Eastern Interconnection Planning Collaborative

Transmission Analysis Working Group

Report for 2028 Summer and Winter Roll-Up Integration Cases

Public Version

Approved by the EIPC Executive Committee

August 28, 2019

Executive Summary

This report details the assessments performed by the Eastern Interconnection Planning Collaborative (EIPC) Transmission Analysis Working Group (TAWG) (previously known as the Steady State Modeling and Load-Flow Working group (SSMLFWG)) to produce Eastern Interconnection roll-up integration cases for 2028 summer (2028S) and 2028 winter (2028W). The TAWG includes representatives from each North American Electric Reliability Corporation (NERC)-registered Planning Coordinator (PC) (previously referred to as a "Planning Authority") and a party to the Eastern Interconnection Planning Cooperative Analysis Team Agreement.

The roll-up integration cases represent the base case for the Eastern Interconnection and may be used as a starting point for additional transfer analysis and analysis of scenarios developed with stakeholder input. The cases are integrated models of the individual PC's plans for the Eastern Interconnection as they existed in January 2019, rather than a single coordinated "blueprint" for expanding the Eastern Interconnection. These cases provide solved power-flow modeling suitable as a starting point for interconnection-wide transmission analysis, and they are available to EIPC members and to all stakeholders who are eligible to obtain critical energy infrastructure information (CEII) in accordance with procedures established by the EIPC to perform their own analyses.

This Report has been approved for use by the public. A more detailed Report is available to all stakeholders who are eligible to obtain critical energy infrastructure information (CEII) in accordance with procedures established bythe EIPC.

As with all power-flow models, the 2028S and 2028W roll-up integration cases represent the power system for a particular "snapshot" in time (2028S and 2028W peak hours) based on actual facilities and planning forecasts as they existed to meet Reliability Standards at the time the model was developed. The TAWG used transmission plans provided by each PC as the source of data for model development. These existing transmission plans are a product of each participating PC and the FERC-approved regional transmission planning processes for each of the participating EIPC members (as applicable) and extend through 2028. It should be noted that loads as well as generation and demand-side resources are inputs into the transmission expansion plans that each PC develops, and were provided by the respective load-serving entities (LSEs), market participants, or other applicable entities within each PC's jurisdiction. Because these inputs are continuously changing, the local and regional transmission plans will necessarily also continuously change, making them more up to date than what wide-area modeling can achieve. Nonetheless, wide-area modeling, such as the 2028S and 2028W roll-up integration cases, provides a sound basis for assessing interdependencies between and among regions. Potential constraints and efficiencies identified through interregional analysis are valuable inputs into local and regional processes where they can be assessed for inclusion into future transmission expansion plans.

Interregional Transmission (Gap) Analysis

The TAWG performed two types of analyses. The first type was an interregional transmission "gap" analysis. The objective of this analysis was to identify potential interconnection-wide power-flow interactions that may result from the effects of plans of one Planning Coordinator on another. Once the PCs' plans were rolled up into a single model, first-contingency (N-1) analysis was performed. Potentially overloaded elements were identified for most Planning Coordinators. New York Independent System Operator (NYISO), PJM Interconnection (PJM) and Santee Cooper (SCPSA) identified potential solutions. Section 3.2 and Section 4.1 of the report show the identified potential overloads and solutions, respectively.

MISO reported 19 overloads in 2028S and 14 overloads in 2028W due to N-1 contingencies. PJM reported 1 overload in 2028W in the system-intact analysis. They reported 24 overloads in 2028S and 3 overloads in 2028W due to N-1 contingencies. Additional available information is included in the comments of the detailed appendices.

Southwest Power Pool (SPP) reported 11 overloads in 2028S and 2 overloads in 2028W due to N-1 contingencies. ISO New England reported 1 overloads in 2028S and no overload in 2028W due to N-1 contingencies. New York ISO reported 6 overloads in 2028S and 1 overloads in 2028W due to N-1 contingencies. SERC reported 1 overload in 2028S and in 2028W in the system-intact analysis and 33 overloads in 2028S and 26 overloads in 2028W due to N-1 contingencies. Under N-1 contingencies, FRCC reported 12 overloads in 2028S and 4 overloads in 2028W. Table ES-1 shows these results.

Table ES-1
General Screening Results for 2028 Roll-Up Integration Cases

Planning Coordinator	Overloads with System Intact		Overloads with N-1 Contingencies	
	2028S	2028W	2028S	2028W
MISO	0	0	19	14
PJM	0	1	24	3
SPP	0	0	11	2
ISO NE	0	0	1	0
NYISO	0	0	6	1
SERC	1	1	33	26
FRCC	0	0	12	4

Solutions for these issues included upgrading facility capacities, adding circuits, following operating procedures, and re-dispatching generation.

Linear Transfer Analysis

The second type of analysis was a linear transfer analysis for demonstrating the amount of power that can be reliably moved between regions. The intent of this analysis for the EIPC Planning Coordinators was not to identify constraints for, and in turn to identify projects that would increase transfer capabilities, but rather to illustrate transfer capabilities of the transmission grid as currently planned (based on the 2028S and 2028W roll-up cases) under a number of transfer patterns. Table ES-2 and Table ES-3 show the regions and transfers between the regions for this analysis. (Refer to Section 1 for the full names of the participating Planning Coordinators.)

Table ES-2
Groupings of Planning Areas for Transfers

FRCC	MISO	NPCC	PJM	SERC		SPP
FPL		New York ISO	PJM	Duke Energy Carolinas	SCPSA	SPP
JEA	MISO	ISO New England		Duke Energy Progress	Southern Company	
Duke Energy Florida				LGE/KU	MEAG	
				GTC	Cube Hydro	
				Power South	TVA	
				DESC	Associated Electric	

Table ES-3
Transfers Performed

Source	Sink					
	FRCC	**MISO**	**NPCC**	**PJM**	**SERC**	**SPP**
FRCC					**Y**	
MISO			**Y**	**Y**	**Y**	**Y**
NPCC		**Y**		**Y**		
PJM		**Y**	**Y**		**Y**	
SERC	**Y**	**Y**		**Y**		**Y**
SPP		**Y**			**Y**	

Each test case transferred 5,000 megawatts (MW) between the regions. Table ES-4 and Table ES-5 show the limits identified from this analysis and the regions involved in the limits. In some cases, the 5,000 MW transfer created no issues, indicating that the limit between the regions is greater than 5,000 MW.

Table ES-4
Linear Transfer Results for Summer 2028 Case

Source		Sink		FCITC (MW)	Limited Planning Coordinator (Lim. PC)	Contingent Planning Coordinator (Con. PC)
A	FRCC	E	SERC	150	FRCC	FRCC
B	MISO	C	NPCC	2400	PJM	N/A

B	MISO	D	PJM	>5000	N/A	N/A
B	MISO	E	SERC	>5,000	N/A	N/A
B	MISO	F	SPP	2300	MISO-SPP	SPP
C	NPCC	B	MISO	4300	PJM	PJM
C	NPCC	D	PJM	30[1]	IESO	IESO
D	PJM	B	MISO	>5,000	N/A	N/A
D	PJM	C	NPCC	2100	PJM	NYISO
D	PJM	E	SERC	>5,000	PJM	N/A
E	SERC	A	FRCC	2100	FRCC	FRCC
E	SERC	B	MISO	2600	SERC	SERC
E	SERC	D	PJM	>5000	N/A	N/A
E	SERC	F	SPP	1200	SPP	MISO-SPP
F	SPP	B	MISO	1100	SPP	SPP
F	SPP	E	SERC	>5000	N/A	N/A

[1] Following the linear transfer analysis, IESO suggests that this constraint could be mitigated by an existing RAS.

Table ES-5
Linear Transfer Results for Winter 2028 Case

Source		Sink		FCITC (MW)	Lim. PA	Con. PA
A	FRCC	E	SERC	1200	FRCC	FRCC
B	MISO	C	NPCC	4200	PJM	N/A
B	MISO	D	PJM	>5000	N/A	N/A
B	MISO	E	SERC	>5000	N/A	N/A
B	MISO	F	SPP	>5000	N/A	N/A
C	NPCC	B	MISO	4900	NPCC-MISO	MISO
C	NPCC	D	PJM	>5000	N/A	N/A
D	PJM	B	MISO	>5000	N/A	N/A
D	PJM	C	NPCC	3600	PJM	N/A
D	PJM	E	SERC	>5000	N/A	N/A
E	SERC	A	FRCC	2100	FRCC	FRCC
E	SERC	B	MISO	>5000	N/A	N/A
E	SERC	D	PJM	2600	SERC	PJM
E	SERC	F	SPP	4100	SPP	MISO-SPP
F	SPP	B	MISO	>5000	N/A	N/A
F	SPP	E	SERC	>5000	N/A	N/A

The transfer analysis results verify that the future transmission system as currently planned is capable of transferring more power than the long-term firm commitments modeled in the roll-up cases between the different regions. This report and the appendices contain more details on all transfers. The additional transfer capability ranges from 30 MW to over 5,000 MW.

The planning processes for the EIPC members have many common aspects, but key differences in the processes exist between Planning Coordinators throughout the very large Eastern Interconnection. These differences are expected outcomes given the diversity of regulations, topography, and characteristics of each Planning Coordinator’s electric transmission system. This report describes in detail the data submitted by each of the EIPC Planning Coordinators, explains differences in the Planning Coordinators’ respective planning processes, and assists stakeholders in understanding what the roll up contains.

Eastern Interconnection Planning Collaborative

Contents

Figure

Tables

Acronyms and Abbreviations

2028S	2028 summer case
2028W	2028 winter case
AE	Atlantic Electric zone (PJM)
AECI	Associated Electric Cooperative, Inc.
AEP	American Electric Power zone (PJM)
AMIL	Ameren-Illinois
APS	Allegheny Power zone (PJM)
ATSI	American Transmission Systems, Inc. (PJM)
BA	balancing area
BAA	balancing authority area
BGE	Baltimore Gas and Electric zone (PJM)
CARIS	Congestion Assessment and Resource Integration Study
CEII	critical energy infrastructure information
CELT Report	Forecast Report of Capacity, Energy, Loads, and Transmission
COMED	Commonwealth Edison zone (PJM)
Con. PC	Contingent Planning Coordinator
CPLE	the eastern BA of the Duke Energy Progress system
CPLW	the western BA of the Duke Energy Progress system
CRP	Comprehensive Reliability Plan
CSPP	Comprehensive System Planning Process
CT	combustion turbine
DAYTON	Dayton Power and Light zone (PJM)
DPL	Delmarva Power and Light zone (PJM)
DQE	Duquesne Lighting Company zone (PJM)
DEC	Duke Energy Carolinas
DEF	Duke Energy Florida
DEP	Duke Energy Progress
DESC	Dominion Energy Inc. South Carolina
DNR	designated network resource
DOE	US Department of Energy
DSM	demand-side management
DUKE	Duke Energy (PJM)
DVP	Dominion Virginia Power
EE	energy efficiency
EES-EAI	Entergy–Arkansas, Inc. (MISO)
EES	Entergy
EIPC	Eastern Interconnection Planning Collaborative
EKPC	East Kentucky Power Cooperative (PJM)
EPP	Economic Planning Process
ERAG MMWG	Eastern Reliability Assessment Group, Multiregional Modeling Working Group
ES	Executive Summary
FCITC	first-contingency incremental transfer capability
FERC	Federal Energy Regulatory Commission
FPL	Florida Power and Light Company

FRCC	Florida Reliability Coordinating Council
FSA	Facility Study Agreement
GTC	Georgia Transmission Corporation
HVDC	high voltage direct current
IA	Interconnection Agreement
ICAP	installed capacity
IESO	Independent Electricity System Operator
ISO-NE	Independent System Operator of New England
ITC	International Transmission Company
ITO	Independent Transmission Organization
ITP	Integrated Transmission Plan
JCPL	Jersey Central Power and Light zone (PJM)
JEA	JEA (Jacksonville, FL)
KU	Kentucky Utilities
kV	kilovolt
LG&E	Louisville Gas and Electric Company
LGE/KU	Louisville Gas & Electric and Kentucky Utilities Company
Lim. PC	Limited Planning Coordinator
LM	load management
LSE	load-serving entity
LTE	long-term emergency
LTP	Local Transmission Owner Plan
LTPP	Local Transmission Planning Process
LTWG	Long-Term Working Group
MEAG	Municipal Electric Authority of Georgia
METED	Metropolitan Edison zone (PJM)
MISO	Midcontinent Independent System Operator
MPRP	Maine Power Reliability Project
MTEP	MISO Transmission Expansion Plan
MVA	megavolt-ampere
MVP	multivalue project
MW	megawatt
N-1	first contingency
N-1-1	second contingency; two lines out during a maintenance case study
N-2	second contingency; two lines out in a peak case study
NBSO	New Brunswick System Operator
NERC	North American Electric Reliability Corporation
NEEWS	New England East–West Solution
NEPA	National Environmental Policy Act
NITS	network-integrated transmission service
NPCC	Northeast Power Coordinating Council
NTC	Notification to Construct
NYCA	New York Control Area
NYISO	New York Independent System Operator
NYPSC	New York State Public Service Commission
OKGE	Oklahoma Gas and Electric
OPA	Ontario Power Authority

OPPD	Omaha Public Power District
PC	Planning Coordinator
PAR	phase-angle regulator
PEC	Progress Energy Carolina
PECO	PECO Energy zone (PJM)
PENLC	Pennsylvania Electric zone (PJM)
PEPCO	Potomac Electric Power zone (PJM)
PGDP	Paducah Gaseous Diffusion Plant
PJM	PJM Interconnection, LLC
PL	PPL Electric Utilities (subzone of PLGroup) (PJM)
PPTPP	Public Policy Transmission Planning Process
PS	Public Service Electric and Gas zone (PJM)
PSP	power system planning
PTP	point-to-point
PV	photovoltaic
RECO	Rockland Electric Company (East) zone (PJM)
RNA	Reliability Needs Assessment
ROW	right-of-way
RPP	Reliability Planning Process
RTEP	Regional Transmission Expansion Plan
RTO	Regional Transmission Operator
SCED	security-Constrained economic dispatch
SCPSA	Santee Cooper
SEC	Seminole Electric Cooperative, Inc.
SEMA	southeastern Massachusetts
SERC	SERC Reliability Corporation
SIA	System Impact Assessment
SPP	Southwest Power Pool
SPS	special protection system
TAWG	Transmission Analsysi Working Group
TDF	Transfer Distribution Factor
TOTS	transmission owners' transmission solution
TVA	Tennessee Valley Authority
TYSP	Ten-Year Site Plan
UGI	UGI Utilities (subzone of PLGroup) (PJM)
VEPCO	Virginia Electric and Power Company (PJM)

Section 1
Introduction

On May 21, 2009, representatives from Planning Coordinators (PCs) in the Eastern Interconnection formed the Eastern Interconnection Planning Collaborative (EIPC). This group agreed to initiate technical work for facilitating the coordination of existing transmission plans and conducting reliability analyses of the combined interconnection system and other studies to support state, provincial, regional, and federal public policy decision making.

The following Planning Coordinators are either members of the EIPC or are providing data and input to the roll-up and integration process:

1. Associated Electric Cooperative, Inc (AECI)
2. Cube Hydro Carolinas
3. Dominion Energy Inc. South Carolina (DESC)
4. Duke Energy Carolinas (DEC)
5. Duke Energy Florida (DEF)
6. Duke Energy Progress (DEP)
7. Florida Power & Light Company, also acting as agent for Gulf Power (FPL)
8. Georgia Transmission Corporation (GTC)
9. ISO New England, Inc. (ISO-NE)
10. JEA (Jacksonville, Florida)
11. Louisville Gas and Electric Company and Kentucky Utilities Company (LGE/KU)
12. Midcontinent Independent Transmission System Operator, Inc. (MISO)
13. Municipal Electric Authority of Georgia (MEAG)
14. New York Independent System Operator, Inc. (NYISO)
15. PJM Interconnection, LLC (PJM)
16. PowerSouth Energy Cooperative
17. Santee Cooper (SCPSA)
18. Southern Company Services Inc. (Southern), as agent for:
    a. Alabama Power Company
    b. Georgia Power Company
    c. Mississippi Power Company
19. Southwest Power Pool (SPP)
20. Tennessee Valley Authority (TVA)

The EIPC complements the regional transmission expansion plans developed each year by its member systems and supports the Federal Energy Regulatory Commission (FERC) Order No. 890 and Order No. 1000 regional planning processes. The EIPC self-funds these efforts on a periodic basis to develop interconnection-wide models, test these models with increased transfers, identify potential gaps that could have an impact on reliability. For the 2018 to 2019 cycle, EIPC modeled two load cycles of a one-year period—2028 summer (2028S) and 2028 winter (2028W). The EIPC continues to provide a transparent and collaborative Eastern Interconnection-wide venue to all interested stakeholders through regional Order 890 and Order 1000 processes.

The purpose of the Transmission Analysis Working Group (TAWG) of the EIPC is as follows:

1. Modify/create steady-state load-flow models
2. Conduct steady-state load-flow analysis (including transfer capability)
3. Report results to stakeholders (subject to applicable Critical Energy Infrastructure Information [CEII] requirements)

Figure 1-1 depicts an overview of the process employed by the EIPC TAWG.

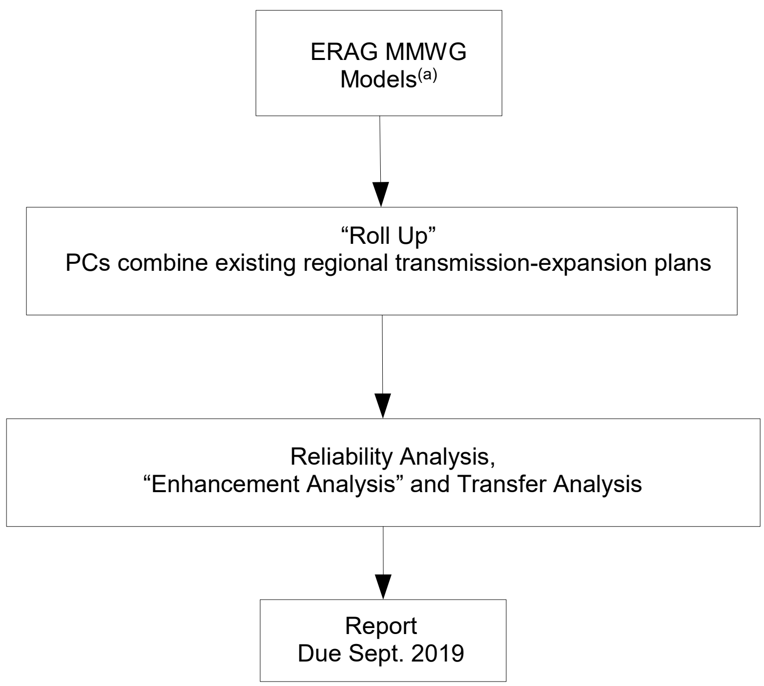

Figure 1-1: EIPC Planning Analysis Process.

(a) "ERAG MMWG" stands for Eastern Reliability Assessment Group, Multiregional Modeling Working Group.

Section 2
Planning Coordinators' Assumptions

This section details the assumptions made by each PC in developing the 2028 summer and winter roll-up integration cases. These include assumptions for load forecasting, the treatment of demand resources and energy efficiency (EE), interchanges with other systems, future transmission and generation project inclusion, and generation dispatch.

In some cases, one or more PC systems may be incorporated into the model roll-up of another PC, without duplication. For example, Georgia Transmission Corporation and MEAG have noted where their information for certain sections are included in Southern Company's responses.

The starting point in creating the 2028 roll-up integration cases included the ERAG MMWG 2018 series cases for the 2028 winter peak and 2028 summer peak. Each PC updated its portion of this model for its respective system in accordance with its regional plan as it existed in January 2019, all of which were then assembled into one complete power-flow model. To assure the accuracy of the database, the TAWG reviewed the case several times before validating it or performing any study work.

2.1 Load Forecasts and Growth Rates

This section describes the load growth rates represented in the roll-up integration case for each EIPC Planning Coordinator through 2028. In addition to the growth rates, the amount of load and origination of the data are discussed. The annual average growth rates are the rates used by each PC in its regional transmission planning processes.

The load forecasts provided by each PC were based on load projections, typically based on the 50/50 load projection where there is a 50% chance the actual load will be higher or lower than the forecast. The load forecasts were not adjusted to provide a coincident peak for the entire Eastern Interconnection. It is appropriate to apply non-coincident peak load forecasts when planning for transmission needs over large regional areas and is in fact the obligation of each NERC-registered PC to plan for the critical system conditions for the area it is responsible for. This approach ensures that the transmission system performance of each PC is reliable, as required by NERC Reliability Standards.

Because the roll-up integration case is based on current transmission plans as of 2019, the vintage of the aggregated load-serving entity (LSE) forecasts is generally late 2018 or early 2019.

Associated Electric Cooperative Inc.

AECI's load forecast uses a biennial calculated load growth value of 0.79% for 2028S and 0.75% for 2028W, resulting in a projected load of 5,195 MW in 2028S and 5,322 MW in 2028W. Load distribution is based on a historic five-year average of non-coincident peak values.

Cube Hydro Carolinas

CHC does not have any retail load, the only load it has is auxiliary load and this load is considered static load with no plans for expansion.

Dominion Energy South Carolina (DESC)

The average annual load growth provided by the LSEs within the DESC planning area is 1.20% for 2028S and 0.80% for 2028W. This load growth results in a projected peak load of 5,976 MW in 2028S and 5,743 MW in 2028W, including load and transmission losses. The load forecasts contained in the 2028 roll-up cases were developed in 2018 and are based on 2018 assumptions, data, and information. The LSEs within the DESC planning area use historical normal weather patterns and various econometric models in determining peak demand forecasts. Each individual LSE develops a forecast that accounts for the individual peak demand forecast. These individual forecasts are then summed to aggregate them into an DESC non-coincident forecast.

Duke Energy Carolinas

The Duke Energy Carolinas (DEC) load forecasting group developed the load forecast in 2017 using data including the forecasts of individual LSEs in the DEC footprint. Duke Energy Carolinas expects an average growth rate of 0.9% through 2028S for a Balancing Authority Area load of approximately 22,715 MW in 2028S and 22,775 MW in 2028W, incorporating the demand from DEC’s wholesale customers coincident with DEC’s peak.

Duke Energy Florida

The Duke Energy Florida (DEF) load forecasting group developed the load forecast in 2014 using data including the forecasts of individual LSEs in the DEF footprint. Duke Energy Florida expects an average growth rate of 1.41% through 2028 for a control area non-coincident peak load of approximately 13,437 MW in 2028S and 14,162 MW in 2028W.

Duke Energy Progress

Duke Energy Progress (DEP) updates its power-flow models on an annual basis. Loads plus losses at the transmission level are scaled to match the system forecast coincident peak load for each load level. Duke Energy Progress expects an average growth rate of 0.9% of its area through 2028 for a balancing area load of approximately 14,962 MW in 2028S and 15,596 MW in 2028W.

Florida Power and Light

The load modeled in the Florida Power and Light (FPL) area in the 2028 roll-up integration case reflects an average annual growth rate of 1.1% for the 2019 to 2028 period. The load assumptions are based on the official FPL 2018 coincident load forecast as filed with the Florida Public Service Commission in the Ten-Year Site Plan (TYSP) document.[2]

[2] Florida Power and Light, Ten-Year Power Plant Site Plan: 2018–2028 (April 2018), https://www.fpl.com/company/pdf/10-year-site-plan.pdf.

Georgia Transmission Corporation

Georgia Transmission Corporation (GTC) prepares a load forecast annually through input from its member cooperatives. The load forecast included in the roll-up case was prepared in 2019, and the average annual growth rate is approximately 1.9% for 2020 to 2028. GTC's forecasted load is included in the Southern Balancing Authority as coincident with other Georgia load.

ISO New England

ISO New England (ISO-NE) expects an average annual growth rate of 0.79% through the summer of 2028 for a control area gross demand of 31,430 MW (accounting for load and losses) based on load forecasts in the ISO-NE 2018 to 2027 Forecast Report of Capacity, Energy, Loads, and Transmission (CELT). With the addition of 5,255 MW of energy efficiency forecast and 1,620 MW of behind the meter solar PV reductions, ISO-NE estimates the control area net demand (including losses) to be 24,555 MW. In the winter of 2028-2029, the ISO-NE control area gross demand (load and losses) is expected to be 24,130 MW. With the addition of 5,255 MW of energy efficiency forecast reduction, ISO-NE estimates the control area net demand (including losses) to be 18,875 MW.

JEA

In early 2019, JEA's Resource Planning Group forecasted the load (both firm and non-firm demands) to increase at an average growth rate of 0.55 percent for summer and 0.75 percent for winter. This includes the non-coincident peak demand for JEA and the expiration of a wholesale power sales agreement beginning in 2018. Accordingly, the forecasted peak demands are 2,649 MW and 2,869 MW for summer 2028 and winter 2028 respectively.

Louisville Gas and Electric Company and Kentucky Utilities

All load-serving entities on the Louisville Gas and Electric Company and Kentucky Utilities (LG&E and KU) transmission system provide load forecasts annually of the network load levels. The Planning Coordinator (PC) forecasted load in the 2028S EIPC roll-up case is 7,271 MW and 7,028 MW in the 2028W EIPC roll-up case.

LG&E and KU's load are based on a 50/50 forecast. The load forecast was submitted by all LSE's per NERC MOD-032 standard in the fall 2017. The LG&E and KU PC load forecast has an average growth rate of approximately 1.5% in the summer and 2.3% in the winter from 2018 through 2028.

Municipal Electric Authority of Georgia Power

A load forecast is prepared annually through input from Municipal Electric Authority of Georgia (MEAG) participants. The load forecast included in the roll-up case was prepared in 2018, and the average annual growth rate is 0.5 % for 2018 to 2028. MEAG's load forecast is included in the Southern Balancing Authority as coincident with other Georgia load.

Midcontinent ISO

For Midcontinent ISO (MISO) members, model load is reflective of LSE forecasts as provided by the transmission owners through the *MISO Transmission Expansion Plan* (MTEP) reliability model building process. For transmission planning purposes, the non-coincident peak loads of the member systems are used in the MTEP models. This approach ensures that the performance of the transmission system is reliable at the member system level, as required by the NERC planning standards.

In 2018, MISO member systems provided power-flow model peak-load projections for the MTEP 2018 vintage model that was the basis of the EIPC roll-up for the MISO system.

The demand projections included in the roll-up integration case for the MISO portion of the EIPC roll-up case are consistent with the MISO section in NERC's *2018 Long-Term Resource Assessment* report.

New York ISO

The New York ISO (NYISO) is forecasting a base 2028 coincident summer and winter peak load for the New York Control Area (NYCA) of approximately 32,469 MW and 23,812 MW, respectively. These values include statewide energy-efficiency programs and represent an average annual growth rate for the summer of -0.13% through 2028, as documented in the NYISO 2018 Load & Capacity Data report.[3]

PJM Interconnection

PJM annually prepares a detailed, independent load forecast for PJM overall and each of its zones and sub-regions. The January 2018 forecast is the basis for the PJM system contained in the EIPC roll-up system. Summer peak load growth for the PJM Regional Transmission Operator (RTO) is projected to average 0.4% over the next 10 years (down from 1.0% in the 2015 EIPC report). The PJM RTO summer non-coincident peak is forecasted to be 157,635 MW in 2028, a 10-year increase of 5,527 MW. Annualized 10-year growth rates for individual PJM zones range from -0.2% to 0.8%. Table 2-1 presents the PJM area-by-area non-coincident peak forecasts. The PJM forecast is based on historical data from January 1998 through August 2017. The models were simulated with weather data from 1994 through 2016, generating 299 scenarios. The economic forecast used was Moody's analytics' September 2017 release.

[3] New York ISO, 2018 Load and Capacity Data (April, 2018).
https://www.nyiso.com/documents/20142/0/2018%20Load%20&%20Capacity%20Data%20(Gold%20Book).pdf/4083d4ea-8647-7330-b0c6-d57a9eedd3d4.

Table 2-1
2018 PJM Area-by-Area Non-Coincident Peak-Load Forecasts for 2018 and 2028 And 10-Year Average Annual Growth Rates (MW, %)

PJM Area	2018 Forecast Non-Coincident Peak Load (MW)	2028 Forecast Non-Coincident Peak Load (MW)	10-year Average Annual Growth Rate
AE	2,460	2,409	-0.2%
AEP	22,876	24,018	0.5%
APS	8,825	9,447	0.7%
ATSI	12,952	13,309	0.3%
BGE	6,848	6,744	-0.2%
COMED	22,121	23,207	0.5%
DAYTON	3,459	3,508	0.1%
DPL	3,937	4,018	0.2%
DQE	2,872	2,924	0.2%
DUKE	5,523	5,860	0.6%
EKPC	1,960	2,033	0.4%
JCPL	5,942	5,943	0.0%
METED	2,974	3,115	0.5%
PECO	8,642	8,979	0.4%
PENLC	2,895	2,922	0.1%
PEPCO	6,493	6,466	0.0%
PL	7,140	7,350	0.3%
PS	9,903	9,876	0.0%
RECO	402	402	0.0%
UGI	190	188	-0.1%
VEPCO	19,596	21,161	0.8%
RTO	152,108	157,635	0.4%

On an interregional basis, regional power flows are rolled up into an Eastern Interconnection model without modification to the regional loads. These power flows are used as starting points for a wide variety of studies and analyses. The entities performing the studies are responsible for any modifications to the power flows or load profiles.

The load forecasts provided by each PC were based on load projections, typically based on the 50/50 load projection where there is a 50% chance the actual load will be higher or lower than the forecast. The load forecasts were not adjusted to provide a coincident peak for the entire Eastern Interconnection. It is appropriate to apply non-coincident peak load forecasts when planning for transmission needs over large regional areas and is in fact the obligation of each NERC-registered PC to plan for the critical system conditions for the area it is responsible for. This approach ensures that the transmission system performance of each PC is reliable, as required by NERC Reliability Standards.

Because the roll-up integration case is based on current transmission plans as of 2019, the vintage of the aggregated load-serving entity (LSE) forecasts is generally late 2018 or early 2019.

PowerSouth Energy Cooperative

PowerSouth receives load data from each of its member-owner distribution cooperatives on an annual basis. The data are then manipulated into a coincident peak number for PowerSouth's area. The load forecasts contained in the 2028 roll ups are based on the approved load forecast completed in 2017. Current projections show that PowerSouth's load will increase 0.79% annually for summer and 0.95% annually for winter for the foreseeable future.

Santee Cooper

Santee Cooper prepared the load forecast used in the EIPC roll-up model in conjunction with Central Electric Power Cooperative, Inc. staff and a consulting firm. The load forecast is for a coincident peak and incorporates updates of the end-use/econometric models developed by the consulting firm on the basis of normal weather assumptions. The forecast uses historical data and a current economic outlook for Santee Cooper's service areas. The load forecast used in the 2028S roll-up case has a peak of 4,884 MW and the 2028W roll-up case peak load of 5,644 MW.

Southern Company

The 10-year load growth provided by the LSEs (non-coincident) within the Southern Balancing Authority averaged 1.01% annually for 2018 through 2028, totaling to a projected load of 48,344 MW in 2028S and 46,159 MW in 2028W.

Southwest Power Pool

SPP depends on load forecasts from its data submitters to apply to the planning models. These load forecast amounts are to be Non-Coincident to the SPP region, meaning that the hour that a Data Submitter's system experiences a peak demand for a particular season, might not be the same hour that SPP, as a region, experiences a peak demand. In order to bring consistency and equivalency to the load forecast data submitted to SPP, load forecast data is based on a 50/50 forecast. The projected non-coincident peak load for SPP was roughly 56,544 MWs in 2028 summer and 45,112 MWs in 2028 winter.

Tennessee Valley Authority

The roll-up integration cases used Tennessee Valley Authority's (TVA's) official February 2018 delivery point load forecast provided by TVA's Enterprise Planning group. This forecast is a coincident system peak forecast assuming normal weather patterns and a medium economic outlook. This load forecast is a 50/50 load projection where the chance that the actual load will be higher or lower than the forecast is 50%. TVA's load forecasts are 32,326 MW for the 2019 summer peak and 32,417 MW for the 2028 summer peak. This reflects a per year load growth of 0.0003% over the next 10 years.

TVA's load forecasts are 32,778 MW for the 2019/20 winter peak and 33,399 MW for the 2028/29 winter peak. This reflects a per year load growth of 0.0021% over the next 10 years.

2.2 Treatment of Energy Efficiency and Demand-Side Resources

This section details the modeling of energy-efficiency programs and demand-side resources in the EIPC roll-up integration case. Because the programs among the jurisdictions differ, the amount and treatment in the power-flow model of energy efficiency or demand-side resources varies within each Planning Coordinator. Some Planning Coordinators consider the effects of energy efficiency and demand-side-resource programs when developing their load forecasts, as discussed in Section 2.1. Other Planning Coordinators use market mechanisms to treat energy efficiency and demand-side resources as energy resources.

While treatment of these programs varies across PCs, it is important to realize that some PCs do not net these demand impacts from the gross demand forecasts used in transmission planning models. The PCs recognize that demand-side resources are an important and evolving element to be considered in transmission planning. Regional differences that include market mechanisms for, penetration of, and behavior of demand-side resources dictate the differing treatments of these resources in the PCs' planning analyses. As such, the load forecasts in the transmission planning model may be expected to differ from those developed for resource requirement planning.

For clarity, the summaries below that contain "included" incorporated" "reflected" or "accounted for" to describe the forecasts or modeled load for the individual PCs cases already reflect reductions for the effects of energy efficiency and demand-side resources.

Associated Electric Cooperative Inc.

Energy efficiency and demand-side resources programs are managed by AECI's member G&Ts. Load forecast is based on metered, non-coincident load values. As such, the load forecast incorporates any energy efficiency programs AECI's member G&Ts use.

Dominion Energy South Carolina (DESC)

DESC is projecting 226 MW of energy-efficiency (EE) programs and 286 MW of demand-side management (DSM) programs in 2028S. In 2028W, DESC is projecting 270 MW of energy-efficiency programs and 332 MW of demand-side management programs. The 2028S and 2028W cases do not include energy efficiency and DSM reductions in the load forecast figures above.

Duke Energy Carolinas

Energy-efficiency efforts, as required to meet state requirements, have been incorporated into the load in the case. Efficiency efforts constitute an approximate reduction of 459 MW in 2028S and 288 MW in 2028W of load modeled. The modeled load did not include the impact of the application of DSM.

Duke Energy Florida

DEF has developed energy efficiency and DSM programs, estimated to total 419 MW for 2024, as required to meet state requirements. The cases do not model energy efficiency and DSM reductions.

Duke Energy Progress

Energy-efficiency efforts, as required to meet state requirements, have been incorporated into the load in the case. Efficiency efforts constitute an approximate reduction of 249 MW in 2028S and 210 MW in 2028W of load modeled. The modeled load did not include the impact of the application of DSM.

Florida Power and Light

The load forecast factors in the impact of higher energy efficiency based on the 2005 National Energy Policy Act, the 2007 Energy Independence and Security Act, and the use of compact fluorescent lights (CFLs) and light emitting diodes (LEDs). From the end of 2018, FPL projects the incremental impact on the summer peak from these energy-efficiency codes and standards will be a reduction of 1,870 MW through 2028. The impact of the application of DSM is not included in the modeled load.

Georgia Transmission Corporation

All demand-side management and energy-efficiency programs are under the direction of GTC's individual member cooperatives. GTC does not administer any demand-side management or energy-efficiency programs. The load forecast is based on actual measured load, and the historical usage of load management (LM) and dispersed generation are added back into the annual results to represent total customer load. The load forecast incorporates the impacts of any energy-efficiency programs GTC's member cooperatives use.

ISO New England

Ten-year energy efficiency (EE) forecasts (*e.g.,* energy efficiency, load management, and distributed generation) have been incorporated into the load in the model. For the summer 2028, a total of 5,255 MW from the EE forecast and 1,620 MW of behind the meter solar PV were included for a total of 6,875 MW. For the winter 2028-2029, a total of 5,255 MW from the EE forecast was included.

JEA

JEA continues to pursue a greater implementation of demand-side management programs where economically beneficial and continues to meet JEA's Florida Energy Efficiency and Conservation Act (FEECA) goals. JEA's demand-side management programs focus on improving the efficiency of customer end uses as well as improving the system load factor. To encourage efficient customer usage, JEA offers customers both education and economic incentives on more efficient end use technologies. For load factor improvement, JEA has implemented a Demand Rate Pilot program with the intent of reducing peaks for residential customers. The current forecast does not include the Demand Rate Pilot program but does include a historical trend of applied energy-efficiency improvements that have naturally occurred in the market place.

Louisville Gas and Electric Company and Kentucky Utilities

All load-serving entities on the LG&E and KU transmission system provide annual load forecasts of the network load levels. The Planning Coordinator (PC) forecasted load in the 2028S EIPC roll-up case is 7,271 MW and 7,028 MW in the 2028W EIPC roll-up case.

LG&E and KU's load are based on a 50/50 forecast. The load forecast was submitted by all LSE's per NERC MOD-032 standard in the fall 2017. The LG&E and KU PC load forecast has an average growth rate of approximately 1.5% in the summer and 2.3% in the winter from 2018 through 2028. The PC load forecast in the EIPC 2028 models for summer and winter reflect a reduction in load of 511 MW and 296 MW, respectively, as a result of energy-efficiency programs and demand-side management resources.

MEAG Power

All demand-side management and energy-efficiency programs are under the direction of MEAG's individual member participants. MEAG does not administer any demand-side management or energy-efficiency programs. The load forecast is based on actual measured load, and historical usage of load management and dispersed generation are added back into the annual results to represent total customer load. The load forecast incorporates the impacts of any energy-efficiency programs used by MEAG's member participants.

Midcontinent ISO

MISO member systems perform their own load forecasting and provide the load projections for the planning horizon power-flow models. The load projections include adjustments for energy efficiency and demand-side measures consistent with the local transmission planning practices of each member system. The demand projections in the 2028 power-flow cases for the MISO portion of the roll-up integration case are consistent with the MISO section of the NERC *2018 Long Term Resource Assessment Report*.

New York ISO

The impacts of energy efficiency and building codes & appliance standards impacts for state-mandated programs are included in the NYISO's load forecasts. For 2028, a reduction of 2,262 MW is included in the summer peak load forecast and a reduction of 1,839 MW is included in winter peak load forecast for these programs.

Impacts of solar photovoltaic (PV) and non-solar distributed generation are included in the NYISO's load forecasts. For 2028, the summer peak load forecast includes a reduction of 1,423 MW for these programs. By 2028, the reduction in winter peak demand from non-solar distributed generation is 385 MW.

Demand-side programs (*e.g.,* demand response) reduce the 2028 summer and winter forecasted loads by 18 MW and 45 MW, respectively.

PJM Interconnection

Load management and energy efficiency (LM and EE) resources have been incorporated into the load forecast report based on amounts cleared in PJM markets for delivery years through 2018. The 2018 values are used as assumptions throughout the forecast horizon. PJM's planning power-flow models appropriately modify the loads or generation models for LM and EE resources, depending on the type of planning analysis being performed. The loads in the 2028 roll-up power-flow case are based on unrestricted peaks, which mean that they are not adjusted for LM and EE. Based on actual operations experience, the load management PJM calls on is fully available but limited in the number times it can be used. Refer to the references in Section 2.1 for more details regarding PJM's LM and EE measures.

PowerSouth Energy Cooperative

The PowerSouth load forecast currently reflects a reduction in load for the year 2028 of 12 MW in the summer, and 30 MW in the winter for its demand side management water heater program. PowerSouth's energy efficiency programs are designed to lower demand growth, improve load factor, increase customer confidence, and add value for the customer. The current program provides rebates and incentives for the purchase of high efficiency electric products. The energy reductions are not directly accounted for in the load forecast process. However, these energy reductions are present in the historical load data used as inputs, and therefore affect the forecasted loads.

Santee Cooper

Santee Cooper prepared the load forecast used in the roll-up integration case in conjunction with Central Electric Power Cooperative, Inc. staff and a consulting firm. The load forecast incorporates updates of the end-use/econometric models developed by the consulting firm and is based on normal weather assumptions. The forecast uses historical data and a current economic outlook for Santee Cooper's service areas. The forecast for industrial customers reflects any additions and changes to existing contracts. The load forecast includes estimated demand and energy savings from future energy-efficiency programs to be implemented by Santee Cooper and Central.

Southern Company

The Southern Company load forecast for 2028 incorporates reductions in load as a result of energy-efficiency programs and non-dispatchable (passive) demand-side management resources. Dispatchable (active) demand-side resources or real-time pricing resources are accounted for and considered as part of the resource decisions provided by each load serving entity.

Southwest Power Pool

Demand Side Management consists of both controllable and non-controllable systems; it is SPP's requirement that load forecasts submitted by its data submitters shall not be reduced for application of controllable Demand Side Management.

Tennessee Valley Authority

TVA's demand-side management program primarily focuses on the areas of pricing products and the direct load control of large industrial customers, HVAC equipment, and water heaters. The load forecasts used in determining TVA's transmission expansion plan reflect its energy-efficiency programs. However, TVA does not include the effects of demand-side management in these forecasts because of the difficulty in predicting the specific delivery points that will be affected by these programs.

2.3 Interchange or Firm Transmission Service Modeled

This section describes the typical interchange or inter-area energy transfers modeled by each Planning Coordinator. Appendix E of this report includes interchange data tables. The roll-up integration case includes full-path transactions between areas (imports/exports) (where both the importing and exporting PCs recognize common commitments), but not partial-path transactions, (where arrangements for transmission service have been made with only one party).

Associated Electric Cooperative Inc.

AECI's forecasted area interchange assumptions included a net of 1,465.9 MW of imports in the 2028S case and a net of 1,549.9 MW of imports in the 2028W case. The forecasted interchange schedule represents coordinated firm transactions, generation agreements, and non-member load transactions.

Cube Hydro Carolinas

In the 2028S case, Cube Hydro Carolinas (previously known as Alcoa Power Generating Inc.-Yadkin) has a net export of 215 MWs. Cube Hydro Carolinas expects to serve its Badin auxiliary load with its internal generation. Cube Hydro imports were not tested as it only has export transfer. Due to the small size of the CHC system, all transmission lines are considered out of service when conducting contingency analysis.

Dominion Energy South Carolina (DESC)

DESC's area interchange assumptions in the 2028 roll-up integration case include 324 MW of imports and 22 MW of exports, in both the 2028S and 2028W cases, resulting in a net interchange of 302 MW of exports. The values represented in Appendix E reflect long-term (one year or more) firm transmission service obligations

Duke Energy Carolinas

In the 2028S case, the DEC Balancing Authority has a net export to CPLW of 150 MW and to CPLE of 850 MW from independent power producers (IPPs) at Rowan and Broad River Energy Center, respectively serving the Duke Energy Progress load; while 205 MW of NCEMC resources in DEC are exported to CPLE. NCEMC also exports 100 MW of its resources to serve its load in DVP (a part of PJM). PMPA imports 179 MW and the City of Seneca, SC imports 51 MW from Santee Cooper to serve its load in DEC. Energy United imports 230 MW from Southern Company to serve its load in DEC. There are imports of 268 MW from SEPA's generation on the Savannah. The DEC net interchange is an export of 575 MW.

In the 2028W case, the DEC Balancing Authority has a net export to CPLW of 150 MW and to CPLE of 850 MW from independent power producers (IPPs) at Rowan and Broad River Energy Center, respectively serving the Duke Energy Progress load; while 205 MW of NCEMC resources in DEC are exported to CPLE. NCEMC also exports 100 MW of its resources to serve its load in DVP (a part of PJM). PMPA imports 61 MW and the City of Seneca, SC imports 31 MW from Santee Cooper to serve its load in DEC. Energy United imports 230 MW from Southern Company to serve its load in DEC. There are imports of 268 MW from SEPA's generation on the Savannah. The DEC net interchange is an export of 713 MW.

Duke Energy Florida

DEF includes confirmed annual firm transmission service requests in accordance with resource projections provided by LSEs and executed contracts for the sale of firm energy. DEF's one balancing area is FPC whose area model includes a net interchange import of 2,399 MW for 2028 summer and 2,501 MW for 2028 winter.

Duke Energy Progress

DEP includes confirmed annual firm transmission service requests in accordance with LSE resource projections and executed contracts for the sale of firm energy. DEP has two balancing areas, CPLE and CPLW. The CPLE area model includes 1,250 MW of imports and 171 MW of exports, resulting in a net interchange import of 1079 MW in 2028S. For 2028W, the CPLE area model includes 1,250 MW of imports and 371 MW of exports, resulting in a net interchange import of 879 MW. The CPLW area model includes 164 MW of imports and no exports, resulting in a net interchange import of 164 MW in 2028S; it has 364 MW of imports and no exports, resulting in a net interchange import of 364 MW in 2028W.

Florida Power and Light

The scheduled net interchange modeled for the FPL area reflects the forecasted, firm interchange transactions as coordinated with the other utilities within the Florida Reliability Coordinating Council (FRCC) Region. In 2028 approximately 457 MW of imports flow into FPL's BA from inside the FRCC associated with unit ownership or PPAs. Approximately 674 MW of imports flow into FPL's BA from outside the FRCC associated with unit ownership or PPAs.

Georgia Transmission Corporation

GTC's information is included in the response from Southern Company.

ISO New England

ISO New England's area interchange assumptions in the 2028S and 2028W roll-up integration cases include 2,608 MW and 308 MW of imports, respectively. In each case, 101 MW of exports are also modeled, resulting in a net import of 2,507 MW in 2028S and 207 MW in 2028W. Most of this interchange comes from 1,725 MW (in 2028S) and 225 MW (in 2028W) imported from Quebec on HVDC lines to northern Vermont and eastern Massachusetts.

JEA

Following the shutdown of a jointly owned generation facility and the expiration of a wholesale power sales agreement from the beginning of 2018, JEA's present obligation is to serve its native retail load only. JEA has territorial system ties at 138 kV and 230 kV levels as well as has allocation rights in the Florida/Georgia 500 kV ties that it partially owns which can be used for power import and export by JEA. As JEA's generation resources also exist outside of its service territory and has firm long-term generation and transmission contracts, these interchanges are modeled in the loadflow cases. In the present study, a firm import of 407 MW from Georgia (Southern Company) to JEA is reflected in both the summer and winter roll-up integration cases.

Louisville Gas and Electric Company and Kentucky Utilities

LG&E and KU's area interchange assumptions in the 2028S roll-up integration case include 462 MW of imports and 828.5 MW of exports, resulting in a net interchange of 366.5 MW of exports. LG&E and KU's area interchange assumptions in the 2028W roll-up integration case include 457 MW of imports and 898 MW of exports, resulting in a net interchange of 441 MW of exports

MEAG Power

MEAG's information is included in the response from Southern Company.

Midcontinent ISO

For MISO members, internal interchange is based on the market dispatch, and interregional interchange is based on currently known net firm drive-in and drive-out transactions between MISO member control areas and external control areas. The amount of net interchange between MISO and its neighboring Planning Coordinators is unchanged from the corresponding MMWG case. Appendix E contains detailed interchange information. Import and export transactions have been agreed to and are consistent with those of external PC regions.

New York ISO

The NYISO coordinates its interchange schedule with its neighboring control areas. Such interchanges represent firm transactions and the expected continuance of current external installed capacity (ICAP) providers as listed in the NYISO 2018 Load and Capacity Data Report.

PJM Interconnection

PJM's interchange with external systems included in the roll-up integration case model represents long-term firm interchange transactions and non-firm transactions chosen by individual transmission owners. This representation is a snapshot of what may be considered "typical" transactions. It is the agreed-upon basis for assembling the interregional reference cases, according to the Eastern Reliability Assessment Group, Multiregional Modeling Working Group process. Because individual Planning Coordinators must assemble interregional reference cases that interchange with many neighbors, the interchanges are necessarily only starting point values that must be appropriately adjusted, depending on the nature of the planning analysis being performed. Interchanges among the areas internal to PJM are the free-flowing result of PJM's single-area market dispatch and do not result from transaction schedules such as the interchanges between PJM and external areas. PJM's planning analyses examine thousands of dispatch scenarios. The internal PJM starting-point interchanges, therefore, are not a focus of PJM planning analyses.

PowerSouth Energy Cooperative

PowerSouth's area interchange assumptions in the 2028S roll-up integration cases include 1,409 MW of generation, resulting in a net interchange of 445 MW. PowerSouth's area interchange assumptions in the 2028W roll-up integration case include 1,854 MW of generation resulting in a net interchange of 663 MW. The values shown in Appendix E reflect long-term (one year or more) firm transmission service obligations as they relate to the transmission service provider.

Santee Cooper

The area interchange schedule for the 2028S roll-up integration case includes 597 MW of imports and 280 MW exports for a net interchange of 317 MW of imports. The 2028W roll-up integration case contains 142 MW of imports and 597 MW of exports for a net interchange of 455 MW of imports. No firm transmission service requests are modeled in either case.

Southern Company

Southern Company's area interchange assumptions in the 2028S roll-up integration case include 1,556 MW of imports and 1,845 MW of exports, resulting in a net interchange of 289 MW of exports. Southern Company's area interchange assumptions in the 2028W roll-up integration case include 1,839 MW of imports and 1,876 MW of exports, resulting in a net interchange of 37 MW of exports. The values represented in Appendix E reflect long-term (one year or more) firm transmission service obligations.

Southwest Power Pool

SPP includes long-term firm transmission service requests in models, as well as non-firm transmission service for the purpose of meeting any generation shortfall. SPP's area interchange assumptions in the 2028S roll-up integration case include roughly 4,728 MWs of imports and 4,517 MWs of exports, resulting in a net interchange of 211 MWs, import. The 2028W roll-up integration case includes 4,096 MWs of imports and 4,165 MWs of exports, resulting in a net interchange of 69 MWs, export.

Tennessee Valley Authority

TVA's area interchange assumptions in the 2028 summer roll-up integration case include 870 MW of imports and 1,513 MW of exports, resulting in a net interchange of 643 MW of exports. The values represented in Appendix E reflect long-term (one year or more) firm transmission service obligations.

TVA's area interchange assumptions in the 2028/29 winter roll-up integration case include 1,101 MW of imports and 1,520 MW of exports, resulting in a net interchange of 419 MW of exports. The values represented in Appendix E reflect long-term (one year or more) firm transmission service obligations.

2.4 Process for Future Transmission Project Inclusion

The section describes each Planning Coordinator's planning process for inclusion of new transmission projects. The tables in Appendix B provide a complete, detailed listing of all new and upgraded transmission projects included in the 2028S and 2028W roll-up integration cases. The "Projected In-Service Date" column in these tables indicates whether the facility was included in the 2028S and 2028W models (2028S) or just the 2028W model (2028W). Since the inclusion of transmission projects varies based on each PA's process, the PCs have agreed to the following terms for describing the status of future projects, which are used in Appendix B:

- **Construction**—project is under construction.

- **Committed**—project has obtained some level of contractual obligation or regulatory approval or is included in approved capital budgets.
- **Planned**—project has completed the respective Planning Coordinator's planning process, including obtaining any applicable regional planning process approvals (for example, ISO or RTO approvals), but specific contractual obligations have not been committed to, or regulatory approvals obtained.
- **Proposed**—project has been proposed but has not yet completed the respective Planning Coordinator's planning process or received applicable regional planning process approvals. In this case, the year of the expected completion of the process and applicable regional approval is listed in Appendix B.
- **Conceptual**—project has been identified as a potential solution to a constraint identified during the validation process for the EIPC roll-up model. The project and constraint have not previously been identified during the Planning Coordinator's normal planning process.
- **On Hold**—project has been withdrawn or suspended.

Associated Electric Cooperative Inc.

AECI's transmission planning is a continuous process to identify needed transmission improvement projects. Transmission improvement projects are developed to meet NERC Reliability Standards or to meet AECI's internal project criteria. Additionally, AECI performs studies to identify transmission projects for generation interconnections and participates in joint coordinated studies with neighboring entities. AECI's transmission planning projects in the roll-up integration cases were modeled based upon in-service dates and probability of completion

Cube Hydro Carolinas

Cube Hydro Carolinas transmission expansion projects are managed by the Engineering and Operations groups. These groups cover the following areas: scope of project, project management, and construction. Once a project has been approved by finance, the engineering team will perform detailed engineering.

Dominion Energy South Carolina (DESC)

DESC includes in its transmission models all transmission projects budgeted and approved to be included in the transmission expansion plan. Not all projects have a commitment to build because they are reviewed for need and modifications on an ongoing basis through the annual and iterative transmission planning process. These reviews occur in the form of transmission system assessments with and without these transmission improvements and reflect changes in assumptions and objectives of the transmission system based on LSE needs, transmission service commitments, and resource interconnections. Transmission projects in DESC's transmission expansion plan and in the EIPC roll-up case include (1) projects required to meet NERC Reliability Standards and DESC Transmission Planning Criteria, (2) projects required for the provision of firm transmission service (network and point-to-point), per the DESC OATT, and (3) system upgrades associated with generator interconnections, per the DESC OATT.

Duke Energy Carolinas

Transmission planning performed by DEC is a continuous process consisting of (1) internal screening and analysis, (2) coordinated studies with neighboring systems, and (3) the development of a collaborative transmission plan with Duke Energy Progress under the North Carolina Transmission Planning Collaborative. The result of these efforts is the identification of projects to upgrade existing facilities or the addition of new facilities needed to meet DEC's transmission planning criteria and NERC Reliability Standards.

Transmission facilities approved and budgeted or where construction has begun have been included in the 2028 summer and winter cases. Other projects the planners believe have a high certainty of being in service in the year being modeled are also included. Engineering judgment has been applied such that a new or upgraded facility marginally necessary may not have been included in the base model so that the timing of the need for the facility can be accurately determined.

Duke Energy Florida

DEF’s transmission expansion plan is the compilation of transmission facility improvements and upgrades necessary for the transmission system to support the proposed resource assumptions, load forecasts, and firm transmission service requirements for the next 10 years in the most reliable and economic manner consistent with NERC Reliability Standards. The expansion plan is based on information obtained through DEF’s internal planning efforts and FERC’s Order No. 890 Attachment K process, as well as through the FRCC long-range study assessments and other joint studies with interconnected neighbors. Transmission facilities that are approved, committed, and budgeted or where construction has begun are included in the case. Other projects the planners believe have a high certainty of being in service in the year being modeled are also included. Most transmission projects are included to meet first-contingency (N-1) criteria; however, some projects are included to meet credible second-contingency (N-2) criteria where there is no operating solution or acceptable special protection system to resolve.

Duke Energy Progress

DEP’s transmission expansion plan is the compilation of transmission facility improvements and upgrades necessary for the transmission system to support the proposed resource assumptions, load forecasts, and firm transmission service requirements for the next 10 years in the most reliable and economic manner consistent with NERC Reliability Standards. The expansion plan is based on information obtained through Duke Energy Progress’s (DEP’s) internal planning efforts as well as through the SERC Long-Term Working Group, North Carolina Transmission Planning Collaborative, Southeastern Interregional Participation Process, and joint studies with interconnected neighbors. Approved, committed, and budgeted transmission facilities, and those under construction, are included in the models. Other projects the planners believe have a high certainty of being in service in the year being modeled are also included. Engineering judgment is applied such that a new or upgraded facility marginally needed may not be included in the base model so that the timing of the need for the facility can be accurately determined. Projects are included to meet P1 through P3 contingency criteria. Additionally, projects that have not been through the state certification process could potentially be included, but this is not the case for the 2028 roll-up integration cases used in this process.

Florida Power and Light

The role-up integration case includes future projects that have undergone FPL's internal budget review process, as well as those projects representative of the Ten-Year Site Plan (TYSP) filing with the Florida Public Service Commission.

Georgia Transmission Corporation

GTC performs transmission planning studies on a continuous basis to identify needed transmission improvements. These studies identify transmission improvement projects required to support the load- serving needs of GTC's member cooperatives and GTC's long-term firm transmission tariff customers. GTC also identifies projects to interconnect new generation, as applicable. To jointly plan for future transmission expansion, GTC reviews and coordinates study recommendations with other transmission owners in Georgia. GTC also reviews study work performed by other transmission owners in Georgia and coordinates with utilities in surrounding regions. The role-up integration case includes transmission improvement projects in GTC's expansion plans.

ISO New England

ISO New England's portion of the 2028 roll-up integration cases include all future projects approved under Section I.3.9 of the ISO New England Open Access Transmission Tariff. Pursuant to Section I.3.9, the ISO reviews proposals for new generation and transmission facilities rated at or above 69 kV. If the ISO determines that a project would have no significant adverse impacts on the stability, reliability, or operating characteristics of existing electrical infrastructure, it approves the project for interconnection to the grid. Projects that have reached this stage are assumed to be in service for the 2028 roll-up cases.

In the case of transmission projects, projects submitted for review pursuant to Section I.3.9 are those which are being developed and generally supported as part of the New England regional transmission planning process. Additionally, some projects were added or removed their Section I.3.9 approval status notwithstanding. Such exceptions are documented in subsequent sections of this report.

JEA

JEA does not include in its load-flow models any transmission projects categorized in this report as "proposed." All projects sponsored by JEA in the roll-up integration cases have the status of "state/budget approval" (categorized in this report as "committed"). JEA's policy and practice is to include in the load-flow transmission model only those committed projects (e.g., facility additions, modifications, retirements, or system topology changes) whose inclusion represents the most probable future scenario. To JEA, this means that a project has, at a minimum, undergone its internal budget review process and has been approved for real estate activities associated with securing rights-of-ways (ROWs) or has been accepted in the capital budget process for legally appropriated funding in the upcoming fiscal year. However, JEA may decide not to add a project to the load-flow models until real estate has been properly secured or the project has a high probability of being successfully acquired.

Louisville Gas and Electric Company and Kentucky Utilities

The primary purpose of LG&E/KU's transmission system is to reliably transmit electric energy from network resources to network loads. LG&E/KU has established Transmission Planning Guidelines to gauge the adequacy of the transmission system to supply projected network customer demand and contracted long-term, firm, point-to-point (PTP) transmission services. The process is an annual cycle designed to incorporate external network changes and to provide information for regional evaluation and coordination through the NERC MMWG model-building process.

LG&E/KU develops seasonal peak power-flow models annually using each model year available in the most recent NERC MMWG model series. The topology of the LG&E/KU transmission system is expanded to provide a more detailed representation of the 69 kV facilities and is updated to reflect the current Transmission Expansion Plan. Network resources and network loads are updated to reflect the most recent information from the network customers. Seasonal peak cases may also be developed without certain generators or major transmission additions to improve the models and their interpolation between model years.

The Transmission Expansion Plan is evaluated and updated through screening, verification, area studies, facility studies, signed agreements, and other periodic studies, as described below:

- **Screening**—Generator and transmission contingencies are simulated on the base cases to identify overloads and low voltages not resolved by the Transmission Expansion Plan.
- **Verification**—Projects in the Transmission Expansion Plan and issues identified in the screening are evaluated to determine the required upgrade or construction along with project need date to identify the reason for the change. The required need date is determined by interpolating flows between model years.
- **Area Studies**—Area studies are performed before major construction to develop multiple long-term options that provide adequate transmission through the planning period. The least-cost option is recommended for approval, and the associated projects are incorporated into the Transmission Expansion Plan.
- **Facility Studies**—Facility studies are performed following a request made by customers through the Independent Transmission Organization (ITO) by a network-integrated transmission service (NITS), designated network resource (DNR), or point-to-point request. The ITO provides the customers multiple options with associated costs and time frames for completing construction of the requested service.
- **Signed Agreements**—Construction and upgrades associated with generator interconnections, transmission-to-transmission interconnections, and network service requests executed by the requestor, which have been submitted to and evaluated by the ITO and LG&E and KU in the previous year, are incorporated into the Transmission Expansion Plan.

Generator and transmission contingencies are routinely simulated to evaluate the adequacy of the transmission system in meeting the "no loss-of-demand or curtailment of firm-transfer" requirements of the Transmission Planning Guidelines.

Periodic studies evaluate the adequacy of the LG&E/KU transmission system in meeting the allowable "no loss-of-demand or curtailment of firm-transfer requirements and system stability." The Transmission Expansion Plan incorporates the necessary construction and upgrades identified by these studies.

Annually, the LG&E and KU Transmission Expansion Plan is submitted to the ITO and RC for independent review, evaluation, and comment regarding any outstanding issues that should be addressed. The ITO must approve the final plan developed by the transmission owner.

MEAG Power

MEAG performs transmission planning studies on a continuous basis to identify transmission improvements required to support the load-serving needs of its participants and long-term firm transmission tariff customers. MEAG also identifies projects to interconnect new generation, as applicable. To jointly plan for future transmission expansion, MEAG reviews and coordinates study recommendations with other transmission owners in Georgia. MEAG also reviews study work performed by other transmission owners in Georgia and coordinates with utilities in surrounding regions. Transmission improvement projects included in MEAG's expansion plans were included in the roll-up integration case.

Midcontinent ISO

MISO produces a MISO Transmission Expansion Plan annually. This regional plan is produced in collaboration with transmission-owning members, using a stakeholder process compliant with FERC Order 890. The regional plan, once approved by the MISO Board of Directors, represents the recommended plan for the region. The member transmission owners are bound by formal agreement to use a good-faith effort to obtain all necessary state and local approvals and to construct the projects so approved for regional implementation.

The criteria applied by MISO for including projects in the roll-up integration case was to include all transmission projects in the agreed-on EIPC status categories of constructed, committed, and planned. MISO included proposed projects pending approval in the MTEP18 planning cycle, which began September 2018 and concluded with board approval December 2018.

New York ISO

The NYISO's Comprehensive System Planning Process (CSPP) covers reliability planning, economic planning, Public Policy Requirements planning, cost allocation and cost recovery, and the interregional planning process. CSPP is comprised of four components:

- Local Transmission Planning Process (LTPP),
- Reliability Planning Process (RPP),
- Congestion Assessment and Resource Integration Study (CARIS), and
- Public Policy Transmission Planning Process (PPTPP).

The first component in the CSPP is the LTPP. Under this process, the local Transmission Owners (TOs) perform transmission studies for their transmission areas according to all applicable criteria.

This process produces the Local Transmission Owner Plan (LTP), which feeds into the NYISO's determination of system needs through the CSPP.

The second component in the CSPP is the RPP. Under this biennial process, the reliability of the New York State Bulk Power Transmission Facilities (BPTF) is assessed, Reliability Needs if any are identified, solutions to identified needs are proposed and evaluated for their viability and sufficiency to satisfy the identified needs, and the more efficient or cost-effective transmission solution to the identified needs if any is selected by the NYISO. This process was originally developed and implemented in conjunction with stakeholders, was approved by FERC in December 2004, and was revised in 2014 to conform to FERC Order No. 1000.

The RPP consists of two studies:

- The Reliability Needs Assessment (RNA). The NYISO performs a biennial study in which it evaluates the resource and transmission adequacy and transmission system security of the New York BPTF over a ten-year Study Period. Through this evaluation, the NYISO identifies Reliability Needs in accordance with applicable Reliability Criteria. This report is reviewed by NYISO stakeholders and approved by the Board of Directors.
- The Comprehensive Reliability Plan (CRP). After the RNA is complete, the NYISO requests the submission of market-based solutions to satisfy the Reliability Need. The NYISO also identifies a Responsible TO and requests that the TO submit a regulated backstop solution and that any interested entities submit alternative regulated solutions to address the identified Reliability Needs. The NYISO evaluates the viability and sufficiency of the proposed solutions to satisfy the identified Reliability Needs and evaluates and selects the more efficient or cost-effective transmission solution to the identified need. In the event that market-based solutions do not materialize to meet a Reliability Need in a timely manner, the NYISO triggers regulated solution(s) to satisfy the need. The NYISO develops the CRP for the ten-year Study Period that sets forth its findings regarding the proposed solutions. The CRP is reviewed by NYISO stakeholders and approved by the Board of Directors.

The third component of the CSPP is the economic planning process in which the NYISO performs the Congestion Assessment and Resource Integration Study (CARIS). The CARIS study utilizes, as its starting point, the results from the viability and sufficiency assessment portion of the CRP process, once they are finalized and become publicly available. CARIS Phase 1 examines congestion on the New York bulk power system, and the costs and benefits of generic alternatives to alleviate that congestion. During CARIS Phase 2, the NYISO evaluates specific transmission project proposals for regulated cost recovery.

The fourth component of the CSPP is the Public Policy Transmission Planning Process. Under this process interested entities propose, and the New York State Public Service Commission (NYPSC) identifies, transmission needs driven by Public Policy Requirements. The NYISO then requests that interested entities submit proposed solutions to the identified Public Policy Transmission Need. The NYISO evaluates the viability and sufficiency of the proposed solutions to satisfy the identified Public Policy Transmission Need. The NYISO then evaluates and may select the more efficient or cost-effective transmission solution to the identified need. The NYISO develops the Public Policy Transmission Planning Report that sets forth its findings regarding the proposed solutions. This report is reviewed by NYISO stakeholders and approved by the Board of Directors.

In concert with these four components, interregional planning is conducted with NYISO's neighboring control areas in the United States and Canada under the Northeastern ISO/RTO Planning Coordination Protocol. The NYISO participates in interregional coordination of planning, as required under Order 1000, and may consider Interregional Transmission Projects in its regional planning processes.

PJM Interconnection

PJM's annual Regional Transmission Expansion Plan process comprehensively examines the transmission system requirements to ensure the reliability, economy, competitiveness, and comparability of service under the PJM tariffs and agreements. PJM is the single Planning Coordinator, transmission planner, reliability authority, and balancing authority for the RTO. The RTEP process first identifies transmission system upgrades and enhancements to preserve grid reliability, the foundation of competitive wholesale power markets. The annual series of RTEP analysis also includes planning for market efficiency that (1) advances planned reliability projects when the economic benefit is sufficient, (2) provides new projects that have sufficient market efficiency benefits to justify their expense, and (3) combines reliability and market efficiency projects when benefits are sufficient to justify added expenditures. A third facet of PJM planning is annually reviewing system operational performance, evaluating any issues, and planning beneficial system upgrades. In addition, PJM tariffs and agreements also provide for interregional upgrades resulting from periodic interregional reviews. This annual series of analyses produces the PJM baseline RTEP system. This system forms the foundation for the incremental assessment of queued requests for interconnection to the transmission system. PJM planning conducts a queue process that sequentially evaluates interconnection requests to determine incremental transmission upgrades necessary for their reliable interconnection and operation with the system.

In addition, pursuant to process enhancements put in place in response to FERC Order No. 1000, PJM plans for public policy transmission needs. Transmission enhancements required to facilitate public policy agreed to by the states and adopted in the PJM RTEP become part of the PJM transmission plans. Also, pursuant to Order No. 1000 interregional enhancements, PJM is beginning assessments of neighboring transmission plans on its borders to determine more efficient and cost-effective interregional plans that may replace separate regional plans.

This series of RTEP analysis is based on maintaining reliability, market efficiency, and operational performance for committed uses of the system and reasonably anticipated load growth and new interconnections. The system is planned for new generation with signed Interconnection Service Agreements or signed Facility Study Agreements.

The recommended transmission upgrades resulting from this series of analyses are subject to ongoing review and input with PJM's stakeholders through the PJM committee process. The resulting RTEP projects are presented to the PJM independent board of managers periodically throughout the year for approval. RTEP-approved projects are cost allocated, assigned for construction, and proceed from planning into the project tracking and construction phase. At this point, entities assigned construction responsibility engage necessary design, siting, and regulatory approval processes. PJM supports the need justification for projects as necessary throughout regulatory approvals.

The PJM RTEP process is ongoing. PJM's reference transmission case changes continuously as new needed RTEP upgrades are identified. At any point in time the PJM reference RTEP power flow includes predominately existing and planned, board-approved facilities. PJM planning only tracks and reports state regulatory approval status of the major "backbone" projects. The PJM reference power flow typically has some very recent necessary upgrades scheduled for approval at the next regularly scheduled board meeting. These most often address recently identified RTEP baseline or queue project issues that surface in the continuous stream of analysis. The projects pending board approval are represented as "proposed" in the PJM list of upgrades. Such projects typically become board approved within months; therefore, for PJM, the "proposed" project label does not represent a material difference from "planned" facilities with regard to the "certainty" of the transmission projects going forward. All the listed PJM projects are required for system reliability by the specified dates and are very likely to proceed. The "certainty" of projects coupled with new interconnection requests, naturally, are linked to the business plans of the interconnection customer. The progress of all projects is tracked, and alternate plans or temporary mitigation actions are developed when issues may delay a project's completion. PJM's RTEP process includes both five-year and 15-year assessments to meet all applicable reliability planning criteria. The applicable reliability planning criteria include the following:

- NERC Planning Standards
- RFC Reliability Principles and Standards
- PJM Reliability Planning Criteria as contained in Manual M14B Attachment G[4]
- Transmission Owner Reliability Planning Criteria. as filed in their respective FERC 715 filing

Five-year-out planning enables PJM to assess and recommend transmission upgrades to meet forecasted load growth and to ensure the safe and reliable interconnection of new generation and merchant transmission projects seeking interconnection within PJM. The 15-year planning horizon for PJM allows for the consideration of many long-lead-time transmission options. These options often comprise larger-magnitude transmission facilities that more efficiently and globally address reliability issues. Typically, these are higher-voltage upgrades that simultaneously address multiple NERC reliability criteria violations at all voltage levels. A 15-year horizon also allows PJM to consider the aggregate effects of many system trends, including long-term load growth, impacts of generation deactivation, and broader generation development patterns across PJM.

PowerSouth Energy Cooperative

PowerSouth's transmission planning is a yearly, continuous process based on a rolling 10-year cycle that identifies needed enhancements to the existing transmission system. PowerSouth coordinates with its neighbors to accurately model shared ownership resources, as well as area interchange values. PowerSouth also submits data to and participates in SERC's Long-Term Working Group (LTWG), which helps create the MMWG models. Projects included in the model can be member driven (i.e., new delivery point), reliability driven (new bulk transmission), as related to the NERC standards, or any combination. PowerSouth, as a G&T Cooperative, is not under any state

[4] This PJM manual is available at http://www.pjm.com/documents/manuals.aspx.

regulation authority. New transmission and generation projects are vetted through a board-approval process.

Santee Cooper

Santee Cooper produces a 10-year transmission plan on an annual basis. The criteria for including projects in the roll-up model include future projects budgeted and approved for implementation by executive management. Planned and uncommitted construction projects are also included in the model but only if the project is judged to be well defined and most likely to be fully implemented. Results of assessments are used to determine whether the current construction schedule of planned transmission facilities should be altered to reflect future system requirements. Proposed additions identified and verified throughout the assessment will be incorporated with a recommended schedule, as needed.

Southern Company

On a continuous, iterative basis, 10-year transmission expansion plans are developed to support load-serving entities and other long-term firm transmission customers under the Open Access Transmission Tariff in delivering energy on a firm basis. Transmission projects in Southern Company's expansion plans and in the roll-up include the following:

- Projects to meet long-term firm service commitments of LSEs and point-to-point transmission customers

- Projects to interconnect new generation customers who have signed interconnection agreements

- For periods later in the 10-year planning horizon, projects associated with network reservations provided by LSEs for generation capacity necessary to meet their respective load obligations

As transmission projects are identified, the requirements of state law are followed to obtain any requisite approvals to move forward with these projects. The level of formality varies within each of the different jurisdictions. If the need for the transmission project is attributable to the planned addition of a supply-side resource, the approval for that project is generally sought in the certification proceeding for that resource. Additionally, the states also vary regarding which transmission projects must receive specific state certification approvals.

Southwest Power Pool

The SPP RTO Integrated Transmission Planning (ITP) assessment is a regional planning process built to leverage knowledge of the transmission system's reliability, public policy, operational, and economic needs, as well as compliance, generator interconnection, and transmission service request impacts to develop a cost-effective transmission portfolio over a 10-year planning horizon. The results of this assessment guide what SPP transmission projects are included in the base cases. Planned Projects resulting from the ITP assessment that receive a Notification to Construct (NTC) are included in the base cases. Additionally, projects can receive an NTC from the Generation Interconnection and Aggregate Service Request study processes. These projects are also included in the base cases.

Tennessee Valley Authority

TVA develops a 10-year transmission expansion plan on an annual basis. The plan supports the firm delivery of energy on the basis of the projected load forecasts for the TVA Balancing Authority (BA) area as well as other long-term firm transmission service customers under the TVA OATT. Transmission projects in TVA's expansion plans and in the roll-up integration cases include the following types of projects:

- Projects associated with network reservations for generation capacity necessary to meet system load obligations
- Projects to meet long-term firm point-to-point transmission service commitments of transmission customers
- Projects to interconnect new generation customers

As a federal entity, TVA follows the requirements of the National Environmental Policy Act (NEPA) to move forward with identified transmission projects. The approval for a transmission project needed as a result of the planned addition of a supply-side resource is obtained through the process for that resource. Planned system modifications are included in TVA's transmission expansion plan as the transmission projects obtain TVA-officer approval. Projects that do not have TVA-officer approval are omitted from the transmission expansion plan until the continued need for the planned corrective action is verified.

2.5 Major New and Upgraded Transmission Facilities

This section describes the major new and upgraded transmission facilities included in each Planning Coordinator's portion of the 2028S and 2028W roll-up integration cases. Major facilities are 230 kV or above. Appendix B of this report includes a complete listing of major new and upgraded projects, as categorized in Section 2.4. Some projects may have multiple facilities listed that are a part of the same project. For example, a long line project may have several line segments and substations between its end points.

Associated Electric Cooperative Inc.

AECI has no major (230 kV and above) projects planned at this time.

Cube Hydro Carolinas

Cube Hydro Carolinas does not have any plans for new or upgrades to its transmission facilities.

Dominion Energy South Carolina (DESC)

The DESC transmission system did not include any major transmission improvements in the 2028 roll-up integration cases.

Duke Energy Carolinas

DEC included a new 230/100 kV tie station between the Lincoln CT site and Longview Tie. Switchable reactors have been added in the double-circuit 230 kV lines between Peach Valley Tie and Riverview Switching Station and between Ernest Tie and Sadler Tie. A new 230/100 kV transformer was modeled at Wilkes Tie and additional 230/100 kV transformer capacity was modeled at Sadler Tie and Pisgah Tie. No other >200 kV projects are expected to be in service by 2028.

Duke Energy Florida

- DEF has included the following 230 kV and 500 kV projects in the 2028 summer and 2028 winter roll-up integration cases:
- Williston—new 230/69 kV substation
- Williston to Bronson—new 230 kV line
- Crystal River East—new replacement 230/115 kV substation with second transformer and loop 230 kV lines
- Dona Vista—new 230/69 kV substation
- Disston to 40th Street—new 230 kV line
- Brooksville—new 230/115 kV substation and 230 kV line to Brooksville West

Duke Energy Progress

DEP has included two 230 kV transmission projects in the 2028 summer and winter roll-up integration cases. The first is a 230 kV line from the Jacksonville 230 kV substation to the new Grants Creek 230 kV substation that will be placed in service by June 2020. The second is a 230 kV line from the new Newport 230 kV substation to the new Harlowe 230 kV substation that will be placed in service by June 2020.

Florida Power and Light

The projects included in the FPL portion of the roll-up integration case are needed to meet FPL's regulatory requirements for the 10 year planning horizon. FPL has several new transmission facilities needed to interconnect new PV plants, battery storage, and the new combined cycle unit, Dania Beach Clean Energy Center Unit 7 in mid-2022.

Georgia Transmission Corporation

GTC's information is included in the response from Southern Company. Please note that in Appendix B, transmission facilities listed under the PC "SBA" also include GTC transmission projects.

ISO New England

ISO-NE has included new transmission projects at 230 kV and above in the 2028 roll-up integration cases. Most of these projects are components of the Greater Boston reliability solutions, including two 345 kV lines anticipated to be in service by 2021 in New England. Other projects include several additional bulk autotransformers located in all six New England States.

For the 2028 roll-up cases, ISO-NE removed QP508, an Elective Transmission Upgrade connecting western Massachusetts to New York via an HVDC link, since it was recently withdrawn from ISO-NE's interconnection queue.

JEA

The major "state/budget approval" projects included in the roll-up integration cases are needed to meet the generation and transmission performance requirements of the JEA electric system, as forecasted in the 10-year planning horizon. JEA currently is not adding any generator capacity within its service territory but has power purchase agreements with other utilities to meet its future load demand for the 10-year planning horizon. JEA is also considering the expansion of its photovoltaic generation by additional 250 MW before the end of 2022 and is currently negotiating the power purchase agreements. To serve the native load as well as to improve the electric reliability, it has plans to construct a new 230 kV transmission circuit and some substations.

LG&E and KU Energy

LG&E/KU has included the addition on a 0.66% reactor in the Trimble County to Clifty Creek 345 kV line. Additionally, there is a second 345/138 kV transformer at the Hardin County station added to the 2028 summer and winter roll-up integration cases. No other >230 kV projects are expected to be in service by 2028.

MEAG Power

MEAG's information is included in the response from Southern Company. Please note that in Appendix B, transmission facilities listed under the PC "SBA" also include MEAG transmission projects.

Midcontinent ISO

Within MISO, the previously approved MTEP Appendix A projects and proposed MTEP Appendix A projects in MTEP18 cycle are included in the model. The major 230 kV and above line upgrades are provided Appendix B of this report. A complete list of all approved MTEP upgrades could be found at MISO website.[5]

New York ISO

NYISO has included new transmission projects in the 2028 roll-up integration cases based on the 2018 Load and Capacity Data. Appendix B of this report includes a list of major new and upgraded projects in the New York Control Area.

PJM Interconnection

The 230 kV and above line upgrades are provided Appendix B of this report. To keep the list manageable, it excludes many high-voltage projects that strictly involve breaker replacement or bus work that does not affect lines, or upgrades to transformers to lower voltages.[6]

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[5] https://www.misoenergy.org/planning/planning-test/mtep-quarterly-status-reports/#t=10&p=0&s=&sd

[6] A complete list of all approved RTEP upgrades, as well as a brief description of the facility, upgrade driver, and current status is available at PJM's "Transmission Construction Status" webpage: http://www.pjm.com/planning/rtep-upgrades-status/construct-status.aspx.

PowerSouth Energy Cooperative

PowerSouth has no major (200 kV and above) projects planned at this time.

Santee Cooper

Santee Cooper's major transmission projects for 2028 include the continued development of a 230 kV transmission system needed for delivering generator output to the load and maintaining reliability of the transmission system. Table 2-2 shows the major transmission improvements included in the 2028 roll-up integration cases.

Table 2-2
Major Santee Cooper Transmission Improvements Included in the 2028 Roll-Up Integration Cases

Projects	Scheduled Completion Year
Sandy Run 230-115 kV Substation	2019
Pomaria—Sandy Run 230 kV line	2019
Sandy Run—Orangeburg 230 kV line	2020
Wassamassaw 230-115 kV Substation	2021
Conway – Marion 230 kV Line	2028
Conway 230 kV Switching Station	2028
Cross – Wassamassaw #2 230 kV Line	2026

Southern Company

Table 2-3 shows the major upgrades within the Southern Balancing Authority Area included in the 2028 roll-up integration cases.

Table 2-3
Major Transmission Improvements in the Southern Balancing Authority Area

Included in the 2028 Roll-Up Integration Cases

Project	Scheduled Completion
EUTAW – SOUTH TUSCALOOSA 115 KV T.L.	Summer 2020
GOODSPRINGS 230/161 KV T.S.	Summer 2020
MOBILE AREA NETWORKING	Summer 2020
HARRIS – NORTH SLEMA 230 KV T.L.	Summer 2021
BASSETT CREEK CORRIDOR PROJECTS	Summer 2022
FAYETTE – GORGAS 161 KV T.L.	Summer 2023
CENTRAL ALABAMA AREA 115 kV PROJECT	Summer 2023

FLOMATON 230/115 KV SUBSTATION	Summer 2023
BLAKELY - MITCHELL 115 KV T.L.	Summer 2020
GRANITEVILLE - SOUTH AUGUSTA 115 & 230 KV T.L.	Summer 2020
NORTH AMERICUS – PERRY 115 KV T.L.	Summer 2020
WADLEY PRIMARY 500/230 KV PROJECT (PHASE 2)	Summer 2021
AVALON JUNCTION – BIO 115 KV T.L.	Summer 2022
GORDON - N. DUBLIN (N. DUBLIN - EVERGRN CH) 115 KV UPGRADE	Summer 2022
SINCLAIR DAM – WARRENTON PRIMARY 115 KV T.L.	Summer 2024
YATES UNIT 8 NETWORK IMPROVEMENTS	Summer 2028
BRANCH UNIT 5 NETWORK IMPROVEMENTS	Summer 2027

Southwest Power Pool

The major transmission improvements to the SPP transmission system included in the 2028 roll-up integration cases are listed in Table 2-4. To keep the list manageable, it excludes many high voltage projects that strictly involve breaker replacement or bus work that does not affect lines or upgrades to transformers to lower voltages.

Table 2-4
Major Transmission Improvements to the SPP Transmission System
Included in the 2028 Roll-Up Integration Cases

Project	Mileage	Scheduled Completion Year
Iatan - Stranger Creek 345 kV Ckt 1 Voltage Conversion	18.2	2018
Knoll - Post Rock 230 kV New Line Ckt 2	0.5	2018
Potash Junction - Road Runner 345 kV Conv. and Transformers at Kiowa and Road Runner	1	
Chisholm–Gracemont 345 kV	104	2018
Elm Creek–Summit 345 kV	58	2018
Gentleman–Cherry Co–Holt Co 345 kV	227	2021
Kiowa–North Loving–China Draw 345 kV	39	2018
Hobbs–Kiowa 345 kV	47	2018
Hobbs 345/230 kV Ckt 1 Transformer		2018
Arcadia–Redbud 345 kV	5	2019
Tuco–Yoakum–Hobbs 345 kV	159	2020
Cimarron–Matthewson–Tatonga–Woodward 345 kV (circuit 2)	126	2021

Tennessee Valley Authority

The major upgrades to the TVA transmission system included in the roll-up integration cases are as follows:

- The Philadelphia-Louisville, Philadelphia-Midway, and Philadelphia-DeKalb 161 kV are long lines out of West Point that support the lower Mississippi area. Long-range load-flow studies show that loss of two lines in a peak or maintenance scenario causes thermal and voltage violations. During spring maintenance outages, when both the Sturgis-Maben Tap 161 kV line and the Sturgis-Adaton 161 kV line are out for maintenance, the Sturgis-Louisville-Philadelphia 161 kV line can exceed its capacity. TVA will construct 50 miles of new transmission line to create the Red Hills-Leake 161 kV line by December 2019.

- Long-range load-flow studies show that during off-peak conditions, when Raccoon Mountain is pumping, the Raccoon Mountain 500/161 kV transformer can overload. Following the shutdown of Widows Creek Fossil Unit 8, these studies show that multiple transmission lines overload and additional voltage support is needed in the Huntsville, Alabama area under contingency. TVA will install a second Widows Creek 500/161 kV transformer by December 2019.
- Long-range load-flow studies show that thermal overloads are present in the Coffeeville, Mississippi area during peak and maintenance scenarios for multiple area contingencies. TVA will construct 30 miles of new transmission line with 954 ACSR at 100°C to create the Oxford-Coffeeville 161 kV line by June 2020.
- Long-range load-flow studies show that for the loss of the Bull Run-Volunteer 500 kV line, the Alcoa SS-Nixon Road 161 kV line will exceed its line capability. TVA will rebuild 12 miles of the Alcoa North-Nixon Road 161 kV line with 1590 ACSR at 100°C and will construct 2 miles of new transmission line to create the Alcoa SS-Nixon Road 161 kV #2 line by June 2021.
- Long-range load-flow studies show that thermal overloads are present and voltage support is needed in the Olive Branch, Mississippi area under contingency. TVA will construct the Chickasaw Trails and Diffee 161 kV substations and 17 miles of new transmission line with 954 ACSR at 100°C to create the Chickasaw Trails-Moscow 161 kV line. TVA will also loop the existing Miller-Holly Springs 161 kV line into the Chickasaw Trails by June 2021.
- Long-range load-flow studies show that when both the Volunteer-Phipps Bend 500 kV line and the East Knox-Dumplin Valley 161 kV line are lost, the Knox-Douglas 161 kV line exceeds its capacity. TVA will rebuild and reconductor portions of the Knox-Douglas 161 kV line, including 15 miles with 954 ACSS at 125°C by June 2022.
- Long-range load-flow studies show that thermal overloads and voltage violations are present in the Golden Triangle area of Mississippi during peak and maintenance scenarios for multiple area contingencies. TVA will construct the Artesia 161 kV switching station and 12 miles of new transmission line with 954 ACSS at 150°C to create the Artesia-W. Columbus 161 kV line. TVA will also reconductor 15 miles of the West Point-Starkville 161 kV line with 954 ACSS at 150°C by June 2022.

2.6 Generation Assumptions (Additions and Retirements)

This section describes assumptions associated with the modeling of new and retiring generation facilities. As with transmission facilities, the processes for including new generation and generation retirements vary among the different Planning Coordinators. This section describes, in general terms, the processes followed and the assumptions made in the 2028 cases regarding generation additions and retirements.

Appendix C provides a complete, detailed listing of all new and upgraded generation projects included in the 2028 roll-up integration cases. The "Projected In-Service Date" column indicates whether the facility was included in the 2028S and 2028W models ("2028S") or just the 2028W model ("2028W"). Planning Coordinators have agreed to the following terms to describe the status of future generation projects:

Construction—resource is under construction or is being commissioned,

Committed—resource has completed the interconnection request process or has obtained applicable transmission service,

Proposed—resource has been proposed and included in the planning process but does not have applicable transmission service, and

Renewable Portfolio Standards — vary from state to state and are expressed in terms of percentage of energy that must be produced from renewable resources for a given state or entity. The entities responsible for meeting the RPS requirements are typically load-serving entities, not the Planning Coordinators.

The transmission analysis performed in this study involves analyzing system reliability during summer peak periods to assess potential transmission system constraints. The renewable resources provided to each Planning Coordinator by its LSEs and other market participants for transmission planning purposes are included in the power-flow modeling of the study. Appendix C lists new generation additions by fuel type, including all new renewable resources included in the modeling. Capacity values for each renewable resource and its output modeled in the peak power-flow cases are included in Appendix C.

Associated Electric Cooperative Inc.

AECI has no generation additions or retirements in the 2028 summer and winter roll-up integration cases.

Cube Hydro Carolinas

Cube Hydro Carolinas does not have any plans for new or upgrades to its generation fleet.

Dominion Energy South Carolina (DESC)

In July 2017 DESC abandoned construction of VC Summer Nuclear Station Units 2 and 3, canceling the project. In addition, previously announced plans to retire existing generation when these units entered service were also canceled. These generation changes are reflected in both the 2028S and 2028W base cases.

Duke Energy Carolinas

The cases include DEC and IPP generation facilities presently in operation. Duke will add a 477 MW combined-cycle plant IPP at the Ernest site and will add a 525 MW combustion turbine at the Lincoln site. Allen units 1, 2, & 3 with an output of 617 MW will be retired.

Duke Energy Florida

The retirement of DEF's Crystal River coal units 1 and 2 became effective December 31, 2018. Continued operations of the peaking units at Higgins and Avon Park are planned until the year 2020 while Bayboro is planned until the year 2028. The Debary P2 - P6 and Bartow P1 & P3 peaking units are planned to retire in 2027. The new Citrus County Combined Cycle plant, with a summer net capability of 1,632 MW, is operational as of December 31, 2018.

Duke Energy Progress

DEP has announced the retirement of two coal units at its Asheville Plant in December 2019 and the addition of two 280 MW combined cycle units at its Asheville Plant in December 2019. These changes have been modelled in the 2028 summer and winter roll-up integration cases.

Florida Power and Light

Future projects that have undergone FPL's internal budget review process as well, as those projects that are representative of the Ten-Year Site Plan filing with the Florida Public Service Commission, are included in the roll-up integration cases. Florida Power and Light plans to retire the Manatee #1 and Manatee #2 steam turbines in 2022 and add up to a cumulative total of 8000MW of solar PV by 2028. FPL's TYSP filing serves as an input for the generation and load assumptions for modeling purposes.

Georgia Transmission Corporation

GTC's member cooperatives provide generation resource assumptions to GTC. In Appendix C, generation resources listed under the PC "SBA" also include generation resources identified by GTC's member cooperatives.

ISO New England

ISO-NE has included QP624 in the roll-up integration cases. This project is an 800 MW off-shore wind farm off the cost of Massachusetts. It was selected by a state sponsored RFP, received an FCA13 Capacity Supply Obligation (CSO), and is currently undergoing the proposed plan application process as described in Section I.3.9 of the ISO New England Tariff. Additionally, two existing resources (Mystic 7 and Mystic Jet), together with a future one (QP489), have been removed from the case because they no longer hold a CSO in ISO-NE's Forward Capacity Market.

JEA

JEA is jurisdictional in the State of Florida and subject to Florida's Electrical Power Plant Siting Act and Transmission Line Siting Act. The Florida Department of Environmental Protection administers these acts, and under the statutes of these acts, the governor and cabinet sit as the siting board and review applications for power plant and transmission line certifications that reach certain minimum levels of impact. Not all power plants and transmission line constructions require cabinet approval. The statutes for these acts require the Florida Public Service Commission to review and grant the "Certificate of Public Convenience and Necessity" applications.

JEA annually produces a Ten-Year Site Plan (TYSP) filing to the Florida Public Service Commission, which contains the 10-year forecast of demand and the associated resources required to meet JEA's

15% planning reserve target. The TYSP serves as the official source for the generation resources provided for in the FRCC load-flow model. JEA currently does not have any plans to retire its existing generators in the 10-year planning horizon.

LG&E and KU Energy

The respective LG&E and KU PC load-serving entities (and market participants securing point-to-point transmission service) provided the resource assumptions contained within the 2028 roll-up integration cases. Resources without long-term firm transmission service may be included in the model but at zero output. “Committed” resources include designated network resources and other resources that have secured long-term firm transmission service. “Proposed” resources are those the LSEs provided to meet their forecasted load-service requirements for future years but have not been designated as a network resource pursuant to the LG&E/KU OATT.

LG&E/KU has retired the E.W. Brown #1 and #2 coal units. These generating units have been removed from the roll-up integration cases.

MEAG Power

MEAG member participants provide the generation resource assumptions. In Appendix C, generation resources listed under the PC “SBA” also include generation resources identified by MEAG.

Midcontinent ISO

Within MISO, the future generation resources modeled come from the MISO generation interconnection process and resource forecasts based on public policy requirements. Future generators with signed interconnection agreements are included in models.

New York ISO

New and upgraded generation projects are modeled based on NYISO’s 2018 Load and Capacity Data. The Indian Point Units 2 and 3 nuclear power plants are modelded out of service in the 2028 roll-up integration cases.

PJM Interconnection

Section 2.4 describes additional information on the PJM planning process. The transmission system is planned for the forecasted load growth and interconnection requests that have reached a specified degree of commitment. This process is according to PJM’s tariff, agreements, and business rules approved in the regulatory and stakeholder processes. In this capacity, PJM’s business is only involved with generation when they initiate a request for interconnection to the transmission system.

In addition to existing in-service generation, the 2028 roll-up integration cases incorporate generation with signed Interconnection Service Agreements and announced generation deactivations (e.g., retirements). Since load-serving entities are responsible for state Renewable Portfolio Standards, PJM plans for the LSE’s resources as they enter the generation queue and fulfill their interconnection commitments. Section 2.4 of this report also describes PJM’s public policy transmission planning.

PJM's power-flow case transmission model includes the network upgrades necessary to accommodate the interconnection and operation of new generation for which an ISA has been signed. Appendix C of this report provides a list of these projects. Announced unit retirements that PJM has accepted are deactivated in the roll-up power flow.

The PJM RTEP process projects renewable requirements based on a detailed review of the state statutes and other information on a state by state basis. PJM includes existing installed renewables and queued generation with signed Interconnection Service Agreements into its baseline RTEP planning and market efficiency planning. This will result in planned transmission upgrades to maintain system capability for delivering these renewables in the PJM market. PJM is responsible for ensuring the deliverability of generation committed to PJM load according to the applicable tariffs and agreements. This is achieved through PJM's comprehensive RTEP planning process.

PowerSouth Energy Cooperative

Resource assumptions contained within the 2028 roll-up integration cases for PowerSouth were determined through power supply studies and our annual capacity planning process. PowerSouth has plans to retire the Lowman coal plant and replace it with a combined cycle natural gas plant. Approximately 556 MW of coal fired generation will be retired by 2021 and approximately 730 MW of new gas generation will be added by 2023. Resource additions in PowerSouth's generation expansion plan are not subject to approval by state regulatory agencies but do require approval by RUS. PowerSouth and its members are not currently impacted by any state or federal Renewable Portfolio Standards.

Santee Cooper

For the 2028 roll-up integration cases, the generation assumptions include both existing generation and future generation as specified in Santee Cooper's current Generation Expansion Plan. The existing generation expansion plan for the VC Summer nuclear units Santee Cooper and SCE&G shared ownership has been cancelled. Santee Cooper is continuing to develop its future generation plans, represented by pseudo generation at Site X.

Southern Company

The respective LSEs (and market participants through securing point-to-point transmission service) provided the resource assumptions contained within the 2028 roll-up integration cases for Southern Company. Resources that have been announced for retirement have been removed from the cases. Resources without long-term firm transmission service may be included in the cases, but at zero output. "Committed" resources include designated network resources and other resources that have secured long-term firm transmission service. "Proposed" resources are those the LSEs provided to meet their forecasted load service requirements in future years but have not been designated as a network resource pursuant to the OATT.

Southwest Power Pool

SPP includes new generators that have a FERC-filed Interconnection Agreement (IA) and not on suspension. New generators without an IA are not added to the models until the IA is executed. Proposed generators without an IA may be added as needed to address generation deficiencies. SPP projects roughly 1,748 MWs of generation retirements between 2019 and 2028.

Tennessee Valley Authority

For resource assumptions, the roll-up integration cases used TVA's official capacity expansion plan provided by TVA's Resource Strategy group (and market participants through securing PTP transmission service). "Committed" resources include designated network resources and other resources that have secured long-term firm transmission service. "Proposed" resources are those included in TVA's official capacity expansion plan to meet forecasted load service requirements in future years but have not been designated as a network resource pursuant to the OATT.

2.7 Generation Dispatch Description

This section explains the methods each Planning Coordinator used to dispatch the available generation in the 2028S and 2028W roll-up integration cases. All PCs apply methods of dispatching their systems representative of actual system dispatch expected to occur based on economic and physical considerations. The precise base dispatch is not critical to determining transmission-expansion plans because these plans are developed on the basis of testing the systems against a variety of system configurations, including variations from the base dispatch, to ensure reliable system performance consistent with applicable system performance standards.

Associated Electric Cooperative Inc.

AECI's generation dispatch is based on economic order to provide for the projected load forecast and any external transactions. Order of economic dispatch is determined by AECI's base load requirements.

Cube Hydro Carolinas

Cube Hydro Carolinas generation dispatch is modeled on the basis of economic dispatch in accordance with the priorities identified by operations. All of CHC energy is modeled as sale of firm energy.

Dominion Energy South Carolina (DESC)

The dispatch of generation resources within the SCE&G planning area is based on the economic merit order of the generating units and is set to meet the requirements of LSEs and executed contracts for the sale of firm energy with firm transmission service.

Duke Energy Carolinas

The DEC system generation dispatch is modeled based on economic dispatch in accordance with the priorities identified in the LSEs' resource projections and according to executed contracts for the sale of firm energy.

Duke Energy Florida

The DEF system generation dispatch is modeled on the basis of economic dispatch in agreement with the priorities identified in the LSEs' resource projections and according to executed contracts for the sale of firm energy.

Duke Energy Progress

The DEP system generation dispatch is modeled on the basis of economic dispatch in agreement with the priorities identified in the LSEs' resource projections and according to executed contracts for the sale of firm energy.

Florida Power and Light

The dispatch of FPL's generation resources is based on economic order for meeting FPL's forecasted load and firm contractual requirements.

Georgia Transmission Corporation

The dispatch of the generation resources contained within the roll-up integration cases is based upon the dispatch merit order identified in the LSEs' resource projections (including GTC's member cooperatives). In addition, generating units associated with long-term firm transmission commitments to external areas are dispatched "on" at an output level consistent with the interchange values discussed in Section 2.4.

ISO New England

In real-time operations, ISO-NE uses security constrained dispatch of generation through a competitive wholesale market that results in the operation of the lowest priced resources to meet system demand for electricity, while avoiding unacceptable potential post-contingency system conditions. The generation dispatch of resources typically among the least cost (*e.g.* nuclear and natural gas combined cycle) are dispatched online, and resources that typically have higher costs (*e.g.* oil combustion turbines and peaking units) are left off-line. The output of wind, solar photovoltaic, and hydroelectric generation is modeled consistent with the reliability analysis resource assumptions used at summer and winter peak load conditions. The New England regional system planning process examines many different possible resource dispatch and unavailability conditions.

JEA

All JEA generators in the roll-up integration cases are dispatched on an economic basis.

LG&E and KU Energy

The LG&E and KU system generation dispatch is modeled in accordance with the priorities identified in the resource projections each Resource Planner (RP) provided.

MEAG Power

The dispatch of the generation resources contained within the roll-up integration cases to serve MEAG participant load is based on the dispatch merit order identified in the resource projections. MEAG Power is not currently subject to RPS mandates.

Midcontinent ISO

The dispatch of MISO members' generation is done at the Local Balancing Authority (LBA) Level. Wind generation is dispatched at capacity credit level in summer peak models and at average and high levels in off-peak models. The system average wind capacity credit is 15.6 percent based on MISO's Loss of Load Expectation study. Solar generation is dispatched at 50 percent of nameplate. New and retiring generation is incorporated through the normal MTEP model building process.

New York ISO

The NYISO generation dispatch in the roll-up cases is based on the typical dispatch pattern observed during peak load. This dispatch represents a single snapshot of a representative dispatch as a starting point. The generation dispatch includes only those external transactions that are firm.

PJM Interconnection

Internal to PJM, the roll-up model dispatch is based on a representative market-based dispatch prepared by the planning department. Similar to the load representation in this model, the dispatch represents only a single snapshot of a representative dispatch as a starting point reference model. The annual series of PJM planning analyses examines thousands of alternative dispatch scenarios. Because of this and because PJM operates and is planned as a single system, these snapshot PJM dispatch values change moment to moment based on a single-area market. The starting representative market dispatch therefore is not a focus for PJM planning analyses.

PowerSouth Energy Cooperative

The generation dispatch of the resources contained within the 2028 roll-up integration cases are economically dispatched according to current fuel-cost assumptions and availability.

Santee Cooper

The Santee Cooper generation dispatch used in the 2028 roll-up integration cases is a strictly economic dispatch model. Combined cycle gas units and available hydro units are all dispatched first, large coal base-load units and all other generating units are economically dispatched. No units are dispatched out of merit to alleviate system loading constraints.

Southern Company

The generation dispatch of the resources contained within the 2028 roll-up integration cases is based on the dispatch merit order identified in the LSE resource projections. In addition, long-term firm transmission commitments to external areas are dispatched "on" at an output level consistent with the interchange values discussed in Section 2.4.

Southwest Power Pool

Each SPP data submitter dispatches its generation in the model to cover its own projected load obligations, including any approved long-term firm transmission service.

Tennessee Valley Authority

Market participants within TVA's Balancing Authority are dispatched at the level of their confirmed long-term, firm transmission service. Production cost dictates the order in which TVA's generation fleet is dispatched in the roll-up integration cases. TVA does not apply a security-constrained dispatch to alleviate system constraints. The typical order of dispatch from most economic to least economic by generator technology is as follows:

- Hydro
- Nuclear
- Pumped storage
- Fossil
- Combustion-cycle gas
- Combustion turbine gas

In addition, long-term, firm transmission commitments to external areas are dispatched "on" at an output level consistent with the interchange values discussed in Section 2.3.

Section 3
Interregional Transmission (Gap) Analysis

Power-flow analysis is often focused on forecasted summer and winter peak conditions, which typically (but not always) represent highest loadings on the facilities. To perform interconnection-wide power-flow analysis, in addition to the modeling developed by each Planning Coordinator, an underlying exchange of energy or interchange among balancing authority areas (BAAs) must be established. It is common for transmission providers to have long-term, firm transmission service commitments with market participants involving deliveries to other balancing authority areas without the market participants "matching" these transmission service commitments with the associated transmission providers in the receiving balancing authority areas. Because market participants can and do purchase long-term firm transmission service on a so-called partial-path basis, determining the energy exchange or interchange among BAAs requires coordination.

EIPC's Interregional Transmission Analysis for the 2028 planning year is a power-flow analysis based on the 2028 roll-up models. These models represent power system facilities and loads for the summer and the winter peak forecast for 2028, as developed by each Planning Coordinator during their then-current planning cycle. The interchange used for this analysis was developed through a coordinated effort of the EIPC Planning Coordinators and is based on a subset of transmission service commitments representing full-path transactions from source to sink.

A contingency analysis was performed in a collective manner. The objective of this analysis is to identify potential interconnection-wide power-flow interactions that may result from the effects of one PA's plans on another. Because this particular set of power flows and energy exchange (interchange) may differ from those assessed during local and regional planning activities, additional constraints may be identified, particularly where interchange or generation dispatch patterns in other regions may differ from local commitments and assessments. To the extent additional constraints or "gaps" are identified during the interregional analysis, the PCs' respective regional planning processes will refer to these constraints and the accompanying power-flow conditions.

This task is a screening analysis, and the PCs' regional planning processes will refer to its results (potential gaps) for detailed assessments. Detailed analysis may or may not indicate a need for system upgrades in future planning cycles. Items identified in the "gap" analysis should not be construed as the baseline topology of the 2028 roll-up model.

System performance was assessed in a manner consistent with the NERC TPL (transmission planning) Reliability Standards. Bulk electric system elements above 100 kV were monitored. Thermal criteria applicable to each facility were applied.

3.1 Contingency Selection

Contingencies representing outages of all transmission elements 230 kV and above and all transformers with a low-side voltage rating of 100 kV or above were modeled and revised. Planning Coordinators also had discretion to simulate contingencies of transmission elements below 230 kV, depending on the composition and characteristics of each PC's bulk electric system.

3.2 Interregional Analysis Results

This section provides a list of the potentially overloaded facilities identified as a result of the EIPC collective or individual PC analysis. The overloads identified were assumed to result from neighboring system interactions that have yet to be assessed in detail. In some cases, the cause and system interactions associated with a potential reliability issue may be difficult to pinpoint. Issues identified will inform the future planning cycles of the PCs' regional planning processes (see Section 4).

3.2.1 Summary of Thermal Results

A collective thermal analysis was performed on the 2028 summer and winter peak roll-up cases for each Planning Coordinator system (NPCC, MISO, PJM, SERC, SPP, and FRCC). Several thermal facility issues that meet the reporting requirements of Section 3.1 were identified in each area for both the summer and winter peak cases and summarized in the tables below (Table 3-1 to Table 3-14). The highest percentage overload was listed for branches found to be overloaded for multiple contingencies.

The respective concerned Planning Coordinators provided the mitigation plans for the identified issues. For the regions with the mitigation plans and upgrades, the focus is mostly on the lower voltage system. For most of the thermal constraints identified in the NPCC area, the mitigation plans are either operator actions or Remedial Action Schemes (RASs).

Independent System Operator New England

Table 3-1 Thermal Overloads in the ISO-NE Area, Summer 2028 Case

Monitored Element	Normal or LTE Rating (MVA)	Loading
		%
113975 KING ST_54 115 114075 W AMESBURY 115 1	289	116.64

Table 3-2 Thermal Overloads in the ISO-NE Area, Winter 2028 Case

Monitored Element	Normal or LTE Rating (MVA)	Loading
		%
N/A	N/A	N/A

New York Independent System Operator

Table 3-3 Thermal Overloads in the NYISO Area, Summer 2028 Case[7]

Monitored Element	Normal or LTE Rating (MVA)	Loading %
125015 AC CBLTP 115 125041 N.CHELSE 115 1	282	105.99
125015 AC CBLTP 115 125080 DANSK-N 115 1	231	129.39
125021 DC CBLTP 115 125041 N.CHELSE 115 1	282	106.24
125021 DC CBLTP 115 125080 DANSK-N 115 1	217	138.06
130792 CORN TP2 115 130800 ETNA 115 115 1	115	105.12
136759 BRNS FLS 115 136807 TAYLORVL 115 2	135	100.51

[7] Mitigation action for thermal overloads in the NYISO area can be found in table 4-1.

Table 3-4 Thermal Overloads in the NYISO Area, Winter 2028 Case

Monitored Element	Normal or LTE Rating (MVA)	Loading %
137454 REYNLD3 345 137528 REY. RD. 115 1	676	110.11

Midcontinent Independent System Operator

Table 3-5 Thermal Overloads in the MISO Area, Summer 2028 Case

Monitored Element	Normal or LTE Rating (MVA)	Loading %
247489 05BOSSERMAN 138 255153 17MICH_CITY 138 1	156	106.71
247489 05BOSSERMAN 138 255184 17TRAIL_CRK 138 1	156	112.99
255150 17LNG 138 255152 17MAPLE 138 1	138	102.75
264730 19CANIFP 120 264538 19CANIF 120 1	468	106.35
264752 19CANIF 345 264730 19CANIFP 120 1	468	106.89
303028 8COTNWOOD1! 500 303029 8XFMRINT1 500 1	360	100.48
303028 8COTNWOOD1! 500 303030 8XFMRINT2 500 1	360	102.74
303302 3MINDEN_LG 115 337361 3MINDEN_LA! 115 1	115	102.34
334120 4NU LJON! 138 334211 4BDAYTON! 138 1	99	108.93
334217 4MAG AMS 138 334218 4PINTAIL% 138 1	112	109.88
335455 4CHAMPAGNE! 138 500720 PLAISAN4 138 1	287	109.18
336131 6ADMSCRK% 230 336136 6BOGALUS% 230 1	883	100.42
336131 6ADMSCRK% 230 336136 6BOGALUS% 230 2	883	100.42
338120 5S.LEAD HILL 161 505461 BULL SH W5 161 1	203	102.72
608657 RVT1BUS7 115 618015 GRE-HILLCTP7 115 1	60	104.27

608740 GR RPDS7 115 618009 GRE-POKEGMT7 115 1	60	112.56
618009 GRE-POKEGMT7 115 618015 GRE-HILLCTP7 115 1	60	107.92
693694 OAK CK LT884 345 699367 ELM ROAD 345 1	300	100.29
698857 OC CRK8 230 693694 OAK CK LT884 345 1	300	102.34

Table 3-6 Thermal Overloads in the MISO Area, Winter 2028 Case

Monitored Element	Normal or LTE Rating (MVA)	Loading %
303220 3PINECLIFF 115 336121 3FRANKLNT 115 Z1	115	103.69
303312 3HOLTON 115 336120 3CHIKFM 115 1	188	101.41
334120 4NU LJON! 138 334211 4BDAYTON! 138 1	99	106.65
334216 4GORDON 138 334217 4MAG AMS 138 1	112	100.9
334217 4MAG AMS 138 334218 4PINTAIL% 138 1	112	109.64
335455 4CHAMPAGNE! 138 500720 PLAISAN4 138 1	287	101.77
336111 3AMITE! 115 336120 3CHIKFM 115 1	188	102.56
336504 3NATCHEZ! 115 336510 3SE.NATCHEZ+ 115 1	108	104.73
337967 3RICUSKEY! 115 337975 3GOODWIN% 115 1	106	113.57
608711 MNTCPTC7 115 608712 MNTCPTA7 115 1	101	121.11
620233 EDGETAP7 115 620234 PEL RPD7 115 1	88	100.4
693694 OAK CK LT884 345 699367 ELM ROAD 345 1	300	102.99
698857 OC CRK8 230 693694 OAK CK LT884 345 1	300	105.09
659300 STANTN.T-BE7 115 661008 BEULAH 7 115 1	132	100.83

PJM Interconnection

Table 3-7 Thermal Overloads in the PJM Area, Summer 2028 Case[8]

Monitored Element	Normal or LTE Rating (MVA)	Loading %
204521 27BAIR 115 204537 27HILL 115 1	160	100.12
204521 27BAIR 115 204540 27JACKSON 115 1	160	112.08
207948 CUMB 230 207950 CUMB TR2 230 1	624	100.82
232002 CEDAR CK 230 232013 SILVER RUN 230 1	679	108.48
243506 05ELLIOT 138 243619 05ROSEWOODSS 138 1	89	123.94
247489 05BOSSERMAN 138 255153 17MICH_CITY 138 1	156	106.71
247489 05BOSSERMAN 138 255184 17TRAIL_CRK 138 1	156	112.99
271219 CLYBOURN ;0R 138 271247 CROSBY ; R 138 2	77	118.92
271221 CLYBOURN ;9R 138 272763 WEST LOOP; Y 138 1	90	105.37
271321 DEVON ;6R 138 272129 NORTHWEST; R 138 1	253	113.2
271322 DEVON ;9B 138 272384 ROSE HILL;BT 138 1	270	108.73
271323 DEVON ;3R 138 272385 ROSE HILL;RT 138 1	270	116.36
271323 DEVON ;3R 138 272471 SKOKIE 85;3T 138 1	332	101.61
271324 DEVON ;0B 138 272128 NORTHWEST; B 138 1	270	105.45
271385 E FRANKFO; R 138 998987 E FRANKFT 83 138 1	480	129.93
271675 HUMBOLT P; R 138 272371 ROCKWELL ; R 138 1	74	115.85
271675 HUMBOLT P; R 138 272371 ROCKWELL ; R 138 2	74	115.85
272129 NORTHWEST; R 138 272385 ROSE HILL;RT 138 1	270	104.77

[8] PJM's assessment of the issues listed in the gap analysis (Table 3-7 and Table 3-8) attributes their cause primarily to increased load levels, generator interconnections requiring further study, local voltage-tuning issues, or issues that could be resolved with re-dispatch. Because all these issues will be addressed to the extent they materialize in the course of completing the necessary regional planning analysis, they are not expected to have an impact on interregional reliability and do not represent "gaps" in the interregional plans.

272794 WOLFS ; B 138 998969 WOLFS 81 138 1	480	100.53
275225 TOLLWAY ;3M 138 272600 TOLLWAY ; B 138 1	480	106.8
314004 6ASHBURN 230 314010 6BEAMEAD 230 1	762	103.56
314004 6ASHBURN 230 314072 6PL VIEW 230 1	762	107.67
314112 3IND HIL 115 314122 3SOWEGO 115 1	179	122.03
314122 3SOWEGO 115 314156 3BRISTER 115 1	239	106.82

Table 3-8 Thermal Overloads in the PJM Area, Winter 2028 Case

Monitored Element	Normal or LTE Rating (MVA)	Loading %
235345 01HINTON 138 242668 05HINTON 138 ZB	23	101.81
235345 01HINTON 138 242668 05HINTON 138 ZB	23	105.46
235506 01RINGLD 230 270071 RICE_230 230 2	830	106.58
242514 05J.FERR 765 242684 05J.FERR 138 2	364	138.22

Southwest Power Pool

Table 3-9 Thermal Overloads in the SPP Area, Summer 2028 Case

Monitored Element	Normal or LTE Rating (MVA)	Loading %
300069 5CHOTEAU1 161 512648 MAID 5 161 1	855	105.51
300320 5LEVASY 161 548808 ECKLES-161 161 1	227	105.65
338120 5S.LEAD HILL 161 505461 BULL SH W5 161 1	203	102.72
507755 S SHV 4 138 507765 WALLAKE4 138 1	188	110.84
509811 T.S.E.-4 138 509833 S.HUD.-4 138 1	168	102.64
523304 MOORE_W 3 115 523315 RB-S&S 3 115 1	79.7	110.11
526160 CARLISLE 3 115 526162 LP-DOUD_TP 3 115 1	119.5	103.02
528018 RED_BLUFF 3 115 528235 WOLFCAMP_TP3 115 1	160	116.18

533370 NORTHST3 115 533371 NORTHVW3 115 1	68	100.6
533370 NORTHST3 115 533371 NORTHVW3 115 2	68	100.6
640304 OGALALANPPD7 115 659800 GRANTNB_-TS7 115 2	147	102.74

Table 3-10 Thermal Overloads in the SPP Area, Winter 2028 Case

Monitored Element	Normal or LTE Rating (MVA)	Loading %
300069 5CHOTEAU1 161 512648 MAID 5 161 1	940	100.76
526269 LUBBCK_STH 6 230 526525 WOLFFORTH 6 230 1	318.7	100.8

SERC

Table 3-11 Thermal Overloads in the SERC Area, Summer 2028 Case

Monitored Element	Normal or LTE Rating (MVA)	Loading %
300069 5CHOTEAU1 161 512648 MAID 5 161 1	855	105.51
300071 5CLINTN 161 300124 5HOLDEN 161 1	227	107.91
300110 5PITTSV 161 300124 5HOLDEN 161 1	227	109.62
300110 5PITTSV 161 300320 5LEVASY 161 1	227	107.78
300320 5LEVASY 161 548808 ECKLES-161 161 1	227	105.65
300599 4KISKER 138 300134 5KISKER 161 3	250	102.58
306001 3CLARK H 115 339150 3JST-SC 115 1	120	102.63
306062 SENCA TB 100 306078 IND 306078 100 1	152	118.54
306071 WESTMNS+ 100 309747 BREC35 100 1	152	109.48
306078 IND 306078 100 309747 BREC35 100 1	152	114.94
306138 E GRNVLE 100 308702 KINGGATE 100 1	132	102.04
306172 LAUEC25 100 306216 LAUEC31 100 1	120	100.28

306226 BRDRVR16 100 306245 CLIFSID 100 1	65	114.09
306269 LAWSONFK 100 308802 PINEWOOD W 100 1	129	108.74
306373 GSTON10T 100 306382 MCADENVL 100 1	120	106.42
306417 WYLIE HY 100 306529 YORK20 T 100 1	149	114.59
306573 CONCORD 100 309611 CONCORD4 100 1	135	107.67
308502 ALLEN2B 100 308750 ALLEN2A 100 Z5	270	105.18
360054 8TRINITY AL 500 360055 5TRINITY AL 161 1	1222	109.48
360152 5S JACKSON 161 361704 5FLEX TN 161 1	226.7	121.69
360214 5BATESVILLE 161 361402 5TALLHACH IP 161 1	334.6	102.08
360238 5MACON MS 161 361444 5PAULETTE TP 161 1	298.7	101.17
360241 5DEKALB MS 161 360370 5SHUQUALAK 161 1	298.7	107.19
360241 5DEKALB MS 161 361671 5CLEVLAND MS 161 1	299.2	105.43
360242 5PHILADEL MS 161 361733 5HOUSE MS TP 161 1	289.5	102.09
360370 5SHUQUALAK 161 361056 5S MACON MS 161 1	298.7	105.37
360589 5BLOOMO MS 161 361671 5CLEVLAND MS 161 1	299.2	104.49
360589 5BLOOMO MS 161 361733 5HOUSE MS TP 161 1	299.2	102.04
361056 5S MACON MS 161 361444 5PAULETTE TP 161 1	298.7	103.21
380491 3E ATHENS 115 382752 3WHITEHALL 115 1	124	100.58
380804 3BONAIRE B1 115 381697 3ANCHOR B JC 115 1	135	119.61
381654 3NORTHROP J 115 381655 3AULTMAN RD 115 1	100	107.92
381676 3SLEEPY HOL 115 382319 3PCH BLOSSOM 115 1	124	103.63

Table 3-12 Thermal Overloads in the SERC Area, Winter 2028 Case

Monitored Element	Normal or LTE Rating (MVA)	Loading %
300040 7FLETCH 345 998934 FLETCHER1 161 1	213	108.66
300069 5CHOTEAU1 161 512648 MAID 5 161 1	940	100.76

300110 5PITTSV 161 300124 5HOLDEN 161 1	273	100.52
300110 5PITTSV 161 300320 5LEVASY 161 1	236	112.84
301532 5FLETCHXF1 161 998934 FLETCHER1 161 1	213	107.34
304435 3MAXTON 115 304440 3IND 304440 115 1	120	102.22
306062 SENCA TB 100 306078 IND 306078 100 1	181	118.2
306071 WESTMNS+ 100 309747 BREC35 100 1	181	110.6
306078 IND 306078 100 309747 BREC35 100 1	181	115.28
306132 CAMPOBEL 100 306198 TIGER 100 1	117	102.28
306226 BRDRVR16 100 306245 CLIFSID 100 1	84	103.53
306247 CLINTON TW 100 307942 CLINTON 100 Z1	41.6	127.58
317264 6ELSNRSW6 230 317246 3ELSNRSW3 115 1	168	106.58
317264 6ELSNRSW6 230 317246 3ELSNRSW3 115 2	168	106.57
339001 BADIN 100 339005 TUCKERTN 100 1	116	106.9
339003 HIGH RCK 100 339005 TUCKERTN 100 1	103	120.42
360152 5S JACKSON 161 361704 5FLEX TN 161 1	310.9	102.34
360214 5BATESVILLE 161 361402 5TALLHACH IP 161 1	334.6	109.81
360236 5COLUMBUS MS 161 361052 5WEYERHSR TP 161 1	334.6	104.68
360242 5PHILADEL MS 161 361733 5HOUSE MS TP 161 1	334.6	105.77
360339 5DAVIDSON #2 161 365160 5DAVIDSON RD 161 1	349.4	114.9
380156 6N DUBLIN B1 230 380833 3N DUBLIN B1 115 1	157	112.11
380612 3FIRST AV B1 115 382227 3COLUMBUS 115 1	137	119.27
381010 3BEMISS 115 382549 3PINE GRV B2 115 1	101	108.84
381676 3SLEEPY HOL 115 382319 3PCH BLOSSOM 115 1	137	105.65
382263 3WATERFORD 115 382351 3BONAIRE B2 115 1	137	107.55

FRCC

Table 3-13 Thermal Overloads in the FRCC Area, Summer 2028 Case

Monitored Element	Normal or LTE Rating (MVA)	Loading %
400025 ARCH CK 138 400619 WOLFSON 138 1	241	105.72
400036 DADE 138 400055 HIALEAH 138 1	222	100.27
400159 PEMBROKE 138 400524 LAUDRDLO 138 1	323	109.73
400162 PLANTATN 138 400524 LAUDRDLO 138 1	287	103.57
400227 FARMLIFE 138 400871 TAVRNIER 138 1	243	123.81
400614 ROSEDALE 138 409381 WEST-FMP 138 1	235	102.24
400871 TAVRNIER 138 400879 ISLMRDASCAP 138 1	241	108.64
400872 ISLMRADA 138 400877 CRAWLKEY 138 1	221	107.28
400872 ISLMRADA 138 400879 ISLMRDASCAP 138 Z1	241	108.63
401146 SADDLEWOOD 138 409851 TRAFALGAR 138 1	296	124.78
406105 CREWSLK 230 409050 PEBB 230 1	535.4	103.34
406725 RUSSELL. 115 406726 FLEMNG I 115 1	235	101.89
409835 WEST CC 138 409838 AGUALINDA 138 1	187	108.12

Table 3-14 Thermal Overloads in the FRCC Area, Winter 2028 Case

Monitored Element	Normal or LTE Rating (MVA)	Loading %
405566 PERSHING 115 405702 PERSHING 230 1	373	110.62
405566 PERSHING 115 405702 PERSHING 230 2	373	114.47
408300 RIVER 230 408301 GANNON-RX230 230 1	535.4	105.12
408301 GANNON-RX230 230 408700 GANNON 230 Z1	535.4	104.66

Section 4
Enhancements

After determining potential "gaps" in the 2028 summer and winter roll-up cases, the Planning Coordinators identified conceptual upgrades to inform the future planning cycles of their respective regional planning processes. This section lists the issues identified by each PC in Section 3, together with high-level conceptual upgrades and the entities with which the PCs may be coordinating on solutions in future planning cycles.

4.1 Issues List, Conceptual Upgrades, and Coordinating Entities

The PCs provided the following upgrades for the issues identified in their respective areas:

Dominion Energy South Carolina (DESC)

DESC did not provide any upgrades.

ISO-NE

A thermal violation on the same King Street to West Amesbury 115kV line described in Table 3-1 was identified during the latest Boston Needs Assessment. The overload identified in the Boston Needs assessment will be addressed using the process in Attachment K of the ISO New England Tariff.

NYISO

The identified overloads in Table 3-3 and Table 3-4 are not expected to adversely impact interregional transmission system reliability. The NYISO and the Transmission Owners have mitigation actions for the listed overloads. The mitigation actions are either operator actions or special protection systems.

Table 4-1 Mitigation Action for Thermal Overloads in the NYISO Area, Summer 2028 Case

PA	Monitored Element	Mitigation Action
NYISO	125015 AC CBLTP 115 125041 N.CHELSE 115 1	STE and Operator Action
NYISO	125015 AC CBLTP 115 125080 DANSK-N 115 1	STE and Operator Action
NYISO	125021 DC CBLTP 115 125041 N.CHELSE 115 1	STE and Operator Action
NYISO	125021 DC CBLTP 115 125080 DANSK-N 115 1	STE and Operator Action
NYISO	130792 CORN TP2 115 130800 ETNA 115 115 1	STE and Operator Action
NYISO	136759 BRNS FLS 115 136807 TAYLORVL 115 2	SPS

Table 4-2 Mitigation Action for Thermal Overloads in the NYISO Area, Winter 2028 Case

PA	Monitored Element	Mitigation Action
NYISO	137454 REYNLD3 345 137528 REY. RD. 115 1	SPS

MISO

MISO did not provide any upgrades.

PJM

After the reviewing the initial thermal and voltage results, PJM provided idevs to update the base cases as well as an exclude file to rerun the analysis. The results presented in Table 3-7 and Table 3-8 are based on the new files provided by PJM.

PJM's assessment of the issues listed in the gap analysis attributes their cause primarily to increased load levels, generator interconnections requiring further study, local voltage-tuning issues, or issues that could be resolved with re-dispatch. Because all these issues will be addressed to the extent they materialize in the course of completing the necessary regional planning analysis, they are not expected to have an impact on interregional reliability and do not represent "gaps" in the interregional plans.

PJM supplied EIPC with idev modeling updates for the 2018 series MMWG 2028S and 2028W future years to be incorporated into both roll-up cases. The EIPC performed a screening analysis of the Eastern Interconnection case using screening techniques generally applicable to power system analysis.

SPP

SPP did not provide any upgrades.

SERC

TVA did not provide any upgrades.

SCPSA provided conceptual upgrades for identified constraints in the study.

Table 4-3 Conceptual upgrades for identified constraints in the SERC area

PA	Facility Issue	Conceptual Upgrades
SERC	312746 3BATESBG 115 312880 2BATESBG 69.0 1	Reconfiguration & Line Rebuild
SERC	312746 3BATESBG 115 312880 2BATESBG 69.0 3	Reconfiguration & Line Rebuild

SERC	312774 3GOOS C 115 312808 3N CHAS 115 1	Line Rebuild

FRCC

FRCC did not provide any upgrades.

4.2 Map of Future Transmission Projects

To facilitate inter-area planning coordination, a map of all proposed major transmission projects in the Eastern Interconnection (generally facilities greater than 230 kV), including major facilities near the boundaries of each PC was developed. This map was built on a base map of existing transmission above 200 kV from a public source[9]. Planning Coordinators provided input to modify the base layer to add projects to the map. This enables a view of proposed projects that might have interregional impacts. This map of existing and proposed transmission is included in Appendix A.

Planning Coordinators may use this or similar maps in future cycles to further monitor current transmission plans and potentially explore joint projects that may mutually benefit multiple regions and areas.

[9] https://hifld-geoplatform.opendata.arcgis.com/datasets/electric-power-transmission-lines/data

Section 5
Linear Transfer Analysis

There is increasing interest in knowing how much power can be reliably moved between regions. Because of the many interconnected paths and the need to remain reliable under contingencies, the capability of the power system to transfer power from one area to another is not a fixed value such as the capacity of a pipe, but rather a range of values based on the use of parallel paths. One tool available that can assist in assessing transfer capability between areas is linear transfer power-flow analysis. As used by the EIPC Planning Coordinators, this analysis is not for identifying constraints and thus identifying projects and increasing transfer capability, but rather to illustrate the transmission grid's transfer capabilities as currently planned (based on the 2028 summer and winter roll-up cases) under a number of transfer patterns. The linear analysis performed involves thermal analysis only, which is used to evaluate the capability of the transmission facilities to withstand the thermal impact created by the increased electrical current flowing through the facilities. The thermal analysis did not examine system voltage, reactive supply, or stability issues, except to the extent that Planning Coordinators apply thermal proxy limits to represent system stability limits.

5.1 Linear Transfer Analysis Inputs

The Transmission Analysis Working Group (TAWG) identified the specific linear power transfers performed and the associated details. Each PC supplied input files for the linear transfer power-flow analysis (*e.g.,* monitored elements, subsystems, contingency files). Transfer subsystems were defined for exports and imports at a transfer test level of 5,000 MW for each transfer, with transfer amounts allocated among the importing areas on a load or generation-availability ratio share. Each transfer was assessed separately. However, because the transfers grouped multiple areas together as the source and as the sink, the analysis reflects simultaneous flows for the particular areas included in the transfer (see Table 5-1 and Table 5-2).

Table 5-1
Groupings of Planning Areas for Transfers

FRCC	MISO	NPCC	PJM	SERC		SPP
FPL		New York ISO	PJM	Duke Energy Carolinas	SCPSA	SPP
JEA	MISO	ISO New England		Duke Energy Progress	Southern Company	
Duke Energy Florida				LGE/KU	MEAG	
				GTC	Cube Hydro	
				Power South	TVA	
				DESC	Associated Electric	

Table 5-2
Transfers Performed

Source	Sink					
	FRCC	MISO	NIPCC	PJM	SERC	SPP
FRCC					Y	
MISO			Y	Y	Y	Y
NIPCC		Y		Y		
PJM		Y	Y		Y	
SERC	Y	Y		Y		Y
SPP		Y			Y	

Table 5-1 and Table 5-2 provide an overview of the transfers performed. Table 5-1 shows the PCs grouped together for transfers as an area, while Table 5-2 shows the combinations of areas (exporting [source] or importing [sink]) for which transfers were performed. For example, Group A includes FPL, JEA, and Duke Energy Florida in associated transfers performed. Note that participation in an area is only based on PCs that are party to the EIPC.

All facilities greater than 100 kV in the base-case model were monitored. Generally, single-contingency events for all facilities 161 kV and above in the base-case model, including generators as appropriate, were assessed. Known, approved, and applicable operating procedures were included in the contingency files.

5.2 Linear Transfer Analysis Process

The thermal-only linear analysis used PTI's PSS/MUST software to calculate transmission-transfer capabilities and did not examine system voltage, reactive supply, or stability issues.[10] Simulations were performed in batch mode, and the results of the study were assembled at the end.

Only those facilities with appreciable flows having a Transfer Distribution Factor (TDF) of 3.0% or greater were reported as limits. The TDF value indicates the percentage of the transfer being studied that actually is flowing on the identified transmission facility under the specific contingency condition. The 3.0% TDF cutoff for reporting is traditionally used in transmission planning to indicate that the transfer has a significant impact on the facility. A TDF less than 3.0% indicates that a facility, if reported, is already heavily loaded without the transfer in place.

[10] "PTI PSS™/MUST" refers to Siemens' Power Technologies International PSS™/Managing and Utilizing System Transmission.

If no constraint was identified up to the transfer test level of 5,000 MW, the limit reported was “>5, 000,” and further transfer capability was not evaluated.

5.3 Linear Transfer Analysis Results

Table 5-3 summarizes the results of the linear transfer analysis for 2028 summer peak conditions, and Table 5-4 summarizes the results of the linear transfer analysis for 2028 winter peak conditions. For each transfer, only the information for the lowest first-contingency incremental transfer capability (FCITC) is listed, along with branch information for the limiting element and associated contingency. The FCITC provides the amount of transfer capability incremental to the base-case interchange between the given subsystems.

Table 5-3
Linear Transfer Analysis Results 2028 Summer Peak

Source	Sink	FCITC (MW)	Limiting Element	Lim. PA	Contingency / Outaged Facility	Con. PA
FRCC	SERC	150	409000 POLKPLNT 230-409050 PEBB 230 230 kV 2	FRCC	409000 POLKPLNT 230-409050 PEBB 230 230 kV 1	FRCC
MISO	NPCC	2400	Cedar Grove-Jackson Road 230 kV 1	PJM	Base	N/A
MISO	PJM	>5000	N/A	N/A	N/A	N/A
MISO	SERC	>5000	N/A	N/A	N/A	N/A
MISO	SPP	2300	ANO 500-515305 FTSMITH8 500 500 kV 1	MISO-SPP	532797 WOLFCRK7 345 345/25 kV 1	SPP
NPCC	MISO	4300	Plano (B)-Electric Jct (B) 345 kV 1	PJM	lectric Jct3 (R)-Plano (R) 345 kV 1	PJM
NPCC	PJM	30[11]	Hanmer TS-Nobel 500 kV 1	IESO	Hanmer TS-Nobel 500 kV 2	IESO
PJM	MISO	>5000	N/A	N/A	N/A	N/A
PJM	NPCC	2100	Cedar Grove-Jackson Road 230 kV 1	PJM	Base	N/A
PJM	SERC	>5000	N/A	N/A	N/A	N/A
SERC	FRCC	2100	ONEIL 230/138 kV 1	FRCC	Thalmann-DUVAL 500 kV 1	SERC-FRCC
SERC	MISO	5000	N/A	N/A	N/A	N/A
SERC	PJM	>5000	N/A	N/A	N/A	N/A
SERC	SPP	1200	505508 DARDANE5 161-505514 CLARKSV5 161 161 kV 1	SPP	ANO 500-515305 FTSMITH8 500 500 kV 1	MISO-SPP
SPP	MISO	1100	645458 S3458 3 345-645456 S3456 3 345 345 kV 1	SPP	645455 S3455 3 345-645740 S3740 3 345 345 kV 1	SPP
SPP	SERC	>5000	N/A	N/A	N/A	N/A

[11] Following the linear transfer analysis, IESO suggests that this constraint could be mitigated by an existing RAS.

Table 5-4
Linear Transfer Analysis Results Summary 2028 Winter Peak Conditions

Source	Sink	FCITC (MW)	Limiting Element	Lim. PA	Contingency / Outaged Facility	Con. PA
FRCC	SERC	1200	MARTIN WEST-Williston 230 kV 1	FRCC	BRONSON-CRYSTAL RIVER PLANT 230KV YARD 230 kV 30	FRCC
MISO	NPCC	4200	Cedar Grove-Jackson Road 230 kV 1	PJM	Base	N/A
MISO	PJM	>5000	N/A	N/A	N/A	N/A
MISO	SERC	>5000	N/A	N/A	N/A	N/A
MISO	SPP	>5000	N/A	N/A	N/A	N/A
NPCC	MISO	4900	KEITH_J5D_PS-Waterman 230 kV 1	NPCC-MISO	Stephens-Caniff 345 kV 1	MISO
NPCC	PJM	>5000	N/A	**N/A**	N/A	N/A
PJM	MISO	>5000	N/A	N/A	N/A	N/A
PJM	NPCC	3600	Cedar Grove-Jackson Road 230 kV 1	PJM	Base	N/A
PJM	SERC	>5000	N/A	N/A	N/A	N/A
SERC	FRCC	2100	BAKER TAP; TALQUIN CO-OP-MICCOSUKEE TAP; TALQUIN CO-OP 115 kV 1	FRCC	FLORIDA GAS TRANSMISSION-PERRY 230 kV 1	FRCC
SERC	MISO	>5000	N/A	N/A	N/A	N/A
SERC	PJM	2600	Volunteer-Phipps Bend 500 kV 1	SERC	Rogers Road 500 kV-Greenville 500 kV 500 kV 1	PJM
SERC	SPP	4100	505508 DARDANE5 161-505514 CLARKSV5 161 161 kV 1	SPP	ANO 500-515305 FTSMITH8 500 500 kV 1	MISO-SPP
SPP	MISO	>5000	N/A	N/A	N/A	N/A
SPP	SERC	>5000	N/A	N/A	N/A	N/A

Appendix D contains more detailed results for each subsystem's linear transfer analysis, including the next two valid limits beyond the most limiting facility. It is possible that generation redispatch could mitigate some of the identified constraints. The more stringent NPCC and New York State Reliability Council (NYSRC) criteria were also applied for the NYISO bulk power system, which did not result in impacts to the above transfer results.

Appendix A: Future Project Map

This appendix now exists as an attached .pdf map ("EIPC Roll-up Appendix A Transmission Map").

Appendix B: New/Upgraded Transmission Projects

This appendix now exists as part of a Microsoft Excel workbook.

Appendix C: New/Upgraded Generation Included in Roll-Up Model

This appendix now exists as part of a Microsoft Excel workbook.

Appendix D: Linear Transfer Analysis Results

This appendix now exists as a Microsoft Excel workbook:

1. EIPC_AppendixD_2028

This appendix contains more detailed results for each subsystem's linear transfer analysis, including the next two valid limits beyond the most limiting facility. The most limiting facility is highlighted in yellow.

Appendix E: Area Interchange Tables

	2028Sum		2028Win	
PC	Load	Interchange	Load	Interchange
ISO-NE	25,052	-2608	19,524	-308
FRCC	54,579	-1505	50,884	-1505
MISO	142,261	-783.8	121,804	375.9
NYISO	32,469	-1844	23,812	-1268
PJM	161,706	-1231.5	138,733	-1428
SERC	143,085	2437.6	142,776	1996.1
SPP	57,242	-211.5	45,795	68.9