NERC

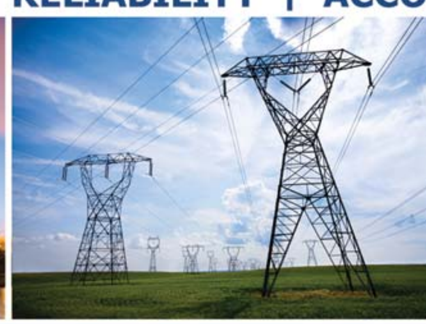
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Seasonal Assessment

Methods and Assumptions

DRAFT

RELIABILITY | ACCOUNTABILITY



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Preface and NERC Mission

The North American Electric Reliability Corporation (NERC) has prepared the following assessment in accordance with the Energy Policy Act of 2005, in which the United States Congress directed NERC to conduct periodic assessments of the reliability and adequacy of the bulk power system of North America.[1,2] NERC operates under similar obligations in many Canadian provinces, as well as a portion of Baja California Norte, México.

The North American Electric Reliability Corporation (NERC) is an international regulatory authority established to evaluate reliability of the bulk power system in North America. NERC develops and enforces reliability standards; assesses reliability annually via a 10-year assessment, and winter and summer seasonal assessments; monitors the bulk power system; and educates, trains, and certifies industry personnel. NERC is the Electric Reliability Organization for North America, subject to oversight by the U.S. Federal Energy Regulatory Commission (FERC) and governmental authorities in Canada.[3]

FRCC	Florida Reliability Coordinating Council
MRO	Midwest Reliability Organization
NPCC	Northeast Power Coordinating Council
RFC	ReliabilityFirst Corporation
SERC	SERC Reliability Corporation
SPP RE	Southwest Power Pool Regional Entity
TRE	Texas Reliability Entity
WECC	Western Electric Coordinating Council

NERC assesses the reliability and adequacy of the North American bulk power system, which is divided into several assessment areas within and across the eight Regional Entity boundaries, as shown in the map and corresponding table above. The users, owners, and operators of the bulk power system within these areas account for virtually all the electricity supplied in the United States, Canada, and a portion of Baja California Norte, México.

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[1] H.R. 6 as approved by of the One Hundred Ninth Congress of the United States, the Energy Policy Act of 2005: http://www.gpo.gov/fdsys/pkg/BILLS-109hr6enr/pdf/BILLS-109hr6enr.pdf

[2] The NERC Rules of Procedure, Section 800, further detail the Objectives, Scope, Data and Information requirements, and Reliability Assessment Process requiring annual seasonal and long-term reliability assessments.

[3] As of June 18, 2007, the U.S. Federal Energy Regulatory Commission (FERC) granted NERC the legal authority to enforce Reliability Standards with all U.S. users, owners, and operators of the bulk power system, and made compliance with those standards mandatory and enforceable. In Canada, NERC presently has memorandums of understanding in place with provincial authorities in Ontario, New Brunswick, Nova Scotia, Québec, and Saskatchewan, and with the Canadian National Energy Board. NERC standards are mandatory and enforceable in British Columbia, Ontario, New Brunswick, and Nova Scotia. NERC has an agreement with Manitoba Hydro making reliability standards mandatory for that entity, and Manitoba has adopted legislation setting out a framework for standards to become mandatory for users, owners, and operators in the province. In addition, NERC has been designated as the "electric reliability organization" under Alberta's Transportation Regulation, and certain reliability standards have been approved in that jurisdiction; others are pending. NERC and NPCC have been recognized as standards-setting bodies by the Régie de l'énergie of Québec, and Québec has the framework in place for reliability standards to become mandatory and enforceable in that jurisdiction.

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ERCOT

Assessment Area Description

The purpose of this section is to present summer 2012 projections for the reliability, resources, demand, and transmission infrastructure in the ERCOT Assessment Area. Data has been collected from individual entities and aggregated using a bottom-up approach with projections based on economic indicators, weather forecasts, and historical load data.

The ERCOT Region is an electric interconnection located entirely in the state of Texas and operated as a single Balancing Authority and Reliability Coordinator area. The reserve margins for the ERCOT Assessment Area are based on Anticipated or Prospective Resources.

Planning Reserve Margins

ERCOT conducts a study to determine a Target Reserve Margin (Reference Margin Level) on a biennial basis. This study includes assessment of generator outage data, load volatility due to weather variations, and output from variable generation to determine the minimum amount of resources required to achieve acceptable levels of system reliability. A description of the most recent analysis and development of the Target Reserve Margin for the ERCOT Region is provided in the report: 2010 ERCOT Target Reserve Margin Study (dated November 1, 2010).[4] An updated study of Target Reserve Margin requirements in the ERCOT Region is being conducted, but the results of this study are not expected to be available prior to the 2012 summer season.

The ERCOT minimum Target Reserve Margin, referred to as the Planning Reserve Margin in ERCOT documentation, of 13.75 percent is based on Loss-of-Load Events (LOLEv) analysis of no more than 0.1 events per year based on an updated probabilistic study completed in 2010.[5]

The Target Reserve Margin is determined using a Monte Carlo Loss-of-Load Probability (LOLP) approach and the industry-standard 1 day in 10 years criteria to determine the appropriate minimum ratio of resources to forecasted loads. This study reflects the availability of all resources within the ERCOT Interconnection, including Existing, Certain, and Future Planned (i.e., generation with signed contracts for transmission service) generation and transmission-connected behind-the-meter generation. Loads used in the study are derived from actual historical weather conditions.

The Target Reserve Margin is reviewed by the ERCOT Board of Directors based on the results of the LOLP studies conducted by ERCOT. The current Target Reserve Margin TRM for the ERCOT Region, 13.75 percent, was established by the ERCOT Board of Directors in November, 2010.

Demand

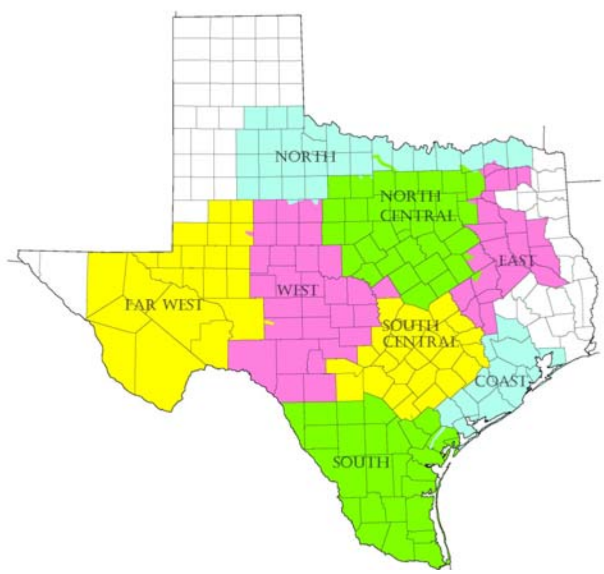
[4] http://www.ercot.com/content/meetings/board/keydocs/2010/1116/Item_07_-_2010_Loss_of_Load_Events_(LOLEV),_Target_Reserve_M.zip

[5] http://www.ercot.com/content/meetings/board/keydocs/2010/1116/Item_07_-_2010_Loss_of_Load_Events_(LOLEV),_Target_Reserve_M.zip

The ERCOT Load Forecast development process is described in the document: 2012 Long-Term Demand and Energy Forecast (2012 LTDEF) (dated December 31, 2011).[6] The 2012 LTDEF for the ERCOT Region is presented in the report, including the methodology, assumptions, and data used in creating the forecast. The forecast is based on a set of econometric and neural network models describing the hourly load in the Region as a function of certain economic (e.g., non-farm payroll employment) and weather variables (e.g., heating and cooling degree days). Economic and demographic data, including a county-level forecast, are obtained on a monthly basis from Moody's Economy.com. Historical monthly economic and demographic data for each county are provided back to 1990. A minimum of 15 years of historical weather data (e.g., hourly dry-bulb temperature, wind speed, and cloud cover) were provided by Telvent/DTN for 20 weather stations in ERCOT.

ERCOT is a summer-peaking region. The average weather profile (50/50) is used for the ERCOT load forecast. The economic factors which drive the load forecast include per capita income, population, gross domestic product (GDP), and various employment measures that include non-farm employment and total employment as described in the 2012 LTDEF. The actual demands used for forecasting purposes are coincident hourly values across the ERCOT Region. The data used in the forecast is differentiated by weather zones shown in Figure 1.

Figure 1: ERCOT Weather Zones



The forecasted peak demands are produced by the ERCOT ISO for the entire ERCOT Region, which is a single Balancing Authority area, based on the Region-wide actual demands. While the forecasted peak demands produced using the average weather profile are used for resource assessments, alternative weather scenarios are used to develop extreme weather load forecasts to assess the impact of weather variability on the peak demand for ERCOT. One scenario is the one-in-ten-year occurrence of a weather event. This scenario is calculated using the 90th percentile of the temperatures in the database spanning

[6] http://www.ercot.com/content/news/presentations/2012/2012%20Long-Term%20Hourly%20Peak%20Demand%20and%20Energy%20Forecast.pdf

the last fifteen years. These extreme temperatures are input into the load-shape and energy models to obtain the forecasts. The extreme temperature assumptions consistently produce demand forecasts that are approximately 2 to 5 percent higher than the forecasts based on the average weather profile (50/50) for the summer season. Together, the forecasts from these temperature scenarios are usually referred to as 90/10 scenario forecasts.

Demand-Side Management

A 2007 Texas state law[7] mandated that at least 20 percent of an investor-owned utility's (IOU's) annual growth in electricity demand for residential and commercial customers shall, by December 31, 2009, be met through energy-efficiency programs each year. The IOUs are required to administer energy-savings incentive programs, which are implemented by retail electric and energy efficiency service providers.

Recently Texas Senate Bill 1125[8] was passed. This Bill set an Energy Efficiency requirement of 0.4 percent of residential and commercial peak demand. It was assumed that half of the Energy Efficiency target from Senate Bill 1125 was already reflected in the load forecast due to review of historical program implementation. Therefore, ERCOT forecasts values of Energy Efficiency as 0.2 percent of the residential and commercial annual peak demand.

In general, utility savings, as measured and verified by an independent contractor, have exceeded the goals set by the utilities.[9] In the latest assessment, utility programs implemented after electric utility industry restructuring in Texas had produced 1,666 MW of peak demand reduction and 4,110 GWh of electricity savings for the years 1999 through 2010.[10] This demand reduction is accounted for within the load forecast and only the expected incremental portion for the coming year, 119 MW, is included as a demand adjustment for the summer season.

There are two controllable load programs administered by ERCOT: Load Resources and Emergency Interruptible Load Service (EILS). EILS is counted on as Demand-Side Contractually Interruptible Demand. The first, Load Resources, is currently limited in participation to 1,150 MW[11] and serves as part of the system-wide procurement of the Responsive Reserve Ancillary Service.[12] These resources are listed as a Demand-Side Load as a Capacity Resource. The second, EILS are controllable loads that are contractually obligated to deploy in the event of notification by ERCOT during system emergency conditions. These resources are listed as Demand-Side Contractually Interruptible Demand.

These resources are monitored using after-the-fact metering and are subject to payment reductions and suspension from the program for failing to meet availability requirements. Both Load Resources and EILS

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7 http://www.capitol.state.tx.us/tlodocs/80R/billtext/html/HB03693F.htm

8 http://www.capitol.state.tx.us/tlodocs/82R/billtext/html/SB01125F.htm

9 http://www.texasefficiency.com/report.html

10 http://www.texasefficiency.com/files/EUMMOT_EEIP_June_2011.pdf

11 There are efforts to change this number and the overall Responsive Reserve Service procured by ERCOT prior to Summer 2012

12 The limit on LRS participation is in the process of being revised due to the increased overall procurement of responsive reserves. See http://www.ercot.com/content/mktrules/issues/nprr/426-450/434/keydocs/434NPRR-12_Board_Report_022112.doc for more information.

products are subject to annual unannounced load-shed testing, to be followed by an additional test if the first is unsuccessful. A second consecutive unsuccessful test subjects the resource to suspension. Measurement and verification procedures for these programs are defined in the Performance Monitoring section of the ERCOT Protocols.[13]

There are no restrictions on the number of deployments in a day for Load Resources procured in the day-ahead Ancillary Services market. EILS Loads are procured for four-month contract periods and are limited to a maximum of eight hours of deployments over those months – with the stipulation that the EILS Loads may not return to service until released by ERCOT operations.

In addition, there are several demand response programs administered by transmission service providers, municipal authorities, and cooperative electric utilities. ERCOT is working with these organizations to better coordinate the utilization of these programs during hours of scarcity to maximize the overall system benefit.

A 2007 Texas state law[14] mandated that at least 20 percent of an investor-owned utility's (IOU's) annual growth in electricity demand for residential and commercial customers shall, by December 31, 2009, be met through energy-efficiency programs each year. The IOUs are required to administer energy-savings incentive programs, which are implemented by retail electric and energy efficiency service providers. Some of these programs, offered by the utilities, are designed to produce system peak demand reductions and energy consumption savings and include the following: Commercial and Industrial, Residential and Small Commercial, Hard-to- Reach, Load Management, Energy Efficiency Improvement Programs, Low Income Weatherization, Energy Star (New Homes), Air Conditioning, Air Conditioning Distributor, Air Conditioning Installer Training, Retro-Commissioning, Multifamily Water & Space Heating, Texas SCORE/City Smart, Trees for Efficiency, and Third Party Contracts.

Generation

ERCOT works with owners of behind-the-meter generation to ensure that the loads and generation resources associated with these facilities are appropriately included in the system-wide planning models. However, it has been difficult in the past to determine the likely contribution of these resources (i.e., the net of load and generation) in the event of system scarcity conditions and resulting high interval pricing (at or near the system maximum price). In other words, it has not been apparent how price sensitive these parties will be, in aggregate. ERCOT has routinely surveyed behind-the-meter resource owners and used their responses to develop an estimate of likely contribution of behind-the-meter generation during system peak conditions.

The number of scarcity hours resulting from the extreme heat conditions during the peak season of 2011 afforded an unprecedented opportunity to assess the price sensitivity of these behind-the-meter resources through analysis of operational results. Analysis of the highest 60 hours of demand indicated

13 http://www.ercot.com/content/mktrules/nprotocols/current/08-020111_Nodal.doc

14 http://www.capitol.state.tx.us/tlodocs/80R/billtext/html/HB03693F.htm

an expected net generation of 4,390 MW from behind-the-meter resources. This capacity is included in the most recent assessments of resource reserves in ERCOT. In the future, ERCOT will survey behind-the-meter resource owners to determine if their capability to support the system has increased or decreased from where it was in the summer of 2011 based on operational results; the results of these surveys will be used as an incremental change from the operational results seen from summer 2011.

ERCOT tracks resources from the initial request for a screening study as part of the interconnection process, through unit operation, to unit idling (mothball status) and retirement. At each step in this process, market protocols require that ERCOT be notified of unit status changes. Using these notifications, ERCOT maintains a database of interconnected resources, specifying certain units as: Future Planned (not yet operational but with a signed contract to take transmission level service); Future-Other (in the interconnection study process); Existing-Certain (operational units); and Existing-Inoperable (mothball status).

ERCOT assesses the effective load carrying capability (ELCC) of wind resources as part of the biennial Loss-of-Load Probability study process. The variability of wind resources (based on experienced weather conditions over a 15-year period) is included in the probabilistic analysis of this study. Following completion of the model inputs, the loss-of-load risk associated with expected resources and expected loads is calculated. As a next step, all of the wind resources are removed from the model (resulting in an increase of loss-of-load expectation because these variable resources are providing some system benefit.) Additional dispatchable generation, modeled as a capacity-weighted average of fleet-wide reliability, is then added into the resource model input until the loss-of-load expectation returns to the level seen with the wind resources included. The resulting additional dispatchable capacity added to the model input is then considered to have the equivalent load-carrying capability as the wind resources included in the model, and a ratio of the two is calculated. The ELCC of wind was determined to be 8.7 percent of wind installed capacity based on a 2007 study. The 2010 LOLEv Study[15] updated the ELCC calculation to 12.2 percent, but ERCOT did not adopt the revised ELCC for use in reserve margin calculations.

The ELCC of wind generation is determined as part of the evaluation of the Target Reserve Margin for the ERCOT Region. Using a Loss-of-Load Probability Monte Carlo model, the reliability impacts of wind generation are compared to average dispatchable generation capacity of the ERCOT fleet to determine the ratio of wind reliability benefits to that of a thermal unit.

Previously there has not been sufficient quantity of solar resources in ERCOT to warrant an in-depth analysis of the ELCC of solar generation. ERCOT plans to conduct an initial assessment of the ELCC of solar resources following completion of the current LOLP analysis.

In the ERCOT Region, independent generator owners and operators are responsible for their own fuel supply and transportation arrangements. In addition, ERCOT is a member of the Texas Energy Reliability

[15] http://www.ercot.com/content/meetings/board/keydocs/2010/1116/Item_07_-_2010_Loss_of_Load_Events_(LOLEV),_Target_Reserve_M.zip

Council; this group coordinates between the gas and electric industries and, if necessary, allocates deliveries of natural gas during periods of high demand. In the event of forecasted extreme weather and possible fuel curtailments, ERCOT may request fuel capability information from entities that represent generation to prepare operationally for potential curtailments.

Capacity Transactions

The ERCOT Region is a separate interconnection with only asynchronous ties to SPP and Mexico's Comisión Federal de Electricidad (CFE) and does not share reserves with other regions. There are two asynchronous ties between ERCOT and SPP with a total of 820 MW of transfer capability and three asynchronous ties between ERCOT and Mexico with a normal total of 280 MW of transfer capability.

The ERCOT Region does not rely on external resources to meet demand under normal operating conditions; however, under emergency support agreements, it may request external resources for emergency services over the asynchronous ties or by block transfer of discrete loads.

Transmission

ERCOT conducts mid-term transmission planning per relevant NERC Reliability Standards, ERCOT Protocols, and ERCOT Planning Guides[16]. ERCOT coordinates this planning process with transmission service providers and with other market participants through an open Regional Planning process. A Five-Year Transmission Plan is developed on an annual basis which includes an evaluation of system reliability needs and assessment of expected system congestion and recommendations for transmission system improvements. Completion of required system upgrades are then coordinated with the appropriate transmission service providers. Transmission projects included in the Five-Year Transmission Plan are listed on the ERCOT Planning and Operations Information web-site (Note: site registration is required). A Constraints and Needs Report, which documents the Five-Year Planning process is also developed on an annual basis.[17]

The Five-Year Transmission Plan includes a steady-state voltage analysis of the ERCOT system for upcoming summer season. Bus voltages are checked for NERC Category A and B contingency conditions. Results from previous voltage stability studies on expected summer network conditions have indicated that the interconnection system has sufficient voltage stability margin when tested with NERC Category A, B and selected C contingencies.

In the Operating horizon, reactive margins are maintained in the major metropolitan areas. Areas of dynamic and static reactive power limitations are Corpus Christi, Houston, Dallas/Fort Worth, Rio Grande Valley, South to Houston generation, South to Houston load, North to Houston generation and North to Houston load. Operating Procedure Manual for the Transmission and Security Desk[18],

[16] http://www.ercot.com/mktrules/guides/planning/

[17] http://www.ercot.com/content/news/presentations/2012/2011%20Constraints%20and%20Needs%20Report.pdf

[18] http://www.ercot.com/mktrules/guides/procedures

Procedure 2.4.3, Voltage Security Assessment Tool, describes the procedure to monitor the system and to prevent voltage collapse using an online voltage stability analysis tool.

The PUCT completed its Competitive Renewable Energy Zone (CREZ)[19] transmission plan in 2008, resulting in bulk transmission being built in west Texas to provide solutions to existing and potential congestion and to enable the installation of more renewable generation in west Texas. All CREZ lines are expected to be in service by the end of 2013. Beyond adding new transmission for CREZ, ERCOT and the Transmission Service Providers are also developing coordinated plans for reactive power control strategies in those regions.

[19] http://www.texascrezprojects.com/default.aspx

FRCC

Planning Reserve Margins

The FRCC has historically used the Loss-of-Load Probability (LOLP) analysis to confirm the adequacy of reserve levels for peninsular Florida. The LOLP analysis incorporates system generating unit information (e.g., Availability Factors and Forced Outage Rates) to determine the probability that existing and planned resource additions will not be sufficient to serve forecasted loads. The objective of this study is to establish resource levels such that the specific resource adequacy criterion of a maximum LOLP of 0.1 day in a given year is not exceeded.

Each individual LSE within the FRCC Region develops a forecast that accounts for the actual peak demand. The individual peak demand forecasts are then aggregated by summing these forecasts to develop the FRCC Region non-coincident forecast. These individual peak demand forecasts are coincident for each LSE but there is some diversity at the region level. The Regional non-coincident forecast is the basis for the evaluation of adequate levels of resources to meet Reserve Margin requirements. The entities within the FRCC region plan their systems to meet the Reserve Margin criteria under both summer and winter peak demand conditions.

Existing – Certain capacity consists of resources that have been classified as operational and available to serve load. FRCC entities have an 'obligation to serve' and this obligation is reflected within each entity's 10-Year Site Plan filed annually with the Florida Public Service Commission. Therefore, FRCC entities consider all future capacity resources as "Future – Planned."

The calculation of Reserve Margin does not include Energy-Only resources. Only resources that have firm contract with firm transmission rights are included in the calculation of capacity available to meet load requirements. There are no constraints or transmission limitations associated with the delivery of firm resources.

Entities within the FRCC use different methods to test and verify Direct Load Control programs such as actual load response to periodic testing of these programs and the use of a time and temperature matrix along with the number of customers participating. Projections incorporate demand impacts of new energy efficiency programs, while there is currently no critical peak pricing with control incorporated into FRCC projections.

Some programs implemented as distributed generation include a Net Metering program and Feed-In-Tariff (FIT) program.[20] Under the Net Metering Program, participants first consume the energy generated directly on-site, where any excess energy generated on-site is fed into the distribution grid. Under the Feed-In-Tariff program all energy generated is fed directly into the Utility's distribution network and none of the energy is consumed exclusively by the on-site customer.

[20] http://www.psc.state.fl.us/utilities/electricgas/docs/2012/GRU.pdf (Page 28)

All external imports into the Region have firm transmission service to ensure deliverability into the FRCC region. No portions of contracts are from Liquidated Damages or “make whole” contracts, and no non-firm or expected transactions are included in the assessment. The FRCC Region does not rely on external resources for emergency imports and reserve sharing. However, there are emergency power contracts (as available) in place between SERC and FRCC entities.

Entities’ individual peak demand forecasts are aggregated by summing all forecasts to develop the FRCC Region non-coincident forecast. The Regional non-coincident forecast is the basis for the evaluation of adequate levels of resources to meet Reserve Margin requirements.

Demand

Each individual LSE within the FRCC Region develops a forecast that accounts for the actual peak demand. The individual peak demand forecasts are then aggregated by summing these forecasts to develop the FRCC Region non-coincident forecast. These individual peak demand forecasts are coincident for each LSE but there is some diversity at the region level. The Regional non-coincident forecast is the basis for the evaluation of adequate levels of resources to meet Reserve Margin requirements. The entities within the FRCC region plan their systems to meet the Reserve Margin criteria under both summer and winter peak demand conditions.

FRCC projected demand is primarily driven by the variability of weather and economic assumptions.[21] Currently, the FRCC is actively evaluating alternative methodologies to evaluate the potential variability in projected demand due to weather, economic, or other key factors. The FRCC is working to develop regional bandwidths based upon hourly load shape curves for the FRCC Region. The purpose of developing bandwidths on peak demand is to quantify uncertainties of demand at the regional level. This would include weather and non-weather demand variability such as demographics, economics, and price of fuel and electricity.

The FRCC Region is typically summer peaking; however, the highest recorded Regional peak occurred during the winter season from an unusually prolonged cold-snap that lasted over a week and a half with average lows below the normal historical lows.

Demand-Side Management

There are a variety of energy efficiency programs implemented by entities throughout the FRCC region. These programs can include commercial and residential audits (surveys) with incentives for duct testing and repair, high efficiency appliances (air conditioning, water heater, heat pumps, refrigeration, etc.) rebates and high efficiency lighting rebates.

[21] FRCC Load Forecast Methodology (Page 21): https://www.frcc.com/Reliability/Shared%20Documents/FRCC%20Reliability%20Assessments/FRCC%202011%20Load%20and%20Resource%20Reliability%20Assessment%20Report%20RE%20PC%20Approved%20070611.pdf

The effects of voluntary and state-mandated conservation measures are accounted for within each Regional member's demand forecast and reflected in the aggregated regional load forecast.

Demand Response is considered as a demand reduction. Entities within the FRCC use different methods to test and verify Direct Load Control programs such as actual load response to periodic testing of these programs and the use of a time and temperature matrix along with the number of customers participating.

Generation

Behind-the-meter generation is modeled with associated loads and netted out since these loads are implicitly accounted for within load forecasts of entities within the FRCC.

Only the minimum firm capacity from intermittent or energy-limited resources is included in Regional assessments, which removes the inherent variability of the non-firm capacity associated with these resources. Only the firm capacities from these resources are included in calculations of Regional Reserve Margins. However, energy from variable resources is taken into account for actual energy delivery and future energy projections.

FRCC supply-side resources considered for the summer assessment are categorized as Existing-Certain, Existing-Other, and Existing-Inoperable.

Capacity Transactions

All firm on-peak capacity imports into the Region have firm transmission service agreements in place to ensure deliverability into the FRCC Region, with such capacity resources included in the calculation of the Region's Reserve Margin. The FRCC Region does not consider expected purchases or sales as capacity resources in the determination of the Region's Reserve Margin.

All firm resource purchases have firm transmission service to ensure deliverability into the FRCC Region; no Imports with partial path reservations are included for Reserve Margin calculations. No portion of imports into the Region from the Southeastern Subregion of SERC is from Liquidated Damages contracts.

Transmission

The FRCC performs a Summer Transmission Assessment and Operational Seasonal Study to assess the adequacy and robustness of the FRCC BES under expected 2012 summer peak load conditions and under anticipated system conditions (taking into account generation and transmission maintenance activities). This regional assessment and operational study analyzes the performance of the transmission system under normal conditions, single contingency events, and selected multiple contingency events determined relevant by pass studies. The results are coordinated and peer-reviewed by the FRCC's Operations Planning Working Group to ensure the Bulk Power System performs adequately throughout the summer timeframe. These study results demonstrated that potential thermal and voltage conditions exceeding the applicable screening criteria could be successfully mitigated under normal conditions, single contingency events, and the selected multiple contingency events. The transmission system within the FRCC Region is expected to perform reliably for the anticipated 2012 summer peak season system operating conditions.

Under firm transactions, reactive power-limited areas can be identified during transmission assessments performed by the FRCC. These reactive power-limited areas are typically localized pockets.. The “FRCC Long Range Study 2012-2021” did not identify any reactive power-limited areas that would impact the BES through 2021. The FRCC Region has not identified the need to develop specific criteria to establish a voltage stability margin. The FRCC Region has not identified any unique transmission issues that would require additional evaluation.

The FRCC region utilizes the FRCC Summer Seasonal Transmission and Operational Seasonal Study in preparation for the upcoming summer season.

Interregional - Coordination

The FRCC interregional coordination process facilitates the communication of modeling information and proposed system expansion plans to other Regions in the Eastern Interconnection. The coordination is performed through the Eastern Interconnection Reliability Assessment Group’s (ERAG) Multiregional Modeling Working Group (MMWG). The MMWG is responsible for developing and maintaining a library of power flow and dynamic base cases that simulate the steady state and dynamic BES behavior. The steady-state and dynamic cases are updated annually with the latest available data containing both transmission expansion plans and generation expansion plans from its members to create initial cases for regional review and go through a series of documented checks. The FRCC Planning Committee (through the FRCC Regional Transmission Planning Process) coordinates with Southeastern Regional Transmission Planning (SERTP) to perform interregional reliability studies/assessments.

In addition to the interregional reliability studies performed by SERTP the FRCC also performs an annual interregional transfer study to evaluate the total transfer capability between FRCC and the Southeastern Subregion of SERC. These joint studies are performed by the Florida/Southeastern Coordinating Group to determine the summer and winter import and export capability. These joint studies account for constraints within the FRCC and/or the Southeastern Subregion of SERC.

Regional Coordination

For capacity constraints due to inadequate fuel supply, the FRCC State Capacity Emergency Coordinator (SCEC) along with the Reliability Coordinator (RC) have been provided with an enhanced ability to assess Regional fuel supply status by initiating Fuel Data Status reporting by Regional utilities. This process relies on utilities to report their actual and projected fuel availability along with alternate fuel capabilities, to serve their projected system loads. This is typically provided by type of fuel and expressed in terms relative to forecast loads or generic terms of unit output, depending on the event initiating the reporting process. Data is aggregated at the FRCC and is provided, from a Regional perspective, to the RC, SCEC and governing agencies as requested. Fuel Data Status reporting is typically performed when threats to Regional fuel availability have been identified and is quickly integrated into an enhanced Regional Daily Capacity Assessment Process along with various other coordination protocols. These processes help improve the accuracy of the reliability assessments of the Region and ensure optimal coordination to minimize impacts of Regional fuel supply issues and/or disruptions on BES facilities and customers.

Regional operators continue to develop mitigation strategies to minimize the effects of supply impacts due to extreme weather during peak load conditions, including fuel supply and transportation diversity as well as alternate fuel capabilities. There are no identified fuel availability or supply issues at this time. Based on current fuel diversity, alternate fuel capability and on-going fuel reliability analyses, the FRCC does not anticipate any fuel transportation issues affecting capability during peak periods and/or extreme weather conditions.

MISO

Assessment Area Description

Load data was collected from MISO load serving entities and aggregated using a bottom-up approach with projections being 50/50 weather normalized forecasts[22] based on economic indicators, long-term weather forecasts, and historic load data. Resource data was collected from MISO market participants and aggregated using a bottom-up approach with projections based on MISO registration and planning reserve margin requirements.

MISO's Planning Authority region covers 750,000 square miles, which includes 11 states. MISO's Energy and Operating Reserves market includes 363 market participants who serve 38.9 million people. MISO experiences its annual peak during the summer seasons.

Planning Reserve Margins

For planning year 2012 MISO's System Installed Generation Planning Reserve Margin ($PRM_{SYSIGEN}$) requirement on a MISO coincident load basis is 16.7 percent. The requirement is determined utilizing GE Multi-Area Reliability Simulation (MARS) software to determine at what reserve level MISO will meet a 1 day in 10 years Loss of Load Expectation (LOLE). The study models MISO as a summer peaking system. For more information on the development of MISO's Planning Reserve Margin Requirement (PRMR) please see the 2012 LOLE study report.[23]

In order to be consistent with the PRMR methodology, MISO bases its Anticipated Capacity Resources Reserve Margin calculation on the following:

- MISO utilizes the forecasted peak summer month from Module E (July 2012) for this assessment. The LOLE model utilizes forecasts from Module E as well.
- The Generating Availability Data System (GADS) provides a standardized means to collect unit performance information. The database that MISO uses is called PowerGADS. This system was used to collect all the data for the MISO generation units in the LOLE model. Existing Capacity resources used to calculate MISO's planning reserve margin, also utilized GADS data.
- Future-Planned generation was added based on unit information in the MISO Interconnection Queue. Only units with a signed interconnection agreement were added to the LOLE model; however, for this assessment, other study statuses were accepted if the project was currently under construction, has proper regulatory permits, or confirmed Transmission Service Request (TSR) in the queue.
- GADS data is not reported for some MISO units, like wind units and other energy-limited types. For these units the measured performance at key peak load hours is used to determine the Unforced Capacity (UCAP) amount of these units for Module E. This is the same output level

[22] 50/50 load forecast means there is a 50 percent chance the forecast will be lower and a 50 percent chance the forecast will be higher. 90/10 load is the same concept.

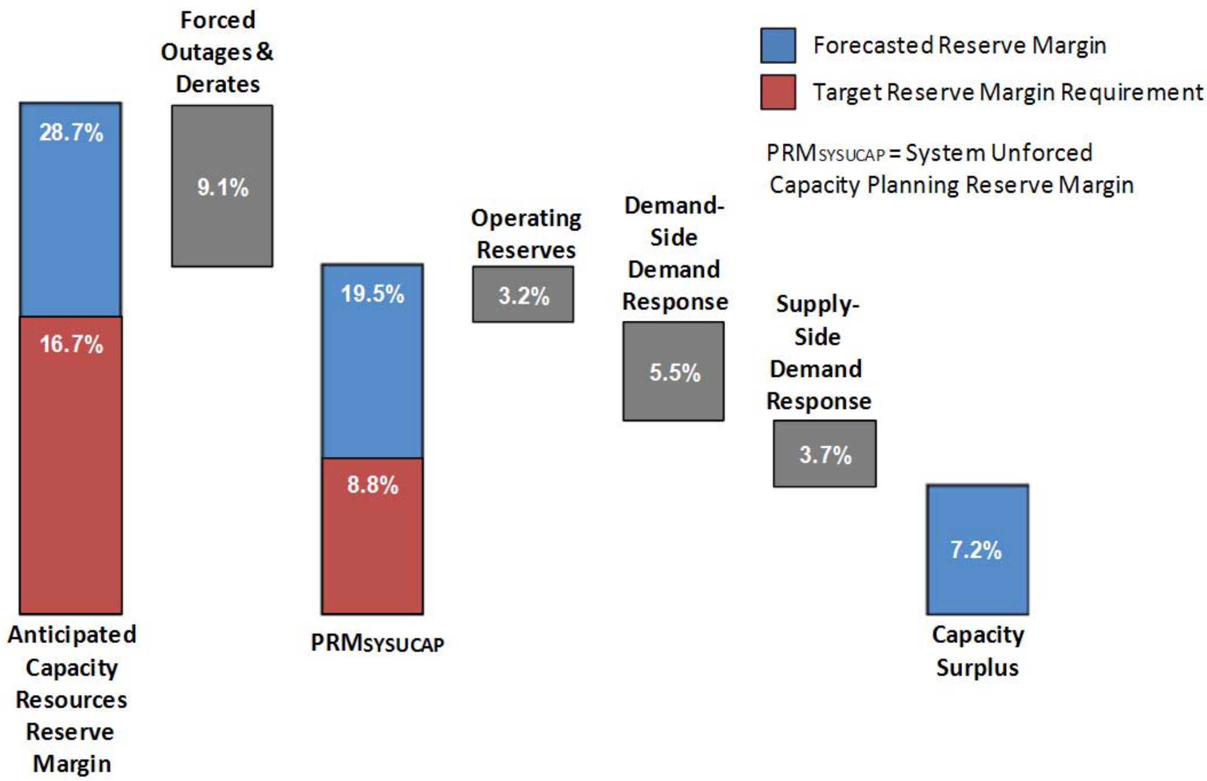
[23] https://www.misoenergy.org/Library/Repository/Study/LOLE/2012%20LOLE%20Study%20Report.pdf

these types of units are set at in the LOLE model and the same level set for this assessment utilizing the 14.7 percent wind capacity credit and generator performance EFORd.

- MISO utilizes the Net Internal Demand forecast in both the LOLE model and this assessment. Module E is the data source for Demand-Side Management resources in both assessments.
- MISO utilizes BTMG as a capacity resource in both the LOLE model and this assessment. Module E is the data source for BTMG resources in both assessments.
- MISO utilizes external resources in both the LOLE model and this assessment; however, the LOLE model is more complex in analysis of external systems and their connections to MISO. For this report MISO utilizes firm purchases from Module E, and other capacity transactions are forecasted based on historical statistical analysis. For more information on how the external world is modeled for LOLE please see the 2012 LOLE study report.
- The demands for both the LOLE and this assessment are as reported by Network Customers, in Module E, which are weather normalized, or 50/50, forecasts. A 50/50 forecast is the mean value in a normal probability distribution, meaning there is a 50 percent chance the actual load will be higher and a 50 percent chance the actual load will be lower than the forecast. Historically, reported load forecasts have been accurate as each member has expert knowledge of their individual loads with respect to weather and economic assumptions.

To forecast forced outages and derates, MISO applies each generating unit's 5-year average Equivalent Forced Outage Rate on Demand (EFORd), from Generator Availability Data System (GADS), to the unit's respective summer ratings. Under normal operating conditions, MISO demand response[24] are inaccessible to the operators. MISO must initiate a level 2 Maximum Generation Emergency Event to access demand response. Also, MISO's Operating Reserves of approximately 2,400 MW are only used given a level 3 event. The waterfall chart below, Figure 2-1, shows the progression of reserve levels from Anticipated Resources Reserve Margin to Capacity Surplus.

[24] Demand-Side Interruptible Load (IL) and Direct Control Load Management (DCLM), Supply-Side Load as a Capacity Resource, behind the meter generation (BTMG)



It is always possible that a combination of high loads due to adverse weather, a lack of wind generation, a high-rate of outage, lack of external support, lack of demand response, or other factors (either single events, or a combination of events) could result in curtailment of Firm load. Such a curtailment is considered to be a low-probability event for this summer for the following reasons:

- The Anticipated Reserve Margin far exceeds the established Reference Margin Level;
- External support and demand response have Firm contracts to serve MISO load this summer through the Module E process.
- Fuel scarcity is not projected to be an issue.

Demand

Demands, as reported by Network Customers, are weather-normalized (50/50, forecasts). A 50/50 forecast is the mean value in a normal probability distribution, meaning there is a 50 percent chance the actual load will be higher and a 50 percent chance the actual load will be lower than the forecast. Historically, reported load forecasts have been accurate as each member has expert knowledge of their individual loads with respect to weather and economic assumptions.

An unrestricted non-coincident peak demand is created on a MISO basis by summing the coincident monthly forecasts for the individual Load Serving Entities (LSE) in the MISO Assessment Area. In MISO's Module E construct, the final Module E forecast is due by June 1, 2012. To capture the uncertainty around final and initial Module E forecast that is used in the Assessment reports, MISO calculated the difference between 2011 initial and final Module E forecast and prorated MISO's total internal demand forecast to capture the uncertainty. Last year's initial forecast was not adjusted. This is a methodology improvement to MISO's forecasting technique this summer season. Similar to last summer, a load diversity factor was calculated by observing the individual peaks of each Local Balancing Authority and comparing them against the system peak. This produced an estimated diversity of 4,500MW to reduce the Non-Coincident demand to a Coincident demand.

The demands as reported by Network Customers are weather normalized, or 50/50, forecasts. A 50/50 forecast is the mean value in a normal probability distribution, meaning there is a 50 percent chance the actual load will be higher and a 50 percent chance the actual load will be lower than the forecast. Historically, reported load forecasts have been accurate as each member has expert knowledge of their individual loads with respect to weather and economic assumptions. MISO is a summer peaking system.

Demand-Side Management

Generation

Behind-the-meter Generation (BTMG) is treated as Supply-Side Demand Response. The Resource Adequacy processes as set forth in Module E of MISO's tariff acts as the measurement and verification tool for Demand Response (Load Modifying Resources).

Existing capacity was determined by evaluating four data sources, Module E Capacity Tracking Tool (MECT), GADS, MISO's March 2012 Commercial Model, and CROW (MISO's Outage Scheduler).

The determination of Existing-Certain capacity is a four step process shown below.

1. First, all MISO non-intermittent units' Must-Offer MW, for each planning month of the summer season, is summed together. Approximately, 92 percent of Existing-Certain capacity consists of Module E Must-Offer MWs. The Must-Offer MWs are not finalized until the month prior to each planning month. To capture the uncertainty around final and initial Module E Must-Offer MW forecasts, MISO took the following steps:

   These steps apply to resources that have a Must-Offer obligation to serve load during the upcoming summer season.

   a) If the unit did not have a Must-Offer MW in Module E for last year's peak month of July, the unit is given Must-Offer MW for each plan month of summer season as of March 1st 2012.[25]
   b) If the unit did have a Must-Offer MW in Module E for last year's peak month of July and the Installed Capacity of the unit remained the same from last year, the unit's Must-Offer MW for each plan month of the summer season as of March 1st 2012 is prorated based on load growth.
   c) If the unit did have a Must-Offer MW in Module E for last year's peak month of July and the Installed Capacity of the unit changed from last year, the unit's

[25] Module E Must Offer capacity for the upcoming summer season was pulled from the MECT on March 1st 2012.

Must-Offer MW for each plan month of the summer season as of March 1st 2012 is prorated based on the Installed Capacity change and load growth.

2. The second step in calculating Existing-Certain capacity is to forecast how much additional non-intermittent capacity will be dispatched during the 2012 summer peak hour. To do this MISO calculated the difference between the Must Offer MWs and Summer Rated Capacity[26] of non-intermittent Designated Network Resources in the Commercial Model. Approximately 7 percent of Existing-Certain capacity consists of this additional non-intermittent capacity.

3. The third step in calculating Existing-Certain capacity is to forecast how much additional intermittent capacity is expected to be available on peak. To do this MISO applied the 14.7 percent wind capacity credit[27] to Designated Network wind Resources registered maximum output in the Commercial Model and other intermittent resources received its Generator Verification Test Capacity. Approximately 1 percent of Existing-Certain capacity consists of this additional intermittent capacity.

4. The fourth and final step is to remove planned outages from the cumulative total from the previous three steps. Planned outages scheduled for the summer months were taken from the CROW Outage Scheduler. The highest amount of planned outages for a single hour of each month was utilized.

Units with an approved Attachment Y to be mothballed or suspended during the 2012 summer season were categorized as Existing-Inoperable. The units on planned outage and all other remaining March 2012 Commercial Model units were categorized as Existing-Other, with wind capacity credit and generator performance testing applied to intermittent resources.

[26] Summer Rated Capacity: GADS Generator Verification Test Capacity as of June 2011 or if no GADS data, the Emergency Maximum Offer during last year’s peak.

[27] 14.7 percent wind capacity credit is based on the Effective Load Carrying Capability of wind. Please see the 2012 LOLE Study report for additional information.

Capacity Transactions

MISO used multiple regression model analysis to forecast a Net Actual Interchange (NAI) for each month of the 2012 summer season. The analysis was based on the past three summer seasons (2009 – 2011). The dependent variable was the hourly NAI, while the independent variables were hourly real-time load and dispatched generation from MISO Market Settlements and hourly outages (Forced, Planned, and Maintenance) from GADS. The output of the multiple regression analysis estimated the following relationships between the NAI and independent variables:

- Y-Intercept is approximately 3,300 MW
- Hourly load coefficient is approximately 0.0005
- Hourly dispatch capacity coefficient is approximately 0.008
- Hourly outage coefficient is approximately -0.0005

The R squared value for the regression analysis was 0.912, which indicates that the regression model was accurate. By substituting the forecasted Net Internal Demand, Existing-Certain capacity, and outages, MISO determined the peak hour NAI for all the 2012 summer months.

In order to allocate the forecasted NAI into the four NERC categories (Firm Imports, Expected Imports, Firm Exports, and Expected Exports) MISO uses the historical Net Scheduled Interchange (NSI) data from MISO's Physical Scheduler System (PSS) to determine historical NSI ratios amongst firm and non-firm capacity transactions. The historical NSI study yielded ratios of 96.5 percent, 41.4 percent, 56.2 percent, and 11.3 percent for Firm Imports, Firm Exports, Expected Imports, and Expected Exports, respectively.

The Resource Adequacy processes as set forth in Module E of MISO's tariff acts as the measurement and verification tool for Firm Full-Responsibility Purchases. The forecasted Firm Imports from the NAI/NSI analysis acts as an incremental adjustment to the Firm Full-Responsibility Purchases from Module E.

Transmission

MISO publishes a summer seasonal transmission assessment on an annual basis. MISO informs operators of potential marginal system conditions expected for the summer peak and evaluates a variety of stress conditions including beyond first contingencies, based on a study scope designed by MISO, MISO members, and adjacent system operations personnel. The 2012 Summer Transmission Assessment is currently being drafted[28]. MISO has performed four sets of analysis for the 2012 summer season:

Base Dispatch Contingency Analysis

- All N-1 including RT Operations EMS contingencies evaluated
- Selected N-2 contingencies evaluated

Critical Interface Voltage Stability (P-V) Analysis

- 2 Interfaces studied based on operational/planning experience

[28] www.misoenergy.org/Library/Repository/Study/Seasonal%20Assessments/2011%20Summer%20CSA%20Final%20Public%20Report.pdf

- Up to N-3 involving line and generator outages

Large Load Area Voltage Stability (V-Q) Analysis

- Supplements P-V analysis for power factor sensitivity and critical bus information
- 3 Large metropolitan areas studied based on operational/planning experience
- Prior studies have evaluated 11 other large metropolitan areas

First Contingency Incremental Transfer Capability (FCITC) Analysis

- 10 Transfer directions studied
- Evaluates maximum steady state flow levels

The results indicate that no outstanding issues exist. All critical interfaces show sufficient transfer levels prior to reaching the stability limits. All large metropolitan areas studied are stable to 2 or more contingencies with sufficient margin on the system load level. Overall, MISO's system is capable of substantial transfers between member systems and with external systems. Most of the transfers show First Contingency Incremental Transfer Capability (FCITC) of more than 1,000 MW.

MRO-Manitoba Hydro

Assessment Area Description

Manitoba Hydro is a Provincial Crown Corporation providing electricity to 537,000 customers throughout Manitoba and natural gas service to 265,000 customers in various communities throughout southern Manitoba. Manitoba Hydro also has formal electricity export sale agreements with more than 35 electric utilities and marketers in the Midwestern U.S., Ontario, and Saskatchewan.

Manitoba Hydro is its own Planning Authority and Balancing Authority (BA). Manitoba Hydro is a coordinating member of the MISO. The MISO is the Reliability Coordinator for Manitoba Hydro.

Manitoba Hydro collects data from various sources including: historical operating data, data from neighboring utilities, physical equipment data, forecasted data generated from internal and external computer models that integrate various data sources, and internal and external reports. Analysis methods include industry accepted practices using computer models.

Data was collected from individual entities and aggregated using a bottom-up approach with projections based on economic indicators, long-term weather forecasts, and historic load data.

Planning Reserve Margins

Manitoba Hydro's projected Planning Reserve Margins include expected on peak capacity, expected future added capacity, and export transactions during the assessment period. There are no import transactions during the assessment period. The values are based on contracted numbers and load forecast which assumes weather variations. Note, however, that Manitoba's annual peak demand does not occur during the summer season.

Existing-Certain resources include all firm resources (hydraulic, gas, coal) available to run during peak periods in the assessment time frame, reduced by any scheduled outages. Future generation include only that which is anticipated to come online during the assessment period.

Reductions in demand as a result of demand-side management programs at the aggregate level are included in total internal demand.

The demand forecast adjusts historical load to remove weather effects for the purpose of forecasting future load. Normal weather for the demand forecast was based on 25 years of Winnipeg temperatures. Economic forecast assumptions were based on the 2011 Economic Outlook and the 2011 Energy Price Outlook. These documents contain Manitoba Hydro's forecasts of economic variables including prices of electricity, natural gas and oil, Gross Domestic Product (GDP), Manitoba population, and housing.

As a predominately hydro region, Manitoba has both an energy criterion and a capacity reserve margin criteria. These criteria are set forth based on system historical adequacy performance analysis and with reference to probabilistic resource adequacy studies. The energy criteria requires adequate energy resources to supply the firm energy demand in the event that the lowest recorded coincident river flow conditions on the 96 year hydraulic flow record are repeated. The capacity reserve margin criterion requires a minimum 12 percent reserve above the forecast peak demand. Manitoba Hydro performs its own Loss-of-Load Expectation studies and in previous years also participated in MAPP regional Loss-of-Load Expectation studies.

Demand

Twenty five years of actual hourly Winnipeg temperature is used to form the Manitoba Hydro peak load data. Economic forecast assumptions come from the 2011 Economic Outlook and the 2011 Energy Price Outlook. The methodology is the same for every season. Load shape determines the demand forecast in each season. Manitoba Hydro is a winter peaking region and its load is reported as a coincident value.

Demand-Side Management

The measurement and verification activities conducted by Manitoba Hydro are tailored to the specific requirements of each energy efficiency program/sector. The intensity of measurement and verification is based upon variability of usage and the benefit of measurement in relation to the cost.

The residential market is characterized by a large volume of customers with typically homogeneous energy usage patterns. Due to the size and homogeneity of the sector, measurement and verification is minimal. Energy savings are based upon a deemed savings per technology in conjunction with surveyed usage patterns. Deemed savings are normally based on engineering estimates that consider generally accepted values (i.e. those used by other utilities) and historical values.

The commercial market is characterized by fewer customers with typically homogeneous usage patterns. Measurement and verification is limited due to cost/benefit implications and the ability to use deemed savings and standardized usage patterns based on technologies.

The industrial market includes programs which will establish an appropriate measurement and verification plan for each customer. The plan will follow the principles outlined in the International Performance Measurement and Verification Protocol – Volume 1 (March 2002).

The Evaluations department within Manitoba Hydro models evaluations according to the International Performance Measurement and Verification Protocols (IPMVP) from the Efficiency Valuation Organization and DSM best practices.

Generation

Existing-Certain is classified as generation resources with firm transmission and is expected to be available during peak periods. Existing-Other is classified as generation resources with non-firm transmission. Future-Planned is based on expected in-service dates.

The expected on-peak values for hydro are determined using testing and data processing procedures in accordance with the Midwest Reliability Organization (MRO) Generator Testing Guidelines. The expected on-peak capacity that a unit can sustain is computed using the test results. These values are adjusted for ambient conditions and don't include any capacity utilized for station service. For reservoir hydro units, the values are corrected to the five-year median head for each month, while for run-of-river hydro units, the calculation is the average net integrated hourly capability for all hours of historical operation for each month.

Expected on-peak values for hydro generation are determined using testing and data processing procedures in accordance with the Midwest Reliability Organization (MRO) Generator Testing Guidelines.[29] The expected on-peak capacity that a unit can sustain is computed using the test results. These values are adjusted for ambient conditions and don't include any capacity utilized for station service. For reservoir hydro units, the values are corrected to the five-year median head for each month, while for run-of-river hydro units, the calculations is the average net integrated hourly capability for all hours of historical operation for each month.

Capacity Transactions

On-peak capacity exports have firm transmission reservations during the assessment period. Manitoba Hydro does not have any capacity imports during the assessment period. Manitoba Hydro does not expect to negotiate any more capacity on-peak export contracts during the assessment period. All firm on-peak capacity export contracts contain liquidated damage clauses and are "make-whole" as defined by FERC Order No. 890.

Transmission

Day-ahead studies are carried out by modeling all the outages valid for the day with the expected generation pattern and load level of the day. This study identifies possible steady state, post contingency thermal and/or voltage concerns, and addresses them before the start of the day. All major outages are studied individually and contingency plans are prepared when necessary.
Modal analysis and PV Curve techniques are used to identify reactive power limited areas. Operating margins are defined as a 10 percent power margin from the knee of the PV curve for pre- and post-disturbance.

Seasonal operating studies are carried out to establish transfer capability for each interface for system intact and various prior outage conditions.

[29] www.midwestreliability.org/03_reliability/06_gtrtf/Documents/MRO_Generator_Testing_Guidelines.pdf

MRO-MAPP

Assessment Area Description

The Mid-Continent Area Power Pool (MAPP) is an association of electric utilities and other electric industry participants operating in all or parts of the following states: Iowa, Minnesota, Montana, North Dakota, and South Dakota.[30] Currently, the MAPP Planning Authority includes entities in two Balancing Authority areas and thirteen Load Serving Entities. The MAPP Planning Authority covers an area of approximately 200,000 square miles and serves a population of about 3.5 million. MAPP typically experiences its annual peak demand in summer.

Each Load Serving Entity (LSE) in the MAPP Planning Authority area provides seasonal assessment data of its forecasted Demand and Resources for the upcoming season. These forecasts are then aggregated to determine the MAPP regional Demand, Generation, and Reserve Margin forecasts for the upcoming summer season.

The LSEs, Transmission Planners, and Resource Planners in the MAPP Planning Authority area also prepare a narrative seasonal assessment of their Transmission, Operations Issues, and Reliability Assessment sections for the coming seasons. These narratives are then combined to form a seasonal assessment of the MAPP region.

Planning Reserve Margins

The MAPP planning reserve margins is referenced against a target reference margin of 15 percent for primarily thermal systems, and 10 percent for primarily hydro systems. These margins have historically been confirmed through probabilistic reliability analysis to provide the adequate reserves to meet the industry standard 0.1 days per year loss of load expectation metric.

MAPP is a summer peaking area that meets its planning reserve margin target without the need to rely on heavy imports from its neighboring regions. Variable capacity resources, such as wind, only count on capacity expected to be available at the time of system peak. MAPP calculates its reserve margin using Existing-Certain resources and does not rely on Future-Planned, Energy-Only, or Transmission-Limited resources. Demand-Side Management and Behind-the-meter generation are often included in the calculation, but account for a minimal percentage of MAPP resources. Firm Imports are added as a resource, while firm exports are subtracted. MAPP assumes a 50/50 demand forecast.

Demand

MAPP is a summer peaking area that assumes normal or 50/50 weather and normal economic assumptions. Non-coincident internal peak demands were used to aggregate individual LSE loads for use in the MAPP forecast. Resource evaluations are based on non-coincident peak demand conditions.

[30] About MAPP section of the MAPP website: http://www.mapp.org

Each MAPP LSE uses its own forecasting methodology. In general, the peak demand forecast includes factors involving recent economic trends (industrial, commercial, agricultural, residential) and normal or 50/50 weather patterns.

Peak demand uncertainty and variability due to extreme weather and/or other conditions are accounted for within the determination of adequate generation reserve margin levels. MAPP LSEs utilize a Load Forecast Uncertainty (LFU) factor within the calculation for the Loss of Load Expectation (LOLE) and/or the percentage reserve margin necessary to obtain a LOLE of 0.1 day per year or 1 day in 10 years. The load forecast uncertainty considers uncertainties attributable to weather and economic conditions.

Demand-Side Management

A wide variety of programs, including direct load control (such as electric appliance cycling) and interruptible load, may be used to reduce peak demand during the summer season. MAPP LSEs utilize various measurement and verification programs for demand response, such as those based upon International Performance Measurement and Verification Protocols (IPMVP). Energy efficiency is verified through several means, such as use of the Minnesota Deemed Savings Database provided by the Minnesota Office of Energy Security.

Generation

For this summer seasonal assessment, all existing generation is reported under the Existing-Certain/Existing-Other/Existing-Inoperable categories. Generation is reported under the Future-Planned/Future-Other categories if it is projected to come online during those months.

With respect to existing wind expected on-peak, MAPP utilizes a methodology that is based on a median of actual wind output. The four peak hours per day for each and every day of the four summer months are used. This dataset uses 10 years or the life of the wind farm.

With respect to existing wind expected on-peak, MAPP utilizes a methodology that is based on a median of actual wind output. The four peak hours per day for each and every day of the four summer months are used.

Capacity Transactions

For both imports and exports, firm contracts exist for both the generation and the transmission service. Transmission providers within MAPP handle Liquidated Damage Contracts (LDC) according to their tariff policies. Most MAPP LSEs are within non-retail access jurisdictions and therefore liquidated damages products are not typically used. MAPP is forecasted to meet the various reserve margin targets without needing to include energy-only, uncertain, or transmission-limited resources.

For both imports and exports, firm contracts exist for both the generation and the transmission service. Firm contracts are at least one year in length, and some extend out twenty years or more. Capacity transactions projected beyond the length of Firm contracts may be based on extensions of those contracts. Transmission providers within MAPP handle Liquidated Damage Contracts (LDC) according to their tariff policies. Most MAPP LSEs are within non-retail access jurisdictions and therefore liquidated damages products are not typically used. MAPP is forecasted to meet the various reserve margin targets without needing to include energy-only, uncertain, or transmission-limited resources. No emergency MW are required to meet the Reserve Margin target in MAPP.

Transmission

MAPP is not aware of any transmission constraints or transmission issues that will affect system reliability (i.e., deliverability of generation to network load) this summer. Various MAPP transmission planning studies are performed in accordance with the MAPP Members Reliability Criteria and Study Procedures Manual.[31] Transient, voltage, and small signal stability[32] studies are performed as part of the near-term/long-term transmission assessments.[33] Reactive power resources are considered in on-going operational planning studies. No transient, voltage, or small signal stability issues are expected that impact reliability during the 2012 summer season.

[31] MAPP Members Reliability Criteria and Study Procedures Manual, November, 2009

[32] MAPP Small Signal Stability Analysis Project Report, November 2010

[33] 2011 MAPP System Performance Assessment

MRO-SaskPower

Assessment Area Description

The Saskatchewan Power Corporation is the Planning Authority / Reliability Coordinator for the province of Saskatchewan, and is the principal supplier of electricity in the province. It is a provincial Crown corporation and under provincial legislation is responsible for the reliability oversight of the Saskatchewan bulk electric system and its interconnections.

SaskPower owns and operates approximately 154,300 km of power lines (approximately 12,200 km of transmission and 142,100 km of distribution), 52 high voltage switching stations, and 175 distribution substations in the province. SaskPower operates networked transmission facilities at the 230 kV and 138 kV voltage levels. This extensive network is designed to serve Saskatchewan's large geographic area and widely-dispersed population. The Saskatchewan transmission system is characterized by relatively long 230 kV and 138 kV transmission lines connecting dispersed generating stations to sparsely distributed load supply points.

Planning Reserve Margins

Saskatchewan uses a probabilistic method of establishing planning reserve (Expected Unserved Energy).The peak season is used as the basis of meeting planning reserve margin requirements. Existing-Certain generation is assumed to be available in the planning reserve margin calculation. Future-planned generation, if applicable, is assumed to be available in the planning reserve margin calculation.

For Saskatchewan, Energy-Only generation is not counted on for reliability purposes. For transmission-limited resources, Saskatchewan does not include the limited portion in its assessment of planning reserve. Demand-side management is considered as a reduction in demand for the planning reserve margin calculation. distributed generation or behind-the-meter generation is reflected in the load forecast used for reliability assessment.

Firm imports backed by contracts, if applicable, are considered as an available resource in the planning reserve margin calculation.

Saskatchewan assumes peak demand in the reserve margin calculation. Energy and peak demand forecasts are developed based on a provincial econometric model and forecasted industrial load data. Forecasts take into consideration the Saskatchewan economic forecast, historic energy sales, customer forecasts, normalized weather and historical data, and system losses. Methodology, assumptions and a summary of results are provided in Saskatchewan's internal load forecast report.

Weather has a significant impact on the amount of electricity consumed by non-industrial customers. Due to this weather sensitivity, average daily weather conditions for the last thirty years are used to develop the energy forecast. Peak load is forecasted on a heating season basis and represents the highest level of demand placed on the supply system. One of the primary economic assumptions is that Saskatchewan's customer base will be maintained.

Saskatchewan uses a probabilistic method of establishing planning reserve (Expected Unserved Energy), and considers the mix of fuel types (coal, hydro, gas).

Demand

Saskatchewan considers coincident hourly peak in determining the on-peak total internal demand. Weather has a significant impact on the amount of electricity consumed by non-industrial customers. Due to this weather sensitivity, average daily weather conditions for the last thirty years are used to develop the energy forecast. Peak load is forecasted on a heating season basis and represents the highest level of demand placed on the supply system. One of the primary economic assumptions is that Saskatchewan's customer base will be maintained. Saskatchewan experiences peak-season in the winter.

Demand-Side Management

Saskatchewan has energy efficiency programs designed to help customers save power, save money and help the environment. These programs include energy-efficiency, conservation, education, and load management programs. Residential programs focus on consumer education on energy efficiency and implementation of energy efficient lighting, appliances and furnace motors including retailer/ manufacturer partnerships and end-user incentives. Commercial and industrial programs include energy performance contracting, energy audits, and information services along with the market transformation of lighting, geothermal and HVAC. Measurement and verification programs are guided by the International Performance Measurement and Verification Protocol (IPMVP)[34] and the California Evaluation Framework.[35]

Saskatchewan has Direct Control interruptible demand contracts with customers. Evaluation measures guided by the International Performance Measurement and Verification Protocol (IPMVP) and the California Evaluation Framework have been established.

Generation

Existing-Certain units are those existing operational units that are expected to be available to meet peak demand, less the expected capacity anticipated to not be available due to seasonal derates or planned maintenance. Existing-Other is the portion of Existing-Certain resources that are expected to be derated or on planned maintenance for the reporting period. Saskatchewan does not have any Existing-Inoperable units.

Saskatchewan classifies units as Future-Planned resources only after they have been approved as part of its supply plan. Units are classified as Future-Other if they are planned but not yet approved.

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[34] International Performance Measurement and Verification Protocol (IPMVP) http://www.evo-world.org

[35] California Evaluation Framework http://www.calmac.org/publications/California_Evaluation_Framework_June_2004.pdf

Other than wind, variable resources are not considered in Saskatchewan's resource adequacy assessment. For reliability purposes, Saskatchewan considers 10 percent of wind nameplate capacity to be available to meet summer peak.

Capacity Transactions

No firm or expected imports or exports are anticipated during the 2012 summer season.

Transmission

Saskatchewan plans for reliable transmission operation on a short term basis by performing daily day-ahead and week-ahead studies, weekly month-ahead studies, and semi-annual joint (with Manitoba Hydro) seasonal studies.[36] For planned and emergency outages, further detailed study work is performed and temporary operating guides are issued as required.

Reactive power resources in Saskatchewan and their limits are considered in on-going operational or planning studies.

Saskatchewan assesses voltage stability on an as needed basis in operating or planning studies and may use a guideline of 5 to 10 percent based on load or power transferred. No issues have been identified requiring application during peak conditions.

[36] Manitoba Hydro - Saskatchewan Power Seasonal Operating Guideline on Manitoba-Saskatchewan Transfer Capability.

NPCC-Maritimes

Planning Reserve Margins

The Reserve Margins for the Maritimes Assessment Area are based in accordance with NPCC Directory #1 Appendix F Procedure for Operational Planning Coordination.[37] As such, the assessment considers the regional operating reserve criteria; 100 percent of the largest single contingency and 50 percent of the second largest contingency.

Demand

The NBSO as the Reliability Coordinator for the Maritimes area uses the non- coincident peak when doing resource evaluations. Economic assumptions are not made when determining the overall Maritimes load forecasts. It should be noted that the Maritimes Area is a winter-peaking system.

Demand-Side Management

The interruptible load demand program uses industrial loads that are metered and therefore can be monitored to determine what level of load would be available to curtail under emergency operating conditions.

The Maritimes Area is broken up into sub-areas and each sub-area has its own energy efficiency programs. These programs are primarily aimed at the residential consumer to help reduce their heating costs. It is usually geared towards heat as the Maritimes Area is a winter peaking system.

Generation

The NBSO classifies units as: Existing-Certain are generators that are capable of being brought on line and Future-Planned are generators scheduled to be brought on line within the assessment period with a scheduled in-service date.

Peak capacity values are calculated based on median historical hourly production values from the previous three years for each individual wind facility. For those facilities that have not been in service that length of time the following method is used. This derating of wind capacity in the Maritimes Area is based upon results from the Sept. 21, 2005 NBSO report "Maritimes Wind Integration Study".[38] This wind study showed that the effective capacity from wind projects, and their contribution to LOLE, was equal to or better than their seasonal capacity factors. Coincidence of high winter wind generation with the peak winter loads results in the Maritimes Area receiving a higher capacity benefit from wind projects versus a summer peaking area. The effective wind capacity calculation also assumes a good geographic dispersion of the wind projects in order to mitigate the occurrences of having zero wind production. Wind is the only variable resource currently considered in the Maritimes Area resource adequacy assessment.

[37] NPCC Directory #1 Appendix F Procedure for Operational Planning Coordination https://www.npcc.org/Standards/Directories/Forms/Public%20List.aspx.

[38] Maritimes Wind Integration Study http://www.nbso.ca/Public/_private/2005%20Maritime%20Wind%20Integration%20Study%20_Final.pdf

Capacity Transactions

No transactions have been scheduled during the summer period.

Transmission

On a short term basis all system elements are considered along with any dispatch plan and potential interface transfers for that particular day. Power system studies are carried out to ensure that no single contingency (using NPCC definitions of a single contingency-event involving the loss of a single element) will cause unacceptable violations within the Assessment Area. If the study of a contingency or contingencies show/s a violation, a mitigation plan is developed which may include cancelling work or rescheduling work to ensure the violation is avoided. Under no condition will a day-ahead plan be approved if unacceptable violations are known to exist for studied contingencies.

Must run generation requirements and reactive element availability requirements are used in the NBSO footprint to ensure reactive power-limited areas have the required reactive power sources and elements necessary to maintain acceptable voltage levels.

The acceptable voltage requirements are 0.95 to 1.05 P.U. pre contingency steady state and 0.90 to 1.10 P.U. post contingency, pre reactive element switching and operator action; ensuring that steady state post contingency levels can be re-established at the 0.95 to 1.05 P.U. levels.

The NBSO conducts NPCC Interim Area and NPCC Comprehensive Area Reviews, as required by NPCC.

NPCC-New England (ISO-NE)

Planning Reserve Margins

ISO New England's projected Planning Reserve Margin is based on the 50/50 load forecast of 26,462 MW, 31,644 MW of Existing-Certain generating capacity, 137 MW of Future-Planned capacity, 2,106 MW of supply-side demand resources, and 676 MW of firm net imports.

The following describes factors that are considered in ISO New England's Planning Reserve Margin calculation:

- Although the reserve margins are calculated for the entire summer period (June – September), the peak season in New England is the months of July and August.
- Existing-Certain resources are all existing ISO-NE generating assets, with ratings that are based on their demonstrated seasonal claimed capability.
- Future-Planned resources are those generators that have begun discussions with ISO New England regarding their upcoming commercial operation.
- Since the full demonstrated capability of generating resources is counted as Existing-Certain or Future-Certain, ISO-NE does not treat any capacity as Energy-Only.
- Although some generators can be transmission-limited at certain times, ISO New England does not report any transmission-limited resources because the limitations depend on the system topology at the time.
- The demand resources with capacity supply obligations in the Forward Capacity Market are treated as capacity resources in the Planning Reserve Margin calculations.
- ISO New England does not track behind-the-meter generation, other than emergency generators that are registered as demand resources.
- The Imports that are included in the reserve margin calculation are those that have obligations in the Forward Capacity Market for the upcoming commitment period.
- The demand is based on the reference forecast (50 percent chance of being exceeded).

ISO New England projects its capacity needs on an annual basis to meet the NPCC once in ten-year loss of load expectation (LOLE) resource planning reliability criterion. The calculations for these capacity needs, known as the Installed Capacity Requirement (ICR), take into account the random behavior of demand and resources in a power system, and the potential load and capacity relief obtainable through the use of various ISO-NE Operating Procedures. The capacity needed to meet this criterion is purchased through annual auctions (FCAs) three years in advance of the year of interest, followed by Annual Reconfiguration Auctions (ARAs) prior to the commencement year. The ICR calculations are performed annually prior to each auction in order to ensure that adequate capacity will be purchased to meet system needs.

The ICR changes annually based on factors such as resource availability and the load forecast.

Demand

ISO-NE develops an independent load forecast for the Balancing Authority area. ISO-NE uses historical hourly demand data from individual member utilities, which is based upon revenue quality metering. This data is then used to develop historical demand data on which the regional peak demand and energy forecasts are based. From this, ISO-NE develops a forecast of both state and monthly peak and energy demands. The peak demand forecast for the region and the states can be considered a coincident peak demand forecast.

The forecast reference case is the 50/50 forecast (50 percent chance of being exceeded), corresponding to a New England three-day weighted, temperature-humidity index (WTHI) of 79.9, which is equivalent to a dry bulb temperature of 90.2 degrees Fahrenheit and a dew point temperature of 70 degrees. The 79.9 WTHI is the 95th percentile of a weekly weather distribution and is consistent with the average of the WTHI value at the time of the summer peak over the last 40 years. The reference demand forecast is based on the reference economic forecast, which reflects the regional economic conditions that would most likely occur.

ISO-NE addresses peak demand uncertainty in two ways:

Weather – Peak demand distribution forecasts are made based on 40 years of historical weather which includes the reference forecast (50 percent chance of being exceeded), and extreme forecast (10 percent chance of being exceeded);

Economics – Alternative forecasts are made using high and low economic scenarios.

The method for determining the expected on-peak capacity for wind, solar, hydro and biomass facilities depends on whether the resource is classified as intermittent or non-intermittent. Generally the smaller hydro units, many of the biomass plants and all of the wind and solar fall under the intermittent category. The summer capability of intermittent units is equal to the median of net output during the hours ending 14:00 through 18:00, each day of the previous summer (June through September), as well as any summer hour with a shortage event.

Non-intermittent resources generally must demonstrate their capability seasonally for a period of one to four hours, depending on the type of unit. Monthly ratings for smaller non-intermittent hydroelectric resources are calculated based on the maximum capacity of the unit(s), adjusted for historical hydrological conditions and upstream storage.

Demand-Side Management

Both active and passive demand resources are treated as capacity under the ISO-NE Forward Capacity Market. Energy efficiency (“EE”) [39] and conservation can be included in the category of either on-peak or

[39] Within this document, the term energy efficiency (“EE”) includes conservation measures.

seasonal peak demand resources.[40] These include installed measures (e.g., products, equipment, systems, services, practices and/or strategies) on end-use customer facilities that result in additional and verifiable reductions in the total amount of electrical energy used during on-peak hours.

The New England states and other stakeholders requested that ISO-NE consider the potential impacts of growing energy efficiency ("EE")/conservation initiatives in the region. The request stems largely from the fact that the New England states have begun to aggressively fund energy EE programs, mostly administered by utility Program Administrators, and require multi-year implementation cycles. Specifically, stakeholders seek the creation of a longer-term forecast of EE and consideration of such a forecast in the transmission planning process, beyond current practices related to the ISO-NE Forward Capacity Market.

Currently, the Forward Capacity Auction procures supply-side resources, including EE, on a three year-ahead basis. The FCM qualification process gives planners confidence that the resources will be in service and can be taken into account in transmission planning studies. However, these studies currently hold the amount of EE constant over the remainder of the long-term planning forecast horizon. An EE forecast will equip planners with more accurate long-term data on the effects of state-sponsored EE programs.

Forecasting EE presents many technical challenges. State programs are complex and the lack of uniformity of state's program structure, planning cycles, and funding make it difficult to compare programs across states. Program changes and impacts may vary both across the region and with time. The long-term funding for state EE programs is also unclear and numerous funding sources have the potential for changes with time. Furthermore, the production cost has two interdependent variables related to technology changes and incentive policies.

ISO-NE has demonstrated through a proof of concept EE forecast, that a budget-based forecast model can provide valuable information about the impact of EE within the 5-10 year planning horizon. The model is based on historical production costs for EE measures and future funding sources. Beginning in spring 2012 the initial EE forecast will be completed as part of the normal forecasting cycle. It will be published to accompany the traditional 10-year demand (peak and energy) forecast. The EE forecast model was developed in consultation with regional stakeholders.

In order to assist ISO-NE in addressing these technical challenges, it established an Energy Efficiency Working Group (EEFWG) to provide ongoing input into the annual EE forecast process. The working group provides input on EE forecast assumptions, data inputs, model validation, and feedback on the model results. EEFWG participants include state agency representatives with strong knowledge of EE programs and funding, and Program Administrators who provide the data used in the forecast methodology. The EEFWG serves in an advisory role to ISO-NE, but the responsibility to produce both the demand forecast and the EE forecast still rests with ISO-NE.

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[40] The rules addressing the treatment of demand resources in the FCM may be found in Section III.13.1.4 of ISO New England's Market Rule 1, Standard Market Design, located at: http://www.iso-ne.com/regulatory/tariff/sect_3/2-16-09_mr1_sect_13-14.pdf

An approved FCM measurement and verification (M&V) plan is used for the purpose of evaluating the performance of energy efficiency, conservation, and both active and passive demand resources. Commercial operation and seasonal audits are conducted, consistent with ISO-NE operating manuals, to ensure that all FCM demand-side resources are capable of providing their contractual demand reductions.

Generation

Behind-the-meter generation basically is unknown to ISO-NE operations for dispatch purposes, but any distributed generation that does register with ISO New England is treated as capacity in this assessment. Distributed generation that has registered with ISO-NE as Real-Time Emergency Generation (RTEG) is in the category of Active DR and is treated as a supply-side capacity resource in this assessment. RTEG is operated based on real-time system conditions via dispatch by ISO-NE, and reduces energy demand during "reliability" hours.

In the Existing-Certain category, ISO-NE includes the capacity of all of its assets based on demonstrated Seasonal Claimed Capability. The Existing-Other category includes wind, hydro and solar derates, which consist of the nameplate minus the Seasonal Claimed Capability.

Included in the Future-Planned category are projects in the ISO-NE Generator Interconnection Queue that have begun discussions with ISO-NE regarding the commercial operation of the generator. Before meeting with the ISO, the generator must have completed a System Impact Study, entered into an Interconnection Agreement, and obtained NEPOOL committee approvals. These are generally projects that are expected to become commercial within the next year.

The on-peak capacity of variable resources during the summer and winter seasons is equal to the median net output during the previous season's reliability hours. For the summer season, the reliability hours are the hours ending 14:00 through 18:00 each day of June through September, and any summer hour with a shortage event.[41]

Although the capacity of most of ISO-NE's hydroelectric facilities is calculated using the method described above, the capacity of some hydro plants is based on the maximum capacity of the unit(s), adjusted for historical hydrological conditions and upstream storage. Those hydro-electric resources with pondage and storage of at least ten times their seasonal claimed capability rating must annually demonstrate their summer and winter capability.

Capacity Transactions

In the case of inadequate ten-minute reserves, ISO New England may implement an OP 4 action in which it arranges to purchase available emergency capacity and energy, or energy only (if capacity backing is not available), from Market Participants or neighboring RCAs/BAAs. Control area-to-control area transactions will normally be used as a last resort, when market-based emergency energy transactions are not available, or not available in a timely fashion. These control area-to-control area transactions are

[41] These are events under which ISO-NE operations is currently experiencing either an operating reserve or capacity deficiency.

taken into consideration as tie benefits in the ISO's Installed Capacity Requirement calculations. Emergency imports are not relied on for meeting the Planning Reserve Margin Reference Level.

ISO-NE firm on-peak capacity transactions are those imports and exports that have a capacity supply obligation in the FCM.

Import and export assumptions are not based on partial path reservations.

There are no capacity import or export contracts that can be characterized as "liquidated damage contracts" as defined by FERC Order 890.

Operations

ISO-NE has put in place facility out guides for specific variable resources that allow for reliable system operation. These guides either stipulate allowed output levels for the variable resource or the change in interface limits for the specific facility out condition based on expected topology.

ISO-NE has detailed Operating Procedures and processes in place to effectively manage minimum generation conditions and has full authority to work with generation and transmission owners to fully mitigate any minimum generation conditions. These procedures have been utilized on multiple occasions to effectively manage such conditions in the past, and ISO New England does not foresee any condition that would not be manageable for the upcoming period.

Any potential minimum generation conditions will be mitigated by implementing some or all of the actions of ISO-NE System Operating Procedure SOP-RTMKTS.0120.0015 - Implement Minimum Generation Emergency Remedial Action. Those actions include decommitting generators, dispatching pumping load at pumped storage facilities, reducing on-line generators, and temporarily curtailing real-time external purchases.

Transmission

For short-term transmission outage coordination, which is defined as up to 21 days in advance, outages are studied in accordance with standing operating procedures, system operating procedures and operating guides.

Transmission operating guides are created for reactive power limited areas to provide control room staff with the required instructions to maintain reliable operation. These operating guides are based upon operating analyses. The operating guides may require resource commitment, posturing, and/or voltage schedule adjustment to maintain reliable operation in reactive power-limited areas.

Voltage stability margins are applied to any study result used as a basis for an operating guide in a reactive power limited area. The study result may also include margin through conservatism that may be found in the study methodology, load level, modeling assumptions, generation dispatch and transfers.

There are stability limits in the area. Reliability is maintained with respect to these stability limits using the same methods described above, using operating guides that are based upon the results of operating studies. The resulting stability limits all include margin.

Transmission planning studies are not used for operational assessments in the short-term. A number of long-term transmission planning studies are underway or have recently been completed. These long-term studies assess the ability of the transmission system to meet reliability criteria in future years. For example, a recently completed study of the Maine transmission system identified a set of upgrades known as the Maine Power Reliability Program. Those upgrades are currently under construction. Examples of other studies that are underway include a study of the New Hampshire and Vermont systems, a study of Southwest Connecticut, and a study of the Greater Boston area.

Vulnerability Assessment

Currently, in New England, variable energy resources (VERs) perform their own forecast of generation for each hour of the next operating day, which they submit to ISO-NE as a self-schedule (forecast) on the day preceding the operating day. Phase 1 of the WPFIP will replace this self-scheduled forecast with a centralized forecasting system, as described above. Phase 2 of the WPFIP will make it possible to dispatch wind plants into the security constrained dispatch process: integration into real-time dispatch means that wind plants will submit economic offers and be able to set price at their local bus, and congestion will be managed in a transparent and automated process (versus the typically manual process that is currently used for real-time self-scheduled resources). Phase 2 of the WPFIP will also include closer coupling with the short-term outage scheduling process and will include publishing of the aggregate week-ahead wind power forecast (similar to the manner in which a week-ahead load forecast is published) in order for the participants to be able to incorporate this information into their decision-making processes and strategies.

NPCC-New York (NYISO)

Planning Reserve Margins

NYISO complies with NPCC and NYSRC resource adequacy criteria of no more than one occurrence of loss of load per ten years due to a resource deficiency, as measured by 0.10 days/year LOLE. The assumptions take into account demand uncertainty, scheduled outages and deratings, forced outages and deratings, assistance over interconnections with neighboring control areas, New York Transmission System emergency transfer capability, and capacity and/or load relief from available operating procedures.

The NYSRC establishes the Installed Reserve Margin ("IRM")[42] based on a technical study conducted by the NYISO and the Installed Capacity Subcommittee (of the NYSRC). Following this study, the NYISO conducts the Locational Installed Capacity Requirements (LCR) study.[43] This study determines the amount of Unforced Capacity (UCAP) that load serving entities must procure to reliably meet demand in New York's high load Areas.

The 16.0percent IRM base case for 2012 represents a 0.5percent increase from the 2011 base case IRM of 15.5percent. The principal drivers that increased the required IRM are:

- Increases in wind-powered generation
- Updated New York Control Area (NYCA) purchase and sale capacity projections
- Reduced availability of NYCA generating units

The above IRM drivers together accounted for an IRM increase percent from the 2011 base case value. There were several updated study parameters that reduced the IRM.

Demand

The peak demand for the New York Control Area is a coincident peak demand. The NYCA is summer peaking.

The weather assumptions for most regions of the state are set at the 50th percentile of the historic series of prevailing weather conditions at the time of the system coincident peak. For Orange & Rockland and for Consolidated Edison, the weather assumptions are set at the 67th percentile of the historic series of prevailing weather conditions at the time of the system coincident peak.

The economic assumptions are for modest growth in peak demand, based on projections for 2012 provided to the NYISO and the state's transmission owners by Moody's Analytics.

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[2] NYSRC Report titled, "New York Control Area Installed Capacity Requirements for the Period May 2012 Through April 2013" (December 2, 2011).

[3] NYISO Report titled "LOCATIONAL MINIMUM INSTALLED CAPACITY REQUIREMENTS STUDY COVERING THE NEW YORK CONTROL AREA For the 2011 – 2012 Capability, January 14, 2011.

Demand-Side Management

Individual utilities include the peak demand impact of these programs in their forecasts. Each utility and agency maintains a database of installed measures from which estimates of impacts can be determined. The impact evaluation methodologies and measurement and verification standards are specified by the state's Evaluation Advisory Group, a part of the New York Department of Public Staff reporting to the NY Public Service Commission.

The Emergency Demand Response Program provides demand resources with the opportunity to earn the greater of $500/MWh or the prevailing locational-based marginal price ("LBMP") for energy consumption curtailments provided when the NYISO calls on the resource. There are no consequences for enrolled EDRP resources that fail to curtail. Resources participate in EDRP through Curtailment Service Providers ("CSPs"), which serve as the interface between the NYISO and resources.

The ICAP Special Case Resource program allows demand resources that meet certification requirements to offer Unforced Capacity ("UCAP') to Load Serving Entities ("LSEs"). Special Case Resources can participate in the Installed Capacity ("ICAP") Market just like any other ICAP Resource; however, Special Case Resources participate through Responsible Interface Parties, which serve as the interface between the NYISO and resources. Resources are obligated to curtail when called upon to do so with two or more hours notice, provided the NYISO notify the Responsible Interface Party a day ahead of the possibility of such a call. In addition, ICAP/SCR resources are subject to testing each Capability Period to verify that they can fulfill their curtailment requirement. Failure to curtail could result in penalties administered under the ICAP program. Curtailments are called by the NYISO when reserve shortages are anticipated. Resources may register for either EDRP or ICAP/SCR but not both. Special Case Resources are eligible for an energy payment during an event, using the same performance calculation as EDRP resources. SCR and EDRP resources are deployed for forecast or actual operating reserve shortages or other emergency reliability needs.

The Targeted Demand Response Program ("TDRP"), introduced in July 2007, is a NYISO reliability program that deploys existing EDRP and SCR resources on a voluntary basis, at the request of a Transmission Owner, in targeted subzones to solve local reliability problems. The TDRP program is currently available in Zone J, New York City.

Generation

Behind the meter generation is accounted for by individual transmission owners and is not assessed by NYISO. All units are considered existing certain.

There are no future-planned additions for the current season. In the event there were, they would be counted in the month they come into service.

On-peak capacity values are determined by applying a derate specific to the type of generator. Wind generators are derated 81.9 percent , run-of-river hydro 45percent, large hydro 2 percent, landfill gas 16.6 percent, refuse and wood biomass 8.05 percent, and thermal units 8.76 percent.

Capacity Transactions

Capacity purchases in New York are not required to have accompanying firm transmission reservations, but adequate transmission rights must be available to assure delivery to New York when scheduled. External capacity is also subject to external availability rights. Availability on the import interface is offered on a first-come first-serve basis. The total capacity purchased for this summer operating period may increase since there remains both time and external rights availability.

Due to NYISO market rules, information on specific import and export transactions is considered confidential. Information on the aggregated or net expected capacity imports and exports during peak winter conditions is not yet known. Capacity is traded in the NYISO market as a monthly product, and total imports and exports are not finalized until shortly before the month begins.

Transmission

The reliable operation of the transmission system on a short term basis is maintained the through the coordinated scheduling of planned transmission and generation outages, the monitoring of real time system configuration, and the invocation of appropriate system transmission limits based on the expected system configuration. Planned outages are scheduled to minimize the limitations on transfer capability within the NYISO area. Commitment, dispatch, and interchange are then developed within the expected transmission system limitations.

Stability and, where appropriate, voltage collapse transfer limits are established for key interfaces on the NYISO system. These limits are established for peak load, all-lines-in service conditions, as well as for bulk power equipment outage conditions.

Pre-contingency high and low voltage limits are established which insure acceptable post-contingency voltage performance for key bulk power stations, under peak load conditions for the most severe criteria contingencies.

The system is committed and dispatched to on a day ahead, next hour and real time basis to respect all thermal limits as well as all interface limits.

In the NYISO, reactive power limitations are addressed through the establishment of pre-contingency high and low voltage limits, interface stability limits and interface voltage collapse limits. Analysis is conducted where transfers are stressed under peak load conditions, and the system response to NPCC criteria contingencies evaluated. (NPCC criteria contingencies include permanent faults on multiple circuit towers as well as stuck breaker contingencies involving multiple transmission elements.)

Pre-contingency voltage limits are established from steady state power flow analysis of peak load transfer conditions, where the most severe criteria contingency results in the local voltage declining to its post contingency low voltage limit (typically 0.95 p.u.).

Interface stability limits are established from dynamic simulation analysis of peak load transfer conditions where the most severe criteria contingency results in a system response that is not clearly damped within 15 seconds.

Interface voltage collapse limits are established from steady state power flow analysis of peak load transfer conditions where the most severe criteria contingency results in a system response of voltage collapse.

A ten percent margin is applied to the highest transfer condition which resulted in a stable peak load system response to establish the interface stability limit.

A five percent margin is applied to the highest transfer condition for which a power flow solution was attainable.

There are no other issues that are unique to the New York Control Area.

The NYISO conducts various transmission planning studies including the following:

- Reliability Needs Assessment analysis.[44]Comprehensive Reliability Plan analysis.[45] An annual Area Transmission Review evaluating the system five years in the future.[46]Locational Minimum Installed Capacity Requirements Study.[47]

[44]http://www.nyiso.com/public/webdocs/services/planning/reliability_assessments/2010_Reliability_Needs_Assessment_Final_Report_September_2010.pdf

[45] http://www.nyiso.com/public/webdocs/services/planning/reliability_assessments/CRP_2010_FINAL_REPORT_January_11__2011.pdf

[46] http://www.nyiso.com/public/webdocs/services/planning/reliability_assessments/NYISO_2011_Interim_ATR_FINAL.pdf

[47] http://www.nyiso.com/public/webdocs/services/planning/resource_adequacy/LCR_OC_report_final.pdf

NPCC-Ontario (IESO)

Planning Reserve Margins

Reserve requirements are established in conformance with the NPCC Regional Reliability Reference Directory #1. The latest study results are published in the "18-Month Outlook Update: An Assessment of the Reliability and Operability of the Ontario Electricity System from March 2012 to August 2013 Interim Update 1". This report and the accompanying methodology document are available at: www.ieso.ca/forecasts.

The Ontario system is summer peaking. Prior to 1999, the system was winter peaking but since that time the system has been summer peaking due to the increased penetration of air conditioning load.

The expected level of Existing-Certain resources is calculated on the "maximum outage day," which is the day with the maximum amount of unavailable generating capacity in that planning week. IESO resource adequacy assessments include a probabilistic allowance for random generator forced outages based on generator reliability information provided by market participants, or on industry-wide data for similar facilities.

Future Planned includes all resources that are scheduled to come into service and are assumed available over the study period. It recognizes resources are not available during times for which the generator has submitted planned outages.

Ontario has no energy only resources to include in the planning reserve margins.

All transmission-constrained generation is subtracted from the Existing-Certain Resources when calculating the Reserve Margin.

Demand-side management programs, including demand response, are treated as resources.

[1.2.7] All incremental distributed generation is being contracted under feed-in-tariff programs run by the Ontario Power Authority (OPA). The OPA provides the IESO with information for distributed generation. Based on the fuel type, a production estimate is generated and applied in the form of a demand reduction starting on the in-service date specified in the contract.

The IESO does not currently account for the impact on demand of the variability in embedded generation. With the growth in behind-the-meter generation, this issue is currently being reviewed to assess how to best incorporate these impacts.

Reserve levels are presented without any imports or exports assumed to be available

The reserve margin assessment includes variability in demand due to weather volatility. This is the most significant contributor to deviations in peak demand. The relatively short length of our reliability analysis (18-month) and frequency of updates (quarterly) means that the IESO does not try to incorporate demand assumption uncertainty. Economic trends do change slowly over time and can be picked up in the next forecast.

The IESO uses the General Electric Multi-Area Simulation (MARS) computer program to determine the reserve margin required to meet the NPCC resource adequacy criterion.

The Reference Planning Reserve Margin Level has decreased since the prior season, as a result of changes in the planned outage schedule, implementation of new generation, and broader implementation of renewable resources.

Demand

The forecasted peak demand is coincident.

The forecasted peak demand is based on Normal weather. The Normal weather scenario uses 31 years of history to determine the median monthly peak demand. Therefore, monthly peaks have a 50/50 chance of being surpassed. Our analysis includes a measure of Load Forecast Uncertainty (LFU) to account for the impact on demand due to the variation of weather. This is accounted for in reserve.

The economic assumptions are based on the most recent expectations for the Ontario economy. Particular attention is given to energy-intensive industries. Overall economic growth is modest and primarily coming from the service and construction sectors. As such, electricity demand is expected to remain fairly flat.

The Ontario system is summer peaking. Prior to 1999, the system was winter peaking but since that time the system has been summer peaking due to the increased penetration of air conditioning load.

Demand-Side Management

Energy efficiency is treated as a part of conservation.

The IESO receives estimates of conservation savings from the Ontario Power Authority (OPA), which is the agency responsible for measuring the impacts of the various conservation programs. The OPA provides the IESO with projected conservation as well. This information is incorporated into the demand forecast and acts to lower both peak and energy demand.

The IESO adds the amounts of dispatched loads back into the demand history. The forecast of demand is made at this “recalibrated” level. In the forecast the amount of reliable demand response is treated as a resource to meet demand.

Generation

All incremental distributed generation is being contracted under feed-in tariff programs run by the OPA. The OPA provides the IESO with the contract information of distributed generation. Based on the fuel type a production estimate is generated and applied to reduce demand starting at the in-service date specified in the contract.

Existing resources include all resources whose commercial in-service date or contract start date precede the most recently published 18-Month Outlook. Existing – Certain includes only the available capacity of these resources, while Existing-Other includes resources that are not available due to seasonal derates and maintenance derates or outages.

Future resources are all planned resources whose commercial in-service date or start of contract begins between the date of the most recently published 18-Month Outlook and the end of the seasonal assessment time frame. The Future-Planned category includes only the available capacity of these resources while the Future-Other includes capacity that may not be available due to seasonal derates and maintenance derates or outages.

To model wind resources in the seasonal assessments, the IESO uses an estimated wind capacity contribution during peak demand hours. This model captures wind output during the top five contiguous daily peak demand hours for the winter and summer seasons, as well as monthly shoulder periods. Two sets of wind data are considered: simulated wind data over a fixed 10-year history, and actual wind farm output data collected since March 2006. A conservative approach is employed, which selects the lesser value of the two data sets (simulated vs. actual) for each winter/summer season and shoulder period month. For the seasonal assessments, wind capacity contribution is represented deterministically, by selecting median values observed during the winter and summer seasons and shoulder period months. The wind capacity contribution for the summer season, June to August, is estimated at 13.4 percent of the installed capacity. The factor used for the shoulder month, September, is 16.6 percent.

Hydroelectric generation output forecast is based on median historical values of hydroelectric production and contribution to operating reserve during weekday peak demand hours. Through this method, routine maintenance and actual forced outages of the generating units are implicitly accounted for in the historical data. Market data, starting from May 2002, is used, with new values calculated annually as additional years of market experience are acquired.

No other variable resources (solar etc.) are connected to the IESO-controlled grid or are expected to be connected in the study period.

The forecast of hydro generation was enhanced in November 2011 to account for the impact of project related long-duration outages (e.g. hydro facility expansions and major equipment replacements and/or repairs) that occur less frequently than regular maintenance. The hydroelectric performance is monitored on a monthly basis and adjustments may also be made to the forecast values when water conditions drive expectations of higher or lower output that deviates from median values by approximately 500 MW for two consecutive months.

Capacity Transactions

In its determination of resource adequacy, the IESO plans for Ontario to meet NPCC regional criteria without reliance on external resources. There are no firm imports or exports identified for the summer period.

Transmission

[6.1] Ontario assesses the current and future adequacy of the IESO-controlled grid, to prepare the IESO's 18-month outlooks, to identify the need for system enhancements and to evaluate the effectiveness of planned generation and transmission enhancements, using the criteria stipulated in the Ontario Resource and Transmission Assessment Criteria Requirements document.[48]

The Ontario Resource and Transmission Criteria document describes the criteria used to measure reactive power-limited areas, voltage stability margins and any other transmission issues.

The IESO regularly conducts transmission studies that include results of stability, voltage, thermal and short-circuit analyses in conformance with NPCC criteria. The IESO's transmission studies are conducted to comply with the NERC TPL standards, in addition to NPCC regional directories.

The IESO has market rules and connection criteria that establish minimum dynamic reactive requirements, and the requirement to operate in voltage control mode for all resources connected to the IESO-controlled grid. In addition, the IESO's transmission assessment criteria include requirements for absolute voltage ranges, and permissible voltage changes, transient voltage-dip criteria, steady-state voltage stability and requirements for adequate margin demonstrated via pre- and post-contingency P-V curve analysis. These requirements are applied in facility planning studies. Operating security limit studies review and confirm the limiting phenomena identified in planning studies.

[48] Ontario Resource and Transmission Assessment Criteria Requirements document http://www.ieso.ca/imoweb/pubs/marketAdmin/IMO_REQ_0041_TransmissionAssessmentCriteria.pdf

NPCC-Québec

Planning Reserve Margins

Assumptions used to establish reserve margin criteria, target margin levels and resource adequacy levels, and results thereof, are discussed in the last 2011 Québec Area Comprehensive Review of Resource Adequacy (Approved by NPCC's Reliability Coordinating Committee on November 29, 2011) and can be found on the NPCC website.

The peak season in Québec is winter. Summer peak loads are typically about 58 percent of winter peak loads. Planning Reserve Margin calculations for summer reflect this state of facts. System planning is based on winter numbers.

Existing-Certain resource reflect generation that is forecasted to be available on the system during the summer period, after having accounted for maintenance outages, hydro and wind derates, and other inoperable resources. In Québec, 97 percent of Existing-Certain resources are hydro.

Summer is the preferred season for transmission maintenance. Therefore, quite a number of 735 kV lines (among other equipment) are out of service for maintenance during this period. This may cause certain transmission limited (bottled) resources over and above generator maintenance because perfect synchronization of all maintenance plans is impossible. However, if this transmission maintenance was forecasted to cause any transmission system client to eventually reduce his obligations (curtail load, exports or imports), then the transmission outages would be recalled and rescheduled on a short term basis. For this reason, no Transmission-Limited Resources have been included in this assessment.

Behind-the-meter generation resources are integrated into the assessment through the demand forecast.

From time to time, Hydro-Québec Distribution may rely on import contracts for resource adequacy. This is usually during Winter Operating Periods. No imports are required for this summer season.

Hydro-Québec Distribution is a full member of the Northeast Power Coordinating Council, inc. (NPCC). As such, in its resource adequacy assessments, HQD follows the directives contained in the document "Regional Reliability Reference Directory #1 – Design and Operation of the Bulk Power System". Compliance with Directory #1's resource adequacy design criterion is based on a loss of load expectation (LOLE) due to resource deficiencies of no more than 0.1 day per year. This resource adequacy criterion is used by the Area to establish its Reference Planning Reserve Margin and is approved by the Québec Energy Board. Since the Québec Area is winter peaking, the target reserve margin is calculated for winter periods and is about 10 percent. The Reference Planning Reserve Margin Level is the same as the one used in the prior season and, as indicated, is set at 10 percent.

Demand

Total Internal Demand is calculated for the Québec Area as a single entity. There is no demand aggregating and the Area's peak forecast information is coincident. The peak season in Québec is winter.

Load forecasts are prepared using end use models for different electricity consumption sectors, combined with data gathered through customer surveys, economic, demographics and technological assessments, as well as other factors that impact electricity use. The peak load forecast is based on 36-year average temperatures (1971-2006), adjusted by 0.30°C (0.54°F) per decade starting in 1971 in order to reflect the impact of climatic change in Québec. Each year of historical climatic data is adjusted ±3 days to gain information on conditions that occurred during either a weekend or a week day. Such an exercise generates a set of 252 different demand scenarios. The base case scenario is the arithmetical average of the peak hour for each scenario.

Demand-Side Management

Energy Efficiency / Conservation Program impacts are first estimated using technical and economic potential models, market/engineering studies or pilot project results. During program operation periods, energy conservation impacts are evaluated by using the number of customers who implement energy efficiency projects and products. Energy conservation impacts are later evaluated by an independent professional firm to validate final results. For industrial customers, a baseline method can also be used. All evaluations of Energy Efficiency / Conservation Program impacts are approved by the Québec Energy Board.

Dispatchable and controllable Demand Response Programs are not required nor available during Summer Operating Periods within the Québec Area.

When forecasting demand, energy efficiency programs and energy saving trends are accounted for by HQD. The total amount of energy efficiency/conservation associated with existing and projected programs is estimated to be equivalent to approximately 900 MW for the 2012 summer's peak.

Generation

Hydro-Québec Distribution offers two options to its customers who produce electricity using their own equipment to meet part of their energy needs:

1) The first option is net metering offered to customers connected to the grid who operate power generation equipment from eligible renewable sources to produce electricity for their own use. Hydro-Québec Distribution allows generation equipment to be connected to the power system and surplus power to be injected onto its grid in exchange for kilowatt hour credits applied to the customers' bill. This type of generation is in an early stage of development and the estimated amount is negligible. 2) The second option is self-generation without compensation offered to customers connected to the grid who operate power generation equipment of any sort (generator, wind turbine, etc.) to produce electricity for their own use. Hydro-Québec Distribution allows generation equipment to be connected to the power system and surplus power to be injected onto its grid, but does not provide compensation. These resources are integrated into the assessment through the demand forecast.

Units classified as "Existing-Certain" are those that are considered available to generate during the assessment period. Equipment that has been mothballed for the assessment period is classified as "Existing-Inoperable".

Future-Planned resource represents generation that will be placed in service during the assessment period.

The Québec Area has not evaluated the value at the summer's peak for wind resources since the Québec Area is winter peaking. For that reason, wind capacity is derated by 100 percent during the summer.

Transmission

TransÉnergie's significant operating studies are performed for the winter season, where weather conditions will translate into higher demand levels. Readers may refer to previous NERC Winter Reliability Assessment for details. Assessments are available at this website address.[49] Summer operating studies usually refer to transmission maintenance scheduling. Transmission outages are scheduled taking into account generation outages, load forecasts, transmission interface loading, firm and non firm exports, and any weather, geomagnetic, or forest fire disturbance that may be forecasted on a short term basis.

The Québec Area participates in NPCC's seasonal CO-12 (Operations Planning) and CP-8 (Multi-Area Probabilistic Assessment) Working Group assessments of system reliability. These assessments are available at this website address.[50]

No particular operational problems have been observed for the oncoming 2012 Summer Operating Period.

Hydro-Québec TransÉnergie's (HQT) system consists of an extensive 735 kV network underlain with 315 kV, 230 kV and 120 kV subsystems totaling close to 21,000 line miles. Large generation complexes have been developed (and are continuing to be developed) in the northern parts of the system whereas load centers are located in the southern parts of the system. Telecommunications and advanced protection and control applications are used to ensure reliability and improve performance. The system is planned according to NPCC and NERC Planning Standards but with additional criteria that consider system topology and substation characteristics particular to HQT's system (Complementary contingencies). Special Protection Systems (SPSs) to ensure reliability (for extreme events) are presently in use. Moreover, the Québec area is one of the four NERC Interconnections. All interconnections with neighboring systems (in the Eastern Interconnection) are either HVdc ties or radial generation/load connected to other systems.

Other tools and technologies used to enhance bulk power system reliability include:

- A planning criterion for voltage sensitivity

[49] http://www.nerc.com/page.php?cid=4|61

[50] https://www.npcc.org/Library/Seasonal%20Assessment/Forms/Public%20List.aspx

- A planning criterion for extreme peak loads
- Synchronous condensers, Static Var Compensators, Variable Frequency Transformers
- Series compensation
- Multi-band power system stabilizers
- Advanced simulation tools
- Digital relaying
- Inertial emulation of wind turbines to provide reserve

Moreover, transient and voltage stability operating studies are performed continuously by TransÉnergie to establish system operating transfer limits on all possible system configurations.
TransÉnergie has a criterion for minimum dynamic reactive requirements. Due to system geography and configuration (as outlined in the paragraph above) this is not applied to generators but to synchronous condensers and Static Var Compensators (SVCs) distributed along the system. There are presently 14 SVCs and 9 synchronous condensers on the system, each with a nominal reactive power range of -100 to +300 MVAR (with a few exceptions). The steady state operating range is -50 to +50 MVAR per compensator, so that a 250 MVAR margin per compensator is available as dynamic reactive reserve. (Up to 5,700 MVAR total). Moreover, a significant amount of 735 kV, 330 and 165 MVAR reactors may be switched on and off the system to continually keep the compensators within their operating range as system conditions change. The SVC and synchronous condenser operating range is strictly monitored during operations so that the dynamic margin is preserved at all times.

The following table shows the voltage-dip criteria applicable to the Bulk Power System and guidelines after a system contingency.

Emergency limits must be respected within five minutes after a contingency. This is done automatically by voltage regulation on the system, with the adequate amount of reactive capacity built into the system. However, the 735 kV Emergency Low Limit is quite stringent and the use of MAIS (French acronym for Automatic Shunt Reactor Switching System) is authorized after a contingency to re-establish 735 kV voltages. On the 735 kV system, the transient limit is 0.80 P.U. voltage for two seconds after fault clearing and the mid-term limit is set at 0.90 P.U. from two seconds up to five minutes after fault clearing. All transient and long term voltage stability analyses must respect these criteria.

Again, due to system geography and configuration, TransÉnergie's Bulk Power System does not necessarily show particular areas where reactive power constraints appear. As mentioned above, reactive power sources are distributed along the system for transient and long term stability considerations.

Moreover, approximately 11,700 MVAR of high voltage (315, 230, 120 and 69 kV) capacitor banks are installed in the southern part of the system. Approximately 5,200 MVAR of mid- voltage (25 and 12 kV) capacitors are installed in distribution substations. A criterion providing for equipment availability (including reactive power availability) to cover extreme peak demands (extreme weather) is implemented at TransÉnergie. This criterion covers extreme peak demands up to 4,000 MW above the normal forecast. Both steady state and stability assessments must respect this criterion.

Finally, it must be said that most of what has been mentioned in this section applies to winter conditions. During Summer Operating Periods, loads are low and challenges relate more to managing maintenance outages.

Hydro-Québec TransÉnergie, as Transmission Planner, performs formal system planning studies, impact studies for generation, load and interconnection integration and NPCC Comprehensive Review Assessments. All these studies and assessments are conducted as per NPCC Regional Reliability Reference Directory #1 "Design and Operation of the Bulk Power System" and according to NERC TPL standards.

For example, a planning study titled "Transmission System reinforcement for Year 2011" (a large scale study of the 735-kV system to cover all impacting changes on the system through 2012) has identified a number of operating limitations due to reactive power supply and the integration of the 1,250 MW interconnection with Ontario. To ensure system stability for these events a number of solutions have been put forward, which include additional reactive power sources.

Other studies such as impact studies for the integration of generation on the system are also performed by TransÉnergie. For example, a study titled "Transmission System Study for the Integration of Fifteen Wind generation sites from Call for Tenders #2005-03" recommends a transmission system upgrade scenario to integrate 2,000 MW of wind generation through 2015.

The filing to the Québec Energy Board for wind generation integration includes shunt capacitor additions, series compensation additions, Static Var Compensator (SVC) additions, nominal current upgrades in existing series compensation and various protection projects. These projects have been approved by the Québec Energy Board.

The next hydroelectric generation project to be integrated on the system from 2014 to 2020 is the Romaine Complex on the Lower North Shore of the St. Lawrence River. This project consists of four generating stations totaling 1,550 MW. The system upgrades and additions – including 735 kV upgrades – needed for the project have been presented to the Québec Energy Board on March 2, 2011 and approved on June 16, 2011. New 735 kV transmission (new Micoua to Outardes line) will be required as well as a new 735 kV switching station (Aux Outardes Station) on the Manicouagan-Québec sub-system in 2014. These studies' object is the mitigation of dynamic and static voltage support on the 735 kV system. Regional integration studies mostly mitigate local overload problems occurring due to the additional capacity in each regional subsystem.

Presently, Hydro-Québec TransÉnergie is adding a new 735-kV section at Bout-de-l'Île (East end of Montréal Island) substation. The Boucherville – Duvernay line (Line 7009) which passes by Bout-de-l'Île will be split into two parts and looped into the new station. The project also includes the addition of two 735/315 kV, 1,650 MVA transformers. This new 735-kV source will permit redistribution of load around the Greater Montréal area and will absorb load growth in the eastern part of Montréal. This project will enable future major modifications to the Montréal area regional sub-system. Many of the present 120 kV distribution stations will be rebuilt into 315 kV stations and the Montréal regional network will be converted to 315 kV.

A number of Regional Planning Studies are presently ongoing leading to Regional Integration Plans in Montréal and Québec City, as well as their suburban areas. These plans are now leading to projects to replace existing 120 kV substations these areas by 315 and 230 kV satellite substations, thus ensuring that the system can pick up load growth in a manageable and sustainable manner.

Other ongoing transmission planning studies concern:

- a new 735-kV line between Chamouchouane substation and Montréal.
- the Québec – New Hampshire 1,200 MW HVdc interconnection.

PJM

Planning Reserve Margins

PJM has adopted a Loss of Load Expectation (LOLE) standard of one occurrence in ten years. PJM performs an annual LOLE study to determine the reserve margin required to satisfy this criterion. The study recognizes, among other factors, load forecast uncertainty due to both economics and weather, generator unavailability, deliverability of resources to load, and the benefit of interconnection with neighboring systems. The methods and modeling assumptions used in this study are available in PJM Manual 20.[51]

Since PJM is summer-peaking, the coincident 50/50 summer peaks are used in resource adequacy evaluations.

PJM's forward capacity market (RPM) requires that units are committed three years in the future. As new units are accepted into the Capacity totals, they are considered Future-Planned for future years. For the period beyond the three-year Capacity market timeframe, projects in the PJM Generation queues with signed Interconnection Service Agreements are also considered Future-Planned.

The remaining generation in the PJM Generation Interconnection Queues is considered Conceptual and is not considered in our Reserve Margin calculation.

Energy-Only units only participate in our Energy Market. They are not considered in our Reserve Margin calculation. Some PJM Energy-Only units are Transmission-Limited resources and only participate in our Energy Market. They are not considered in our Reserve Margin calculation.

Demand side resources accepted through the forward capacity market is DSM that is dispatched like generator resources and is treated as such. The more typical type of Demand side resource is the kind that is retained for use by the PJM operators during capacity emergencies and reduces load.

Behind-the-meter generation is not considered at all in PJM Reserve Margin calculations.

External imports are fully counted in Reserve Margin studies if the transfer is firm for both generation and transmission.

The PJM Reserve Requirement has remained relatively unchanged for the last several years; varying by 0.1 percentage points. This change can be attributed to varying forced outage rates.

PJM has no subregions.

[51] http://www.pjm.com/documents/~/media/documents/manuals/m20.ashx

Demand

The PJM Load forecasting methodology is in PJM Manual 19.[52]

As PJM is summer-peaking, the coincident 50/50 summer peaks are used in resource adequacy evaluations.

Demand-Side Management

Energy Efficiency programs included in the load forecast are approved for use in the PJM Reliability Pricing Model (RPM). Measurement and verification (M&V) of energy efficiency programs are governed by rules specified in PJM Manual 18B.[53] To demonstrate the value of an energy efficiency resource, resource providers must comply with the measurement and verification standards defined in this manual by establishing M&V plans, providing post-installation M&V reports, and undergoing an M&V audit. Participants submit load data from the EDC meters used for retail service or from meters meeting PJM's standards. See PJM Manual 11, Section 10.6.[54] Participants can be audited.

Generation

Distributed generation accepted in the PJM forward capacity Market is treated just like any other generator. Behind-the-meter generation is not accounted for in PJM.

Existing-Certain are units that have been accepted in PJM's forward capacity market for the current year. No capacity resource changes are expected though the summer of 2012. Acceptance of Capacity changes as Existing Certain occur only on June 1 of each year. Existing-Other is used to account the portion of variable units not accepted a PJM Capacity. Existing-Inoperable is not used in PJM at this time.

PJM's forward capacity market (RPM) requires that units are committed three years in the future. As new units are accepted into the Capacity totals, they are considered Future-Planned for future years. For the period beyond the three-year Capacity market timeframe, projects in the PJM Generation queues with signed Interconnection Service Agreements are also considered Future-Planned. Future-Other is used to account the portion of variable units not accepted a PJM Capacity.

Variable resources are only counted partially for PJM resource adequacy studies. Both wind and solar initially utilize class average capacity factors which are 13 percent for wind and 38 percent for solar. Performance over the peak period is tracked and the class average capacity factor is supplanted with historic information. After three years of operation only historic performance over the peak period is used to determine the individual unit's capacity factor.

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[52] http://www.pjm.com/~/media/documents/manuals/m19.ashx

[53] http://www.pjm.com/~/media/documents/manuals/m18b.ashx

[54] http://www.pjm.com/~/media/documents/manuals/m11.ashx

Capacity Transactions

All transactions are firm for both generation and transmission. Transactions that are not firm for both generation and transmission are not included in a reliability assessment. No imports or exports are based on partial path reservations or Liquidated Damage Contracts. There are no capacity transaction details that are unique to PJM.

Transmission

Outages of both generation and transmission are studied at various operational time horizons: seasonal, weekly and daily. Operations Planning can shuffle around planned outages to take into account forced outages and abnormal weather. Section 4 of PJM Manual 3[55] describes the outage planning process.

RFC and SERC interregional studies are performed each season under the Easter Interconnection Reliability Assessment Group (ERAG). These studies monitor transmission and generation constraints in all the regions under study.

PJM has developed Reactive Transfer Interfaces to ensure sufficient dynamic MVAR reserve in load centers that rely on economic imports to serve load. PJM day-ahead and real-time Security Analysis ensure sufficient generation is scheduled / committed to control pre-/post-contingency voltages and voltage drop criteria within acceptable predetermined limits as outlined in M-3, section 3.[56]
There are no other transmission issues unique to PJM.

The 2011 PJM Regional Transmission Expansion Plan[57] report was issued on February 28, 2012.

[55] http://www.pjm.com/~/media/documents/manuals/m03.ashx

[56] http://www.pjm.com/~/media/documents/manuals/m03.ashx

[57] http://www.pjm.com/documents/reports/rtep-report.aspx

SERC-E

Planning Reserve Margins

Individual entity reserve/target margin criteria or resource adequacy levels are based on prevailing expectations of reasonable lead times for the development of new generation, procurement of purchased capacity, siting of transmission facilities, and other historical experiences that are sufficient to provide reliable power supplies. Other assumptions include levels of potential DSM activations, scheduled maintenance, environmental retrofit equipment, environmental compliance requirements, purchased power availability, and peak-demand transmission capability/availability. Risks that would have negative impacts on reliability are also an important part of the process to establish assumptions. Some of these risks would include the deteriorating age of existing facilities on the system, significant amount of renewables, increases in Energy-Efficiency/DSM programs, extended base-load capacity lead times (i.e., coal and nuclear), environmental pressures, and derating of units caused by extreme hot weather/drought conditions. In order to address these concerns, companies continue to monitor these risks in the future and make any necessary adjustments to the reserve margin target in future plans.

Utility planning reserve margins in the SERC-E reporting area are based on summer peaks (as reported in February 2012). All resources included in entity resource adequacy assessments are firm capacity resources and are either located inside the area or are delivered over firm transmission contracts. Therefore, energy-only and transmission-limited resources are not considered in these assessments. Import and export commitments have been included in the reserve margin calculations for the reporting area. Behind-the-meter generation is not a part of the calculation in this reporting. However, some rely on standby generator programs and the interruptible service programs to help maintain the reliability of its electrical system. There are currently about 200 MW of capacity made available to the system through these programs. Load forecast include the impact of specific DSM. These values of demand and energy are based on analysis of historical customer usage reductions associated with existing internal programs. Demand assumptions are assessed through a variety of methods to predict load. These may include regressing demographics, economics, specific historical weather and demand assumptions, or the use of a Monte Carlo simulation using multiple years of historical weather.

Utilities within this reporting area do not establish any regional/reporting area targets or reserve margin criteria on an area-wide basis. As stated above, entity results show that they are planning for reserves in the range of 12 to 15 percent for the upcoming summer through various methods. Additionally, the reported margins show planning margins are above the NERC Reference Margin Level of 15 percent.

Demand

The 2012 summer total internal demand projection is based on average historical summer weather and is the sum of non-coincident forecast data reported by utilities in this summer-peaking area. Assumptions have been adjusted for normal weather and declining economic conditions for both the United States and regional economies. Since the economic recession and subsequent initial recovery, entities report that they have significantly adjusted their long-term models and enhanced near-term hourly forecast models, which is the initial year of the long-term outlook.

Demand-Side Management

Measurements and Verification (M&V) for interruptible Demand Response programs for larger customers are conducted on a customer-by-customer basis. These include an annual review of customer information and firm load requirements. Compliance is determined by a review of customer load data as related to the terms and conditions of the electric rate schedule.

Independent third-party consultants specializing in the M&V of Energy-Efficiency program impacts provide the appropriate specific procedures involving the following phases:

- Sample design and selection
- Data collections (such as field verification of installations, billing data, metering data, building/equipment/occupant characteristics data, customer surveys, etc.)
- Statistical/engineering analysis
- Reporting of results.

Generation

The SERC-E reporting area has minimal distributed generation or behind-the-meter generation. Behind-the-meter generation is accounted for by netting out generation with loads when performing reliability studies. Consequently, distributed generation or behind-the-meter generation is not reported separately in the assessment.

Existing-Certain generation resources are available to operate and deliver power within or into the region during the period of analysis in the assessment. Existing-Other generation resources may be available to operate and deliver power within or into the region during the period of analysis in the assessment, but may be curtailed or interrupted at any time for various reasons. This category also includes portions of intermittent generation not included in Existing-Certain. Existing-Inoperable generation resources are out-of-service and cannot be brought back into service to serve load during the period of analysis in the assessment.

Future-Planned generation resources are anticipated to be available to operate and deliver power within or into the region during the period of analysis in the assessment. Future-Other generation resources are future generating resources that do not qualify in Future-Planned are not included in the Conceptual category.

Existing (Certain, Other. and Inoperable) resources are currently in-service or "iron-in-the-ground" at the time of reporting. This capacity is projected to help meet demand during this time period. Future resources are anticipated to be added during the assessment reporting period (as of February 2012). These resources have achieved one or more of these milestones: construction has started, regulatory permits (including site, construction, environmental) have been approved, regulatory approval has been received to be in the rate base, approved power purchase agreement, and approved and/or designated as a resource by a market operator.

Variable resources are limited within the SERC-E reporting area. However, biomass that is located in the area is firm capacity. It is calculated to an hourly megawatt value that is based on expected firm/non-firm capacity and forecasted availability. Variable resources are assessed for their availability to meet the needs of customers reliably and economically, based on the requirements of the standard and maintaining the flexibility to make long-term resource decisions. Due to limited availability of this resource, no enhancements have been made to entity processes since the last reporting period.

Capacity Transactions

All purchases are backed by firm contracts for both generation and transmission and are not considered to be based on partial path reservations. Of the imports/exports below, very few are associated with LDC in which the contracts are considered 100 percent “make-whole.” No additional detail is available to describe the uniqueness of the contracts.

Transmission

Annual and seasonal assessments are performed for the area regularly. These assessments serve to develop a seasonal strategy for maintaining adequate system operating performance. Entities are also active participants in the SERC Near-term Study Group (NTSG), which regularly performs annual reliability studies for summer and winter peak conditions, as well as quarterly OASIS studies for summer, fall, winter, and spring conditions. This group also studies interregional transfer capabilities and shares the results with neighboring utilities within the group through a secured site. Internal company studies are performed each spring for summer operating conditions (forecasted load, generation resource availability, scheduled transmission outages, available transmission service). Based on the seasonal operating study, procedural guidance is updated for the upcoming summer seasonal period for mitigation of identified potential reliability issues. In one case, a list of critical transmission equipment for summer operations is updated and communicated to the transmission maintenance crews to ensure the equipment is properly maintained prior to the upcoming summer peak season. Any concerns identified in the seasonal operating study are also communicated to the planners so that these issues can be studied and, if needed, plans are developed to minimize reliability impacts that may occur in future summer seasons. However, no unique operational problems were observed for the 2012 summer season.

Transmission maintenance schedules are carefully reviewed and evaluated to insure reliability concerns are addressed, and to permit as much prioritized maintenance as can be accommodated prior to seasonal peak periods. Likewise, new construction efforts are focused on completing facilities ahead of seasonal peak periods. Annual planning activities continue to address both near- and long-term facility needs.

Static reactive power and dynamics assessments are performed and produced on an individual company basis within the SERC-E reporting area. Most entities participate in the SERC Dynamics Study Group (DSG) and individually assess dynamic conditions on the system annually. Voltage stability and dynamic assessments/criteria studies are performed on an individual company basis within the reporting area. In addition, most entities participate in the Carolinas Transmission Planning Coordination Arrangement (CTPCA) to assess annual dynamic and voltage conditions on the system.

The majority of the studies for the upcoming season do not show any issues that will impact reliability. However, a study was done on the eastern North Carolina coastal area (Jacksonville/Havelock/Morehead City area) which resulted in a long-term project to install a large static VAR compensator at the Jacksonville 230 kV substation. Similarly, another dynamic study was recently performed in the western area of North Carolina, which validated the existing procedure to operate a minimum complement of generators at various load/import levels to ensure adequate dynamic reactive resources are available for this area.

Outside of regular operational studies, constraints external to the SERC subregion are evaluated as part of the SERC East-RFC-NPCC Seasonal Study Group efforts. Participation in these non-public joint studies provides companies with insight into transmission and generation constraints external to the area

Vulnerability Assessment

The study recognizes, among other factors such as load forecast uncertainty due to economics and weather, generator unavailability, deliverability of resources to load, and the benefit of interconnection with neighboring systems. Uncertainties may also be addressed through capacity margin objectives and practices in other resource assessments at the operational level. These studies may be performed annually using inputs provided from generator operators. As conditions warrant, entities may see the need to perform additional assessments to mitigate challenging conditions on the system. Entities report that historical studies have determined that a minimum reserve of 12 percent is adequate for reliability. The latest studies have identified that future generation is needed to achieve planning adequate reserves. Entities will account for this in their long-term generation plans. Overall, operational problems are not anticipated for the summer.

SERC-N

Planning Reserve Margins

Individual entity criteria are established based on the Balancing Authority's criteria such as most severe single contingency, cost of unserved energy, unit availability, import availability/capability, load forecast, and loss-of-load probability studies (such as 1 day in 10 years). Other utilities report that planning reserve margins are established with the objective of minimizing overall cost of reliability to the customer, while not exposing customers to significant risk. To achieve this goal, planning reserves are calculated on a probabilistic assessment of reliability under uncertainty, which includes uncertainty related to weather, economic growth, unit availability, transmission capability, and other drivers, to determine expected reliability costs at various levels of reliability. Using this analysis as a basis, a target level of planning reserves is selected such that the cost of additional reserves plus the cost of reliability events to the customer is minimized. This target (optimal) reserve margin is then adjusted to reduce risks and enhance reliability beyond minimum levels to produce the final level of planning reserves that are used for study purposes. Entity results show that they are planning for reserves in the range of 12 to 15 percent for the upcoming summer. Entities continue to implement new study capabilities and detailed probabilistic assessments into their annual planning processes.

Utility planning reserve margins in the SERC-N reporting area are based on projected summer peaks (as reported in February 2012). Transmission-limited or energy-only resources are not considered in resource adequacy area assessments. Import and export commitments have been included in the reserve margin calculations for the reporting area. However, behind-the-meter generation is not a part of the calculation in this reporting. Currently, the contributions of demand response programs are included in long-range capacity planning studies based on analysis of the particular program impacts, historical trends of DR effectiveness in the region, and system cost-effectiveness criteria, which combine to set a dependable capacity value of DR for use in summer peak adequacy assessments. It is treated as a resource within most entity assessments and not as a reduction in load. Scenario planning is employed to evaluate the impact on system reliability for differing assumptions of DR effectiveness. To address demand assumptions, entities base expected economic and normal weather forecast conditions as determined by historical system average weather. Demographics, employment projections, energy exports, and gross regional product increases and decreases are considered in the forecast.

Utilities within this area do not adhere to any regional/reporting area targets or reserve margin criteria. As stated above, entity results show that they are planning for reserves in the range of 12 to 15 percent for the upcoming summer through various methods. Additionally, the reported margins show planning margins are above the NERC Reference Margin Level of 15 percent.

Utilities do not adhere to any regional or Assessment Area Reference Reserve Margin Level. However, some individual entity criteria is established based on state public service commissions or the Balancing Authority's criteria, such as most severe single contingency, cost of unserved energy, unit availability, import capability, load forecast, and loss-of-load probability studies (such as 1 day in 10 years). Other utilities reported that planning reserve margins are established with the objective of minimizing overall cost of reliability to the customer, while not exposing customers to significant risk. To achieve this goal, planning reserves are calculated on a probabilistic assessment of reliability under uncertainty, which includes uncertainty related to weather, economic growth, unit availability, transmission capability, and other drivers, to determine expected reliability costs at various levels of reliability. Using this analysis as a basis, a target level of planning reserves is selected such that the cost of additional reserves plus the cost of reliability events to the customer is minimized. This target (optimal) Reserve Margin is then adjusted to reduce risks and enhance reliability beyond minimum levels to produce the final level of planning reserves that are used for study purposes.

Demand

The 2012 summer total internal demand projection is based on average historical summer weather and is the sum of non-coincident forecast data reported by utilities in this summer-peaking area. Assumptions have been adjusted for normal weather and current economic conditions for both the US and regional economies. Since the economic recession, entities report that they have significantly adjusted their long-term models and enhanced near-term hourly forecast model.

Secondary forecasts are also developed for extreme and mild weather conditions and for optimistic and pessimistic economic scenarios.

Demand-Side Management

Demand Response can be tracked and verified by meter reading. Some entities test summer load-control programs, residential and commercial, for operational functionality each spring and analysis of load profiles allows for verification of demand reduction. Measurement and verification for energy efficiency programs occur on a rolling schedule and consist of onsite audits, including measurement of equipment performance metrics for some, in conjunction with participant surveys for a sample of program participants. Third-party evaluators may be utilized to review the performance of programs and ensure the programs continue to achieve expected levels of reduction. Some entities plan to further refine estimates of program performance using statistical analysis of billing data for samples of participants and non-participants.

Generation

Distributed generation and behind-the-meter generation are accounted for by modeling net load and generation. A distributed or behind-the-meter generation facility is shown explicitly only if an agreement is in place for that generation to be utilized (i.e. controlled) by a Balancing Authority in SERC-N. Currently, there is no behind-the-meter generation to report in the area.

Existing (Certain, Other. and Inoperable) resources are currently in-service or “iron-in-the-ground” at the time of reporting. This capacity is projected to help meet demand during this time period. Future resources are anticipated to be added during the assessment reporting period (as of February 2012). These resources have achieved one or more of these milestones: construction has started, regulatory permits (including site, construction, environmental permit) have been approved, regulatory approval has been received to be in the rate base, approved power purchase agreement, and approved and/or designated as a resource by a market operator. Future Other units are generally designated as Conceptual.

Variable resources are very limited within this area, although there are some purchases sourced from wind that are included in the transfer amount, and a small amount of solar supply that is part of a customer-owned generation buy-back program. The assumed contribution at the time of the system peak is computed by applying a 12 percent capacity credit factor to the nameplate ratings of the associated wind generators. The contribution from the customer-owned solar resources is based on the solar insolation values for the area at the time of the summer peak. No enhancements have been made to entity processes since the last reporting period.

Capacity Transactions

The majority of exports is backed by firm contracts and do not include “make-whole provisions”. However, more than half of the imports, 3,759 MW, reported by entities within SERC-N during the peak month are not backed by a firm contract. Although not reported, import assumptions are not based on partial path reservations. No additional detail is available to describe the uniqueness of the contracts.

Transmission

Many entities within the area perform routine operating studies (biannual load forecast study; monthly, weekly, and daily operational planning efforts; annual assessment of summer peak and temperature, etc.) to assess the system. These studies take into consideration weather, demand, and unit availability. Based on the results of these studies, entities do not anticipate operational problems.

Many utilities coordinate operations processes to capture current transmission system configurations. If a transmission service request was made for long-term service, it would be evaluated from a contingency impacted transfer capability on the transmission system. Such practices are outlined in planning guidelines and communicated with third party impacts to external parties. If necessary local area generation may be re-dispatched or transmission elements reconfigured to alleviate anticipated next contingency overloads. NERC Transmission Loading Relief procedures will be invoked in scenarios that are not easily remedied by a local area solution.

Dynamics and static reactive power studies are also upheld by utilities on an individual basis. Some utilities follow the procedure of making sure the steady-state operating point is at least 5 percent below the voltage collapse point at all times to maintain voltage stability. Studies are performed on peak cases to verify system stability margins. Other utilities follow guidelines to ensure that voltage stability will be maintained via Q-V assessment. P-V analysis for certain areas of the system is also performed to monitor reliability. These studies have identified some potential localized voltage stability concerns. Entities are in the process of developing a voltage stability limit for the interface of concern. Other entities report that no static reactive power-limited areas were found. Operating guides are in place that address existing issues found in previous studies.

Utilities in the area also participate in transfer capability studies with neighboring entities through coordinated study processes (SERC, ERAG, SIRPP, and EIPC). Participation in these joint studies provides companies with insight into transmission and generation constraints external to the area. In response to developing EPA requirements, entities will work to address system changes as needed to maintain reliability.

Vulnerability Assessment

In order to ensure fuel delivery, the practice of having a diverse portfolio of suppliers is common within the Assessment Area. Entity fuel departments typically monitor supply conditions on a daily basis through review of receipts and coal burns, and interact daily with both coal and transportation suppliers to review situations and foreseeable interruptions. Any identifiable interruptions are assessed with regard to current and desired inventory levels. By purchasing from different regions, coal is projected to move upstream and downstream to various plants. Some plants have the ability to reroute deliveries among themselves. Some stations having coal delivered by rail can also use trucks to supplement deliveries.

Utilities have reported that they maintain fuel reserve targets greater than 30 days of on-site coal inventory. Fuel supplies are reported to be adequate and readily available for the upcoming summer. Multiple utilities have contracts for local coal from area mines. In the event of a potential supply or transportation disruption, entity processes allow the engagement of stakeholders that provide coal and gas services plans to manage the situation, potentially resulting in the delay or cancelation of planned unit maintenance outages or derates.

SERC-SE

Planning Reserve Margins

The contributing factors to adequate margins in the area are the addition of resources, and the expiration/acquisition of firm purchase contracts. Reserves for 2012 are anticipated to be adequate due to load forecast reductions resulting from the recent recession and economic downturn, assuming typical weather and operating conditions. Analyses also account for planned generation additions, retirements, deratings due to environmental control additions, load deviations, weather uncertainties, and forced outages and other factors. Resource adequacy is determined by extensive analysis of costs associated with expected unserved energy, market purchases and new capacity. These costs are balanced to identify a minimum cost point that is the optimum reserve margin level.

Utility planning reserve margins in the SERC-SE reporting area are based on summer peaks (as reported in February 2012). Transmission limited or energy only resources are not considered in resource adequacy area assessments. Import and export commitments have been included in the reserve margin calculations for the reporting area. However, behind-the-meter generation is not a part of the calculation in this reporting. Currently, the effects of projected DR programs are treated as minor peak demand reductions until sufficient historical data and participation in the programs can be established. However, there are some entities that capture extreme real time pricing load response in their resource analysis as a capacity resource. Overall, entities base economic and normal weather forecast conditions as determined by historical system-average weather.

Utilities within this area do not adhere to any regional/reporting area targets or reserve margin criteria. However, the State of Georgia requires maintaining at least 13.5 percent near-term (less than 3 years) and 15 percent long-term (3 years or more) reserve margin levels for investor-owned utilities. All entities indicate that projected reserve margins remain well above 15 percent which is the NERC Reference margin Level.

Demand

The 2012 summer total internal demand projection is based on average historical summer weather and is the sum of non-coincident forecast data reported by utilities in this summer-peaking area. Entities continue to use a variety of methods to predict load. These may include regressing demographics, specific historical weather and demand assumptions, or the use of a Monte Carlo simulation using multiple years' of historical weather. The economic assumptions in the forecast are from economics vendor's (Moody's Analytics, Economy.com, etc) baseline economics forecast. A very moderate escalation in the real price of electricity, continuous income growth and normal consumer load growth are also included.

Normal weather assumptions were used to forecast the load shapes for various classes. Economic assumptions are captured from analytical vendors for the area. The recession affected short-term growth for energy and peak demand forecast. Adjustments were needed to reflect lower energy sales, milder temperatures and a slower economic recovery, as well as capturing a more attainable consumer forecast.

Demand-Side Management

To address Measurement and Verification of Energy-Efficiency and DSM programs, entities may use third parties to conduct impact/process evaluations for commercial programs, or entities may use load response statistical models to identify the difference between the actual consumption and the projected consumption absent the curtailment event. Response may also be tracked and verified by the readings of meters, as well as testing residential and commercial summer load-control programs for verification of demand reduction through generation dispatch personnel. Evaluations may be conducted annually with a comprehensive report due at the end of a program cycle. Reports are projected to determine annual energy savings and portfolio cost-effectiveness.

Demand Response programs within the area consist of programs ranging from customer stand-by generation, real-time pricing or critical-peak pricing (reduces energy use based on price signaling) and interruptible demand programs (requests customers to reduce energy use) to direct load control programs (energy provider reduces customer energy use). Various utilities have residential Energy-Efficiency programs that may include educational presentations, home energy audits, home inspector programs, compact fluorescent light bulbs, electric water heater incentives, heat pump incentives, energy-efficient new-home programs, Energy Star-rated appliance promotions, appliance recycling programs, loans or financing options/incentives, weatherization, programmable thermostats, and ceiling insulation. Commercial programs may include energy audits, lighting programs, and plan review services.

Other programs such as business assistance/audits, weatherization assistance for low-income customers, residential energy audits, and comfort advantage energy-efficient home programs promote reduced energy use, supply information, and develop Energy-Efficiency presentations for various customers and organizations. Some entities are beginning to work with states' energy divisions on Energy-Efficiency planning efforts. Training seminars addressing energy efficiency, HVAC sizing, and energy-related end-use technologies are also offered to educate customers.

Generation

Distributed generation and behind-the-meter generation are accounted for by modeling net of the load and generation. A distributed or behind-the-meter generation facility will only be shown explicitly if an agreement is in place for that generation to be utilized (i.e. controlled) by a Balancing Authority in SERC-SE. Currently, there is no behind-the-meter generation to report in the SERC-SE reporting area.

In the SERC-SE reporting area, Existing (Certain, Other. and Inoperable) resources are currently in-service or "iron-in-the-ground" at the time of reporting. A unit designated as Existing-Certain is projected to help meet demand during this time period and cannot be curtailed. A unit designated as Existing-Other is available to help meet demand during this time period but can be curtailed or interrupted at any time. A unit designated as Existing-Inoperable is a unit that is unable to help meet demand during this time period but in the future could return to service. Future-Planned resources are anticipated to be added during the assessment reporting period (as of February 2012). These resources have achieved one or more of these milestones: construction has started, regulatory permits (including site, construction, environmental permit) have been approved, regulatory approval has been received to be in the rate base, approved power purchase agreement, and approved and/or designated as a resource by a market operator. Future units not meeting the Future-Planned designation are generally designated as Conceptual.

As stated, variable resources (i.e. wind and solar) are limited within this reporting area and are evaluated by analyzing their historical or projected output profiles. The result for some entities may be a determination of the comparative capacity value to that of a typical combustion turbine on the system. For many, biomass (i.e. wood, wood waste, municipal solid waste, landfill gas, ethanol, and other biomass) is the most viable renewable resource. Future planned biomass generation is included in the Integrated Resource Plans at less than the nameplate capacity for converted boilers, and at nameplate capacity for units receiving new boilers. Landfill gas facilities are included at their nameplate ratings. Contracts with external parties for these resources usually require proof of capacity and allow for capacity payment penalties for excessive unavailability and derating events. No enhancements have been made to entity processes since the last reporting period.

Variable resources are evaluated by analyzing their historical or projected output profiles. The result is a determination of the comparative capacity value to that of a typical combustion turbine on the system. There are no operational changes, concerns, or special operating procedures related to distributed resource integration or minimum demand or over generation for the period. Entities are in the process of revising their methodologies to incorporate variable resources. Projected program effects are treated as minor peak demand reductions until sufficient historical data and participation in the programs can be established. Historical observations show that load is expected to drop at weather normal peaking price levels, and reduces peak load in the resource adequacy analysis. Other forms of real-time pricing (RTP) load response are expected to drop at higher pricing level and are subdivided into separate blocks, each having an amount and a price trigger determined by analysis. This type of RTP is included in the resource analysis as a capacity resource. Interruptible load is evaluated to determine its capacity equivalent, based on the contract criteria, relative to the benefit of a combustion turbine. The resulting value is included in the resource analysis as a capacity resource limited by the contract callable terms: hours-per-day, days-per-week, and hours-per-year. Additionally, entities do not expect restrictions on Demand Response programs during this summer.

Various companies within the Assessment Area have firm transportation diversity, diverse fuel mixes, gas/coal storage, firm pipeline capacity, and on-site fuel supplies to meet the peak demand. When situations limit supply, established communications allow for additional supplies. These lines of communications include daily e-mails, phone calls, internet accessibility, SCADA and instant messaging so that entities are well aware of fuels moving to various generating stations or to storage. Some utilities have implemented fuel storage and coal conservation programs, and various fuel policies, to address concerns. Policies are also in place to ensure that storages are filled well in advance of hurricane season (by June 1 of each year). These tactics help to ensure balance and create flexibility to serve anticipated generation needs. Relationships with coal mines and coal suppliers, daily communication with railroads for transportation updates, and ongoing communication with the coal plants and energy suppliers ensures that supplies are adequate and potential problems are communicated well in advance to enable adequate response time.

Only Firm capacity is counted toward the peak in calculations. However, Future-Planned biomass generation is included in the Integrated Resource Plans at less than the nameplate capacity for converted boilers, and at nameplate capacity for units receiving new boilers. Landfill gas facilities are included at their nameplate ratings. Contracts with external parties for these resources usually require proof of capacity and allow for capacity payment penalties for excessive unavailability and derating events.

Currently, entities are developing a methodology for incorporating variable resources into planning processes. Variable resources are currently evaluated by analyzing historical and projected output profiles. The result will be a determination of the comparative capacity value to that of a typical combustion turbine on the system.

Capacity Transactions

All imports/exports were reported to be backed by firm contracts for both generation and transmission, but none are associated with LDCs or considered “make whole.” No imports/exports have been reported to be based on partial path reservations. The majority of the contracts in the area are yearly firm agreements typically lasting five or more years. Yearly firm agreements for five or more years are given “Rollover Rights”, meaning the contract can be renewed with one year notice of contract expiration.

Transmission

Transmission planners in the area regularly evaluate the transmission system through their participation in local, inter-regional and inter-regional studies. Operational studies are performed for 12 to 13 months into the future. These studies include the most up-to-date information regarding load forecasts, transmission and generation status, and firm transmission commitments for the time period studied and are often updated on a monthly basis. Additionally, reliability studies are conducted on two-day-out and next-day conditions. Studies are updated as changing system conditions warrant. Transmission constraints identified in current operational planning studies for the 2012 summer can be mitigated through generation adjustments, system reconfiguration, or other operating procedures. If additional constraints occur, mitigation procedures are in place to relieve constraints.

Utilities individually perform studies and maintain individual criteria to address any dynamic and static reactive issues. Studies are created each year for the upcoming summer and generally for a future year case. The studies did not indicate any issues that would impact reliability in the 2012 summer season. For example, several companies have performed fault-induced delayed voltage recovery (FIDVR) studies. To address dynamic reactive criterion, some utilities follow the practice of having a sufficient amount of generation on-line to ensure that no bus voltage is expected to be subjected to a delayed voltage recovery following the transmission system being subjected to a worst-case, normally cleared fault. Studies of this involve modeling half of the area load as small motor load in the dynamics model. Prior to each summer, an operating study is performed to quantify the impact of generating units in preventing voltage collapse following a worst-case, normally cleared fault. The generators are assigned points, and the system must be operated with a certain number of points on-line depending on current system conditions including the amount of load on-line and the current transmission system configuration. The study is performed over a range of loads from 105 percent of peak summer load down to around 82 percent of peak summer load conditions.

Outside of regular planning studies, individual companies have conducted assessments of the impacts of the EPA CSAPR requirements on system dispatch. Although constraints were identified through non-public studies, the EPA stayed implementation of the rule. It is uncertain at this time whether CSAPR requirements will be reinstated in 2012. Entities are working together to identify potential transmission enhancements for possible inclusion in a 2012 expansion plan.

SERC-W

Planning Reserve Margins

Individual entity reserve margin criteria are established by allocations assigned as a member of the SPP Reserve Sharing Group, a Balancing Authority's most severe single contingency, load forecast, and reserve requirement using historical allocations, and Loss-of Load expectation studies (0.1 day/year). Resource adequacy studies are conducted by the use of an LOLP model. This proprietary computer simulation model that uses Monte Carlo statistical techniques to estimate each day's "actual" peak load based on the forecast load and the load forecast variance. It also captures the total resources available to serve that load, forced outages, the characteristics of each resource, the probability of being able to meet the load, off-system sales and operating reserves. The fundamental objective of the process is: 1) to identify the amount of incremental resources necessary to serve firm load at a reliability level of no more than 1 day in 10 years loss-of-load expectation and 2) to serve interruptible retail/ limited-firm wholesale loads with an average of 10 or fewer days of interruption during the summer.

Utility planning reserve margins in the SERC-W reporting area are based on summer peaks (as reported in February 2012). Only firm capacity is counted toward the peak in calculations. In most cases, entities do not count variable resources due to its irregularity during peak demand periods. However, other entities consider wind values based on a time-period method using monthly capacity value measures. The process first examines the highest 10 percent of load hours for the respective month, and ranks wind generation in those hours from high to low. The wind generation value that exceeds 85 percent of the time is defined as the capacity value of the wind resource. This method is based on research from various sources discussing estimation of the capacity value of wind resources. For base load resources like biomass and in-stream hydro, the assumption is 100 percent of the rated capacity value. In addition, firm transmission reservations are considered for network resources that are either owned by the utility or under an executed power purchase contract. Import and export commitments are also accounted for in the reserve margin calculations. However, Behind-the-meter generation is not a part of the calculation in this reporting. Utility-administered energy efficiency and Demand Response programs are considered and will be incorporated in the retail sales and load forecast as approved.

Entities within this area do not adhere to any regional/reporting area targets or reserve margin criteria. The margins reported are well above the 15 percent NERC Reference Marginal Level. Current entity processes in assessing demand, capacity and reserve margin projections are considered to be consistent with the assumptions portrayed in last summer's reporting period. Margins are considered to be adequate for the reporting period's demand projections.

Demand

The 2012 summer total internal demand projection is based on average historical summer weather and is the sum of non-coincident forecast data reported by utilities in this summer-peaking area. Typical weather conditions are used to forecast the load shapes for the residential, commercial, and governmental classes. The forecast is also based on a forecast study that produced new econometrically based forecasts of residential/commercial/industrial load, future economic/demographic conditions, and historical data. Typical weather is defined by calculating an average daily temperature from 10 years of historical weather data and determining a month that contains the lowest differential from the ten-year monthly average. However, recent forecast reflect a slightly reduced outlook for near term electric sales and a more significantly reduced long term outlook for electric sales. The economic recession and slow recovery contribute to the reduced long term outlook; however other factors, such as increased energy efficiency, also play a part.

Typical weather conditions are used to forecast the load shapes for the residential, commercial, and governmental classes. The forecast assumes a gradual economic recovery. Entities in the area regularly develop load scenarios for outage planning purposes. These load scenarios include load forecasts based on high and low scenarios for energy sales and scenarios for alternative capacity factors. No significant changes are reflected in this year's assumptions.

Demand-Side Management

Measurements and Verification for interruptible Demand Response programs for larger customers are conducted on a customer-by-customer basis. These include an annual review of customer information and firm load requirements. Annual measurements of energy savings and costs for each of these energy-efficiency programs are also assessed. Information from these programs is used to fine tune energy-efficiency programs and to determine their cost effectiveness. Compliance is determined by a review of customer load data as related to the terms and conditions of the electric rate schedule and the requirements set forth by state regulators.

Although no Energy Efficiency contributions were reported, these programs are implemented to distribution cooperatives and the residential sector. A variety of programs ranging from home energy audits, CFL lighting, and Energy Star-rated washing machines and dishwashers, to Energy Star-rated heat pumps and air conditioners, weatherization and high efficiency water heaters have been added to company portfolios over the years. Utilities plan to offer these types of programs as long as they are determined to be cost-effective. Annual Measurement & Verification (M&V) programs measure energy savings and costs for each of these Energy-Efficiency programs. Information from these M&V programs will be used to fine tune Energy-Efficiency programs and to determine their cost effectiveness. The current forecast includes Energy-Efficiency programs that have received regulatory approval. As programs advance, they will be incorporated into retail sales and load forecasts. M&V for interruptible Demand Response programs for larger customers are conducted on a customer-by-customer basis. These include an annual review of customer information and Firm load requirements. Compliance is determined by a review of customer load data as related to the terms and conditions of the electric rate schedule. Companies adhere to measurement and verification requirements set forth by state regulators

Generation

Distributed generation and behind-the-meter generation are accounted for by modeling net load and generation. A distributed or behind-the-meter generation facility will only be shown explicitly if an agreement is in place for that generation to be utilized (i.e. controlled) by a Balancing Authority in SERC-W.

Existing (Certain, Other. and Inoperable) resources are currently in-service or "iron-in-the-ground" at the time of reporting. This capacity is projected to help meet demand during this time period. A unit designated as Existing-Certain is projected to help meet demand during this time period and cannot be curtailed. A unit designated as Existing-Other is available to help meet demand during this time period but can be curtailed or interrupted at any time. A unit designated as Existing-Inoperable is a unit that is unable to help meet demand during this time period but in the future could return to service. Future resources are anticipated to be added during the assessment reporting period (as of February 2012). These resources have achieved one or more of these milestones: construction has started, regulatory permits (including site, construction, environmental permit) have been approved, regulatory approval has been received to be in the rate base, approved power purchase agreement, and approved and/or designated as a resource by a market operator.

As stated, firm capacity is only counted toward peak calculations. In most cases, entities do not count variable resources due to its irregularity during peak demand periods. However, other entities consider wind values based on a time-period method using monthly capacity value measures. The process first examines the highest 10 percent of load hours for the respective month, and ranks wind generation in those hours from high to low. The wind generation value that exceeds 85 percent of the time is defined as the capacity value of the wind resource. This method is based on research from various sources discussing estimation of the capacity value of wind resources. For base load resources like biomass and in-stream hydro, the assumption is 100 percent of the rated capacity value. No additional enhancements have been made to entity processes since the last reporting period.

Only firm capacity is counted toward the peak in calculations. In most cases, entities do not count variable resources due to its irregularity during peak demand periods. However, other entities consider wind values based on a time-period method using monthly capacity value measures. The process first examines the highest 10 percent of load hours for the respective month, and ranks wind generation in those hours from high to low. The wind generation value that exceeds 85 percent of the time is defined as the capacity value of the wind resource. This method is based on research from various sources discussing estimation of the capacity value of wind resources. For base load resources like biomass and in-stream hydro, the assumption is 100 percent of the rated capacity value.

Due to an insignificant amount of variable generation connected to the distribution system, there are no concerns about integrating these resources onto the system. Currently entities are also studying potential approaches for incorporating variable resources into its planning processes. Wind agreements are used as a tool to allow operators to enhance reliability and can be used in situations such as curtailing for Transmission Loading Relief and managing minimum generation problems. An energy forecasting package is used to predict wind farm output given meteorological data collected at the wind farms. No issues are anticipated for the upcoming period.

Capacity Transactions

All contracts for these imports/exports are backed by firm transmission and are tied to specific generators. No imports/exports have been reported to be based on partial path reservations.

Additionally, none are associated as liquidated damage and "make whole" contracts. No additional detail is available to describe the uniqueness of the contracts.

Transmission

Transmission planners in the area regularly evaluate the transmission system through their participation in local, inter-regional and inter-regional studies. Companies within the SERC-W area regularly participate in intra-regional SERC NTSG seasonal reliability studies and in the ERAG MRO-RFC-SERC West-SPP (MRSWS) interregional studies. The preliminary study results indicate that overall, both the import and export transfer capability for SERC-W in 2012 summer is expected to slightly increase as compared to the summer of 2011. The current NTSG studies include a review of both subregional-to-subregional and company-to-company transfer capabilities. These studies do not exactly include the new SERC- W defined area transfer, but the SERC-W area is very similar to one of the defined company areas that are included in the NTSG study. Therefore, it is reasonable to expect that similar increases in the transfer capability levels would occur if a specific comparison to the SERC-W area could be made.

Companies that are transmission dependent also rely on operating studies that are performed by transmission operators. Any issues that result from the studies are addressed within the appropriate timeframe. Curtailment Processes and Emergency Response Plans are routinely updated. As necessary, transmission-wide and local area procedures, redispatch, and operating guidelines will be implemented to maintain reliability for the summer. As necessary, transmission-wide and local area procedures will be implemented, including redispatch and the implementation of operating guidelines, to maintain reliability for the 2012 summer. Because EEAs have been issued in the past for the Acadiana Load Pocket, the SPP Independent Coordinator of Transmission-Entergy will continue to monitor this area closely and implement mitigation plans as necessary as part of its Reliability Coordinator function. Entergy and other utilities within the Acadiana Load Pocket are in the process of constructing a new 230 kV overlay of the area. This project, referred to as the Acadiana Load Pocket Improvement Project, is being developed in two phases. Phase 1 one of the project was completed and placed in service by the fall of 2011. Phase 2 of the project, which is currently under construction, is scheduled to be completed by summer 2012.

Individually, transient dynamics, voltage, and small-signal stability studies are perform to assess issues for summer conditions in the near-term planning horizons as required by NERC Reliability Standards. Entities also participate in various SERC study groups to annually assess potential issues on the system. For the 2012 summer, an Under Voltage Load Shedding (UVLS) study was performed to assess the existing UVLS scheme on voltage stability and rotor angle stability in western area of Texas. The study results indicated that the potential of slow voltage recovery due to a heavy concentration of load in the area. An update of the existing UVLS scheme indicated that the existing UVLS logic should be retained, with a reduction of load block size on both blocks.

On an annual basis, long term reliability plans are developed to identify projects created to address projected reliability issues. A listing of the projects and their proposed in-service dates can be found posted in the public area of Entergy's OASIS[58].

[58] http://www.oatioasis.com/EES/EESdocs/ICT_PlanningStudiesAndRelatedDocuments.htm

SPP

Planning Reserve Margins

SPP Criteria establishes the methods and assumptions for SPP RTO members to use for projecting Planning Reserve Margins for their assessment areas[59]; they are expected to meet the Capacity Margin requirements as stated in the Criteria. SPP RTO staff creates an annual internal report that reviews capacity margins of each reporting member based on their Long Term Reliability Assessment data.

SPP RTO is a summer peaking Region; the Planning Reserve Margin is based on the summer months of June, July, August, and September. Existing-Certain capacity resources are reported by SPP RTO members and aggregated into one dataset for the Region. These resources include Internal Firm Transactions and Behind-the-meter generation. Future-Planned resources are reported by SPP RTO members and shown as future capacity resources. External Imports are reported by SPP RTO members and compared to Modeling Transactions that SPP RTO gathers annually. Demand Response Assumptions are made by SPP RTO members and are used as a load shedding tool instead of a capacity resource.

Based on SPP RTO's 2011 LOLE study, the capacity and reserve margin requirements for SPP RTO remained unchanged.

Demand

SPP RTO's Total Internal Demand is a non-coincident number based on member-submitted coincident data. Although actual demand is very dependent on weather conditions and typically includes the effects of interruptible loads, forecasted Net Internal Demands are based on a 10 to 30[60] year average summer weather, or 50/50 weather. Some SPP RTO members base their peak load forecasts on a 50 percent confidence level as approved by their respective state commission(s). This means the actual weather on the peak summer day is expected to have a 50 percent likelihood of being hotter and a 50 percent likelihood of being cooler than the weather assumed in deriving the load forecast. SPP RTO members include economic assumptions specific to their area in their individual load forecasting methods.

Demand-Side Management

SPP RTO members track and measure their own Energy Efficiency programs, which are used as a reduction to their load. SPP RTO members track Total Dispatchable and Controllable Demand Response programs, which are used as peak load shaving programs.

Generation

Behind-the-meter generation is reported to the SPP RTO by individual members and is considered to be an Existing, Certain resource.

59 SPP Criteria

60 SPP RTO members use different historical yearly averages, with the least amount being 10 years and the greatest being 30 years.

Existing-Certain units are generation on the ground and available during peak load conditions. Existing-Other generation are capacity resources that are not relied on to meet peak load, capacity not used by SPP RTO members, and/or capacity resources that are inoperable for a short period of time. SPP RTO does not include the wind de-rates when reporting values for Existing-Other total capacity. Existing-Inoperable capacity is resources that are being retired or taken out of service during the whole assessment timeframe.

SPP RTO members use SPP Criteria guidelines to calculate variable generation on-peak capacity values.[61]

Capacity Transactions

A small portion of SPP RTO capacity or Reserve Margin includes purchases external to the SPP RTO Region. The sales and Firm contracts are backed by Firm generation and transmission and are based on firm reservations.

Transmission

SPP RTO annually evaluates the transmission system on a near-term basis. The near-term analysis uses the more restrictive of NERC Planning Standards, SPP Criteria, or transmission owner criteria. The near-term analysis evaluates TPL-001 and TPL-002, and each season evaluated includes two scenarios: (1) *expected* long-term firm transmission service and (2) *all* SPP long-term firm transmission service. The 2012 Near-Term Study analysis includes both summer and winter seasons through 2017. The near-term assessment includes upgrades identified by the SPP Generation Interconnection and Aggregate Study processes. The 2012 near-term study analysis includes a voltage stability analysis of major SPP load centers by increasing transfers into the load center and testing them during non-contingency and contingency conditions.

SPP monitors voltage to ensure its system meets the more restrictive of NERC, SPP, or transmission owner criteria. SPP reviews the non-converged cases for locations that may not converge as a result of a reactive power-limited area. The 2012 near-term study will also review transfers into load centers to determine if there is potential for voltage collapse.

SPP Transmission Planning Studies Include:

1. 2012 Integrated Transmission Plan Near-Term Assessment Report, January 9, 2012[62]
2. SPP 2011 TPL Compliance Report[63]

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[61] SPP Criteria: http://www.spp.org/publications/Criteria%20and%20Appendices%20October%2024,%202011.pdf

[62] http://www.spp.org/publications/2012%20ITPNT%20Report_Board%20Approved.pdf

[63] http://www.spp.org/publications/SPP%20Comprehensive%202011%20TPL%20Compliance%20Report.doc.pdf

WECC

Assessment Area Description

The Western Electricity Coordinating Council (WECC) is one of eight electric reliability councils in North America, and is responsible for coordinating and promoting Bulk Electric System reliability in the Western Interconnection. WECC is geographically the largest and most diverse of the eight Regional Entities that have Delegation Agreements with the North American Electric Reliability Corporation (NERC). WECC's service territory extends from Canada to Mexico. It includes the provinces of Alberta and British Columbia in Canada, the northern portion of Baja California in Mexico, and all or portions of the 14 Western states in between.

Planning Reserve Margins

WECC staff and the WECC Loads and Resources Subcommittee perform an annual Power Supply Assessment (PSA) that uses a building block methodology for determining subregion Planning Reserve Margin 'targets.' Due to the construct of the building block methodology, the subregion 'target' margins vary seasonally and the 'target' margins vary among subregions. The resulting reserve margins used in the PSA are not the values used by individual LSEs or their regulators, or local governing boards to evaluate individual resource adequacy and they are not intended to supplant any of those values. Detailed information regarding the building block methodology is available in WECC's PSA report.[64]

The PSA modeling reflects an assumed 8,760-hour year with data extracts, for assessment purposes, based on the hour of the WECC Region maximum total peak demand. Resources are categorized by the BAs based on definitions provided by the Loads and Resources Subcommittee. Those definitions are essentially consistent with the NERC resource definitions but exclude the concept of Energy-Only resources. Demand-Side Management programs, out of service generation (long-term cold standby units), and behind-the-meter generation are not treated as resources. The modeling does not represent firm transfers but calculates potential inter-subregion transfers based on an assumed economic dispatch scenario with interchanges among neighboring systems (Eastern Interconnection and eastern Mexico) assumed to be zero. Intra-subregion transmission limitations, if any, are excluded. Generation is represented using seasonal ratings for most resource categories while historic hourly generation shapes are used for solar and wind resources. The amount of hydroelectric capacity modeled in this assessment is limited to the actual energy generated during an adverse hydro condition year.

Demand

The WECC modeling methodology uses monthly non-coincident Total Internal Demand and Net Energy Load forecasts that are based on an assumed average weather condition (a 50/50 forecast) and historic BA-based hourly demand load shapes that have been adjusted to reflect estimated customer demand that was un-served due to actual DSM activations. The hourly demand-load shaping effectively converts the non-coincident forecasts into hourly-coincident forecasts. Both the load forecasts and the hourly load shapes exclude behind-the-meter demands and station-service loads, including pump storage pumping loads. The BA-based forecasts are generally calculated using recent weather-normalized

[64] WECC's 2011 PSA: http://www.wecc.biz/Planning/ResourceAdequacy/PSA/Documents/2011%20Power%20Supply%20Assessment.pdf

historic loads adjusted to reflect assumed economic growth factors, expected effects of energy efficiency, the expected ‘activated’ components of DSM programs, and significant potential changes in large commercial and industrial customer demands.

Demand-Side Management

The effects of existing energy efficiency are inherently reflected in the weather-normalized historic loads used in the BAs' forecast methodologies. The expected effects of future energy efficiency and conservation programs are treated by the BAs as adjustments to the weather-normalized projections. The BAs adjust the resulting demand forecasts to reflect expected activated (used) DSM and un-activated (unused) DSM. The expected activated DSM is subtracted from the weather-normalized forecast to arrive at an expected served-demand forecast, which is reported in this assessment as Total Internal Demand. The unused DSM (i.e., served demand, not un-served demand) is reflected in this assessment as the difference between Total Internal Demand and Net Internal Demand and is subdivided into the four NERC-defined categories of: Demand-Side Direct Control Load Management (DCLM), Demand-Side Contractually Interruptible (Curtailable), Demand-Side Critical Peak-Pricing (CPP) with Control, and Demand-Side Load as a Capacity Resource.

The DSM capacities presented in this assessment reflect the non-coincident sums of LSE-based program estimates. This summation technique is consistent with the NERC-directed data reporting process. It should be noted that activation of DSM is generally under the control of the LSE and may only be indirectly controllable by a BA. Further, a BA’s activation of available local DSM may or may not occur if an external subregion or remote BA is experiencing a resource adequacy issue. The sharing of DSM capacity among BAs and subregions may not occur to the extent implied in this assessment.

It is important to the LSEs and the BAs that the programs perform as expected. LSEs routinely test their programs and program activation processes and procedures to ensure that expected program responses will occur as and when needed. Many of the programs have associated limitations such as a limited number of activations or limited activation duration over a pre-defined time period. Consequently, the LSEs and their BAs generally reserve activations for use only in emergency situations.

Generation

One of the primary concepts incorporated into WECC’s assessment process is that all generators that are metered by BA energy management systems for load calculations are included in the assessment modeling and are reported to NERC as Existing-Certain resources. All generators that are not metered by the BAs for load calculations, such as behind-the-meter generation and most distributed generation, are excluded in the assessment modeling.

Long-term cold standby units, often referred to as ‘mothballed’ units, are modeled at zero capacity and are reported to NERC as Existing-Inoperable resources. Out-of-service generation is reflected in the modeling as a scheduled maintenance/inoperable capacity reduction. WECC does not classify any resources as Existing-Other or Future-Other.

WECC classifies sun-, water-, and wind-powered generation as variable generation and models the capacity for this generation using energy-based historic data or data created for other modeling purposes. The historic data are area-specific and some BAs may cover multiple areas. The modeling for wind resources uses generation curves created from three years of one-hour interval wind speed data. Modeling for solar resources uses generation curves created from two years of insolation data. Hydro generation is modeled as being dispatched economically, limited by expected annual energy generation. The variable generation capacities used for assessment purposes reflects the modeled capacity, based on energy output, during the hour of WECCs modeled maximum Total Internal Demand.

The NERC assessment process excludes Scheduled Outage – Maintenance quantities when calculating expected reserve margins. This exclusion seemingly assumes that BA-directed scheduled maintenance may be canceled if a BA is experiencing a resource adequacy issue. However, the capacity increases that are due to cancelations of maintenance outages may not occur to the extent implied in this assessment. This is particularly true if a resource adequacy shortfall occurs unexpectedly or a shortfall expectation is identified in a time-frame that does not allow for significant scheduled maintenance adjustments by generator operators. As with DSM, there is also a possibility that sharing of a potential capacity increase may not occur among BAs and subregions.

Capacity Transactions

The WECC assessment modeling excludes contractual capacity and energy exchanges except for a few inter-subregion, plant-contingent, capacity allocations. Capacity and energy transactions with external entities (the Eastern Interconnection, and central and eastern Mexico) are not model input data and are not allowed as model dispatch options. For NERC data reporting purposes, inter-subregion interchange dispatch results are adjusted by the pre-specified capacity exchanges and are reported to NERC as Full-Responsibility Purchases/Sales while the pre-specified capacity exchanges are reported as Owned Capacity/Entitlement Located Outside the Region/Subregion

Transmission

Four subregional study groups perform seasonal System Operating Limit studies and establish limits for major transmission paths within the Western Interconnection. Information regarding the four subregional quarterly studies is routinely posted on the WECC website.[65] The seasonal operating limit studies are based on seasonal power flow base cases prepared by WECC staff.

In addition to the seasonal operating limit studies, transmission operators are responsible for establishing System Operating Limits (SOLs). A detailed presentation regarding the SOL process is available on the WECC website.[66] The WECC RC facilitates the seasonal SOL process and coordinates the communication of the SOLs. This process is detailed in its *System Operating Limits Methodology for the Operations Horizon* document.[67] The WECC RC is responsible for continuous monitoring of power system

[65] WECC Seasonal System Operating Limits (SOL)

[66] SOL Methodology Presentation

[67] System Operating Limits Methodology for the Operations Horizon

conditions, including transmission line flows, system frequency, and bus voltages. Documents related to these functions are posted on the WECC website.[68]

System operations groups are involved in transmission facility outage coordination studies on an on-going basis that involves quarterly, monthly, weekly, and/or daily outage scheduling. The WECC RC plays a key role in the daily outage scheduling process. Further details regarding the WECC RC's involvement in the outage scheduling process are presented in WECC's *Reliability Coordination – Operations Planning* document.[69]

WECC provides agreed upon processes and procedures to Transmission Planners to facilitate reactive and voltage stability studies. These documents are posted on the WECC website.[70]

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68 WECC RC Documents: http://www.wecc.biz/awareness/Reliability/Pages/default.aspx

69 Reliability Coordination - Operations Planning: http://www.wecc.biz/awareness/Reliability/WECC%20RC%20Operating%20Procedures/WECC%20RC%20Operations%20Planning.pdf

70 WECC Technical Studies Subcommittee: http://www.wecc.biz/committees/StandingCommittees/PCC/TSS/Shared%20Documents/Forms/AllItems.aspx