	**656**	**659**	**661**	**665**	**667**	**670**	**673**	**675**	**676**	**681**	**703**	**711**	**720**	**728**	**737**	**748**	**758**
CVR Level 1	200	202	204	204	205	207	209	210	211	212	213	214	217	227	232	236	240	245	250	255
CVR Level 2	200	202	204	204	205	207	209	210	211	212	213	214	217	227	232	236	240	245	250	255
DER Customer Program	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DPEC	92	92	92	92	92	92	92	92	92	92	92	92	92	92	92	92	92	92	92	92
RTPeDA	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
RTPeHA	124	124	124	124	124	124	124	124	124	124	124	124	124	124	124	124	124	124	124	124
Temp Check	29	29	29	29	29	29	29	29	29	29	29	29	29	29	29	29	29	29	29	29

Energy Storage	**-**	**-**	**812**	**825**	**825**	**825**	**825**	**825**	**825**	**825**	**825**	**825**	**825**	**825**	**825**	**825**	**825**	**825**	**825**	**825**
2019 IRP BESS DEMO	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2019 IRP BESS DEMO - FORT STEWART 4 HR BESS	-	-	-	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13
2022 IRP MCGRAU FORD 2 HR BATTERY	-	-	265	265	265	265	265	265	265	265	265	265	265	265	265	265	265	265	265	265
2023 IRP UPDATE - HAMMOND	-	-	58	58	58	58	58	58	58	58	58	58	58	58	58	58	58	58	58	58
2023 IRP Update - MCGRAU FORD PHASE 2	-	-	265	265	265	265	265	265	265	265	265	265	265	265	265	265	265	265	265	265
2023 IRP UPDATE - MOODY AFB	-	-	45	45	45	45	45	45	45	45	45	45	45	45	45	45	45	45	45	45
2023 IRP UPDATE - ROBINS AFB	-	-	115	115	115	115	115	115	115	115	115	115	115	115	115	115	115	115	115	115

	MOSSY BRANCH	-	-	65	65	65	65	65	65	65	65	65	65	65	65	65	65	65	65	65	65
Resource Additions (Nameplate MW)			-	-	2,055	4,125	4,125	5,025	9,170	10,820	11,930	16,330	18,750	20,270	22,060	24,150	25,970	27,360	28,730	30,110	31,690
	CT w/ SCR	0	0	0	0	0	0	0	500	500	560	710	710	820	1070	1320	1450	1580	1840	1930	2160
	CC	0	0	0	0	0	0	0	1000	1000	1000	1340	1340	1430	1650	2200	2270	2510	2600	2660	2690
	CC w/ CCS - Local	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	CC w/ CCS - Distant	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Solar	0	0	0	1370	2750	2750	3350	4340	5330	6320	7310	8330	9350	10370	11390	12410	13430	14450	15470	16490
	Wind	0	0	0	0	0	0	0	0	240	300	600	900	1200	1500	1770	2070	2070	2070	2070	2370
	Battery 4-hr (T1)	0	0	0	685	1375	1375	1530	1530	1530	1530	1530	1530	1530	1530	1530	1530	1530	1530	1530	1530
	Battery 4-hr (T2)	0	0	0	0	0	0	145	1800	2220	2220	2640	2640	2640	2640	2640	2640	2640	2640	2640	2640
	Battery 4-hr (T3)	0	0	0	0	0	0	0	0	0	0	2200	3000	3000	3000	3000	3000	3000	3000	3000	3000
	Battery 4-hr (T4)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Battery 4-hr (T1_2)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Battery 4-hr (T2_2)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Medium Duration Storage	0	0	0	0	0	0	0	0	0	0	0	300	300	300	300	600	600	600	600	600
	Nuclear	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	210	210
Resource Additions (Effective MW)			-	-	651	1,306	1,306	1,562	4,304	4,703	4,784	6,794	7,599	7,904	8,479	9,373	9,978	10,348	10,698	11,058	11,423
1.0	CT w/ SCR	0	0	0	0	0	0	0	500	500	560	710	710	820	1070	1320	1450	1580	1840	1930	2160
1.0	CC	0	0	0	0	0	0	0	1000	1000	1000	1340	1340	1430	1650	2200	2270	2510	2600	2660	2690
1.0	CC w/ CCS - Local	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
1.0	CC w/ CCS - Distant	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
0.0	Solar	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
0.4	Wind	0	0	0	0	0	0	0	0	84	105	210	315	420	525	619.5	724.5	724.5	724.5	724.5	829.5
1.0	Battery 4-hr (T1)	0	0	0	650.75	1306.25	1306.25	1453.5	1453.5	1453.5	1453.5	1453.5	1453.5	1453.5	1453.5	1453.5	1453.5	1453.5	1453.5	1453.5	1453.5
0.8	Battery 4-hr (T2)	0	0	0	0	0	0	108.75	1350	1665	1665	1980	1980	1980	1980	1980	1980	1980	1980	1980	1980
0.5	Battery 4-hr (T3)	0	0	0	0	0	0	0	0	0	0	1100	1500	1500	1500	1500	1500	1500	1500	1500	1500
0.3	Battery 4-hr (T4)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
1.0	Battery 4-hr (T1_2)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
0.8	Battery 4-hr (T2_2)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
1.0	Medium Duration Storage	0	0	0	0	0	0	0	0	0	0	0	300	300	300	300	600	600	600	600	600
1.0	Nuclear	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	210	210

Georgia Power Territorial Base Case Load vs. Existing Capability MG0, Half Large Load (Winter)

Year	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
Peak Demand (MW), (A)	16,264	16,664	17,473	18,555	19,568	20,381	20,900	21,208	21,458	21,671	21,867	22,022	22,228	22,441	22,735	22,991	23,323	23,665	24,028	24,391
Owned Generating Capacity (MW)	14,306	15,164	16,545	16,801	17,272	17,273	17,218	13,228	13,228	13,228	12,759	12,759	12,759	12,759	12,110	12,110	12,110	12,110	12,110	12,110
Purchased Generating Capacity (MW), (B)	5,913	6,012	6,242	6,503	5,723	5,830	3,787	3,787	3,732	3,729	2,412	1,830	1,763	1,414	1,414	1,054	1,034	1,031	1,028	1,028
Dispatchable DSOs (MW), (C)	649	652	656	656	659	661	665	667	670	673	675	676	681	703	711	720	728	737	748	758
Total Capacity (MW)	20,868	21,829	23,443	23,960	23,654	23,765	21,671	17,683	17,631	17,630	15,845	15,265	15,203	14,875	14,235	13,884	13,871	13,879	13,887	13,896
Capacity Required to Meet GPC Target (MW), (D)	(602)	(1,064)	(1,671)	(742)	832	1,739	4,483	8,856	9,220	9,488	11,518	12,291	12,612	13,206	14,214	14,887	15,314	15,735	16,181	16,625
GPC Reserve Margin (%)	28.3%	31.0%	34.2%	29.1%	20.9%	16.6%	3.7%	-16.6%	-17.8%	-18.6%	-27.5%	-30.7%	-31.6%	-33.7%	-37.4%	-39.6%	-40.5%	-41.4%	-42.2%	-43.0%
Total Capacity with Generic Additions (MW)	20,868	21,829	23,443	24,611	24,960	25,471	26,154	26,587	26,933	27,123	27,339	27,564	27,807	28,083	28,658	28,762	29,189	29,627	30,005	30,509
Capacity Deficit (Surplus) MW	(602)	(1,064)	(1,671)	(1,393)	(474)	33	(1)	(48)	(82)	(5)	25	(7)	9	(2)	(209)	9	(4)	(13)	63	12
Reserve Margin (%)	28.3%	31.0%	34.2%	32.6%	27.6%	25.0%	25.1%	25.4%	25.5%	25.2%	25.0%	25.2%	25.1%	25.1%	26.1%	25.1%	25.2%	25.2%	24.9%	25.1%

Notes

(A) Territorial Load requirements less non-dispatchable DSOs

(B) Includes territorial and imported power purchases. Capacity does not include the Winter 2027/2028 BESS Request for Proposals (RFP) approved in the 2023 Integrated Resource Plan (IRP) Update to show total procurement needs.

(C) Values stated in combustion turbine equivalence terms

(D) Does not consider planning reserve sharing. Reflects GPC's Target Reserve Margin, resulting from a System Target Reserve Margin of 25.50% (2025-2027) and 26% (2028 and beyond).

Existing Capability

	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
Owned Generating Capacity (MW)	**14,306**	**15,164**	**16,545**	**16,801**	**17,272**	**17,273**	**17,218**	**13,228**	**13,228**	**13,228**	**12,759**	**12,759**	**12,759**	**12,759**	**12,110**	**12,110**	**12,110**	**12,110**	**12,110**	**12,110**
Nuclear	**3,049**	**3,049**	**3,049**	**3,049**	**3,049**	**3,049**	**3,049**	**3,049**	**3,049**	**3,049**	**3,049**	**3,049**	**3,049**	**3,049**	**3,049**	**3,049**	**3,049**	**3,049**	**3,049**	**3,049**
HATCH 1	451	451	451	451	451	451	451	451	451	451	451	451	451	451	451	451	451	451	451	451
HATCH 2	454	454	454	454	454	454	454	454	454	454	454	454	454	454	454	454	454	454	454	454
VOGTLE 1	560	560	560	560	560	560	560	560	560	560	560	560	560	560	560	560	560	560	560	560
VOGTLE 2	563	563	563	563	563	563	563	563	563	563	563	563	563	563	563	563	563	563	563	563
VOGTLE 3	510	510	510	510	510	510	510	510	510	510	510	510	510	510	510	510	510	510	510	510
VOGTLE 4	510	510	510	510	510	510	510	510	510	510	510	510	510	510	510	510	510	510	510	510
Coal	**4,045**	**4,045**	**4,045**	**4,045**	**4,045**	**4,045**	**3,990**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
BOWEN 1	740	740	740	740	740	740	740	-	-	-	-	-	-	-	-	-	-	-	-	-
BOWEN 2	760	760	760	760	760	760	760	-	-	-	-	-	-	-	-	-	-	-	-	-
BOWEN 3	950	950	950	950	950	950	950	-	-	-	-	-	-	-	-	-	-	-	-	-
BOWEN 4	910	910	910	910	910	910	910	-	-	-	-	-	-	-	-	-	-	-	-	-
SCHERER 1	75	75	75	75	75	75	75	-	-	-	-	-	-	-	-	-	-	-	-	-
SCHERER 2	72	72	72	72	72	72	72	-	-	-	-	-	-	-	-	-	-	-	-	-
SCHERER 3	537	537	537	537	537	537	482	-	-	-	-	-	-	-	-	-	-	-	-	-
WANSLEY 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
WANSLEY 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Combined Cycle	**4,169**	**4,169**	**4,169**	**4,169**	**4,169**	**4,169**	**4,169**	**4,169**	**4,169**	**4,169**	**4,169**	**4,169**	**4,169**	**4,169**	**4,169**	**4,169**	**4,169**	**4,169**	**4,169**	**4,169**
MCDONOUGH 4	934	934	934	934	934	934	934	934	934	934	934	934	934	934	934	934	934	934	934	934
MCDONOUGH 5	928	928	928	928	928	928	928	928	928	928	928	928	928	928	928	928	928	928	928	928
MCDONOUGH 6	930	930	930	930	930	930	930	930	930	930	930	930	930	930	930	930	930	930	930	930
MCINTOSH 10	692	692	692	692	692	692	692	692	692	692	692	692	692	692	692	692	692	692	692	692
MCINTOSH 11	685	685	685	685	685	685	685	685	685	685	685	685	685	685	685	685	685	685	685	685
Oil/Gas Steam	**1,108**	**1,108**	**1,108**	**1,108**	**1,108**	**1,108**	**1,108**	**1,108**	**1,108**	**1,108**	**648**	**648**	**648**	**648**	**-**	**-**	**-**	**-**	**-**	**-**
GASTON 1 GAS	127	127	127	127	127	127	127	127	127	127	-	-	-	-	-	-	-	-	-	-
GASTON 2 GAS	128	128	128	128	128	128	128	128	128	128	-	-	-	-	-	-	-	-	-	-
GASTON 3 GAS	102	102	102	102	102	102	102	102	102	102	-	-	-	-	-	-	-	-	-	-
GASTON 4 GAS	103	103	103	103	103	103	103	103	103	103	-	-	-	-	-	-	-	-	-	-
YATES 6 GAS	323	323	323	323	323	323	323	323	323	323	323	323	323	323	-	-	-	-	-	-
YATES 7 GAS	326	326	326	326	326	326	326	326	326	326	326	326	326	326	-	-	-	-	-	-
Combustion Turbine	**1,855**	**1,855**	**2,211**	**2,454**	**2,925**	**2,925**	**2,925**	**2,925**	**2,925**	**2,925**	**2,915**	**2,915**	**2,915**	**2,915**	**2,915**	**2,915**	**2,915**	**2,915**	**2,915**	**2,915**
GASTON A	10	10	10	10	10	10	10	10	10	10	-	-	-	-	-	-	-	-	-	-
MCDONOUGH 3A	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31
MCDONOUGH 3B	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31
MCINTOSH 1A	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95
MCINTOSH 2A	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95
MCINTOSH 3A	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95
MCINTOSH 4A	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95
MCINTOSH 5A	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95
MCINTOSH 6A	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95
MCINTOSH 7A	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95
MCINTOSH 8A	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95
MCMANUS 3A	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55

	MCMANUS 3B	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55
	MCMANUS 3C	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55
	MCMANUS 4A	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55
	MCMANUS 4B	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55
	MCMANUS 4C	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55
	MCMANUS 4D	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55
	MCMANUS 4E	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55
	MCMANUS 4F	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55
	MCMANUS DIESEL	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	WANSLEY 5A	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	WARNER ROBINS 1	93	93	93	93	93	93	93	93	93	93	93	93	93	93	93	93	93	93	93	93
	WARNER ROBINS 2	93	93	93	93	93	93	93	93	93	93	93	93	93	93	93	93	93	93	93	93
	WILSON 1A	66	66	66	66	66	66	66	66	66	66	66	66	66	66	66	66	66	66	66	66
	WILSON 1B	65	65	65	65	65	65	65	65	65	65	65	65	65	65	65	65	65	65	65	65
	WILSON 1C	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53
	WILSON 1D	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40
	WILSON 1E	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59
	WILSON 1F	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59
	WILSON DIESEL	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	YATES 10	-	-	-	200	357	357	357	357	357	357	357	357	357	357	357	357	357	357	357	357
	YATES 8	-	-	357	200	357	357	357	357	357	357	357	357	357	357	357	357	357	357	357	357
	YATES 9	-	-	-	200	357	357	357	357	357	357	357	357	357	357	357	357	357	357	357	357
Pump Storage		**403**	**403**	**403**	**403**	**403**	**403**	**403**	**403**	**403**	**403**	**403**	**403**	**403**	**403**	**403**	**403**	**403**	**403**	**403**	**403**
	ROCKY MTN 1 PS	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63
	ROCKY MTN 2 PS	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63
	ROCKY MTN 3 PS	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63
	WALLACE DAM 1 PS	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53
	WALLACE DAM 2 PS	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53
	WALLACE DAM 5 PS	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53
	WALLACE DAM 6 PS	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53
Hydro		**678**	**691**	**697**	**697**	**697**	**697**	**697**	**697**	**697**	**697**	**697**	**697**	**697**	**697**	**697**	**697**	**697**	**697**	**697**	**697**
	BARTLETT'S FERRY 1 HY	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17
	BARTLETT'S FERRY 2 HY	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17
	BARTLETT'S FERRY 3 HY	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17
	BARTLETT'S FERRY 4 HY	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22
	BARTLETT'S FERRY 5 HY	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60
	BARTLETT'S FERRY 6 HY	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60
	BURTON 1 HY	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
	BURTON 2 HY	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
	ESTATOAH 1 HY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	FLINT RIVER 1 HY	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
	FLINT RIVER 2 HY	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
	FLINT RIVER 3 HY	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
	GOAT ROCK 3 HY	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
	GOAT ROCK 4 HY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	GOAT ROCK 5 HY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	GOAT ROCK 6 HY	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
	GOAT ROCK 7 HY	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
	GOAT ROCK 8 HY	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
	LANGDALE 5 HY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	LANGDALE 6 HY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	LLOYD SHOALS 1 HY	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
	LLOYD SHOALS 2 HY	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
	LLOYD SHOALS 3 HY	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
	LLOYD SHOALS 4 HY	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
	LLOYD SHOALS 5 HY	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
	LLOYD SHOALS 6 HY	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
	MORGAN FALLS 1 HY	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
	MORGAN FALLS 2 HY	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
	MORGAN FALLS 3 HY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	MORGAN FALLS 4 HY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	MORGAN FALLS 5 HY	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
	MORGAN FALLS 6 HY	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
	MORGAN FALLS 7 HY	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
	NACOOCHEE 1 HY	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
	NACOOCHEE 2 HY	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
	NORTH HIGHLANDS 1 HY	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11
	NORTH HIGHLANDS 2 HY	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11
	NORTH HIGHLANDS 3 HY	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11
	NORTH HIGHLANDS 4 HY	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
	OLIVER 1 HY	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17
	OLIVER 2 HY	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17
	OLIVER 3 HY	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17
	OLIVER 4 HY	-	-	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6
	RIVERVIEW 1 HY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	RIVERVIEW 2 HY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	SINCLAIR 1 HY	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22
	SINCLAIR 2 HY	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22
	TALLULAH 1 HY	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12
	TALLULAH 2 HY	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12
	TALLULAH 3 HY	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12
	TALLULAH 4 HY	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12
	TALLULAH 5 HY	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12
	TALLULAH 6 HY	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12
	TERRORA 1 HY	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9
	TERRORA 2 HY	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9

TUGALO 1 HY	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13
TUGALO 2 HY	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13
TUGALO 3 HY	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13
TUGALO 4 HY	-	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13
WALLACE DAM 3 HY	57	57	57	57	57	57	57	57	57	57	57	57	57	57	57	57	57	57	57	57	57
WALLACE DAM 4 HY	57	57	57	57	57	57	57	57	57	57	57	57	57	57	57	57	57	57	57	57	57
YONAH 1 HY	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
YONAH 2 HY	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
YONAH 3 HY	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
Solar	**51**	**51**	**51**	**51**	**51**	**52**	**52**	**52**	**52**	**52**	**52**	**52**	**52**	**52**	**52**	**52**	**52**	**52**	**52**	**52**	**52**
COMMUNITY SOLAR - COMER	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
COMMUNITY SOLAR - GUYTON	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
COMMUNITY SOLAR - WAYNESBORO	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FALCONS	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FORT BENNING	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6
FORT GORDON	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6
FORT STEWART SOLAR	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6
FORT VALLEY STATE UNIVERSITY	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
KINGS BAY SOLAR	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6
MCINTOSH CLOSED ASH POND	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
MCLB	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6
MOODY AFB	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
RIGHT OF WAY SOLAR	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ROBINS AFB	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13
UGA SOLAR	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Unassigned Self-Build Solar	-	-	-	-	-	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
System Sales	**(1,052)**	**(206)**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
SYSTEM SALE	(1,052)	(206)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Purchased Generating Capacity (MW)	**5,913**	**6,012**	**6,242**	**6,503**	**5,723**	**5,830**	**3,787**	**3,787**	**3,732**	**3,729**	**2,412**	**1,830**	**1,763**	**1,414**	**1,414**	**1,054**	**1,034**	**1,031**	**1,028**	**1,028**
2019 IRP RENEWABLES - DGS2230	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2019 IRP RENEWABLES - DGS2330	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
2019 IRP RENEWABLES - DGS2430	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2019 IRP RENEWABLES - DGW2330	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
2019 IRP RENEWABLES - DGW2430	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
2022 IRP BIOMASS - AGE	-	-	-	-	-	35	35	35	35	35	35	35	35	35	35	35	35	35	35	35	35
2022 IRP ESS RFP	-	-	-	-	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500
2022 IRP SOLAR DG RFP 1	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
2022 IRP SOLAR DG RFP 2	-	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12
2022 IRP SOLAR US RFP 1	-	-	-	-	-	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72
2022 IRP SOLAR US RFP 2	-	-	-	-	-	-	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24
2022/2023 US - FLINT RIVER SOLAR	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
2022/2023 US - TIMBERLAND SOLAR	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7
2022/2023 US - WADLEY SOLAR	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13
2022/2023 US - WASHINGTON COUNTY SOLAR	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8
2023 IRP UPDATE BESS RFP	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
ADDISON 1 (WEST GA)	186	186	186	186	186	186	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
ADDISON 3 (WEST GA)	181	181	181	181	181	181	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
ALBANY RENEWABLE ENERGY	50	50	50	50	50	50	50	50	50	50	50	50	50	-	-	-	-	-	-	-	-
ASI CLASSIC 210 MW - DGS1320	0	0	0	0	0	0	0	0	0	-	-	-	-	-	-	-	-	-	-	-	-
ASI CLASSIC 210 MW - DGS1420	2	2	2	2	2	2	2	2	2	2	-	-	-	-	-	-	-	-	-	-	-
ASI CLASSIC 210 MW - DGS1520	6	6	6	6	6	6	6	6	6	6	6	-	-	-	-	6	-	-	-	-	-
ASI CLASSIC 210 MW - DGS1620	0	0	0	0	0	0	0	0	0	0	0	0	-	-	-	-	-	-	-	-	-
ASI CLASSIC 210 MW - DGW1420	3	3	3	3	3	3	3	3	3	-	-	-	-	-	-	-	-	-	-	-	-
ASI CLASSIC 210 MW - DGW1520	4	4	4	4	4	4	4	4	4	4	-	-	-	-	-	-	-	-	-	-	-
ASI CLASSIC 210 MW - DGW1620	0	0	0	0	0	0	0	0	0	0	0	-	-	-	-	-	-	-	-	-	-
ASI CLASSIC 210 MW - US 1: DUBLIN SOLAR CENTER - DUBLIN	1	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-
ASI CLASSIC 210 MW - US 1: RICHLAND SOLAR CENTER	5	5	5	5	5	5	5	5	5	5	5	-	-	-	-	-	-	-	-	-	-
ASI CLASSIC 210 MW - US 1: RINCON SOLAR CENTER	4	4	4	4	4	4	4	4	4	4	4	4	-	-	-	-	-	-	-	-	-
ASI CLASSIC 210 MW - US 2: BUTLER SOLAR FARM	4	4	4	4	4	4	4	4	4	4	4	4	-	-	-	-	-	-	-	-	-
ASI CLASSIC 210 MW - US 2: DECATUR COUNTY SOLAR PROJECT	5	5	5	5	5	5	5	5	5	5	5	-	-	-	-	-	-	-	-	-	-
ASI CLASSIC 210 MW - US 2: HECATE ENERGY - OLD MIDVILLE RD LLC	5	5	5	5	5	5	5	5	5	5	5	5	-	-	-	-	-	-	-	-	-
ASI CLASSIC 210 MW - US 2: SOLARGLYNN	4	4	4	4	4	4	4	4	4	4	4	4	-	-	-	-	-	-	-	-	-
ASI PRIME 525 MW - DGS1625	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	-	-	-	-
ASI PRIME 525 MW - DGS1635	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ASI PRIME 525 MW - DGS1725	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	-	-	-
ASI PRIME 525 MW - DGS1730	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
ASI PRIME 525 MW - DGS1735	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
ASI PRIME 525 MW - DGS1815	0	0	0	0	0	0	0	0	0	-	-	-	-	-	-	-	-	-	-	-	-
ASI PRIME 525 MW - DGS1820	0	0	0	0	0	0	0	0	0	0	0	0	0	0	-	-	-	-	-	-	-
ASI PRIME 525 MW - DGS1825	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	-
ASI PRIME 525 MW - DGS1835	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	-
ASI PRIME 525 MW - DGW1725	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	-	-	-	-
ASI PRIME 525 MW - DGW1730	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
ASI PRIME 525 MW - DGW1735	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ASI PRIME 525 MW - DGW1815	0	0	0	0	0	0	0	0	0	-	-	-	-	-	-	-	-	-	-	-	-
ASI PRIME 525 MW - DGW1820	0	0	0	0	0	0	0	0	0	0	0	0	0	-	-	-	-	-	-	-	-
ASI PRIME 525 MW - DGW1825	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	-	-	-
ASI PRIME 525 MW - DGW1830	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
ASI PRIME 525 MW - DGW1835	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
ASI PRIME 525 MW - US 1: BUTLER SOLAR	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25
ASI PRIME 525 MW - US 1: DECATUR PARKWAY SOLAR PROJECT	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	-	-	-	-	-
ASI PRIME 525 MW - US 1: PAWPAW SOLAR	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8
ASI PRIME 525 MW - US 2: LIVE OAK SOLAR	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
ASI PRIME 525 MW - US 2: WHITE OAK SOLAR	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15

ASI PRIME 525 MW - US 2: WHITE PINE SOLAR	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20
AXIUM US SOLAR HOLDINGS (SD&D)	0	0	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
BLUE CANYON	82	82	82	82	82	82	82	82	82	82	82	-	-	-	-	-	-	-	-	-
CCSP DG - ONLINE	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CCSP DG - REMAINING	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
COCA-COLA	6	6	6	6	6	6	6	6	6	6	6	-	-	-	-	-	-	-	-	-
CONYERS RENEWABLE ENERGY	3	3	3	3	3	3	3	3	3	3	3	3	3	-	-	-	-	-	-	-
DAHLBERG 1	-	-	-	87	87	87	87	87	87	87	87	87	87	-	-	-	-	-	-	-
DAHLBERG 10	89	88	88	88	88	88	88	88	88	88	88	-	-	-	-	-	-	-	-	-
DAHLBERG 2	88	87	87	87	87	87	87	87	87	87	87	-	-	-	-	-	-	-	-	-
DAHLBERG 3	-	-	-	87	87	87	87	87	87	87	87	-	-	-	-	-	-	-	-	-
DAHLBERG 4	87	87	87	87	87	87	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DAHLBERG 5	-	-	-	87	87	87	87	87	87	87	87	-	-	-	-	-	-	-	-	-
DAHLBERG 6	88	88	88	88	88	88	88	88	88	88	88	-	-	-	-	-	-	-	-	-
DAHLBERG 8	86	86	86	86	86	86	86	86	86	86	86	-	-	-	-	-	-	-	-	-
DAHLBERG 9	-	88	88	88	88	88	88	88	88	88	88	-	-	-	-	-	-	-	-	-
EXELON HEARD 1	158	158	158	158	158	158	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EXELON HEARD 2	158	158	158	158	158	158	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EXELON HEARD 3	158	158	158	158	158	158	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EXELON HEARD 4	158	158	158	158	158	158	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EXELON HEARD 5	158	158	158	158	158	158	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EXELON HEARD 6	158	158	158	158	158	158	-	-	-	-	-	-	-	-	-	-	-	-	-	-
GEORGIA RENEWABLE POWER FRANKLIN LLC	58	58	58	58	58	58	58	58	58	58	58	58	58	58	58	58	58	58	58	58
GEORGIA RENEWABLE POWER MADISON	58	58	58	58	58	58	58	58	58	58	58	58	58	58	58	58	58	58	58	58
GREEN POWER SOLUTIONS	29	29	29	29	29	29	29	29	29	29	29	-	-	-	-	-	-	-	-	-
HARRIS 1	668	668	668	668	668	668	-	-	-	-	-	-	-	-	-	-	-	-	-	-
HARRIS 2	690	690	690	690	690	690	690	690	690	690	-	-	-	-	-	-	-	-	-	-
INTERNATIONAL PAPER - FLINT RIVER	27	27	27	27	27	27	27	27	27	27	27	27	-	-	-	-	-	-	-	-
INTERNATIONAL PAPER - PORT WENTWORTH	30	30	30	30	30	30	30	30	30	30	30	30	-	-	-	-	-	-	-	-
LSS 50 MW - HSH PEMBROOKE	0	0	0	0	0	0	0	0	0	0	0	-	-	-	-	-	-	-	-	-
LSS 50 MW - SIMON SOLAR FARM	6	6	6	6	6	6	6	6	6	6	6	-	-	-	-	-	-	-	-	-
LSS 50 MW - SOLAR D & D CAMILLA	3	3	3	3	3	3	3	3	3	3	3	-	-	-	-	-	-	-	-	-
LSS 50 MW - SOLAR D & D CAMP (MERIWETHER COUNTY)	1	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-
MAS GEORGIA LFG - OAK GROVE	6	6	6	6	6	6	6	6	6	6	6	6	-	-	-	-	-	-	-	-
MAS GEORGIA LFG - PINE RIDGE	6	6	6	6	6	6	6	6	6	6	6	6	-	-	-	-	-	-	-	-
MAS GEORGIA LFG - RICHLAND CREEK	11	11	11	11	11	11	11	11	11	11	11	11	-	-	-	-	-	-	-	-
MID-GEORGIA COGEN	300	300	300	300	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MONROE POWER	360	360	360	360	360	360	360	360	360	360	360	360	360	360	360	-	-	-	-	-
MPC PPA	750	750	750	750	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
PIEDMONT GREEN POWER	55	55	55	55	55	55	55	55	-	-	-	-	-	-	-	-	-	-	-	-
REDI 1400 MW - C&I: DOUGHERTY COUNTY SOLAR	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12
REDI 1400 MW - C&I: TANGLEWOOD SOLAR	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6
REDI 1400 MW - DG CSS 1920	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	-	-	-	-	-
REDI 1400 MW - DG CSS 1925	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
REDI 1400 MW - DG CSS 1930	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
REDI 1400 MW - DG CSS 1935	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
REDI 1400 MW - DG CSW 1925	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	-
REDI 1400 MW - DG CSW 1930	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
REDI 1400 MW - DG CSW 1935	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
REDI 1400 MW - DGS 2030	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
REDI 1400 MW - DGS 2035	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8
REDI 1400 MW - DGW 2030	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
REDI 1400 MW - DGW 2035	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
REDI 1400 MW - US 1: QUITMAN SOLAR	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15
REDI 1400 MW - US 1: SOUTHERN OAK SOLAR	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16
REDI 1400 MW - US 1: TWIGGS COUNTY SOLAR	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20
REDI 1400 MW - US 2: COOL SPRINGS	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21
REDI 1400 MW - US 2: HICKORY PARK	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20
REDI 1400 MW - US 2: QUITMAN II	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15
REDI CS2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
SANTA ROSA	-	-	230	230	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
SUPERIOR - WASTE MANAGEMENT	6	6	6	6	6	6	6	6	6	6	6	6	6	-	-	-	-	-	-	-
WALTON COUNTY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
WANSLEY 6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
WANSLEY 7	622	622	622	622	622	622	622	622	622	622	622	-	-	-	-	-	-	-	-	-
WASHINGTON COUNTY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Dispatchable DSOs (MW)	**649**	**652**	**656**	**656**	**659**	**661**	**665**	**667**	**670**	**673**	**675**	**676**	**681**	**703**	**711**	**720**	**728**	**737**	**748**	**758**
CVR Level 1	200	202	204	204	205	207	209	210	211	212	213	214	217	227	232	236	240	245	250	255
CVR Level 2	200	202	204	204	205	207	209	210	211	212	213	214	217	227	232	236	240	245	250	255
DER Customer Program	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DPEC	92	92	92	92	92	92	92	92	92	92	92	92	92	92	92	92	92	92	92	92
RTPeDA	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
RTPeHA	124	124	124	124	124	124	124	124	124	124	124	124	124	124	124	124	124	124	124	124
Temp Check	29	29	29	29	29	29	29	29	29	29	29	29	29	29	29	29	29	29	29	29

Energy Storage	**-**	**-**	**812**	**825**	**825**	**825**	**825**	**825**	**825**	**825**	**825**	**825**	**825**	**825**	**825**	**825**	**825**	**825**	**825**	**825**
2019 IRP BESS DEMO	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2019 IRP BESS DEMO - FORT STEWART 4 HR BESS	-	-	-	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13
2022 IRP MCGRAU FORD 2 HR BATTERY	-	-	265	265	265	265	265	265	265	265	265	265	265	265	265	265	265	265	265	265
2023 IRP UPDATE - HAMMOND	-	-	58	58	58	58	58	58	58	58	58	58	58	58	58	58	58	58	58	58
2023 IRP Update - MCGRAU FORD PHASE 2	-	-	265	265	265	265	265	265	265	265	265	265	265	265	265	265	265	265	265	265
2023 IRP UPDATE - MOODY AFB	-	-	45	45	45	45	45	45	45	45	45	45	45	45	45	45	45	45	45	45
2023 IRP UPDATE - ROBINS AFB	-	-	115	115	115	115	115	115	115	115	115	115	115	115	115	115	115	115	115	115

	MOSSY BRANCH	-	-	65	65	65	65	65	65	65	65	65	65	65	65	65	65	65	65	65
Resource Additions (Nameplate MW)		-	-	2,055	4,125	4,525	8,360	13,770	15,420	16,640	19,930	22,350	24,070	26,390	29,200	30,870	32,330	33,780	35,170	36,880
	CT w/ SCR	0	0	0	0	400	420	2100	2100	2270	3350	3350	3350	3350	3350	3350	3500	3930	4090	4480
	CC	0	0	0	0	0	1260	4000	4000	4000	4500	4500	4500	4500	5220	5270	5560	5560	5560	5560
	CC w/ CCS - Local	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	CC w/ CCS - Distant	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Solar	0	0	1370	2750	2750	3350	4340	5330	6320	7310	8330	9350	10370	11390	12410	13430	14450	15470	16490
	Wind	0	0	0	0	0	0	0	240	300	600	900	1200	1500	1770	2070	2070	2070	2070	2370
	Battery 4-hr (T1)	0	0	685	1375	1375	1530	1530	1530	1530	1530	1530	1530	1530	1530	1530	1530	1530	1530	1530
	Battery 4-hr (T2)	0	0	0	0	0	1800	1800	2220	2220	2640	2640	2640	2640	2640	2640	2640	2640	2640	2640
	Battery 4-hr (T3)	0	0	0	0	0	0	0	0	0	0	800	1200	2200	3000	3000	3000	3000	3000	3000
	Battery 4-hr (T4)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Battery 4-hr (T1_2)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Battery 4-hr (T2_2)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Medium Duration Storage	0	0	0	0	0	0	0	0	0	0	300	300	300	300	600	600	600	600	600
	Nuclear	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	210	210
Resource Additions (Effective MW)		-	-	651	1,306	1,706	4,484	8,904	9,303	9,494	11,494	12,299	12,604	13,209	14,423	14,878	15,318	15,748	16,118	16,613
1.0	CT w/ SCR	0	0	0	0	400	420	2100	2100	2270	3350	3350	3350	3350	3350	3350	3500	3930	4090	4480
1.0	CC	0	0	0	0	0	1260	4000	4000	4000	4500	4500	4500	4500	5220	5270	5560	5560	5560	5560
1.0	CC w/ CCS - Local	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
1.0	CC w/ CCS - Distant	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
0.0	Solar	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
0.4	Wind	0	0	0	0	0	0	0	84	105	210	315	420	525	619.5	724.5	724.5	724.5	724.5	829.5
1.0	Battery 4-hr (T1)	0	0	650.75	1306.25	1306.25	1453.5	1453.5	1453.5	1453.5	1453.5	1453.5	1453.5	1453.5	1453.5	1453.5	1453.5	1453.5	1453.5	1453.5
0.8	Battery 4-hr (T2)	0	0	0	0	0	1350	1350	1665	1665	1980	1980	1980	1980	1980	1980	1980	1980	1980	1980
0.5	Battery 4-hr (T3)	0	0	0	0	0	0	0	0	0	0	400	600	1100	1500	1500	1500	1500	1500	1500
0.3	Battery 4-hr (T4)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
1.0	Battery 4-hr (T1_2)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
0.8	Battery 4-hr (T2_2)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
1.0	Medium Duration Storage	0	0	0	0	0	0	0	0	0	0	300	300	300	300	600	600	600	600	600
1.0	Nuclear	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	210	210

Georgia Power Territorial Base Case Load vs. Existing Capability MG0, High Solar (Winter)

Year	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
Peak Demand (MW), (A)	16,264	16,892	18,334	20,320	22,168	23,612	24,469	24,900	25,213	25,451	25,653	25,768	25,987	26,216	26,605	26,917	27,295	27,687	28,118	28,544
Owned Generating Capacity (MW)	14,306	15,164	16,545	16,801	17,272	17,273	17,218	17,194	17,194	17,194	16,724	12,759	12,759	12,759	12,110	12,110	12,110	12,110	12,110	12,110
Purchased Generating Capacity (MW), (B)	5,913	6,012	6,242	6,503	5,723	5,830	3,787	3,787	3,732	3,729	2,412	1,830	1,763	1,414	1,414	1,054	1,034	1,031	1,028	1,028
Dispatchable DSOs (MW), (C)	649	652	656	656	659	661	665	667	670	673	675	676	681	703	711	720	728	737	748	758
Total Capacity (MW)	20,868	21,829	23,443	23,960	23,654	23,765	21,671	21,648	21,596	21,595	19,811	15,265	15,203	14,875	14,235	13,884	13,871	13,879	13,887	13,896
Capacity Required to Meet GPC Target (MW), (D)	(602)	(781)	(598)	1,467	4,086	5,783	8,948	9,511	9,954	10,252	12,290	16,980	17,316	17,930	19,057	19,799	20,284	20,768	21,299	21,822
GPC Reserve Margin (%)	28.3%	29.2%	27.9%	17.9%	6.7%	0.6%	-11.4%	-13.1%	-14.3%	-15.1%	-22.8%	-40.8%	-41.5%	-43.3%	-46.5%	-48.4%	-49.2%	-49.9%	-50.6%	-51.3%
Total Capacity with Generic Additions (MW)	20,868	21,829	23,443	26,603	27,773	29,584	30,604	31,204	31,570	31,914	32,068	32,235	32,541	32,782	33,300	33,717	34,169	34,640	35,222	35,800
Capacity Deficit (Surplus) MW	(602)	(781)	(598)	(1,176)	(33)	(36)	15	(45)	(20)	(66)	32	11	(22)	23	(8)	(35)	(14)	7	(36)	(82)
Reserve Margin (%)	28.3%	29.2%	27.9%	30.9%	25.3%	25.3%	25.1%	25.3%	25.2%	25.4%	25.0%	25.1%	25.2%	25.0%	25.2%	25.3%	25.2%	25.1%	25.3%	25.4%

Notes

(A) Territorial Load requirements less non-dispatchable DSOs

(B) Includes territorial and imported power purchases. Capacity does not include the Winter 2027/2028 BESS Request for Proposals (RFP) approved in the 2023 Integrated Resource Plan (IRP) Update to show total procurement needs.

(C) Values stated in combustion turbine equivalence terms

(D) Does not consider planning reserve sharing. Reflects GPC's Target Reserve Margin, resulting from a System Target Reserve Margin of 25.50% (2025-2027) and 26% (2028 and beyond).

Existing Capability

	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
Owned Generating Capacity (MW)	**14,306**	**15,164**	**16,545**	**16,801**	**17,272**	**17,273**	**17,218**	**17,194**	**17,194**	**17,194**	**16,724**	**12,759**	**12,759**	**12,759**	**12,110**	**12,110**	**12,110**	**12,110**	**12,110**	**12,110**
Nuclear	**3,049**	**3,049**	**3,049**	**3,049**	**3,049**	**3,049**	**3,049**	**3,049**	**3,049**	**3,049**	**3,049**	**3,049**	**3,049**	**3,049**	**3,049**	**3,049**	**3,049**	**3,049**	**3,049**	**3,049**
HATCH 1	451	451	451	451	451	451	451	451	451	451	451	451	451	451	451	451	451	451	451	451
HATCH 2	454	454	454	454	454	454	454	454	454	454	454	454	454	454	454	454	454	454	454	454
VOGTLE 1	560	560	560	560	560	560	560	560	560	560	560	560	560	560	560	560	560	560	560	560
VOGTLE 2	563	563	563	563	563	563	563	563	563	563	563	563	563	563	563	563	563	563	563	563
VOGTLE 3	510	510	510	510	510	510	510	510	510	510	510	510	510	510	510	510	510	510	510	510
VOGTLE 4	510	510	510	510	510	510	510	510	510	510	510	510	510	510	510	510	510	510	510	510
Coal	**4,045**	**4,045**	**4,045**	**4,045**	**4,045**	**4,045**	**3,990**	**3,965**	**3,965**	**3,965**	**3,965**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
BOWEN 1	740	740	740	740	740	740	740	740	740	740	740	-	-	-	-	-	-	-	-	-
BOWEN 2	760	760	760	760	760	760	760	760	760	760	760	-	-	-	-	-	-	-	-	-
BOWEN 3	950	950	950	950	950	950	950	950	950	950	950	-	-	-	-	-	-	-	-	-
BOWEN 4	910	910	910	910	910	910	910	910	910	910	910	-	-	-	-	-	-	-	-	-
SCHERER 1	75	75	75	75	75	75	75	75	75	75	75	-	-	-	-	-	-	-	-	-
SCHERER 2	72	72	72	72	72	72	72	72	72	72	72	-	-	-	-	-	-	-	-	-
SCHERER 3	537	537	537	537	537	537	482	458	458	458	458	-	-	-	-	-	-	-	-	-
WANSLEY 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
WANSLEY 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Combined Cycle	**4,169**	**4,169**	**4,169**	**4,169**	**4,169**	**4,169**	**4,169**	**4,169**	**4,169**	**4,169**	**4,169**	**4,169**	**4,169**	**4,169**	**4,169**	**4,169**	**4,169**	**4,169**	**4,169**	**4,169**
MCDONOUGH 4	934	934	934	934	934	934	934	934	934	934	934	934	934	934	934	934	934	934	934	934
MCDONOUGH 5	928	928	928	928	928	928	928	928	928	928	928	928	928	928	928	928	928	928	928	928
MCDONOUGH 6	930	930	930	930	930	930	930	930	930	930	930	930	930	930	930	930	930	930	930	930
MCINTOSH 10	692	692	692	692	692	692	692	692	692	692	692	692	692	692	692	692	692	692	692	692
MCINTOSH 11	685	685	685	685	685	685	685	685	685	685	685	685	685	685	685	685	685	685	685	685
Oil/Gas Steam	**1,108**	**1,108**	**1,108**	**1,108**	**1,108**	**1,108**	**1,108**	**1,108**	**1,108**	**1,108**	**648**	**648**	**648**	**648**	**-**	**-**	**-**	**-**	**-**	**-**
GASTON 1 GAS	127	127	127	127	127	127	127	127	127	127	-	-	-	-	-	-	-	-	-	-
GASTON 2 GAS	128	128	128	128	128	128	128	128	128	128	-	-	-	-	-	-	-	-	-	-
GASTON 3 GAS	102	102	102	102	102	102	102	102	102	102	-	-	-	-	-	-	-	-	-	-
GASTON 4 GAS	103	103	103	103	103	103	103	103	103	103	-	-	-	-	-	-	-	-	-	-
YATES 6 GAS	323	323	323	323	323	323	323	323	323	323	323	323	323	323	-	-	-	-	-	-
YATES 7 GAS	326	326	326	326	326	326	326	326	326	326	326	326	326	326	-	-	-	-	-	-
Combustion Turbine	**1,855**	**1,855**	**2,211**	**2,454**	**2,925**	**2,925**	**2,925**	**2,925**	**2,925**	**2,925**	**2,915**	**2,915**	**2,915**	**2,915**	**2,915**	**2,915**	**2,915**	**2,915**	**2,915**	**2,915**
GASTON A	10	10	10	10	10	10	10	10	10	10	-	-	-	-	-	-	-	-	-	-
MCDONOUGH 3A	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31
MCDONOUGH 3B	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31
MCINTOSH 1A	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95
MCINTOSH 2A	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95
MCINTOSH 3A	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95
MCINTOSH 4A	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95
MCINTOSH 5A	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95
MCINTOSH 6A	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95
MCINTOSH 7A	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95
MCINTOSH 8A	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95
MCMANUS 3A	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55

	MCMANUS 3B	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55
	MCMANUS 3C	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55
	MCMANUS 4A	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55
	MCMANUS 4B	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55
	MCMANUS 4C	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55
	MCMANUS 4D	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55
	MCMANUS 4E	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55
	MCMANUS 4F	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55
	MCMANUS DIESEL	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	WANSLEY 5A	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	WARNER ROBINS 1	93	93	93	93	93	93	93	93	93	93	93	93	93	93	93	93	93	93	93	93
	WARNER ROBINS 2	93	93	93	93	93	93	93	93	93	93	93	93	93	93	93	93	93	93	93	93
	WILSON 1A	66	66	66	66	66	66	66	66	66	66	66	66	66	66	66	66	66	66	66	66
	WILSON 1B	65	65	65	65	65	65	65	65	65	65	65	65	65	65	65	65	65	65	65	65
	WILSON 1C	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53
	WILSON 1D	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40
	WILSON 1E	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59
	WILSON 1F	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59
	WILSON DIESEL	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	YATES 10	-	-	-	200	357	357	357	357	357	357	357	357	357	357	357	357	357	357	357	357
	YATES 8	-	-	357	200	357	357	357	357	357	357	357	357	357	357	357	357	357	357	357	357
	YATES 9	-	-	-	200	357	357	357	357	357	357	357	357	357	357	357	357	357	357	357	357
Pump Storage		**403**	**403**	**403**	**403**	**403**	**403**	**403**	**403**	**403**	**403**	**403**	**403**	**403**	**403**	**403**	**403**	**403**	**403**	**403**	**403**
	ROCKY MTN 1 PS	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63
	ROCKY MTN 2 PS	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63
	ROCKY MTN 3 PS	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63
	WALLACE DAM 1 PS	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53
	WALLACE DAM 2 PS	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53
	WALLACE DAM 5 PS	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53
	WALLACE DAM 6 PS	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53
Hydro		**678**	**691**	**697**	**697**	**697**	**697**	**697**	**697**	**697**	**697**	**697**	**697**	**697**	**697**	**697**	**697**	**697**	**697**	**697**	**697**
	BARTLETT'S FERRY 1 HY	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17
	BARTLETT'S FERRY 2 HY	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17
	BARTLETT'S FERRY 3 HY	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17
	BARTLETT'S FERRY 4 HY	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22
	BARTLETT'S FERRY 5 HY	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60
	BARTLETT'S FERRY 6 HY	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60
	BURTON 1 HY	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
	BURTON 2 HY	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
	ESTATOAH 1 HY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	FLINTRIVER 1 HY	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
	FLINTRIVER 2 HY	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
	FLINTRIVER 3 HY	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
	GOATROCK 3 HY	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
	GOATROCK 4 HY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	GOATROCK 5 HY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	GOATROCK 6 HY	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
	GOATROCK 7 HY	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
	GOATROCK 8 HY	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
	LANGDALE 5 HY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	LANGDALE 6 HY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	LLOYD SHOALS 1 HY	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
	LLOYD SHOALS 2 HY	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
	LLOYD SHOALS 3 HY	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
	LLOYD SHOALS 4 HY	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
	LLOYD SHOALS 5 HY	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
	LLOYD SHOALS 6 HY	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
	MORGAN FALLS 1 HY	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
	MORGAN FALLS 2 HY	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
	MORGAN FALLS 3 HY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	MORGAN FALLS 4 HY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	MORGAN FALLS 5 HY	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
	MORGAN FALLS 6 HY	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
	MORGAN FALLS 7 HY	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
	NACOOCHEE 1 HY	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
	NACOOCHEE 2 HY	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
	NORTH HIGHLANDS 1 HY	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11
	NORTH HIGHLANDS 2 HY	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11
	NORTH HIGHLANDS 3 HY	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11
	NORTH HIGHLANDS 4 HY	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
	OLIVER 1 HY	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17
	OLIVER 2 HY	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17
	OLIVER 3 HY	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17
	OLIVER 4 HY	-	-	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6
	RIVERVIEW 1 HY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	RIVERVIEW 2 HY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	SINCLAIR 1 HY	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22
	SINCLAIR 2 HY	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22
	TALLULAH 1 HY	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12
	TALLULAH 2 HY	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12
	TALLULAH 3 HY	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12
	TALLULAH 4 HY	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12
	TALLULAH 5 HY	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12
	TALLULAH 6 HY	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12
	TERRORA 1 HY	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9
	TERRORA 2 HY	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9

TUGALO 1 HY	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13
TUGALO 2 HY	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13
TUGALO 3 HY	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13
TUGALO 4 HY	-	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13
WALLACE DAM 3 HY	57	57	57	57	57	57	57	57	57	57	57	57	57	57	57	57	57	57	57	57	57
WALLACE DAM 4 HY	57	57	57	57	57	57	57	57	57	57	57	57	57	57	57	57	57	57	57	57	57
YONAH 1 HY	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
YONAH 2 HY	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
YONAH 3 HY	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
Solar	**51**	**51**	**51**	**51**	**51**	**52**	**52**	**52**	**52**	**52**	**52**	**52**	**52**	**52**	**52**	**52**	**52**	**52**	**52**	**52**	**52**
COMMUNITY SOLAR - COMER	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
COMMUNITY SOLAR - GUYTON	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
COMMUNITY SOLAR - WAYNESBORO	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FALCONS	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FORT BENNING	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6
FORT GORDON	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6
FORT STEWART SOLAR	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6
FORT VALLEY STATE UNIVERSITY	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
KINGS BAY SOLAR	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6
MCINTOSH CLOSED ASH POND	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
MCLB	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6
MOODY AFB	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
RIGHT OF WAY SOLAR	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ROBINS AFB	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13
UGA SOLAR	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Unassigned Self-Build Solar	-	-	-	-	-	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
System Sales	**(1,052)**	**(206)**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
SYSTEM SALE	(1,052)	(206)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Purchased Generating Capacity (MW)	**5,913**	**6,012**	**6,242**	**6,503**	**5,723**	**5,830**	**3,787**	**3,787**	**3,732**	**3,729**	**2,412**	**1,830**	**1,763**	**1,414**	**1,414**	**1,054**	**1,034**	**1,031**	**1,028**	**1,028**
2019 IRP RENEWABLES - DGS2230	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2019 IRP RENEWABLES - DGS2330	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
2019 IRP RENEWABLES - DGS2430	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2019 IRP RENEWABLES - DGW2330	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
2019 IRP RENEWABLES - DGW2430	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
2022 IRP BIOMASS - AGE	-	-	-	-	-	35	35	35	35	35	35	35	35	35	35	35	35	35	35	35	35
2022 IRP ESS RFP	-	-	-	-	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500
2022 IRP SOLAR DG RFP 1	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
2022 IRP SOLAR DG RFP 2	-	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12
2022 IRP SOLAR US RFP 1	-	-	-	-	-	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72
2022 IRP SOLAR US RFP 2	-	-	-	-	-	-	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24
2022/2023 US - FLINT RIVER SOLAR	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
2022/2023 US - TIMBERLAND SOLAR	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7
2022/2023 US - WADLEY SOLAR	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13
2022/2023 US - WASHINGTON COUNTY SOLAR	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8
2023 IRP UPDATE BESS RFP	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
ADDISON 1 (WEST GA)	186	186	186	186	186	186	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
ADDISON 3 (WEST GA)	181	181	181	181	181	181	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
ALBANY RENEWABLE ENERGY	50	50	50	50	50	50	50	50	50	50	50	50	50	-	-	-	-	-	-	-	-
ASI CLASSIC 210 MW - DGS1320	0	0	0	0	0	0	0	0	0	-	-	-	-	-	-	-	-	-	-	-	-
ASI CLASSIC 210 MW - DGS1420	2	2	2	2	2	2	2	2	2	2	-	-	-	-	-	-	-	-	-	-	-
ASI CLASSIC 210 MW - DGS1520	6	6	6	6	6	6	6	6	6	6	6	-	-	-	-	6	-	-	-	-	-
ASI CLASSIC 210 MW - DGS1620	0	0	0	0	0	0	0	0	0	0	0	0	-	-	-	-	-	-	-	-	-
ASI CLASSIC 210 MW - DGW1420	3	3	3	3	3	3	3	3	3	-	-	-	-	-	-	-	-	-	-	-	-
ASI CLASSIC 210 MW - DGW1520	4	4	4	4	4	4	4	4	4	4	-	-	-	-	-	-	-	-	-	-	-
ASI CLASSIC 210 MW - DGW1620	0	0	0	0	0	0	0	0	0	0	0	-	-	-	-	-	-	-	-	-	-
ASI CLASSIC 210 MW - US 1: DUBLIN SOLAR CENTER - DUBLIN	1	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-
ASI CLASSIC 210 MW - US 1: RICHLAND SOLAR CENTER	5	5	5	5	5	5	5	5	5	5	5	-	-	-	-	-	-	-	-	-	-
ASI CLASSIC 210 MW - US 1: RINCON SOLAR CENTER	4	4	4	4	4	4	4	4	4	4	4	4	-	-	-	-	-	-	-	-	-
ASI CLASSIC 210 MW - US 2: BUTLER SOLAR FARM	4	4	4	4	4	4	4	4	4	4	4	4	-	-	-	-	-	-	-	-	-
ASI CLASSIC 210 MW - US 2: DECATUR COUNTY SOLAR PROJECT	5	5	5	5	5	5	5	5	5	5	5	-	-	-	-	-	-	-	-	-	-
ASI CLASSIC 210 MW - US 2: HECATE ENERGY - OLD MIDVILLE RD LLC	5	5	5	5	5	5	5	5	5	5	5	5	-	-	-	-	-	-	-	-	-
ASI CLASSIC 210 MW - US 2: SOLARGLYNN	4	4	4	4	4	4	4	4	4	4	4	4	-	-	-	-	-	-	-	-	-
ASI PRIME 525 MW - DGS1625	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	-	-	-	-
ASI PRIME 525 MW - DGS1635	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ASI PRIME 525 MW - DGS1725	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	-	-	-
ASI PRIME 525 MW - DGS1730	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
ASI PRIME 525 MW - DGS1735	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
ASI PRIME 525 MW - DGS1815	0	0	0	0	0	0	0	0	0	-	-	-	-	-	-	-	-	-	-	-	-
ASI PRIME 525 MW - DGS1820	0	0	0	0	0	0	0	0	0	0	0	0	0	0	-	-	-	-	-	-	-
ASI PRIME 525 MW - DGS1825	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	-
ASI PRIME 525 MW - DGS1835	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	-
ASI PRIME 525 MW - DGW1725	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	-	-	-	-
ASI PRIME 525 MW - DGW1730	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
ASI PRIME 525 MW - DGW1735	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ASI PRIME 525 MW - DGW1815	0	0	0	0	0	0	0	0	0	-	-	-	-	-	-	-	-	-	-	-	-
ASI PRIME 525 MW - DGW1820	0	0	0	0	0	0	0	0	0	0	0	0	0	-	-	-	-	-	-	-	-
ASI PRIME 525 MW - DGW1825	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	-	-	-
ASI PRIME 525 MW - DGW1830	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
ASI PRIME 525 MW - DGW1835	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
ASI PRIME 525 MW - US 1: BUTLER SOLAR	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25
ASI PRIME 525 MW - US 1: DECATUR PARKWAY SOLAR PROJECT	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	-	-	-	-
ASI PRIME 525 MW - US 1: PAWPAW SOLAR	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8
ASI PRIME 525 MW - US 2: LIVE OAK SOLAR	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
ASI PRIME 525 MW - US 2: WHITE OAK SOLAR	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15

ASI PRIME 525 MW - US 2: WHITE PINE SOLAR	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20
AXIUM US SOLAR HOLDINGS (SD&D)	0	0	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
BLUE CANYON	82	82	82	82	82	82	82	82	82	82	82	-	-	-	-	-	-	-	-	-
CCSP DG - ONLINE	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CCSP DG - REMAINING	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
COCA-COLA	6	6	6	6	6	6	6	6	6	6	6	-	-	-	-	-	-	-	-	-
CONYERS RENEWABLE ENERGY	3	3	3	3	3	3	3	3	3	3	3	3	3	-	-	-	-	-	-	-
DAHLBERG 1	-	-	-	87	87	87	87	87	87	87	87	87	87	-	-	-	-	-	-	-
DAHLBERG 10	89	88	88	88	88	88	88	88	88	88	88	-	-	-	-	-	-	-	-	-
DAHLBERG 2	88	87	87	87	87	87	87	87	87	87	87	-	-	-	-	-	-	-	-	-
DAHLBERG 3	-	-	-	87	87	87	87	87	87	87	87	-	-	-	-	-	-	-	-	-
DAHLBERG 4	87	87	87	87	87	87	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DAHLBERG 5	-	-	-	87	87	87	87	87	87	87	87	-	-	-	-	-	-	-	-	-
DAHLBERG 6	88	88	88	88	88	88	88	88	88	88	88	-	-	-	-	-	-	-	-	-
DAHLBERG 8	86	86	86	86	86	86	86	86	86	86	86	-	-	-	-	-	-	-	-	-
DAHLBERG 9	-	88	88	88	88	88	88	88	88	88	88	-	-	-	-	-	-	-	-	-
EXELON HEARD 1	158	158	158	158	158	158	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EXELON HEARD 2	158	158	158	158	158	158	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EXELON HEARD 3	158	158	158	158	158	158	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EXELON HEARD 4	158	158	158	158	158	158	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EXELON HEARD 5	158	158	158	158	158	158	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EXELON HEARD 6	158	158	158	158	158	158	-	-	-	-	-	-	-	-	-	-	-	-	-	-
GEORGIA RENEWABLE POWER FRANKLIN LLC	58	58	58	58	58	58	58	58	58	58	58	58	58	58	58	58	58	58	58	58
GEORGIA RENEWABLE POWER MADISON	58	58	58	58	58	58	58	58	58	58	58	58	58	58	58	58	58	58	58	58
GREEN POWER SOLUTIONS	29	29	29	29	29	29	29	29	29	29	29	-	-	-	-	-	-	-	-	-
HARRIS 1	668	668	668	668	668	668	-	-	-	-	-	-	-	-	-	-	-	-	-	-
HARRIS 2	690	690	690	690	690	690	690	690	690	690	-	-	-	-	-	-	-	-	-	-
INTERNATIONAL PAPER - FLINT RIVER	27	27	27	27	27	27	27	27	27	27	27	27	-	-	-	-	-	-	-	-
INTERNATIONAL PAPER - PORT WENTWORTH	30	30	30	30	30	30	30	30	30	30	30	30	-	-	-	-	-	-	-	-
LSS 50 MW - HSH PEMBROOKE	0	0	0	0	0	0	0	0	0	0	0	-	-	-	-	-	-	-	-	-
LSS 50 MW - SIMON SOLAR FARM	6	6	6	6	6	6	6	6	6	6	6	-	-	-	-	-	-	-	-	-
LSS 50 MW - SOLAR D & D CAMILLA	3	3	3	3	3	3	3	3	3	3	3	-	-	-	-	-	-	-	-	-
LSS 50 MW - SOLAR D & D CAMP (MERIWETHER COUNTY)	1	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-
MAS GEORGIA LFG - OAK GROVE	6	6	6	6	6	6	6	6	6	6	6	6	-	-	-	-	-	-	-	-
MAS GEORGIA LFG - PINE RIDGE	6	6	6	6	6	6	6	6	6	6	6	6	-	-	-	-	-	-	-	-
MAS GEORGIA LFG - RICHLAND CREEK	11	11	11	11	11	11	11	11	11	11	11	11	-	-	-	-	-	-	-	-
MID-GEORGIA COGEN	300	300	300	300	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MONROE POWER	360	360	360	360	360	360	360	360	360	360	360	360	360	360	360	-	-	-	-	-
MPC PPA	750	750	750	750	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
PIEDMONT GREEN POWER	55	55	55	55	55	55	55	55	-	-	-	-	-	-	-	-	-	-	-	-
REDI 1400 MW - C&I: DOUGHERTY COUNTY SOLAR	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12
REDI 1400 MW - C&I: TANGLEWOOD SOLAR	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6
REDI 1400 MW - DG CSS 1920	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	-	-	-	-	-
REDI 1400 MW - DG CSS 1925	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
REDI 1400 MW - DG CSS 1930	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
REDI 1400 MW - DG CSS 1935	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
REDI 1400 MW - DG CSW 1925	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	-
REDI 1400 MW - DG CSW 1930	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
REDI 1400 MW - DG CSW 1935	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
REDI 1400 MW - DGS 2030	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
REDI 1400 MW - DGS 2035	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8
REDI 1400 MW - DGW 2030	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
REDI 1400 MW - DGW 2035	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
REDI 1400 MW - US 1: QUITMAN SOLAR	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15
REDI 1400 MW - US 1: SOUTHERN OAK SOLAR	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16
REDI 1400 MW - US 1: TWIGGS COUNTY SOLAR	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20
REDI 1400 MW - US 2: COOL SPRINGS	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21
REDI 1400 MW - US 2: HICKORY PARK	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20
REDI 1400 MW - US 2: QUITMAN II	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15
REDI CS2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
SANTA ROSA	-	-	230	230	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
SUPERIOR - WASTE MANAGEMENT	6	6	6	6	6	6	6	6	6	6	6	6	6	-	-	-	-	-	-	-
WALTON COUNTY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
WANSLEY 6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
WANSLEY 7	622	622	622	622	622	622	622	622	622	622	622	-	-	-	-	-	-	-	-	-
WASHINGTON COUNTY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Dispatchable DSOs (MW)	**649**	**652**	**656**	**656**	**659**	**661**	**665**	**667**	**670**	**673**	**675**	**676**	**681**	**703**	**711**	**720**	**728**	**737**	**748**	**758**
CVR Level 1	200	202	204	204	205	207	209	210	211	212	213	214	217	227	232	236	240	245	250	255
CVR Level 2	200	202	204	204	205	207	209	210	211	212	213	214	217	227	232	236	240	245	250	255
DER Customer Program	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DPEC	92	92	92	92	92	92	92	92	92	92	92	92	92	92	92	92	92	92	92	92
RTPeDA	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
RTPeHA	124	124	124	124	124	124	124	124	124	124	124	124	124	124	124	124	124	124	124	124
Temp Check	29	29	29	29	29	29	29	29	29	29	29	29	29	29	29	29	29	29	29	29

Energy Storage	**-**	**-**	**812**	**825**	**825**	**825**	**825**	**825**	**825**	**825**	**825**	**825**	**825**	**825**	**825**	**825**	**825**	**825**	**825**	**825**
2019 IRP BESS DEMO	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2019 IRP BESS DEMO - FORT STEWART 4 HR BESS	-	-	-	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13
2022 IRP MCGRAU FORD 2 HR BATTERY	-	-	265	265	265	265	265	265	265	265	265	265	265	265	265	265	265	265	265	265
2023 IRP UPDATE - HAMMOND	-	-	58	58	58	58	58	58	58	58	58	58	58	58	58	58	58	58	58	58
2023 IRP Update - MCGRAU FORD PHASE 2	-	-	265	265	265	265	265	265	265	265	265	265	265	265	265	265	265	265	265	265
2023 IRP UPDATE - MOODY AFB	-	-	45	45	45	45	45	45	45	45	45	45	45	45	45	45	45	45	45	45
2023 IRP UPDATE - ROBINS AFB	-	-	115	115	115	115	115	115	115	115	115	115	115	115	115	115	115	115	115	115

	MOSSY BRANCH	-	-	65	65	65	65	65	65	65	65	65	65	65	65	65	65	65	65	65
Resource Additions (Nameplate MW)		-	-	5,170	8,943	10,643	14,695	16,925	19,318	21,310	25,263	33,848	36,133	38,618	41,673	44,358	46,543	48,728	51,023	53,508
	CT w/ SCR	0	0	0	800	1100	1400	1900	1900	2100	2600	3800	4000	4400	4700	5000	5200	5600	5900	6300
	CC	0	0	0	0	1400	4100	4100	4100	4100	5100	7100	7100	7100	7800	7800	8000	8000	8000	8000
	CC w/ CCS - Local	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Solar	0	0	2055	4125	4125	5025	6510	7995	9480	10965	12495	14025	15555	17085	18615	20145	21675	23205	24735
	Wind	0	0	0	0	0	0	0	240	300	600	900	1200	1500	1770	2070	2070	2070	2070	2370
	Battery 4-hr (T1)	0	0	1530	1530	1530	1530	1530	1530	1530	1530	1530	1530	1530	1530	1530	1530	1530	1530	1530
	Battery 4-hr (T2)	0	0	1585	2488	2488	2640	2640	2640	2640	2640	2640	2640	2640	2640	2640	2640	2640	2640	2640
	Battery 4-hr (T3)	0	0	0	0	0	0	245	913	1160	1828	3000	3000	3000	3000	3000	3000	3000	3000	3000
	Battery 4-hr (T4)	0	0	0	0	0	0	0	0	0	0	2083	2338	2593	2848	3103	3358	3613	3868	4123
	Medium Duration Storage	0	0	0	0	0	0	0	0	0	0	300	300	300	300	600	600	600	600	600
	Nuclear	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	210	210
Resource Additions (Effective MW)		-	-	2,642	4,119	5,819	8,934	9,556	9,974	10,319	12,258	16,969	17,338	17,907	19,065	19,834	20,298	20,761	21,335	21,904
1.0	CT w/ SCR	0	0	0	800	1100	1400	1900	1900	2100	2600	3800	4000	4400	4700	5000	5200	5600	5900	6300
1.0	CC	0	0	0	0	1400	4100	4100	4100	4100	5100	7100	7100	7100	7800	7800	8000	8000	8000	8000
1.0	CC w/ CCS - Local	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
1.0	CC w/ CCS - Distant	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
0.0	Solar	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
0.4	Wind	0	0	0	0	0	0	0	84	105	210	315	420	525	619.5	724.5	724.5	724.5	724.5	829.5
1.0	Battery 4-hr (T1)	0	0	1453.5	1453.5	1453.5	1453.5	1453.5	1453.5	1453.5	1453.5	1453.5	1453.5	1453.5	1453.5	1453.5	1453.5	1453.5	1453.5	1453.5
0.8	Battery 4-hr (T2)	0	0	1188.75	1865.625	1865.625	1980	1980	1980	1980	1980	1980	1980	1980	1980	1980	1980	1980	1980	1980
0.5	Battery 4-hr (T3)	0	0	0	0	0	0	122.5	456.5	580	914	1500	1500	1500	1500	1500	1500	1500	1500	1500
0.3	Battery 4-hr (T4)	0	0	0	0	0	0	0	0	0	0	520.75	584.5	648.25	712	775.75	839.5	903.25	967	1030.75
1.0	Battery 4-hr (T1_2)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
0.8	Battery 4-hr (T2_2)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
1.0	Medium Duration Storage	0	0	0	0	0	0	0	0	0	0	300	300	300	300	600	600	600	600	600
1.0	Nuclear	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	210	210
			MG20 bess	2430	3330	3330	3330	3330	3750	3750	4170	7170	7170	7170	7170	7170	7170	7170	7170	7170
			MG20 solar	1370	2750	2750	3350	4340	5330	6320	7310	8330	9350	10370	11390	12410	13430	14450	15470	16490
			50% more solar	2055	4125	4125	5025	6510	7995	9480	10965	12495	14025	15555	17085	18615	20145	21675	23205	24735
			incremental solar additions	685	1375	1375	1675	2170	2665	3160	3655	4165	4675	5185	5695	6205	6715	7225	7735	8245
			additional bess	685	687.5	687.5	837.5	1085	1332.5	1580	1827.5	2082.5	2337.5	2592.5	2847.5	3102.5	3357.5	3612.5	3867.5	4122.5
			total bess	3115	4018	4018	4168	4415	5083	5330	5998	9253	9508	9763	10018	10273	10528	10783	11038	11293
			total solar units	6.9	13.8	13.8	16.8	21.7	26.7	31.6	36.6	41.7	46.8	51.9	57	62.1	67.2	72.3	77.4	82.5
			additional bess units	2.3	2.3	2.3	2.8	3.6	4.4	5.3	6.1	6.9	7.8	8.6	9.5	10.3	11.2	12	12.9	13.7

Georgia Power Territorial Base Case Load vs. Existing Capability MG0, Combined (Winter)

Year	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
Peak Demand (MW), (A)	16,264	16,664	17,473	18,555	19,568	20,381	20,900	21,208	21,458	21,671	21,867	22,022	22,228	22,441	22,735	22,991	23,323	23,665	24,028	24,391
Owned Generating Capacity (MW)	14,306	15,164	16,545	16,801	17,272	17,273	17,218	13,228	13,228	13,228	12,759	12,759	12,759	12,759	12,110	12,110	12,110	12,110	12,110	12,110
Purchased Generating Capacity (MW), (B)	5,913	6,012	6,242	6,503	5,723	5,830	3,787	3,787	3,732	3,729	2,412	1,830	1,763	1,414	1,414	1,054	1,034	1,031	1,028	1,028
Dispatchable DSOs (MW), (C)	649	652	656	656	659	661	665	667	670	673	675	676	681	703	711	720	728	737	748	758
Total Capacity (MW)	20,868	21,829	23,443	23,960	23,654	23,765	21,671	17,683	17,631	17,630	15,845	15,265	15,203	14,875	14,235	13,884	13,871	13,879	13,887	13,896
Capacity Required to Meet GPC Target (MW), (D)	(602)	(1,064)	(1,671)	(742)	832	1,739	4,483	8,856	9,220	9,488	11,518	12,291	12,612	13,206	14,214	14,887	15,314	15,735	16,181	16,625
GPC Reserve Margin (%)	28.3%	31.0%	34.2%	29.1%	20.9%	16.6%	3.7%	-16.6%	-17.8%	-18.6%	-27.5%	-30.7%	-31.6%	-33.7%	-37.4%	-39.6%	-40.5%	-41.4%	-42.2%	-43.0%
Total Capacity with Generic Additions (MW)	20,868	21,829	23,443	23,960	24,509	25,593	26,154	26,539	26,905	27,148	27,363	28,295	28,401	28,242	28,440	28,797	29,189	29,630	30,072	30,570
Capacity Deficit (Surplus) MW	(602)	(1,064)	(1,671)	(742)	(23)	(90)	(1)	(0)	(54)	(30)	1	(738)	(586)	(160)	9	(27)	(3)	(16)	(4)	(48)
Reserve Margin (%)	28.3%	31.0%	34.2%	29.1%	25.3%	25.6%	25.1%	25.1%	25.4%	25.3%	25.1%	28.5%	27.8%	25.8%	25.1%	25.3%	25.1%	25.2%	25.2%	25.3%

Notes

(A) Territorial Load requirements less non-dispatchable DSOs

(B) Includes territorial and imported power purchases. Capacity does not include the Winter 2027/2028 BESS Request for Proposals (RFP) approved in the 2023 Integrated Resource Plan (IRP) Update to show total procurement needs.

(C) Values stated in combustion turbine equivalence terms

(D) Does not consider planning reserve sharing. Reflects GPC's Target Reserve Margin, resulting from a System Target Reserve Margin of 25.50% (2025-2027) and 26% (2028 and beyond).

Existing Capability

	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
Owned Generating Capacity (MW)	**14,306**	**15,164**	**16,545**	**16,801**	**17,272**	**17,273**	**17,218**	**13,228**	**13,228**	**13,228**	**12,759**	**12,759**	**12,759**	**12,759**	**12,110**	**12,110**	**12,110**	**12,110**	**12,110**	**12,110**
Nuclear	**3,049**	**3,049**	**3,049**	**3,049**	**3,049**	**3,049**	**3,049**	**3,049**	**3,049**	**3,049**	**3,049**	**3,049**	**3,049**	**3,049**	**3,049**	**3,049**	**3,049**	**3,049**	**3,049**	**3,049**
HATCH 1	451	451	451	451	451	451	451	451	451	451	451	451	451	451	451	451	451	451	451	451
HATCH 2	454	454	454	454	454	454	454	454	454	454	454	454	454	454	454	454	454	454	454	454
VOGTLE 1	560	560	560	560	560	560	560	560	560	560	560	560	560	560	560	560	560	560	560	560
VOGTLE 2	563	563	563	563	563	563	563	563	563	563	563	563	563	563	563	563	563	563	563	563
VOGTLE 3	510	510	510	510	510	510	510	510	510	510	510	510	510	510	510	510	510	510	510	510
VOGTLE 4	510	510	510	510	510	510	510	510	510	510	510	510	510	510	510	510	510	510	510	510
Coal	**4,045**	**4,045**	**4,045**	**4,045**	**4,045**	**4,045**	**3,990**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
BOWEN 1	740	740	740	740	740	740	740	-	-	-	-	-	-	-	-	-	-	-	-	-
BOWEN 2	760	760	760	760	760	760	760	-	-	-	-	-	-	-	-	-	-	-	-	-
BOWEN 3	950	950	950	950	950	950	950	-	-	-	-	-	-	-	-	-	-	-	-	-
BOWEN 4	910	910	910	910	910	910	910	-	-	-	-	-	-	-	-	-	-	-	-	-
SCHERER 1	75	75	75	75	75	75	75	-	-	-	-	-	-	-	-	-	-	-	-	-
SCHERER 2	72	72	72	72	72	72	72	-	-	-	-	-	-	-	-	-	-	-	-	-
SCHERER 3	537	537	537	537	537	537	482	-	-	-	-	-	-	-	-	-	-	-	-	-
WANSLEY 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
WANSLEY 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Combined Cycle	**4,169**	**4,169**	**4,169**	**4,169**	**4,169**	**4,169**	**4,169**	**4,169**	**4,169**	**4,169**	**4,169**	**4,169**	**4,169**	**4,169**	**4,169**	**4,169**	**4,169**	**4,169**	**4,169**	**4,169**
MCDONOUGH 4	934	934	934	934	934	934	934	934	934	934	934	934	934	934	934	934	934	934	934	934
MCDONOUGH 5	928	928	928	928	928	928	928	928	928	928	928	928	928	928	928	928	928	928	928	928
MCDONOUGH 6	930	930	930	930	930	930	930	930	930	930	930	930	930	930	930	930	930	930	930	930
MCINTOSH 10	692	692	692	692	692	692	692	692	692	692	692	692	692	692	692	692	692	692	692	692
MCINTOSH 11	685	685	685	685	685	685	685	685	685	685	685	685	685	685	685	685	685	685	685	685
Oil/Gas Steam	**1,108**	**1,108**	**1,108**	**1,108**	**1,108**	**1,108**	**1,108**	**1,108**	**1,108**	**1,108**	**648**	**648**	**648**	**648**	**-**	**-**	**-**	**-**	**-**	**-**
GASTON 1 GAS	127	127	127	127	127	127	127	127	127	127	-	-	-	-	-	-	-	-	-	-
GASTON 2 GAS	128	128	128	128	128	128	128	128	128	128	-	-	-	-	-	-	-	-	-	-
GASTON 3 GAS	102	102	102	102	102	102	102	102	102	102	-	-	-	-	-	-	-	-	-	-
GASTON 4 GAS	103	103	103	103	103	103	103	103	103	103	-	-	-	-	-	-	-	-	-	-
YATES 6 GAS	323	323	323	323	323	323	323	323	323	323	323	323	323	323	-	-	-	-	-	-
YATES 7 GAS	326	326	326	326	326	326	326	326	326	326	326	326	326	326	-	-	-	-	-	-
Combustion Turbine	**1,855**	**1,855**	**2,211**	**2,454**	**2,925**	**2,925**	**2,925**	**2,925**	**2,925**	**2,925**	**2,915**	**2,915**	**2,915**	**2,915**	**2,915**	**2,915**	**2,915**	**2,915**	**2,915**	**2,915**
GASTON A	10	10	10	10	10	10	10	10	10	10	-	-	-	-	-	-	-	-	-	-
MCDONOUGH 3A	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31
MCDONOUGH 3B	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31
MCINTOSH 1A	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95
MCINTOSH 2A	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95
MCINTOSH 3A	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95
MCINTOSH 4A	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95
MCINTOSH 5A	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95
MCINTOSH 6A	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95
MCINTOSH 7A	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95
MCINTOSH 8A	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95
MCMANUS 3A	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55

	MCMANUS 3B	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55
	MCMANUS 3C	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55
	MCMANUS 4A	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55
	MCMANUS 4B	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55
	MCMANUS 4C	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55
	MCMANUS 4D	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55
	MCMANUS 4E	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55
	MCMANUS 4F	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55
	MCMANUS DIESEL	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	WANSLEY 5A	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	WARNER ROBINS 1	93	93	93	93	93	93	93	93	93	93	93	93	93	93	93	93	93	93	93	93
	WARNER ROBINS 2	93	93	93	93	93	93	93	93	93	93	93	93	93	93	93	93	93	93	93	93
	WILSON 1A	66	66	66	66	66	66	66	66	66	66	66	66	66	66	66	66	66	66	66	66
	WILSON 1B	65	65	65	65	65	65	65	65	65	65	65	65	65	65	65	65	65	65	65	65
	WILSON 1C	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53
	WILSON 1D	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40
	WILSON 1E	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59
	WILSON 1F	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59
	WILSON DIESEL	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	YATES 10	-	-	-	200	357	357	357	357	357	357	357	357	357	357	357	357	357	357	357	357
	YATES 8	-	-	357	200	357	357	357	357	357	357	357	357	357	357	357	357	357	357	357	357
	YATES 9	-	-	-	200	357	357	357	357	357	357	357	357	357	357	357	357	357	357	357	357
Pump Storage		**403**	**403**	**403**	**403**	**403**	**403**	**403**	**403**	**403**	**403**	**403**	**403**	**403**	**403**	**403**	**403**	**403**	**403**	**403**	**403**
	ROCKY MTN 1 PS	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63
	ROCKY MTN 2 PS	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63
	ROCKY MTN 3 PS	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63
	WALLACE DAM 1 PS	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53
	WALLACE DAM 2 PS	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53
	WALLACE DAM 5 PS	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53
	WALLACE DAM 6 PS	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53
Hydro		**678**	**691**	**697**	**697**	**697**	**697**	**697**	**697**	**697**	**697**	**697**	**697**	**697**	**697**	**697**	**697**	**697**	**697**	**697**	**697**
	BARTLETT'S FERRY 1 HY	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17
	BARTLETT'S FERRY 2 HY	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17
	BARTLETT'S FERRY 3 HY	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17
	BARTLETT'S FERRY 4 HY	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22
	BARTLETT'S FERRY 5 HY	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60
	BARTLETT'S FERRY 6 HY	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60
	BURTON 1 HY	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
	BURTON 2 HY	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
	ESTATOAH 1 HY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	FLINT RIVER 1 HY	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
	FLINT RIVER 2 HY	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
	FLINT RIVER 3 HY	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
	GOAT ROCK 3 HY	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
	GOAT ROCK 4 HY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	GOAT ROCK 5 HY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	GOAT ROCK 6 HY	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
	GOAT ROCK 7 HY	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
	GOAT ROCK 8 HY	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
	LANGDALE 5 HY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	LANGDALE 6 HY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	LLOYD SHOALS 1 HY	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
	LLOYD SHOALS 2 HY	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
	LLOYD SHOALS 3 HY	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
	LLOYD SHOALS 4 HY	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
	LLOYD SHOALS 5 HY	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
	LLOYD SHOALS 6 HY	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
	MORGAN FALLS 1 HY	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
	MORGAN FALLS 2 HY	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
	MORGAN FALLS 3 HY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	MORGAN FALLS 4 HY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	MORGAN FALLS 5 HY	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
	MORGAN FALLS 6 HY	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
	MORGAN FALLS 7 HY	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
	NACOOCHEE 1 HY	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
	NACOOCHEE 2 HY	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
	NORTH HIGHLANDS 1 HY	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11
	NORTH HIGHLANDS 2 HY	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11
	NORTH HIGHLANDS 3 HY	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11
	NORTH HIGHLANDS 4 HY	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
	OLIVER 1 HY	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17
	OLIVER 2 HY	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17
	OLIVER 3 HY	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17
	OLIVER 4 HY	-	-	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6
	RIVERVIEW 1 HY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	RIVERVIEW 2 HY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	SINCLAIR 1 HY	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22
	SINCLAIR 2 HY	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22
	TALLULAH 1 HY	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12
	TALLULAH 2 HY	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12
	TALLULAH 3 HY	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12
	TALLULAH 4 HY	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12
	TALLULAH 5 HY	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12
	TALLULAH 6 HY	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12
	TERRORA 1 HY	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9
	TERRORA 2 HY	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9

TUGALO 1 HY	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13
TUGALO 2 HY	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13
TUGALO 3 HY	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13
TUGALO 4 HY	-	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13
WALLACE DAM 3 HY	57	57	57	57	57	57	57	57	57	57	57	57	57	57	57	57	57	57	57	57	57
WALLACE DAM 4 HY	57	57	57	57	57	57	57	57	57	57	57	57	57	57	57	57	57	57	57	57	57
YONAH 1 HY	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
YONAH 2 HY	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
YONAH 3 HY	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
Solar	**51**	**51**	**51**	**51**	**51**	**52**	**52**	**52**	**52**	**52**	**52**	**52**	**52**	**52**	**52**	**52**	**52**	**52**	**52**	**52**	**52**
COMMUNITY SOLAR - COMER	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
COMMUNITY SOLAR - GUYTON	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
COMMUNITY SOLAR - WAYNESBORO	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FALCONS	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FORT BENNING	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6
FORT GORDON	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6
FORT STEWART SOLAR	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6
FORT VALLEY STATE UNIVERSITY	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
KINGS BAY SOLAR	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6
MCINTOSH CLOSED ASH POND	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
MCLB	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6
MOODY AFB	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
RIGHT OF WAY SOLAR	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ROBINS AFB	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13
UGA SOLAR	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Unassigned Self-Build Solar	-	-	-	-	-	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
System Sales	**(1,052)**	**(206)**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
SYSTEM SALE	(1,052)	(206)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Purchased Generating Capacity (MW)	**5,913**	**6,012**	**6,242**	**6,503**	**5,723**	**5,830**	**3,787**	**3,787**	**3,732**	**3,729**	**2,412**	**1,830**	**1,763**	**1,414**	**1,414**	**1,054**	**1,034**	**1,031**	**1,028**	**1,028**
2019 IRP RENEWABLES - DGS2230	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2019 IRP RENEWABLES - DGS2330	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
2019 IRP RENEWABLES - DGS2430	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2019 IRP RENEWABLES - DGW2330	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
2019 IRP RENEWABLES - DGW2430	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
2022 IRP BIOMASS - AGE	-	-	-	-	-	35	35	35	35	35	35	35	35	35	35	35	35	35	35	35	35
2022 IRP ESS RFP	-	-	-	-	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500
2022 IRP SOLAR DG RFP 1	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
2022 IRP SOLAR DG RFP 2	-	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12
2022 IRP SOLAR US RFP 1	-	-	-	-	-	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72
2022 IRP SOLAR US RFP 2	-	-	-	-	-	-	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24
2022/2023 US - FLINT RIVER SOLAR	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
2022/2023 US - TIMBERLAND SOLAR	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7
2022/2023 US - WADLEY SOLAR	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13
2022/2023 US - WASHINGTON COUNTY SOLAR	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8
2023 IRP UPDATE BESS RFP	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
ADDISON 1 (WEST GA)	186	186	186	186	186	186	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
ADDISON 3 (WEST GA)	181	181	181	181	181	181	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
ALBANY RENEWABLE ENERGY	50	50	50	50	50	50	50	50	50	50	50	50	50	-	-	-	-	-	-	-	-
ASI CLASSIC 210 MW - DGS1320	0	0	0	0	0	0	0	0	0	-	-	-	-	-	-	-	-	-	-	-	-
ASI CLASSIC 210 MW - DGS1420	2	2	2	2	2	2	2	2	2	2	-	-	-	-	-	-	-	-	-	-	-
ASI CLASSIC 210 MW - DGS1520	6	6	6	6	6	6	6	6	6	6	6	-	-	-	-	6	-	-	-	-	-
ASI CLASSIC 210 MW - DGS1620	0	0	0	0	0	0	0	0	0	0	0	0	-	-	-	-	-	-	-	-	-
ASI CLASSIC 210 MW - DGW1420	3	3	3	3	3	3	3	3	3	-	-	-	-	-	-	-	-	-	-	-	-
ASI CLASSIC 210 MW - DGW1520	4	4	4	4	4	4	4	4	4	4	-	-	-	-	-	-	-	-	-	-	-
ASI CLASSIC 210 MW - DGW1620	0	0	0	0	0	0	0	0	0	0	0	-	-	-	-	-	-	-	-	-	-
ASI CLASSIC 210 MW - US 1: DUBLIN SOLAR CENTER - DUBLIN	1	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-
ASI CLASSIC 210 MW - US 1: RICHLAND SOLAR CENTER	5	5	5	5	5	5	5	5	5	5	5	-	-	-	-	-	-	-	-	-	-
ASI CLASSIC 210 MW - US 1: RINCON SOLAR CENTER	4	4	4	4	4	4	4	4	4	4	4	4	-	-	-	-	-	-	-	-	-
ASI CLASSIC 210 MW - US 2: BUTLER SOLAR FARM	4	4	4	4	4	4	4	4	4	4	4	4	-	-	-	-	-	-	-	-	-
ASI CLASSIC 210 MW - US 2: DECATUR COUNTY SOLAR PROJECT	5	5	5	5	5	5	5	5	5	5	5	-	-	-	-	-	-	-	-	-	-
ASI CLASSIC 210 MW - US 2: HECATE ENERGY - OLD MIDVILLE RD LLC	5	5	5	5	5	5	5	5	5	5	5	5	-	-	-	-	-	-	-	-	-
ASI CLASSIC 210 MW - US 2: SOLARGLYNN	4	4	4	4	4	4	4	4	4	4	4	4	-	-	-	-	-	-	-	-	-
ASI PRIME 525 MW - DGS1625	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	-	-	-	-
ASI PRIME 525 MW - DGS1635	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ASI PRIME 525 MW - DGS1725	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	-	-	-
ASI PRIME 525 MW - DGS1730	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
ASI PRIME 525 MW - DGS1735	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
ASI PRIME 525 MW - DGS1815	0	0	0	0	0	0	0	0	0	-	-	-	-	-	-	-	-	-	-	-	-
ASI PRIME 525 MW - DGS1820	0	0	0	0	0	0	0	0	0	0	0	0	0	0	-	-	-	-	-	-	-
ASI PRIME 525 MW - DGS1825	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	-	-
ASI PRIME 525 MW - DGS1835	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	-	-
ASI PRIME 525 MW - DGW1725	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	-	-	-	-
ASI PRIME 525 MW - DGW1730	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
ASI PRIME 525 MW - DGW1735	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ASI PRIME 525 MW - DGW1815	0	0	0	0	0	0	0	0	0	-	-	-	-	-	-	-	-	-	-	-	-
ASI PRIME 525 MW - DGW1820	0	0	0	0	0	0	0	0	0	0	0	0	0	-	-	-	-	-	-	-	-
ASI PRIME 525 MW - DGW1825	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	-	-	-
ASI PRIME 525 MW - DGW1830	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
ASI PRIME 525 MW - DGW1835	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
ASI PRIME 525 MW - US 1: BUTLER SOLAR	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25
ASI PRIME 525 MW - US 1: DECATUR PARKWAY SOLAR PROJECT	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	-	-	-	-
ASI PRIME 525 MW - US 1: PAWPAW SOLAR	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8
ASI PRIME 525 MW - US 2: LIVE OAK SOLAR	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
ASI PRIME 525 MW - US 2: WHITE OAK SOLAR	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15

ASI PRIME 525 MW - US 2: WHITE PINE SOLAR	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20
AXIUM US SOLAR HOLDINGS (SD&D)	0	0	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
BLUE CANYON	82	82	82	82	82	82	82	82	82	82	82	-	-	-	-	-	-	-	-	-
CCSP DG - ONLINE	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CCSP DG - REMAINING	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
COCA-COLA	6	6	6	6	6	6	6	6	6	6	6	-	-	-	-	-	-	-	-	-
CONYERS RENEWABLE ENERGY	3	3	3	3	3	3	3	3	3	3	3	3	3	-	-	-	-	-	-	-
DAHLBERG 1	-	-	-	87	87	87	87	87	87	87	87	87	87	-	-	-	-	-	-	-
DAHLBERG 10	89	88	88	88	88	88	88	88	88	88	88	-	-	-	-	-	-	-	-	-
DAHLBERG 2	88	87	87	87	87	87	87	87	87	87	87	-	-	-	-	-	-	-	-	-
DAHLBERG 3	-	-	-	87	87	87	87	87	87	87	87	-	-	-	-	-	-	-	-	-
DAHLBERG 4	87	87	87	87	87	87	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DAHLBERG 5	-	-	-	87	87	87	87	87	87	87	87	-	-	-	-	-	-	-	-	-
DAHLBERG 6	88	88	88	88	88	88	88	88	88	88	88	-	-	-	-	-	-	-	-	-
DAHLBERG 8	86	86	86	86	86	86	86	86	86	86	86	-	-	-	-	-	-	-	-	-
DAHLBERG 9	-	88	88	88	88	88	88	88	88	88	88	-	-	-	-	-	-	-	-	-
EXELON HEARD 1	158	158	158	158	158	158	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EXELON HEARD 2	158	158	158	158	158	158	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EXELON HEARD 3	158	158	158	158	158	158	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EXELON HEARD 4	158	158	158	158	158	158	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EXELON HEARD 5	158	158	158	158	158	158	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EXELON HEARD 6	158	158	158	158	158	158	-	-	-	-	-	-	-	-	-	-	-	-	-	-
GEORGIA RENEWABLE POWER FRANKLIN LLC	58	58	58	58	58	58	58	58	58	58	58	58	58	58	58	58	58	58	58	58
GEORGIA RENEWABLE POWER MADISON	58	58	58	58	58	58	58	58	58	58	58	58	58	58	58	58	58	58	58	58
GREEN POWER SOLUTIONS	29	29	29	29	29	29	29	29	29	29	29	-	-	-	-	-	-	-	-	-
HARRIS 1	668	668	668	668	668	668	-	-	-	-	-	-	-	-	-	-	-	-	-	-
HARRIS 2	690	690	690	690	690	690	690	690	690	690	-	-	-	-	-	-	-	-	-	-
INTERNATIONAL PAPER - FLINT RIVER	27	27	27	27	27	27	27	27	27	27	27	27	-	-	-	-	-	-	-	-
INTERNATIONAL PAPER - PORT WENTWORTH	30	30	30	30	30	30	30	30	30	30	30	30	-	-	-	-	-	-	-	-
LSS 50 MW - HSH PEMBROOKE	0	0	0	0	0	0	0	0	0	0	0	-	-	-	-	-	-	-	-	-
LSS 50 MW - SIMON SOLAR FARM	6	6	6	6	6	6	6	6	6	6	6	-	-	-	-	-	-	-	-	-
LSS 50 MW - SOLARD&D CAMILLA	3	3	3	3	3	3	3	3	3	3	3	-	-	-	-	-	-	-	-	-
LSS 50 MW - SOLARD&D CAMP (MERIWETHER COUNTY)	1	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-
MAS GEORGIA LFG - OAK GROVE	6	6	6	6	6	6	6	6	6	6	6	6	-	-	-	-	-	-	-	-
MAS GEORGIA LFG - PINE RIDGE	6	6	6	6	6	6	6	6	6	6	6	6	-	-	-	-	-	-	-	-
MAS GEORGIA LFG - RICHLAND CREEK	11	11	11	11	11	11	11	11	11	11	11	11	-	-	-	-	-	-	-	-
MID-GEORGIA COGEN	300	300	300	300	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MONROE POWER	360	360	360	360	360	360	360	360	360	360	360	360	360	360	360	-	-	-	-	-
MPC PPA	750	750	750	750	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
PIEDMONT GREEN POWER	55	55	55	55	55	55	55	55	-	-	-	-	-	-	-	-	-	-	-	-
REDI 1400 MW - C&I: DOUGHERTY COUNTY SOLAR	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12
REDI 1400 MW - C&I: TANGLEWOOD SOLAR	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6
REDI 1400 MW - DG CSS 1920	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	-	-	-	-	-
REDI 1400 MW - DG CSS 1925	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
REDI 1400 MW - DG CSS 1930	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
REDI 1400 MW - DG CSS 1935	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
REDI 1400 MW - DG CSW 1925	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	-
REDI 1400 MW - DG CSW 1930	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
REDI 1400 MW - DG CSW 1935	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
REDI 1400 MW - DGS 2030	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
REDI 1400 MW - DGS 2035	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8
REDI 1400 MW - DGW 2030	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
REDI 1400 MW - DGW 2035	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
REDI 1400 MW - US 1: QUITMAN SOLAR	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15
REDI 1400 MW - US 1: SOUTHERN OAK SOLAR	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16
REDI 1400 MW - US 1: TWIGGS COUNTY SOLAR	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20
REDI 1400 MW - US 2: COOL SPRINGS	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21
REDI 1400 MW - US 2: HICKORY PARK	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20
REDI 1400 MW - US 2: QUITMAN II	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15
REDI CS2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
SANTA ROSA	-	-	230	230	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
SUPERIOR - WASTE MANAGEMENT	6	6	6	6	6	6	6	6	6	6	6	6	6	-	-	-	-	-	-	-
WALTON COUNTY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
WANSLEY 6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
WANSLEY 7	622	622	622	622	622	622	622	622	622	622	622	-	-	-	-	-	-	-	-	-
WASHINGTON COUNTY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

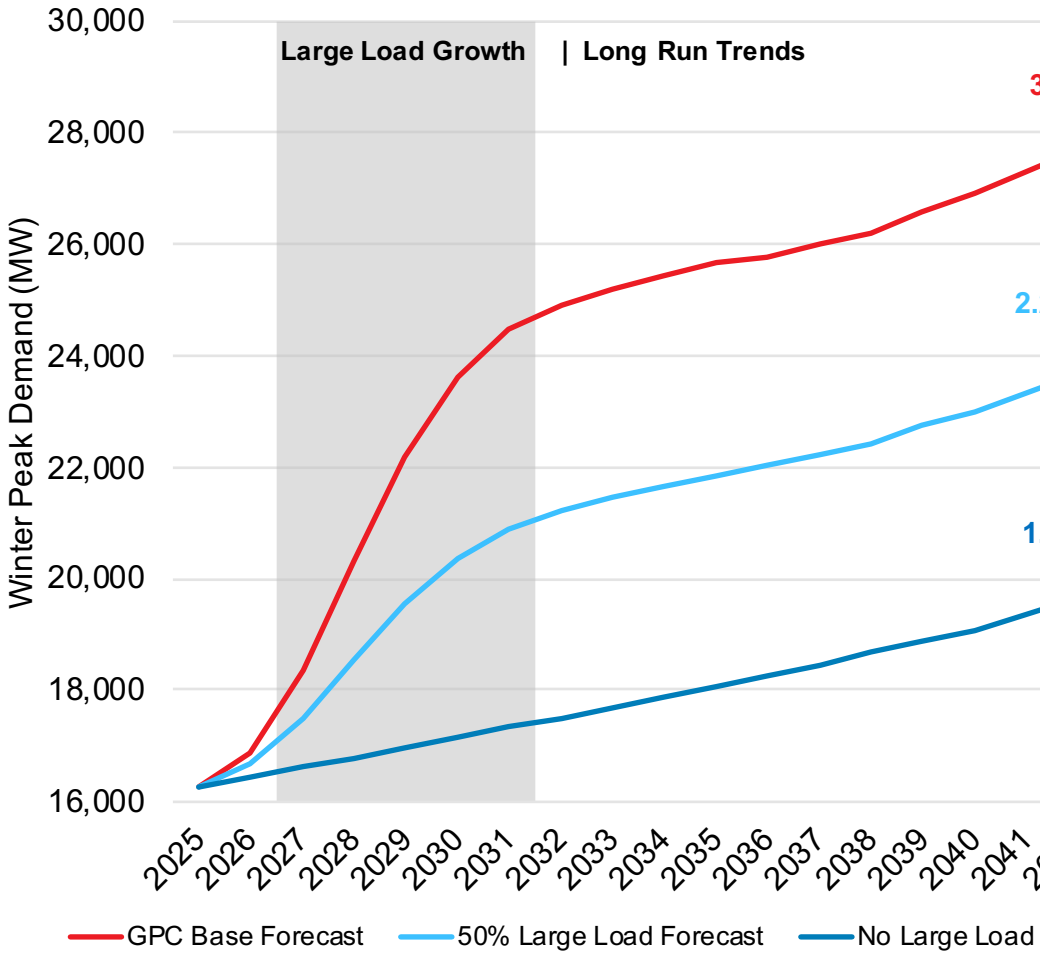
Dispatchable DSOs (MW)	**649**	**652**	**656**	**656**	**659**	**661**	**665**	**667**	**670**	**673**	**675**	**676**	**681**	**703**	**711**	**720**	**728**	**737**	**748**	**758**
CVR Level 1	200	202	204	204	205	207	209	210	211	212	213	214	217	227	232	236	240	245	250	255
CVR Level 2	200	202	204	204	205	207	209	210	211	212	213	214	217	227	232	236	240	245	250	255
DER Customer Program	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DPEC	92	92	92	92	92	92	92	92	92	92	92	92	92	92	92	92	92	92	92	92
RTPeDA	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
RTPeHA	124	124	124	124	124	124	124	124	124	124	124	124	124	124	124	124	124	124	124	124
Temp Check	29	29	29	29	29	29	29	29	29	29	29	29	29	29	29	29	29	29	29	29

Energy Storage	**-**	**-**	**812**	**825**	**825**	**825**	**825**	**825**	**825**	**825**	**825**	**825**	**825**	**825**	**825**	**825**	**825**	**825**	**825**	**825**
2019 IRP BESS DEMO	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2019 IRP BESS DEMO - FORT STEWART 4 HR BESS	-	-	-	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13
2022 IRP MCGRAU FORD 2 HR BATTERY	-	-	265	265	265	265	265	265	265	265	265	265	265	265	265	265	265	265	265	265
2023 IRP UPDATE - HAMMOND	-	-	58	58	58	58	58	58	58	58	58	58	58	58	58	58	58	58	58	58
2023 IRP Update - MCGRAU FORD PHASE 2	-	-	265	265	265	265	265	265	265	265	265	265	265	265	265	265	265	265	265	265
2023 IRP UPDATE - MOODY AFB	-	-	45	45	45	45	45	45	45	45	45	45	45	45	45	45	45	45	45	45
2023 IRP UPDATE - ROBINS AFB	-	-	115	115	115	115	115	115	115	115	115	115	115	115	115	115	115	115	115	115

	MOSSY BRANCH	-	-	65	65	65	65	65	65	65	65	65	65	65	65	65	65	65	65	65
Resource Additions (Nameplate MW)		-	-	2,055	5,025	6,155	10,245	16,225	18,618	20,510	24,523	29,908	31,993	34,078	36,813	39,438	41,563	43,718	45,873	48,278
	CT w/ SCR	0	0	0	0	0	260	1820	1820	1920	2980	2980	2980	2980	2980	3080	3180	3550	3710	4030
	CC	0	0	0	0	0	790	3480	3480	3480	3980	3980	3980	3980	4660	4800	5040	5040	5040	5040
	CC w/ CCS - Local	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	CC w/ CCS - Distant	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Solar	0	0	2055	4125	4125	5025	6510	7995	9480	10965	12495	14025	15555	17085	18615	20145	21675	23205	24735
	Wind	0	0	0	0	0	0	0	240	300	600	900	1200	1500	1770	2070	2070	2070	2070	2370
	Battery 4-hr (T1)	0	0	0	900	1530	1530	1530	1530	1530	1530	1530	1530	1530	1530	1530	1530	1530	1530	1530
	Battery 4-hr (T2)	0	0	0	0	500	2640	2640	2640	2640	2640	2640	2640	2640	2640	2640	2640	2640	2640	2640
	Battery 4-hr (T3)	0	0	0	0	0	0	245	913	1160	1828	3000	3000	3000	3000	3000	3000	3000	3000	3000
	Battery 4-hr (T4)	0	0	0	0	0	0	0	0	0	0	2083	2338	2593	2848	3103	3358	3613	3868	4123
	Battery 4-hr (T1_2)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Battery 4-hr (T2_2)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Medium Duration Storage	0	0	0	0	0	0	0	0	0	0	300	300	300	300	600	600	600	600	600
	Nuclear	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	210	210
Resource Additions (Effective MW)		-	-	-	855	1,829	4,484	8,856	9,274	9,519	11,518	13,029	13,198	13,367	14,205	14,914	15,318	15,751	16,185	16,674
1.0	CT w/ SCR	0	0	0	0	0	260	1820	1820	1920	2980	2980	2980	2980	2980	3080	3180	3550	3710	4030
1.0	CC	0	0	0	0	0	790	3480	3480	3480	3980	3980	3980	3980	4660	4800	5040	5040	5040	5040
1.0	CC w/ CCS - Local	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
1.0	CC w/ CCS - Distant	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
0.0	Solar	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
0.4	Wind	0	0	0	0	0	0	0	84	105	210	315	420	525	619.5	724.5	724.5	724.5	724.5	829.5
1.0	Battery 4-hr (T1)	0	0	0	855	1453.5	1453.5	1453.5	1453.5	1453.5	1453.5	1453.5	1453.5	1453.5	1453.5	1453.5	1453.5	1453.5	1453.5	1453.5
0.8	Battery 4-hr (T2)	0	0	0	0	375	1980	1980	1980	1980	1980	1980	1980	1980	1980	1980	1980	1980	1980	1980
0.5	Battery 4-hr (T3)	0	0	0	0	0	0	122.5	456.5	580	914	1500	1500	1500	1500	1500	1500	1500	1500	1500
0.3	Battery 4-hr (T4)	0	0	0	0	0	0	0	0	0	0	520.75	584.5	648.25	712	775.75	839.5	903.25	967	1030.75
1.0	Battery 4-hr (T1_2)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
0.8	Battery 4-hr (T2_2)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
1.0	Medium Duration Storage	0	0	0	0	0	0	0	0	0	0	300	300	300	300	600	600	600	600	600
1.0	Nuclear	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	210	210

Winter Peak Load Forecast (MW)

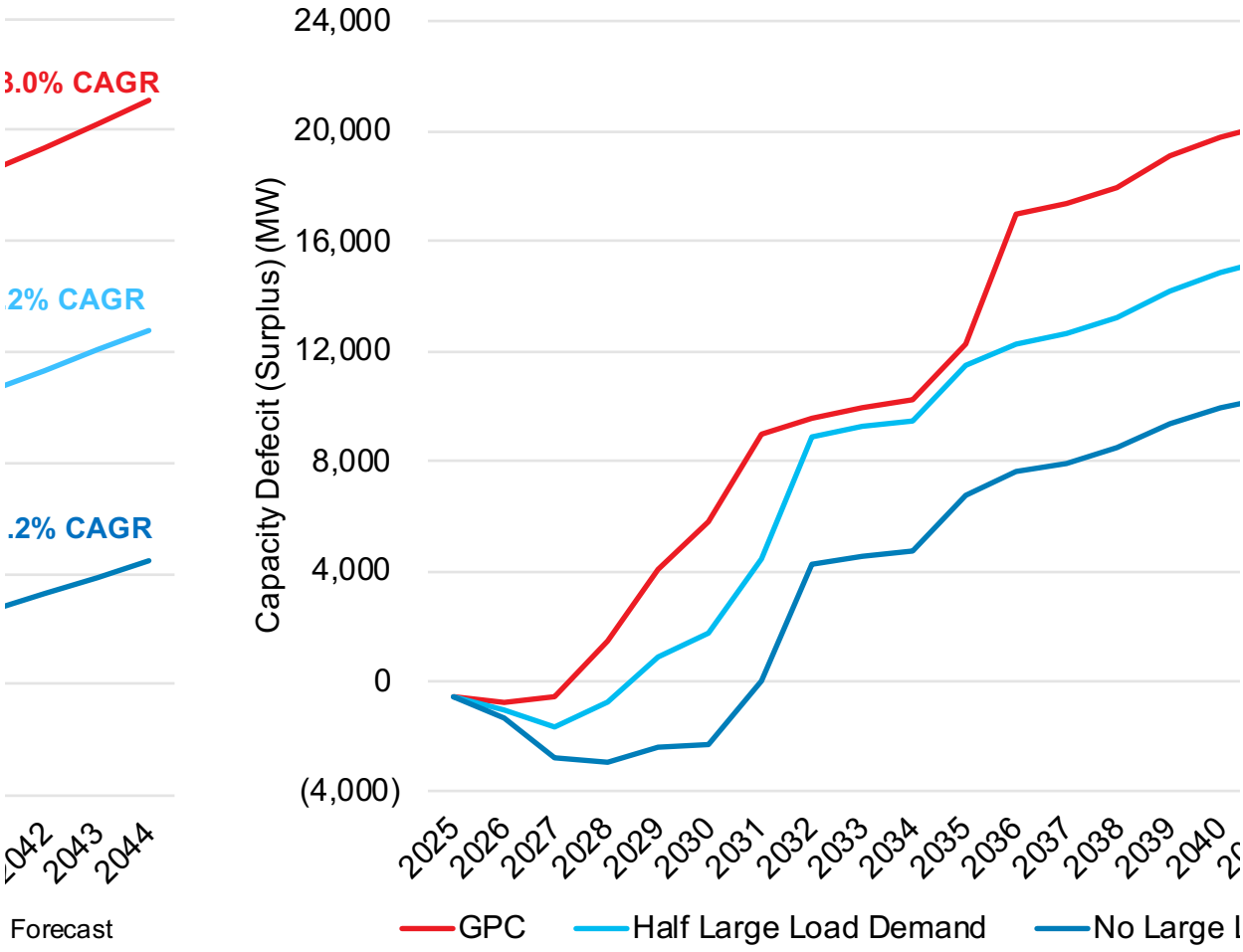
	2025	2026	2027	2028	2029
Large Load Grwoth Period	0	0	1	1	1
GPC	16,264	16,892	18,334	20,320	22,168
No Large Load	16,264	16,437	16,613	16,789	16,968
Implied Large Load Demand		454	1,721	3,530	5,200
Half Large Load Demand	16,264	16,664	17,473	18,555	19,568
GPC Peak Winter Demand Growth (%)		3.9%	8.5%	10.8%	9.1%
		1.1%	1.1%	1.1%	1.1%
		2.5%	4.9%	6.2%	5.5%
Target Rese	25%	25%	25%	25%	25%



Summer Peak Load Forecast (MW)

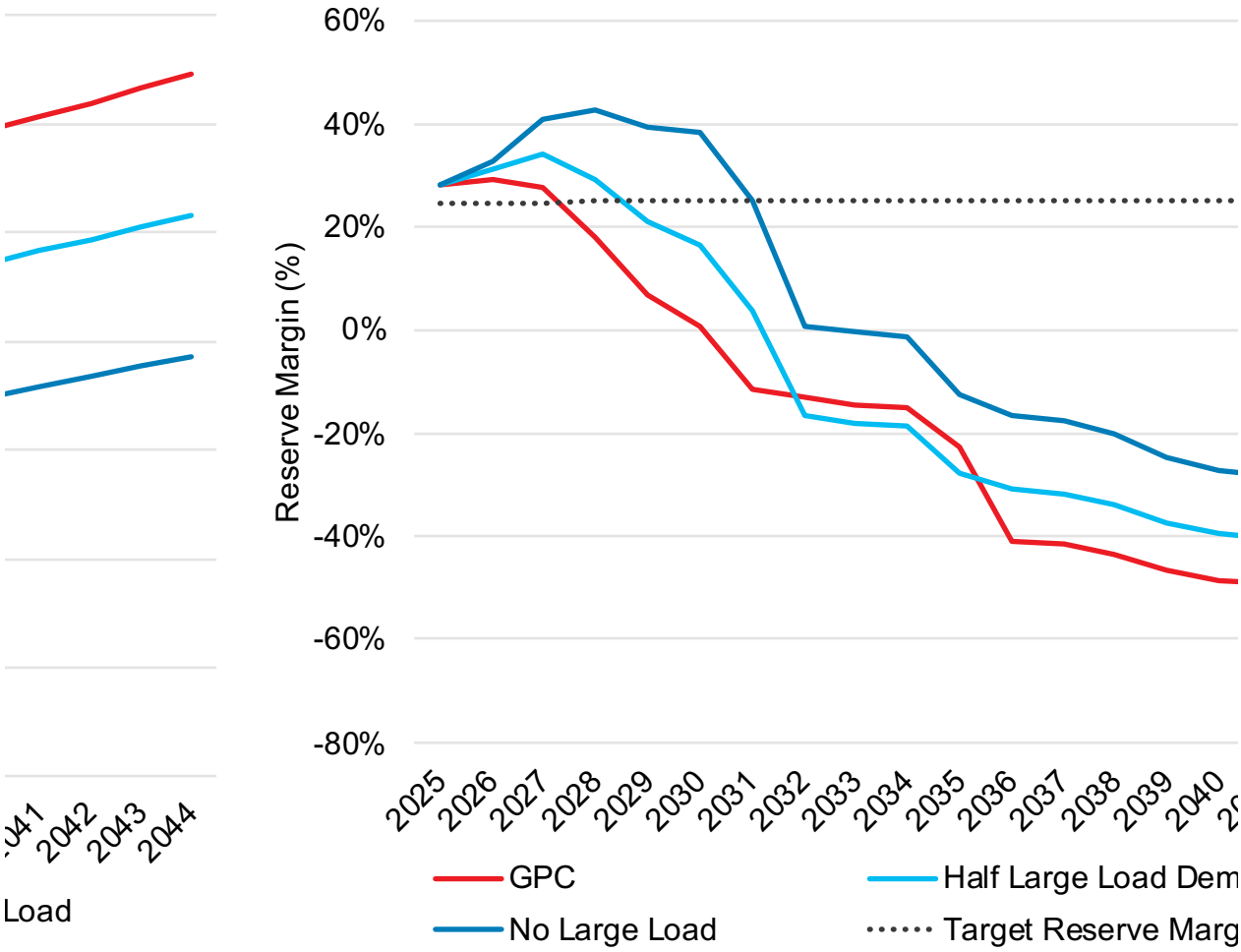
	2025	2026	2027	2028	2029
Large Load Boom Period	0	0	1	1	1
GPC	17,802	18,770	**20,552**	**22,730**	**24,621**
No Large Load	17,802	17,966	18,132	18,299	18,467
Implied Large Load Demand (Summer)		804	2,420	4,431	6,154
Half Large Load Demand	17,802	18,368	19,342	20,514	21,544
GPC Peak Summer Demand Growth (%)		5.4%	9.5%	10.6%	8.3%
		0.9%	0.9%	0.9%	0.9%
		3.2%	5.3%	6.1%	5.0%
Annual Energy (GWh)	95,294	102,557	116,340	133,719	148,718
Large Load Energy (GWh)	0	4,960	16,324	31,384	44,756
Annual Energy, No Large Loads (GWh)	95,294	97,597	100,016	102,335	103,962
Half Large Load Energy (GWh)	0	2,480	8,162	15,692	22,378
Annual Energy, Half Large Loads (GWh)	95,294	100,077	108,178	118,027	126,340

2030	2031	2032	2033	2034	2035	2036	2037
1	1	0	0	0	0	0	0
23,612	24,469	24,900	25,213	25,451	25,653	25,768	25,987
17,149	17,332	17,516	17,703	17,891	18,082	18,275	18,469
6,463	7,137	7,384	7,510	7,559	7,570	7,494	7,518
20,381	20,900	21,208	21,458	21,671	21,867	22,022	22,228
6.5%	3.6%	1.8%	1.3%	0.9%	0.8%	0.5%	0.8%
1.1%	1.1%	1.1%	1.1%	1.1%	1.1%	1.1%	1.1%
4.2%	2.5%	1.5%	1.2%	1.0%	0.9%	0.7%	0.9%
25%	25%	25%	25%	25%	25%	25%	25%



2030	2031	2032	2033	2034	2035	2036	2037
1	1	0	0	0	0	0	0
25,841	26,554	26,895	27,268	27,550	27,790	27,939	28,206
18,638	18,809	18,983	19,158	19,334	19,512	19,692	19,874
7,203	7,744	7,912	8,110	8,216	8,277	8,246	8,332
22,239	22,682	22,939	23,213	23,442	23,651	23,815	24,040
5.0%	2.8%	1.3%	1.4%	1.0%	0.9%	0.5%	1.0%
0.9%	0.9%	0.9%	0.9%	0.9%	0.9%	0.9%	0.9%
3.2%	2.0%	1.1%	1.2%	1.0%	0.9%	0.7%	0.9%
159,372	165,702	169,287	171,652	174,043	176,365	178,515	180,221
53,873	58,663	60,298	61,572	62,185	62,472	62,048	62,480
105,499	107,039	108,989	110,080	111,858	113,893	116,467	117,741
26,936	29,331	30,149	30,786	31,093	31,236	31,024	31,240
132,435	136,370	139,138	140,866	142,951	145,129	147,491	148,981

2038	2039	2040	2041	2042	2043	2044	
0	0	0	0	0	0	0	
26,216	**26,605**	**26,917**	27,295	27,687	28,118	28,544	
18,666	18,865	19,066	19,352	19,643	19,938	20,238	
7,550	7,740	7,851	7,942	8,044	8,179	8,306	
22,441	22,735	22,991	23,323	23,665	24,028	24,391	CAGR ('31-'40
0.9%	1.5%	1.2%	1.4%	1.4%	1.6%	1.5%	**1.07%**
1.1%	1.1%	1.1%	1.5%	1.5%	1.5%	1.5%	**1.07%**
1.0%	1.3%	1.1%	1.4%	1.5%	1.5%	1.5%	**1.07%**
25%	25%	25%	25%	25%	25%	25%	



2038	2039	2040	2041	2042	2043	2044	
0	0	0	0	0	0	0	
28,412	**28,675**	**28,839**	**29,219**	**29,619**	**30,030**	**30,514**	
20,057	20,242	20,428	20,726	21,027	21,334	21,644	
8,355	8,433	8,411	8,493	8,592	8,697	8,870	
24,234	24,458	24,634	24,972	25,323	25,682	26,079	CAGR ('31-'44
0.7%	0.9%	0.6%	1.3%	1.4%	1.4%	1.6%	**0.92%**
0.9%	0.9%	0.9%	1.5%	1.5%	1.5%	1.5%	**0.92%**
0.8%	0.9%	0.7%	1.4%	1.4%	1.4%	1.5%	**0.92%**
182,040	184,137	186,391	188,280	190,386	192,476	194,890	
62,696	63,755	64,105	64,788	65,578	66,526	67,705	
119,344	120,383	122,286	123,492	124,808	125,950	127,185	
31,348	31,877	32,053	32,394	32,789	33,263	33,853	
150,692	152,260	154,338	155,886	157,597	159,213	161,037	

CAGR ('41-'44)	AGR ('25-'44)
1.50%	3.00%
1.50%	1.16%
1.50%	2.16%

CAGR ('41-'44)	AGR ('25-'44)
1.46%	2.88%
1.46%	1.03%
1.46%	2.03%

Resource Type	UCAP
CT w/ SCR	100%
CC	100%
CC w/ CCS - Local	100%
CC w/ CCS - Distant	100%
Solar	0%
Wind	35%
Battery 4-hr (T1)	95%
Battery 4-hr (T2)	75%
Battery 4-hr (T3)	50%
Battery 4-hr (T4)	25%
Battery 4-hr (T1_2)	95%
Battery 4-hr (T2_2)	75%
Medium Duration Storage	100%
Nuclear	100%

*source: Aurora input files

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

AJ GOULDING

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 OVERVIEW

INTRODUCTION AND QUALIFICATIONS

Q. Please state your name, title, and employer business address.

A. My name is AJ Goulding. My business address is 717 Atlantic Avenue, Suite 1A, Boston, MA 02111. I am the President of London Economics International, LLC. I also serve as an adjunct associate professor at Columbia University's School of International and Public Affairs, where I teach a course in electricity markets and oversee graduate workshops.

Q. Please describe London Economics International LLC.

A. London Economics International LLC ("LEI") is a global economic, financial, and strategic advisory professional services firm specializing in energy, water, and infrastructure. LEI is organized as a limited liability corporation, domiciled in Massachusetts. It is US-owned and US-operated. LEI's areas of expertise include (i) price forecasting and asset valuation; (ii) regulatory economics, performance-based ratemaking, and market design; (iii) expert testimony and litigation consulting; (iv) transmission and distribution; (v) renewable energy; and (vi) procurement. LEI has more than 25 years' experience modeling and analyzing regulatory and market issues across the United States.

The firm combines a detailed understanding of specific network and commodity industries, such as electricity generation and distribution, with sophisticated analysis and a suite of proprietary quantitative models to produce reliable and comprehensible results. LEI has its roots in advising on the initial round of privatization of electricity, gas, and water companies in the United Kingdom. Since then, the firm has supported private sector clients, market institutions, regulatory agencies, public advocates, and governments on privatization, asset valuation, deregulation, tariff design, market power, and strategy worldwide, in virtually all the deregulated markets. LEI also has decades of experience in the vertically integrated power systems in the United States.

Q. Please briefly summarize your relevant educational and professional background.

A. I hold a master's degree in International Business from Columbia University's School of International and Public Affairs, and a bachelor's degree in economics from Earlham College. I have over 30 years of experience in the energy sector, having advised clients in North American Europe, Asia, and the Middle East. I began my career performing natural gas market analysis and later advised the United States Agency for International Development ("USAID") on electric power sector restructuring in India.

In my role as president of LEI, I manage an international consulting firm focused on finance, economic, and strategic consulting to the energy and infrastructure industries. In addition to serving as a sector expert in electricity and gas markets, my responsibilities include project management, marketing, budget and financial control, and recruiting. I have led and completed many of LEI's regulatory engagements related to utility proceedings, including testifying in proceedings in the United States, including the in Southeast, and in Canada. Through these engagements, I have directed and authored independent reports to commissions, prepared discovery questions, responded to interrogatories from parties, authored rebuttals, provided cross-examination of expert witnesses, and provided oral testimony.

I have published widely on energy issues, and I have extensive experience testifying, including before FERC, other federal agencies, international arbitration panels, and state and provincial regulatory bodies.

Q. What is your experience related to the matters in this case?

A. As the President of LEI, I have had oversight of the company's engagements including: analysis of data center load and implication for rate design, transmission system planning, integrated resource planning, fuel price forecasting, and review of competitive solicitations.

My CV is included as Attachment A.

Q. Was this testimony prepared under your supervision? Who else assisted in the preparation of this testimony?

A. Yes, this testimony was prepared under my supervision. Several members of the LEI team assisted in the underlying research, review and analysis stages. However, I will be able to testify orally to all matters in this testimony.

Q. What is the purpose of your testimony in this proceeding?

A. LEI was retained by the Natural Resources Defense Council, Sierra Club, and Southern Alliance for Clean Energy to provide expert technical analysis related to certain aspects of Georgia Power Company's ("GPC's") 2025 IRP filed in this docket.[1] LEI was asked to look at specific aspects of the IRP. LEI examined GPC's outlook for large load customers, the methodology used to project transmission needs, its approach to forecasting natural gas commodity prices, and its process for procurement of new generating resources. LEI was not asked to perform a review of the entire IRP (which would include analysis of total load growth, retirements, and adequacy of existing fleet, among other aspects). The views stated in this testimony are based on material that was available as of the time LEI performed our analysis. We reserve our right to change our findings if new information comes to light.

The purpose of my testimony is to summarize the findings from LEI's analysis and provide recommendations.

Q. On whose behalf are you testifying in this case?

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

Q. Are you sponsoring any exhibits with your testimony?

A. Yes, I am sponsoring the exhibits listed below.

[1] GPSC Docket #56002. Georgia Power Company. *2025 Integrated Resource Plan*. January 2025.

Table 1. List of Exhibits

Exhibit #	Title	Confidential
AJG-1	Resume of AJ Goulding	Public
AJG -2	Company response to Staff discovery request STF-JKA-1-2a	Public
AJG -3	Company response to Staff discovery request STF-GS-1-8	Public
AJG -4	Company response to Staff discovery request STF-PIA-5-17	Trade Secret
AJG -5	Company response to Staff discovery request STF-GS-1-1	Public
AJG -6	Company response to Staff discovery request STF-JKA-1-12	Public
AJG -7	Company response to Staff discovery request STF-JKA-2-6	Public
AJG -8	Company response to Hearing Request HR-1-1 Attachment	Trade Secret
AJG -9	Company response to Staff discovery request STF-JKA-1-12 Attachment B	Trade Secret

SUMMARY OF CONCLUSIONS AND RECOMMENDATIONS

Q. Please summarize your primary conclusions and recommendations.

A. Our primary conclusions include the following:

- GPC's outlook for large customer load is an important component of its total load outlook. LEI's careful review of GPC's quarterly large load announcement reports indicates that growth through 2028 and perhaps beyond is likely to be slower than GPC is projecting. GPC is considering not just load with contracts but also load under various stages of development, including those under technical review. Not all these load projects are guaranteed to materialize - and likely will not for a variety of reasons.

  Because of the inherent uncertainty about data center load growth, and because GPC's large load announcement reports reflect a potential near-term slowdown in project commitment, LEI recommends that GPC continue to monitor attrition in its quarterly *Large Load Economic Development Report* to ensure that its large load forecast does not outrun the actual pace of load growth. LEI also believes a more realistic projection of large load demand is called for. LEI created an alternative baseline scenario which

reflects recent experience with attrition in GPC's announcements of potential large load customers.

- GPC's transmission plan identifies projects that it believes are needed to reliably support load and generation resources across the Georgia Integrated Transmission System ("GA ITS") over a ten-year planning horizon. Transmission constraints are identified and alternative solutions are subsequently evaluated using a cost/benefit analysis framework that considers economic factors and engineering benefits. Though LEI did not examine each project in detail and does not have a view as to whether or not GPC overstated or understated its need for transmission investment, GPC's projections of transmission needs did not consider the possibility that load growth may be slower than assumed, though they did examine a scenario in which load growth would be higher than in the base case. Testing a lower load forecast sensitivity (which would reflect the substantial uncertainty associated with prospective large load customers) would enable GPC to identify which transmission projects could potentially be deferred. GPC's projections of transmission needs also did not consider a longer (20-year) planning horizon. Extending the transmission planning horizon is important to capture the longer-term benefits of projects and enable more proactive investments that are better equipped to respond to the evolving nature of the grid. LEI recommends consideration of these two issues in the forecasting of transmission needs.

- GPC's forecast of natural gas prices employs a reasonable methodology for annual and monthly gas prices. However, gas prices can be volatile (gas purchase contracts are usually not for fixed prices, but are indexed to market prices), and GPC's approach ignores the impact of volatility on customer costs. LEI recommends that GPC refer to historical short-term volatility of gas prices and examine the impact of such volatility on ratepayer costs across its scenarios.

- GPC's process for procuring supply resources meets Commission requirements, but it could be made more competitive if it incorporated practices used by other utilities, such as allowing a longer period from Commission-approved RFP to bid deadline and not requiring a bid security payment before short-listing bidders. Making the RFP

process more bidder-friendly reduces risk and cost to bidders, which can result in more competition and lower prices, to the benefit of ratepayers.

- Any aspects of GPC's 2025 IRP not discussed in this testimony should not be interpreted as agreement with GPC on those aspects.

ORGANIZATION OF TESTIMONY

Q. How is the remainder of your testimony organized?

A. LEI's testimony is organized as follows: Part II addresses LEI analysis of GPC's large customer load forecast; Part III addresses GPC's methodology for projecting transmission needs; Part IV addresses GPC's gas price forecasting approach, and Part V addresses GPC's process for competitive solicitation of generation resources.

II. GPC'S FORECAST OF DATA CENTER LOAD DOES NOT REFLECT RECENT ATTRITION IN ITS LOAD ANNOUNCEMENT DATA

Q. How did LEI evaluate GPC's forecast of large loads?

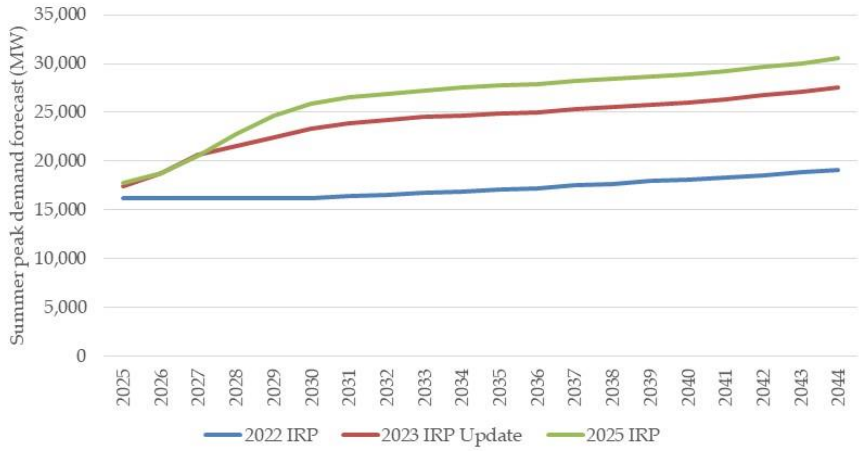
A. LEI examined trends in US data center electricity demand and compared them to recent experience for announced projects in GPC's quarterly reports, known as *Large Load Economic Development* reports, as well as GPC's methodology for projecting load growth. As described in detail in this section, GPC very likely overestimated future load from data centers for the period of its IRP because it did not reflect the attrition of data center projects that is evident in GPC's quarterly *Large Load Economic Development* reports in 2024, nor the very slow growth in signed contracts for service and requests for service that also appears in GPC's *Large Load Economic Development* reports. LEI concludes this section with an alternative outlook and recommends that GPC carefully track trends in the quarterly attrition reported in the *Large Load Economic Development* reports to ensure that its outlooks for large load do not run ahead of actual experience with this customer class.

Q. Is GPC's forecast of large loads a material portion of its load outlook?

A. Yes. In GPC's 2025 IRP, it projected an increase of approximately 9.7 GW of new summer peak demand by 2034 (the green line in Figure 1). GPC projected a similar increase in new

winter peak demand – a 9.2 GW increase by 2034. GPC noted that this load growth is driven by a continued increase in requests for service from large load customers.

Figure 1. GPC base case summer peak demand (2025-2044)



Note: GPC refers to its base load forecast as "Budget 2025" in the 2025 IRP document.

Source: GPSC Docket #56002. GPC. *2025 IRP Update, Technical Appendix Volume 1: Load and Energy Forecast.* January 2025. https://psc.ga.gov/search/facts-document/?documentId=221233.

Q. Are there any issues to consider in projecting GPC's large customer load growth?

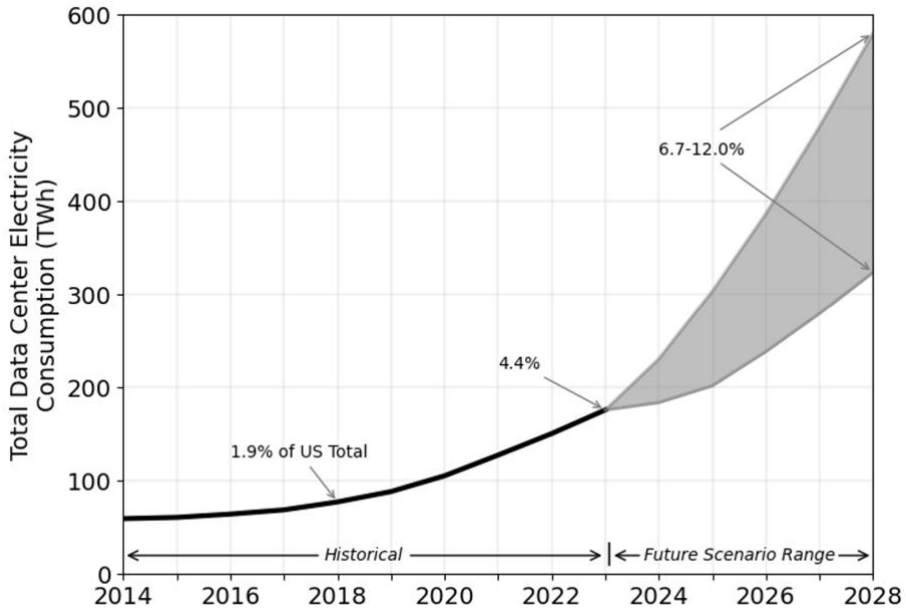
A. Yes, as discussed in detail below, much of the large customer load growth that GPC is projecting would be from data centers. Data center development is subject to particular demand and supply factors that can lead to difficulties in forecasting their load. These factors are discussed next.

NEW DATA CENTER LOAD IS DRIVEN BY A VARIETY OF DEMAND AND SUPPLY FACTORS

Q. Why is data center load growth hard to forecast?

A. Growth in electricity demand from data centers has been rapid in the United States and other regions, but it is a nascent phenomenon and forecasts for future growth from this customer sector show a wide range of uncertainty (see, for example, the graph below displaying a wide range of future data center energy requirements that were recently estimated by Lawrence Berkeley National Labs, Figure 2). This uncertainty is driven by a variety of factors, related to both demand and supply.

Figure 2. Total US data center electricity consumption from 2014 through 2028



Source: Shehabi, A., Smith, S.J., Hubbard, A., Newkirk, A., Lei, N., Siddik, M.A.B., Holecek, B., Koomey, J., Masanet, E., Sartor, D. 2024. *2024 United States Data Center Energy Usage Report*. Lawrence Berkeley National Laboratory, Berkeley, California. LBNL-2001637.

Q. What are some supply factors impacting data center growth?

A. On the supply side, there are uncertainties related to the future efficiency of equipment for computing and the speed of expansion of chip manufacturing capability, both of which can impact the rate of growth of power needs of data centers.

Q. What are some demand factors impacting data center growth?

A. On the demand side, the key question is whether a data center is needed, and this is best understood in the context of the services the data center provides. Services provided by data centers include training and use of artificial intelligence ("AI") tools, which in turn depend on and the pace of uptake of AI tools; cryptocurrency mining; and traditional data center services for data storage and cloud computing services supplied by technology companies such as Amazon, Microsoft, and Google. Data centers which provide services to a variety of clients may expect a ramping of load. In other words, even if such a data center expects to use 1,000 MW eventually, in the first years, it will start with lower level

and ramp up as it adds tenants (which is why data center customers often ask the utility for a ramping period when they request service).

Q. How does a utility plan for meeting future data center load?

A. A utility has an obligation to provide electricity to customers in its territory—and it cannot jeopardize the reliability of the service it provides to existing customers to take on new customers. Therefore, the utility periodically performs forward-looking load studies, which must incorporate assumptions about the interest of new potential customers, and the load growth which will ultimately materialize. To serve a large load customer, utilities often require a signed energy service agreement ("ESA") in addition to the terms and conditions of the tariff. A customer which has signed such a contract has "skin in the game" if the contract includes terms that penalize the customer for not using the level of demand that it initially requested. This creates an incentive for the customer not to overstate the service it will need and supports an accurate load forecast by the utility. The ESA serves as a formal milestone in the process of bringing potential load growth to realization. Potential customers which may have requested service but have not signed an ESA do not have the same level of obligations and therefore are not formally committed to ultimately becoming a customer of the utility.

The utility must also acquire the resources and build the infrastructure to serve the new customer. This process is much more complex than adding a new household to the grid, as many elements (such as construction of new distribution facilities, and, potentially, transmission and generation facilities) need to be coordinated to ensure that all the pieces come together. Because of the complexity, there will inevitably be delays and those delays can lead to attrition of initially interested large load customers as part of this process. In instances where new generation resources are needed to serve a new customer, it is important to recognize that getting the generation designed, permitted, financed, and built is a lengthy process and often subject to some delays. The potential data center customer may not have the appetite for facing such delays, especially if they have options at other potential sites (which we discuss further below). In addition, whether an integrated utility can get new utility scale generation built quickly enough to serve the needs of a new customer in the near term could be in doubt given global supply chain issues. Tight supplies

of power generation equipment could become a bottleneck to supplying the potential load from data centers. Industry observers report an average lead time of three years for delivery of large transformers; and in some cases, lead times as long as five years.[2] Siemens and GE Vernova, two industry leaders in turbine manufacturing, are seeing lead times increase for turbine delivery; the lead time for a 200 MW Siemens turbine has increased to three years,[3] and GE Vernova has a company backlog through 2028 for delivery times on orders.[4] Therefore, in addition to having an ESA with the potential customer, until the utility orders necessary equipment it needs to procure, and a notice to proceed ("NTP") on construction of substation or other required facilities is authorized, there is no clear timeline of when the utility can serve the new load. If generation equipment is delayed, then load growth will have to be deferred.[5]

Furthermore, even assuming many data centers are built in the United States (rather than elsewhere in the world), until a new customer signs an ESA or some other contract requiring financial commitment, there is no guarantee that the data center would be built in any given utility's territory versus somewhere else; and developers have an incentive to duplicate interconnection requests, as explained below.

Q. How do data center developers determine where to locate?

A. The design of a data center may be for a specific activity and therefore varies, but at its most basic, data center developers have to take into account certain essential requirements: availability of affordable land, accessibility to fiber capacity (and adequate latency), water for cooling (if the design uses water cooling), and high quality electricity service. There

[2] Seiple, Chris. "Gridlock: The demand dilemma facing the US power industry." *Wood Mackenzie.* October 2024. <https://www.woodmac.com/horizons/gridlock-demand-dilemma-facing-us-power-industry/?__FormGuid=81d8a1b9-fba3-4634-bdc1-67c626a6af21&__FormLanguage=en&__FormSubmissionId=0696f8bf-d3df-4fde-a7bc-09d3bbce9d7d>

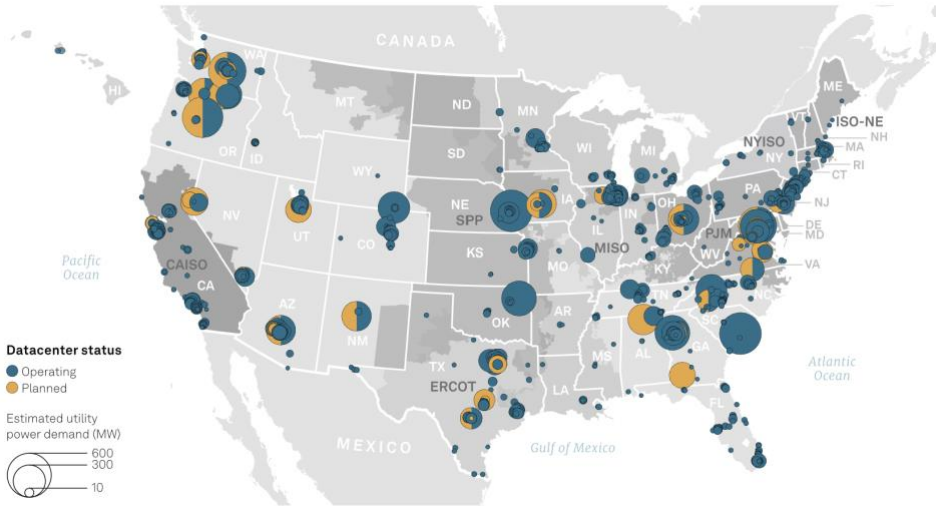
[3] Malik, Maureen S. "Gas Power Won't Provide an Easy Fix for AI Boom." *Bloomberg*. January 8, 2025. <https://www.bloomberg.com/news/newsletters/2025-01-08/gas-power-won-t-provide-an-easy-fix-for-ai-boom>

[4] Casey, Simon. "GE Vernova CEO Sees Order Backlog Stretching Into 2028." *Bloomberg.* March 11, 2025. <https://www.bloomberg.com/news/articles/2025-03-11/ge-vernova-ceo-sees-order-backlog-stretching-into-2028?utm_source=chatgpt.com&embedded-checkout=true>

[5] GPC noted that it has already contracted the gas turbines necessary for its Plant Yates Units 8-10; this amounts to 1.3 GW of new gas capacity, with Units 8, 9, and 10 set to come online in December 2026, May 2027, and August 2027, respectively. Source: GPSC Docket #56002. GPC. *2025 IRP Main Document*. January 2025. P. 126. https://psc.ga.gov/search/facts-document/?documentId=221233.

are many locations in the United States that meet these criteria and are home to a large and growing data center sector (see Figure 3).

Figure 3. Data centers in the United States as of 2023



Source: Anderson, Jared; Sweeney, Darren; and Canonica, Rocco. "POWER OF AI: Wild predictions of power demand from AI put industry on edge." S&P Global. October 16, 2023. https://www.spglobal.com/commodity-insights/en/news-research/latest-news/electric-power/101623-power-of-ai-wild-predictions-of-power-demand-from-ai-put-industry-on-edge.

Developers also want flexibility to choose between different sites because the centers can be developed quickly compared to the time it takes to develop and build energy generation, transmission and delivery facilities. It typically takes two to three years to design, permit, and build a data center, though some potential customers are looking to build large data centers in as little as six to nine months.[6] In contrast, the time it takes for a utility to plan and construct a power plant and/or expand transmission capacity is usually much longer.

Q. Why do data center developers have an incentive to duplicate requests for electric service?

A. The timing mismatch noted above, coupled with the low barrier to entry in submitting a request for service to a utility (no deposit seems to be required to begin the GPC technical

[6] Ben Levitt. "AI and Energy, the Big Picture." S&P Global December 2024, and Bain and Company. "Utilities Must Reinvent Themselves to Harness the AI-Driven Data Center Boom." <https://www.bain.com/insights/utilities-must-reinvent-themselves-to-harness-the-ai-driven-data-center-boom>

review phase), is a strong incentive for potential data center customers to submit duplicate requests for service across several utility jurisdictions. Industry experts have observed that *"[D]ata center developers consider multiple states as possible locations for data centers, and they query multiple utilities simultaneously for electricity rates and incentives prior to making a final selection."*[7] Parties to a recent FERC docket noted "… *PJM has no way to cross-check whether a data center in, for example, Exelon's service territory has also made the same proposal in Dominion's territory, and both proposals end up in PJM's forecast even though only one will be built. … [I]n a recent presentation at the Pennsylvania Environmental Law Forum, PJM's own Senior Manager of Government Services, Stephen Bennett, stated that data center companies "are pitching the same data centers in different locations*.""[8]

Because of concerns over potential duplication of requests, executives in the US natural gas industry have recently tempered their expectations for growth in gas demand from data center electric power customers. The Vice President of New Ventures for pipeline company Williams noted at an industry event: *"… if you look at how these [data center] projects are coming into different organizations, there is double and triple [counting] … it is the same project because you have different players that are developing pieces*." [9] "*It's creating a lot of problems for these regulators and utilities because how do you differentiate between a real project and a fake project?*" said the president of a shale gas producer at the same event, remarking that he expects that only 10% of data center projects that have been announced will be built.[10]

[7] Koomey, Jonathan (Koomey Analytics), Schmidt, Zachary (Koomey Analytics), and Das, Tania (Bipartisan Policy Center). Electricity Demand Growth and Data Centers: A Guide for the Perplexed. February 2025. P. 10. </https://bipartisanpolicy.org/download/?file=/wp-content/uploads/2025/02/BPC-Report-Electricity-Demand-Growth-and-Data-Centers-A-Guide-for-the-Perplexed.pdf>

[8] FERC Docket No. EL25-49-000. Public Interest Organizations. *Comments of Public Interest Organizations in response to PJM Interconnection, L.L.C.'s 03/24/2025 Answer to FERC's 02/20/2025 Order under EL25-49.* April 23, 2025. P. 17. https://elibrary.ferc.gov/eLibrary/filedownload?fileid=9D23F7BC-5484-CAA9-9030-96645FF00000.

[9] Energy Intelligence. "US Gas Companies Temper Data Center Demand Expectations." *Natural Gas Week*, Vol. 41, No. 11. March 14, 2025. https://www.energyintel.com/00000195-9503-d464-a7b7-d7bff5ce0000.

[10] *Id.*

In addition to the uncertainty around counting new projects, a recent industry report indicates that a slowdown in data center growth may be on the horizon. Microsoft is walking away from preliminary agreements for projects in which it planned to lease space developed by a third party and has put some of its self-build projects on hold globally; *"[n]umerous multi-hundred-MW Microsoft campuses have shown underwhelming progress, despite our research indicating that these projects have secured energy and all necessary approvals."*[11]

GPC'S OUTLOOK LIKELY OVERESTIMATES FUTURE LOAD FROM DATA CENTERS

Q. How does GPC project new large load?

A. In a reporting process separate from its IRP, GPC tracks requests for interconnection (referred to as "announcements") by large load customers and classifies them as to the type of customer and stage of development.[12] This tracking is reported in the quarterly *Large Load Economic Development Report* referred to earlier. The three stages of development are, from earliest to latest: "technical review," "request for electric service," and "contract for electric service."

GPC stated that it relied on its June 2024 (Q2 2024) *Large Load Economic Development Report* in its IRP load forecast.[13] A few projects are in the stages referred to as "request for electric service" or "contract for electric service" with GPC. However far more projects - those in the "technical review" phase - have no contract, have not selected GPC as their utility service provider yet, or have not even selected Georgia as the construction location (see Figure 4). The vast majority of announcements in terms of MW (83% as of Q2 2024) were from data centers.[14]

[11] Patel, Dylan; Jeremie Eliahou Ontiveros; Maya Barkin. "Microsoft's Datacenter Freeze - 1.5GW Self-Build Slowdown & Lease Cancellation Misconceptions." *SemiAnalysis*. April 28, 2025. https://semianalysis.com/2025/04/28/microsofts-datacenter-freeze/.

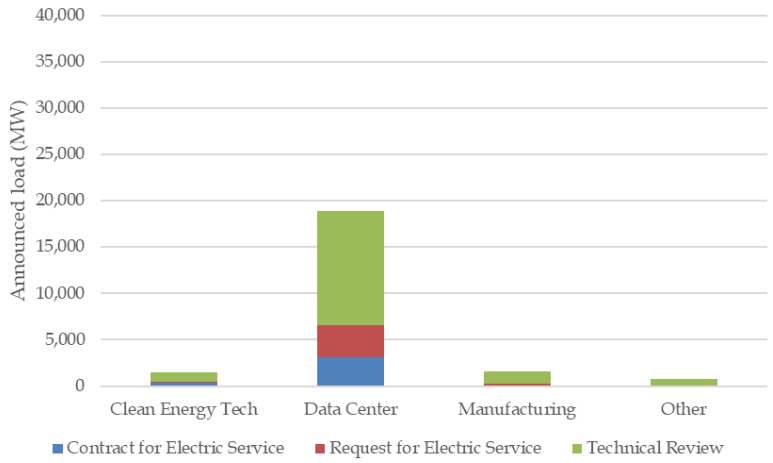
[12] GPSC Docket #55378. GPC. *Large Load Economic Development Report* (various dates). https://psc.ga.gov/search/facts-document/?documentId=219697

[13] GPSC Docket #56002. GPC. *2025 IRP Main Document.* January 2025. P. 36. https://psc.ga.gov/search/facts-document/?documentId=221233.

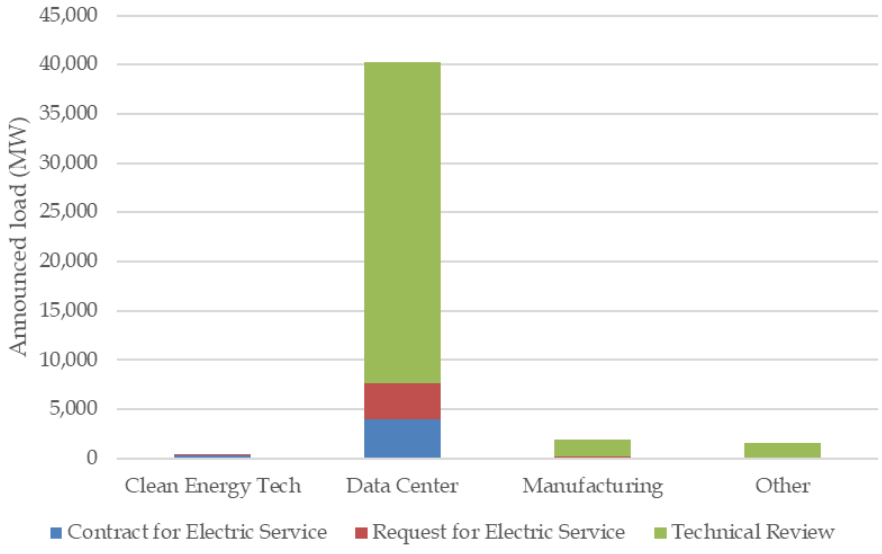
[14] GPC relied on its Q2 2024 report for the purposes of projecting large load for its 2025 IRP. LEI examines more recent quarterly reports later in this section.

Figure 4. GPC large load project announcements

As of June 30, 2024



As of December 30, 2024



Source: GPSC Docket #55378. GPC. *Q2 2024 Large Load Economic Development Report.* August 2024. https://psc.ga.gov/search/facts-document/?documentId=219697 and GPC. Q4 2024 *Large Load Economic Development Report*. February 2025. https://psc.ga.gov/search/facts-document/?documentId=221545.

Note: Though GPC has filed more recent *Large Load Economic Development Reports*, the Q2 2024 report was the one that was available to GPC and relied on by GPC at the time of its 2025 IRP filing, so LEI refers to it in our analysis.

GPC included all large load projects, including those in technical review, in its Load Realization Model ("LRM"), and applied a probabilistic (i.e., statistical) analysis to project future large load. GPC said that it assigned a lower probability to projects in the technical review stage, but it did not disclose what those probabilities were.[15] Georgia Rule 515-3-4-.03(3)(d) dictates that "*[w]here statistical or econometric methods are used in developing forecast inputs or in the forecasting process, analyses of the reasonableness of such methods and models shall be presented, including computer outputs with parameter estimates.*"[16] GPC provided the probabilities that it assigned to some characteristics of large customers (such as [redacted] load but did not provide information as to resulting probabilities for the classification of load (e.g., whether it is a contracted project, versus those with requests for service, versus those in the technical review stage).

GPC then used the results of its probabilistic analysis in a Monte Carlo simulation producing 100,000 load forecasts, which GPC ranked from lowest to highest in terms of projected load. GPC selected the 50th percentile forecast of large load to add to its overall load forecast (see Figure 5).[17]

[15] GPC response to DR STF-JKA-1-2a.
[16] GA R&R 515-3-4-.03(3)(d).
[17] [TRADE SECRET] GPSC Docket #56002. GPC. *2025 IRP, Technical Appendix Volume 1: B2025 Load and Energy Forecast.* January 2025. P. 107. https://psc.ga.gov/search/facts-document/?documentId=221233 [TRADE SECRET].

Figure 5. [TRADE SECRET] GPC's P50 outlook for large load (data centers and other segments)

Q. What adjustments did LEI make to GPC's large load forecast, and why?

A. GPC's large load announcements are dominated by data center projects (the second stacked bar from left in Figure 4 shown previously) that are not committed to GPC, because most data center projects are in the "technical review" phase (as shown by the relative size of the green portion of the bars in Figure 4). In the six months since GPC's Q2 2024 report, data center projects in the "contract for electric service" category with target on-line dates through 2028 increased by only 0.6 GW; and "requests for service" for data centers with target on-line dates through 2028 declined by 0.2 GW (see Figure 6). Only if **all** the 2.56 gigawatts ("GW") of contracted and **all** the 1.60 GW of requested load materializes (and on time) for a total of 4.16 of new data center load would there be a need for 4.37 GW of additional service to large loads by 2028. GPC is projecting [redacted] which implies more than just all contracted and all the requested load would have to materialize.

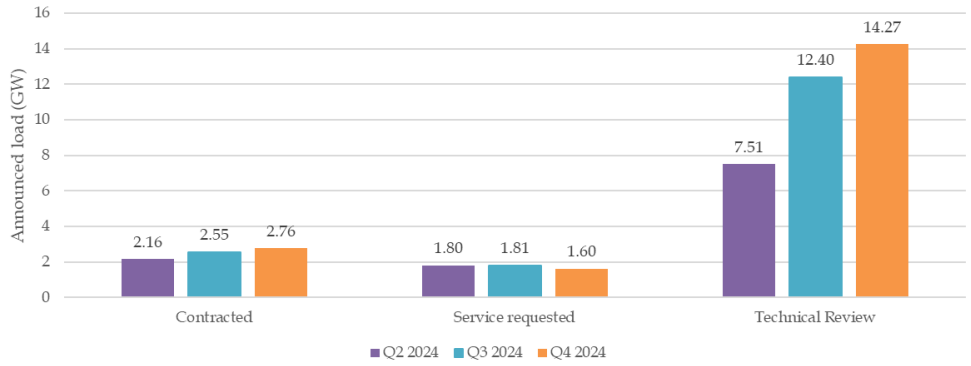
Given that requests for service ultimately either become contracted customers or drop out, this analysis also indicates that the 3-year data center pipeline (projects which have

requested service and intend to be operating by 2028) at 1.6 MW as shown in Figure 6, is not very large relative to projects in technical review. Growth that can materialize in the near term depends on projects which have contracts and have requested service—the projects which are in technical review generally have online dates further into the future. These contracted and requested categories reflect an initial surge of interest by data centers as evidenced by the level of contracted load as of Q2 2024 but the pipeline increased only slowly during 2024, as shown in the comparison of data center service requests for Q2 2024, Q3 2024, and Q4 2024 (see Figure 6).

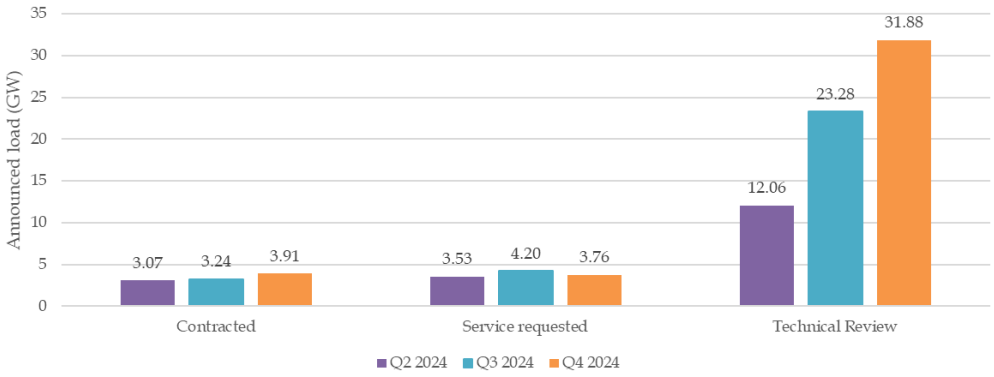
The majority (77%) of announced data center load for 2028 based on the Q4 2024 report is from projects in technical review (see Figure 6). For the longer term (targeted online dates out to 2034) the percentage in technical review is 81%. These online dates are far into the future, so the projects may never materialize given the various uncertainties discussed above.

Figure 6. GPC's data center announcements and status of projects

Target online through 2028



Target on line through 2034



Sources: GPSC Docket #55378. GPC. *Q2 2024 Large Load Economic Development Report.* August 2024. https://psc.ga.gov/search/facts-document/?documentId=219697; GPSC Docket #55378. GPC. *Q3 2024 Large Load Economic Development Report.* November 2024. https://psc.ga.gov/search/facts-document/?documentId=220461; GPSC Docket #55378. GPC. *Q4 2024 Large Load Economic Development Report.* February 2025. https://psc.ga.gov/search/facts-document/?documentId=221545.

Q. Do the *Large Load Development* reports show reductions in previously identified loads for proposed data centers?

A. Yes. In the most recent reporting quarter (Q4 2024), GPC's data center announcements lost about half the new capacity that they gained (see Figure 7). New uncontracted projects with projected in-service dates through 2028 amounted to 5,177 MW. During the same quarter, 1,698 MW targeting service by 2028 were removed owing to project cancellations or the

developer choosing a location outside of GPC's territory.[18] In addition, planned capacity for existing data center projects was reduced by 957 MW.[19] These changes in aggregate amounted to a 51% attrition for the quarter, for data center projects targeted to be in service by 2028 as seen in the figure below.

Figure 7. GPC data center Q4 2024 activity (projects with target in-service dates through 2028)

New projects added (MW)	5,177
Projects removed (MW)	(1,698)
Changes to planned capacity (MW)	(957)
Percent attrition	51%

Source: GPSC Docket #55378. GPC. *Large Load Economic Development Report for Q4 2024*. February 2025. File: "PD Lg Ld Econ Dev Report Q4 2024 – Attachment." <https://psc.ga.gov/search/facts-document/?documentId=221545>

This systematic review of GPC's large load pipeline from Q2 2024 through Q4 2024 indicates that growth through 2028 and perhaps beyond may be slower than GPC had projected at the time of its IRP because the projects with the status "service requested " for operations by 2028 are such as small share of announced projects.

GPC has provided evidence of a near-term weakness in its outlook for large load demand. GPC compared the P50 outlook it relied upon for the large load forecast in the 2025 IRP with the P50 outlook that would result from applying the same methodology to its February 2025 large load data.[20] HR-1-1 Attachment Trade Secret [redacted]

[18] GPSC Docket #55378. GPC. *Q4 2024 Large Load Economic Development Report*. February 2025. File: "PD Lg Ld Econ Dev Report Q4 2024 – Attachment." <https://psc.ga.gov/search/facts-document/?documentId=221545>.
[19] *Id.*
[20] GPSC Docket # 56002. GPC. HR-1-1 Attachment Trade Secret.

LEI'S DETAILED REVIEW INDICATES ADJUSTMENTS ARE CALLED FOR

Q. Based on this analysis, what does LEI recommend?

A. Because of the inherent uncertainty about data center load growth for any given utility, and because GPC's project announcements reflect a potential near-term slowdown in project commitment, LEI recommends that an additional demand forecast be considered which reflects the real-world realized levels of attrition of GPC's data center load.

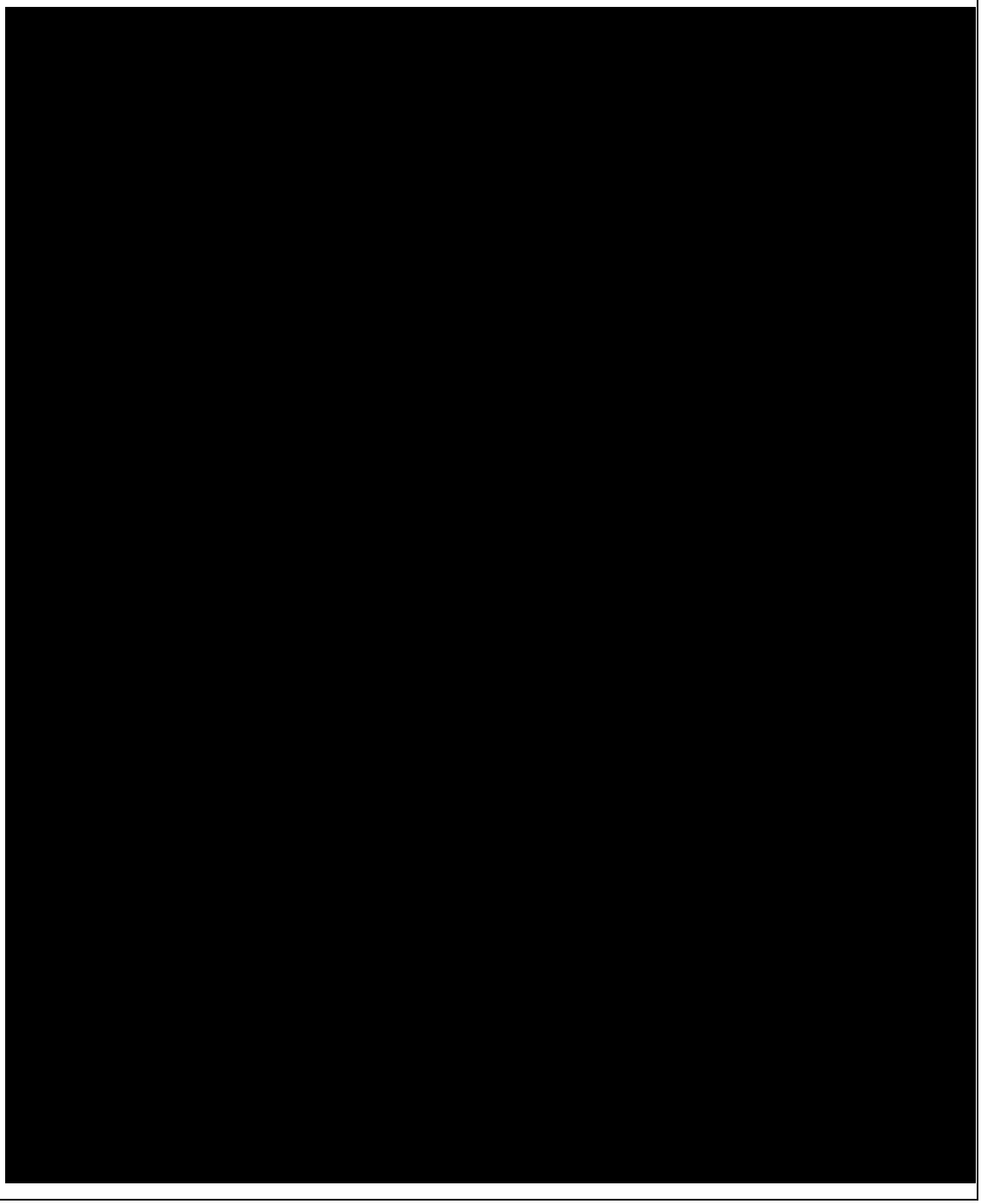
To reflect this attrition, LEI developed an alternative forecast method that assumed that incremental new data center load for 2025-2027 would reflect an attrition rate of 25%, and incremental new load for 2028 – 2044 would reflect an attrition rate of 37% (about halfway between 25% and 51%).[21] LEI assumed more attrition in the longer term because timing becomes more challenging: data centers want fast service, but it takes time to build the resources, and the data center could in the meantime choose another jurisdiction. LEI's assumed attrition rates are lower (in other words, the rates allow more projects to go forward) than the attrition rate of 51% from the Q4 2024 report shown above, but the 51% included projects which were only in technical review, whereas GPC's near-term outlook probably includes a greater share of projects which have signed ESAs or requested service. LEI applied the 25% and 37% to GPC's P50 total large load projections (not only data centers) and arrived at a forecast of new large load of about 3 GW by 2028, and about 5.5 GW for the longer term (see Figure 8).

[21] Adjusting large load pipelines which include large quantities of data center load based on actual experience is becoming an accepted practice. For example, the Electric Reliability Council of Texas ("ERCOT") reduces the outlooks it receives from its transmission and distribution service providers based on actual experience. Source: ERCOT. *2025 ERCOT System Planning, Long-term Hourly and Peak Demand Energy Forecast*. April 8, 2025.

Figure 8. [TRADE SECRET] GPC P50 large load outlook, and LEI large load outlook

In order to capture the change to GPC's load forecast from this realistic adjustment, the difference between LEI's outlook for large load and GPC's outlook should be subtracted from GPC's total load outlook, to arrive at a total outlook which reflects the attrition evidenced by LEI's detailed review of GPC's large load announcements (see Figure 9).

Figure 9. [TRADE SECRET] GPC P50 total load and LEI adjusted total load



Because of the inherent uncertainty about data center load growth for any given utility, and because GPC's project announcements reflect a potential near-term slowdown in project commitment, LEI recommends GPC should also carefully monitor its *Large Load*

Development reports to ensure its large load projections do not outrun the actual pace of large load demand and result in over-building of system facilities.

III. GPC'S TRANSMISSION ASSUMPTIONS DID NOT CONSIDER LOWER LOAD OUTCOMES OR LONGER PLANNING HORIZONS

Q. What are GA PSC transmission planning requirements?

A. GA PSC Utility Rule 515-3-4-.04, *Identification of Capacity Resources,* requires GPC to submit a comprehensive and detailed bulk transmission plan of the Georgia Integrated Transmission System ("GA ITS") every three years.[22] The GA ITS includes GPC, Georgia Transmission Corporation ("GTC"), the Municipal Electric Authority of Georgia ("MEAG"), and Dalton Utilities ("DU"). The plan must identify transmission investments required to reliably support load and resources across the GA ITS over a ten-year planning horizon.

The Rule also requires GPC to file specific transmission-related documentation with the GA PSC. GPC met these filing requirements in its 2025 IRP (see Figure 10). Most transmission-related documentation is included in Volume 3 of the IRP's Technical Appendix, which spans 979 pages. Given the volume of transmission-related documentation provided by GPC, as well as the limited time LEI had for review and to prepare testimony, LEI relied primarily on Chapter 11 of GPC's 2025 IRP, which focuses on transmission planning, as well as the GA ITS Ten-Year Plan (2025-2034), which is included in GPC's 2025 IRP Technical Appendix, Volume 3(A). LEI is not an engineering firm, so LEI reviewed these materials from an economic perspective.

[22] GPSC Docket #25981-U*, Order Adopting Rule: Georgia Public Service Commission Rulemaking Regarding Revisions of Commission Utility Rule 515-3-4-.04 "Identification of Capacity Resources".* December 4, 2007.

Figure 10. Transmission planning documents required in GPC's 2025 IRP

GA PSC required documentation	GPC's 2025 filing
Executive summary with an overview of the plan, results, conclusions, and recommendations	• 2025 IRP • Volume 3(D) Georgia ITS
Processes, procedures, guidelines, and applicable planning standards used in the development of the plan	• Volume 3(A) Transmission Planning Description and Process • Volume 3(B) Planning Guidelines
Review and analysis of any major outage events in the prior three years	• Volume 3(C) System Operations
Ten-year plan for the transmission network	• Volume 3(D) Georgia ITS • Volume 3(E) Interface and Interconnections • Volume 3(F) GPC Distribution Substation Projects & Forecast (Five-Year Loading Plan) • Volume 3(G) Budgeting
Appendix with load flow program data files	• Volume 3(H) Appendix
Preferred sites for interconnection of new generation	• Volume 3(E) Interface and Interconnections

Source: GPSC Docket #25981-U. *Order Adopting Rule: Georgia Public Service Commission Rulemaking Regarding Revisions of Commission Utility Rule 515-3-4-.04 "Identification of Capacity Resources".* December 4, 2007.

HIGHLIGHTS OF GPC'S TEN-YEAR PLAN

Q. What does GPC's transmission planning process entail?

A. GPC's most recent GA ITS Ten-Year Plan, published in Fall 2024, outlines planned transmission investments to reliably meet generation and load growth forecasts for GPC, GTC, MEAG, and DU. Specifically, GPC's transmission planning model identifies transmission constraints over the next ten years and evaluates alternative solutions (projects) to address those constraints. As discussed in more detail below, GPC's 2024 GA ITS Ten-Year Plan incorporates load from 24 large load customers, five of whom require transmission upgrades. This implies that the remaining 19 large load customers might be sited such that they don't trigger a need for transmission upgrades, although GPC does not say this explicitly.

Evaluation of transmission solutions and non-transmission alternatives is conducted using a cost/benefit analysis framework, which considers economic factors and engineering

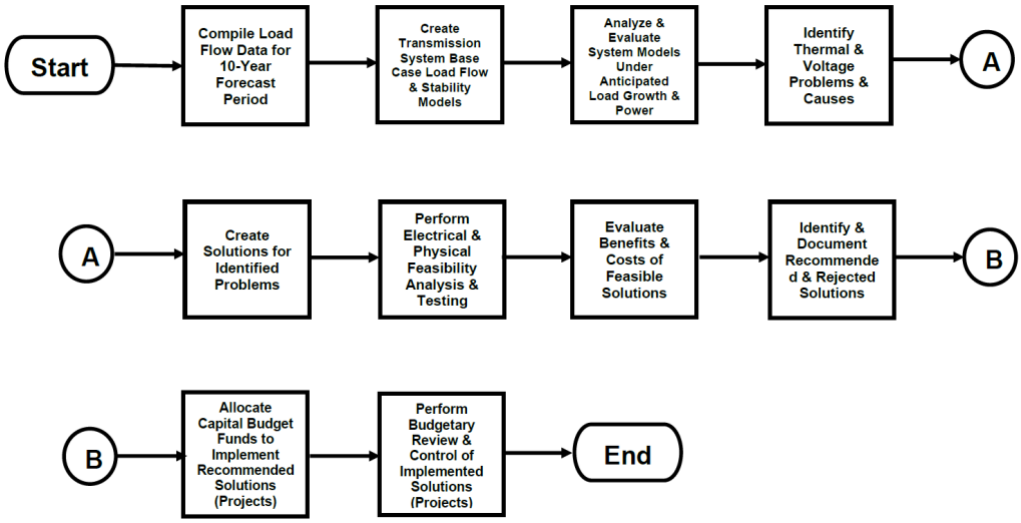
benefits. According to GPC, the benefits considered include: (1) the extent to which the alternative restores the transmission system to an acceptable operational level; (2) whether the alternative addresses other problems (not specified in detail by GPC); (3) improvement in reliability levels in terms of loss of load and system security; (4) degree of flexibility with regard to future development; (5) ease and simplicity of operation; (6) improvement in system stability; (7) increase in interchange capability; (8) ease of protection (not measurable, per GPC); and (9) environmental factors (not measurable, per GPC).[23]

Although the plan identifies projects over a ten-year planning horizon, more in-depth transmission project proposals are only developed for the first five years; projects in the latter five years of the planning horizon are not fully scoped or budgeted due to higher uncertainty.[24] Planned transmission projects are then reassessed every year until they transition from a planned project to a committed project, confirming details such as continued need, timing, and scope. In LEI's view, this approach of only committing projects closer to the time of need provides GPC with the benefits of flexibility and optionality to defer transmission investments as needed.

An overview of key steps in GPC's transmission planning process is illustrated in Figure 11 below.

[23] GPC. *2025 IRP, Technical Appendix, Volume 3(A): Transmission Planning Description & Process.* P. 22-26.
[24] *Id.* P. 15.

Figure 11. GPC transmission planning process flow chart



Source: GPC. *2025 IRP, Technical Appendix, Volume 3(A): Transmission Planning Description & Process.* P. 36.

Q. What is GPC's assumed transmission build-out in the 2024 GA ITS Ten-Year Plan (2025-2034)?

A. GPC's 2024 GA ITS Ten-Year Plan identifies 214 transmission projects over the 2025-2034 planning horizon (see Figure 12). These projects include 59 new transmission lines, 111 transmission lines requiring rebuilding or reconductoring, 1 transmission line requiring upgrading, as well as installation of 31 transformers, 5 capacitor banks, 6 series reactors, and 1 Static Var Compensator ("SVC") system. Estimated costs for these projects identified over the 2025-2034 planning horizon total $10.99 billion for the GA ITS, $6.78 billion of which is attributable to GPC (or 62% of the total).

Figure 12. GPC planned transmission projects, 2025-2034

Project type	Number of projects for 2025-2029 (first 5 years)	Number of projects for 2025-2034 (full 10 years)
New transmission lines requiring new right of way	38	59
Transmission lines to be rebuilt/reconductored	81	111
Transmission lines to be upgraded	1	1
Transformers to be installed	16	31
Capacitor banks to be installed	2	5
Series reactors to be installed	2	6
SVC systems to be installed	1	1
Total	**141**	**214**

Source: GPC. *2025 IRP, Technical Appendix, Volume 3(D1): Georgia ITS Ten Year Transmission Expansion Plan (2025-2034).* P. 5-6.

Notably, 90 of these 214 planned transmission projects (or 42%) incorporate advanced transmission technologies ("ATTs"). Of these 90 ATT projects, 87 leverage advanced conductors (a wires-based solution), whereas the remaining 3 leverage static synchronous compensators ("STATCOM") and power flow controllers.[25]

GPC'S TEN-YEAR PLAN DOES NOT CONSIDER POTENTIAL FOR LOWER LOAD OR LONGER PLANNING HORIZONS

Q. Does LEI take issue with any aspect of GPC's transmission planning approach?

A. LEI takes issue with two aspects of GPC's 2024 GA ITS Ten-Year Plan: a lack of consideration of lower load forecasts, as well as use of the use of 10-year horizon for assessing the benefits, which likely results in lower benefits than if a 20-year horizon had been used. We discuss each of these issues in turn below.

Lack of consideration of lower load forecasts:

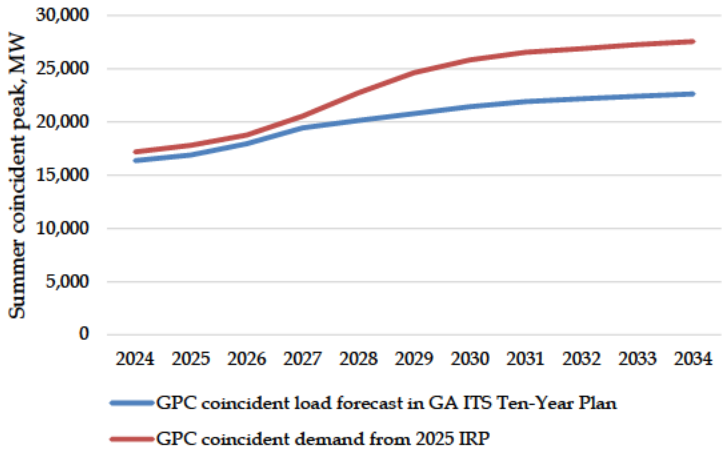
GPC's 2024 GA ITS Ten-Year Plan is predicated on a load forecast that is slightly lower that the near-term load forecast included in GPC's 2025 IRP (in the first four years of the forecast period), which LEI has critiqued above (see Figure 13). Furthermore, GPC's 2024 GA ITS Ten-Year Plan incorporates load from 24 large load customers, five of whom

[25] GPC response to DR STF-GS-1-8.

require [redacted]

[redacted] GPC does not specify in public information how many of these 24 customers have signed ESAs. GPC's public filings also did not specify what accounts for the difference between the load forecast used in the 2025 IRP and the load forecast used in the GA ITS Ten-Year Plan.

Figure 13. GPC load forecast underlying 2024 GA ITS Ten-Year Plan versus 2025 IRP



Sources: GPC. *2025 IRP, Technical Appendix, Volume 3(D1): Georgia ITS Ten Year Transmission Expansion Plan (2025-2034).* Table 5; GPC. *2025 IRP, Technical Appendix, Volume 1: Budget 2025 Load and Energy Forecast 2025 to 2044.* Attachment 6.0-1.

LEI's concerns with GPC's load forecast have been outlined above. These concerns carry over to GPC's 2024 GA ITS Ten-Year Plan, given that the level of transmission investments identified depends on the underlying load growth assumptions. 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.

[26] GPC response to DR STF-PIA-5-17.

Relatively short-term planning horizon:

GPC's 2024 GA ITS Ten-Year Plan considers only a ten-year planning horizon. However, recent rulings emphasize the importance of considering longer-term (20-year) planning horizons (as well as explicitly acknowledging uncertain future trends in demand which we have already critiqued above). For example, the Federal Energy Regulatory Commission ("FERC") issued Order No. 1920 in May 2024, setting out regional transmission planning requirements to "improve long-term assessments of transmission needs and adequately prepare for the future of the electric grid" through a "sufficiently long-term, forward-looking, and comprehensive approach."[27] Specifically, under FERC Order No. 1920, transmission providers are required to consider 20-year transmission planning horizons and assess at least three scenarios and subsequent sensitivities to serve as "stress tests" when conducting regional transmission planning. These sensitivities should consider "uncertain operational outcomes", such as outages due to extreme weather events, cyberattacks, significant forecast error, or fuel price volatility. Then, the selection of proposed transmission facilities should be based on benefits, including the extent to which each project can mitigate these "unexpected system conditions."

GPC itself acknowledges the importance of considering longer planning horizons, and has indicated that it plans to move to a 20-year planning horizon for the purposes of Southeast Regional Transmission Planning ("SERTP") on or before June 12, 2026.[28] GPC stated: *"Across the utility industry, it is becoming more common to extend the transmission planning horizon, with FERC Order No. 1920 driving the industry towards longer planning horizons in regional planning processes. While these FERC requirements and some industry activity may push the boundaries on what future assumptions are reasonable for planning, strategic planning beyond ten years will be an important part of the Company's planning process going forward. The Company's longer-term planning horizon will ensure projects are identified with sufficient lead time to provide timely construction and optionality while balancing the appropriate local customer value with regional*

[27] FERC. *Explainer on the Transmission Planning and Cost Allocation Final Rule.* September 25, 2024.
[28] GPC response to DR STF-GS-1-1.

considerations."[29] LEI agrees – adoption of a longer-term planning horizon enables more proactive investments that are better equipped to respond to the evolving nature of the grid. LEI suggests that GPC adopt a 20-year transmission planning horizon in time for its next IRP filing in 2028.

IV. GPC'S NATURAL GAS PRICE FORECASTS IGNORE VOLATILITY

Q. What was GPC's process for developing its gas fuel price outlook?

A. GPC's 2025 IRP relied on a range of natural gas price scenarios derived from a combination of natural gas forwards and the US Energy Information Administration's ("EIA") 2023 Annual Energy Outlook ("AEO").[30] GPC relied on three AEO scenarios for natural gas price projections starting in 2029:

- **Lower Price Case:** Based on AEO's High Oil and Gas Supply scenario, this case assumes higher recoverable gas resources and improved technology, translating into cheaper gas development costs and lower long-run prices for natural gas.

- **Moderate (Reference Case):** Based on AEO's Reference Case, this case reflects mid-range assumptions for supply and demand drivers (including recoverable gas resources and production technology) (see Figure 14). This serves as the primary or "base" gas price forecast in GPC's IRP.

- **Higher Price Case:** Based on AEO's Low Oil and Gas Supply scenario, this case assumes constrained supply (lower resource recovery and slower technology gains), resulting in higher natural gas prices over time. This reflects a future where it is more expensive to developing gas, pushing prices upward.

[29] GPC. *2025 IRP Main Document.* January 2025. P. 114.
[30] EIA did not produce a 2024 AEO, so the 2023 AEO was EIA's current view during 2024. https://www.eia.gov/outlooks/aeo/.

Figure 14. Key natural gas assumption for EIA's AEO 2023 Reference Case

Driver	Key Values for AEO 2023 Reference Case
Resource Size	• 445.3 Tcf in proved shale reserves (20.1 Tcf decrease from AEO 2022) • 2,973 Tcf in total technically recoverable (TTR) U.S. dry natural gas resources (1.6% growth from AEO 2022 to AEO 2023)
Technological Improvement	• Drilling costs fall by 1%/yr • Equipment costs fall by 0.5%/yr • Well productivity increase up to 4%/ yr

Source: AEO 2023.

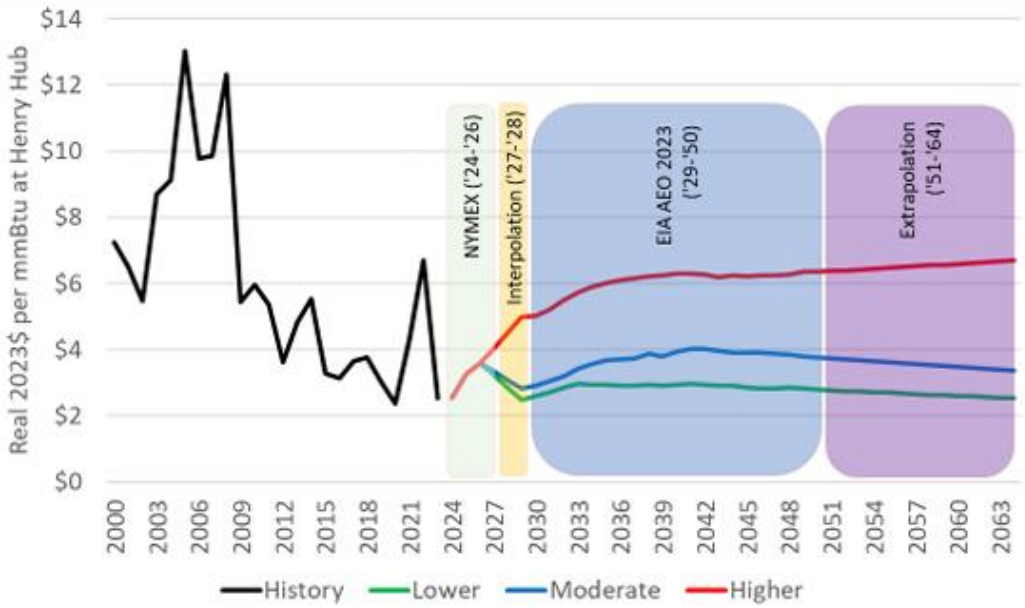
The long-term forecast scenarios from AEO provide annual price projections through 2050 in real dollars; GPC then escalated these prices by GPC's forecast of inflation.[31]

For the near-term forecast years of 2024-2026, GPC used average closing prices on the New York Mercantile Exchange ("NYMEX") for natural gas contracts for future delivery. It relied on a 20-day average (August 5-30, 2024), rather than a single-day outlook. This yields a single near-term price outlook, which GPC applied across all scenarios (no divergence between scenarios). For the transition period of 2027–2028, GPC applied a linear interpolation between the last NYMEX-based price (2026) and the AEO price in 2029 price for each scenario.

All three scenarios started from the same near-term market-based level (reflecting current future prices), then diverged to the different scenarios: the Moderate (Reference) case exhibited a gradual rise followed by a decline starting in 2043, the Lower case stayed relatively flat or declining, and the Higher case climbed more steeply over the long run (see Figure 15).

[31] GPC response to STF-JKA-1-12.

Figure 15. GPC's 2025 IRP Henry Hub price forecast, 2023 dollars



Source: GPC 2025 IRP.

Note: For modeling beyond 2050, GPC extrapolated the trend for another decade (though the IRP's planning focus is a 20-year horizon).

GPC then adjusted nominal annual AEO outlooks for Henry Hub prices to reflect monthly average gas prices, based on monthly percentage assumptions (see Figure 16). These appear to reflect typical seasonal trends in Henry Hub gas prices, though GPC did not explain how it arrived at the shaping percentages.

Figure 16. GPC's monthly shaping assumption [TRADE SECRET]

[redacted]

Finally, GPC added additional costs to arrive at local gas prices and delivered prices for generic gas units in each of Georgia, Alabama, and Mississippi to be used in its model.[32]

Q. Is GPC's gas price forecasting approach reasonable?

A. Overall, the approach was reasonable, but LEI has a few concerns. First, the long-term Henry Hub price outlook was based on stale information. GPC relied on EIA's AEO, which is a widely used, well-documented, publicly available projection developed using the National Energy Modeling System ("NEMS"), which is detailed and transparent. GPC also incorporated three distinct scenarios, which acknowledge the uncertainty of long-term gas prices reflecting technology and the extent of the resource base.

However, the EIA AEO 2023 was out of date at the time GPC was preparing its gas price forecast—EIA did not issue an AEO for 2024 (it took a year-long hiatus to re-tool the NEMS). Therefore, the long-term gas price forecasts do not account for potential impacts from recent supply and demand trends, geopolitical uncertainties, or proposed tariff measures, all of which could introduce additional volatility, and increase or reduce demand. GPC could have contracted for an up-to-date gas price outlook from a specialized energy consultancy such as Wood Mackenzie, or RBAC, but chose not to.

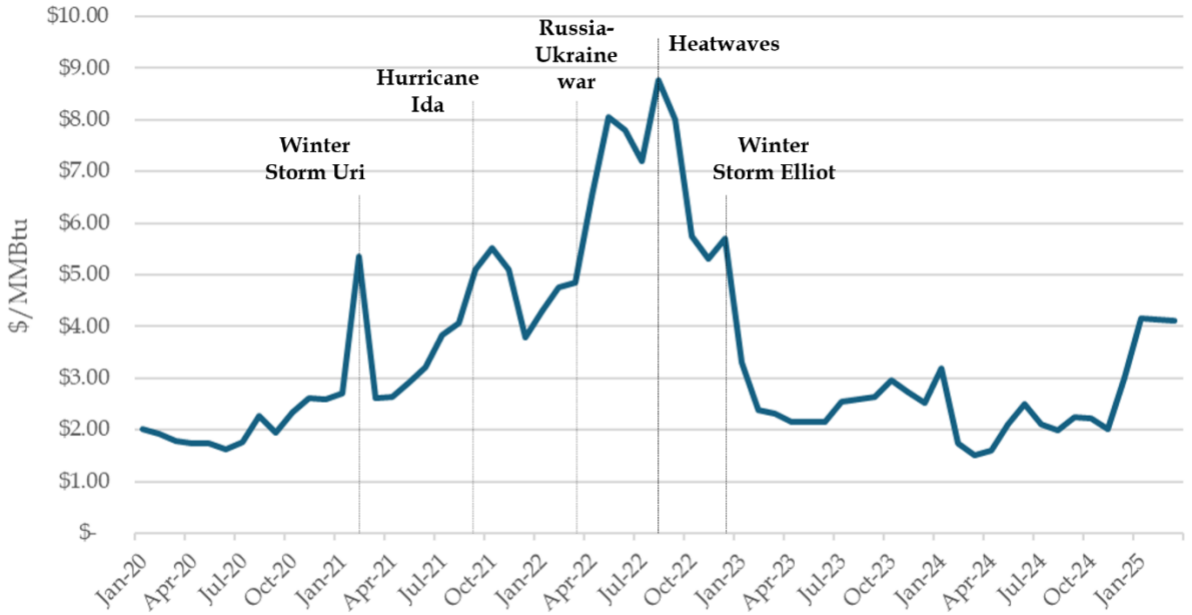
For the near-term portion of its outlook, GPC relied on a 20-day sample of NYMEX Henry Hub future prices, rather than a single-day outlook, which is reasonable.

Q. Are there any issues with GPC's gas price outlooks that could lead to higher-than necessary costs for ratepayers?

A. Yes. Where GPC's gas outlook does not incorporate an analysis that reflects the risk to customers of the impact of gas price volatility. Weather and political events can significantly influence natural gas prices (see Figure 17). Extreme weather (heatwaves or cold spells) can spike demand or disrupt supply, driving prices up dramatically, though briefly. Political events including wars, sanctions, and shifts in energy policy, can disrupt global energy flows and affect gas prices, and for longer periods than weather events.

[32] GPC response to STF-JKA-1-12.

Figure 17. Monthly historical Henry Hub gas prices



Source: EIA

Gas price volatility represents an additional risk to ratepayers which is particular to natural gas fired plants. Changes in natural gas prices directly impact ratepayers, and for GPC customers this cost is passed through the Fuel Cost Recovery mechanism. In the 2023 Fuel Cost Recovery docket, the Commission approved GPC's $2.1 billion in additional fuel expenses from the three prior years.[33]

The risk and potential cost of gas price volatility is not addressed by GPC's IRP, despite the potentially large impact on customers. A utility may use mechanisms to hedge such volatility, but these cannot be evaluated without an estimate of the impact of volatility on ratepayers.

Q. What does LEI recommend?

A. LEI recommends the GPC include an analysis in which it examines the cost to ratepayers of a temporary but substantial surge in gas prices, across its base case and other scenarios.

[33] GPC. "2023 Fuel Cost Recovery." Accessed April 2025. <https://www.georgiapower.com/about/company/filings/fuel-cost html>.

If GPC examines hedging, it would be important to reflect potential drops in price as well as increases, because hedging against a spike in price incurs a cost to settle the hedge if prices fall.

V. GPC'S PROCUREMENT PROCESS COULD BE IMPROVED TO THE BENEFIT OF RATEPAYERS

GPC'S TWO-TRACK SOLICITATION OF GENERATION RESOURCES COULD BE MADE MORE COMPETITIVE

Q. How does GPC procure new generation resources?

A. GPC utilizes two separate solicitations for competitive solicitations to add new resources: i) all-source capacity requests for proposals ("RFPs") to meet general capacity needs, and ii) Clean and Renewable Energy Subscription ("CARES") utility-scale RFPs to supply renewables for the voluntary CARES program. Under the CARES program, customers can sign up for renewable capacity that GPC then acquires through the dedicated CARES RFPs; participating customers pay for a pro-rata share of the production of renewable resources procured and receive the associated renewable energy credits ("RECs").[34]

GPC's 2025 IRP described a series of RFPs and procurement programs, some already underway and others planned, to meet identified capacity needs. Below is an overview of the procurement activities and timeline as described in the IRP:

- **Current active RFPs (approved in prior proceedings):** GPC is currently conducting two major solicitations initiated under the 2022 IRP and 2023 IRP to address capacity needs through the winter of 2030/2031. These are: (1) an All-Source Capacity RFP for 2029–2031, issued on June 20, 2024;[35] and (2) a Winter 2027/2028 battery energy storage system ("BESS") RFP targeting new storage resources, issued on August 9,

[34] Georgia Power. "Clean And Renewable Energy Subscription." Accessed April 2025. <https://www.georgiapower.com/business/products-programs/business-solutions/commercial-solar-solutions/clean-and-renewable-energy-subscription html>.

[35] GPSC Docket #52268. "Georgia Power Company's 2029-2031 All-Source Capacity Request For Proposal ("RFP")." <https://psc.ga.gov/search/facts-docket/?docketId=55268>.

2024.[36] GPC is currently evaluating bids received for both solicitations with oversight from an independent evaluator and GA PSC Staff, and is also assessing whether additional backup options are needed in case these RFPs do not fully meet the capacity requirements.

- **Proposed All-Source RFP in 2025:** The 2025 IRP proposed to issue a new All-Source Capacity RFP in the third quarter of 2025 to address resource needs in 2032 and 2033. The exact MW target for this RFP would be determined closer to issuance, factoring in how much capacity is already secured via the outstanding RFPs and the final approved IRP. The timeline envisioned is: i) GA PSC approval of the RFP plan in mid-2025, ii) issuance of the RFP in Q3 2025, iii) bid submissions and evaluations in late 2025/early 2026, and iv) selection of a shortlist of projects by 2026.

- **Proposed 2025 CARES RFP:** The 2025 IRP proposed to issue a CARES utility-scale RFP in the second quarter of 2025 with a target procurement of 475 MW of renewable resources.

- **Proposed 2026-2027 CARES RFPs:** In addition to the 2025 CARES RFP, the 2025 IRP also seeks approval to issue three subsequent RFPs to secure additional renewable resources, including utility-scale renewable resources and distributed generation ("DG") solar, to supply GPC's voluntary CARES program:

    - For utility-scale projects (typically solar or wind), GPC seeks approval for 1,000 MW of new renewable capacity. This RFP would include the possibility of procuring an additional 3,000 MW beyond the 1,000 MW target if beneficial opportunities exist to supply capacity needs identified by GPC (outside of the CARES program). GPC expects to issue this RFP in the third quarter of 2026, pending GA PSC approval.[37]

    - For DG projects (smaller, localized projects), the 2025 IRP proposed two DG solar RFP rounds, each targeting 50 MW (total 100 MW) to reach commercial operation

[36] GPSC Docket #55763. "Georgia Power Company's Winter 2027 - 2028 BESS RFP." <https://psc.ga.gov/search/facts-docket/?docketId=55763>.
[37] GPC response to STF-JKA-2-6.

in 2027, 2028, and 2029. GPC expects to issue these RFPs in the first quarters of 2026 and 2027, pending GA PSC approval.[38]

Q. What is GPC's process for solicitation and procurement?

A. The 2025 IRP does not provide details on the process and rules for resource procurement. Therefore, LEI reviewed the latest RFPs to examine GPC's procurement process: the 2029–2031 All-Source Capacity RFP (Docket #55268) and the 2023 CARES Utility-Scale RFP (Docket #45084).[39] LEI found that both solicitations followed standard utility procurement practices including alignment with a Commission approved IRP and the oversight of an IE.[40]

As an example of an independent energy regulator's standards, FERC provides four high-level regulatory framework principles as a guideline for Commissions to assess fairness in utility competitive procurement:

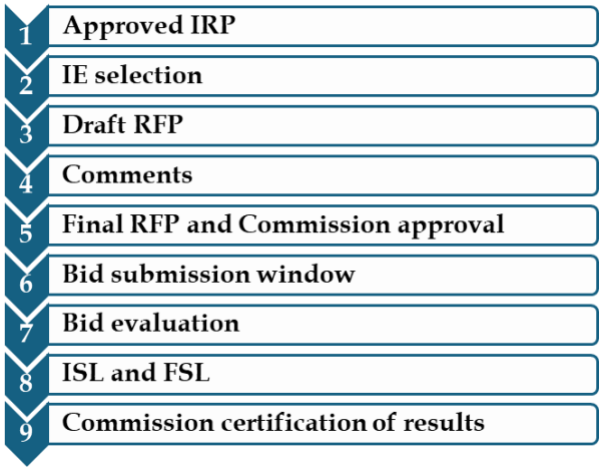
> *"a. Transparency: the competitive solicitation process should be open and fair;*
> *b. Definition: the product or products sought through the competitive solicitation should be precisely defined;*
> *c. Evaluation: evaluation criteria should be standardized and applied equally to all bids and bidders;*
> *d. Oversight: an independent third party should design the solicitation, administer bidding, and evaluate bids prior to the company's selection."* [41]

GPC followed this basic framework and conducted a multi-step RFP process (see Figure 18), which began by defining the needs to be met by the IRP, followed by the selection of

[38] GPC response to STF-JKA-2-7.
[39] GPSC Docket #45084. "Georgia Power Company's CARES 2023 Utility Scale Renewable Request For Proposals." Docket #45084. <https://psc.ga.gov/search/facts-docket/?docketId=45084>
[40] Rules and Regulations of the State of Georgia. Department 515, Chapter 515-3, Subject 515-3-4 Integrated Resource Planning, Rule 515-3-4-.04 Identification of Capacity Resources, Item (3) Request for Proposals Procedure for Long-Term New Supply-Side Options. Accessed April 2025. <https://rules.sos.state.ga.us/gac/515-3-4>
[41] FERC. "Order Granting Authorization to Make Affiliate Sales." Docket No. ER04-730-000, 108 FERC ¶ 61,082. Issued July 29, 2004.

an IE.[42] For both the 2029-2031 All-Source and 2023 CARES RFPs, Accion Group LLC was selected as the IE. The IE acts as a neutral administrator, hosting the RFP website, collecting bids, and overseeing evaluation with GA PSC Staff involvement.

Figure 18. GPC's RFP multi-step process



After the selection of the IE, the RFP process is launched and GPC, the IE, and GA PSC Staff collaborate to draft RFP documents including pro forma contracts for power purchase agreements ("PPAs"), build-transfer agreements ("BTAs"), and asset purchases. GPC hosts a bidders' webinar to explain RFP requirements, including transmission and interconnection guidelines. A public comment period is provided for each RFP's draft documents: stakeholders and potential bidders review the draft, suggest edits (often via a redline comment process on the IE's website), and seek clarifications. After addressing comments, the final RFP is filed for GA PSC approval. Once GA PSC approves it, the RFP is formally issued to the market. The next steps are:

- ***Submitting company and affiliate bids:*** GPC must submit any self-build or affiliate proposals before seeing market bids. This ensures a fair "blind" evaluation of utility proposals against third-party bids.

[42] The utility must engage an IE pursuant to GPSC's RFP process rules. Source: Rules and Regulations of the State of Georgia. Department 515, Chapter 515-3, Subject 515-3-4 Integrated Resource Planning, Rule 515-3-4-.04 Identification of Capacity Resources, Item (3) Request for Proposals Procedure for Long-Term New Supply-Side Options. Accessed April 2025. <https://rules.sos.state.ga.us/gac/515-3-4>

- The All-Source 2029–2031 RFP tentative schedule provided a one-month response time from RFP issuance date (June 20, 2024) and affiliate bid due date (July 18, 2024).

- ***Submitting market bids:*** After company and/or affiliate bids are submitted, the bid window opens to all third-party bidders.
  - Market bids were due one day after the affiliate bids (this timing is not unusual, as other jurisdictions such as Oregon also use a one-day difference). This ensures that there is no bias or information asymmetry, and that market bids are essentially based on the same market information relied upon by affiliates.

- ***Initial evaluation and shortlisting:*** Once the bidding window is closed, GPC's evaluation team – under IE supervision – conducts a two-stage evaluation: an Initial Short List ("ISL") screening, followed by a more detailed Final Short List ("FSL") selection. The bid evaluation process includes the following steps:
  1. **Error cure period:** First, the IE reviews key elements of each bid to screen for errors and omissions and, if necessary, reach out to the bidder. In consultation with Staff and the Evaluation Team, the IE could provide the bidder an opportunity to cure deficiencies. The time allowed to correct errors was not specified, and there is no guarantee that a bidder would be given the opportunity to correct errors.
  2. **Minimum eligibility criteria:** The evaluation first checks compliance and viability, assessing whether bids meet minimum requirements (such as creditworthiness, development feasibility, conforming contract terms) and eliminates non-conforming bids.
  3. **ISL:** Then GPC applies an economic scoring framework to all conforming bids, calculating the total cost to customers and reliability value of each proposal – with active oversight from the IE and GA PSC Staff – for the selection of the ISL. The ISL is the set of top-ranked bids after this preliminary scoring.
  4. **FSL:** The ISL bids then move to a second-stage evaluation, which includes more in-depth analyses including production cost modeling for system impact, transmission studies for deliverability, and credit for dispatchability or firm capacity. GPC's evaluation team refines the scores and the FSL of winning projects

is selected. Once a FSL is selected, GPC must file a certification application for the winning bids for GA PSC approval.

5. **Selection of winners and contracting:** After final GA PSC authorization, GPC proceeds to implement the selected projects with IE oversight.

This process seems to be generally consistent with what LEI has seen used in other jurisdictions. The only question is the extent to which non-pricing terms are renegotiated one-on-one and therefore the final winner is given some accommodation that other bidders did not receive.

In the 2025 IRP, GPC is also seeking approval of the following procurement process enhancements for the upcoming CARES RFPs:

- flexible Commercial Operation Dates ("CODs");
- new processes including the "buy down" option[43] and extended RFP periods with a goal to maximize project selection and procurement;
- expand DG procurements to seek flexible resources that include dispatchable storage and updated locational value assessments (to help determine whether a DG project's location on the distribution system would create reliability challenges or alternatively support reliability); and
- require visibility and control of new renewable resources through integration with GPC's Distributed Energy Resource Management System ("DERMS").

Q. Do any of GPC's solicitation practices inhibit competition?

A. A generic goal of a competitive bidding process is the identification of the lowest cost, lowest risk resource. LEI has extensive experience serving as an IE and procurement monitor across US jurisdictions. Based on LEI's experience, GPC procurement process meets basic practices for electric utility procurement in terms of regulatory compliance with GA PSC's RFP process rules. However, in several areas GPC procurement process

[43] The buy down option proposes extending the RFP process to allow for additional bids to be selected, where bids in the RFP not selected in ISL would be provided an option to buy-down the price of the bid to meet the average Total Net Benefits of the selected portfolio. This process will be designed in compliance with Commission rules to ensure additional bids selected meet the Commission's certification requirements.

practices can inhibit participation by qualified third-party bidders. In a solicitation, the more qualified bidders which are involved, the more competition there is among potential suppliers. In turn, competition is generally expected to put pressure on bidders to bid as low as they can and therefore reduce the price for winning projects and cost for ratepayers. The following areas could use some improvement compared to practices seen in recent new supply RFPs in other US jurisdictions:[44]

- **RFP timeline:** GPC provided only a 30-day period from Commission-approved RFP to bid deadline. This is a tight timeline for preparation of bids, compared to 60-90 days offered in similar competitive solicitations in other jurisdictions.

- **Lack of transparency regarding resource needs and modeling assumptions:** GPC does not clearly state their resource needs in terms of MW and resource types. It also uses a proprietary model for which assumptions are not provided in the RFP. This makes it difficult for bidders to understand how they will be evaluated and how they compete against other resources.

- **Bid security fee is required for all qualified bids:** GPC requires a high bid security payment for all qualifying bids (bids that meet the minimum eligibility criteria) to move to the shortlist phase: "*Any Bidder with a Bid that advances to the Conforming List must post Bid Security by no later than 15 Business Days after Bidder receives notice from GPC. […] The Bid Security amount must equal the product of in the amount of either: (i) 2% multiplied by the sum of the expected revenues during the PPA Term; or (ii) 2% of the purchase price for an APA or BTA Bid.*"[45] This fee is refundable if the bid is released from consideration or after the contract is executed, but it is non-refundable if the bidder withdraws its bid or otherwise fails to execute the pro forma contract after being advanced to the Short List.

[44] The other RFPs reviewed are: (1) Public Service Company of Colorado, an operating company subsidiary of Xcel Energy Inc., 2022 All-Source RFP. Colorado PUC proceeding 21A-0141E; (2) Idaho Power Company's ("IPC") 2028 All-Source RFP. Oregon PUC docket UM 2255.

[45] GPSC Docket #55268. "Georgia Power Company's 2029-2031 All-Source Capacity Request For Proposal ("RFP")." <https://psc.ga.gov/search/facts-docket/?docketId=55268>.

- The non-refundable clause for bids not executing a contract gives GPC leverage during contract negotiation. This is particularly concerning given the short time to review all materials, including pro-forma contracts, before submitting a bid.
- Other jurisdictions (for example Idaho Power 2028 All-Source RFP,[46] and the Xcel Energy 2022 All-Source RFP)[47] do not require a bid security payment before the ISL phase, or even later.

LEI reviewed a recent RFP process in Colorado as an example of a competitive bidding process that yielded what the Colorado utility referred to as an "unprecedented response with 1,073 total proposals (approximately 170 individual projects) received from bidders".[48] Below is a summary of key features of the process.

- **IRP and RFPs approved in the same docket**
  - Commission approved resource needs, planning assumptions, RFP documents, and modeling parameters as part of the IRP; and
  - Utility then conducted a competitive all-source RFP to fulfill approved needs.
- **All-source RFP with a single MW target for procurement**
  - Three RFPs were issued on the same day with three separate bidding instructions and pro-forma contracts tailored to i) dispatchable, ii) renewable, and iii) company owned resources (which applies to the following commercial structures: build-own transfer ("BOT"), existing resource sales, and company self-build (affiliate). The RFP announced that bids from affiliates would be considered. The separate bidding instructions made it easier for the bidders, because they do not have to wade through dozens of pages of instructions that do not apply to their bid. The same timeline

[46] Idaho Power Company's 2028 All-Source RFP, Oregon PUC docket UM 2255.
[47] Public Service Company of Colorado ("PSCo") an operating company subsidiary of Xcel Energy Inc., 2022 All-Source RFP, Colorado PUC proceeding 21A-0141E.
[48] Xcel Energy. Proceeding No. 21A-0141E. Appendix C: Phase II Process Overview 120-Day Report. September 18, 2023. <www.xcelenergy.com/staticfiles/xe-responsive/Company/Rates%20&%20Regulations/Appendix%20C%20-%20Phase%20II%20Process%20Overview.pdf>.

and submission deadlines applied to all the bidders. Ultimately all types of resources competed with one another within the RFP.

- **Timeline and oversight**
  - 90-day bid window, 120-day evaluation, followed by IE and stakeholder review; and
  - the IE monitored every step and filed a 30-day post-bid report.
- **Portfolio-based evaluation**
  - models considered reliability, emissions, and cost using consistent assumptions;
  - final plan selected a least-cost, policy-compliant portfolio; and
  - security fee was required at the contract negotiation phase.
- **Transparency and stakeholder input**
  - all assumptions, bid categories, and scoring criteria were public; and
  - stakeholders could comment on Xcel's 120-Day Report and IE's report before Commission approval.
- **Strong market response**

The bidding demonstrated strong market interest and price discovery.[49]

- over 1,073 proposals, including:
- 900+ renewable or hybrid bids;
- ~90 standalone storage bids; and
- 262 utility ownership proposals.

Xcel Energy reported that this RFP attracted an unprecedented bid volume and record-low prices (see Figure 19).

[49] *Id.*

Figure 19. Xcel 2022 RFP bid price

Table C2 – Solicitation Responses by Generation Technology

Company Ownership RFP Bids

Generation Technology	# of Bids*	Bid MW**	Median Bid Price ($/kW Installed)
Gas	25	10,397	$965
Biomass	1	19	small sample
Solar	66	19,493	$1,635
Solar/Storage	61	28,712	$1,628
Storage	11	2,065	$1,627
Wind	96	36,206	$1,822
Wind/Solar	2	601	small sample

Renewable and Dispatchable RFP Bids

Generation Technology	# of Bids*	Bid MW**	Median Bid Price ($/MWh levelized)	Median Bid Price ($/kW-mo levelized)
Gas	13	3,347	-	$10.65
Other***	3	163	small sample	small sample
Solar	210	55,212	$32.73	-
Solar/Storage	223	110,119	$39.89	$ 9.69
Storage	80	14,833	-	$12.14
Wind	210	84,533	$21.99	-
Wind/Solar	10	15,801	$28.67	-
Wind/Solar/Storage	40	19,703	$38.20	$6.94
Wind/Storage	6	3,156	$19.62	$12.61

* # of Bids reflects number of proposals, the unique projects are less than this value
** Bid MW column provides total MW bid across all proposals, the MWs of unique projects are less than this value
*** Includes biomass and compressed air storage.

Source: *Id.*

Xcel's process had a longer timeline for bidders to respond than GPC allows; it was transparent as to resource needs, and it did not require a bid security fee for qualifying bids, only for contract negotiations. In LEI's opinion, these factors made the process in Xcel's competitive solicitation bidder-friendly, which in turn contributed to large volume of bidders, competition and low prices, which benefit customers. Industry commentary owed the large number of bids and low prices to the fact that it was an all-source procurement, with appropriate Commission involvement, and a transparent process.[50]

[50] Trabish, Herman. *"Xcel's record-low-price procurement highlights benefits of all-source competitive solicitations.*" Utility Dive. June 1, 2021. https://www.utilitydive.com/news/xcels-record-low-price-procurement-highlights-benefits-of-all-source-compe/600240/.

Q. What does LEI recommend for the solicitation process?

A. LEI recommends the Commission make the process more attractive to bidders, thereby increasing competition and reducing costs to ratepayers. This could involve extending the timeline for bids due from 30 days to 60 or 90 days; increasing the transparency of modeling assumptions and resource targets; and delaying the bid security fee until after the ISL or FSL is determined.

CONCLUSIONS AND RECOMMENDATIONS

Q. Please summarize your primary conclusions and recommendations.

A. Our conclusions and recommendations are:

- GPC's outlook for large customer load is an important component of its total load outlook. LEI's careful review of GPC's quarterly large load announcement reports indicates that growth through 2028 and perhaps beyond is likely to be slower than GPC is projecting because GPC is considering not just load with contracts but also load under various stages of development, include those under technical review. Not all these load projects are guaranteed to materialize. LEI recommends considering a baseline scenario which reflects recent experience with attrition in GPC's announcements of potential large load customers. LEI also recommends that GPC continue to monitor attrition in its quarterly *Large Load Economic Development Report* to ensure that its large load forecast does not outrun the actual pace of load growth.

- GPC's projections of transmission needs did not consider the possibility that load growth may be slower than assumed. Testing a lower load forecast sensitivity (which would reflect the substantial uncertainty associated with prospective large load customers) would enable GPC to identify which transmission projects could potentially be deferred. GPC's projections of benefits around proposed transmission investment also did not consider a longer (20-year) planning horizon. LEI recommends consideration of these two issues in transmission planning.

- GPC's forecast of natural gas prices relied upon a long-term Henry Hub forecast which was out of date. It did not recognize the potential impact of volatility on ratepayer costs. LEI recommends developing a case based on historical volatility, to examine the impact on ratepayers across scenarios.
- GPC's process for procuring supply resources could be made more competitive if it incorporated practices used by other utilities. Making the RFP process more bidder-friendly reduces risk and cost to bidders, which can result in more competition and lower prices, to the benefit of ratepayers.

Q. Does this conclude your testimony?

A. Yes.