NERC

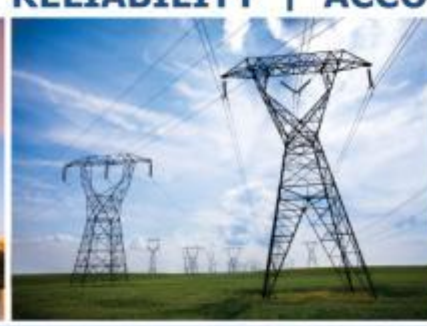
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

2012 Probabilistic Assessment

Methods and Assumptions

June 2013

RELIABILITY | ACCOUNTABILITY



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ERCOT

Summary

Electric Reliability Council of Texas (ERCOT) as a single Planning Authority operates as a single Balancing Authority and experiences its annual peak demand during summer seasons. ERCOT manages the flow of electric power to 23 million Texas customers representing 85 percent of the Texas electric load. This Loss of Load study has been prepared to fulfill the NERC requirements of a probabilistic assessment which complements the Long-Term Reliability Assessment (LTRA). It is anticipated that this report will be updated on a biennial basis. ERCOT last updated the Loss of Load Study for the ERCOT Region in 2010. The previous (2010) study was prepared internally by ERCOT Staff. The current (2012) study was outsourced to the consulting firm Ecco International. This company utilized a product called ProMaxLT™ to perform the analysis. The objective of the study is to calculate Loss of Load (LOL) Events (LOLEV), Loss of Load Hours (LOLH), and Expected Unserved Energy (EUE).

ERCOT is modeled as a single area for determination of the Target Reserve Margin of the Region. Additional analysis was done to consider transmission limitations internally to ERCOT.

As shown in Table 1 and 2, the total installed capacity was 89,051 MW in summer 2014 (91,595 MW in winter) and 94,303 MW in summer 2016 (97,082 MW in winter). The summer capacity for 2014 in the 2012 LTRA was 85,724 MW. The main reason for this difference is that the net Private Use Network (PUN) capacity[1] in the 2012 LTRA is only 4,390 MW whereas the LOL study considers the total PUNs capacity which is 8,541 MW[2]. The capacity was derated 10,156 MW in both summer and winter in both years to account for the 14.2% Non-Coastal and 32.9% Coastal Effective Load Carrying Capability (ELCC) of wind. With the inclusion of weighted average forced outage rates, the operable capacity resources was 75,011 MW in summer 2014 (77,429 MW in winter) and 80,002 MW in summer 2016 (82,644 MW in winter)[1].

No demand response was included in the Loss of Load analysis. In the 2012 LTRA, 1,318.3 MW summer (1,530.0 MW winter) for 2014 and 1,409.1 MW summer (1,665.0 MW winter) for 2016 was noted.

Ecco utilized 15 years of hourly wind data (consistent with weather conditions experienced in the years 1997 to 2011). These hourly wind generation patterns were developed in a manner consistent with the development of 15 years of load shapes for the ERCOT region. No hydroelectric generation is included in the Loss of Load study.

All generators other than wind units are modeled as thermal generators. The program assumes that these units are available to provide capacity unless the unit is on planned or forced outage. All Switchable units that can switch between the ERCOT Region and other Regions were included in the study. No solar generation was included in this study.

No sales to or purchases from regions outside of the ERCOT area of study were assumed in the LOL study. The study assumed no contribution from DC tie flows.

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[1] Private Use Network (PUN) is the "behind the meter" industrial generation in ERCOT. Net capacity reporting reflects subtraction of internal load from gross generation.

[2] In addition, the following generation units were not included in the Loss of Load Study but were included in the 2012 LTRA:

a. Green Bayou (406 MW summer)
b. Spencer 4 (61 MW summer) and 5 (61 MW summer)
c. Applied Energy (138 MW summer)
d. Webberville Solar (28.5 MW summer)
e. Big Spring (17.5 MW summer)

The 2006 load shape is closest to the 50/50 peak load in the LTRA and is used in the summary spreadsheet. For the LOL study, 15 years of hourly load profiles data were developed from the historical actual weather data (1997-2011) for those specific years and were used in the study model.

Table 1: Installed Capacity by Unit Type – Winter/Summer 2014

Supply	Summer	Winter
Coal	19,954	20,114
Oil	0	0
Gas	51,457	53,809
Nuclear	5,157	5,198
Hydro	0	0
Wind	12,255	12,255
Biomass	212	203
Solar	0	0
Other Storage	0	0
Demand Response	0	0
Other	16	16
Total	89,051	91,595

Table 2: Installed Capacity by Unit Type – Winter/Summer 2016

Supply	Summer	Winter
Coal	19,954	20,114
Oil	0	0
Gas	56,709	59,296
Nuclear	5,157	5,198
Hydro	0	0
Wind	12,255	12,255
Biomass	212	203
Solar	0	0
Other Storage	0	0
Demand Response	0	0

Other	16	16
Total	94,303	97,082

The net energy for load in the LTRA was 349,131.2 GWh in 2014 and 376,102.0 GWh in 2016. The net energy for load in the LOL study was 390,007.0 GWh in 2014 and 417,104 GWh in 2016. The difference is the Private Use Networks (PUNs) net energy load of 40,876 GWh in 2014 and 41,002 GWh in 2016 which is the gross PUNs load.

The net internal demand load in the LTRA was 68,402.7 MW in 2014 and 73,956.9 MW in 2016. The net internal demand load in the LOL study was 74,928 MW in 2014 and 80,879 MW in 2016. The higher LOL load is attributable to the PUN net demand of 4,639 MW being added to the LOL study demand data, and the projected energy efficiency and demand response capacity is excluded from the LOL study demand. In the LTRA, Demand-Side Contractually Interruptible capacity of 432.3 MW in 2014 and 523.1 MW was included. In addition, in the LTRA, Demand-Side Loads as Capacity Resource of 886 MW was included in both 2014 and 2016. Also, New Conservation (Energy Efficiency) was included in the LTRA which was 366 MW in 2014 and 635 MW in 2016.

The study found the Loss of Load Hours (LOLH) to equal 0.242 hours per year in 2014 and 0.151 in the 2016 runs. In addition, the Expected Unserved Energy (EUE) for 2014 was 266.7 MWh and for 2016 was 164.3 MWh.[3]

Table 3: ERCOT LOL Study: Annual Demand Capacity Resources and Reliability Indices

Year	2014	2016
Net Energy for Load (GWh)	390,007	417,104
Total Internal Demand (MW)	74,928	80,879
Net Internal Demand (MW)	74,928	80,879
Forecast Capacity Resources (MW)	78,895	84,147
Forecast Operable Capacity Resources (MW)	75,011	80,002
Expected Unsupplied Energy (EUE) (MWh)	266.700	164.300
Expected Unsupplied Energy (EUE) (ppm)	0.684	0.394
Loss of Load Hours (LOLH) (hours/year)	0.242	0.151
Forecast Planning Reserve Margin (%)	5.29%	4.04%
Forecast Operable Reserve Margin (%)	0.11%	-1.08%

With the inclusion of the full transmission system in the study, both the LOLH and EUE increase. The Loss of Load Hours (LOLH) increases to 0.304 hours per year in 2014 and 0.221 hours per year in 2016. In addition, the Expected Unserved Energy (EUE) for 2014 increases to 279.2 MWh and for 2016 was 167.7 MWh.

[3] These results assume a 1% probability of occurrence of the year 2011. This assumption may change after discussion with stakeholders at ERCOT.

Software Model Description

Ecco International used the ProMaxLT™ software to conduct this analysis[4]. ProMaxLT is stochastic in nature; it uses a Monte-Carlo random outage scheduler to create full and partial outage states for generating units. The Monte Carlo forced outage event modeling in the software allows the impact of multiple coincident outages to be forecasted across multiple iterations of the same scenario.

An exponential distribution (also known as a negative exponential distribution) is used in ProMaxLT™ to randomly determine the outage and repair times for each unit. Four Exponential Distributions are used: a) Full Time to Failure, b) Full Time to Repair, c) Partial Time to Failure, and d) Partial Time to Repair. As a result of this process the simulated failure and repair patterns are determined.

Separate instances of the random number algorithm are used for all generation units. This ensures that outage sequences of all plants are independent. All random number sequences are chosen to be dependent on the single seed which is independent of the time clock. In that way, if the same seed is used in a repeated simulation at another time, the study can be exactly reproduced. The reference time for each unit is chosen to be at a fixed reference time in the past, so that multiple runs with different input parameters may be performed with the same outage sequence. This is an important requirement for sensitivity runs. The outages need to be sequential for the LOL events to be appropriately estimated.

Power system reliability indices can be calculated using a variety of methods. The two main approaches are analytical and simulation. Monte Carlo simulation is utilized in this study because it allows for a more comprehensive modeling of system behavior and provides a more informative set of system reliability indices. The time step of the simulations was one hour.

The Monte Carlo approach for reliability studies requires a large number of simulations to produce dependable reliability indices and ensure statistical significance. However, the marginal improvement in the results decreases as the number of simulations increases. The study has shown that convergence occurs at around 400 iterations.

The following convergence criterion was used in these simulations:

The standard deviation of LOLEV/square root of n (the number of iterations) should be a small fraction (approximately 0.005 at 400 iterations) of the mean value of LOLEV.

Demand Modeling

Load forecast uncertainties due to weather were studied by running Monte Carlo simulation for various load scenarios. Fifteen sets of hourly chronological load profiles for the two study years (2014 and 2016) were prepared by ERCOT. These 15 years of hourly load profile data were built from the historical actual weather data for 1997-2011.

The LTRA uses a 50/50 load forecast. The weather year 2006 is used as a close approximation for an average year. The economic growth assumption behind all scenarios was based on Moody's base economic forecast.

Since ERCOT is not synchronously connected to any other regions, all loads are contained within the assessment area. The study assumed no contribution from DC tie flows. PUN generation and loads were incorporated into the study. A flat load (i.e. consistent in all hours) of 4,639 MW was assumed for the aggregate behind-the-meter loads.

[4] http://www.eccointl.com/downloads/ProMaxLT_Overview.pdf

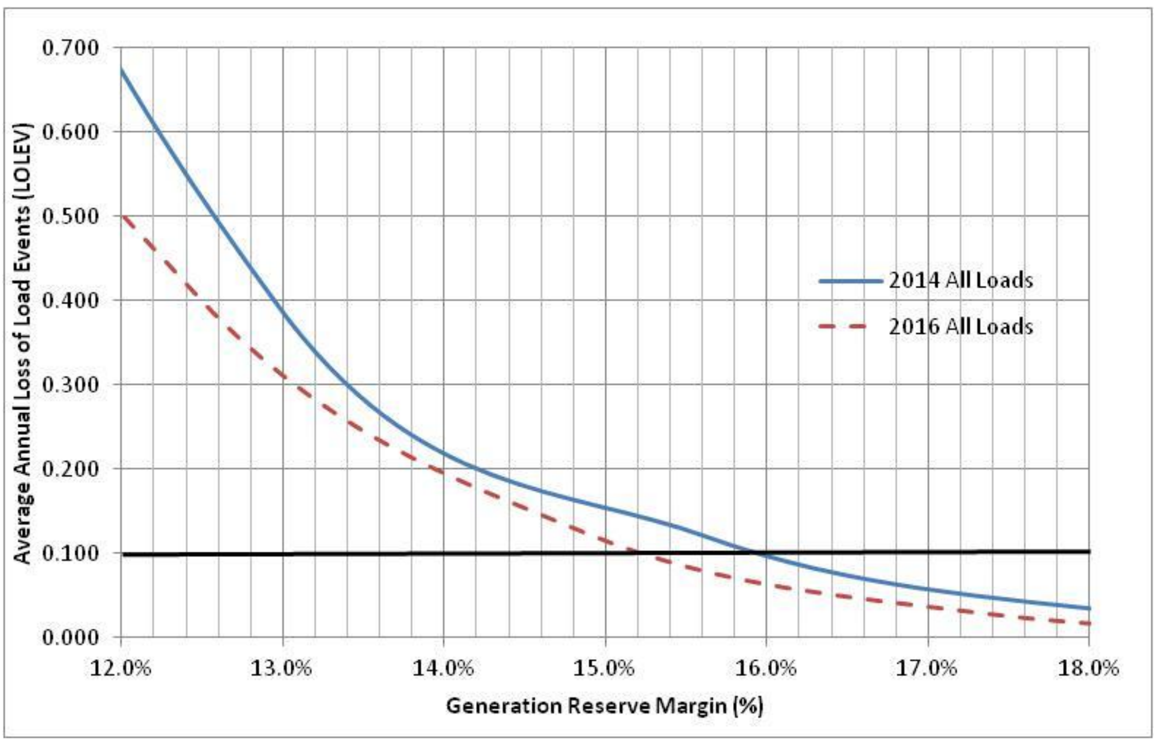
Controllable Capacity Demand Response Modeling

Controllable capacity demand response was not modeled in the Loss of Load study. Since ERCOT, when in an emergency energy situation, will request firm load shed prior to when the actual point that demand exceeds generation, controllable capacity is removed to reflect this operational reality.

Capacity Modeling

In order to simulate different levels of reserve margins using all 15 years of weather data, generation units had to be added or removed. In addition, some known generation sites have been included in the study that is not included in the LTRA. The calculated target reserve margin (16.0%) is used in identifying the level of capacity that points to the resulting LOLH and EUE reported. ERCOT recognizes that generic generation resources were added to the model in order to determine the level of generation capacity needed to yield one in ten (1/10) year's loss of load event and the corresponding reliability indices. The majority of the generation additions were needed because higher than expected load forecast and the total gross internal load demand were used in the LOL study instead of the net internal load demand level expected during a loss of load event. Recent updates to the load forecast assume Moody's low economic growth. Approximately 950 MW of generic generation resources were added in 2014 and 350 MW in 2016 to extract the reported LOLH and EUE results. Figure 1 below shows the relationship between the LOLEV and the Planning Reserve Margin.

Figure 1: LOLEV versus Reserve Margin



In addition to the generation included in the baseline, sufficient new generic combustion turbine capacity was added to ensure reserve margin levels are met for the simulations. For the 2014 run, up to approximately 13 GW of new generation was added. For the 2016 run, up to 14 GW was added. The following methodology was used to change the generation capacity for this analysis:

- **To increase capacity**

Use the following mothballed (MB) units which are outside of NAAQS (National Ambient Air Quality Standards) non-attainment zones and larger than 100 MWs. Aggregate capacity is 1,990 MW (summer rating).

  - Valley 1 to 3 – (1,069 MW summer)
  - Permian Basin 6 – (515 MW summer)
  - Green Bayou 5 – (406 MW summer)

Use existing generation sites of up to 11,500 MW (increase small and medium generation unit capacities such that the existing transmission network can support increased generation capacity; these increases also avoid non-attainment zones)

Additional incremental capacity (up to 2,419 MW) was added at the South Texas Project substation southwest of Houston along the Gulf of Mexico.

- **To decrease capacity**

The entire generation fleet is derated in order to capture the tails of the LOLEV curve for applicable profiles.

All resources are deliverable within the ERCOT Region based on the results of the detailed regional transmission planning studies conducted annually. ERCOT future year transmission models used to conduct the annual load flow studies include system additions, upgrades and retirements. In addition, PUC Rule 25.198 requires Transmission Service Providers to construct new facilities or modify existing facilities to interconnect generation to the ERCOT transmission grid. Firm non-intermittent resources in ERCOT must meet the following criteria:

The resource has a Texas Commission on Environmental Quality (TCEQ)-approved air permit, and has a signed Standard Generation Interconnect Agreement (SGIA); OR

The resource has a public, financially-binding agreement between the Resource owner and Transmission Service Provider (TSP) under which generation interconnection facilities would be constructed; OR

For a Municipally Owned Utility (MOU) or Electric Cooperative (EC), a public commitment letter to construct a new Resource.

The proposed Cobisa Greenville facility (1,792 MW winter and 1,750 MW summer) was included in this analysis although this resource is not included in the LTRA. Other resource additions match the LTRA.

Table 4: New Generation added in ERCOT

New Generation	Date Generation Added	Summer Capacity (MW)	Winter Capacity (MW)
Sandy Creek 1	Online by 2014 in study	925	925
Panda Sherman	Online by 2016 in study	717	755
Panda Temple 1	Online by 2016 in study	743	780
Panda Temple 2	Online by 2016 in study	742	780
Pondera King	Online by 2016 in study	1,300	1,380
Cobisa Greenville	Online by 2016 in study	1,750	1,792

Since ERCOT is a single assessment area, accounting for jointly owned units is not an issue. No purchases or sales were included in this study.

The study uses 15 years of hourly wind shapes for each wind farm obtained from AWS Truepower. In this study, no solar and hydroelectric generation is included. The hourly wind shapes utilized have been correlated with the hourly load shapes, e.g. January 1, 1997 load uses the same weather assumptions as January 1, 1997 wind.

ERCOT obtained outage data from the NERC GADs database and also directly from generators. Useable unit-specific outage data was only available for 34% of the units connected to the ERCOT system. For the remaining 66%, generic outage data was used. This generic outage data was developed from the data within the NERC GADS database for ERCOT.

ProMaxLT™ utilizes a three state model for Monte Carlo outage analysis. The three available states are:

Available – unit is fully available and can generate to its maximum limit

Derated – unit is available but at less than full capability (50% in the ERCOT LOL studies).

Unavailable – Unit is off and unavailable

The transitions between these states are created by generating separate outage sequences for full and partial outages using the Mean Time to Failure (MTTF) and Mean Time to Repair (MTTR) values derived from the outage data provided by ERCOT. This approach implicitly models all the possible transitions between the 3 states, and produces outage statistics that match the input outage values provided by ERCOT.

Transmission

Additional analysis was done to consider transmission limitations internally to ERCOT. Inclusion of the transmission system resulted in the increase of the both the LOLH and EUE. The Loss of Load Hours (LOLH) increases by 0.062 hours per year in 2014 and 0.07 hours per year in 2016. In addition, the Expected Unserved Energy (EUE) increases for 2014 by 12.5 MWh and for 2016 by 3.4 MWh.

Ecco's ProMaxLT™ used a detailed DC transmission model, with single and double contingency constraints, developed by ERCOT to model the effect of transmission constraints on the network. ProMaxLT™ incorporates an accurate transmission model with a nodal configuration which optimizes network flows and constraints using dynamically calculated limits on an hourly basis. The model is built bottom up, with every generating unit modeled in terms of its capacity, maintenance plans and forced outage rates. Every transmission line or group of lines is modeled in terms of its electrical properties and thermal transmission limits. For DC modeling ProMaxLT™ reads the susceptance matrix of the network from a power flow solution file and converts the susceptance matrix into linearized constraint equations. The power flow equations are explicitly modeled in the solution. The bi-directional line limits on each line are also read into the database and converted to constraint equations.

Line Outage Distribution Factors are calculated for each contingency constraint so that the flow in the post contingent state may be calculated from the base case flow in the lines that are taken out of service.

Contingency constraints are also explicitly represented by adding additional constraints "on the fly" that express the flow in the constrained lines as a set of linear shift factors of the generation output levels. The Line Outage Distribution Factors are used to calculate the post-contingent flows in the constrained lines. These shift factors for the contingency constraints are derived directly from the network admittance matrix with the outages (see below) as specified by the contingency set incorporated into the study case. The "on the fly" determination of the contingency constraints is critical to ensure the accuracy of the modeling process reflecting actual operating conditions as opposed to relying on static "event" files to contain contingency constraints pre-determined by the user.

Stability limits were incorporated in the modeling formulation as constraints on groups of lines. Two stability constraints were incorporated, the North to Houston constraint (N_TO_H) and the Rio Grande Valley import constraint (VALIMP). The West-North constraint was not included because the Competitive Renewable Energy Zones (CREZ) lines were assumed operational. The VALIMP constraint was only enforced in the 2014 study, as the 2016 transmission system had been augmented to remove the need for this constraint.

Table 5: ERCOT Transmission Stability Limits

Name	Limit	Line Name	Flow Direction	Factor	From bus	To bus	Circuit ID	Base year
N_TO_H	3486.8	44645 SNGLTN_345 46500 TOMBAL__345 74	*from-to*	1	44645	46500	74	2014
N_TO_H	3486.8	44645 SNGLTN_345 44900 Zenith__345 99	*from-to*	1	44645	44900	99	2014
N_TO_H	3486.8	44645 SNGLTN_345 44900 Zenith__345 98	*from-to*	1	44645	44900	98	2014
N_TO_H	3486.8	40600 ROANS___345 45972 KUYDAL75501 75	*from-to*	1	40600	45972	75	2014
VALIMP	1300	8902 LHRHL 80076 AJO7A 1	*to-from*	1	8902	80076	1	2014
VALIMP	1300	8795 ROMATP4 80106 FALCONSW4A 1	*to-from*	1	8795	80106	1	2014
VALIMP	1300	8383 NEDIN7A 8901 LHEDM 33	*to-from*	1	8383	8901	33	2014
VALIMP	1300	8380 NEDIN4A 8896 RACHAL4A 1	*to-from*	1	8380	8896	1	2014
VALIMP	1300	8302 RAYMOND24A 8702 YTURRIASUB8 1	*to-from*	1	8302	8702	1	2014
N_TO_H	3486.8	44645 SNGLTN_345 46500 TOMBAL__345 74	*from-to*	1	44645	46500	74	2016
N_TO_H	3486.8	44645 SNGLTN_345 44900 Zenith__345 99	*from-to*	1	44645	44900	99	2016
N_TO_H	3486.8	44645 SNGLTN_345 44900 Zenith__345 98	*from-to*	1	44645	44900	98	2016
N_TO_H	3486.8	40600 ROANS___345 45972 KUYDAL75501 75	*from-to*	1	40600	45972	75	2016

Table 5 provides the definition and list of the stability constraints enforced in the Monte-Carlo solution.

ProMaxLT™ iterates the full power flow to update the constraint working set and the original line flow equation terms of the solved AC power flow terms. A constraint is entered into the working set if the flow is within 85% of the limit. Once a constraint enters the working set it remains there for subsequent iterations, to avoid oscillations even if the flow falls below 85%.

Contingency constraints are modeled explicitly using linearized sensitivities of the flow changes from the line outage.

Assistance from External Resources

Outside resources were not considered in this study.

Definition of Loss-Of-Load Event

In this study a loss-of-load event was defined as any hour or continuous set of hours in which the net internal demand exceeded the available generation.

FRCC

Summary

Individual entities within the Florida Reliability Coordinating Council (FRCC) Region are aggregated and modeled as a single combined entity. Entities in this aggregation include: Florida Keys Electric Cooperative, Florida Municipal Power Agency, Florida Power & Light Company, Gainesville Regional Utilities, Homestead Energy Services, JEA, City Of Lakeland, New Smyrna Beach Utilities, Orlando Utilities Commission, Progress Energy Florida, Reedy Creek Improvement District, Seminole Electric Cooperative Inc, City Of St Cloud, City Of Tallahassee, Tampa Electric Company, U.S. Corps Of Engineers Mobile, and The City Of Vero Beach. This aggregation of individual entities is representative of the FRCC Region, and for purposes of this Study will be referred to as the assessment area.

Below are projected firm resources for the assessment. For this Study, winter seasons commence at the end of the year shown (e.g., the winter of 2014 represents the winter season for the Region that typically spans from December 2014 through about the end of February 2015).

Table 6: Seasonal Capacity Totals (MW)

[1] Season	[2] Controllable Capacity Demand Response	[3] Variable Resources	[4] Traditional Capacity	[5] Sales	[6] Purchases (Imports)	[7] =[2]+[3]+[4]-[5]+[6] Total
Summer 2014	3,239	0	53,271	143	2,206	58,573
Winter 2014/15	3,340	0	59,120	0	2,212	64,672
Summer 2016	3,352	0	55,709	143	866	59,784
Winter 2016/17	3,382	0	60,036	0	972	64,390

Both Study Years used a 50/50 Non-Coincident peak seasonal demand for the assessment area's aggregated forecast, which was the same demand forecasts as reported in the 2012 Long-Term Reliability Assessment (LTRA).

Table 7: Net Energy for Load and Metrics

Study Year	LTRA reported NEL (GWh)	Simulated NEL (GWh)	Expected Unserved Energy (MWh)	Loss of Load Hours (H/Y)	Summer Peak*	Winter Peak*

2014	230,481	230,498	0.000000	0.000000	46,857	47,568
2016	239,191	239,212	0.000000	0.000000	48,594	48,797

*Summer and winter peak values are the same for the LTRA and the Simulation.

Software Model Description

The FRCC uses the Tie Line and Generation Reliability Program (TIGER) in this Study for the computation of Loss of Load Hours (LOLH) and Expected Unserved Energy (EUE) metrics. The simulation software is based on the analytical method of recursive convolution for the calculation of generating capacity reliability indices which employs an algorithm tested compliant with the standard Reliability Test System modeled by Institute of Electrical and Electronics Engineers (IEEE) Power System Engineering Committee. The model does not have an algorithm to reduce the number of hours included in the metric calculations when the hours have no material impact on the metrics.

Demand Modeling

The foundation of the forecasted chronological load model was first developed by collecting over ten years of actual hourly loads from all member entities of the assessment area. The aggregation was adjusted for the removal of double-counted load and the addition of any Controllable Capacity Demand Response (CCDR) that was exercised in order to obtain the true historical assessment area system peak demands. Weather normalization was applied to this dataset for some summer and winter seasons to remove abnormal variations in demand caused by unusual weather conditions (e.g., high frequencies of hurricane activity, prolonged cold weather fronts, or unusually warm summers). Further adjustments were performed by taking into consideration customer count data and various economic indicators particular to the FRCC Region. This dataset formed the basis for the historical load series used to derive the annual hourly forecasts for the Study Years.

Hourly load forecasts were based on Monte Carlo simulations of weather, population growth, with additional Florida economic outlook indicators. Uncertainties were developed on the basis of the daily peaks and not annual seasonal peaks, with adjustments from demand and energy impacts emanating from The Energy Policy Act of 2005 that caused variations in the current and future hourly load shapes.

All loads are contained within the geographic boundary of the FRCC Assessment Area and are not accounted elsewhere under any other reporting assessment area. Behind-the-meter generation is modeled with associated loads and netted out since these loads are implicitly accounted for within load forecasts of entities which constitute the assessment area.

Controllable Capacity Demand Response Modeling

Capacity from CCDR was projected to be available at all times and not derated based on utilization. For the purposes of this assessment, CCDR is modeled as a “generating” resource where its capacity varies on a monthly basis. (The FRCC typically accounts for CCDR as a load/demand reducing resource because that more accurately reflects the actual impact of CCDR.)

Capacity Modeling

The reported LTRA capacity for the FRCC is the same as the assessment area capacity used for this Study. Generation capacity for both the LTRA and the simulation is based on the seasonal net capability of each unit. 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 "Planned".

New generation and capacity re-ratings have been incorporated into the seasonal capacities. There are no jointly-owned units within the FRCC that share capacity with another assessment area. However, the FRCC Region has 143 MW of generation from a single unit that is under Firm contract to have its capacity exported during the summer season only into the Southeastern Subregion of the SERC Reliability Corporation (SERC) Region through 2020. These sales have firm transmission service to ensure deliverability in the SERC Region

Capacity purchases/imports into the FRCC Region averaged 1,350 MW during the summer and winter Study seasons, while externally-owned capacity located outside the FRCC Region is approximately 830 MW.

With only one exception, no intermittent or energy-limited resources for either Study year are included in this Study. The only variable resource included in this Study were hydroelectric generators, with only the minimum firm capacity of such units included as firm resources so that any variability in unit capacity was removed. All traditional dispatchable capacity was modeled as firm capacity available to serve load. Summer and winter unit ratings were based upon forecasted capacities planned to be available during forecasted system seasonal peaks.

Forced outage rates (which are also used to account for unplanned maintenance outages) are applied on an individual generator basis, based on historic individual unit data. Generator maintenance is assumed to be planned, and each unit is assigned an annual maintenance rate in weeks. The rate is between one to five weeks and considers the type of unit and cyclical nature of major and minor maintenance over multiple years. Since the planned maintenance in any given year changes frequently and is subject to forced outages and other planned and non-planned events, the maintenance schedule is normalized to an annual rate to represent a typical year.

The TIGER modeling program uses annual maintenance rates and utilizes an automatic maintenance method to levelize reserves by scheduling the majority of the maintenance during high reserve margin months and less (or none) during low reserve margin months. Once the maintenance algorithm has calculated the amount of generation capacity out on maintenance for each month, the monthly available generation capacity is reduced by this amount. The effect of using this automatic maintenance algorithm results in the majority of maintenance being scheduled during the fall and spring, and less during the peak demand months.

Transmission

The Study model assumes that all firm capacity resources are deliverable within the FRCC Region based on the results of detailed regional transmission studies. Therefore, only inter-regional transmission facility data was considered for this assessment.

Although the forced outage rates of transmission lines were not modeled during this Study, regional transmission assessments indicate that transmission capability within the FRCC Region is expected to be adequate to supply firm customer demand and planned firm transmission service under normal conditions and following single contingency events. It is anticipated that existing operational procedures and pre-planning will be used to adequately manage and mitigate any potential impacts to the bulk transmission system arising from unplanned outages of transmission facilities or generating units within the FRCC Region.

Assistance from External Resources

Existing firm power purchase agreements (Unit Power Sales) along with owned capacity outside the FRCC Region totals approximately 2,200 MW. All such capacity has firm transmission service to ensure deliverability into the FRCC Region and the transfer is well below the maximum transfer capability into the FRCC Region from the SERC Region. Only these firm power transfers are modeled in the assessment.

Definition of Loss-of-Load Event

A Loss-of-Load Event (e.g., Occurrence) would be a single instance where firm load exceeds available capacity, where the frequency of Events are forecasted to be less than the standard industry threshold of 1 day in 10 years. Voltage reductions and/or public appeals within the FRCC Region are not considered a Loss-of-Load Event.

MISO

Summary

The Midwest Independent Transmission System Operator, Inc. (MISO) is a not for-profit, member-based organization administering wholesale electricity markets that provide our customers with valued service, reliable, cost-effective systems and operations, dependable and transparent prices, open access to markets, and planning for long-term efficiency.

MISO as a Planning Authority operates as a single Balancing Authority and experiences its annual peak during the summer season. MISO's scope of operations covers 11 U.S. states and the Canadian province of Manitoba with 49,670 miles of transmission. MISO's membership consists of 35 Transmission Owners and 97 Non-Transmission Owners. In December 2012, 7 new transmission-owning members were approved by MISO's Board of Directors. The six Entergy utility operating companies along with South Mississippi Electric Power Association (SME) are planned to be fully integrated into MISO by December 2013. Louisiana's Cleco Corporation also has plans to integrate into MISO by December 2014. These companies were not included as part of this assessment.

For this analysis, internal and external entities to MISO were modeled. The MISO footprint was comprised of 28 Local Balancing Authorities (LBAs) and was modeled as a single combined entity while the external entities varied in the way in which they were modeled. The external entities for this analysis were either aggregated or modeled individually to form seven zones. Both the internal and external entities modeled for this analysis can be seen in Tables 9 and 10 below.

Table 8: Internal MISO Areas

Internal Area Names	Local Balancing Authority (LBA)	NERC Region
Dairyland Power Cooperative	DPC	MRO
Great River Energy	GRE	MRO
Minnesota Power and Light Company	MP	MRO
Montana-Dakota Utilities Co.	MDU	MRO
Northern States Power Company	NSP	MRO
Otter Tail Power Company	OTP	MRO
Southern MN Municipal Power Agency	SMMPA	MRO
Alliant East - Wisconsin Power and Light Company	ALTE	MRO
Madison Gas and Electric Company	MGE	MRO
Upper Peninsula Power Company	UPPC	MRO
Wisconsin Electric Power Company	WEC	RFC
Wisconsin Public Service Corporation	WPS	MRO
Alliant West - Interstate Power & Light	ALTW	MRO
MidAmerican Energy Co.	MEC	MRO
Muscatine Power & Water	MPW	MRO

Table 8: Internal MISO Areas		
Internal Area Names	**Local Balancing Authority (LBA)**	**NERC Region**
Ameren Illinois	AMIL	SERC
Southern Illinois Power Co-operative	SIPC	SERC
Springfield Illinois - City Water Light & Power	CWLP	SERC
Ameren Missouri	AMMO	SERC
Columbia Missouri Water and Light Department	CWLD	SERC
Big Rivers Electric Corp	BREC	SERC
Duke Energy Indiana	DUK-IN	RFC
Hoosier Energy Rural Elec.	HE	RFC
Indianapolis Power & Light	IPL	RFC
Northern Indiana Public Service Co.	NIPS	RFC
Southern Indiana Gas & Electric Co.	SIGE	RFC
Consumers Energy - METC	CONS	RFC
Detroit Edison Company	DECO	RFC

Table 9: External MISO Areas	
External Area Names	**NERC Region**
MAPP	MRO
Manitoba Hydro	MRO
PJM	RFC
IESO	NPCC
SPP	SPP
Entergy	SERC
SERC	SERC

Table 10: Seasonal Capacity Totals				
Subcategory	**2014**		**2016**	
	Summer	**Winter**	**Summer**	**Winter**
Total Seasonal Capacities (MW)	117,201	117,745	117,924	118,097
Controllable Capacity Demand Response	7,802	5,232	7,802	5,232
Intermittent and Energy-Limited Resources	2,128	2,128	2,128	2,128
Traditional Dispatchable Capacity	107,271	110,385	107,994	110,737
Sales	0	0	0	0
Purchases	3,277	3,277	3,277	3,277

Table 11: 50/50 Peak Seasonal Demands				
Total Internal Demand (MW)	2014		2016	
	Summer	Winter	Summer	Winter
LTRA	96,129	78,143	97,811	79,521
MARS	96,565	78,703	98,069	79,917

Table 12: Net Energy for Load		
Net Energy for Load (GWh)	2014	2016
LTRA	462,645	458,284
MARS	524,115	533,074

Table 13: MISO Metrics Results		
Calculated Indices	2014	2016
EUE (MWh/yr)	0.1	0.3
LOLH (hrs/yr)	0.000	0.000

Software Model Description

The Multi-Area Reliability Simulation (MARS) program developed by General Electric was used to calculate the assessment area metrics for this analysis.

MARS uses a sequential Monte Carlo simulation to model a generation system and assess the system's reliability based on any number of interconnected areas. MARS calculates the indices by defined area used for this assessment, which are hourly LOLH (hours/year) and expected unserved energy (LOEE in MWh/year). MISO was modeled as one area for this assessment. In addition, time-correlated statistics such as frequency (outages/year) and duration (hours/outage) can be computed by using a sequential Monte Carlo approach.

MARS steps through the year chronologically and takes into account generation, load, equipment forced outages, planned and maintenance outages, as well as load forecast uncertainty.

MARS has an algorithm to reduce the number of hours included in the metric calculations when the hours have no material impact on the metrics. This algorithm was used for this assessment.

Demand Modeling

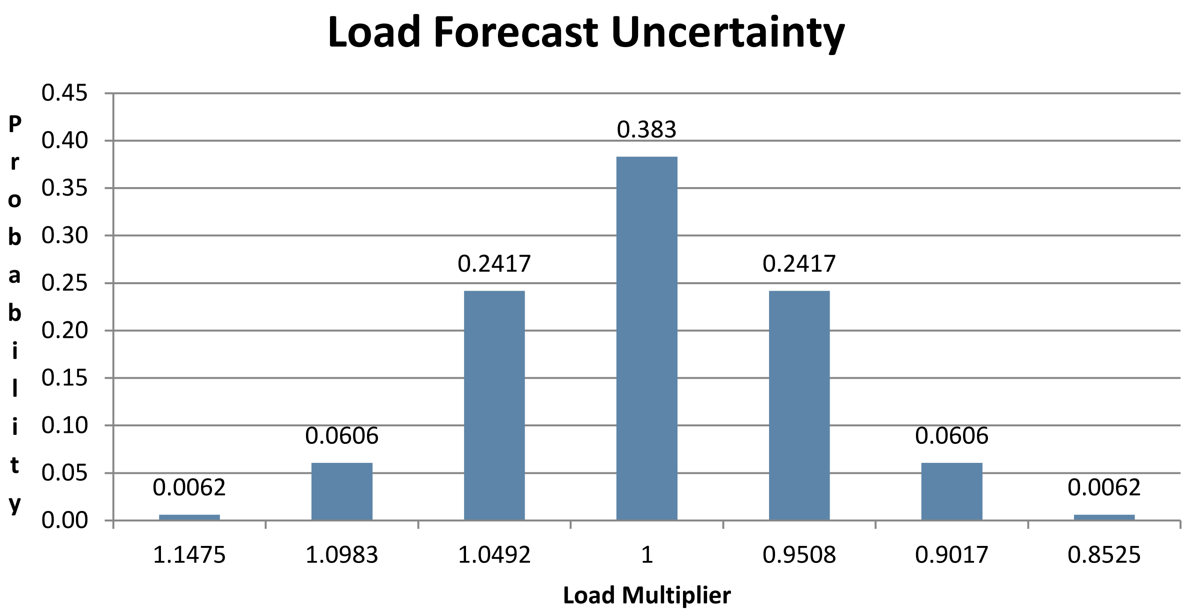
The difference between the load data used for this assessment and the 2012 Long-Term Reliability Assessment (LTRA) is minimal. Module E was the source of the load and energy data used for the LTRA as well as the MARS model created for this assessment. Module E is the section of the MISO Tariff that provides resource adequacy requirements to be met by the Transmission Provider, Market Participants serving load in the Transmission Provider Region or serving load on behalf of a Load Serving Entity ("LSE"), or other Market Participants. The data is submitted by LSE's and Market Participants through the Module E Capacity Tracking Tool (MECT). Any differences between the loads in the LTRA and MARS can be explained by updates to the load forecasts submitted in the MECT. The MARS model created for this assessment was built for the MISO annual Planning Reserve Margin (PRM) Study and any updates to the load forecasts after the MISO PRM Study was conducted would only be seen in the LTRA.

The Net Energy for Load values seen in the LTRA differ greatly from what was seen in the MARS output for this assessment. In many cases, the Net Energy Load values that were submitted in the MECT were too low based on the load forecasts that were submitted. The LTRA used the energy forecasts that were submitted in the MECT while the MARS model calculated its own energy forecasts based on the load forecast values from the MECT.

The MISO system demand and energy forecast data used for this assessment were based on the forecasts submitted by Load Serving Entities (LSE) through the MECT tool. These non-coincident MISO peak load forecast values from the LSEs were applied to individual historic 2005 load shapes and aggregated to form the MISO hourly load models and MISO coincident load peak created for this assessment. The historic year 2005 was chosen because it represents a typical load pattern year for MISO.

This assessment used MISO-specific historical load data and applied the NERC Bandwidth methodology to compute Load Forecast Uncertainty (LFU). In the past, MISO used the summation of NERC regional variances to determine LFU, however, the NERC Load Forecasting Working Group was disbanded in 2011. Therefore, MISO adopted the 2011 NERC bandwidth methodology to perform LFU analysis and developed regression models similar to NERC. MISO then included more recent historical data (2008, 2009, 2010, 2011 and 2012) to determine the MISO LFU value of 4.92 percent. The 4.92% MISO LFU was then applied to the entire MISO footprint and can be seen in Figure 2 below.

Figure 2: Load Forecast Uncertainty



Forecasts cannot precisely predict the future. Instead, many forecasts append probabilities to the range of possible outcomes. Each demand projection, for example, represents the midpoint of possible future outcomes. This means that a future year's actual demand has a 50 percent chance of being higher and a 50 percent chance of being lower than the forecast value.

For planning and analytical purposes, it is useful to have an estimate not only of the midpoint of possible future outcomes, but also of the distribution of probabilities on both sides of that midpoint. Accordingly (similar to NERC Bandwidth Methodology), MISO developed upper and lower 80 percent confidence bands. Thus, there is an 80 percent chance of future demand occurring within these bands, a 10 percent chance of future demand occurring below the lower band, and an equal 10 percent chance of future demand occurring above the upper band.

The principal features of the bandwidth method[5] include a univariate time series model in which the projection of demand is modeled as a function of past demand. This approach expresses the current value of the time series as a linear function of the previous value of the series and a random shock. In equation form, the first-order autoregressive model can be written as $y_t = a + \varnothing_1 y_{t-1} + \varepsilon_t$, Where $\varnothing_1$ is the autoregressive parameter that describes the effect of a unit change in y_{t-1} and y_t

The variability observed in demand is used to develop uncertainty bandwidths. Variability, represented by the variance σ_ε of the historic data series, is combined with other model information to derive the uncertainty bandwidths.

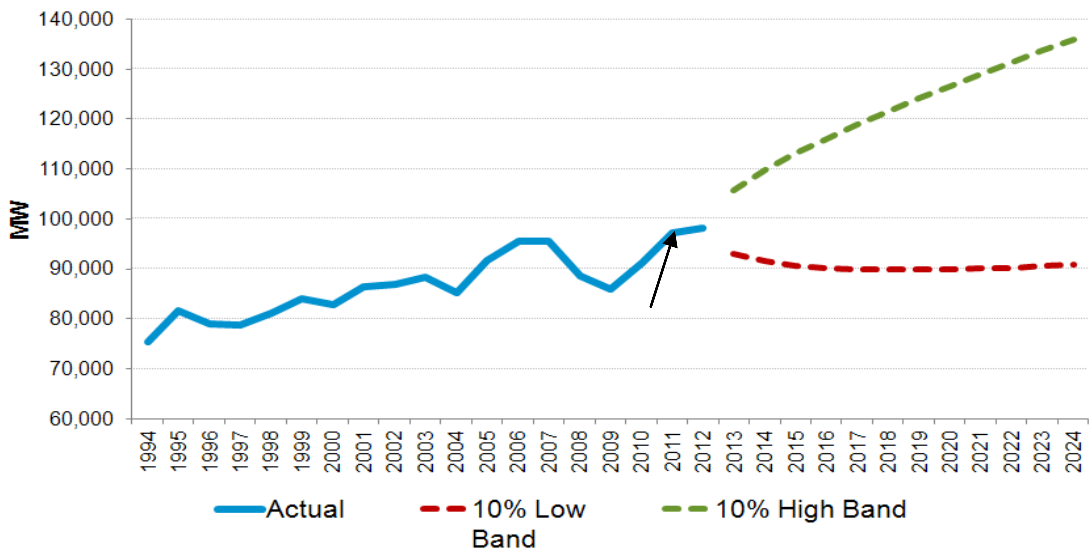
The LFU value that was calculated for this assessment used historical data that MISO collected from 1994 to 2012 for each Local Balancing Authority (LBA). MISO collected historical load data from 1994 to 2010 from EIA-860[6] and FERC Order 714[7] forms. In order to fill missing data from these forms, MISO extracted the LBA-based load information from MISO's market settlements. MISO collected LBA-level load data consistent with the LBAs shown in Table 8 above.

[5] More details about the NERC methodology can be found at http://www.nerc.com/filez/lfwg.html
[6] http://www.eia.gov/electricity/data/eia861/index.html
[7] http://www.ferc.gov/docs-filing/forms/form-714/data.asp

Starting in 2005, the Ameren LBA was split into two LBAs: Ameren Illinois (AMIL) and Ameren Missouri (AMMO). Therefore, MISO developed a historical data series (from 1994 to 2005) for both LBAs. Due to changes in the former Cinergy area in 2011 (the exit of Duke Ohio and Duke Kentucky), MISO only included demand data for Duke Indiana. While the LBAs Dairyland Power Cooperative and Big River Electric Co. joined MISO in 2010, historical data was developed for these LBAs starting from 1994.

As mentioned above, the MISO LFU used for this assessment is 4.92 percent. Figure 3 shows that the MISO system load varies as it generally increases from historical year 1994 to 2012. The dashed lines from 2013 to 2024 are projections based on the historical variance. The 4.92 percent LFU bandwidth in the first projection year (2013) applies to all future years being studied.

Figure 3: MISO Summer Peak Demand (MW)



Behind-the-Meter generation is modeled as a generation resource. Many behind-the-meter generators report to the MISO PowerGADS and are required to submit a Generation Verification Test Capacity (GVTC) value annually. The Module E Capacity Tracking (MECT) pulls the GVTC and Equivalent Forced Outage Rate Demand (EFORd) from PowerGADS for each behind-the-meter generator and calculates an Unforced Capacity (UCAP). The UCAP is equal to the GVTC multiplied by one minus the EFORd. If there was not sufficient PowerGADS data to calculate an EFORd for a particular unit then a MISO or NERC class average value was used. After the UCAP values are calculated for each unit, an aggregate total UCAP MW is calculated for each Area. For this assessment, each Area's aggregate total behind-the-meter generation UCAP was modeled in MARS as a generation resource.

Controllable Capacity Demand Response Modeling

Direct Control Load Management and Interruptible Demand type of demand-response were explicitly included in the MARS model created for this assessment as energy-limited resources. These resources were limited to the number of times they could be called upon and the duration of their run time. These demand resources are implemented in the MARS simulation before accumulating LOLE or shedding of firm load.

Capacity Modeling

All Generation Resources, External Resources, Demand Response Resources backed by a behind the meter generator and Behind-the-Meter Generation are required to perform a real power test according to the MISO Generator Test Requirements and submit the GVTC to the MISO PowerGADS in order to qualify as a Planning Resource.

The data used for this assessment and the LTRA only differ slightly. They both used the same sources for the data, which was MISO's Commercial Model, PowerGADS, and the MECT tool. However, the LTRA used the designated capacity that was submitted in MISO's MECT tool for these resources and in some cases this value differed from the Generation Verification Test Capacity (GVTC) submitted in PowerGADS. This assessment utilized the GVTC data entered into PowerGADS for traditional dispatchable capacity.

Future generation was added based on unit information in the MISO Generator Interconnection Queue. Only units with a signed generator interconnection agreement were added to the MARS model used for this assessment. These new units were assigned the class-average forced outage rate based on their particular class. All future resources are considered firm deliverable capacity resources. Retirement of generation or inclusion of units in the mothballed or suspension state was based on information provided from MISO's Attachment-Y filing process. The Generation Interconnection Queue can be found on MISO's website, www.misoenergy.org, under the *Planning* tab.

With new membership into MISO, generators are required to submit their GVTC to the MISO PowerGADS in order to qualify as a Planning Resource. Additionally, generation additions and capacity re-ratings are entered annually into the MISO PowerGADS. A monthly profile is determined based on the GVTC submitted and the monthly Net Dependable Capacities (NDC) entered in the MISO PowerGADS. Therefore, this assessment accounted for generation additions and capacity re-ratings.

Jointly-owned units (JOU) were modeled for this assessment as one unit. Typically, the majority owner is the sole entity to submit data to the MISO PowerGADS. Therefore, each unit is modeled like any other generation resource with one capacity and one EFORd, etc.

The model created for this assessment included 3,277 MW of purchases. The specific external areas involved with these purchases cannot be disclosed because that information is confidential.

This assessment utilized a Wind Capacity Credit of 14.7% of the Registered Max capacity of wind resources, which was set by MISO for the Planning Year 2012. The 14.7% value was based on calculating the Effective Load Carrying Capacity (ELCC) of the intermittent wind resources over 7 historical years and aligning each year to a trend.

A first LOLE simulation is done with the historical hourly load and same corresponding historical hour wind resource outputs, and this sets an LOLE benchmark. In a second LOLE simulation the wind resources are removed, and replaced with trial amounts of load reduction until the same benchmark LOLE result is achieved. The amount of load reduction that achieves the same LOLE result is then the ELCC. As a percentage the ELCC is the (resulting load reduction MW) divided-by (installed wind capacity MW).

MISO calculates ELCC percentage results for historic years 2005 through 2011, and at multiple penetration levels, corresponding to 10 GW, 20 GW, and 30 GW of installed wind capacity[83]. This creates an ELCC and penetration characteristic for each year, and those are the various annual curves shown in Figure 4. The initial left most and therefore the lowest penetration point on each characteristic curve represents the actual annual ELCC for that year, and the values at the higher penetration levels reflect what that year's wind resource would have as an ELCC if more capacity had been

[8] MISO first examined the relationship of the declining capacity effectiveness of wind resources as penetration increases, in the 2010 LOLE report's Appendix E and demonstrated the decline utilizing the ELCC method.

installed over the same footprint. The high end 30 GW level of penetration is an estimate of the amount of wind generation that could result in MISO, as the LSE's collectively meet renewable resource mandates of the various MISO States. Figure 4 illustrates the ELCC versus penetration characteristic of each year, and how those characteristics from multiple years were merged to set an on-going wind capacity credit.

The PY 2012 wind capacity credit was determined by averaging the seven ELCC values found along each year's ELCC-and-penetration characteristic curve. The averaging is done at the penetration level that corresponds to the penetration level at the end of the 2nd Quarter 2011.

The end of the 2nd Quarter is the convention used to set the capacity going into the summer season. For comparison, over the course of 2011 the January installed capacity was 9,232 MW, versus the 2nd Quarter 9,996 MW, and the following January value was greater than 9,996 MW. The penetration level at the end of the 2nd Quarter 2011 was 9.7%. Specifically as a percentage, the 2011 penetration level is the 2nd Quarter 9,996 MW from column 4 of Table 14 divided by the 102,804 MW peak load in column 1. The vertical line called out in the legend of Figure 4 as "Points Averaged at Penetration to date to get ELCC" illustrates where each of the seven ELCC values from each year's characteristic intersect with the most recent 9.7%, historical penetration, and the notes reflect that the intersected values that were averaged to get the 14.7% system wide ELCC for PY 2012.

The resulting Wind capacity credit is expressed in Unforced Capacity (UCAP) megawatts. If the individual wind units were to have full deliverability via the Generator Interconnection process, the system wide capacity rating could have represented as much as 1,469 MW of UCAP in 2012. Table 15 shows the tracking of wind at time of peak since 2005.

Table 14 shows that MISO set an 8% capacity credit in PY 2010. In contrast, Table15 shows a 12.4% capacity credit value for PY 2010, which reflects applying the method that was not fully developed until 2011. PY 2011 was the first year where the fully developed quantitative method for merging multiple historical ELCC characteristics was applied, as illustrated in Figure 4.

Figure 4: Seven Years of Historical ELCC Penetration Characteristics

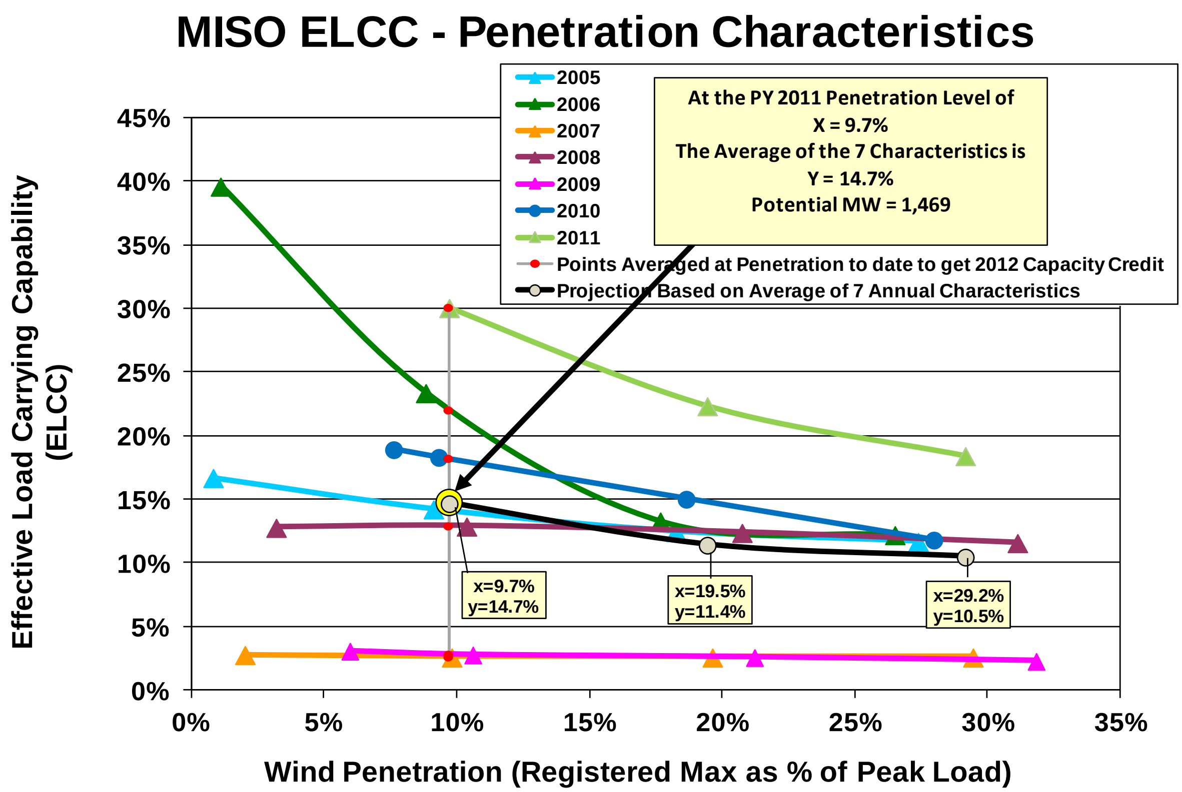


Table 14: Historical Tracking of Wind Related Metrics: Market-wide Operational Tracking							
Peak Load (MW)	Planning Year	Actual Metered Wind MW at Peak Load[1]	Registered Max MW Capacity (R_{Max})	Peak Day % of (R_{Max})	Historical Penetration	Annual Historical ELCC	MISO Capacity Credit
109,473	2005	104	908	11.5%	0.8%	16.7%	N/A
113,095	2006	700	1,251	56.0%	1.1%	39.6%	N/A
101,800	2007	44	2,065	2.1%	2.0%	2.8%	N/A
96,321	2008	384	3,086	12.4%	3.2%	12.8%	N/A
94,185	2009	86	5,636	1.4%	6.0%	3.1%	20.0%
107,171	2010	1,770	8,179	21.3%	7.6%	18.9%	8.0%
102,804	2011	4,421	9,996	42.8%	9.7%	30.1%	12.9%
96,794	2012	1,152	11,774	9.8%	12.2%	11.1%	14.7%

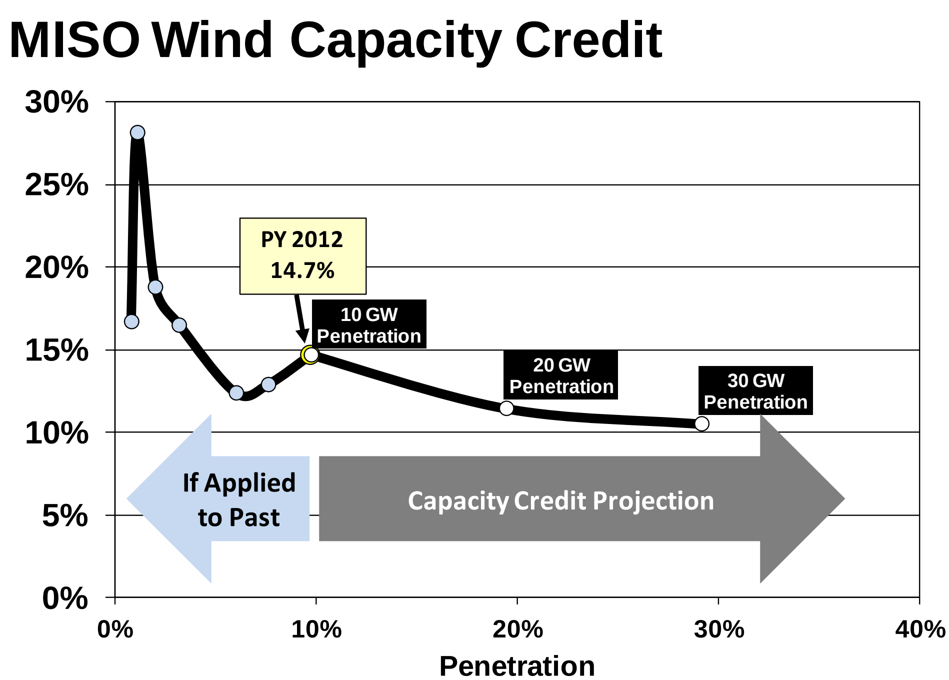
Note 1 Curtailed and Dispatchable Intermittent Resources (DIR) MW have been added to settlement MW

While in Table 14 the record "Annual Historical ELCC" of 39.6% from 2006 still exceeds the 30.1% ELCC in 2011, the two ELCCs are at different penetration levels. Therefore, as shown in Figure 4, the historical performance for 2011 set a new record high wind ELCC characteristic, because the curve for 2011 is above all other curves. The current method to set the capacity credit was developed at the LOLE Working Group, and was first applied to PY 2011. Table 15 shows the consistency of that method's results over three Planning Years, including if the current method had also been applied in PY 2010. Again, the black curve in Figure 4 is the projection going forward, where the influence of future annual ELCC characteristics are still pending. For related study work that require hourly wind and load patterns, such as required in PROMOD ® simulations, MISO has indicated that the historical 2005 wind and load shapes are typical of the wind integration situation at MISO. The applicability of continuing to use 2005 as a typical year is confirmed in Figure 4, since the black trend line that reflects all history is approximated by the blue line representing the single year 2005. Figure 5 demonstrates the increasing volatility that would have resulted if the currently developed capacity credit calculating process had been applied to ever fewer sets of historical annual ELCC penetration characteristics. Figure 5 also repeats the projection from Figure 4.

Table 15: Consistent and Responsive System Wide ELCC

Planning Year	Wind Penetration	ELCC
PY 2010	6.0%	12.4%
PY 2011	7.6%	12.9%
PY 2012	9.7%	14.7%

Figure 5: Demonstration of Applying Capacity Credit Method Starting with PY 2006



Other energy-limited variable resources, such as run-of-river hydro units, had their capacity value determined based on the 3 year historical average output of the resource from 1500-1700 EST for the most recent Summer months (June, July, and August). The resource capacity determined from this methodology was modeled for this assessment with a forced outage rate of zero.

As mentioned above, all generation resources are required to perform a real power test annually according to the MISO Generator Test Requirements and submit the Generation Verification Test Capacity (GVTC) to the MISO PowerGADS in order to qualify as a Planning Resource. The GVTC values from the MISO PowerGADS were used for this assessment.

The forced outage rates utilized for this assessment were established by the MISO PowerGADS. PowerGADS calculates an Equivalent Forced Outage Rate Demand (EFORd) for each generation resource. The EFORd values were calculated based off of 5 years (2007-2011) historical data from PowerGADS and each unit was modeled individually with its unit specific EFORd value. If a unit did not have greater than 12 months of data then a class average EFORd was assigned.

The EFORd values were broke up by fuel type and weighted against each unit's Generator Verification Test Capacity (GVTC) for the summary sheet for this assessment.

Planned outages were modeled by summing the equivalent planned outage factor and equivalent maintenance outage factor produced from the MISO PowerGADS. Each generation resource was assigned the new planned outage rate in the MARS model. The equivalent planned outage factor and equivalent maintenance outage factor accounted for the outages not included in the EFORd calculation. This differs from how the LTRA treated Planned Outages. The LTRA utilized MISO's Outage Coordination Tool (CROW) for Planned Outages.

Transmission

The MISO system was modeled as an unconstrained zone and did not have any transmission additions or retirements for this assessment.

Transmission is modeled within the MISO system as if there are no transmission constraints. External to the MISO system, transmission constraints are determined by the historical high observed Network Scheduled Interchange (NSI). MISO ties and interfaces with the external system are limited to the 2011-historically NSI maximum amount.

Assistance from External Resources

Any external resources above and beyond the 3,277 MW of purchases are considered non-firm resources. The non-firm resources are modeled up to the tie line limits based on historical high observed NSI and provide support which is based on availability and as needed. This process is described below.

This assessment utilized an external model with seven external zones. In order to determine an appropriate level of support that MISO could expect from the external systems, each external zone was modeled at its appropriate target Planning Reserve Margin (PRM) level plus any additional resources needed to account for firm contracts (resources dedicated to serve MISO from a given external zone). The tie capacity value to each external zone was derived from an analysis of the 2011 Historical Net Scheduled Interchange (NSI) data. Historical NSI data is available under MISO Market Reports[9]. The historically observed 2011 maximum NSI into MISO from 13 first-tier Balancing Authorities (BA) was used to set the rating into MISO from each Balancing Authority (BA). Some of the 13 external BAs were merged, resulting in the seven modeled external zones. The external model process was approved through stakeholder involvement at the MISO Loss of Load Expectation Working Group.[10]

The historic 10,421 MW value shown in Figure 6 is the maximum coincident import flow, which sets the limit that the model allows into MISO. Other maximum non-coincident values from each of the external zones are also shown. For example, 1,870 MW is the non-coincident limit from the external zone "Ex 5." Ex 5 is also a merged zone, since it is a zone derived from observing the historical first-tier NSI from three BAs.

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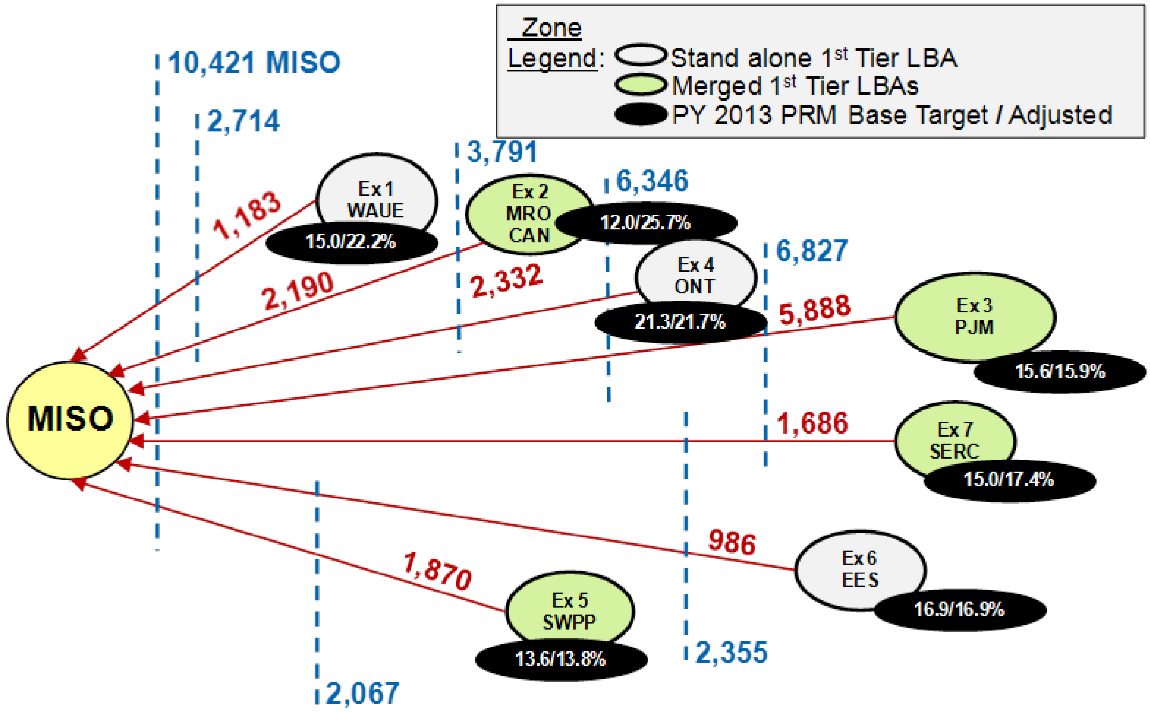
[9] MISO Market Reports; (https://www.midwestiso.org/Library/MarketReports/Pages/MarketReports.aspx)
[10] MISO LOLEWG April 20, 2012, Meeting Materials; (https://www.misoenergy.org/Events/Pages/LOLEWG20120420.aspx)

Features in the MARS simulation can simultaneously track the supporting flows up to a zone's individual non-coincident maximum flow from a BA (indicated in Figure 6 in red) and also limit the support amount to a lower level as dictated by the coincident sum combinations (indicated by the grouped coincident values in blue font in Figure 6). The 10,421 MW limit in blue font is the overall MISO coincident limit.

For the external zones, all load and generator data came from vendor-supplied databases since MISO only collects detailed information on MISO load and generation resources.

Figure 6: 2013 LOLE external ties model



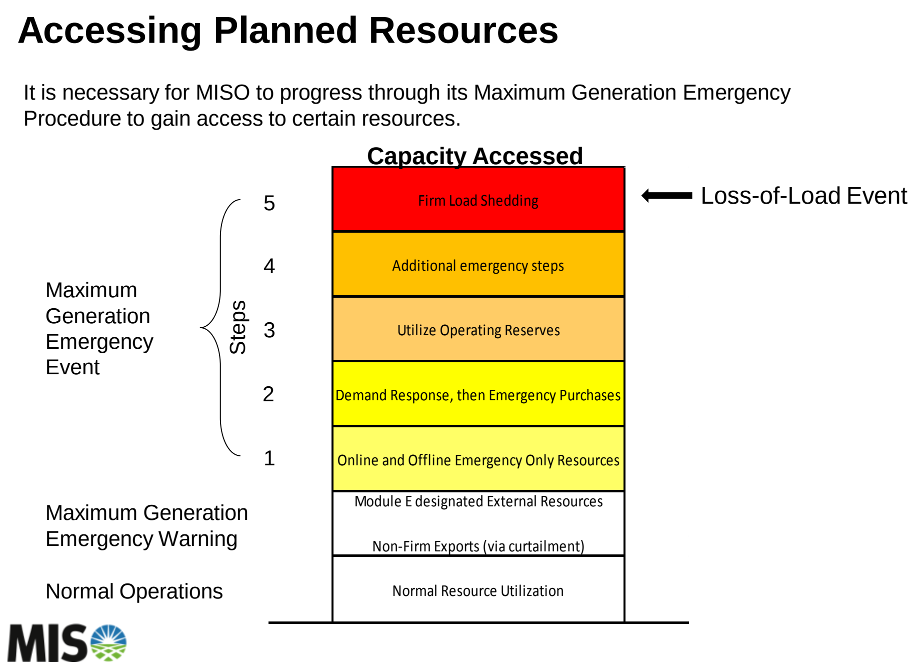
Flow Legend:
2011 Non-coincidently observed import limit
2011 Coincidently observed flow limit combinations

For more information regarding the external system, please see Appendix D of MISO's 2013 LOLE Study at www.misoenergy.org > ***Planning*** Tab > **Resource Adequacy (Module E)**.

Definition of Loss-of-Load Event

MISO defines a loss-of load event as anytime the amount of available system generation falls short of meeting the system's firm load. The Loss-of-Load Expectation (LOLE) is defined as the sum of the Loss-of-Load Probability for the integrated daily peak hour for each day of the year. Typically, the requirement is set such that the LOLE is no greater than one (1) day in ten (10) years. Figure 7 below shows how Real-Time Operations would step through its Emergency Operating Procedures. This assessment only utilized steps 1 and 2.

Figure 7: MISO Loss-of-Load Event



Manitoba Hydro

Summary

This report summarizes the results of NERC 2012 probabilistic assessment for Manitoba Hydro system. The probabilistic assessment was conducted using the Multi-Area Reliability Simulation (MARS) program developed by the General Electric Company. A summary of the software and major modeling assumptions is provided in Table 16. The reliability indices of the annual Loss of Load Hours (LOLH) and the Expected Unserved Energy (EUE) for Year 2 (2014) and Year 5 (2016) were calculated considering different types of generating units (thermal, hydro and wind), contractual sales and purchases, interconnection assistances, interface transmission constraints, peak load, load variations, and load forecast uncertainty. Most of the data used in the MARS simulation model are consistent with the date reported in the 2012 LTRA submittals from Manitoba to NERC [1]. The major input data used in this assessment and the assessment results are provided in the following tables for Year 2 and Year 5.

Table 16: Seasonal Capacity Totals by Subcategory

	2014		2016	
	Summer (MW)	Winter (MW)	Summer (MW)	Winter (MW)
Supply-Side Contractually Interruptible	225	225	225	225
Wind	21	0	21	0
Coal	97	97	97	97
Gas	356	395	356	395
Hydro	5177	5181	5177	5181
Sales	1250	550	925	325
Purchases	0	500	0	350
Total Installed Capacity	5651	5673	5651	5673

Table 17: 50/50 Peak Seasonal Demand

	2014		2016	
	Summer (MW)	Winter (MW)	Summer (MW)	Winter (MW)
LTRA	3228	4712	3244	4781
Simulation	3228	4712	3244	4781

Table 18: Net Energy for Load

	2014 (GWh)	2016 (GWh)
LTRA	25,881	26,036
Simulation	25,881	26,036

Table 19: Manitoba Hydro Metrics Results

	2011 (MWh)	2014 (MWh)
LOLH (hours/year)	0	0
EUE (/10^6)	0	0
EUE (MWh/year)	0	0

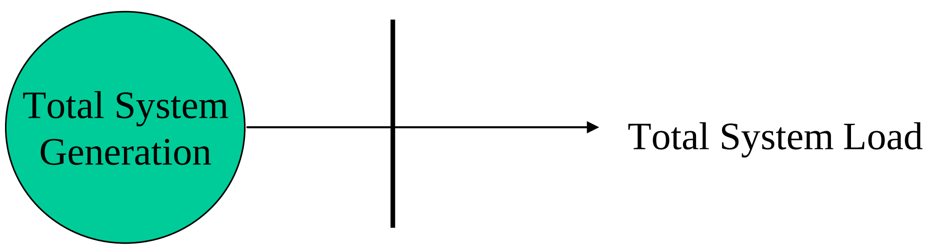
Software Model Description

The computing tool used for the calculation of the reliability indices in this assessment is the Multi-Area Reliability Simulation (MARS) program developed by General Electric Company (GE). MARS uses a sequential Monte Carlo simulation technique to calculate the reliability indices of a generation system that is made up of a number of interconnected areas. Generating units and an hourly load profile are assigned to each area. MARS performs a chronological hourly simulation of the interconnected system, comparing the hourly load in each area to the total available generation in the area taking into account the random outages of thermal generating units, availability of interconnection tie lines and the energy limited nature of hydro and wind resources. If an area's available generation, including assistance from other areas, is less than its load, the area will be in a loss of load state for that hour and statistics required to compute the reliability indices will be collected. This process will be continued for all of the hours in a sample year.

The Monte Carlo simulation is repeated for a large number of sample years in order to obtain the desired level of accuracy. The accuracy of the indices estimated by a simulation technique is improved by increasing the number of sample years. It is, however, not practical to run the simulation for a very large number of samples in order to achieve an extremely high level of accuracy. The number of samples used in this study was 2,000 for each reporting year. A detailed description of the simulation program can be found in GE's Multi-Area Reliability Simulation Program (MARS) User's Manual.

The primary concern in probabilistic resource adequacy assessment is to assess the capability of system resource to satisfy the total system demand. Traditionally, the reliability of the transmission and its ability to deliver the generated energy to the customer load point is not included in resource adequacy study. The system is therefore simply represented by a single bus as shown in Figure 8, at which the total generation and total load are connected.

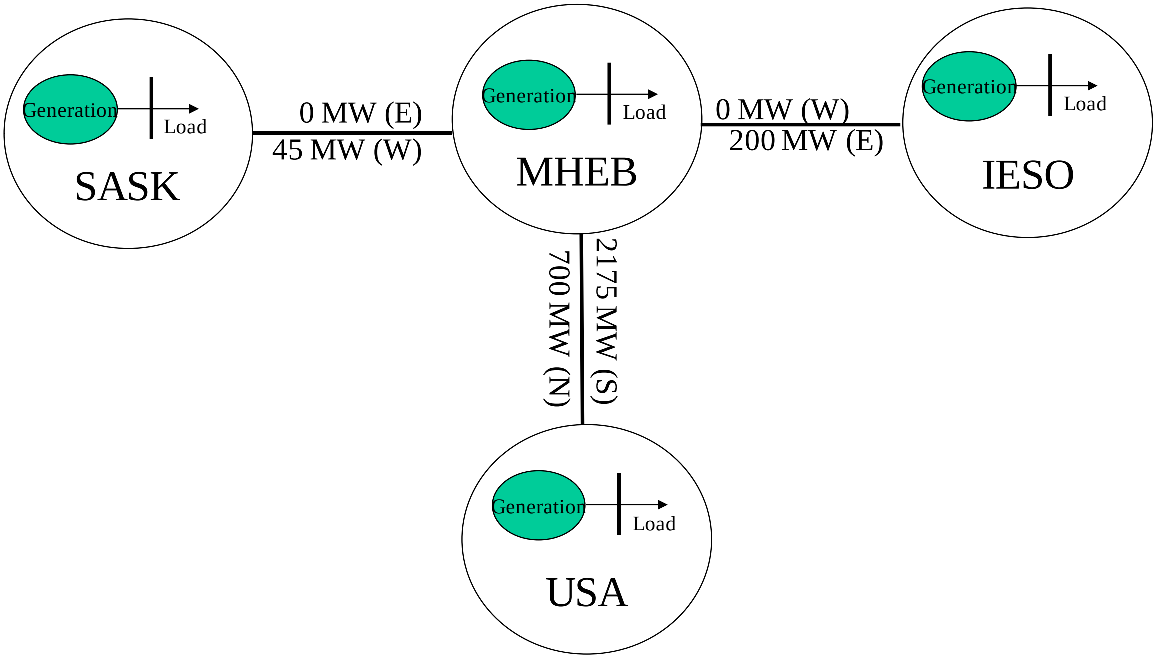
Figure 8: Generating System Representation for Resource Adequacy Assessment



In MARS, a generation system can be modeled as a number of interconnected areas. Each area is composed of one or several individual generating systems which can be represented as a single bus system as shown in Figure 1. The areas are defined by the limiting interfaces that may exist throughout the transmission system. The program assumes that there are no transmission limits within an area. Any generating units assigned to an area can, therefore, serve any load associated with that area. A simplified diagram of Manitoba and its neighboring systems for this assessment using MARS is shown in Figure 2. The interconnected system can be modeled as four areas consisting of Manitoba, Saskatchewan (SASK), Ontario (IESO) and the west zone of Midwest ISO (US), which is consisted of several load serving entities (LSE) within or directly interconnected to the Midwest ISO Reliability Authority Footprint[11] [3].

[11] Midwest Planning Reserve Sharing Group, "LOLE study report", April, 2008.

Figure 9: Representation of Manitoba Hydro and Neighboring Systems in MARS

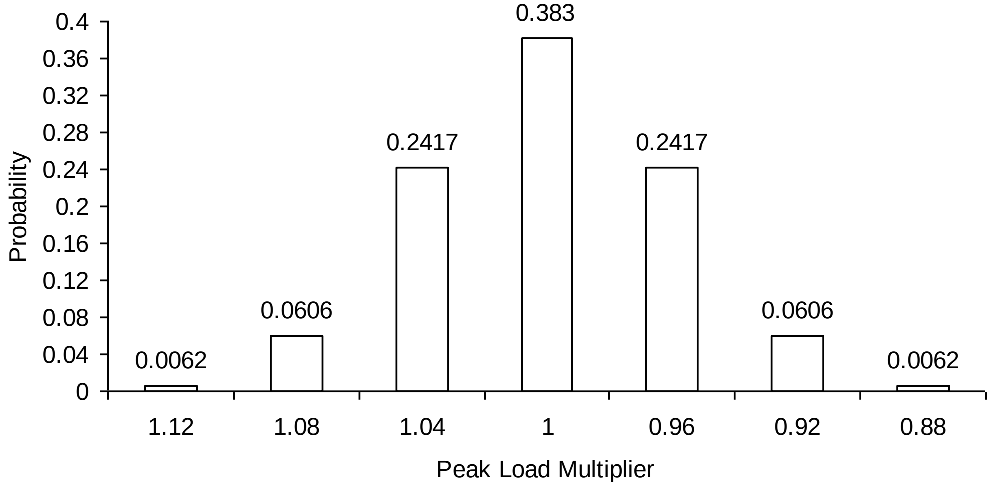


Demand Modeling

The load model used in this assessment was obtained from the most recent Manitoba peak load forecast for 2011/2012-2031/2032. The forecast peak loads used in this assessment are the same as those numbers reported in the MH 2012 LTRA submittal to NERC. The 8760 point hourly load records of a typical year (2002) were used to model the annual load curve shape. The simulation software automatically modifies the input hourly load profile to meet the specified peak load and energy.

The load forecast uncertainty (LFU) is considered in the assessment for both reporting year. It is assumed that the annual LFU is normally distributed with a 4% standard deviation in this assessment. A seven-step approximation of the normal distribution is shown in Figure 3.

Figure 10: Load Forecast Uncertainty Assumption



Controllable Capacity Demand Response Modeling

Manitoba is anticipating approximately 225 MW controllable capacity demand response program in the form of interruptible load. This demand response program was modeled as a simple load modifier with a flat profile on a weekly base. It was found that incorporation of the demand response program has no impact on the reliability metrics calculated in this assessment.

Capacity Modeling

Three different types of resources are modeled in this assessment. These are hydro resources, thermal resources including both coal and gas units and intermittent wind resources. All of these are "existing certain" resources and there is no new generation addition and generation retirement for the assessment period. A brief description of the modeling of these resources in this assessment is provided as follows:

The vast majority of Manitoba Hydro's generating facilities are use or energy limited hydro units. The output of these facilities is mostly dependent on the availability of the water resource. The effect of unit forced unavailability is not significant on hydro generating system reliability. All hydro units are, therefore, modeled as Type 2 energy limited units in this assessment. The MARS input parameters for each hydro power plant are installed/in-service and retirement dates, monthly maximum and minimum output of each plant and monthly available energy from each plant. It is assumed that the available water for each plant is known with little or no uncertainty and water resource is in a drought condition.

Each energy limited hydro unit is scheduled on a monthly basis. The first step is to dispatch the unit's minimum rating for all of the hours in the month. The remaining capacity and energy is then scheduled as needed during the Monte Carlo simulation. With this approach, the Type 2 energy-limited units are used only if the base loaded capacity is not sufficient to serve the load. If there is base loaded capacity in a given hour, the energy of the Type 2 energy-limited units will be saved for use in some future hour when it is needed. Any energy that is not used in a given month can be carried forward into the next month.

Each of these thermal units is modeled as two state units in which the generating unit is considered to be either fully available or totally out of service. Outage statistics for the years of 2005-2009 inclusive was used to determine the forced outage rate and average forced outage duration of each thermal. Planned outages on thermal units are modeled by removing the unit from service for the specified periods of time.

Wind energy based generating systems convert the natural energy available due to the wind resource at the system location into electric energy. The usable energy that can be converted depends on the amount of available energy contained in the site resource. Due to the highly variable nature of wind resource, wind energy based generating systems are inherently energy limited and pose some special difficulties in modeling and related reliability analyses. Two wind farms with 120 MW and 138 MW name plate capacity were modeled for both years of 2014 and 2016. In this study, wind generation was modeled as a simple load modifier as follows:

The available monthly wind energy was profiled based on analysis of actual wind data in Manitoba.

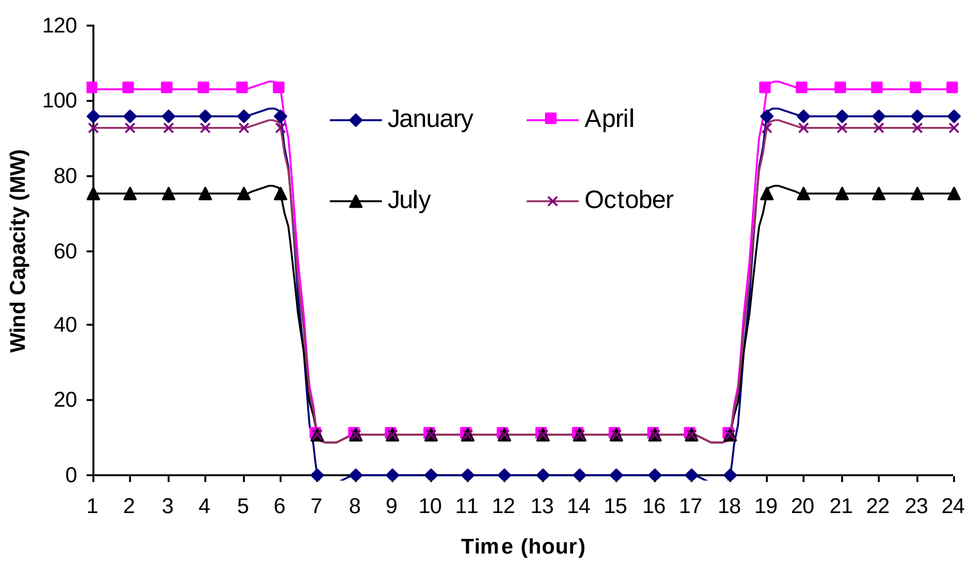
For the wind on peak period (defined for wind as the 7x12 period, or 50% of the time), wind plant output was modeled as a constant 8% of nameplate for the off peak months. The 8% figure was based on the capacity value of wind generation as determined by the Midwest ISO [4].

For the off peak period (non 7x12), calculate how much of the monthly wind energy was not consumed in the on peak period, and allocate it to the off peak, at a flat output.

No capacity value was given to wind for the peak months of December, January and February.

Figure 5 shows St. Joseph wind farm capacity output for a typical day in January, April, July and October. It can be seen from Figure 5 that St. Joseph wind farm on peak period capacity would be 0 for the peak month of January and 8% of 138 MW or 11.04 MW for the off peak months of April, July and October.

Figure 11: Wind Farm Model at St. Joseph for a Typical Day in Different Seasons



The contracts were modeled as load modifiers considering the special characteristics of Manitoba contracted power sales and purchases such as contract variability and diversity. These contracts represent energy exchanges between Manitoba and several external parties in MISO.

MH has no Behind-the-Meter generation and Jointly-Owned units for the period of assessment to model.

Transmission

Internal transmission for Manitoba is assumed to be 100% reliable. The transmission between Manitoba and its neighboring systems as shown in Figure 2 is modeled with interface transfer limits. Each interface consists of two ties: one from Manitoba to a neighboring system (export) and the other is from a neighboring system to Manitoba (import). Each interface limit was determined based on steady-state and transient stability analyses [5], which can be find from Manitoba Hydro OASIS website. MARS can simulate random forced outages on the interface between areas. Interface forced outages were, however, not modeled in this study. Each interface consists of two or more transmission lines and the outage probability of each interface is therefore negligible. In addition, individual line contingencies of each interface have already been taken into account when determining the interface transfer limit.

Assistance from External Resources

The reliability of the Manitoba system can be assessed under isolated and/or interconnected conditions. Reliability assessment for the Manitoba system on an isolated basis considers the generation, load, firm export/import sales, demand side management programs and interruptible load. An interconnected evaluation includes all of these plus the assistances from external resources. Only the results of interconnected scenario are summarized and reported.

The generation data used for representing the systems external to Manitoba Hydro were taken from Promod database which was initially compiled by NewEnergy Associates. The 8760 point hourly loads for the same year of 2002 were used to model the annual load curve shape for the external systems [3]. The external systems were modeled in the same detail as the Manitoba system rather than simple equivalent models. It is assumed in this study that non-firm interconnected assistance is possible only from MISO but not from neighboring Canadian utilities because Manitoba Hydro has no planning or operating reserve sharing agreement with these utilities and there is limited firm transmission capability from both Saskatchewan and Ontario to Manitoba Hydro. It is further assumed that potential non-firm assistance from the assisting system is available only if the reliability of the assisting system is better than 0.1 days/year of LOLE.

Definition of Loss-of-Load Event

A loss of load event is defined in this assessment as the situation in which the net load (adjusted by demand side programs and sales/purchases) exceeds the total available resource including the assistance from external resources. Emergency operating procedures associated with load control for example disconnecting interruptible loads, public appeals to reduce demand, and voltage reductions are not considered in this assessment. Generation supplements including overloading units, emergency purchases, and reducing operating reserves are also not considered.

Saskatchewan

Summary

The assessment area modeled includes the area of Saskatchewan. All data is consistent with the 2012 LTRA except where indicated.

Saskatchewan is a winter peaking area and the seasonal capacity totals for summer and winter are included in Table 20. Intermittent and variable resources are based on the maximum capacity output and traditional capacity includes monthly derates.

Table 20: Seasonal Capacity (MW)

Season	Demand Response	Intermittent and variable resources	Traditional Capacity	Sales	Purchases	Total
Summer 2014	91	198	3920	0	0	4209
Winter 2014	91	198	4121	0	0	4410
Summer 2016	91	428	4134	0	0	4653
Winter 2016	91	428	4336	0	0	4855

Table 21: Seasonal Peak Demand and Energy Requirements

Season	Peak Demand (MW)	Energy Requirement (GWh)
Summer 2014	3426	
Winter 2014	3829	
2014		25,310
Summer 2016	3624	
Winter 2016	4050	
2016		27,162

It should be noted that Saskatchewan is currently not using a 50/50 forecast. A 90/10 probability forecast methodology is currently used for reliability planning. Saskatchewan anticipates to report based on a 50/50 forecast for the 2013 LTRA. The same demand and energy forecast has been utilized for this assessment. Saskatchewan will add new capacity once a sustained unserved energy greater than the reliability criterion is met. The assessment area metrics results for year 3 and year 5 are 1,885 and 2,266 MWh/year of EUE respectively.

Software Model Description

SaskPower utilizes PROMOD IV for reliability planning. The software simulates the operation of an electric utility generation system. The model is used to project future operating costs and to evaluate system reliability. The analytical program computes the amount of unserved energy and the number of hours during which demand requirements will not be satisfied with supply sources. The model contains an integrated probabilistic analysis of system reliability, detailed modeling of partial availabilities, load representation by sub-period, energy limitations of hydro units as well as limited fuels. PROMOD IV models every hour of a typical week and calculates the amount of unserved energy based on the probability of insufficient generating capacity to meet load for each hour due to generating units forced outage rate.

Demand Modeling

Saskatchewan develops energy and peak demand forecasts 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. The demand and energy forecast utilized for this assessment is consistent with the 2012 LTRA.

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.

High and low forecasts are developed for Saskatchewan to cover possible ranges in economic variations and other uncertainties such as weather using a Monte Carlo simulation model to reflect those uncertainties. This model considers each variable to be independent from other variables and assumes the distribution curve of a probability of occurrence of a given result to be normal. The probability of the load falling within the bounds created by the high and low forecasts is expected to be 90% (confidence interval). High and low demand cases are modeled separately as sensitivity cases. The load forecast also has a chronological 8760 load shape that is modeled based on historical load profiles.

In the past, significant behind-the-meter generation was netted from load. Currently, SaskPower has very limited behind-the-meter generation and subsequently is not being modeled.

Controllable Capacity Demand Response Modeling

Demand response is modeled as a resource. SaskPower has contracts in place with customers for the reduction of load based on a defined demand response program. The program is currently modeled as a fuel limited, last dispatched combustion turbine.

Capacity Modeling

Capacity data for the individual units modeled in the assessment area is consistent with the LTRA. Unit data is provided by SaskPower on an annual basis and updated into the model. Unit characteristics such as maximum and minimum capacity, monthly derates, forced outage rates, maintenance schedules, ramp rates and other pertinent information is included in the analysis.

SaskPower either has approval or firm contracts in place for the future planned generation or the supply source is a part of the 10 year resource plan. Any future planned generation that is included in the resource plan goes through a decision making process to get government approval as required. A thorough system economic risk evaluated analysis is completed on each project to determine the optimal solution to meet reliability requirements.

The following projects, as included in the 2012 LTRA, are currently under development and have firm commitment and approval:

- Northland (261 MW Combined Cycle Gas Turbine)
- BD3 Clean (115 MW Integrated Carbon Capture and Sequestration)
- QE Expansion (205 MW Combined Cycle Gas Turbine)
- Biomass (36 MW biomass facility)
- Chaplin Wind (175 MW Wind facility)
- GOPP (25 MW multiple wind facilities)

- Island Falls (3.5 MW hydro re-rating)
- The following projects are seeking approval:
- GOPP (30 MW multiple wind facilities)
- The following projects require final economic analysis and approval:
- Gas CC (280 MW Combined Cycle Gas Turbine)
- Biomass (70 MW biomass facility)
- BD4 and BD5 Clean (250 MW Integrated Carbon Capture and Sequestration)

SaskPower has no jointly owned units that are shared by entities in different assessment areas. All output from SaskPower owned and Independent Power Producer's facilities is utilized serve Saskatchewan demand.

SaskPower has no long-term capacity sales or purchases at this time.

Wind is modeled as a transaction with an hourly profile based on historical generation data. For reliability planning purposes, a 10% summer and 20% winter capacity credit based on the nameplate rating is allocated.

Annual hydro energy is calculated based on historical data that has been accumulated over the last 50 plus years. It is modeled as a load modifier and utilized based on the monthly energy available before dispatchable units are modeled to meet the remaining load.

For traditional dispatchable capacity, rated capacity is based on historical operation of the facilities and what is expected during the planning period. Units are modeled with a maximum and minimum capacity rating. Depending on individual units, multiple capacity segments are modeled. Forced outages are modeled based on two and three state models. Natural gas units are typically modeled with a two state unit and it is either available to run at full load or is on a full forced outage with zero generation. Coal facilities typically are modeled as a three-state unit with a full load, a derated forced outage and a full forced outage state. SaskPower has a five year planned maintenance schedule that is included in detail in the model. A number of IPP generators are modeled with specific maintenance for the planning period. Other maintenance outages are modeled with automatic scheduling which allows the model to select the annual timing of maintenance after the 5 year planned timeline.

Transmission

No transmission facility data is used in this assessment as the model assumes that all firm capacity resources are deliverable within the assessment area. Separate transmission planning assessments indicate that transmission capability is expected to be adequate to supply firm customer demand and planned transmission service for generation sources.

Assistance from External Resources

SaskPower does not rely on non-firm assistance from resources outside of the assessment area and it is not included in the model.

Definition of Loss-of-Load Event

A Loss-of-Load Event is defined as any hour where firm load exceeds available system capacity and some portion of a customer's firm load is not served.

NPCC

Geographically, the NPCC Region covers nearly 1.2 million square miles and is populated by more than 55 million people. NPCC U.S. includes the six New England states (New Hampshire, Vermont, Massachusetts, Connecticut, Rhode Island, & Maine) and the state of New York. NPCC Canada includes the provinces of Ontario, Québec and the Maritime provinces of New Brunswick and Nova Scotia. In total, from a net energy for load perspective, NPCC is approximately 45% U.S. and 55% Canadian. With regard to Canada, approximately 70% of Canadian net energy for load is within the NPCC Region.

At the December 2008 NERC Planning Committee (PC) meeting, the PC approved the formation of a Generation & Transmission Reliability Planning Models Task Force (G&TRPMTF) with two main deliverables in the scope to evaluate approaches and models for composite generation and transmission (G&T) reliability assessment, and provide a common set of probabilistic reliability indices and recommend probabilistic-based work products that could be used to supplement the NERC's long term reliability assessments.

At the September 2010 PC meeting, the G&TRPMTF Final Report on Methodology and Metrics was approved. The metrics recommended in the Final Report included the : (i) annual Loss-of Load Hours (LOLH), (ii) Expected Unserved Energy (EUE), and (iii) Expected Unserved Energy as a percentage of Net Energy for Load (normalized EUE) for two common forecasted years – year 2 and year 5.

This *2012 Probabilistic Assessment* (based on the *NPCC 2012 Long Range Adequacy Overview*[12]) uses the NERC *2012 Long Term Reliability Assessment* reference case data. This assessment provides the required reliability indices for study the years of 2014 (year 2) and 2016 (year 5), and includes complete coverage of all NERC assessment areas.

General Electric's (GE) Multi-Area Reliability Simulation (MARS) program [13] was selected by NPCC for its analysis. GE Energy Consulting was retained by the Working Group to conduct the simulations. MARS version 3.14 was used for the assessment.

Summary

The estimated Expected Unserved Energy (EUE) and the estimated Loss-of-load hours (LOLH) shown in Table 22 are based on the results of NPCC's 2012 Long Range Adequacy Overview, [14] with assumptions consistent with those used for NPCC in the NERC 2012 Long-Term Reliability Assessment. The two years reported in this trial/pilot assessment are the years 2014 and 2016.

Table 22 shows the percentage difference between the amount of annual energy estimated by the GE MARS program and the amount reported in the *NERC 2012 Long Term Reliability Assessment*. This is primarily due to the differences in the NPCC Area assumptions used for their respective energy forecasts. The GE MARS estimate for the total estimated NPCC annual energy is approximately 2% higher than the corresponding sum of the NPCC Areas annual energy forecasts.[15]

[12] See: https://www.npcc.org/Library/Resource%20Adequacy/Forms/Public%20List.aspx

[13] See: http://www.gepower.com/prod_serv/products/utility_software/en/ge_mars.htm

[14] See: https://www.npcc.org/Library/Resource%20Adequacy/Forms/Public%20List.aspx

[15] The sum of the chronological loads for an ASSESSMENT AREA (simulated NEL) may differ from the Net Energy for Load reported in the LTRA. The development of a chronological ASSESSMENT AREA load model from the chronological load forecasts of the ASSESSMENT AREA entities may require adjustments.

Table 22: Comparison of Energies Modeled (Annual MWh)

Year	2014	2016
Quebec		
MARS	193,158,912	193,727,648
2012 LTRA	189,428,847	194,009,355
(MARS-LTRA)	3,730.065	-281,688
% (MARS-LTRA)/LTRA	2.0	-0.1
Maritimes		
MARS	26,879,986	27,078,624
2012 LTRA	26,879,000	27,130,000
(MARS-LTRA)	986	-51,376
% (MARS-LTRA)/LTRA	0	-0.2
New England		
MARS	143,568,960	149,563,936
2012 LTRA	140,520,000	143,815,000
(MARS-LTRA)	3,048,960	5,748,936
% (MARS-LTRA)/LTRA	2.2	4.0
New York		
MARS	170,351,547	171,281,939
2012 LTRA	165,340,000	166,915,000
(MARS-LTRA)	5,011,547	4,366,939
% (MARS-LTRA)/LTRA	3.0	2.6
Ontario		
MARS	139,139,187	131,834,107
2012 LTRA	139,139,000	131,834,000
(MARS-LTRA)	187	107
% (MARS-LTRA)/LTRA	0	0
NPCC		
MARS	673,098,624	673,486,272
2012 LTRA	661,306,847	663,703,336
(MARS-LTRA)	11,791,777	9,782,936
% (MARS-LTRA)/LTRA	1.8	1.5

Software Model Description

General Electric's Multi-Area Reliability Simulation (MARS) program [16] allows assessment of the reliability of a generation system comprised of any number of interconnected areas.

A sequential Monte Carlo simulation forms the basis for MARS. The Monte Carlo method allows for many different types of generation and demand-side options.

In the sequential Monte Carlo simulation, chronological system histories are developed by combining randomly generated operating histories of the generating units with the inter-area transfer limits and the hourly chronological loads. Consequently, the system can be modeled in great detail with accurate recognition of random events, such as equipment failures, as well as deterministic rules and policies that govern system operation.

The following reliability indices are available on both an isolated (zero ties between areas) and interconnected (using the input tie ratings between areas) basis:

[16] See: http://www.gepower.com/prod_serv/products/utility_software/en/ge_mars.htm

- Daily Loss of Load Expectation (LOLE - days/year)
- Hourly LOLE (hours/year)
- Loss of Energy Expectation (LOEE -MWh/year)
- Frequency of outage (outages/year)
- Duration of outage (hours/outage)
- Need for initiating Operating Procedures (days/year or days/period)

The use of Monte Carlo simulation allows for the calculation of probability distributions, in addition to expected values, for all of the reliability indices. These values can be calculated both with and without load forecast uncertainty.

The MARS program probabilistically models uncertainty in forecast load and generator unit availability. The program calculates expected values of Loss of Load Expectation (LOLE) and can estimate each Area's expected exposure to their Emergency Operating Procedures. Scenario analysis is used to study the impacts of extreme weather conditions, variations in expected unit in-service dates, overruns in planned scheduled maintenance, or transmission limitations.

The first step in calculating the reliability indices is to compute the area margins on an isolated basis, for each hour. This is done by subtracting from the total available capacity in the area for the hour the load demand for the hour. If an area has a positive or zero margin, then it has sufficient capacity to meet its load. If the area margin is negative, the load exceeds the capacity available to serve it, and the area is in a loss-of-load situation.

If there are any areas that have a negative margin after the isolated area margins have been adjusted for curtailable contracts, the program will attempt to satisfy those deficiencies with capacity from areas that have positive margins. Two methods are available for determining how the reserves from areas with excess capacity are allocated among the areas that are deficient. In the first approach, the user specifies the order in which an area with excess resources provides assistance to areas that are deficient. The second method shares the available excess reserves among the deficient areas in proportion to the size of their shortfalls. The user can also specify that areas within a pool will have priority over outside areas. In this case, an area must assist all deficient areas within the same pool, regardless of the order of areas in the priority list, before assisting areas outside of the pool. Pool-sharing agreements can also be modeled in which pools provide assistance to other pools according to a specified order.

MARS has the capability to model the following different types of resources such as thermal, energy-limited, cogeneration, energy-storage, demand-side management. An energy-limited unit can be modeled stochastically as a thermal unit with an energy probability distribution (Type 1 energy-limited unit), or deterministically as a load modifier (Type 2 energy-limited unit). Cogeneration units are modeled as thermal units with an associated hourly load demand. Energy-storage and demand-side management impacts are modeled as load modifiers.

For each unit modeled, the installation and retirement dates and planned maintenance requirements are specified. Other data such as maximum rating, available capacity states, state transition rates, and net modification of the hourly loads are input depending on the unit type.

The planned outages for all types of units in MARS can be specified by the user or automatically scheduled by the program on a weekly basis. The program schedules planned maintenance to levelize reserves on either an area, pool, or system basis. MARS also has the option of reading a maintenance schedule developed by a previous run and modifying it as specified by the user through any of the maintenance input data. This schedule can then be saved for use by subsequent runs.

In addition to the data described previously, thermal units (including Type 1 energy-limited units and cogeneration) require data describing the available capacity states in which the unit can operate. This is input by specifying the maximum rating of each unit and the rating of each capacity state as a per unit of the unit's maximum rating. A maximum of eleven capacity states are allowed for each unit, representing decreasing amounts of available capacity as governed by the outages of various unit components.

Because MARS is based on a sequential Monte Carlo simulation, it uses state transition rates, rather than state probabilities, to describe the random forced outages of the thermal units. State probabilities give the probability of a unit being in a given capacity state at any particular time, and can be used if you assume that the unit's capacity state for a given hour is independent of its state at any other hour. Sequential Monte Carlo simulation recognizes the fact that a unit's capacity state in a given hour is dependent on its state in previous hours and influences its state in future hours. It thus requires the additional information that is contained in the transition rate data.

For each unit, a transition rate matrix is input that shows the transition rates to go from each capacity state to each other capacity state. The transition rate from state A to state B is defined as the number of transitions from A to B per unit of time in state A:

If detailed transition rate data for the units is not available, MARS can approximate the transition rates from the partial forced outage rates and an assumed number of transitions between pairs of capacity states. Transition rates calculated in this manner will give accurate results for LOLE and LOEE, but it is important to remember that the assumed number of transitions between states will have an impact on the time-correlated indices such as frequency and duration.

Type 1 energy-limited units are modeled as thermal units whose capacity is limited on a random basis for reasons other than the forced outages on the unit. This unit type can be used to model a thermal unit whose operation may be restricted due to the unavailability of fuel, or a hydro unit with limited water availability. It can also be used to model technologies such as wind or solar; the capacity may be available but the energy output is limited by weather conditions.

Type 2 energy-limited units are modeled as deterministic load modifiers. They are typically used to model conventional hydro units for which the available water is assumed to be known with little or no uncertainty. This type can also be used to model certain types of contracts. A Type 2 energy-limited unit is described by specifying a maximum rating, a minimum rating, and a monthly available energy. This data can be changed on a monthly basis. The unit is scheduled on a monthly basis with the unit's minimum rating dispatched for all of the hours in the month. The remaining capacity and energy can be scheduled in one of two ways. In the first method, it is scheduled deterministically so as to reduce the peak loads as much as possible. In the second approach, the peak-shaving portion of the unit is scheduled only in those hours in which the available thermal capacity is not sufficient to meet the load; if there is sufficient thermal capacity, the energy of the Type 2 energy-limited units will be saved for use in some future hour when it is needed.

MARS models cogeneration as a thermal unit with an associated load demand. The difference between the unit's available capacity and its load requirements represents the amount of capacity that the unit can contribute to the system. The load demand is input by specifying the hourly loads for a typical week (168 hourly loads for Monday through Sunday). This load profile can be changed on a monthly basis. Two types of cogeneration are modeled in the program, the difference being whether or not the system provides back-up generation when the unit is unable to meet its native load demand.

Energy-storage units and demand-side management impacts are both modeled as deterministic load modifiers. For each such unit, the user specifies a net hourly load modification for a typical week which is subtracted from the hourly loads for the unit's area.

The transmission system between interconnected areas is modeled through transfer limits on the interfaces between pairs of areas. The transfer limits are specified for each direction of the interface and can be changed on a monthly basis. Random forced outages on the interfaces are modeled in the same manner as the outages on thermal units, through the use of state transition rates.

Contracts are used to model scheduled interchanges of capacity between areas in the system. These interchanges are separate from those that are scheduled by the program as one area with excess capacity in a given hour provides emergency assistance to a deficient area.

Each contract can be identified as either firm or curtailable. Firm contracts will be scheduled regardless of whether or not the sending area has sufficient resources on an isolated basis, but they will be curtailed because of interface transfer limits. Curtailable contracts will be scheduled only to the extent that the sending Area has the necessary resources on its own or can obtain them as emergency assistance from other areas.

Demand Modeling

The loads for each area were modeled on an hourly, chronological basis. The MARS program modified the input hourly loads through time to meet each Area's specified annual or monthly peaks and energies.

For the past several years, the Working Group has been using different load shapes for the different seasonal assessments. The Working Group considered the 2002 load shape to be representative of a reasonable expected coincidence of area load for the summer assessments. Likewise, the 2003 – 2004 load shape has been used for the winter assessments. The selection of these load shapes was confirmed earlier this year based on a review of the weather characteristics and corresponding loads of the years from 2002 through 2008.

For a study such as this that focuses on the entire year rather than a single season, the Working Group agreed to develop a composite load shape from the historical hourly loads for 2002, 2003, and 2004. January through March of the composite shape was based on the data for January through March of 2004. The months of April through September were based on those months for 2002, and October through December was based on the 2003 data.

Before the composite load model was developed by combining the various pieces, the hourly loads for 2003 and 2004 were adjusted by the ratios of their annual energy to the annual energy for 2002. This adjustment removed the load growth that had occurred from 2002, from the 2003 and 2004 loads, so as to create a more consistent load shape throughout the year.

The resulting load shape was then adjusted through the study period to match the monthly or annual peak and energy forecasts. The impacts of Demand-Side Management programs were included in each Area's load forecast.

Load forecast uncertainty was also modeled. The effects on reliability of uncertainties in the load forecast, due to weather and economic conditions, were captured through the load forecast uncertainty model in MARS. The program computes the reliability indices at each of the specified load levels (for this study, seven load levels were modeled) and calculates weighted-average values based on input probabilities of occurrence.

While the per unit variations in Area and sub-Area load can vary on a monthly and annual basis, For example, Table 3 shows the values assumed for January 2013, corresponding to the assumed occurrence of the NPCC system peak load (assuming the composite load shape). Table 3 also shows the probability of occurrence assumed for each of the seven load levels modeled.

In computing the reliability indices, all of the areas were evaluated simultaneously at the corresponding load level, the assumption being that the factors giving rise to the uncertainty affect all of the areas at the same time. The amount of the effect can vary according to the variations in the load levels.

For this study, the reliability indices were calculated for the expected load conditions, derived from computing the reliability at each of the seven load levels modeled, and computing a weighted-average expected value based on the specified probabilities of occurrence.

Table 23: Per Unit Variation in Load Assumed (Month of January 2013)							
Area	Per-Unit Variation in Load						
MT	1.1000	1.1000	1.0500	1.0000	0.9500	0.9000	0.9000
NE	1.0934	1.0383	0.9971	0.9635	0.9402	0.8500	0.8000
NY	1.0430	1.0310	1.0160	0.9980	0.9750	0.9440	0.9050
ON	1.0835	1.0557	1.0278	1.0000	0.9722	0.9443	0.9165
QC	1.0837	1.0825	1.0368	0.9999	0.9632	0.9255	0.9163
Prob.	0.0062	0.0606	0.2417	0.3830	0.2417	0.0606	0.0062

Behind-the-meter generation was modeled as netted from load.

Controllable Capacity Demand Response Modeling

Each area takes defined steps as their reserve levels approach critical levels. Table 4 shows these steps, consisting of those load control and generation supplements that can be implemented before firm load has to be disconnected. Load control measures could include disconnecting or reducing interruptible loads, making public appeals to reduce demand, and/or implementing voltage reductions. Other measures could include calling on generation available under emergency conditions, and/or reducing operating reserves.

The need for an area to begin these operating procedures is modeled in MARS by evaluating the daily probabilistic expectation at specified margin states. The user specifies these margin states for each area in terms of the benefits realized from each emergency measure, which can be expressed in MW, as a per unit of the original or modified load, and as a per unit of the available capacity for the hour.

Table 24: NPCC Operating Procedures to Mitigate Resource Shortages 2013 Peak Month Load Relief Assumptions - MW

Actions	MT (Feb)	NE (Aug)	NY (Aug)	ON (July)	QC (Jan)
1. Curtail Load / Utility Surplus				148	1,339
Appeals				1% of load	
RT-DR/SCR/EDRP		875 [17]	1,748		
SCR Load /Man. Volt. Red.			0.36% of load		
2. No 30-min Reserves	234	600	765	473	500
3. Voltage Reduction		374	1.20% of load		250
Interruptible Loads [18]	253				
4. No 10-min Reserves	660			1,080	750
RT-EG		387 [19]			
General Public Appeals			213		
5. 5% Voltage Reduction				2.60% of load	
No 10-min Reserves		1,575	1,200		

[17] Derated value shown accounts for assumed availability.
[18] Interruptible Loads for the Maritimes area (implemented only for the Area), Voltage Reduction for all others.
[19] Derated value shown accounts for assumed availability.

Capacity Modeling

Details regarding the NPCC area's assumptions for generator unit availability are described in the latest NPCC Seasonal Multi-Area Probabilistic Assessment. [20]

Figures 1 through 6 summarize area capacity and load assumed in this overview at the time of area peak for the 2013–2017 period. Area peak load is shown against the initial area generating capacity (includes demand resources modeled as resources), adjusted for purchases, retirements, and additions. New England generating capacity also includes active Demand Response, based on the Capacity Supply Obligations obtained through ISO-NE's Forward Capacity Market three years in advance.

Figure 12: Maritimes Area Capacity and Load;

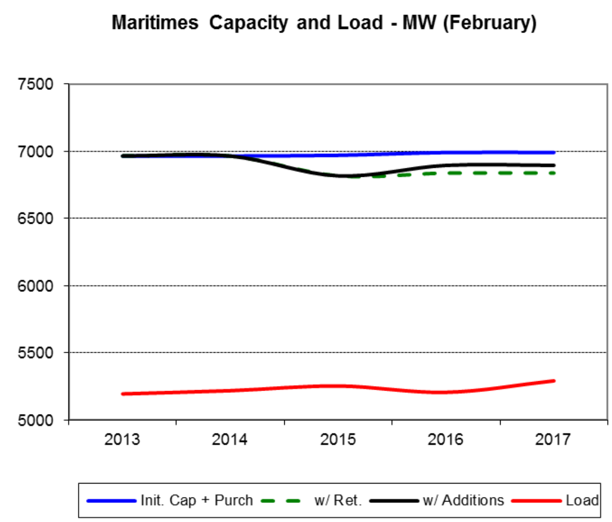


Figure 13: New England Capacity and Load

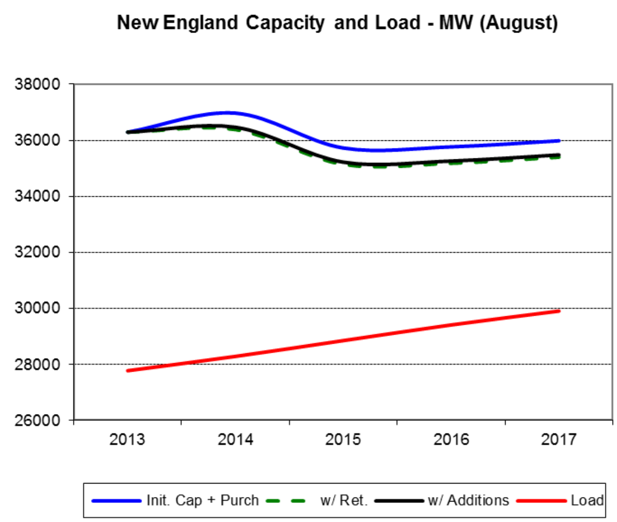


Figure 14: New York Area Capacity and Load;

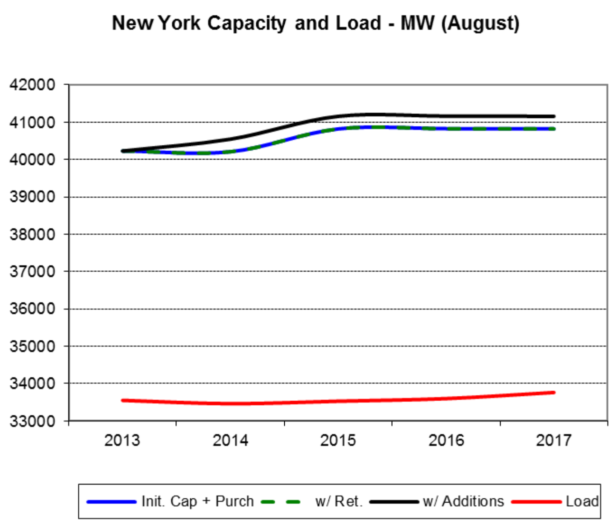
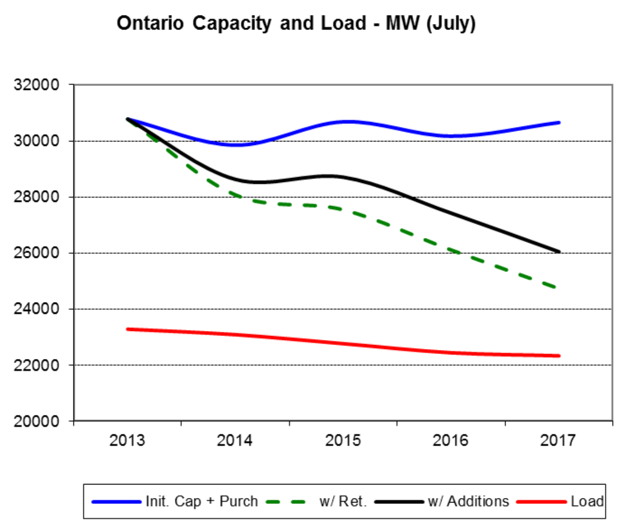


Figure 15: Ontario Capacity and Load



[20] See: http://www.npcc.org/adequacy.cfm

Figure 16: Québec Capacity and Load;

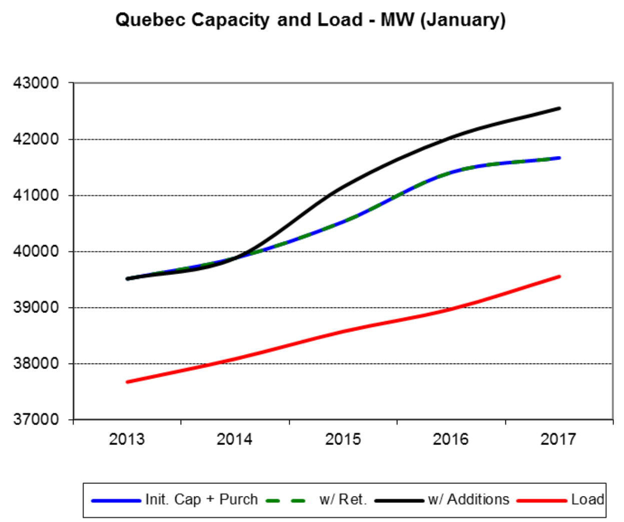
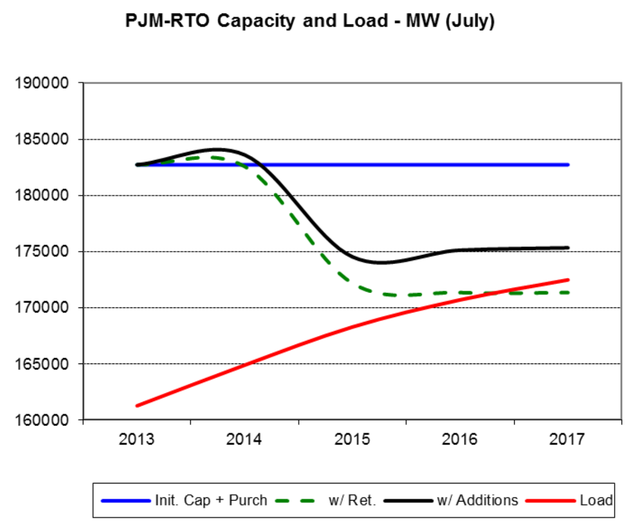


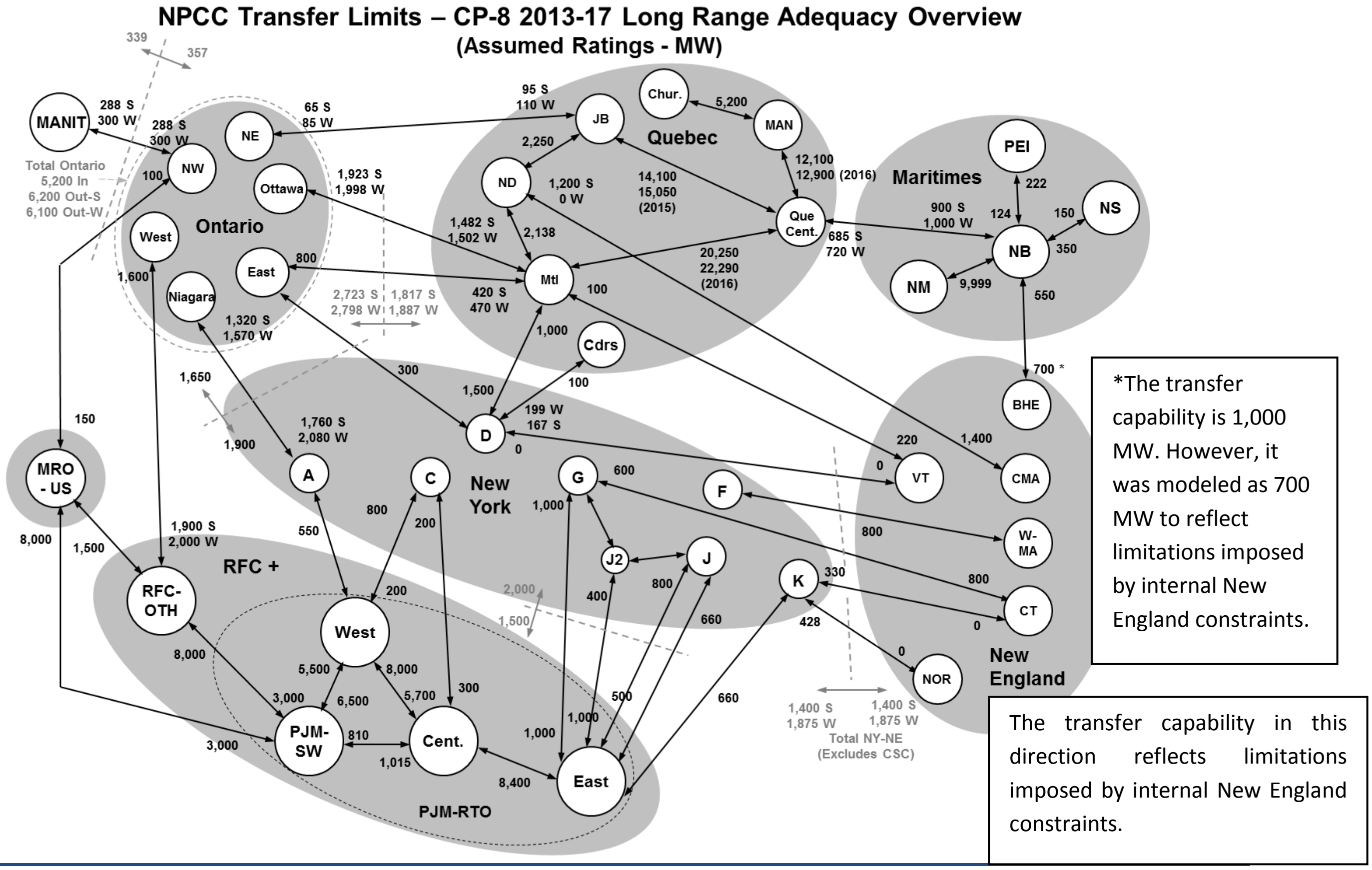
Figure 17: PJM-RTO Capacity and Load



Transmission

Transmission additions and retirements for 2013 through 2017 assumed in the modeling was consistent with the data provided for the NERC LTRA. Figure 7 stylistically summaries the transmission system that was assumed, showing area and assumed transfer limits for the assessment time period.

Figure 18: Assumed Transfer Limits

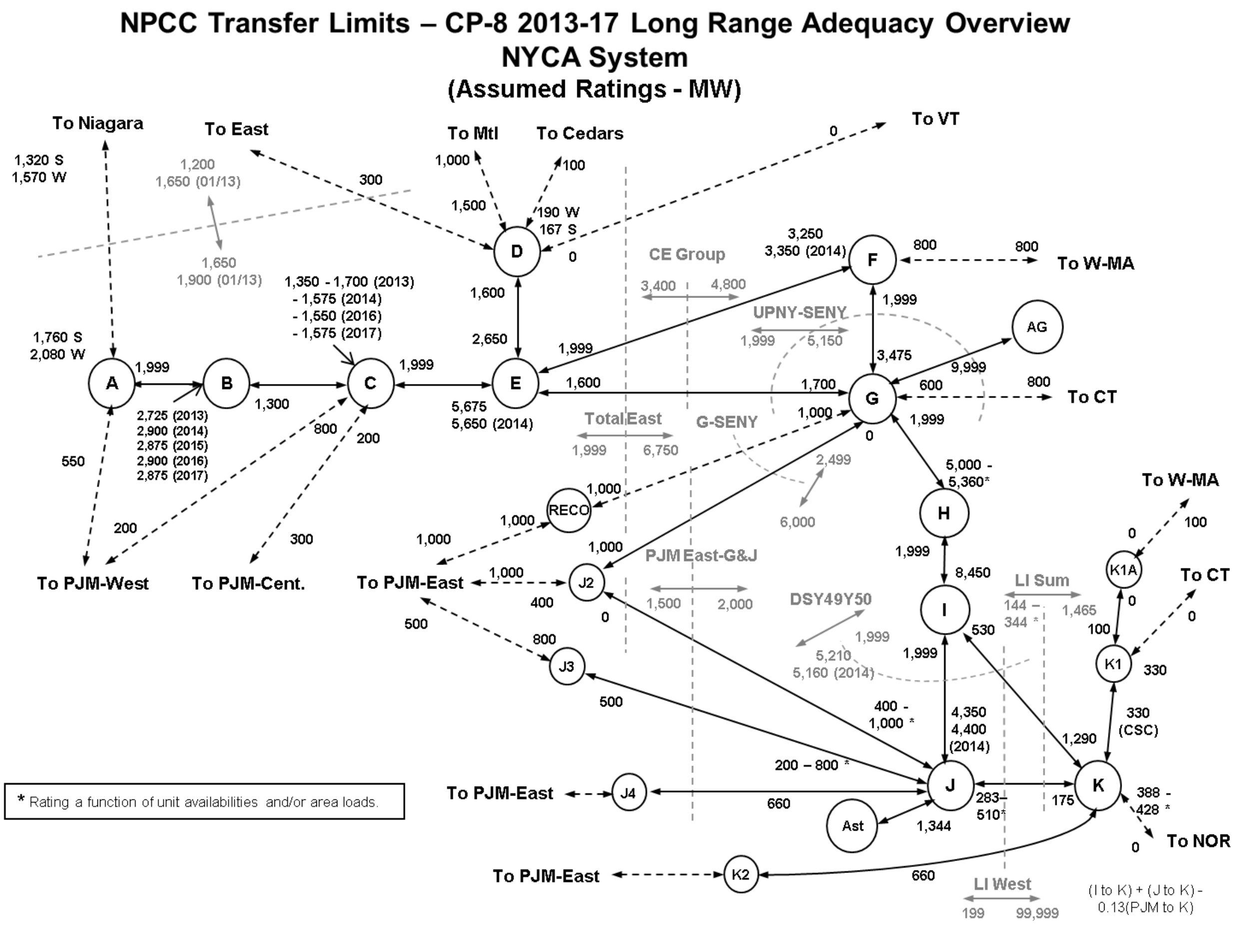


Transfer limits between and within some areas are indicated in Figure 7 with the assumed seasonal ratings (S- summer, W- winter) where appropriate. The acronyms and notes used in Figure 7 are defined as follows:

Chur	- Churchill Falls	NOR	- Norwalk – Stamford	NM	- Northern Maine
MANIT	- Manitoba	BHE	- Bangor Hydro Electric	NB	- New Brunswick
ND	- Nicolet-Des Cantons	Mtl	- Montréal	PEI	- Prince Edward Island
BJ	- Bay James	C MA	- Central MA	CT	- Connecticut
MN	- Minnesota	W MA	- Western MA	NS	- Nova Scotia
MAN	- Manicouagan	NBM	- Millbank	NW	- Northwest (Ontario)
NE	- Northeast (Ontario)	VT	- Vermont	RFC	- Reliability*First* Corp.
MRO	- Midwest Reliability	Que	- Québec Centre	MT	- Maritimes Area

Details regarding the development of the transmission representation for New York shown in Figure 7(a) are consistent with the New York State Reliability Council "New York Control Area Installed Capacity Requirements for the Period May 2012 through April 2013" Technical Study Report, December 2, 2011.[21]

Figure 19: Assumed New York Transmission Limits



Details regarding the development of the transmission representation for New England shown in Figure 7(b) can be found in the New England Regional System Plan 2012.[22]

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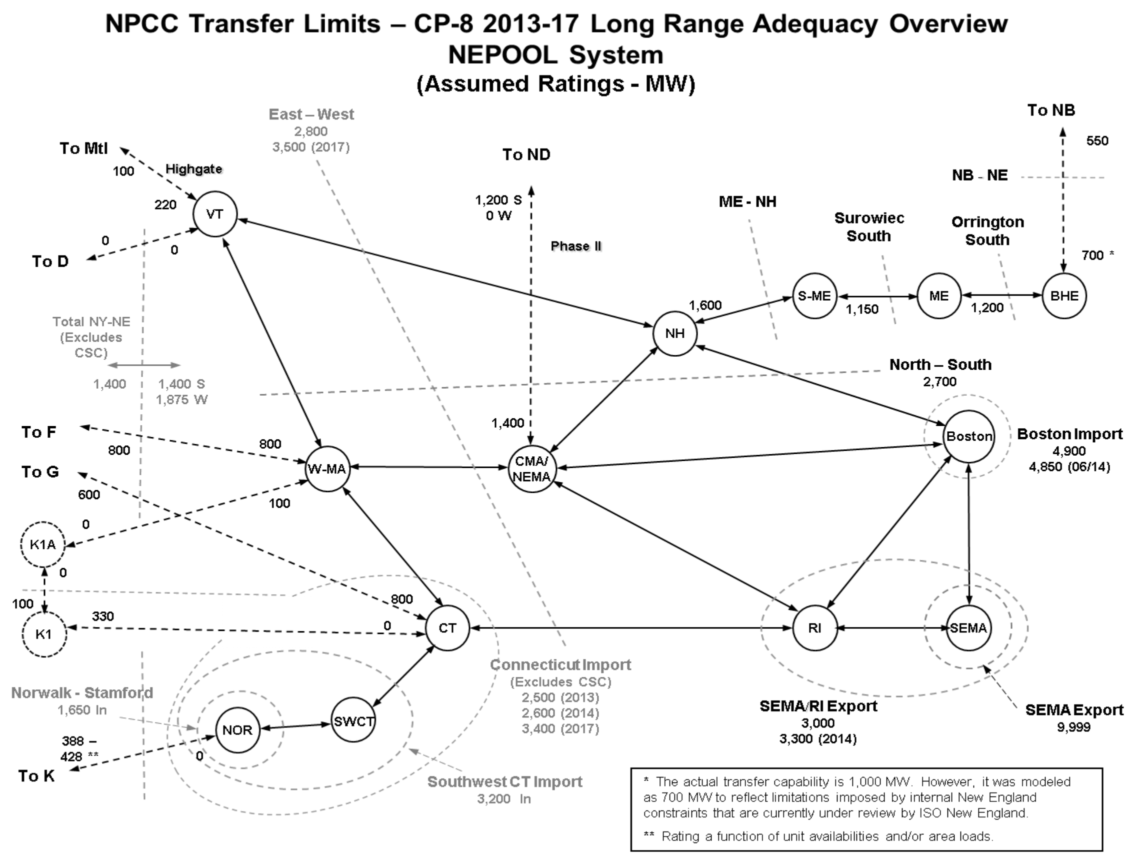
[21] See: http://www.nysrc.org/pdf/Reports/2012%20IRM%20Final%20Report.pdf

[22] See: http://www.iso-ne.com/trans/rsp/index.html

Figure 20: New England Transmission Limits



The modeling of Quebec shown in Figure 7 is consistent with its 2012 NPCC Interim Review of Resource Adequacy [23] and with the second progress report of Hydro- Québec Distribution

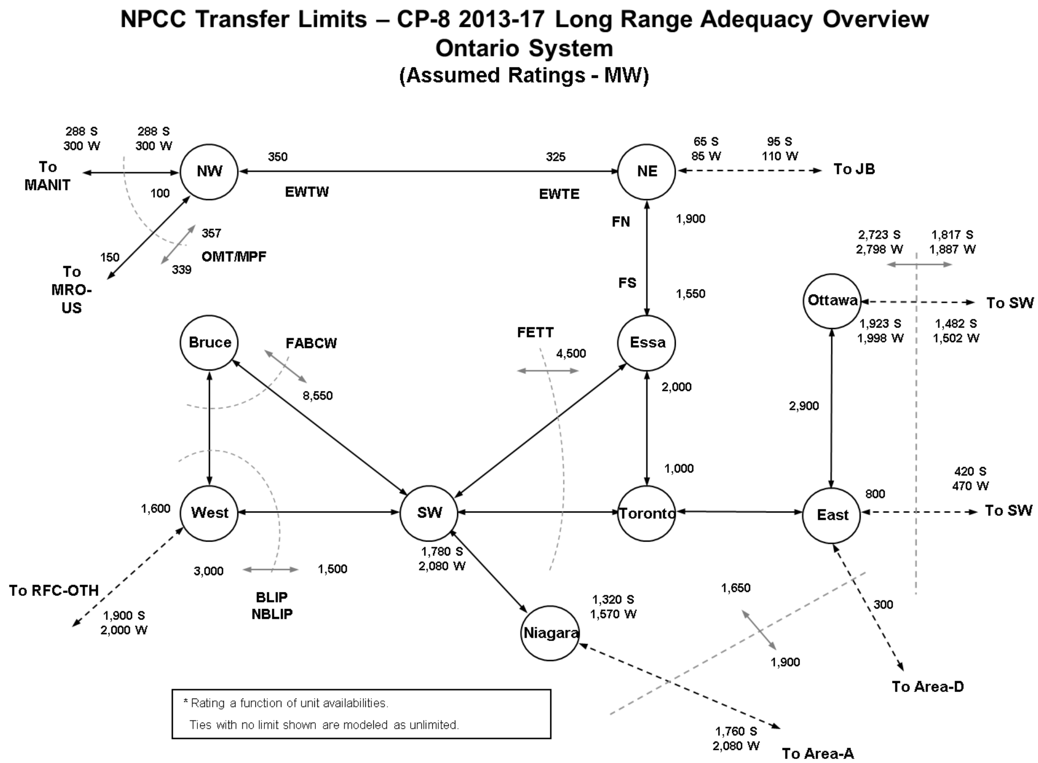
(HQD) 2011-2020 Supply Plan filed with the Québec Energy Board on November 1, 2012. [24]

The modeling of the Maritimes shown in Figure 7 is consistent with its 2012 NPCC Interim Review of Resource Adequacy. [25]

Details regarding the development of the transmission representation for Ontario shown in Figure 7(c) can be found in the "Ontario Transmission System," November 2011.[26]

[23] See: https://www.npcc.org/Library/Resource%20Adequacy/Forms/Public%20List.aspx
[24] See: http://www.regie-energie.qc.ca/audiences/Suivis/index.html
[25] See: https://www.npcc.org/Library/Resource%20Adequacy/Forms/Public%20List.aspx
[26] See: http://www.ieso.ca/imoweb/pubs/marketReports/OntTxSystem_2011nov.pdf

Figure 21: Ontario Transmission Limits



The modeling of PJM-RTO shown in Figure 7 breaks the PJM region into four distinct areas: Eastern Mid-Atlantic, Central Mid-Atlantic, Western Mid-Atlantic, and the PJM Western areas combined with PJM South. This modeling follows known operational models and constraints while recognizing that areas with high reserves have few events invoking emergency operating procedures. The model in this study used many of the same modeling assumptions used in the PJM 2012 reserve requirement study.[27] All transmission projects are treated in aggregate, with the appropriate timing and transfer values changing in the model, consistent with PJM's Regional Transmission Expansion Plan (RTEP.) [28]

Assistance from External Resources

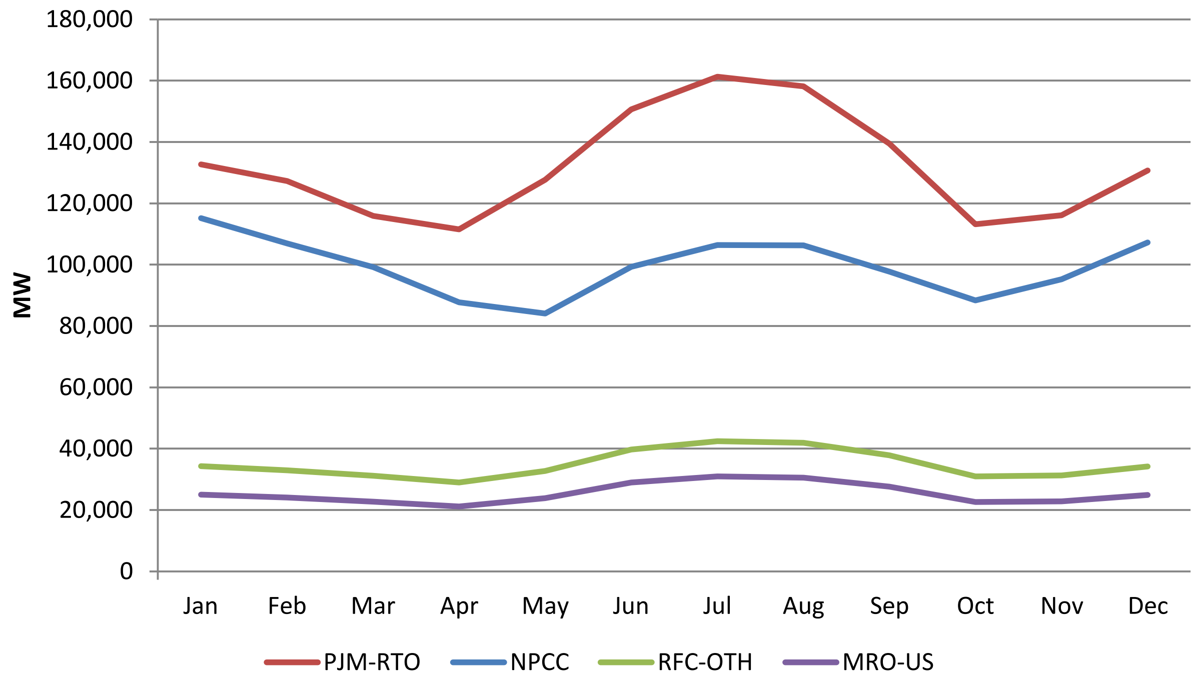
All Areas received assistance on a shared basis in proportion to their deficiency. In this analysis, each step was initiated simultaneously in all Areas and sub-Areas.

A detailed representation of the neighboring regions of RFC (Reliability*First* Corp.) and the MRO-US (Midwest Reliability Organization – US portion) was assumed. The assumptions are summarized in Table 25 and Figure 22.

[27] See: http://www.pjm.com/committees/planning/downloads/20051130-item8-pjm-irm-letter.pdf
[28] See: http://pjm.com/planning.aspx

Table 25: PJM, RFC-Other and MRO-US 2013 Assumptions [29]			
	PJM	RFC-Other	MRO-US
Peak Load (MW)	161,240	42,428	30,923
Peak Month	July	July	July
Assumed Capacity (MW)	183,856	48,711	35,318
Purchase/Sale (MW)	-802	0	0
Reserve (%)	14	15	14
Operating Reserves (MW)	3,400	2,206	1,700
Curtailable Load (MW)	10,278	3,568	2,600
No 30-min Reserves (MW)	2,765	1,470	1,200
Voltage Reduction (MW)	2,201	1,100	1,100
No 10-min Reserves (MW)	635	736	500
Appeals (MW)	400	200	200
Load Forecast Uncertainty	94.66% +/- 5.57%, 11.13%, 16.7%	94.44% +/- 4.78%, 9.57%, 14.36%	94.44% +/- 4.78%, 9.57%, 14.36%

Figure 22: 2013 2013 Projected Coincident Expected Monthly Peak Loads - MW Composite Load Shape



Reliability*First*

Reliability*First* is a not-for-profit company whose goal is to preserve and enhance electric service reliability and security for the interconnected electric systems within its territory. Reliability*First* was approved by the North American Electric Reliability Council (NERC) to become one of eight Regional Reliability Councils in North America and began operations on January 1, 2006.

[29] Load and capacity assumptions for RFC-Other and MRO-US based on NERC's Electricity, Supply and Demand Database (ES&D) available at: http://www.nerc.com/~esd/

Reliability*First* is the successor organization to three former NERC Regional Reliability Councils: the Mid-Atlantic Area Council (MAAC), the East Central Area Coordination (ECAR) Agreement, and the Mid-American Interconnected Network (MAIN) organizations. The year 2006 is a period of transition for the ECAR, MAAC and MAIN organizations, as their responsibilities are identified and transferred to Reliability*First*.

The RFC-Other area modeled in this analysis was intended to represent the non-PJM-RTO region data within RFC. The modeling of the RFC region is in transition due to changes in the regional boundaries between RFC, MRO, and SERC. This model was based on publicly available data from the 2008 NERC *Electricity Supply & Demand* (ES&D), which reported the data according to the old boundary definitions. The modeling of RFC-Other is expected to evolve for future studies as data reflecting the new regional boundaries becomes available. For now, the RFC-Other area is the non-PJM-RTO region that was formerly in either MAIN or ECAR.

Unit data was from the publicly available NERC data. Each individual unit represented in the non-PJM RFC region was assigned unit performance characteristics based on PJM RTO fleet class averages (consistent with PJM 2012 RRS Report).

MRO

The Midwest Reliability Organization (MRO) is a non-profit organization dedicated to ensuring the reliability of the bulk power system in the North Central part of North America. The primary focus of the MRO is ensuring compliance with regional and international reliability standards and criteria utilizing open, fair processes in the public interest.

Formation of the MRO was approved by the Mid-Continent Area Power Pool (MAPP) Executive Committee in November 2002. In 2005, this organization became operational and replaced the MAPP Regional Reliability Council of the North American Electric Reliability Council.

The U.S. portion of the MRO was modeled in this study, recognizing the strong transmission ties to the rest of the study system. Each individual unit represented in the MRO-US region was assigned unit performance characteristics based on PJM RTO fleet class averages (consistent with PJM 2012 RRS Report).

PJM-RTO

The forecast contained in the January 2012 PJM Load Forecast [30] was used, consistent with the 2012 RRS. The methods and techniques used in the load forecasting process are documented in Manual 19 (Load Forecasting and Analysis) and Manual 20 (PJM Resource Adequacy Analysis.) [31] The hourly load shape is based on observed 2002 calendar year values, which reflects representative weather and economic conditions for a peak planning study. The hourly loads were then adjusted per the PJM Load Forecast Report, January 2012, for the forecast monthly loads. This study modeled load forecast uncertainty consistent with that used in recent probabilistic PJM models, per the above references, which reflects uncertainty for loads at a predetermined probability of occurrence. This load uncertainty typically reflects factors such as weather, economics, diversity (timing) of peak periods among internal PJM zones or regions, the period years the model is based on, sampling size, and how many years ahead in the future the load is forecast.

The modeling of PJM-RTO breaks the PJM region into four distinct areas: Eastern Mid-Atlantic Central Mid-Atlantic, Western Mid-Atlantic, and the PJM Western areas combined with PJM South. This modeling follows known operational models and constraints while recognizing that areas with high reserves have few events invoking emergency operating procedures. The model in this study used many of the same modeling assumptions used in the PJM 2012 reserve requirement study.

[30] See: http://www.pjm.com/~/media/documents/reports/2011-pjm-load-report.ashx

[31] Please refer to PJM Manual 19 http://pjm.com/~/media/documents/manuals/m19.ashx and PJM Manual 20, http://ftp.pjm.com/~/media/documents/manuals/m20.ashx for technical specifics.

All generators that have been demonstrated to be deliverable were modeled as PJM capacity resources in the PJM-RTO study area. Active generation projects in the PJM interconnection queues were modeled in the PJM-RTO study area after applying a suitable commercial probability.

The transfer values shown in the study are reflective of peak load flow model conditions. PJM is a summer peaking area. The studies performed to determine these transfer values are in line with the Regional Transmission Planning Process employed at PJM, of which the Transmission Expansion Advisory Committee (TEAC) reviews these activities. All activities of the TEAC can be found at the pjm.com web site. All transmission projects are treated in aggregate, with the appropriate timing and transfer values changing in the model, consistent with PJM's Regional Transmission Expansion Plan (RTEP.)[32]

Definition of Loss-of-Load Event

NPCC Regional Reliability Reference Directory No. 1 "Design and Operation of the Bulk Power System" Section 5.2 Resource Adequacy – Design Criteria states: [33]

"The probability (or risk) of disconnecting firm load due to resource deficiencies shall be, on average, not more than one day in ten years as determined by studies conducted for each Resource Planning and Planning Coordinator Area. Compliance with this criterion shall be evaluated probabilistically, such that the loss of load expectation (LOLE) of disconnecting firm load due to resource deficiencies shall be, on average, no more than 0.1 day per year. This evaluation shall make due allowance for demand uncertainty, scheduled outages and deratings, forced outages and deratings, assistance over interconnections with neighboring Planning Coordinator Areas, transmission transfer capabilities, and capacity and/or load relief from available operating procedures."

Area operators may invoke their available operating procedures in any order, depending on the situation faced at the time; for this analysis, the reliability indices were calculated following the sequential order shown in the tables below; the CP-8 Working Group agreed that modeling the actions this way was a reasonable approximation for this analysis.

It should be recognized that changing the assumed order of the operating procedures in the analysis will change the magnitude of the calculated indices. The highlighted values for the metrics in the Tables 26, 27, 28, and 29 below are consistent with NPCC's Resource Adequacy – Design Criteria; i.e., they are calculated following all possible allowable "load relief from available operating procedures."

Table 26: Base Case Results for 2014 – LOLH (hours/year)

	Expected Load				
	Q	MT	NE	NY	ON
Curtail Load / Utility Surplus	0.238	10.224	1.071	3.404	0.193
No 30-min Reserves	0.010	10.224	0.359	0.576	0.025
Volt. Red. or Inter. Loads	-	4.301	0.162	0.172	0.001
No 10-min Reserves (NY - Public Appeals)	-	0.235	0.102	0.076	-
General Public Appeals (NY - No 10-min.)	-	0.010	0.049	0.041	-
Disconnect Load	-	0.010	0.002	0.003	-

[32] See: http://pjm.com/planning.aspx
[33] See: http://www.npcc.org/documents/regStandards/Directories.aspx

Table 27: Base Case Results for 2014 – EUE (MWh of EUE per Million MWh of Annual Load Energy)					
	Expected Load				
	Q	MT	NE	NY	ON
Curtail Load / Utility Surplus	0.465	20.938	6.938	16.830	0.944
No 30-min Reserves	0.010	20.938	1.842	1.443	0.067
Volt. Red. or Inter. Loads	-	8.114	0.705	0.403	0.001
No 10-min Reserves (NY - Public Appeals)	-	0.439	0.407	0.150	-
General Public Appeals (NY - No 10-min.)	-	0.022	0.178	0.076	-
Disconnect Load	-	0.022	0.006	0.005	-

Table 28: Base Case Results for 2016 – LOLH (hours/year)					
	Expected Load				
	Q	MT	NE	NY	ON
Curtail Load / Utility Surplus	0.092	8.097	3.785	7.599	0.851
No 30-min Reserves	0.004	8.097	0.883	1.251	0.236
Volt. Red. or Inter. Loads	-	3.325	0.482	0.434	0.091
No 10-min Reserves (NY - Public Appeals)	-	0.191	0.333	0.192	0.047
General Public Appeals (NY - No 10-min.)	-	0.005	0.201	0.107	0.001
Disconnect Load	-	0.005	0.014	0.012	-

Table 29: Base Case Results for 2016 – EUE (MWh of EUE per Million MWh of Annual Load Energy)					
	Expected Load				
	Q	MT	NE	NY	ON
Curtail Load / Utility Surplus	0.144	16.090	31.147	34.405	4.630
No 30-min Reserves	0.004	16.090	7.194	3.416	1.167
Volt. Red. or Inter. Loads	-	6.116	3.300	1.095	0.337
No 10-min Reserves (NY - Public Appeals)	-	0.318	1.849	0.375	0.112
General Public Appeals (NY - No 10-min.)	-	0.007	0.911	0.194	0.002
Disconnect Load	-	0.007	0.045	0.018	-

Detailed Area Modeling Assumptions

The assumptions used in NPCC's Long Range Adequacy Overview are consistent with the assumptions of the following recently completed Area studies, described and referenced below,

New York

This study was based upon the 2012 Reliability Needs Assessment [34] (RNA), published on September 18, 2012 in accordance with its Comprehensive System Planning Process (CSPP). The NYISO's CSPP encompasses the existing reliability planning processes with the new economic planning process called the Congestion Analysis and Resource Integration Study (CARIS). The 2012 RNA provides a long-range reliability assessment of both resource adequacy and transmission security of the New York bulk power system conducted over a ten-year Study Period (2013-2022). The RNA evaluates the New York Bulk Power Transmission Facilities to determine if Reliability Criteria are met, and identifies Reliability Needs if they are not met.

[34] See: http://www.nyiso.com/public/webdocs/services/planning/reliability_assessments/2012_RNA_Final_Report_9-18-12_PDF.pdf

The 2012 RNA identified two types of reliability issues: transmission security violations, which could manifest as soon as 2013, and resource adequacy violations, which could occur by 2020.

The NYISO's previous RNA (completed in 2010) found that the state's electric power resources (generation, transmission and demand-side program) would meet reliability needs through 2020, assuming energy efficiency programs and planned resource additions proceed as anticipated and no significant facilities were retired from service. There are several reasons cited by the 2012 RNA for reliability needs related to resource adequacy by 2020. The main reason is that generation modeled in the 2012 RNA is about 1,000 megawatts less due to retirements or mothballing of generating units. In addition, the load forecast for 2020 is slightly higher, and the amount of projected demand-side resources is slightly lower.

Based on the finding of reliability needs in the 2012 RNA, the next steps in the NYISO's comprehensive planning process are requests for market-based and regulated solutions. Following an analysis and evaluation of the solutions received, the NYISO will develop and issue a Comprehensive Reliability Plan (CRP) that will determine how the reliability needs identified in the RNA are resolved by the solutions.

New England

The New England Regional System Plan (RSP) is ISO-New England's annual planning report that identifies the resources and transmission facilities needed to maintain reliable and economic operation of New England's bulk electric power system over a ten-year horizon. A public meeting to discuss ISO-New England's Draft 2012 RSP and other planning issues facing the New England region was held on September 13, 2012. The New England 2012 RSP [35] was approved by ISO-New England's Board of Directors on November 2, 2012.

The economic recession has slowed the growth of the summer peak demand, while wholesale electricity markets and other factors have stimulated the development of supply and demand resources and transmission infrastructure to meet the needs of the New England region. Operational challenges, such as LNG supply issues to NEMA/Boston, are being addressed, and the issues for further analysis are being incorporated into the planning process. To meet future system needs, the planning process considers the likelihood of power plant retirements, the expected development and integration of the region's renewable resources, the impact of public policies, and the close interaction between the natural gas and electric power system infrastructure.

The region's heavy dependence on natural-gas-fired generation to meet its electricity needs is expected to grow, with the likely retirement of old coal and oil units and their replacement, in whole or in part, with generators in the queue, and with the possibility of nuclear outages or retirements. At the same time, environmental and economic incentives provided by governmental policies are encouraging the development of low-emitting, renewable resources, such as wind and solar. Passive demand resources are expected to increase as well, as shown by the ISO's energy-efficiency forecast for this planning period. Economic studies are showing the effects of these types of resources and possible new imports from Canada, providing useful information for policymakers and resource developers. Also, smart grid technologies are being developed to improve the electric power system's performance and operating flexibility and its potential to grow active demand resources.

RSP12 and its associated *RSP Project List*, needs assessments, and solutions studies provide detailed information about the system changes needed to reliably serve load in New England for the next 10 years. Transmission projects are in various stages of development, and many have begun or have completed the siting process. Elective and merchant transmission facilities, in various stages of development, have the potential to provide access to renewable resources in remote areas of the region and in neighboring areas.

[35] See: http://www.iso-ne.com/trans/rsp/index.html

In its Strategic Planning Initiative, the ISO has identified risks to the regional electric power system; the likelihood, timing, and potential consequences of these risks; and possible mitigating actions. Through an open process, regional stakeholders and the ISO are developing an approach to address these issues, which could include further infrastructure development as well as changes to the wholesale electricity market design and the system planning process. Through current and planned activities, the region is well positioned to meet all challenges to reliable and economic system performance.

Ontario

The Independent Electricity System Operator of Ontario regularly assesses the adequacy and reliability of Ontario's power system. The latest Assessment of the Reliability and Operability of the Ontario Electricity System Update [36] provides Ontario's supply outlook over the next 18 months. New resources - two refurbished units at the Bruce nuclear station plus the province's first grid-connected solar farm - as well as new tools to effectively integrate renewable resources are described.

Approximately 2,200 megawatts (MW) of grid-connected renewable capacity will be added to the system between December 2012 and May 2014, including the completion of Ontario's first transmission-connected solar project, a 100 MW solar farm in Haldimand County. By May 2014, distribution- and transmission-connected wind and solar generation in Ontario is expected to reach approximately 5,500 MW.

The refurbishment and reliable operation of two Bruce nuclear units is an integral requirement for the scheduled elimination of coal-fired capacity. Both Bruce nuclear units have now completed commissioning; once these units have demonstrated sustained reliable performance, Ontario will be in a good position to continue the removal of coal-fired generation from the system

Québec

The Québec assumptions used in this study are consistent with its 2012 NPCC Interim Review of Resource Adequacy [37] and the 2012 NERC Long-Term Reliability Assessment. [38] Major resource assumptions include:

The retirement of the La Citière oil G.S. (280 MW) & the Tracy thermal G.S. (450 MW);

The delayed commissioning of one unit of La Sarcelle hydro G.S (50 MW);

The retirement of the Gentilly-2 nuclear G.S which was previously expected to be refurbished from 2013 to 2014 (a decrease of 700 MW from the expected capacity after refurbishment); and,

The mothballing period extension of the natural gas unit operated by TransCanada Energy (TCE) beyond the period covered by this review (547 MW).

Maritimes

The Maritimes Area is a winter peaking area with separate markets and regulators in New Brunswick, Nova Scotia, Prince Edward Island (PEI), and Northern Maine. The New Brunswick System Operator (NBSO) is the Reliability Coordinator for the Maritimes Area. The assumptions used in this study are consistent with its most recent NPCC Maritimes Review of Resource Adequacy; [39] results indicate that the Maritimes Area will comply with the NPCC resource adequacy criterion.

On October 19, 2011 the New Brunswick government released its new energy blueprint, a three year energy strategy aimed at reducing and stabilizing energy prices, providing energy security, ensuring reliability of the electrical system,

[36] See: http://www.ieso.ca/imoweb/pubs/marketReports/18MonthOutlook_2012nov.pdf
[37] See: https://www.npcc.org/Library/Resource%20Adequacy/Forms/Public%20List.aspx
[38] See: http://www.nerc.com/page.php?cid=4|61
[39] See: https://www.npcc.org/Library/Resource%20Adequacy/Forms/Public%20List.aspx

environmental responsibility, and providing effective regulation. The plan amalgamates the NB Power group of companies and the New Brunswick System Operator into a single vertically integrated Crown utility but will not affect resource adequacy in the Maritimes Area.

The 660 MW Point Lepreau Nuclear Generating Station was placed back into service at the end of November 2012. Even without Point Lepreau capacity, the Maritimes Area meets the NPCC resource adequacy criterion for all years from 2013-15.

PJM-RTO

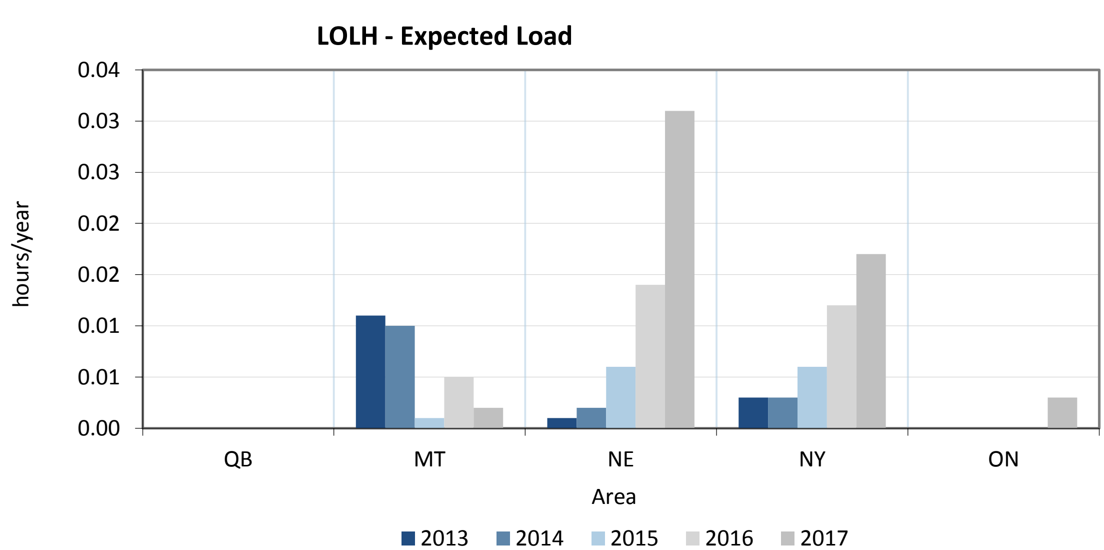
The annual PJM Reserve Requirement Study (RRS) [40] calculates the reserve margin that is required to comply with the Reliability Principles and Standards as defined in the PJM Reliability Assurance Agreement (RAA) and Reliability*First* Corporation (RFC) in compliance with Standard BAL-502-RFC-02. This study is conducted each year in accordance with the process outlined in PJM Manual 20 (M-20), PJM Resource Adequacy Analysis. M-20 focuses on the process and procedure for establishing the resource adequacy (capacity) required to reliably serve customer load with sufficient reserves.

The results of the RRS provide key inputs to the PJM Reliability Pricing Model (RPM). The results of the RRS are also incorporated into PJM's Regional Transmission Expansion Plan (RTEP) process, pursuant to Schedule 6 of the PJM Operating Agreement, for the enhancement and expansion of the transmission system in order to meet the demands for firm transmission service in the PJM Region.

Results

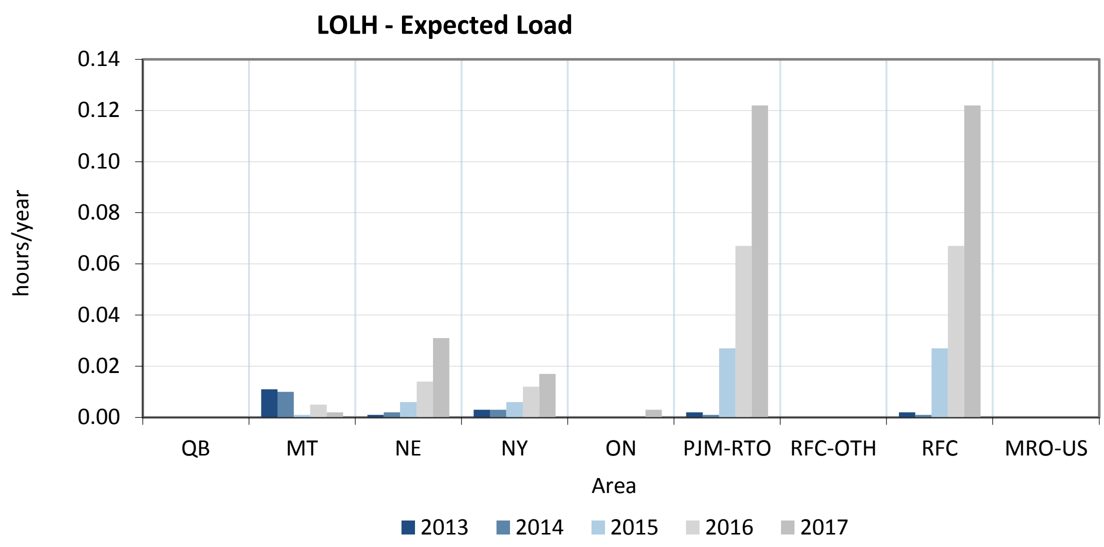
Figures 9(a) and 9(b) shows the estimated annual Loss of Load Expectation (LOLH) for NPCC Areas and neighboring Regions for the 2013-2017 period, assuming all allowable operating procedures have been taken.

Figure 23: Estimated Annual LOLH for NPCC Areas (2013 – 2017)



[40] See: http://pjm.com/~/media/planning/res-adeq/2012-pjm-reserve-requirement-study.ashx

Figure 24: Estimated Annual LOLH for NPCC Areas and Neighboring Regions (2013 – 2017)



Figures 10(a) and 10(b) shows the estimated annual Expected Unserved Energy (EUE) for NPCC Areas for the 2013 - 2017 period, assuming all allowable operating procedures have been taken.

Figure 25: Estimated Annual NPCC Area EUE (2013 – 2017)

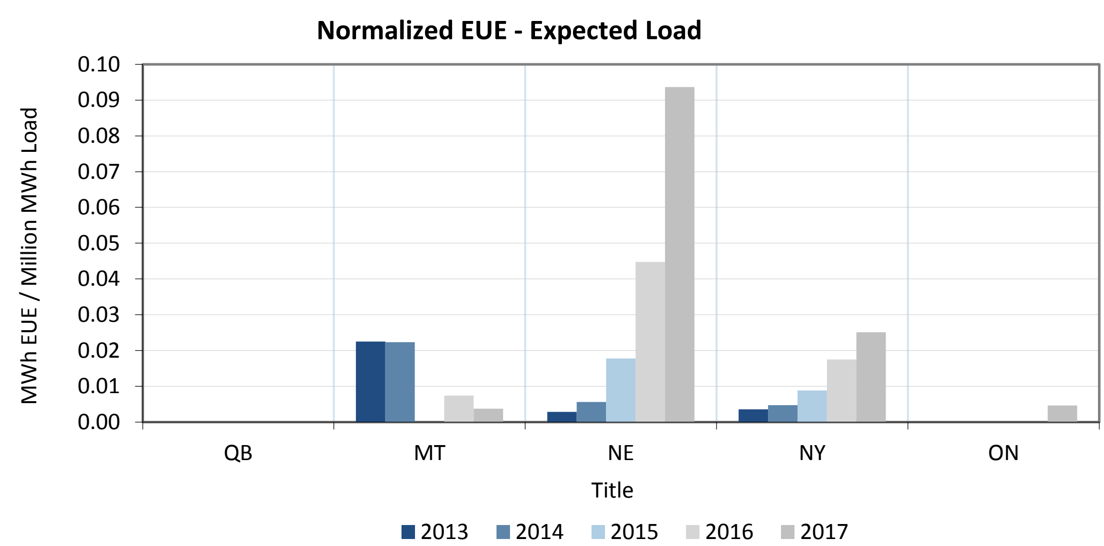
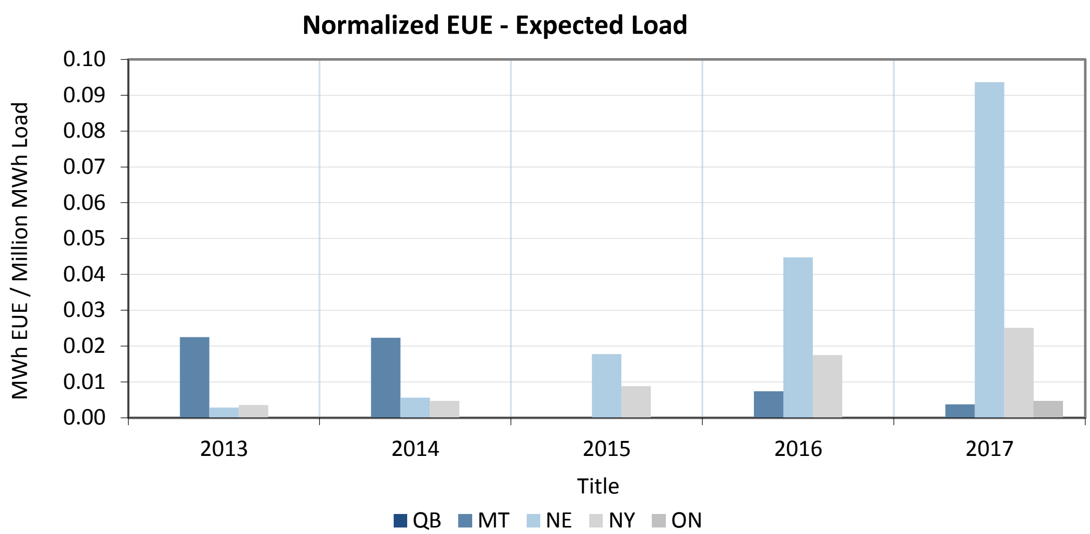


Figure 26: Estimated Annual NPCC Area EUE (2013 – 2017)



Figures 11(a) and 11(b) shows the estimated annual Expected Unserved Energy (EUE) for NPCC and the neighboring Regions for the 2013-2017 period, assuming all allowable operating procedures have been taken.

Figure 27: Estimated Annual EUE for NPCC Areas and Neighboring Regions (2013 – 2017)

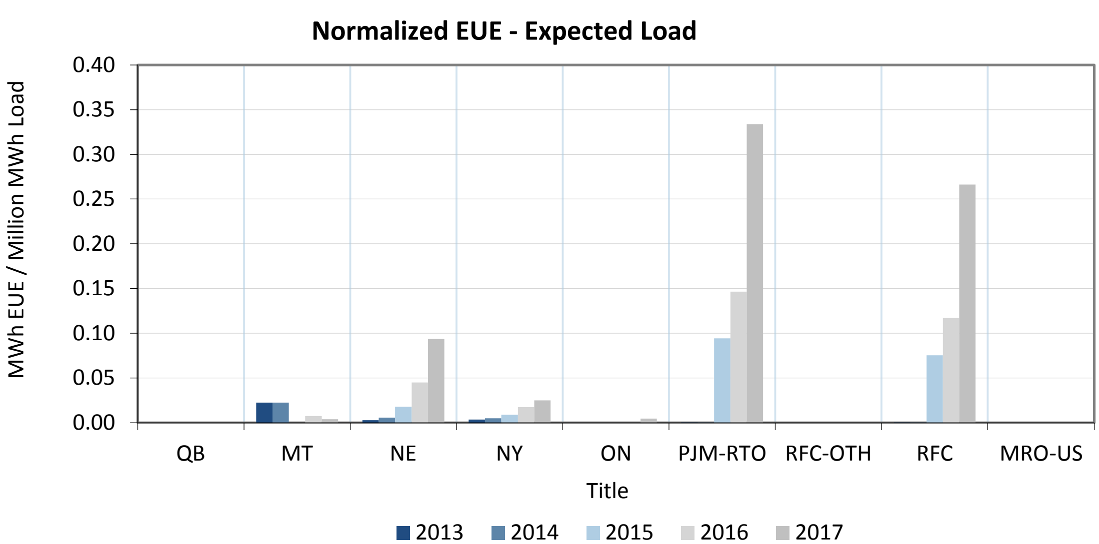
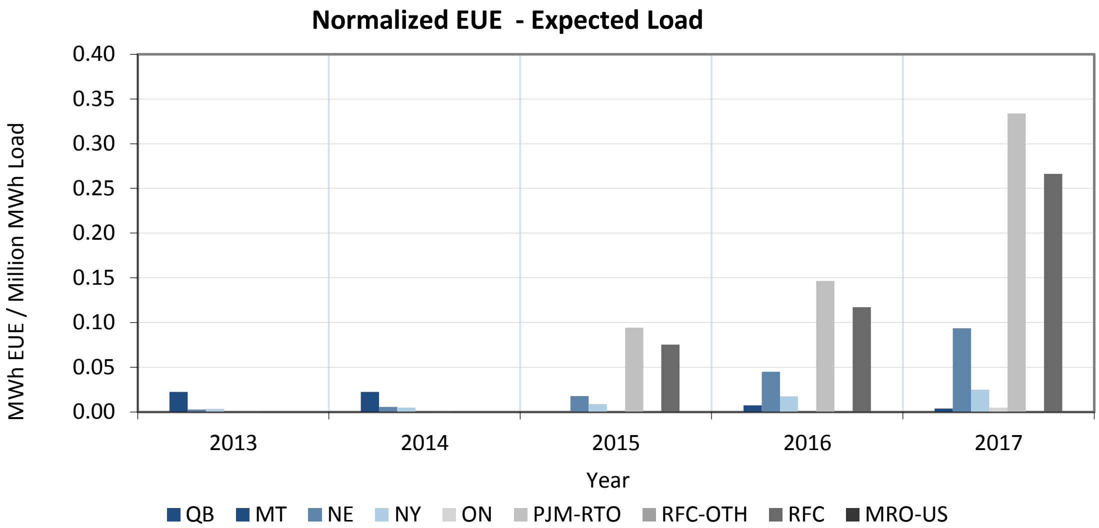


Figure 28: Estimated Annual EUE for NPCC Areas and Neighboring Regions (2013 – 2017)



PJM

Summary

The purpose of this assessment is to provide the NERC mandated Adequacy metrics, Expected Unserved Energy (EUE) and Loss of Load Hours (LOLH) for the PJM RTO region in 2014 and 2016.

The tool used to carry out this study is GE-MARS, a multiple-area hourly simulation model developed by General Electric.

The study was conducted by the NPCC CP-8 WG, with full participation of PJM Staff. PJM staff has participated in the CP-8 WG efforts since 2005. PJM supplied the modeling data for most of the CP-8 WG external region which includes the full PJM RTO footprint. NPCC collaborates with PJM on interregional assessments to allow sharing of model data, analysis methods, and assessment techniques.

Refer to the NPCC probabilistic assessment for further specific data modeling and techniques used. The PJM region results, as reported, are from the same CP-8 WG study as those results reported by NPCC.

The study model has similar model characteristics as reported in the PJM 2012 Reserve Requirement Study (RRS) Report.

The Study model is consistent with the PJM 2011 RTEP Report.

The 2012 RRS Report and 2011 RTEP Report are, to a great extent, consistent with the 2012 NERC LTRA data submission. The same underlying database is used to populate the generation model for the LTRA and RRS and all three models are based on the same PJM 2012 Load Forecast Report. However, there are some differences:

Differences in total capacity values between this Study and the 2012 NERC LTRA are due to the following: the NERC LTRA classifies generation resources as existing, future, and conceptual. The 2012 RRS Report and this study consider only existing generation resources and future generation resources. The future generation resources in this study are assigned a commercial probability that describes the chance of the resource coming into service. See Table 36 of the 2012 RRS Report for details.

In the model used for this study, the PJM region is broken into four sub-regions. For each of the sub-regions, the 2002 hourly load shape is considered; each shape is then multiplied by the Non Coincident Peak (NCP) as per the 2012 PJM Load Forecast Report. The RTO peak load in Table 30 is obtained by computing the maximum hourly load of the combined load shape (this combined load shape is obtained by adding up the 4 sub-regions loads hour by hour). This value is ~5,000 MW higher (in 2014 and 2016) than the PJM RTO peak load values submitted to the *2012LTRA*.

The results for EUE and LOLH metrics in Table 31 are after implementing PJM's final emergency operating procedure (EOP). For the list of EOPs considered in this study, see Table 34 or 35. In addition, PJM supplies the metrics at the various EOP levels. The order of these EOPs is only representative; PJM dispatchers can, at their discretion and due to various system conditions, invoke any EOP step at any time regardless of the order indicated in this study.

The PJM RTO consists of the following regions: PJM Mid-Atlantic Region, Allegheny Energy (APS), American Electric Power (AEP), Commonwealth Edison (ComEd), Dayton Power and Light (Dayton), Dominion Virginia Power (DOM), Duquesne Light Co. (DLCO), American Transmission System Inc. (ATSI),and Duke Energy Ohio and Kentucky (DEOK).

As mentioned earlier, for the purpose of this study, the PJM-RTO region is broken into four sub-regions. The sub-regions are as follows (refer to Glossary section for a description of each region below):

- Eastern Mid-Atlantic: AE, DPL, JCPL, PECO, PS, RECO
- Central Mid-Atlantic: BGE, MetEd, PEPCO, PL, UGI

- Western Mid-Atlantic: PN
- PJM Rest: PJM Western (AEP, APS, ATSI, ComEd, Day, DEOK, and DLCO) plus Southern (DOM)

The Expected Unserved Energy (EUE) and Loss-of-Load Hours (LOLH) are reliability metrics directly supplied by the GE-MARS simulation. The requirements for this year's study establish 2014 and 2016 as the reporting years. The table below presents the EUE and LOLH for 2014 and 2016, as well as the values of other parameters associated with system reliability.

Table 30: Annual Peak Demand and Capacity Resources

Year	Net Energy for Load (GWh)	Net Internal Demand (MW)	Forecast Capacity Resources (MW)	Forecast Operable Capacity Resources (MW)	Expected Unsupplied Energy (EUE)	Loss of Load Hours (LOLH)	Forecast Planning Reserve Margin (%)	Forecast Operable Reserve Margin (%)
2014	881079	149,900	184,172	170,853	0.000	0.001	22.9%	14.0%
2016	911645	155,717	175,273	163,315	0.146	0.067	12.6%	4.9%

*Forecast Capacity Resources equals the total installed capacity, minus capacity derates, plus net firm transactions
**Forecast Operable Capacity Resources equals Forecast Capacity Resources minus generator forced outage rates
***Net Internal Demand equals total internal demand minus demand response

Note that Demand Response (DR) and Energy Efficiency (EE) resources (14,165 MW in DR and 804 MW in EE for both, 2014 and 2016) are subtracted from the Total Internal Demand yielding the Net Internal Demand value in the third column above.

Table 31: Comparison with last assessment for 2014

Year	Net Energy for Load (GWh)	Forecast 50/50 Peak Demand (MW)	Forecast Capacity Resources (MW)	Forecast Operable Capacity Resources (MW)	Expected Unsupplied Energy (EUE)	Loss of Load Hours (LOLH)	Forecast Planning Reserve Margin (%)	Forecast Operable Reserve Margin (%)
2014*	865723	161,824	188,592	175,239	0.014	0.012	16.5%	8.3%
2014	881079	149,900	184,172	170,853	0.000	0.001	22.9%	14.0%

* Results from the 2011 Probabilistic Assessment

For 2014, there are two major differences between the 2011 ProbA Pilot and this year's study. In the former, there were around 4,400 MW more in Forecast Capacity Resources for 2014 than in this year's study. This difference is due to recently announced generation retirements and changes in the generation interconnection queue. The second difference is the greater amount of Demand Response and Energy Efficiency resources available for 2014 in this year's study, 14,969 MW, compared to 3,257 MW in the 2011 ProbA Pilot study. This produces a 2014 Net Internal Demand in this year's study that is significantly lower than in the 2011 ProbA Pilot study. The difference in Net Internal Demand is the main driver of the lower EUE and LOLH values observed in this year's study.

Table 32 below presents the total seasonal capacities, 50/50 unrestricted peak seasonal loads, seasonal wind capacity, and the net of purchases and sales for the reporting years.

Table 32: Capacity and load at time of Region Peak – Base Case with composite load shape		
	Summer	**Winter**
2014		
Capacity (MW)	184,973	184,223
Purchase/Sale (MW)	-801	-810
Load (MW) **	164,869	137,153
Max. Wind Capacity (MW) *	1,391	1,610
2016		
Capacity (MW)	176,074	176,209
Purchase/Sale (MW)	-801	-810
Load (MW) **	170,686	141,119
Max. Wind Capacity (MW) *	1,650	1,650
*Wind capacity included at maximum output for the month, not nameplate rating. ** Demand response not included.		

As noted earlier in this document, for this study, the PJM region is broken into four sub-regions. For each of the sub-regions, the 2002 hourly load shape is considered; each shape is then multiplied by the corresponding Non Coincident Peak (NCP) as per the 2012 PJM Load Forecast Report. The RTO peak loads in Table 33 are obtained by computing the maximum hourly load of the combined load shape (created by adding the four sub-region load shapes multiplied by its corresponding NCP). This combined peak load value is ~5,000 MW higher (in 2014 and 2016) than the PJM RTO summer peak load values submitted to the 2012 NERC LTRA and ~2,500 MW higher than the 2012 NERC LTRA winter peak load values. This implies that the diversity value implicit in the load shapes used in this study is different than the diversity value used in the 2012 PJM Load Forecast (and the latter diversity value is reflected in the 2012 NERC LTRA submission).

Table 33: Comparison of Energies Modeled		
	2014	**2016**
MARS	881,079	911,645
2012 LTRA	851,726	888,097
(MARS - LTRA)	29,353	23,548
% (MARS - LTRA) / LTRA	3.45%	2.65%

The difference observed in Net Energy for Load in 2014 and 2016 between the LTRA data and the results from this study is explained by the higher peak loads considered in this study compared to the peak loads submitted to the 2012 LTRA (see discussion in previous paragraph).

The following tables 34 and 35 show the estimated annual PJM RTO region Loss of Load Hours (LOLH) and Expected Unserved Energy (EUE) for the years 2014 and 2016 at each one of 6 emergency operating procedures[41].

[41] From NPCC 2012 Probabilistic Assessment Report

Table 34: Results for 2014 – LOLH (Hours/year) and EUE (PPM) (MWh of EUE per Million MWh of Annual Load Energy)		
	LOLH	**EUE**
Curtail Load / Utility Surplus	3.069	8.375
No 30 min Reserves	0.137	0.063
Volt. Red. Or Inter. Loads	0.036	0.005
No 10 min Reserves	0.016	0.001
General Public Appeals	0.011	0.001
Disconnect Load	0.001	0.000

Table 35: Results for 2016 – LOLH (Hours/year) and EUE (PPM) (MWh of EUE per Million MWh of Annual Load Energy)		
	LOLH	**EUE**
Curtail Load / Utility Surplus	10.364	67.041
No 30 min Reserves	0.711	2.830
Volt. Red. Or Inter. Loads	0.320	1.111
No 10 min Reserves	0.164	0.435
General Public Appeals	0.117	0.261
Disconnect Load	0.067	0.146

The values at each of the EOPs are derived from the reliability values at each of the seven load levels (see Table 37), computing a weighted-average expected value based on the specified probabilities of occurrence (also in Table 36).

Demand Response and Energy Efficiency resources (14,969 MW in both, 2014 and 2016) are modeled as the first EOP (Curtail Load/Utility Surplus) in Table 34 and Table 35. This explains the significant drop in LOLH and EUE observed after the first EOP.

Software Model Description

The primary tool for performing reliability analyses at PJM is PRISM. However, due to the hourly nature of the outputs required in this study, GE-MARS, an hourly Monte Carlo simulation tool, was considered to be more adequate to carry out the study. Information about GE-MARS' solution method and techniques is summarized in the publicly available comparison of PRISM and GE-MARS report (specifically, Appendix D of the report, as documented by GE Power Systems). The comparison of PRISM and GE-MARS report was developed by the PJM Resource Adequacy analysis Subcommittee (RAAS) with feedback from GE Power Systems Staff and members of LOLE Industry groups.

GE-MARS uses a Monte Carlo simulation approach which requires an 8760 hour-long load shape as one of its inputs. The software compares available capacity with load during each of the 8760 hours. (GE-MARS has the capability to reduce the number of hours included in the metric calculations yet this option was not used to carry out this study). One thousand replications were performed. GE-MARS inputs are fully described in Appendix F of the comparison of PRISM and GE-MARS report.

Other key items to review in the aforementioned PRISM-MARS report include:

- GE-MARS Calculation Process, especially: (see Appendix A of this report for the most used options of the Master Input File (MIF)).
- Figure 7 showing the relationship of high loads, with low probability, to LOLE.
- Discussion on Standard Error
- Example of Multi Area modeling – Figure 10
- Use of Emergency Operating Procedures – Figure 11

GE-MARS uses transition states to model generation unit performance. PJM produces these states via an internal GE-MARS algorithm (option in the table INT-ONLY of the MIF) that combines a unit's forced outage rate (UNT-FORS in MIF) with the number of state transitions (NUM-TRNS in MIF).

The transmission pipe size limit inputs are determined by assessment work outside of GE-MARS calculations. The values for these pipes limits are an aggregated amount of many transmission facilities, considering the periods of high demand and emergency operating procedure conditions. They represent the total inputs that can simultaneously (Simultaneous Import Limit (SIL)) come into a given area. The current values are from a mixture of analysis and technical experience, discussions with the Operations staff, and discussions within Planning Division staff. See the presentation (NERC 4/27/2010 LOLE WG meeting) titled item8-CapacityBenefit_Margin_rev.pdf, slides 12-17, concerning the various items that help determined these values. Further details about the PJM SIL study can be found from the same meeting titled: Item8-Reference-SIL_PJMRTO_Study.

Contracts and Sales/Purchases are modeled for firm transactions, and determined by mutual consent and collaboration of the parties involved.

GE-MARS's algorithm is typically used to equally share resources based on mitigating LOLE states.

Several items of the detailed GE-MARS model are confidential and require a signed Non-disclosure Agreement to exchange data per the PJM Operating Agreement, section 18.17.1 paragraph B.

Demand Modeling

For this study, the PJM region is broken into four sub-regions. For each of the sub-regions, the 2002 hourly load shape is considered; each shape is then multiplied by the corresponding Non Coincident Peak (NCP) as per the 2012 PJM Load Forecast Report. The RTO peak loads reported in this study are obtained by computing the maximum hourly load of the combined load shape (created by adding the four sub region load shapes multiplied by its corresponding NCP). The resulting peak load is ~5,000 MW higher (in 2014 and 2016) than the PJM RTO summer peak load values submitted to the 2012 NERC LTRA and ~2,500 MW higher than the 2012 NERC LTRA winter peak load values.

The above implies that the diversity value implicit in the 2002 load shapes is different than the diversity value used in the 2012 PJM Load Forecast (this latter diversity value is reflected in the 2012 NERC LTRA submission).

The hourly load shape determined to be the most appropriate for the PJM RTO's LOLE assessments is calendar year 2002. This choice has been confirmed by recent assessments of other candidate years.

The 2002 hourly load shape of each of the 4 PJM sub-regions (Eastern Mid-Atlantic, Central Mid-Atlantic, Western Mid-Atlantic, and PJM Rest) was considered for this study.

Figure 29: July 2002 per-unitized Load Shape for Four Sub-regions and PJM RTO

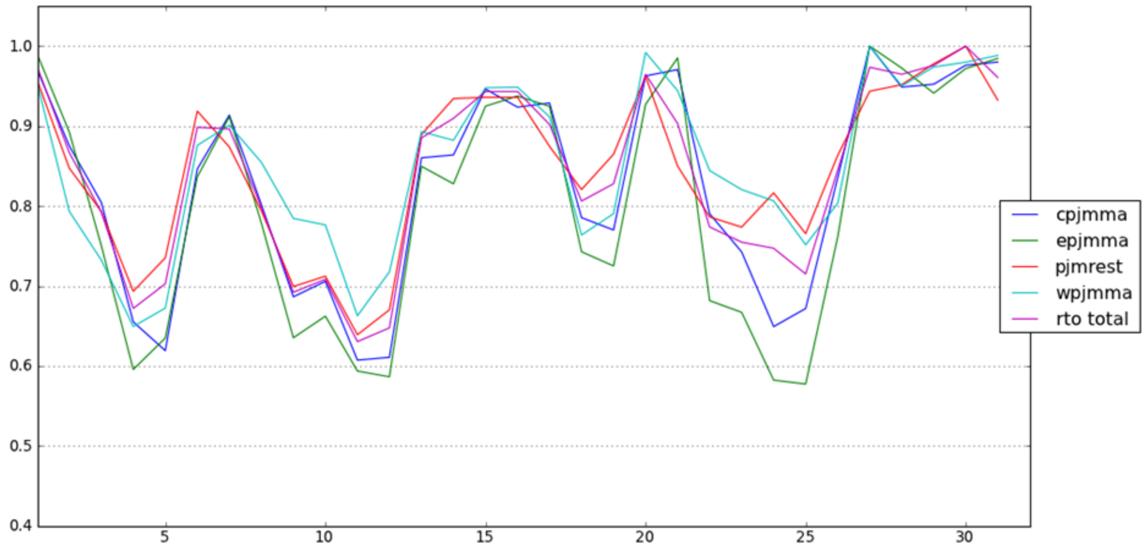


Figure II - 1 shows the per-unitized daily peak (with respect to corresponding annual peak) load shape for July 2002 for PJM RTO and the four sub-regions. It can be observed that in 2002 the PJMREST region peaks on a different day (around July 30th) than the Mid-Atlantic regions (around July 26th).

The PJM RTO probabilistic load model in PRISM was translated into the load forecast uncertainties used in the LOD-UNCY table in the GE-MARS MIF. The translation process uses a daily mean and standard deviation, a standard normal distribution, a forecast error factor, and a first order statistic to develop an expected weekly maximum (EWM). The daily EWM for each week is translated into monthly load forecast uncertainty values. See Appendix B of the PRISM-MARS comparison report for the mathematical details of the procedure. The daily mean and standard deviation, forecast error factor, first order statistic and expected weekly maximum (EWM) are all explained in the 2012 RRS Report.

The load forecast uncertainty is different for each sub region and varies from month to month. For illustrative purpose, Table 36 shows the load forecast uncertainty for July 2014. Table 37 also shows the probability of occurrence assumed for each of the seven load levels modeled (see last row of Table 36).

In computing the reliability indices, all of the areas were evaluated simultaneously at the corresponding load level, the assumption being that the factors giving rise to the uncertainty affect all of the areas at the same time.

For this study, reliability measures (EUE and LOLH) are reported for the expected load conditions. The values for the expected load condition are derived from computing the reliability indices at each of the seven load levels presented in Table 36, and computing a weighted-average expected value based on the specified probabilities of occurrence.

Table 36: Load Forecast Uncertainty for 4 sub-regions (July 2014)

	Per Unit Variation in Load						
Sub Region Name	Load Level 1	Load Level 2	Load Level 3	Load Level 4	Load Level 5	Load Level 6	Load Level 7
Eastern Mid-Atlantic	1.16005	1.07293	0.98580	0.89868	0.81156	0.72443	0.63731
Central Mid-Atlantic	1.13198	1.06013	0.98829	0.91645	0.84461	0.77277	0.70093
Western Mid-Atlantic	1.07737	1.03525	0.99314	0.95102	0.90891	0.86679	0.82468
PJM Rest	1.11344	1.05169	0.98994	0.92819	0.86644	0.80469	0.74294
Probability	0.0062	0.0606	0.2417	0.383	0.2417	0.0606	0.0062

Behind the Meter Generation is not modeled in this study.

In GE-MARS, Demand Response and Energy Efficiency Resources were modeled as an emergency operating procedure triggered whenever RTO reserves fall below 3,400 MW. Once DR is called, it reduces the load on a 1-to-1 MW basis.

Capacity Modeling

Generation Forecast Modeling consistent with 2012 RRS report

The capacity modeling is consistent with the discussion in the section Generation Forecasting of the 2012 RRS Report. The 2012 RRS Report is, to a great extent, consistent with the 2012 NERC LTRA data submission. The same underlying database is used to populate the generation model for the LTRA and RRS. Differences in total capacity values between this study and the 2012 NERC LTRA are due to the following: the NERC LTRA classifies generation resources as existing, future, and conceptual. The 2012 RRS Report and this study consider only existing generation resources and future generation resources. The future generation resources in this study are assigned a commercial probability that describes the chance of the resource coming into service.

Details directly applicable to this study are shown in the following subsections of the 2012 RRS Report:

- GADS, eGADS and PJM fleet class average values,
- Generating Unit Owner Review of Detailed Model,
- Forced Outage Rates: EFORd and EEFORd,
- Modeling of Generating Units' Ambient Deratings,
- Generation Interconnection Forecast

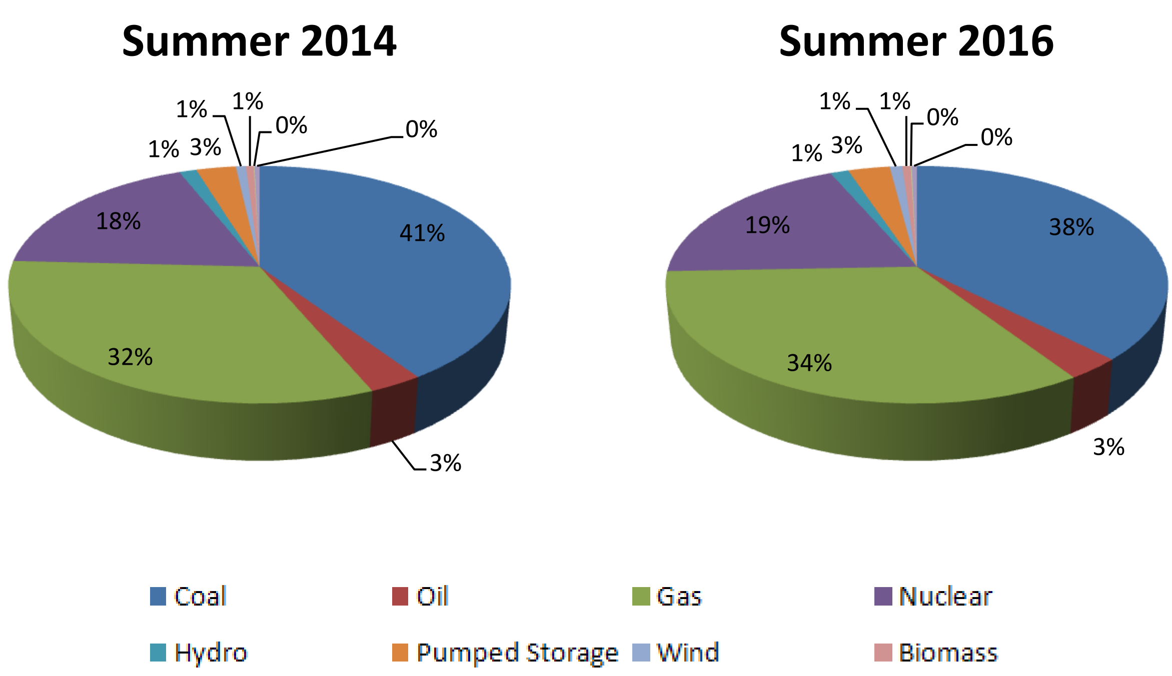
The GE-MARS model uses the UNT-FORS and NUM-TRNS tables along with an option in the INT-ONLY table to transition from units with forced outages rates to units having a transition state matrix (see Appendix A for details on the tables). The resulting GE-MARS capacity model is consistent with the capacity model used in PRISM. All units' planned maintenance outages (PO) are directly inputted using the MNT-UNOP table. GE-MARS schedules the PO events to levelize reserves over the calendar year.

The PJM RTO fleet of units for Summer and Winter 2014/16 is summarized by primary fuel in Table 37. Seasonal ratings are as per information submitted by generation owners to PJM's Reliability Pricing Model (RPM). Outage rates and planned outages (for all units except wind and solar) are based on 5-year (2007-11) GADS data. (Class average representative data was used for units with less than 5 years of data.) Wind and solar units are assigned a forced outage rate of 0 and a capacity credit factor computed based on generating output on peak hours (hours ending 3, 4, 5, and 6 PM Local Prevailing Time) during the past 3 summer periods (for more information see PJM Manual 21). The currently effective class average capacity credit factors are 13% for wind and 38% for solar of their nameplate capacity.

Note that the total capacity in Winter 2014/15 is lower than in Summer 2014 due to retirements taking place right after Summer 2014. Figure II - 2 presents all PJM RTO capacity by fuel type for years 2014 and 2016.

Table 37: PJM RTO Fleet-based Unit Performance by Primary Fuel Category in 2014 and 2016								
	Summer 2014		Winter 2014		Summer 2016		Winter 2016	
Fuel Category	Total MW	Forced Outage Rates %	Total MW	Forced Outage Rates %	Total MW	Forced Outage Rates %	Total MW	Forced Outage Rates %
Coal	75,101	9.09%	73,837	9.04%	66,299	8.49%	66,302	8.49%
Oil	5,577	15.53%	5,585	15.67%	5,352	16.00%	5,360	16.13%
Gas	59,511	7.15%	59,708	7.16%	59,333	6.91%	59,408	6.91%
Nuclear	33,658	2.92%	33,687	2.92%	33,658	2.92%	33,687	2.92%
Hydro	2,385	3.65%	2,407	3.69%	2,403	3.68%	2,407	3.71%
Pumped Storage	5,475	2.37%	5,475	2.37%	5,475	2.37%	5,475	2.37%
Wind	1,391	0.00%	1,610	0.00%	1,650	0.00%	1,650	0.00%
Biomass	1,081	8.56%	1,083	8.56%	1,091	8.56%	1,093	8.56%
Solar	96	0.00%	119	0.00%	119	0.00%	119	0.00%
Other	698	11.27%	712	10.75%	694	11.31%	708	10.79%
TOTAL	184,973	7.20%	184,223	7.16%	176,074	6.79%	176,209	6.79%

Figure 30: PJM RTO Capacity by Fuel Type in Summer 2014 and Summer 2016



Consistent with established modeling practices, the inclusion of planned generation was modeled based on commercial probabilities. A commercial probability factor was applied to all planned units, adjusting the rating presented in the generation interconnection process queue. Commercial probabilities are discussed in the Generation Forecasting section of the 2012 RRS Report. Table 38 provides a summary of the generator additions and retirements modeled for this study.

Table 38: New Expected and Retiring Generation within PJM RTO	
	MW
Installed Capacity - July 2012	185323
Expected Additions Before July 2014	2581
Announced Retirements Before July 2014	-2931
Expected Installed Capacity - July 2014	184973
Expected Additions Before July 2016	2332
Announced Retirements Before July 2016	-11231
Expected Installed Capacity - July 2016	176074

Transmission

The GE-MARS modeling and analysis is consistent with the 2011 RTEP Report which is the basis for the 2012 LTRA submission.

GE-MARS uses a transportation model to simulate the flows between regions. The transfer limits between the 4 PJM sub-regions in the GE-MARS model are as in Figure II – 3. These values represent simultaneous short-term emergency ratings and are consistent with the 2011 RTEP Report and the 2012 LTRA submission. No transmission outages were considered in the analysis.

The simultaneous import limit (SIL) capabilities in the GE-MARS transportation model are determined between each external area and PJM. Figure II - 3 shows that the PJM RTO has an approximate total SIL value of 12,000 MW. This transmission is not fully reserved for reliability purposes. In the PJM RRS 2012 (where the PJM's Installed Reserved Margin is computed), the portion of total import capability that is reserved for reliability purposes is 3,500 MW. As with the internal transfer limits, the external transfer limits represent simultaneous short-term emergency ratings and are consistent with the 2011 RTEP and the 2012 LTRA submission. No transmission outages were considered.

The reliability calculations (LOLH, EUE) are done on an area basis, for each load level specified, at each EOP level on an hourly basis. If an area needs assistance to avoid an LOLE state before invoking the EOPs, assistance is considered from the other areas in the model. See the comparison of PRISM and GE-MARS report, Figures 5A- 5C for further details on the solution process.

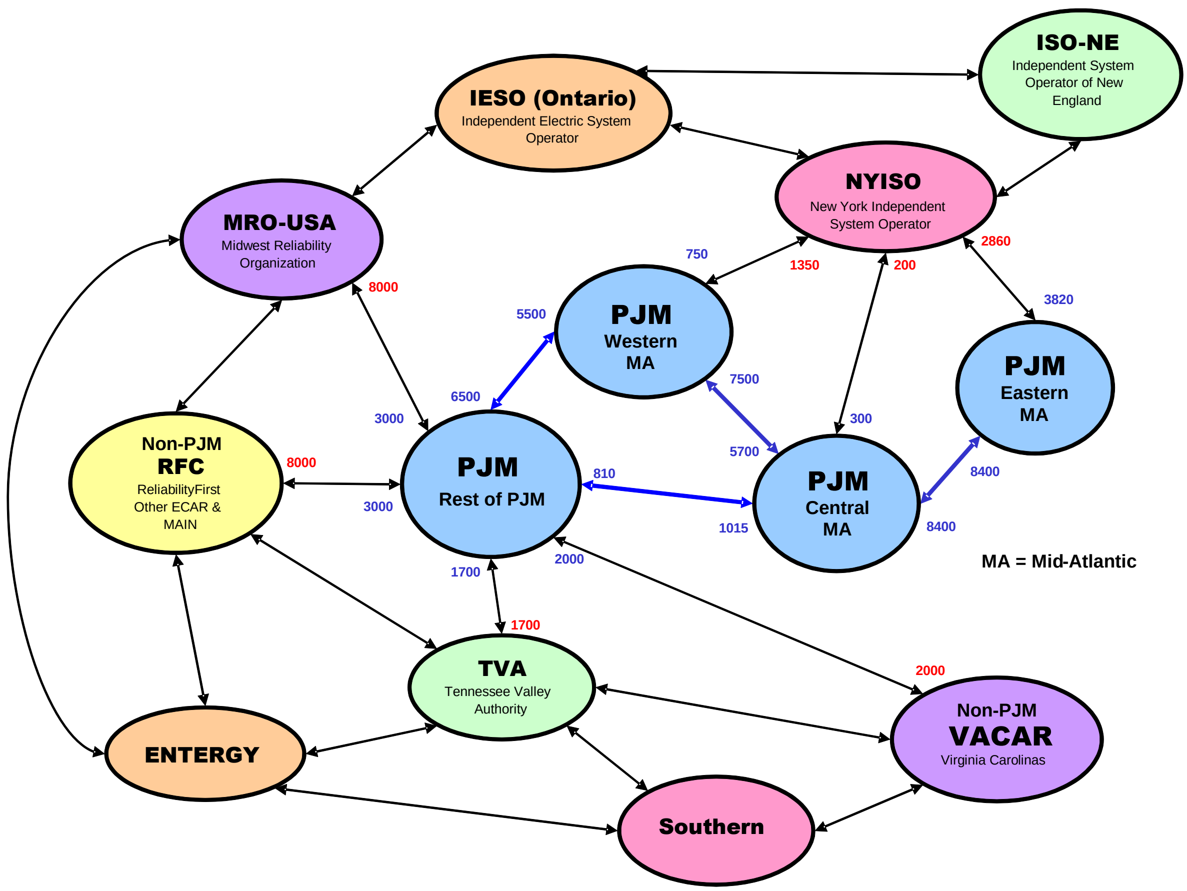
All internal generators that have been demonstrated to be deliverable are modeled as PJM capacity resources in the PJM study area (i.e., in one of the 4 PJM subregions in Figure II-3). See PJM Manual 14b for details on deliverability tests. Some external capacity resources are modeled as internal to PJM if they meet the following requirements:

Firm Transmission service to the PJM border

Firm ATC reservation into PJM

Letter of non-recallability from the native control zone

Figure 31: PJM RTO Transfer Limits



Assistance External Resources

MRO-USA and Non-PJM RFC were modeled at the MISO reserve target required to satisfy the 1 in 10 criterion (as per MISO's 2012 LOLE Study Report). NYISO, on the other hand, was modeled assuming the system "as-is". Load forecast information for the MISO areas was obtained from MISO's 2012 LOLE Study Report while the total capacity for the MISO areas was set to match the MISO reserve target that satisfies the 1 in 10 criterion as mentioned above. PJM class average statistics were then applied to the units created in the MISO areas. For more information on the modeling of MRO-USA and Non-PJM RFC refer to the 2012 RRS report (see discussion of Figure I-2 and Figure I-4 in that report). Load and capacity for NYISO and other NPCC areas was obtained from the 2012 NERC Probabilistic Assessment, NPCC region. (As stated earlier in the document, the PJM analysis for this report was conducted by the NPCC CP-8 group.)

The load diversity between PJM and the outside World is captured by using the 2002 Load Shape for all internal and external regions.

The table INF-TRLM in the MIF file allows for the inputting of interface transfer limits. Assistance from outside regions to PJM in an emergency situation depends upon the limits of the interface ties and the availability of generation in the outside world at the time of the emergency. Similarly, assistance from PJM to an outside region undergoing an emergency depends upon the tie limits and the availability of PJM resources at the time of the emergency.

Contracts are modeled over the transmission pipes. Firm contracts are scheduled regardless of whether or not the sending area has sufficient resources on an isolated basis (to avoid loss of load), but they can be curtailed because of interface transfer limits. Firm contracts are scheduled first, in the order in which they appear in the FCT-DATA table. When a contract is scheduled, the limits on these interfaces and related interface groups are adjusted accordingly. The contracts scheduled between PJM RTO and neighboring regions for this study are shown in Table 39.

Table 39: Contracts

Description	From	To	Rating (MW)
NYPA - AO	Area-A	PJM-MidA West	121 (S), 112 (W)
NYPA - PC	Area-A	PJM-MidA West	56 (S), 55 (W)
NYPA - NJ	Area-C	PJM-MidA Central	19 (S), 20 (W)
PJM-MidA-W - A	PJM-MidA West	Area-A	13
PJM-MidA-W - C	PJM-MidA West	Area-C	19
PJM-MidA-C - C	PJM-MidA Central	Area-C	5
Linden VFT **	PJM-MidA East	Area-J	300
Neptune **	PJM-MidA East	Area-K	660
** Modeled as PJM units assigned to a NY zone			

Definition of Loss-of-Load Event

For all PJM RTO Adequacy assessments, the emergency operations procedure that defines a loss of load event is the invocation of a voltage drop. Per the results shown, this is at EOP step 2 of this study as results are after a given step has been invoked. Table 40 shows the rest of the EOPs considered in this study as well as the MWs available by implementing each one of them.

For consistency in performing interregional study efforts, the reported metrics in Table 30 are down to the EOP step 5.

Table 40: Emergency Operations Procedures during 2014 and 2016

	EOP	Unit	Amount (MW)
	Operating Reserves	MW	3,400
1	Curtail Load / Utility Surplus	MW	14,969
2	No 30-min Reserves	MW	2,765
3	Voltage Reduction	MW	2,201
4	No 10-min Reserves	MW	635
5	Appeals / Curtailments	MW	400

SERC

Summary

The objective of this study is to respond to NERC's request for a 2012 Probabilistic Assessment effort. The RAS piloted this effort in 2011 to produce enhanced resource adequacy metrics for the 2010 Long-Term Reliability Assessment. The NERC Planning Committee (PC) approved the recommendations from this report which initiates a mandatory probabilistic assessment study to be performed biennially.

The SERC Region is a summer peaking region covering all or portions of 16 central and southeastern states[42] serving a population of more than 60 million. Owners, operators, and users of the Bulk Electric System (BES) in these states cover an area of approximately 560,000 square miles. In the SERC Region, there are 33 Balancing Authorities (BAs) and more than 200 Registered Entities under the NERC functional model.

The following report is a summary describing reliability metrics for the following assessment areas within the SERC footprint: SERC-N, SERC-SE, SERC-E, and SERC-W. A listing of BAs within the SERC reporting areas can be found in Attachment 1. Summer and winter assessment data for these areas are aggregated to produce metrics for years three and five (2014 and 2016) of the 2012 Long-Term Reliability Assessment (LTRA) dataset within the GE Multi-Area Reliability Simulation (MARS) model. Metrics for each of the areas are calculated as interconnected and isolated. For isolated calculations, each area is isolated as though it had no interconnections with the other areas. However, firm imports from the external regions are considered in this calculation. Each area is measured to its ability to serve its load with only its own resources and firm imports. The interconnected indices reflect the emergency, non-firm assistance that the areas could provide to one another. It also includes non-firm emergency assistance from the outside regions.

Installed capacity for each of the reporting areas is shown in the table below for both years and seasons. Intermittent and energy limited variable resources include subsets labeled "Hydro," "Wind," and "Solar" as listed below. Traditional dispatchable capacity is included in the table.

Table 41: Installed Capacity by Unit Type – Winter/Summer 2014 (MW)

	Winter				Summer			
	SERC-N	SERC-SE	SERC-E	SERC-W	SERC-N	SERC-SE	SERC-E	SERC-W
Biomass	17	67	40	110	17	67	40	160
CC-Dual Fuel	0	135	424	531	0	138	418	465
CC-Gas	8,386	14,722	4,512	9,460	7,787	14,102	4,131	9,159
CC-Oil	0	0	0	0	0	0	0	0
CT-Dual Fuel	6,342	3,826	4,624	0	5,298	3,575	4,014	0
CT-Gas	5,554	10,842	7,715	8,250	4,975	9,677	6,985	7,605
CT-Oil	103	1,255	1,078	51	98	890	871	46
Nuclear	8,076	5,818	11,830	5,401	7,833	5,818	11,456	5,324
Other	27	55	269	173	27	53	262	164
PSH	1,652	1,632	3,044	0	1,652	1,632	3,044	0
Steam-Coal	27,345	24,524	18,326	6,294	26,911	25,089	18,110	6,304
Steam-Dual Fuel	860	0	129	0	860	0	130	0

[42] Alabama, Arkansas, Florida, Georgia, Iowa, Illinois, Kentucky, Louisiana, Missouri, Mississippi, North Carolina, Oklahoma, South Carolina, Tennessee, Texas, and Virginia

Steam-Gas	0	1,374	0	12,842	0	1,471	0	12,741
Steam-Oil	0	122	88	0	0	122	84	0
Diesel	0	0	0	0	0	0	0	0
Fossil	0	0	0	0	0	0	0	0
Hydro	5,002	3,311	3,094	302	5,317	3,360	3,087	311
Wind	28	0	0	0	28	0	0	0
Solar	0	4	32	0	0	4	32	0
Total	63,391	67,688	55,206	43,414	60,802	66,000	52,664	42,278

Table 42: Installed Capacity by Unit Type – Winter/Summer 2016 (MW)

	Winter				Summer			
	SERC-N	SERC-SE	SERC-E	SERC-W	SERC-N	SERC-SE	SERC-E	SERC-W
Biomass	17	67	40	360	17	67	40	360
CC-Dual Fuel	0	135	424	531	0	138	418	465
CC-Gas	9,079	14,722	4,512	10,060	9,432	14,102	4,131	9,759
CC-Oil	0	0	0	0	0	0	0	0
CT-Dual Fuel	6,342	3,826	4,624	0	5,298	3,575	4,014	0
CT-Gas	5,554	10,842	7,715	8,534	4,975	9,677	6,985	7,877
CT-Oil	103	1,255	1,078	51	98	890	871	46
Nuclear	8,076	5,818	11,830	5,401	7,833	6,918	12,573	5,324
Other	27	151	269	173	27	149	262	164
PSH	1,652	1,632	3,044	0	1,652	1,632	3,044	0
Steam-Coal	25,474	24,954	18,326	6,300	25,071	24,934	18,020	6,310
Steam-Dual Fuel	860	0	129	0	860	0	130	0
Steam-Gas	0	1,200	0	12,842	0	1,197	0	12,741
Steam-Oil	0	122	88	0	0	122	84	0
Diesel	0	0	0	0	0	0	0	0
Fossil	0	0	0	0	0	0	0	0
Hydro	5,004	3,311	3,094	329	5,321	3,360	3,087	338
Wind	28	0	0	5	28	0	0	5
Solar	0	4	32	0	0	4	32	0
Total	62,215	68,040	55,206	44,586	60,6111	66,7677	53,6911	43,388

Controllable capacity Demand Response is not modeled as a generation resource. Instead, it is included within each of the reporting area Emergency Operating Procedures (EOP) steps as illustrated in Table 43. EOP steps are measures that the system operator can take as available reserves approach critical levels. These steps consist of those load control and generation supplements that can be implemented before firm load has to be disconnected. Load control measures could include disconnecting or reducing interruptible loads, making public appeals to reduce demand, and/or implementing voltage reductions. Other area measures could include calling on generation available under emergency conditions, and/or reducing operating reserves. For this study, the data provided describes the various EOP measures that are available in each area (based on consensus of the SERC Resource Adequacy Working Group). The EOP values below are for years 2014 and 2016.

Table 43: Summary of Emergency Operating Procedures (MW)					
Steps	EOP Action	2014		2016	
	SERC-N	Summer	Winter	Summer	Winter
0*	Total Operating Reserves	1,583	1,583	1,583	1,583
1	Curtail Non-Firm Off-System Sales	0	0	0	
2	Demand Response	469	1,704	1,638	1,710
3	Peak Generation	324	0	0	
4	Reduce Operating Reserves	0	0	0	0
5	Interruptibles	755	953	988	963
6	Operating Reserves to Zero[43]	1276	1,583	1,583	1,583
	SERC-SE	Summer	Winter	Summer	Winter
0*	Operating Reserves Requirements	1,250	1,250	1,250	1,250
1	Voltage Reduction & DSM	709	650	714	654
2	Reduce Operating Reserves	0	0	0	0
3	Standby Generation	72	72	81	81
4	Interruptibles	1,594	1,594	1,475	1,475
5	Emergency Generation	670	670	650	670
6	Operating Reserves to Zero	250	250	250	250
	SERC-E	Summer	Winter	Summer	Winter
0*	Operating Reserves Requirements	1,694	1,694	1,694	1,694
1	Direct Control Load Management	969	508	1,105	527
2	Contractually Interruptible (Curtailable)	968	953	988	963
3	Demand Response (Total)	1,630	1,704	1,638	1,710
4	Supply-Side Load as a Capacity Resource	0	0	0	0
5	Emergency Generation	0	0	0	0
6	Operating Reserves to Zero	1,694	1,694	1,694	1,694
	SERC-W	Summer	Winter	Summer	Winter
0*	Total Operating Reserves	600	600	600	600
1	Emergency Generation	0	0	0	0
2	Curtail interruptible load (1+ hr notice)	909	793	944	799
3	Reduce Operating Reserves	600	600	600	600
4	SPP Reserve Sharing Program	0	0	0	0
5	Disconnect Curtailable Load	0	0	0	0
6	Operating Reserves to Zero	0	0	0	0

*Step 0 is the initial condition that accounts for operating reserve requirements set aside as the first step of calculating the required metrics, as stated in Table SERC-5.

Firm purchases and sales are considered within the transmission model. Please see the transmission section below for more information.

For this study, annual load shapes for ten years between 2002 and 2011 were used to develop the Base Case load model for the SERC areas. This data was extracted from the Ventyx Velocity Suite database, which reports the hourly loads by Transmission Zone, then aggregated from Transmission Zone to SERC. External regions used the 2008 load shape which was selected as being representative of a year with normal summer weather.

In Tables 47 through 54 and in the accompanying figures 32 through 35, the monthly peak loads (Total Internal Demand) are shown for the model developed by the program for each area. Due to the adjustment of historical loads to forecasted values, each month of each of the ten years has a different peak projection. While the last report included the projected

[43] Note that reserves can be called on under emergency conditions and/or reducing operating reserves.

peaks from the MARS model, they are excluded from this report because of the use of ten different years in the assessment.

Table 44: Net Energy for Load (GWh)

	Simulated NEL	
	2014 LOLH	2016 EUE
SERC-N	251,971	260,237
SERC-SE	261,407	268,058
SERC-E	229,273	234,780
SERC-W	139,934	144,009

There are no significant differences indicated in the model from this data. Reported energy specified in the LTRA was used as a starting point and is adjusted to the target peaks. Table 44 shows the Net Energy for Load simulated in MARS.

The 2014 and 2016 load and capacity for SERC Assessment Areas are summarized in Table 45. All of the quantities shown are for the peak month of each assessment area. The table also captures the area's MW-weighted average forced outage rate.

Table 45: Load and Capacity at Time of SERC Areas' Annual Peak (MW)

2014	SERC-N	SERC-SE	SERC-E	SERC-W
Capacity	60,580	66,000	52,664	42,278
Annual Peak	43,526	48,622	41,235	25,018
Average EFORd (percent)	6.22%	5.92%	6.08%	6.40%
2016	SERC-N	SERC-SE	SERC-E	SERC-W
Capacity	60,611	66,767	53,691	43,388
Annual Peak	44,622	49,222	42,152	25,413
Average EFORd (percent)	6.22%	5.92%	6.08%	6.40%

Metric calculations for the areas include Loss-Of-Load Expectation (LOLE), Loss-Of-Load Hours (LOLH), Expected Unserved Energy (EUE), and normalized EUE. These metric calculations have been calculated for 2014 and 2016. Table 46 shows that EUE are shown in both MWh per year and normalized in terms of MWh per million MWh of load energy (or MPM). Each of the "as-found"[44] areas is demonstrated to have reserves and access to neighboring area[45] assistance. This allows for the areas to meet the 0.1 days/year daily LOLE level.

[44] "As-found": the system Load and Capacity in its existing capability state prior to adjusting capacity to assess "at criteria" of a loss of load of one day in ten years; LOLE=0.1

[45] See Figure 41

Table 46: Reliability Indices for "As-Found" System for 2014 and 2016								
	Isolated				Interconnected			
	DLOLE (days/yr)	LOLH (hrs/yr)	EUE (MWh/yr)	EUE (MPM)	DLOLE (days/yr)	LOLH (hrs/yr)	EUE (MWh/yr)	EUE (MPM)
2014								
SERC-N	0.040	0.133	125.3	0.50	0.000	0.000	0.0	0.00
SERC-SE	0.001	0.002	1.4	0.01	0.000	0.000	0.0	0.00
SERC-E	0.012	0.030	24.3	0.11	0.000	0.000	0.3	0.00
SERC-W	0.000	0.000	0.0	0.00	0.000	0.000	0.0	0.00
2016								
SERC-N	0.062	0.206	218.4	0.84	0.000	0.000	0.0	0.00
SERC-SE	0.004	0.011	12.0	0.05	0.000	0.000	0.0	0.00
SERC-E	0.015	0.035	30.1	0.13	0.000	0.001	0.4	0.00
SERC-W	0.000	0.000	0.0	0.00	0.000	0.000	0.0	0.00
*Metrics are calculated after operating reserves and emergency operating procedures (see Table 43) are applied.[46]								

Software Model Description

GE Energy's MARS[47] is used to complete the study. A sequential Monte Carlo simulation forms the basis for MARS. The Monte Carlo method provides a fast, versatile, and easily-expandable program that can be used to fully model many different types of generation and demand-side options. In the sequential Monte Carlo simulation, chronological system histories are developed by combining randomly generated operating histories of the generating units with the inter-area transfer limits and the hourly chronological loads. Consequently, the system can be modeled in great detail with accurate recognition of random events. Modeled events can range from equipment failures to deterministic rules and policies which govern system operations. This can be done without simplifying or idealizing assumptions, which is often required in analytical methods. In addition, the model incorporated an algorithm to reduce the number of hours included in the metric calculations when the hours have no material impact on the metrics.

SERC reporting areas are modeled as six interconnected areas with four metric reporting areas: SERC-N, SERC-SE, SERC-E, and SERC-W. Metrics for Gateway and the portions of VACAR that are part of PJM are modeled, but not reported. Five external regions are also modeled: PJM (modeled as four areas), the non-PJM portions of RFC (Reliability*First* Corporation), MRO (Midwest Reliability Organization), SPP (Southwest Power Pool, RE), and FRCC (Florida Reliability Coordinating Council). The bubble diagrams in the Transmission section shows a system representation of the model.

Demand Modeling

Load shapes were formed from historical hourly load profiles and were scaled to annual forecasted peaks taken from the 2012 LTRA filings. Monthly peaks were then created by distributing the forecasted values according to the proportionality of each month's energy in the original load shape. Tables 47 through 54 and the accompanying figures 32 through 35, show the historic monthly peak loads (Total Internal Demand) for the model developed by the program for each area. It should also be noted that similar to the reported LTRA data, behind-the-meter generation is modeled with the load. This generation is not itemized from the load in the data that is reported by SERC entities.

[46] Each of the EOPs listed in Section 1 can contribute to avoiding a loss of load. Accordingly the LOLE is calculated after these EOP steps are invoked.

[47] http://site.ge-energy.com/prod_serv/products/utility_software/en/ge_mars.htm

Figure 32: Monthly Peak Loads, SERC-N, 2014

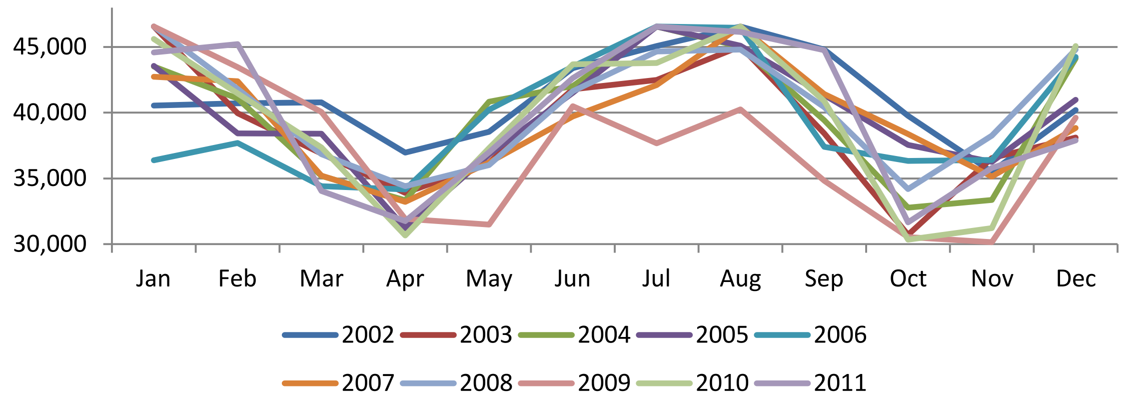


Table 47: Monthly Peak Loads, SERC-N, 2014

Month	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Jan	40,551	46,542	43,501	43,552	36,388	42,727	46,542	46,542	45,602	44,577
Feb	40,721	39,954	41,087	38,433	37,693	42,400	41,804	43,468	41,474	45,217
Mar	40,776	36,903	35,202	38,397	34,419	35,224	36,850	40,066	37,352	34,049
Apr	36,970	33,909	33,342	31,214	34,169	33,222	34,413	31,924	30,671	31,754
May	38,547	36,214	40,825	36,826	40,218	36,202	36,012	31,502	37,305	36,988
Jun	43,388	41,776	42,039	41,517	43,516	39,705	41,646	40,503	43,694	42,640
Jul	45,067	42,488	46,542	46,542	46,542	42,104	44,646	37,680	43,778	46,542
Aug	46,542	45,039	45,014	45,097	46,452	46,542	44,798	40,248	46,542	46,141
Sep	44,796	38,438	39,429	41,344	37,398	41,414	40,411	34,826	40,893	44,745
Oct	39,772	30,719	32,792	37,543	36,343	38,381	34,201	30,542	30,357	31,656
Nov	35,518	36,552	33,368	36,271	36,410	35,143	38,246	30,144	31,234	35,809
Dec	40,202	38,116	44,116	40,974	44,245	38,845	44,809	39,620	45,071	37,881

Table 48: Monthly Peak Loads, SERC-N, 2016

Month	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Jan	41,799	47,974	44,839	44,892	37,508	39,182	47,974	47,974	47,005	45,949
Feb	42,031	41,183	39,930	39,615	38,853	44,041	43,090	44,806	42,750	46,608
Mar	38,840	36,886	36,286	39,578	35,478	36,308	37,984	41,299	38,501	35,097
Apr	38,107	34,952	34,367	32,175	35,220	32,460	35,472	32,907	31,614	32,731
May	44,554	37,328	42,081	37,960	41,456	37,316	39,455	36,414	38,453	42,796
Jun	44,723	43,061	43,332	44,530	44,855	40,926	42,927	41,749	45,038	43,952
Jul	46,453	43,795	47,974	47,974	47,974	42,102	46,020	38,839	45,125	47,974
Aug	47,974	46,425	46,399	46,485	47,881	47,974	46,177	41,486	47,974	47,561
Sep	45,162	39,621	40,642	42,617	38,548	42,688	41,654	35,898	42,151	46,122
Oct	33,176	32,361	34,032	38,698	37,461	39,562	35,253	31,482	31,291	31,023
Nov	39,334	37,677	36,460	37,387	37,530	35,447	39,423	34,964	36,342	36,911
Dec	41,439	39,289	45,473	42,235	45,606	40,041	46,187	40,839	46,458	39,046

Figure 33: Monthly Peak Loads, SERC-SE, 2014

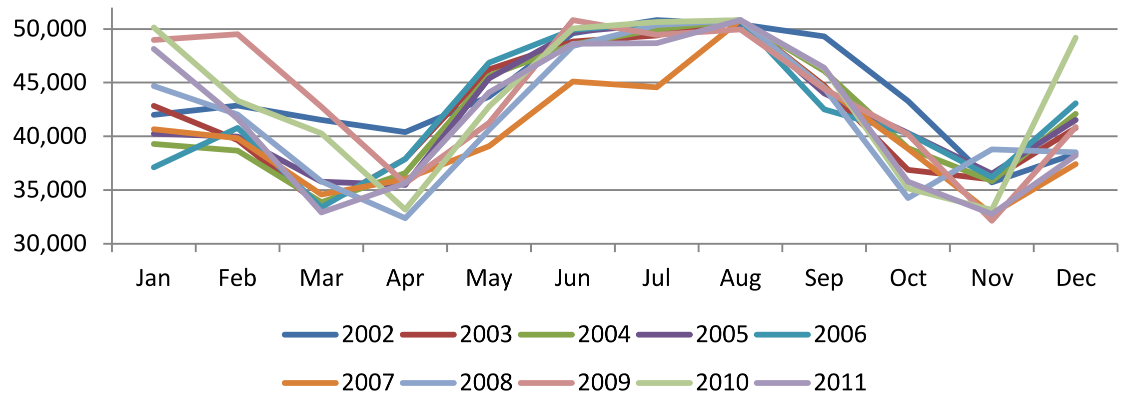


Table 49: Monthly Peak Loads, SERC-SE, 2014

Month	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Jan	42,009	42,822	39,299	40,247	37,115	40,655	44,687	48,967	50,144	48,132
Feb	42,881	39,654	38,674	39,966	40,769	39,830	42,025	49,525	43,302	41,648
Mar	41,533	33,435	33,863	35,784	33,398	34,571	35,809	42,749	40,259	32,911
Apr	40,395	37,892	36,580	35,479	37,885	36,024	32,383	35,638	33,178	35,631
May	43,689	46,221	45,641	45,387	46,845	39,070	40,611	41,249	42,768	44,101
Jun	49,610	48,819	48,549	49,715	49,933	45,111	48,412	50,838	50,042	48,620
Jul	50,838	49,383	49,972	50,438	50,547	44,568	50,382	49,444	50,656	48,671
Aug	50,448	50,838	50,838	50,838	50,838	50,838	50,838	49,945	50,838	50,838
Sep	49,302	44,726	46,079	44,005	42,519	44,567	44,493	44,403	46,315	46,372
Oct	43,297	36,886	38,911	40,313	40,266	38,842	34,258	40,190	35,141	35,772
Nov	35,726	35,969	35,827	36,520	36,179	32,761	38,793	32,144	33,146	32,770
Dec	38,404	40,777	42,094	41,520	43,081	37,418	38,509	40,859	49,195	38,223

Table 50: Monthly Peak Loads, SERC-SE, 2016

Month	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Jan	43,006	43,839	40,232	41,202	37,997	37,743	44,178	50,129	51,334	49,275
Feb	43,899	40,596	39,592	40,915	41,737	41,620	43,023	50,701	44,330	42,636
Mar	42,519	34,229	34,667	36,634	34,191	35,392	36,659	43,764	41,215	33,692
Apr	42,372	40,066	37,449	36,321	38,784	32,584	33,151	36,484	33,966	36,477
May	50,788	47,319	46,725	46,464	47,958	39,494	46,481	45,809	43,784	47,321
Jun	49,185	49,978	49,702	50,896	51,118	46,182	49,561	52,045	51,230	49,774
Jul	52,045	50,555	51,159	51,636	51,417	45,625	51,578	49,497	52,045	49,826
Aug	51,646	52,045	52,045	52,045	52,045	52,045	52,045	51,130	51,427	52,045
Sep	50,473	44,199	43,933	45,050	43,968	45,625	45,549	45,457	47,415	46,707
Oct	42,547	37,762	39,834	41,270	41,222	39,764	35,072	41,144	35,975	32,416
Nov	39,316	36,823	36,271	37,387	37,038	33,538	39,714	35,755	36,792	35,757
Dec	37,751	41,745	43,093	42,506	44,104	38,307	39,153	41,829	50,363	39,131

Figure 34: Monthly Peak Loads, SERC-E, 2014

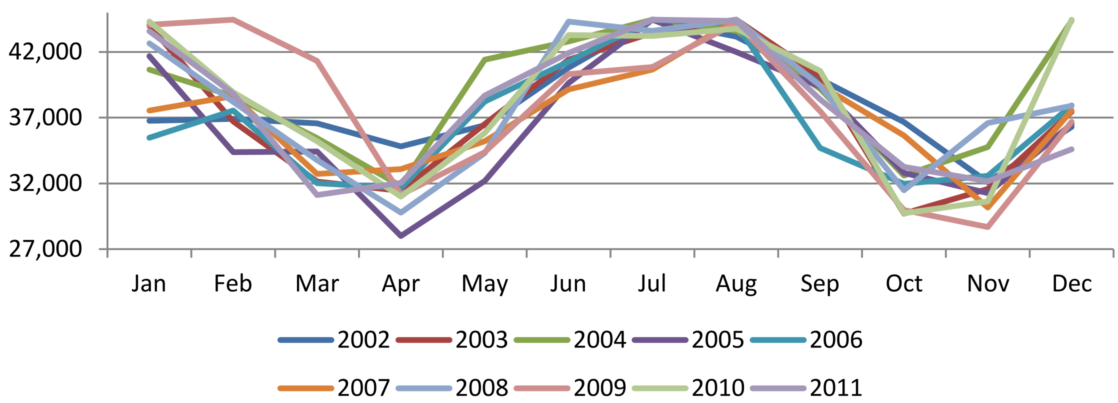


Table 51: Monthly Peak Loads, SERC-E, 2014

Month	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Jan	36,768	43,998	40,660	41,679	35,476	37,536	42,661	44,074	44,307	43,579
Feb	36,900	36,720	38,638	34,381	37,531	38,648	38,203	44,457	38,940	38,823
Mar	36,560	32,140	35,439	34,422	32,009	32,726	33,771	41,310	35,219	31,125
Apr	34,830	31,429	31,800	27,996	31,647	33,082	29,781	31,143	31,005	32,039
May	36,417	36,529	41,413	32,197	38,220	35,218	34,318	34,370	35,851	38,696
Jun	40,804	41,408	42,797	39,626	41,265	39,146	44,307	40,314	43,275	41,924
Jul	44,457	43,458	44,457	44,457	44,457	40,662	43,595	40,844	43,211	44,457
Aug	43,162	44,457	43,618	41,998	44,121	44,457	44,457	44,202	43,784	44,355
Sep	39,919	40,138	39,210	39,379	34,704	39,461	39,449	37,484	40,565	38,388
Oct	36,678	29,699	32,594	32,809	31,974	35,638	31,484	29,989	29,744	33,263
Nov	32,086	31,574	34,767	31,275	32,580	30,182	36,583	28,680	30,631	32,172
Dec	36,294	37,440	44,387	36,532	37,938	37,552	37,909	36,700	44,457	34,610

Table 52: Monthly Peak Loads, SERC-E, 2016

Month	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Jan	37,577	44,966	41,555	42,596	36,257	36,519	43,600	45,044	45,283	44,538
Feb	37,712	37,528	39,489	35,138	38,357	39,498	39,044	45,436	39,797	39,677
Mar	37,364	32,588	36,219	35,179	32,714	33,446	34,514	42,220	35,994	32,745
Apr	35,597	32,121	32,500	28,612	32,343	29,568	30,436	31,828	31,688	31,775
May	40,657	37,333	42,325	32,906	39,061	35,352	36,492	39,306	36,640	42,484
Jun	41,702	42,320	43,738	40,498	42,173	40,008	45,282	41,201	44,228	42,847
Jul	45,436	44,414	45,436	45,436	43,433	41,557	44,554	41,743	44,162	45,436
Aug	44,112	45,436	44,578	42,922	45,436	45,436	45,436	45,175	44,748	45,332
Sep	39,636	39,079	37,204	38,620	35,468	40,330	40,317	38,309	40,070	39,233
Oct	35,401	30,353	32,220	31,325	32,677	36,423	32,829	30,649	30,399	29,141
Nov	37,093	35,479	35,533	31,964	33,297	30,846	38,743	32,759	31,305	32,880
Dec	34,019	38,264	45,364	37,336	38,773	38,379	38,182	37,507	45,436	35,372

Figure 35: Monthly Peak Loads, SERC-W, 2014

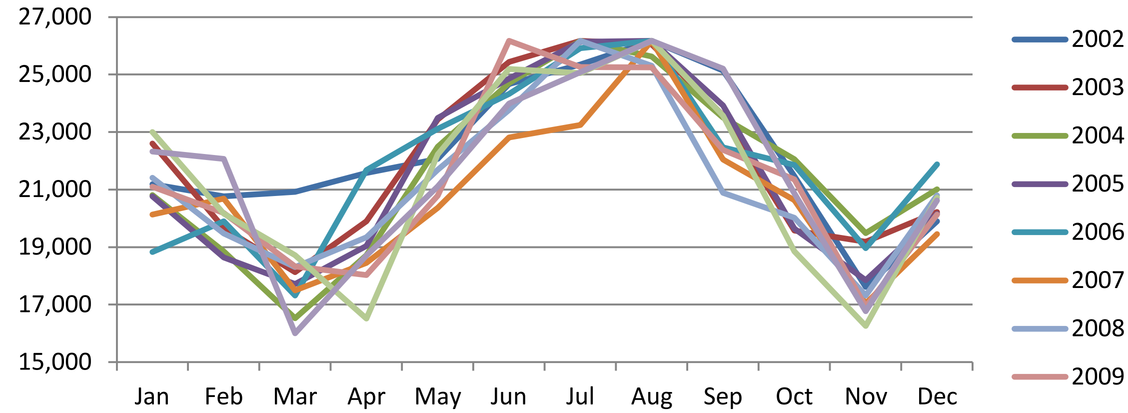


Table 53: Monthly Peak Loads, SERC-W, 2014

Month	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Jan	21,184	22,597	20,809	20,770	18,835	20,133	21,405	21,098	23,005	22,325
Feb	20,768	19,660	18,853	18,640	19,898	20,686	19,477	20,182	20,164	22,063
Mar	20,918	18,127	16,528	17,720	17,319	17,491	18,307	18,323	18,716	16,000
Apr	21,581	19,902	18,718	19,040	21,678	18,448	19,336	18,023	16,516	18,709
May	22,063	23,440	22,487	23,496	23,116	20,366	21,687	20,792	22,223	21,111
Jun	24,673	25,435	24,708	24,857	24,328	22,816	23,765	26,166	25,190	23,987
Jul	25,344	26,166	26,166	26,144	25,911	23,251	26,166	25,258	25,048	25,081
Aug	26,166	26,050	25,627	26,166	26,166	26,166	25,302	25,244	26,166	26,166
Sep	25,139	23,582	23,500	23,930	22,463	22,044	20,891	22,374	23,567	25,200
Oct	21,461	19,580	22,056	19,636	21,859	20,635	20,015	21,358	18,855	20,870
Nov	17,616	19,182	19,483	17,853	18,965	17,039	17,314	16,927	16,258	16,768
Dec	19,899	20,220	21,013	20,158	21,873	19,450	20,796	20,130	20,719	20,622

Table 54: Monthly Peak Loads, SERC-W, 2016

Month	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Jan	21,763	23,214	21,378	21,338	19,350	20,683	20,542	21,674	23,634	22,935
Feb	21,490	20,197	19,369	19,149	20,442	21,251	20,009	20,734	20,715	22,666
Mar	20,852	17,676	16,980	18,204	17,350	17,969	18,808	18,484	19,227	16,437
Apr	22,170	21,762	19,230	19,561	22,270	18,207	19,865	18,567	17,186	19,220
May	25,347	24,080	23,101	24,138	23,747	20,923	24,095	22,109	23,022	23,059
Jun	25,228	26,131	25,383	25,830	24,993	23,440	24,414	26,881	25,878	24,643
Jul	26,881	26,881	26,881	26,858	26,620	23,886	26,881	25,791	25,733	25,766
Aug	26,336	26,762	26,327	26,881	26,881	26,881	25,179	25,934	26,881	26,881
Sep	25,826	24,155	24,142	24,584	23,077	22,646	21,462	22,985	24,211	24,124
Oct	20,333	20,115	22,658	20,173	22,456	21,199	20,562	21,942	19,370	19,179
Nov	19,039	19,706	18,271	18,341	19,067	17,505	19,233	18,855	18,838	18,712
Dec	20,443	20,773	21,587	20,708	22,470	19,982	21,364	20,680	21,285	21,185

Load forecast uncertainty is one of the largest drivers of the Planning Reserve Margin. This study accounted for this in two ways. The first was to utilize ten different load shapes, representing ten years of historical weather patterns from 2002 through 2011. Each of these shapes was scaled to meet the target peak; the results of this scaling were shown in the previous section.

This method of capturing uncertainty can significantly change the time during the year of the peak for an area. Using SERC-N as an example in Figure SERC-1, three of the load shapes used caused a winter peak to be modeled. Table 55 shows the months the area peak occurred for all of the areas and load shapes used.

Table 55: Month of Area Peak

	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
SERC-N	Aug	Jan	Jul	Jul	Jul	Aug	Jan	Jan	Aug	Jul
SERC-SE	Jul	Aug	Aug	Aug	Aug	Aug	Aug	Jun	Aug	Aug
SERC-E	Jul	Aug	Jul	Jul	Jul	Aug	Aug	Feb	Dec	Jul
SERC-W	Aug	Jul	Jul	Aug	Aug	Aug	Jul	Jun	Aug	Aug

The long-term load forecast uncertainty was then represented in MARS through multipliers on the projected peak load and the probability of occurrence for each load level. This data, which can vary by month and area, is often specified in terms of a seven-point normal distribution with values for the mean and for points one, two, and three standard deviations above and below the mean.

For this study, historical data from 1987 through 2010 for monthly peak load projections and actual experienced peak loads were analyzed to develop these multipliers for SERC-N, SERC-SE, SERC-E, and SERC-W. The data for all of the years was not available for all of the areas and some region definitions had changed through time. This caused the number of data points actually available for use to vary somewhat between areas: there were only twelve years of data available for SERC-W, while the other three areas had twenty four. The multipliers for each area by month are shown in Figures SERC-5 through SERC-8.

MARS calculates the reliability indices at each of the load forecast uncertainty load levels. The results for each of the load levels are then combined using the associated probabilities of occurrence to calculate the expected value of the indices. In this study, each year's shape was weighted equally, with a 10 percent probability of occurrence, and each peak forecast multiplier was weighted by the probability of occurrence within one, two, or three standard deviations, for a total of seventy load levels being evaluated.

Figure 36: Load Forecast Uncertainty Multipliers for SERC-N

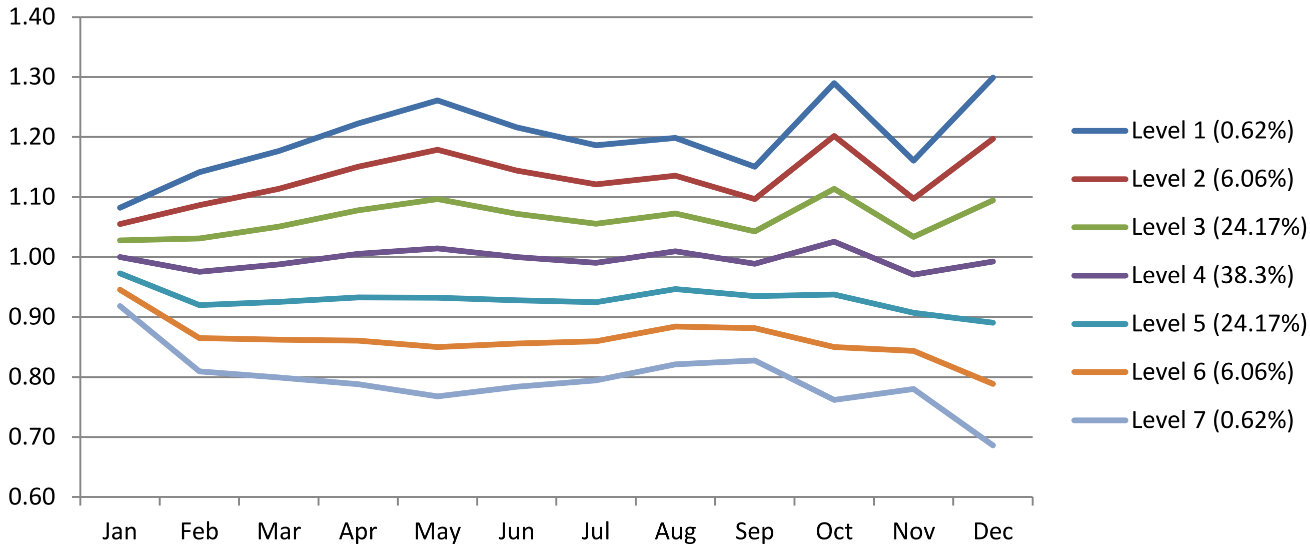


Figure 37: Load Forecast Uncertainty Multipliers for SERC-W

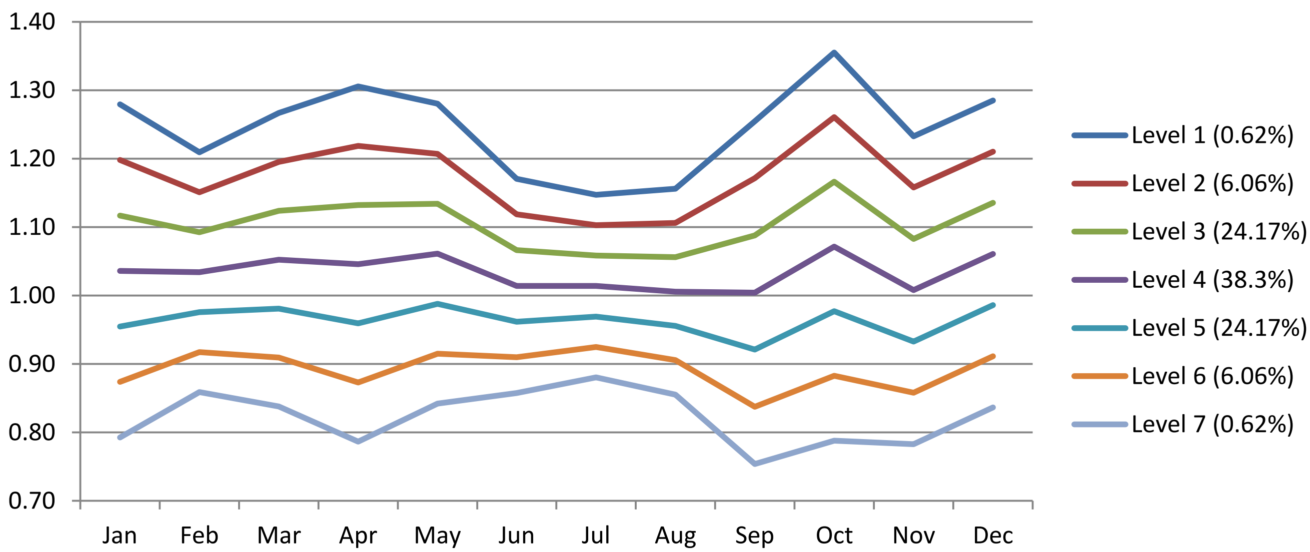


Figure 38: Load Forecast Uncertainty Multipliers for SERC-SE

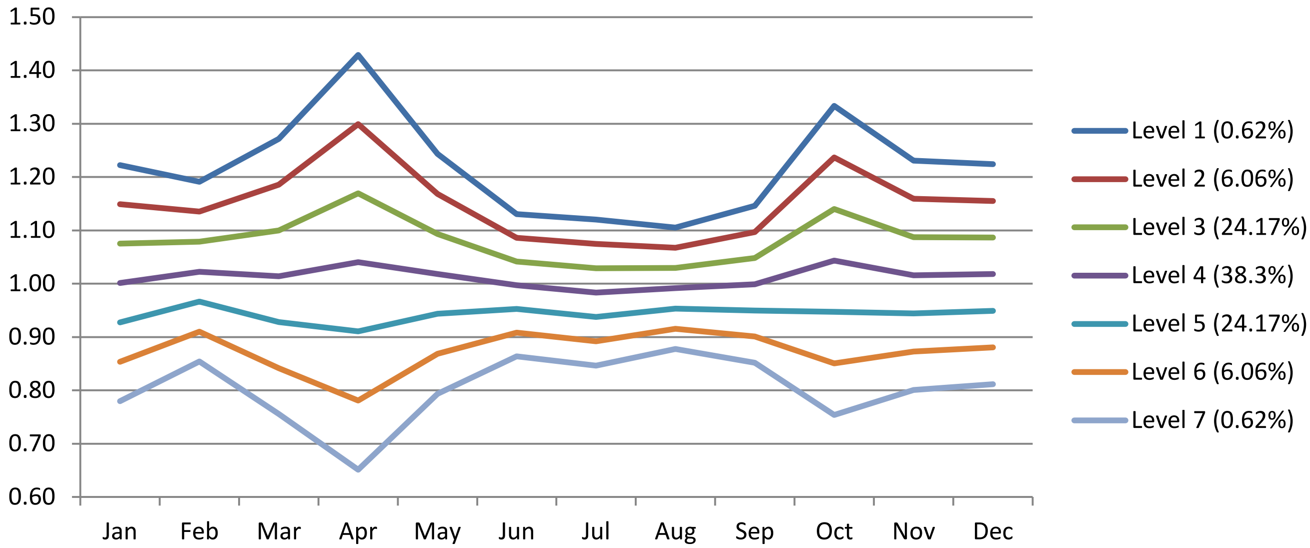
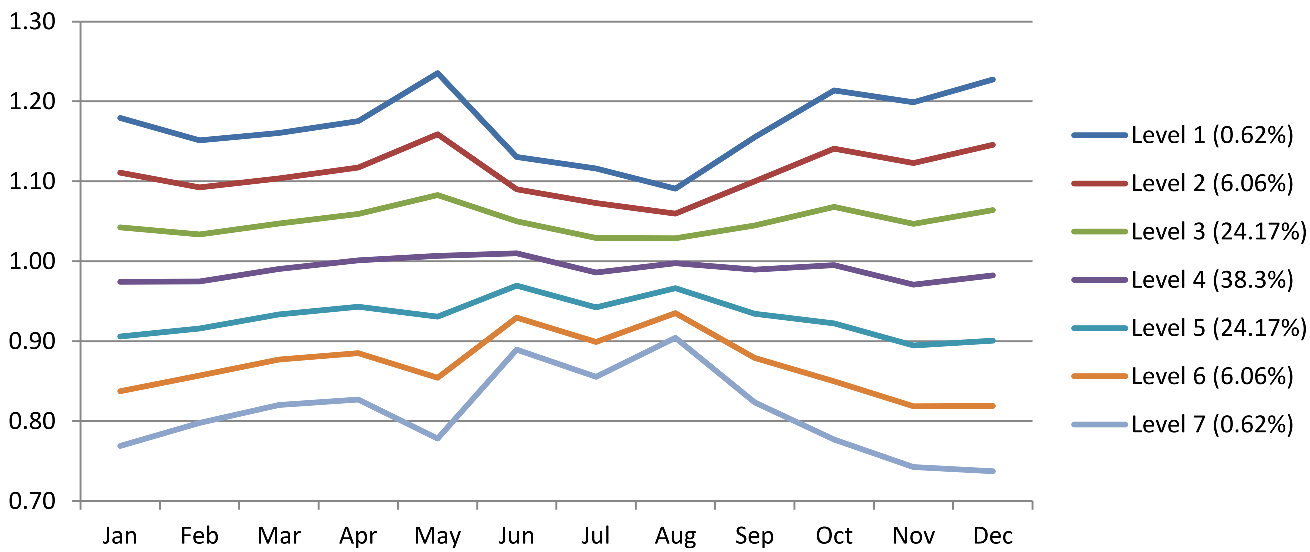


Figure 39: Load Forecast Uncertainty Multipliers for SERC-E



Capacity Modeling

Capacity data for the individual units modeled in the reporting areas is taken from the 2012 LTRA. The unit data for the external regions is provided by PJM participants. There are no significant differences between the reporting area and LTRA capacity data, as described in the *Methodology and Metrics* document.[48]

For deliverability of existing and planned generation, each interconnecting utility transmission planner accounted for their individual transmission plans studied within the SERC study groups for the near-term (2014) and long-term (2016) study years. These plans account for the deliverability of the firm capacity in the study. Transfer limits are established between the areas and are provided by these groups to provide a "pipe and flow model" in the study. Additionally, entity generation retirements, additions and re-ratings are accounted for within the transfers and capacity data listed in 41 through the LTRA process.

Capacity designations are determined through the LTRA process. The model assigns generation specified within a specific area. Ownership distinction of generation is considered irrelevant to this reliability assessment. More important is the accuracy of the capacity and the location, i.e. correctly identifying in which areas the generation resides to capture the transfer limitations between each area. Firm transactions are considered within the transfers, whereas temporary sales and purchases are not represented in the modeling. Firm transactions from the LTRA are assumed to be taken into account in the transmission model.

The quantities of intermittent and energy limited variable resources are described in Table 41. These area resources reflect capacity dedicated to hydro, biomass, wind, and solar within the model.

MARS schedules the dispatch of hydro units in two steps. The minimum rating of each unit, which represents the run-of-river portion of the unit, is dispatched across all of the hours of the month. The remaining capacity and energy are then scheduled on an hourly basis as needed to serve any load that cannot be met by the thermal generation on the system.

The contribution of a thermal unit to the reliability of the system is a function of the unit's rating and outage rates. If the unit is not on outage, it can contribute to meeting the load. For hydro units, which are more likely to be energy limited, their capacity factors (the ratio of the energy output to the maximum possible if operated at full output for all of the hours in the period) are an indication of their contribution to meeting load.

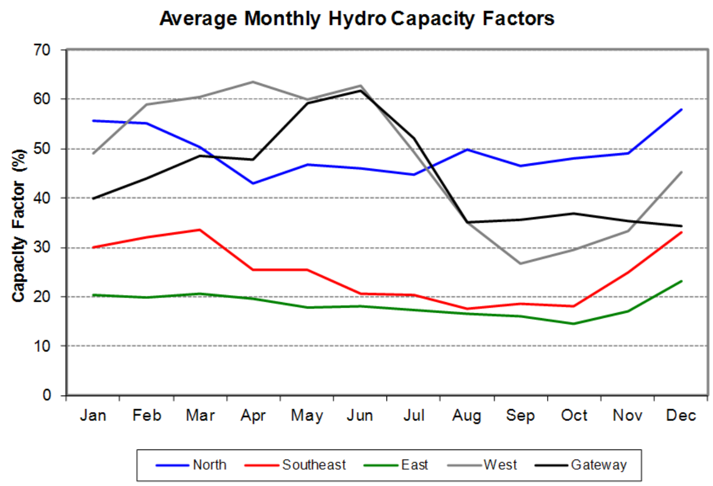
The hydro data was extracted from the Ventyx Velocity Suite database (July 2011) and then adjusted to match the seasonal ratings of the units from the 2012 LTRA data. The monthly energy is the average for the years 2001 through 2010. Figure SERC-9 shows the average monthly capacity factors, by area, for the more than 130 hydro units modeled in this study for 2012. This figure shows that the capacity factors, with the exception of the SERC-N area, tended to be somewhat lower during the peak summer months of July and August.

Controllable Capacity Demand Response Modeling

Energy Efficiency is netted from load in the model. Controllable capacity Demand Response is not modeled as a generation resource in the MARS model. As described above, it is included as Emergency Operating Procedure steps as illustrated in Table 43. These steps consist of those load control and generation supplements that can be implemented before firm load has to be disconnected. Load control measures could include disconnecting or reducing interruptible loads, making public appeals to reduce demand, and/or implementing voltage reductions. Other measures could include calling on generation available under emergency conditions, and/or reducing operating reserves.

[48] http://www.nerc.com/filez/ris.html

Figure 40: Average Monthly Capacity Factors of Hydro Capacity



The actual hourly output for the wind units is a very small amount and is specified through an hourly profile for all of the hours in the year or for a typical week each month. Some of the wind resources are modeled with hourly profiles developed by the National Renewable Energy Laboratory (NREL). The wind capacity shown in the summaries for these units is based on the sum of the non-simultaneous maximum output of the units in the month rather than the nameplate installed capacity. Other wind units are modeled as thermal units with a capacity representing the effective capacity of the plant at time of peak load.

MARS can model several different categories of generating units. The three categories modeled in this study are thermal, energy limited, and hourly resources. Most of the generating units are modeled as thermal units, for which the program assumes that the unit is always available to provide capacity unless it is on planned or forced outage. The energy limited category is used to model those units whose operation can be scheduled to some extent, but for which the output may be constrained due to energy limits. This is typically used to model hydro units with a limited amount of storage capacity. The hourly resource category is used to model wind units for which the actual hourly output of the units is specified through input. MARS does not explicitly model forced outages on the hydro or wind units. Energy storage units are modeled as thermal units, based on the assumption that they would be available to generate for at least the peak hours of the day when the risk is most likely to occur.

Each unit is specified in terms of its installation, any associated retirement dates, the area in which it is located, monthly maximum ratings, and planned maintenance requirements. All of the thermal units are modeled with two capacity states; available, or on forced outage. Additional data for the hydro units included the minimum rating (which represented the run-of-river portion of the unit) and the available energy on a monthly basis. The data for the individual units modeled in the four SERC areas is taken from the 2012 LTRA filings.

MARS models both planned and forced outages on the thermal generating units. The forced outages are modeled as events that remove units from service at random times throughout the year during the Monte Carlo simulation. The NERC Generator Availability Data System (GADS)[49] database for units reporting events from 2005 through 2009 is the source of the thermal unit outage rate data. Average forced outages are listed above in Table 45. These forced outage rates are consistent with the NERC Generating Availability reports[50], which have gained wide spread industry acceptance. Planned

[49] http://www.nerc.com/page.php?cid=4|43
[50] http://www.nerc.com/page.php?cid=4|43|47

outages are scheduled by the program on a weekly basis by area, so as to level out the available reserves over the entire year.

Transmission

Transmission modeling is taken from the vendor Ventyx Velocity Suite Transmission Zones, the LTRA, and the SERC study groups. Zones are assigned according to the table below.

Table 56: Assignment of Transmission Zones

SERC Reporting Areas	SERC Registered Entity
SERC-N	Associated Electric Cooperative Inc.
	E.ON US
	East Kentucky Power Coop.
	Electric Energy Inc.
	Tennessee Valley Authority
	Alcoa Power Generating, Inc. (Tapoco)
SERC-SE	Alabama Power Company
	Georgia Power Company
	Gulf Power Company
	Mississippi Power Company
	PowerSouth Energy Coop
	South Mississippi Electric Power Association
SERC-E	Duke Energy Carolinas
	Progress Energy Carolinas East
	Progress Energy Carolinas West
	Santee Cooper
	South Carolina Electric & Gas Company
	Alcoa Power Generating, Inc. (Yadkin)
SERC-W	Entergy Arkansas
	Entergy Gulf States
	Entergy Louisiana
	Entergy Mississippi
	Entergy New Orleans
	Entergy Texas
	Louisiana Generating/Cajun Electric

Transmission additions and retirements are accounted for in the transfer studies mentioned in detail below. Load flow studies take into account the status of the existing system for the 2014 cases and in 2016 (upgrades, additions, new generation, retirements, operating guides, etc.) Most projects are accounted for in the LTRA forecast, but the power flow cases are updated throughout the year to account for continuous improvements/adjustments to the system.

Import limits were calculated for each reporting area by simulating maximum transfers with load-to-load shifts into each area simultaneously from each adjacent area using linear transfer techniques. Once accomplished, each incremental interface import capability was then allocated to each transfer line(s) separating each of the areas, including the external areas, using a ratio of each area's participation factor matrix. For the 2012 study, this was based on the area's interface thermal rating. The incremental value calculated was added to the base transfers embedded in the transmission model to obtain the total interface limits for the reliability analysis.

The parameters given for this study are as follows:

The SERC entity grouping will be based on reporting areas and will account for transfers from non-SERC control areas adjacent to the importing control area (includes the imports into the Gateway areas and portions of VACAR within PJM);

Values for first contingency incremental transfer capability (FCITC) and any embedded transfers modeled in the base case should be reported.

To initially perform an interface limit transfer analysis, the amount that each reporting area participates in the incremental transfer needed to be specified. The characteristics of the transmission system defined the participation factors, along with a final ratio of thermal limits for allocation of the ultimate interface limits.

Incremental transfer participation amounts were based on the ratio of physical transmission facility (tie-line) ratings ("interface capability") between each area. This method of establishing the participation factor matrix provided a representative starting point, but generally is not optimal to establish as the final matrix because embedded transfers and loop flows in the transmission model may skew calculation results. Optimally, the transfer analysis would be performed while iterating through various participation factors to determine the maximum import amount.

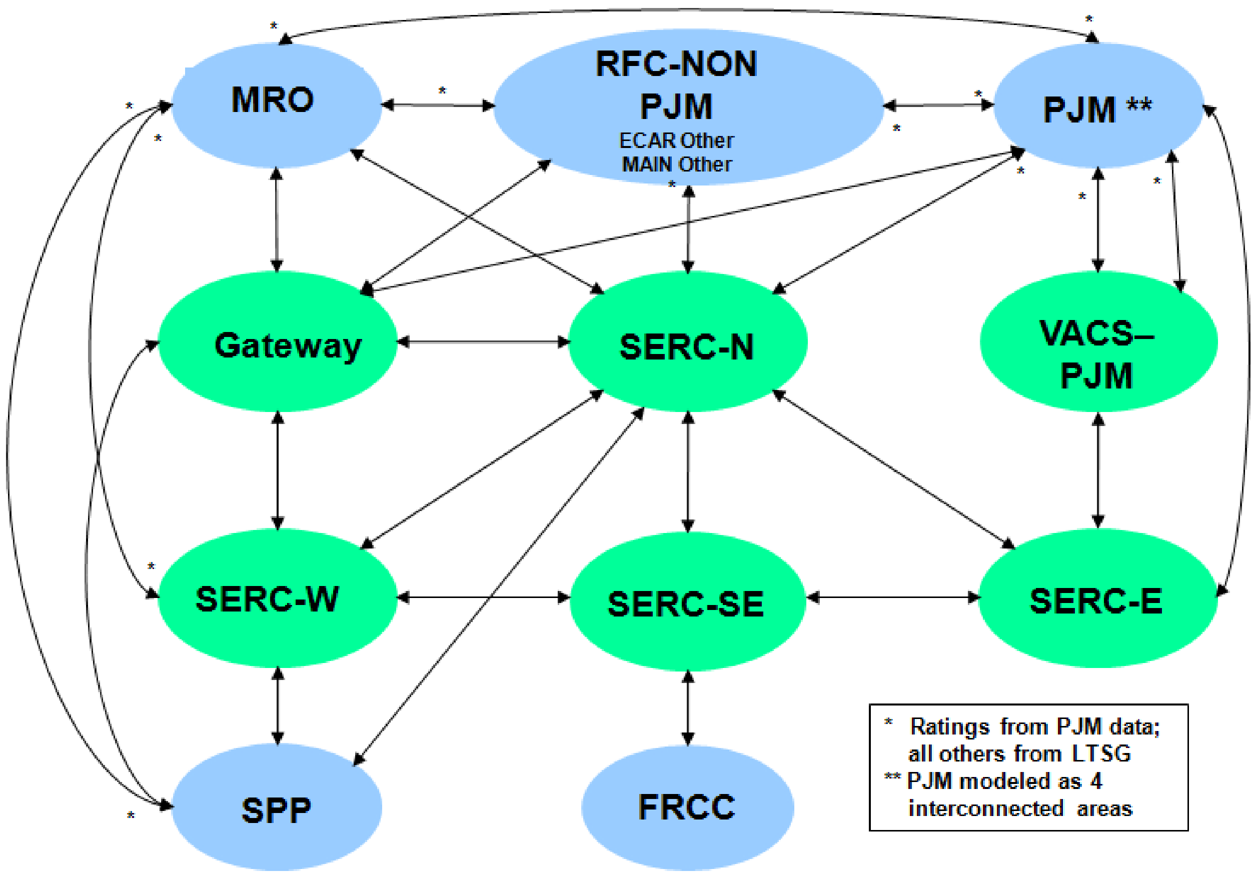
To derive the transfer participation factors, the combined interface capability of all interfaces that comprise each reporting area was determined first. Once determined, a reporting area's pro-rata share of the total interface capability of all the reporting areas participating in the transfer to determine the factor at which it will participate was used. Then, that factor was multiplied by the total transfer test level to calculate how much that particular reporting area would contribute. If a respective interface limit appeared low relative to the operating experience, then the participation factors were adjusted and a new series of interface limits was determined. The process of adjusting the participation factors was repeated as necessary to determine an interface limit that was reasonably commensurate with actual operational experience.

Once the total interface limits for each area were calculated using this method, the allocation of total imports to each "pipe" separating the bubbles was based upon a ratio of the participation factors used to calculate the optimum import. For the 2014 and 2016 studies, established participation factors were adjusted to maximize imports to some areas.

Once all of the appropriate Power Technology, Inc.'s Managing and Utilizing System Transmission (MUST) application subsystem descriptions were created, the AC transfer analysis was performed similar to that of the SERC Near-Term Study Group (NTSG) reliability transfer study process. Potential limits to transfer were observed if the response factor (PTDF or OTDF) was three percent or greater and a viable operating procedure was not available. It is common for a limit to be reached and be sensitive to transfers associated with a particular interface, but to not be sensitive to transfers associated with other interfaces. However, for the purposes of this study, any transfer that reached the specified transfer limit was shared amongst the adjacent reporting areas. As in the case of the transfer participation, the FCITC was also shared amongst the adjacent reporting areas by interface capability ratio share. After the associated area to area FCITC was determined, the associated base transfers between those two reporting areas were added to determine the first contingency total transfer capability (FCTTC).

The topology, with the transfer limits omitted for confidentiality reasons, as determined by the SERC Long-Term Study Group (LTSG) for 2014 and 2016 are shown in Figure SERC-10. The figure shows the interfaces between the areas that were modeled in each direction between the pairs of interconnected areas.

Figure SERC-410 Study System Transfer Limits Topology (MW) – 2014/2016



As necessary, transfer limits with external regions were taken from the PJM data and are shown in the figures with an asterisk. In some instances, the transfer limit was available for only one direction of an interface; in these cases, the same value was assumed for both directions.

For all of the external regions except for FRCC, the hourly loads and individual generating units were modeled to the same level of detail as the SERC areas, using data provided by PJM. FRCC was modeled simply in terms of its firm transactions with SERC.

Although SPP was modeled with an import capability from SERC, based on the calculated value from SPP to SERC-N, it required very little, if any, assistance from SERC because of its high level of reliability on an isolated basis.

Assistance from External Resources

For the isolated reliability indices, each area is modeled as though it had no interconnections with the other areas, other than the firm imports from the external regions. As such, each area is measured as to its ability to serve its load with only its own resources and firm imports. The interconnected indices reflect the emergency, non-firm assistance that the areas could provide to one another. The interconnected indices also include non-firm emergency assistance from the outside regions. Another assumption is that external assistance is available and the neighboring areas' "as-is" model is better than 0.1 day/yr.

Definition of Loss-of-Load Event

A loss-of-load event can be defined as the shedding of any firm load. LOLE is the sum of the loss-of-load probability for the integrated daily peak hour for each day of the year. Typically, the requirement is set such that the loss of load is no greater than 1 day/10 years. For the SERC study, the LOLE is measured after implementation of the EOPs described in Section 1.

SPP

SUMMARY

The SPP 2012 Probabilistic Assessment is a mandatory study requested by NERC under the guidance of the Reliability Assessment Subcommittee (RAS). One objective of this assessment is to provide a common set of probabilistic reliability indices and recommend probabilistic-based work products that could be used to supplement NERC's Long-Term Reliability Assessments (LTRA). The terminology of assessment area for this report is synonymous with the reporting subregions of the LTRA. For this report Southwest Power Pool (SPP) is considered an assessment area. This study is based on the 2012 LTRA data, which included entities in the SPP Regional Entity footprint plus Nebraska entities.

Another objective, which is a requirement of SPP's Criteria and not of the NERC RAS, is to assess whether the capacity margin requirement of 12% is adequate to maintain a Loss of Load Expectation (LOLE) of 1 day in 10 years.

The first objective of this report is to provide additional probabilistic statistics as a complement to the 2012 LTRA data. SPP used GridView version 8.2.2, an ABB application, to perform the probabilistic analysis of the 2012 LTRA data for study years 3 and 5, 2014 and 2016 respectively. Three metric results were calculated in this study: annual Loss of Load Hours (LOLH), Expected Unserved Energy (EUE), and Expected Unserved Energy as a percentage of Net Energy for Load (normalized EUE). For the purposes of the SPP Criteria, the LOLE in days/year will also be provided.

The second objective of this assessment is to validate the capacity margin requirement as listed in the SPP Criteria section 4.3.5 which states:

"SPP will use a probabilistic approach for Regional and sub-regional Generation Reliability assessments. These assessments will be performed by the SPP on a biennial basis. Generation Reliability assessments examine the regional ability to maintain a Loss of Load Expectation (LOLE) standard of 1 day in ten years. The SPP capacity margin Criteria requires each control area to maintain a minimum of 12% capacity margin for steam-based utilities and 9% for hydro-based utilities. Historical studies indicate that the LOLE of one day in ten years can be maintained with a 10% - 11% capacity margin."

The 2012 Probabilistic Assessment is a mandatory near term pilot study requested by NERC. The final report, upon endorsement by the Economic Studies Working Group (ESWG), will be submitted to NERC in the first quarter of 2013. The LOLE and capacity margin assessments will continue to be performed at least on a biennial basis by SPP. The next Probabilistic Assessment cycle will be in 2014.

Nineteen (19) entities (geographic subregions) were modeled within the SPP RE footprint including the Nebraska entities. The SPP RE footprint includes all or parts of Arkansas, Kansas, Louisiana, Mississippi, Missouri, New Mexico, Oklahoma, and Texas. In the 2011 Probabilistic Assessment, the Nebraska demand and capacity was not included, but for the 2012 Probabilistic Assessment the Nebraska entity's (GIUD, Hastings, LES, MEAN, NPPD, OPPD) demand and capacity were included since they were reported in the 2012 LTRA report. Also Entergy demand and capacity within the AECC and CELE areas were subtracted from the totals before any analysis was performed.

Table 57: Assessment Area geographic subregions for the 2012 Probabilistic Assessment

Acronym	Utilities
AEPW[51,52]	American Electric Power System West
CELE[53]	Central Louisiana Electric Company, Incorporated
EMDE	Empire District Electric Company
GRDA	Grand River Dam Authority
INDN	Independence Power & Light Department
KACY	Board of Public Utilities, Kansas City, Kansas
KCPL	Kansas City Power & Light Company
LAFA	City of Lafayette, Louisiana
LEPA	Louisiana Energy & Power Authority
LES	Lincoln Electric System
GMO (MPS)	Greater Missouri Operations Company
NPPD	Nebraska Public Power District
OKGE	Oklahoma Gas and Electric Company
OPPD	Omaha Public Power District
SPS	Southwestern Public Service Company
SUNC(SEPC)	Sunflower Electric Cooperative
SWPA[,54]	Southwestern Power Administration
WERE[55]	Westar Energy, Incorporated
WFEC	Western Farmers Electric Cooperative

Capacity data modeled in this assessment was derived from the 2012 LTRA. The table below provides the makeup of the capacity categories and amounts used in this assessment by study year (2014, 2016). Differences in capacity values between this assessment and the 2012 SPP LTRA report are listed in this report under section 5a. For purposes of clarification, the summer season includes: April – September, and the winter season includes: January – March, and October – December.

Table 58: Seasonal capacity totals

Category	2014		2016	
	Summer (MW)	Winter (MW	Summer (MW)	Winter (MW)
Controllable capacity demand response	1,120	1,120	1,190	1,190
Intermittent and energy-limited variable resources	1,197	1,206	1,295	1,304
Traditional dispatchable capacity (Coal)	28,056	25,773	28,587	26,078
Traditional dispatchable capacity (Gas / Oil)	30,623	29,627	30,705	29,612
Traditional dispatchable capacity (Hydro)	2,653	2,286	2,675	2,326
Traditional dispatchable capacity (Nuclear)	2,466	2,466	2,466	2,466
Sales	2,358	2,250	2,407	1,939
Purchases	2,408	2,051	2,408	1,959
Total Capacity	66,893	63,029	67,469	63,527

[51] FERC 714 Hourly Load data for AECC is reported through AEPW, OKGE, and SWPA.
[52] FERC 714 Hourly Load data for OMPA is reported through AEPW, OKGE, and WFEC.
[53] Non-Entergy portion of the demand and capacity in the SPP RE footprint for CELE was included.
[54] FERC 714 Hourly Load data for SPRM is reported in SWPA through 2010. 2011 SPRM Hourly Load data was added to SWPA numbers to create the Load Uncertainty Model.
[55] FERC 714 Hourly Load data for MIDW is reported through WERE.

SPP members provided their peak seasonal forecast demand data based on individual member's forecast methodology, which may or may not be coincident forecasts. The SPP 2012 LTRA non-coincident forecasted seasonal values are listed below.

Table 59: 50/50 peak seasonal demands

Peak Load	2014		2016	
	Summer (MW)	Winter (MW	Summer (MW)	Winter (MW)
LTRA	55,732	42,010	56,364	42,644
Simulation	52,957	39,800	53,139	41,067

Table 60: Net Energy for Load

Net Energy	2014	2016
	(MWh)	(MWh)
LTRA	269,434,200	271,343,300
Simulation	254,642,847	259,767,659
[56]Difference	14,791,353	11,575,641

LOLH, Loss of Load Hour, is the Hourly Loss-Of-Load expectation. This metric provides the hours of resource reliability shortfall per year, which is the time in hours that the demand exceeds the capacity throughout the year. Per the SPP Criteria, generation reliability assessments examine the regional ability to maintain a Loss of Load Expectation (LOLE) standard of 1 day in ten years (0.1 day / year). The LOLH is measured in hours in GridView, which is the number of hours that a loss of load event occurred. This value is a summation of hourly events for a 24 hour period, which is then averaged over the number of yearly trials. GridView provides Expected Energy Not Served (EENS), which equates to Expected Unserved Energy (EUE).

Daily LOLE, Loss of Load Expectation, is the expected daily occurrences of the loss of load throughout the year.

Daily Peak LOLE, Loss of Load Expectation, is the expected occurrences of loss of load during the daily peak load hour, throughout the year.

EUE, Expected Unserved Energy, is the expected amount of megawatt-hours of load that will not be served in a given year. This is the summation of the expected amount of unserved energy during the time that the demand exceeds the capacity throughout the study year.

Normalized EUE provides a sense of how much energy, relative to the area's size, could be expected to be unserved. The calculation for normalized EUE is as follows:

Normalized EUE = [EUE / (Net Energy for Load simulated)] x 1,000,000

[56] The Probabilistic Assessment model does not include the AECC Entergy footprint, as reported in the SPP LTRA Net Energy for load.

In this study, the capacity margin percentage was determined to be 20.83% for the peak hour of 2014 and 20.74% for the peak hour of 2016. The values in the table below reflect the results of the GridView LOLH/LOLE simulations for both study years (2014, 2016).

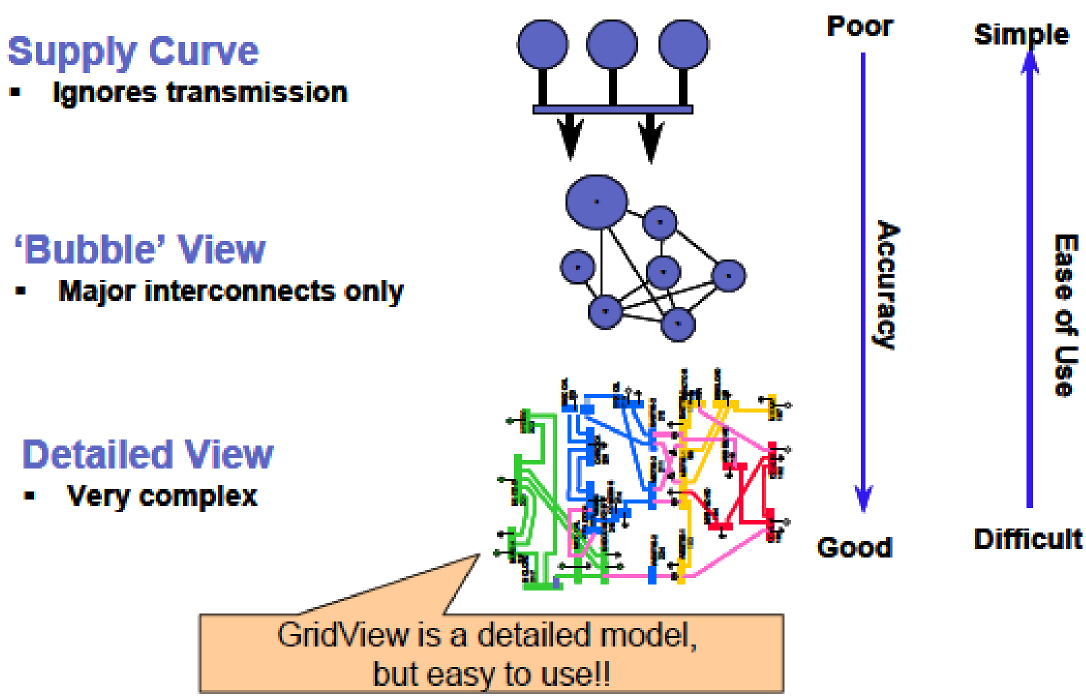
Table 61: Assessment Area Metric Results

SPP Region	2014	2016
LOLE (days/year)	0	0
LOLH (hours/year)	0	0
EUE (MWh/year)	0	0
EUE (Normalized MWh/year)	0	0

Software Model Description

GridView 7.3, 8.2.2, and 8.3 were used to perform the analysis. GridView is a software application developed by ABB Inc. to simulate the economic dispatch of an electric power system while monitoring key transmission elements for each hour. GridView can be used to study the operational and planning issues facing regulated utilities, as well as competitive electric markets. The key advantage of using the GridView application is having the ability to model a detailed transmission system in the study region, not just a transportation model. The transmission model allows for realistic power delivery based on actual modeled limits on transmission lines imported from power flow models. Some other features available in this program include contingency constraints, nomograms, and emergency imports. A Monte Carlo simulation was used to perform the analysis of the SPP reliability assessment.

Figure 42: GridView Uses Detailed Transmission System Model



Monte Carlo simulation is a method for iteratively evaluating a deterministic model using sets of random numbers as inputs. The goal is to determine how random variation or error affects the reliability of the system that is being modeled. Monte Carlo simulation is categorized as a sampling method because the inputs are randomly generated from probability distributions to simulate the process of sampling from an actual population. Within GridView, Monte Carlo simulation allows detailed modeling of the pre-contingency conditions and the outages of generation and/or transmission equipment and/or changes in demand, fuel prices, and/or wind generation. GridView can also model the correlation between area load demands and fuel prices. It uses probability distributions for equipment outages during a sequential mode of simulations hour by hour, and typically for a year. The selection of testing conditions is by random sampling. In order to obtain accurate risk indices, many simulations will have to be performed (2400 simulations / year for this assessment). In general, the simulations provide the loss of load reliability indices. For reliability assessment, a linear model is applied to the generation dispatch calculation for every hour in each trial in order to compute the amount of load that has to be shed in order to eliminate Transmission overload problems. The engineer performing the analysis will choose a distribution for the inputs that most closely matches data that the assessment area already has, or best represents the assessment area's current state of knowledge. SPP, as an assessment area, created a load forecast uncertainty model in order to randomly select a determined set of load probability multipliers within GridView.

Demand Modeling

The reported 2012 LTRA demand and energy include the Entergy portion of AECC, was not included in the Probabilistic Assessment totals. At the time of the study it was believed that the Entergy portion of AECC was not part of the SPP RE footprint. The Entergy portion of AECC demand and energy is part of the SPP RE footprint and will be included in future assessments.

Behind-The-Meter generation that could not be added to same bus units was subtracted from demand totals. The combination of these two differences reduced the total peak load and energy amounts compared to the 2012 LTRA data.

Each area modeled has its own expected 8760 hourly load profile. The hourly load curves were 2005 load shapes, the same as used in the Integrated Transmission Plan (ITP) process. SPP used 2014, and 2016 hourly non-coincident peak load forecast data to modify the 2005 hourly load profiles for each entity included in this assessment. No out of region load was modeled in this assessment.

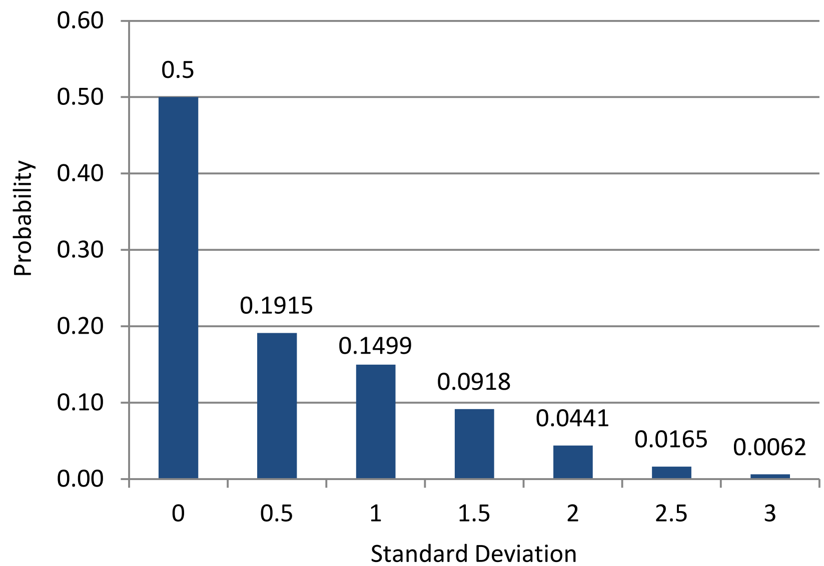
GridView allows for two options in dealing with load uncertainty, 1) User defined uncertainty pattern, and 2) probability distribution.

For this study, a user defined uncertainty pattern and a probability distribution were used to add uncertainty to the load values.

A load model was used to define the peak load multipliers used to modify forecasted loads. The daily peak was selected and regressed against historical peak temperatures. Crystal Ball Pro was used to analyze the probability distributions of temperatures observed at key weather stations throughout the SPP footprint. The load model increases load as the winter temperatures decreased and as the shoulder and summer temperatures increased. A forecast was then created for both study years. Based on the forecasts, multipliers were calculated which were populated in a user defined uncertainty pattern. The user defined uncertainty pattern allows users to provide 7 monthly load patterns. Each area has a different value for each month times 7 probabilities (a total of 84 values). GridView randomly selects the load pattern at the beginning of the simulation hour and applies it for that trial.

The randomly selected load multipliers are determined by sampling from a uniform distribution, and selecting one of seven possible multipliers. These multipliers have dramatically decreasing likelihoods (e.g., Set 1 is 50% likely, Set 2 is 19% likely, Set 7 is 0.6% likely). Multiplier Set 7 contain the highest multipliers, and are the least likely to occur. As such, this set should be considered SPP's extreme peak. For this study, there are no multipliers that decrease the load values. Multiplier Set 1 is the base case multiplier, and effectively multiplies all loads by 1. Sets 2 – 7 are intended to proportionally increase loads up to SPP expected extreme peaks.

Figure 43: Demand Forecast Probability vs. Standard Deviation



The load uncertainty probability took into consideration stochastic temperature within the different areas in addition to recognizing the structural affects that holidays, weekends, quarters, and previous hour's load have on load expectations. Other sources of error that are reasonably independent of temperature are modeled, and are considered to be sufficiently small in magnitude.

Behind the meter generation is netted and modeled with customer load. If the behind the meter generation is not netted, then it will be modeled as regular generation. If the behind the meter generation was not tied to its own bus, then the capacity was divided between generation units that it was associated with in the power flow model.

Controllable Capacity Demand Response Modeling

SPP has controllable capacity demand in the form of Interruptible (Curtailable) demand. The areas that reported the controllable capacity demand had Thermal units modeled with high run costs so that it would run last to reflect demand response operating scenarios.

Capacity Modeling

Differences between assessment area and LTRA capacities consisted of the following: 1) Demand Response was modeled per Balancing Authority, as Thermal units to add to the total assessment area capacity. 2) Reserve sharing amounts (External reserves) were modeled as Thermal units which increased the total assessment area capacity. These values were not reported in the LTRA. 3) Behind-The-Meter generation that did not have a bus associated with it in the power flow model was subtracted from the peak load values for its respective area.

It is assumed that "Future, Planned" generation that is included in the LTRA is "firm and deliverable". Based on this assumption it is also assumed that the "Future, Planned" generation modeled in this assessment is "firm and deliverable" as well.

New generation units were added to the GridView model and put in service based on the commission date. The new thermal and hydro units were modeled with a max capacity based on the expected on-peak summer rating reported in the LTRA. New Hourly resource units were modeled with a max capacity based on the nameplate value. Only Existing, Certain and Future, Planned units that were within the study period were modeled based on the LTRA data.

Jointly owned units were modeled with the maximum capacity matching that of the value reported in the LTRA On-peak summer capacity rating. This rating is the amount that is owned by the individual area owner. Only the portion of capacity belonging to the area owner within the SPP RE footprint and Nebraska entities were modeled.

Sales external to the region were modeled as hourly resources with a flat value shape close to the border of the importing Balancing Authority, but within the exporting Balancing Authority and tied to the highest voltage tie-line bus. The hourly resources have a negative capacity. For DC ties, 2011 actual hourly values were used to generate the hourly shape. Sales between entities within the SPP RE footprint plus Nebraska entities were incorporated in the existing certain value of the LTRA and were modeled as Thermal or Hydro units based upon the type of unit committed to meet the transfer requirement. The internal limits are actual interface limits between Balancing Authorities in SPP and were provided by SPP operations.

Purchases from the external region were modeled as hourly resources with a flat value shape close to the border of the exporting Balancing Authority, but within the importing Balancing Authority and tied to the highest voltage tie-line bus. The hourly resources have a positive capacity. For DC ties, 2011 actual hourly values were used to generate the hourly shape. Purchases between entities within the SPP RE footprint plus Nebraska entities were incorporated in the existing certain value of the LTRA and were modeled as Thermal or Hydro units based upon the type of unit committed to meet the transfer requirement. The internal limits are actual interface limits between Balancing Authorities in SPP and were provided by SPP operations.

Wind generation was modeled as an hourly resource using the 2005 National Renewable Energy Laboratory (NREL) data as a reference for the wind shapes. The hourly wind shapes consist of 8760 hourly values for year 2014 and 8784 values for year 2016. The 2005 hourly wind shapes were imported into GridView to provide an accurate profile of the wind generation output for each hour in the year. A ratio of the shape peak to peak capacity reported in the LTRA was used as a multiplier to adjust the shape to the peak at the peak capacity reported in the LTRA.

The on-peak capacity ratings are developed by the SPP member's capability testing. The capability testing procedure and requirements are described in SPP Criteria section 12.1.1[57]

Forced outage modeling within GridView consists of using the Equivalent Forced Outage Rate – demand (EFORd) values provided from GADS. Due to this data constraint, the Forced outage modeling was done using the GADS EFORd data averaged from 2001 – 2011. An average of the EFORd value based on Fuel Code and Unit Type was used for units without GADS EFORd values. On a random basis, an unlimited number of units per trial can be removed from service for the entire trial.

Planned outages for thermal units were modeled by using the scheduled maintenance function in GridView to take units offline for a specified period of time based on start time, end time, and duration. Once the outage duration elapsed, the unit was placed back online in the model.

[57] http://www.spp.org/publications/SPP%20Criteria%20and%20Appendices%20Jan.%202012.pdf

Transmission

System Topology was drawn from the Model Development Working Group (MDWG) summer models for the 2014 and 2016 study years. Transmission additions and retirements were captured in the MDWG models that are built with the SPP member's input and modeling. Transmission additions were modeled and retirements were removed from the GridView models.

GridView allows importing of Transmission data from a PSS/E power flow model. For each study year (2014, 2016), separate MDWG models were imported to represent the latest representation of the SPP Transmission grid.

External interface limits for years 2014 and 2016 were the same even though the limits for 2016 should increase. A separate study has been performed that shows increased interface limits in 2014 and 2016, but an updated definition of the interfaces has not been approved to be released, therefore the existing limits were used. External interface limits are based upon the 2012 average reserve sharing amounts sourced from SPP operations.

The flowgates were modeled in conjunction with the SPP OPS OASIS Flowgate list. The flowgates considered "Permanent" were monitored in the study and are as follows: COOPER_S_MAPP, SPPSPSTIES, SPSNORTH_STH_SPP, and SPSSPPTIES_SPP. SPP Operations suggested these flowgates as valid interfaces that are monitored by the Real Time Response Factor Calculation (RTRFCALC) application.

SPP requested Transmission Availability Data System (TADS) data from NERC in order to build a transition rate table for random Transmission outages. The granularity of the data was insufficient to build the transition rate table and therefore random Transmission outages were not incorporated in the Monte Carlo simulations.

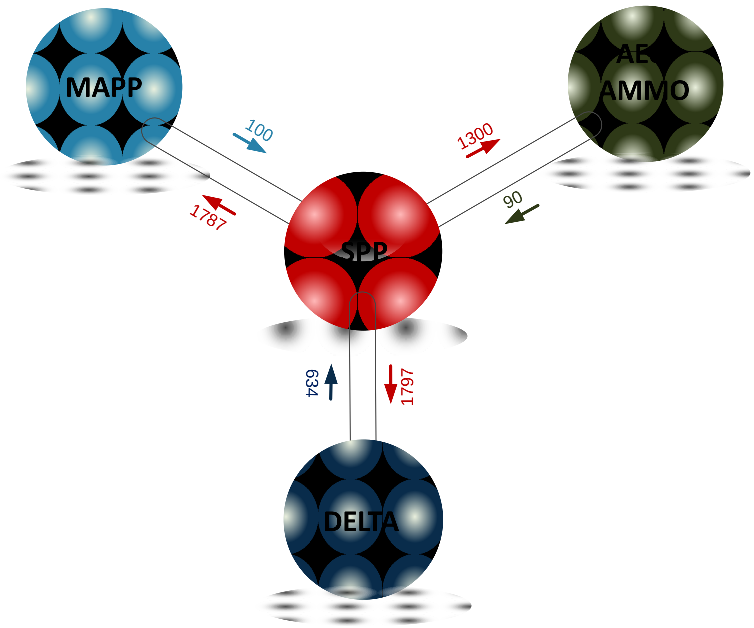
Assistance from External Resources

For this Probabilistic Assessment it is assumed that SPP does not rely on non-firm assistance from resources outside of the SPP RE footprint or Nebraska entities, consistent with the values contained in the LTRA report.

The SPP Operating Reserve Sharing program was instituted to provide both reliability and economic benefits to its members. This program reduces the amount of internal operating reserves each entity is required to maintain while providing an automated way of allocating resources on a region wide level to ensure quick recovery for the loss of any unit. Transmission facilities must be able to support the automatic implementation of the Reserve Sharing program. Transfer values below are average daily contingency reserve obligations. The transfer values (in red) from SPP to other companies are the sum of all companies transfer amounts minus the transfer amount from that company. These values are not the amounts that SPP reserves for each individual company. For example, Delta (Entergy subregion) can call upon 1300 MW from SPP, MISO, MAPP, AECI, and AMMO as a joint transfer. These values were used as limits on the interfaces between SPP and external companies.

A separate study was performed to calculate the First Contingency Total Transfer Capability (FCTTC). The FCTTC limits were not used due to high transfer levels that might influence the results of the LOLE study. The capability to import large quantities of power from neighboring regions can lower self-reliance results of a region to serve its native load in GridView and therefore it was assumed that SPP would use reserve sharing amounts to limit the imports from its neighbors. The FCTTC limit values are confidential and therefore not included in this report.

Figure 44: Reserve sharing availability in MW units



Definition of Loss-of-Load Event

A loss-of-load event, as defined in this Probabilistic Assessment, is any load that is not served, or load that is greater than generation after Operating Reserves are depleted.

WECC

Due to complication with the software used to perform the Monte Carlo simulations reported in the Probabilistic Assessment, WECC was not able to participate in the 2011 pilot study. For the 2012 assessment WECC was able to run the model and calculate the Expected Unserved Energy (EUE) and Loss of Load Hours (LOLH) as requested by NERC. However, WECC questions the results of these simulations and is working to resolve issues associated with the Probabilistic Assessment. Therefore, the 2012 Probabilistic Assessment results may not be indicative of future assessment results, or results of similar studies performed by WECC members.

Summary

The 37 Balancing Authorities[58] (BA) within WECC were modeled when creating the NERC Probabilistic Assessment. For purposes of this report, and the NERC Long-Term Reliability Assessment (LTRA), the BAs were aggregated into nine Assessment Areas[59].

Below are projected resources for the assessment. For this assessment the winter seasons occur in the same calendar year for the year shown (e.g., winter 2014 covers the first few months of 2014 for the winter season that began in the later months of 2013 and ended in early months of 2014).

Table 62: Seasonal Capacity Totals (MW)

Area	Season	Controllable Capacity Demand Response	Variable Resources (Expected)	Traditional Capacity (Expected)	External Sales (Exports)	External Purchases (Imports)	Total
WECC	S 2014	0	48,750	197,105	0	0	181,841
	W 2014	0	45,918	123,215	0	0	169,133
	S 2016	0	53,317	135,331	0	0	188,648
	W 2016	0	48,775	125,486	0	0	174,261
US	S 2014	0	38,679	119,334	74	0	157,939
	W 2014	0	33,622	107,890	0	1,106	142,618
	S 2016	0	42,062	119,392	1,298	0	160,156
	W 2016	0	35,256	108,472	0	823	144,551
CAN	S 2014	0	13,365	13,113	74	0	26,404
	W 2014	0	17,434	13,346	800	0	29,980

58 Balancing Authorities in WECC are: Alberta Electric System Operator, British Columbia Hydro and Power Authority, Avista Corporation, Bonneville Power Authority – Transmission, Tacoma Power, NaturEner Glacier Wind Energy, Northwestern Energy, Pacificorp – West, Portland General Electric Company, PUD No. 1 of Chelan County, PUD No. 2 of Grant County, PUD No. 1 of Douglas County, Puget Sound Energy, Seattle Department of Lighting, Western Area Power Administration – Upper Great Plains West, Idaho Power Company, Pacificorp – East, Sierra Pacific Power Company, Public Service Company of Colorado, Western Area Power Administration – Colorado-Missouri Region, Arizona Public Service Company, Arlington Valley, El Paso Electric Company, Gila River Maricopa Arizona, Griffith Energy, Harquahala Generating Maricopa Arizona, Nevada Power Company, Public Service Company of New Mexico, Salt River Project, Tucson Electric Power Company, Western Area Power Administration – Lower Colorado Region, California Independent System Operator, Balancing Authority of Northern California, Turlock Irrigation District, Imperial Irrigation District, Los Angeles Department of Water and Power, and Comision Federal de Electricidad.

59 Assessment Areas are: Alberta Electric System Operator (AB), British Columbia Hydro and Power Authority (BC), Pacific Northwest (NW), Northern California (NC), Southern California (SC), Rocky Mountain Area (RM), Basin Area (BN), Desert Southwest Area (SW), and Baja Mexico (MX).

Table 62: Seasonal Capacity Totals (MW)							
Area	Season	Controllable Capacity Demand Response	Variable Resources (Expected)	Traditional Capacity (Expected)	External Sales (Exports)	External Purchases (Imports)	Total
	S 2016	0	14,795	15,013	1,297	0	28,511
	W 2016	0	18,654	15,081	800	0	32,935
MX	S 2014	0	0	2,641	0	0	2,641
	W 2014	0	0	2,923	0	306	3,229
	S 2016	0	0	2,923	0	0	2,923
	W 2016	0	0	2,923	0	23	2,946
NW	S 2014	0	28,894	8,370	8,223	74	29,115
	W 2014	0	22,045	10,097	0	4,000	36,142
	S 2016	0	29,447	8,248	8,323	1,297	30,669
	W 2016	0	23,460	10,085	0	4,000	37,545
BN	S 2014	0	1,872	10,164	2,760	4,313	13,589
	W 2014	0	1,448	10,480	2,760	2,020	11,188
	S 2016	0	2,112	10,081	2,760	4,313	13,746
	W 2016	0	1,597	10,397	2,760	1,650	10,884
SW	S 2014	0	2,322	36,702	4,806	2,306	36,524
	W 2014	0	1,314	36,432	7,583	131	30,294
	S 2016	0	2,376	36,925	3,953	3,539	38,887
	W 2016	0	1,191	37,042	7,738	942	31,437
BC	S 2014	0	10,802	1,310	874	0	12,986
	W 2014	0	12,912	1,360	800	600	14,072
	S 2016	0	11,717	1,310	2,097	0	10,930
	W 2016	0	13,510	1,360	800	600	14,670
AB	S 2014	0	1,211	11,155	0	800	13,166
	W 2014	0	4,347	11,492	600	0	15,239
	S 2016	0	1,727	13,055	0	800	15,582
	W 2016	0	4,971	13,227	600	0	17,598
NC	S 2014	0	7,231	21,048	100	4,100	32,279
	W 2014	0	4,907	15,044	0	1,200	21,151
	S 2016	0	7,279	21,048	100	4,200	32,427
	W 2016	0	3,787	15,194	1,200	2,500	20,281
SC	S 2014	0	6,589	30,037	3,564	7,481	40,543
	W 2014	0	4,277	22,263	5,500	8,987	30,027
	S 2016	0	8,736	30,101	4,783	6,862	40,916
	W 2016	0	4,033	22,332	6,311	8,196	28,250
RM	S 2014	0	1,033	13,012	531	634	14,148
	W 2014	0	511	13,583	901	0	13,193
	S 2016	0	1,042	12,988	531	400	13,899
	W 2016	0	730	13,431	531	670	14,300

Both assessment years, 2014 and 2016, used a 50/50 Coincident peak seasonal demand for the Area's aggregated forecast, which is the same demand forecasts reported in the LTRA.

Table 63: Peak Seasonal Demand					
Area	Study Year	LTRA Peak Summer Demand (MW)	Simulated Peak Summer Demand (MW)	LTRA Peak Winter Demand (MW)	Simulated Peak Winter Demand (MW)
WECC	2014	152,907	152,772	136,843	136,722
	2016	160,110	159,957	140,882	140,747
US	2014	131,129	130,987	111,994	111,873
	2016	137,984	137,821	114,492	114,357
CAN	2014	20,010	20,058	23,725	23,784
	2016	21,348	21,349	25,229	25,230
MX	2014	2,260	2,260	1,532	1,532
	2016	2,374	2,374	1,610	1,610
NW	2014	24,694	24,601	30,577	30,462
	2016	25,270	25,165	31,148	31,019
BN	2014	14,144	14,113	11,215	11,190
	2016	14,765	14,734	11,721	11,697
SW	2014	27,847	27,847	18,380	18,380
	2016	28,679	28,679	19,117	19,117
BC	2014	8,684	8,684	11,738	11,738
	2016	8,913	8,913	12,050	12,050
AB	2014	11,548	11,549	12,162	12,163
	2016	12,642	12,643	13,382	13,383
NC	2014	26,972	26,972	18,977	18,977
	2016	27,904	27,904	19,498	19,498
SC	2014	31,896	31,896	23,753	23,753
	2016	32,821	32,821	24,332	24,332
RM	2014	12,107	12,107	9,978	9,978
	2016	12,563	12,563	10,486	10,486

Software Model Description

WECC used the computing tool PROMOD IV (PROMOD), an ABB/Ventyx program, to calculate the reliability indices reported in this assessment. PROMOD uses a sequential Monte Carlo simulation technique to calculate the resource adequacy across the multiple Areas. Generation units and hourly load profiles are assigned to each area, along with transmission limits between the various Areas zones. PROMOD performs a chronological hourly simulation of the Areas that compares the hourly load in each area with the in-area thermal generation, adjusted for random outages, energy from hydro, wind, and solar resources, and feasible transfers between Areas zones. Multiple studies were performed by varying hourly demand and generation forced outage rates.

PROMOD has an algorithm that reduces the number of hours included in the metric calculation that can be used to reduce the run time of the Monte Carlo simulations, however, this functionality was not used to perform the Probabilistic assessment.

Table 64: Net Energy for Load and Metrics					
Area	Study Year	LTRA reported NEL (GWh)	Simulated NEL (GWh)	Expected Unserved Energy (MWh)	Loss of Load Hours (H/Y)
WECC	2014	913,841	913,036	0.00	0.00
	2016	946,314	945,407	0.00	0.00
US	2014	750,432	749,622	0.00	0.00
	2016	772,063	771,150	0.00	0.00
CAN	2014	151,156	151,520	0.00	0.00
	2016	161,956	161,961	0.00	0.00
MX	2014	11,893	11,894	0.00	0.00
	2016	12,295	12,296	0.00	0.00
NW	2014	175,372	174,715	0.00	0.00
	2016	179,164	178,423	0.00	0.00
BN	2014	78,444	78,271	0.00	0.00
	2016	82,552	82,381	0.00	0.00
SW	2014	136,787	136,787	0.00	0.00
	2016	141,565	141,565	0.00	0.00
BC	2014	64,551	64,551	0.00	0.00
	2016	66,620	66,620	0.00	0.00
AB	2014	86,965	86,969	0.00	0.00
	2016	95,336	95,341	0.00	0.00
NC	2014	129,092	129,092	0.00	0.00
	2016	131,704	131,704	0.00	0.00
SC	2014	163,995	163,995	0.00	0.00
	2016	167,729	167,729	0.00	0.00
RM	2014	66,762	66,762	0.00	0.00
	2016	69,349	69,349	0.00	0.00

Demand Modeling

The load used in this assessment was developed using BA historical hourly load shapes that are averaged and scaled by BA-level peak demand and energy load forecasts. The BA-level peak demand and energy load forecasts are based on assumed average weather and expected economic conditions. The load shapes used in the assessment are the same as those reported in the LTRA.

All loads are contained within the geographic boundary of the Area and are not accounted elsewhere by any other reporting Area. 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 Areas.

PROMOD determines the hourly load forecast based on user defined monthly peak and overall annual energy levels for each BA. Load forecast uncertainty is then created in PROMOD using a Monte Carlo function where the user defined inputs are subject to a standard deviation of plus or minus 10 percent for the monthly peak and plus or minus 4 percent for the annual energy. A Monte Carlo function applies a number scale to a deviation range and then draws a random number for each probabilistic iteration. Depending on what two numbers are drawn, one for the peak and one for the annual energy, PROMOD varies the user defined data by the corresponding place on the deviation range.

Controllable Capacity Demand Response (CCDR) Modeling

WECC has historically treated Controllable Capacity Demand Response (CCDR) as a load modifier (e.g., demand reduction). For the purposes of this assessment CCDR was added to the total demand and was included as load when calculating un-served energy. WECC is developing a procedure to include CCDR in future studies, but for the current assessment CCDR was not counted as either a resource or as a reduction to demand.

Capacity Modeling

Resources classified in the LTRA as Existing-Certain, Existing-Other, Future-Planned, and Future-Other, are included in this assessment and are the same resources, including additions and retirements that are included in the LTRA. All generation resources, in all classifications, are considered "firm and deliverable" because the assessment model assumes that all generation is deliverable to all demand within the WECC Area zones. There are no jointly-owned units within WECC that share capacity with another Area outside of the western interconnection, and no imports or exports from other Areas are counted in this assessment.

Intermittent or energy-limited resources, such as wind, solar and hydro, are modeled in this assessment as they are modeled in the LTRA[60]. Hydro generation is constrained by annual energy limits that are based on actual energy production from 2003 for Northwest hydro generation and from 2002 for California hydro generation. These two years were selected by WECC's Transmission Expansion Planning Policy Committee (TEPPC) Data Work Group as low water years that would best reflect adverse hydro conditions.

Wind generation is modeled using at least five years of actual hourly wind generation data. The data is averaged into six four-hour blocks for each week of the year. Solar generation is modeled using up to five years of actual hourly solar generation data. The data is averaged into three block curves (morning, daylight, and evening) for each week of the year.

All traditional dispatchable generation was modeled as capacity that is available to serve load. Summer and winter unit ratings were based upon BA reported capacities that are expected to be available during forecasted system seasonal peaks.

Forced outage rates and duration of the outages are applied on a generator type basis. For generator maintenance, each generator type is assigned an annual maintenance rate in weeks. The rate is between one to five weeks and considers the type of unit and cyclical nature of major and minor maintenance over multiple years. Since maintenance in any given year changes frequently and is subject to forced outages and other planned and non-planned events, the maintenance schedule is normalized to an annual rate reflective of a typical year.

Transmission

The assessment model assumes that all generation is deliverable within the WECC Area zones, with limited transmission between the zones. The same transmission treatment including limits, configurations, additions, and retirements are used in the LTRA.[61]

Although the forced outage rates of transmission lines were not modeled during this assessment, regional transmission assessments indicate that transmission capability within WECC is expected to be, and has shown to be, adequate to supply customer demand. It is anticipated that existing operational procedures and pre-planning will be used to adequately

[60] Treatment of Intermittent resources is detailed in the LTRA Attachment II: Methods and Assumptions.
[61] More detailed transmission information is contained in the LTRA Attachment II: Methods and Assumptions.

manage and mitigate any potential impacts to the bulk transmission system arising from unplanned outages of transmission facilities or generating units within WECC.

Assistance from External Resources

WECC does not use or model resources outside of the western interconnection when performing the Probabilistic, or any other reliability assessment.

Definition of Loss-of-Load Event

A Loss-of-Load Event (e.g., Occurrence) would be a single instance where demand exceeds available capacity, after all reserves and emergency procedures have been used.