Eastern Interconnection Planning Collaborative

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Steady State Modeling and Load Flow Working Group

2020 Roll-Up Integration Case Report

DRAFT

November 19, 2010

Executive Summary

This report details the efforts of the EIPC Steady State Modeling and Load Flow Working Group (SSMLFWG) to create a 2020 Roll-Up Integration Case of the Eastern Interconnection and provide a summary of the assessments performed. The SSMLFWG contains representatives from each NERC registered Planning Authority ("PA") that is a party to the EIPC Analysis Team Agreement.

The Roll-Up Integration Case represents an important stand-alone aspect of the work of the Planning Authorities as part of the Eastern Interconnection Planning Collaborative. As detailed in the bid submitted to DOE by the Eastern Interconnection Planning Authorities, the roll-up integration case represents the first of its kind review and analysis of the approved plans of each of the Planning Authorities in the Eastern Interconnection. The purpose of the roll-up is to "provide the platform for the stakeholder driven scenario analysis". The roll-up integration case, as depicted in this report, provides information which can be useful in each Planning Authorities' respective Order 890-approved planning process and will also be of value to stakeholders as they conduct standalone analyses to assess their particular interests. The roll-up integration case is an integrated model of the expansion plans for the Eastern Interconnection as they existed going into this year, not a single "blueprint" for expanding the system. This case provides solved power flow modeling suitable as a starting point for transmission analysis on an inter-connection-wide basis.

As with all power flow models, the 2020 roll-up integration case is a representation of the power system for a particular "snapshot" in time (2020 Summer Peak) 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 2020. 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 are 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. Nonetheless, wide-area modeling, such as the 2020 roll-up integration case, provides a sound basis for assessing inter-dependencies between and among regions which may not be achievable through local assessments individually. Potential constraints and efficiencies identified through inter-regional analysis are valuable inputs into local and regional processes, where they can be assessed for inclusion into transmission expansion plans.

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 draft of the report serves to describe in detail the data submitted by each of the EIPC Planning Authorities, explain differences in the PAs' respective planning processes and assist the SSC in understanding what is contained in the roll-up. In addition, the final report will serve to address EIPC deliverables as related to the DOE Cooperative Agreement (FOA Funding Opportunity Number: DE-FOA0000068). The associated deliverables are listed below:

Subtask 2.B Conduct interregional transmission analyses for Roll-up Integration Case and identify potential transmission conflicts/opportunities among regional plans; e.g., gap analysis.
Subtask 2.C Develop transmission options to address reliability impacts associated with potential conflicts among regional plans.
Subtask 2.D Document and communicate results for consideration in regional planning activities and post the analysis on the EIPC website.
Subtask 2.E Develop flowgates.

NOTE: Titles in the Table of Contents will be adjusted when the final headings are decided.

Table of Contents

Executive Summary 2
Table of Contents 4
Section 1 Introduction 5
Section 2 2020 Roll-up Integration Plans 8
2.1 Introduction 8
2.2 Load Forecasts and Growth Rates 8
2.3 Treatment of Energy Efficiency and Demand-Side Resources 14
2.4 Interchange or Firm Transmission Service Modeled 18
2.5 Process for Future Transmission Project Inclusion 22
2.6 Major New and Upgraded Facilities 32
2.7 Generation Assumptions (Additions and Retirements) 40
2.8 Generation Dispatch Description 46
Section 3 Gap Analysis [This Section in Development] 50
Section 4 Inter-Area Enhancements [This Section in Development] 51
Section 5 Linear Transfer Analysis [This Section in Development] 52
Appendix A: Future Project Map [This Section in Development] 53
Appendix B: New/Upgraded Transmission Projects 54
Appendix C: New/Upgraded Generation Included in Roll-Up Model 55
Appendix D: Linear Transfer Analysis Results [This Section in Development] 56

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 group completed an application for funding from the U.S. Department of Energy (DOE) in response to FOA-0000068. The application was submitted by PJM Interconnection, LLC on behalf of PAs representing the entire Eastern Interconnection. Eight PAs elected to represent the Eastern Interconnection as Principal Investigators (PIs). In addition to the eight principal investigators and Eastern Interconnection Planning Collaborative (EIPC) planning authorities, additional participants to the DOE bid include Charles River Associates (CRA) and the Keystone Center.

Each PI is listed below:
1. PJM Interconnection, L.L.C. ("PJM")
2. New York Independent System Operator, Inc. ("NYISO")
3. ISO New England, Inc. ("ISO-NE")
4. Midwest Independent Transmission System Operator, Inc. ("Midwest ISO")
5. Southern Company Services Inc. ("Southern"), as agent for
    a. Alabama Power Company
    b. Georgia Power Company
    c. Gulf Power Company
    d. Mississippi Power Company
6. Tennessee Valley Authority ("TVA")
7. Mid-Continent Area Power Pool, by and through its agent, MAPPCOR
8. Entergy Services, Inc. on behalf of the Entergy Corporation Utility Operating Companies ("Entergy")

The following Planning Authorities are also participating in the EIPC study:
1. Alcoa Power Generating
2. American Transmission Company ("ATC")
3. Duke Energy Carolinas ("DEC")
4. Electric Energy Inc.
5. E.ON (Louisville/Kentucky Utilities)
6. Florida Power & Light ("FPL")
7. Georgia Transmission Corporation ("GTC")
8. IESO (Ontario, Canada)
9. International Transmission Company ("ITC")
10. JEA (Jacksonville, Florida)
11. Municipal Electric Authority of Georgia ("MEAG")
12. New Brunswick System Operator ("NBSO")
13. PowerSouth Energy Coop
14. Progress Energy – Carolinas ("PEC")
15. Progress Energy – Florida ("PEF")

16. South Carolina Electric & Gas ("SCE&G")
17. Santee Cooper ("SCPSA")
18. Southwest Power Pool ("SPP")

On Dec. 18, 2009, the EIPC was selected by DOE to receive approximately $16 Million. PJM elected to serve as the Lead PI for the DOE Project.

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). The EIPC provides a transparent and collaborative venue to interested stakeholders: states, provincial and federal policy makers, consumers, environmental interests, transmission planning authorities and market participants that generate, transmit or consume electricity within the Eastern Interconnection.

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. Report results as required/necessary

The EIPC Web site contains a detailed description of the work to be performed as part of the DOE funding:

http://www.eipconline.com/Documents/EIPSC_SSC_Proposal_5-6-10.pdf

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

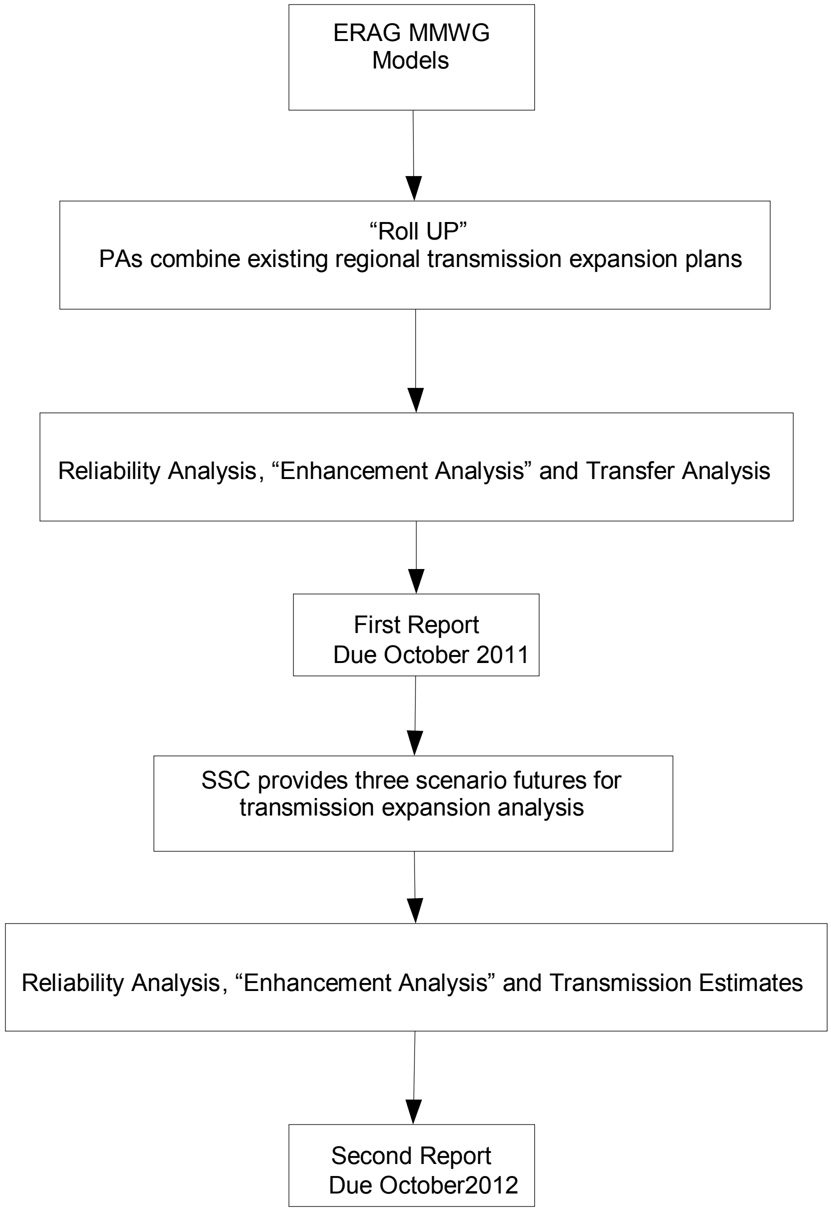

Figure 1 – EIPC Planning Analysis Process

Section 2 2020 Roll-up Integration Plans

2.1 Introduction

This section details assumptions made by each PA in developing the 2020 roll-up integration case. 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, Midwest ISO has incorporated into the Midwest ISO 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 Midwest ISO portions includes the integration of the ATC LLC and ITC system information. In addition, Georgia Transmission Company and MEAG have noted where their information for certain sections are included in Southern Company's responses.

In creating the 2020 roll-up integration case, the 2009 Series, 2020 Summer Peak, Eastern Reliability Assessment Group, Multi-Region Modeling Working Group ("ERAG MMWG") case was 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 model. The case went through several iterations of review and validation by the working group 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 2020. In addition to the growth rates, the amount of load, and origination of the data are discussed. The growth rates are the rates used by each PA in their regional transmission planning processes. The rates vary from a minimum of -0.63% to a maximum of 3.00% over the ten year period from 2010 to 2020.

The load forecasts provided by each PA were 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 2010, the vintage of the aggregated LSE forecasts is generally late 2009 or early 2010.

Alcoa Power Generating
Alcoa Yadkin Division's load growth from 2010 to 2010 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.
Alcoa Tapoco Division's load is included in TVA's load.

Duke Energy Carolinas
Duke Energy's load forecasting group developed the load forecast in 2009 utilizing data including the forecasts of individual LSE's in the DEC footprint. Duke Energy Carolinas (DEC) expects an average growth rate of 1.6% through 2020 summer for a control area load of approximately 22,380 MW.

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 1.3% for the period 2010 through 2020 totaling to a projected load of 28,864 MW in 2020. The load forecasts contained in the 2020 Roll-Up were developed in 2009 based upon 2009 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 2020 roll-up integration case reflects an average growth rate of 1.97% up to the 2020 period. The load assumptions are based on then official FPL 2009 load forecast as filed with the Florida Public Service commission in the Ten Year Site Plan (TYSP) document.

Georgia Transmission Company
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 2009, and the average annual growth rate is 3.0% for the period 2010 to 2020. 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 load forecast regularly. As of November 2009, the Ontario normal weather peak demand for Summer 2020 was forecasted to be 22,645 MW, reflecting a net annualized 10 year growth rate of -0.63%. 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 reduction 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 2020 summer for a control area demand (load & losses) of approximately 31,028 MW, based on load forecasts in the ISO-NE 2010-2019 Forecast Report of Capacity, Energy, Loads, and Transmission. For the purposes of this model, this projection was down-rated by 4% to 29,787 MW to eliminate the impact of transmission system losses. With the addition of 2,767 MW of Demand Resource load reduction, the ISO-NE estimates the control area demand (load & losses) to be 27,019 MW.

State	2020 CELT Load Forecast (MW)	Down-rated by 4%*
Maine	2340.3	2246.7
New Hampshire	2850.4	2736.4
Vermont	1195.1	1147.3
Massachusetts	14461.5	13883.0
Rhode Island	2065.2	1982.6
Connecticut	8115.5	7790.9
Total	**31,028.0**	**29786.9**

* Eliminates projection of transmission system losses in 2020 CELT Load Forecast

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 2.0% to 3,557 MW for the summer of 2020; as used in the 2020 roll-up integration case. The forecast was done in April 2009 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 load in the 2020 EIPC roll-up case is 8849 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 2009 and based on 2009 summer actual loads. The LG&E/KU native LSE expects an average growth rate of approximately 1.0% from 2010 through 2020.

MAPPCOR

Mid-Continent Area Power Pool (MAPP) Transmission Owners provide load forecast data annually through the MAPP and MRO model building process. The 2020 summer peak model was built using non-coincident peak load forecasts for 2020 reported by MAPP Transmission Owners in 2009. MAPP expects an average annual growth rate of 1.5% for the period 2010 through 2020 for a total projected load of 9,352 MW in 2020.

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 2009, and the average annual growth rate is 1.4% for the period 2010 to 2020. MEAG's load forecast is included in the Southern Balancing Authority as coincident with other Georgia load.

Midwest ISO

For Midwest ISO members, model load is reflective of Load Serving Entity forecasts as provided by the Transmission Owners through the Midwest ISO 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 the Midwest ISO by member systems in 2009 for the MTEP 2010 vintage model that was the basis of the EIPC roll-up for the Midwest ISO system.

The demand projections included in the roll-up integration case for the Midwest ISO portion of the EIPC roll-up case is consistent with the Midwest ISO 2010 Long Term Resource Assessment report which is available on the Midwest ISO web site at http://www.midwestmarket.org/publish/Document/6a7e86_12bc0f1b440_-7fc50a48324a?rev=1.

See Section 2.3 for more details on the 2020 forecast underlying the rollup power flow model.

New Brunswick System Operator

The NBSO load forecast is reflective of the forecast provided by NB Power Distribution and Customer Service, the Load Serving Entity that supplies over 99% of New Brunswick customers. The 10-year load forecast is updated by January 31 of each year for the next 10-year fiscal period beginning on April 1. The most recent forecast is for the period 2010/11 to 2019/20.

Forecast average annual growth rate in New Brunswick between 2010/11 to 2019/20 is 0.6% for both annual energy and peak hourly demand. Peak demand is forecast as the coincident regional load.

New York ISO

The NYISO is forecasting a base 2020 summer peak load for the New York Control Area (NYCA) of approximately 35,300 MW which represents an average annual growth rate of 0.68% through 2020, as documented in the NYISO 2010 Load & Capacity Data report: http://www.nyiso.com/public/webdocs/services/planning/planning_data_reference_documents/2010_GoldBook_Public_Final_033110.pdf

PJM Interconnection

PJM annually prepares a detailed, independent load forecast for PJM and each of its zones and sub-regions. The January 2010 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 the integration of the ATSI system that is scheduled for 2011) is projected to average 1.7% per year over the next 10 years, and 1.4% over the next 15 years. These growth rates are calculated assuming the ATSI system is in PJM in both the start and end years. (ATSI integration into PJM is scheduled for June 1, 2011.) The PJM RTO summer coincident peak is forecasted to be 174,724 MW in 2020, a 10-year increase of 26,933 MW, and reaches 182,665 MW in 2025, a 15-year increase of 34,874 MW. Annualized 10-year growth rates for individual PJM zones range from 1.0%

to 2.5%. 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.

PJM Zone	2010 Coincident Peak Load (MW)	2020 Coincident Peak Load (MW)	Average Annual Growth Rate
AE	2,628	3,308	2.3%
BGE	7,173	8,571	1.8%
DPL	3,873	4,421	1.3%
JCPL	6,203	7,312	1.7%
METED	2,803	3,309	1.7%
PECO	8,212	9,432	1.4%
PENLC	2,710	3,275	1.9%
PEPCO	6,787	7,601	1.1%
PL	6,883	7,893	1.4%
PSEG	10,523	11,943	1.3%
RECO	417	474	1.3%
UGI	182	201	1.0%
AEP	22,358	25,469	1.3%
APS	8,328	9,506	1.3%
ATSI	N/A	14,084	N/A
COMED	21,652	26,723	2.1%
DAY	3,207	3,638	1.3%
DLCO	2,757	3,176	1.4%
DOM	19,056	24,389	2.5%

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 2020 Roll-Up were developed in 2010 based upon 2010 data. PowerSouth's calculated annual growth rate for the period 2010 through 2020 is 1.6%.

Progress Energy Carolinas

Progress Energy Carolinas (PEC) updates its power flow models on an annual basis. Loads plus losses at the transmission level will be scaled to match the system forecast for each load level. Progress Energy Carolinas (PEC) expects an average growth rate of 1.8% of its area through 2020 summer for a balancing area load of approximately 15,476 MW. The load forecast contained in the roll-up integration case was developed in early 2009 and is based on coincident peaks provided by the LSEs.

Progress Energy Florida

Progress Energy Florida (PEF) updates its power flow models on an annual basis. Loads plus losses at the transmission level are scaled to match the system forecast for peak load level. Progress Energy Florida (PEF) expects an average growth rate of 1.2% of its area through 2020 summer for a balancing area load of approximately 14,160 MW. The load forecast contained in the roll-up integration case was developed in early 2010 and is based on non-coincident peaks provided by the LSEs.

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 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 load forecast used in the roll up case has approximately 333 MW of Energy Efficiency and Demand Side Management reduced from the gross load forecast to produce a net peak load for the 2020 summer peak load of approximately 6,558 MW which represents an average annual growth rate of 2.6% through 2020.

South Carolina Electric and Gas
The average annual load growth provided by the LSEs within the SCE&G planning area is 1.74% for the 2010 through 2020 period. This load growth results in a projected peak load of 5,824 MW in 2020 including load and transmission losses. The load forecasts contained in the 2020 roll-up case were developed in 2009 and are based on 2009 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 2.13% for the period 2010 through 2020 totaling to a projected load of 57,385 MW in 2020. The load forecasts contained in the 2020 Roll-Up were developed in 2009 based upon 2009 actuals.

Southwest Power Pool
Southwest Power Pool (SPP) expects a regional compound load growth rate of 1.4% per year through 2020. This forecast was produced by SPP in 2010 and approved by its members. The regional coincident forecasted peak load for 2020 is roughly 59,000MW.

Tennessee Valley Authority
The load forecast used in roll-up integration case used TVA's official February 2010 delivery point load forecast provided by TVA's Forecasting & Competitive Intelligence (F&CI) 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 2010 is 30,738 MW. TVA's load forecast for summer peak 2020, which was used in the roll-up integration case, is 37,213 MW. This reflects a 2.1% 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 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, these 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 demand side programs varies across PAs, it is important to realize that many PAs do not net these demand impacts from the gross demand forecasts that are used in transmission planning models. The reason for this is that while demand side impacts are an essential part of resource requirement planning, the transmission system may be required to meet the gross demand if the demand side resources are not utilized. For example, it may be more economical not to utilize any or all of the demand resources on a given day, or the contractual provisions associated with the demand resource may not require their use when there are alternative resources. 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

This draft does not include the table laying out load forecasts and DR values submitted by each PA; this will be included in a future draft.

Duke Energy Carolinas
Energy efficiency efforts as required to meet state requirements have been incorporated into the load in the case. For 2020 summer, efficiency efforts constitute an approximate reduction of 450 MW 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 2020 roll-up integration case takes 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 825 MW for Entergy by 2020. 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 2020 will be

approximately 2095 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 Company
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 4,491 MW. 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 (2010 FCA-4 for the Commitment Period June 1, 2013 to May 31, 2014) have been incorporated into the load in the model. For the summer of 2020, a total of 1,298 MW of Passive Demand Resources / Energy Efficiency (On-Peak and Seasonal-Peak) and 1,363 MW of Active Demand Resources / Demand Side Management (Real Time Demand Resource) were included for a total of 2,661 MW. This number was then adjusted up by 4% to 2,767 MW to account for transmission and distribution system losses; this is the actual amount reflected in ISO-NE's portion of the roll-up model.

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 2020 summer model reflects a reduction in load of 500 MW 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 for 2020 included an energy efficiency of 234MW.

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.

Midwest ISO

For Midwest ISO members, 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 2020 power flow case for the Midwest ISO portion of the roll-up integration case is consistent with the Midwest ISO 2010 Long Term Resource Assessment report which is available on the Midwest ISO web site at http://www.midwestmarket.org/publish/Document/6a7e86_12bc0f1b440_-7fc50a48324a?rev=1. That report indicates the following projections for the plan year 2019, and the 2020 projections have been estimated based on information from that report:

	2019	**2020**
Unrestricted Non-Coincident	124,723	126,095
Estimated Diversity	5,613	5,674
Total Internal	119,110	120,421
Direct Control Load Management	467	467
Interruptible Load	2,874	2,874
Net Internal Demand	***115,769***	***117,080***

Note that the projections for Direct Control Load Management and Interruptible Load is not increased from values reported by LSEs for 2010. The underlying long term growth rate for the period 2010 through 2020 is 1.1%.

Also note that the above figures for Non-Coincident load include projections for ATSI system load based on our published 2010 Long Term Resource Assessment report. Because ATSI is intending to move to PJM in 2011, PJM has also provided a PJM system load forecast figure for 2020 that includes 14,048 for ATSI. The combined Midwest ISO and PJM peak load projections can be reconciled by taking into consideration the 14,048 MW PJM has included for ATSI. This treatment does not indicate any double counting of load with respect to the roll-up model however, as Midwest ISO and PJM have coordinated on the roll-up power flow case such that there is no double counting of load for the ATSI system in the case.

New Brunswick System Operator

Energy efficiency in New Brunswick for 2020 is forecast to be 90 MW. The forecast for DSM is zero. The energy efficiency forecast is provided by Efficiency New Brunswick, and it is incorporated into the base load forecast. Efficiency New Brunswick estimates are related to the following programs:

- Existing Homes Energy Upgrades Program
- Energy Efficient New Homes Program
- Upgrades Program for Multi-Unit Residential Buildings

- Retrofit Program for low-income households

New York ISO

Energy efficiency efforts as required to meet state requirements have not been fully incorporated into the load forecast as the programs are just beginning and a level of conservatism in the base case was desired. For 2020 summer, if the full targets of statewide required efficiency efforts were assumed to be fully met (15% by 2015), an additional reduction in the forecast peak of approximately 2,500 MW would occur. Impacts of demand side programs such as Emergency Demand Response Program (EDRP) are not included in the forecasted load. Interruptible load, and distributed generation resources of approximately 2,250 MW (referred to as Special Case Resources in New York) are not included.

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 through 2012. The 2012 values are used as assumptions throughout the forecast horizon. Projections for changes to LM and EE past 2012 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 2020 rollup power flow case are based on unrestricted peaks, which means that they are not adjusted for LM and EE. For 2020 summer, DR and EE constitute an approximate equivalent reduction of 549 MW of EE and 6823 MW of LM for a total of 7372 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 2020 reflects a reduction in load of 15 MW as a result of energy demand side management resources (water heater program). This 15 MW reduction is reflected in PowerSouth's net peak load.

Progress Energy Carolinas

PEC has developed Energy Efficiency and DSM programs, estimated to total 1,427 MW for the year 2020, as required to meet state requirements. For the 2020 summer, Energy Efficiency constitutes an approximate reduction of 396 MW of load modeled in the power flow case. DSM constitutes an approximate potential reduction of 1,031 MW but is not modeled in the case.

Progress Energy Florida

PEF has developed Energy Efficiency and DSM programs, estimated to total 3,285 MW for the year 2020, as required to meet state requirements. For the 2020 summer, Energy Efficiency constitutes an approximate reduction of 1,525 MW of load modeled in the power flow case. DSM constitutes an approximate potential reduction of 1,732 MW but is not modeled in the case.

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 load forecast used in the roll up case has approximately 333 MW of Energy Efficiency and Demand Side Management reduced from the gross load forecast to produce a net peak load for the 2020 summer peak load of approximately 6,558 MW which represents an average annual growth rate of 2.6% through 2020.

South Carolina Electric & Gas
SCE&G is projecting 325 MW of energy efficiency programs in 2020. 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 210 MW of demand side management programs in 2020. 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 2020 reflects a reduction in load of 996 MW as a result of energy efficiency programs and non-dispatchable (passive) demand side management resources. The modeling does not include dispatchable (active) demand side resources or real-time pricing resources which increase generation reserve margins but may not be relied upon to reduce particular transmission loadings.

Southwest Power Pool
There are no state requirements for energy efficient projects; however, individual SPP members do include energy efficient projects as well as DSM in the modeled loads. The expected DSM load in the 2020 roll-up integration case is 492 MW. Energy Efficiency projects total 248 MW for 2020.

Tennessee Valley Authority
TVA has an aggressive energy efficiency and demand-side management initiative, projecting over 2,400 MW under the program by 2020. 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. 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
The 2020 roll-up integration case has no interchange for Alcoa's Yadkin division.

Duke Energy Carolinas
Duke has a net export to CPLE of 995 MW from Rowan and Broad River Energy Center serving Progress Energy load, while NCEMC resources in CPLE and Duke are shared between the areas. NCEMC also has an export 50 MW of its resources to serve its load in DVP (a part of PJM). Duke imports 268 MW from SEPA's generation on the Savannah River and 31 MW from SOCO to serve the city of Seneca, SC. The resultant net interchange is an export of 746 MW.

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

Entergy Services
Entergy Electric System area interchange assumptions in the 2020 roll-up integration case include 1,139 MW of imports and 1,967 MW of exports, resulting in a net interchange of 828 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 1590 MW of imports into FPL's BA from outside the FRCC that are associated with unit ownership or PPAs.

Georgia Transmission Company
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 2020 model has a zero net interchange.

ISO New England
ISO New England's area interchange assumptions in the 2020 roll-up integration case include 2,381 MW of imports and 330 MW of exports resulting in a net import of 2051 MW. The majority of this interchange comes from 1500 MW imported from hydroelectric plants in 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 2020. 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 406 MW import from Georgia (Southern Company) to JEA and 259 MW export from JEA to the FRCC region; with a resultant 147 MW net power interchange (import) in the 2020 roll-up integration case.

LG&E and KU Energy
LG&E/KU's area interchange assumptions in the 2020 roll-up integration case include 1142 MW of imports and 441 MW of exports, resulting in a net interchange of -701 MW. Values represented in Appendix E reflect long-term (one year or more) firm transmission service obligations.

MAPPCOR
The 2020 MAPP model includes an area interchange value of 703 MW MAPP imports and 3,192 MW MAPP exports for a net interchange value of 2,489 MW.

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

Midwest ISO
For Midwest ISO 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 Midwest ISO member control areas and external control areas. The amount of net interchange between the Midwest ISO 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. Midwest ISO 2020 model includes 8,986 MW of imports, and 4,076 MW of exports, for a net interchange of 4,911 MW.

New Brunswick System Operator

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 2010 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 from neighbors in the 2020 roll up model is 433 MW and non-firm net interchange to neighbors is 899 MW for a total net export of 466 MW. 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 planning analyses.

PowerSouth Energy Cooperative

PowerSouth's area interchange assumptions in the 2020 roll-up integration case include 541 MW of imports and 1242 MW of exports, resulting in a net interchange of 701 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.

Progress Energy Carolinas
PEC 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. PEC has two balancing areas named CPLE and CPLW. The CPLE area model includes 1650 MW of imports and 449 MW of exports, resulting in a net interchange import of 1201 MW. The CPLW area model includes 1 MW of imports and 150 MW of exports, resulting in a net interchange export of 149 MW.

Progress Energy Florida
PEF 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. PEF has one balancing area named FPC. FPC area model includes a net interchange import of 3888 MW.

Santee Cooper
The area interchange schedule consists of both imports and exports with a net interchange import of 1595 MW. Santee Cooper's scheduled imports for 2020 summer consist of Santee Cooper's share of Summer Units #1-#3 for a total of 1370 MW with additional imports scheduled under grandfathered contracts with Southeastern Power Administration for 275 MW. Santee Cooper's scheduled exports are for grandfathered exports to Woodland Hills for 16 MW, and to Charleston Navy for 15 MW and New Horizons (to SCE&G) for 19 MW. There are no firm transmission service requests modeled in the 2020 roll-up integration case.

South Carolina Electric & Gas
SCE&G's area interchange assumptions in the 2020 roll-up integration case include 72 MW of imports and 1,370 MW of exports, resulting in a net interchange of 1,298 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 2020 roll-up integration case include 2,200 MW of imports and 3,286 MW of exports, resulting in a net interchange of 1,086 MW. Values represented in Appendix E reflect long-term (one year or more) firm transmission service obligations.

Southwest Power Pool
SPP includes long term firm transmission service requests in models, as well as related projects with an approved FERC filed NTC (Notification to Construct).

Tennessee Valley Authority
TVA's area interchange assumptions in the 2020 roll-up integration case include 139 MW of imports and 789 MW of exports, resulting in a net interchange of 650 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. 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:

- State/Budget Approval: 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.

Alcoa Power Generating
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 Progress Energy Carolinas 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 2020 roll-up integration case. 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.

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 2020 roll-up integration case transmission projects identified in Entergy's 2010 – 2012 Final Construction Plan Update 4 posted on OASIS. The projects identified in Entergy's 2010 – 2012 Final Construction Plan Update 4 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 Company

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 Coordinator, conducts transmission and resource adequacy assessments as follows:

- An Ontario Reliability Outlook with a five-year horizon, that is issued annually;
- 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.

In 2005, the Ontario Government established the Ontario Power Authority (OPA) to address the long-term system planning. Part of the OPA's mandate is to develop an Integrated Power System Plan (IPSP) to provide 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 2020 roll-up integration case includes 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 2020 roll-up case.

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 case have the status of "State/Budget Approval". JEA's policy and practice is to only include "State/Budget Approval" 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 EON in the previous year, are incorporated into the Transmission Expansion Plan.

Periodically, studies are performed to evaluate the adequacy of the EON 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 sub regional planning groups (SPGs) activity and sub regional plans submitted by the MAPP SPGs and approved through the MAPP Transmission Planning Subcommittee (TPSC). 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.

Midwest ISO

The Midwest ISO produces a Midwest ISO 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 Midwest ISO Board of Directors represents the recommended plan for the region, and the member transmission owners are bound by forming 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 the Midwest ISO for including projects in the roll-up integration case was to include all transmission projects in the agreed upon EIPC status categories of State/Budget Approval, Planned, or Proposed. Midwest ISO included proposed projects that are pending approval in the current planning cycle MTEP 11 that began September 2010 and will conclude with Board approval December 2011, and other projects that are proposed to meet NERC reliability standards in the 2010-2020 ten year horizon, but that are targeted for regional approval after 2011.

New Brunswick System Operator

The transmission plan is produced each year by NBSO within the annual update of the NBSO 10-Year Outlook report. The transmission plan represents an analysis of the existing high voltage transmission network, and the development required to meet the forecast load in compliance with the established transmission planning criteria.

NBSO is responsible for ensuring that the integrated electricity system, at all times, has adequate capacity to satisfy all applicable reliability criterion. NBSO is also responsible for addressing congestion issues that impact the efficient operation of the Electricity Market.

NBSO, upon identifying a system adequacy issue or a congestion issue, will consult with Transmitters and Market Participants to develop technically feasible options for addressing the issue. These options will then be published on the NBSO website, along with a notice of intent by NBSO to request proposals to resolve the issue. Transmitters and Market Participants may then participate in a formal Request for Proposals process leading to the final selection by NBSO of the preferred project.

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. As provided in the NYISO Tariff, the NYS Public Service Commission will make the final determination as to which solution will proceed.

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. This 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 quarterly queue process that sequentially evaluates interconnection requests to determine incremental transmission upgrades necessary for their reliable interconnection and operation with the system.

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 dimensions assessment 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 (SoCo) 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 area 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.

Progress Energy Carolinas
PEC'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 2020 roll-up integration case used in this process.

Progress Energy Florida
PEF'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 PEF'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.

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 to the SPP region 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 regional customers improved access to the SPP region's diverse resources. Development of the ITP was driven by the need to develop a transmission backbone large enough in both scale and geography to provide flexibility to meet SPP's future needs.

The ITP is an iterative three-year process that includes 20-Year, 10-Year, and Near-Term Assessments and targets a reasonable balance between long-term transmission investment and customer congestion costs (as well as many other benefits).

The ITP creates synergies by integrating existing SPP activities: the Extra High Voltage (EHV) Overlay, the Balanced Portfolio, and the SPP Transmission Expansion Plan (STEP) Reliability Assessment. Consequently, and reaching the balance above, efficiencies are expected to be realized in the Generation Interconnection and Aggregate Transmission Service Request study processes. The ITP works in concert with SPP's existing sub-regional planning stakeholder process, and parallels the NERC TPL Reliability Standards compliance process.

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 the transmission project is due to the planned addition of a supply-side resource, then approval for that project is obtained through the approval for that resource. Planned system modifications are included in TVA's transmission expansion plan as the transmission projects obtain TVA officer approval during the planning process. Projects that do not have TVA officer approval are omitted from the transmission expansion plan to verify the continued need for the planned corrective action.

2.6 Major New and Upgraded Facilities

The following section includes a description of the major new and upgraded transmission facilities included in each Planning Authority's portion of the 2020 roll-up integration case. 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
Alcoa's Yadkin division has no new or upgraded facilities planned.

Duke Energy Carolinas
DEC has included three new > 200 kV transmission projects in the 2020 roll-up integration case. DEC has a project to upgrade the conductor on its 230 kV line from Pisgah Tie to Shiloh Switching Station by 2013 in order to accommodate additional transmission service into CPLW. A new 230 kV tie line to CPLE will be completed by 2011 between DEC's Pleasant Garden Tie and CPLE's Asheboro Station to enhance reliability in the western CPLE area. The Cliffside 6 generation project requires addition of a 500 kV tap station between Jocassee Tie and McGuire Nuclear Station by 2011. No other > 200kV projects are expected to be in service by 2020.

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 2020 roll-up integration case 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 2010 – 2012 Final Construction Plan Update 4 posted on OASIS.

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 twelve new transmission line projects in the 2020 model that will amount to an estimated total of 200 miles of new 230 kV and 86 miles of 500 kV transmission lines.

Georgia Transmission Company
GTC's information is included in the response from Southern Company. Please note that in Appendix B, transmission facilities listed under the PA "SOCO" 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 2017. Additional transmission development may be identified in the future when there are further developments on the resource options.

The 2020 roll-up integration case includes transmission system reinforcements in various parts of the province such as a new double circuit 500 kV line between Bruce and Milton, and the reinforcement of the Windsor area transmission. In addition, to accommodate new renewable energy generating facilities under the Ontario Feed-in-tariff (FIT) program and Ontario's agreement with the Korean Consortium several new transmission projects have been proposed at 230 and 500 kV. These plans are currently under review.

ISO New England
ISO-NE has included 45 new transmission projects at 230 kV and above in the 2020 roll-up integration case. 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 case 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 adding more generator capacity within its service territory and has power purchase agreements with other utilities to meet its future load demand. It also has plans to construct new transmission circuits at 230 kV and additional auto-transformation capacity from the 230 kV level to serve the 138 kV and 69 kV connected loads.

LG&E and KU Energy
LG&E/KU does not have any new or upgraded facilities 230kV and above in the 2020 roll-up integration case.

MAPPCOR
Below are the major new and upgraded transmission facilities included in the 2020 roll-up integration case for MAPPCOR.

Manitoba Hydro additions/upgrades:
- St Joseph Wind 1 and 2 to Letellier Substations with 4.8 mile connection 230kV lines planned to be built in 2010.
- Herblet Lake to Ralls Island 103 mile 230 kV line planned to be built in 2011.
- Herblet Lake to Wuskwatim 85.2 mile long double circuit 230 kV line planned to be built in 2011.
- St Vital to Letellier 77.7 mile 230 kV line planned to be built in 2012.
- LaVerendrye to St Vital 21.1 mile 230 kV line planned to be built in 2014.
- Dorsey to Portage South 43.5 mile 230 kV line owned by Manitoba Hydro is proposed to be converted to double circuit line by 2014.
- New Conawapa to Riel converter stations and 805 mile 500 kV bipole DC transmission line between Conawapa and Riel converter stations proposed to be built by 2017.
- Conawapa to Henday 19miles, 230kV quadruple circuit line proposed to be built by 2017.

- Conawapa to Long Spruce 34 miles, 230kV double circuit line proposed to be built by 2017.
- Dorsey to Riel 31 mile 500kV line proposed to be built by 2018.

South Dakota WAPA/BEPC facility additions/upgrades:
- Lower Brule 230kV substation is planned to be built.
- Big Bend to Lower Brule to Fort Thompson 11.4 mile 230kV line planned to be built.
- Witten substation is proposed to be upgraded from 115kV to 230/115 substation in 2012.
- Reliance 230kV substation is proposed to be built in 2012.
- Witten to Reliance to Big Bend 43 mile, 230kV line proposed to be built in 2012.

North Dakota WAPA/BEPC facility additions/upgrades:
- Watford City substation is planned to be upgraded from 115 kV to 230/115 substation in 2011.
- Wolf Point substation in Montana and Williston substation proposed 230kV line that will be operated at 115kV to be built by2012.
- Williston to Watford City 42mile 115kV line planned to be uprated to 230kv line in 2010, Williston to Tioga 45 mile 230 kV line planned to be built in 2010, and a Watford City to Charlie Creek 34 mile 115 kV line planned to be uprated to 230kV in 2011.

Minnesota facility additions/upgrades:
- Appledorn 230kV substation is planned to be built in 2011.
- Cass Lake 230/115 kV substation is planned to be built in 2011.
- Boswell (Bemidji) to Wilton (clay Boswell) 230kV, 72mile line is proposed to be built by 2012 and will pass through the new Cass Lake 230/115 kV substation.

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 "SOCO" also include MEAG transmission projects.

Midwest ISO
Major 345 kV line additions (20 miles or longer) that are either Planned, or have State/Budget approvals and that are included in EIPC 2020 Roll-Up case are:

- Gibson to AB Brown to Reid 345 kV line (64 miles)
- Hazelton to Salem 345 kV line (81 miles)
- Cardinal to Rockdale 345 kV line (32 miles)
- Maple River- Alexandria - Waite Park - Monticello 345 kV line (225 miles)
- Brookings County to Lyon County to Cedar Mountain to Helena to Lake Marion to Hampton Corner 345 kV line (206 miles)
- Hampton Corners to North Rochester to North La Crosse 345 kV line (118 miles)
- Rapson to Sandusky to Greenwood to Fitz 345 kV double circuit line (81 miles)
- Fargo to Maple Ridge 345 kV line (20 miles)
-

The following transmission projects are included in the model as Proposed projects, and are currently being evaluated for recommendation in 2011 to the Midwest ISO Board of Directors for approval. These projects are listed as "MVP" projects which in this case means that they or equivalent are intended to address the aggregate RPS requirements of Midwest ISO states by 2020.

Proposed Project Description	Location	Mileage	Expected In-Service Date	Expected Regional Approval Date
MVP1: 345 kV Line Brookings to Big Stone	SD	35	2017	2011
MVP3: 345 kV Line Lakefield to Mitchell County	IA/MN	86	2015	2011
MVP4: 345 kV Line Sheldon to Webster to Blackhawk to Hazelton 345 kV line	IA	250	2015-2018	2011
MVP5: 345 kV Line Dubuque to Spring Green to Cardinal and La Crosse to North Madison to Cardinal	IA/WI/MN	260	2015-2020	2011
MVP6: 345 kV Line Ellendale to Big Stone	ND	114	2019	2011
MVP7: 345 kV Line Thomas Hill to Adair to Ottumwa	IA/MO	206	2014	2011
MVP8: 345 kV Line Adair to Palmyra	MO	64	2018	2011
MVP9: 345 kV Line Palmyra to SE Quincy to Meredosia to Ipava, and Ipava to Meredosia to Pawnee	IL/MO	158	2015-2018	2011
MVP10: 345 kV Line Pawnee to Pana	IL	22	2019	2011
MVP11: 345 kV Line Pana to Mt. Zion to Kansas to Sugar Creek	IL	117	2019	2011
MVP12: 345 kV Line Reynolds to E. Winamac to Burr Oak to Hiple	IN	97	2013	2011
MVP13: 345 kV Line Beaver to Davis Besse	OH	19	2013	2011
MVP14: 345 kV Line Sidney to Rising	IL	27	2017	2011
MVP15: 765 kV Line Sullivan to Meadow Lk to Greentown	IN	192	2018	2011
MVP18: 345 kV Line Fargo to Oak Grove	IL	102	2016	2011

In addition, the following Proposed projects are included in the roll-up integration case as identified solutions to reliability issues that are expected to occur in the 10 year planning horizon. The approval of these projects or equivalent by the Midwest ISO Board of Directors is expected after 2011.

Proposed Project Description	Location	Mileage	Expected In-Service Date	Expected Regional Approval Date
345 kV Line Petersburg to Francis: Increase line rating	IN	111	2013	>2011
New 345/138 kV Fulton substation and transformer	OH	0	2014	>2011
345 kV Line Guion to Whitestown: Increase line rating	IN	11	2015	>2011
New 345/138 kV Tr. Sub 39 3-5	IL	0	2014	>2011
345 kV Line Sub 39 to MEC Cordova	IL	16	2014	>2011
345 kV Line Raun to Sioux City	IA	23	2016	>2011
345 kV Line Barnhart to Branch River	WI	36	2018	>2011
345 kV Line Branch River to Forrest Jct	WI	13	2018	>2011
345 kV Line Pleasant Prairie to Zion	WI/IL	6	2014	2011

New Brunswick System Operator

Major transmission projects proposed within the next 10 years that impact the NBSO bulk transmission system include:

- Refurbishment of the Eel River HVDC station between New Brunswick and Québec is under review.
- Planning studies are ongoing to propose transmission solutions that will reliably supply the forecast loads in Southeastern NB and meet the current and future needs of the interconnections with PEI and Nova Scotia.
- Proposed expansions of the interconnections between New Brunswick and neighboring jurisdictions include:
    - A new 345 kV line between NB and Nova Scotia by 2015.
    - A new 138 kV cable between NB and PEI by 2013.
    - Expansion of ties between Québec and NB, as well as NB and ISO New England, in order to accommodate Transmission Service Requests by Nalcor Energy for 2015.

New York ISO

NYISO has included in the roll-up integration case a new 345 kV controllable AC transmission project into New York City known as M29, various upgrades to existing 345 kV circuits within New York City, and a new 230/115 kV station in western New York.

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 involves major "backbone" upgrades at 500 kV and above. The backbone projects are best tracked on the planning pages of the PJM.com website. They can be identified by the descriptions that follow:

Project	Date Required for Reliability	Length	Status
Carson-Suffolk 500 kV	June 1, 2011	60 miles in VA	State Approved and Under Construction
TRAIL 500 kV	June 1, 2011	215 miles In PA, WV and VA	State Approved and Under Construction
Susquehanna-Roseland 500 kV	June 1, 2012	146 miles in PA and NJ	State Approved, Extensive Land Acquisition Engineering Design, and Procurement complete and remainder under way.
PATH 765 kV	June 1, 2015	275 miles WV, MD and VA	State Approval pending, Land Acquisition, Engineering Design, and Procurement are in progress
MAPP 500 kV and direct current	June 1, 2014	80 miles of 500 kV and 90 miles of DC in MD and DE	Approval, Land Acquisition, Engineering Design, and Procurement are in progress
345 kV Line Pleasant Prairie to Zion	WI/IL	6	This is a MISO project proposed for 2014 that ties to PJM. The project is under joint review. This project may be proposed as a 2011 Supplemental RTEP Upgrade. Modeling will be "open" the base roll up case.
765 kV Line Sullivan to Meadow Lake to Greentown	IN	192	This is a MISO project proposed for 2018 that ties to PJM. The project is under joint review. Modeling will be "open" the base roll up case.

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

Progress Energy Carolinas
PEC has included six new 230 kV transmission projects in the 2020 roll-up integration case. The first is a new 230 kV line from Richmond to Fort Bragg Woodruff Street Substation to accommodate new generation at Richmond in June 2011. A new 230 kV tie line to DEC will be completed by June 2011

between DEC's Pleasant Garden Tie and CPLE's Asheboro Substation to enhance reliability in the CPLE area. A new 230 kV line will be constructed from Rockingham to West End Substation also by June 2011. By December 2011, a new 230 kV line from Clinton to Lee Substation will be completed. By June 2014, a new 230 kV line will be placed in service from Harris to RTP Switching Station. Finally, a new 230 kV line is planned from Greenville to Kinston by June 2017.

PEC has also included two new 230 kV substation projects in the 2020 roll-up integration case. The first is the conversion of the existing Enka 115 kV Switching Station to 230 kV by December of 2010. The second substation project is the construction of Folkstone 230 kV Substation which is a new networked 230/115 kV Switching Station scheduled for completion by June of 2013.

Progress Energy Florida
PEF has included four new 500 kV and six 230 kV transmission projects in the 2020 roll-up integration case. First these include two new 500 kV lines from Levy to Citrus, a new 500 kV line from Levy to Crystal River Plant, a new 500 kV line from Levy to Central Florida South, a new 230 kV line from Lake Tarpon to Kathleen, and a new 230 kV line from Crystal River Plant to Brookridge all to accommodate new generation at Levy in June 2021. Second a new 230 kV line from Loughman/Intercession City to Gifford by June 2013 to mitigate a credible double contingency and provide local area support for PEF load. Finally a new 230 kV line from Disston to Fortieth Street by June 2014 to increase reliability in PEF Suncoast load area, and a new 230 kV Line from Hines to West Lake Wales by June 2011.

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 $830 million of planned and proposed additions and upgrades expected to be in service through the year 2020 for all classes. There are approximately 363 miles of new transmission projected to be added to the system for all voltage classes (69 -230 kV) through 2020.

South Carolina Electric & Gas
The major transmission improvements to the SCE&G transmission system that are included in the 2020 roll-up integration case include:

Project	Scheduled Completion Year
Pepperhill – Canadys 230kV	2013
Pepperhill – Church Creek 230kV	2013
VC Summer #1 – Killian 230kV	2015
VC Summer #2 – Lake Murray 230kV #2	2015
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 2020 roll-up integration case include:

- a new 500/230 kV transformer at Autagaville substation in 2013

- the construction of a new 500/230 kV substation at East Walton in 2015
- the construction of a new 500 kV Switching Station (at Rockville) along the Scherer to Warthen 500 kV line in 2015
- the construction of a new 46.6 mi 500 kV line from Rockville to E. Walton in 2015
- the construction of a new 50 mi 500 kV line from Vogtle to Thomson in 2016
- the construction of a new 35 mi 500 kV line from South Hall to E. Walton in 2020

Southwest Power Pool

SPP includes reliability projects, as well as other projects deemed necessary due to either customer request or those for economic reasons. These projects typically have an NTC (Notification to construct). The SPP Transmission Plan includes a group of high priority projects noted as “Priority Projects”. In April 2010 the SPP Board of Directors and Members Committee approved construction of these priority high voltage (345 kV) electric transmission projects estimated to bring benefits of at least $3.7 billion to the SPP region over 40 years. The projects will improve the regional electric grid by reducing transmission congestion, better integrating SPP’s east and west regions, improving SPP member’s ability to deliver power to customers, and facilitating the addition of new renewable and non-renewable generation to the electric grid.

The approved Priority Projects are:

- Double-circuit 345 kV line from Spearville, KS, to Comanche County, KS, to Medicine Lodge, KS to Wichita, KS*
- Double-circuit 345 kV line from Comanche County, KS to Woodward, OK*
- Double-circuit 345 kV line from Woodward, OK to Hitchland, TX*
- Single-circuit 345 kV line from Nebraska City, NE, to Maryville, MO, to Sibley, MO
- Single-circuit 345 kV line from Valliant, OK to Texarkana, TX
- New reactor in Tulsa County, OK

* These double-circuit 345 kV lines are being reviewed as part of the ITP20 to see if existing NTCs need to be modified with higher voltage solutions which will be presented to the SPP BOD for action in January 2011.

The Balanced Portfolio was an initiative to develop a group of economic transmission upgrades that benefit the entire SPP region, and to allocate those project costs regionally. The benefits of this group of 345 kV transmission upgrades have been demonstrated by model analysis to outweigh the costs, and the regional cost sharing creates balance across the SPP region. The Balanced Portfolio contains a diverse group of 345kV transmission projects addressing many of SPP's top flowgates:

- The 250 mile "Woodward -Tuco" line between Hale County, Texas (north of Abernathy) and Woodward, Oklahoma.
- The 215 mile "Spearville-Knoll-Axtell" line between Spearville, Kansas (east of Dodge City); Hays County, Kansas; and Axtell, Nebraska.
- The 100 mile "Seminole-Muskogee" line between Seminole County and Muskogee, Oklahoma.
- The 36 mile "Sooner-Cleveland" line between Sooner Lake in Noble County, Oklahoma and Cleveland, Oklahoma.
- The 30 mile "Iatan-Nashua" line between Iatan and Nashua, Missouri (north of Kansas City).
- The Anadarko Autotransformer in Anadarko, Oklahoma.
- The Swissvale-Stilwell Tap near Gardner, Kansas.

Tennessee Valley Authority
The major upgrades to the TVA transmission system that are included in the 2020 roll-up integration case include:

- By summer 2011, the Gallatin FP - Lafayette line overloads for loss of the Gallatin Primary - Portland line. The voltage at the East Gallatin 161-kV stations will drop below TVA planning criteria to 94.3% for the same outage. A new 161-kV line from Gallatin FP along with a new Angeltown 161-kV Switching Station will be built with a projected in-service date of June 2011.
- Load growth in the West Point, MS area is accelerating the need for additional 500-161-kV transformer capacity in the area. Current area forecasted load growth will exceed the capacity of the Lowndes and West Point 500/161-kV transformers. By summer 2011, Clay 500-kV Substation will add the additional 500/161-kV transformer capacity required to serve the area.
- New generation expansion at the Lagoon Creek site, will overload the existing Jackson 500/161-kV transformer for the loss of the Weakley 500/161-kV transformer bank. In addition to the Jackson bank overloading, there are five 161-kV line sections in the Jackson area that will overload if the Jackson 500/161-kV bank is lost. A project is in place to install a 2nd 500/161-kV transformer at the Jackson 500-kV Substation with a projected in-service date of 2011.
- By the summer of 2013, the 161-kV system cannot maintain adequate voltage in the Clarksville area for the loss of the Montgomery 500/161-kV transformer. Also projected load growth in the area, will overload the existing 500/161-kV transformer. A second 500/161-kV transformer will be needed at Montgomery 500-kV Sub to support the area.
- 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 June 2018.

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, a process for inclusion of new generation varies between different Planning Authorities.

A complete detailed listing of all new and upgraded generation projects included in the 2020 roll-up integration case is provided in Appendix C. Planning Authorities have agreed to the following terms to describe the status of future generation projects:

- Committed: The resource has completed the interconnection 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.

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

Duke Energy Carolinas
DEC generation facilities that are approved & budgeted or where construction has begun are included in the roll-up integration case. Non-DEC generation facilities that have a signed interconnection agreement are also included. DEC has included several new generation projects in the roll-up integration case. These are projects that Duke Energy is committed to building and has state approval for, or IPP's with a signed IA. The Duke units are Dan River combined cycle (620 MW), Buck combined cycle (620 MW) and Cliffside 6 fossil (825 MW). An IPP combustion turbine site has been included at Cleveland County (716 MW). All these facilities are presently under construction. Duke plans to retire all unscrubbed fossil units at Cliffside, Riverbend, Buck and Dan River by 2015, which total approximately 1300 MW. The 2020 roll-up integration case assumes the retirement of a number of small older Duke oil-fired combustion turbine facilities totaling about 250 MW by 2012.

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 2020 roll-up integration case is 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.

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 4900 MW of additional generation (as compared with 2010) are included in the FPL 2020 case. All of these projects have gone through the FPL System Impact Study process and are part of FPL's official resource plan. FPL's TYSP filing serves as an input for the generation and load assumptions for modeling purposes. FPL is required to maintain a reserve margin of 20%.

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

Independent Electricity System Operator

Ontario is planning to phase out coal-fired generation by the end of 2014. Through this initiative, approximately 6500 MW of generation will be removed from service. In response to the phase out, Ontario has procured over 6000 MW of gas-fired generation with approximately 1100 MW of the procured resources are still yet to come online in the next few years. In addition, together with the proposed transmission developments, over 7000 MW of renewable generation resources, including wind, solar, biomass, and hydro, are planned to come online and connect to the Ontario grid, These resources include sources in the Feed-in-Tariff (FIT) program, Ontario's agreement with the Korean Consortium, and other procurements by the Ontario Power Authority. These resource additions are anticipated to be online by the end of 2017, with further development still under planning assessments.

Unit	System	Announced Retirement Date
Lambton G1	Ontario	2010/10/01
Lambton G2	Ontario	2010/10/01
Lambton G3	Ontario	2014
Lambton G4	Ontario	2014
Nanticoke G1	Ontario	2014
Nanticoke G2	Ontario	2014
Nanticoke G3	Ontario	2010/10/01
Nanticoke G4	Ontario	2010/10/01
Nanticoke G5	Ontario	2014
Nanticoke G6	Ontario	2014
Nanticoke G7	Ontario	2014
Nanticoke G8	Ontario	2014
Atikokan G1	Ontario	2012 converts to biomass
Thunder Bay G1	Ontario	2014
Thunder Bay GS2	Ontario	2014
Thunder Bay GS3	Ontario	2014

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 one new wind farm, three natural gas combined cycle plants, and four different 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 is currently constructing a generation project within its service territory, consisting of two 150 MW natural gas-fired simple cycle combustion turbines, with a commercial operation date of summer 2011. JEA also has included in the roll-up integration case a "Proposed" project to convert these units to combined-cycle operation with the addition of heat recovery steam generators. JEA has obtained from the Florida Public Service

Commission a Certificate of Public Convenience and Necessity; however, a final approval for the conversion project is still pending Florida Cabinet approval. 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 2020 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 120 MW generator being built by a 3rd Party IPP at West Irvine by 2013. This unit is not dispatched in the 2020 EIPC roll-up integration case.

MAPPCOR

MAPP area transmission owners determine which generation facilities proposed or committed are added in a model during the model building process.

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 "SOCO" also include generation resources identified by MEAG.

Midwest ISO

Within the Midwest ISO, future generation resources modeled come from the Midwest ISO generation interconnection process and resource forecasts based on public policy requirements. Future generators with signed interconnection agreements are included in models. Future Proposed generators associated with public policies which are law (e.g. Renewable Portfolio Standards) are included at locations and in amounts consistent with the renewable energy zones agreed to by the Midwest ISO states via discussions with the Upper Midwest Transmission Development Initiative and the Midwest Governors Association. For the year 2020 roll-up peak load case, the amount of such Proposed generators dispatched in the case is 389 MW. These resources are listed as Proposed in Appendix C.

There are no publically announced retirements of generating units modeled in the Midwest ISO roll-up.

New Brunswick System Operator

In New Brunswick, generation retirements publicly announced in 2010 to 2020 period include:

- 5 MW at Musquash (January 2010)
- 57 MW at Grand Lake (March 2010)
- 299 MW at Dalhousie (March 2011)

New York ISO

The NYISO has included several new generation projects in its 2020 roll-up integration case. These are projects that have passed certain milestones to be included in the NYISO planning databases utilized in its Comprehensive Reliability Planning Process. Additionally, the model will represent the New York State

Renewable Portfolio Standard of 30% by 2015, which will require approximately 4,250 MW of installed nameplate wind turbine capability. Presently, there is approximately 1,300 MW of wind turbine power installed in New York. To meet the RPS goal, the case includes approximately 3,000 MW of proposed wind projects from the NYISO Interconnection Queue.

PJM Interconnection

Additional information on the PJM planning process is described in section 2.5. PJM is the independent planner and operator of the transmission system and power markets. 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 2020 roll-up integration case incorporates 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.

- Mid-Atlantic PJM included 500 MW of new generation with a signed ISA and 3,500 MW of projects with a signed facility study agreement.
- Western PJM included 1,000 MW of new generation with a signed ISA and 900 MW of projects with a signed facility study agreement. In addition, Catoctin generation was not modeled.
- Southern PJM included 500 MW of new generation with a signed ISA and 650 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-retirements.aspx .

PowerSouth Energy Cooperative

Resource assumptions contained within the 2020 roll-up integration case for PowerSouth were determined through power supply studies and our annual capacity planning process. PowerSouth has no "Committed" resources between 2010 and 2020. There is one "Proposed" resource needed to meet our forecasted load growth before 2020. 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 2010 and 2020.

Progress Energy Carolinas
PEC has included one new PEC generation project in the roll-up integration case at Richmond County Plant. In general new generation is included that PEC is committed to building and has state approval or IPP's with a signed interconnection agreement and firm transmission. PEC has recently announced plans to retire existing coal units at its Lee, Sutton, Weatherspoon, and Cape Fear coal plants. Retired generation will be replaced with combined cycle gas plants at Lee and Sutton Plants. These retirements are not reflected in the 2020 model.

Progress Energy Florida
PEF has included one new PEF generation project in the roll-up integration case at a new Levy County Plant site. In general new generation connected to the PEF is included in the model if the project is committed to by PEF or PEF customer. PEF has announced no plans to retire existing units prior to 2020, however, it has been announced that PEF will retire its Crystal River Coal Units 1 and 2 after the second unit at the Levy County site completes its first fuel cycle.

Santee Cooper
For the 2020 roll-up integration case, 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 includes all existing generating units in Santee Cooper system and assumes that there are no retirements of any type of generating units within Santee Cooper.

South Carolina Electric & Gas
Resource additions included in the 2020 roll-up integration case for SCE&G include committed generation projects that are under construction. 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; however, specific generating units have not been identified to date. A potential generator retirement option is modeled in the roll-up integration case where the outputs of these potential retirement units are set at zero MW.

Southern Company
Resource assumptions contained within the 2020 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 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 generation interconnection request projects that have a FERC filed IA (Interconnection Agreement). GI projects without an IA are not added to the models until the IA is executed. Generation projects without an IA are added as needed to address generation deficiencies.

Tennessee Valley Authority
Resource assumptions contained within the 2020 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. Evident in TVA's official capacity expansion plan is TVA's commitment for cleaner energy resources, filling base load requirements with Nuclear and peak load requirements with Gas expansion.

- In order to meet customer demand, TVA will complete construction on the 540 MW Lagoon Creek 2x1 Combined Cycle plant by October 2010. This project is currently Committed and under construction.

- By June 2012, TVA will complete construction on the 878 MW John Sevier 3x1 Combined Cycle plant. This project is currently Committed and under construction.

- By June 2013, TVA will complete construction on the 1204 MW Watts Bar Nuclear Unit 2. This project is currently Committed and under construction.

- By June 2018, TVA will complete construction on the 1192 MW Bellefonte Nuclear Unit. This project is currently Proposed and in TVA's capacity expansion plan.

2.8 Generation Dispatch Description

This section explains the methods used by each Planning Authority to dispatch the available generation in the 2020 roll-up integration case. 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
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.

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 Company
The dispatch of the generation resources contained within the 2020 roll-up integration case 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 2020 roll-up case reflects a typical generation dispatch 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 Working Group (TRAWG).

MEAG Power
The dispatch of the generation resources contained within the 2020 roll-up integration case to serve MEAG participant load is based upon the dispatch merit order identified in the resource projections

Midwest ISO
Midwest ISO members' generation is dispatched on a market-wide basis using security constrained economic dispatch (SCED) methodology. Renewable generation is set to desired level before applying the security constrained economic dispatch and renewable resources are not adjusted in the SCED process. Wind plants are dispatched at 5% of nameplate during summer peak condition.

New Brunswick System Operator
Generation in the New Brunswick Electricity Market is dispatched using security constrained economic dispatch (SCED) methodology. Wind resources are dispatched according to hour-ahead forecasts.

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 2020 roll-up integration case is economically dispatched according to current fuel cost assumptions and availability.

Progress Energy Carolinas
The PEC 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.

Progress Energy Florida
The PEF 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.

Santee Cooper
The Santee Cooper generation dispatch used in the 2020 roll-up integration case 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 2020 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 2020 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
- Fossil
- Pumped storage
- 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.

Section 3 Gap Analysis [This Section in Development]

Section 4 Inter-Area Enhancements [This Section in Development]

Section 5 Linear Transfer Analysis [This Section in Development]

Appendix A: Future Project Map [This Section in Development]

Appendix B: New/Upgraded Transmission Projects

This Appendix now exists as part of an attached Microsoft Excel workbook, along with the contents of Appendix C.

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

This Appendix now exists as part of an attached Microsoft Excel workbook, along with the contents of Appendix B.

Appendix D: Linear Transfer Analysis Results [This Section in Development]

Appendix E: Area Interchange Table

Duke Energy Carolinas

DEC Balancing Authority Area Imports:

To Area #	To Area		
353	SEHA	(SEPA)	-155
340	CPLE	(NCEMC#1)	-150
355	SETH	(SEPA)	-113
340	CPLE	(NCEMC/Anson)	-60
346	SOUTHERN	(Seneca)	-31
		TOTAL IMPORTS	-509

DEC Balancing Authority Area Exports:

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

TOTAL IMPORTS/EXPORTS **746 MW**

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

Entergy Services

ENTERGY ELECTRIC SYSTEM BALANCING AUTHORITY ("EES") AREA INTERCHANGE
Area (s) in the case that make up the EES: 351
EIPC 2020 Summer Future Year Study

Entergy Balancing Authority Area Scheduled Imports/Contract Purchases:

SWPA	1440190 (SPA - AECC)	-100 MW
SWPA	1448044 (SPA - Thayer)	-4 MW
SWPA	1602650 (SPA - BRAZOS)	-3 MW
AEPW	1084342 (AEPW - ETEC)	-50 MW
AEPW	AEPW Load on EES	-5 MW
OKGE	1348508 (OKGE - MDEA)	-10 MW
LAGN	569011 (Big Cajun - EES)	-242 MW
LAGN	851493 (Big Cajun - SMEPA)	-13 MW
LAGN	1477069 (Big Cajun - EES)	-10 MW
TVA	850239 (TVA - MEAM)	-19 MW
TVA	1096986 (TVA Load on EES)	-30 MW
TVA	1161925 (TVA - MDEA)	-11 MW
SMEPA	810234 (SMEPA - SMEPA load)	-642 MW
Total		**-1139 MW**

Entergy Balancing Authority Area Scheduled Exports/Contract Sales:

CELE	Toledo Bend	20 MW
504	LEPA 1461442 (Mury - LEPA)	12 MW
SWPA	759196 (Blakley - SPA)	143 MW
SWPA	1024194 (White Bluff - SPA)	81 MW
SWPA	1024198 (ISES - SPA)	163 MW
SWPA	1440189 (White Bluff - SPA)	85 MW
SWPA	73884558 (PLUM - SPA)	40 MW
AEPW	759294 (ISES - AEPW)	30 MW
MIPU	1460876 (Crossroads - MIPU)	75 MW
MIPU	1460878 (Crossroads - MIPU)	75 MW
MIPU	1460879 (Crossroads - MIPU)	75 MW
MIPU	1460881 (Crossroads - MIPU)	75 MW
EMDE	1340028 (Plum Point - EDE)	50 MW
EMDE	1340029 (Plum Point - EDE)	50 MW
AECI	1340019 (Plum Point - AECI)	35 MW
DERS	DERS - Other Resources	76.1 MW
DENL	1410022 (Plum Point - DENL)	60 MW
DENL	1498120 (Plum Point - DENL)	60 MW
DENL	DENL - Other Resources	85.2 MW
WESTMEMP	1381404 (ISES - WMUC)	17 MW
WESTMEMP	1381406 (White Bluff - WMUC)	17 MW
WESTMEMP	1470484 (Plum Point - WMUC)	20 MW

CONWAY	1381398 (White Bluff - CNWY)	34 MW
CONWAY	1381400 (ISES - CNWY)	34 MW
CONWAY	1498129 (Plum Point - CNWY)	50 MW
CONWAY	City of Conway - Other Resources	86.4 MW
BUBA	1498122 (Plum Point - BUBA)	30 MW
BUBA	City of Benton - Other Resources	63.5 MW
SMEPA	1139982 Grand Gul.f - SMEPA load)	125 MW
SMEPA	1406786 (Plum Point - SMEPA load)	100 MW
SMEPA	1408199 (Plum Point - SMEPA load)	100 MW
Total		**1967.2 MW**

Notes:

3. Positive interchange indicates an export
4. Negative interchange indicates an import

Independent Electricity System Operator

ONTARIO BALANCING AUTHORITY ("IESO") AREA INTERCHANGE
Area (s) in the case that make up the IESO: 103
EIPC 2020 Summer Future Year Study

IESO Balancing Authority Area Scheduled Imports/Contract Purchases:

IESO	ITCT	0 MW
Total		**0 MW**

IESO Balancing Authority Area Scheduled Exports/Contract Sales:

IESO	NYISO	0 MW
Total		**0 MW**

Total Net Interchange	**0 MW**

Notes:

1. The small flows observed at these interfaces are not scheduled

ISO New England

ERAG MULTIREGIONAL MODELING WORKING GROUP (ERAG MMWG)
INTERCHANGE DATA FOR 2009 SERIES LOAD FLOW BASE CASES

ISO-NE Area 101

REGION	From Area #	From Area Name	To Area #	To Area Name	Comments	Firm	*2020SUM*
NPCC	101	ISO-NE	102	NYISO	NYPA Hydro Contracts	x	-81.0
NPCC	101	ISO-NE	102	NYISO	Cross Sound HVDC Cable		330.0
NPCC	101	ISO-NE	104	TE	Highgate HVDC		-200.0
NPCC	101	ISO-NE	104	TE	Phase II HVDC		-1500.0
NPCC	101	ISO-NE	105	NB			-600.0
	101	**ISO-NE**			**NET SCHEDULE**		**-2051.0**

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 2020 Summer Future Year Study

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

TVA	SEPA Power	-62 MW
TVA	Warren Load on LGEE	-110 MW
BREC	BREC Load on LGEE	-11 MW
EKPC	EKPC Load on LGEE	-562 MW
DEM	DEM Load on LGEE	-6 MW
DEM	KMPA Load on LGEE	-100 MW
AMIL	KMPA Load on LGEE	-128 MW
OVEC	Clifty Creek Surplus	-163 MW
Total		**- 1,142 MW**

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

AEP	IMPA Trimble #1	66 MW
AEP	IMPA Trimble #2	94 MW
AMIL	IMEA Trimble #1	62 MW
AMIL	IMEA Trimble #2	89 MW
EKPC	LGEE Load on EKPC	130 MW
Total		**441 MW**

Total Net Interchange	**-701 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, 667, 680
EIPC 2020 Summer Future Year Study

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

OTP	Joint Owned Unit BSP II	-99.0
MRES	MRES Gen in OTP BA	-33.0
OTP	BIG STONE GENERATION	-110.0
OTP	COYOTE GENERATION	-40.0
MRES	MRES Gen in ALTW BA	-22.0
MEC	Neal #4	-31.0
MEC	Wisdom #2	-40.0
MRES	MRES Gen in XCEL BA	-18.0
MEC	NEAL 4 GENERATION	-55.0
MEC	WAPA(Harlan)/MEC LOUISA GEN	-6.0
MEAN	HCPD(WAPA)/MEAN WEC2- Intraregional	-61.0
NPPD	GEN (NPPD/WAPA) - Intraregional	-20.0
NPPD	NPPD Loads in NPPD BA (Reduction of WAPA Firm)	-4.0
WPS	75439243 Weston 4	-150.0
WPS	76288610 Weston 4	-14.0
Total		**-703 MW**

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

GRE	Supplemental Power	367.0
GRE	WAPA/GRE (CPA) #233493	86.0
GRE	WAPA/GRE (UPA) #233481	3.0
MPC	WAPA/MPC #1603	35.0
ALTW	WAPA/ALTW (CIPCO) #233579	12.0
MEC	Cornbelt	50.0
MEC	50 MW 7x16 -> 5/31/11	0.0
MEC	WAPA/MEC (CBPC) #233581	20.0
MEC	WAPA/MEC (Atlantic) #287697	8.0
MEAN	Redirect from Cooper	0.0
NPPD	Tri-State + Rushmore Co-supply	357.0
NPPD	HCPD(WAPA)/NPPD CNS- Intraregional	0.0

NPPD	WAPA/NPPD (F+P) #234276- Intraregional	436.0
NPPD	WAPA/NPPD (RMR) #345442- Intraregional	4.0
NPPD	WAPA/NPPD (LOUP) #251005- Intraregional	15.0
GRIS	WAPA/NPPD (GRIS) #224204- Intraregional	9.0
NPPD	LOAD (WAPA/NPPD) - Intraregional	86.0
NPPD	LES WAPA Firm Delivery	56.0
NPPD	LES WAPA Firm Peaking Delivery	54.0
OPPD	WAPA/OPPD #363404- Intraregional	82.0
OPPD	WAPA/OPPD Product K Agree- Intraregional	0.0
OPPD	LOAD (WAPA/OPPD) - Intraregional	22.0
LES	Laramie River Station	182.0
SUNF	WAPA/SUNF #286879- Intraregional	7.0
XEL		375.0
MP		250.0
WPS		500.0
XEL		4.0
GRE		172.0
Total		**3192 MW**

Total Net Interchange	**2,489 MW**

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

Midwest ISO

MIDWEST ISO BALANCING AUTHORITY ("Midwest ISO")
AREA INTERCHANGE
Areas in the case that make up the Midwest ISO: 28
EIPC 2020 Summer Future Year Study

Midwest ISO Balancing Authority Area Scheduled Imports/Contract Purchases:

MISO Area	Other Area	Comments	Purchases
ALTE	CE	76672473, PJM 403520.2	-140 MW
ALTW	CE	PJM 340493, 340502, 502025	-264 MW
ALTW	WAPA	WAPA/ALTW (CIPCO) #233579	-12 MW
AMIL	AECI	Mt. Pleasant #1180678	-4 MW
AMIL	EEI	Ameren share EEI CTG's	-70 MW
AMIL	EEI	Ameren CTG's in EEI (3x55 MW)	-165 MW
AMIL	EEI	GF Ameren Share Joppa	-1000 MW
AMIL	LGEE	IMEA-Trimble 1	-62 MW
AMIL	LGEE	IMEA-Trimble 2	-89 MW
AMMO	AECI	City of Rolla, Entitlements	-54 MW
AMMO	ENTERGY	392740 (White Bluff - AMRN)	-160 MW
CIN	NYISO		-7 MW
CWLD	KACY	(Kansas) BPU	-20 MW
CWLD	KAPL	KCPL	-20 MW
CWLD	SWPA	Fulton-Hydro.	-3 MW
CWLD	SWPA	Fulton-Sikston.	-11 MW
CWLD	SWPA	Sikston Only.	-66 MW
DEM	AEP	Buckeye	-73 MW
DEM	AEP	CCD-Conesville	-312 MW
DEM	DAY	Killen	-198 MW
DEM	DAY	Stuart 1-4	-912 MW
DEM	OVEC	Surplus	-180 MW
FE	AEP	CPP/AMPO/Gorsuch	-10 MW
FE	AEP	AMPO-Belleville	-38 MW
FE	AEP	CPP/AMPO/AMPGS (Virtual)	-80 MW
FE	AEP	AMPO-Gorsuch	-132 MW
FE	AEP	Buckeye-OE	-213 MW
FE	AEP	AMPO-Virtual (AMPGS)	-440 MW
FE	NYPP	AMPO-NYPA	-83 MW
FE	OVEC	Surplus	-230 MW
GRE	BEPC	Supplemental Power	-367 MW
GRE	DPC		-172 MW
GRE	WAPA	WAPA/GRE #233481	-3 MW
GRE	WAPA	WAPA/GRE #233493	-86 MW

MISO Area	Other Area	Comments	Purchases
HE	AEP	VIRTUAL	-1000 MW
MEC	BEPC	Basin Allocation to CBPC	-50 MW
MEC	CE	MEC Share of QCNS	-449 MW
MEC	WAPA	WAPA/MEC (Atlantic) #287697	-8 MW
MEC	WAPA	WAPA Allocation to CBPC #233581	-20 MW
METC	AEP	AMPO-Virtual (AMPGS) (CONS)	-152 MW
MGE	CE	72765702 Kendall, PJM 412941.22	-50 MW
MP	MH	Term Sheet	-250 MW
NIPS	AEP	NIPS-Virtual	-200 MW
SIGE	OVEC	Surplus	-30 MW
SIPC	TVA	(SEPA)	-28 MW
WEC	CE	76743102 WPPI	-10 MW
WEC	CE	72850702 WPPI (Kendall)	-25 MW
WEC	CE	72850706 WPPI (Kendall)	-25 MW
WEC	CE	75285088 WPPI	-30 MW
WEC	CE	PJM #276594.6	-90 MW
WPS	MH	76703671 in study status	-500 MW
XEL	DPC	Remote generation	-4 MW
XEL	MH	#76703494	-375 MW
XEL	OPPD	CMMPA purchase from NC2	-3 MW
XEL	OPPD	CMMPA purchase from NC2	-11 MW
		Total Purchases	**-8986 MW**

Midwest ISO Balancing Authority Area Scheduled Exports/Contract Sales:

MISO Area	Other Area	Comments	Sales
AMIL	AEP	Amp-Ohio	117 MW
AMIL	AP	Amp-Ohio	1 MW
AMIL	CE	Clinton Generation	1045 MW
AMIL	CE	St. Charles-IMEA	90 MW
AMIL	CE	Winnetka	43 MW
AMIL	CE	Rock Falls	25 MW
AMIL	DAY	Amp-Ohio	66 MW
AMIL	LGEE	KMPA	128 MW
DEM	AEP	CCD-Zimmer	330 MW
DEM	AEP	CCD-Beckjord	52 MW
DEM	AEP	WVPA-AKSTEEL	37 MW
DEM	DAY	Zimmer	365 MW
DEM	DAY	Beckjord 6	207 MW
DEM	DAY	East Bend 2	186 MW
DEM	DAY	Miami Fort 7	180 MW
DEM	DAY	Miami Fort 8	180 MW
DEM	LGEE	KMPA	100 MW

MISO Area	Other Area	Comments	Sales
DEM	LGEE	HE-Bridgeport	6 MW
HE	AEP	HE-Drewersburg, HE-Hunstville on AEP	10 MW
HE	AEP	Lynn MP, Winchester MP, Modoc MP	6 MW
MEC	BEPC	Basin Share of Wisdom CT #2	40 MW
MEC	BEPC	NIPCO Share of Neal 4	31 MW
MEC	LES	CB3 to LES	50 MW
MEC	LES	CB4 to LES	50 MW
MEC	NWPS	NWPS Share of Neal 4	55 MW
MEC	WAPA	Harlan (WAPA) Share of Louisa	6 MW
MP	MPC	MPC Share Young 2	227 MW
OTP	MRES	BIG STONE II	99 MW
OTP	NWPS	Big Stone Generation	110 MW
OTP	NWPS	Coyote Generation	40 MW
SIGE	AEP	Cannelton	20 MW
SIGE	DAY	Cannelton	10 MW
WPS	DPC	75439243 Weston 4	150 MW
WPS	DPC	76288610 Weston 4	14 MW
		Total Sales	**4076 MW**

Total Net Interchange **-4,911 MW**

Notes:

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

New York ISO (NYISO)

ERAG MULTIREGIONAL MODELING WORKING GROUP (ERAG MMWG)
INTERCHANGE DATA FOR 2009 SERIES LOAD FLOW BASE CASES

NYISO Area 102

REGION	From Area #	From Area Name	To Area #	To Area Name	Comments	Firm	*2020SUM*
NPCC	102	NYISO	225	PJM	NJ Co-ops	x	17.0
NPCC	102	NYISO	225	PJM	PA Co-ops	x	50.0
NPCC	102	NYISO	225	PJM	Neptune HVDC		-685.0
NPCC	102	NYISO	225	PJM	VFT		-330.0
NPCC	102	NYISO	225	PJM	RECO Supply	x	-599.0
	102	NYISO	225	PJM	Subtotal		-1547.0
NPCC	102	NYISO	226	PENELEC	Net PJM-NYSEG		-750.0
NPCC	102	NYISO	226	PENELEC	NYSEG al PENELEC	x	-36.0
	102	NYISO	226	PENELEC	Subtotal		-786.0
NPCC	102	NYISO	237	RECO	RECO Load	x	599.0
NPCC	102	NYISO	202	FE		x	83.0
NPCC	102	NYISO	205	AEP		x	18.0
NPCC	102	NYISO	208	CIN		x	7.0
NPCC	102	NYISO	209	DPL		x	2.3
NPCC	102	NYISO	101	ISO-NE		x	81.0
NPCC	103	NYISO	102	ISO-NE	Cross Sound Cable		-330.0
NPCC	102	NYISO	104	TE			-1200.0
NPCC	102	NYISO	107	CORNWALL			0.0
	102	**NYISO**			**NET SCHEDULE**		**-3072.7**

PJM Interconnection

From Area	To Area	Interchange	Firm?	Comment
AEP	NYISO	-18.0	x	AMPO-NYPA
AEP	OVEC	-1229.0	x	Surplus
AEP	HE	-10.0	x	HE-D&H Load
AEP	HE	-6.0	x	HE-L&W&M Load
AEP	HE	1000.0		Virtual
AEP	DEM	73.0	x	Buckeye
AEP	DEM	-37.0	x	WVPA-AKSTEEL
AEP	DEM	312.0	x	CCD-Conesville
AEP	DEM	-52.0	x	CCD-Beckjord
AEP	DEM	-330.0	x	CCD-Zimmer
AEP	DEM	0.0		Virtual
AEP	SIGE	0.0		Virtual
AEP	SIGE	-20.0	x	Cannelton
AEP	NIPS	200.0		NIPS-Virtual
AEP	METC	152.0		AMPO-Virtual (AMPGS) (CONS)
AEP	EKPC	0.0		Peaking
AEP	CPLE	100.0	x	NCEMC-1
AEP	CPLE	100.0	x	NCEMC-2
AEP	AMIL	-117.0	x	AMPO-Prairie State
AEP	LGEE	-66.0	x	IMPA-Trimble-1
AEP	LGEE	-94.0	x	IMPA-Trimble-2
AEP	AEPW	250.0	x	Merger
AP	AMIL	-1.0	x	Amp-Ohio
AP	OVEC	-70.0	x	Surplus
CE	ALTW	65.0	x	PJM#502025
CE	ALTW	149.0	x	PJM#340502
CE	ALTW	50.0	x	PJM#340493
CE	AMIL	-90.0		St. Charles
CE	AMIL	-43.0		Winnetka
CE	AMIL	-25.0		Rock Falls
CE	AMIL	-1045.0		Clinton Output
CE	WEC	0.0	x	PJM #276592.5
CE	WEC	90.0	x	PJM #276594.6
CE	ALTE	140.0	x	PJM 403520.2
CE	MGE	50.0	x	PJM 412941.22
CE	MEC	449.0	x	25% Quad Cities

CE	GRE	0.0	x	PJM 847949
DAY	OVEC	-98.0	x	Surplus
DAY	DEM	-207.0	x	Beckjord 6
DAY	DEM	-180.0	x	Miami Fort 7
DAY	DEM	-180.0	x	Miami Fort 8
DAY	DEM	-186.0	x	East Bend 2
DAY	DEM	-365.0	x	Zimmer
DAY	DEM	912.0	x	Stuart 1-4
DAY	DEM	198.0	x	Killen
DAY	NYPP	-2.3	x	AMPO-NYPA
DAY	AMIL	-66.0	x	Amp-Ohio
DAY	SIPC	0.0	x	AMPO-Smithland (SERC)
DAY	SIGE	-9.5	x	AMPO-Cannelton
DVP	CPLE	-182.0	x	NCEMPA
DVP	CPLE	95.0	x	SEPA-KERR
DVP	CPLE	-10.0	x	Littleton
DVP	DUKE	-100.0	x	NCEMC
FE	OVEC	-230.0	x	Surplus
FE	SIGE	-45.7	x	AMPO-Cannelton
FE	AMIL	-112.1	x	AMPO-Praire State
FE	DEM	0.0	x	AMPO-Barclays
FE	DEM	0.0	x	Integrys Purchase
FE	DEM	0.0	x	AMPO-Barclays
FE	ITC	-296.0	x	Sumpter
FE	NYPP	-83.0	x	AMPO-NYPA
PENELEC	NYISO	750.0		Net MAAC-NYCA
PENELEC	NYISO	36.0	x	NYSEG al PENELEC
PJM	NYISO	-17.0	x	NJ Co-ops
PJM	NYISO	-50.0	x	PA Co-ops
PJM	NYISO	599.0	x	RECO Supply
PJM	NYISO	685.0	x	Neptune
PJM	NYISO	330.0	x	VFT
PJM	CPLE	-47.0	x	(PJM-Cravenwood)
RECO	NYISO	-599.0	x	RECO Load
Total Net Interchange:		466.4		

PowerSouth Energy Cooperative

POWERSOUTH PLANNING AUTHORITY ("PPA") AREA INTERCHANGE
Area (s) in the case that make up the PPA: 350
EIPC 2020 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	-125 MW
SOCO	Purchase from SH LFG	-5 MW
SOCO	Purchase from Yellow Pine	-30 MW
Total		- 541 MW

PowerSouth Planning Authority Area Scheduled Exports/Contract Sales:

SOCO	PowerSouth load on SOCO + Losses	1174 MW
SMEPA	SEPA – PS - SMEPA	68 MW
Total		1242 MW

Total Net Interchange 701 MW

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

Progress Energy Carolinas

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

CPLW	Transfer	-150 MW
Duke	Broad River	-850 MW
Duke	NCEMC/CNS	-105 MW
Duke	NCEMC#2	-100 MW
Duke	PEC-Rowan	-150 MW
DVP	SEPA-Kerr	-95 MW
AEP	NCEMC	-100 MW
AEP	NCEMC#2	-100 MW
Total		**- 1,650 MW**

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

Duke	NCEMC	150 MW
Duke	NCEMC/Anson	60 MW
DVP	NCEMPA	182 MW
DVP	Littleton	10 MW
PJM	Cravenwood	47MW
Total		**449 MW**
Total Net Interchange-CPLE		**-1,201 MW**

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

TVA	SEPA	-1 MW
Total		**-1 MW**

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

CPLE	Transfer	150 MW
Total		**150 MW**
Total Net Interchange-CPLW		**149 MW**

Notes:

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

Progress Energy Florida

Progress Energy Florida (PEF) Balancing Authority Scheduled Imports/Contract Purchases:

Southern	PEF	Firm	-424 MW
FRCC	PEF	Firm (Intra-FRCC)	-3464 MW
Total			**- 3,888 MW**

Progress Energy Florida (PEF) Balancing Authority Scheduled Exports/Contract Sales:

Total	**0 MW**
Total Net Interchange-PEF	**-3,888 MW**

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

Santee Cooper

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
DETAILED INTERCHANGE
EIPC 2020 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	15 MW
SCE&G	Woodland Hills	16 MW
SCE&G	NHEC	19 MW
Total		**50 MW**

Total Net Interchange **-1,595 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 2020 Summer Future Year Study

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

SEPA	Thurmond Dam	-22 MW
SCPSA	Charleston Navy	-15 MW
SCPSA	Woodland Hills Load on SCE&G	-16 MW
SCPSA	NHEC Load on SCE&G	-19 MW
Total		**- 72 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		**1,298 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 2020 Summer Future Year Study

Southern Balancing Authority Area Scheduled Imports/Contract Purchases:

SEPA	Hartwell Dam	-280 MW
SEPA	Russell Dam	-258 MW
SEPA	Thurmond Dam	-143 MW
TVA	TVA Load on Southern	-187 MW
PowerSouth	PowerSouth Load on Southern	-1174 MW
SMEPA	SMEPA Load on Southern	-158 MW
Total		**- 2,200 MW**

Southern Balancing Authority Area Scheduled Exports/Contract Sales:

Duke	City of Seneca	31 MW
TVA	Southern Load on TVA	139 MW
PowerSouth	SEPA Sales to PowerSouth	100 MW
PowerSouth	SEPA Sales to SMEPA via PowerSouth	68 MW
PowerSouth	SEPA Preferred Customers	99 MW
PowerSouth	Plant Miller Ownership	114 MW
PowerSouth	PowerSouth Purchase from SH LFG	5 MW
PowerSouth	PowerSouth Purchase from MEAG	125 MW
PowerSouth	PowerSouth Purchase from GTC	30 MW
SMEPA	SMEPA Purchase	152 MW
FPL	Sum of Point to Point Transactions	930 MW
FPL	Scherer #4 Ownership	649 MW
FPL	GTC to FPL	13 MW
FPC	Sum of Point to Point Transactions	424 MW
JEA	Sum of Point to Point Transactions	206 MW
JEA	Scherer #4 Ownership	201 MW
Total		**3,286 MW**

Total Net Interchange **1,086 MW**

Notes:
2. Positive interchange indicates an export
3. 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
EIPC 2020 Summer Future Year Study

TVA Balancing Authority Area Scheduled Imports/Contract Purchases:

SOCO	SOCO Load	-139 MW
Total :		**-139 MW**

TVA Balancing Authority Area Scheduled Exports/Contract Sales:

CPLW	SEPA	1 MW
SOCO	TVA Load	187 MW
LGEE	SEPA	62 MW
LGEE	TVA Load	110 MW
BREC	SEPA	190 MW
EKPC	SEPA	100 MW
SIPC	SEPA	28 MW
SMEPA	SEPA	51 MW
EES	TVA Load	30 MW
EES	SEPA to MEAM	19 MW
EES	SEPA to MDEA	11 MW
Total :		**789 MW**

Total Net Interchange **650 MW**

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