Eastern Interconnection Planning Collaborative

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Steady State Modeling and Load Flow Working Group

Report for 2018 and 2023 Roll-Up Integration Cases

Final Report

February 14, 2014

Executive Summary

This report details the efforts of the EIPC Steady State Modeling and Load Flow Working Group (SSMLFWG) to produce a 2018 and a 2023 Roll-Up Integration Case of the Eastern Interconnection and provide a summary of the assessments performed. The SSMLFWG includes representatives from each NERC registered Planning Authority ("PA") that is a party to the EIPC Analysis Team Agreement.

The Roll-Up Integration Case represents the base case for the Eastern Interconnection and a starting point for additional transfer analysis and analysis of scenarios developed with stakeholder input. The Roll-Up Integration Case is an integrated model of the expansion plans for the Eastern Interconnection as they existed in 2013, not a single "blueprint" for expanding the system. These cases provide solved power flow modeling suitable as a starting point for transmission analysis on an inter-connection-wide basis and they are available to all stakeholders who have CEII clearance to perform their own analyses.

As with all power flow models, the 2018 and 2023 roll-up integration cases are a representation of the power system for a particular "snapshot" in time (2018 and 2023 Summer Peak hours) based upon actual facilities and planning forecasts as they existed to meet Reliability Standards at the time the model was developed The SSMLFWG utilized transmission plans that were provided by each PA as the source of data for model development. These existing transmission plans are a product of each participating PA and the FERC approved regional transmission planning processes for each of the participating EIPC members (as applicable) and extend out through the year 2023. It should be noted that loads as well as generation and demand-side resources are inputs into the transmission expansion plans developed by each Planning Authority, and that these inputs were provided by the respective Load Serving Entities (LSEs), market participants, or other applicable entities within each Planning Authority's jurisdiction. Because these inputs are continuously changing, the local and regional transmission plans will necessarily also continuously change resulting in them being more current than can be achieved in wide-area modeling of the Eastern Interconnection. Nonetheless, wide-area modeling, such as the 2018 and 2023 roll-up integration cases, provides a sound basis for assessing inter-dependencies between and among regions. Potential constraints and efficiencies identified through inter-regional analysis are valuable inputs into local and regional processes, where they can be assessed in local and regional transmission planning and be addressed if appropriate.

Interregional Transmission (Gap) Analysis

Two types of analyses were performed by the SSMLFWG. The first type of analysis can be characterized as a interregional transmission "gap" analysis. The objective of this analysis was to identify potential power flow interactions from an interconnection-wide perspective that may result from the effects of plans of one Planning Authority on another. The interactions could be due to numerous issues such as new long term firm interface commitments, new transmission facilities planned in a neighboring PA, new load projections, new generation dispatch, etc., that may have occurred since the PAs developed the MMWG cases. When the PAs' plans were rolled up into a single model N-1 contingency analysis was performed. For most Planning Authorities, there were no potential constraints identified. Three PAs, MISO, PJM and SPP, identified potential constraints and solutions. The identified potential constraints and solutions can be seen in Section 3.3 and Section 4.2 of the report respectively.

MISO reported four overloads in 2023 in the system intact analysis; they reported five overloads in 2018 and four overloads in 2023 due to N-1 contingencies. Their solutions for these issues included upgrading facility capacities and adding circuits. PJM reported three overloads in 2018 and one overload in 2023 due to N-1 contingencies. PJM also reported seven voltage issues in 2018 and six voltage issues in 2023 due to N-1 contingencies. Their solutions included generation re-dispatch. SPP reported four overloads in 2013 and two overloads in 2018 due to N-1 contingencies. SPP also reported two voltage issues in 2018 and one in 2023 due to N-1 contingencies. SPP has mitigation plans for these thermal and voltage issues which including approved and pending projects, as well as system redispatch.

Linear Transfer Analysis

The second type of analysis that was performed was a linear transfer analysis. The objective of this analysis was to demonstrate how much power can be reliably moved between areas beyond the existing long term firm commitments. between PAs. As utilized by the EIPC Planning Authorities, the intent of this analysis was to illustrate transfer capabilities of the transmission grid as currently planned (based on the 2018 and 2023 roll-up cases) under a number of transfer patterns. The objective was not to identify projects to potentially increase transfer capability, but to demonstrate the transfer capability of the planned system. For this analysis, the areas and transfers between the areas were defined as can be seen in Tables ES-1 and ES-2.

Table ES - 1: Groupings of Planning Areas for Transfers

A	B	C	D	E		F
FPL	MAPPCOR	New York ISO	PJM	Duke Energy Carolinas	SC	SPP
JEA	MISO	ISO New England		Duke Energy Progress	Southern Company	
Duke Energy Florida	ATC	Ontario IESO		LGE/KU	MEAG	
	ITC	NBSO		GTC	Alcoa Power Generating, Inc.	
	Entergy			Power South	TVA	
				SCEG	Electric Energy, Inc.	

Table ES-2: Transfers Performed

	Sink					
Source	**A**	**B**	**C**	**D**	**E**	**F**
A					Y	
B			Y	Y	Y	Y
C		Y		Y		
D		Y	Y		Y	
E	Y	Y		Y		Y
F		Y			Y	

Each of the transfers performed tested transferring 5,000 MWs between the areas. Tables ES-3 and ES-4 show the limits identified from this analysis and the areas that were involved in the limits. In some cases, the 5,000 MW transfer created no issues, indicating that the limit between the areas is greater than 5,000 MWs.

Table ES-3: 2018 Linear Transfer Results				
Source	Sink	FCITC (MW)	Lim. PA	Con. PA
A	E	2,500	DEF	DEF
B	C	2,800	PENELEC-PJM	NYISO/PENELEC-PJM
B	D	>5,000	N/A	N/A
B	E	>5,000	N/A	N/A
B	F	2,700	EES	EES/OKGE-SPP
C	B	1,800	NYISO	NYISO
C	D	1,400	NYISO	NYISO
D	B	2,900	CE-PJM	CE-PJM
D	C	1,900	PENELEC-PJM	NYISO/PENELEC-PJM
D	E	>5,000	N/A	N/A
E	A	1,900	SBA/FRCC	FPL
E	B	4,800	TVA	TVA
E	D	1,500	BREC-MISO	N/A
E	F	2,200	EES-MISO	EES-MISO/OKGE-SPP
F	B	1,100	WERE-SPP	WERE-SPP
F	E	1,200	WERE-SPP	WERE-SPP

Table ES-4: 2023 Linear Transfer Results				
Source	Sink	FCITC (MW)	Lim. PA	Con. PA
A	E	1,600	DEF	DEF
B	C	3,400	PENELEC-PJM	N/A
B	D	>5,000	N/A	N/A
B	E	>5,000	N/A	N/A
B	F	650	EES	EES/OKGE-SPP
C	B	1,800	NYISO	NYISO
C	D	1,500	NYISO	NYISO
D	B	1,600	ALTW-MISO	CE-PJM/MEC-MISO
D	C	2,100	PENELEC-PJM	N/A
D	E	>5,000	N/A	N/A
E	A	1,900	SBA/FRCC	FPL
E	B	2,200	TVA	TVA
E	D	1,900	BREC-MISO	N/A
E	F	550	SWPA-SPP	EES/OKGE
F	B	850	WERE-SPP	WERE-SPP
F	E	950	WERE-SPP	WERE-SPP

The transfer analysis results verify that the currently planned future transmission system is capable of transferring power on a large area basis above the long term firm commitments modeled in the roll-up cases. The additional transfer capability ranges from 550 MW to over 5,000 MW.

The planning processes for the EIPC members have many common aspects, but key differences in the processes do exist between Planning Authorities. These differences are expected and, in fact, required given the diversity in the form of regulation, the topography and characteristics of each Planning Authorities' electric transmission system throughout the very large Eastern Interconnection. This report serves to describe in detail the data submitted by each of the EIPC Planning Authorities, explain differences in the Planning Authorities' respective planning processes and assist stakeholders in understanding what is contained in the roll-up.

Eastern Interconnection Planning Collaborative

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Section 1 Introduction

On May 21, 2009, the Eastern Interconnection Planning Collaborative was formed by representatives from Planning Authorities ("PAs") in the Eastern Interconnection. This group agreed to initiate the technical work to facilitate coordination of existing transmission plans, conduct reliability analyses of the combined interconnection system, and conduct studies to support state, provincial, regional or federal public policy decision making.

The following Planning Authorities are also participating in the EIPC study:

1. Alcoa Power Generating, Inc.
2. American Transmission Company ("ATC")
3. Duke Energy Carolinas ("DEC")
4. Duke Energy Florida ("DEF")
5. Duke Energy Progress ("DEP")
6. Electric Energy Inc.
7. Entergy Services, Inc. on behalf of the Entergy Corporation Utility Operating Companies ("Entergy")
8. LG&E and KU Energy LLC (Louisville/Kentucky Utilities)
9. Florida Power & Light ("FPL")
10. Georgia Transmission Corporation ("GTC")
11. IESO (Ontario, Canada)
12. International Transmission Company ("ITC")
13. ISO New England, Inc. ("ISO-NE")
14. JEA (Jacksonville, Florida)
15. Mid-Continent Area Power Pool, by and through its agent, MAPPCOR
16. Mid-Continent Independent Transmission System Operator, Inc. ("MISO")
17. Municipal Electric Authority of Georgia ("MEAG")
18. New York Independent System Operator, Inc. ("NYISO")
19. PJM Interconnection, L.L.C. ("PJM")
20. PowerSouth Energy Coop
21. Santee Cooper ("SCPSA")
22. South Carolina Electric & Gas ("SCE&G")
23. Southern Company Services Inc. ("Southern"), as agent for
    a. Alabama Power Company
    b. Georgia Power Company
    c. Gulf Power Company
    d. Mississippi Power Company
24. Southwest Power Pool ("SPP")
25. Tennessee Valley Authority ("TVA")

The EIPC is intended to complement the regional transmission expansion plans developed each year (plans that are well vetted through the respective FERC Order 890 Regional Planning Processes) and utilizes the regions' Order 890 Regional Planning Processes and selected interconnection wide webinars/meetings to solicit input and feedback from stakeholders. Subsequent to the work done on the DOE grant, the EIPC elected to continue and self-fund the effort to develop interconnection wide models, test those models with increased transfers, identify potential gaps from a reliability perspective and analyze scenarios developed with stakeholder input. The EIPC chose to model two years rather than one and to focus on years that are more representative, thus the results will flow into regional processes more seamlessly. For this two-year analysis cycle, the EIPC has modeled 2018 and 2023. The EIPC continues to provide a transparent and collaborative Eastern Interconnection-wide venue to all interested stakeholders through regional Order 890 processes and interconnection-wide webinars and meetings.

The purpose of the Steady State Modeling and Load Flow Working Group (SSMLFWG) is to:

1. Modify/create steady state load-flow models
2. Conduct steady-state load-flow analysis (including transfer capability)
3. Analyze selected scenarios based on selected NERC reliability standards
4. Report results as required/necessary

The EIPC Web site contains information about the work to be performed:

http://www.eipconline.com/Non-DOE_Documents.html,
and http://www.eipconline.com/Stakeholder_Activities.html.

For an overview of the process that will be employed by the EIPC SSMLFWG, see the flowchart depicted in Figure 1 below. Dates represented are tentative and for illustration purposes only.

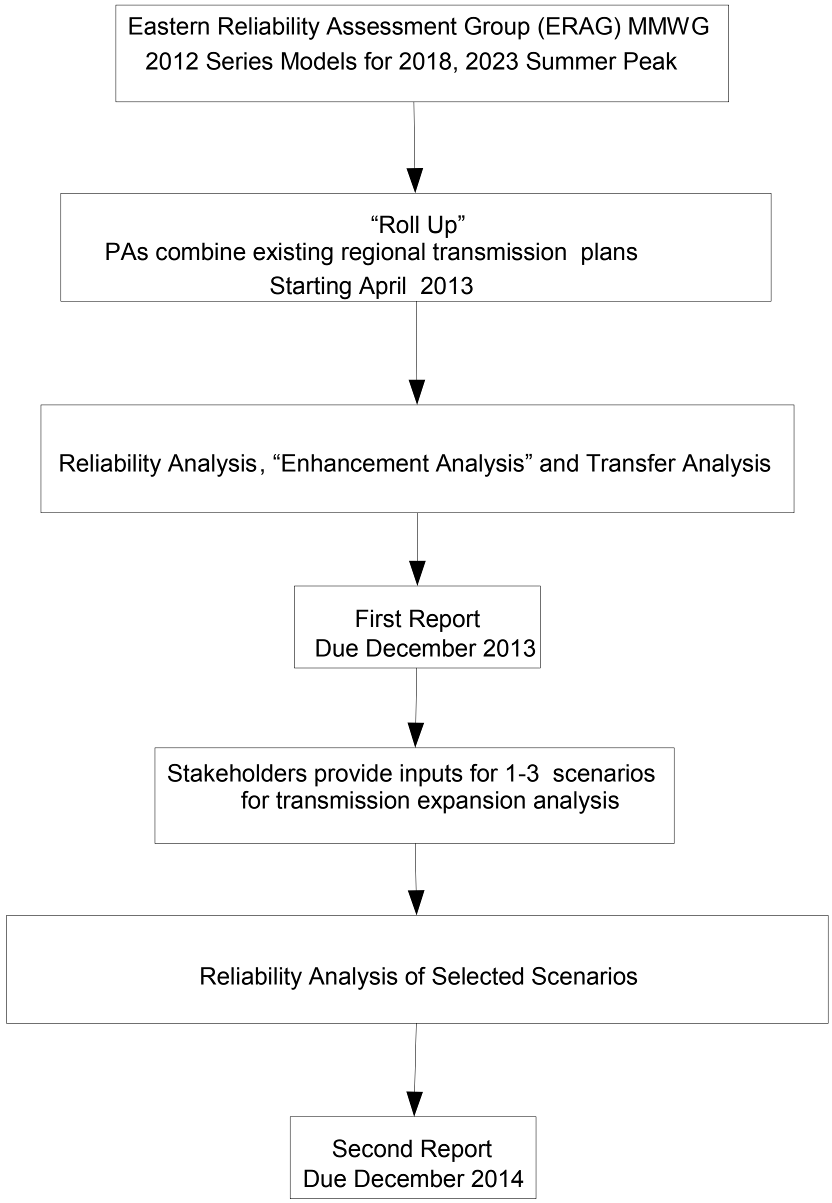

Figure 1 – EIPC Planning Analysis Process

Section 2 – Planning Authorities' Assumptions

2.1 Introduction

This section details assumptions made by each PA in developing the 2018 and 2023 roll-up integration cases. This includes load forecasting, the treatment of demand resources and energy efficiency, interchanges with other systems, future transmission and generation project inclusion, and generation dispatch.

In some cases, one or more PA systems may be incorporated into the model roll-up of another PA, without duplication. For example, Mid-continent ISO (MISO) has incorporated into the MISO roll-up input from the Midwest ISO members American Transmission Company LLC (ATC LLC) and International Transmission Company (ITC) which are also Planning Authorities that are participating in the EIPC study. In the Planning Authority specific subsections below, the Mid-continent ISO portions includes the integration of the ATC LLC and ITC system information. In addition, Georgia Transmission Corporation and MEAG have noted where their information for certain sections are included in Southern Company's responses.

In creating the 2018 and 2023 roll-up integration cases, the 2012 Series, 2018 and 2023 Summer Peak, Eastern Reliability Assessment Group, Multi-Region Modeling Working Group ("ERAG MMWG") cases were the starting point. Each PA updated their portion of that model, or submitted new models of their respective systems, which were then assembled into one complete power flow model. The case went through several iterations of review and validation by the SSMLFWG in order to assure the accuracy of the database before any study work was performed.

2.2 Load Forecasts and Growth Rates

The following section describes the load growth rates represented in the roll-up integration case for each EIPC Planning Authority through the year 2018 and 2023. 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 PA in their regional transmission planning processes.

The load forecasts provided by each PA 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 PA to plan for the critical system conditions for the area in which they are responsible. This approach provides for assurance of reliable transmission system performance of each PA, as required by the NERC Reliability Standards.

Because the roll-up integration case is based upon current transmission plans as of 2012, the vintage of the aggregated LSE forecasts is generally late 2012 or early 2013.

Alcoa Power Generating, Inc.
APGI Yadkin Division's load growth from 2010 to 2020 is less than 1.0% Alcoa serves its own load. The load forecast is based on a history of usage. There are no loads other than Yadkin's in their area, therefore by definition this load is a coincident peak.

APGI Tapoco Division's load includes South Plant. APGI Tapoco has no generators, they purchase power to serve their load.

Duke Energy Carolinas
Duke Energy's load forecasting group developed the load forecast in 2012 utilizing data including the forecasts of individual LSE's in the DEC footprint. Duke Energy Carolinas (DEC) expects an average growth rate of 1.7% through 2023 summer for a control area load of approximately 22,042 MW in 2018 and 23,293 MW in 2023 incorporating the demand from DEC's wholesale customers coincident with DEC's peak.

Duke Energy Florida
Duke Energy's load forecasting group developed the load forecast in 2012 utilizing data including the forecasts of individual LSEs in the DEF footprint. Duke Energy Florida (DEF) expects an average growth rate of 1.4% through 2023 summer for a control area non-coincident peak load of approximately 12,871 MW in 2018 and 13,829 MW in 2023.

Duke Energy Progress
Duke Energy Progress (DEP) updates its power flow models on an annual basis. Loads plus losses at the transmission level will be scaled to match the system forecast coincident peak load for each load level. Duke Energy Progress (DEP) expects an average growth rate of 1.4% of its area through 2023 summer for a balancing area load of approximately 14,313 MW in 2018 and 15,226 MW in 2023.

Electric Energy Inc.
Electric Energy Inc. has no native load and therefore does not compile a load forecast.

Entergy Services
The 10 year load growth provided by the LSEs (non-coincident) within the Entergy control area averaged 0.72% for the period 2013 through 2023 totaling to a projected load of 27,846 MW in 2018 and 28,932 MW in 2023. The load forecasts contained in the 2018 and 2023 Roll-Up cases were developed in 2013 based upon 2012 actuals. The most recent peak demand provided by the LSE is used because it reasonably reflects load adjustments (e.g., losses, load growth, load reductions, cogeneration) that would have occurred prior to the peak load period. If there are significant load changes (additions or reductions) that occurred within the System after the summer peak, the load forecast is adjusted to take these changes into consideration. The LSEs are required to provide a load forecast annually to the Transmission Provider. The types of loads represented in these load forecasts include the loads of the following customer types: retail, wholesale (including wholesale load under the Tariff and grandfathered agreements), industrial, nuclear generating facility, and cogenerating facility.

Florida Power & Light
The load modeled in the FPL area in the 2023 roll-up integration case reflects an average annual growth rate of 1.27% up to the 2023 period. The load assumptions are based on then official FPL 2012

coincident load forecast as filed with the Florida Public Service commission in the Ten Year Site Plan (TYSP) document.

Georgia Transmission Corporation
A load forecast is prepared annually through input from GTC's member cooperatives. The load forecast included in the roll-up case was prepared in 2013, and the average annual growth rate is approximately 2.5% for the period 2013 to 2023. GTC's forecasted load is included in the Southern Balancing Authority as coincident with other Georgia load.

Independent Electricity System Operator
The IESO, in conjunction with the Ontario Power Authority, produces a load forecast regularly. As of March 2013, the Ontario non-coincident normal weather peak demand for Summer 2018 and Summer 2023 was forecasted to be 22,844 MW and 23,875 MW respectively, reflecting a net annualized 10 year growth rate of 0.3%. The normal weather scenario is based on historical weather from the past 31 years and represents typical weather on a monthly basis.

The main reasons for the small growth rate of the Ontario demand are lower economic growth, energy conservation, utilization of embedded generation and changes in electricity consumption patterns due to the introduction of time of use rates at the residential level.

ISO New England

ISO New England (ISO-NE) expects an average annual growth rate of 1.20% through 2018 summer for a control area demand (load & losses) of approximately 32,675 MW, based on load forecasts in the ISO-NE 2012-2021 Forecast Report of Capacity, Energy, Loads, and Transmission ("CELT"). With the addition of 3,184 MW of Demand Resource load reduction, the ISO-NE estimates the control area demand (load & losses) to be 29,442 MW. In 2023, ISO New England coincident control area demand (load & losses) is expected to be 30,400 MW accounting for 4,011 MW of demand resource load reduction.

JEA
The total internal demand (firm and non-firm demands) for the summer peak for JEA is forecasted to increase at an average annual growth rate of 0.9% to 3,014 MW for the summer of 2023; as used in the roll-up integration case. The forecast was done in April 2013 and incorporates the non-coincident peak demand from JEA's wholesale customer located adjacent to JEA's service territory in Northeast Florida.

LG&E and KU Energy
All Load Serving Entities (LSE) on the LG&E/KU transmission system provide load forecasts annually of the Network Load levels. The balancing authority forecasted coincident load in the 2018 EIPC roll-up case is 7214 MW and 2023 EIPC roll-up case is 7540 MW.

The LG&E/KU's native LSE load level is based on a 50/50 forecast with all curtailable loads being served. The native load forecast was developed in the fall of 2012 and based on 2012 summer actual loads. The LG&E/KU native LSE expects an average growth rate of approximately 1.0% from 2013 through 2023.

MAPPCOR
Mid-Continent Area Power Pool (MAPP) Transmission Owners provide load forecast data annually through the MAPP and MRO model building process. The 2018 and 2023 summer peak models were built using non-coincident peak load forecasts for each year reported by MAPP Transmission Owners in 2012. MAPP expects an average annual growth rate of approximately 2.0% for the period 2013 through 2023 for a total projected load of 5,788 MW in 2018 and 6,254 MW in 2023.

MEAG Power
A load forecast is prepared annually through input from MEAG's participants. The load forecast included in the roll-up case was prepared in 2013, and the average annual growth rate is 1.1% for the period 2013 to 2023. MEAG's load forecast is included in the Southern Balancing Authority as coincident with other Georgia load.

Mid-continent ISO (MISO)
For MISO members, model load is reflective of Load Serving Entity 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 is used in the MTEP models. This approach provides for assurance of reliable transmission system performance at the member system level, as required by the NERC planning standards.

Power flow model peak load projections were provided to MISO by member systems in 2012 for the MTEP 2013 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 is consistent with the MISO 2013 Long Term Resource Assessment report which will be available on the MISO web site at a later date.

New York ISO
The NYISO is forecasting a base 2018 and 2023 coincident summer peak load for the New York Control Area (NYCA) of approximately 35,103 MW and 36,613 MW, respectively, which is inclusive of statewide energy efficiency programs and represents an average annual growth rate of 0.96% through 2023, as documented in the NYISO 2013 Load & Capacity Data report:
http://www.nyiso.com/public/webdocs/markets_operations/services/planning/Documents_and_Resources/Planning_Data_and_Reference_Docs/Data_and_Reference_Docs/2013_GoldBook.pdf

PJM Interconnection
PJM annually prepares a detailed, independent load forecast for PJM and each of its zones and sub-regions. The January 2013 forecast is the basis for the PJM system contained in the EIPC roll up system. The complete underlying assumptions and process for the development of this forecast are found at http://www.pjm.com/planning/resource-adequacy-planning/load-forecast-dev-process.aspx. Summer peak load growth for the PJM RTO (including American Transmission System integrated into PJM during 2011 and the East Kentucky Power Cooperative integrated into the PJM RTO on June 1, 2013) is projected to average 1.0% per year over the next 5 years and 1.3% over the next 10 years (down from 1.7% in the 2010 EIPC report.) The PJM RTO summer coincident peak is forecasted to be 16,8811 MW in 2018, a 5-year increase of 13,259 MW, and reaches 17,7439 MW in 2023, a 10-year increase of 22,254 MW. Annualized 10-year growth rates for individual PJM zones range from .7% to 2.0% (compared to 1.0% to 2.5% in the 2010 EIPC report). The roll up case is based on the PJM coincident peak forecast.

The area by area coincident peak forecasts are presented in the table below. The annual PJM forecasts prepared by PJM, however, also include non-coincident peak forecasts that are used in the series of annual planning analyses. In addition, the annual series of planning analyses examine ranges of load levels. The PJM forecast is based on historical data from January 1998 through August 2012. The models were simulated with weather data from years 1973 through 2011, generating 507 scenarios. The economic forecast used was Moody's analytics' November 2012 release.] Since PJM performs complete integrated modeling for both non-coincident area forecasts and the coincident RTO forecast, this means that PJM does not need a process to "roll up" area forecasts to determine the RTO forecast.

PJM Area	2011 Coincident Peak Load (MW)	2012 Coincident Peak Load (MW)	2013 Coincident Peak Load (MW)	2018 Forecast Coincident Peak Load (MW)	2023 Forecast Coincident Peak Load (MW)	5 year Average Annual Growth Rate	10 year Average Annual Growth Rate
AE	2520	2600	2590	2834	2942	0.8%	1.3%
BGE	6960	6870	6920	7422	7744	0.9%	1.1%
DPL	3920	3950	3970	4310	4547	1.1%	1.4%
JCPL	5960	5960	6020	6493	6806	0.9%	1.2%
METED	2800	2820	2840	3160	3378	1.3%	1.7%
PECO	8370	8320	8360	9147	9656	1.1%	1.5%
PENLC	2720	2740	2770	3143	3390	1.5%	2.0%
PEPCO	6600	6540	6520	6892	7109	0.6%	0.9%
PL	6880	6890	6930	7545	7952	1.1%	1.4%
PSEG	10150	10100	10120	10736	11063	0.6%	0.9%
RECO	400	400	400	419	429	0.5%	0.7%
UGI	185	185	185	201	210	0.9%	1.3%
AEP	22460	22670	22670	24466	25503	0.8%	1.2%
APS	8210	8210	8270	8977	9444	1.0%	1.3%
ATSI	12620	12660	12680	13471	13928	0.7%	0.9%
COMED	21480	21650	21830	24147	25583	1.2%	1.6%
DAY	3180	3230	3260	3655	3883	1.2%	1.8%
DEOK	5250	5240	5270	5685	5960	0.9%	1.2%
DLCO	2800	2800	2820	3057	3188	0.8%	1.2%
EKPC			1780	1958	2045	0.9%	1.4%
DOM	18530	18570	18980	21093	22679	1.5%	1.8%
RTO	151995	152405	155185	168811	177439	1.0%	1.3%

Assembly of Interregional Power Flows
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. Any modification to the power flows or load profiles is the responsibility of the entity performing the study.

PowerSouth Energy Cooperative
PowerSouth (a G&T Cooperative) receives load data from each of its member owner distribution cooperatives. This data is then manipulated into a coincident peak number for PowerSouth's area. The load forecasts contained in the 2018 and 2023 Roll-Ups were developed in 2013 based upon 2013 data. PowerSouth's calculated annual growth rate for the period 2013 through 2023 is 1.01%.

Santee Cooper
The load forecast used in the EIPC roll up model was prepared by Santee Cooper 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 consulting firm and is based on normal weather assumptions. The forecast utilizes historical data and a current economic outlook for Santee Cooper's service areas. The load forecast used in the 2018 roll-up case has a summer peak of 5,017 MW representing a -1.2% growth rate from 2012. The 2023 roll-up case summer peak load of 5,264 MW represents a -0.2% growth rate from 2012.

South Carolina Electric and Gas
The average annual load growth provided by the LSEs within the SCE&G planning area is 1.03% for 2018 and 1.16% for 2023. This load growth results in a projected peak load of 5,043 MW in 2018 and 5,671 MW in 2023 including load and transmission losses. The load forecasts contained in the 2018 and 2023 roll-up cases were developed in 2013 and are based on 2013 assumptions, data and information. The LSEs within the SCE&G planning area use historical normal weather patterns and various econometric models in determining peak demand forecast. Each individual LSE develops a forecast that accounts for the individual peak demand forecast. The individual peak demand forecasts are then aggregated by summing these forecasts to develop the SCE&G non-coincident forecast.

Southern Company
The 10 year load growth provided by the LSEs (non-coincident) within the Southern Balancing Authority averaged 1.57% for the period 2013 through 2023 totaling to a projected load of 49,436 MW in 2018 and 53,086 MW in 2023. The load forecasts contained in the 2018 and 2023 Roll-Up were developed in 2013 based upon 2012 actuals.

Southwest Power Pool
The average forecasted annual load growth provided by the Southwest Power Pool (SPP) members is 1.3% for the 2013 through 2023 period, which results in a projected non-coincident load of 53,943 MW in 2018 and 56,936 MW in 2023. The load forecasts contained in the 2018 and 2023 roll-up cases were developed in 2012 based upon 2012 actuals. .

Tennessee Valley Authority
The load forecast used in this roll-up integration case used TVA's official February 2013 delivery point load forecast provided by TVA's Enterprise Planning group. This forecast is a coincident system summer peak forecast assuming normal weather patterns and a medium economic outlook. This load

forecast is a 50/50 load projection; where there is a 50% chance the actual load will be higher or lower than the forecast.

TVA's load forecast for summer peak 2013 is 31,711 MW. TVA's load forecast for summer peak 2018, which was one of two cases used in the roll-up integration case, is 33,931 MW. TVA's load forecast for summer peak 2023, which was the second of the two cases used in the roll-up integration case, is 35,880 MW. This reflects a 1.3% annual load growth over the next 10 years.

2.3 Treatment of Energy Efficiency and Demand-Side Resources

This section details the modeling of energy efficiency programs and demand-side resources[1] in the EIPC roll-up integration case. Because of differences in programs among jurisdictions, the amount and treatment in the power flow model of energy efficiency or demand resources varies within each Planning Authority. For some Planning Authorities, energy efficiency and demand-side resource programs' effects are considered when developing the load forecast discussed in section 2.2 and for others, market mechanisms are used to treat these as energy resources. While treatment of these programs varies across PAs, it is important to realize that some PAs do not net these demand impacts from the gross demand forecasts that are used in transmission planning models. The PAs 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 PAs' 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, if the individual PA descriptions below contain the terms "included"," incorporated", "reflected", or "accounted for" to describe forecasts or modeled load, it means that the forecast in the case already has been reduced for these effects.

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 384 MW in 2018 summer and 720 MW in 2023 summer of load modeled. Impact of the application of DSM was not included in modeled load.

Duke Energy Florida
DEF has developed Energy Efficiency and DSM programs, estimated to total 1,717 MW for the year 2018 and 1,897 MW for the year 2023, as required to meet state requirements. Energy Efficiency and DSM reductions are not modeled in the cases.

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 227 MW in 2018 summer and 361

[1] Demand-side resources include a variety of programs and resources, such as direct load control, dispersed generation, passive/active demand resources, DSM, etc.

MW in 2023 summer of load modeled. Impact of the application of DSM was not included in modeled load.

Electric Energy Inc.
Since Electric Energy Inc. has no native load, a load forecast is not compiled. EE and DSM are not applicable.

Entergy Services
Entergy's load forecast projection included in the 2018 and 2023 roll-up integration cases take into consideration energy efficiency impacts by utilizing EIA efficiency indices in the development of retail sales forecasts. Existing utility sponsored DSM programs are also accounted for in the peak load forecast. Incremental Utility-Sponsored DSM are new programs pending regulatory approval which have not been incorporated into the peak load forecast. It is estimated that successful implementation of these new programs could potentially result in a peak demand reduction of 878 MW for Entergy by 2018 and 1402 MW by 2023. The modeled loads do not reflect a reduction associated with interruptible contracts signed with large industrial customers in the area.

Florida Power & Light
The impact of higher energy efficiency based on the new 2005 and 2007 federal standards for lighting and appliance is factored into the load forecast. It is estimated the summer peak demand in 2023 model will be approximately 1484 MW lower than it would have otherwise been absent energy efficiency. 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 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 GTC's member cooperatives.

Independent Electricity System Operator
The Ontario Power Authority is overseeing the Conservation and Demand Management programs in Ontario and provides projections of long-term peak-demand reduction due to those programs. The aggregation of energy efficiency and demand side programs included in the load forecast consists of 3,549 MW and 4,451 MW for years 2018 and 2023, respectively. These include: energy conservation, fuel substitution and changes in electricity consumption patterns due to the introduction of time of use rates at the residential level.

ISO New England
Energy efficiency measures that have cleared in the most recent Forward Capacity Auction (2013 FCA-7 for the Commitment Period June 1, 2016 to May 31, 2017) including EE forecasts have been incorporated into the load in the model. For the summer of 2018, a total of 2,205 MW of Passive Demand Resources / Energy Efficiency (On-Peak and Seasonal-Peak) and 979 MW of Active Demand Resources / Demand Side Management (Real Time Demand Resource) were included for a total of 3,184 MW. For the summer of 2023, a total of 3,032 MW of Passive Demand Resources / Energy Efficiency (On-Peak and Seasonal-

Peak) and 979 MW of Active Demand Resources / Demand Side Management (Real Time Demand Resource) were included for a total of 4,011 MW.

JEA

No planned incremental energy efficiency programs are represented in JEA's demand forecast represented in the roll-up integration case. However, JEA's demand forecast does include a historical trend of applied energy efficiency improvements that have naturally occurred in the market place. Concerning load management and interruptible rate subscribers, JEA does not currently reduce the peak demand in developing the load flow models. Today, JEA's forecasted peak demand reductions from energy efficiency programs, load management programs, and interruptible rate subscribers have not reached a level warranting consideration in transmission capacity avoidance benefits.

LG&E and KU Energy

The LG&E/KU native LSE load forecast in the EIPC 2018 and 2023 summer model reflects a reduction in load of 259 MW and 277 MW respectively as a result of energy efficiency programs and demand side management resources.

MAPPCOR

Energy efficiency efforts as required to meet state requirements are incorporated into the reported load in the model through the MAPP and MRO model building process. The impact of the application of DSM was not included in the modeled load. MAPP Transmission Owners load forecast included an energy efficiency of 248 MW by 2018 and 274 MW by 2023.

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.

Mid-continent ISO (MISO)

For MISO, load projections for planning horizon power flow models are provided by the member systems that perform their own load forecasting. Energy efficiency and demand-side adjustments are included in those load projections consistent with the local transmission planning practices of each member system. The demand projections in the 2018 and 2023 power flow cases for the MISO portion of the roll-up integration case is consistent with the MISO 2013 Long Term Resource Assessment report which will be available on the MISO web site at a later date.

New York ISO

Energy efficiency impacts for state-mandated programs are included in the NYISO's load forecasts. For the year 2018, the summer peak load forecast includes a reduction of 1,516 MW for these programs. By 2023, the reduction in summer peak demand from energy efficiency programs is 2,129 MW. Impacts of demand side programs (e.g. - demand response) are not included in the forecasted load. Interruptible load, and distributed generation resources of 1,558 MW (referred to as Special Case Resources in New York) are not included in the load forecast.

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 2015. The 2015 values are used as assumptions throughout the forecast horizon. Projections for changes to LM and EE past 2015 are not currently factored into the forecasts although changes to this procedure are under consideration. PJM planning power flow models appropriately modify the loads and/or generation models for LM and EE resources depending on the type of planning analysis being performed. The loads in the 2018 and 2023 rollup power flow case are based on unrestricted peaks which means that they are not adjusted for LM and EE. For 2023 summer, DR and EE constitute an approximate equivalent reduction of 891 MW of EE and 14,648 MW of LM for a total of 15,539 MW. Based on actual operations experience, LM called upon by PJM is fully available but limited in the number times it may be used. More detail regarding PJM's LM and EE can be found in the references of section 2.2.

PowerSouth Energy Cooperative
The PowerSouth load forecast for 2018 reflects a reduction in load of 7 MW as a result of energy demand side management resources (water heater program). DSM is projected to be 9 MW in 2023. These reductions are reflected in PowerSouth's net peak load per year.

Santee Cooper
The load forecast used in the roll-up integration case was prepared by Santee Cooper 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 consulting firm and is based on normal weather assumptions. The forecast utilizes 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. The net load forecast used in the 2018 roll up case has approximately 167 MW of Energy Efficiency and Demand Side Management. The 2023 roll-up case has approximately 180 MW of Energy Efficiency and Demand Side Management.

South Carolina Electric & Gas
SCE&G is projecting 149 MW of energy efficiency programs in 2018 and 339 MW of energy efficiency programs in 2023. All of this was reduced from gross load forecast to produce the net peak load used for the SCE&G system in the EIPC roll-up integration case. SCE&G is projecting 261 MW of demand side management programs in 2018 and 275 MW of demand side management programs in 2023. None of this was reduced from the gross load forecast to produce the net peak load used for the SCE&G system in the roll-up integration.

Southern Company
The Southern Company load forecast for 2018 and 2023 reflects a reduction in load of 1,751 MW in 2018 and 2,118 MW in 2023 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 that are provided by each load serving entity.

Southwest Power Pool
SPP members have developed energy efficiency and demand-side management programs, estimated to total 1,254 MW for the year 2018 and 1,704 MW for 2023. However, SPP is not currently modeling energy efficiency and demand-side management as a source of load reduction in this model case.

Tennessee Valley Authority
TVA's demand-side management program primarily focuses in the areas of pricing products and direct load control of large industrial customers, HVAC equipment, and water heaters. TVA's energy efficiency programs are reflected in the load forecasts used in determining TVA's transmission expansion plan. However, TVA does not include the effects of demand-side management in these forecasts due to the difficulty in predicting which specific delivery points will be affected by these programs.

2.4 Interchange or Firm Transmission Service Modeled

The following section includes a description of the typical interchange or inter-area energy transfers modeled by each Planning Authority. Interchange data in the form of tables is included in Appendix E at the end of this report . For transactions between areas (import/export), full path transactions are included in the roll-up integration case, (where both the importing and exporting PAs recognize common commitments). Partial path transactions (where arrangements for transmission service have only been made with one party) are not included in the roll-up model.

Alcoa Power Generating, Inc.
The 2020 roll-up integration case has no interchange for Alcoa's Yadkin division.

Duke Energy Carolinas
In the 2018 summer case, DEC BA has a net export to CPLE of 1000 MW from IPP's at Rowan and Broad River Energy Center serving Duke Energy Progress load, while NCEMC resources in CPLE and DEC are shared between the areas. NCEMC also has an import of 163 MW from SOCO and an export 50 MW of its resources to serve its load in DVP (a part of PJM). NHEC imports 23 MW and PMPA 208 MW from SCPSA to serve its load in DEC. There is import of 268 MW from SEPA's generation on the Savannah River and 29 MW from SOCO to serve the city of Seneca, SC. The resultant net interchange is an export of 440 MW.

In the 2023 summer case, DEC BA has a net export to CPLE of 1000 MW from IPP's at Rowan and Broad River Energy Center serving Duke Energy Progress load, while NCEMC resources in CPLE and DEC are shared between the areas. NCEMC also has an import of 180 MW from SOCO and an export 50 MW of its resources to serve its load in DVP (a part of PJM). PMPA imports 244 MW from SCPSA to serve its load in DEC. There is import of 268 MW from SEPA's generation on the Savannah River and 32 MW from SOCO to serve the city of Seneca, SC. The resultant net interchange is an export of 374 MW.

Duke Energy Florida
DEF includes confirmed annual firm transmission service requests that are in accordance with resource projections provided by LSEs and executed contracts for the sale of firm energy. DEF has one balancing area named FPC. FPC area model includes a net interchange import of 2,820 MW for 2018 and 2,627 MW for 2023.

Duke Energy Progress

DEP includes confirmed annual firm transmission service requests that are in accordance with resource projections provided by LSE's and executed contracts for the sale of firm energy. DEP has two balancing areas named CPLE and CPLW. The CPLE area model includes 1500 MW of imports and 230 MW of exports, resulting in a net interchange import of 1270 MW in 2018, and 1500 MW of imports and 263 MW of exports, resulting in a net interchange import of 1237 MW in 2023. The CPLW area model includes 1 MW of imports and 0 MW of exports, resulting in a net interchange import of 1 MW in both 2018 and 2023.

Electric Energy Inc.

The output of Electric Energy, Inc. generation is modeled as an export to AMIL.

Entergy Services

Entergy Arkansas Inc. (EAI) area interchange assumptions in the 2018 roll-up integration case include 551 MW of imports and 1,876 MW of exports for a net interchange of 1,325 MW. The 2023 roll-up case include 551 MW of imports and 1,889 MW of exports, resulting in a net interchange of 1338 MW.

Entergy Mississippi Inc. (EMI) area interchange assumptions in the 2018 roll-up integration case include 1,380 MW of imports and 1,620 MW of exports for a net interchange of 240 MW. The 2023 roll-up case include 1,425 MW of imports and 1,845 MW of exports, resulting in a net interchange of 420 MW.

The remaining Entergy Operating Companies (Entergy Louisiana, Entergy Gulf States Louisiana, Entergy New Orleans and Entergy Texas) area interchange assumptions in the 2018 roll-up integration case include 1,285 MW of imports and 200 MW of exports for a net interchange of 1,084 MW. The 2023 roll-up case include 1,284 MW of imports and 205 MW of exports, resulting in a net interchange of 1080 MW.

Values represented in Appendix E reflect long-term (one year or more) firm transmission service obligations.

Florida Power & Light

The scheduled net interchange modeled for the FPL area reflects the forecasted firm interchange transactions as coordinated with the other utilities within the FRCC Region. There are approximately 886 MW of imports into FPL's BA from inside the FRCC that are associated with unit ownership or PPAs. There are approximately 946 MW of imports into FPL's BA from outside the FRCC that are associated with unit ownership or PPAs.

Georgia Transmission Corporation

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

Independent Electricity System Operator

Transmission service is not sold in Ontario; transactions at the interties are scheduled based on economic merit through the energy market. If a transaction is successfully scheduled, it will be provided with access to the transmission system. Therefore, IESO 2018 and 2023 models have a zero firm transactions.
IESO area interchange assumptions in the 2018 and 2023 roll-up integration cases include a net import of 1,250 MW from Quebec on HVDC lines.

ISO New England

ISO New England's area interchange assumptions in the 2018 roll-up integration case and 2023 roll-up integration case include 2,607 MW and 2408 MW of imports respectively. I n each case, 344 MW of exports are also modeled resulting in a net import of 2,263 MW in year 2018 and 2,064 MW in year 2023. The majority of this interchange comes from 1,725 MW imported from Quebec on HVDC lines to northern Vermont and eastern Massachusetts.

JEA

In addition to JEA's obligation to serve JEA's native retail territorial load, JEA also has contractual obligations to provide transmission service for the transmission-level customer and for delivery of contractual power from jointly owned and independent power producer plants. The transactions included in JEA's load flow model include all the firm long-term generation and transmission service capacities through the year 2023. In addition to JEA's territorial system ties supporting import and export capabilities, JEA also has allocation rights in the Florida/Georgia 500 kV tie import and export capacity. The power interchange used for this study includes 300 MW import from Georgia (Southern Company) to JEA and 627 MW export from JEA to the FRCC region; with a resultant 327 MW net power interchange (export) in the 2018 roll-up integration case. For the 2023 case, the import from Georgia to JEA is 400 MW and export to FRCC region is 250 MW; with a net of 150 MW flowing in to JEA.

LG&E and KU Energy

LG&E/KU's area interchange assumptions in the 2018 roll-up integration case include 304 MW of imports and 309 MW of exports, resulting in a net interchange of -5 MW. LG&E/KU's area interchange assumptions in the 2023 roll-up integration case include 305 MW of imports and 309 MW of exports, resulting in a net interchange of -4 MW. Values represented in Appendix E reflect long-term (one year or more) firm transmission service obligations.

MAPPCOR

The MAPP model for the 2018 summer peak includes an area interchange value of 1,685 MW for exports and 640 MW imported, creating a net interchange of 1,045 MW. The 2023 MAPP model includes an area interchange value of 540 MW MAPP imports and 1,736 MW MAPP exports for a net interchange value of 1,196 MW.

MEAG Power

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

Mid-continent ISO (MISO)

For MISO members, internal interchange is based on the market dispatch. Inter-regional interchange is determined 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 Authorities is unchanged from the corresponding ERAG case. Please refer to Appendix E for detailed interchange information. Import and export transactions have been agreed to and are consistent with those of external PA regions. The 2018 model has a net MISO import of 2803 MW while the 2023 model has a net MISO import of 3327 MW.

New York ISO
The NYISO coordinates its interchange schedule with its neighbors and represents firm transactions and the expected continuance of current external ICAP providers as listed in the NYISO 2013 Load & Capacity Data Report.

PJM Interconnection
PJM 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 assembly of interregional reference cases according to the Eastern Reliability Assessment Group, Multi-regional Modeling Working Group process. Since individual Planning Authorities must assemble interregional reference cases that interchange with many neighbors, this interchange is necessarily only a starting point value to be appropriately adjusted depending on the nature of the planning analysis being performed. The series of annual PJM RTEP transmission studies plan for firm interchange values between PJM and neighbors. PJM net firm interchange with neighbors in the 2018 roll up model is 51 MW (export) and in the 2023 model is 484 MW (import). Non-firm interchanges were not modeled in either case. Interchange 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 like 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 2018 roll-up integration case include 444.8 MW of imports and 1081.2 MW of exports, resulting in a net interchange of 636.4 MW. PowerSouth's area interchange assumptions in the 2023 roll-up integration case include 507.8 MW of imports and 1150.7 MW of exports, resulting in a net interchange of 642.9 MW. Values represented in Appendix E reflect long-term (one year or more) firm transmission service obligations as it relates to the transmission service provider.

Santee Cooper
The area interchange schedule for the 2018 roll-up integration case includes 1,645 MW of imports and 336 MW exports for a net interchange of 1,309 MW importing. The 2023 roll-up integration case contains 1,645 MW of imports and 323 MW of exports for a net interchange of 1,296 MW importing. There are no firm transmission service requests modeled in either case.

South Carolina Electric & Gas
SCE&G's area interchange assumptions in the 2018 and 2023 roll-up integration case include 77 MW of imports and 1,370 MW of exports, resulting in a net interchange of 1,293 MW exporting. Values represented in Appendix E reflect long-term (one year or more) firm transmission service obligations.

Southern Company
Southern Company's area interchange assumptions in the 2018 roll-up integration case include 2,062 MW of imports and 2,748 MW of exports, resulting in a net interchange of 686 MW. Southern Company's area interchange assumptions in the 2023 roll-up integration case include 2,156 MW of imports and 2,682 MW of exports, resulting in a net interchange of 526 MW. Values represented in Appendix E reflect long-term (one year or more) firm transmission service obligations.

Southwest Power Pool

SPP's area interchange assumptions in the 2018 roll-up integration case include 2,039 MW of imports and 1,910 MW of exports, resulting in a net interchange of 129 MW importing for the 2018 roll-up case. The 2023 roll-up integration case includes 1,908 MW of imports and 1,431 MW of exports, resulting in a net interchange of 477 MW importing. SPP includes long term firm transmission service requests in models, as well as related projects with an approved FERC filed NTC ("Notification to Construct").

Tennessee Valley Authority

TVA's area interchange assumptions in the 2018 summer roll-up integration case include 1033 MW of imports and 1104 MW of exports, resulting in a net interchange of 71 MW. For the 2023 summer roll-up integration case, TVA's area interchange assumptions include 1040 MW of imports and 1114 MW of exports, resulting in a net interchange of 74 MW. Values represented in Appendix E reflect long-term (one year or more) firm transmission service obligations.

2.5 Process for Future Transmission Project Inclusion

Each Planning Authority's planning process for inclusion of new transmission projects is described in this section. A complete detailed listing of all new and upgraded transmission projects included in the 2018 and 2023 roll-up integration cases is provided in Appendix B. The "Model Year" column indicates whether the facility was included in the 2018 and 2023 models ("2018") or just the 2023 model ("2023"). Since inclusion varies based on each PA process, the PAs have agreed to the following terms in order to describe the status of future transmission projects, which are used in Appendix B:

- Construction: The project is under construction.
- Committed: The project has obtained some level of contractual obligation, regulatory approval, or is included in approved capital budgets.
- Planned: The project has completed the respective Planning Authority's planning process, including 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: The project has been proposed but has not yet completed the respective Planning Authority's planning process nor received applicable regional planning process approvals. In this case, the year in which completion of the process and applicable regional approval is expected is listed in Appendix B.
- Conceptual: The project has been identified as a potential solution to a constraint identified during the EIPC Roll-Up model validation process. The project and constraint have not previously been identified during the Planning Authority's normal planning process.
- On Hold: The project has been withdrawn or suspended.

Alcoa Power Generating, Inc.
Alcoa's Yadkin division has no plans for future generation or transmission expansions.

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

Transmission facilities that are approved and budgeted or where construction has begun have been included in the 2018 and 2023 summer 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 that is 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 which are 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, FERC Order 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 & 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 N-1 contingency criteria; however, some projects are included to meet credible 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 which are 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 PEC's internal planning efforts as well as through the SERC Long Term Study Group, North Carolina Transmission Planning Collaborative, Southeastern Inter-Regional Participation Process, and joint studies with interconnected neighbors. Transmission facilities that are approved, committed & budgeted or where construction has begun 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 that is 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 N-1 contingency criteria. Furthermore, projects could potentially be included that have not been through the state certification process but that is not the case for the 2018 and 2023 roll-up integration cases used in this process.

Electric Energy Inc.

Electric Energy, Inc. (through the services of consulting companies) performs an annual analysis and evaluation of the Electric Energy, Inc. transmission system response to generation and transmission system expansion plans, and expected power purchased by Electric Energy, Inc. and others through short-term and long-range transmission planning studies. The transmission system analysis is carried out through active participation in NERC and SERC committee work, as well as internal Electric Energy, Inc. transmission planning studies. The objective of Electric Energy, Inc. is to provide adequate electrical capacity and transfer capability to serve Electric Energy, Inc. customers with acceptable reliability, commensurate with cost, and to accommodate power transfers by others without excessively burdening the Electric Energy, Inc. system. Electric Energy, Inc. subscribes to all NERC and SERC planning standards, which are available from those organizations. The study models used for Electric Energy, Inc. planning are based on the ERAG Multi-region Modeling Working Group (MMWG) models and the related SERC seasonal assessment models. Electric Energy, Inc. participates annually in building the MMWG models and in the preparation of seasonal assessment models for near term and long term summer and winter assessments as requested by SERC. Electric Energy, Inc. has no native load within its service territory. As a result, the net system import requirements are essentially zero. Historically, the Paducah Gaseous Diffusion Plant (PGDP) is the major customer for Electric Energy, Inc.. The general transmission planning philosophy is to provide adequate and sufficiently reliable generating plant outlet transmission capability to assure that the needs of the PGDP are satisfied, and during periods of light PGDP load, Electric Energy, Inc. has sufficient transmission transfer capability to export the full generation capacity.

Entergy Services

On an annual basis, Entergy develops its 10 year transmission plan which includes projects identified to support Load Serving Entities (“LSEs”) and other long-term firm transmission customers under the Open Access Transmission Tariff (OATT) in delivering energy on a firm basis. Transmission projects in Entergy’s transmission plan may include:

- Projects identified to meet long term reliability needs.
- Projects identified 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.
- Projects associated with network reservations provided by LSEs for generation capacity necessary to meet their respective load obligations.

Entergy included in the 2018 and 2023 roll-up integration cases transmission projects identified in Entergy’s 2013 – 2017 Final Construction Plan Update 3 posted on OASIS. The projects identified in Entergy’s 2013 – 2017 Final Construction Plan Update 3 have been reclassified in order to conform with the agreed upon EIPC status categories of State/Budget Approval, Planned, or Proposed.

As transmission projects are identified or move forward towards implementation, all required laws and regulations are followed according to the specific jurisdiction to obtain necessary approvals. If the need for the transmission project is due to the planned addition of a supply-side resource, then approval for that project is generally sought in the certification proceeding for that resource. Furthermore, the states also vary with regard to which transmission projects have to receive specific state certification approvals.

Florida Power & 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 (TYSP) filing with the Florida Public Service Commission are included in the roll-up integration case.

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. In order to jointly plan for future transmission expansion, study recommendations are reviewed and coordinated 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. Transmission improvement projects included in GTC's expansion plans were included in the roll-up integration case.

Independent Electricity System Operator

Planning in Ontario is conducted on two fronts - assessing future system conditions with known and expected facilities in place, and developing future plans on resources and transmission to meet the needs of the system. Both processes use applicable NERC reliability standards and NPCC regional reliability standards to evaluate the reliability performance of the proposed projects.

On the assessment front, the IESO, as the Planning Authority, conducts transmission and resource adequacy assessments as follows:

- An Ontario Reliability Outlook with a five-year horizon, that is issued on an as required basis;
- An 18-Month Outlook Update that is conducted semi-annually;
- A Review of Resource Adequacy with a 5-year horizon, submitted annually to NPCC, and
- A Review of Transmission Adequacy with a 5-year horizon, submitted annually to NPCC

These assessments provide an evaluation of the future conditions such as system constraints and resource adequacy based on planned system conditions; they do not propose resource or transmission plans to meet adequacy needs or to alleviate system constraints. Market participants use the information provided in the reports to make decisions on investments in the power system assets.

On the developing future plans the Ontario Power Authority (OPA) addresses the long-term system planning. through an independent and integrated plan for conservation, generation and transmission over a 20 year period.

Through OPA's planning activities, the OPA identifies resource and transmission requirements, procures resources and promote conservation as required to ensure supply adequacy and respond to other system and policy needs. Transmission Owners develop options to meet the transmission facility proposals, which include route selections, line types, associated facilities, etc. These options are evaluated by the IESO through the System Impact Assessment (SIA) process, to evaluate system performance under forecast system conditions and when subjected to various contingencies.

The applicable seasonal peak power flow models developed annually by IESO for MMWG available in the most recent NERC ERAG Model series are updated to include all future transmission and generation projects in Ontario that passed the IESO Connection Assessment and Approval (CAA) process, along with any upgrades required to maintain the reliability of the IESO system including the future transmission and generation.

ISO New England

ISO New England's portion of the 2018 & 2023 roll-up integration cases include all future projects that have been approved under Section I.3.9 of the ISO New England Tariff. Pursuant to Section I.3.9, the ISO reviews proposals for new generation and transmission facilities rated at or above 69 kV. If it is determined that a project would not have a significant adverse impact on the stability, reliability or operating characteristics of existing electrical infrastructure, the ISO would approve the project for interconnection to the grid. Projects that have reached this stage are assumed to be in service for the 2018 and 2023 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.

JEA

JEA does not include any "Proposed" transmission projects in its load flow models. All projects sponsored by JEA in the roll-up integration cases have the status of "State/Budget Approval"(now called "Committed"). JEA's policy and practice is to only include "Committed" projects (facility additions, modifications, retirements, or system topology changes) to the load flow transmission model if the inclusion of those projects represents the most probable future scenario. To JEA, this means that the projects have, as a minimum, undergone JEA's internal budget review process and have been approved for real estate activities associated with securing rights-of-ways 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 has achieved a substantial chance of reaching successful acquisition.

LG&E and KU Energy

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 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 ERAG model building process.

Seasonal peak power flow models are developed annually (first quarter) by LG&E/KU using each model year available in the most recent NERC ERAG 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 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 generator and/or major transmission additions to provide better models for 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. Generator and transmission contingency simulations are routinely performed to evaluate the adequacy of the transmission system against the no "Loss of Demand or Curtailment of Firm Transfer" requirements of the Transmission Planning Guidelines.

- 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 completion date, to determine the upgrade or construction required and to identify the reason for the change. The required completion date is determined by interpolating flows between model years.
- Area Studies – Area studies are performed prior to 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 ITO by a Network Integrated Transmission Service (NITS), Designated Network Resource (DNR), or Point-To-Point (PTP) request. Multiple options with an associated cost and time frame to complete construction to provide the requested service is provided back to the customers through the ITO.
- 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/KU in the previous year, are incorporated into the Transmission Expansion Plan.

Periodically, studies are performed to evaluate the adequacy of the LG&E/KU transmission system against the allowable “Loss of Demand or Curtailment of Firm Transfer” requirements and “System Stability”. Necessary construction and upgrades identified by these studies are incorporated into the Transmission Expansion Plan.

Annually, the LG&E/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 final plan developed by the Transmission Owner must be approved by the ITO.

MAPPCOR

MAPP’s expansion planning process is an annual process for the 10-year planning horizon. For this 10-year planning horizon needed enhancements to the existing transmission system are identified for the next 10 years. The expansion of the transmission system is based on MAPP’s updated models with the ERAG MMWG models representing the external system. The transmission and resource assumptions included are the latest transmission expansion additions reported through the open process of the MAPP Regional Planning Group (RPG) activity and local plans submitted by the MAPP Stakeholders and approved through the MAPP Transmission Planning Committee (TPC). The transmission owner determines the future transmission projects that are included during the model building process.

MEAG Power

MEAG 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 MEAG’s participants and MEAG’s long-term firm transmission tariff customers. MEAG also identifies projects to interconnect new generation, as applicable. In order to jointly plan for future transmission expansion, study recommendations are reviewed and coordinated 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.

Mid-continent ISO (MISO)
MISO produces a MISO Transmission Expansion Plan (MTEP) annually. This regional plan is produced in collaboration with transmission owning members and using a stakeholder process that is FERC Order 890 compliant. 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 upon EIPC status categories of Planned, Proposed or Conceptual. MISO included proposed projects that are pending approval in the current planning cycle, MTEP13, which began September 2012 and will conclude with Board approval December 2013.

New York ISO
The NYISO Comprehensive Reliability Planning Process (CRPP) encompasses a ten-year planning horizon and evaluates the future reliability of the New York bulk power system. In order to preserve and maintain system reliability, the NYISO, in conjunction with Market Participants, identifies the reliability needs over the planning period and issues its findings in the Reliability Needs Assessment (RNA). A request for solutions to identified reliability needs is issued with the expectation that Market-Based Solutions will come forward to meet the identified needs. All resources (generation, transmission and demand response) are eligible for consideration as potential solutions. In the event that Market-Based Solutions are not sufficient, to meet the reliability needs in a timely manner, the process provides for the identification of Regulated Backstop Solutions proposed by designated transmission owners, and Alternative Regulated Solutions proposed by any market participant. The NYISO then evaluates all proposed solutions to determine whether they will meet the identified reliability needs. Thus, the Comprehensive Reliability Plan (CRP) is developed in conjunction with NYISO stakeholders and approved by the NYISO Board, which sets forth the resources, plans and schedules that are expected to be implemented to meet the Reliability Needs, if any, that were identified in the RNA. In the event that there are insufficient market-based solutions to meet an identified Reliability Need, the NYISO directs the Responsible Transmission Owner to proceed with developing its Regulated Backstop Solution. When the TO applies for necessary siting approvals at the state level, other developers may choose to propose an Alternative Regulated Solution for consideration. Under the current NYISO Tariff, the NYS Public Service Commission would make the final determination as to which solution will proceed. A revised process has been proposed in compliance with FERC Order 1000.

PJM Interconnection
PJM's annual Regional Transmission Expansion Plan (RTEP) 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 Authority, 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 there is sufficient economic benefit, (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 annually reviews system operational performance, evaluates any issues and plans system upgrades as may be beneficial. 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 Order No. 1000, PJM plans for public policy transmission needs. Transmission enhancements required to facilitate public policy that are agreed to by the states and adopted in the PJM RTEP become part of the PJM transmission plans. Also, pursuant to Order 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 that are 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 that are 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 in 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. All projects' progress toward completion 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:

- NERC Planning Standards
  (http://www.nerc.com/~filez/standards/Reliability_Standards.html)
- RFC Reliability Principles and Standards

(http://www.rfirst.org/Standards/ApprovedStandards.aspx)

- PJM Reliability Planning Criteria as contained in Manual M14B Attachment G (http://www.pjm.com/documents/manuals.aspx)
- 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. PJM's 15-year planning horizon permits 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 and is based on a rolling 10-year cycle, in which needed enhancements to the existing transmission system are identified. PowerSouth coordinates with Southern Company and South Mississippi Electric Power Association (SMEPA) to accurately model shared ownership resources, as well as area interchange values. PowerSouth also submits data to and participates in SERC's Long Term Study Group (LTSG) which is used to create the MMWG models. Projects that are included in the model can be member driven (i.e. new delivery point), reliability driven (new bulk transmission) and/or as related to the NERC standards. PowerSouth, as a G&T Cooperative, is not under any state regulation authority. New transmission and/or 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 are to include future projects that are budgeted and approved by executive management for implementation. Planned and uncommitted construction project are also included in the model, but only if the project is judged to be well-defined and it is very likely to be fully implemented. Results of assessments are used to determine if 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.

South Carolina Electric & Gas

SCE&G includes in its transmission models all transmission projects that are budgeted and approved to be included in the transmission expansion plan. Not all projects have a commitment to build as 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 assessments of the transmission system with and without these transmission improvements and are reflective of changes in assumptions and objectives of the transmission system based on LSE needs, transmission service commitments and resource interconnections. Transmission projects in SCE&G's transmission expansion plan and in the EIPC roll-up case include 1) projects required to meet NERC Reliability Standards and SCE&G Transmission Planning Criteria, 2) projects required for the provision of firm transmission service (Network and Point-to-Point), per the SCE&G OATT and 3) system upgrades associated with generator interconnections, per the SCE&G OATT.

Southern Company

On a continuous, iterative basis, ten-year transmission expansion plans are developed to support Load Serving Entities ("LSEs") and other long-term firm transmission customers under the Open Access Transmission Tariff (OATT) in delivering energy on a firm basis. Transmission projects in Southern's expansion plans and in the roll-up include:

- 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 ten-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 those projects. The level of formality varies within each of the different jurisdictions. If the need for the transmission project is due to the planned addition of a supply-side resource, then approval for that project is generally sought in the certification proceeding for that resource. Furthermore, the states also vary with regard to which transmission projects have to receive specific state certification approvals.

Southwest Power Pool

The Integrated Transmission Plan (ITP) is SPP's approach to planning transmission needed to maintain reliability, provide economic benefits and achieve public policy goals in both the near and long-term. The ITP enables SPP and its stakeholders to facilitate the development of a robust transmission grid that provides customers improved access to the SPP region's diverse resources.

The ITP is an iterative three-year process that includes 20-Year, 10-Year, and Near-Term Assessments. The result of these assessments guides what SPP transmission projects are included in the base case. Projects resulting from the ITP that receive a Notification to Construct (NTC) are included in the base case. Additionally, projects can receive an NTC from the Generation Interconnection and Aggregate Service Request study processes. These projects are also included in the base case.

Tennessee Valley Authority

TVA develops a ten-year transmission expansion plan on an annual basis to support the projected load forecasts within the TVA Balancing Authority (BA) area as well as other long-term firm transmission service customers under the Open Access Transmission Tariff (OATT) in delivering energy on a firm basis.

Transmission projects in TVA's expansion plans and in the roll-up include:

- 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. If the need for a transmission project is due to the planned addition of a supply-side resource, then approval for that project 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.

2.6 Major New and Upgraded Transmission Facilities

The following section includes a description of the major new and upgraded transmission facilities included in each Planning Authority's portion of the 2018 and 2023 roll-up integration cases. Major facilities are facilities of 230 kV or above. In addition to this section, a complete listing of major new and upgraded projects are tabulated in Appendix B of this report and categorized as defined in Section 2.5. 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.

Alcoa Power Generating, Inc.
Alcoa's Yadkin division has no new or upgraded facilities planned.

Duke Energy Carolinas
DEC has included two new > 200 kV transmission projects in the cases. DEC has a project to upgrade the conductor on its 230 kV line from Pisgah Tie to Shiloh Switching Station by winter 2013 in order to accommodate additional transmission service into CPLW. The capacity of the two 500/230 kV transformers at Antioch Tie will be increased from 840 MVA per transformer to 1680 MW per transformer by summer of 2014. No other > 200kV projects are expected to be in service by 2023.

Duke Energy Florida
DEF has included the following 230 kV and 500 kV projects in the 2018 and 2023 roll-up integration cases:

- New 230 kV line from Disston Substation to Fortieth Street Substation in St. Petersburg;
- Second 230 kV line from Kathleen Substation to Zephyrhills North Substation in Zephyrhills;
- Removal of limiting elements to accommodate full ampacity of the Crystal River Plant to Central Florida 500 kV line;
- A new 230/115 kV transformer at Fort White Substation in Columbia County.

Duke Energy Progress
DEP has included three new 230 kV transmission projects in the 2018 and 2023 roll-up integration cases. The first is a new 230 kV line that will be placed in service by June 2014 from Harris to RTP Switching Station. Also, a new 230 kV line will be constructed from Lilesville to Rockingham by June 2014. Finally, a new 230 kV line is planned from Greenville to Kinston by June 2014.

Electric Energy Inc.
There are no new Electric Energy, Inc. transmission facilities in the 2020 roll-up integration case.

Entergy Services
Entergy included in the 2018 and 2023 roll-up integration cases projects that have been identified to meet the reliability needs of the transmission system over the ten year planning horizon. These projects

include constructing new 230 kV and 161 kV transmission lines, conversion of lower voltage lines to 230 kV operation, various upgrades of existing transmission lines, and the installation of additional 500 kV, 345 kV, and 230 kV autotransformers. Some of the projects included are also associated with transmission service request. A complete listing of all projects included in the roll-up integration case can be found in Entergy's 2013 – 2017 Final Construction Plan Update 3 posted on OASIS and also in Appendix B of this report.

Florida Power & 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 included two new transmission line projects in the 2023 model that will amount to an estimated total of 25 miles of new 230 kV transmission lines.

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 PA "SBA" also include GTC transmission projects.

Independent Electricity System Operator

Ontario is proposing to develop or enhance network transmission facilities to accommodate renewable resources. These transmission enhancements are planned to be in service by 2018. Additional transmission development may be identified in the future when there are further developments on the resource options.

The 2018 and 2023 roll-up integration cases include transmission system reinforcements in various parts of the province such as a new double circuit 230 kV line between Lakehead and Wawa, the reinforcement of the Oshawa, Whitby and Ajax areas and the upgrading of the existing double circuits 230 kV between Lambton TS and Longwood TS.

ISO New England

ISO-NE has included new transmission projects at 230 kV and above in the 2018 and 2023 roll-up integration cases. Most of these projects are components of either the Maine Power Reliability Project ("MPRP") or the New England East-West Solution ("NEEWS"), two major 345-kV plans anticipated to be in service by 2020 in New England. Other projects include the Vermont Southern Loop 345-kV project, Long-Term Lower Southeastern Massachusetts (SEMA) project, a new 345-kV substation in Rhode Island, and several additional bulk autotransformers located in all six New England States.

JEA

The major "State/Budget Approval" projects included in the roll-up integration cases are required to meet the generation and transmission performance requirements of 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. It also has plans to construct a new transmission circuit at 230 kV and some additional substations to serve the load.

LG&E and KU Energy

LG&E/KU does have projects to upgrade the 345 kV system in the 2018 or 2023 roll-up integration case. These project include; the addition of a 4^{th} Middletown 345/138 kV transformer, tapping the Mill Creek to Paddys West 345 kV line and installing a 345/138 kV transformer at Cane Run and a breaker station connecting the Speed to Ramseys 345 kV line to LG&E/KU's Paddys West to Northside 345 kV line.

MAPPCOR

Below are the major new and upgraded transmission facilities included in the roll-up integration cases for the MAPP region. A more detailed list of projects included in the 2018 and 2023 roll-up cases is provided in Appendix B.

North and South Dakota WAPA/BEPC facility additions/upgrades:

- Re-termination of the Heskett end of the Center to Heskett 230 kV line into the Mandan Substation
- Center to Grand Forks 345 kV line with three new, and one moved 345/230 kV transformers
- Maple River to Frontier to Wahpeton 230 kV line
- Tioga to Williston to Watford City to Antelope Valley 345 kV line
- New 230 kV substations at Lower Brule, Reliance and Whitten in South Dakota and at Larson, ND.
- New 345/230 kV substations at Judson and Tande, ND.

Minnesota facility additions/upgrades:

- Bemidji to Cass Lake to Grand Rapids 230 kV line with a new 230/115 kV transformer at Cass Lake.
- CapX2020 additions which include two new 345/116 kV transformer, one serving the Rochester, MN area and the other serving the La Crosse, WI area. Also including the Hampton to Rochester to La Crosse 345 kV line addition. Also included in the CapX2020 project is a rebuild of the Alexandria Switching Station to receive the 345 kV line from Monticello to Quarry to Alexandria to Bison
- Richer to Roseau to Moranville 230 kV line
- Winger to Thief River Falls 230 kV line with a capacity upgrade to the Winger 230/115 kV transformer.

MEAG Power

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

Mid-continent ISO (MISO)
Planned, major 230 kV and above line additions included in the powerflow models are shown in the table below.

Project Description	Location	Mile age	Expected In-Service Date
Pleasant Prairie - Zion Energy Center 345 kV MVP	WI/IL	5	12/31/13
Brookings, SD - SE Twin Cities 345 kV MVP	SD/MN	494	12/26/14
Fargo, ND - St Cloud/Monticello, MN area 345 kV	ND/MN	190	05/31/15
DEM Speed - LGEE New Albany 345 kV	IN	2	06/01/15
Michigan Thumb 345 kV MVP	MI	280	12/31/15
SE Twin Cities - Rochester, MN - LaCrosse, WI 345 kV	MN/WI	118	05/15/16
Sidney - Rising 345 kV MVP	IL	27	11/15/16
North Appleton - Morgan 345 kV	WI/IL	40	12/31/16
Big Stone South - Brookings 345 kV MVP	SD	35	09/30/17
Palmyra Tap -Quincy-Meredosia - Ipava & Meredosia-Pawnee 345 kV MVP	IL/MO	158	11/15/17
Reynolds - Greentown 765 kV MVP	IN	192	06/01/18
Lakefield Jct. - Winnebago - Winco - Kossuth County & Obrien County - Kossuth County - Webster 345 kV MVP	MN/IA	218	06/01/18
Adair - Ottumwa 345 MVP	IA/MO	71	11/15/18
Fargo - Galesburg - Oak Grove 345 kV MVP	IL	102	11/15/18
Pawnee - Pana 345 kV MVP	IL	22	11/15/18
Adair - Palmyra Tap 345 kV MVP	MO	64	11/15/18
N LaCrosse - N Madison - Cardinal - Eden - Dubuque Area 345 kV MVP	IA/WI/MN	260	12/31/18
Winco - Hazleton 345 kV MVP	IA	153	12/31/18
Pana - Mt. Zion - Kansas - Sugar Creek 345 kV MVP	IL	117	11/15/19
Ellendale - Big Stone South 345 kV MVP	ND	114	12/31/19
Reynolds - Burr Oak - Hiple 345 kV MVP	IN	97	12/31/19
Ramsey - Grand Forks 230 kV Rebuild	ND	81	05/31/21

The following transmission projects are included in the model as Proposed projects and are currently being evaluated for recommendation in 2013 to the MISO Board of Directors for approval.

Project Description	Location	Mileage	Expected In-Service Date	Expected Regional Approval Date
Turkey Hill - Cahokia Rebuild to 345 kV	IL	19	06/01/15	2013

New York ISO
NYISO has included the following in both 2018 and 2023 roll-up integration cases:

- Hudson Transmission Partners (HTP) – New line consisting of a back-to-back DC converter located in Bergen, NJ, tying into Con Edison's West 49th St. 345 kV substation in Manhattan, NY via a 345 kV cable; In-service as of summer 2013
- Station 255 (New Rochester) 345 kV Substation – New 345 kV substation taps the existing Niagara/Somerset to Rochester 345 kV lines with two 345/115 kV transformers; Expected in-service by 2016

- Five Mile Road 345 kV Substation – New 345 kV substation taps the existing Stolle Road – Homer City 345 kV (NYISO-PJM tie-line) with one 345/230 kV transformer; Expected in-service by 2015.

PJM Interconnection
A complete list of all approved RTEP upgrades, as well as a brief description of the facility, upgrade driver and current status can be found on PJM's Web site via the following URL link: http://www.pjm.com/planning/rtep-upgrades-status/construct-status.aspx

The 230 kV and above line upgrades are provided in an appendix to 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. A subset of the upgrades reported in the appendix was selected to depict a sampling of the more significant upgrades being implemented through PJM's RTEP process. The descriptions of these lines follow:

Project	**Date Required for Reliability**	**Status**
Loop in the Meadow Lake - Olive 345 kV circuit into Reynolds 765/345 kV station	6/1/2018	Board Approved; Engineering Procurement
Upgrade the Chalk Point - T133TAP 230 kV Ck. 1 (23063) and Ckt. 2 (23065) to 1200 MVA ACCR	6/1/2018	Board Approved; Engineering Procurement
Build a 2nd Loudoun - Brambleton 500 kV line within the existing ROW.	6/1/2018	Board Approved; Engineering Procurement
Rebuild Susquehanna – Jenkins 230 kV circuit	11/30/2019	Board Approved; Engineering Procurement
Rebuild the Siegfried-Frackville 230 kV line	6/1/2018	Board Approved; Engineering Procurement
Reconfigure the Sewaren 230 kV; Convert the two 138 kV circuits from Sewaren – Metuchen to 230 kV circuits including Lafayette and Woodbridge substation; Reconfigure the Metuchen 230 kV station to accommodate the two converted circuits	6/1/2015	Board Approved; Engineering Procurement
Build a new 230 kV line from Dooms to Lexington on existing ROW	6/1/2016	Board Approved; Engineering Procurement
Reconductor the AEP portion of the Cloverdale – Lexington 500 kV line	3/1/2014	Board Approved; Engineering Procurement
Construct 230 kV OH line along existing Line #2035 corridor, approx. 2.4 miles from Idylwood -	6/1/2017	Board Approved; Engineering

Dulles Toll Road (DTR) and 2.1 miles on new right-of-way along DTR to new Scott's Run Substation		Procurement
Construct a new Byron to Wayne 345 kV circuit	6/1/2017	Required for Economics
PSEG 345kV double circuit solution – Isolate Hudson 230kV from the 138kV at Marion and 345kv at Farragut; Convert the 138kV facilities on the path from Linden to Bergen to double circuit 345kV	6/1/2015	Planned. Not yet board approved.

In the previous EIPC analysis, PJM had major backbone 500kV projects in different planning stages. The following backbone projects were completed since the 2010 EIPC report: Carson – Suffolk 500kV, 502 Junction – Loudoun 500 kV (TRAIL), Susquehanna – Roseland 500kV. PJM performs annual reviews of major backbone projects to assess the continued need. Two major backbone projects reported in the 2010 EIPC rollup report have been canceled due to these reassessments. The first of the cancelled projects (PATH) was a 765kV line from Amos substation near St. Albans, West Virginia to the proposed Kemptown Substation southeast of New Market, Maryland and the second was the MAPP line, a 500kV line going from Possum Point in Virginia to two substations in Maryland and ending at a point near Calvert Cliffs where it would be converted into DC to continue to two points in Delaware.

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 the period 2020 include continued development of a 230 kV transmission system necessary to deliver generator output to the load and maintain reliability of the transmission system. Santee Cooper has approximately $600 million of planned and proposed additions and upgrades expected to be in service through the year 2023 for all classes.

South Carolina Electric & Gas
The major transmission improvements to the SCE&G transmission system that are included in the 2018 and 2023 roll-up integration cases include:

Project	**Scheduled Completion Year**
VC Summer #1 – Killian 230kV	2014
VC Summer #2 – Lake Murray 230kV #2	2014
VC Summer #2 – St George 230kV #1	2018
VC Summer #2 – St George 230kV #2	2018
St George – Summerville 230kV	2018

Southern Company
The major upgrades within the Southern Balancing Authority that are included in the 2018 and 2023 roll-up integration case include:

- the construction of a new 8-mile 500 kV line from Dresden to Heard County including the installation of a new 500/230 kV transformer at Dresden in 2014

- the construction of a new 58 mile 230 kV line from Greene County to Bassett Creek in 2015
- the construction of a new 17 mile 230 kV line from North Brewton to Alligator Swamp in 2015
- the construction of a new 21 mile 230 kV line for Laguna Beach to South Rosa in 2015
- the construction of a new 55 mile 500 kV line from Vogtle to Thomson in 2017
- the construction of a new 25 mile 230 kV line from Holt to South Bessemer in 2019
- the construction of a new 25 mile 230 kV line from Bassett Creek to ARN230 in 2020
- the reconstruction of an existing 22 mile 115 kV line from Pine Grove to Jasper FL in 2015.

Southwest Power Pool

The major transmission improvements to the SPP transmission system that are included in the 2018 and the 2023 roll-up integration cases are listed below. 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.

Project	Mileage	Scheduled Completion Year
Muskogee - Seminole 345kV	100	2013
Tuco - Woodward 345kV	327	2014
Hitchland - Woodward (Double Circuit) 345kV	244	2014
Thistle - Woodard (Double Circuit) 345kV	218	2014
Thistle - Wichita (Double Circuit) 345kV	155	2014
Spearville - Clark Co - Thistle (Double Circuit) 345kV	227	2014
Oasis - Pleasant Hill - Roosevelt 230kV	42	2014
Iatan - Nashua 345kV	61	2015
Valiant - NW Texarkana 345kV	76	2015
Messick 500/230kV Xfmr		2015
Cherry - Potter Interchange 230kV		2015
Newhart - Swisher 230kV	19	2015
Flint Creek - Shipe Rd - E Rogers - Kings River 345kV	59	2016
Hoskins - Neligh 345kV	41	2016
Nebraska City - Mullins Creek - Sibley 345kV	181	2017
Carlisle - Wolfforth 230kV	17	2017
Tuco - Stanton 345kV	14	2018
Chisholm - Gracemont 345kV	123	2018
Elm Creek - Summit 345kV	58	2018
Gentleman - Cherry Co - Holt Co 345kV	227	2018
Grassland - Wolfforth 230kV	47	2018
Arcadia - Redbud 345kV	5	2019
Tuco - Amoco - Hobbs 345kV	182	2020
Cimarron - Matthewson - Tatonga 345kV	126	2021

Tennessee Valley Authority

The major upgrades to the TVA transmission system that are included in the 2018 and 2023 roll-up integration cases include:

2018:

- Paducah Gaseous Diffusion Plant (also known as the United States Enrichment Corporation, or USEC) near Shawnee Fossil Plant in Paducah, Kentucky closed its uranium enrichment facility in May 2013. The resulting projected load for USEC will be reduced to 30 MW. To ensure that generation from Marshall and Shawnee remain deliverable, TVA is required to reconductor the Marshall to C-33 161 kV line.

- Load flow studies have determined the Volunteer-Knox #1 161 kV line overloads for loss of the Volunteer-Knox #2 161 kV when hydro generators are turned off in the area. Also, the voltage at the East Knox 161 kV sub will drop below criteria for loss of the Nixon Rd-East Knox 161 kV line. A new 161 kV line from Volunteer to East Knox will be built with a projected in-service date of June 2015.

- Long-range load flow studies show that a high-voltage source will be required in the Cookeville area when the area loads reach 650-700 MW. This new 500 kV source will be needed to supply the increasing area load and to transfer the increased generation from the 500 kV system to the 161 kV system. The Plateau 500/161 kV transformer will be in service by June 2016.

- If the Union 500/161 kV transformer is interrupted during periods of high load in the summer, voltages around Tupelo will drop below planning criteria. The Union 500/161 kV #2 transformer will be in service by June 2014 to accommodate low voltages in the Tupelo area.

2023:
New generation capacity expansion in the Bellefonte, AL area will create the need to construct a new Bellefonte 500 kV Substation. This substation will terminate the existing Widows Creek-Madison and the Widows Creek-East Point 500 kV lines creating 4 new 500 kV line names. The projected in-service date of this project is November 2022.

2.7 Generation Assumptions (Additions and Retirements)

The following section describes assumptions related to modeling of new and retiring generation facilities. As with transmission facilities, the processes for inclusion of new generation and retirement of generation vary between different Planning Authorities. This section describes, in general terms, the processes people follow and/or the assumptions that were made in the 2018 and 2023 cases regarding generation additions and retirements.

A complete detailed listing of all new and upgraded generation projects included in the 2018 and 2023 roll-up integration cases is provided in Appendix C. The “Model Year” column and indicates whether the facility was included in the 2018 and 2023 models (“2018”) or just the 2023 model (“2023”). Planning Authorities have agreed to the following terms to describe the status of future generation projects:

- Construction: The resource is under construction or is being commissioned.
- Committed: The resource has completed the interconnection request process, or has obtained applicable transmission service.
- Proposed: The resource has been proposed and included in the planning process, but does not have applicable transmission service.

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 (LSEs), not the Planning Authorities.

The transmission analysis performed in this study involves analyzing summer peak period loading from a reliability perspective to assess potential transmission system constraints. The renewable resources provided to each Planning Authority 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 also included in the Appendix C.

Alcoa Power Generating, Inc.
Alcoa's Yadkin division has no generation changes planned for the future.

Duke Energy Carolinas
Only DEC and IPP generation facilities that are presently in operation are included in the cases. Duke plans to retire Lee 1 and 2 by 2015 and repower Lee 3 from coal to gas operation.

Duke Energy Florida
As of Phase 1, it had been announced that DEF would retire its Crystal River Coal Units 1 and 2 after the second unit at the Levy County site completes its first fuel cycle. At present, the Levy County project is canceled and the retirements of Crystal River Coal Units 1 and 2, Higgins CTs and Suwannee CTs have all been deferred until further notice.

Duke Energy Progress
DEP has included one new DEP generation project in the roll-up integration cases at Sutton Plant. In general new generation is included that DEP is committed to building and has state approval or IPP's with a signed interconnection agreement and firm transmission. DEP has recently announced plans to retire existing coal units at its Sutton and Cape Fear coal plants. Retired generation will be replaced with a combined cycle gas plant at Sutton Plant.

Electric Energy Inc.
Electric Energy, Inc. has no generation additions or retirements in the 2020 roll-up integration case.

Entergy Services
Entergy generation modeled in the case includes all in-service units and any planned units that have firm transmission service scheduled from them after their completion. The resource plan assumed in the 2018 and 2023 roll-up integration cases are driven by the need to satisfy reserve margin obligations and to meet energy demand during system peak load conditions. Resources without long-term firm transmission service may be included in the model, but at zero output.

As part of the planning process, the existing units are assessed to determine their ability to economically remain in the portfolio relative to other available resource alternatives. This assessment seeks to consider the total supply cost and operational attributes of the existing generating units relative to the available resource alternatives to determine whether the existing units should be removed from the portfolio, phased out of the portfolio over time, proactively maintained in their current state to remain in the portfolio, or refurbished and/or upgraded to remain in the portfolio. Units that are expected to be removed from the portfolio or phased out of the portfolio over time are reflected in the unit deactivation assumptions for assessing capacity needs. Whereas, units that are expected to be maintained in their current state to remain in the portfolio or refurbished and/or upgraded to remain in the portfolio defer the need for new capacity additions.

Florida Power & Light

Future projects that have undergone FPL's internal budget review process as well as those projects that are representative of the (TYSP) filing with the Florida Public Service Commission are included in the roll-up integration case. Approximately 2500 MW of additional generation (as compared with 2012) are included in the FPL 2023 case. All of these projects have gone through the FPL System Impact Study process and are part of FPL's official resource plan. Florida Power & Light plans to retire the Turkey Point #1 steam turbine (396 MW) in 2016. The generator will be converted to synchronous condenser operation. FPL's TYSP filing serves as an input for the generation and load assumptions for modeling purposes.

Georgia Transmission Corporation

Generation resource assumptions are provided to GTC by its member cooperatives. Please note that in Appendix C, generation resources listed under the PA "SBA" also include generation resources identified by GTC's member cooperatives.

Independent Electricity System Operator

Ontario plans to retire 6 units at Pickering A and B nuclear generation stations by the end of 2020, which will remove approximately 3240 MW of generation from service. In response to the retirement of these units, Clarington TS is built to reinforce the supply of Oshawa – Whitby areas and approximately 6000 MW of renewable generation resources, including wind, solar, biomass, and hydro, are planned to come online and connect to the Ontario grid. Most of these resource additions are anticipated to be online by the end of 2018, with further development still under planning assessments.

Unit	System	Expected Retirement Date
Pickering G1	Ontario	2020
Pickering G4	Ontario	2020
Pickering G5	Ontario	2020
Pickering G6	Ontario	2020
Pickering G7	Ontario	2020
Pickering G8	Ontario	2020

ISO New England

ISO-NE has included several new generation projects in the roll-up integration case. These are projects that have been approved under Section I.3.9 of the ISO New England Tariff. Projects over 100 MW include uprates to a number of hydroelectric and steam turbine plants, as well as eight new wind farms, two natural gas combined cycle plants, and gas combustion turbine projects. ISO-NE generally does not assume generation retirements unless a generator has taken formal action to withdraw from the Forward Capacity Market by submitting either a Non-Price Retirement Bid or a De-List Bid.

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 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 certification 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 any existing generators in the ten year planning horizon.

LG&E and KU Energy

Resource assumptions contained within the 2018 and 2023 roll-up integration case for the LG&E/KU were provided by the respective LSEs (and market participants through securing Point to Point transmission service). 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 which have secured long-term firm transmission service. "Proposed" resources are those provided by LSEs to meet their forecasted load service requirements in future years, but which have not been designated as a network resource pursuant to the OATT.

LG&E/KU currently has one "Committed" resource to interconnect a 660 MW generator being built by LG&E/KU generation by 2015. This unit is dispatched in the 2018 and 2023 EIPC roll-up integration case. All announced generation retirements were incorporated into the EIPC cases.

MAPPCOR

MAPP area transmission owners determine which generation facilities proposed or committed are added in a model during the model building process, the retirement of Rochester Public Utilities' Silver Lake plant accounts for all retired capacity in the MAPP region through 2023.

MEAG Power

Generation resource assumptions are provided to MEAG by its member participants. Please note that in Appendix C, generation resources listed under the PA "SBA" also include generation resources identified by MEAG.

Mid-continent ISO

Within MISO, 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
The NYISO has included several new generation projects in its 2018 and 2023 roll-up integration cases. These are projects that have passed certain milestones to be included in the NYISO planning databases utilized in its Comprehensive Reliability Planning Process. The generation reflected in the roll-up cases includes approximately 700 MW of new wind nameplate capacity, 925 MW of combined cycle capacity and 168 MW of additional nuclear capacity. . NYISO generally does not assume generation retirements unless a generator has submitted a formal retirement or mothball notice. Although a mothball notice has been issued for Cayuga Units 1 and 2, both units are modeled in the 2018 and 2023 roll-up integration cases for providing Reliability Support Services under a temporary agreement entered into with New York State Electric & Gas Corporation (NYSEG, subject to periodic review..

PJM Interconnection
Additional information on the PJM planning process is described in section 2.5. 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 2018 and 2023 roll-up integration cases incorporate generation with signed Interconnection Service Agreement (ISAs), generation with signed Facility Study Agreements (FSA), and announced generation deactivations (e.g., retirement). Since State Renewable Portfolio Standards (RPS) are the responsibility of the Load Serving Entities (LSE), PJM plans for the resources of the LSE's as they enter the generation queue and fulfill their interconnection commitments. Section 2.5 of this report also describes PJM public policy transmission planning.

- Mid-Atlantic PJM included 3,305 MW of new generation with a signed ISA and 11,520 MW of projects with a signed facility study agreement.
- Western PJM included 4,749 MW of new generation with a signed ISA and 11,722 MW of projects with a signed facility study agreement.
- Southern PJM included 1,969 MW of new generation with a signed ISA and 905 MW of projects with a signed facility study agreement.

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 and generation with a signed FSA.

A listing of all generation and merchant transmission interconnection requests in PJM's queues can be obtained from the following links:
Generation: http://www.pjm.com/planning/generation-interconnection.aspx
Merchant Transmission: http://www.pjm.com/planning/merchant-transmission.aspx . The appendix to this report provides a convenient list of these projects at the time this report is assembled.
Announced unit retirements that have been accepted by PJM are deactivated in the roll up power flow. A list of these units and scheduled deactivation dates can be found at http://www.pjm.com/planning/generation-deactivation.aspx .

PJM Planning For Renewables
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 or Facilities 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. The following table provides the current status of renewable generation in the various stages of planning and development.

2028 PJM Wind and Solar Requirements (GW)		
Target installed Nameplate for Renewables based on State Targets	Solar	5.6
	Wind	32.3
	Total	37.9
Existing Installed Nameplate	Solar	0.2
	Wind	6.6
	Total	6.9
PJM Wind and Solar expansion with planned transmission in RTEP	Solar	2.2
	Wind	15.7
	Total	17.9
Additional Wind and Solar needed	Solar	3.2
	Wind	10.0
	Total	13.2

PowerSouth Energy Cooperative

Resource assumptions contained within the 2018 and 2023 roll-up integration cases for PowerSouth were determined through power supply studies and our annual capacity planning process. PowerSouth has no "Committed" resources between 2013 and 2023. There is one "Proposed" resource needed to meet our forecasted load growth before 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. There are no planned generation retirements between 2013 and 2023.

Santee Cooper

For both the 2018 and 2023 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 current Generation Expansion Plan, updated yearly, has Santee Cooper as a partial ownership with SCE&G in two nuclear units budgeted and scheduled for commercial operation in 2016 and 2019. The existing generation expansion plan also includes approximately 470 MW of retired generation.

South Carolina Electric & Gas

Resource additions included in the 2018 and 2023 roll-up integration cases for SCE&G include committed generation projects that are under construction. SCE&G is scheduled to complete construction on VC Summer Nuclear Units 2 & 3 in 2016 and 2019, and will share joint ownership of these units with Santee Cooper. These projects have been approved by the Public Service Commission of South Carolina.

LSEs within the SCE&G planning area have announced planned retirements in specific years within the next 10 years. A potential generator retirement option is modeled in the roll-up integration cases where the outputs of these potential retirement units are set at zero MW.

Southern Company
Resource assumptions contained within the 2018 and 2023 roll-up integration case for the Southern Companies were provided by the respective LSEs (and market participants through securing Point to Point transmission service). 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 case, but at zero output. “Committed” resources include designated network resources and other resources which have secured long-term firm transmission service. “Proposed” resources are those provided by LSEs to meet their forecasted load service requirements in future years, but which 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). 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 929 MW of generation retirements between 2013 and 2023, not including retirements or derates that may occur in response to developing EPA regulations.

Tennessee Valley Authority
Resource assumptions contained within the 2023 roll-up integration case for TVA are included in TVA’s official capacity expansion plan and provided by TVA’s System Planning group (and market participants through securing Point to Point transmission service). “Committed” resources include designated network resources and other resources which 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 which have not been designated as a network resource pursuant to the OATT.

- By November 2015, TVA will complete construction on the 1204 MW Watts Bar Nuclear Unit 2. This project is currently Committed and under construction.
- By November 2022, TVA will complete construction on the 1335 MW Bellefonte Nuclear Unit. This project is currently Proposed and in TVA’s capacity expansion plan.
- By December 2017, TVA will retire Johnsonville Fossil Units 1-10.

2.8 Generation Dispatch Description

This section explains the methods used by each Planning Authority to dispatch the available generation in the 2018 and 2023 roll-up integration cases. All PAs apply methods of dispatching their systems that are representative of actual system dispatch that is expected to occur based on economic and physical considerations. The precise base case dispatch is not critical to determining transmission expansion plans as these plans are developed based on 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.

Alcoa Power Generating, Inc.
Alcoa's Yadkin division load is served from the Badin generator.

Duke Energy Carolinas
The DEC system generation dispatch is modeled according to economic dispatch in accordance with the priorities identified in the resource projections provided by LSE's and according to executed contracts for the sale of firm energy. Large base load fossil and nuclear units are dispatched with remaining load served by a mix of hydro, combined cycle and gas turbine generation.

Duke Energy Florida
The DEF system generation dispatch is modeled according to economic dispatch in agreement with the priorities identified in the resource projections provided by LSEs and according to executed contracts for the sale of firm energy.

Duke Energy Progress
The DEP system generation dispatch is modeled according to economic dispatch in agreement with the priorities identified in the resource projections provided by LSE's and according to executed contracts for the sale of firm energy.

Electric Energy Inc.
Electric Energy, Inc. resources are fully dispatched in the 2020 roll-up integration case.

Entergy Services
To meet the area requirements firm generation is dispatched in the model, followed by non-firm network resources, generation owned by the LSEs and then non-firm energy only resources. Entergy dispatches generation representing firm energy contracts and economically dispatches firm network resources for load. Additional generation is dispatched on a pro-rata basis in the following order: non-firm network resources, LSE-owned non-firm energy-only generation, then non-firm, energy-only resources within the BA that are owned by others.

Florida Power & Light
FPL's generation resources are dispatched on an economic basis in order to meet 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 resource projections provided by the Load Serving Entities (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.

Independent Electricity System Operator
The IESO system generation dispatch is modeled based on economic dispatch in accordance with the demand to be served and the resource projections for the scenario under study.

ISO New England
In real-time operations, ISO-NE dispatches generation through a competitive wholesale market that results in the lowest priced resources being dispatched to meet system demand for electricity. However, because of uncertainties in future costs and bids from existing and new generators, the generation dispatch in the 2018 and 2023 roll-up cases reflect typical generation dispatches under summer peak conditions. Units that are typically among the least expensive (for example, nuclear, coal, and natural gas combined cycle) are dispatched, and units that typically have higher costs and bids (for example, oil combustion turbines and fast-start units) are left offline. The output of wind and hydroelectric generation will be modeled consistent with historical generation data for these units at summer peak load conditions.

JEA
All of JEA generators in the roll-up integration case are dispatched first on minimum contractual requirements and then on an economic basis.

LG&E and KU Energy
The LG&E/KU system generation dispatch is modeled according to economic dispatch in accordance with the priorities identified in the resource projections provided by each LSE.

MAPPCOR
MAPP Transmission owning members do their own generation dispatch and provide the value to our regional model building entity (MRO) and to the MAPP Transmission Reliability Assessment Subcommittee (TRAS).

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

Mid-continent ISO (MISO)
MISO members' generation is dispatched on a market-wide basis using security constrained economic dispatch (SCED) methodology. Renewable generation is set to its desired level before applying the SCED and renewable resources are not adjusted in the SCED process. Wind generators are dispatched at 20% of nameplate during summer peak condition. New and retiring generation is incorporated through the normal MTEP model building process.

New York ISO
The NYCA system generation dispatch includes only the impact of firm external transactions. Generation dispatch is consistent with typical dispatch observed during peak load.

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 2018 and 2023 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 2018 and 2023 roll-up integration cases is a strictly economic dispatch model. Nuclear units and large coal base load units are all dispatched first and then all other generating units are economically dispatched according to cost. There are no units dispatched out of merit to alleviate system loading constraints.

South Carolina Electric & Gas
The dispatch of generation resources within the SCE&G planning area is based on the economic dispatch 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.

Southern Company
The generation dispatch of the resources contained within the 2018 and 2023 roll-up integration case is based upon the dispatch merit order identified in the resource projections provided by the Load Serving Entities.

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 member dispatches its generation in the model to cover its own projected load obligations including any approved long term firm service transactions.

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 2023 roll-up integration case. TVA does not apply a security constrained dispatch to alleviate system constraints. The order of dispatch from most economic to least economic by generator technology is typically:

- Hydro
- Nuclear
- Pumped storage
- Fossil
- Combined 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 2.4. Interregional Transmission (Gap) Analysis.

Section 3 Interregional Transmission (Gap) Analysis

Power flow analysis is often focused on forecasted summer peak conditions which represent the lowest thermal ratings of facilities and typically (but not always) their highest loadings. To perform power flow analysis on an interconnection-wide basis, in addition to the modeling developed by each Planning Authority, an underlying exchange of energy or Interchange among Balancing Areas 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 Areas, but for which the market participants have not made "matching" transmission service commitments with the associated Transmission Providers in the receiving Balancing 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 Balancing Areas requires coordination.

The Interregional Transmission Analysis performed by the EIPC for the 2018 and 2023 planning years is a power flow analysis based upon the 2018 and 2023 roll-up models, which represent power system facilities and loads for the summer peak conditions forecast for the two years, as developed by each Planning Authority during their then-current planning cycle. The Interchange utilized for this analysis was developed though a coordinated effort of the EIPC Planning Authorities and is based upon a subset of transmission service commitments representing full path (as opposed to "partial-path") transactions from source to sink.

A contingency analysis was performed in a collective manner as described in Sections V.C. and V.D. of the "Steady State Modeling Load-Flow Working Group Procedural Manual"[2]. The objective of this analysis is to identify potential power flow interactions from an interconnection-wide perspective. These interactions may result from the effects of one Planning Authority's plans on another Planning Authority. Because the particular set of power flows and energy exchange (Interchange) in this analysis may differ from those assessed during local and regional planning activities, it is possible that 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, these constraints and the accompanying power flow conditions will be referred to the respective regional planning processes of the PAs.

This task is a screening analysis and its results (potential gaps) will be referred to the regional planning processes of the Planning Authorities 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 necessitating modification of the baseline topology of the 2018 or 2023 roll-up modeling to be applied in subsequent scenario analysis.

3.1 Thermal and Voltage Criteria

System performance was assessed in a manner consistent with the NERC TPL reliability standards as described in Section V.D. of the "Steady State Modeling Load-Flow Working Group Procedure Manual".

[2] The SSMLFWG manual can be found at: http://www.eipconline.com/uploads/SMLFWG_Procedure_Manual_Rev0_Final.pdf

Bulk Electric System elements above 100 kV were monitored. Thermal and voltage criteria applicable to each facility were applied.

3.2 Contingency Selection

As described in the "Steady State Modeling Load-Flow Working Group Procedure Manual", Section V.C., contingencies representing outages of all transmission elements 230 kV and above and all transformers with a low-side voltage rating of 110 kV or above were performed. Planning Authorities were also given discretion to simulate contingencies of transmission elements below 230 kV depending upon the composition and characteristics of each PA's bulk electric system.

3.3 Interregional Analysis Results

In this section, each Planning Authority provides a list of the constraining facilities that were identified as a result of the collective or individual Planning Authority analysis. It is assumed that the constraints identified are the result of neighboring system interactions that have yet to be assessed in detail. In some cases, a potential reliability issue may be difficult to pinpoint as to its cause with respect to system interactions. Issues identified will be utilized to inform the regional planning processes of the Planning Authorities in future planning cycles (See Section 4, Enhancements).

3.3.1 Summary of Thermal Results

Thermal Results by Planning Authority	2018 Results	2023 Results
Alcoa Power Generating	Nothing to report	Nothing to report
Duke Energy Carolinas	Nothing to report	Nothing to report
Duke Energy Florida	Nothing to report	Nothing to report
Duke Energy Progress	Nothing to report	Nothing to report
Electric Energy, Inc.	Nothing to report	Nothing to report
Entergy Services	Nothing to report	Nothing to report
Florida Power & Light	Nothing to report	Nothing to report
Georgia Transmission Corporation	Nothing to report	Nothing to report
Independent Electricity System Operator	Nothing to report	Nothing to report
ISO New England	Nothing to report	Nothing to report
JEA	Nothing to report	Nothing to report
LG&E and KU Energy	Nothing to report	Nothing to report
MAPPCOR	Nothing to report	Nothing to report
MEAG Power	Nothing to report	Nothing to report
Mid-Continent ISO (MISO)	**SEE BELOW**	**SEE BELOW**
NYISO	Nothing to report	Nothing to report
PJM Interconnection	**SEE BELOW**	**SEE BELOW**
Power South Energy Cooperative	Nothing to report	Nothing to report
Santee Cooper	Nothing to report	Nothing to report
South Caroline Electric & Gas	Nothing to report	Nothing to report
Southern Company	Nothing to report	Nothing to report
Southwest Power Pool	**SEE BELOW**	**SEE BELOW**
Tennessee Valley Authority	Nothing to report	Nothing to report

Mid-continent ISO (MISO)

A thermal analysis of the Mid-continent ISO system in the 2018 and 2023 Roll-Up cases was performed. About a dozen thermal facility issues were identified which meet the reporting requirements of Section 3.1. If a branch was overloaded for multiple contingencies, the highest overload was listed. Most overloads are close to 100% of rating indicated. There were other issues identified, however, a majority of the events have previously identified mitigations plans which were not modeled in the 2018 and 2023 Roll-Up cases. Many of the mitigation plans for multiple contingencies are operator actions. The items listed below are either planning coordination issues with neighboring Planning Authorities or internal Mid-continent ISO issues which are new to the 2018 and 2023 Summer Peak Roll-Up model.

Facility Issue	Contingency	Scenario
Winamac – Monticello 138 kV loads to 101% of 138 MVA	Loss of Dumont to Greentown 765 kV line	2018
Alma – Lufkin 161 kV loads to 101.6% of 194 MVA	Loss of A.S. King to Eau Clair 345 kV line	2018
Buena Vista – Owen 138 kV loads to 103.6% of 135 MVA	Loss of Worthington – Bloomington 345 kV line	2018
Rosser – Ridgeway 230 kV loads to 104.2% of 460.5 MVA	Loss of Dorsey – Ridgeway 230 kV line	2018
Raven Lake 230/110 transformer loads to 109% of 100 MVA	Loss of Reston – Cornwallis 230 kV line	2018
Williston 230/110 kV transformer loads 102.4% of 200 MVA	Base Case	2023
McHenry 230/120 kV transformer loads to 103.2% of 84 MVA	Base Case	2023
Henday – Long Spruce 230 kV ckt 1, ckt 2, ckt 3 loads to 110.7% of 348.6 MVA	Base Case	2023
Radison – Kelsey Terminal 138 kV loads to 196.8% of 125 MVA	Base Case	2023
Worthington - Buena Vista 138 kV loads to 106.8% of 135 MVA	Loss of Worthington – Bloomington 345 kV line	2023
Bedford – Owen 138 kV loads to 100.3% of 135 MVA	Loss of Worthington – Bloomington 345 kV line	2023
Buena Vista – Owen 138 kV loads to 103.6% of 135 MVA	Loss of Worthington – Bloomington 345 kV line	2023
Calamus East – Substation 56 161 kV loads to 116.1% of 223 MVA	Loss of Quad City to Rock Creek 345 kV line	2023

PJM Interconnection
2018 Case

Facility Issue	Contingency
East Lima - Maddox 345 kV line loaded to 111.42% of 1022 MVA	Loss of Robison Park - RPMONE 345kV line
Reynolds - Meadow 345 kV line loaded to 102.79% of 1195 MVA	Loss of Jefferson - Rock Port 765kV line
Dresden - Elwood 345 kV line loaded to 100.21% of 1479 MVA	Loss of Dresden - Electric Junction 345kV, Dresden 345/138kV, Dresden 138/34.5kV, Dresden Red - Dresden Blue 138kV lines

2023 Case

Facility Issue	Contingency
Quad Cities - Rock Creek 345 kV line loaded to 101.45% of 1153 MVA	Loss of Quad Cities - Sub 91 345kV, Sub 91 345/161kV, Sub 91 - Sub 56 345kV lines

Southwest Power Pool

Model	Facility Issue	Contingency
2018	Hemphill to Pendleton 138kV ckt 1 loads to 103.0% of 98 MVA	345kV Dolet Hill to SW Shreveport outage
2018	Hemphill to Sixmile 138kV ckt 1 loads to 115.1% of 98 MVA	345kV Dolet Hill to SW Shreveport outage
2018	Grapevine 230/115 kV Transformer ckt 1 loads to 111.0% of 112 MVA	230/115kV Wheeler transformer outage
2023	Grapevine 230/115 kV Transformer ckt 1 loads to 115.9% of 112 MVA	230/115kV Wheeler transformer outage
2023	Yoakum 230/115 kV Transformer ckt 1 loads to 106.5% of 150 MVA	230/115kV Yoakum ckt 2 transformer outage

3.3.2 Summary of Voltage Results

Voltage Results by Planning Authority	2018 Results	2023 Results
Alcoa Power Generating	Nothing to report	Nothing to report
Duke Energy Carolinas	Nothing to report	Nothing to report
Duke Energy Florida	Nothing to report	Nothing to report
Duke Energy Progress	Nothing to report	Nothing to report
Electric Energy, Inc.	Nothing to report	Nothing to report
Entergy Services	Nothing to report	Nothing to report
Florida Power & Light	Nothing to report	Nothing to report
Georgia Transmission Corporation	Nothing to report	Nothing to report
Independent Electricity System Operator	Nothing to report	Nothing to report
ISO New England	Nothing to report	Nothing to report

JEA	Nothing to report	Nothing to report
LG&E and KU Energy	Nothing to report	Nothing to report
MAPPCOR	Nothing to report	Nothing to report
MEAG Power	Nothing to report	Nothing to report
Mid-Continent ISO (MISO)	Nothing to report	Nothing to report
NYISO	Nothing to report	Nothing to report
PJM Interconnection	**SEE BELOW**	**SEE BELOW**
Power South Energy Cooperative	Nothing to report	Nothing to report
Santee Cooper	Nothing to report	Nothing to report
South Caroline Electric & Gas	Nothing to report	Nothing to report
Southern Company	Nothing to report	Nothing to report
Southwest Power Pool	**SEE BELOW**	**SEE BELOW**
Tennessee Valley Authority	Nothing to report	Nothing to report

PJM Interconnection
2018 Case

Facility Issues	Contingency
345kV bus at South Erie low voltage of 90.73% of nominal	Loss of South Erie - West Erie 345kV line
230kV bus at Carbon Center low voltage of 90.04% of nominal	Loss of Carbon Center - Elko 230kV line
230kV bus at Carroll low voltage of 90.45% of nominal	Loss of Carroll - Mt. Airy 230kV line
230kV bus at Boones low voltage of 90.7% of nominal	Loss of Doubs - Ringgold - Boonesboro 230kV line
345kV bus at Daymry low voltage of 84.14% of nominal	Loss of Marysville - Daymry 345kV line
230kV bus at Hayes low voltage of 88.62% of nominal	Loss of Gaines Point - Yorktown 230kV, Gaines Point - Hayes 230kV line
230kV bus at Prince George low voltage of 89.03% of nominal	Loss of Prince George - Hopewell 230kV line

2023 Case

Facility Issues	Contingency
230kV bus at Carbon Center low voltage of 89.95% of nominal	Loss of Carbon Center - Elko 230kV line
230kV bus at Carroll low voltage of 90.85% of nominal	Loss of Carroll - Mt. Airy 230kV line
230kV bus at Boones low voltage of 90.8% of nominal	Loss of Doubs - Ringgold - Boonesboro 230kV line
345kV bus at Daymry low voltage of 84.09% of nominal	Loss of Marysville - Daymry 345kV line
230kV bus at Hayes low voltage of 88.72% of nominal	Loss of Gaines Point - Yorktown 230kV, Gaines Point - Hayes 230kV line
230kV bus at Prince George low voltage of 88.94% of nominal	Loss of Prince George - Hopewell 230kV line

Southwest Power Pool

Model	Facility Issue	Contingency
2018	230 kV bus at LP-Milwaukee low voltage of 65.02% of nominal	Loss of LP-Milwaukee – Carlisle 230kV line
2018	115 kV bus at Howard low voltage of 89.51% of nominal	Loss of Wheeler 230/115kV transformer
2023	115 kV bus at TC-Whiting low voltage of 87.76% of nominal	Loss of Hitchland 230/115kV transformer

Section 4 Enhancements

4.1 Introduction

After Planning Authorities performed analysis on the 2018 and 2023 roll-up cases to determine potential "gaps" between regional planning analyses and this roll-up model, conceptual upgrades were identified such that the respective regional planning processes could be informed for future planning cycles. This section lists the issues identified by each PA in Section 3, together with high-level conceptual upgrades and the entities with which the PA will be coordinating on solutions in future planning cycles.

4.2 Issues List, Conceptual Upgrades, and Coordinating Entities

PA	Facility Issue	Contingency	Model Year	Conceptual Upgrades	Coordinating Entities
MISO	Winamac – Monticello 138 kV loads to 101% of 138 MVA	Loss of Dumont to Greentown 765 kV line	2018	Upgrade facility capacity	N/A
MISO	Alma – Lufkin 161 kV loads to 101.6% of 194 MVA	Loss of A.S. King to Eau Clair 345 kV line	2018	Upgrade facility capacity	N/A
MISO	Buena Vista – Owen 138 kV loads to 103.6% of 135 MVA	Loss of Worthington – Bloomington 345 kV line	2018	Upgrade facility capacity	N/A
MISO	Rosser – Ridgeway 230 kV loads to 104.2% of 460.5 MVA	Loss of Dorsey – Ridgeway 230 kV line	2018	Additional circuit added	N/A
MISO	Raven Lake 230/110 transformer loads to 109% of 100 MVA	Loss of Reston – Cornwallis 230 kV line	2018	Upgrade facility capacity	N/A
MISO	Henday – Long Spruce 230 kV ckt 1, ckt 2, ckt 3 loads to 110.7% of 348.6 MVA	Base Case	2023	Additional circuit added	N/A
MISO	Radison – Kelsey Terminal 138kV loads to 196.8% of 125 MVA	Base Case	2023	Upgrade facility capacity	N/A
MISO	Worthington - Buena Vista 138 kV loads to 106.8% of 135 MVA	Loss of Worthington – Bloomington 345 kV line	2023	Upgrade facility capacity	N/A
MISO	Bedford – Owen 138 kV loads to 100.3% of 135 MVA	Loss of Worthington – Bloomington 345 kV line	2023	Upgrade facility capacity	N/A
MISO	Buena Vista – Owen 138 kV loads to 103.6% of 135 MVA	Loss of Worthington – Bloomington 345 kV line	2023	Upgrade facility capacity	N/A
MISO	Calamus East – Substation 56 161 kV loads to 116.1% of 223 MVA	Loss of Quad City to Rock Creek 345 kV line	2023	Upgrade facility capacity	N/A

PJM Interconnection

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

PJM supplied EIPC with PJM's Regional Transmission Expansion Plan (RTEP) model for the 2018 future year to be incorporated into both Roll-up cases. This model was concomitantly studied using PJM's criteria and the upgrades resulting from this year's RTEP analysis for 2018 were incorporated into both Roll-up models. The EIPC performed a screening analysis of the Eastern Interconnection case using screening techniques generally applicable to power system analysis. Each EIPC region also performs specific, detailed reliability analysis using region specific techniques. PJM, therefore, performed an additional N-1 contingency analysis to both models after the incorporation of RTEP upgrades and using PJM specific techniques. No valid constraints to interregional transfers were detected. The results for facilities above 200 kV from the PJM analysis are depicted in section 3 of this report. The thermal results presented are related to the snapshot dispatch modeled in each case. Re-dispatch of PJM's generation would alleviate those issues. The voltage results observed are associated with radial feed to serve local load that could be voltage tuned for local analyses. These local issues do not adversely impact the use of this case for interregional assessments.

4.3 Map of Future Transmission Projects (Projects Near PA Boundaries)

One of the tools utilized to facilitate inter-area coordination was a map of all proposed major transmission projects in the Eastern Interconnection (generally facilities greater than 230 kV) including major facilities that were near the boundaries of each PA. This map was built on a base map of existing transmission above 200kV from the Ventyx Velocity Suite. Each Planning Authority provided input to modify the base layer to add projects to the map. The added projects on the map are both the major new and upgraded transmission facilities added into the roll-up model described in Section 2.6 and conceptual upgrades listed in Section 4.2.

Planning Authorities may utilize this tool in future cycles to further monitor current transmission plans and potentially explore joint projects that may mutually benefit multiple regions/areas.

Section 5 Linear Transfer Analysis

5.1 Introduction

There is growing interest in 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 upon the usage of parallel paths. One tool available that can assist in assessing transfer capability between areas is linear transfer power flow analysis. As utilized by the EIPC Planning Authorities, the intent of this analysis is not to identify constraints such that projects could be identified and transfer capability increased, but rather to illustrate transfer capabilities of the transmission grid as currently planned (based on the 2018 and 2023 roll-up cases) under a number of transfer patterns. The linear analysis performed only involves thermal analysis, 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 Authorities apply thermal proxy limits to represent system stability limits.

5.2 Linear Transfer Analysis Inputs

Linear transfer power flow analysis input files (monitored elements, subsystems, contingency files) were supplied by each PA. Transfer subsystems were defined for exports and imports (see Section IV.B.3 of the "Steady State Modeling Load-Flow Working Group Procedure Manual") at a transfer test level of 5,000 MW for each transfer, with transfer amounts allocated amongst the importing areas on a load or generation availability ratio share. The analysis was performed on a non-simultaneous basis meaning that each transfer was assessed one at a time. 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 1 and Table 2). The multiple areas grouped together were assembled by geographical proximity and by RTO/non-RTO planning practices. The approach used in performing the linear transfer analysis was a generation to generation shift.

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.

5.3 Linear Transfer Analysis Process

The linear analysis was performed using PTI's PSS/MUST software. As previously mentioned, this is thermal only analysis and does not examine system voltage, reactive supply, or stability issues. Simulations were performed in batch mode and the results of the study were assembled at the end.

Only those facilities with appreciable flows related to the transfer (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 the value traditionally used in transmission planning analysis to indicate that the transfer has a significant impact on the facility. A TDF less than 3% indicates that a facility, if reported, is already heavily loaded without the transfer in place.

If no constraint was identified up to the transfer test level of 5000 MW, the limit reported was ">5000" and further transfer capability was not evaluated. When the incremental transfer capabilities (expressed in MW) were equal to or exceeded 1,000 MW, they were rounded down to the nearest 100 MW. When they were less than 1,000 MW, they were rounded down to the nearest 50 MW.

5.4 Linear Transfer Analysis Results

As previously mentioned, the specific linear power transfers performed and the details associated are identified in Section IV.B.3 of the "Steady State Modeling Load-Flow Working Group Procedure Manual". An overview of the transfers performed is also listed below. Table 1 describes the PAs that were grouped together for transfers as an area while Table 2 describes 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 upon PAs that are parties to the EIPC.

Table 1: Groupings of Planning Areas for Transfers

A	B	C	D	E		F
FPL	MAPPCOR	New York ISO	PJM	Duke Energy Carolinas	SC	SPP
JEA	MISO	ISO New England		Duke Energy Progress	Southern Company	
Duke Energy Florida	ATC	Ontario IESO		LGE/KU	MEAG	
	ITC	NBSO		GTC	Alcoa Power Generating, Inc.	
	Entergy			Power South	TVA	
				SCEG	Electric Energy, Inc.	

Table ES-2: Transfers Performed

	Sink					
Source	A	B	C	D	E	F
A					Y	
B			Y	Y	Y	Y
C		Y		Y		
D		Y	Y		Y	
E	Y	Y		Y		Y

F		Y			Y	

Table 3a summarizes the results of the results of the linear transfer analysis for 2018 and Table 3b summarizes the results of the linear transfer analysis for 2023. For each transfer, only the information for the lowest FCITC (First Contingency Incremental Transfer Capability) 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. Additional base cases were developed by the working group for analysis of transfer directions that are highly dependent upon Phase Angle Regulator (PAR) settings, in areas such as the Independent Electricity System Operator (IESO) and New York Independent System Operator (NYISO), for import/export transfers from/to the Northeast Power Coordinating Council (NPCC) region. More detailed results for each subsystem's linear transfer analysis can be found in Appendix D including the next five valid limits beyond the most limiting facility.

Table 3a: Linear Transfer Analysis Results Summary for 2018

Source	Sink	FCITC (MW)	Limiting Element	Lim. PA	Contingency / Outaged Facility	Con. PA
A	E	2500	403159 ARCHER 230 KV 403171 HAILE TAP 230 KV	DEF	403522 CRYST RVR PL 230 KV 403526 KINGROAD PEF 230 KV	DEF
B	C	2800	200673 26SOUTH TR 115KV 200885 26EVERT DR 115KV	PENELEC-PJM	130757 WATRC345 345KV 200930 26MAINESBURG 345KV	NYISO/PENELEC-PJM
B	D	>5000	N/A N/A	N/A	N/A N/A	N/A
B	E	>5000	N/A N/A	N/A	N/A N/A	N/A
B	F	2700	337904 5RUSSELVL.S 161 KV 337905 5RUSSELVL.E! 161 KV	EES	337909 8ANO% 500 KV 515305 FTSMITH8 500 KV	EES / OKGE-SPP
C	B	1800	135303 SAWYER77 230KV 135415 PACKARD2 230KV	NYISO	SB: PACKARD 230 KV R3230	NYISO
C	D	1400	135303 SAWYER77 230KV 135415 PACKARD2 230KV	NYISO	SB: PACKARD 230 KV R3230	NYISO
D	B	2900	270781 ITASCA ; R 345KV	CE-PJM	270713 DES PL 46; R 345KV	CE-PJM

			270813 LOMBARD ; R 345KV		270813 LOMBARD ; R 345KV	
D	C	1900	200673 26SOUTH TR 115KV 200885 26EVERT DR 115KV	PENELEC-PJM	130757 WATRC345 345KV 200930 26MAINESBURG 345KV	NYISO/PENELEC-PJM
D	E	>5000	N/A N/A	N/A	N/A N/A	N/A
E	A	1900	VOLTAGE SECURITY	SBA/FRCC	SANFORD #4 GENERATOR	FPL
E	B	4800	360025 8CORDOVA TN 500 KV	TVA	360050 8MAURY TN 500 KV	TVA
			360612 8BENTON MS 500 KV		360052 8 BR FERRY NP 500 KV	
E	D	1500	340618 5LIVING 161 KV 340621 5COLEEHV 161 KV	BREC-MISO	NO CONTINGENCY	N/A
E	F	2200	337904 5RUSSELVL.S 161 KV 337905 5RUSSELVL.E! 161 KV	EES-MISO	337909 8ANO% 500 KV 515305 FTSMITH8 500 KV	EES-MISO / OKGE-SPP
F	B	1100	532765 HOYT 7 345 KV 532766 JEC N 7 345 KV	WERE-SPP	532766 JEC N 7 345 KV 532767 GEARY 7 345 KV	WERE-SPP
F	E	1200	532765 HOYT 7 345 KV 532766 JEC N 7 345 KV	WERE-SPP	532766 JEC N 7 345 KV 532767 GEARY 7 345 KV	WERE-SPP

Table 3b: Linear Transfer Analysis Results Summary for 2023

Source	Sink	FCITC (MW)	Limiting Element	Lim. PA	Contingency / Outaged Facility	Con. PA
A	E	1600	403528 MARTIN WEST 230 KV 407120 SLV_SP_N 230 KV	DEF	403522 CRYST RVR PL 230 KV 403526 KINGROAD PEF 230 KV	DEF
B	C	3400	200769 26HOMER CY 345KV 200942 FARM_V_345 345KV	PENELEC-PJM	NO CONTINGENCY	N/A
B	D	>5000	N/A N/A	N/A	N/A N/A	N/A
B	E	>5000	N/A N/A	N/A	N/A N/A	N/A
B	F	650	337904 5RUSSELVL.S 161 KV 337905 5RUSSELVL.E! 161 KV	EES	337909 8ANO% 500 KV 515305 FTSMITH8 500 KV	EES / OKGE-SPP
C	B	1800	135303 SAWYER77 230KV	NYISO	SB: PACKARD 230 KV R3230	NYISO
			135415 PACKARD2 230KV			
C	D	1500	129270 E.G.C 138 KV 129288 ROSLYN 138 KV	NYISO	SB: PV345_RNS3	NYISO
D	B	1600	631140 SALEM 3 345 KV 631141 ROCK CK3 345 KV	ALTW-MISO	270866 QUAD 6-7 345KV 636610 SUB 91 3 345KV	CE-PJM / MEC-MISO
D	C	2100	200769 26HOMER CY 345KV 200942 FARM_V_345 345 KV	PENELEC-PJM	NO CONTINGENCY	N/A
D	E	>5000	N/A N/A	N/A	N/A N/A	N/A
E	A	1900	VOLTAGE SECURITY	SBA/FRCC	SANFORD #4 GENERATOR	FPL
E	B	2200	360025 8CORDOVA TN 500 KV 360612 8BENTON MS 500 KV	TVA	360050 8MAURY TN 500 KV 360052 8 BR FERRY NP 500 KV	TVA
E	D	1900	340618 5LIVING 161 KV 340621 5COLEEHV 161 KV	BREC-MISO	NO CONTINGENCY	N/A
E	F	550	505508 DARDANE5 161 KV 505514 CLARKSV5 161KV	SWPA-SPP	337909 8ANO% 500 KV 515305 FTSMITH8 500 KV	EES/OKGE-SPP

F	B	850	532765 HOYT 7 345 KV 532766 JEC N 7 345 KV	WERE-SPP	532766 JEC N 7 345 KV 532767 GEARY 7 345 KV	WERE-SPP
F	E	950	532765 HOYT 7 345 KV 532766 JEC N 7 345 KV	WERE-SPP	532766 JEC N 7 345 KV 532767 GEARY 7 345 KV	WERE-SPP

Appendix A: Future Project Map

This Appendix now exists as a posted .pdf map ("EIPC Transmission Upgrades").

To access, go to the link below:
http://www.eipconline.com/uploads/Posted_Draft_1_EIPC_Rollup_Appendix_A_12.06.13.pdf

Appendix B: New/Upgraded Transmission Projects

This Appendix is a Microsoft Excel spreadsheet and is posted at the link below.

http://www.eipconline.com/Non-DOE_Documents.html

The most current copy is called Posted Draft 1 EIPC Roll-Up – Appendix B (12/06/2013).

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

This Appendix is a Microsoft Excel spreadsheet and is posted at the link below.
http://www.eipconline.com/Non-DOE_Documents.html.

The most current copy is called Posted Draft 1 EIPC Roll-Up – Appendix C (01/03/2014).

Appendix D: Linear Transfer Analysis Results

This Appendix now exists as two Microsoft Excel workbooks:

1. EIPC_AppendixD_2018
2. EIPC_AppendixD_2023.

The files are posted at the link below
http://www.eipconline.com/Non-DOE_Documents.html.

The most current copies are called:

Posted Draft 1 EIPC Roll-Up – Appendix D 2018 (12/06/2013), and
Posted Draft 1 EIPC Roll-Up – Appendix D 2023 (12/06/2013).

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

Appendix E: Area Interchange Table

Alcoa Power Generating, Inc.

APGI - Yadkin
DETAILED INTERCHANGE

APGI - Yadkin Interchange Schedule

Total Net Interchange 0 MW

Duke Energy Carolinas

DEC Balancing Authority Area Imports:

From Area #	From Area		2018	2023
340	CPLE	(NCEMC/Anson)	-120	-120
340	CPLE	(NCEMC#1)	-0	-33
343	SCEG	(Chappels)	-2	-2
344	SCPSA	(PMPA)	-208	-244
344	SCPSA	(NHEC)	-23	0
345	PJM	(DVP)	-2	-2
346	SOUTHERN	(NCEMC)	-163	-180
346	SOUTHERN	(Seneca)	-29	-32
353	SEHA	(SEPA)	-155	-155
355	SETH	(SEPA)	-113	-113
		TOTAL IMPORTS	-815	-881

DEC Balancing Authority Area Exports:

To Area #	To Area		2018	2023
340	CPLE	(Broad River)	850	850
340	CPLE	(Rowan)	150	150
340	CPLE	(NCEMC/CNS)	105	105
340	CPLE	(NCEMC#2)	100	100
345	DVP	(NCEMC)	50	50
		TOTAL EXPORTS	1255	1255

	2018	2023
TOTAL NET INTERCHANGE	**440 MW**	**374 MW**

Notes:

1. Positive interchange indicates an export
2. Negative interchange indicates an import

Duke Energy Florida

Duke Energy Florida (DEF) Balancing Authority Scheduled Imports/Contract Purchases:

Southern	PEF	Firm	-424 MW
FRCC	PEF	Firm (Intra-FRCC)	-2420 MW
Total			**- 2,820 MW**

Duke Energy Florida (DEF) Balancing Authority Scheduled Exports/Contract Sales:

Total	**0 MW**
Total Net Interchange-DEF	**-2,820 MW**

Notes:

1. Positive interchange indicates an export
2. Negative interchange indicates an import

Duke Energy Progress

Duke Energy Progress East (CPLE) Balancing Authority Scheduled Imports/Contract Purchases:

		2018	2023
Duke	Broad River	-850 MW	-850 MW
Duke	NCEMC/CNS	-105 MW	-105 MW
Duke	NCEMC#2	-100 MW	-100 MW
Duke	PEC-Rowan	-150 MW	-150 MW
DVP	SEPA-Kerr	-95 MW	-95 MW
AEP	NCEMC	-100 MW	-100 MW
AEP	NCEMC#2	-100 MW	-100 MW
Total		**- 1,500 MW**	**- 1,500 MW**

Duke Energy Progress East (CPLE) Balancing Authority Scheduled Exports/Contract Sales:

		2018	2023
Duke	NCEMC#1	0 MW	33 MW
Duke	NCEMC/Anson	120 MW	120 MW
PJM	Hamlet#1	55 MW	55 MW
PJM	Hamlet#2	55 MW	55 MW
Total		**230 MW**	**263 MW**
Total Net Interchange - CPLE		**-1,270 MW**	**-1,237 MW**

Duke Energy Progress West (CPLW) Balancing Authority Scheduled Imports/Contract Purchases:

		2018	2023
TVA	SEPA	-1 MW	-1 MW
Total		**-1 MW**	**-1 MW**

Duke Energy Progress West (CPLW) Balancing Authority Scheduled Exports/Contract Sales:

		2018	2023
None		0 MW	0 MW
Total		**0 MW**	**0 MW**
Total Net Interchange - CPLW		**-1 MW**	**-1 MW**

Notes:
1. Positive interchange indicates an export
2. Negative interchange indicates an import

Entergy Services

ENTERGY ELECTRIC SYSTEM BALANCING AUTHORITY AREA INTERCHANGE
Areas in the case that make up the Entergy Electric System Balancing Authority: 326, 327 and 351
EIPC 2018 and 2023 Summer Future Years Study

Entergy Mississippi Balancing Authority Area Scheduled Imports and Exports:

To Area		2018S	2023S
SMEPA	810234 (SMEPA - SMEPA load)	-830	-873
EES-EAI	ISES 2 - EMI	-211	-211
EES-EAI	ISES 1 - EMI	-209	-209
PLUM	1356328 (PLUM - MEAM)	-40	-40
TVA	1096986 (TVA - TVA embedded)	-28	-30
PLUM	1468113 (PLUM - MEAM)	-20	-20
TVA	850239 (TVA - MEAM)	-19	-19
LAGN	851493 (Big Cajun 2 - MEAM	-13	-13
OKGE	MDEA	-10	-10
SMEPA	(Silver Creek)	0	225
SMEPA	1658088 (Grand Gulf - SMEPA load)	21	21
GMO	CROSSROADS	75	75
GMO	CROSSROADS	75	75
GMO	CROSSROADS	75	75
GMO	CROSSROADS	75	75
SMEPA	1139982 Grand Gul.f - SMEPA load)	125	125
SMEPA	1035455 (Batesville - SMEPA load)	280	280
EES-EAI	Grand Gulf - EAI	432	432
EES	Grand Gulf - EES	462	462
Net Schedule		**240**	**420**

Entergy Arkansas Balancing Authority Area Scheduled Imports and Exports:

To Area		2018S	2023S
EES-EMI	Grand Gulf - EAI	-432	-432
SWPA	(SWPA load - Hydro reciepts)	-104	-104
AECI	1655366 (AECI - Thayer)	-6	-6
PLUM	1352704 (PLUM - THAYER/CAMPBELL)	-5	-5
SWPA	(SWPA load - Augasta)	-4	-4
WMU	1381404 (ISES - WMU)	0	5
SWPA	(SWPA load - Thayer in EN)	0	-0.3
OMLP	1380484 (ISES - OMLP)	9	9

AEPW	759294 (ISES - AEPW (ETEC Load 1))	10	10
EES	ISES 1 - EES	14	14
CWAY	City of Conway - Other Resources	14.3	4.9
NLR	NLR - Other Resources	15	21.6
EES	White Bluff 1 - EES	25	25
EES	White Bluff 2 - EES	25	25
EES	1000000 (ISES - ETEC)	29	29
CWAY	1381398 (White Bluff - CWAY)	34	34
CWAY	1381400 (ISES - CWAY)	34	34
EES	ANO 1 - EES	46	46
EES	ANO 2 - EES	54	54
SWPA	(OASIS# 759196, DeGray)	68	68
SWPA	(OASIS# 759196, Blakeley)	75	75
SWPA	(OASIS# 966982, Jonesboro load)	81	81
BUBA	City of Benton - Other Resources	82.9	86.3
SWPA	(EN load - Norfork, Glencoe & Buford in SWPA)	90	100
SWPA	(OASIS# 966987, Jonesboro load)	163	163
EES-EMI	ISES 1 - EMI	209	209
EES-EMI	ISES 2 - EMI	211	211
EES	Ouachita - EES	267	267
AEPW	563117 (White Bluff - AECC)	320	318
Net Schedule		**1325.2**	**1338.5**

Entergy Gulf States Louisiana, L.L.C., Entergy Louisiana LLC, Entergy New Orleans, Inc. and Entergy Texas, Inc. Balancing Authority Area Scheduled Imports and Exports:

To Area		**2018S**	**2023S**
EES-EMI	Grand Gulf - EES	-462	-462
EES-EAI	Ouachita - EAI	-267	-267
LAGN	569011 (Big Cajun 2 - EES)	-242	-242
EES-EAI	ANO 2 - EES	-54	-54
PLUM	1425495 (PLUM - ETEC)	-50	-50
AEPW	ETEC Load 2	-50	-50
EES-EAI	ANO 1 - EES	-46	-46
EES-EAI	1000000 (ISES - ETEC)	-29	-29
EES-EAI	White Bluff 1 - EES	-25	-25
EES-EAI	White Bluff 2 - EES	-25	-25
EES-EAI	ISES 1 - EES	-14	-14
LAGN	1477069 (Big Cajun 2 - EES)	-10	-10
AEPW	AEPW Load on EES; Caster, Ringold load	-5	-5
LAGN	74305339 (LAGN - Newton)	-4.5	-4.8

CELE	Richard losses	-1	-1
LEPA	1461442 (Mury - LEPA)	12	12
CELE	Toledo Bend	20	20
DERS	DERS - Other Resources	68.7	72.5
BRAZ	Other Resources	100	100
Net Schedule		**-1083.8**	**-1080.3**

Notes:

1. Positive interchange indicates an export
2. Negative interchange indicates an import

Georgia Transmission Corporation (Included as part of Southern Companies)

Independent Electricity System Operator

ONTARIO BALANCING AUTHORITY ("IESO") AREA INTERCHANGE
Area (s) in the case that make up the IESO: 103
EIPC 2018 and 2023 Summer Future Year Study

IESO Area 103

REGION	From Area #	From Area Name	To Area #	To Area Name	Comments	Firm	*SUM*
NPCC	103	IESO	218	METC			*0*
NPCC	103	IESO	219	ITC			*0*
NPCC	103	IESO	102	NYISO			*0*
NPCC	103	IESO	667	MHEB(Manitoba)		x	*0*
NPCC	103	IESO	608	MP (Minnesota)		x	*0*
NPCC	103	IESO	104	TE(Outaouais)	HVDC		*-1250*
	103	IESO			NET SCHEDULE		*-1250.0*

Notes:
Negative interchange indicates an import.

1.

ISO New England

INDEPENDENT SYSTEM OPERATOR OF NEW ENGALND (“ISO-NE”) AREA INTERCHANGE
Area (s) in the case that make up the ISO-NE: 101
EIPC 2018 and 2023 Summer Future Year Study

REGION	From Area #	From Area Name	To Area #	To Area Name	Comments	2018	*2023*
NPCC	101	ISO-NE	102	NYISO	NYPA Hydro Contracts	-83.0	-89.0
NPCC	101	ISO-NE	102	NYISO	Cross Sound HVDC Cable	344.0	344.0
NPCC	101	ISO-NE	104	TE	Highgate HVDC	-228.0	-228.0
NPCC	101	ISO-NE	104	TE	Phase II HVDC	-1500.0	-1500.0
NPCC	101	ISO-NE	105	NB		-800.0	-594.0
	101	**ISO-NE**			**NET SCHEDULE**	**-2263.0**	**-2064.0**

LG&E and KU Energy

LG&E/KU BALANCING AUTHORITY ("LGEE") AREA INTERCHANGE
Area (s) in the roll-up case that make up the EBA: 363
EIPC 2018 and 2023 Summer Future Years

LG&E/KU Balancing Authority Area Scheduled Imports/Contract Purchases:

HE	HE-Bridgeport	-7 MW
AEP	KMPA Virtual	-55 MW
AEP	AMPO-KMPA	-9 MW
AMIL	KMPA	-128 MW
OVEC	Clifty Creek Surplus	-163 MW
Total		**- 362 MW**

LG&E/KU Balancing Authority Area Scheduled Exports/Contract Sales:

AEP	IMPA Trimble #1	65 MW
AEP	IMPA Trimble #2	94 MW
AMIL	IMEA Trimble #1	61 MW
AMIL	IMEA Trimble #2	89 MW
Total		**309 MW**

Total Net Interchange **-53 MW**

Notes:
1. Positive interchange indicates an export
2. Negative interchange indicates an import

MAPPCOR

MID-CONTINENT AREA POWER POOL ("MAPP") AREA INTERCHANGE
Area (s) in the case that make up the MAPP: 652
EIPC 2018 and 2023 Summer Future Years Study

Mid-Continent Area Power Pool (MAPP) Area Scheduled Imports/Contract Purchases:

		2018	2023
ALTW	Duane Arnold Energy Center	-60	-60
ALTW	Hancock County Wind	-2	-2
MEC	Neal South #4	-147	-147
MEC	Walter Scott #3	-27	-27
MEC	Walter Scott #4	-62	-62
MP	Boswell 4 Purchase	-100	0
OTP	Herd Lake Wind PPA	-40	-40
WEC	Point Beach uprates to MRES	-34	-34
MEC	NEAL 4 GENERATION	-56	-56
MEC	WAPA(Harlan)/MEC LOUISA GEN	-6	-6
MEAN	HCPD(WAPA)/MEAN WEC2- Intraregional	-80	-80
NPPD	NPPD Loads in WAPA BA (Reduction of WAPA Firm)	-4	-4
NPPD	Sidney DC Tie Schedule	-22	-22
Total		**-640 MW**	**-540 MW**

Mid-Continent Area Power Pool (MAPP) Area Scheduled Exports/Contract Sales:

		2018	2023
GRE	Crow Wing	34	43
GRE	MN Valley	39	57
GRE	East River	7	13
GRE	L&O (Federated)	22	23
GRE	Wright Hennepin	21	31
NPPD	Laramie River #1 Share	189	189
NPPD	BEPC Load in NPPD BA	18	19
NPPD	BEPD Load in NPPD BA	359	361
OTP	BEPC Share of OTP LBA Losses	3	3
OTP	MRES Share of OTP LBA Losses	4	4
MEC	MRES Deliveries to Atlantic & Pella IA	48	52
MEC	WAPA/MEC (Atlantic) #287697	8	8
GRE	WAPA/GRE (CPA) #233493	86	86

GRE	WAPA/GRE (UPA) #233481	3	3
ALTW	WAPA/ALTW (CIPCO) #233579	12	12
MPC	WAPA/MPC #1603	35	35
OTP	WAPA/MPC #1603 Losses	4	4
SUNF	WAPA/SUNF #286879- Intraregional	7	7
OPPD	WAPA/OPPD #73144699 (old #363404)- Intraregional	82	82
OPPD	LOAD (WAPA/OPPD) – Intraregional	22	22
NPPD	WAPA/NPPD/LES #1586479 firm	56	56
NPPD	WAPA/NPPD/LES #1586478 peaking	54	54
NPPD	WAPA/NPPD (F+P) #234276- Intraregional	440	440
NPPD	WAPA/NPPD (RMR) #345442- Intraregional (LAP)	4	4
NPPD	WAPA/NPPD (LOUP) #251005- Intraregional	15	15
GRIS	WAPA/NPPD (GRIS) #224204- Intraregional	9	9
NPPD	LOAD (WAPA/NPPD) - Intraregional (WAPA in NPPD BA)	87	87
MMPA	WAPA/MMPA Olivia and EGF Allocation	17	17
Total		1,685 MW	1,736 MW

Notes:
1. Positive interchange indicates an export
2. Negative interchange indicates an import

Mid-continent ISO (MISO)

MISO BALANCING AUTHORITY
AREA INTERCHANGE
Areas in the case that make up MISO: 28
EIPC 2018 and 2023 Summer Future Years Study

MISO Balancing Authority Area Scheduled Imports/Contract Purchases:

MISO Area	Other Area	Comments	2018SUM	2023SUM
ALTE	CE	76672473 *rollover rights	-140	-140
WEC	CE	76743102 WPPI	-10	-10
WEC	CE	76808277 WPPI(Kendall)	-25	-25
WEC	CE	76808278 WPPI(Kendall)	-25	-25
WEC	CE	75285088 WPPI	-30	-30
WEC	MRES	resale of WPPI 20% share of Point Beach uprates to MRES	33	33
WPS	MH	76902944	-100	-100
WPS	MH	76914351 (losses)	-8	-8
GRE	BEPC	Crow Wing BEPC Supplied	-25	-33
GRE	BEPC	MN Valley EC BEPC Supplied	-14	-28
GRE	BEPC	East River (MN4) BEPC Supplied	-10	-15
GRE	BEPC	L&O (Federated) BEPC Supplied	-25	-26
GRE	BEPC	Wright Hennepin BEPC Supplied	0	-3
GRE	WAPA	WAPA/GRE (CPA) #233493	-86	-86
GRE	WAPA	WAPA/GRE (UPA) #233481	-3	-3
ALTW	CE		-264	-264
ALTW	TVA	Pioneer Prairie I	115	115
ALTW	BEPC	Duane Arnold Energy Center	60	60
ALTW	BEPC	Hancock County Wind	2	2
ALTW	WAPA	WAPA	-12	-12
MEC	BEPC	NIPCO & CBPC Share of Neal 4	145	145
MEC	BEPC	CBPC Share of WSEC3	26	26
MEC	BEPC	CBPC/NIMECA Share of WSEC4	62	62
MEC	CE	MEC Share of QCNS	-451	-451
MEC	LES	WS3 to LES	50	50
MEC	LES	WS4 to LES	50	50
MEC	MRES	MRES Deliveries to Atlantic & Pella IA	-51	-55
MEC	NWPS	NEAL 4 GENERATION	56	56
MEC	WAPA	WAPA/MEC (Atlantic) #287697	-8	-8

MISO Area	Other Area	Comments	2018SUM	2023SUM
MEC	WAPA	WAPA/MEC (Louisa gen for Harlan)	6	6
MP	MH	Term Sheet	0	-250
MP	BEPC	MN Power Boswell 4 Purchase	100	0
MPC	WAPA	WAPA ALLOCATION	-35	-35
MRES	MRES	MRES Gen in ALTW BA (dual transaction)	5	26
MRES	MRES	MRES Gen in OTP BA (dual transaction)	2	12
MRES	MRES	MRES Gen in XCEL BA (dual transaction)	0	12
OTP	NWPS	Big Stone Generation	111	111
OTP	NWPS	Coyote Generation	42	42
OTP	MRES	MRES PPA with Rugby Wind	40	40
OTP	MRES	MRES share of losses in the OTP LBA	-4	-4
XEL	OPPD	NC2 gen for CMMPA	-15	-15
XEL	MH	76861971 MH	-213	-213
XEL	MH	76861973 MH	-375	-375
XEL	MH	79861973 MH	-125	-125
XEL	MH	76861975 MH	-150	-150
XEL	MH		-879	-629
HE	AEP	HE-DREWERSBURG, HE-HUNSTVILLE on AEP	7	7
HE	AEP	LYNN MP, WINCHESTER MP, MODOC MP	3	4
HE	LGEE	HE-BRIDGEPORT on LGEE	7	7
DEI	DEO&K	Transfer	461	-75
SIGE	ATSI	Cannelton	42	42
SIGE	AEP	Cannelton	27	27
SIGE	DAY	Cannelton	9	9
SIGE	OVEC	Surplus	-30	-30
SIGE	AEP	Fowler Ridge Wind Farm	-5.4	-5.4
NIPS	LGE-KU	IMPA-Trimble #1 Generator	-66	-66
METC	AEP	AMPO-Meldahl/Greenup	-5	-5
METC	AP	AMPO-Willow	-3	-3
BREC	TVA	Pass-Thru	-190	-190
CWLD	KAPL	KCPL	-20	-20
CWLD	KACY	(Kansas) BPU	-20	-20
AMMO	LAGN	1631135 Big Cajun 2	-206	-206
AMMO	LAGN	76767669 Big Cajun 2	-103	0
AMMO	LAGN	1452307 AMRN - LAGN	100	100
AMMO	LAGN	1452308 AMRN - LAGN	100	100
AMMO	CWAY	1659388 AMRN - CWAY	100	100

MISO Area	Other Area	Comments	2018SUM	2023SUM
AMMO	NLR	1555122 AMRN - NLR	25	25
AMMO	PLUM	1495910 PLUM - AMMO	28	28
AMIL	EEI	Ameren CTG's in EEI	-165	-165
AMIL	EEI	GF Ameren Share Joppa	-1000	-1000
AMIL	EEI	Ameren share EEI CTG's	-70	-70
AMIL	LGEE	IMEA-Trimble 1	-66	-66
AMIL	FE	Amp-Ohio	137	137
AMIL	AEP	Amp-Ohio	111	111
AMIL	DAY	Amp-Ohio	66	66
AMIL	CE	IMEA - MISO #76745780 & 75937622 St. Charles	90	90
AMIL	CE	IMEA - MISO #76756562 Winnetka	39	39
SIPC	TVA	(SEPA)	-28	-28
TOTAL			**-2803.4**	**-3327.4**

Notes:

1. Positive interchange indicates a sale (export)
2. Negative interchange indicates a purchase (import)

Municipal Electric Authority of Georgia (Included as part of Southern Companies)

New York ISO (NYISO)

ERAG MULTIREGIONAL MODELING WORKING GROUP (ERAG MMWG)
INTERCHANGE DATA FOR 2012 SERIES LOAD FLOW BASE CASES

NYISO Area 102

REGION	FROM	AREA	TO	AREA	COMMENTS	FIRM	2018SUM	2023SUM
NPCC	102	NYISO	225	PJM500	NJ Co-Ops	x	19	19
NPCC	102	NYISO	225	PJM500	PA Co-Ops	x	55	55
NPCC	102	NYISO	225	PJM500	Neptune HVDC		-660	-660
NPCC	102	NYISO	225	PJM500	Linden VFT		-315	-315
NPCC	102	NYISO	225	PJM500	RECO Supply	x	-451	-467
NPCC	102	NYISO	225	PJM500	HTP HVDC		-320	-320
NPCC	102	NYISO	226	PENELEC	NYSEG al PENELEC	x	-37	-37
NPCC	102	NYISO	237	RECO				
NPCC	102	NYISO	237	RECO	RECO Load	x	451	467
NPCC	102	NYISO	202	FE		x	30	30
NPCC	102	NYISO	205	AEP		x	56	56
NPCC	102	NYISO	209	DPL		x	7	7
NPCC	102	NYISO	212	DEO&K		x	3	3
					Subtotal RFC		-1162	-1162
NPCC	102	NYISO	101	ISO-NE		x	84	84
NPCC	102	NYISO	101	ISO-NE	CSC HVDC		-330	-330
NPCC	102	NYISO	101	HVDC			0	0
NPCC	102	NYISO	103	IESO			0	0
NPCC	102	NYISO	104	TE			-1310	-1310
NPCC	102	NYISO	107	Cornwall			0	0
	102	**NYISO**		**NET SCHEDULE**			**-2718**	**-2718**

PJM Interconnection

From Area	To Area	Interchange		Firm?	Comment
		2018	2023		
ATSI	NYPP	-18	-18	x	AMPO-NYPA
ATSI	NYPP	-12	-12	x	CPP-NYPA
AEP	NYISO	-9	-9	x	AMPO-NYPA
AEP	NYISO	-47	-47	x	Buckeye-NYPA
PJM	NYISO	-19	-19	X	NJ Co-ops
PJM	NYISO	-55	-55	X	PA Co-ops
PJM	NYISO	451	467	X	RECO Supply
PJM	NYISO	660	660	x	Neptune
PJM	NYISO	320	320	x	Hudson Transmission Partners (O66)
PJM	NYISO	315	315	x	VFT
PENELEC	NYISO	37	37	x	NYSEG al PENELEC
DEO&K	NYPP	-3	-3	x	AMPO-NYPA
DAY	NYPP	-7	-7	x	AMPO-NYPA
RECO	NYISO	-451	-467	X	RECO Load
AP	OVEC	-70	-70	x	Surplus
AEP	OVEC	-1229	-1229	x	Surplus
DAY	OVEC	-98	-98	x	Surplus
DEO&K	OVEC	-180	-180	x	Surplus
PJM	OVEC	-230	-230	x	Surplus
AEP	HE	-7	-7	x	HE-D&H Load
AEP	HE	-3	-4	x	HE-L&W&M Load
DEO&K	DEI	-461	75	x	Transfer
ATSI	SIGE	-42	-42	x	AMPO-Cannelton
AEP	SIGE	-27	-27	x	Cannelton
AEP	SIGE	5	5	x	Fowler Ridge Wind Farm
DAY	SIGE	-9	-9	x	AMPO-Cannelton
AP	METC	3	3	x	AMPO-Willow
AEP	METC	5	5	x	AMPO-Meldahl/Greenup
AEP	METC	0	0	x	AMPO-Morgan Stanley
CE	WEC	90	90	x	To WPPI Energy
AEP	EKPC	0	0		PPA (7x24)
AEP	EKPC	0	0		Peaking (Virtual)
AEP	CPLE	100	100	x	NCEMC-1
AEP	CPLE	100	100	x	NCEMC-2
PJM	CPLE	-55	-55	x	(NCEMC/Hamlet#1)

PJM	CPLE	-55	-55	x	(NCEMC/Hamlet#2)
DVP	CPLE	95.0	95.0	x	SEPA-KERR
DVP	DUK	- 50.0	- 50.0	x	NCEMC
DVP	DUK	2.0	2.0	x	(PJM)
CE	TVA	300	300	x	PJM#1302456
CE	TVA	200	200	x	PJM#1903315, 1903316
EKPC	TVA	-100	-100	x	SEPA
ATSI	AMIL	0	0	x	CPP/AMPO/Prairie State
ATSI	AMIL	-137	-137	x	AMPO-Prairie State
AEP	AMIL	-111	-111	x	AMPO-Prairie State
DAY	AMIL	-66	-66	x	AMPO-Prairie State
CE	AMIL	-90	-90	x	St. Charles (PJM# 276651, 440490)
CE	AMIL	-39	-39	x	Winnetka (PJM#930679)
ATSI	SIPC	0	0	x	CPP/AMPO/Smithland
AEP	LGEE	-65	-65	x	IMPA-Trimble-1
AEP	LGEE	-94	-94	x	IMPA-Trimble-2
AEP	AEPW	250	250	x	Merger
CE	ALTW	115	115	x	PJM#3744114
CE	ALTW	149	149	x	PJM#3743934
CE	MEC	451	451	x	25% Quad Cities
CE	ALTE	140	140	x	PJM#3744167
Total Net Interchange		-51	484		

PowerSouth Energy Cooperative

POWERSOUTH PLANNING AUTHORITY ("PPA") AREA INTERCHANGE
Area (s) in the case that make up the PPA: 350
EIPC 2018 Summer Future Year Study

PowerSouth Planning Authority Area Scheduled Imports/Contract Purchases:

SEPA	Sales to PowerSouth	-100 MW
SEPA	Preferred Customers	-99 MW
SEPA	Sales to SMEPA	-68 MW
SOCO	Plant Miller	-114 MW
MEAG	PowerSouth Purchase	-62 MW
SOCO	Purchase from SH LFG	-4.8 MW
Total		- 444.8 MW

PowerSouth Planning Authority Area Scheduled Exports/Contract Sales:

SOCO	PowerSouth load on SOCO + Losses	1013.2 MW
SMEPA	SEPA – PS - SMEPA	68 MW
Total		1081.2 MW

Total Net Interchange 701 MW

Notes:
1. Positive interchange indicates an export
2. Negative interchange indicates an import

POWERSOUTH PLANNING AUTHORITY ("PPA") AREA INTERCHANGE
Area (s) in the case that make up the PPA: 350
EIPC 2023 Summer Future Year Study

PowerSouth Planning Authority Area Scheduled Imports/Contract Purchases:

SEPA	Sales to PowerSouth	-100 MW
SEPA	Preferred Customers	-99 MW
SEPA	Sales to SMEPA	-68 MW
SOCO	Plant Miller	-111 MW

MEAG	PowerSouth Purchase	-125 MW
SOCO	Purchase from SH LFG	-4.8 MW
Total		- 507.8 MW

PowerSouth Planning Authority Area Scheduled Exports/Contract Sales:

SOCO	PowerSouth load on SOCO + Losses	1082.7 MW
SMEPA	SEPA – PS - SMEPA	68 MW
Total		1150.7 MW

Total Net Interchange 642.9 MW

Notes:
1. Positive interchange indicates an export
2. Negative interchange indicates an import

Santee Cooper

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
DETAILED INTERCHANGE
EIPC 2018 Summer Future Year Study

SCPSA Scheduled Imports/Contract Purchases:

SCE&G	VC Summer	-1,370 MW
SEPA	Russell	-212 MW
SEPA	Thurmond	-63 MW
Total		**- 1,645 MW**

SCPSA Scheduled Exports/Contract Sales:

SCE&G	Charleston Navy	21 MW
SCE&G	Woodland Hills	15 MW
SCE&G	NHEC	19 MW
SOCO	AMEA	50 MW
DUKE	NHEC	23 MW
DUKE	PMPA	208 MW
Total		**336 MW**

Total Net Interchange **-1,309 MW**

Notes:

1. Positive interchange indicates an export
2. Negative interchange indicates an import

South Carolina Electric & Gas

SCE&G BALANCING AUTHORITY ("SCE&G") AREA INTERCHANGE
Area(s) in the case that make up SCE&G: 343
EIPC 2018 & 2023 Summer Future Year Study

SCE&G Balancing Authority Area Scheduled Imports/Contract Purchases:

SEPA	Thurmond Dam	-22 MW
SCPSA	Charleston Navy	-21 MW
SCPSA	Woodland Hills Load on SCE&G	-15 MW
SCPSA	NHEC Load on SCE&G	-19 MW
Total		**- 77 MW**

SCE&G Balancing Authority Area Scheduled Exports/Contract Sales:

SCPSA	VC Summer #1, #2, #3	1370 MW
Total		**1,370 MW**

Total Net Interchange	**1,293 MW**

Notes:
1. Positive interchange indicates an export
2. Negative interchange indicates an import

Southern Company

SOUTHERN BALANCING AUTHORITY ("SBA") AREA INTERCHANGE
Area (s) in the case that make up the SBA: 346
EIPC 2018 and 2023 Summer Future Year Study

Southern Balancing Authority Area Scheduled Imports/Contract Purchases:

		2018	2023
SEPA	Hartwell Dam	-280 MW	-280 MW
SEPA	Russell Dam	-258 MW	-258 MW
SEPA	Thurmond Dam	-143 MW	-143 MW
TVA	TVA Load on Southern	-162 MW	-170 MW
PowerSouth	PowerSouth Load on Southern	-1013 MW	-1083 MW
SMEPA	SMEPA Load on Southern	-143 MW	-143 MW
AMEA	AMEA Load on Southern	-50 MW	-50 MW
Blountstown	City of Blountstown Load	-13 MW	-15 MW
Total		**- 2,062 MW**	**- 2,156 MW**

Southern Balancing Authority Area Scheduled Exports/Contract Sales:

		2018	2023
Duke	NCEMC	163 MW	163 MW
Duke	City of Seneca	29 MW	29 MW
TVA	Southern Load on TVA	98 MW	98 MW
PowerSouth	SEPA Sales to PowerSouth	100 MW	100 MW
PowerSouth	SEPA Sales to SMEPA via PowerSouth	68 MW	68 MW
PowerSouth	SEPA Preferred Customers	99 MW	99 MW
PowerSouth	Plant Miller Ownership	111 MW	111 MW
PowerSouth	PowerSouth Purchase from SH LFG	5 MW	5 MW
PowerSouth	PowerSouth Purchase from MEAG	62 MW	62 MW
SMEPA	SMEPA Purchase	242 MW	242 MW
FPL	Sum of Point to Point Transactions	272 MW	272 MW
FPL	Scherer #4 Ownership	649 MW	649 MW
FPL	GTC to FPL	25 MW	25 MW
FPC	Sum of Point to Point Transactions	424 MW	424 MW
JEA	Sum of Point to Point Transactions	200 MW	200 MW
JEA	Scherer #4 Ownership	201 MW	201 MW
Total		**2,748 MW**	**2,682 MW**

Total Net Interchange **686 MW** **526 MW**

Notes:
1. Positive interchange indicates an export
2. Negative interchange indicates an import

Southwest Power Pool

Southwest Power Pool ("SPP") AREA INTERCHANGE
Areas in the case that make up SPP:
515,520,523,524,525,526,527,531,534,536,540,541,542,544,545,546,640,645,650
EIPC 2018 and 2023 Summer Study

Southwest Power Pool Area Scheduled Imports/Contract Purchases:

		2018 Summer	2023 Summer
AECI	New Madrid	-6.0	-6.0
AECI	China (AECI)	-5.3	-5.6
ENTR	(OASIS# 759196, Blakeley, ends 2021)	-75.0	0
ENTR	(OASIS# 759196, DeGray, ends 2021)	-68.0	0
ENTR	(Norfork, Glencoe & Buford in SWPA)	-90.0	-100.0
PLUM	Plum Point to Poplar Bluff	-20.0	-20.0
PLUM	Plum Point to Kennett	-20.0	-20.0
PLUM	Plum Point to Malden	-7.0	-7.0
PLUM	Plum Point to Cathrage	-12.0	-12.0
PLUM	Plum Point to Piggott	-8.0	-8.0
AECI	KAMO	-46.1	-48.8
AEPE		-250.0	-250.0
LAGN		-50.0	-50.0
CELE	50% JOU #68009	-325.0	-325.0
ENTR	AECC Schedule	-320.0	-318.0
ENTR	ISES	-10.0	-10.0
ERCOT (North)	AEP - ERCOTN	-139.0	-139.0
ERCOT (North)	OMPA - ERCOTN	-80.0	-81.0
WECC	PSCO-Lamar	-101.0	-101.0
WAPA		-7.0	-7.0
EES	CROSSROADS	-300.0	-300.0
PLUM	Plumpoint	-100.0	-100.0
Total		**-2039.4**	**-1908.4**

Southwest Power Pool Area Scheduled Exports/Contract Sales:

		2018 Summer	2023 Summer
AECI	AECI	478.0	478.0
AECI	Hermann	5.8	5.8
AECI	Lamar	12.0	12.0
AECI	West Plains	15.0	15.0
AECI	Sikeston to AECI Firm	27.0	27.0
ENTR	(SWPA load - Augasta)	4.0	4.0
ENTR	(SWPA load - Thayer in EN)	3.0	3.0
ENTR	(SWPA load - Hydro reciepts)	100.0	100.0
CWLD	Sikeston Only. Path is through Amren.	66.0	66.0
CWLD	Fulton-Hydro. Path is through Associated	3.0	3.0
CWLD	Fulton-Sikeston. Path is through Amren.	11.0	11.0
LAFA	Path is through AEPW & CELE	6.0	6.0
LEPA	Path is through Entergy	6.0	6.0
LAGN	Path is through Entergy	92.0	92.0
DERS		5.0	5.0
CELE		209.0	231.0
EES	AEPW Load on EES; Caster, Ringold load	5.0	5.0
EES	ETEC Load 2	50.0	50.0
ERCOT (East)	Texla - ERCOTE	48.0	48.0
ERCOT (East)		500.0	0.0
AECI	KAMO GRDA #2	182.0	182.0
WECC	LOAD	2.0	2.0
AECI	AECI-KGE-KPL	40.0	40.0
CWLD	Iatan 2 Participation	20.0	20.0
CWLD	Columbia Missouri Nearman	20.0	20.0
Total		**1909.8**	**1431.8**

Notes:

1. Positive interchange indicates an export
2. Negative interchange indicates an import

Tennessee Valley Authority

TVA BALANCING AUTHORITY AREA INTERCHANGE
Area (s) in the case that make up the TVA BA: 347 & 365
EIPC 2018 & 2023 Summer Future Year Study

Area 347 TVA Scheduled Imports/Contract Purchases:

		18S	23S
CE	Cayuga Ridge (Wind)	-300 MW	-300 MW
CE	Bishop Hill (Wind)	-200 MW	-200 MW
ALTW	Pioneer Prairie (Wind)	-115 MW	-115 MW
SMT	Brookfield/Smoky Mountain	-320 MW	-320 MW
SOCO	SOCO Load	-98 MW	-105 MW
Total :		**-1033 MW**	**-1040 MW**

Area 347 TVA Scheduled Exports/Contract Sales:

		18S	23S
CPLW	SEPA	1 MW	1 MW
SOCO	TVA Load	162 MW	170 MW
BREC	SEPA	190 MW	190 MW
LAGN	Choctaw	525 MW	525 MW
EKPC	SEPA	100 MW	100 MW
SIPC	SEPA	28 MW	28 MW
SMEPA	SEPA	51 MW	51 MW
EES-EMI	SEPA to MEAM	19 MW	19 MW
EES-EMI	TVA Load	28 MW	30 MW
Total :		**1104 MW**	**1114 MW**

	18S	23S
Total Net Interchange	**71 MW**	**74 MW**

Area 365 SMT Scheduled Exports/Contract Sales:

		18S	23S
TVA	Brookfield/Smoky Mountain	320 MW	320 MW
TAP	Tapoco	64 MW	64 MW
Total :		**384 MW**	**384 MW**

	18S	23S
Total Net Interchange	**384 MW**	**384 MW**

Notes:

1. Positive interchange indicates an export
2. Negative interchange indicates an import