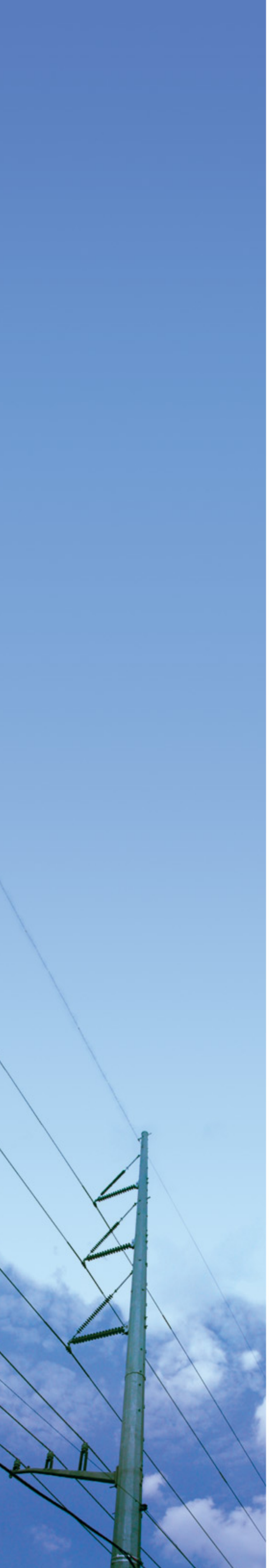

2010 Loss of Load Expectation Report

PUBLISHED: 10/01/2010
LATEST REVISION: 10/08/2010

SPP Southwest Power Pool

Table of Contents

Introduction

SPP Criteria 4.3.5 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 (2.0) 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."

Though criteria requires SPP to conduct LOLE studies on a biennial basis, SPP plans to conduct LOLE assessments on an annual basis, rotating between near-term and long-term assessments each year.

The Loss of Load Expectation (LOLE) study investigates the expected number of days per year for which available generating capacity is insufficient to serve the daily peak demand. The LOLE is usually measured in days/year or hours/year. The convention is that when given in days/year, it represents a comparison between daily peak values and available generation. When given in hours/year, it represents a comparison of hourly load to available generation. LOLE is sometimes referred to as loss of load probability (LOLP), where LOLP is the proportion (probability) of days per year, hours per year, or events per season that available generating capacity/energy is insufficient to serve the daily peak or hourly demand. This analysis is generally performed for several years into the future and the typical standard metric is the loss of load probability of one day in ten years or 0.1 day/year. LOLE is a DC power flow study, so it does not address voltage or stability issues.

Objective

The LOLE study has two purposes. First, this study provides an assessment of whether currently installed generation capacity is adequate to serve the forecasted load, given a set of random generator outages. Second, this study will assess whether the capacity margin requirement of 12% is adequate to maintain an LOLE of 1 day in 10 years.

Background

SPP performed a LOLE study in 2008 specifically for the SPS area. The following suggestions were made in the conclusion of the report for near-term reliability support:

- Build a new 345 kV transmission line from Woodward to Tuco
- Increase the SPP-SPS flowgate limit to 1,134 MW
- Add new generation resources in SPS area

These conclusions are addressed in this study. Specific assumptions in the SPS area were made as discussed in later sections.

Study Assumptions

Study year:	2016
Powerflow base:	2010 MDWG 2016 Summer Peak
Transmission projects:	Board of Directors-approved 2009 STEP Appendix B projects through 2016, Balanced Portfolio, 2010 Priority Projects
Forced Outage Rate:	Based on GADS data, updated with ITP20 PROMOD data
Peak Demand:	52,460 MW (Summer Peak)
Installed Capacity:	65,612 MW (Capacity of all generators in SPP in the PROMOD model excluding wind) 69,274 MW (Capacity of all generators in SPP in the PROMOD model including wind)

Data discussion

Production-cost models such as GridView require many different and detailed data inputs. Presented below is a discussion of the sources of data to be used for this study.

Topology

The study case uses the topology from the MDWG 2016 Summer Peak model as a base. In addition, the Board of Directors-approved 2009 STEP Appendix B projects through 2016 and the Priority Projects will be added to the model. In order to investigate the impact of the Priority Projects on the LOLE, a separate simulation of the base case without the Priority Projects was run.

Load

The study case uses the peak loads of each SPP area from current PROMOD data. ABB has provided load shapes for individual areas which have been adjusted with the PROMOD peak loads.

Generation

ABB provides the base generator data based upon generic data. The ABB data within SPP were updated with the Generation Capacity, Forced Outage Rate, Outage Duration, Fuel Price, Maintenance, Minimum Up Time and Minimum Down Time from current PROMOD data.

Wind

The model includes all wind generation currently installed (approximately 4 GW of nameplate capacity). Hourly wind generation is based upon historical profiles for 2009. The Monte Carlo analysis adjusts the historical profiles randomly with a 10% uncertainty factor. Uniform distribution is used, and wind generation varies within 10% of the forecast with equal probability. For example, the variation of a 100 MW wind generator is 10 MW. If the historical hourly profile at a certain hour is 30 MW, the adjusted wind generation may vary between 20 MW and 40 MW.

Constraints

A selected number of transmission constraints are selected for the model. These constraints are derived from the current PROMOD event file, current Book of Flowgates and current market constraints. The number of transmission constraints needs to be kept to a small number in order to minimize run-time. The penalty of violating any constraint is $1,000/MWh while the load shedding penalty is $800/MWh. Therefore, the system tends to shed load before violating any transmission constraint. The penalty cost is the same as in the 2008 study.

Monte Carlo Simulation

SPP conducts the Monte Carlo Simulation with at least 50 draws, in which a maximum of five generators in SPP may be forced out of service at the same hour of study. The draws account for variations in forced generator outages and wind output. Each trial represents a single 8784-hour[1] simulation. The stop criteria for the Monte Carlo simulation is to make the standard deviation of LOLE less than or equal to a threshold, i.e., 0.05. GridView calculates standard deviations to determine whether more simulation is needed. This software provides a chart to illustrate the convergence of the Monte Carlo simulation. The program can model detailed transmission and generation limitations, simplification of transmission constraints and generation models helps to reduce the run-time as well.

Flowgate Assumptions

In response to the suggestions in the 2008 study, the following flowgate assumption is made in the SPS area in this study:

- SPP-SPS Interface Limits: 1,140 MW
- SPS North-South Limit: 800 MW

The changes in import limits for this study were made based on the addition of the Tuco-Woodward 345 kV.[2] In the 2008 study, the following assumption was made:

- SPP-SPS Interface Limits: 1,027 MW
- SPS North-South Limit: 800 MW

[1] The year of 2016 is a leap year, so the total number of hours is 8,784 instead of 8,760.

[2] The adjusted SPP-SPS interface limit assumption does not reflect the actual power flow limit after the addition of the Tuco-Woodward and Woodward-Hitchland lines.

Study Process

As part of the study process, several different cases (or scenarios) were run. These different cases were run to evaluate whether the system meets the LOLE requirement of 1 day in 10 years under various system conditions. The cases are further described below.

In Case 1, the Priority Projects are included in the base case model, and the capacity margin is 20%. The LOLE is 0 hour/year, which meets the standard of 1 day in 10 years.

In Case 2, the capacity margin is decreased to 12% as a sensitivity to determine whether LOLE is within target at the required capacity margin for the SPP region. To decrease the capacity margin, the load is increased in each SPP area proportionally by 10%. The peak load is increased from 52,460 MW to 57,706 MW. The LOLE is 0.3 hour/year, which still meets the standard of 1 day in 10 years, or 2.4 hours/year.

In Case 3, the capacity margin is decreased to the point where the LOLE is about 2.4 hours/year, as a sensitivity to determine at what capacity margin the system would reach the target LOLE of 1 day in 10 years. The load in each SPP area is increased proportionally until the calculated LOLE is about 2.4 hours/year. To achieve an LOLE of 2.4 hours/year, the load is increased by 13.5% from 52,460 MW to 59,540 MW, and the LOLE is 2.5 hours/year. The capacity margin is 9.25%, which is lower than the 12% requirement.

In Case 4, Case 1 is used as the base, and the Priority Projects are removed from the base case model. The capacity margin remains at 20%. This sensitivity was run to determine the impact of the Priority Projects on the LOLE. The LOLE is 0.28 hour/year, which still meets the standard of 1 day in 10 years.

When unserved load was observed in Case 2, 3 and 4, that unserved load was in the SPS area.

The figures below illustrate the results of the Monte Carlo simulations that GridView performs. The horizontal axis is the number of trials (or simulations), and the vertical axis is the Expected Energy Not Served (EENS) in MWh/year on the top graph, and the Loss of Load Expectation in Hours/year on the bottom. The resulting LOLE is taken from the tail of the graph where the LOLE begins to converge towards a single value.

Figure 5 shows the graphical interpretation of the above cases. The blue curve refers to Case 1 to 3. The red curve refers to Case 4. In Case 1, the base case with Priority Projects is studied. The LOLE is 0 hour/year. In Case 2, as the load is increased, the capacity margin is decreased. The LOLE increases. In Case 3, as the load is further increased, the LOLE increases further to the threshold of 2.4 hours/year. In Case 4, Priority Projects are not included, and the LOLE of the system increases. The blue curve shifts to the left to become the red curve, and a non-zero LOLE is obtained for the base case

Results

Case 1: LOLE Study with 2016 forecasted peak load

- Peak Load = 52,460 MW
- Number of Iteration = 50
- Expected Energy Not Served (EENS) = 0 MWh/year
- LOLE = 0 hour/year
- Capacity margin = 20%
- This is a base case study with Priority Projects included.

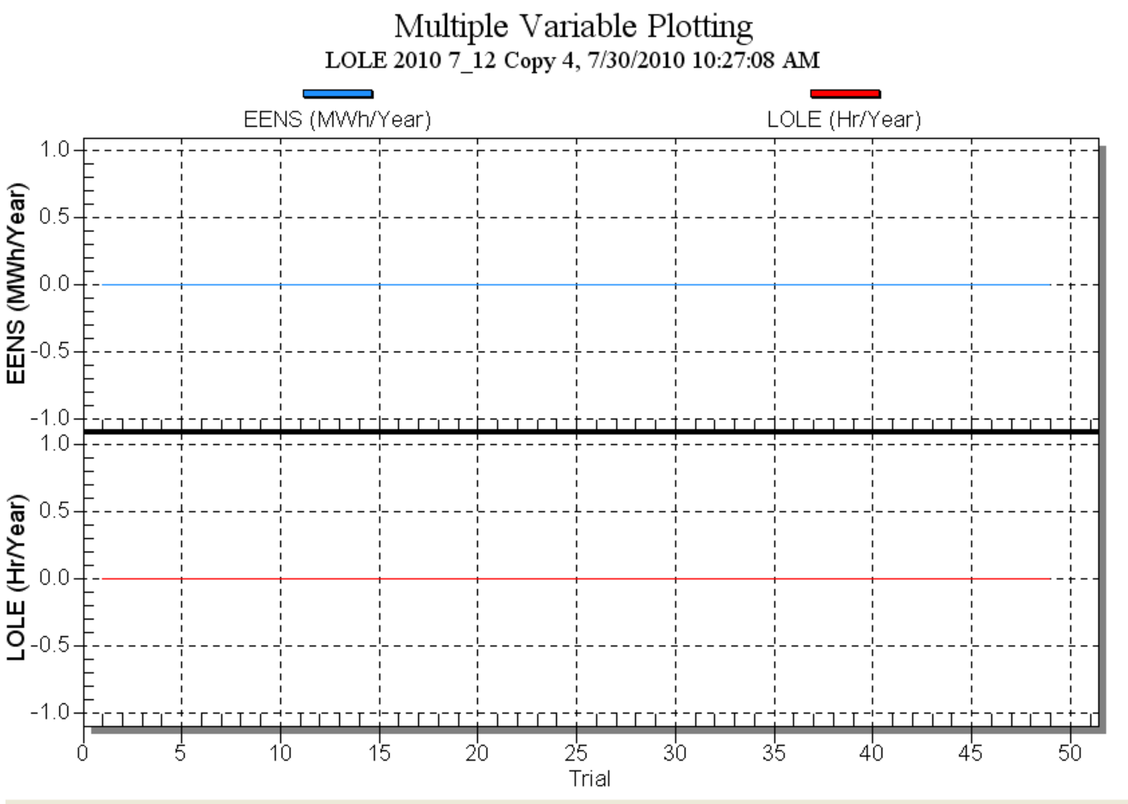

Figure 1: LOLE and EENS for Case 1

Case 2: LOLE Study with 12% capacity margin by increasing load

- Peak Load = 57,706 MW
- Number of Iteration = 500
- Expected Energy Not Served (EENS) = 40 MWh/year
- LOLE = 0.3 hour/year
- Capacity margin = 12%.

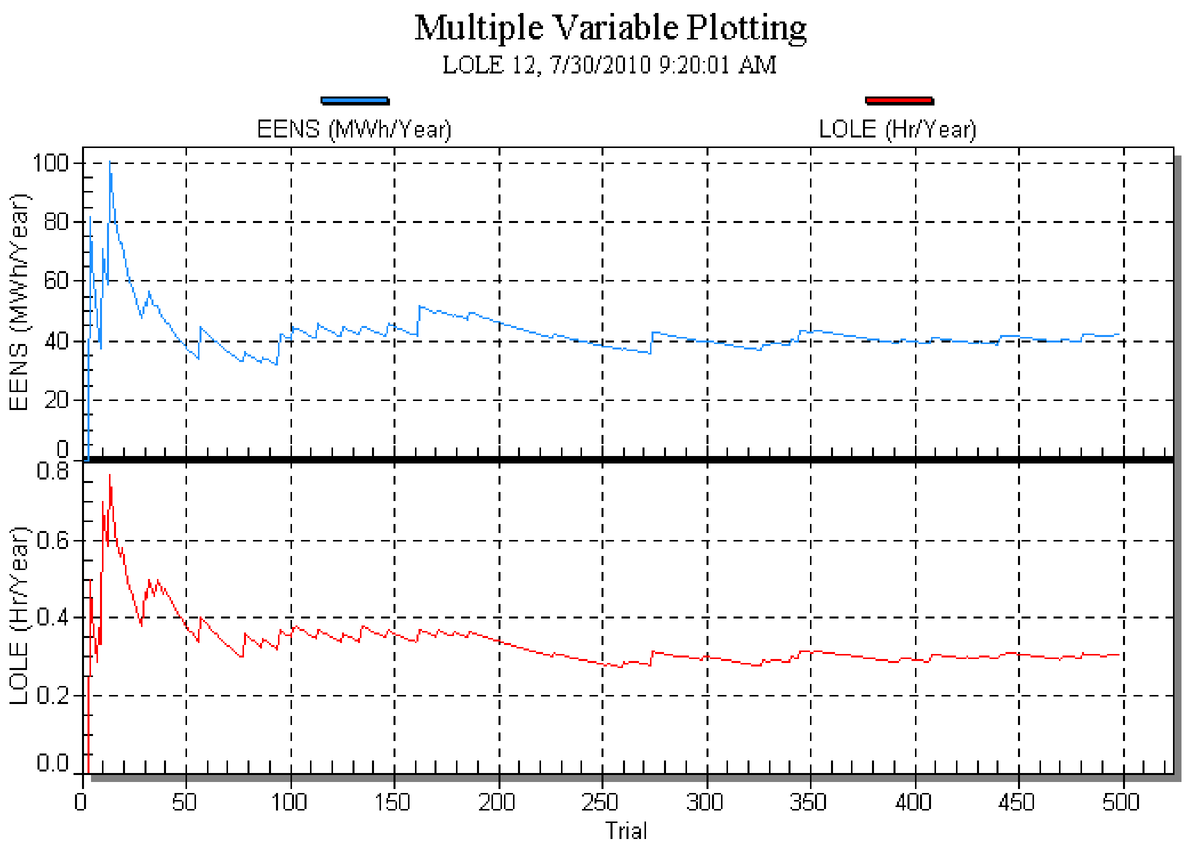

Figure 2: LOLE and EENS for Case 2

Case 3: LOLE Study with 2.4 hours/year by increasing load

- Peak Load = 59,540 MW
- Number of Iteration = 500
- Expected Energy Not Served (EENS) = 450 MWh/year
- LOLE = 2.5 hour/year
- Capacity margin = 9.25%

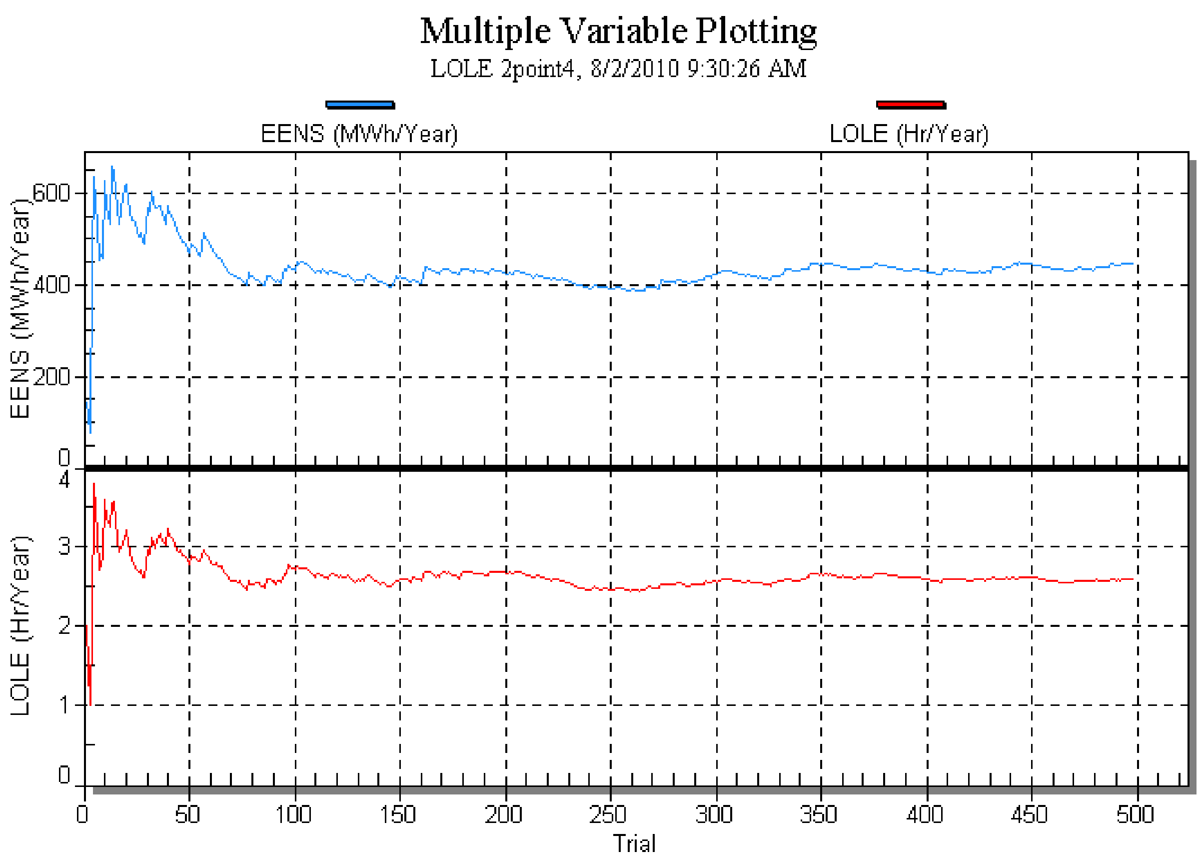

Figure 3: LOLE and EENS for Case 3

Case 4: LOLE Study with 2016 forecasted peak load excluding Priority Projects

- Peak Load = 52,460 MW
- Number of Iteration = 2,000
- Expected Energy Not Served (EENS) = 31 MWh/year
- LOLE = 0.28 hour/year
- Capacity margin = 20%

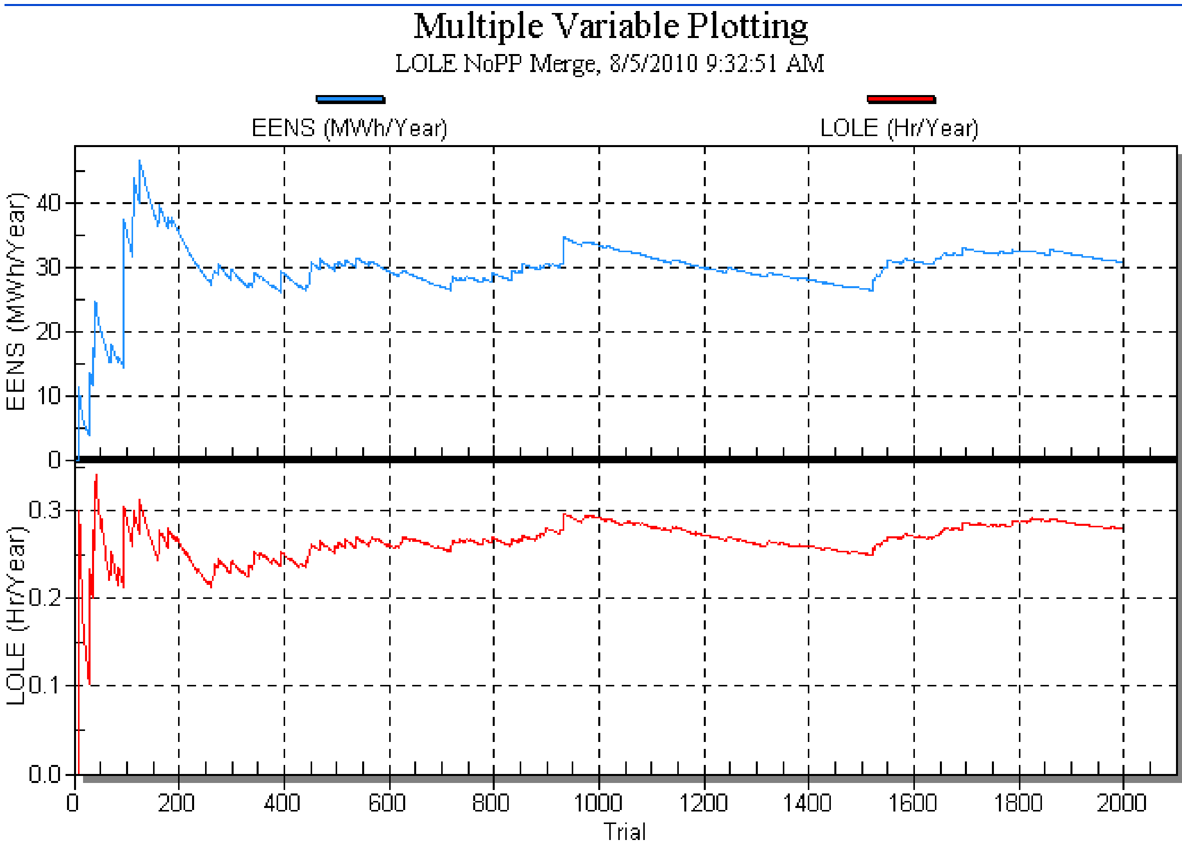

Figure 4: LOLE and EENS before the inclusion of Priority Project in Case 4

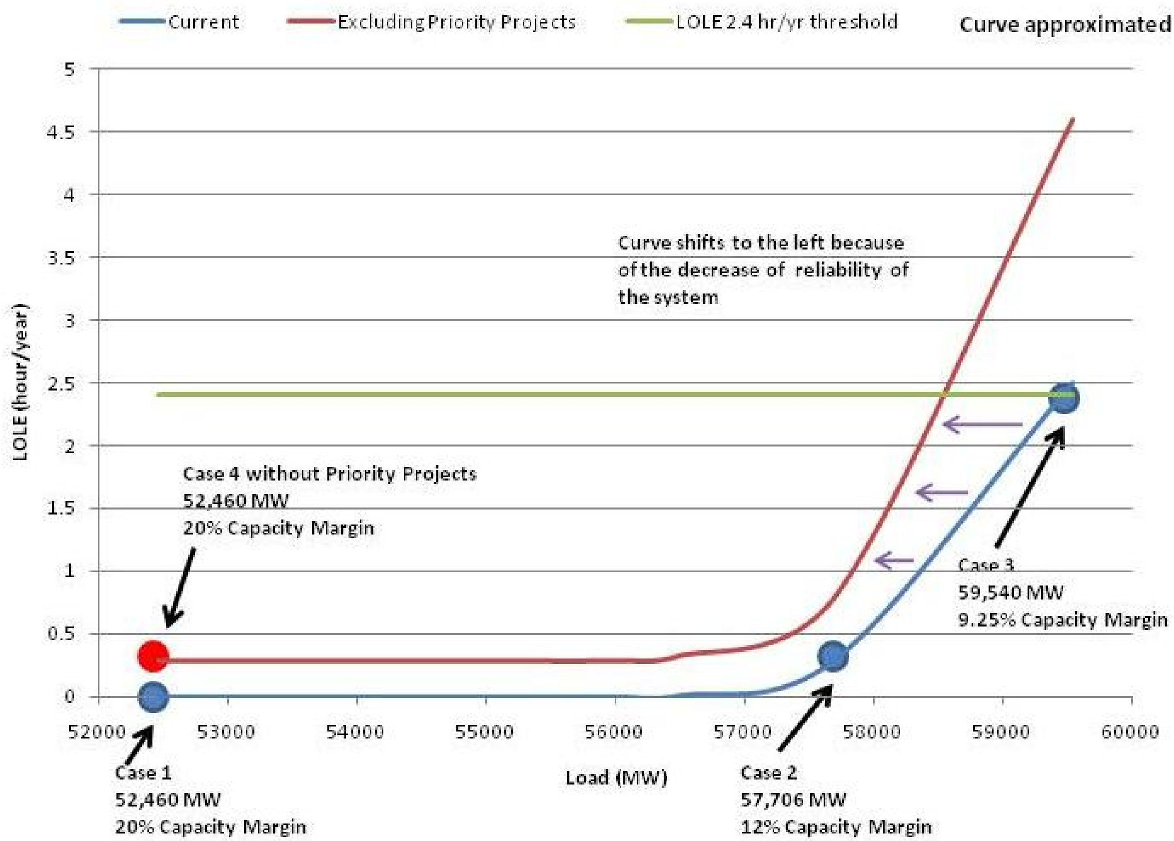

Figure 5: Graphical Interpretation for the above cases (LOLE versus Load), the curve is only approximated from the measurements in the 4 cases

Conclusion

Based on the results of this study, the SPP region does not need any additional reliability support. The LOLE is zero after the inclusion of Priority Projects, and the LOLE standard of one day in ten years is maintained with a capacity margin of 9.25%[3], which is below the SPP requirement of 12%.

The reliability of the system increases due to the implementation of the suggestions in the 2008 study. The LOLE of the system is about 0.28 hour/year before the inclusion of Priority Projects. All unserved load in the SPS area is caused by congestion on the SPP-SPS Interface.

In the 2008 LOLE study, three suggestions were made to improve the reliability of the system in the near-term. Those suggestions were:

- Build a new 345 kV transmission line from Woodward to Tuco
- Increase the SPP-SPS flowgate limit to 1,134 MW
- Add new generation resources in SPS area

The Woodward-Tuco 345 kV line was approved as part of the Balanced Portfolio and is included in the base case models for this study. Due to the addition of this line, the SPP-SPS Interface limit is increased from 1,027 MW to 1,140 MW, for the purpose of this study. The increase in the SPP-SPS interface limit contributes to a reduction in congestion of the SPP-SPS interface. The addition of the Hitchland-Woodward 345 kV line from the Priority Projects significantly reduces congestion on the SPP-SPS interface as well.

The Jones 3 generator and additional wind farms including the Antelope are added to the base case. Additional resources in the SPS area also contribute to a reduction in imports across the SPP-SPS interface. This reduction also contributes to a decrease in LOLE.

The results of this study confirm the results of the 2008 study. The 2008 study identified additional reinforcements in the SPS area that would be necessary to decrease the probability of lost load. All of those suggestions have been incorporated into this study, and the results show that additional transmission and generation capacity in the SPS region contributes to reducing the LOLE to zero under forecasted conditions in 2016.

Recommendation

Based on the results on this report, it is not recommended to change the SPP capacity margin requirement of 12%, due to the fact that this assessment is focused on future conditions. The next near-term LOLE assessment may provide a better basis for assessing the capacity margin requirement for the SPP system.

[3] The capacity margin calculation is based on the assumption of 0% capacity credit for wind farms. If a 5% capacity credit were considered, the capacity margin would be 9.51%

Appendix

These are the model areas that were included in these studies:

AEPW	American Electric Power System
CELE	Central Louisiana Electric Company, Incorporated
EMDE	Empire District Electric Company
GRDA	Grand River Dam Authority
INDN	City Power & Light, Independence, Missouri
KACP	Board of Public Utilities, Kansas City, KS
KCPL	Kansas City Power and Light Company
LAFA	City of Lafayette
LEPA	Louisiana Energy & Power Authority
LES	Lincoln Electric System
MIDW	Midwest Energy, Incorporated
MIPU	Missouri Public Service Company
MKEC	Mid-Kansas Electric Company
NPPD	Nebraska Public Power District
OKGE	Oklahoma Gas and Electric Company
OMPA	Oklahoma Municipal Power Authority
OPPD	Omaha Public Power District
SPRM	City Utilities, Springfield, Missouri
SPS	Southwestern Public Service Company
SUNC	Sunflower Electric Cooperative
SWPA	Southwestern Power Administration
WERE	Westar Energy, Incorporated
WFEC	Western Farmers Electric Cooperative