Midwest PRSG

Reliability through Collaboration

LOLE Study Report

4-4-08

Introduction

The Midwest Planning Reserve Sharing Group (Midwest PRSG) is a group of Load Serving Entities (LSE) which are located within or directly interconnected to the Midwest ISO Reliability Authority Footprint. Officially formed in May of 2007, the group set out to study the collective resources of the Midwest PRSG participants to determine the minimum level of reserve requirements based upon Reliability Principles and Standards set forth by applicable Reliability Entities.

This report summarizes the results of a Loss of Load Expectation (LOLE) Study and provides a recommended reserve margin for the June 2008 through May 2009 planning period. This report also documents the analysis tools, data assumptions and methodology used to perform this study.

The Midwest PRSG contracted the Midwest ISO to act as the Group Administrator in May of 2007. In this capacity the Midwest ISO conducted the Loss of Load Expectation (LOLE) Study for the Midwest PRSG, determined each Participant's Forecast Participant Requirement, and gathered any applicable data from each Participant.

The Midwest PRSG is continuing work on completing the LOLE Study and reserve margin determination for June 2009 through May 2018. An addendum to this report will be provided after the analysis has been reviewed and approved.

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Study Objective

The objective of the Midwest PRSG is to perform a LOLE study to establish the minimum planning reserve margin for the planning period of June 2008 through May 2009. Consistent with the Resource Adequacy Assessment Standards of Reliability First Corporation and Midwest Reliability Organization, a resource adequacy metric of no greater than 0.1 day in one (1) year LOLE was used to determine the minimum planning reserve margin.

Technical Terms & Definitions

The following are technical definitions of terms used throughout this document.

LOLP – Loss of Load Probability
The probability of load demand not met in a given hour.

LOLE – Loss of Load Expectation
Is the sum of multiple LOLP values usually from daily peak hours or over a certain period of time.

FCITC – First Contingency Incremental Transfer Capability
The amount of power, incremental above normal base power transfers, that can be transferred between two areas of the interconnected transmission systems under conditions where first contingency transfer limits reach ratings of a facility.

FCTTC – First Contingency Total Transfer Capability, FCTTC = FCITC + Base Case Transfers
The total amount of electric power (net of normal base power transfers plus first contingency incremental transfers) that can be transferred between two control areas of the interconnected transmission systems in a reliable manner.

Forced Outage Rate (FOR) [Definition taken from IEEE Standard 762]

$$FOR = \left(\frac{FOH}{SH + FOH}\right) \times 100$$

In Service
The in-service state is where a unit is electrically connected to the system and performing generation function.

Service Hours (SH)
Represents the number of hours a unit was in the in-service state.

Forced Outage Hours (FOH)
Represents the number of hours a unit was in a Class 0, Class 1, Class 2 or Class 3 unplanned outage state
.

Class 0 unplanned outage (starting failure) results from the unsuccessful attempt to place the unit in service.
Class 1 unplanned outage (immediate) requires the immediate removal from the existing state.
Class 2 unplanned outage (delayed) does not require immediate removal from the in-service state, but requires removal within 6 hours.
Class 3 unplanned outage (postponed) can be postponed beyond 6 hours, but requires that a unit be removed from the in-service state before the end of the next weekend.

Analysis Tools – Description & Background

This section provides a brief description and background of the tools utilized to calculate LOLP for this study. The following is a list of tools used and the vendors that support them:

Siemens Power Transmission & Distribution, Inc., Power Technologies International
PSS/MUST™ – Managing and Utilizing System Transmission

General Electric International, Inc., GE Energy
MARS – Multi-Area Reliability Simulation

The primary tool for the calculation of the reliability indices in this study was GE's Multi-Area Reliability Simulation program (MARS). MARS is based on a sequential Monte Carlo simulation which provides for a detailed representation of the hourly loads, generating units, and interfaces between the interconnected areas. The sequential simulation steps through time chronologically, modeling the system, which can consist of any number of interconnected areas and pools, in great detail.

MARS calculates, on an area, area group, and pool basis, the standard reliability indices of daily or hourly LOLE (days/year or hours/year) and expected un-served energy (LOEE in MWh/year). This study focused on the daily LOLE index.

MARS determines the daily LOLE index by comparing the peak hourly load with the available generation for every day of the year. If the Monte Carlo draw of available generation is less than the peak hourly load for that day, 1 day of loss of load is accumulated. This process is repeated for each day of the year to determine the number of loss of load days for the year. This yearly simulation, with the Monte Carlo pick of available generation, is performed numerous times. Each yearly simulation will have a certain amount of days with outage depending upon the Monte Carlo draw for that year. By summing the total number of days with loss of load for all simulations and then dividing by the number of simulations, a yearly loss of load expectation is derived. To obtain a LOLE of no more than 0.1 days per year, no more than 100 days of loss of load could occur over a study with 1000 simulations (100 days of loss of load divided by 1000 simulations = 0.1 days/year LOLE).

The Midwest PRSG LOLE calculations were performed on a zonal level in which loads and generation are assigned to zones and transfer limits are specified between the zones. These zones were then aggregated into a region known as the Midwest PRSG. The indices for the Midwest PRSG region are computed from the Midwest PRSG zones; if one or more of the zones in the region are deficient for the day, then the region is counted as being deficient.

As a result, the LOLE for a region will be no better than the LOLE of the least reliable zone in that region. This would be true if all of the outages of the other zones coincided with those of the least reliable zone. Likewise, the LOLE of the region will be no worse than the sum of the zonal values, which would occur if none of the zonal outages overlapped. For example, a region consisting of three zones (each with one day of loss of load) would have a regional loss of load of only two days if two of the zone's loss of load events occurred on the same day of the year.

The transfer and tie limits between zones used in the LOLE analysis were determined by the software program PSS/MUST (Managing and Utilizing System Transmission). This program utilizes a full network model representation and is able to calculate transfer limits using a source/sink relationship between defined sub-systems such as Midwest PRSG zones. The transfer calculation is performed by monitoring multiple transmission elements under first contingency analysis know as First Contingency Total Transfer Capability (FCTTC). It is this calculated FCTTC value that is used as the transfer and tie limits between the study zones.

More exact details of the study analysis will be included in the Study Methodology Section.

Data Assumptions & Analytic Inputs

For this study the default generator and load data originated from the Midwest ISO PowerBase database. This database was initially compiled by NewEnergy Associates from the following sources:

- Platts NewGen Database
- EIA 411 Reports
- NERC GADS Database
- FERC 714 filings
- Other Public Information

Each Midwest PRSG member was allowed to review and update the default data for their respective companies. All updates received were reviewed for reasonableness by the Group Administrator and applied to the study database. The original default data was also utilized for representing the systems external to the Midwest PRSG. The following sub-sections detail the data that was utilized in this study.

Thermal Unit Data

Thermal units are generator sources whose reliability and availability is mostly limited by their rate of failure and forced outage maintenance. These types of units included units powered by coal, nuclear, gas and oil. The following is a list of the thermal unit input parameters that was used in the analysis of this study.
- Future in-service dates and up-coming retirement dates
- Monthly maximum output ratings to represent seasonal capacity profile
- Planned maintenance requirement such as the typical planned annual maintenance duration
- Forced Outage Rates and average forced outage duration were requested as an update to the default data; however, parties supplied the information they had available pertaining to their specific units, including Equivalent Forced Outage Rates and outage rates calculated using other methodologies.

Energy Limited Unit Data

Energy limited units are renewable types of units such as those powered by hydro and wind whose output is mostly dependent on the availability of the supplying energy source. Hydro units are dispatched as peak shaving while wind units are modeled with a flat energy profile. The following is a list of the energy limited unit input parameters that were used in the analysis of this study:
- Future in-service dates and up-coming retirement dates
- Monthly maximum output ratings to represent seasonal capacity profile
- Monthly minimum output ratings to represent the must run portion of the unit
- Planned maintenance requirement such as the typical planned annual maintenance duration
- Monthly capacity factors to help account for the limited availability of the energy supply

Load Data
The load input data consisted of a historical hourly profile based on the typical load year of 2002 and monthly peak load forecast for all study years. The historical load shape is adjusted by the monthly peak 50/50 load forecast as provided by the Midwest PRSG membership. Also load forecast uncertainty was analyzed and modeled as a study input variable. By using the load forecast uncertainty, different weighted probabilities above and below the 50/50 load forecast values are evaluated. The primary sources for this information came from the three years of Midwest ISO market history and other LOLE studies.

Emergency Operation Procedures (EOPs)
Interruptible loads were included as load modifiers and modeled as emergency measures which were utilized as necessary during simulation runs. The use of Emergency Operation Procedures does not constitute a loss of load event.

Firm Contract Data
Contracts were modeled for each Midwest PRSG zone to represent firm purchases, sales of generation, and portions of a unit's capacity designated outside the area which it is physically located such as situations involving joint owned units. These contracts represent both exchanges between Midwest PRSG zones and exchanges between a Midwest PRSG zone and external party.

June 2008 - May 2009
Midwest PRSG Study Input Data Summary

Zone	Annual Peak Load (MW)	Capacity at Time of Peak (MW)	Contracts at Time of Peak (MW)	Interruptible Load (MW)
EAST	36,551	38,441	973	776
CENTRAL	41,798	48,235	77	746
WEST	43,785	50,468	1,972	1,872
MHEB	4,442	5,525	-540	212

Study Methodology

The following sections will explain the details of the study methodology and analysis techniques utilized in the Midwest PRSG Reserve Margin Study.

Study Area Definition

The following area configuration was studied in this analysis. Zones studied here were based on a three region (Central, East and West) default study approach established by the Midwest PRSG membership. This method allowed any Midwest PRSG member company the option to be studied as a separate inter-connected zone different from one of the default three. This was the case with the Manitoba Hydro zone.

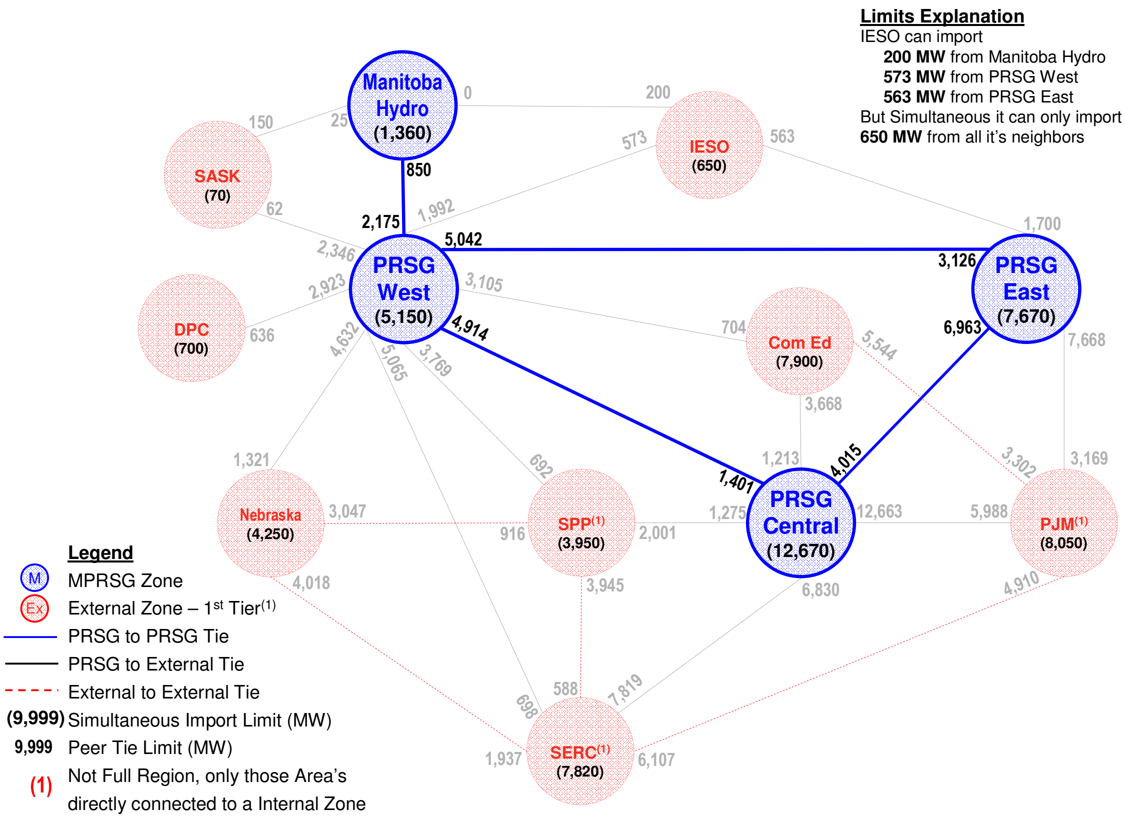
The study zones also form the data infrastructure basis to which all input data is established and set up. Zones are also used to represent the limited ability of energy to move unrestricted throughout the electrical system. This is accomplished by modeling tie limits between the zones.

Study Zone Definition

Midwest PRSG Member	M-PRSG Zone
Ameren	Central
Duke Energy	Central
Hoosier Energy Rural Electric Coop, Inc.	Central
Illinois Municipal Electric Agency	Central
Indianapolis Power & Light Co.	Central
Northern Indiana Public Service Co.	Central
Southern Indiana Gas & Electric Company, Inc.	Central
Wabash Valley Power Association, Inc.	Central
City of Lebanon	East
Consumers Energy Co.	East
Detroit Edison Co.	East
First Energy	East
Lansing Board of Water & Light	East
Michigan Public Power Agency	East
Wolverine Power Supply Coop, Inc.	East
Manitoba Hydro	Manitoba Hydro

Midwest PRSG Member	M-PRSG Zone
Alliant Energy	West
Basin Electric Power Cooperative	West
Central Iowa Power Cooperative	West
Great River Energy	West
Madison Gas & Electric Co.	West
MidAmerican Energy Co.	West
Minnesota Power, Inc.	West
Montana Dakota Utilities Co.	West
NorthWestern Energy	West
Otter Tail Power Co.	West
Southern Minnesota Municipal Power Agency	West
Upper Peninsula Power Company	West
We Energies	West
Western Area Power Administration	West
Wisconsin Public Power, Inc.	West
Wisconsin Public Service Corp.	West
Xcel Energy	West

Study Zone Configuration and Transfer Analysis Results



Transfer Analysis

A transfer analysis was conducted to calculate both the zone to zone tie limits as well as the simultaneous import limit for every zone. This information is used by the LOLE model to represent the inter-connected system and allow the zones to share available resources. First Contingency Transfer Analysis using the PSS/E MUST tool was utilized to calculate these limits. The transfer limit for exporting systems equaled the First Contingency Incremental Transfer Capability (FCITC), while the transfer limit for importing systems equaled the FCITC + Base Imports, which is also called the First Contingency Total Transfer Capability, or FCTTC.

The analysis included monitoring zone branches and ties 100kV and above for thermal ratings overload while the contingencies tested also included the zone branches and ties 100kV and greater. The individual transfers performed for the calculation of the zone to zone tie limits included each zone as the designated transfer sink while each of the directly connected neighboring zones was analyzed separately as the transfer source. These results can be seen on the ties in the zone configuration diagram. The simultaneous import limits shown in parentheses in the same zone diagram were found by taking the maximum transfer limit into the zone from anyone of the other zones based on a FCITC analysis.

The FCTTC represents the maximum import capability available to a zone in order to help maintain resource adequacy. The actual amount of transfer capability that MARS utilized to maintain an LOLE of 0.1 days/year, as an alternative to internal resources, for all MPRSG zones, including flow through utilized to support each other, is reported in Appendix A.

LOLE Analysis and Reserve Margin Calculation

In this study the reserve margins were calculated at two different distinct LOLE target levels, but using exactly the same methodology, technique and rules of addition.

Target Level A: Each of the zones at 0.1 days/year

Target Level B: Midwest PRSG as a whole at 0.1 days/year and each zone at a common lower LOLE

Target Level B results in a higher level of reliability (or lower LOLE) for each zone in the Midwest PRSG because each zone's LOLE contributes to the overall Midwest PRSG LOLE.

The reserve margins were determined by using the MARS program to calculate the LOLE for both the individual zones and the Midwest PRSG. By adding a simple proxy adjustment unit to each of the study zones, LOLE runs were sequentially conducted and incremental adjustments made to the proxy units until the desired LOLE target was reached. The adjustment mega-watts from the proxy units were then applied directly to the reserve margin calculation for each of the zones. The following was the equation used for calculation of reserve margins.

$$\text{Reserve Margin} = \frac{\text{Capacity@PeakLoad} + \text{FirmContract@PeakLoad} + \text{Adjustment} - (\text{PeakLoad} - \text{InterruptibleLoad})}{\text{PeakLoad} - \text{InterruptibleLoad}}$$

Sensitivities

The following is a list of the study sensitivities that were examined using the MARS software:

Isolated Zones: A reserve margin calculation was performed where there was no sharing of availability resources between zones except for firm contracts. This sensitivity help demonstrate the benefits of pooling and sharing of resources. {Cases 0 & 1}

Unconstrained System "Copper Sheet": Sensitivity was conducted where there was no tie limits between zones and thus no boundary for reserve sharing. {Case 2}

Inter-Connected Zones: The LOLE calculations performed with the inter-connected zones included the tie and import limits calculated during the transfer analysis. {Cases 3 thru 10}

FOR Increase: A 25% increase in Forced Outage Rate for all units was used to help capture the effects of forced unit de-rates not accounted for in the forced outage rate equation. This sensitivity also helps test the volatility of calculated reserve margins due to unit reliability. {Cases 7, 9 & 10}

Load Forecast Uncertainty (LFU): Sensitivities were performed with varied amounts of load forecast uncertainty. This helped provide insight into the effect of load forecast uncertainty on planning reserve margins. The different amounts of load forecast uncertainty tested include:

- No Load Forecast Uncertainty {Cases 0 & 5}
- **Seasonal Zonal LFU** was calculated from participant data compiled in MISO Module E submittals, uniquely for each MPRSG zone. LFU based on two years of market operations data {Cases 1, 2 & 3}
- Using the same MISO data **Seasonal Common LFU** was compiled by averaging the entire MPRSG region {Cases 4 & 7}
- 3% standard deviation based on a seven point normal distribution {Cases 8 & 9}
- 4% standard deviation based on a seven point normal distribution {Cases 6 & 10}

Unique Zonal and Common Midwest PRSG Seasonal LFU Standard Deviation Values.

The following Load Forecast Uncertainty (LFU) values were applied to the three month summer and winter periods during the Seasonal LFU cases. Summer values were applied to June, July and August while winter Values were applied to December, January and February. The remaining months were given an LFU value of 0%.

Summer	
Central	2.52%
West	2.75%
East	5.28%
MH	3.59%
Midwest PRSG	2.65%

Winter	
Central	6.38%
West	3.11%
East	3.30%
MH	5.31%
Midwest PRSG	4.51%

Load forecast uncertainty levels for the Midwest PRSG were calculated at two separate levels. As individual zones, the uncertainty levels were ascertained using analysis of load forecasts and actual load levels. This was done with information aggregated on a zonal basis. As an entire Midwest PRSG the uncertainty decreases because analysis is performed on a larger load. If certain zones of the Midwest PRSG were historically forecasting higher load levels when compared to actual load levels and other zones forecasting lower load levels, the aggregated load forecast would be closer to actual due to the high load forecast being offset by the low load forecast.

Conclusion

The Midwest PRSG approved the following minimum reserve margin targets for the 2008 – 2009 planning year for the four zones within the Midwest PRSG utilizing LOLE analysis Case 10 assumptions using the Level A technique. The Midwest PRSG membership recommended use of Case 10a was based on the review of all LOLE sensitivity analyses, and represents the group's collective consensus of the minimum reserve margins necessary to maintain a resource adequacy criterion of 1 day in 10 years LOLE. The MPRSG decided to add in an additional ½ % of reserve margin to Case 10a in order to provide an additional level of conservatism to this initial MPRSG analysis. This Study was conducted consistent with both RFC Adequacy Standard BAL-502-RFC-01 and MRO Standard RES-501-MRO-01 requirements.

Midwest PRSG Reserve Margins	
East	13.7 %
Central	14.3 %
West	14.2 %
Manitoba Hydro	7.7 %

June 2008 - May 2009 Midwest PRSG Study Reserve Margin Cases

In all the cases presented a zero transfer of power to and from entities outside of the MPRSG is assumed, except for established contracts.

Cases 0 and 1 results show reserve margin levels for all the zones isolated - assuming no transmission line transfers, except for contracts. These cases provide a view of reserve margins if no transfer occurred between MPRSG zones. Case 0 doesn't consider any load forecast uncertainty (LFU) while Case 1 includes a zonal LFU.

Cases 2-10 provide both Target Level A and B for reserve margin calculation as referenced on page 12.

Case 0	**Isolated Midwest PRSG Zones No Ties Between Zones Except for Contracts Zones Adjusted to 0.1 days/year No-LFUs**		
PRSG Zone	**LOLE (d/y)**		**Reserve Margin (%)**
EAST	0.100		10.6
CENTRAL	0.100	0	11.7
WEST	0.100		10.2
MHEB	0.102		17.2

Case 1	**Isolated Midwest PRSG Zones No Ties Between Zones Except for Contracts Zones Adjusted to 0.1 days/year Zonal LFUs**		
PRSG Zone	**LOLE (d/y)**		**Reserve Margin (%)**
EAST	0.100		15.8
CENTRAL	0.100	1	12.9
WEST	0.100		11.7
MHEB	0.100		18.8

Case 2 provides a view of reserve margins when the transfer capabilities between the zones are unlimited. This assumption of unlimited transfer ability in this case is the opposite of the Case 0 and Case 1 that sets the transfer capability to zero. Case 2 utilizes zonal load forecast uncertainty.

"Copper-Sheet" Sensitivity Results

Case 2	Interconnect Midwest PRSG Zones (Infinite Tie Limits) No External Zones Except for Contracts Zones Adjusted to 0.1 days/year Zonal LFUs		Interconnect Midwest PRSG Zones (Infinite Tie Limits) No External Zones Except for Contracts Group Adjusted to 0.1 days/year Zonal LFUs	
PRSG Zone	LOLE (d/y)	Reserve Margin (%)	LOLE (d/y)	Reserve Margin (%)
	2A		**2B**	
EAST	0.101	13.8	0.054	14.6
CENTRAL	0.100	8.8	0.052	9.4
WEST	0.100	9.0	0.053	9.6
MHEB	0.100	-70.9	0.050	-55.4

In Cases 3, 4, 5, 6 and 8 the transfer limits between zones were limited by the levels provided by the MUST transfer analysis (see Transfer Analysis Results). The five cases differ by the amount of load forecast uncertainty (LFU) used in the analysis. Case 3 uses the zonal LFU. Case 4 uses the Common LFU assumption, Case 5 uses a load forecast with no uncertainty, Case 6 uses a 4% standard deviation LFU and Case 8 uses a 3% standard deviation LFU.

Zonal Load Forecast Uncertainty Results

Case 3	Interconnect Midwest PRSG Zones No External Zones Except for Contracts Zones Adjusted to 0.1 days/year Zonal LFUs		Interconnect Midwest PRSG Zones No External Zones Except for Contracts Group Adjusted to 0.1 days/year Zonal LFUs	
PRSG Zone	LOLE (d/y)	Reserve Margin (%)	LOLE (d/y)	Reserve Margin (%)
	3A		**3B**	
EAST	0.101	12.0	0.044	13.5
CENTRAL	0.100	7.0	0.044	8.0
WEST	0.100	7.0	0.044	7.9
MHEB	0.100	3.1	0.039	4.1

Common Midwest Group Load Forecast Uncertainty Results

Case 4	Interconnect Midwest PRSG Zones No External Zones Except for Contracts Zones Adjusted to 0.1 days/year Common Group LFU 4A		Interconnect Midwest PRSG Zones No External Zones Except for Contracts Group Adjusted to 0.1 days/year Common Group LFU 4B	
PRSG Zone	LOLE (d/y)	Reserve Margin (%)	LOLE (d/y)	Reserve Margin (%)
EAST	0.101	7.2	0.042	8.0
CENTRAL	0.099	7.6	0.040	8.9
WEST	0.099	7.3	0.041	8.3
MHEB	0.101	1.9	0.042	2.8

No Load Forecast Uncertainty Sensitivity Results

Case 5	Interconnect Midwest PRSG Zones No External Zones Except for Contracts Zones Adjusted to 0.1 days/year No-LFU 5A		Interconnect Midwest PRSG Zones No External Zones Except for Contracts Group Adjusted to 0.1 days/year No-LFU 5B	
PRSG Zone	LOLE (d/y)	Reserve Margin (%)	LOLE (d/y)	Reserve Margin (%)
EAST	0.103	4.5	0.038	5.2
CENTRAL	0.100	5.9	0.037	6.7
WEST	0.100	4.9	0.036	5.6
MHEB	0.103	0.9	0.038	1.2

Load Forecast Uncertainty with 4% Standard Deviation Sensitivity Results

Case 6	Interconnect Midwest PRSG Zones No External Zones Except for Contracts Zones Adjusted to 0.1 days/year LFU: 4% StdDev 6A		Interconnect Midwest PRSG Zones No External Zones Except for Contracts Group Adjusted to 0.1 days/year LFU: 4% StdDev 6B	
PRSG Zone	LOLE (d/y)	Reserve Margin (%)	LOLE (d/y)	Reserve Margin (%)
EAST	0.100	11.8	0.043	13.1
CENTRAL	0.098	11.8	0.042	13.3
WEST	0.099	12.1	0.043	13.3
MHEB	0.100	7.0	0.042	7.7

Cases 7, 9 and 10 provide a view of reserve margins when the historic forced outage rate (FOR) of generating units is increased by 25%. Case 7 is the same as Case 4 with the 25% adder for FOR. The 25% FOR factor added to Case 8 provides the results in Case 9. Case 10 is the result when the 25% factor is added to Case 6.

Common Midwest Group Load Forecast Uncertainty with 25% Forced Outage Rate Increase Results

Case 7	Interconnect Midwest PRSG Zones No External Zones Except for Contracts Zones Adjusted to 0.1 days/year Common Group LFU & +25% FOR (7A)		Interconnect Midwest PRSG Zones No External Zones Except for Contracts Group Adjusted to 0.1 days/year Common Group LFU & +25% FOR (7B)	
PRSG Zone	LOLE (d/y)	Reserve Margin (%)	LOLE (d/y)	Reserve Margin (%)
EAST	0.100	8.6	0.041	9.7
CENTRAL	0.100	9.5	0.040	10.7
WEST	0.099	9.1	0.040	10.2
MHEB	0.100	2.2	0.041	2.9

Load Forecast Uncertainty with 3% Standard Deviation Sensitivity Results

Case 8	Interconnect Midwest PRSG Zones No External Zones Except for Contracts Zones Adjusted to 0.1 days/year LFU: 3% StdDev (8A)		Interconnect Midwest PRSG Zones No External Zones Except for Contracts Group Adjusted to 0.1 days/year LFU: 3% StdDev (8B)	
PRSG Zone	LOLE (d/y)	Reserve Margin (%)	LOLE (d/y)	Reserve Margin (%)
EAST	0.100	8.8	0.040	9.9
CENTRAL	0.100	9.0	0.040	10.1
WEST	0.101	8.8	0.040	10.1
MHEB	0.101	4.6	0.042	5.2

3% StdDev Load Forecast Uncertainty with 25% Forced Outage Rate Increase Results

Case 9	Interconnect Midwest PRSG Zones No External Zones Except for Contracts Zones Adjusted to 0.1 days/year 3% StdDev LFU & +25% FOR (9A)		Interconnect Midwest PRSG Zones No External Zones Except for Contracts Group Adjusted to 0.1 days/year 3% StdDev LFU & +25% FOR (9B)	
PRSG Zone	LOLE (d/y)	Reserve Margin (%)	LOLE (d/y)	Reserve Margin (%)
EAST	0.100	10.3	0.041	11.5
CENTRAL	0.100	10.9	0.041	12.2
WEST	0.100	10.7	0.040	11.8
MHEB	0.102	4.8	0.040	5.4

4% StdDev Load Forecast Uncertainty with 25% Forced Outage Rate Increase Results

Case 10	Interconnect Midwest PRSG Zones No External Zones Except for Contracts Zones Adjusted to 0.1 days/year 4% StdDev LFU & +25% FOR (10A)		Interconnect Midwest PRSG Zones No External Zones Except for Contracts Group Adjusted to 0.1 days/year 4% StdDev LFU & +25% FOR (10B)	
PRSG Zone	LOLE (d/y)	Reserve Margin (%)	LOLE (d/y)	Reserve Margin (%)
EAST	0.100	13.2	0.042	14.7
CENTRAL	0.099	13.8	0.042	15.3
WEST	0.100	13.7	0.042	15.0
MHEB	0.100	7.2	0.042	7.8

Sensitivity Comparisons

The sensitivity comparisons provide the impact on reserve margin when key assumptions are changed. Comparisons 1-3 and 5 provide the change in reserve margin levels when the level of load forecast uncertainty is adjusted, compared to a case that has no LFU (Case 5).

Effect of Zonal Load Forecast Uncertainty Values (Case 3-5)

Comp 1	Interconnect Midwest PRSG Zones No External Zones Except for Contracts Zones Adjusted to 0.1 days/year		Interconnect Midwest PRSG Zones No External Zones Except for Contracts Group Adjusted to 0.1 days/year	
PRSG Zone	Extra Capacity Needed as a result of LFU (MW)	Reserve Margin Increase as a result of LFU (%)	Extra Capacity Needed as a result of LFU (MW)	Reserve Margin Increase as a result of LFU (%)
		C-1A		C-1B
EAST	2,661	7.4	2,975	8.3
CENTRAL	444	1.1	510	1.2
WEST	890	2.1	940	2.2
MHEB	92	2.2	123	2.9

Effect of Common Group Load Forecast Uncertainty Values (Case 4-5)

Comp 2	Interconnect Midwest PRSG Zones No External Zones Except for Contracts Zones Adjusted to 0.1 days/year		Interconnect Midwest PRSG Zones No External Zones Except for Contracts Group Adjusted to 0.1 days/year	
PRSG Zone	Extra Capacity Needed as a result of LFU (MW)	Reserve Margin Increase as a result of LFU (%)	Extra Capacity Needed as a result of LFU (MW)	Reserve Margin Increase as a result of LFU (%)
		C-2A		C-2B
EAST	960	2.7	1,035	2.9
CENTRAL	688	1.7	890	2.2
WEST	1,007	2.4	1,100	2.6
MHEB	40	0.9	65	1.5

Effect of 4% StdDev Load Forecast Uncertainty (Case 6-5)

Comp 3	Interconnect Midwest PRSG Zones No External Zones Except for Contracts Zones Adjusted to 0.1 days/year		Interconnect Midwest PRSG Zones No External Zones Except for Contracts Group Adjusted to 0.1 days/year	
PRSG Zone	Extra Capacity Needed as a result of LFU (MW)	Reserve Margin Increase as a result of LFU (%)	Extra Capacity Needed as a result of LFU (MW)	Reserve Margin Increase as a result of LFU (%)
		C-3A		C-3B
EAST	2,595	7.3	2,845	8.0
CENTRAL	2,440	5.9	2,690	6.6
WEST	3,000	7.2	3,210	7.7
MHEB	258	6.1	272	6.4

Comparison 4 provides the additional reserve margin required when the forced outage rate (FOR) for generating units is increased by 25%. Comp 4 compares Cases 7 and 4 that utilize a common LFU assumption. It is assumed that comparing other similar cases would provide an equivalent reserve margin differential. This is evident when looking at Comparison 6 and 7. The change in reserve margin, with the 25% increase in FOR, is similar for each comparison at differing LFU levels.

Effect of 25% Forced Outage Rate Increase (Case 7-4)

Comp 4	Interconnect Midwest PRSG Zones No External Zones Except for Contracts Zones Adjusted to 0.1 days/year		Interconnect Midwest PRSG Zones No External Zones Except for Contracts Group Adjusted to 0.1 days/year	
PRSG Zone	Extra Capacity Needed as a result of FOR Increase (MW)	Reserve Margin Increase as a result of FOR Increase (%)	Extra Capacity Needed as a result of FOR Increase (MW)	Reserve Margin Increase as a result of FOR Increase (%)
		C-4A		C-4B
EAST	495	1.4	585	1.6
CENTRAL	782	1.9	750	1.8
WEST	759	1.8	798	1.9
MHEB	12	0.3	6	0.1

Effect of 3% StdDev Load Forecast Uncertainty (Case 8-5)

Comp 5	Interconnect Midwest PRSG Zones No External Zones Except for Contracts Zones Adjusted to 0.1 days/year		Interconnect Midwest PRSG Zones No External Zones Except for Contracts Group Adjusted to 0.1 days/year	
PRSG Zone	Extra Capacity Needed as a result of LFU (MW)	Reserve Margin Increase as a result of LFU (%)	Extra Capacity Needed as a result of LFU (MW)	Reserve Margin Increase as a result of LFU (%)
		C-5A		C-5B
EAST	1,525	4.3	1,695	4.7
CENTRAL	1,255	3.1	1,390	3.4
WEST	1,645	3.9	1,860	4.4
MHEB	157	3.7	168	4.0

Effect of 25% Forced Outage Rate Increase on 3% StdDev LFU (Case 9-8)

Comp 6	Interconnect Midwest PRSG Zones No External Zones Except for Contracts Zones Adjusted to 0.1 days/year		Interconnect Midwest PRSG Zones No External Zones Except for Contracts Group Adjusted to 0.1 days/year	
PRSG Zone	Extra Capacity Needed as a result of FOR Increase (MW)	Reserve Margin Increase as a result of FOR Increase (%)	Extra Capacity Needed as a result of FOR Increase (MW)	Reserve Margin Increase as a result of FOR Increase (%)
		C-6A		C-6B
EAST	530	1.5	565	1.6
CENTRAL	812	2.0	840	2.0
WEST	767	1.8	710	1.7
MHEB	5	0.1	9	0.2

Effect of 25% Forced Outage Rate Increase on 4% StdDev LFU (Case 10-6)

Comp 7	Interconnect Midwest PRSG Zones No External Zones Except for Contracts Zones Adjusted to 0.1 days/year		Interconnect Midwest PRSG Zones No External Zones Except for Contracts Group Adjusted to 0.1 days/year	
PRSG Zone	**Extra Capacity Needed as a result of FOR Increase (MW)**	**Reserve Margin Increase as a result of FOR Increase (%)**	**Extra Capacity Needed as a result of FOR Increase (MW)**	**Reserve Margin Increase as a result of FOR Increase (%)**
		C-7A		**C-7B**
EAST	525	1.5	565	1.6
CENTRAL	795	1.9	840	2.0
WEST	705	1.7	710	1.7
MHEB	5	0.1	7	0.2

Appendix A:

June 2008 – Dec 2008
Midwest PRSG Study Case 10A Interface Flow Summary

Interconnect Midwest PRSG Zones No External Zones Except for Contracts Zones Adjusted to 0.1 days/year 4% StdDev LFU & +25% FOR						
MPRSG Zone Ties or Zone Interface	Jun-Dec 2008 Simulation Flows (MW)					
	Positive Direction			Negative Direction		
	Limit	Maximum	Average	Limit	Maximum	Average
CENT to EAST	6,963	2,214	517	4,015	3,006	727
CENT to WEST	4,914	4,507	1,493	1,401	1,055	616
EAST to WEST	5,042	3,817	1,127	3,126	1,917	30
MHEB to WEST	2,175	1,118	1,007	850	850	850
CENT imports	12,670	3,678	78	99,999	5,540	1,477
EAST imports	7,670	3,657	688	99,999	3,884	921
MHEB imports	1,360	850	850	99,999	1,118	1,007
WEST imports	5,150	5,080	597	99,999	1,416	655

Jan 2009 – May 2009
Midwest PRSG Study Case 10A Interface Flow Summary

Interconnect Midwest PRSG Zones No External Zones Except for Contracts Zones Adjusted to 0.1 days/year 4% StdDev LFU & +25% FOR						
MPRSG Zone Ties or Zone Interface	Jan-May 2009 Simulation Flows (MW)					
	Positive Direction			Negative Direction		
	Limit	Maximum	Average	Limit	Maximum	Average
CENT to EAST	6,963	0	0	4,015	0	0
CENT to WEST	4,914	1,016	624	1,401	0	0
EAST to WEST	5,042	0	0	3,126	30	30
MHEB to WEST	2,175	0	0	850	850	850
CENT imports	12,670	77	77	99,999	962	625
EAST imports	7,670	973	688	99,999	0	0
MHEB imports	1,360	850	850	99,999	0	0
WEST imports	5,150	1,549	542	99,999	0	0