Book 2
Resource Adequacy

2016

Chapter 6

Resource Adequacy

2016

6.0 Resource Adequacy Introduction and Enhancements

MISO's ongoing goal is to support the achievement of Resource Adequacy — to ensure enough capacity is available to meet the needs of all consumers in the MISO footprint during peak times and at just and reasonable rates. The responsibility for Resource Adequacy does not lie with MISO, but rather rests with Load Serving Entities and the states that oversee them (as applicable by jurisdiction). Additional Resource Adequacy goals include maintaining confidence in the attainability of Resource Adequacy in all time horizons, building confidence in MISO's Resource Adequacy assessments and providing sufficient transparency and market mechanisms to mitigate potential shortfalls.

Five guiding principles provide the framework necessary to achieve these goals.

1. Resource Adequacy processes must ensure confidence in Resource Adequacy outcomes in all time horizons
2. MISO will work with stakeholders to ensure an effective and efficient Resource Adequacy construct with appropriate consideration of all eligible internal and external resources and resource types and recognition of legal/regulatory authorities and responsibilities
3. MISO will determine adequacy at the regional and zonal level and provide appropriate regional and zonal Resource Adequacy transparency and awareness for multiple forward time horizons
4. MISO will administer and evolve processes in a manner that provides transparency and reasonable certainty, appropriately protects individual market participant proprietary information in order to support efficient stakeholder resource and transmission investment decisions
5. MISO's resource planning auction and other processes will support multiple methods of achieving and demonstrating Resource Adequacy, including self-supply, bilateral contracting and market-based acquisition.

To date, the Resource Adequacy Requirements process has been a successful tool for facilitating and demonstrating Resource Adequacy in the near term, through such tools as the Loss of Load Expectation analysis, the Planning Resource Auction, and the Organization of MISO States-MISO Survey. With the resource portfolio now evolving due to coal retirements and the increase in gas-fired generation, MISO is evaluating the Resource Adequacy requirements. This evaluation has led to a number of proposed reforms of the Resource Adequacy construct:

- Informed by stakeholder feedback, MISO is developing a capacity market construct (referred to as the "Competitive Retail Solution") for retail choice areas to assure Resource Adequacy while preserving the existing construct for the remainder of the footprint
- Interconnection Queue Reform
- Seasonal Reliability and Locational proposals including:
    - Visibility into winter resource adequacy risk
    - Ensuring the seasonal variation in resource capability are accounted for
    - Aligning treatment of external and internal resources.

6.1 Planning Reserve Margin

The MISO Installed Capacity Planning Reserve Margin (PRM ICAP) for the 2016-2017 planning year, spanning from June 1, 2016, through May 31, 2017, is 15.2 percent, an increase of 0.9 percentage point from the 14.3 percent PRM set in the 2015-2016 planning year (Figure 6.1-1).

The PRM ICAP is established with resources at their installed capacity rating at the time of the system-wide MISO coincident peak load. The 0.9 percentage point PRM ICAP increase was the net effect of several modeling parameters such as changes to load forecast, load forecast uncertainty and resource characteristics.

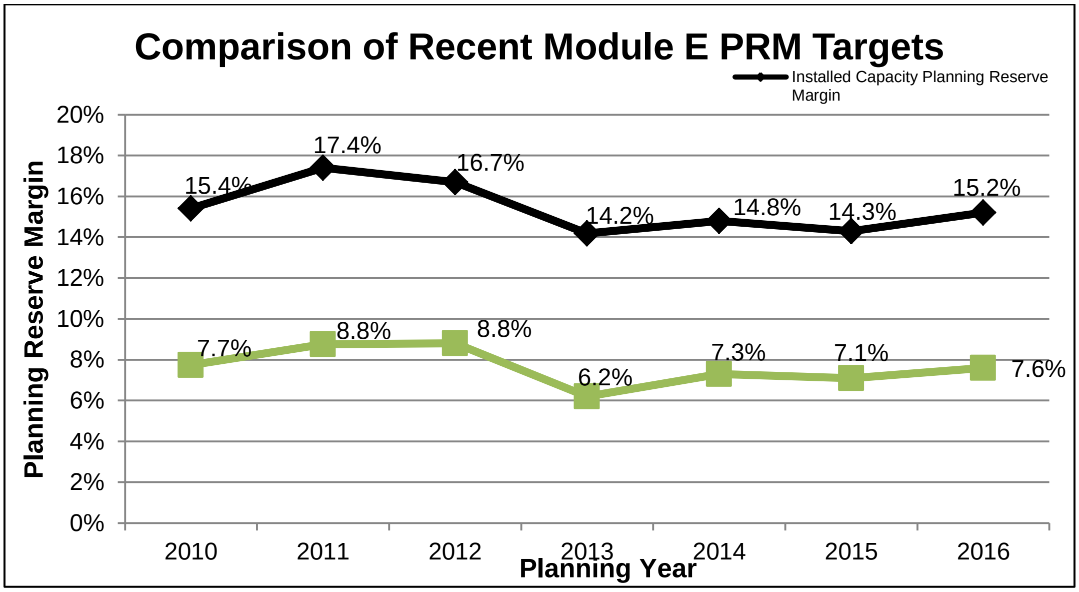


Figure 6.1-1: Comparison of recent PRM

As directed under Module E-1 of the MISO Tariff, MISO coordinates with stakeholders to determine the appropriate Planning Reserve Margin (PRM) for the applicable planning year based upon the probabilistic analysis of the ability to reliably serve MISO Coincident Peak Demand for that planning year. The probabilistic analysis uses a Loss of Load Expectation (LOLE) study that assumes no internal transmission limitations within the MISO Region. MISO calculates the PRM such that the LOLE for the next planning year is one day in 10 years, or 0.1 days per year. The minimum amount of capacity above Coincident Peak Demand in the MISO Region required to meet the reliability criteria is used to establish the PRM. The PRM is established as an unforced capacity (PRM UCAP) requirement based upon the weighted average forced outage rate of all Planning Resources in the MISO Region.

The LOLE study and the deliverables from the Loss of Load Expectation Working Group (LOLEWG) are based on the Resource Adequacy construct per Module E-1. MISO performs an LOLE study to determine the congestion-free PRM on an installed and unforced capacity basis for the MISO system. In addition, a per-unit zonal Local Reliability Requirement (LRR) for the planning year is determined for each Local Resource Zone (LRZ) (Figure 6.1-2), which is defined as the amount of resources a particular area needs to meet the LOLE criteria of one day in 10 years without the benefit of the Capacity Import Limit (CIL).

These results are merged with the CIL, Capacity Export Limit (CEL) and Wind Capacity Credit results to form the deliverables to the annual Planning Resource Auction.

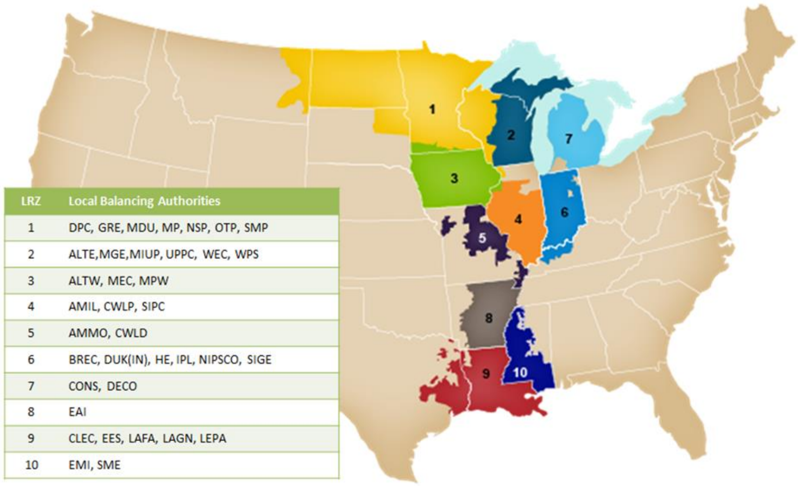


Figure 6.1-2: Local Resource Zones (LRZ)

2016-2017 Deliverables to the Planning Resource Auction

The PRM deliverables are needed for the Planning Resource Auction (PRA). These deliverables include the PRM UCAP, a per-unit zonal LRR, and CIL and CEL values (Table 6.1-1). The PRM UCAP increased from 7.1 percent to 7.6 percent due to the modeling parameter changes. More information on the increase is available in the 2016 LOLE report. Under the existing construct, the PRM UCAP is applied to the peak of each Load Serving Entity coincident with the MISO peak. A zonal CIL and CEL for each LRZ was calculated with the monitored and contingent elements reported (Tables 6.1-2 and 6.1-3; Figures 6.1-3 and 6.1-4). Adjustments were made to CIL based on FERC order on accommodation of resources committed to non-MISO load. The ultimate PRM, CIL and CEL values for a zone could be adjusted within the PRA depending on the demand forecasts received and offers into the auction to assure that the resources cleared in the auction can be reliably delivered.

RA and LOLE Metrics	LRZ 1	LRZ 2	LRZ 3	LRZ 4	LRZ 5	LRZ 6	LRZ 7	LRZ 8	LRZ 9	LRZ 10
Default Congestion Free PRM UCAP	7.6%	7.6%	7.6%	7.6%	7.6%	7.6%	7.6%	7.6%	7.6%	7.6%
LRR UCAP per-unit of LRZ Peak Demand	1.110	1.143	1.129	1.218	1.210	1.108	1.132	1.257	1.125	1.392
Capacity Import Limit (CIL) (MW)	3,436	1,609	1,186	6,323	4,837	5,610	3,521	3,527	4,490	2,653
Capacity Export Limit (CEL) (MW)	590	2,996	1,598	7,379	896	2,544	4,541	2,074	1,261	1,857

Table 6.1-1: Deliverables to the 2016-2017 Planning Resource Auction (PRA)

LRZ	Tier	16-17 Limit (MW)[1]	Monitored Element	Contingent Element	Figure 6.1-3 Map ID	Initial Limit (MW)[2]	Generation Redispatch Details		15-16 Limit (MW)
							MW	Area(s)	
1	1 & 2	3,436	Colby to Northern Iowa Windpower 161 kV Line	Adams to Barton 161 kV Line	1	3,432	N/A	N/A	3,735
2	1	1,609	Stoneman to Nelson-Dewey 161 kV Line	Wempletown to Paddock 345 kV Line	2	1,111	188	METC, XEL, MP, DPC	2,903
3	1	1,186	Palmyra 345-161 kV Transformer	Palmyra Tap to Sub T 345 kV Line	3	989	2,000	WEC, AMMO, AMIL, GRE, MPW	1,972
4	1 & 2	6,323	Palmyra 345/161 kV Transformer	Montgomery to Spencer 345 kV Line	3	1,970	2,164	WEC & EES	3,130
5	1	4,837	Russellville East to Russellville South 161 kV Line	Arkansas Nuclear One to Fort Smith 500 kV Line	4	4,297	491	AMIL, ALTW, OTP, MEC	3,899
6	1 & 2	5,610	Rising 345/138 kV Transformer	Clinton to Brokaw 345 kV Line	5	3,598	3,020	METC & AMIL	5,649
7	1 & 2	3,521	Argenta to Battle Creek 345 kV Line	Paxton to Tompkins 345 kV Line	6	1,970	2,000	NIPS, CE, WEC	3,813
8	1	3,527	Montgomery to Clarence 230 kV Line	Hartburg to Layfield 500 kV Line	7	0	2,000	AMMO, EES	2,074
9	1	4,490	Andrus 230/115 kV Transformer	Andrus to Indianola 230 kV Line	8	2,579	717	EES & LAGN	*4,008
10	1	2,653	Ray Brasswell Transformer	Ray Brasswell to Lakeover 500 kV Line	9	172	2,000	SMEPA & EES-EMI	*2,630

*Values determined in LRZ Re-evaluation study presented on February 4, 2015, LOLE Working Group

Table 6.1-2: 2016-2017 Planning Year Capacity Import Limits

[1] The 16-17 Limit represents the limit after consideration for redispatch and adjustment for FERC order
[2] The Initial Limit represents the limit before considering redispatch.

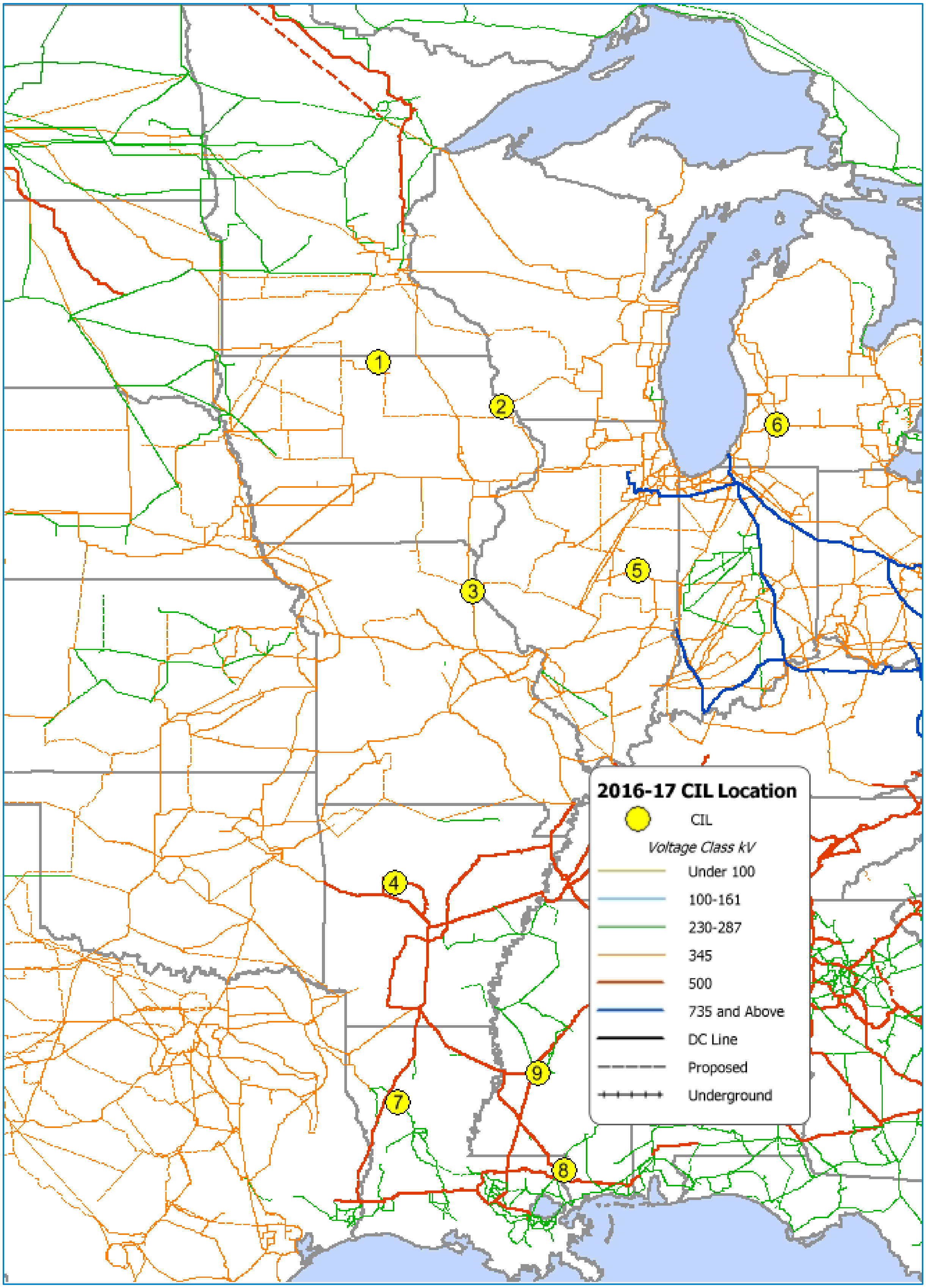


Figure 6.1-3: 2016-2017 Capacity Import Limit map

LRZ	16-17 Limit (MW)	Monitored Element	Contingent Element	Figure 6.1-4 Map ID	Initial Limit (MW)	Generation Redispatch Details		15-16 Limit (MW)
						MW	Area	
1	590	Lakefield to Dickinson 161 kV Line	Raun to Highland 345 kV Line	1	0	1,627	XEL, MP, GRE, OTP, ALTW, MEC, WPS	604
2	2,996	St Rita To Racine 138 kV Line	Racine to Elm Road 345 kV Line	2	1,259	965	CE	1,516
3	1,598	Oak Grove to Mercer 161 kV Line	Havana Unit 6	3	1,598	0	N/A	1,477
4	7,379	Newton to Casey 345 kV Line	Casey West to Neoga 345 kV Line	4	7,379	0	N/A	4,125
5	896	Newton To Casey 345 kV Line	Casey West to Neoga 345 kV Line	4	0	224	AMMO	0
6	2,544	Tap to AEP Rockport to Grandview 138 kV Line	AB Brown to Reid EHV Substation to Wilson 345 kV Line	5	2,544	0	N/A	2,930
7	4,541	Benton Harbor 345/138 kV Transformer	Benton to Cook 345 kV Line	6	4,541	0	N/A	4,804
8	2,074	Russelville North to Russelville East 161 kV Line	Arkansas Nuclear One to Fort Smith 500 kV Line	7	2,074	0	N/A	3,022
9	1,261	Port Neches Bulk to Flatland 138 kV Line	Sabine 345/138 kV Transformer	8	0	2,000	EES, LAFA, LEPA, CLECO	*2,418
10	1,857	Plant Morrow to Purvis Bulk 161 kV Line	Plant Morrow to Purvis Bulk 161 kV Line	9	0	2,000	EES-EMI, SMEPA	*1,959

*Values determined in LRZ Re-evaluation study presented on February 4, 2015, LOLE Working Group

Table 6.1-3: 2016-2017 Planning Year Capacity Export Limits

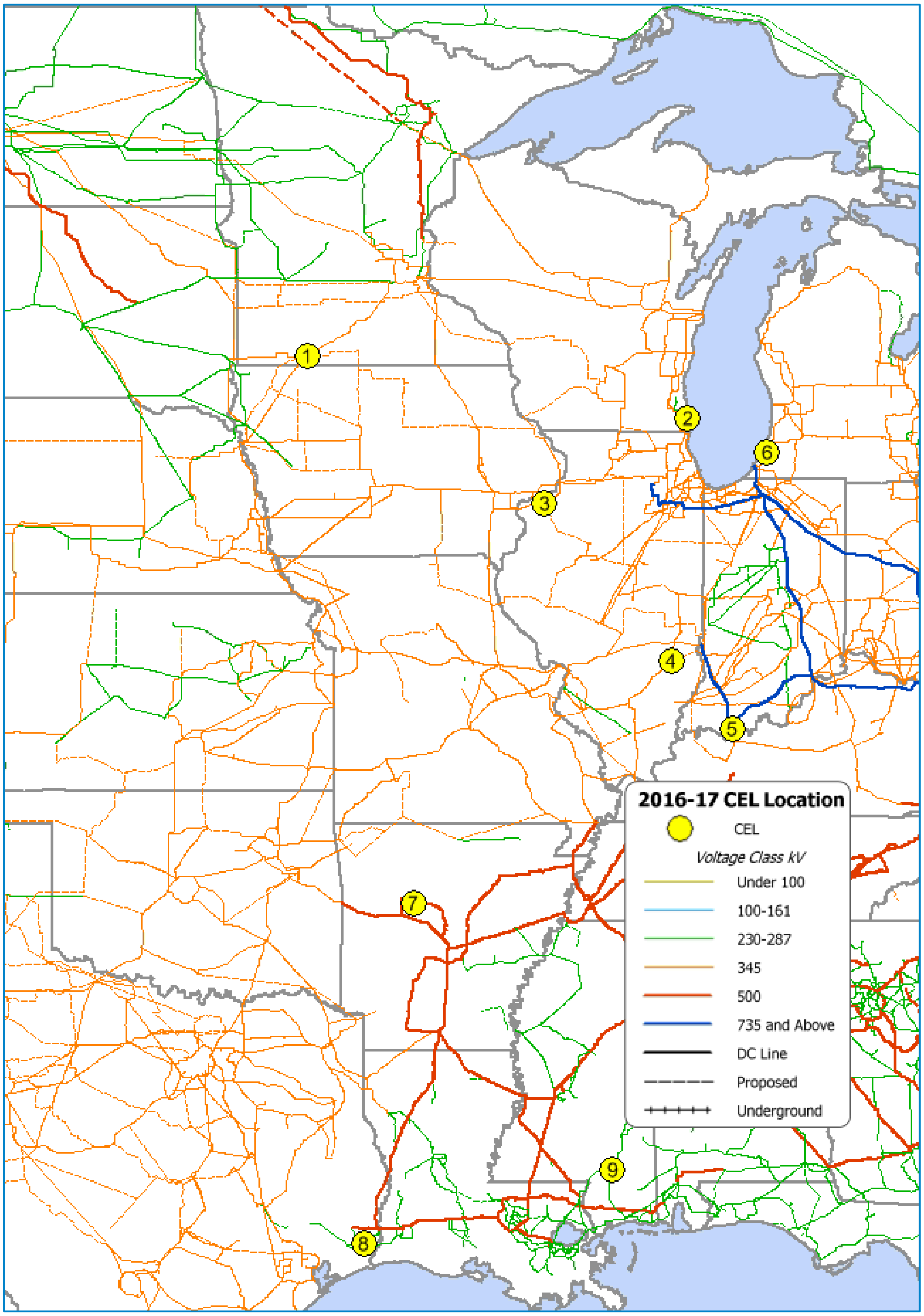


Figure 6.1-4: 2016-2017 Capacity Export Limit map

MTEP Projects and Capacity Import and Export Limits

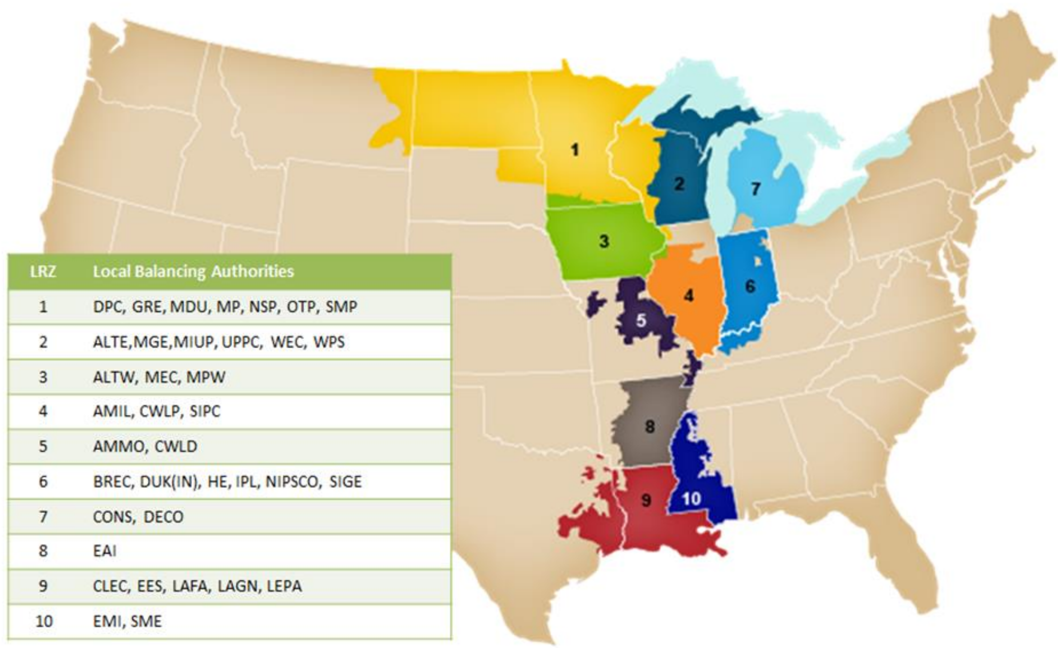
The Capacity Import and Export Limits are deliverables to the PRM for the Planning Resource Auction and are considered in the development of the MTEP. Table 6.1-4 is a list of projects potentially impacting the most limiting elements observed in the CIL and CEL results as shown in Tables 6.1-2 and 6.1-3.

Year	LRZ	CEL or CEL	Monitored Element	Contingent Element	MTEP Project ID	Target Appendix	Project Name	Min Expected ISD
16-17	1	CEL	Lakefield to Dickinson 161 kV Line	Raun to Highland 345 kV Line	3205, 3213	A in MTEP14	Proposed MVP Portfolio 1: Lakefield Jct. – Winnebago – Winco – Kossuth County & Obrien County – Kossuth County – Webster 345 kV line and Proposed MVP Portfolio 1 – Winco to Hazleton 345 KV line	9/28/2015 – 6/1/2018, 6/1/2015 – 12/31/2018
16-17	2	CIL	Stoneman to Nelson-Dewey 161 kV Line	Wempletown to Paddock 345 kV Line	3127	A in MTEP11	Proposed MVP Portfolio 1: North LaCrosse – North Madison – Cardinal – Eden – Hickory Creek 345 kV Line	12/31/2017 – 12/31/2023
16-17	2	CEL	St Rita To Racine 138 kV Line	Racine to Elm Road 345 kV Line	3894, 3895	A in MTEP13	Reconductor Racine – Oak Creek 138 kV, Reconductor Oak Creek – Kansas 138 kV	2/22/2016, 6/1/2016
16-17	3, 4	CIL	Palmyra Transformer	Montgomery to Spencer 345 kV	3017	A in MTEP11	Proposed MVP Portfolio 1: Maywood – Herleman – Meredosia – Ipava & Meredosia – Austin 345 kV Line	11/15/2017
16-17	7	CIL	Argenta to Battle Creek 345 kV Line	Paxton to Tompkins 345 kV Line	8067, 4509	A in MTEP15	Beals Road 138 kV Station Equipment Replacement, Argenta – Battle Creek 345 kV Sag Remediation and Station Equipment	6/1/2017, 12/31/2017
16-17	9	CIL	Andrus 230/115 kV Transformer	Andrus to Indianola 230 kV Line	8520	B in MTEP16	Upgrade Andrus 230/115 kV autotransformer. Install 2nd 230/115 kV autotransformer at Indianola.	6/1/2020
16-17	10	CIL	Ray Braswell Transformer	Ray Brasswell to Lakeover 500 kV Line	9829	B in MTEP16	Ray Braswell 500/115 upgrade 115 kV breakers	6/1/2019

Table 6.1-4: MTEP projects potentially impacting the most limiting constraints

Wind Capacity Credit

A class-average wind capacity credit of 15.6 percent was established for the 2016-2017 planning year by determining the Effective Load Carrying Capability (ELCC) of wind resources. The wind capacity credit increased 0.9 percentage point from the wind capacity credit of 14.7 percent established in the 2015-2016 Planning Year (Figure 6.1-5). For more information, refer to the complete 2016 Wind Capacity Credit Report[3].



LRZ	Local Balancing Authorities
1	DPC, GRE, MDU, MP, NSP, OTP, SMP
2	ALTE,MGE,MIUP, UPPC, WEC, WPS
3	ALTW, MEC, MPW
4	AMIL, CWLP, SIPC
5	AMMO, CWLD
6	BREC, DUK(IN), HE, IPL, NIPSCO, SIGE
7	CONS, DECO
8	EAI
9	CLEC, EES, LAFA, LAGN, LEPA
10	EMI, SME

Metric	MISO	Zone 1	Zone 2	Zone 3	Zone 4 and Zone 5	Zone 6	Zone 7	Zone 8	Zone 9	Zone 10
Registered Max (MW)	14,732	4,315	627	7,379	644	282	1,486	0	0	0
UCAP (MW)	2,292	813	87	1,042	80	27	244	0	0	0
ELCC %	15.6%	18.8%	13.8%	14.1%	12.4%	9.6%	16.4%	0.0%	0.0%	0.0%
Wind CPnode Count	196	69	10	81	8	4	24	0	0	0

Figure 6.1-5: Wind Capacity Credit by Local Resource Zones (LRZ) for 2016-2017 Planning Year

Solar Capacity Credit

A class-average solar capacity credit of 50 percent was established for the 2016-2017 planning year by estimating the peak period contribution from historical solar irradiance simulation data. New resources without summer operating history will receive this class average capacity credit until at least 30 consecutive days of summer performance data are available, at which time the resource's individual capacity credit will be based on its own operating history. More details can be found in the MISO BPM-011 in section 4.

For more information related to the LOLE study, refer to the Planning Year 2016 LOLE study report.

[3] Or: https://www.misoenergy.org/Library/Repository/Report/2016%20Wind%20Capacity%20Report.pdf

6.2 Long-Term Resource Assessment

The Long-Term Resource Assessment (LTRA) examines the balance between projected resources and the projected load. These resources are compared with Planning Reserve Margin Requirements (PRMR) to calculate a projected surplus or shortfall.

MISO forecasts the reserve margin will drop below the PRMR of 15.2 percent beginning in 2018, and will remain below the PRMR for the rest of the assessment period (Table 6.2-1). Falling below the PRMR signifies that the MISO region is projected to operate at a reliability level lower than the one-day-in-10 standard in 2018 and beyond. MISO anticipates the projected margin shortfall will change significantly as Load Serving Entities and state commissions solidify future capacity plans.

This is an expected result, as 91 percent of the load in the MISO footprint is served by utilities with an obligation to serve. This obligation is reflected as a part of state and locally jurisdictional integrated resource plans that only become certain upon the receipt of proper regulatory approvals, such as a Certificate of Public Convenience and Necessity (CPCN). Two years is not sufficient lead time for Load Serving Entities to plan, build and operate new resources to meet the projected shortfall in 2018 and beyond.

In GW (ICAP)	PY 2017/18	PY 2018/19	PY 2019/20	PY 2020/21	PY 2021/22	PY 2022/23	PY 2023/24	PY 2024/25	PY 2025/26	PY 2026/27
(+) Existing Resources	151.6	151.0	150.7	150.1	149.9	147.8	146.2	145.9	144.9	144.6
(+) New Resources	1.6	2.0	2.6	2.6	2.7	2.7	2.7	2.7	2.7	2.7
(+) Imports	4.2	4.1	4.1	4.1	4.2	4.2	4.2	4.2	4.2	4.2
(-) Exports	4.7	4.7	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9
(-) Low Certainty Resources	1.8	2.6	3.0	3.0	3.1	3.2	3.2	3.2	3.2	3.2
(-) Transfer Limited	2.9	2.2	1.9	1.8	1.6	1.3	1.0	0.7	0.4	0.1
Available Resources	147.9	147.6	148.7	148.2	148.1	146.3	145.0	144.9	144.3	144.2
Demand	127.6	128.4	129.5	130.2	130.9	131.7	132.3	133.0	133.6	134.5
PRMR	147.0	147.9	149.2	150.0	150.8	151.7	152.4	153.2	153.9	154.9
PRMR Shortfall	0.9	-0.4	-0.5	-1.9	-2.6	-5.4	-7.4	-8.2	-9.6	-10.7
Reserve Margin Percent (%)	15.9%	14.9%	14.8%	13.8%	13.2%	11.1%	9.6%	9.0%	8.0%	7.3%

Table 6.2-1: MISO anticipated PRMR details (cumulative)

The anticipated PRMR shows a potential regional shortfall against the reserve requirements of 0.4 GW, which is two years earlier than the 2015 MISO LTRA results. The conclusions from the long-term resource assessments are:

- A decrease in resources committed to serving MISO load mainly by independent power producers (IPP)
- A decrease in load forecasts where the biggest drop was in Zone 6 (Indiana)
- The increase in committed resources (Tier 1) in Zone 7 (Michigan)
- MISO projects that each zone within the MISO footprint will have sufficient resources within its boundaries to meet its Local Clearing Requirements, or the amount of its local resource requirement, which must be contained within their boundaries
- Several zones are short against their total zonal reserve requirement, when only resources within their boundaries or contracted to serve their load are considered. However, those zones have sufficient import capability and the MISO region has sufficient surplus capacity in other zones to support this transfer. Surplus generating capacity for zonal transfers within MISO could become scarce in later years if no action is taken in the interim by MISO load-serving entities.
- All zones within MISO are sufficient from a resource adequacy point of view in the near term, when available capacity and transfer limitations are considered. Regional shortages in later years may be rectified by the utilities; also MISO is engaged with stakeholders in a number of resource adequacy reforms to help rectify these out-year shortages.

Policy and changing generation trends continue to drive new potential risks to resource adequacy, requiring continued transparency and vigilance to ensure long-term needs.

MISO projects that reserve margins will continue to tighten over the next five years, approaching the reserve margin requirement.

Operating at the reserve margin creates a new operating reality for MISO members where the use of all resources available on the system and emergency operating procedures are more likely. This reality will lead to a projected dependency in the use of Load Modifying Resources (LMR), such as Behind-the-Meter Generation (BTMG) and Demand Response (DR)

Assumptions

At the end of 2013 MISO and the Organization of MISO States (OMS) conducted a Resource Adequacy survey of load-serving entities to help bridge the gap of limited visibility that exists between the annual Module E Tariff process and Forward Resource Assessment. MISO finished the third iteration of the OMS-MISO survey in June 2016, and it was instrumental in the development of the Long-Term Resource Assessment and the Resource Adequacy outlook for the MISO region.

Demand Growth

In 2017, MISO anticipates that the MISO Region’s coincident demand will be 127,607 MW, which is a 50/50 weather-normalized load forecast.

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Load-serving entities submit demand forecasts for the upcoming 10 years. MISO utilizes these forecasts to calculate a MISO business-as-usual load growth. Based on these forecasts, MISO anticipates a system-wide average growth rate of 0.6 percent for the period from 2016 to 2026.

Resources

In 2017, MISO expects a total of 147,900 MW of Anticipated Capacity Resources to be available on peak.

In 2017, MISO expects a total of 147,900 MW of Anticipated Capacity Resources to be available on peak

MISO's current registered capacity (nameplate) of 173,289 MW steps down to Existing-Certain Capacity Resources of 141,100 MW by accounting for summer on-peak generator performance (including wind capacity at 15.6 percent of nameplate), transmission limitations and energy-only capacity (Existing-Other Capacity Resources). MISO only relies on 141,100 MW towards its PRMR to meet a loss-of-load expectation of one day in 10 years.

BTMG, Interruptible Load (IL), Direct Control Load Management (DCLM) and Energy Efficiency Resources (EER) are eligible to participate as registered LMRs. All of these are emergency resources available to MISO only during a Maximum Generation Emergency Event Step 2b per MISO's Emergency Operating Procedures. MISO assumes the 4,144 MW of BTMG dropping to 4,132 in 2021 and 5,827 MW of LMR DR that was qualified in the 2016 Planning Resource Auction to be available throughout the assessment period.

This year, MISO and OMS completed the third iteration of the Resource Adequacy Survey. In the survey, resources that were identified to have a low certainty of serving load were not included (Table 6.2-1).

Through the Generator Interconnection Queue (GIQ) process, MISO anticipates 2,665 MW of future firm capacity additions and uprates to be in-service and expected on-peak during the assessment period (Figure 6.2-1). This is based on a snapshot of the GIQ as of June 2016 and is the aggregation of active projects with a signed Interconnection Agreement.

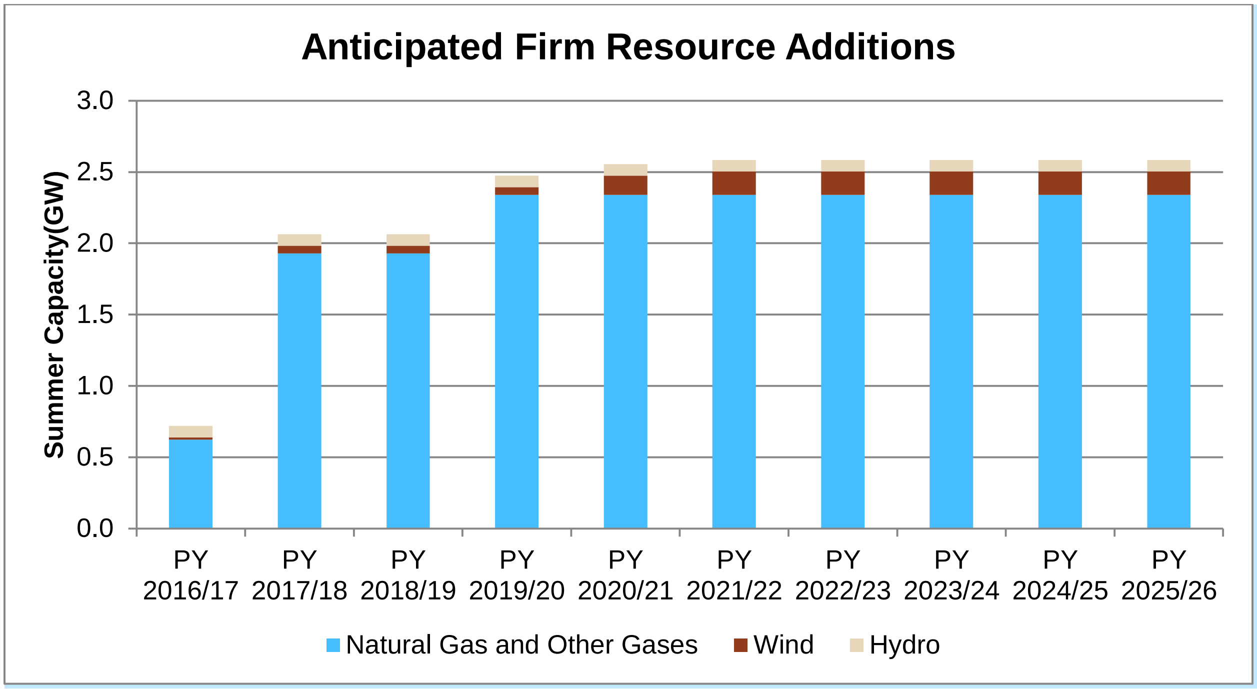

Figure 6.2-1: Anticipated resource additions and uprates (cumulative) in the MISO Region

Imports and Exports

MISO assumes a forecast of 4,213.3 MW of capacity from outside of the MISO footprint to be designated firm for use during the assessment period and cannot be recalled by the source transmission provider. This capacity was designated to serve load within MISO through the Module E process for summer 2016. It's assumed that the firm imports continue at this level for the assessment period. MISO assumes a forecast of 4,744.7 MW of firm capacity exports in year 2017. Exports are projected to decrease to 3,900 MW in 2019 and remain at that level for the rest of the assessment period.

When comparing reserve margin percent numbers between Table 6.2-1 and the NERC LTRA, the percent for each planning year will be slightly lower in the NERC LTRA because of differences in the reserve margin percent calculation. MISO's resource adequacy construct counts DR as a resource while the NERC calculates DR on the demand side. While the percent will be slightly different, the absolute GW shortfall/surplus is comparable between the two.

6.3 Seasonal Resource Assessment

MISO conducts seasonal resource assessments for the winter months of December, January and February as well as for summer months of June, July and August. Seasonal assessments primarily evaluate the expected near-term system performance and prepare operators for the upcoming season. The MISO resource assessments coincide with NERC seasonal reliability assessments and MISO operational readiness workshops held prior to the assessment's season.

The 2015-2016 winter and 2016 summer season findings show that the projected capacity levels exceed the Planning Reserve Margin Requirement, with adequate resources to serve load.

Seasonal Assessment Methods

MISO studies multiple scenarios at varying capacity resource levels, expected demand levels and forced outage rates. In order to align with intra-Regional Transmission Owner (RTO) expected dispatch, only 876 MW above the MISO South load and reserve margin were counted toward aggregate margins at coincident peak demand in all of the projected scenarios for the 2016 Summer Assessment.

MISO coordinates extensively with neighboring Reliability Coordinators as part of the seasonal assessment and outage coordination processes, via scheduled daily conference calls and ad-hoc communications as need arises in real-time operations. There is always the potential for a combination of higher loads, higher forced outage rates and fuel limitations. In the summer, unusually hot and dry weather can lead to low water levels and/or high water temperatures. This can impact the maximum operating capacity of thermal generators that rely on water resources for cooling, leading to added deratings in real time and lowering functional capacity. MISO resolves these situations through existing procedures depending on the circumstances, and several scenarios are studied for each season to project the possible reserve margins expected.

Demand

Based on 21 years of historic actual load data, MISO calculates a Load Forecast Uncertainty (LFU) value from statistical analysis to determine the likelihood that actual load will deviate from forecasts. A normal distribution is created around the 50/50 forecast based on a standard deviation equal to the LFU of the 50/50 forecast. This curve represents all possible load levels with their associated probability of occurrence. At any point along the curve it is possible to derive the percent chance that load will be above or below a load value by finding the area under the curve to the right or left of that point. MISO chooses the 90th percentile for the High Load scenarios. For more information regarding this analysis, refer to the Planning Year 2016 LOLE Study.

Demand Reporting

MISO does not forecast load for the Seasonal Resource Assessments. Instead, Load Serving Entities (LSEs) report load projections under the Resource Adequacy Requirements section (Module E-1) of the MISO Tariff. LSEs report their annual load projections on a MISO Coincident basis as well as their Non-Coincident load projections for the next 10 years, monthly for the first two years and seasonally for the remaining eight years. MISO LSEs have the best information of their load; therefore, MISO relies on them for load forecast information.

For these studies, MISO created a Non-Coincident and a Coincident peak demand on a regional basis by summing the annual peak forecasts for the individual LSEs in the larger regional area of interest.

2015-2016 Winter Overview

For planning year 2015-2016, MISO's Planning Reserve Margin Requirement (PRMR) was 14.3 percent. For the 2015-2016 winter peak hour, MISO expected adequate resources to serve load, with a NERC-reported base projected reserve margin of 41.0 percent, which far exceeds the PRMR of 14.3 percent. The winter scenarios project the reserve margin to be in the range of 34.1 to 43.6 percent (Figure 6.3-1).

MISO's 50/50 coincident peak demand for the 2015-2016 winter season was forecasted to be 103,965 MW including transmission losses, with 146,613 MW of capacity to serve MISO load during the 2015-2016 winter season. Excluded from the capacity are 3,955 MW of MISO South resources to align with the Planning Resource Auction (PRA) Sub-Regional Export Constraint (SREC).

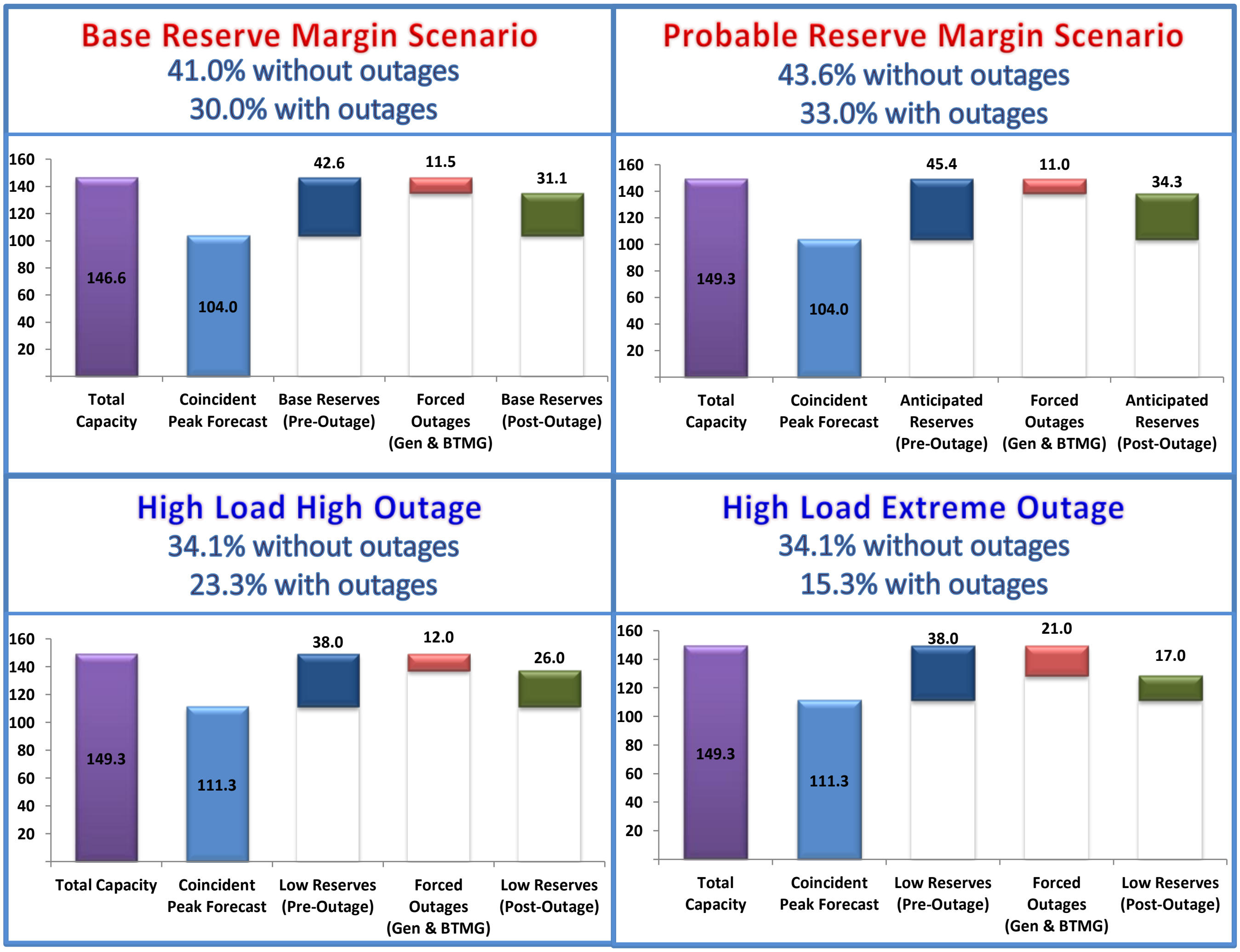

Figure 6.3-1: Winter 2015-2016 Projected Reserve Margin scenarios (GW)

2015-2016 Winter Rated Capacity

For the 2015-2016 winter season, MISO projected 146,613 MW of existing certain capacity to serve MISO load during the winter. The capacity includes 2,699 MW of Behind-the-Meter Generation (BTMG) and 4,047 MW of Demand Resource (DR) programs, with 56 MW of Net Firm Exports. MISO expected 1,388 MW of wind capacity to be available to serve load for the winter.

MISO arrived at the Winter Rated Capacity value by reducing the Nameplate Capacity of its market footprint by multiple variables. The majority of the derates expected at-peak are due to resource interconnection limitations of 6,009 MW; thermal unit winter output reductions of 7,307 MW; and reductions due to the Effective Load Carrying Capability of wind resources of 10,321 MW based on available nameplate wind resources of 12,161 MW. Capacity from the South, equal to its load and reserve margin requirement, was included in the regional total. Additionally, it assumed that 1,000 MW of excess capacity transferred to the North/Central region of the footprint due to the estimated SREC for the PRA.

For more information regarding methodology and assumptions of the Winter Rated Capacity, refer to Appendix A.2 of the 2015-2016 Winter Resource Assessment.

Winter Reserve Margin Scenarios

MISO's projected 2015-2016 MISO Winter Rated Capacity varies by scenario (Figures 6.3-2 through 6.3-6). MISO chose the 90th percentile of the normal distribution around a 50/50 load forecast for the High Load scenarios, which was 111,313 MW for the 2015-2016 winter. For more information regarding each scenario, refer to Appendix A.3 of the 2015-2016 Winter Resource Assessment.

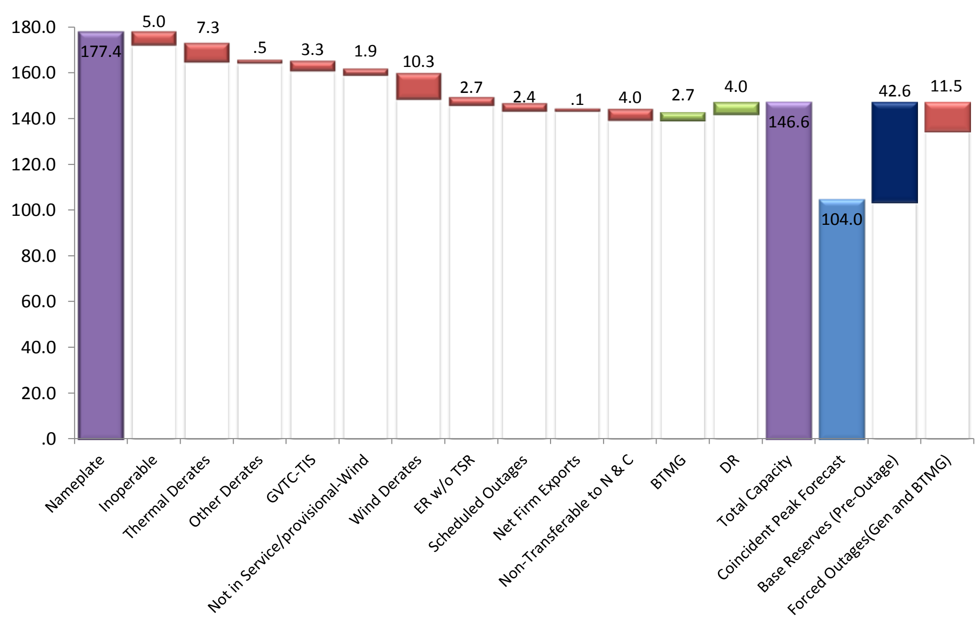

Figure 6.3-2: 2015-2016 Winter Rated Capacity projected Base scenario (GW)

The anticipated scenario contains additional assumptions (Figure 6.3-3). MISO expects that any energy resource without firm point-to-point Transmission Service Rights will serve load locally, termed Energy Only. The portion of Energy Only from the MISO South region is excluded from the calculation to align with the 1,000 MW contract path limitation for the 2015-16 Planning Year.

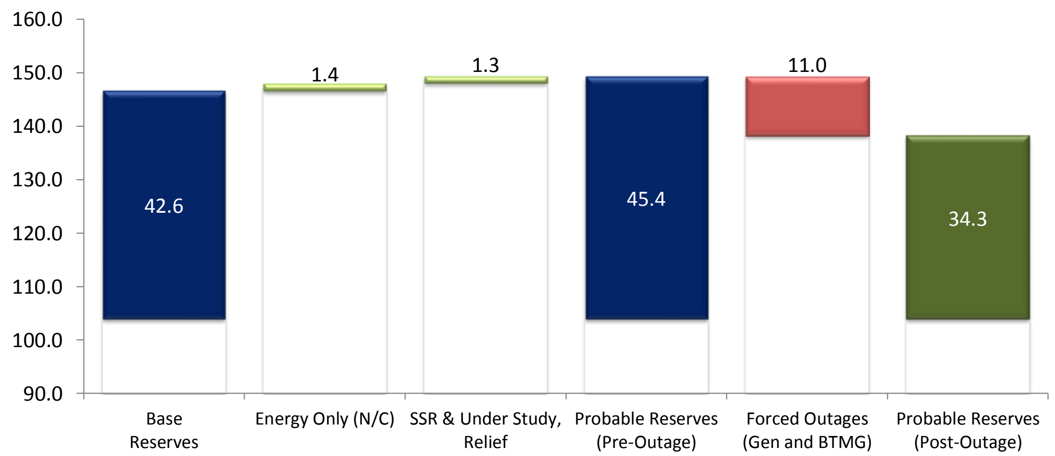

Figure 6.3-3: 2015-2016 Winter Rated Capacity projected Anticipated scenario (GW)

In real-time, during normal operating conditions, MISO must carry Operating Reserves above load to maintain system reliability. The amount of Operating Reserves required to clear on a daily basis for the 2015-2016 winter season was 2,400 MW, which is called on as a last resort before load shed (Figure 6.3-4). These reserves are made up of a combination of Regulating Reserves, Spinning Reserves and Supplemental Reserves.

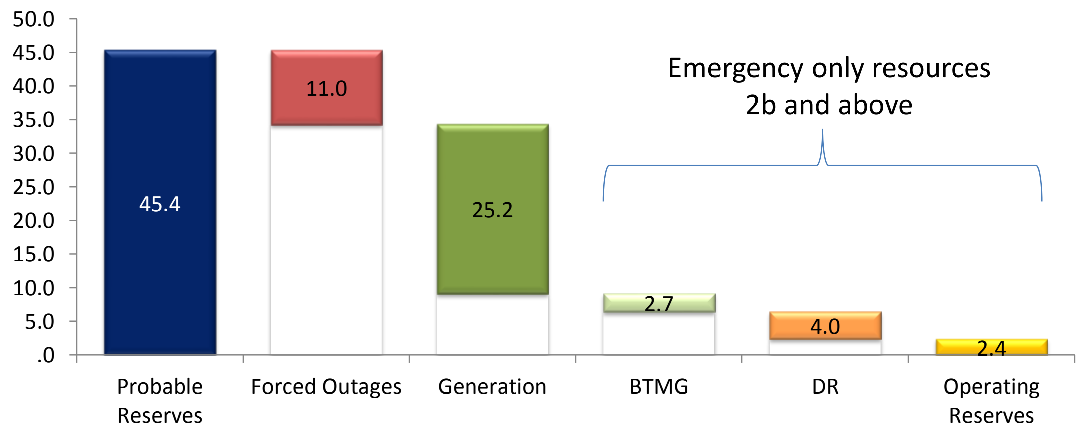

Figure 6.3-4: 2015-2016 Winter Rated Capacity projected Anticipated scenario reserves (GW)

The High Demand, High Outage scenario has added assumptions (Figure 6.3-5). Beginning with the anticipated reserves from the Anticipated scenario (Figure 6.3-3), the load increases to show the higher load from a 90/10 forecast. A higher forced outage rate is assumed, using the highest historical forced outage rate applied to the capacity resources available. An extreme forced outage rate is applied to the Extreme scenario, based on information from the polar vortex of the 2013-2014 winter.

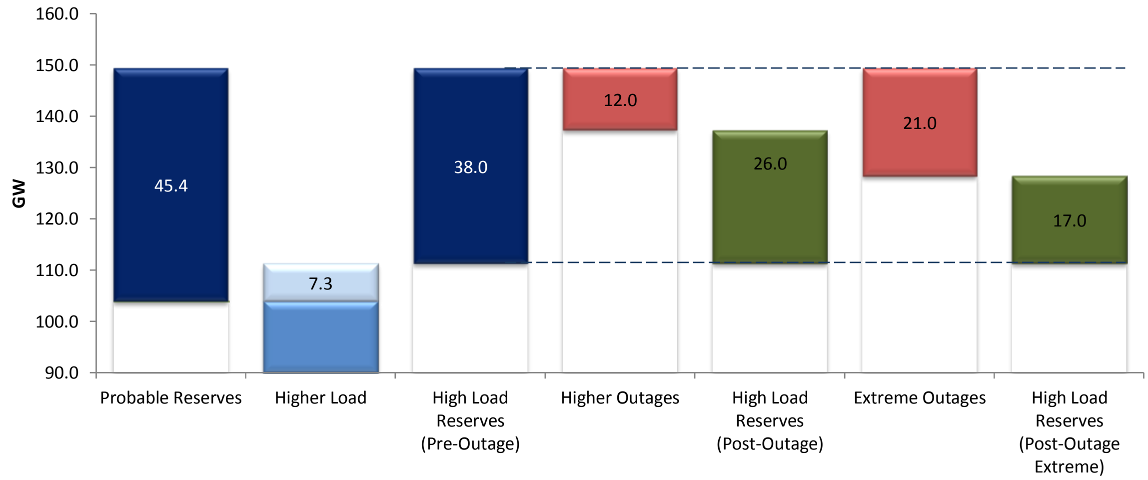

Figure 6.3-5: Winter Rated Capacity projected High-Demand, High-Outage scenario (GW)

2016 Summer Overview

For planning year 2016-2017, MISO's PRM is 15.2 percent. During the 2016 summer peak hour, MISO expected adequate resources to serve load, with a NERC-reported base projected reserve margin of 18.2 percent, which exceeds the requirement of 15.2 percent by 3.0 percentage points. The summer scenarios project the reserve margin to be in the range of 13.5 to 19.2 percent (Figure 6.3-7).

MISO's 50/50 coincident peak demand for the 2016 summer season was forecasted to be 125,913 MW including transmission losses, with 148,778 MW of capacity to serve MISO load. Excluded from the capacity are 2,874 MW of MISO South resources to align with the 876 MW intra-RTO contract path.

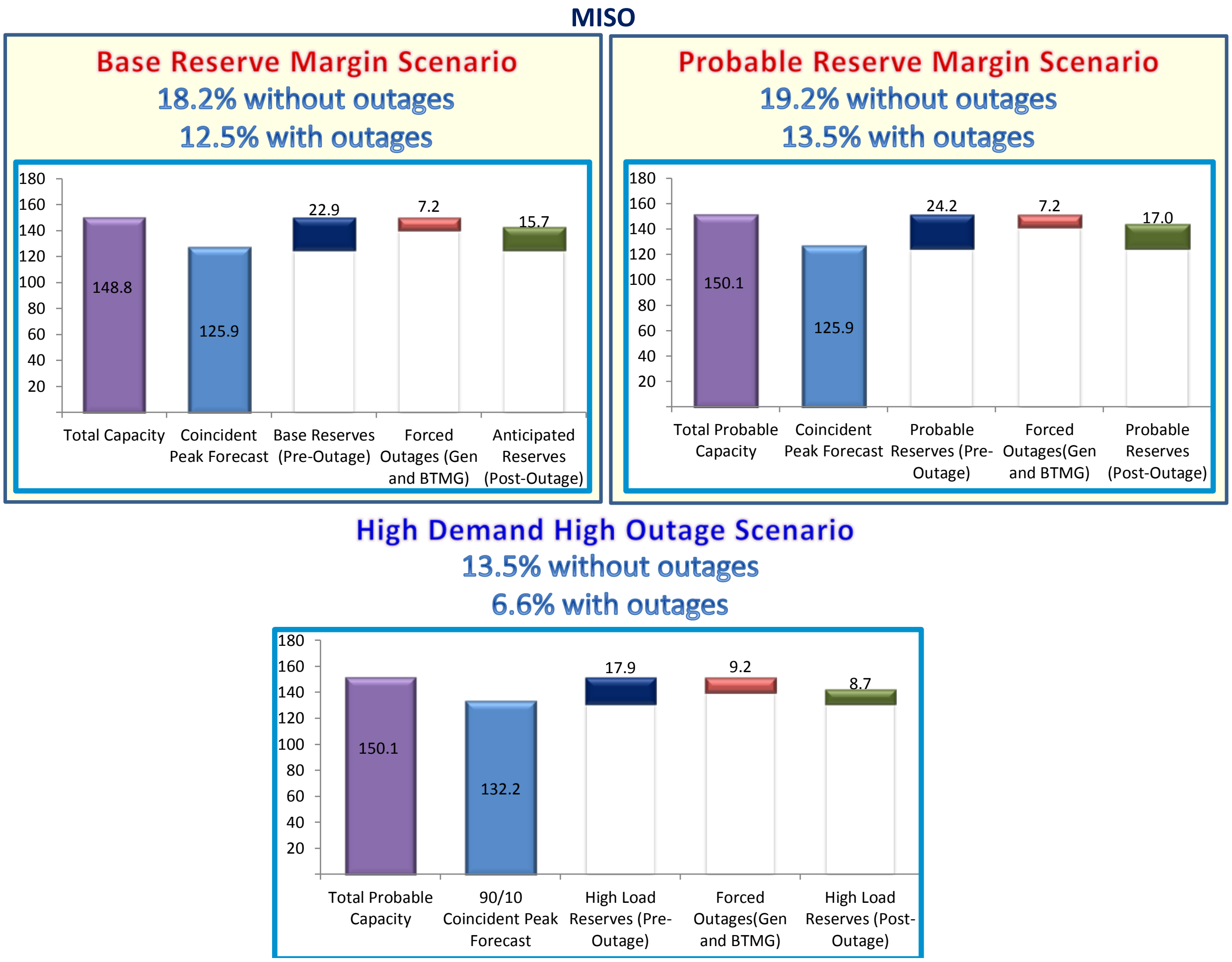

Figure 6.3-6: Summer 2016 Projected Reserve Margin scenarios

2016 Summer Rated Capacity

For 2016, MISO projected 148,778 MW of capacity to serve MISO load during the 2016 summer season. The capacity includes 3,724 MW of BTMG and 5,819 MW of DR programs, while including 965 MW of Net Firm Imports. MISO expected 1,773 MW of wind capacity to be available to serve load this summer, after discounting wind capacity in the Commercial Model with pending interconnection agreements and capacity with Energy Resource Interconnection Service without a firm point-to-point Transmission Service Request. Capacity from the South, equal to its load and reserve margin requirement, was included in the regional total. Additionally, 876 MW of excess capacity was assumed as transferred to the North/Central region of the footprint.

MISO arrived at the Summer Rated Capacity value by reducing the Nameplate Capacity of its market footprint by multiple variables. The majority of the derates expected at-peak are due to resource interconnection limitations (760 MW); thermal unit summer output reductions (12,031 MW); and reductions due to the Effective Load Carrying Capability of wind resources (12,031 MW). Also, any MISO South capacity over the total of South Load, South reserve margin requirement, and 1,000 MW of contract path was not included in the regional value. This means that 2,874 MW of MISO South excess capacity was excluded from the calculation to align with 876 MW contract path limitation.

Reserve Margin Scenarios

MISO's projected 2016 MISO Summer Rated Capacity varies by scenario (Figures 6.3-8 through 6.3-10). MISO chose the 90th percentile of the normal distribution around a 50/50 load forecast for the High Load scenarios, which was 132,231 MW for the 2016 summer.

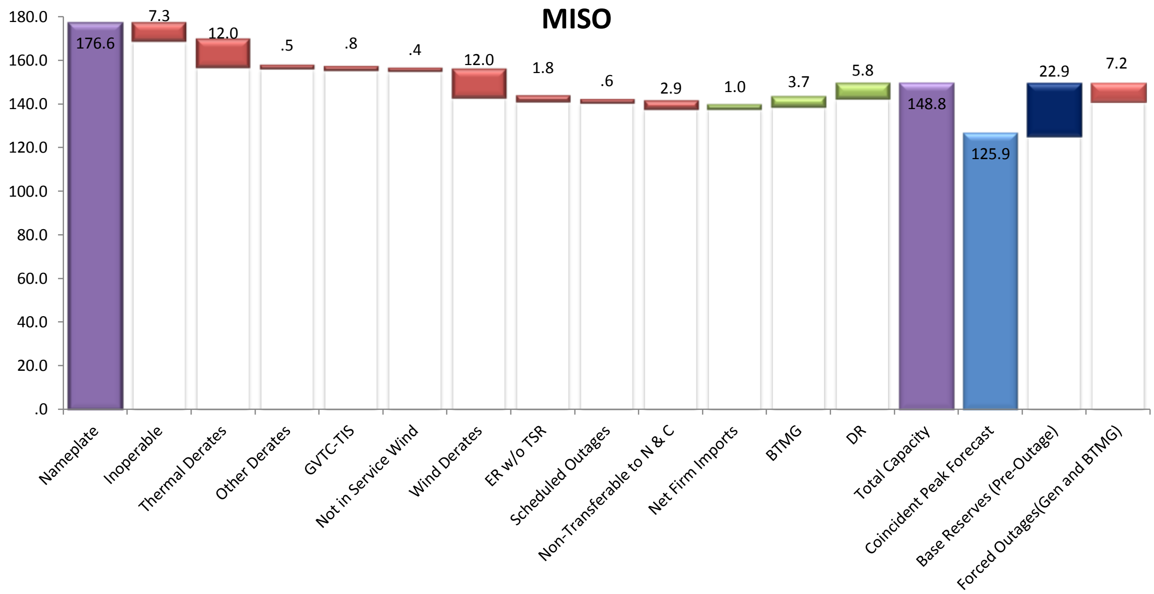

Figure 6.3-7: 2016 Summer Rated Capacity projected Base scenario (GW) showing the reduction from Installed Nameplate Resource Capacity. This includes derates and transmission limited resources.

The Probable scenario uses additional assumptions (Figure 6.3-9). MISO expects that any energy resource without firm point-to-point Transmission Service Rights will serve load locally, termed Energy Only. The portion of Energy Only from the MISO South region is excluded from the calculation to align with 876 MW contract path limitation. Additionally, any units designated as Under Study through the Attachment Y process are considered available.

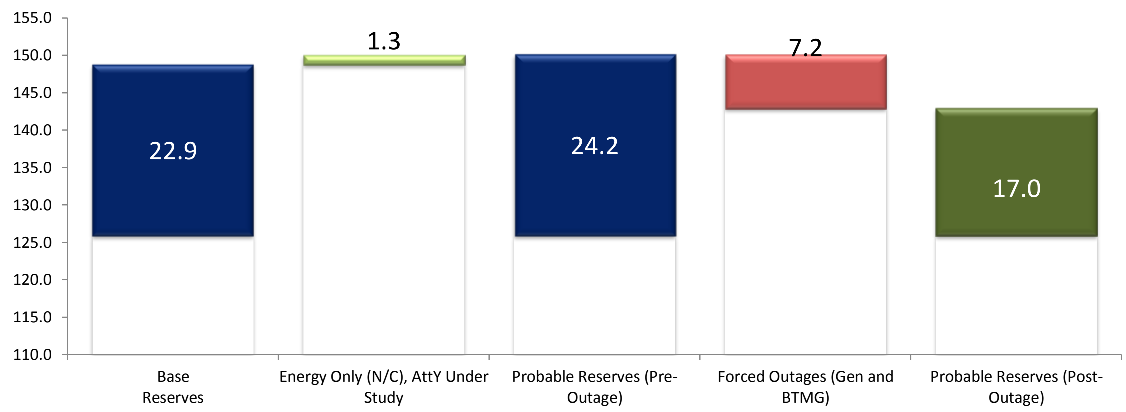

Figure 6.3-8: 2016 Summer Rated Capacity projected Probable scenario (GW), showing added capacity assumptions

The High Demand, High Outage scenario has added assumptions (Figure 6.3-10). Beginning with the Probable Reserves from the Probable Scenario (Figure 6.3-9), the load is increased to show the higher load from a 90/10 forecast. Also a higher forced outage rate is assumed, using the highest historical forced outage rate applied to the capacity resources available.

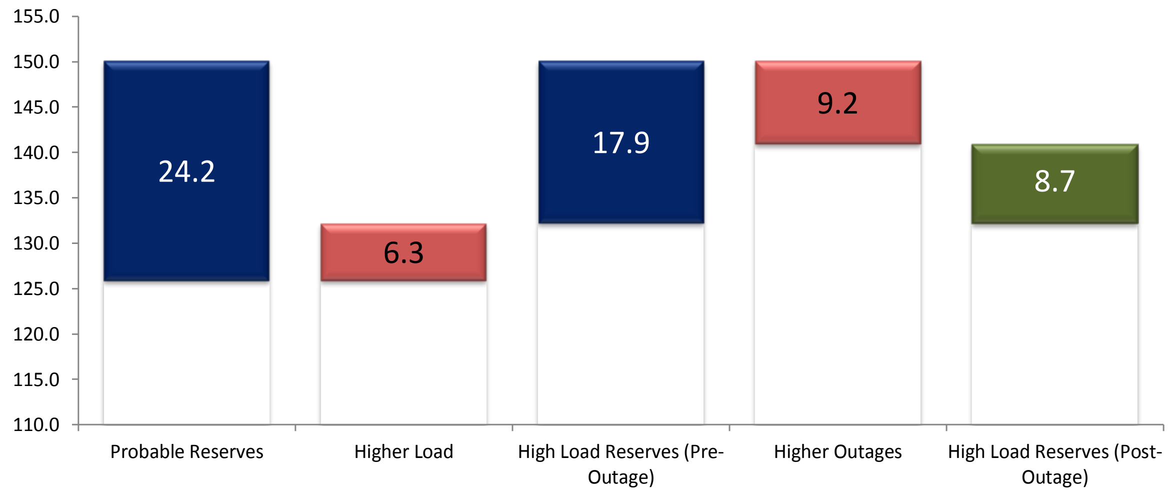

Figure 6.3-9: Summer Rated Capacity projected High Demand, High Outage scenario (GW)

2016 Summer Risk Assessment

MISO performs a probabilistic assessment on the region to determine the percent chance of utilizing Load Modifying Resources and Operating Reserves or having to curtail firm load. A risk profile is generated from this analysis (Figure 6.3-10).

It is always possible for a combination of higher loads, higher forced outage rates, fuel limitations, low water levels and other factors to lead to the curtailment of firm load. The Loss of Load Expectation (LOLE) model that MISO utilizes for PRMR takes into account the uncertainties associated with load forecasts (e.g., 50/50 versus 90/10) and generation outages (both forced and scheduled).

The chance of realizing an event is where the risk profile intersects the event range (Figure 6.3-10). As shown, the probabilistic analysis indicated a 72 percent chance of MISO calling a Maximum Generation Emergency Event Step 2b to access Load Modifying Resources; a 10.5 percent chance of initiating further steps to access Operating Reserves; and a 4.3 percent chance of curtailing firm load during the 2016 summer peak hour.

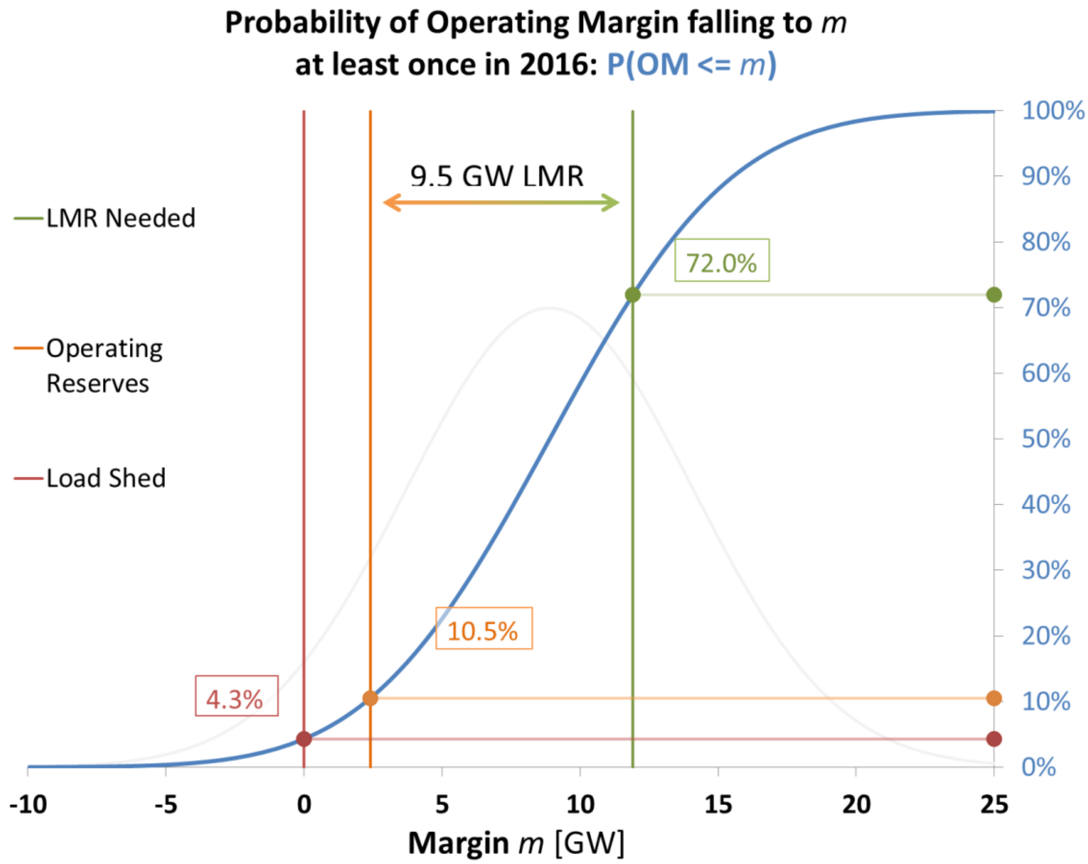

Figure 6.3-10: MISO 2016 summer chance of initiating Maximum Generation Emergency Step 2b or higher at forecasted Probable Reserve Margin

The reserves available in the Probable scenario are shown after forced outages are applied, showing the amount of Generation, BTMG, DR and Operating Reserves expected (Figure 6.3-11). In real-time, during normal operating conditions, MISO must carry Operating Reserves above load to maintain system reliability. The amount of Operating Reserves required to clear on a daily basis for the 2016 summer season was 2,400 MW, which is called on as a last resort before load shed. Operating reserves are made up of a combination of Regulating Reserves, Spinning Reserves and Supplemental Reserves.

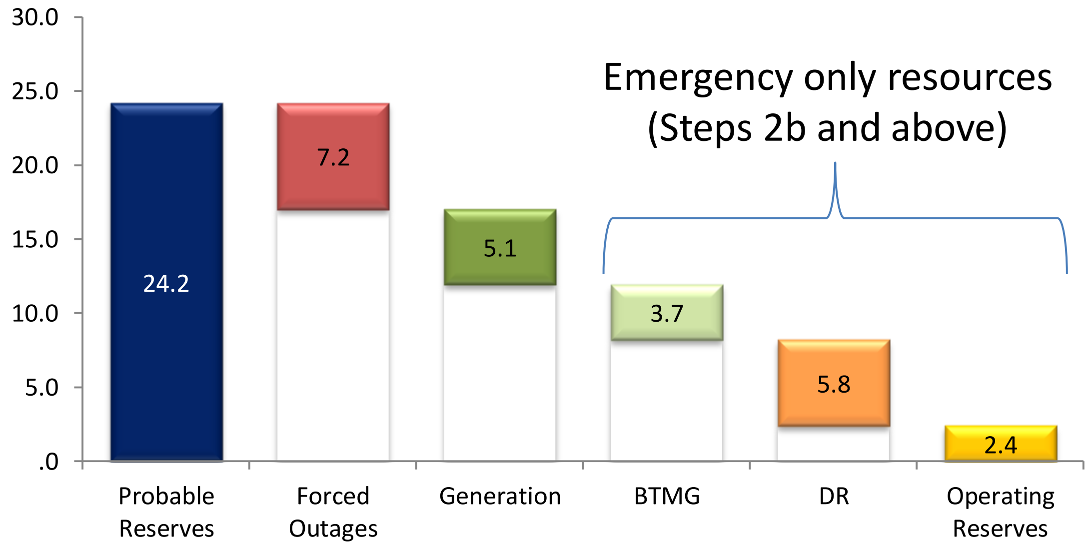

Figure 6.3-11: Summer Rated Capacity projected Probable Reserves (GW)

MISO Summer Rated Capacity Methodology

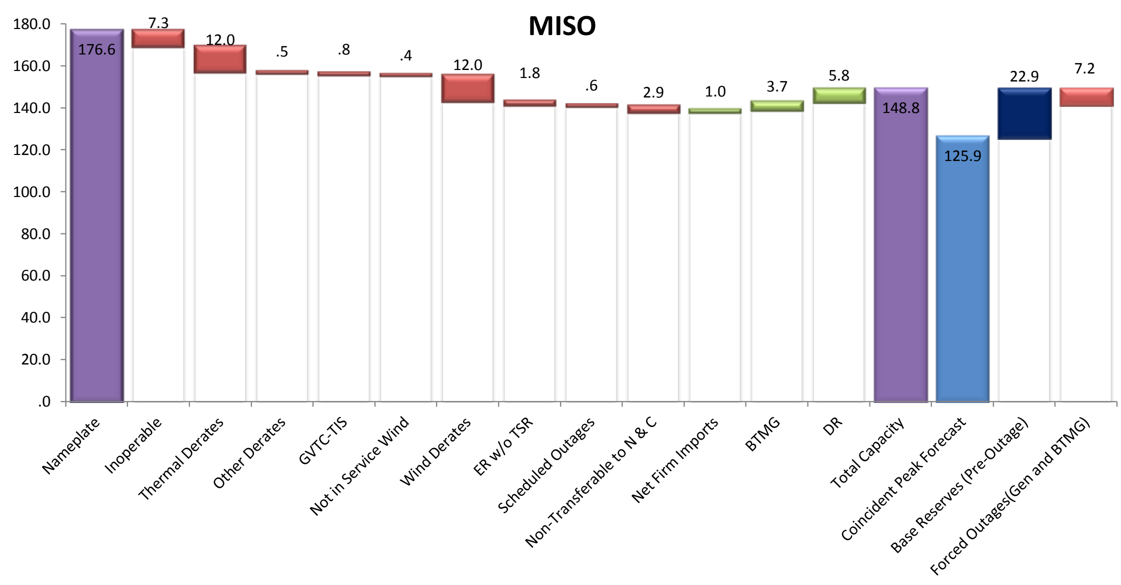

Figure 6.3-12: MISO 2016 Summer Rated Capacity waterfall chart, Base scenario (GW)

The calculation of MISO Summer Rated Capacity resources separates into 13 parts (Figure 6.3-12). Separation of the Winter Rated Capacity is similar, with additional details found in the MISO 2015-2016 Winter Resource Assessment. The 13 parts include:

1. *Nameplate*: the summation of the maximum output from the latest commercial model. This reflects the amount of registered generation available internal to MISO.
2. *Inoperable:* the summation of approved mothballed or retired units determined through the Attachment Y process, which are still represented in the latest commercial model.
3. *Thermal Derates:* the summation of differences in unit nameplate capacities and the latest Generator Verification Test Capacity (GVTC) results, excluding inoperable resources.
4. *Other Derates*: the summation of differences in non-wind intermittent resource nameplate capacities and the resource averages of historical summer peak performance, excluding inoperable resources.
5. *Transmission-limited resources (GVTC-TIS)*: the summation of differences in GVTC and the unit's Total Interconnection Service (TIS) rights based on latest unit deliverability test results. Transmission-limited resources for wind are the summation of differences in nameplate capacity and TIS.
6. *Not-in-Service and provisional wind*: units that are registered in the latest commercial model, but are not in service yet; the wind units that are connected to the system but their interconnection process is not completed yet.
7. *Wind Derates*: the summation of the differences in wind unit Nameplate Capacities and the unit wind capacity credit, which is determined based on the Effective Load Carrying Capability of wind. This excludes Inoperable Resources and Transmission-Limited MWs.
8. *ER w/o TSR Energy-only:* resources with Energy Resource Interconnection Service (ERIS) without a firm point-to-point Transmission Service Right.
9. *Scheduled Outages*: Scheduled generator outages from June 1, 2016, through August 31, 2016, were pulled from MISO's Control Room Operator's Window (CROW) outage scheduler in March 2016. The data pulled met the following criteria: 1. Mapped to the latest commercial model; 2. Outage Request Status is equal to Active, Approved, Pre-Approved, Proposed, Study or Submitted; 3. Request priority is equal to planned; 4. Equipment request type is equal to Out of Service (OOS) or "Derated To 0 MW."
   In order to calculate the expected scheduled outages on peak, MISO calculates the amount of outages on a daily basis assuming that if a unit is out for as little as one hour, that unit will be out for that entire day. The highest amount of outages during the month of July is assumed to be equal to the amount of outage during summer peak conditions.
   This calculation amounts to an expected scheduled maintenance of 619 MW.
10. Net Firm Exports: MISO anticipated the net firm interchange to be importing 965 MW for the 2016 summer.
11. *Non-Transferable to N&C*: 2,874 MW of MISO South resources were excluded from the available capacity to align with 876 MW intra-RTO contract path.
12. *Behind-the-Meter Generation (BTMG)*: the summation of approved and cleared load-modifying resources identified as Behind-the-Meter Generation through the Resource Adequacy (Module E) process. Based on the planning year 2016-2017 Planning Resource Auction, 3,724 MW of BTMG cleared to be available for the 2016 summer season.
13. *Demand Resource*: MISO currently separates contractual demand resource into two separate categories: Direct Control Load Management (DCLM) and Interruptible Load (IL).
    DCLM is the magnitude of customer service (usually residential) that can be interrupted at the time of peak by direct control of the applicable system operator. DCLM is typically used for "peak shaving." In MISO, air conditioner interruption programs account for the vast majority of DCLM during the summer months.
    IL is the magnitude of customer demand (usually industrial) that, in accordance with contractual arrangements, can be interrupted at the time of peak by direct control of the system operator (remote tripping) or by action of the customer at the direct request of the system operator. The amount of registered and cleared load-modifying resources identified as demand resource through the Resource Adequacy (Module E) process is 5,819 MW for the 2016 summer season.

6.4 Demand Response, Energy Efficiency, Distributed Generation

Applied Energy Group (AEG) developed a 20-year forecast of existing, planned and technical potential demand response (DR); energy efficiency (EE) and distributed generation (DG) resources; and costs for MISO and the Eastern Interconnection regions modeled in economic planning. This study, completed in February 2016, is a refresh of the MISO 2009-2010 Demand Response and Energy Efficiency study.

This most-recent study added the South region, provided analysis at the local resource zone (LRZ) level, added DG programs, added behavioral programs and accounts for appliance standards, building codes, and programs not currently in use. This forecast meets both ongoing and emerging business needs.

AEG received utility program data through a survey they conducted. Survey responses accounted for 93 percent of the load, and that data was supplemented with information from EIA Form 861.

In this report, the Existing Programs Plus case uses existing 2015 program data from the utility survey and assumes a small annual increase in participation in current programs through 2035 (0.5 percent increase each year; maximum 10 percent over 20 years). Savings are broken down by LRZ and different cases are analyzed in the full report. Summary results for the Existing Programs Plus cases are:

- Peak demand savings from DR programs are 5 percent of the baseline summer demand in 2015. Peak demand savings from DR, EE, and DG programs increase to 15 percent of the baseline summer demand by 2035.
    - On the residential side, appliance incentives, customer solar PV and customer wind turbines are the programs with the greatest estimated impact by 2025.
    - On the commercial and industrial side, custom incentives, prescriptive rebates and customer wind turbines are the programs with the greatest estimated impact by 2025.
- Annual energy savings are 0.5 percent of the baseline annual energy in 2015. Annual energy savings increase to 7 percent of the baseline annual energy in 2035. Throughout this forecast, energy savings come primarily from EE programs.
    - On the residential side, appliance incentives, customer wind turbines and whole-home audits are the programs with the greatest estimated impact by 2025.
    - On the commercial and industrial side, custom incentives, prescriptive rebates, and retro commissioning are the programs with the greatest estimated impact by 2025.
    - DG is a negligible percentage of these estimates with only a 0.6 percent cumulative effect by 2035.

At the scoping phase of this project, Clean Power Plan was in its draft form, which included energy efficiency as a building block. Hence, it made sense to include a specific 111(d) case in this study at that time. In this 111(d) 2014 case, to meet the compliance targets, the consultant assumed utilities would see significant peak demand savings starting with a slight ramp-up in 2018 to reach the EE goals in 2020[4]. Although the case specifically focuses on EE, AEG anticipates modest savings from demand response programs, as well. Savings are broken down by LRZ and different cases are analyzed in the full report.

[4] AEG assumed additional programs will be added in order to help meet the compliance goals in the following manner: for existing programs, AEG assumed a higher participation rate as a result of presumed increase in marketing and awareness, and for programs not currently offered in the LRZ, AEG assumed that the program comes online in 2018 at a low participation rate.

Summary results (Table 6.4-1) for the 111(d) 2014 case are:

- Similar to the Existing Programs Plus case, the peak demand savings from DR programs are 5 percent of the baseline summer demand in 2015. However, peak demand savings from DR, EE and DG programs increased to 27 percent of the baseline summer demand by 2035, relative to the 15 percent in the Existing Programs Plus case.
- Annual energy savings are 0.5 percent of the baseline annual energy in 2015. Annual energy savings increase to 7 percent of the baseline annual energy in 2035. Throughout this forecast, energy savings come primarily from EE programs.

Additionally, at the scoping phase of this project, MTEP16 futures definitions included high-demand and low-demand futures. The high-demand future captured the effect of increased economic growth, whereas the low demand future captured the effect of decreased economic growth. AEG provided estimates for savings under both those future definitions.

Summary results for the high-demand future case are:

- Similar to the Existing Programs Plus case, the peak demand savings from DR programs are 5 percent of the baseline summer demand in 2015. However, peak demand savings from DR, EE and DG programs increased to 20 percent of the baseline summer demand by 2035, relative to the 15 percent in the Existing Programs Plus case.
- Annual energy savings are 0.5 percent of the baseline annual energy in 2015. Annual energy savings increase to 9 percent of the baseline annual energy in 2035.

Summary results for the low-demand future case are:

- Similar to the Existing Programs Plus case, the peak demand savings from DR programs are 5 percent of the baseline summer demand in 2015. However, peak demand savings from DR, EE and DG programs increased to 13 percent of the baseline summer demand by 2035 relative to the 15 percent in the Existing Programs Plus case.
- Annual energy savings are 0.5 percent of the baseline annual energy in 2015. Annual energy savings increase to 6 percent of the baseline annual energy in 2035.

MISO	Peak Demand (MW) baseline					Annual Energy (GWh) baseline				
	2015	2016	2017	2025	2035	2015	2016	2017	2025	2035
Baseline Projection	118,235	119,349	120,058	126,174	136,441	678,651	685,467	690,015	732,076	801,747
Existing Programs Plus Case Savings	6,326	6,900	7,466	12,481	20,263	3,221	5,326	7,447	25,314	53,225
Existing Programs Plus Case Savings %	5%	6%	6%	10%	15%	0%	1%	1%	3%	7%
CPP 111(d) Savings	6,326	6,900	7,466	19,408	36,495	3,221	5,326	7,447	54,458	124,709
CPP 111(d) Savings %	5%	6%	6%	15%	27%	0%	1%	1%	7%	16%
High Demand Savings	6,326	7,049	7,763	14,522	27,350	3,221	5,470	7,786	29,078	69,800
High Demand Savings %	5%	6%	6%	12%	20%	0%	1%	1%	4%	9%
Low Demand Savings	6,326	6,882	7,405	11,466	17,259	3,221	5,309	7,375	23,406	46,119
Low Demand Savings %	5%	6%	6%	9%	13%	0%	1%	1%	3%	6%

Table 6.4-1: MTEP16 futures

In addition to the MTEP16 future definition cases, AEG was also tasked with providing an estimate of DG programs and their impact on peak demand and annual energy savings. The primary driver for this DG related analysis was Organization of MISO States (OMS) request for additional DG analysis, as well as general trends in the industry pointing towards decrease in solar PV and battery storage costs. Hence, the consultant looked at increases in customer-cited solar PV, wind, CHP, battery storage and thermal storage. AEG created two levels of increased distributed generation (Table 6.4-2):

- Demand-side DG, which assumed a ramp-up to reach specific solar targets, battery storage targets, or increased growth in wind, CHP and thermal storage
- High-penetration DG, which assumed a theoretical upper-limit that reflected 100 percent participation in DG.

Summary results for the demand-side DG case are:

- Similar to Existing Programs Plus case, the peak demand savings from DR programs are 5 percent of the baseline summer demand in 2015. However, peak demand savings from DR, EE and DG programs increased to 22 percent of the baseline summer demand by 2035 relative to the 15 percent in Existing Programs Plus case.
- Annual energy savings are 0.5 percent of the baseline annual energy in 2015. Annual energy savings increase to 10 percent of the baseline annual energy in 2035.

Summary results for the high-penetration DG case are:

- The peak demand savings from DR, EE and DG programs increased to 46 percent of the baseline summer demand by 2035 relative to the 22 percent in demand-side DG case.
- The annual energy savings increased to 20 percent of the baseline annual energy in 2035 relative to the 10 percent in demand-side DG case.

MISO	Peak Demand (MW) baseline					Annual Energy (GWh) baseline				
	2015	2016	2017	2025	2035	2015	2016	2017	2025	2035
Demand side DG Savings	6,373	6,998	7,619	15,068	30,173	3,423	5,740	8,083	33,608	83,968
Demand side DG Savings %	5%	6%	6%	12%	22%	1%	1%	1%	5%	10%
High Penetration DG Savings	6,373	11,348	14,097	35,613	62,207	3,423	14,769	21,617	77,869	156,870
High Penetration DG Savings %	5%	10%	12%	28%	46%	1%	2%	3%	11%	20%

Table 6.4-2: DG Case

The industry is increasing its focus on initiatives that include DR, EE, and DG in order to meet federal or state policy requirements and other enacted or emerging environmental regulations. MISO needed to refresh its models for DR and EE and explicitly include DG for modeling of future transmission capacity as well as understand the potential and cost of these programs both internally and for its stakeholders.

This forecast allows MISO to analyze the impacts related to DR, EE, and DG programs for transmission planning, real-time operations, and market operations (including resource adequacy). This forecast positions MISO to understand emerging technologies and the role they will play in transmission planning as there is a specific case on distributed generation both at a base case level and increased penetration level. Additionally, this forecast was incorporated into the Independent Load Forecast models by providing the “net” forecasts.

6.5 Independent Load Forecast

MISO procured an independent vendor, State Utility Forecasting Group (SUFG), to develop three 10-year horizon load forecasts[5]. SUFG provides data used to develop an independent regional load forecast for the MISO Balancing Authority (BA). The first 10-year forecast (2015-2024) was delivered in November 2014; the second (2016-2025) was delivered in November 2015; the third (2017-2026) was due November 2, 2016.

SUFG produces econometric models for 15 MISO states. The independent load forecast includes annual energy demand and a seasonal (summer and winter) peak forecast on a non-coincident basis with the MISO system peak for MISO and each of the 10 local resource zones. The long-term forecast will be based on MISO Business as Usual (BAU) planning future each year.

The base independent load forecast will be a 50/50 forecast, meaning there is a 50 percent probability that the load will be either higher or lower than the forecasted value. The load forecast (demand and energy) for the MISO BA will be forecasted for each state, and then aggregated into each MISO Local Resource Zone (LRZ) using state allocation factors. The MISO BA has 36 Local Balancing Authorities (LBA). The LBAs are aggregated into 10 Local Resource Zones (LRZs) (Figure 6.5-1).

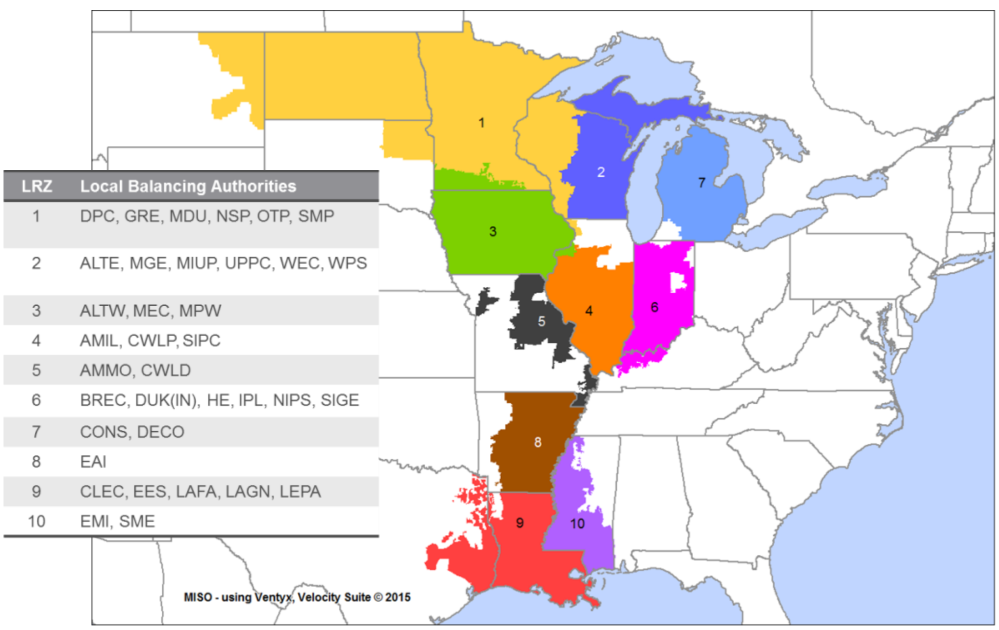

Figure 6.5-1: MISO LRZ Map for Planning Year 2016.

The independent load forecast is not intended to replicate or replace an individual Load Serving Entity (LSE) or Transmission Owner (TO) forecast. This is an independent and transparent approach to develop a MISO load forecast that relies on publically available data. This limits dependence on confidential or vendor data and new data requests. Each state forecast model and the associated assumptions will be

[5] https://www.misoenergy.org/Planning/Pages/IndependentLoadForecasts.aspx

made available to stakeholders, and will require no vendor-specific software. SUFG is using common industry econometric forecast data and software (Global Insight, EViews).

Project Schedule and Deliverables

This project is a three-year effort (Figure 6.5-2), with forecast deliverables due annually at the beginning of November 2014, 2015 and 2016. Key activities and milestones are outlined for the 2017-2026 forecast (Table 6.5-1).

MISO made progress on a load forecast comparison between the Independent Load Forecast and the Aggregated LSEs Forecast. The objective of this comparison is to identify where the forecasts differ in order to determine if model, methodology or inputs can explain these differences. The load forecast comparison does not test whether one forecast is more accurate than the other; the goal is to understand where and why there are differences. Data inputs that explained some of the differences were identified. MISO used historical energy and demand data from 2010 to 2014 to attempt to put forecast starting points and trends in perspective. Since forecasts assume normal weather, this MISO historical data was then weather normalized so that historical data without the effects of weather would be available.

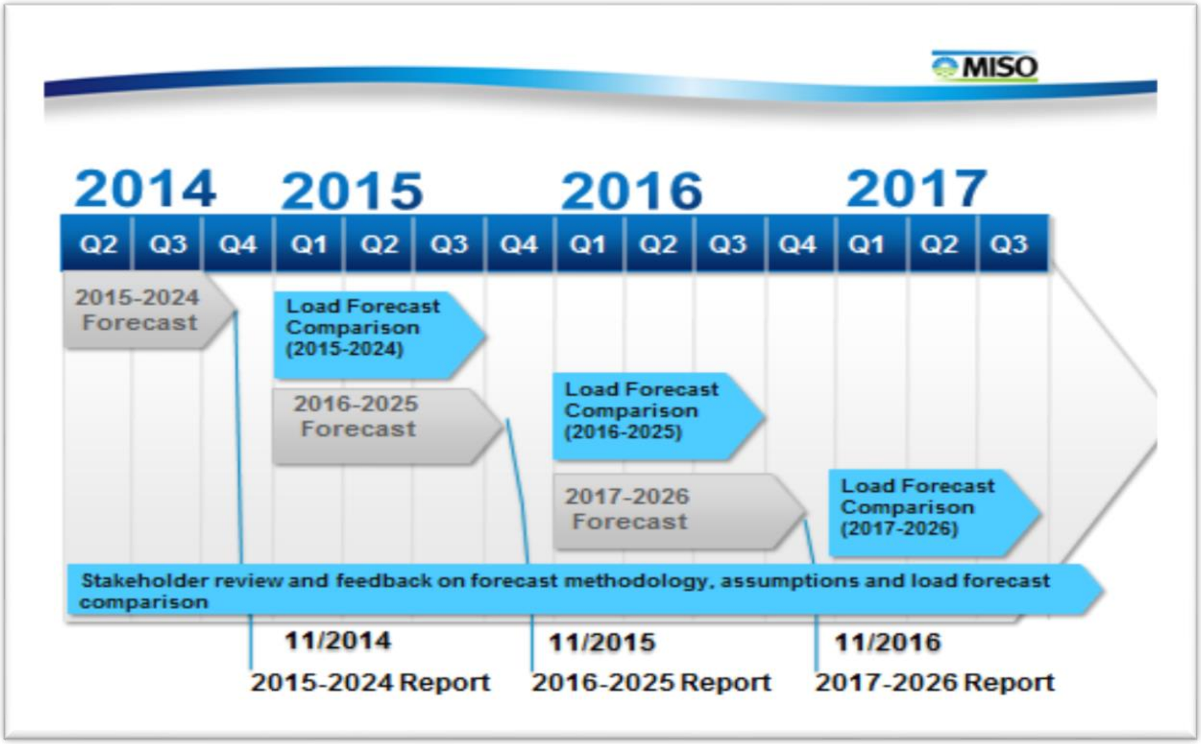

Figure 6.5-2: Independent Load Forecasting Project high-level schedule

KEY ACTIVITIES COMPLETE AND MILESTONES	TARGET DATE
2017-2026 Independent Load Forecast	**11/1/2016**
Stakeholder Workshop #1 – Review 2016 project plan, discuss potential improvements, next steps	1/18/16
Stakeholder Comments on Potential improvements Due	2/8/16
Acquire (update) state level historical data	March 2016
Update econometric forecasting models for each state	April 2016
Stakeholder Workshop #2 - Load forecast comparison	4/18/2016
Stakeholder Workshop #2 Comments Due	5/9/2016
Determine allocation factors to convert state energy forecasts to each Local Resource Zone forecast, Incorporate econometric model drivers	6/2016
Review energy to peak demand conversion model for each Local Resource Zone, Generate a 10 year annual energy forecast for each state using its econometric forecast model	7/2016
Stakeholder Workshop #3, Eagan	July 25, 2016
Stakeholder Workshop #3 Comments Due	August 15, 2016
Determine 10 year annual energy forecast for each Local Resource Zone	8/2016
Determine 10 year seasonal peak demand for each Local Resource Zone	8/2016
Determine MISO's 10 year forecast for annual energy and seasonal peak demand	9/2016
Stakeholder Workshop #4 - Review 2016-2025 Forecast results, Carmel	September 26, 2016
Stakeholder Comments Workshop #4 Due	3 weeks after
Doug's presentation to Oct Planning Advisory Committee (PAC)	October 19, 2016
Independent 10 year (2016-2025) Demand and Energy forecast report completed	11/1/16
Doug's presentation to Nov Planning Advisory Committee (PAC)	November 16, 2016

Table 6.5-1: Independent Load Forecasting project detailed project schedule, 2016.

Project Justification

The MISO transmission system needs to be planned such that it is prepared for changes in the resource mix caused by changing environmental regulations, commodity prices, renewable integration and economic conditions.

More than 141 LSEs and approximately 41 TOs submit demand forecasts annually, each with potentially different assumptions and methodologies. Each LSE and TO uses its own parameters, making it impossible to develop a MISO region-wide load forecast based on a common set of economic conditions for scenario analysis in long-term studies. An unaccounted-for deviation in a load forecast can result in increased reliability risk from the industry reliability standard (one day in 10 years) because it is difficult — if not impossible — to understand the drivers and changes in an aggregated bottom-up, long-term forecast.

A single, MISO region-wide load forecast can be viewed as a top-down approach for the region; it has the benefits of one set of assumptions, and can be used in other regional studies and future analysis. This top-down approach for load forecast fits in with MISO's Top-Down, Bottom-Up transmission planning process.

This is an alternative forecast methodology. It is not intended to replicate or replace each LSE's or TO's forecast process. MISO will continue to use the load forecasts provided by the LSEs and TOs in MTEP and Module E: Resource Adequacy as required by the MISO Tariff.