2017 Loss of Load Expectation Scope

Resource Adequacy

Southwest Power Pool

Revision History

Date or Version Number	Author	Change Description	Comments
1/17/2017	SPP Staff	Initial Draft	
4/20/2017	SPP Staff	Inserted clarification language, inserted Additional Sensitivities section, and removed Items to Consider section	
7/12/2017	SPP Staff	Inserted additional sensitivity analysis	
7/27/2017	SPP Staff and SAWG	Updated language	SAWG approved the updates

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Introduction

Attachment AA of the SPP Open Access Transmission Tariff (OATT) states SPP shall perform a biennial Loss of Load Expectation (LOLE) study, which investigates the expected number of days per year of available generating capacity to serve forecasted Peak Demand. The LOLE is usually measured in days/year or hours/year. The understanding is that when given in days/year, it represents a comparison between daily peak values and installed capacity. This study will be performed biennially based upon the typical industry standard metric, which is the loss of load probability of one day in ten years or 0.1 day/year. LOLE studies are resource adequacy assessments that are performed with a DC powerflow analysis.

The current SPP Planning Reserve Margin (PRM) is twelve percent (12%). If a modeled area's capacity mix is comprised of at least seventy-five percent (75%) hydro-based generation, then such entity's PRM shall be nine point eight nine percent (9.89%). Any change to the PRM will be filed with the Federal Energy Regulatory Commission (FERC).

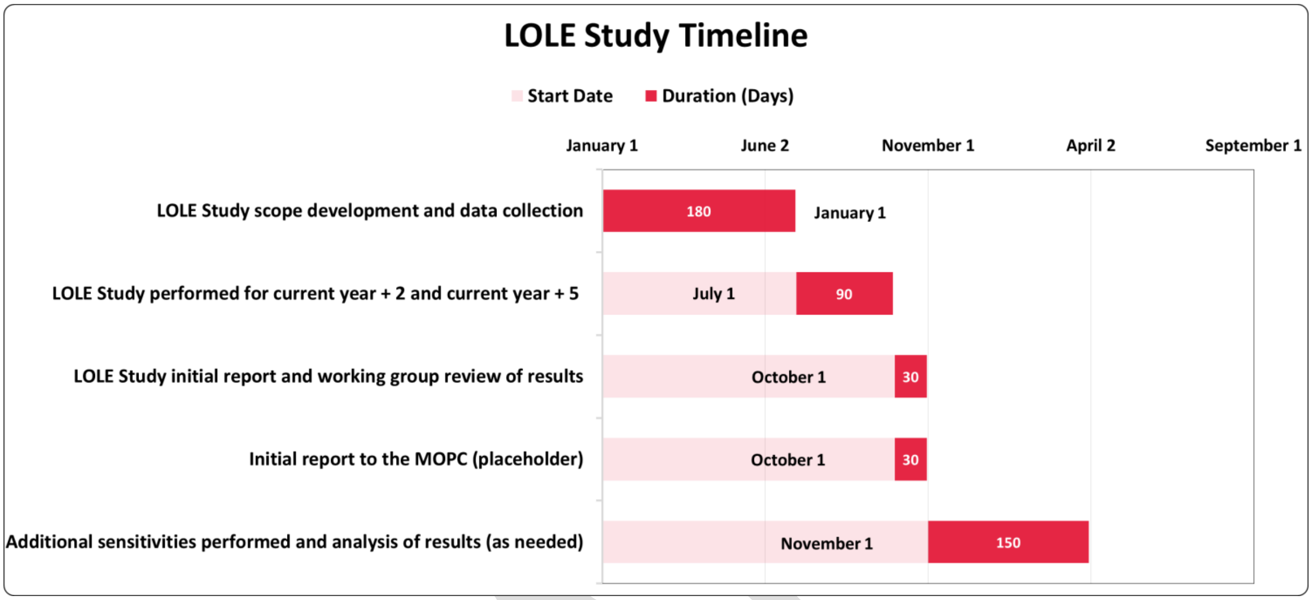
Executive Overview

Determination of the PRM will be supported by a probabilistic LOLE Study, which will analyze the ability to reliably serve the SPP Balancing Authority Area's forecasted Peak Demand while utilizing a Security Constrained Economic Dispatch. SPP, with input from the stakeholders, will develop the inputs and assumptions to be used for the LOLE Study. SPP will study the PRM such that the LOLE for the applicable planning year does not exceed one (1) day in ten (10) years, or 0.1 day per year. At a minimum, the PRM will be determined using probabilistic methods by altering capacity through the application of generator forced outages and forecasted demand through the application of load uncertainty to ensure the LOLE does not exceed 0.1 day per year. Final metric results will be compiled into a report and presented to the Supply Adequacy Working Group.

Objective

The LOLE study provides an assessment of whether installed and proposed capacity is adequate to serve the forecasted Peak Demand while determining an appropriate PRM to maintain an LOLE of 1 day in 10 years.

Study Timeline



LOLE Study Timeline

1. LOLE Study scope development and data collection
2. LOLE Study performed for current year + 2 and current year + 5
3. LOLE Study initial report and working group review of results
4. Initial report presented to MOPC (placeholder)
5. Additional sensitivities performed and analysis of results (as needed)

Process Steps

Step 1: Create and finalize scope
Step 2: Gather input data
Step 3: Model data and assumptions
Step 4: Run simulations
Step 5: Evaluate results
Step 6: Compile results into a report
Step 7: Present to stakeholders for review and approval

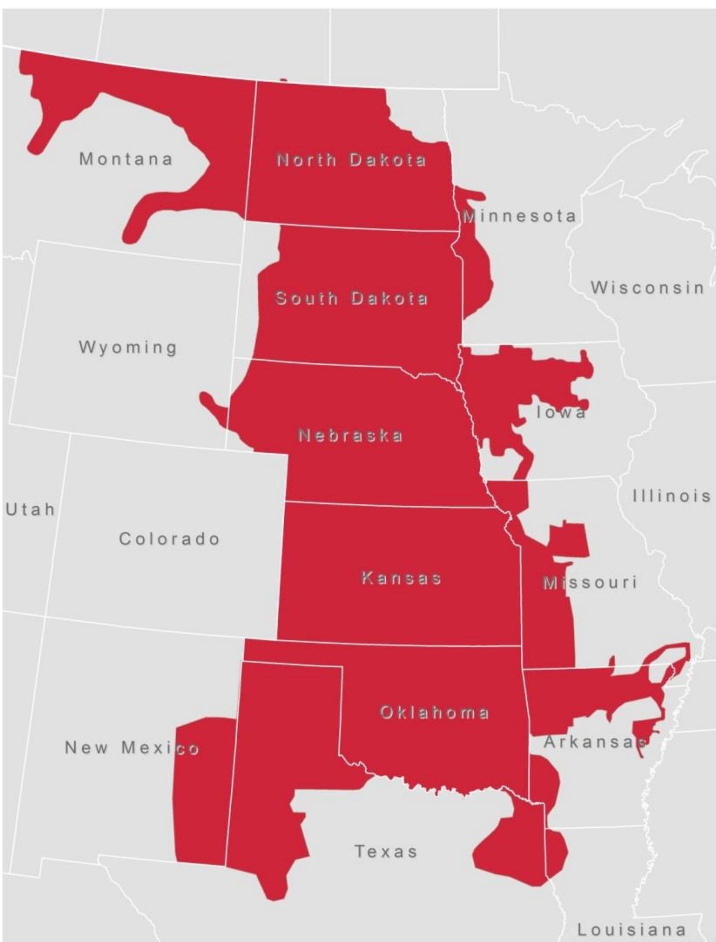
Input Data

Software

GridView will be the resource adequacy software used for the 2017 LOLE Study. GridView is a production-cost software, which performs a Security Constrained Economic Dispatch while utilizing a Monte-Carlo algorithm when varying the uncertainty of load and availability of capacity through multiple simulations.

Area Modeling

The LOLE Study is performed on the SPP Balancing Authority Area footprint, which includes all or parts of Arkansas, Kansas, Louisiana, Missouri, New Mexico, Nebraska, Oklahoma, Texas, Iowa, Minnesota, Montana, North Dakota, and South Dakota. Each modeled area will be modelled as a separate area to reflect the diversity of Load Forecast Uncertainty (LFU) factors and adjust each area's demand to a testing reserve margin.



Base Models and Topology

The 2017 LOLE Study will utilize the system topology from the 2017 series Integrated Transmission Planning Near-Term (ITPNT) summer peak models for the 2019 and 2022 study years. Transmission additions and retirements are captured in the ITPNT models with SPP member input from the ITPNT process[1].

Hourly Load Profiles

Historical hourly load data from 2014 will be used to produce an 8,760 hourly load profile for each modeled area. The historical data is obtained through SPP operational data. FERC 714 filings will be used to complete any missing or abnormal data for each profile.

Generation Modeling

Generation data includes the following: Generation capacity, Forced Outage Rates, outage duration, maintenance schedules, and jointly owned resource information from data obtained through Astrape, modelling parameters in the Integrated Transmission Planning Near-Term process, or data sourced from the Resource Adequacy Workbook.

Ratings

The maximum capacity ratings will be based on the modeled PMAX in the 2017 ITP planning model as developed by the SPP member's capability testing and verified against the values submitted in the Resource Adequacy Workbook. The capability testing procedure and requirements are described in SPP Planning Criteria section 7.1[2].

Resource forced outage and economic modeling

Forced outage modeling and economic parameters will consist of using the Equivalent Forced Outage Rate – demand (EFORd) values, forced outage durations, scheduled maintenance, and economic parameters provided by Astrape. Astrape derives outage-modeling parameters by using data from the NERC Generating Availability Data Systems (GADS).

Simulation parameters for random forced outages in GridView are to be compared to historical forced outages. The maximum number of outages per hour and number of new outages per hour parameters will be established through the analysis of historical outages.

Planned outage modeling

Planned outages for thermal resources are modeled using the scheduled maintenance function in GridView by switching the status of each resource to "off-line" for a specified period of time based on start time and duration. Once the outage duration has elapsed, the resource is placed back online in the model. Previous planned outages will be taken into consideration when modeling the maintenance window for each resource and sourced from Control Room

[1] Link to the latest ITPNT process scope and ITP Manual: https://www.spp.org/engineering/transmission-planning/
[2] https://www.spp.org/documents/33003/spp%20effective%202016%20planning%20criteria%201.pdf

Operations Window (CROW) software SPP members use to plan maintenance outages. GridView determines the best time to force a maintenance outage based upon a set seasonal timeframe window.

Behind-the-meter generation

Behind-the-meter generation is generally netted and modeled with Peak Demand. If the behind-the-meter generation is not netted in the Resource Adequacy Workbook submissions and modeled as generation in the ITPNT models, then it will be modeled as generation for the LOLE study.

Wind Modeling

The model includes all wind resources currently installed or proposed to be in-service in the SPP Balancing Authority Area footprint with an hourly wind generation profile assigned to each resource. Hourly wind generation is based upon historical profiles from 2014, which are obtained through SPP Operations. The wind shape is separate from the calculated accreditation value based upon current SPP Criteria 12.1.5.3 section G. The accredited value will be used when calculating the testing reserve margin for demand adjustments.

Constraints and Monitored Elements

Internal and crossing interfaces and flowgates for years 2019 and 2022 are to be implemented using the latest SPP OASIS list flowgates and interfaces. Interfaces are key groups of transmission lines that are observed as one group between Balancing Authority regions or internal areas.

The penalty of violating any constraint is $6,000/MWh while the load shedding penalty is $2000/MWh. Therefore, the system will shed load before violating any transmission constraint. Not only are specific constraints monitored, specific groups of ties between regions and every branch 100 kV and above within the SPP region is monitored as well.

DC Tie and External Capacity Modeling

DC tie and external capacity transactions that are supported by firm commitments will be modeled as hourly generators at the point of interconnection to SPP. They are initially dispatched at the committed firm capacity amount and have a max capacity value equivalent to the amount reserved for firm transmission service. The transactions used for both study years are obtained through the Resource Adequacy Workbook submissions and verified against transactions used in the SPP ITPNT planning process.

If the sale or purchase of capacity is between a SPP area and an outside entity, a generator is placed on the SPP entity's swing bus for the amount of the transaction. If the transaction is a sale to the outside entity, there would be an export of capacity. If the transaction is a purchase, there would be an import of capacity.

Demand Response Modeling

In areas that reported controllable-capacity demand through the Resource Adequacy Workbook, equivalent thermal resources were added to the model with high fuel costs, so those resources would be dispatched last to reflect demand response operating scenarios.

Modeling Load Forecast Uncertainty

Method

GridView allows for two options in dealing with demand uncertainty: 1) User defined uncertainty pattern, and 2) probability distribution. For this study, a user-defined uncertainty pattern and a probability distribution are both used to add uncertainty to the load values. A different load uncertainty distribution pattern will be modeled for each modeled area.

Uncertainty Components

A load model is used to define the peak-demand multipliers used to modify forecasted Peak Demand. The daily peak was selected and regressed against historical peak temperatures from 2006-2016. Excel was used to analyze the probability distributions of temperatures observed at key weather stations throughout the SPP footprint. A forecast was then created for both study years. Based on the forecasts, multipliers were calculated and were populated in a user defined uncertainty pattern. The user-defined uncertainty pattern allows users to provide seven monthly demand patterns. Each area has a different value for each month multiplied by seven probabilities (a total of 84 values). GridView randomly selects the demand pattern at the beginning of the simulation hour, and applies it for that trial. The random load uncertainty allows for unexpected increases of demand in addition to the adjusted testing reserve margin.

Demand Adjustment

The forecasted Peak Demand shall be adjusted for each modeled area in GridView scaling each area's peak hour demand by the amount needed to meet the testing reserve margin. Each area shall be set to the testing reserve margin based upon the expected or forecasted accredited capacity of each area. Only scalable loads identified in the ITPNT models will be subject to incremental load increases.

Summary of Assumptions

1) Each simulation period will be from January 1 to December 31
2) The summer period is defined as June 15th – September 15th
3) Load shed penalty is $2000/MWh, Branch overload penalty is $6000/MWh
4) At a minimum, 3000 trials per simulation will be run, to reach a convergence of 90% or greater
5) Only existing and planned reported generation is modeled
6) Forego SPP operating reserves
7) Monitored branches include anything that is 100 kV and above
8) Flowgates and interfaces used in the study are limits established in the SPP book of flowgates
9) The forecasted Peak Demand shall be adjusted for each modeled area in GridView scaling each area's peak hour demand by the amount needed to meet the testing reserve margin.
10) Number of resource outages will be determined by comparing GridView simulation outages to real time historical outages
11) Generation is dispatched using a Security Constrained Economic Dispatch algorithm based on the SPP Balancing Authority Area boundary

Simulation and Study Process

SPP will conduct the GridView Monte-Carlo simulation at 3000 trials (or more as needed), in which resources in SPP may be randomly forced out of service during each hour of the study. Each trial accounts for a different variation of forced outages, wind output, and load uncertainty. Each trial represents a single 8760-hour simulation. The stop criteria for the Monte-Carlo simulation is to make the convergence factor of LOLE greater than or equal to 90% for consideration of probabilistic indices. GridView calculates the convergence factor to determine if additional simulations are needed.

Reporting

The LOLE Study scope and results will be reviewed and approved by the Supply Adequacy Working Group with additional review by the Operational Reliability Working Group and the Transmission Working Group. Once the final metric results are calculated, they will be compiled in a report, which will be presented to the appropriate working groups for review.

Additional Sensitivities

This section provides an overview of sensitivities in addition to the base assumptions for the LOLE Study.

Low Wind During Summer Peak Hours

Considering all other base assumptions remain unchanged, this sensitivity provides insight to low wind output during the summer season. A wind year representing low wind output during summer peak hours for 2012 will be chosen and modelled for simulation.

Demand Adjustment – Equal Coincident Peak Scaling Analysis

The forecasted Peak Demand shall be adjusted for the entire SPP footprint in GridView scaling SPP's peak hour demand by the amount needed to meet the testing reserve margin on an SPP coincident peak (CP) basis. The SPP CP testing reserve margin studied will match the CP testing reserve margin in the base analysis and will have the same available accredited capacity studied in the base analysis. In this sensitivity, the demand adjustment for each modeled area in GridView will have the same scaling factor applied. All other base assumptions will remain unchanged. The study results for this sensitivity will be reported on both an SPP CP reserve margin basis and the equivalent area's peak demand reserve margin basis (i.e. the non-coincident peak reserve margin).