Transmission Expansion Plan 2014

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MTEP14
Executive Summary

The annual Midcontinent Independent System Operator (MISO) Transmission Expansion Plan (MTEP) proposes transmission projects to maintain a reliable electric grid and deliver the lowest-cost energy to customers in the MISO region. As part of MTEP14, MISO staff recommends $2.5 billion of new transmission expansion through 2023, as described in Appendix A, to the MISO Board of Directors for review, approval and subsequent construction.

MTEP14, the 11th edition of this publication, is the culmination of more than 18 months of collaboration between MISO planning staff and stakeholders

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MTEP projects seek to:

- Ensure the reliability of the transmission system
- Provide economic benefits, such as increased market efficiency
- Facilitate public policy objectives, such as meeting Renewable Portfolio Standards
- Address other issues or goals identified through the stakeholder process

Additionally, MTEP provides a discussion of key system issues and impacts facing the MISO region.

Notable work efforts from this planning cycle include:

- First planning cycle to include full participation of South Region members in both reliability and economic planning
- Increased efforts to identify and provide opportunities to better utilize existing capacity resources
- Increasing interregional study emphasis along the seams with MISO neighbors
- Design and implementation of Transmission Developer Qualification and Selection underway

MTEP14 Highlights:

- 369 new projects for inclusion in Appendix A provides an incremental $2.5 billion in transmission infrastructure investment
- Approval of a $676 million, 500 kV “Great Northern Transmission Line” long-term Transmission Service Request (TSR) from the Manitoba border to the Minnesota Iron Range
- $7.4 billion in projects constructed in the MISO region since the first MTEP cycle in 2003
- Reserve margin projected to drop below the Planning Reserve Margin Requirement (PRMR) of 14.8 percent beginning in 2016
- Second consecutive MTEP cycle containing a minimal number of cost-shared projects
- Generator interconnection requests shifting from predominantly wind to a gas/wind mix
- Increased number of System Support Resource (SSR) agreements
- MVP Portfolio business case not only remains intact but has increased in value since MTEP11 board-approval

MTEP14 is organized into four Books and a series of detailed Appendices.

- Book 1 summarizes this cycle’s projects and the analyses behind them
- Book 2 describes annual and targeted analyses for Resource Adequacy – including Planning Reserve Margin (PRM) requirement analysis and Long Term Resource Assessments.
- Book 3 presents policy studies. It summarizes regional studies like the MTEP14 MVP Triennial Review, Independent Load Forecasting, and cross-border studies.
- Book 4 presents additional regional energy information.
- Appendices A through F provide detailed assumptions, results, project information, and stakeholder feedback.

Book 1: Transmission Studies

MTEP Overview – Chapter 2

The 369 MTEP14 new Appendix A projects represent an incremental $2.5 billion in transmission infrastructure investment and fall into the following three categories:

- **50 Baseline Reliability Projects (BRP) totaling $269.5 million –** BRPs are required to meet North American Electric Reliability Corp. (NERC) reliability standards
- **6 Generator Interconnection Projects (GIP) totaling $38.8 million** – GIPs are required to reliably connect new generation to the transmission grid
- **312 Other Projects totaling $1.5 billion -** "Other" projects include a wide range of projects, such as those that support lower-voltage transmission systems or provide local economic benefit, but do not meet the threshold to qualify as Market Efficiency Projects
- **1 Transmission Delivery Service Projects (TDSP) totaling $676 million –** TDSP's are Network Upgrades driven by Transmission Service Requests (TSR)

As in MTEP13, this cycle contains a minimal number of cost-shared projects – five projects, all of which are GIPs.

The newly integrated South Region MISO members participated fully in MTEP14. South Region stakeholders submitted projects and participated in a series of Subregional Planning Meetings (SPM) in Little Rock, Arkansas., and Metairie, Louisiana. Stakeholders worked collaboratively with MISO staff to update models and validate analysis results. MTEP14 recommends $113 million of Baseline Reliability Projects and $246 million of Other projects for Board Approval for the South Region (Table 1.1-1)

Region	Baseline Reliability Project (BaseRel)	Generator Interconnection Project (GIP)	Other	Transmission Delivery Service Projects (TDSP)	Total
Central	$36,068,000	$0	$434,695,000	$0	$470,763,000
East	$95,610,000	$35,378,000	$284,483,000	$0	$415,471,000
West	$24,984,000	$3,444,000	$568,370,000	$676,243,000	$1,273,041,000
South	$112,844,000	$0	$246,386,000	$0	$359,230,000
Grand Total	$269,506,000	$38,822,000	$1,533,934,000	$676,243,000	$2,518,505,000

Table 1.1-1: MTEP14 New Appendix A projects by region and type

The active project investment for Appendix A, with the addition of MTEP14 new projects, increases to 839 projects amounting to approximately $12.9 billion (Table 1.1-2).

MISO Region	Number of Appendix A Projects	Appendix A Estimated Cost
Central	171	$2,685,762,000
East	239	$2,017,282,000
West	354	$7,844,991,000
South	75	$359,230,000
Total	839	$12,907,265,000

Table 1.1-2: Cumulative Appendix A

MTEP History – Chapter 3

Since the first MTEP report in 2003, more than $7.4 billion in projects have been constructed in the MISO region. MISO expects $2.08 billion of MTEP projects to go into service in 2014. Not including withdrawn projects, there are currently $20.2 billion of approved and pending projects in various stages of design, construction, or already in-service through the MTEP14 cycle. MISO surveys all Transmission Owners on a quarterly basis to determine the progress of each project (Figure 1.1-1).

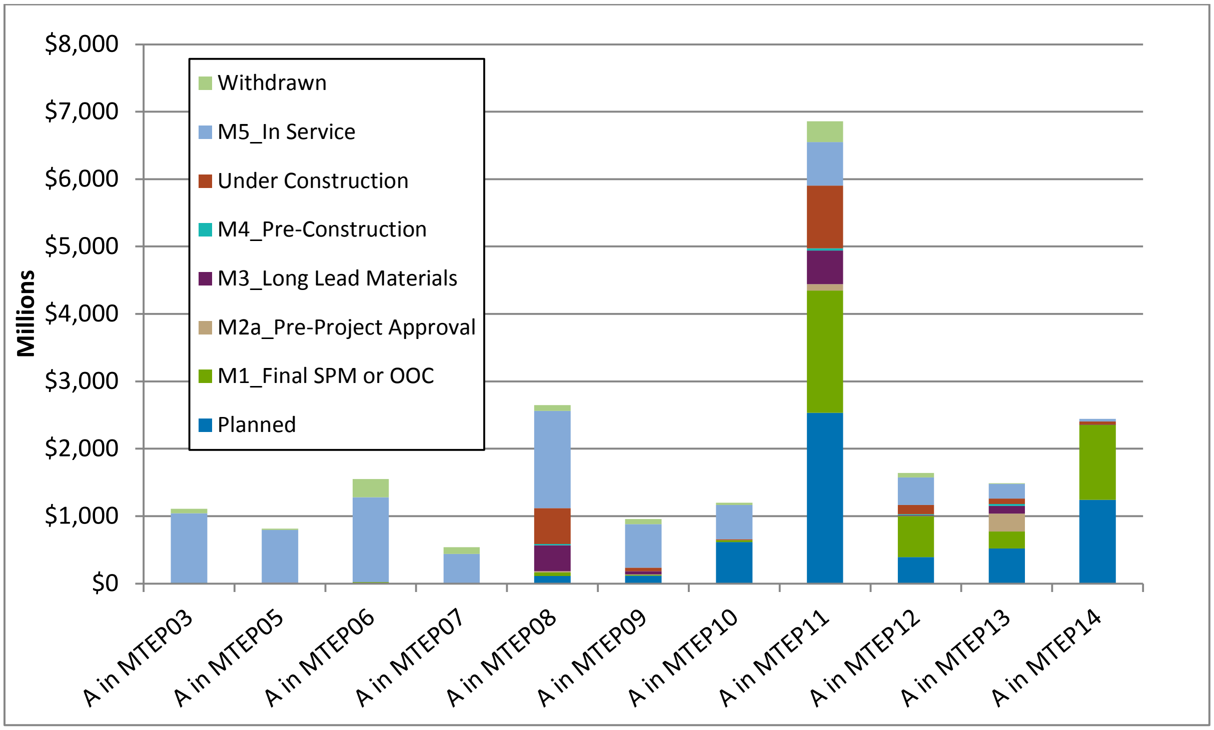

Figure 1.1-1: Approved MTEP investment by year and facility status

Reliability Analysis – Chapter 4

Maintaining system reliability is the primary purpose of most MTEP projects. In support of this goal, MISO conducts Baseline Reliability studies to ensure the transmission system is in compliance with two sets of standards:

- Applicable North American Electric Reliability Corporation (NERC) reliability standards
- Reliability standards adopted by Regional Entities (RE) applicable within the transmission provider region

These mandatory standards define acceptable power flows, voltage levels and system stability limits. MISO is required, as a registered Planning Authority/Planning Coordinator, to identify a solution for each identified violation that could otherwise lead to overloads, equipment failures or blackouts.

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MISO's studies include simulations to assess transmission reliability in the near and long term, using analytical models representing various system conditions two, five and 10 years out. MISO planners study reliability from a thermal perspective – to ensure the transmission facilities do not overheat; and from voltage and dynamic perspectives – to ensure the frequency remains stable. The results of these analyses, detailed in Appendix D, create a comprehensive assessment of long-term system reliability, as well as evidence for NERC compliance. MTEP14 marks the first cycle when South Members can point to MTEP as evidence of compliance with NERC and other regional reliability standards.

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Under the Tariff provisions, MISO has the ability to require generators to maintain operation as a System Support Resource (SSR) if the generator is needed to avoid violations of applicable NERC and Transmission Owner's (TO) planning criteria. In exchange the generator will receive compensation for its operating costs for the duration of the contract. MISO has executed eight SSR agreements during the course of the SSR program (Figure 1.1-2)

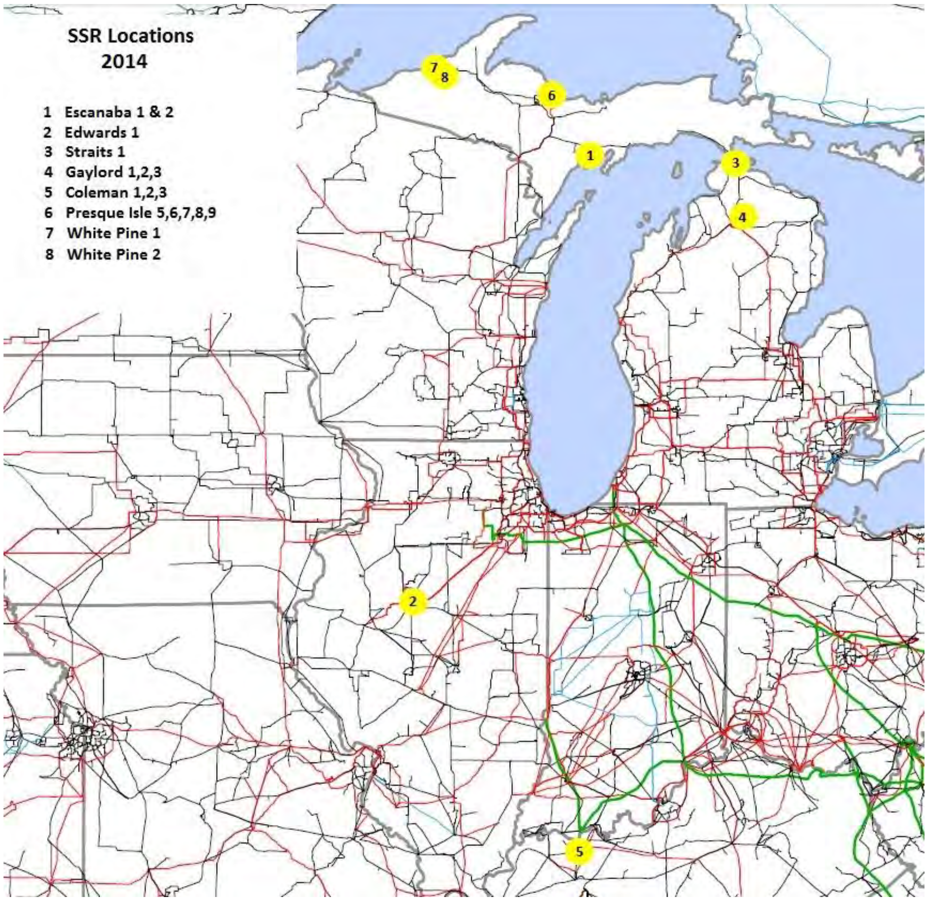


Figure 1.1-2: System Support Resource agreements

Economic Analysis – Chapter 5

In addition to maintaining reliability, MISO explores the potential for economically justified projects by using economic analysis to identify solutions that minimize total system costs (Figure 1.1-3). This type of analysis was extended to the South Region in MTEP14. Cross-border analysis was completed in 2014 on the PJM seam, and commenced on the SPP seam.

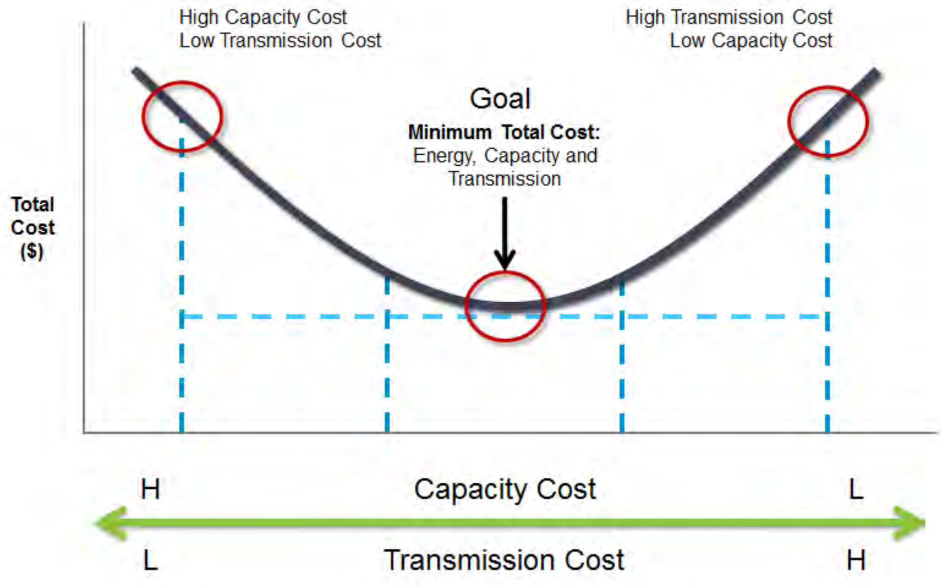


Figure 1.1-3: Capacity vs Transmission Costs

Book 2 - Resource Adequacy

MISO forecasts the reserve margin will drop below the Planning Reserve Margin Requirement (PRMR) of 14.8 percent beginning in 2016

In conjunction with transmission studies, MISO assesses the adequacy of generation for the current planning year and future planning horizons.

The MISO region has historically operated with healthy reserve margins. That long-term Resource Adequacy picture is changing in response to new and proposed emission regulations. The uncertainty increases with the potential for carbon emission limitations. MISO forecasts the reserve margin will drop below the Planning Reserve Margin Requirement (PRMR) of 14.8 percent beginning in 2016. Avoiding these negative outcomes requires increased collaboration among MISO and its members, the Organization of MISO States (OMS) and other industry stakeholders.

One example of this collaboration is the Unused Generation Capacity Study, which seeks to identify and inform Market Participants of unused generation resources already on the MISO system, that could be made available for capacity resource requirements prior to the summer of 2016. Another example is the South to North/Central Capacity Transfer Analysis, which explores ways to improve the physical transfer capability between the regions.

Book 3 - Policy Landscape Studies

MISO strives to provide meaningful analyses to help inform policy discussions and decisions amidst evolving state and federal policies, fuel prices, load patterns and transmission configurations,

Regional Studies – Chapter 7

MTEP14 MVP Triennial Review

The MTEP14 Triennial Multi-Value Project (MVP) Review provides an updated view into the projected economic, public policy and qualitative benefits of the MVP Portfolio. The analysis found that the benefits originally projected for the MVP Portfolio not only remain intact but have increased since the MTEP11 board-approved business case.

The 2014 Triennial Review finds that the MVP Portfolio:

- Provides benefits in excess of its costs, with its benefit-to-cost ratio ranging from 2.6 to 3.9; an increase from the 1.8 to 3.0 range calculated in MTEP11
- Creates $13.1 to $49.6 billion (in 2014 dollars) in net benefits over the next 20 to 40 years, an increase of approximately 50 percent from MTEP11 (Figure 1.1-4)
- Enables 43 million MWh of wind energy to meet renewable energy mandates and goals through year 2028, an additional 2 million MWh from the MTEP11 year 2026 forecast
- Provides additional benefits to each local resource zone relative to MTEP11

Benefit increases are primarily congestion and fuel savings largely driven by natural gas prices.

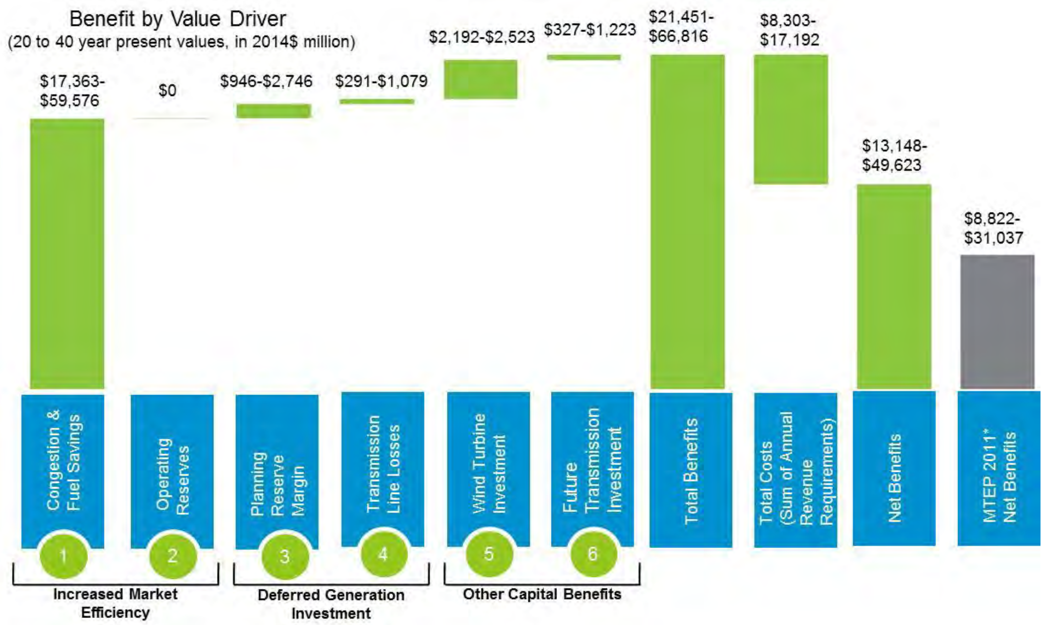


Figure 1.1-4: MVP Portfolio Economic Benefits from MTEP14 MVP Triennial Review

Voltage and Local Reliability Study (VLR)

MISO began a planning study to ascertain whether there are cost-effective alternatives to serve load at a lower overall cost by eliminating or minimizing VLR-triggered resource commitments in the South Region, which includes parts of Louisiana and Texas (Figure 1.1-5). Preliminary results indicate that the existing transmission system may need significant 500 kV and 230 kV upgrades to completely eliminate VLR commitments. Proposed solutions will be recommended as projects for approval when a business case can be established on the basis of benefits that are shown to exceed commensurate costs. Recommendations could be submitted to the MISO board for approval as early as the middle of 2015.

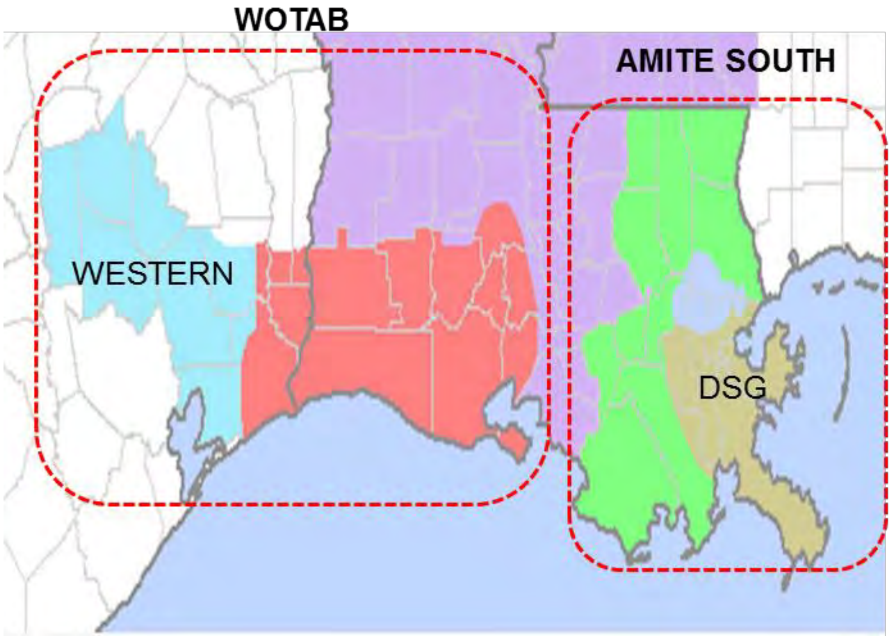


Figure 1.1-5: MISO South VLR Study Region

Carbon Analysis

In June 2013, the Obama Administration issued its Climate Action Plan, which directed the EPA to develop draft rules on carbon emissions from electric power generation. In January 2014, the EPA released its standards for carbon emissions from new power plants and in June 2014, a draft rule on carbon emissions from existing power generators was issued.

On-going carbon regulation impact analysis by MISO focuses on the EPA's 2014 draft rule, applying lessons learned from previous studies. The intent of this analysis is to inform policy makers and stakeholders and to better understand the potential impacts of carbon reduction on transmission system operation. The results of this study are intended to assist stakeholders in forming comments on the draft rule to submit to the EPA.

Interregional Studies – Chapter 8

Cross-Border Studies

FERC Order 1000 requires coordination with neighboring regions to identify and evaluate possible interregional transmission facilities that could address transmission needs more efficiently or cost-effectively than separate regional transmission facilities (Figure 1.1-6).

MISO and PJM completed a Joint Planning Study in 2014 that evaluated cross-border seams issues and identified transmission solutions that promote market efficiency. Potential solutions were evaluated under a multi-year and multi-scenario economic analysis and measured against the Cross-Border Market Efficiency Projects (CBMEP) criteria specified in Article IX of the current MISO-PJM Joint Operating Agreement (JOA). Two projects met both the cost and benefit-to-cost ratio CBMEP criteria. The two projects will be referred to the respective regional MISO and PJM planning processes. As stipulated by the JOA, the projects must also meet the regional Market Efficiency Project (MEP) criteria. Neither projects meet the voltage threshold under MISO regional tariff for Market Efficiency Projects (MEP) and will not be considered as CBMEPs.

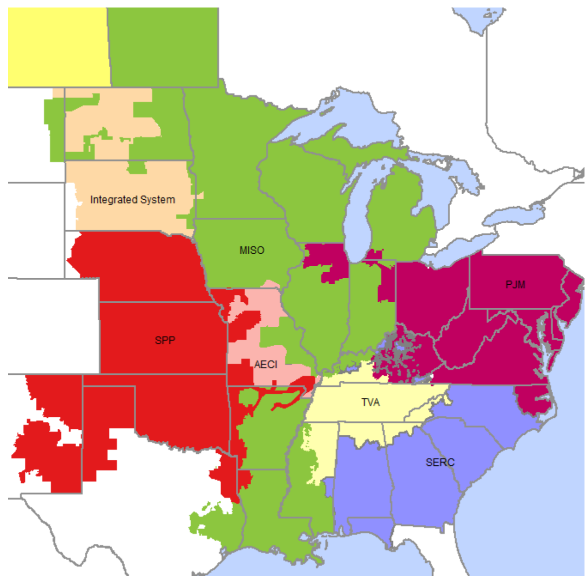


Figure 1.1-6: MISO seams

MISO and Southwest Power Pool (SPP) filed interregional coordination agreements in July 2013 in response to FERC's Order 1000. Shortly after filing, MISO and SPP established the Joint Planning Committee (JPC) and began work on a Coordinated System Plan (CSP) study (Figure 1.1-7). Engaging stakeholders, the JPC agreed to a comprehensive CSP study scope. The scope encompasses congestion, reliability, markets and public policy elements. The Interregional Planning Stakeholder Advisory Committee (IPSAC) is the forum where both MISO and SPP stakeholders participate directly in the study. MISO will review study progress and results through the Planning Advisory Committee (PAC) and other applicable stakeholder forums. MISO and SPP are working collaboratively towards developing an ongoing process to jointly evaluate seams related transmission issues.

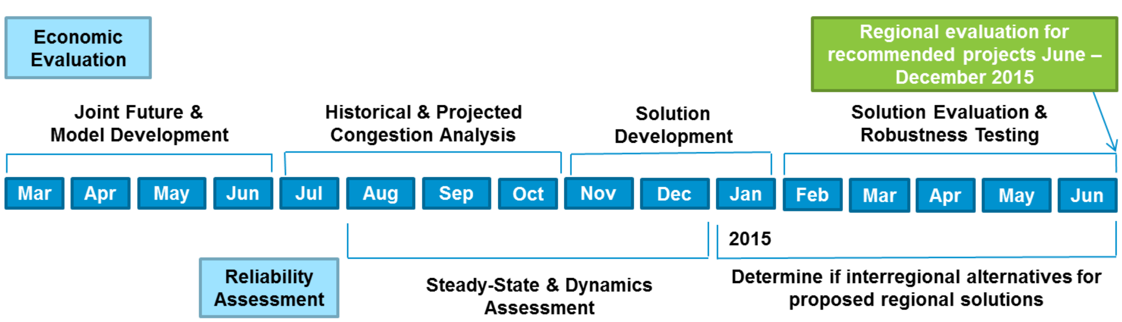


Figure 1.1-7: MISO-SPP Coordinated System Plan Schedule

Book 4 – Regional Energy Information

Book 4 describes some additional MISO functions, and presents regional energy information not otherwise included.

For example, Locational Marginal Prices (LMP) can reflect the effects of supply and demand factors on wholesale costs. The effect of weather is apparent in MISO data during the two-week period around January 6, 2014, when MISO set a new all-time winter instantaneous peak load (Figure 1.1-8).

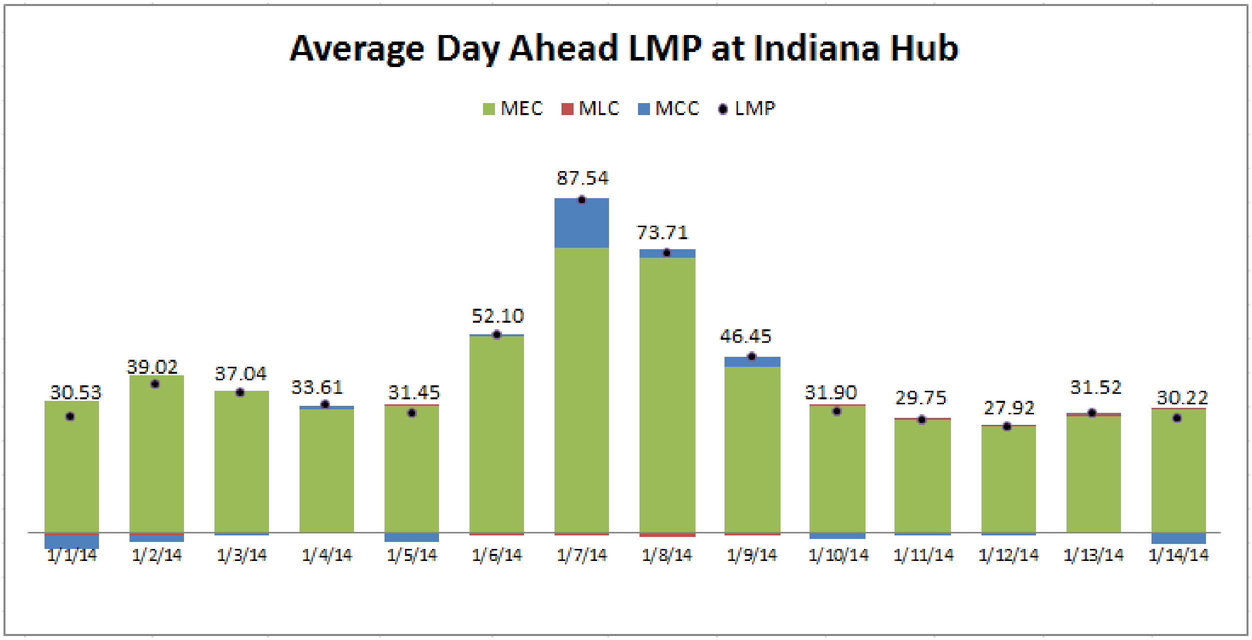


Figure 1.1-8: Average day-ahead LMP at the Indiana hub

The MISO Planning Approach

A defined set of principles, established by MISO's Board of Directors, guides the organization's planning efforts. These principles, last reconfirmed August 2014[1], were created to improve and guide transmission investment in the region and to furnish strategic direction to the MISO transmission planning process.

Guiding Principles for Expansion Plans

The system expansion plans, produced through the MISO planning process, must ensure the reliable operation of the transmission system, support achievement of state and federal energy policy requirements, and enable a competitive electricity market to benefit all customers. The planning process, in conjunction with an inclusive, transparent stakeholder process, must identify and support development of transmission infrastructure that is sufficiently robust to meet local and regional reliability standards, and enable competition among wholesale capacity and energy suppliers.

In support of these goals, the MISO regional expansion planning process should meet each of the following Guiding Principles:

Guiding Principle	MTEP14 Highlight
Make the benefits of an economically efficient electricity market available to customers by identifying transmission projects that provide access to electricity at the lowest total electric system cost.	• Chapter 5 - Economic Analysis • Chapter 7.1 - MTEP14 MVP Triennial Review • Chapter 7.3 - Voltage and Local Reliability Planning • Chapter 8.3 - HVDC Network
Develop a transmission plan that meets all applicable NERC and Transmission Owner planning criteria and safeguards local and regional reliability through identification of transmission projects to meet those needs.	• Chapter 4 - Reliability Analysis
Support state and federal energy policy requirements by planning for access to a changing resource mix.	• Chapter 6 - Resource Adequacy • Chapter 7.1 - MTEP14 MVP Triennial Review • Chapter 7.3 - Independent Load Forecasting • Chapter 7.4 - Carbon Analysis
Provide an appropriate cost allocation mechanism that ensures that costs of transmission projects are allocated in a manner roughly commensurate with the projected benefits of those projects.	• Chapter 2.2 - Cost Sharing Summary • Chapter 2.4 - MTEP Project Types • Chapter 5.1 - Economic Analysis Introduction • Chapter 7.1 - MTEP14 Triennial Review
Analyze system scenarios and make the results available to state and federal energy policy makers and other stakeholders to provide context and to inform choices.	• Chapter 5 - Economic Analysis • Chapter 7.2 - Minnesota Renewable Integration Study • Chapter 7.5 - Carbon Analysis • Chapter 7.6 - Economic Impact Studies
Coordinate planning processes with neighbors and work to eliminate barriers to reliable and efficient operations.	• Chapter 8 - Interregional Studies

[1] These Guiding Principles were initially adopted by the Board of Directors, pursuant to the recommendation of the System Planning Committee, on August 18, 2005, and reaffirmed by the System Planning Committee in February 2007, August 2009, May 2011, March 2013, and August 2014.

To support these principles, MISO's transmission planning process reflects its commitment to reliability, market efficiency, public policy and other value drivers across all planning horizons studied. A number of conditions must be met through this process to build long-term transmission that can support future generation growth and accommodate documented energy policy mandates or laws. These conditions are intertwined with the MISO Board of Directors' planning principles and include:

- A robust business case for the plan
- Increased consensus around regional energy policies
- A regional tariff matching who benefits with who pays over time
- Cost recovery mechanisms to reduce financial risk

Conclusion

MISO is proud of its independent, transparent and inclusive planning process - and grateful for the input and support from our stakeholder community. This support is essential to creating well-vetted, cost-effective and innovative solutions to provide reliable delivered energy at the least cost to consumers. MISO welcomes feedback and comments from stakeholders, regulators and interested parties on the evolving electric transmission system. For detailed information about MISO, MTEP14, Resource Adequacy, and other planning efforts, visit www.misoenergy.org.

Book 1
Transmission Studies

Chapter 2
MTEP14 Overview

The ultimate deliverable of MTEP is a list of transmission projects for recommendation to the MISO Board of Directors. This chapter provides highlights of MTEP projects, both new and already-approved. A complete list of all MTEP projects is included in Appendices A and B. A further explanation of Appendix A and B definitions can be found in Section 2.4.

2.1 Investment Summary

The 369 MTEP14 new Appendix A projects represent an incremental $2.5 billion[2] in transmission infrastructure investment and fall into the following three categories:

- **50 Baseline Reliability Projects (BRP) totaling $269.5 million –** BRPs are required to meet North American Electric Reliability Corp. (NERC) reliability standards.
- **6 Generator Interconnection Projects (GIP) totaling $38.8 million** – GIPs are required to reliably connect new generation to the transmission grid.
- **312 Other Projects totaling $1.5 billion -** “Other” projects include a wide range of projects, such as those that support lower-voltage transmission systems or provide local economic benefit, but do not meet the threshold to qualify as Market Efficiency Projects.
- **1 Transmission Delivery Service Projects (TDSP) totaling $676 million –** TDSP’s are Network Upgrades driven by Transmission Service Requests (TSR)

The largest 10 projects represent 50 percent of the total cost and are distributed across the MISO region (Figure 2.1-1).

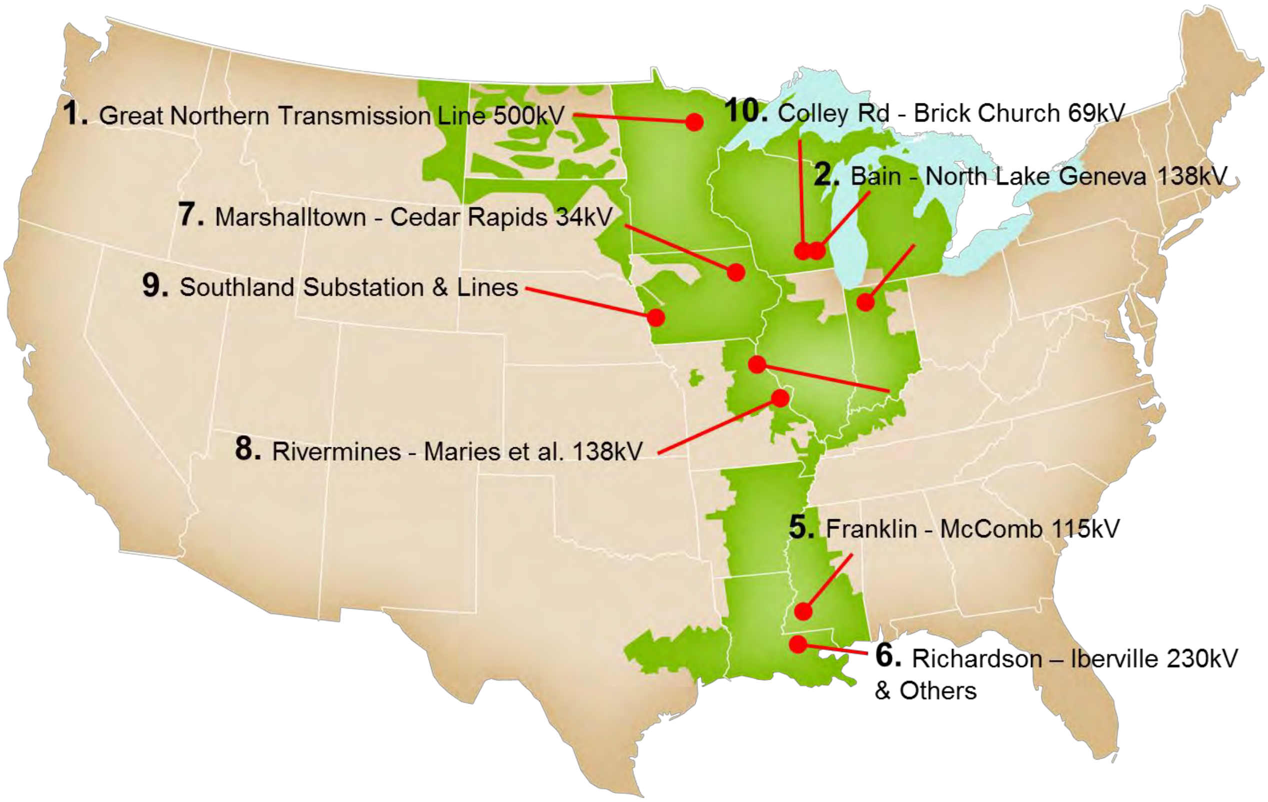


Figure 2.1-1: Top 10 MTEP14 new Appendix A projects (in descending order of cost)

[2] The MTEP14 report and project totals reflect all project approvals during the MTEP14 cycle, including those approved on an out-of-cycle basis prior to December 2014.

The new projects recommended for approval in MTEP14 Appendix A are broken down by region and project type (Table 2.1-1). New projects in MTEP14 Appendix A contain five cost-shared Generator Interconnection Projects. Cost sharing information is provided in Chapter 2.2.

Newly integrated South Region MISO members participated in its first MTEP. South Region stakeholders submitted projects and participated in a series of Subregional Planning Meetings (SPM) in Little Rock, Ark., and Metairie, La. Stakeholders worked collaboratively with MISO staff to update models and validate analysis results. MTEP14 recommends $113 million of Baseline Reliability Projects and $186 million of Other projects for Board Approval for the South Region (Table 2.1-1).

Region	Baseline Reliability Project (BaseRel)	Generator Interconnection Project (GIP)	Other	Transmission Delivery Service Projects (TDSP)	Total
Central	$36,068,000	$0	$434,695,000	$0	$470,763,000
East	$95,610,000	$35,378,000	$284,483,000	$0	$415,471,000
West	$24,984,000	$3,444,000	$568,370,000	$676,243,000	$1,273,041,000
South	$112,844,000	$0	$246,386,000	$0	$359,230,000
Grand Total	$269,506,000	$38,822,000	$1,533,934,000	$676,243,000	$2,518,505,000

Table 2.1-1: MTEP14 new Appendix A investment by project category and planning region

"Other" Project Type

Within the Other project type, there are a number of subtypes that give more insight into the purpose of these projects (Figure 2.1-2). Almost half of the "Other" projects are to address reliability issues, followed by about 26 and 21 percent to address condition and distribution, respectively.

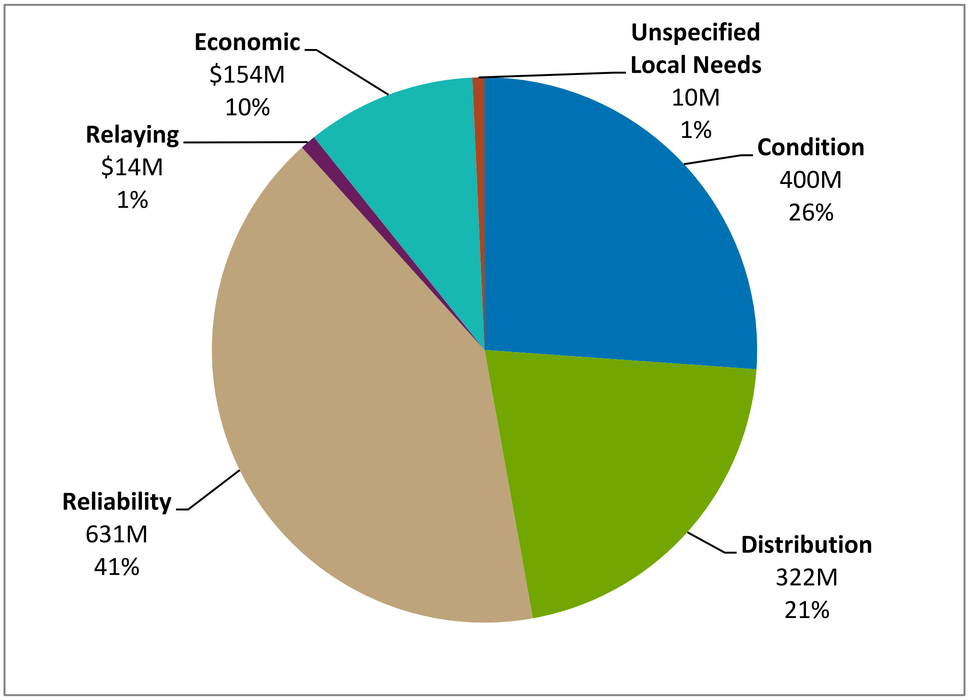


Figure 2.1-2: Subtype breakdown of new MTEP14 Appendix A Other projects

Facility Type

Each MTEP project is composed of one or more facilities. The facilities consist of elements such as substations, transformers, and various types of transmission lines (Figure 2.1-3). About 65 percent of facility cost is categorized as transmission line.

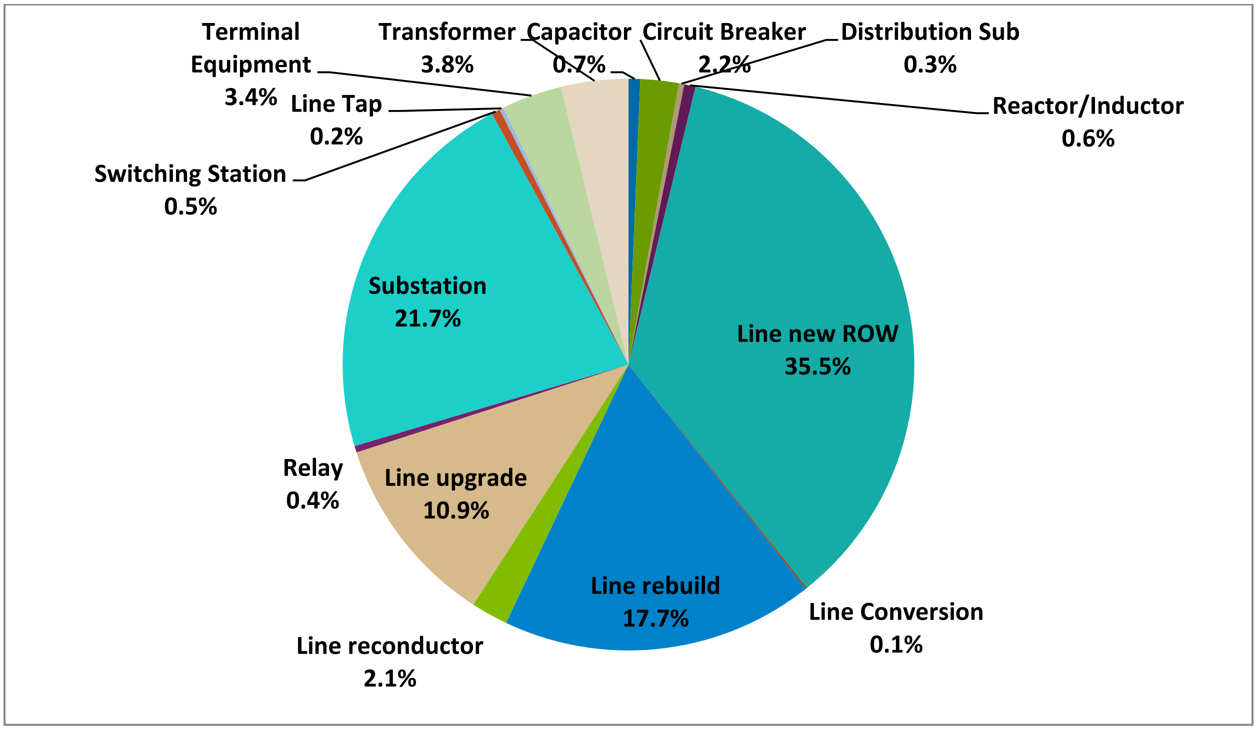


Figure 2.1-3: Facility type for new MTEP14 Appendix A projects

New Appendix A projects are spread over many states, with eight states scheduled for more than $100 million in new investment (Figure 2.1-4). A few projects have investment in more than one state, but the statistics in the figure are aggregated to the primary state. These geographic trends vary greatly year to year as existing capacity in other parts of the system is consumed and “new build” becomes necessary. The large Minnesota investment in this MTEP cycle is dominated by the “Great Northern Transmission Line” Transmission Delivery Service Project (TDSP) based on Transmission Service Requests (TSR) analysis.

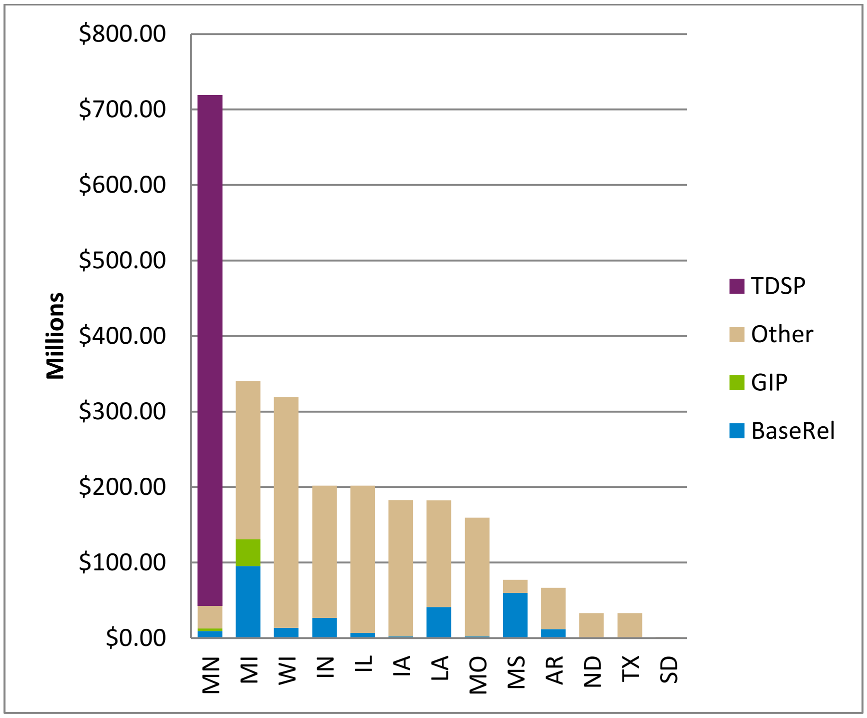


Figure 2.1-4: New MTEP14 Appendix A Investment Categorized by State

Active Appendix A Investment

The active project spending for Appendix A, with the addition of MTEP14 new projects, increases to 839 projects amounting to approximately $12.9 billion of investment (Figure 2.1-5). MTEP14 Appendix A contains newly approved projects and previously approved projects that are not yet in service. Projects may be comprised of multiple facilities. Investment totals by year assume that 100 percent of a project’s investment is fulfilled when the facility goes into service. Large project investment is shown in a single year but often occurs over multiple years.

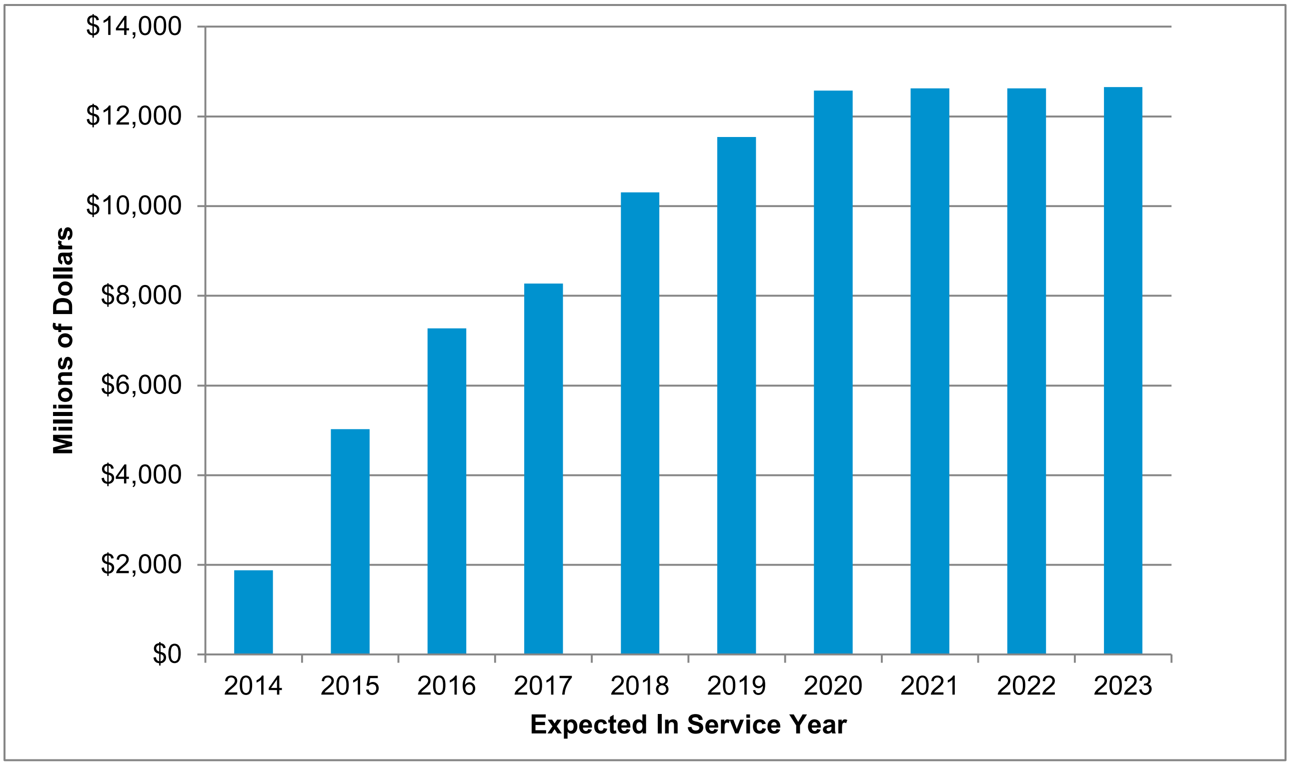


Figure 2.1-5: MTEP14 Appendix A projected cumulative investment by year

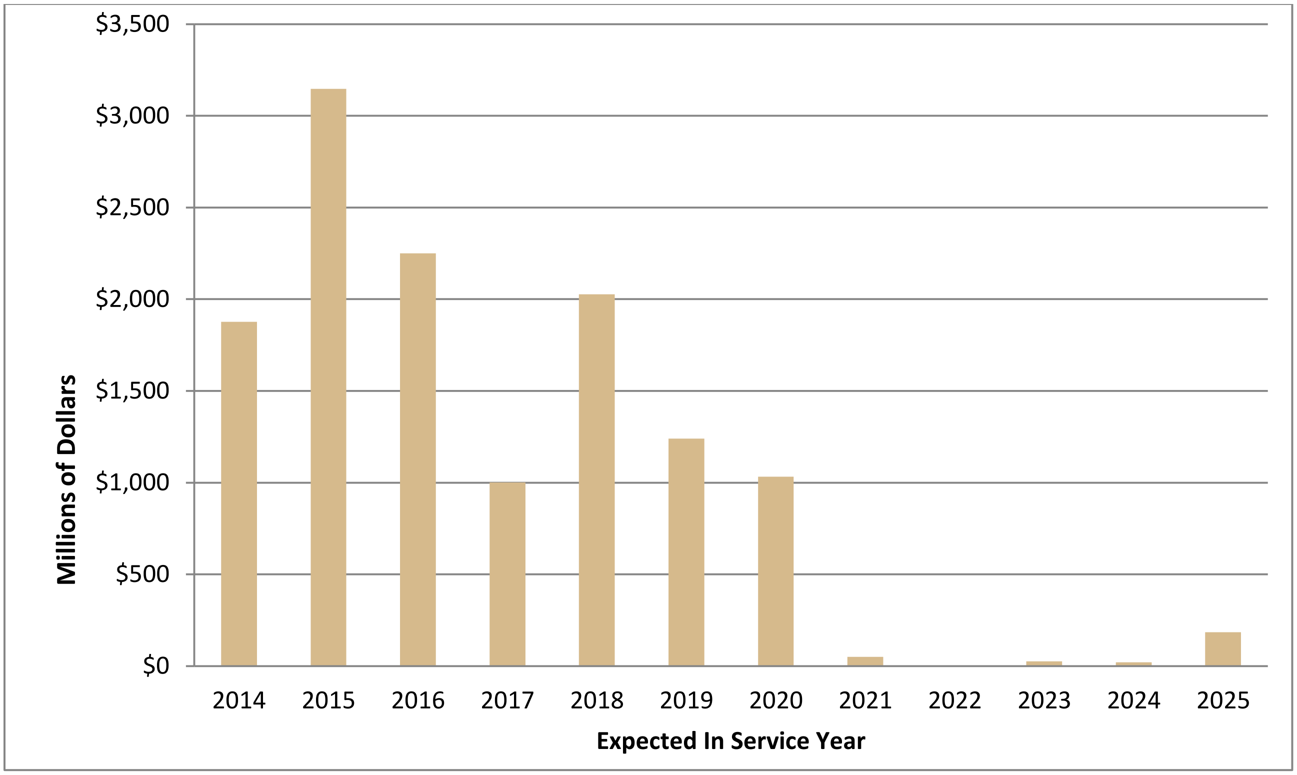


Figure 2.1-6: MTEP14 Appendix A projected incremental investment by year

MISO Transmission Owners[3] have committed to significant investments in the transmission system (Table 2.1-2). Cumulative MTEP transmission investment for Appendix A is approximately $12.9 billion with another $1.9 billion in Appendix B. New MTEP14 Appendix A projects represents $2.5 billion of this investment. Projects associate primarily with a single planning region, though some projects may involve multiple planning regions. About $5 billion of the $12.9 billion in cumulative Appendix A is from the Multi-Value Projects (MVP) approved in MTEP11. Projects are spread across the four MISO geographic planning regions: East, Central, West and South (Figure 2.1-7).

MISO Region	Number of Appendix A Projects	Appendix A Estimated Cost	Number of Appendix B Projects	Appendix B Estimated Cost
Central	171	$2,685,762,000	52	$302,520,000
East	239	$2,017,282,000	24	$580,879,000
West	354	$7,844,991,000	41	$734,969,000
South	75	$359,230,000	27	$263,251,000
Total	839	$12,907,265,000	144	$1,881,619,000

Table 2.1-2: Projected transmission investment by planning region through 2023

[3] https://www.misoenergy.org/Library/Repository/Communication%20Material/Corporate/Current%20Members%20by%20Sector.pdf

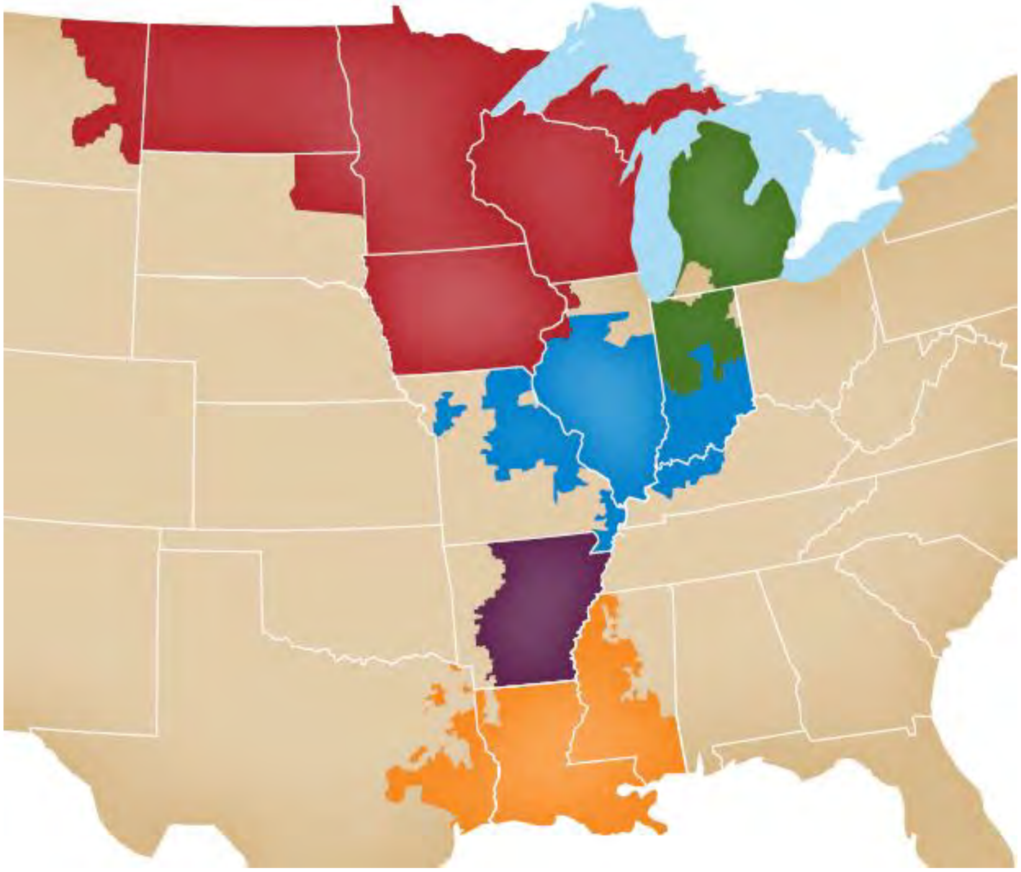


Figure 2.1-7: MISO footprint and planning regions (South contains two SPM regions)

Active Appendix A Line Miles Summary

MISO has approximately 65,800 miles of existing transmission lines. There are approximately 8,400 miles of new or upgraded transmission lines projected in the 10-year planning horizon in MTEP14 Appendix A (Figure 2.1-8).

- 4,980 miles of upgraded transmission line on existing corridors are planned.
- 3,440 miles of new transmission line on new corridors are planned

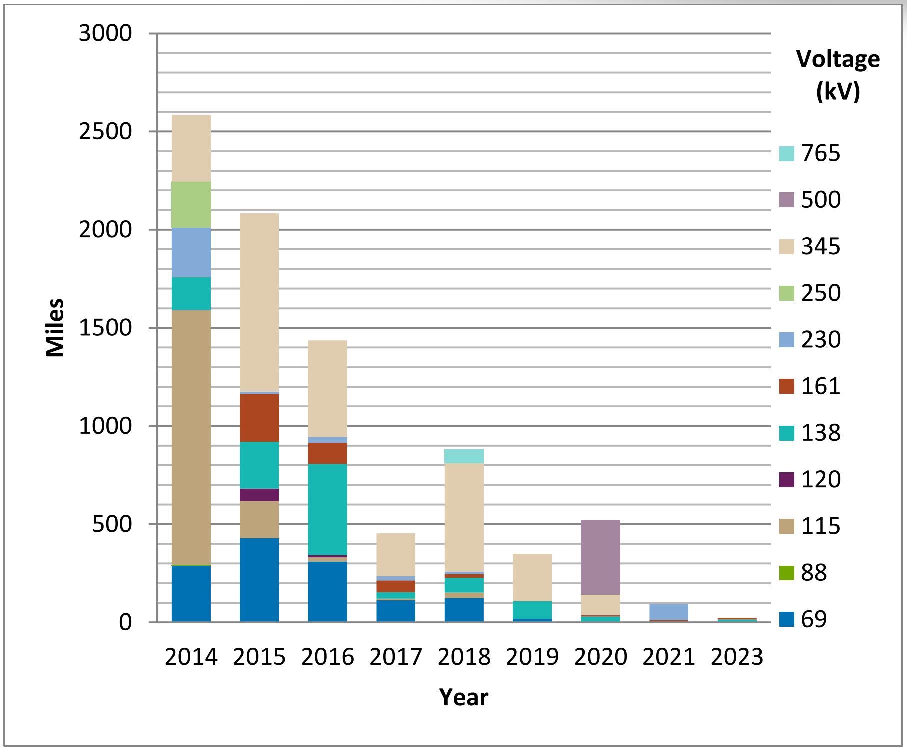


Figure 2.1-8: New or upgraded line miles by voltage class (kV) in Appendix A through 2023

2.2 Cost Sharing Summary

New MTEP14 Appendix A Cost-Shared Projects

In MTEP14 there are five Generator Interconnection Projects (GIPs) designated as cost-shared projects with all of the costs for those projects allocated to the pricing zone where the projects are located.

- Five GIPs with a total project cost of \$35.4 million: \$17.7 million of the total cost allocated to load and the remaining \$17.7 million allocated directly to the generator[4]

MISO employs a collection of cost allocation mechanisms that seek to match the costs of transmission investment to those who benefit from that investment (Section 5.1, Table 5.1-1).

Cost Allocation Between Planning Areas For GIPs

With the integration of the MISO South region on December 19, 2013, a cost allocation transition period started that determines how approved cost-shared projects are shared amongst the pricing zones in the MISO North/Central planning area and MISO South planning. The transition period concludes when certain Tariff criteria are met, likely in MTEP19.[5] The cost-shared projects in MTEP14 are GIPs that terminate exclusively in the MISO North/Central planning area, and are cost shared amongst the MISO North/Central planning area pricing zones (Figure 2.2-1).

Type and Location of Project	Approved Before Transition Period		Approved and/or Identified During Transition Period		Approved After Transition Period Ends
	Treatment During Transition Period	Treatment After Transition Period	Treatment During Transition Period	Treatment After Transition Period	
GIPs terminating exclusively in <u>one</u> Planning Area	Within North/Central Planning Area	Within North/Central Planning Area	Within applicable Planning Area	Within applicable Planning Area	Applicable to both Planning Areas
GIPs terminating in <u>both</u> Planning Areas	Not Applicable	Not Applicable	Applicable to both Planning Areas	Applicable to both Planning Areas	Applicable to both Planning Areas

Figure 2.2-1: Cost-shared GIP transition period Tariff provisions

[4] The \$17.7 million value indicated as allocated to generators does not account for the Transmission Owners who reimburse qualifying generators 100 percent of the costs incurred for Generation Interconnection Projects

[5] According to the Tariff: ***Second Planning Area's Transition Period:*** The period: (i) commencing when the first Entergy Operating Company conveys functional control of its transmission facilities to the Transmission Provider to provide Transmission Service under Module B of this Tariff; (ii) consisting of at least five consecutive (5) years, plus the time needed to complete the MTEP approval cycle pending at the end of the fifth year; (iii) ending on the day after the conclusion of such MTEP approval cycle, which in no case shall be more than six years after the start of that period

Cumulative Summary of All Cost-Shared Projects Since MTEP06

A total of 157 projects have been eligible for cost sharing since cost sharing methodologies were first incorporated into the MTEP process. Cost sharing began in 2006 with Baseline Reliability Projects[6] (BRP) and GIPs and was later augmented with Market Efficiency Projects (MEP) in 2007 and Multi-Value Projects (MVP) in 2010. Starting with MTEP13 and going forward the costs for BRPs were removed from cost sharing and are allocated to the pricing zone where the project is located. The cost-shared projects represent $9.2 billion in transmission investment, excluding projects that have subsequently been withdrawn or had a portion of project costs allocated directly to generators for GIPs (Figure 2.2-2 and Table 2.2-1). The distribution of projects includes:

- Baseline Reliability Projects (BRP) – 76 projects, $3.05 billion
- Generation Interconnection Projects (GIP) – 62 projects, $290 million (excluding the portion of project costs allocated directly to the generator)
- Market Efficiency Projects (MEP) – 2 projects, $13.6 million
- Multi-Value Projects (MVP) – 17 projects, $5.84 billion

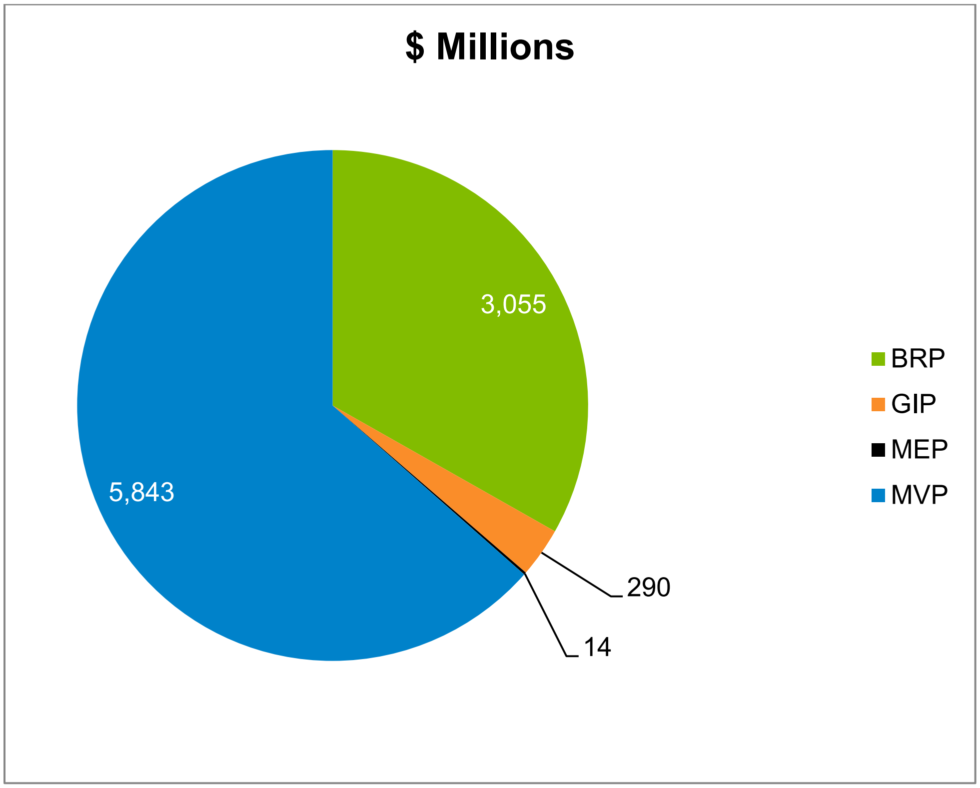


Figure 2.2-2: MTEP cumulative cost sharing by project type ($ millions)

[6] For Baseline Reliability Projects effective June 1, 2013, all project costs are allocated to the pricing zone where the project is located.

Cost-Shared Project Type	BRP	GIP	MEP	MVP	Total
A in MTEP06	678.4	27.7	-	-	706.1
A in MTEP07	92.8	16.6	-	-	109.4
A in MTEP08	1,230.6	12.8	-	-	1,243.4
A in MTEP09	171.3	60.7	5.6	-	237.6
A in MTEP10	43.2	1.9	-	510.0	555.1
A in MTEP11	363.1	42.2	-	5,333.6	5,738.9
A in MTEP12	475.2	106.0	8.0	-	589.2
A in MTEP13	-	4.0	-	-	4.0
A in MTEP14	-	17.7	-	-	17.7
Total	3,054.6	289.6	13.6	5,843.6	9,201.5

Table 2.2-1: MTEP06 to MTEP14 cost-shared project costs by MTEP cycle and project type (shown in $ millions)

Cost allocation methods vary depending on the classification of the project. For BRPs, GIPs and MEPs, the majority of the costs are allocated to the pricing zone where the project is located (see Section 5.1 for more information on project cost allocation). Of the $3.35 billion in approved costs for these project types (not including MVPs), approximately 68.7 percent ($2.3 billion) is allocated to the pricing zone where the project is located. The remaining 31.3 percent ($1.05 billion) is allocated to neighboring pricing zones or to all pricing zones system-wide.

68.7 percent ($2.3 billion) of BRP, GIP and MEP remains in the pricing zone where the project is located with the remaining 31.3 percent ($1.05 billion) allocated to neighboring pricing zones or system-wide to all pricing zones

The total project cost allocated to each pricing zone for BRPs, GIPs and MEPs are broken down into two components: the portion of costs for projects located outside the pricing zone (Table 2.2-2, Column 3) and the portion of costs for projects located within the pricing zone (Column 4). Column 2 provides the total project cost of approved BRPs, GIPs and MEPs that are located in the pricing zone. The values shown in Figure 2.2-2 exclude the portion of GIPs assigned directly to the generator.

Pricing Zone	Total Approved Cost Shared Transmission Investment	Costs Allocated for Projects Located Outside Pricing Zone	Costs Allocated for Projects Located within the Pricing Zone	Total Project Cost Allocated to Pricing Zone
[1]	[2]	[3]	[4]	[5] = [3] + [4]
AMIL	164.2	39.9	135.8	175.7
AMMO	88.8	29.6	82.8	112.3
ATC	936.0	77.6	782.3	859.9
BREC	0.0	1.8	0.0	1.8
CLEC	0.0	0.0	0.0	0.0
CWLD	0.0	1.0	0.0	1.0
CWLP	7.0	1.6	7.0	8.7
DPC	21.4	3.6	10.1	13.7
DUK*	48.4	96.4	44.3	140.6
EATO	0.0	0.0	0.0	0.0
ELTO	0.0	0.0	0.0	0.0
EMTO	0.0	0.0	0.0	0.0
ETTO	0.0	0.0	0.0	0.0
FE*	16.5	35.8	14.7	50.5
GRE	191.5	27.2	9.5	36.7
HE	0.0	12.3	0.0	12.3
IPL	23.4	17.8	5.0	22.9
ITC	189.4	36.4	165.6	202.1
ITCM	143.2	47.8	126.8	174.6
LAFA	0.0	0.0	0.0	0.0
MDU	8.3	9.1	8.1	17.3
MEC	0.6	3.9	0.0	4.0
METC	430.4	81.9	417.0	498.9
MI13AG	0.0	2.3	0.0	2.3
MI13ANG	0.0	2.6	0.0	2.6
MP	129.0	101.4	36.4	137.8
MPW	0.0	0.1	0.0	0.1
NIPS	21.5	17.4	20.4	37.8
NSP	605.9	254.3	340.9	595.2
OTP	176.4	123.0	38.5	161.5
SIPC	0.0	1.8	0.0	1.8
SME	0.0	0.0	0.0	0.0
SMMPA	0.0	18.2	0.0	18.2
VECT	155.9	5.8	62.0	67.8
Total	3,358.0	1,050.8	2,307.2	3,358.0

Table 2-2.2: Allocated project cost from MTEP06 to MTEP14 for approved Baseline Reliability (cost-shared through MTEP13), Generation Interconnection and Market Efficiency projects[1]

For the approved portfolio of MVPs, the costs are allocated 100 percent region-wide and recovered from customers through a monthly energy charge calculated using the applicable monthly MVP Usage Rate. The MVP charge will apply to all MISO load, excluding load under grandfathered agreements and export and wheel-through transactions sinking in PJM.

Indicative annual MVP Usage Rates[7] (dollar per MWh), are based on the approved MVP portfolio using current estimated project costs and in-service dates. The MVP usage rates have been calculated for the period 2015 to 2054 and are shown by the blue line (Figure 2-2.3).[8] The red and green lines in Figure 2-2.3 represent an average of the estimated MVP Usage Rates over 20 and 40 year periods. For the average residential household that uses 1,000 kWh each month, the estimated monthly cost for MVPs averages to $1.38 per month over the next 20 years.

For the average residential household that uses 1,000 kWh each month, the estimated monthly cost for MVPs averages to $1.38 per month over the next 20 years

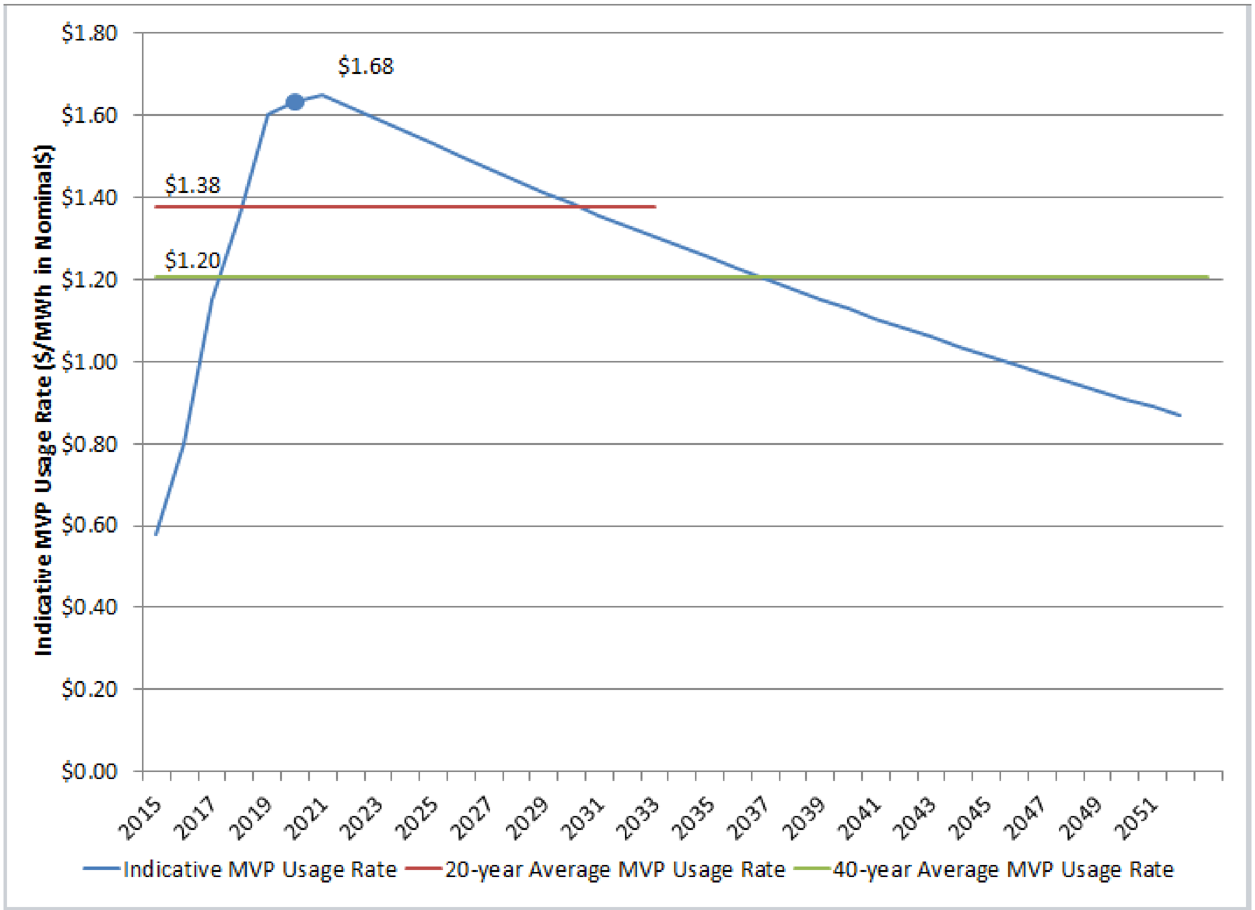


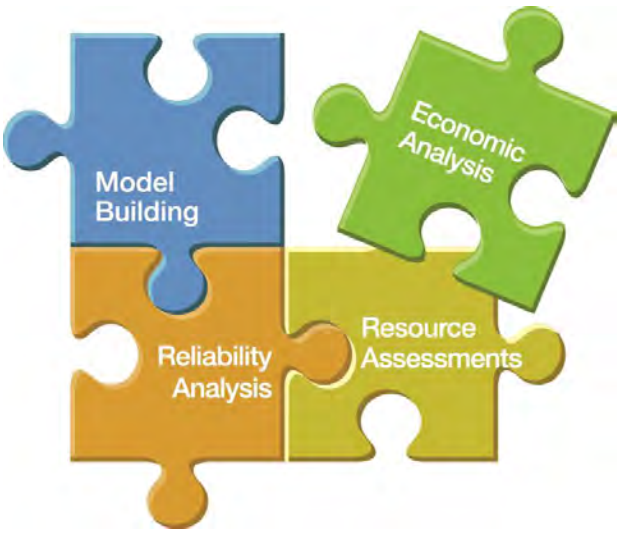
Figure 2-2.3: Indicative MVP usage rate for approved MVP portfolio from 2014 to 2054

[7] The MVP Usage Rate is charged via Schedule 26-A to: 1) Export and Through-Schedules excluding deliveries sinking in PJM; and 2) Monthly Net Actual Energy Withdrawals, excluding those Monthly Net Actual Energy Withdrawals provided under GFAs. For Withdrawing Transmission Owners with obligations for approved Multi-Value Project those charges are recovered through Schedule 39

[8] The annual estimated MVP Usage Rates for 2015 to 2054 shown in Figure 2-2.3 are included in Appendix A-3. Additional information on the indicative annual MVP Usage Rates, including indicative annual MVP charges by Local Balancing Authorities can be found on the MISO website at the following URL under the MTEP Study information section: https://www.misoenergy.org/Planning/TransmissionExpansionPlanning/Pages/MTEPStudies.aspx

2.3 MTEP Process and Schedule

MTEP is a myriad of moving pieces. Each piece needs to fit together to create the complete plan. At its most basic level MTEP is MISO's annual process to study and recommend transmission expansion projects for inclusion in MTEP Appendix A. Official approval of this report and its list of transmission projects traditionally occurs, if justified, at MISO's December 2014 Board of Directors meeting.



The process to produce the list of Appendix A projects requires 18 months of model building, stakeholder input, reliability analysis, economic analysis, resource assessments and report writing (Figure 2.3-1). It requires many hand-offs between various work streams and stakeholders. Along the way, the process produces sub-deliverables, such as Planning Reserve Margins, resource forecasts and regional policy studies.

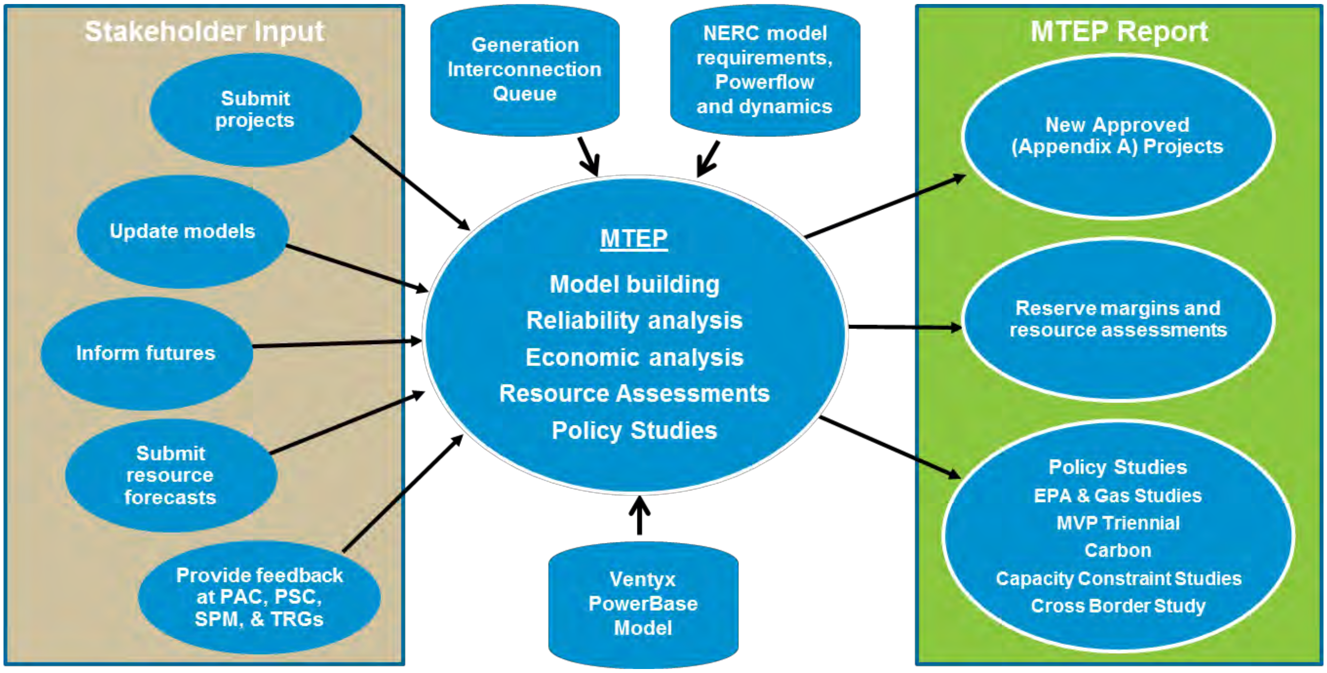


Figure 2.3-1: MTEP inputs and outputs

MTEP Planning Approach

To incorporate multiple perspectives MISO conducts reliability analysis and economic analysis from several angles, both bottom-up and top-down. It evaluates generator requests to connect to the grid via the Generator Interconnection Queue. MTEP also reports on studies that address public policy questions (Figure 2.3-2).

Figure 2.3-2: MISO Value-Based Planning Approach

MTEP14 Workstreams

Completion of MTEP14 requires coordination between multiple subject matter experts and different types of analyses (Figure 2.3-3). It integrates reliability, transmission access, market efficiency, public policy and other value drivers across all planning horizons.

At the core is model building (Section 2.5). The models are updated by stakeholders and serve as the basis for the various types of analyses. The MTEP futures (what-if scenarios) feed the capacity expansion analysis (Section 5.2), Resource Adequacy studies (Sections 6.1 and 6.2) and policy studies (Book 3). The MTEP process culminates in recommendations for various types of transmission expansion.

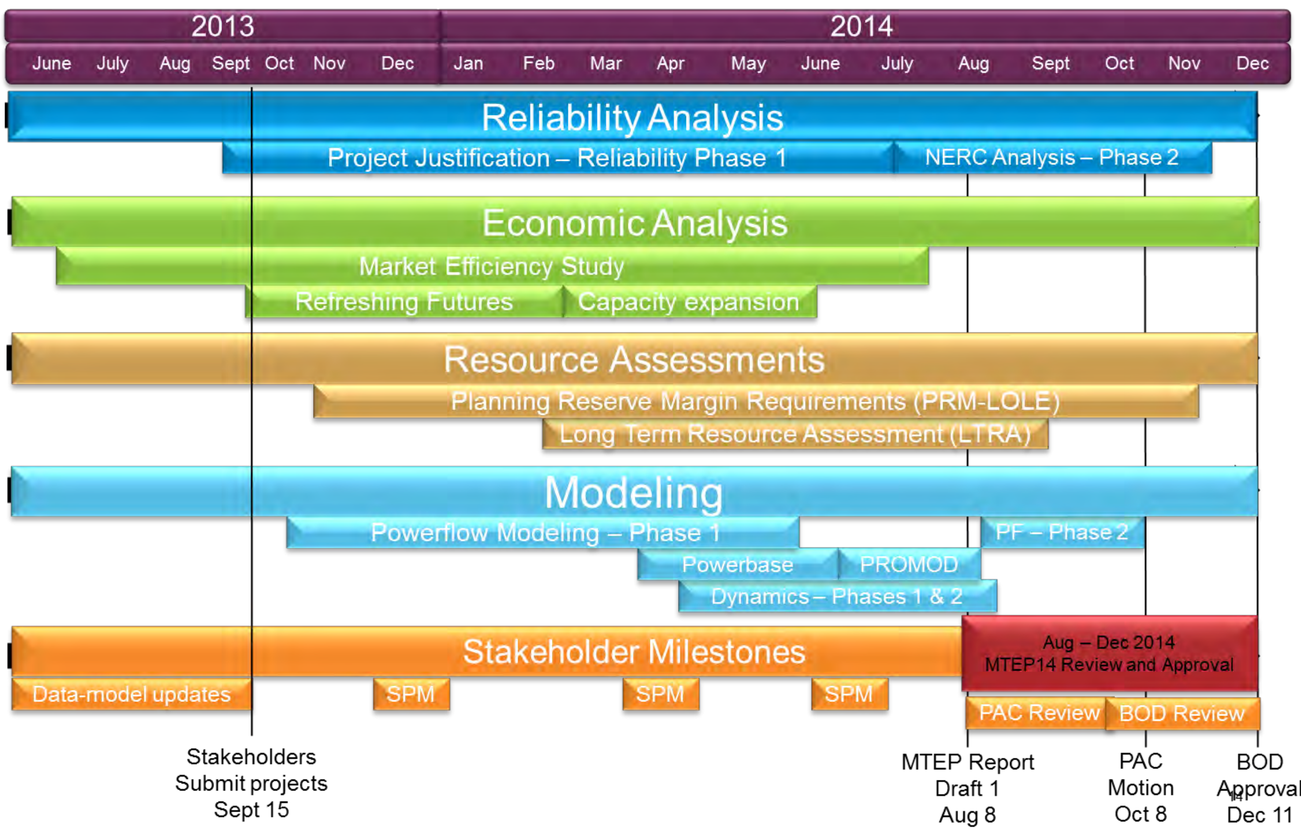


Figure 2.3-3: MTEP14 timelines

Stakeholder Involvement in MTEP14

Stakeholders provide model updates; project submissions; input on appropriate assumptions; and review the results and report. This feedback occurs through a series of stakeholder forums. Each of the five subregions holds Subregional Planning Meetings (SPM) at least three times a year (per FERC Order 890 requirements) to review projects specific to its region. MISO staff and stakeholders review system needs for each project. Some projects may also use stakeholder Technical Study Task Forces (TSTF) to discuss analytical results in greater detail or when these results are Critical Energy Infrastructure Information (CEII). See Section 4.1 for more information about FERC Order 890 requirements and milestones. The SPMs report up to the Planning Subcommittee (PSC). The Planning Advisory Committee (PAC) reviews the full MTEP report in detail, and provides formal feedback to the System Planning Committee (SPC), which is made up of members of the MISO Board of Directors. The SPC makes its recommendations to the full Board, which has final approval authority (Figure 2.3-4).

Figure 2.3-4: MTEP stakeholder forums

MTEP14 Schedule

Each MTEP cycle spans 18 months. MTEP14 began June 1, 2013, and ends December 2014 with Board approval consideration (Figure 2.3-5).

MTEP14 begins with information exchanges	June 1, 2013
Stakeholders submit proposed MTEP14 projects	September 15, 2013
First round of Subregional Planning Meetings (SPM)	December, 2013
Stakeholders submit GADS data	January 31, 2014
Models for MTEP14 Project justification complete (RMD)	February 2014
Second round of SPM	March, 2014
NERC Reliability Study – Phase 1 Powerflow models complete	April 30, 2014
Capacity expansion and generation siting complete	June, 2014
PowerBase modeling complete	July, 2014
Third round of SPM	June, 2014
PROMOD models complete	August, 2014
MTEP14 Report first draft posted	August 8, 2014
NERC Reliability Study – Phase 2 Powerflow models complete	August, 2014
NERC Reliability Study – Dynamics Models complete	August, 2014
Planning Advisory Committee final review and motion	October 8, 2014
MISO Board - System Planning Committee review	October 22, 2014
MISO Board of Directors meeting to consider MTEP14 approval	December 11, 2014

Figure 2.3-5: MTEP14 schedule, major milestones

A Guide to MTEP Report Outputs

MTEP14 is organized into four Books and a series of detailed Appendices.

- Book 1 summarizes this cycle's projects and the analyses behind them
- Book 2 describes annual and targeted analyses for Resource Adequacy – including Planning Reserve Margin (PRM) requirement analysis and Long Term Resource Assessments.
- Book 3 presents policy studies. It summarizes regional studies like the MTEP14 MVP Triennial Review, Independent Load Forecasting, and cross-border studies.
- Book 4 presents additional regional energy information to paint a more complete picture of the regional energy system.
- Appendices A through F provide the detailed project information, assumptions, results, and stakeholder feedback.

2.4 MTEP Project Types and Appendix Overview

MTEP Appendices A and B indicate the status of a given project in the MTEP review process. Projects submitted into the MTEP process transfer to Appendix B when MISO has documented the project need and effectiveness, but are not ready for execution. A project moves to Appendix A after approval by the MISO Board of Directors to proceed with permitting and construction. While moving from Appendix B to Appendix A is the most common progression through the appendices, projects may also remain in Appendix B for a number of planning cycles.

Projects are submitted into the MTEP process, and are transferred to Appendix B when MISO has documented the project need and effectiveness, and then move to Appendix A after approval by the MISO Board of Directors.

Appendix A includes projects from prior MTEPs that are not yet in service, as well as new projects and associated facilities recommended to the MISO Board of Directors for approval in this cycle. The newest projects are indicated as "A in MTEP14" in the "Target Appendix" field of Appendix A. The Appendix AB field defines the 2014 progression of projects: "B>A" for new projects; "A" for previously approved projects.

Projects in Appendix A are classified on the basis of their respective designation in Attachment FF of the MISO Tariff.

- **Baseline Reliability Projects (BRP)** are required to meet North American Electric Reliability Corp. (NERC) standards. Costs for Baseline Reliability Projects approved in MTEP cycles prior to 2013 may be shared if the voltage level and project cost meet the thresholds designated in the Tariff. Since MTEP13, Baseline Reliability Projects are no longer cost shared.

- **Generation Interconnection Projects (GIP)** are upgrades that ensure the reliability of the system when new generators interconnect. The customer may share the costs of network upgrades if a contract for the purchase of capacity or energy is in place, or if the generator is designated as a network resource. Not all network upgrades associated with GIPs are eligible for cost sharing between pricing zones.

- **Transmission Delivery Service Project (TDSP)** projects are required to satisfy a transmission service request. The costs are generally assigned to the requestor.

- **Market Efficiency Projects (MEP)**, formerly referred to as regionally beneficial projects, meet Attachment FF requirements for reduction in market congestion. MEPs are shared based on benefit-to-cost ratio, cost and voltage thresholds.

- **Multi-Value Projects (MVP)** meet Attachment FF requirements to provide regional public policy, economic and/or reliability benefits. Costs are shared with loads and export transactions in proportion to metered MWh consumption or export schedules.

- **Other** projects do not meet the specific criteria for the classifications above, but still address a wide range of project drivers and system needs. Some of these needs may include local reliability, economic benefits and/or public policy initiatives (not meeting requirements of Baseline Reliability, MEPs or MVPs) or projects less than 100 kV required on the transmission system but are not part of the bulk electric system under MISO functional control. Because of this variety, Other projects generally get classified in one of the following sub-types:

    - Reliability
    - Economic
    - Condition
    - Distribution
    - Relaying/Control and Substation Reconfiguration

MTEP Appendix A

MTEP Appendix A contains transmission expansion plan projects recommended by MISO staff and approved by the MISO Board of Directors for implementation by Transmission Owners.[9]

Projects in Appendix A have a variety of drivers. Many are required for maintaining system reliability in accordance with NERC Planning Standards. Others may be required for Generation Interconnection or Transmission Service. Some projects may be required for Regional Reliability Organization standards. Other projects may be required to provide distribution interconnections for load-serving entities. Appendix A projects may be required for economic reasons, to reduce market congestion or losses in a particular area. They may also decrease resource adequacy requirements through reduced losses during system peak or reduced planning reserve needs. Projects may be necessary to enable public policy requirements, such as current state renewable portfolio standards or Environmental Protection Agency standards. All projects in Appendix A address one or more MISO-documented transmission needs. Projects in Appendix A may be eligible for regional cost-sharing per provisions in Attachment FF of the Tariff.

Projects must go through a specific process to move into Appendix A. MISO staff must:

- Review the projects via an open stakeholder process at Subregional Planning Meetings
- Validate that the project addresses one or more transmission needs
- Consider and review alternatives
- Consider and review costs

[9] Projects with a Target Appendix A in the current MTEP cycle are not officially placed into Appendix A until Board of Directors approval in December of the cycle year.

- Endorse the project

- Verify whether the project is qualified for cost sharing as a Generation Interconnection Project, Market Efficiency Project or Multi-Value Project per provisions of Attachment FF or will be participant-funded

- Hold a stakeholder meeting to review a project or group of projects in which costs can be shared, or other major projects for zones where 100 percent of costs are recovered under the Tariff

- Take the new project to the Board of Directors for approval. Projects may move to Appendix A following a presentation at any regularly scheduled board meeting

The MTEP Active Project List is periodically updated and posted as projects go through the MTEP process and are approved. Projects generally move to Appendix A in conjunction with the annual approval of the MTEP report. In addition to the regular annual approval process, under specific circumstances, recommended projects need not wait for completion of the next MTEP for Board of Directors approval and inclusion in Appendix A, but can go through an expedited Out-of-Cycle approval process.

MTEP Appendix B

Projects in Appendix B have been analyzed to ensure they effectively address one or more documented transmission issues. In general, MTEP Appendix B contains projects still in the Transmission Owners' planning processes or still in the MISO review and recommendation process. Appendix B may contain multiple solutions to a common set of transmission issues. Projects in Appendix B are not yet recommended or approved by MISO, so they are not evaluated for cost sharing. Any designation of project type (Baseline Reliability Projects, Market Efficiency Projects or Multi-Value Projects) for projects in Appendix B is preliminary. Thus, while some projects may eventually become eligible for cost-sharing, the target date does not require a final recommendation for the current MTEP cycle. The project will likely be held in Appendix B until the review process is complete and the project is moved to Appendix A.

MTEP Appendix C

Appendix C has been retired in the MTEP14 planning cycle due to Order 1000.

2.5 MTEP14 Model Development

Transmission system models are the foundation of MTEP. The accuracy and viability of the study results hinges on the accuracy of the models used. Planning model development at MISO is a collaborative process with significant stakeholder interaction and neighbor coordination. Stakeholders provide modeling data, help develop assumptions for modeling future transmission system scenarios, and review the models. MTEP models are also coordinated with MISO's tier one neighboring entities and their system representation is updated based on their feedback. With the integration of the MISO South region, MTEP14 is the first planning cycle where MISO South stakeholders participate directly in the model development process.

Transmission system models are the foundation of MTEP

For MTEP studies, reliability (powerflow and dynamics) and economic models are built to represent a planning horizon spanning the next 10 years. The primary sources of information used to develop the models are:

- MISO members, including Transmission Owners, Generation Owners and Load-Serving Entities
- Model on Demand (MOD) base case
- Latest available Eastern Reliability Assessment Group (ERAG) Multi-regional Modeling Working Group (MMWG) series models
- PowerBase database
- Tier one neighboring entities

MTEP14 models are interdependent (Figure 2.5-1).

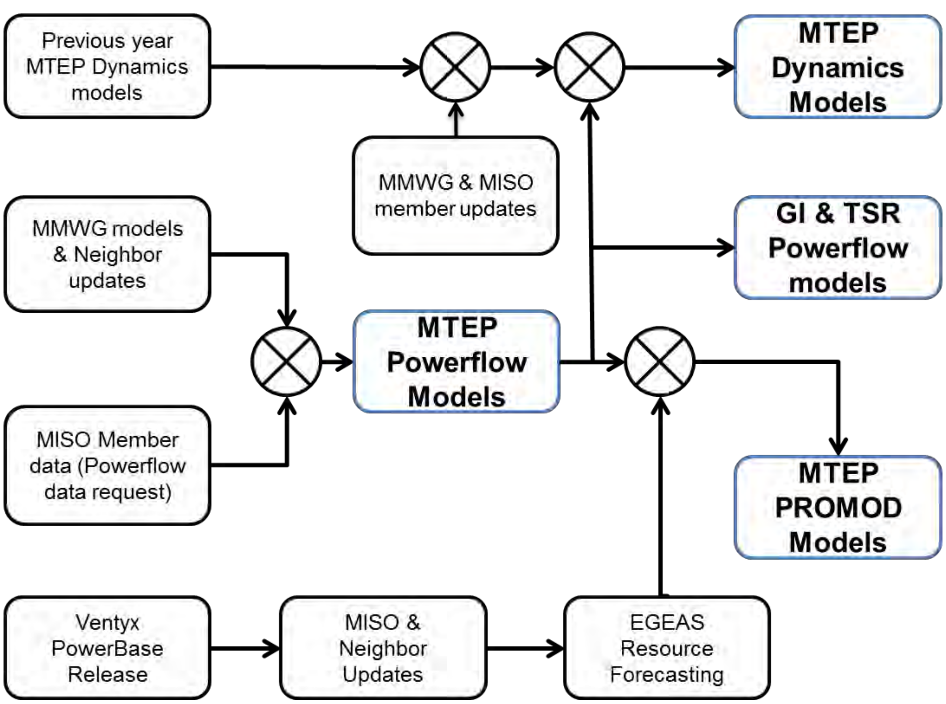


Figure 2.5-1: MTEP14 model relationships

Reliability Study Models

Powerflow Models

For MTEP14, MISO conducted regional studies using these base models:

- 2016 Summer Peak
- 2019 Summer Peak
- 2019 Shoulder Peak
- 2019 Light Load
- 2019/2020 Winter Peak
- 2024 Summer Peak
- 2024 Shoulder Peak

In September 2013, MISO members were asked to submit modeling information data to MOD. MISO staff reviewed the data submitted for validity before using it to model the MISO system representation. The ERAG MMWG cases are the base starting point for non-MISO external system representation in MTEP models. Requests for updated information to the ERAG MMWG models from bordering neighbors were sent after these models were released in late November 2013. Preliminary models were built from MOD and posted for stakeholder review in early December 2013. After incorporating the feedback received, models needed for MISO's independent evaluation of Transmission Owner projects were built and posted in February 2014. The powerflow models needed for NERC Transmission Planning Standards (TPL) Compliance assessment were developed in the April/May timeframe, closer to the commencement of those studies (see Section 4.1). The process followed a defined timeline with key milestones (Figure 2.5-2).

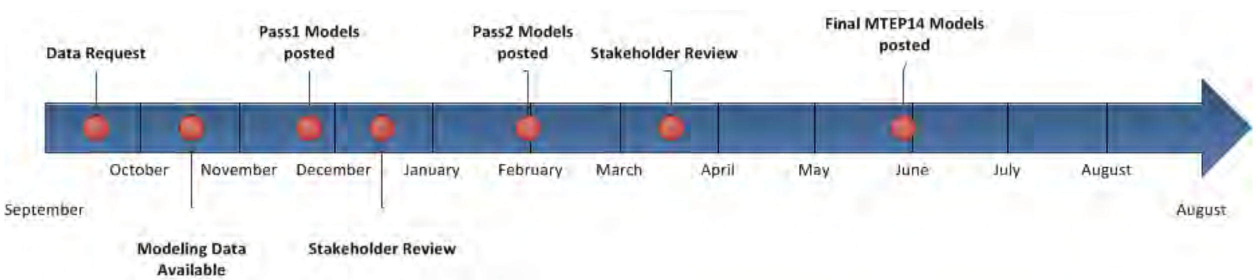


Figure 2.5-2: MTEP14 powerflow model development timeline

Assumptions regarding inclusion of future transmission, generation and load facilities are summarized as:

Load

- Load is modeled based on seasonal load projections provided by member companies in MOD

Generation

- Existing and planned generators with signed Generation Interconnection Agreements, with expected in-service dates through the corresponding season being modeled
- Models used for need-verification of member-submitted local transmission upgrades contain a Local Balancing Authority (LBA) area level Network Resource dispatch. For implementation, Network Resources are dispatched in an economic order to meet the load,

loss and interchange level for each LBA. The generation and load profiles submitted by members, in MOD, are used as the starting point for this dispatch.
- Some of the models used to verify sufficiency of the member TO plans and identify additional projects to ensure a reliable transmission plan, contain a Security Constrained Economic Dispatch (SCED).
- Generation is dispatched to allow for the cumulative MISO net area interchange level to be consistent with the equivalent ERAG MMWG cases.

Transmission topology
- In-service and future transmission facilities approved through prior Transmission Owner or MTEP studies are included.
- Transmission projects submitted for approval in MTEP14 planning cycle are also included to verify their need and sufficiency in ensuring system reliability. Any projects whose need is not justified are subsequently removed from the models.

Throughout the modeling process, powerflow models are reviewed for reasonableness of data and performance. This review is achieved through extensive data checks and stakeholder review and feedback. MISO planning staff produces a model verification document, which is made available to the stakeholders along with the models.

Dynamic Stability Models

For MTEP14, MISO conducted dynamic stability analysis using these models:

- 2019 Light Load
- 2019 Summer Shoulder load

The MTEP13 dynamics model was used as a starting point for the MTEP14 models. MISO leveraged many improvements made during MTEP13 for MTEP14 models. Additionally, the ERAG MMWG 2013 dynamic stability models were reviewed and any improved modeling data was incorporated in the MTEP14 models. Dynamics models are used for transient stability assessment performed as part of NERC TPL compliance and generation interconnection studies (see Section 4.2).

In collaboration with stakeholders, during the MTEP14 planning cycle, MISO has developed a list of standardized generator component dynamic models. These models will be used to replace legacy models (available in PSS/E library) and certain proprietary user-defined models, for improved dynamic representation of the system, starting from MTEP14. Dynamic modeling standardization also supports compliance obligations, results in increased efficiency and makes modeling practices consistent across the entire MISO footprint. This list will be maintained on an ongoing basis and models will be updated as needs and modeling capabilities evolve.

The dynamics package is verified by running a 20-second, no-disturbance simulation and some other sample disturbances at important generator locations in the MISO footprint. Simulation results obtained using a correct dynamics package show expected performance of generators and active elements within the MISO system. Charts showing simulation results are posted for stakeholder review along with a map showing geographical location of generators monitored.

MTEP14 dynamic models were posted for stakeholder review towards the end of July 2014. During the review period stakeholders were asked to provide:

- Updates to existing dynamics data
- Additional dynamic models for new equipment
- Updates to existing disturbance files
- Additional disturbances to be studied in MTEP14
- Output quantities to be measured

The MTEP14 dynamics model development timeline had many key milestones during the study year (Figure 2.5-3). The MTEP14 dynamics cases were finalized and posted in August 2014.

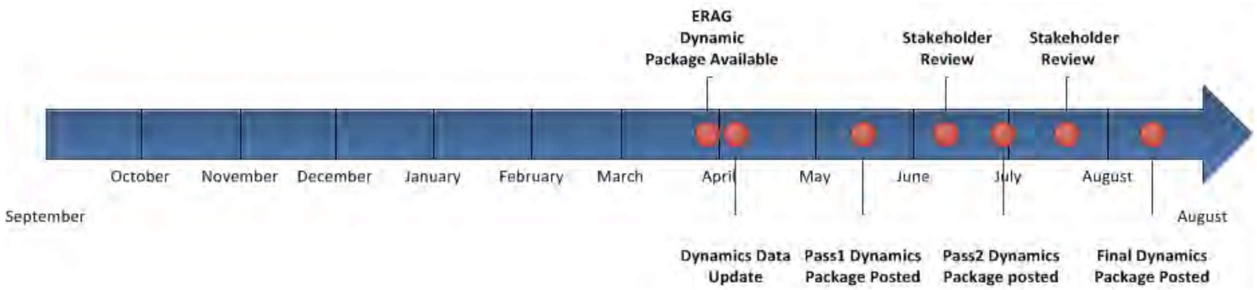


Figure 2.5-3: MTEP14 dynamics model development timeline

Economic Study Models

The economic study models used in the MTEP process are forward-looking, time-dependent models based on assumptions discussed and agreed upon through the stakeholder process. For MTEP14, the Planning Advisory Committee (PAC) approved the following future scenarios:
Central and North Regions

- Business as Usual (BAU)
- High Growth (HG)
- Limited Growth (LG)
- Generation Shift (GS)
- Public Policy (PP)

South Region

- Business as Usual (BAU)
- Robust Economy (RE)

The details on these scenarios are available in Sections 5.2 and 5.3.

The base data used in all future scenarios is maintained through the PROMOD PowerBase database. This centralized database uses data provided annually by ABB Ventyx as a starting point. MISO then goes through an extensive model development process that updates the original data provided by Ventyx with more accurate data specific to MISO.

Updates include data obtained from the following sources:

- Commercial Model
- Generator Interconnection Queue
- Module E data
- Powerflow model (developed through the MTEP process)
- Publically announced generation retirements

- Specific stakeholder comments/updates
- Generation capacity expansion (developed by MISO staff – see Section 5.2)

As part of the model development process, PowerBase database is verified to ensure data accuracy through numerous checks. Model verification is broadly comprised of generator economic data validation, demand and energy data checks and PowerBase-powerflow network topology mapping.

The PowerBase database, including system topology, was posted for stakeholder review and feedback in July 2014. During the review period stakeholders were asked to provide:

- Updates to generator data
    - Maximum and minimum capacity
    - Retirement dates
    - Emission rates
- Updates to powerflow mapping
    - Generator bus mapping
    - Demand mapping
- Updates to contingencies and flowgates/interfaces monitored

In addition to the stakeholder review process, MISO continued to collaborate with neighboring entities to develop a coordinated model that more accurately reflects the neighbor's systems. Highlights of this collaboration include extensive updates from PJM Interconnection and SPP. The economic model development timeline is an 11-month process (Figure 2.5-4).

The PowerBase model was finalized in July 2014.

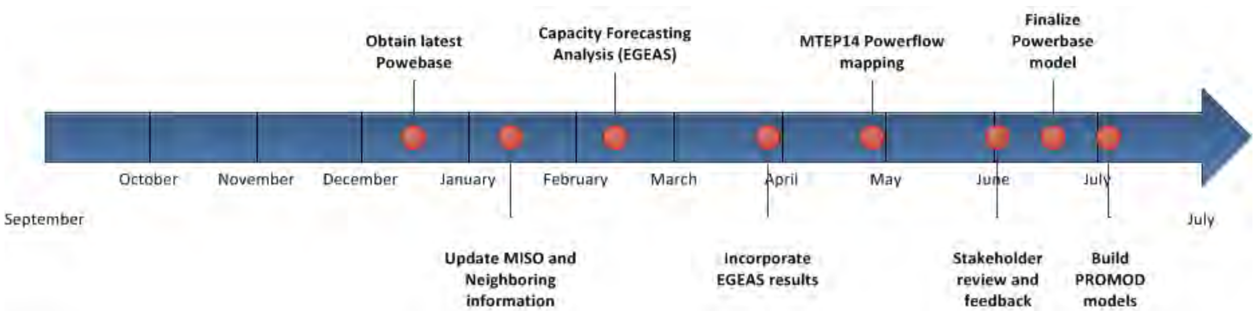


Figure 2.5-4: MTEP14 economic model development timeline

2.6 Transmission Developer Qualification and Selection

Overview

MTEP14 is the first MTEP cycle in which eligible transmission facilities are subject to MISO's competitive developer selection process, referred to as Transmission Developer Qualification and Selection (TDQS). This process implements FERC's Order 1000 requirement to eliminate federal Right of First Refusal (ROFR) on eligible transmission facilities. While MTEP14 is the first MTEP cycle in which the TDQS process is applicable, as discussed in Section 5.3, MTEP14 Appendix A does not contain any eligible TDQS projects.

Since MTEP13[10], MISO has submitted additional compliance filings to FERC, and has begun implementing many of the Right of First Refusal (ROFR) elimination provisions. These include:

- Tariff Filings
    - MISO made a compliance filing on July 22, 2013, based on the March 2013 FERC Order to MISO.
    - Received FERC Order on May 15, 2014, based on MISO's July 2013 compliance filing.
    - MISO made a compliance filing, part 1 of 2, on June 4, 2014, based on May 15, 2014, FERC Order to MISO.
    - MISO made a compliance filing, part 2 of 2, on July 14 2014 based on May 15, 2014, FERC Order to MISO.

- Process Activities
    - Developed business practice language for the Prequalification process (BPM 027). This work was accomplished through the Planning Advisory Committee (PAC) open stakeholder process between September 2013 and January 2014.
    - Kicked-off the first prequalification window in January 2014 to prequalify potential transmission developers.
    - Launched a dedicated web page[11] on the MISO website as a resource for information to all stakeholders.
    - A dedicated e-mail address was created (TDQS@misoenergy.org) for all potential transmission developers and other stakeholders to pose questions, comments, etc. on the TDQS process.
    - Multiple stakeholder workshops were held throughout 2014 to receive transmission developer and stakeholder input on process development.
    - Multiple formal feedback requests were made to stakeholders asking for responses to specific topics and questions regarding the TDQS process. These feedback requests were disseminated via the PAC e-mail distribution list.

[10] Section 9.1
[11] https://www.misoenergy.org/Planning/Pages/TransDevQualSel.aspx

Process

The prequalification process is an annual cycle that opens in January. All developers must submit an application and be approved in the prequalification process to become Qualified Transmission Developers (QTD). Only QTDs are allowed to bid on transmission projects eligible for the TDQS process. Once a potential transmission developer becomes a QTD, that entity will need to renew its status annually during the prequalification cycle.

Transmission projects eligible for TDQS are developed through the MTEP Top Down process. Eligible projects, referred to as Open Transmission Projects, contain transmission facilities that are approved by the MISO Board of Directors as part of a Market Efficiency Project (MEP) or a Multi-Value Project (MVP) (Figure 2.6-1). Eligible transmission facilities include those facilities that are not upgrades or otherwise assigned to an incumbent Transmission Owner due to Applicable Laws and Regulations pursuant to Attachment FF Section VIII.A of the MISO Tariff.

TDQS has no impact on the MTEP process, but uses the MTEP output to determine Open Transmission Projects. All Open Transmission Projects will be posted to the MISO website for bidding within 30 days of the MISO Board of Directors' approval of the MTEP report (typically in December of each year) (Figure 2.6-2). All Qualified Transmission Developers then have six months to submit their bids, defined as New Transmission Proposal (NTP) in the MISO Tariff, on each posting. MISO has an additional six months to analyze those NTPs and select a QTD for each posted Open Transmission Project.

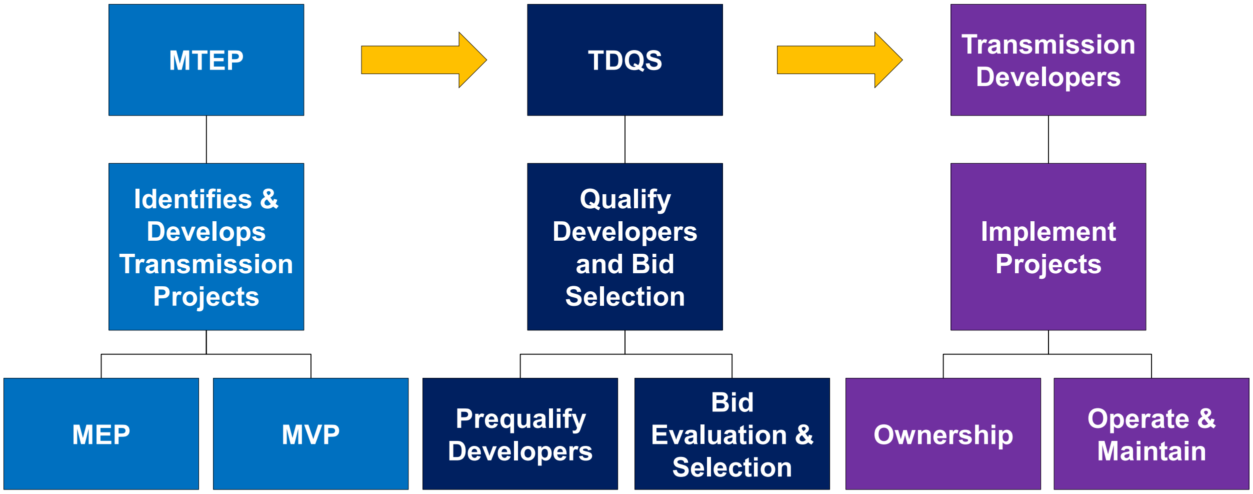


Figure 2.6-1: Process flow for Transmission Developer Qualification and Selection

MTEP15 (typical annual cycle)

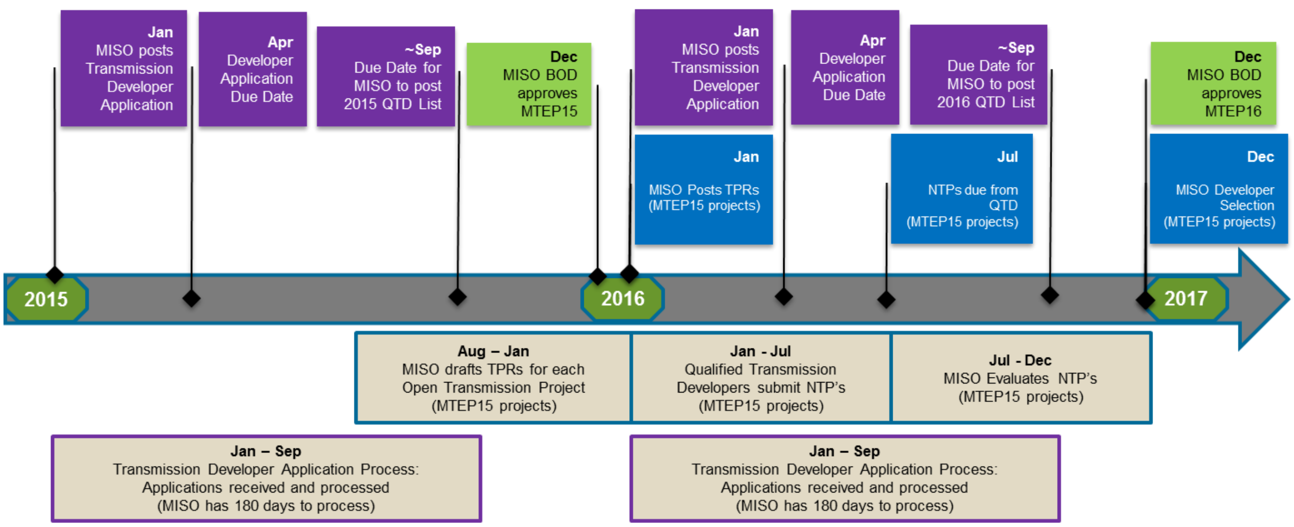


Figure 2.6-2: Annual Cycle

Bidder Selection Process Development

MISO held multiple stakeholder workshops in 2014 to facilitate the development of the bidder selection portion of the TDQS process and associated Business Practices Manual (BPM-027) (Figure 2.6-3). The summer workshops were to elicit feedback from stakeholders and transmission developers with the following specific objectives:

- Identify principles, issues and elements that should be accounted for in the process
- Develop ideas to address issues in the process
- Develop principles and ideas to apply the tariff-defined weighting criteria to bid evaluation and selection

The fall/winter workshops were used to vet and finalize BPM-027 language. The BPM language was a compilation of stakeholder input received during the workshops, information provided from MISO's consultants and MISO's own ideas, all based on requirements defined in the MISO Tariff. Each workshop averaged more than 50 registered participants, including transmission developers, regulators, and other interested stakeholders.

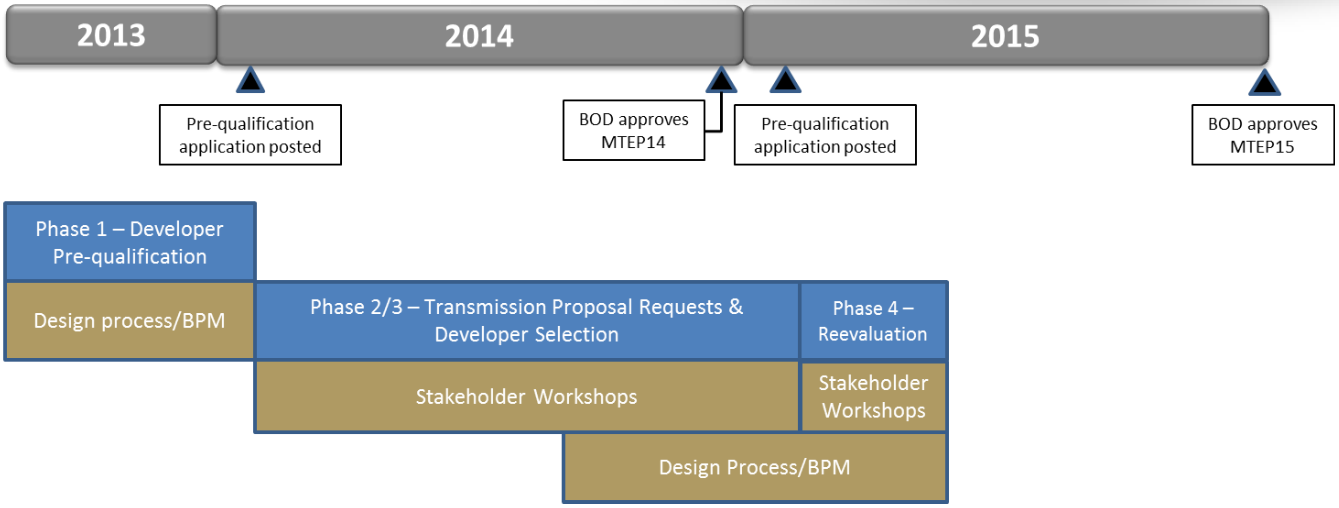


Figure 2.6-3: Process development timeline for TDQS process and Business Practices Manual language

Chapter 3 Historical MTEP Plan Status

Since the first MTEP report in 2003, more than $7.4 billion in projects have been constructed in the MISO region. Not including withdrawn projects, there are currently $19.5 billion of approved projects in various stages of design, construction, or already in-service through the MTEP14 cycle.

Section 3.1 presents a status update on the implementation of active projects approved in previous MTEP reports. Section 3.2 provides a historical perspective of past MTEP approved plans.

3.1 MTEP13 Status Report

MISO transmission planning responsibilities include monitoring the status of previously approved MTEP Appendix A projects. MISO surveys all Transmission Owners on a quarterly basis to determine the progress of each project. These status updates are reported to the MISO Board of Directors and posted to the MISO MTEP Studies[12] web page. This chapter provides a summary of this quarterly status report, and elaborates on the status of the MTEP11-approved Multi-Value Project (MVP) Portfolio.

Since 2006, the MISO Board of Directors has received quarterly status updates on active plans. The information in this report reflects project status as of the first quarter 2014 report to the Board of Directors, which includes the status of MTEP13 Appendix A projects as of April 2014. The statistics include in-service and cost variance for several milestones of the planning and construction time periods.

Tracking the progress of projects ensures a good-faith effort to move projects forward, as prescribed in the Transmission Owners' Agreement. Most approved projects move forward despite possible complications, such as equipment procurement delays, construction difficulties and longer-than-anticipated regulatory processes. A project is only considered "off-track" if MISO cannot determine a reasonable cause for delay or withdrawal. MTEP13 Appendix A contains 703 projects comprised of 1,482 facilities. These figures have been updated to reflect the progress of members' projects. MTEP13 Appendix A includes expansion facilities through 2021. As of the second quarter of 2014, more than 98 percent of the approved facilities included in MTEP13 are either in service, on track or have encountered reasonable delays. That translates to $11.24 billion of the $11.379 billion on track in MTEP13 Appendix A.

MISO transmission planning responsibilities include monitoring progress and the implementation of previously approved MTEP Appendix A projects

This year marks the first full implementation of the milestone-driven project update process. This process focuses on the progress of projects through their construction, and requests updates when projects pass key milestones in their implementation milestones. These milestones are:

- Milestone 1: Final Subregional Planning Meeting / Out of Cycle Request Submittal
- Milestone 2a: Pre-project approval
- Milestone 2b: Developer selection
  - Only applicable for Market Efficiency Projects (MEP) and MVPs that will proceed through the MISO inclusive evaluation process to select the transmission developer
- Milestone 3: Prior to ordering long lead materials
- Milestone 4: Pre-construction
- Milestone 5: Facility completion

The milestone-driven updates will contain, at a minimum, the following data:

[12] https://www.misoenergy.org/Planning/TransmissionExpansionPlanning/Pages/MTEPStudies.aspx

- Most recent milestone achieved
- In-service date
- Planning status (Proposed, Planned, Under Construction, In Service)
- Total project cost estimate

Additionally, under the milestone-driven updates, facilities more than $50 million and regionally or inter-regionally cost-shared projects are required to supply additional details. Details include line cost estimates, substation cost estimates, regulatory costs and explanations on current variances. Although the details provided remain confidential, a key outcome of the reporting process is improved summary variance explanations for applicable projects.

In conjunction with the milestone-driven project status updates, MISO continues to work to improve the manner in which project costs and schedules are tracked and reported. In addition to the “on-track” metric, MTEP14 contains cost and schedule variance analysis. The cost and schedule variance summarizes the differences between what was originally approved in MTEP and most up-to-date projections as of April 2014. This year’s analysis is a continuation of the process started in MTEP13 and uses the current data available, which is largely collected through quarterly status updates. As the milestone-driven status update and transmission developer selection processes mature and provide additional details on project costs and in-service dates, the MTEP project variance analysis will increase in terms of both granularity and substance.

The MTEP14 cost and variance analysis considers all MTEP13 Appendix A projects that are not in-service or withdrawn as of April 2014. Additionally, because of the amount of investment of the MVP Portfolio relative to other projects included in Appendix A, the MVP Portfolio is excluded from the subset used in the variation analysis (Figures 3.1-1 through 3.1-6) and instead detailed in a status report (Figure 3.1-7). The MTEP13 Appendix A projects in the variance analysis represents 487 projects totaling $4.15 billion in approved investment. Of the projects in MTEP13 Appendix A, 33 percent were approved in MTEP13 and the remaining 67 percent were approved in MTEP03 through MTEP12. All costs contained within this section are in nominal, as-spent dollars.

Non-MVP Project Cost Variation

The total costs for the 487 MTEP13 Appendix A projects have increased from the MTEP-approved $4.15 billion to $4.56 billion, thus the average cost variance is 9.7 percent (Figure 3.1-1). In MTEP13, the average cost increase from approval was 8.8 percent for a similar subset of MTEP approved projects. Costs can vary for multiple reasons. At the time of Board approval, a project cost estimate reflects:

- Rough line routing and station costs
- Estimated labor and materials
- Known environmental concerns
- Contingency allowance

At project completion, after regulatory issues have been addressed and uncertainties eliminated, a project’s updated cost reflects:

- Final line routing and costs
- Actual commodity and labor costs
- Total environmental mitigation costs

Additionally, a project cost’s perceived variance from approval to the current estimate may be attributable to different types of dollars, such as real versus nominal/as-spent, or a different basis year, i.e. $-current vs. $-in-service year, being used for an estimate. As the new status reporting procedures are implemented, the issues around consistent dollar type and basis year should continue to decline.

The current estimates have no reported cost increase from the approval estimates for 70 percent of the non-MVP MTEP13 Appendix A projects; 85 percent of estimates have deviated by less than 25 percent (Figure 3.1-2). Overall, projects with larger percent cost increases were a minority. The projects with a largest percentage deviation were generally projects with a small total cost.

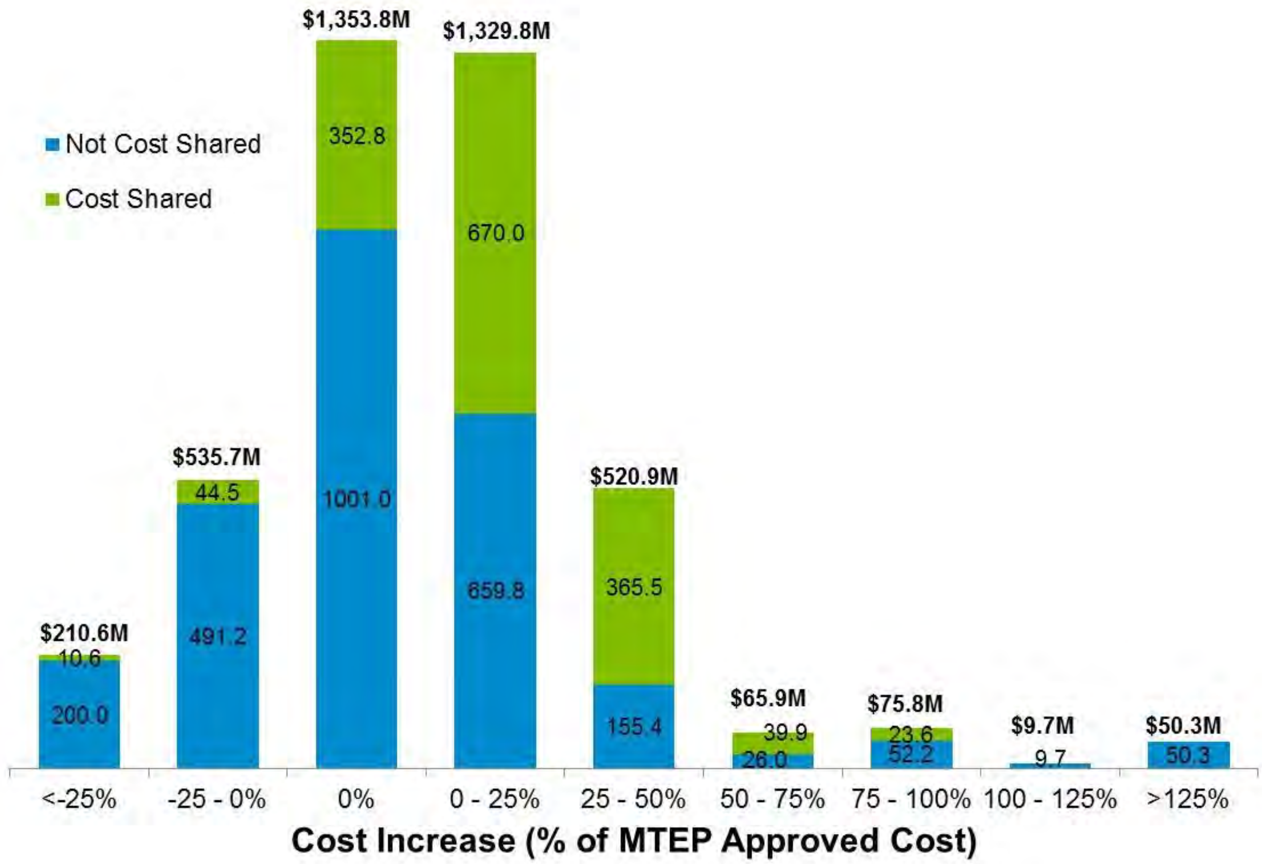


Figure 3.1-1: Total project cost sum of cost variation from approval to current for non-MVP MTEP13 Appendix A projects as of Q1 2014

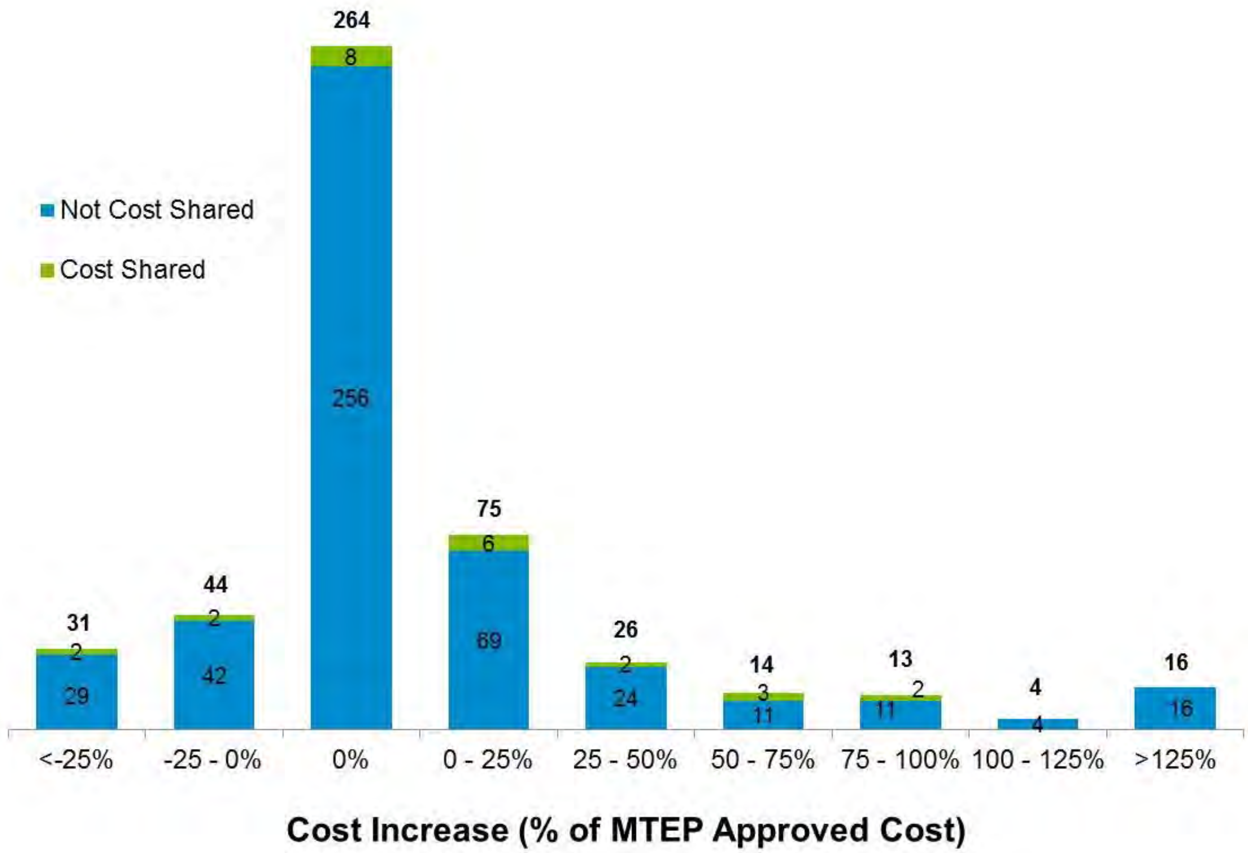


Figure 3.1-2: Frequency of cost variation from approval to current for non-MVP MTEP13 Appendix A projects as of Q1 2014

Non-MVP Cost-Shared Project Cost Variation

The cost-shared projects of the MTEP13 Appendix A subset represent $1.51 billion in approved MTEP investment (Figure 3.1-3). Of the 25 cost-shared projects' cost estimates, 48 percent have not increased since approval. Seven projects' (28 percent) costs are projected to increase by more than 25 percent - all of these projects are Baseline Reliability Projects not justified based on economics. The largest deviations on a percentage basis are primarily small projects. Each of these projects had small changes in scope (substation work, right of way, routing) that was a large percentage of the total project cost. There is one exception: A $300 million Baseline Reliability Project currently has a projected cost variance of 31 percent attributed to a state commission requiring a longer line routing and the ability for future expansion.

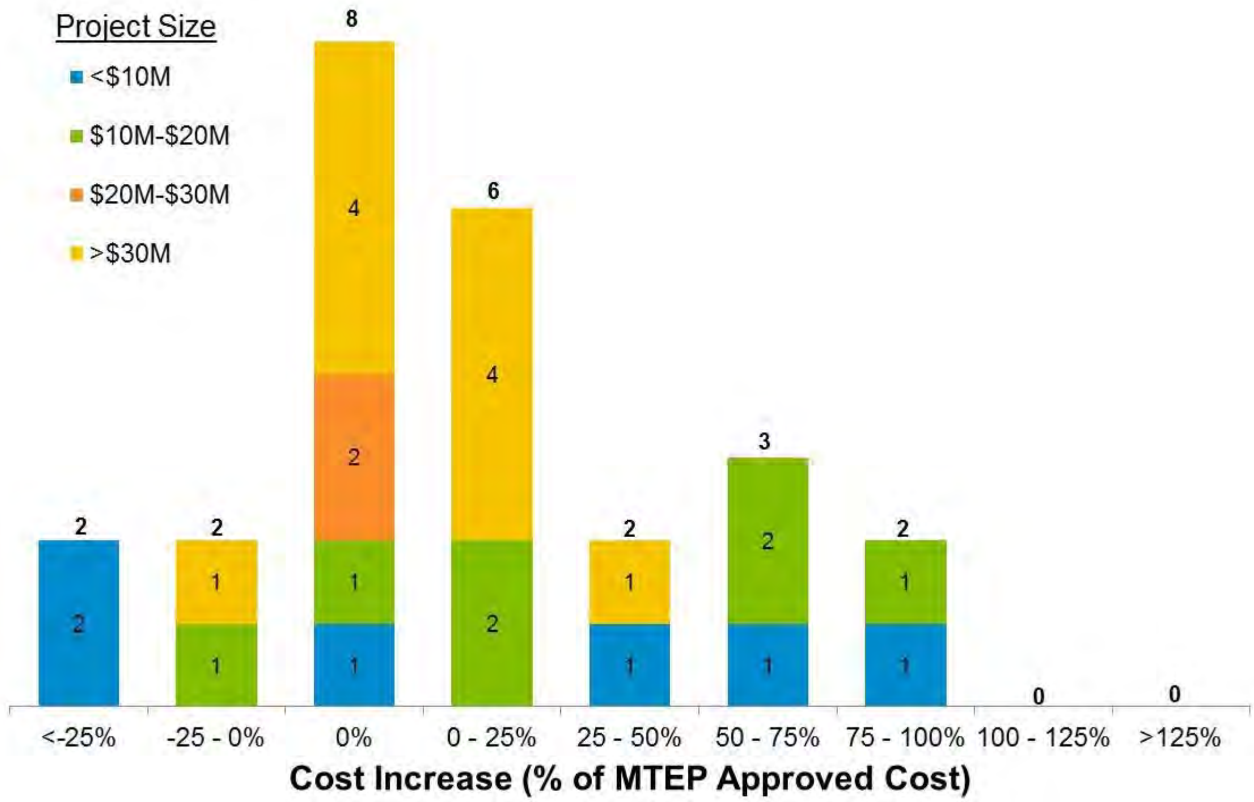


Figure 3.1-3: Frequency of cost variation from approval to current for cost-shared non-MVP MTEP13 Appendix A projects as of Q1 2014

Non-MVP Project Schedule Variation

The 487 MTEP13 Appendix A projects not in service, withdrawn or included in the MVP Portfolio have, on average, adjusted their in-service date back by 16 months. In the MTEP13 report, the average in-service delay for a similar subset of projects was 15 months. Little or no impact on reliability is expected from the adjusted in-service dates. Transmission Owners may adjust project in-service dates to match system needs. Common drivers of schedule variance include:

- Budgetary constraints
- Weather
- Length of regulatory process
- Equipment or material delays
- Time required to secure property rights
- Changes in design resulting from routing changes

The expected in-service date of 48 percent of MTEP13 Appendix A projects have extended beyond the MTEP-approved estimate (Figure 3.1-4). Projected in-service dates have extended beyond 24 months for 35 percent of the MTEP13 Appendix A investments (Figure 3.1-5). Because common drivers for schedule variances primarily result in project delays as opposed to a project moving ahead of schedule, Figures 3.1-4 and 3.1-5 have negatively or left-skewed distributions.

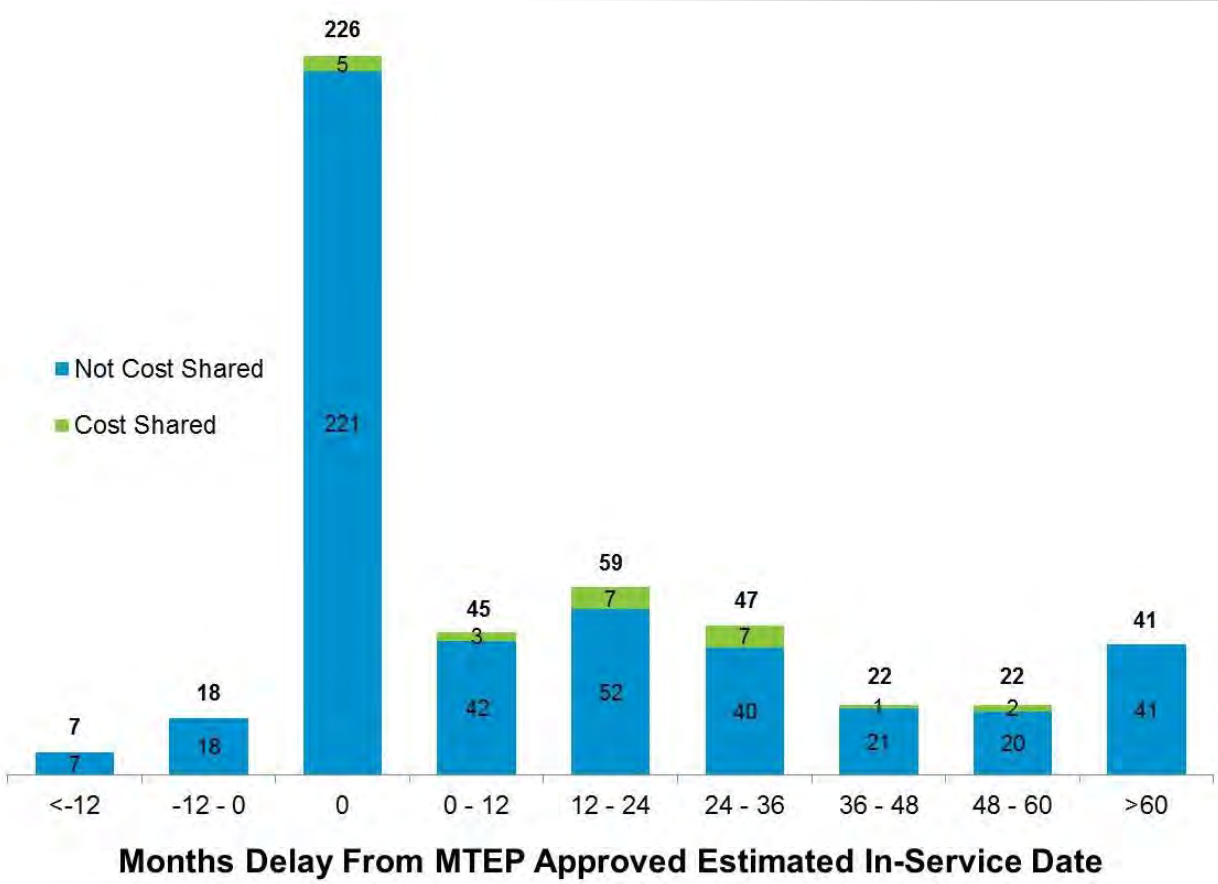


Figure 3.1-4: Frequency of schedule variation from approval to current for non-MVP MTEP13 Appendix A projects as of Q1 2014

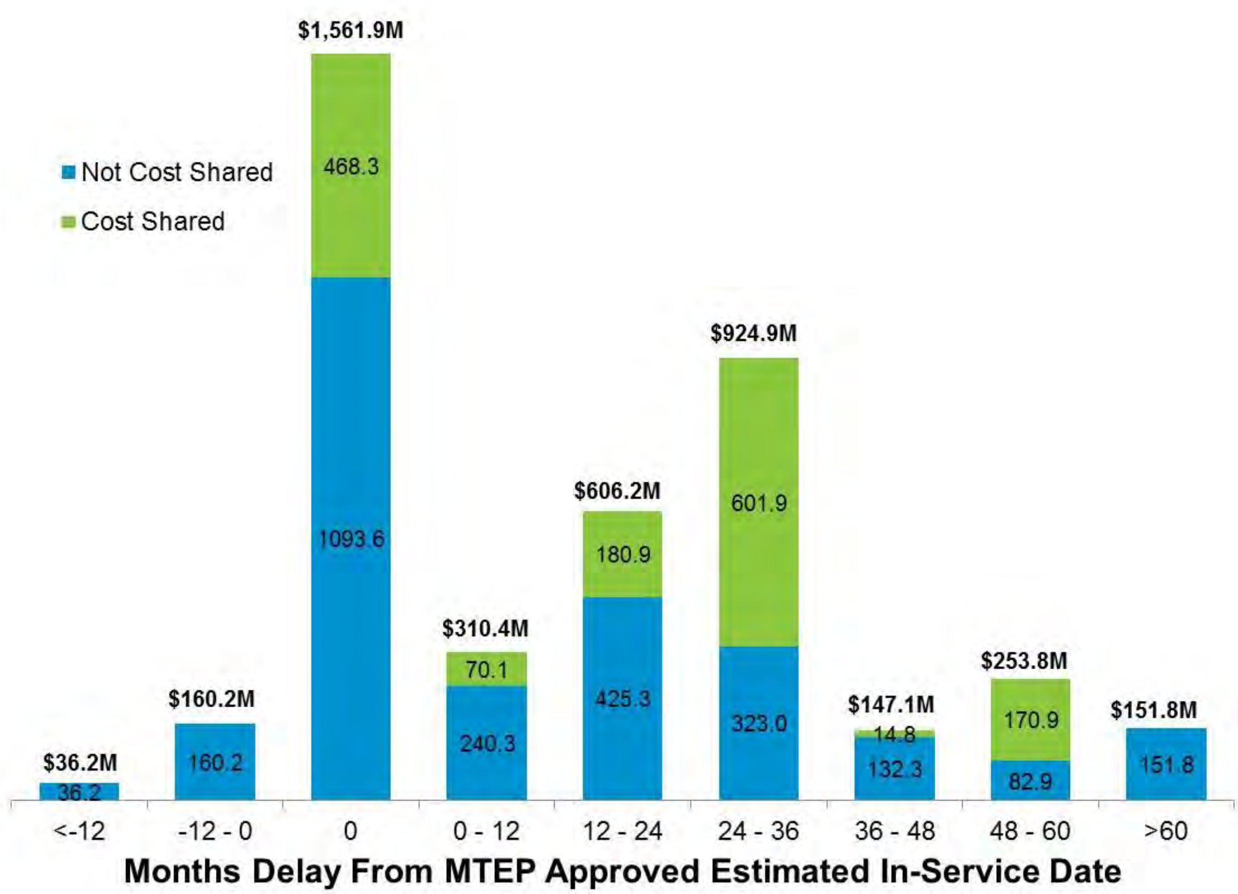


Figure 3.1-5: Total project cost sum of schedule variation from approval to current for non-MVP MTEP13 Appendix A projects as of Q1 2014

Non-MVP Cost-Shared Project Schedule Variation

The current expected in-service date has not changed for five of the 25 cost-shared MTEP13 Appendix A project subset (Figure 3.1-6). Three projects' in-service date have extended less than 12 months. In-service dates for 17 projects have extended beyond a year and 10 projects beyond two years. Three of the 10 projects with in-service date extensions beyond two years attributed the delays to customer need and two were attributed to delays in the regulatory process; the remaining five were delayed because of budgetary constraints, forecast changes, or scope alterations.

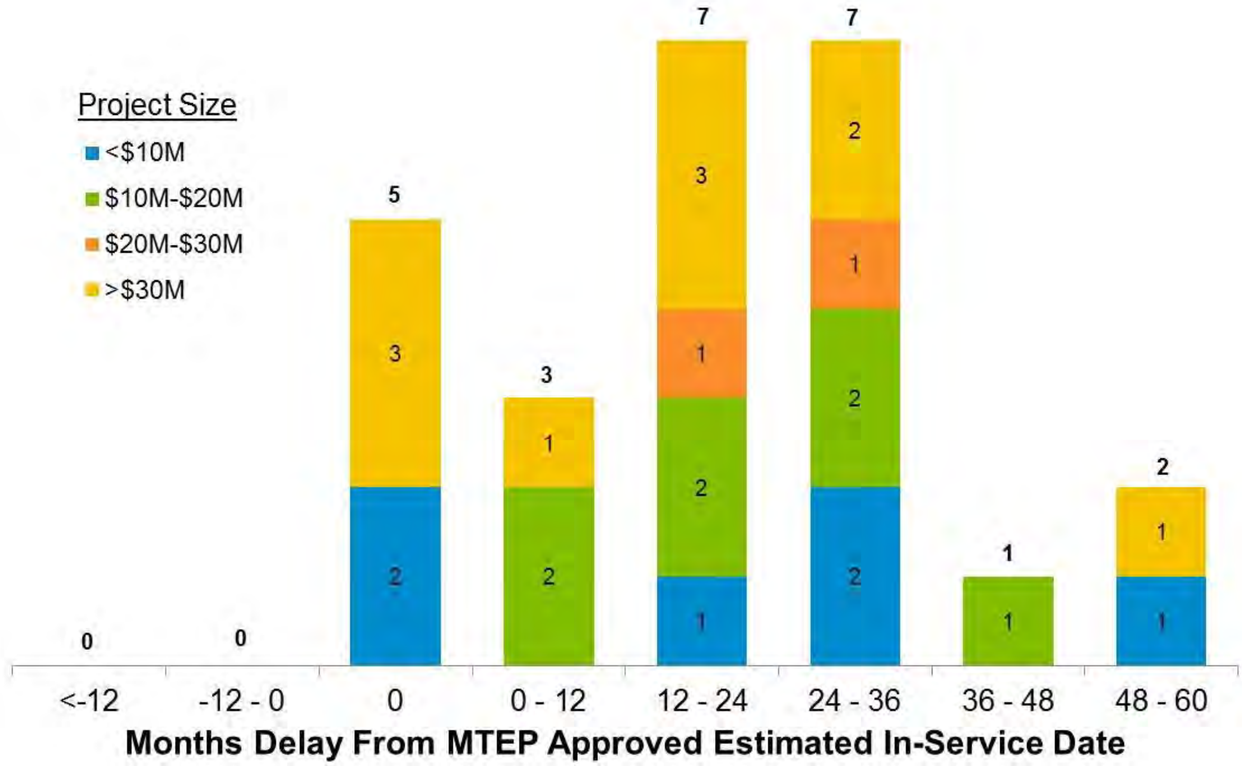


Figure 3.1-6: Frequency of schedule variation from approval to current for cost-shared non-MVP MTEP13 Appendix A projects as of Q1 2014

Multi-Value Project Portfolio Status

The MVPs are part of a regionally planned portfolio of transmission projects (Figure 3.1-7). The MVP Portfolio represents the culmination of more than eight years of planning efforts to find cost-effective regional transmission solutions while meeting local energy and reliability needs. The MVP Portfolio is expected to[13]:

- Provide benefits in excess of its costs under all scenarios studied with benefit-to-cost ratios ranging from 1.8 to 3.0
- Resolve reliability violations on approximately 650 elements for more than 6,700 system conditions and mitigate 31 system instability conditions
- Enable 41 million MWh of wind energy per year to meet renewable energy mandates and goals

The 17 MVPs are generally projected to meet budget and schedule expectations. As of April 2014, one project is in-service, two projects are under construction or partially in-service, seven projects have progressed beyond the regulatory process or have no regulatory process requirements, four are in the regulatory process, and three projects are pre-regulatory (Figure 3.1-8). Since the MTEP11 approval, the

[13] Source: Candidate MVP Report. A review of the MVP Portfolio's benefits is contained in Section 7.1.

total projected budget for the MVP Portfolio has increased by 5.3 percent, the result of longer-than-planned line routing, substation design changes, and use of more developed construction estimates. Additionally, several MVPs' cost estimates have decreased since approval through a combination of design and schedule optimization, implementation of contracting/risk sharing strategies, and favorable commodity prices.

Going forward, the MVP dashboard (Figure 3.1-8) will be updated at least semi-annually to reflect changes, if any, provided through the standard milestone process.

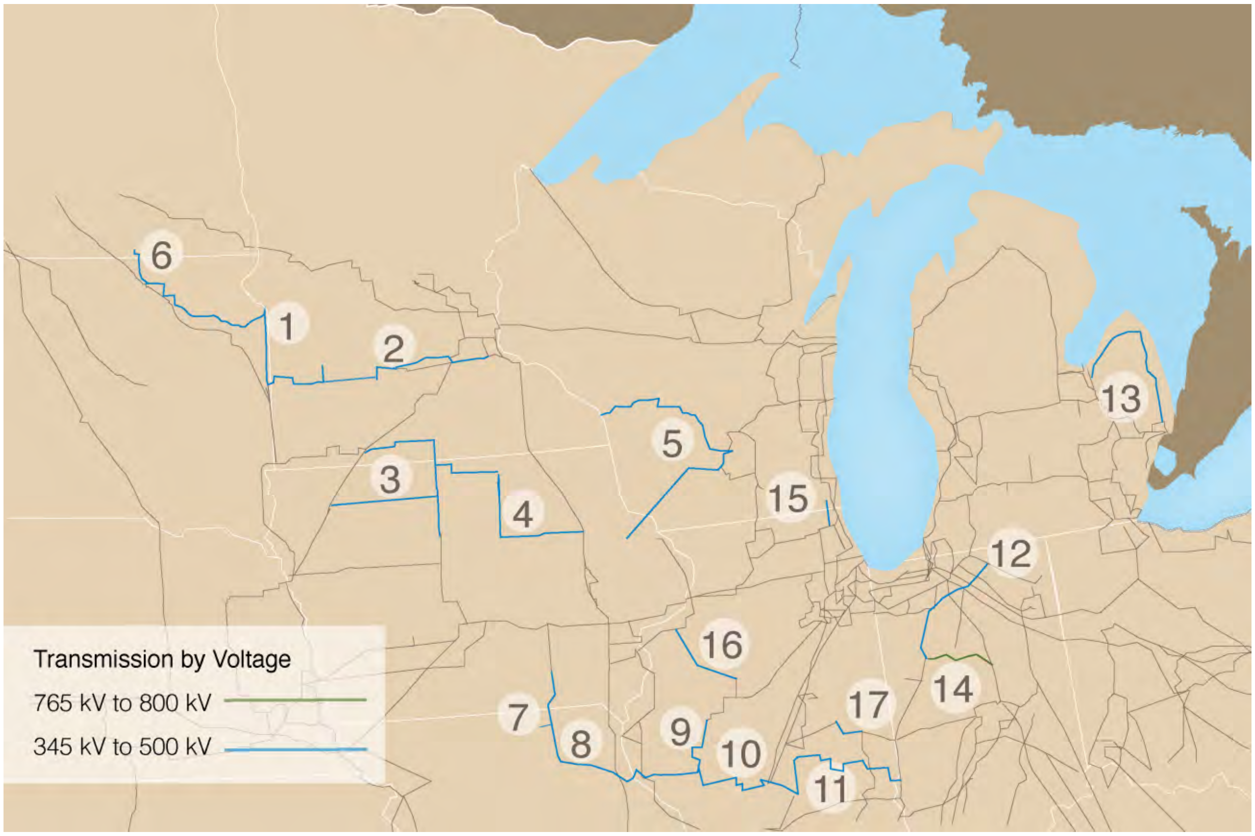


Figure 3.1-7: MVP Portfolio[14]

[14] Map for illustrative purposes only. Actual line routing may differ.

MVP No.	Project Name	State	Estimated In Service Date[1]		Status		Cost[1]	
			MTEP Approved	Q1 2014	State Regulatory Status	Construction	MTEP Approved	Q1 2014
1	Big Stone-Brookings	SD	2017	2017	●	Pending	226.7	226.7
2	Brookings, SD-SE Twin Cities	MN/SD	2011-2015	2013-2015	●	Underway	738.4	640.9
3	Lakefield Jct. - Winnebago-Winco-Burt area & Sheldon-Burt Area-Webster	MN/IA	2015-2016	2016-2018	◑	Pending	550.4	541.1
4	Winco-Lime Creek-Emery-Black Hawk-Hazelton	IA	2015	2015-2018	◑	Pending	468.6	464.3
5	N. LaCrosse-N. Madison-Cardinal (a/k/a Badger-Coulee Project) & Hickory Creek – Eden	WI/IA	2018-2020	2013-2018	◑	Pending	797.5	879.0
6	Big Stone South - Ellendale	ND/SD	2019	2019	◑	Pending	330.7	395.7
7	Adair-Ottumwa	IA/MO	2017-2020	2017-2018	○	Pending	152.3	178.2
8	Adair-Palmyra Tap	MO	2016-2018	2016-2018	○	Pending	112.8	108.1
9	Palmyra Tap-Quincy-Merdosia-Ipava & Meredosia-Pawnee	MO/IL	2016-2017	2016-2017	●	Pending	432.2	524.2
10	Pawnee-Pana	IL	2018	2016-2018	●	Pending	99.4	108.6
11	Pana-Mt. Zion-Kansas-Sugar Creek	IL/IN	2018-2019	2016-2019	●	Pending	318.4	356.2
12	Reynolds-Burr Oak-Hiple	IN	2019	2019	●	Pending	271.0	271.0
13	Michigan Thumb Loop Expansion	MI	2013-2015	2013-2015	●	Underway	510.0	510.0
14	Reynolds-Greentown	IN	2018	2018	●	Pending	245.0	328.7
15	Pleasant Prairie-Zion Energy Center	WI	2014	2013	●	Complete	28.8	33.0
16	Fargo-Galesburg-Oak Grove	IL	2014-2019	2016-2018	○	Pending	199.0	225.5
17	Sidney-Rising	IL	2016	2016	●	Pending	83.2	66.3
						Totals:	***5,564***	***5,858***

State Regualtory Status Indicator Scale

- ○ Pending
- ◑ In regulatory process
- ● Regulatory process complete or no regulatory process requirements

1. Estimates provided by constructing Transmission Owners. Costs stated in millions of nominal dollars.

Figure 3.1-8: MVP planning and status dashboard

3.2 MTEP Implementation History

The annual MTEP report, now in its 11th cycle with the MTEP14 plan, represents 11 years of planning, essential upgrades and expansions to the electric transmission grid. The number of projects and investment can vary dramatically from year to year depending on a variety of system needs. Project drivers could include changes in generation mix due to economics or environmental emissions control, the need to mitigate system congestion at load delivery points, or the addition of large industrial loads. These projects improve the deliverability of energy both economically and reliably to consumers in the MISO footprint and beyond.

The cumulative investment dollars for projects, categorized by plan status for MTEP03 through the current MTEP14 cycle, is more than $21.2 billion (Figure 3.2-1). MTEP14 data depicted in this figure, subject to Board approval will be added to the data tracked for the MISO Board of Directors. These statistics only include projects for MISO members who participated in this planning cycle. Previously approved projects for prior MISO members are not included in these statistics.

- Since MTEP03, more than $7.4 billion of cumulative approved projects have been constructed and are in service as of June 2014.
- $2.08 billion of MTEP projects are expected to go into service in 2014

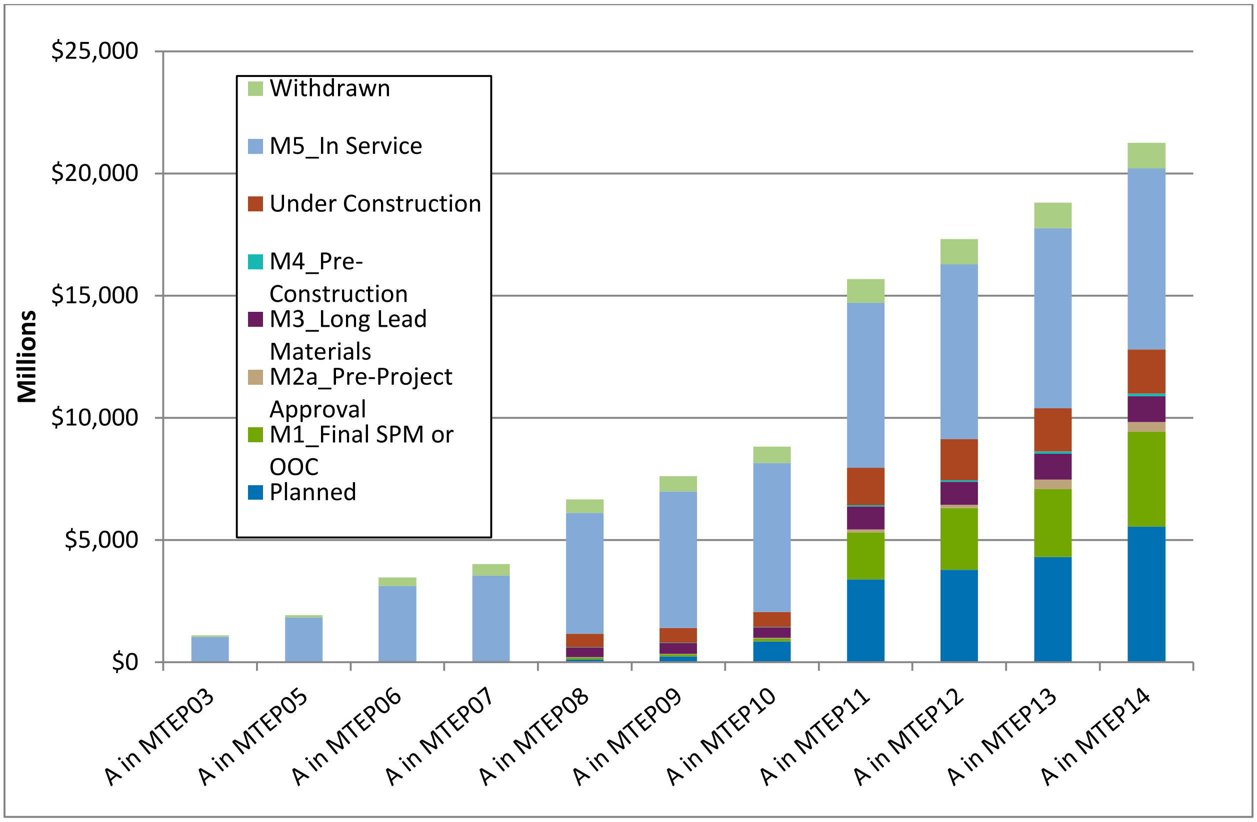


Figure 3.2-1: Cumulative approved investment by facility status[15]

[15] Project milestones described in Chapter 3.1

The historical perspective of MTEP project investment for each MTEP cycle shows extensive variability in development (Figure 3.2-2). This is caused by the long development time of transmission plans and the regular, periodic updating of the transmission plans. Approval of the Multi-Value Projects (MVP) portfolio explains the large increase between MTEP10 and MTEP11.

- MTEP06 and MTEP07 were approved in the same calendar year, which accounts for the comparatively small number of projects in MTEP07.
- MTEP08 shows the number of developing needs increased the number of planned projects, including several large upgrades.
- MTEP09 was a year for analyses and determination of the best plans to serve those needs. The in-service category increases in past MTEPs as projects are built.
- MTEP10 contains significant adjustments for reduced load forecasts.
- MTEP11 contains most of the MVP portfolio, which is approximately $5.1 billion of transmission investment.
- MTEP12 reflects a return to a more typical MTEP, primarily driven by reliability projects.
- MTEP13 reflects a continuation of a typical MTEP, primarily driven by reliability projects.
- MTEP14 reflects a continuation of a typical MTEP, primarily driven by reliability projects, with the inclusion of the new MISO South region projects.

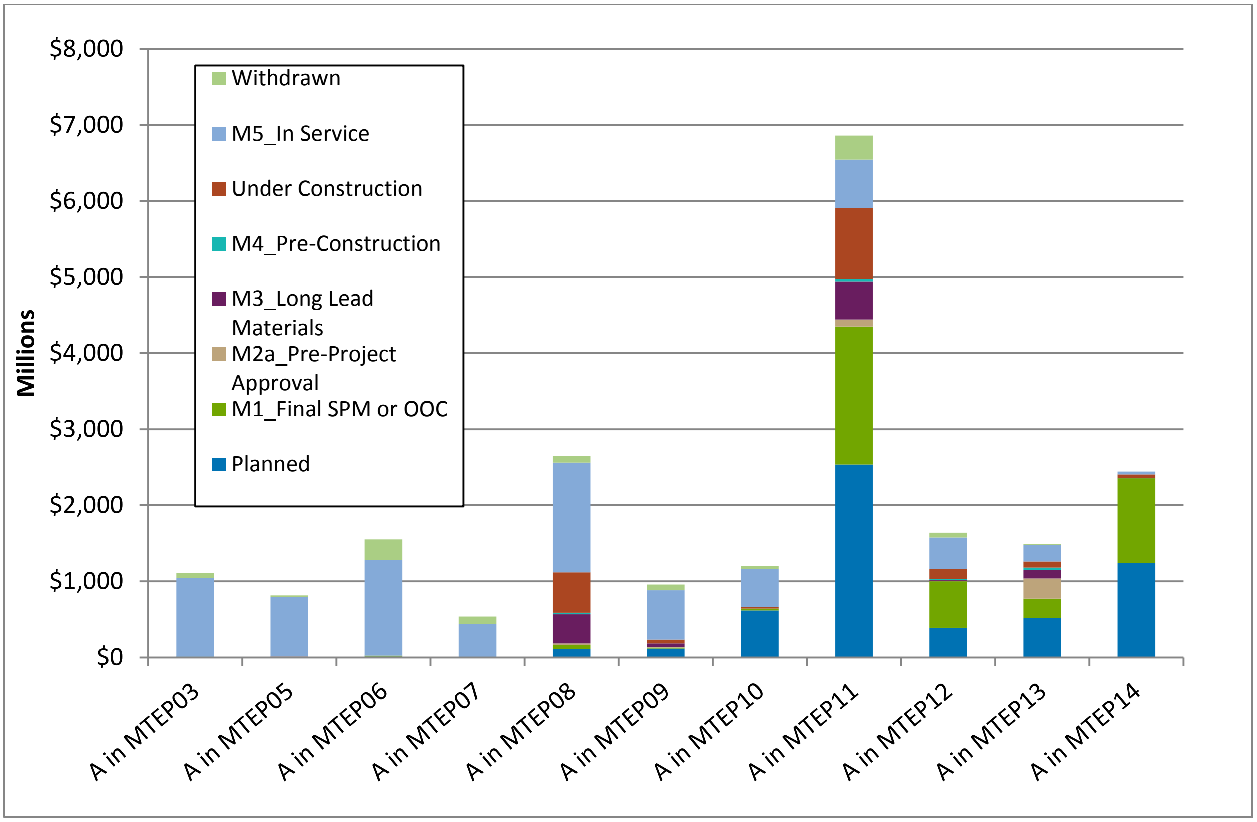


Figure 3.2-2: Approved investment by MTEP cycle[16]

[16] New Appendix A projects in the MTEP14 column contain a few in-service and under-construction projects. There are a few reasons why this occurs. Generator interconnection projects with network upgrades are approved via a separate Tariff process and

Since MTEP03, 119 MTEP-approved projects totaling $1.05 billion in investment have been withdrawn. MISO documents all withdrawn projects to ensure the planning process addresses required system needs. Common reasons for withdrawal include:

- The customer's plans changed or the service request was withdrawn
- A material system change resulted in no further need for the project

Of the withdrawn facilities, $406 million were attributed to service requests or generation interconnection being cancelled. A single generator retirement in 2013 resulted in the withdrawal of $133 million in generator interconnection related projects. A single $150 million baseline reliability project was withdrawn in 2009 due to the economic downturn.

are brought into the current MTEP cycle after their approval. There are also projects driven by condition that must be addressed promptly to maintain system reliability. There are clearance projects that should be addressed promptly to maintain system reliability. Finally, there are relocation projects driven by other's schedules.

Chapter 4
Reliability Analysis

4.1 Reliability Assessment Overview

System reliability is the primary purpose of most MTEP projects. In support of this goal, MISO performs an annual reliability assessment. MISO planners study reliability from thermal and voltage perspectives to confirm the transmission system has sufficient capacity to provide quality reliable service to customers. From a dynamic perspective, the system will return to a stable operating system after disturbances. Detailed results of these analyses are included in Appendix D of the MTEP14 report.

MISO conducts baseline reliability studies to ensure the transmission system is in compliance with two sets of standards:

- Applicable North American Electric Reliability Corp. (NERC) reliability standards
- Reliability standards adopted by Regional Entities (RE) applicable within the transmission provider region

These analyses also consider local Transmission Owner (TO) planning criteria after it is filed and approved by Federal Energy Regulatory Commission (FERC). The TO's criteria may drive additional upgrades, to the extent it is more strict than NERC requirements. MISO's studies typically include simulations to assess transmission reliability in the near and long term by using powerflow models representing various system conditions two, five and 10 years out.

Each project included in MTEP Appendix A is the preferred solution to a transmission need when its implementation timeline requires near-term progress towards regulatory approval and construction. Proposed transmission upgrades with sufficient lead times are included in Appendix B for further review in future planning cycles.

The results of these reliability analyses were presented and peer-reviewed at sub-regional planning meetings (SPM) in December 2013, March 2014 and June 2014. The final results of this reliability analyses are summarized in this chapter and Appendix D of this MTEP14 report.

MISO performs rigorous studies to ensure the continued reliability of the transmission system, as measured by compliance against NERC and local TO planning criteria. These standards define minimum requirements for long-term system planning and require explicit solutions for violations that occur in a 10-year timeframe. MISO is required to identify a solution for each identified violation that could otherwise lead to overloads, equipment failures or blackouts.

MISO is required to identify a solution for each identified violation that could otherwise lead to overloads, equipment failures or blackouts

MISO's MTEP reliability assessment focuses out two, five and 10 years into the future. The combination of these analyses allows MISO to assess and recommend reliability upgrades to meet near-term system load growth and reliability concerns. They also allow MISO to look into longer-term system trends and assess potential transmission and non-transmission alternatives for future evaluation.

The MISO reliability assessment is broken into two parts: 1) project justification reviews and 2) the NERC reliability assessment. The two portions of the analysis feed and provide information for the other, as new constraints determined during the NERC reliability assessment may lead to new projects in the next project justification cycle.

Project Justification Analysis and Subregional Planning Meetings

MISO evaluates project submissions from the TOs through an annual series of internal analysis and discussions of these projects through five Subregional Planning Meetings (Figure 4.1-1). These public stakeholder forums are held at least three times during the year to allow for transparency around project submittals; identified need drivers; and transmission or non-transmission alternatives.

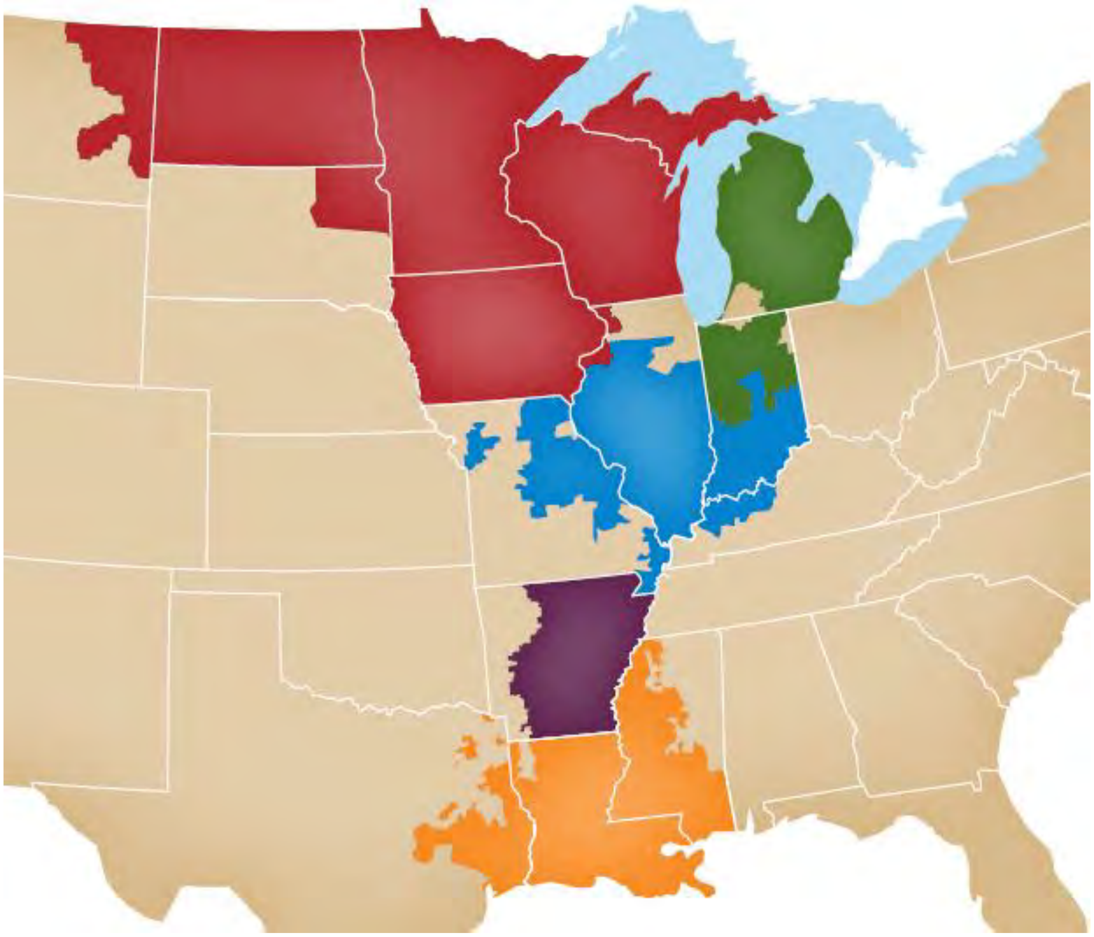


Figure 4.1-1: MISO Planning Subregions

Additionally, Technical Study Task Force meetings are convened for each subregion on an as-needed basis to discuss confidential system information (Figure 4.1-2). These meetings are open to any stakeholders who are able to sign Critical Energy Infrastructure Information and non-disclosure agreements. At this end of this project review and alternative assessment, MISO staff recommends a set of projects to the MISO Board of Directors for review and approval. These projects are summarized in Chapter 2 of the MTEP14 report.

Date	Meeting	Location
20-Nov-13	West Technical Study Task Force (closed meeting)	Web-ex/conf. call
5-Dec-13	South Subregional Planning Meeting (Mississippi, Louisiana, Texas)	New Orleans, La.
9-Dec-13	East Subregional Planning Meeting	Detroit, Mich.
11-Dec-13	West Subregional Planning Meeting	Eagan, Minn.
12-Dec-13	Central Subregional Planning Meeting	Carmel, Ind.
16-Dec-13	South Subregional Planning Meeting (Arkansas)	Little Rock, Ark.
19-Dec-13	West Technical Study Task Force (closed meeting)	Web-ex/conf. call
17-Jan-14	West Technical Study Task Force (closed meeting)	Web-ex/conf. call
25-Feb-14	Michigan Technical Study Task Force Meeting	Novi, Mich.
25-Mar-14	East Subregional Planning Meeting	Novi, Mich.
25-Mar-14	West Technical Study Task Force (closed meeting)	Web-ex/conf. call
27-Mar-14	Central Subregional Planning Meeting	Carmel, Ind.
2-Apr-14 **(AM)**	West Subregional Planning Meeting	Eagan, Minn.
2-Apr-14 **(PM)**	South Subregional Planning Meeting (Arkansas)	Little Rock, Ark.
7-Apr-14	South Subregional Planning Meeting (Mississippi, Louisiana, Texas)	Metairie, La.
2-May-14	Michigan Technical Study Task Force Meeting	Jackson, Mich.
10-June-14	South Subregional Planning Meeting (Arkansas)	Little Rock, Ark.
16-June-14	West Subregional Planning Meeting	Eagan, Minn.
17-June-14	Central Subregional Planning Meeting	St. Louis, Mo.
19-June-14	Michigan Technical Study Task Force Meeting	Cadillac, Mich.
19-June-14	East Subregional Planning Meeting	Cadillac, Mich.
23-June-14	South Subregional Planning Meeting (Mississippi, Louisiana, Texas)	Metairie, La.

Figure 4.1-2: MTEP14 Technical Study Task Force and Subregional Planning Meeting schedule

NERC Reliability Assessment

MISO performs an annual assessment of the transmission system against all reliability standards and requirements, including local planning criteria. The results of this analysis feed into the subsequent cycle of bottom-up transmission planning and project justification analysis, as MISO and its TOs are required to develop and implement solutions for each identified constraint. The results of these analyses, as detailed in Appendix D, create a comprehensive assessment of long-term system reliability, as well as evidence for NERC compliance.

The results of these analyses, as detailed in Appendix D, create a comprehensive assessment of long-term system reliability, as well as evidence for NERC compliance

Based on MISO's NERC reliability assessment, potential thermal and voltage reliability issues are identified. The majority of these identified violations may be mitigated via system reconfigurations, including generation re-dispatch. For all other issues, mitigations, in the form of future proposed transmission upgrades, will be identified for the projected thermal and voltage issues. These network upgrade mitigations will be investigated further in future MTEPs.

The results of MTEP14 Reliability Analyses will be included in Appendix D2-D9 and are posted at the MISO Planning Portal.

Models

MISO Planning Regions are separated into West, Central, East and South. Generation, load, losses and interchange are modeled in each of the six planning models used in MTEP14 Reliability Analysis. Find more information in Appendix D2.

In MTEP 2014, MISO conducted regional studies using the following base models:

- 2016 Summer Peak
- 2019 Summer Peak
- 2019 Shoulder Peak
- 2019 Light Load
- 2024 Summer Peak
- 2024 Shoulder Peak

MISO member companies and external Regional Transmission Organizations use firm drive-in and drive-out transactions to determine net interchanges for these models. These are documented in the 2014 series Multi-Area Modeling Working Group (MMWG) interchange. MISO determines the total generation dispatch needed for each of the models after aggregating the total load with input received from TOs.

Generation dispatch within the model-building process is complex. Growing inputs from various planning processes and expected shifts in the generation portfolio within the MISO footprint are key factors in this complexity.

Inputs in the dispatching process include:

- Generation retirements
- Generator market cost curves
- Generator deliverable capacity designation
- Wind generation output modeling under various system conditions
- Incremental generation needed to meet applicable renewable mandates

Loads are modeled based on direct input from MISO members. Generation dispatched in each region is based on a number of assumptions, such as for the modeling of wind. For example, wind generation is dispatched at 20 percent of nameplate in the summer peak case and 90 percent of nameplate in the shoulder and light-load cases. These wind dispatch levels were selected through MISO planning stakeholder process. More information on the models may be found in Appendix D2 of this report.

Steady-State Analysis Results

Appendix E1.1.4 documents contingencies tested in steady-state analysis. These contingencies were used in the MTEP14 2016 summer peak model; the 2019 summer peak, shoulder peak and light-load models; and the 2024 summer peak and shoulder peak models. All steady-state analysis-identified constraints and associated mitigations are contained in the results tables in Appendix D3, demonstrating compliance with applicable NERC transmission standards.

Voltage Stability Analysis Results

Appendix E1.1.1 documents types of transfers tested in voltage stability analysis. A summary report with associated P-V plots is documented in Appendix D4.

Dynamic Stability Analysis Results

Appendix E1.1.4 documents types of disturbances tested in dynamic stability analysis. Disturbances were simulated in MTEP14 2019 light load and shoulder peak load models. Results tables listing all simulated disturbances along with damping ratios are tabulated in Appendix D5, demonstrating compliance with applicable NERC transmission standards.

4.2 Generation Interconnection Projects

MISO provides safe, reliable, equal and non-discriminatory access to electric transmission system customers requesting interconnection to the transmission system. Generation Interconnection Projects (GIP) are upgrades to the transmission system necessary to ensure the reliability of the system when new power generators interconnect. MTEP14 contains six Target Appendix A GIPs totaling about $38.8 million (Table 4.2-1). These GIPs are associated with the generation interconnection requests G540, J075, J161, J202, J235 and G997 (Figure 4.2-1 and Table 4.2-2).

Among these GIP projects, those in Michigan have cost-share potential. Five of the six GIPS are cost shared. Of the total cost-shared project cost of $35.4 million, $17.7 million is allocated to load and the remainder to the generator based on Attachment FF ITC provision.

MTEP Project ID	Project Name	Submitting Company	Preliminary Share Status	Region	Estimated Cost ($)
4450	G540 Adams 161/69kV Transformer Upgrade	ITCM	Not Shared	West	$3,444,000
4364	J075 Generation Interconnection	ITCT	Shared	East	$9,744,000
4365	J161 Generation Interconnection	ITCT	Shared	East	$9,769,000
4366	J202 Generation Interconnection	ITCT	Shared	East	$5,254,283
4713	J235 Generation Interconnection	ITCT	Shared	East	$9,861,000
4725	G997 Big Turtle Wind Farm	ITCT	Shared	East	$750,000
Total Estimated Cost ($)					$38,822,283

Table 4.2-1 Generation Interconnection Projects in MTEP14 target Appendix A

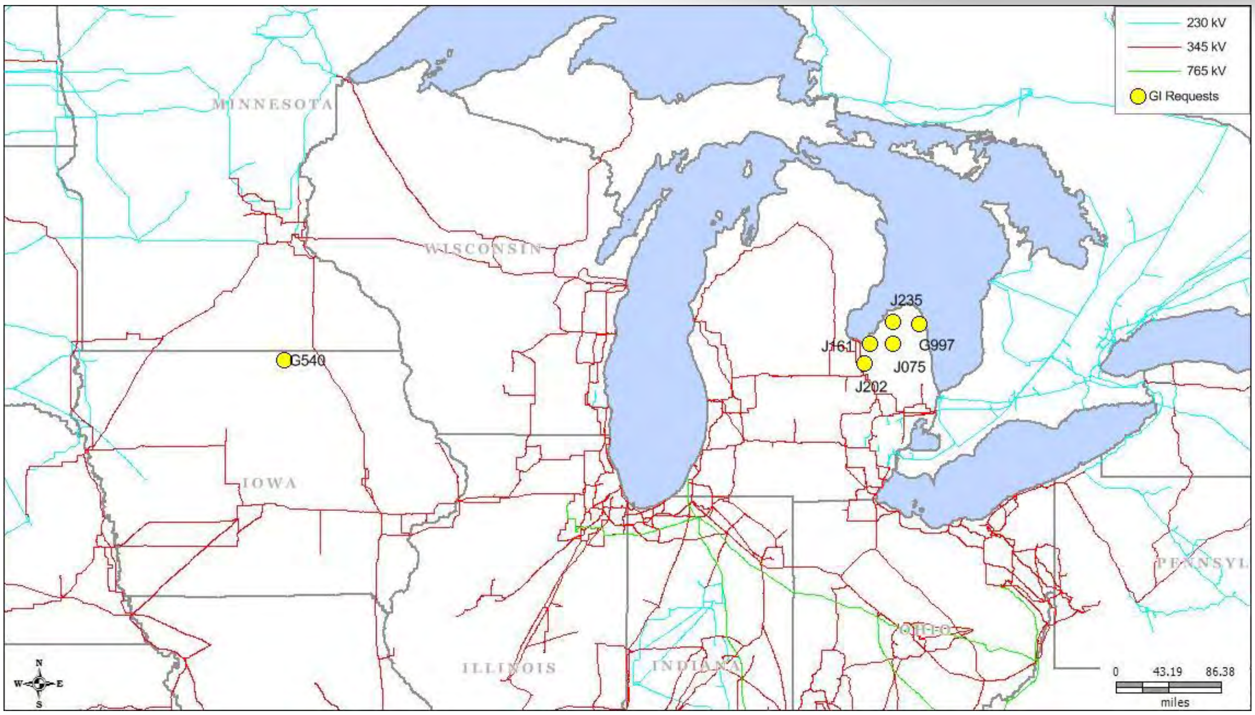


Figure 4.2-1: Generation Interconnection requests associated with MTEP14 Target Appendix A

GI Project No.	TO	County	State	Study Cycle	Service Type	Point of Interconnection	Max Summer Output	Fuel Type	GIA
G540	ITCM	Worth	IA	Group 5	NRIS	Adams - Lime Creek 161 kV	80	Wind	GIA
G997	ITCT	Huron	MI	DPP-2013-AUG	NRIS	ITCT Minden Substation	50	Wind	GIA
J075	ITCT	Huron	MI	DPP-2012-AUG	NRIS	Bauer - Rapson 345 kV	150	Wind	GIA
J161	ITCT	Tuscola	MI	DPP-2012-AUG	NRIS	Bauer - Rapson 345 kV	155	Wind	GIA
J202	ITCT	Tuscola	MI	DPP-2012-AUG	NRIS	ITC Atlanta - Tuscola 120 kV	101	Wind	GIA
J235	ITCT	Huron	MI	DPP-2012-AUG	NRIS	Bauer - Rapson 345 kV	110	Wind	GIA

Table 4.2-2: Generation Interconnection requests associated with Target Appendix A

MTEP14 GIPs In Detail

MTEP Project 4450

The Adams 161/69 kV Transformer replacement enables the generation interconnection of G540 Barton wind power.

G540 is a 160 MW wind farm consisted of 80, 2.0 MW Gamesa turbines. Its Point of Interconnection locates at the 161 kV bus of ITC Midwest's Barton switch station.

The generation interconnection project is also contingent upon the following MVPs:

- Brookings County-Twin Cities 345 kV
- North Lacrosse-Cardinal 345 kV
- Pleasant Prairie to Zion Energy Center 345 kV (already in service)

MTEP 4450 replaces the existing 75 MVA, 161/69 kV transformer with a new 150 MVA, 161/69 kV transformer. It is estimated to cost $3.4 million.

MTEP Project 4725

This project is associated with Generation Interconnection request G997. The G997 generation project is a 50 MW wind-powered generating facility (Big Turtle Wind Farm), located in Huron County, Mich. There will be 25 Gamesa G114 2.0 MW wind turbines. These are considered Transmission Owner Interconnection Facilities, and will cost about $320,080.

The Transmission Owner will construct a new line position at the existing Minden substation by adding two 120 kV, 2,000 A disconnects switches and a single 120 kV breaker, and associated relaying. These network upgrades are estimated to be about $429,557.

MTEP Project 4725 includes both the Transmission Owner Interconnection Facilities and the network upgrades; total estimated cost is $750,000, with an anticipated completion date of October 15, 2014.

MTEP Projects 4364, 4365 and 4713

The three MTEP projects 4364, 4365 and 4713 facilitate interconnection of wind generating facilities in the "thumb" region of Michigan.

MTEP Project 4364 is for generation interconnection of J075, a 150 MW wind plant, located in Huron County, Mich.; project 4365 is for a new 155 MW wind farm, J161, located in Tuscola County, Mich.; while project 4713 is for J235, a new 110 MW wind farm, located in McKinley, Chandler and Oliver Townships, Huron County, Mich. Both J075 and J161's Point of Interconnections are on Bauser – Rapson circuit #1, and J235 is on Bauser – Rapson circuit #2.

J075 consists of 88 – GE 1.7 MW wind turbines. The total estimated cost was $9.74 million and they were completed in the fall of 2013.

J161 consists of 97 – GE 1.6 MW wind turbines. The total estimated cost is $9.77 million and they were completed in the first half of 2014.

J235 will consist of 70 – GE 1.6 MW wind turbines. The total estimated cost for this project is $9.86 million and the estimated completion date is October 31, 2014.

MTEP Project 4366

Facilitates a 101 MW wind-powered generating facility in Tuscola County, Mich. It will be consist of 59 GE 1.7 MW wind turbines. The Point of Interconnection is a new J202 Junction substation (Dixon) on ITC's Atlanta - Tuscola 120 kV.

ITC will construct the new three-breaker 120 kV J202 Junction substation and loop in the 120 kV Atlanta - Tuscola circuit. The new substation will be named Dixon. It is estimated to cost $5.25 million.

How the Queue Process Works

Requests to connect new power generation to the system are studied and approved under the interconnection queue process. Each generator must fund a study to ensure the new connection will not cause reliability issues. Each project proceeds through a formal queue process, where milestones must be met in order to proceed to the next phase of the interconnection process (Figure 4.2-2).

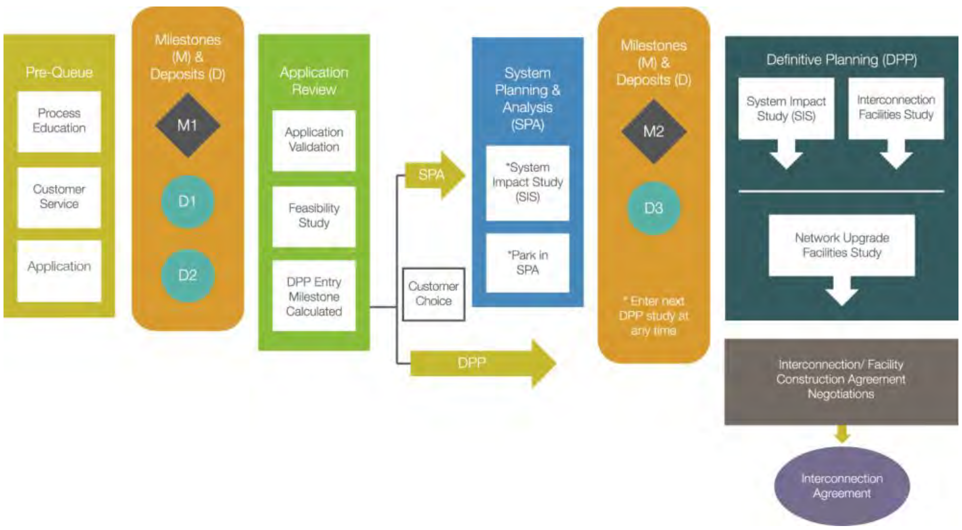


Figure 4.2-2: The queue process

Since the beginning of the queue process in 1995, MISO and its Transmission Owners have received approximately 1,393 interconnection requests totaling 280 GW (Figure 4.2-3). Among them, 28,760 MW are now connected to the transmission system. These generation additions enhance reliability, ensure resource adequacy, provide a competitive market to deliver benefit to ratepayers, and help the industry meet renewable portfolio standards.

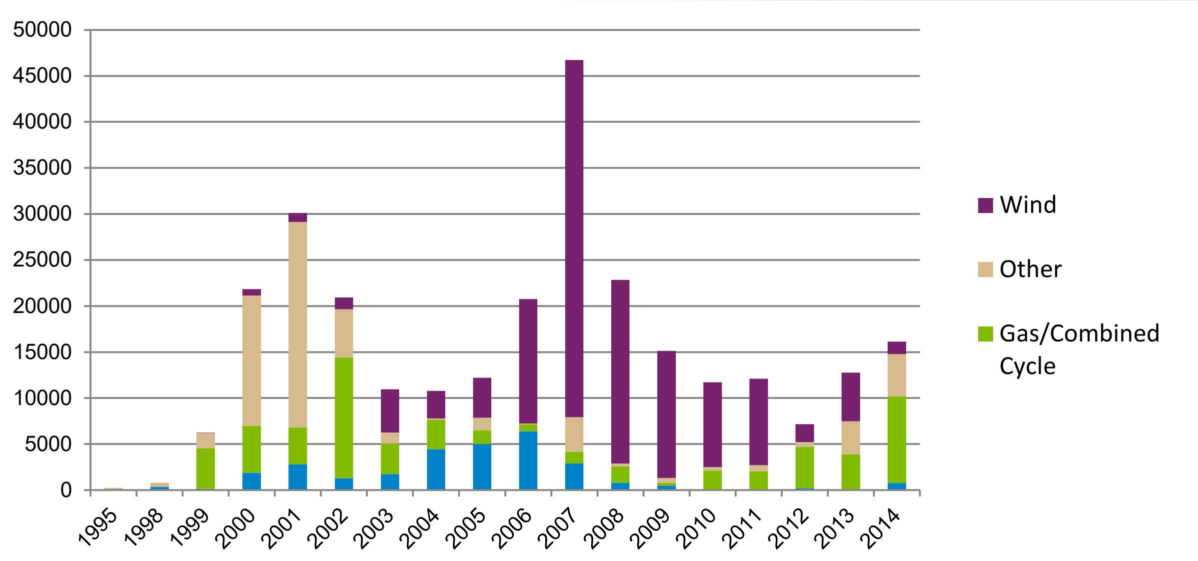


Figure 4.2-3: Queue Trends

Renewable Portfolio Standards (RPS) have become more common since the late 1990s. By 2007, 21 states and the District of Columbia had mandatory RPS obligations. In addition, many other states adopted voluntary renewable energy standards. Between 2005 and 2011, MISO experienced exponential growth in wind project requests. In 2007, wind generation requests in the MISO queue peaked at about 39 GW. These requests reflect the dramatic increase in registered nameplate wind capacity in MISO (Figure 4.2-4).

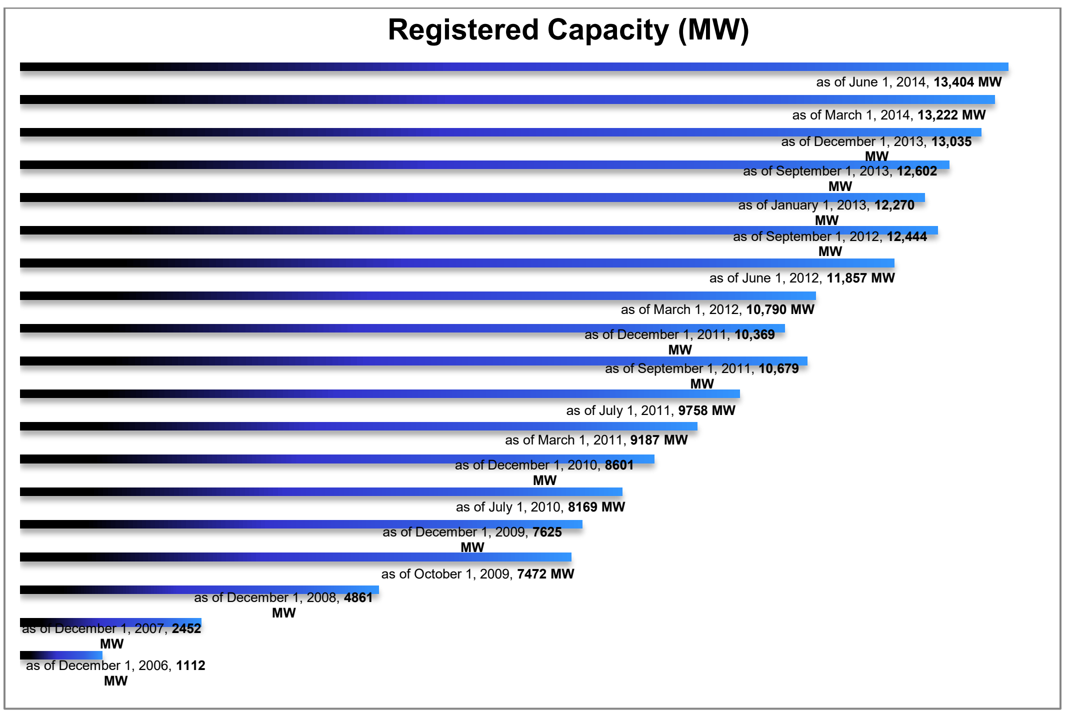


Figure 4.2-4: Nameplate Wind Capacity Registered for MISO

Recently, the MISO interconnection queue has seen more growth in natural gas related generation requests (Table 4.2-3). This is mostly due to relatively cheap gas prices and new environmental rules. From April 16, 2015, through the end of 2017, all entities subject to complying with the Environmental Protection Agency's (EPA) Mercury and Air Toxics Standard (MATS) will be planning outages for retro-fits, repowering, as well as retiring coal-fired generating units.

Recently, the MISO interconnection queue has seen more growth in natural gas related generation requests

Year	Gas Requests (MW)	% Of All New Requests
2014	9,424	58%
2013	3,835	30%
2012	4,509	63%
2011	1,994	16%

Table 4.2-3: Recent Years Natural Gas Requests

Furthermore, there are about 810 MW of new solar requests in 2014. This could be the result of recent federal energy legislation and the economic stimulus package, and the lower price of solar photovoltaic (PV) modules.

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Queue Process Improvement

In light of the latest 2012 Queue Reform, which largely addressed backlogs in the generator interconnection queue and late-stage terminations of generator interconnection agreements, MISO continues to seek more opportunities to improve the queue process. There are several drivers for this effort, such as five years' worth of lessons learned, evolving industry standards, more variable generation in the queue and constructed across MISO footprint, changing technology and physical capabilities of generation equipment and stakeholders' feedback. The goal of this effort is to review current process and study criteria, and identify areas for improvement.

For the past few Definitive Planning Phase (DPP) study cycles, System Impact Studies indicated that the majority of generator interconnection requests in the west area of MISO's footprint are conditional on a few transmission projects that are not scheduled to be in service until 2018. This conditionality has been restricting the ability of a few "ready" generators to achieve Commercial Operation within the next couple of years. MISO proposed a short term plan at the April 2014 Interconnection Process Task Force (IPTF) that would grant interim injection rights via a Provisional Interconnection Agreement until such time when the long term transmission upgrades are in service.

Furthermore, MISO worked with the stakeholders to refine the GIA Exhibit A10 contingency list determination process. Specifically, MISO changed the algorithm that determines the contingency list for inclusion in the Generator Interconnection Agreement Appendix A10. This refinement to the algorithm will further reduce the conditionality associated with the Network Upgrades that get included in the GIA. Similarly, MISO better aligned Generation Interconnection process with the Attachment Y process to capture generator retirements in analyses while awaiting FERC approval. These changes significantly reduced the uncertainties currently faced by the Interconnection Customers.

Some other process improvement focus areas MISO have been working on are: 1) compliance with New TPL001-4 standards; 2) consistency in the planning model; 3) Attachment Y process coordination; 4) study time-line improvement; 5) seams coordination; 6) Energy Resource and Network Resource differences; 7) continuing to streamline queue process with MISO energy market and capacity construct; and 8) exploring economic analysis related options.

4.3 Transmission Service Requests

Acquiring a Transmission Service Request (TSR) is the first step in creating schedules to move energy in, out, through or within the MISO Market footprint or to make bilateral contracts to receive or supply energy within the MISO Market footprint. When a customer or Market Participant submits and confirms a TSR on the MISO Open Access Same Time Information Service (OASIS), it reserves transmission capacity. Long-term TSRs (one year or longer) must be evaluated for impacts on system reliability by the MISO Transmission Service Planning Group. Short-term TSRs (less than one year) are evaluated by MISO Tariff Administration.

Acquiring a TSR is the first step in creating schedules to move energy in, out, through or within the MISO Market footprint

From June 2013 to June 2014, MISO Transmission Service Planning processed 349 long-term TSRs (Figure 4.3-1) and completed 29 System Impact Studies. Of these System Impact Studies, seven were confirmed, 10 were withdrawn or refused, three executed a Facilities Study Agreement, one was offered a Facilities Study Agreement, and eight are waiting for corresponding external System Impact Studies to be completed. An increase of TSRs processed in March and April 2014 stemmed from a change in the Resource Adequacy process that states Generation Resources, Intermittent Generation, Dispatchable Intermittent Resources (DIRs), Limited Resources, External Resources, Behind-the-Meter Generation (BTMG), and Demand Response Resources (DRRs) that do not pass the deliverability test may procure firm transmission service to meet the deliverability requirements to qualify as a Capacity Resource.

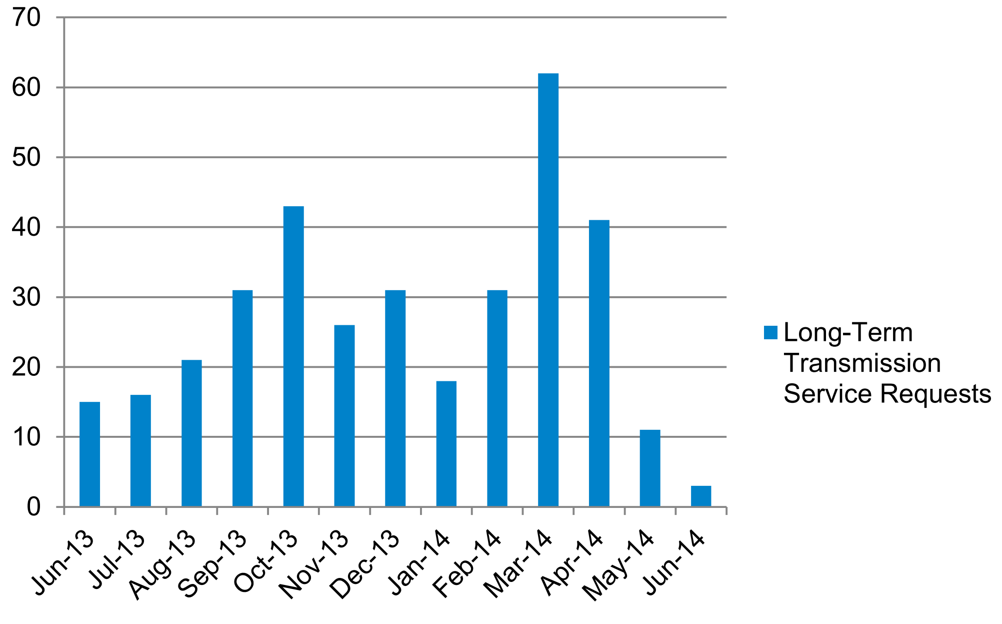


Figure 4.3-1: MISO Long-Term TSRs processed from June 2013 through June 2014 (does not include Entergy ICT TSR data)

Before the full integration of the MISO South region, MISO performed Independent Coordinator of Transmission (ICT) services for Entergy from December 2012 until December 2013. During that time period, 133 Long-Term TSRs were processed.

MISO concluded a group study consisting of 10 long-term TSRs, that reserve up to 883 MW of yearly, firm, Network Integration Transmission Service (NITS) and Point-to-Point Transmission Service to and from the Manitoba Hydro interface, would require the construction of a new 500 kV Transmission Line valued at $676 million. The System Impact Study and Facility Study have been completed for this group and a Facility Construction Agreement has been executed. Minnesota Power's Great Northern Transmission Line, a 500 kV transmission line from the Minnesota-Manitoba border to the Blackberry 500 kV substation near Grand Rapids, Minn., has been included as a major upgrade associated with this study and became an MTEP14 Appendix A Transmission Delivery Service Project (TDSP)[17] following FERC approval of the Facilities Construction Agreement on November 25, 2014.

Long-term TSRs processed and evaluated by MISO planning staff are either Firm Point-to-Point or NITS. Point-to-Point Transmission Service is the reservation and transmission of capacity and energy from the Point(s) of Receipt to the Point(s) of Delivery while NITS allows a Network Customer to efficiently and economically utilize its Network Resources, as well as other non-designated generation resources, to serve its Network Load located in the Transmission Owner's Local Balancing Authority Area or pricing zone.

Short-term TSRs evaluated by Tariff Administration have a term of less than one year and can be Firm or Non-Firm. Tariff Administration looks at the Available Flowgate Capacity (AFC) on the 15 most limiting constrained facilities on a TSR path to verify adequate capacity. If the AFC is positive for all 15 constrained facilities, the request is likely to be approved. Negative AFC on one or more of the 15 constrained facilities results in either a counter-offer or denial.

New long-term TSRs are processed based on queue order and type in the Triage phase (Figure 4.3-2). A TSR can be one of the three following types: Original, a new TSR; Renewal, a continuation of an existing TSR; or Redirect, the changing of the Source and/or Sink of an existing TSR.

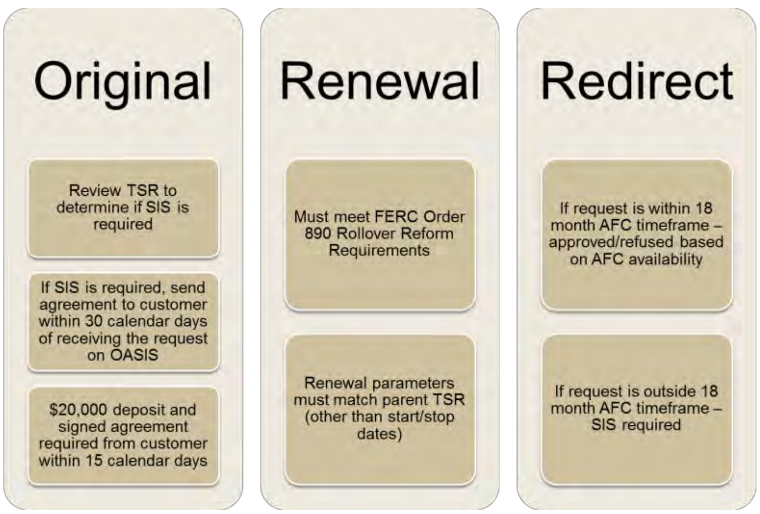


Figure 4.3-2: TSR Triage Phase Processing

17 " Transmission Delivery Service Projects are Network Upgrades driven by Transmission Service Request (TSR) study procedures and agreements. These upgrades are needed to respond to requests for new Point-To-Point Transmission Service, or requests under Module B of the Tariff for Network Service or a new designation of a Network Resource. Cost of these upgrades are either directly assigned or rolled-in as per Attachment N of the Tariff."

If a System Impact Study (SIS) is needed and the transmission customer returns the executed study agreement and deposit, MISO must complete the study within 60 calendar days from the time the agreement and deposit are received. MISO can accept the TSR and request specification sheets from the transmission customer if no constraints are identified in the study or if partial capacity can be granted. A Facilities Study is required if constraints are identified in the SIS.

MISO then sends out a Facility Study Agreement within 30 calendar days for the customer to return along with a study deposit if they would like to move forward. If the agreement and deposit are not received, the TSR is refused. The Facility Study provides the costs and schedules to build upgrades required to mitigate the constraints identified in the SIS. Once complete, the customer has the option to take a reduced amount of transmission service, as identified in the SIS, proceed with a Facility Construction Agreement (FCA), or withdraw the TSR.

If the customer signs the FCA, the identified upgrades are included in MTEP Appendix A as Transmission Delivery Service Projects (TDSP). The costs of these upgrades are either directly assigned or rolled-in as per Attachment N of the Tariff. MISO can then request specification sheets and conditionally accept the TSR until all upgrades are in-service.

Transmission Service Restriction

On March 28, 2014, the Federal Energy Regulatory Commission (FERC) accepted, over MISO's objection, a Transmission Service Agreement filed by Southwest Power Pool (SPP), requiring MISO to pay SPP for any flow on SPP's transmission system above the existing 1,000 MW contract path between MISO North and MISO South. This contract path limitation is currently being litigated before FERC. Due to this limitation, MISO has adopted a short-term mitigation strategy of limiting to 1,000 MW the Long-Term Transmission Service sourcing or sinking between MISO South and any non-contiguous region. MISO is carefully considering how to implement processes that respect the contract path limit consistent with MISO's flow-based methodology for evaluating TSRs.

Meanwhile, MISO is delaying the processing of Long-Term Firm TSRs involving generation flows between MISO South and MISO North, Specifically, MISO is using the following process:

1. All currently confirmed TSRs will be honored by MISO (subject to limitations that may be imposed by other transmission service providers in the TSR path)
2. For TSRs that have been accepted by MISO, but not confirmed by the Requestor, the Requestor will be given the option to withdraw the TSR or confirm the TSR subject to redirection
3. TSRs that are pending, or queued in the future, will remain in study mode until MISO's dispute with SPP regarding the SPP Agreement, and the MISO-SPP Joint Operating Agreement, is settled or resolved, or an appropriate solution is developed

On May 22, 2014, in FERC Docket No. ER14-2022-000, MISO filed, and continues to pursue, a Tariff waiver request to allow implementation of the above-described interim process for TSRs.

4.4 Generation Retirements and Suspensions

The permanent or temporary cessation of operation of generation resources can significantly impact the reliability of the transmission system. The MISO Attachment Y process ensures that the retirement or suspension of these assets is evaluated to determine if transmission is adequate to permit the generators to discontinue operation. Under the Tariff provisions, MISO has the ability to require the owner to maintain operation of the generation as a System Support Resource (SSR) if the generator is needed to avoid violations of applicable NERC and Transmission Owner's (TO) planning criteria; in exchange, the generator will receive compensation for its operating costs. SSR costs are paid by the loads in areas that benefit from the SSR generation. An SSR is considered a temporary measure where no other alternatives exist to maintaining reliability until transmission upgrades are completed to address the issues caused by the unit change in status.

The MISO Attachment Y process ensures that the retirement or suspension of generation resources is evaluated to determine if transmission is adequate to permit the generators to discontinue operation

Attachment Y Requests and Status

MISO has received 10 Attachment Y requests (1,710 MW) for unit retirements and one Attachment Y request (200 MW) for unit suspension during the first six months of 2014 (Figure 4.4-1). The same period (January-June) in 2013 saw nine Attachment Y Retirement Notices (1,203 MW) and three Attachment Y Suspension Notices (2,037 MW) (Figure 4.4-3).

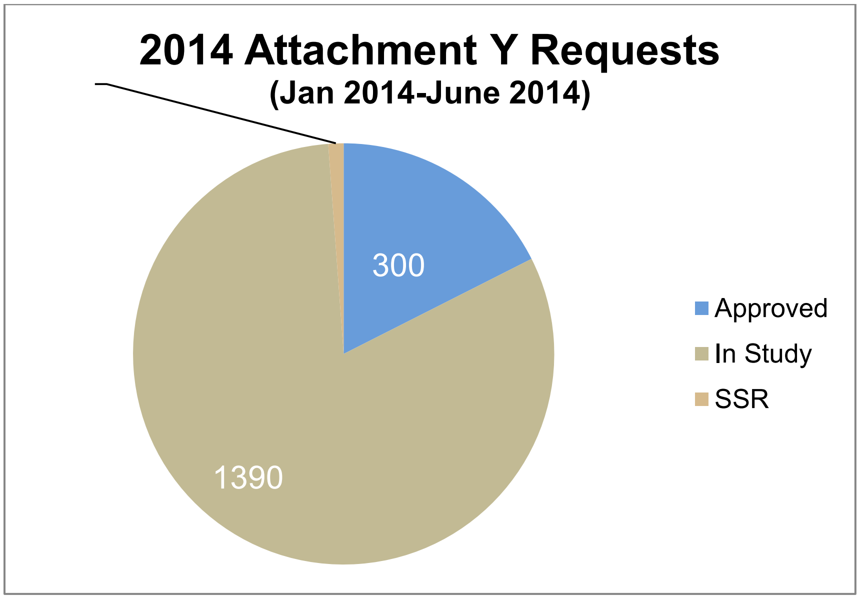


Figure 4.4-1: Attachment Y requests (Aggregate MW) in 2014

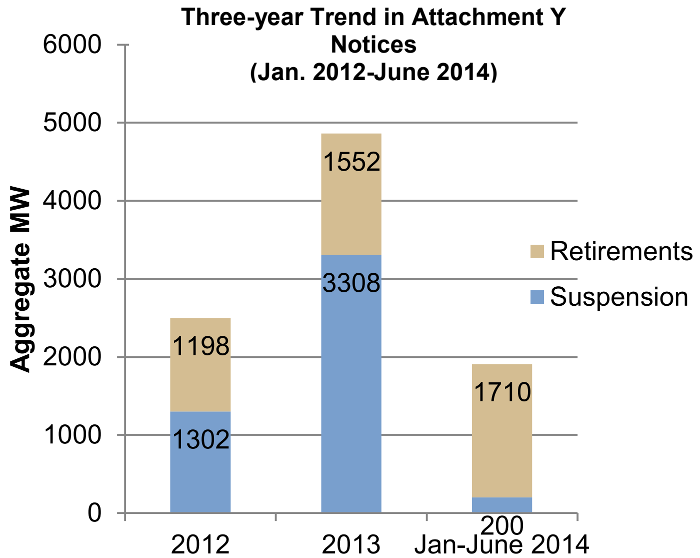


Figure 4.4-2: Three-year trend in Attachment Y notices (aggregate MW)

The overall status of the requests processed in the last three years shows that there were 51 requests (9,272 MW) received that were completed or remain active (Figure 4.4-3). This includes 20 requests (4,810 MW) for unit suspension and 31 requests (4,460 MW) for unit retirement.

While the volume of Attachment Y Notices has remained slightly below the 2013 volume, the outlook in light of environmental compliance and economics suggests that the number of requests will increase over the next 12 months.

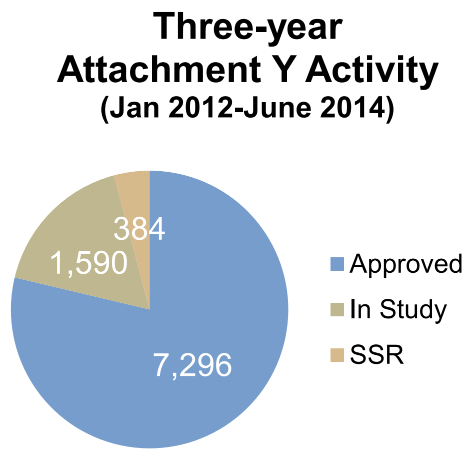


Figure 4.4-3: Three-year Attachment Y requests (aggregate MW) overall activity

SSR Agreements

A number of Attachment Y generators have been identified as potential SSR candidates. MISO has executed eight SSR agreements during the course of the SSR program, some of which have been terminated (Figure 4.4-4). As of June 2014, seven Attachment Y notices require continued operations under SSR agreements.

Escanaba 1, 2 (25 MW) – The Escanaba Units 1 and 2 requested to suspend operation from June 15, 2012, to June 15, 2015, and have been on SSR Agreements since June 15, 2012. The agreement has recently been renewed and filed with FERC for a third term covering June 15, 2014, to June 15, 2015.

Edwards 1 (103 MW) – The Edwards Unit 1 requested to retire on December 31, 2012, and was identified to be needed as SSR until transmission improvements are completed in December 2016. The SSR Agreement has been in place since January 1, 2013, and was renewed for the January 1, 2014, to December 31, 2014, term.

Straits 1 (21 MW) – The Straits Unit 1 requested to suspend from February 15, 2012, to February 15, 2015, and was required to remain in operation as an SSR unit until transmission projects are completed in 2014. The initial SSR Agreement was filed for October 1, 2013, through September 30, 2014. It was recently reviewed for annual renewal and determined to be needed as an SSR for another term.

Gaylord 1, 2, 3 (51 MW) - The Gaylord Units 1, 2 and 3 requested to suspend from February 15, 2012, to February 15, 2015, and were required to remain in operation as SSR units until transmission projects are completed in 2014. The initial SSR Agreement was filed for October 1, 2013, through September 30, 2013. It was recently reviewed for annual renewal and determined to be needed as an SSR for another term.

Coleman 1, 2, 3 (443 MW) – The Coleman Units 1, 2 and 3 requested to suspend operation from September 1, 2013, to December 31, 2016, and were determined to be needed as SSR units for the suspension period. The SSR Agreement was executed for an initial period from September 1, 2013, to August 31, 2014. During the initial term, an alternative solution was developed and implemented to allow the early termination of the contract and the units were approved to suspend operation on May 1, 2014.

Presque Isle 5, 6, 7, 8, 9 (344 MW) – The Presque Isle Units 5, 6, 7, 8 and 9 requested to suspend operation from February 1, 2014, to June 1, 2015. The generators were determined to be needed as SSR units until transmission projects are complete in the 2020 timeframe, and the SSR agreement was executed for an initial term of February 1, 2014 to January 31, 2015. The owner subsequently submitted a new Attachment Y Notice to retire the units on October 15, 2014, and a new agreement is being negotiated.

White Pine 1 (20 MW) – White Pine Unit 1 requested to retire on April 16, 2014, and was determined to be needed as an SSR unit until projects are implemented in the 2019 to 2022 timeframe. The initial term of the SSR Agreement was established for April 16, 2014, to April 15, 2015.

White Pine 2 (20 MW) – White Pine Unit 2 requested to retire on January 1, 2015, and was determined to be needed as an SSR unit until projects are implemented in the 2019 to 2022 timeframe. The initial term of the SSR Agreement is in negotiation for the January 1, 2015, through December 31, 2015 period.

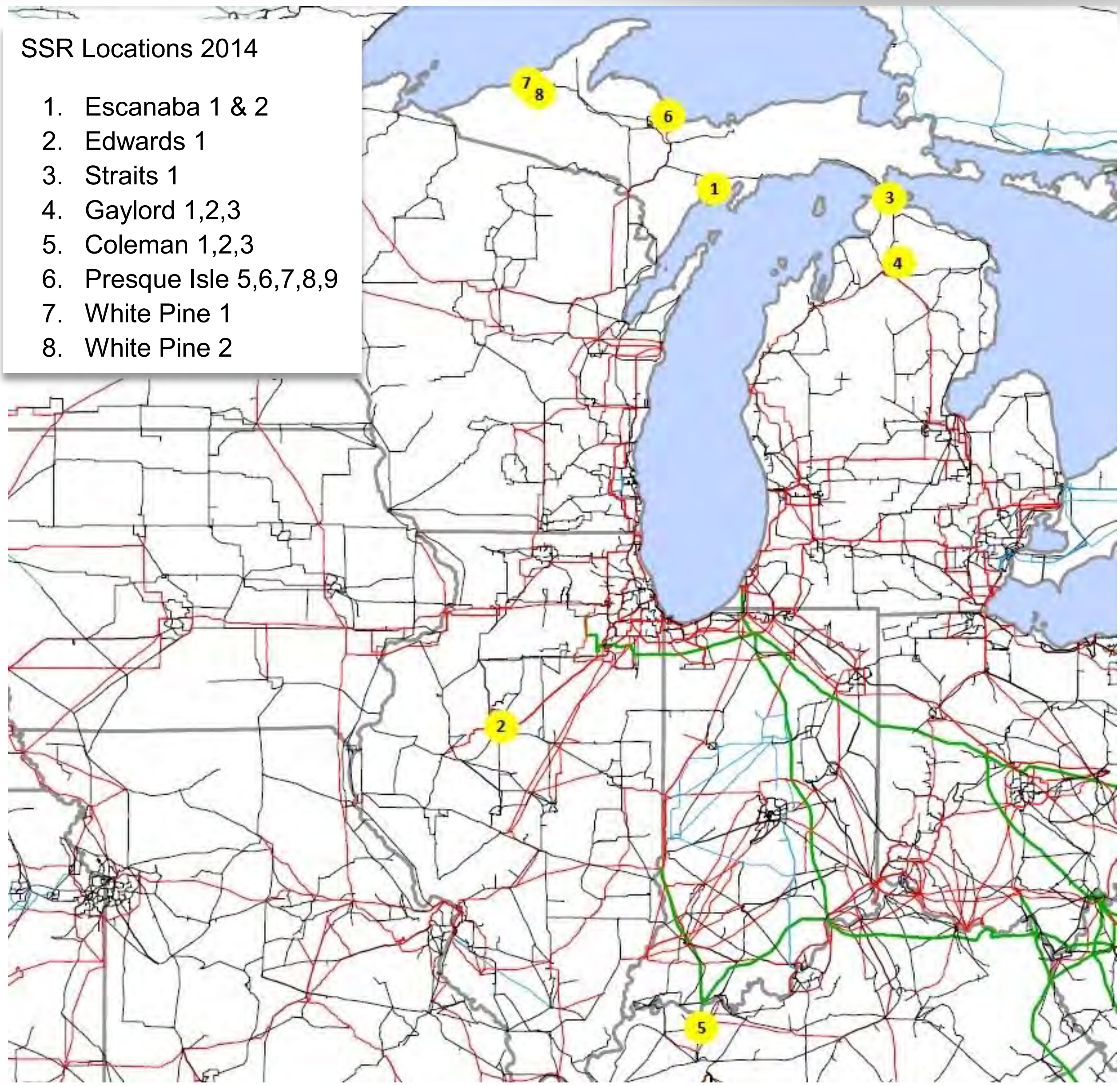


Figure 4.4-4: SSR agreement locations

Process

Market participants that own or operate generation resources must submit an Attachment Y Notice to MISO of their intent to retire or suspend operation of any unit at least 26 weeks prior to the effective date of the change in status (Figure 4.4-5). MISO collaborates with the affected TOs to perform analysis to determine if any violations of applicable NERC and TO planning criteria are caused by the unit retirement/suspension.

Within a 75 day period, MISO provides a response to the market participant indicating the study conclusion. MISO will approve the Attachment Notice if there are no violations of applicable planning criteria or if the issues are resolved by a planned upgrade. Any unresolved issues require the need for a stakeholder-inclusive process to evaluate alternatives that would avoid the need for an SSR contract.

If reliability issues are found in the study, MISO convenes an open stakeholder review of the Attachment Y issues and alternatives through Universal Non-disclosure Agreement (UNDA) and Critical Energy Infrastructure Information (CEII)-protected Technical Study Task Force meetings. Alternatives that provide comparable benefit to retaining the SSR unit are considered and evaluated for effectiveness in relieving the violations and include such options as new/re-powered generation, reconfiguration, remedial action plans or System Protection Schemes, demand response and transmission reinforcements. If an alternative is available the Attachment Y Notice is approved. If the alternative does not eliminate all the reliability issues, MISO and the market participant will negotiate the terms of the SSR Agreement, which will be filed with FERC prior to the effective date. The agreement is subject to an annual review and renewal to allow the opportunity to terminate the need for an SSR Agreement if an alternative becomes available. Attachment Y information is considered confidential unless a reliability issue is identified in the study.

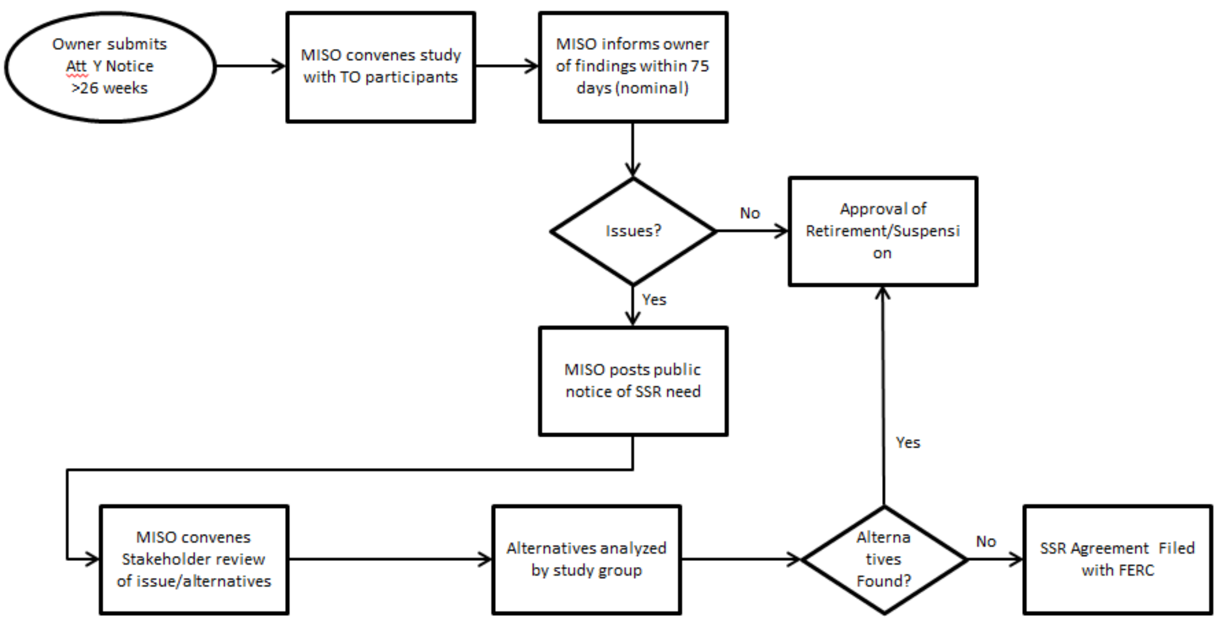


Figure 4.4-5: MISO Attachment Y process

4.5 Generator Deliverability Analysis

MISO performs generator deliverability analysis as a part of MTEP14 to ensure continued deliverability of generating units with Network Resource Interconnection Service (NRIS). Results of the assessment are based on an analysis of near-term (five-year) and long-term (10-year) summer peak scenarios. Analysis results show a total of 3.8 GW of deliverability is restricted due to constraints in MTEP14 near-term scenario. More than 7.6 GW are restricted in the long-term 2024 planning scenario. Constraints observed that are restricting generation beyond the established Network Resource amounts in both scenarios will be mitigated (Figure 4.5-1).

A total of 3.8 GW of deliverability is restricted due to constraints under MISO functional control identified in MTEP14

This analysis revealed 53 constraints that restrict existing deliverable amounts (Table 4.5-1) in the 2019 scenario with 51 constraints requiring mitigation. MTEP projects will be created for the mitigation required to alleviate the constraints identified.

To understand Table 4.5-1:

- “Overload Branch” is caused by bottling-up of aggregate deliverable generation
- “Area” is the Transmission Owner of the facility
- “Map ID” is the approximate location of the overloaded element (Figure 4.5-1)
- “Contingency” is the outage causing the overload. In some cases, the system may be intact, so there is no outage.
- “Rating” the limit of the element in the analysis. The normal rating applies if the system is intact and emergency ratings apply for post-contingent facilities or based on the Transmission Owners criteria.
- “Mitigation Required” represents constraints that were observed in both the near-term (five-year) and long-term (10-year) analysis.
- “MW Restricted” is the total amount of Network Resource Interconnection Service that is limited by the overloaded branch.

Overloaded Branch	Area	Map ID	Rating (MVA)	Mitigation Required	MW Restricted
Rockland - Mass 69 kV	698 UPPC	1	46.0	Yes	10.2
Rockland Junction - Rockland 69 kV	698 UPPC	1	46.0	Yes	10.7
Rockland Junction - UPPSCO TAP 69 kV	698 UPPC	1	46.0	Yes	4.5
Victoria - Rockland Junction 1 69 kV	698 UPPC	1	46.0	Yes	6.8
Victoria - Rockland Junction 2 69 kV	698 UPPC	1	46.0	Yes	10.8
ALTW Tiffin - Tiffin 69 kV	627 ALTW	2	76.0	Yes	76.0
Hunter Creek - Tiffin REC 69 kV	627 ALTW	2	77.0	Yes	22.0
Tiffin - Hunter Creek 69 kV	627 ALTW	2	77.0	Yes	62.8
Tiffin REC - Heartland Tap 69 kV	627 ALTW	2	77.0	Yes	22.0
Wisdom - Spencer 69 kV	652 WAPA	2	57.4	Yes	44.0
Albany - York 161 kV	627 ALTW	3	200.0	Yes	30.6
Burlington - South Burlington 69 kV	627 ALTW	3	87.0	Yes	561.4
Burlington 4th St - Agency 69 kV	627 ALTW	3	69.0	Yes	166.2
Council Bluffs - Beacon 161 kV	627 ALTW	3	340.0	Yes	105.7
Ottumwa - Bridgeport 161 kV	627 ALTW	3	335.0	Yes	115.2
Pine St - Isett Ave 69 KV	633 MPW	3	55.0	Yes	50.2
Tiffin - ALTW Tiffin 69 kV	635 MEC	3	90.0	Yes	64.0
Units 7/8/8A SUB 69 KV - Pine St 69 KV	633 MPW	3	72.0	Yes	56.1
West Sub - Isett Ave 69 KV	633 MPW	3	72.0	Yes	61.3
Cobb White - Sternberg 138 kV	218 METC	4	123.0	Yes	1166.4
Pere Marquette - Lake County 138 kV	218 METC	4	117.1	Yes	210.3
Claremont - Layton 138 kV	218 METC	5	120.0	Yes	395.6
Hemphill - Sabine 1 138 kV	218 METC	5	178.0	Yes	136.2
Sabine 2 - Halsey 138 kV	218 METC	5	175.0	Yes	231.4
Connersville - Connersville 30Th 69 kV	208 DEI	6	45.0	Yes	56.6
Marion - Marion Power Plant 69 kV	361 SIPC	7	61.6	No	225.8
Marion Power Plant - Marion 69 kV	361 SIPC	7	61.6	No	227.6
Hoxie South AECC - Walnut Ridge 161 kV	327 EES-EAI	8	167.0	Yes	343.6
Newport - Newport Industrial 161 kV	327 EES-EAI	8	335.0	Yes	972.1
Newport Industrial - Newport Air Base 161 kV	327 EES-EAI	8	335.0	Yes	138.1
West Memphis 500/161 kV Transformer	327 EES-EAI	8	450.0	Yes	845.7
Arklahoma - Tigre Ss 115 kV	327 EES-EAI	9	201.0	Yes	280.0
Butterfield - Haskel 115 kV	327 EES-EAI	9	239.0	Yes	330.5
Carpenter Dam - Hot Springs South 115 kV	327 EES-EAI	9	159.0	Yes	206.5
Cheetah - Hot Springs Village 115 kV	327 EES-EAI	9	106.0	Yes	165.1
Hot Springs - Fountain Lake – Cheetah 115 kV	327 EES-EAI	9	201.0	Yes	10.8
Hot Springs East - Butterfield 115 kV	327 EES-EAI	9	239.0	Yes	387.2
Panther SS - Hot Springs - Fountain Lake 115 kV	327 EES-EAI	9	201.0	Yes	248.0
Russellville East - Russellville South 161 kV	327 EES-EAI	9	446.0	Yes	206.1

Overloaded Branch	Area	Map ID	Rating (MVA)	Mitigation Required	MW Restricted
Russellville North - Russellville East 161 kV	327 EES-EAI	9	396.0	Yes	354.7
Tigre Ss - Panther SS 115 kV	327 EES-EAI	9	201.0	Yes	248.0
Greenville - Greenville East 115 kV	351 EES	10	120.0	Yes	71.2
Layfield - Carroll 230 kV	502 CLEC	11	412.0	Yes	211.1
Rodemacher - East Leesville 230 kV	502 CLEC	11	416.0	Yes	171.9
Cleveland - Tarkington 138 kV	351 EES	12	101.0	Yes	25.2
Sabine 138 - Linde 138 kV	351 EES	12	288.0	Yes	84.0
Sabine - Port Neches 138 kV	351 EES	12	287.0	Yes	169.1
South Beaumont 138/69 kV Transformer	351 EES	12	100.0	Yes	77.5
South Beaumont 138/69 kV Transformer	351 EES	12	100.0	Yes	71.1
Chlomal - Iowa 69 kV	351 EES	13	39.0	Yes	12.0
Moril - Delcambre Rural 138 kV	351 EES	13	191.0	Yes	198.5
Fancy Point - Port Hudson 230 kV	351 EES	14	593.0	Yes	65.8
Fancy Point - Port Hudson 230 kV	351 EES	14	593.0	Yes	37.6
Rockland - Mass 69 kV	698 UPPC	1	46.0	Yes	10.2
Rockland Junction - Rockland 69 kV	698 UPPC	1	46.0	Yes	10.7
Rockland Junction - UPPSCO Tap 69 kV	698 UPPC	1	46.0	Yes	4.5
Victoria - Rockland Junction 1 69 kV	698 UPPC	1	46.0	Yes	6.8

Table 4.5-1: MTEP14 near-term constraints that limit deliverability of Network Resources.

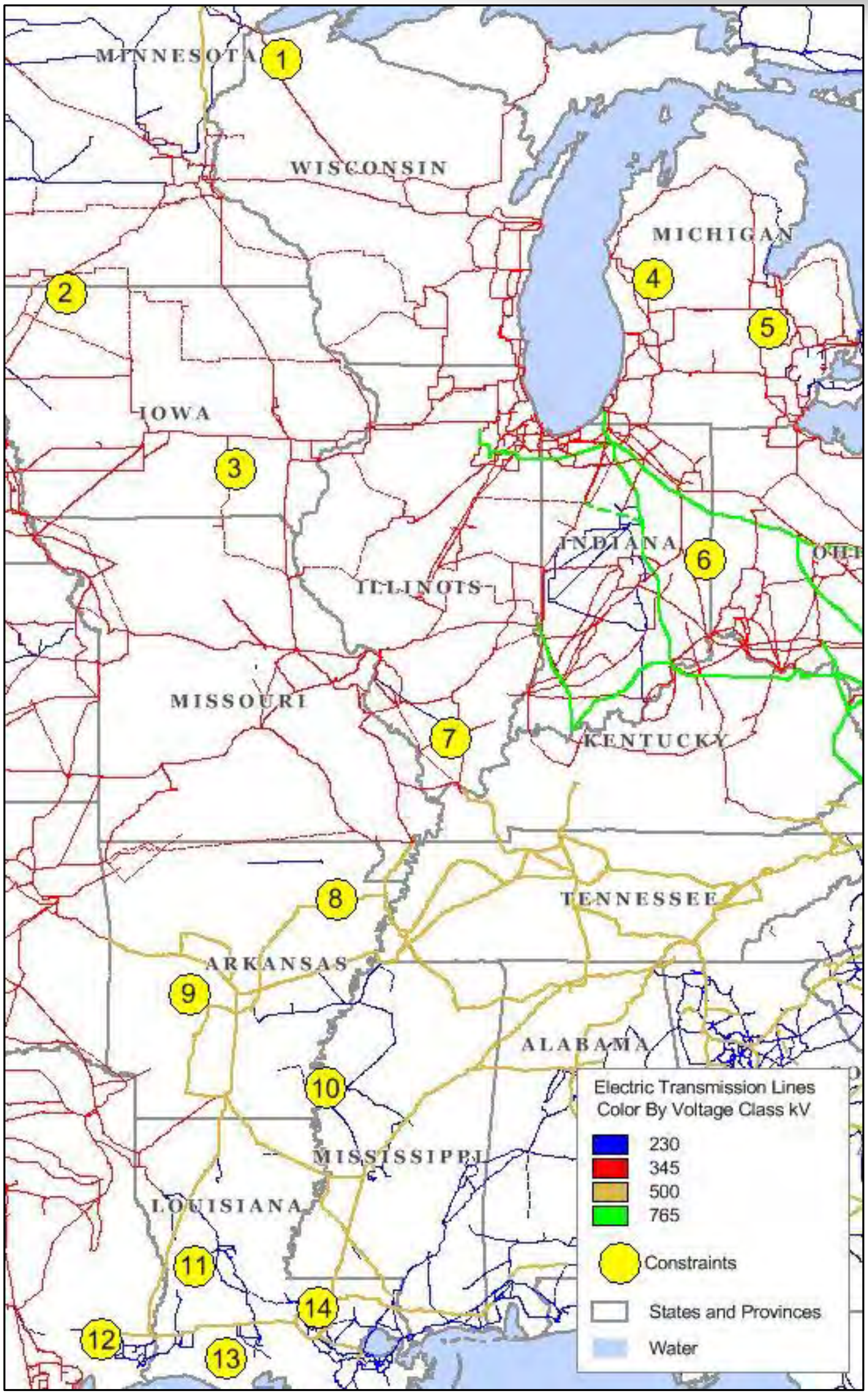


Figure 4.5-1: MTEP14 2019 Generator Deliverability constraints requiring mitigation

Additional 2024 constraints (Table 4.5-2) will be monitored in future MTEP studies to determine if mitigation is required through the MTEP generator deliverability analysis. Appendix D6 lists detailed results for impacted Network Resource Interconnection Service projects**.**

Overloaded Branch	Area	Rating (MVA)	Mitigation Required	MW Restriction
Ohio River - Iowa Junction 69 kV	210 SIGE	70	No	4.9
Cash - Jonesboro 161 kV	327 EES-EAI	335	No	31.1
Haskel - Woodlawn Road 115 kV	327 EES-EAI	261	No	8.1
Hollis AECC - Ola 115 kV	327 EES-EAI	106	No	299
Hot Springs Village - Hollis AECC 115 kV	327 EES-EAI	106	No	355.9
Independence - Moorefield 161 kV	327 EES-EAI	310	No	231.7
London - Russellville North 161 kV	327 EES-EAI	518	No	374.1
Moorefield - Batesville 161 kV	327 EES-EAI	310	No	102.0
Ola - Danville 115 kV	327 EES-EAI	106	No	84.0
Pleasant Hill 500/161 kV Transformer	327 EES-EAI	600	No	74.0
White Bluff - Keo 500 kV	327 EES-EAI	2165	No	1048.3
Woodlawn Road - Bauxite 115 kV	327 EES-EAI	159	No	53.2
Ninemile Point - Westwego 115 kV	351 EES	229	No	62.3
Senatobia - Coldwater 115 kV	351 EES	108	No	18.1
Marion - Marion Power Plant 69 kV	361 SIPC	61.6	No	294.2
Marion Power Plant - Marion 69 kV	361 SIPC	61.6	No	296.1
Ruby Tap - Rugby 115 kV	620 OTP	79.7	No	22.7
Rugby - 230/115 kV Transformer	620 OTP	125	No	7.5
Rugby - 230/115 kV Transformer	620 OTP	125	No	10.1
Beaver - Rock Creek 161 kV	627 ALTW	237	No	25.5
Burlington - Flint Bridge 69 kV	627 ALTW	103	No	26.2
Heartland Tap - Coralville Tap 69 kV	627 ALTW	77	No	22
Ottumwa - Montezuma 345 kV	627 ALTW	540	No	257
South Burlington - Burlington 4th St 69 kV	627 ALTW	103	No	2.4
Stoney Point - E Avenue Substation 69 kV	627 ALTW	58	No	22.0
York - Savanna 161 KV	627 ALTW	182	No	123.5
Aurelia Tap - Cherokee North 69 kV	635 MEC	36	No	1.2
Beacon - Council Bluffs Transformer 161 kV	635 MEC	340	No	482.1
Buena Vista - ALTA Municipal Tap 69 kV	635 MEC	36	No	2.4
ALTA Municipal Tap - Aurelia Tap 69 kV	652 WAPA	36	No	2.1
Aviation – North Fond Du Lac 138 kV	696 WPS	187	No	601.4
Sherman St. - Sunnyvale 115 kV	696 WPS	205	No	173.4

Table 4.5-2: MTEP14 constraints observed in the 2024 Scenario

FERC Order 2003 mandated that "Network Resource Interconnection Service provides for all of the network upgrades that would be needed to allow the Interconnection Customer to designate its Generating Facility as a Network Resource and obtain Network Integration Transmission Service. Thus, once an Interconnection Customer has obtained Network Resource Interconnection Service, any future transmission service request for delivery from the Generating Facility would not require additional studies or Network Upgrades"[18] to be funded by the Interconnection Customer.

Once an Interconnection Customer has obtained Network Resource Interconnection Service, any future transmission service request for delivery from the Generating Facility would not require additional studies or Network Upgrades

Deliverability was tested only up to the granted network resource levels of the existing and future network resources units modeled in the MTEP14 2019 case (Figure 4.5-2). No new interconnection service is granted through the annual MTEP deliverability analysis. Changes to aggregate deliverability could be caused by changes in load and transmission topology.

The total MW restricted varies across the MISO footprint in the near term MTEP deliverability analysis (Figure 4.5-3). Appendix D6 includes a summary of generators restricted by multiple constraints.

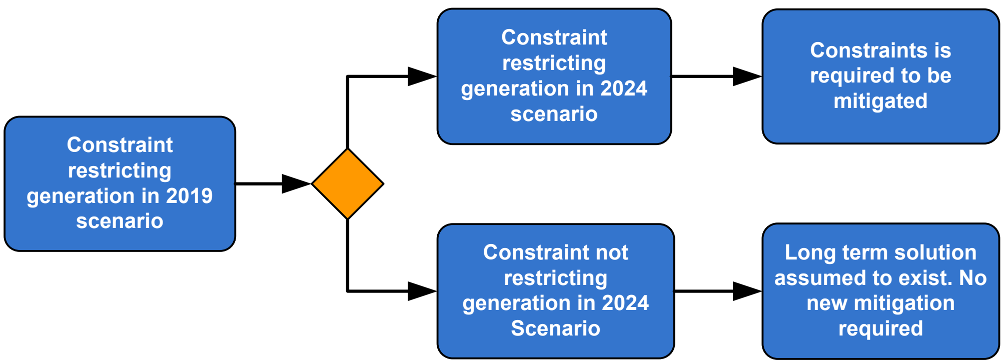


Figure 4.5-2: MTEP deliverability study analysis overview

[18] FERC Order 2003 Final Rule, paragraph 756: http://elibrary.ferc.gov/idmws/common/opennat.asp?fileID=9746398

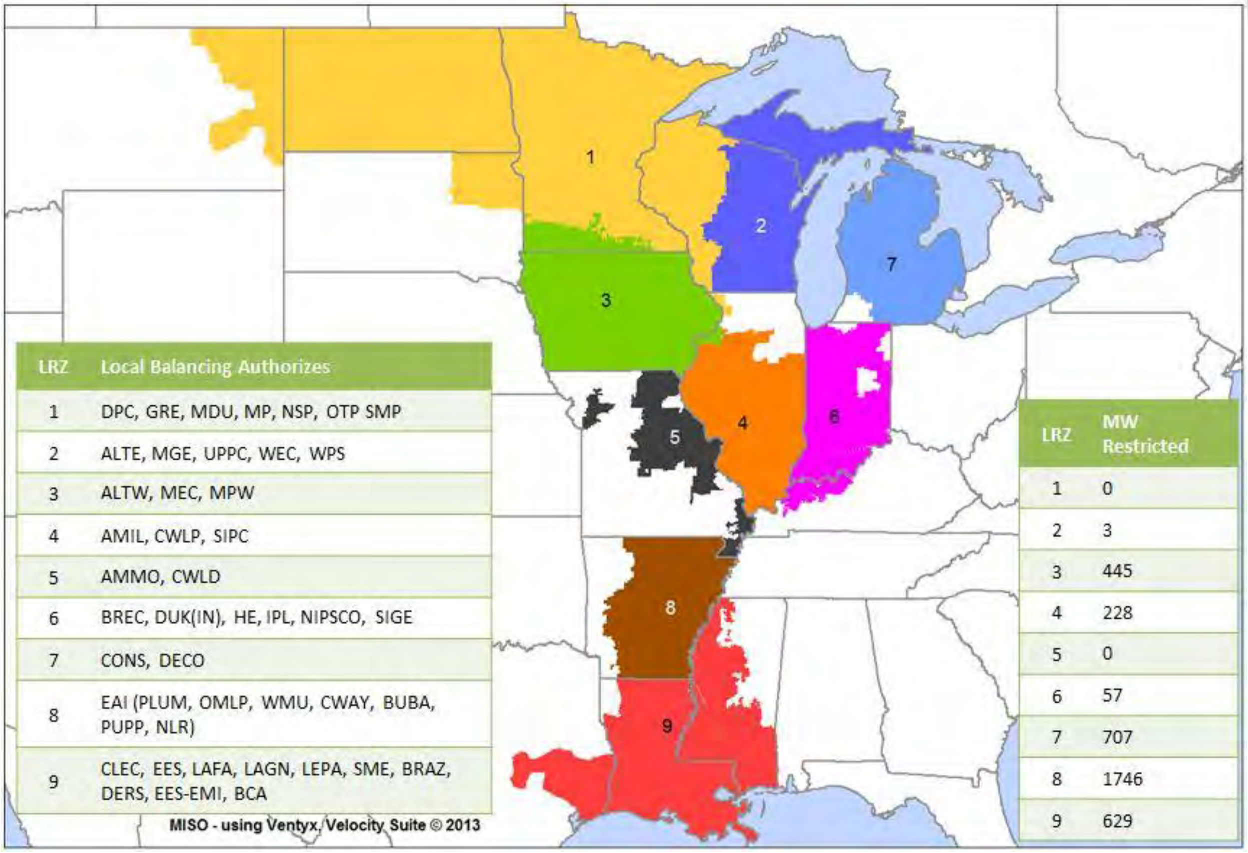


Figure 4.5-3: Local resource zones (LRZ)

Since MTEP09, MISO has performed annual generator deliverability studies to better monitor the restricted megawatts of Network Resources. The 3.8 GW of restricted deliverability from MTEP14 compares to more than 495 MW in MTEP13, 1000 MW in MTEP12, 350 MW in MTEP11, 900 MW in MTEP10 and more than 3,000 MW of restricted deliverability in MTEP09 (Figure 4.5-4).

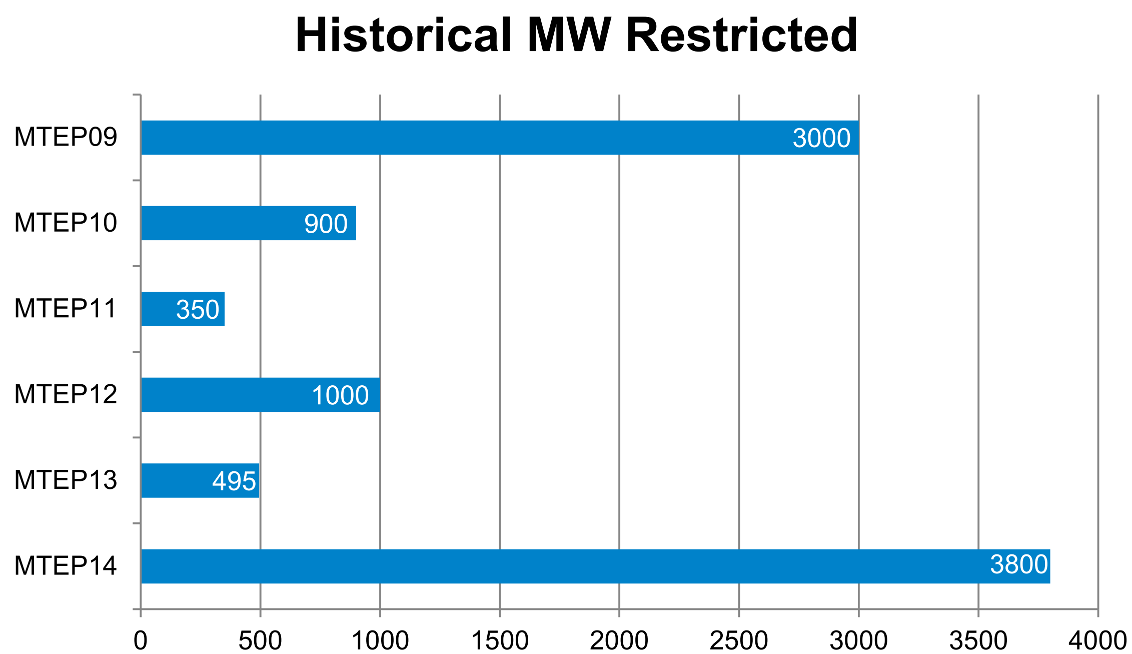


Figure 4.5-4: Restricted MW identified concluded through MTEP cycles

MTEP13 Constraints Pending Upgrades

MTEP13 identified 125 MW of deliverable generation restricted in the near term and out year under MISO functional control and an addition 370 MW of deliverability restricted to 69 kV constraints identified on non-transferred transmission facilities subject to MISO Agency Agreements[19]. Of the 495 MW, 50 MW had existing plans to mitigate the constraint. Planned upgrades were identified to mitigate the remaining restricted MWs. (Table 4.5-3).

[19] MISO Transferred and Non-Transferred Transmission Facilities: https://www.misoenergy.org/StakeholderCenter/Members/Pages/TransmissionFacilities.aspx

MTEP13 Deliverability Constraint	Total Generation Restricted (2018)[20]	Rating (MVA)	Percent Overload	MTEP ID
Blackdog to Wilson 115 kV	124.5	239.0	112%	N/A
Burlington to S. Burlington 69 kV	115.8	87.0	108%	Mitigation Required
Triboji 69/161 kV transformer	110.9	82.0	109%	N/A
Lansing 69/161 kV transformer	53.4	69.0	101%	Unit Retirement
Braham to Grasston 69 kV	46.7	42.4	111%	Mitigation Required
Kansas Ave Tap to Tiffin 69 kV	22.0	77.0	104%	Mitigation Required
Tiffin to ITC Midwest Tiffin 69 kV	22.0	76.0	110%	Mitigation Required

Table 4.5-3: Mitigations for constraints requiring mitigation from MTEP13

[20] Generators have the potential to be restricted by multiple constraints. Reported MW restricted represented the most restricting amount for each generator

4.6 Long Term Transmission Rights (LTTR) Analysis Results

MTEP involves, among other objectives, evaluating the ability of the Transmission System to fully support the simultaneous feasibility of Long Term Transmission Rights (LTTR). To that effect, MISO performs an annual review of the drivers of the LTTR infeasibility results from the most recent annual Auction Revenue Rights (ARR) Allocation and determines the sufficiency of MTEP upgrades in resolving this infeasibility.

This chapter details the financial uplift associated with infeasible LTTRs (Table 4.6-1) and documents planned upgrades that may mitigate the drivers of LTTR infeasibility identified using the annual Financial Transmission Rights (FTR) auction models.

MTEP transmission expansions provide for reliable and economic use of resources, reducing the likelihood of infeasible LTTRs

As part of the annual ARR allocation process, MISO runs a simultaneous feasibility test (SFT) to determine how many ARRs, in megawatts, can be allocated. This test determines to what extent LTTRs granted the prior year can be allocated as feasible LTTRs in the current year. The remaining unallocated LTTRs are deemed infeasible, and their cost is uplifted to the LTTR holders.

The South Region did not have previously existing LTTRs in the MTEP14 cycle. Therefore, it was not possible to calculate infeasibility or uplift for MTEP14 in the South Region. The South Region will have LTTR infeasibility analysis conducted during the MTEP15 cycle. However it was allocated year one LTTRs.

Conditions experienced in real-time systems and markets during calendar year 2013 continue the restrictive model trend for the 2014-2015 ARR Allocation. The model resulted in high prices and a high impact of constraints on LTTRs for 2014-2015, though a slight increase in LTTR allocation was observed. The uplift ratio decreased from 6.91 in MTEP13 to 5.06 percent in MTEP14 (Table 4.6-1), as noted in the 2014 Annual ARR Allocation. The 2014 allocation of total infeasible uplift for MISO is $24.3 million out of total LTTR payments of $479.3 million in the (MISO Central and North planning regions).

Year	Total Stage1A (GW)	Total LTTR Payment ($M) (including infeasible Uplift)	Total Infeasible Uplift ($M)	Uplift Ratio
2014 Allocation	326	479.3	24.3	5.06 percent

Table 4.6-1: Uplift costs associated with infeasible LTTR in the 2014 Annual ARR Allocation (MISO Central and North)

Infeasibility in any annual allocation of rights can occur due to near-term conditions and their impact on the ARR allocation models. However, as MTEP projects are completed, reliability limits are eliminated and economic congestion is reduced across the transmission system. This provides for the more reliable and efficient use of resources associated with LTTRs in general, resulting in reduced infeasibility of financial rights over time.

Planned mitigations associated with limited LTTR feasibility are listed in Table 4.6-2. Binding constraints are filtered for those with values greater than $200,000. Other constraints will continue to be monitored in the annual allocation process for feasibility status. MISO will coordinate with its Transmission Owners to investigate constraints in the MTEP14 planning cycle. Additionally, MISO will coordinate with adjacent regional transmission organizations on seams constraints.

Constraint	Summer 2014	Fall 2014	Winter 2014	Spring 2015	Grand Total	Planned Mitigation
ALBANY-BVR CH FLO CORDOVA-NELSON+SPS			$1,051,259	$1,432,903	$2,484,162	Project ID: 4093 Beaver Channel-Albany 161kV Uprate ISD: 4/1/2013
PLEASAN1 PLST-P T2 BASE	$138,354			$1,558,915	$1,697,269	TBD
OTTMWA-BRDGPRT FLO OTTUMWA-TRI CNTY 161	$156,629	$181,162	$874,252	$350,271	$1,562,314	Project ID: 4095 Ottumwa-Bridgeport North 161kV Uprate ISD: 12/31/2014
NERC # 552 (CherryValley_SilverLake15616_345kV_line)	$161,364			$445,420	$606,784	TBD
OVER XFMR AUTO FLO NEOSHO-LACYGNE 345	$589,601				$589,601	Project ID: 2998 Overton Transformer Replacement ISD: 11/17/2014
ALBANY-BVR CH FLO CORDOVA-NELSON 15503		$584,545			$584,545	Project ID: 4093 Beaver Channel-Albany 161kV Uprate ISD: 4/1/2013

Constraint	Summer 2014	Fall 2014	Winter 2014	Spring 2015	Grand Total	Planned Mitigation
ALBANY-BVRCH FLO STERLING STEEL-NELSON	$518,493				$518,493	Project ID: 4093 Beaver Channel-Albany 161kV Uprate ISD: 4/1/2013
ALBANY-BVR CH FLO QUAD CITIES-STERLING			$499,411		$499,411	Project ID: 4093 Beaver Channel-Albany 161kV Uprate ISD: 4/1/2013
ADAMS I TR2 FLO BVR-HARM-ADAMS-RICE	$160,210	$61,661	$112,597	$162,428	$496,896	Project ID: 4450 Adams 161/69kV Transformer Upgrade ISD: 1/7/2015
ALBANY-BEAVERCHNL FLO ROCKCK-SALEM	$421,266		$21,918		$443,184	Project ID: 4093 Beaver Channel-Albany 161kV Uprate ISD: 4/1/2013
MCLEAN-ELPASOTP FLO BROKAW-PONTIAC			$371,338	$46,431	$417,769	Project ID: 3344 El Paso Tap-Minonk - Check Line Hardware ISD: 6/1/2018
LUCAS-LUCT FLO CHARITON-LUCAS	$20,512	$57,885	$158,688	$149,605	$386,690	Project ID: 4100, 3641, 3644 Knoxville-Lucas County-Chariton 69 kV Line Rebuild
STATLIN_WOLFLK FLO WILTN CNTR_DMNT		$327,179	$35,561		$362,739	Project ID: 4441 State Line 161kV Source Project Conceptual

Constraint	Summer 2014	Fall 2014	Winter 2014	Spring 2015	Grand Total	Planned Mitigation
LUCAS 369 69.0 kV to LUCT 800 69.0 kV	$11,745	$54,861	$256,364	$16,106	$339,077	Project ID: 4100, 3641, 3644 Knoxville-Lucas County-Chariton 69 kV Line Rebuild
NEWTNV T3 FLO NEWTNV T5	$13,354	($107)	$403	$322,506	$336,156	Project ID: 4399 Newtonville 161 kV ring bus conversion ISD: 12/31/2022
MGPJ JT 138 kV to BEECHER B2 138 kV	$171,344	$30,564		$120,831	$322,739	Project ID: 4513 Beecher - MGP 138kV Station Equipment ISD: 6/1/2017
OVER XFMR AUTO FLO THOMAS HILL 345/161 T	$1,584			$289,892	$291,476	Project ID: 2998 Overton Transformer Replacement ISD: 11/17/2014
STONEPT-BLPLN FLO M TOWN 161/115 TR5			$142,729	$142,628	$285,357	Project ID: 1289 Marshalltown - Toledo - Belle Plaine - Stoney Point 115 kV line rebuild ISD: 4/25/2014
REYNOLDS-MONTICELLO FLO CAYUGA-EUGENE	$20,771			$255,979	$276,751	Project ID: 4810 Reynolds-Monticello-E. Winamac 138kV circuit upgrades ISD: 1/14/2015
08WVRICH A 69.0 kV to ROCH__TP 201 69.0 kV		$266,381			$266,381	TBD

Constraint	Summer 2014	Fall 2014	Winter 2014	Spring 2015	Grand Total	Planned Mitigation
OTTMWA-WAPLLO 2 FLO OTTMWA-WAPLLO 1	$4,768	($582)	$253,893		$258,080	Project ID: 4096 Ottumwa-Wapello #2 161kV Uprate ISD: 12/31/2014
STILWEL_BABCOCK FLO WLTN CNTR_DMNT				$252,492	$252,492	Project ID: 3882 MTEP11 TCFS Flowgate I Option 1 ISD: 1/1/2015
FXLAKE-RTLND FLO LKFLDGS-FLDN-WLMRTH	$2,186	$148,614	$68,292		$219,092	Project ID: 1746 Lakefield-Adams 161 kV Rebuild ISD: 12/31/2018
AZLTON TR3 XFMR	$63,982	$9,293	$99,187	$45,985	$218,447	Project ID: 3978 Hazleton 161-69kV Terminal Equipment ISD: 12/31/2016
FOX_LK FOX_LRUTLA16_11 LN	$129,458			$88,240	$217,698	
MHEX INTF	$23,820	$193,619	($573)		$216,866	TBD
ALW16031_OTTUMWA_OTTUMWAPEL16_1_1			$181,031	$27,821	$208,851	Project ID: 4096 Ottumwa-Wapello #2 161kV Uprate ISD: 12/31/2014

Table 4.6-2: Infeasible uplift to binding constraints from the 2014 annual FTR Auction

Chapter 5
Economic Analysis

5.1 Economic Analysis Introduction

The MISO Value-Based Planning Process ensures transmission expansion plans minimize the total electric costs to consumers, maintain an efficient market, and enable state and federal public energy policy - all while maintaining system reliability. The Multi-Value Project Portfolio, approved in MTEP11, demonstrates the success of the Value-Based Planning Process. The Multi-Value Projects will save Midwest energy customers more than $1.2 billion in projected annual costs and enable 41 million MWh of wind energy to meet renewable energy mandates and goals.[21]

MISO's Value-Based Planning Process ensures the benefits of an economically efficient energy market are available to customers by identifying transmission projects that provide the highest-value electric system cost

The objective of MISO's value-based planning approach is to develop cost-effective transmission plans while maintaining system reliability. Cost-effectiveness considers not only the capital cost of transmission projects but also the projected cost of energy (production cost) and generation capacity.

During the Regional Generator Outlet Study (RGOS)[22], extensive analysis was performed to determine an optimal balance point between transmission investment and generation production costs. Through RGOS, it was determined that expansion plans that minimized transmission capital costs, but had high production costs through the use of less-efficient local generation resources, yielded the highest total system cost. RGOS found the same high cost was present with expansion plans that minimized generation costs by siting generation optimally, but away from load centers, and invested heavily in regional transmission development. The "bottom-up, top-down" planning approach evaluates both locally identified transmission projects (bottom-up) and also regional transmission development opportunities (top-down) to find the dynamic balance that minimizes both transmission capital costs and production costs (Figure 5.1-1).

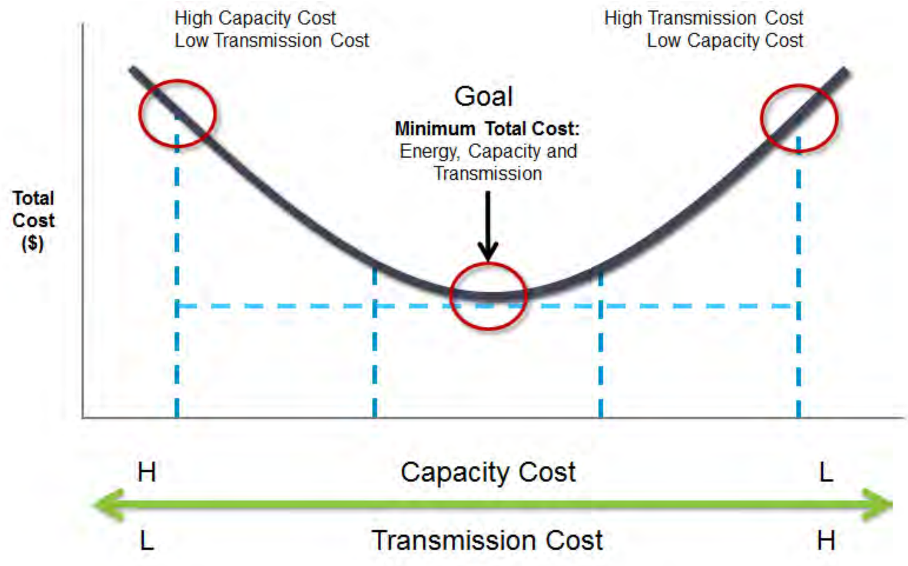


Figure 5.1-1: The goal of the MISO Value-Based Planning Process

[21] Source: Multi-Value Project Portfolio - MTEP 2011
[22] https://www.misoenergy.org/Library/Pages/ManagedFileSet.aspx?SetId=224

Since MTEP06, the MISO planning process has used multiple future scenarios to model out-year policy, economic, and social uncertainty. However, MISO is not a regional resource planner. Instead MISO's futures provide multiple reasonable resource forecasts based on probable out-year conditions including, but not limited to: fuel costs; fuel availability; environmental regulations; demand and energy levels; and available technology. Regional resource forecasts are developed based on a least-cost methodology and generation and demand-side management resources are geographically sited based on a stakeholder resource planner vetted hierarchy. MISO regional resource forecasts include consideration of thermal units, intermittent resources, demand-side management and energy efficiency programs. These regional forecasts ensure that out-year planning reserve margins are maintained.

MISO's Value-Based Planning Process supports state and federal policy requirements by planning for access to a changing resource mix

Policy assessment requires a continuing dialogue between MISO, local entities and regulatory bodies. This dialogue must identify new and existing policies and discuss how local entities intend to comply with them. It should also identify any potential regional needs or solutions to policy-driven issues. State and federal energy policy requirements and goals are the primary drivers and first step of MISO's Value-Based Planning Process.

Value-Based Planning Process

The objective of MISO's Value-Based Planning Process is to develop the most robust plan under a wide variety of economic and policy conditions as opposed to the least-cost plan under a single scenario. While the "best" transmission plan may be different in each policy-based future scenario, the transmission plan that is the best fit - or most robust - against all these scenarios should offer the most value in supporting the future resource mix.

Multiple future scenarios are analyzed to model out-year policy, as well as social and economic uncertainty, to provide context and inform choices for stakeholders and policy makers

A planning horizon of at least 15 years is needed to accomplish long-range economic transmission development, since it is not uncommon for large projects to take 10 years to complete. Performing a credible economic assessment over this time is a challenge. Long-range resource forecasting, powerflow and security-constrained economic dispatch models are required to extend to at least 15 years. Since no single model can perform all of the functions for integrated transmission development, the Value-Based Planning Process integrates multiple study techniques using the best models available, including:

- Energy Planning – PROMOD and Plexos
- Reliability Planning – PSS/E, PSLF and TARA
- Decision Analysis – GE-MARS, PROMOD and EGEAS
- Strategic Planning – EGEAS
- Generation Portfolio Development – EGEAS

MISO's Value-Based Planning Process is also known as the Seven-Step Planning Process (Figure 5.1-2). While the Value-Based Planning Process is chronologically sequenced, not all projects must start at Step 1 and end at Step 7. For example, depending on scope, a project may begin with pre-existing assumptions or plans and therefore start in Steps 3, 4, 5 or 6. Generally, Steps 1 and 2 are performed only annually. The Value-Based Planning Process is cyclical, and therefore the outputs of and project approvals are used as inputs in the next cycle. Additionally, the Step 7 to Step 1 link serves as the bridge between planning and operations to refresh assumptions based on approved projects.

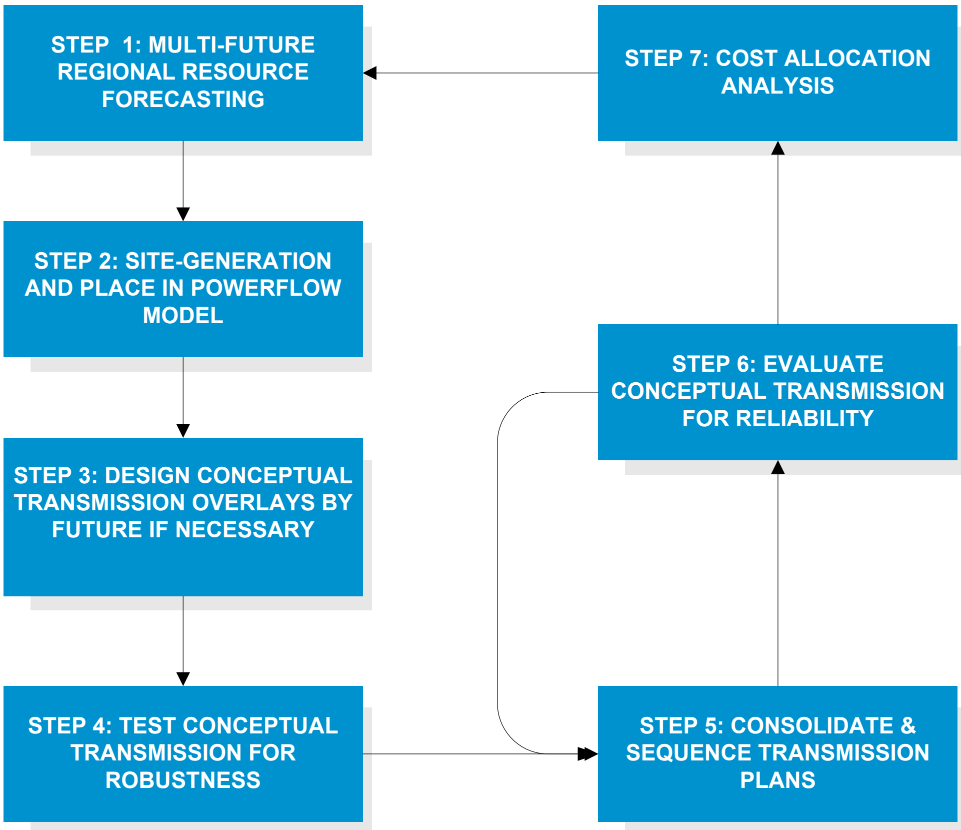


Figure 5.1-2: MISO's Value-Based, Seven-Step Planning Process

Step 1: Futures Development and Regional Resource Forecasting

Scenario-based analysis provides the opportunity to develop plans for different future scenarios. A future scenario is a postulate of what could be, which guides the assumptions made about a given model. The outcome of each modeled future scenario is a resource expansion plan, or resource portfolio. Resource portfolios identify the least-cost generation required to meet reliability criteria based on the assumptions for each scenario.

Future scenarios and underlying assumptions are developed annually and collaboratively with stakeholders through the Planning Advisory Committee. The goal is a range of futures, linked to likely real-life scenarios, that provides an array of outcomes that are significantly broad, rather than a single expected forecast.

A more detailed discussion of the assumptions and methodology around the MTEP14 future scenarios is in Section 5.2.

Step 2: Siting of Regional Resource Forecast Units

Generation resources forecasted from the expansion model for each of the future scenarios are specified by fuel type and timing; however, these resources are not site-specific. Future generation units must be sited within all planning models to provide an initial reference position five to 20 years into the future. Completing the process requires a siting methodology tying each resource to a specific bus in the powerflow model. A guiding philosophy and rule-based methodology, developed in conjunction with industry expertise, is used to site forecasted generation. The siting of regional resource forecast units is reviewed annually by the Planning Advisory Committee. A more detailed discussion of the siting methodology around each MTEP14 future is in Section 5.2.

Step 3: Design Conceptual Transmission By Future

With initial forecasts developed in Steps 1 and 2, economic potential outputs from the planning models become a road map to design conceptual transmission for each future scenario. Economic potential information identifies both the location and the magnitude of effective transmission expansion potential. Economic potential information includes but is not limited to:

- Source and sink plots
- Locational marginal price forecasts
- Historical and forward-looking congestion reports
- Optimal incremental interface flows

Conceptual transmission designs by future consider both MISO-identified regional projects as well as local projects identified by Transmission Owners. Combining regional and local projects, transmission expansion plans can be designed and analyzed to find the optimal balance point between local and regional development for each MTEP future scenario.

The conceptual transmission design process using economic potential information is shown in Section 5.3.

Step 4: Test Conceptual Transmission For Robustness

Through Step 3 of the process, transmission plans are developed for each future scenario in isolation of other future scenarios or plans. The ultimate goal of Step 4’s robustness testing is to develop one transmission expansion plan capable of accommodating the various uncertainties inherent to potential policy outcomes and that can perform reasonably well under a broad set of future scenarios. To perform robustness tests, each preliminary transmission plan is assessed against the metrics used across each of the other future scenarios. The plan emerging from this assessment with the highest value, most flexibility and lowest risk will be selected to move forward as the best-fit solution.

Step 5: Consolidate and Sequence Transmission

Once robustness testing has been conducted, it may be necessary to develop appropriate portfolios of transmission projects to complete the overall, long-term plan. One key consideration in consolidating plans is the need to maintain flexibility in adapting to future changes in energy policies. In order to create a transmission infrastructure that will support changes to generation and market requirements with the least incremental investment and rework, a comprehensive plan, which offers the most benefit under all outcomes, is developed from elements of the best-performing preliminary plan.

Step 6: Evaluate Conceptual Transmission For Reliability

Detailed reliability analysis is required to identify additional issues that may be introduced by the long-term transmission plans developed through economic assessment. These plans may need to be adjusted to ensure system reliability. Additionally, the reliability assessment determines the reliability-based value contribution of the long-term plans. As value-driven regional expansions are justified, traditionally developed intermediate-term reliability plans may be affected. The combined impact of both reliability and value-based planning strategies must be fully understood in order to further the development of an integrated transmission plan.

Step 7: Cost Allocation

MISO employs a collection of cost allocation mechanisms that seek to match the costs of transmission investment to those who benefit from that investment (Table 5.1-1). In general, the cost allocation method is dependent on whether the transmission is needed to maintain reliability, improve market efficiency, interconnect new generation, and/or support energy policy mandates and goals. Cost allocation mechanisms are developed and revisited in a collaborative and open stakeholder process through the Regional Expansion Criteria and Benefits (RECB) Task Force.

Allocation Category	Driver(s)	Allocation to Beneficiaries
Participant Funded (“Other”)	Transmission Owner-identified project that does not qualify for other cost allocation mechanisms; can be driven by reliability, economics, public policy or some combination of the three	Paid by requestor (local zone(s))
Transmission Delivery Service Project	Transmission Service Request	Generally paid for by Transmission Customer; Transmission Owner can elect to roll-in into local zone rates
Generation Interconnection Project	Interconnection Request	Primarily paid for by requestor; 345 kV and above 10 percent postage stamp to load
Baseline Reliability Project	NERC Reliability Criteria	100 percent allocated to local Pricing Zone
Market Efficiency Project	Reduce market congestion when benefits exceed costs by 1.25 times	Distributed to Local Resource Zones commensurate with expected benefit; 345 kV and above 20 percent postage stamp to load
Multi-Value Project	Address energy policy laws and/or provide widespread benefits across footprint that exceed costs	100 percent postage stamp to load and exports other than PJM

Table 5.1-1: Summary of MISO cost allocation mechanisms

MISO’s Value-Based Planning Process continues to evolve to better integrate different planning functions, take advantage of new technology and meet stakeholder needs, in both scope and complexity.

Enhancements to the existing value-based planning process to accommodate new Order 1000 requirements have been identified and implemented through a robust stakeholder process, including:

- Identification and selection of transmission issues through a multifaceted needs assessment upfront, encompassing both public policy needs and economic congestion issues/opportunities
- Open and transparent transmission solution idea solicitation with a formalized solution idea request form to document and track solution ideas
- Development of an integrated transmission development process to categorize and group issues identified, screen solution ideas with a systematic approach, refine solution ideas and formulate most cost effective projects to exploit synergistic benefits

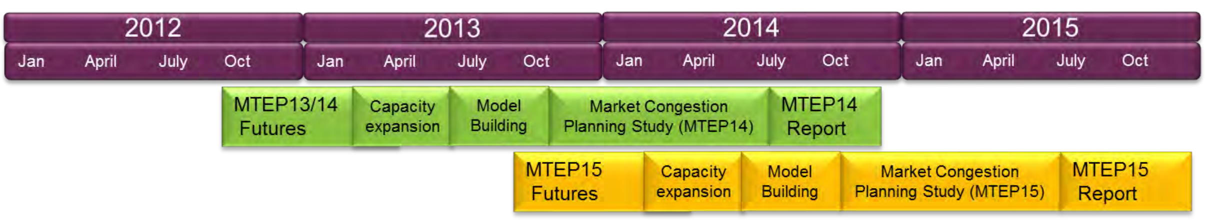
In MTEP14, MISO’s Value-Based Planning Process is exemplified in the Generation Portfolio Analysis (Section 5.2), Market Congestion Planning Studies (Section 5.3), MTEP 2014 MVP Triennial Review (Section 7.1), and Cross-Border Planning (Sections 8.1 and 8.2).

5.2 Generation Portfolio Analysis

In 2014, MISO changed the way in which economic MTEP series models are identified. In 2013 and prior years, economic models were identified by the MTEP cycle in which the building process began. Because of the amount of time in which it takes to fully build a new economic model (develop assumptions, capacity expansions, topology updates, etc.) the vintage was always a year behind the report containing the results using said model. As such, beginning with MTEP15, models are now identified by the report where the data will be contained (Table 5.2-1). In this 2014 transition year, the names MTEP13 vintage and MTEP14 are used interchangeably to describe the series developed through the Planning Advisory Committee (PAC) in 2013. The MTEP14 report details the futures and associated generation expansion analysis results that were used in downstream work efforts such as the PROMOD production cost modeling and powerflow analyses. MTEP14 Market Congestion Planning Studies (MCPS) also utilize the MTEP14 futures as a basis for model development and analysis. Meanwhile, MTEP15 MCPS will use the MTEP15 Economic Model (created in 2014).

Economic Model Vintage	MTEP Report
MTEP12	MTEP13
MTEP13 Vintage/MTEP 14 Report	MTEP14
MTEP15	MTEP15
MTEP16	MTEP16

Table 5.2-1: Model vintage and associated MTEP report



This chapter describes the MTEP generation expansion results created in 2013 and used for MTEP14 (MTEP13 Vintage/MTEP14 report), for both the North/Central and South regions. MISO completed this assessment of generation using the Electric Generation Expansion Analysis System (EGEAS) model in 2013. Using assumptions developed in coordination with the Planning Advisory Committee for the North/Central regions, and workshops entitled “Futures Development for MISO South” for the South region. MISO developed these models to identify the least-cost generation portfolios needed to meet the resource adequacy requirements of the system for each future scenario.

MTEP15 Capacity Expansion results were produced in 2014 and will be used for MTEP15. MTEP15 capacity expansion results are presented in Appendix E2.

North and Central Region Capacity Expansion Results

In the Business As Usual future, it is projected that between 2013 and 2028, 24.9 GW of additional capacity will need to be added to the MISO system while 12.6 GW of capacity will retire

The study determined the aggregated, least-cost, capacity expansions for each defined future scenario through the 2028 study year (Figure 5.2-1). This added capacity is required to maintain planning reliability targets for each region. The reliability targets for MISO are defined in the Module E Resource Adequacy Assessment described in Book 2.

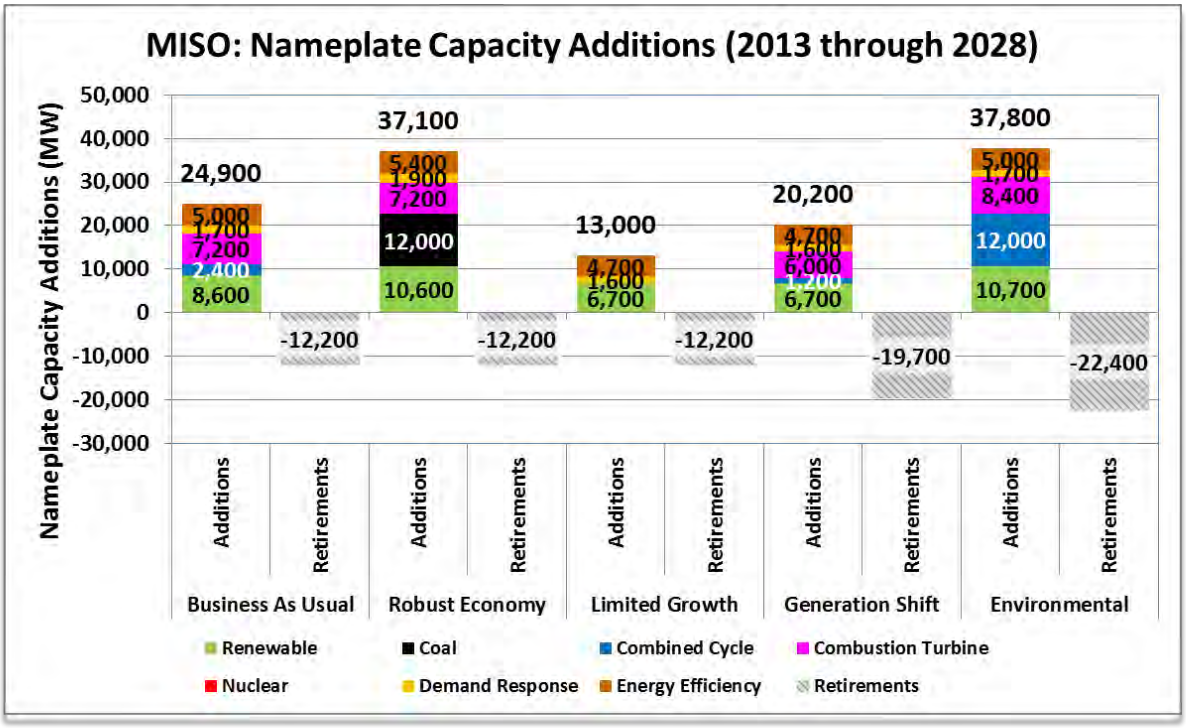


Figure 5.2-1: MISO nameplate capacity additions by future (2013-2028 EGEAS model)[23]

Results of the assessment for the Business as Usual (BAU) future show that 24,900 MW of additional nameplate capacity is expected to be needed between 2013 and 2028, while an additional 12.2 GW of coal capacity is forecasted to retire. MISO, with advice from the Planning Advisory Committee (PAC), is modeling 12.6 GW of coal retirements in all future scenarios except the Environmental scenario, which models 23 GW[24], and the Generation Shift future, which includes age-related retirements in addition to

[23] Due to coal plant retirements that have already occurred, only the additional amounts of modeled retirements are shown in the figure.

[24] MISO performed an EPA impact analysis study in 2011 in order to determine the potential of coal fleet retirements. The EPA analysis produced three levels of potential coal retirements, 3 GW, 12.6 GW and 23 GW. To capture these potential retirements in the

the 12.6 GW assumed in the other futures. The future capacity expansions include demand response (DR) and energy efficiency (EE) programs, as well as natural gas combustion turbines, natural gas combined cycle units, wind and solar. The retired capacity is mostly coal generation, resulting from simulation of the impacts of pending EPA regulations.

Futures Development

Scenario-based analysis provides the basis for developing economically feasible transmission plans for the future. A future scenario is a stakeholder-driven postulate of what could be. This determines the non-default model parameters (such as assumed values) driven by policy decisions and industry knowledge. With the increasingly interconnected nature of organizations and federal interests, forecasting a range of plausible futures greatly enhances the planning process for electric infrastructure. The futures development process provides information on the cost-effectiveness of environmental legislation, wind development, demand-side management programs, legislative actions or inactions and many other potential scenarios.

Future scenarios and their associated assumptions are developed with high levels of stakeholder involvement. As a part of compliance with the FERC Order 890 planning protocols, MISO-member stakeholders are encouraged to participate in PAC meetings to discuss transmission planning methodologies and results. Scenarios have been developed and refreshed annually to reflect items such as shifts in energy policy, changing demand and energy growth projections, and/or changes in long-term projections of fuel prices. The work completed in recent studies, including MTEP09, MTEP10, MTEP11, MTEP12, the Joint Coordinated System Planning Study, and the Eastern Wind Integration and Transmission Study, demonstrate MISO's continued commitment to robust transmission planning.

The following narratives describe the MTEP14 future scenarios and their key drivers:

- The **Business as Usual** (BAU) future is considered the status quo future and continues current economic trends. This future models the power system as it exists today with reference values and trends. Renewable portfolio standards vary by state and **12.6 GW of coal unit retirements** are modeled.
- The **Environmental (Env)** future considers a future where policy decisions have a heavy impact on the future generation mix. Mid-level demand and energy growth rates are modeled. Potential new EPA regulations are accounted for using a carbon tax and state-level renewable portfolio standard mandates and goals are assumed to be met**.** A total of **23 GW of coal unit retirements** are modeled.
- The **Limited Growth** (LG) future models a future with low demand and energy growth rates due to a very slow economic recovery and impacts of EPA regulations. This can be considered a low-side variation of the BAU future. Renewable portfolio standards vary by state and **12.6 GW of coal unit retirements** are modeled.
- The **Generation Shift (GS)** future considers a future with low demand and energy growth rates due to a very slow economic recovery. This future models a changing base load power system due to many power plants nearing the end of their useful life. In addition to the **12.6 GW of coal unit retirements** modeled as a minimum in all futures, this future also models the retirement of

scenario-based analysis, MISO analysts, in conjunction with the Planning Advisory Committee (PAC), chose to model a minimum of 12.6 GW of retirements in all futures, with the exception of 23 GW of retirements being modeled in the Environmental future.

each thermal generator (except coal or nuclear) in the year that it reaches 50 years of age or each hydroelectric facility in the year that it reaches 100 years of age during the study period. Renewable portfolio standards vary by state.

- The **Robust Economy (RE)** future is considered a future with a quick rebound in the economy. This future models the power system as it exists today with historical values and trends for demand and energy growth. Demand and energy growth is spurred by a sharp rebound in manufacturing and industrial production. Renewable portfolio standards vary by state and **12.6 GW of coal unit retirements** are modeled.

These scenarios were developed and approved prior to the current 111(d) rule the EPA has recently proposed and MISO is not specifically looking at that rule in MTEP14. The biggest driver of coal retirements in the BAU, Robust Economy, and Limited Growth scenarios is the EPA Mercury and Air Toxics Standard (MATS). In the Generation Shift scenario, the same EPA rule is considered, but MISO also considers additional retirements of generators due strictly to their age. In the Environmental scenario, MISO considers EPA MATS plus other pending regulations such as Cooling Water Intake Structures (CWIS) and Coal Combustion Residuals (CCR).

Effective Demand and Energy Growth Rates

Many states have encouraged, and in some cases mandated, the use of demand-side management (DSM) technologies in order to reduce the need for investment in new power generation. To evaluate the potential of DSM within the footprint, MISO consulted with Global Energy Partners, LLC in 2010. This effort led to the development of 20-year forecasts for various types of DSM for the MISO region and the rest of the Eastern Interconnection. The study found DSM programs have the potential to significantly reduce the load growth and future generation needs of the system. For MTEP14, the DSM program's magnitudes were scaled to reflect state-level energy efficiency and/or demand response mandates and goals. To calculate the effective demand and energy growth rates, which are ultimately input into the production cost models (Steps 3, 4 and 5 of the MTEP planning process), MISO nets out only the impact of the energy efficiency programs from the baseline demand and energy growth rates. The resulting growth rates for the various futures range from 0.22 percent to 1.25 percent for demand and 0.29 percent to 1.34 percent for energy (Table 5.2-2). Demand response programs are modeled within the production costing simulations as oil-fired generators with a significantly high fuel cost when compared to other generators.

	Baseline Growth Rates		Effective Growth Rates	
Future Scenarios	Demand	Energy	Demand	Energy
Business as Usual	1.06%	1.06%	0.75%	0.81%
Environmental	1.06%	1.06%	0.76%	0.81%
Limited Growth	0.53%	0.53%	0.22%	0.29%
Generation Shift	0.53%	0.53%	0.22%	0.29%
Robust Economy	1.59%	1.59%	1.25%	1.34%

Table 5.2-2: 2013 Effective demand and energy growth rates

Production and Capital Costs

EGEAS capacity expansion data provides the present value of production and capital costs for the study period through 2028 (Figure 5.2-2). While EGEAS does not model transmission congestion, the results nonetheless demonstrate scenarios in which higher or lower production costs could be incurred when compared to a Business as Usual-type scenario. Production costs include fuel; variable and fixed operations and maintenance; and emissions costs (where applicable). Capital costs represent the annual revenue needed for new capacity. Each future scenario has a unique set of input assumptions, such as demand and energy growth rates, fuel prices, carbon costs and Renewable Portfolio Standard (RPS) requirements that drive the future capacity expansion capital investments and total production costs.

Due to the significantly higher production costs in the Environmental future, it should be noted that approximately $152 billion of the total $276 billion in production costs are due to the $50/ton carbon tax modeled in that future. Also, the retirement of 23 GW of coal units (versus 12.6 GW in the other futures) leads to higher production costs resulting from higher capacity factors of gas-fired generation, which has a higher modeled fuel price than coal.

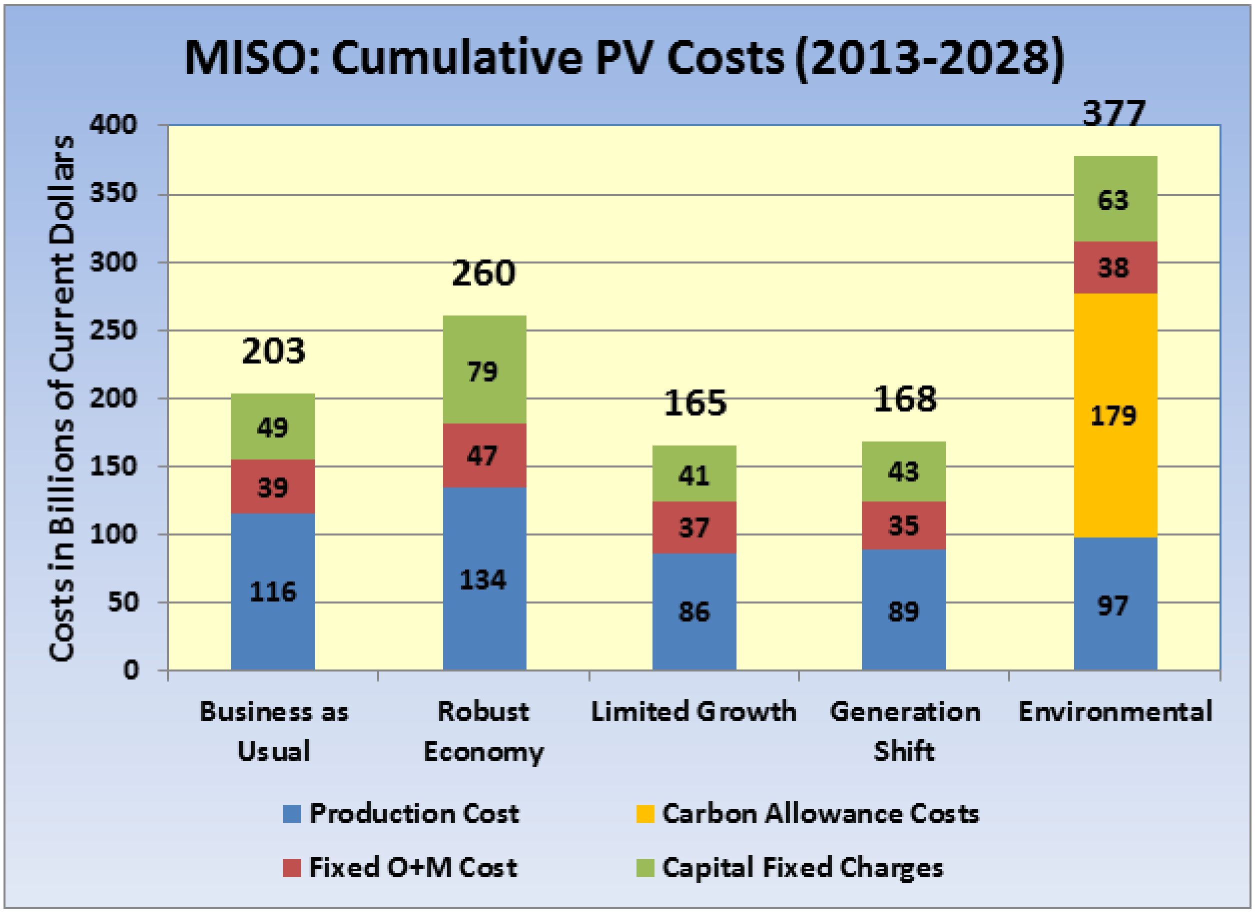


Figure 5.2-2: MISO present value of cumulative costs in 2013 U.S. dollars

Natural Gas Fuel Price Forecasting

Accurate modeling of future natural gas prices is a key input to the MTEP planning process. While natural gas prices have remained relatively low over the past few years, they have reached well over $10/MMBtu as recently as 2008. Therefore, it is important to capture a wide range of forecasts that take into account this potential volatility. For MTEP14, a baseline natural gas forecast was developed using a combination of NYMEX exchange and Energy Information Agency (EIA) forecasts. The gas price modeling approach uses a NYMEX forecast of monthly natural gas prices from January 30, 2013, through December 2015. To populate values beyond 2015, the EIA Annual Energy Outlook Reference case was used only to provide year-over-year growth rates, which were then applied to the NYMEX forecast. High and low forecasts were developed by adding or subtracting 20 percent from the baseline. Since NYMEX and EIA assume an inflation rate of approximately 1.75 percent in their forecasts, it was necessary to remove this inflation rate and to use the inflation rates for each future scenario that were identified by the PAC and MISO in the futures development process. The five resulting MTEP14 natural gas forecasts are shown in nominal dollars per MMBtu (Figure 5.2-3).[25]

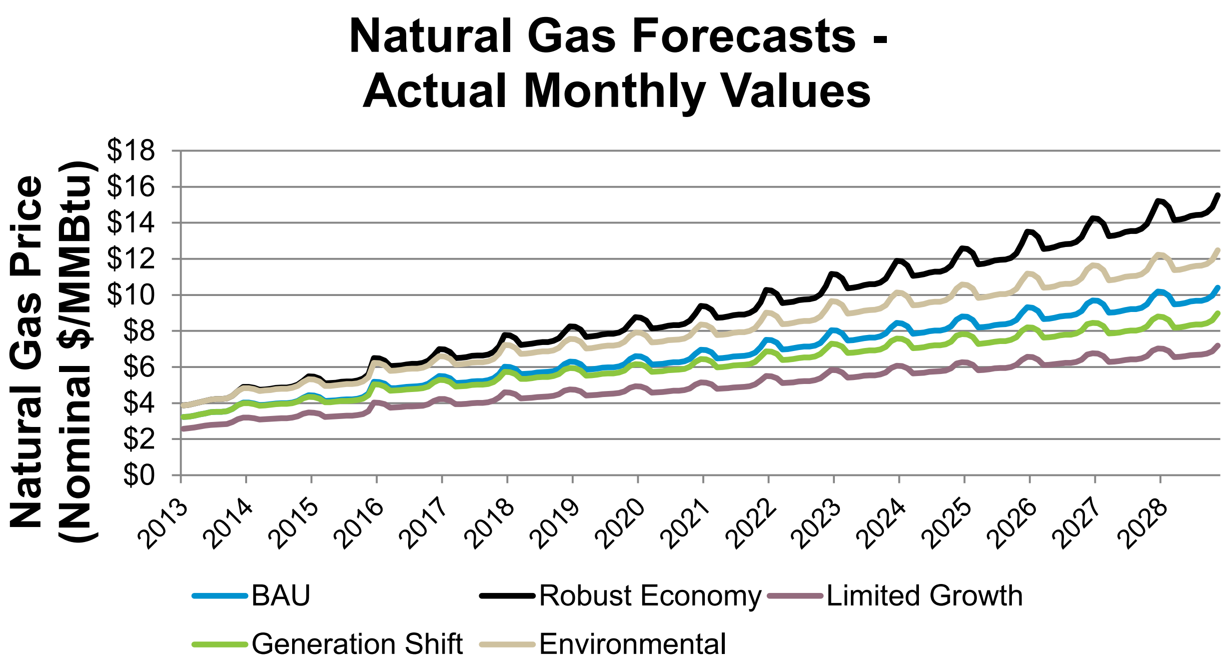


Figure 5.2-3: Natural gas forecasts by future

Renewable Portfolio Standards

Nearly every state in the MISO North and Central footprints has some form of state mandate or goal to provide a specified amount of future energy from renewable resources. The Department of Energy's Database of State Incentives for Renewables and Efficiency (DSIRE) provides a breakdown of each state's mandate or goal. MISO uses the DSIRE information to calculate future penetrations of

[25] Additional information on natural gas forecasts and futures is in Appendix E2

renewables, which are assumed to be primarily wind and solar, in each of the MTEP futures (Table 5.2-3). All MTEP14 futures model state-mandated wind and solar only, with the exception of the Environmental future, which models both state mandates and goals.

Future Scenario	MISO Midwest Incremental Wind Penetration	MISO Midwest Incremental Solar Penetration	Percentage of Energy from All Renewable Resources in 2028
Business As Usual	6,900 MW	1,725 MW	15%
Environmental	9,000 MW	1,725 MW	16%
Limited Growth	5,100 MW	1,600 MW	15%
Generation Shift	5,100 MW	1,600 MW	14%
Robust Economy	8,700 MW	1,850 MW	14%

Table 5.2-3: MISO Midwest wind and solar penetrations (including those with signed generation interconnection agreements through 2028)

Carbon Emissions

Each of the future scenarios has a different impact on carbon dioxide output (Figure 5.2-4). These output values for 2028 for the different capacity expansions can be compared to the base year, 2013, CO_2 output. For all futures, except the Robust Economy future, total CO_2 emissions decline or remain flat between 2013 and 2028. Coal plant retirements, in combination with increased levels of renewables and demand-side management programs, are key factors in allowing carbon emissions to decline. When compared to the previous MTEP analysis, the carbon output numbers for similar futures are higher, which is a direct reflection of the reduced levels of DSM being modeled in MTEP14.

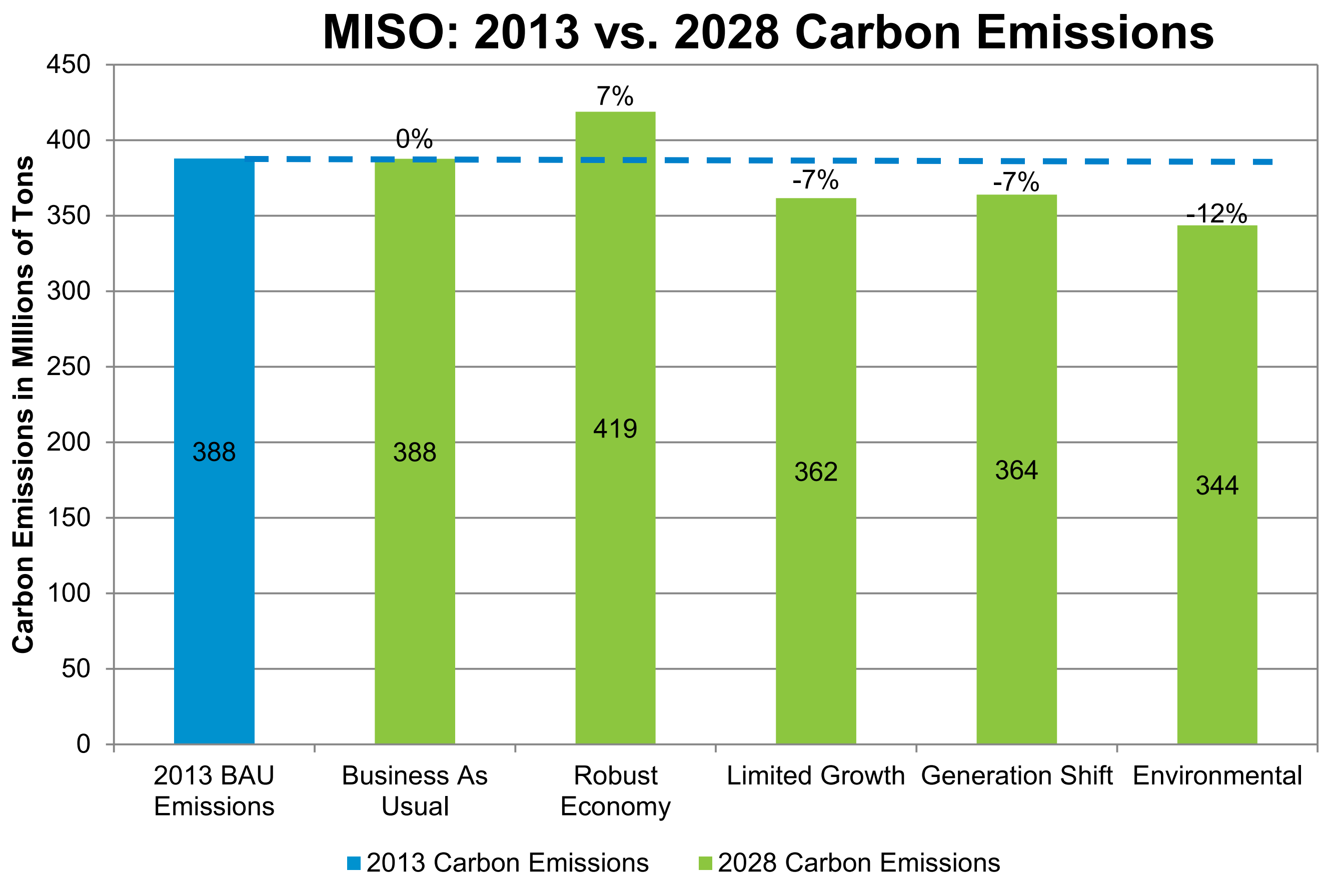


Figure 5.2-4: MISO carbon dioxide production

An alternative way of looking at carbon emissions is to investigate total CO_2 emissions per MWh of total annual energy (Figure 5.2-5). Coal retirements, coupled with increased renewable energy penetration, lead to declining rates of emissions in all MTEP scenarios. The sharpest decrease can be seen in the Environmental future, which analyzes the highest amount of coal unit retirements.

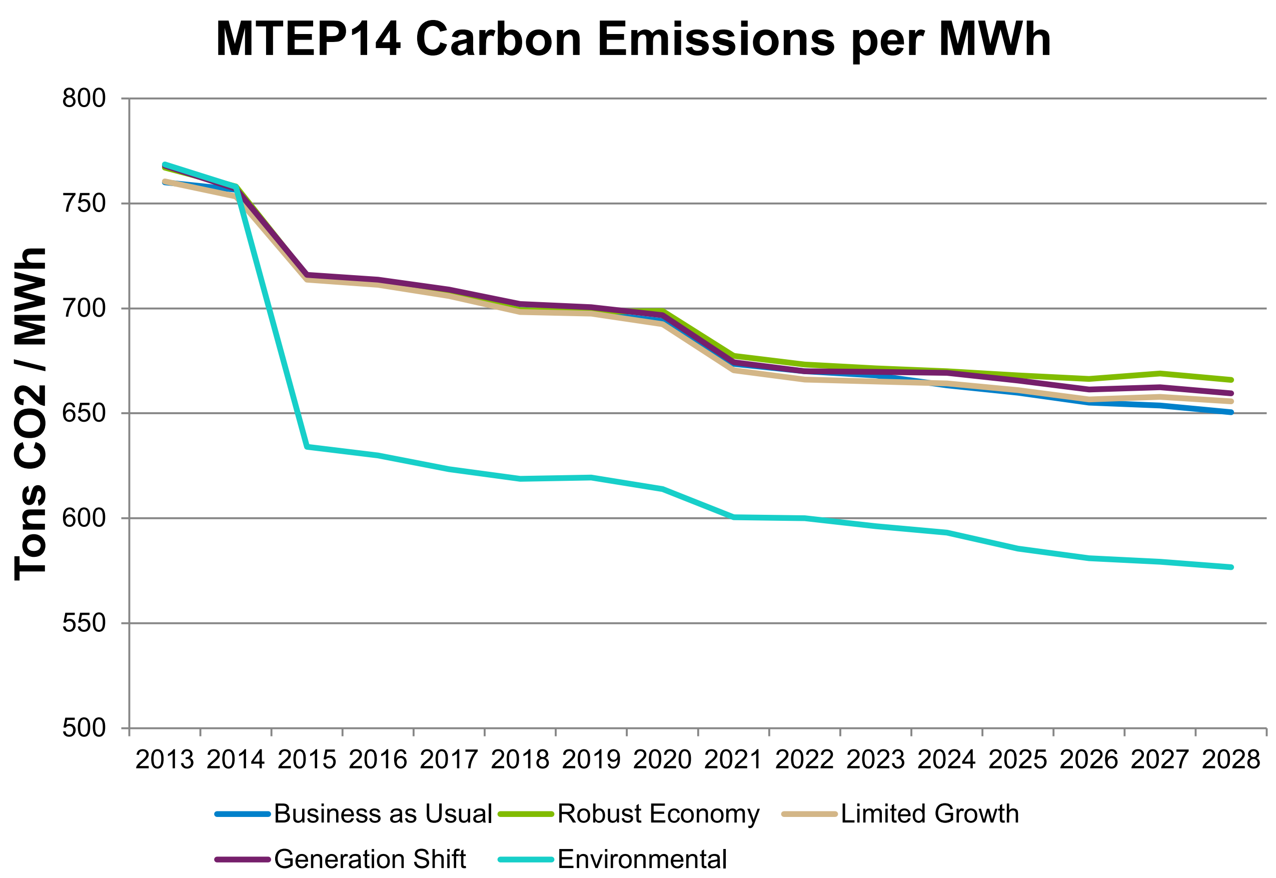


Figure 5.2-5: Carbon emissions per megawatt hour

Siting Of Capacity

Generation resources forecasted from EGEAS are specified by fuel type and timing, but these resources are not site-specific. The process requires a siting methodology tying each resource to a specific bus in the powerflow model and uses the MapInfo Professional Geographical Information System (GIS) software.

DR programs are sited at the top five load buses for each LSE in each state having a DR mandate or goal. The amount of DR remains constant across all futures. More detailed siting guidelines, methodologies and the results for the other futures are depicted in Appendix E2.

South Region Capacity Expansion Results

In order to sync MISO South with the MTEP14 economic planning process, MISO conducted a Marketing Efficiency Planning Study focused on the MISO South region. This study incorporates stakeholder informed futures, capacity expansion analysis, model building and economic analysis.

One focus of MISO's planning effort is the development of a set of futures that capture current and future potential energy policy outcomes. Futures are a set of postulates that aim to capture a plausible range of future outlooks. The futures development considers environmental regulations, renewable portfolio standards, demand-side management programs and other potential policies.

MISO developed two futures in collaboration with MISO South stakeholders:

- The **Business as Usual (BAU)** future is considered the status quo scenario and continues current economic trends. This future models the power system as it exists today with reference values and trends.
- The **Robust Economy (RE)** future models significant economic development in Southern Louisiana and Southeast Texas areas with considerable development occurring in all the areas due to consistently low fuel prices providing economic opportunity for electric growth and system expansion. The future assumes that the development of liquefied natural gas (LNG) facilities will not increase the price of natural gas above a $6/MMBtu real value.

There is a relationship between all the variables as assumed for the various futures that are input into the PROMOD PowerBase, EGEAS capacity forecasting model and the PROMOD production costing models. Each future is defined by a set of uncertainty variables, such as the variables that change from one future to another. Appendix E2 has more details on the variables for these futures.

South Region Regional Resource Forecasting (RRF)

MISO completed an assessment of generation required for the MISO footprint using the EGEAS model. Using assumed projected demand and energy for each company and common assumptions for resource forecasting, MISO developed these models to identify the least-cost generation portfolios needed to meet the resource adequacy requirements of the system for each future scenario.

In all futures initially modeled, except the Robust Economy, the MISO South Region has excess capacity for the duration of the 20-year study period (Figure 5.2-6). To meet the resource adequacy target in the Robust Economy future, the system will need 7,200 MW of thermal capacity in excess of goal-driven Demand Response and Energy Efficiency resource additions. For the traditional MTEP14 analysis, the South was modeled as a separate region because the futures were developed prior to full integration.

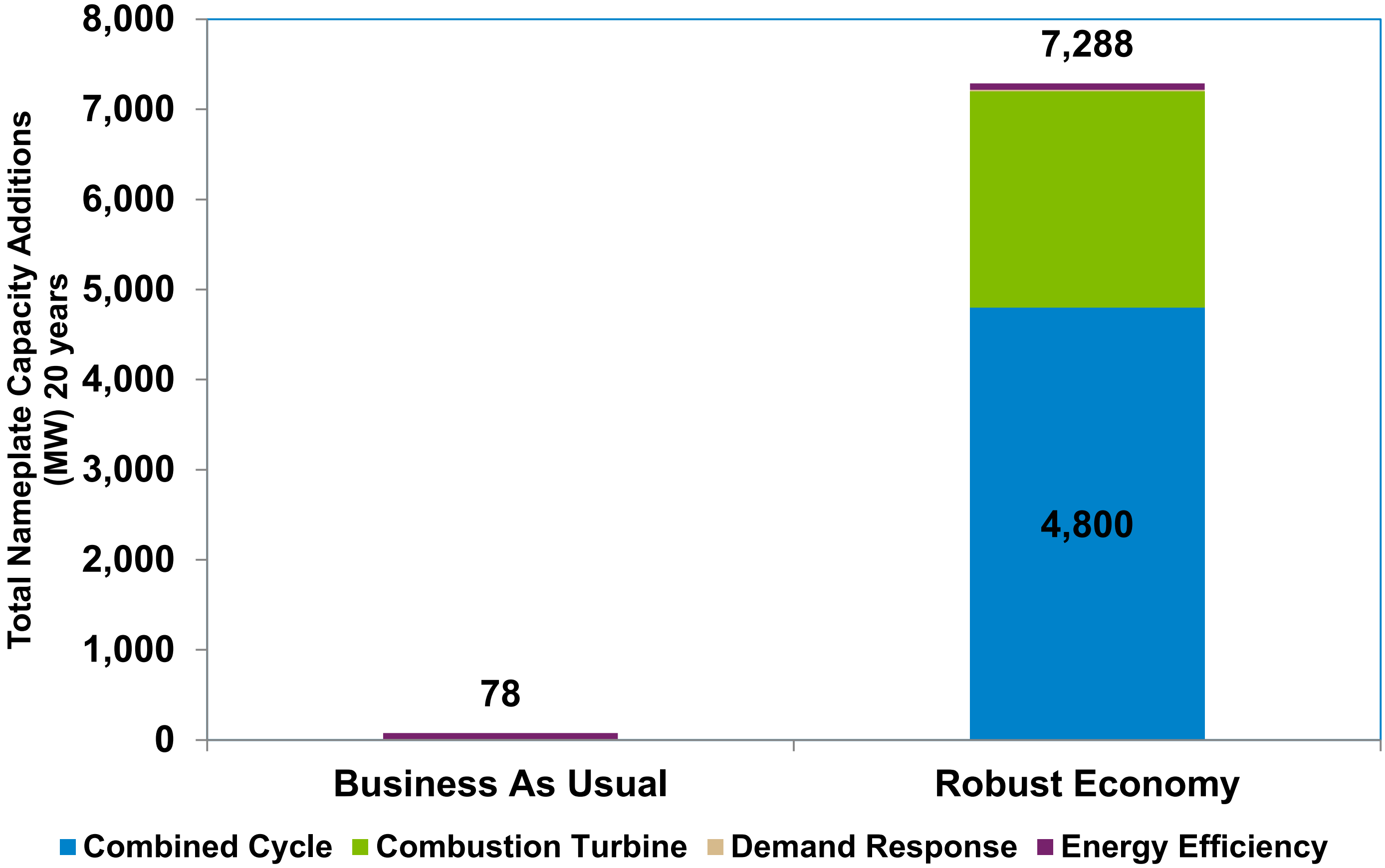


Figure 5.2-6: Nameplate capacity additions by future for MISO South

Siting The Regional Resource Forecasting Units

Regional Resource Forecast is specified by fuel type and timing, but these resources are not site-specific. The second step in the MISO's Value-Based Planning process is to tie the future resource additions (RRF units) to a bus location in the powerflow for production cost modeling purposes only. MISO uses a siting methodology to identify a bus location in the powerflow model using Geographical Information System (GIS) software, MapInfo Professional 10.0.

For the BAU future, no new thermal capacity was added in the MISO South region (Figure 5.2-7). In most other study regions, Combined Cycle resources were forecasted due to the thermal capacity retirement assumption. The least-cost peaking capacity Combustion Turbine resources were also added. Renewable Portfolio Standards mandate wind (shown in green) and solar (yellow) additions for the footprint.

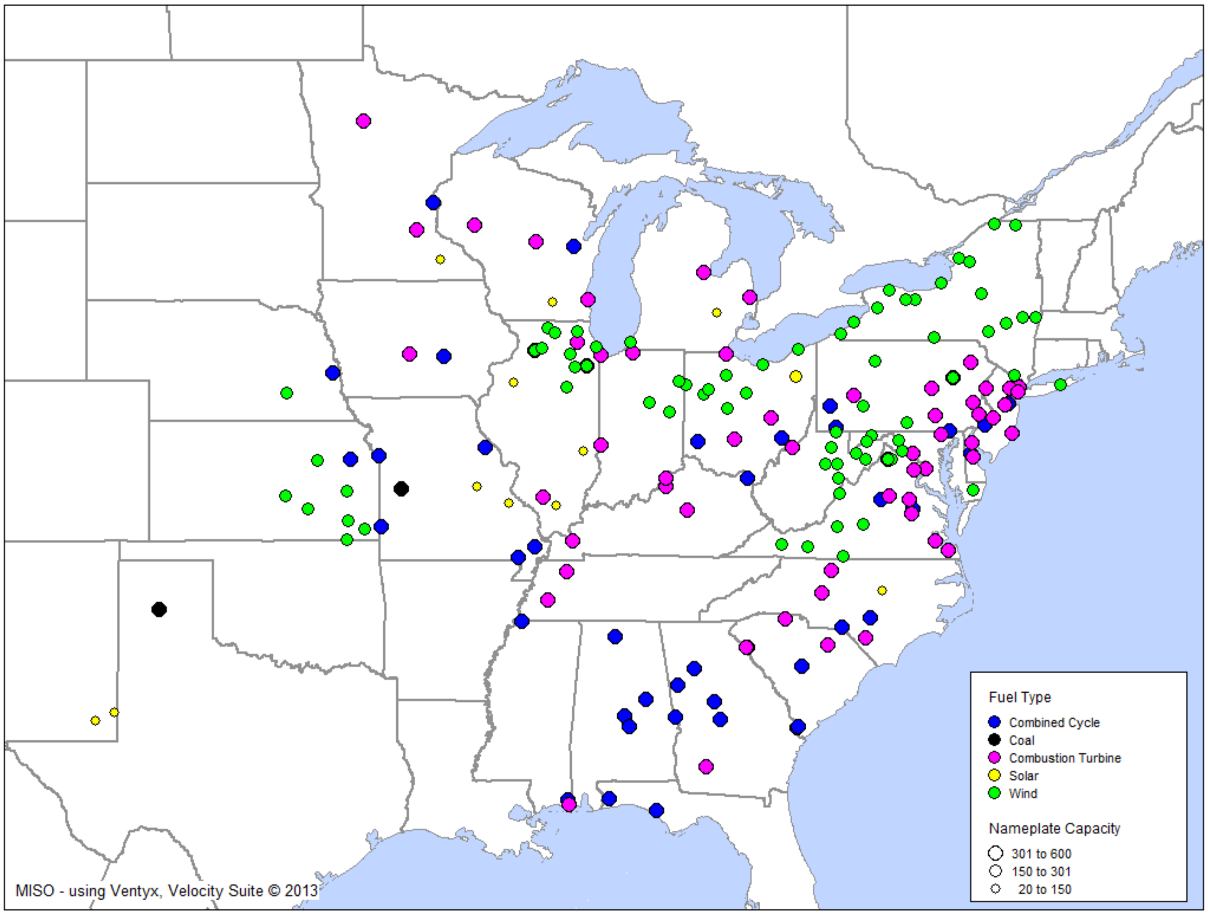


Figure 5.2-7: Regional resource forecast sites for the MISO-South Business as Usual future

The Robust Economy future requires more Combined Cycle (CC) units, compared to the BAU future, because it models higher demand and energy growth rates. The MISO South region will need a total of 7,288 MW of thermal capacity for the 20-year study period (through 2032), all of which comes in during the second half of the study period (Figure 5.2-8).

For the Robust Economy future, the MISO South region will add a total of 7,288 MW of thermal capacity required for the 20-year study period (through 2032)

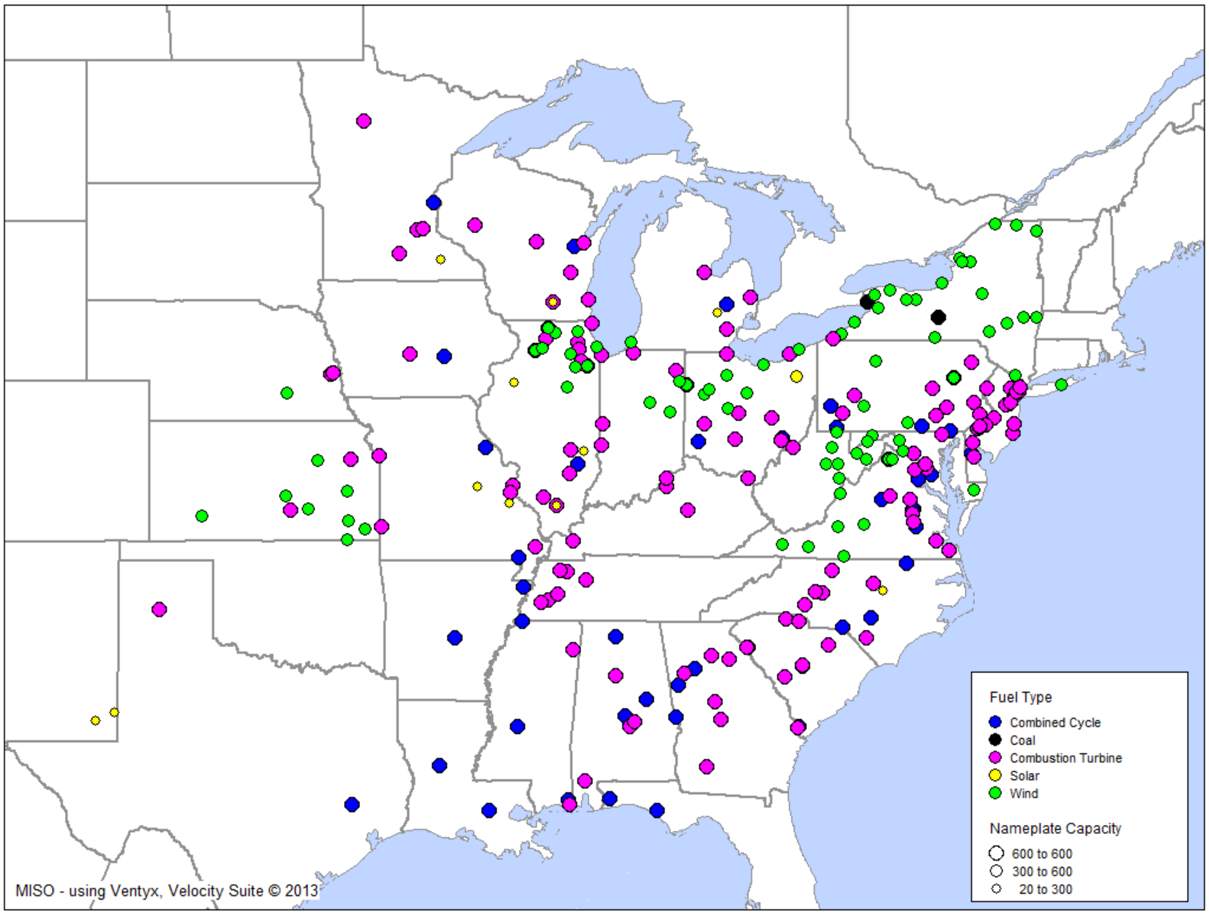


Figure 5.2-7: Regional resource forecast sites for the MISO-South Robust Economy future

5.3 Market Congestion Planning Study

The purpose of the Market Congestion Planning Study (MCPS), formerly called the Market Efficiency Planning Study, is to evaluate transmission needs and identify solutions to promote market efficiency from a regional view. By identifying and addressing both near-term transmission issues and long-term economic opportunities, this study seeks to find more efficient and cost-effective near-term solutions to support long-term goals.

Expanded from the former Top Congested Flowgate Study (TCFS), a narrowly defined flowgate-specific approach, MCPS identifies and evaluates transmission plans to enhance market efficiency more broadly, both within the MISO footprint and on its seams.

Parallel economic planning efforts have been undertaken for the MISO North/Central and South regions to engage full stakeholder participation across the entire MISO footprint in the MTEP14 planning cycle.

In the MISO South MCPS, a total of 82 transmission solution ideas were proposed and studied. MISO evaluated these solution ideas and formulated 21 preliminary project candidates for further robustness testing, in conjunction with south region stakeholders. Of the 21 preliminary project candidates, 8 were selected by MISO with stakeholder inputs as best-fit project candidates that produced a weighted net present value (NPV) benefit-to-cost ratio greater than 1.25. Of these 8 selected best-fit project candidates, three project candidates met the Market Efficiency Project (MEP) voltage and cost thresholds and require further evaluation for MEP qualification:

- Waterford – Nine Mile 500 kV
- Bogalusa – Bogue Chitto – Michoud 500 kV
- ERCOT HVDC Interconnection

The Waterford – Nine Mile 500 kV and Bogalusa – Bogue Chitto – Michoud 500 kV project candidates need further evaluation, along with other proposed alternatives, through the ongoing Voltage and Local Reliability (VLR) Planning Study process, in order to identify the optimal solutions to address VLR unit commitment in the MISO South Region load pockets. In coordination with ERCOT, the ERCOT HVDC Interconnection project candidate will require further evaluation to better quantify the benefits, estimated costs, and reliability impacts. As part of this coordination effort, the project candidate costs will be re-evaluated to better quantify the benefit to cost analysis and to determine potential cost allocation between MISO and ERCOT. Therefore, no projects will be recommended as Market Efficiency Projects to the MISO Board of Directors in the MTEP14 planning cycle.

With respect to the Waterford-Nine Mile 500 kV and Bogalusa – Bogue Chitto – Michoud 500 kV project candidates, if these project candidates are determined to be the recommended solutions to address VLR commitments and pass the Market Efficiency Project tariff thresholds as the result of the VLR planning study MISO could recommend them to the Board for approval as MTEP15 Market Efficiency Projects prior to the traditional MTEP15 December schedule during the second quarter of 2015.

Similarly, in the MISO North/Central MCPS, a total of 135 transmission solution ideas were proposed and studied. MISO evaluated these solution ideas in conjunction with North/Central stakeholders and formulated 27 preliminary project candidates for further transmission evaluation to ensure both economic and reliability needs will be met. Of the 27 preliminary project candidates, seven were selected as best-fit project candidates with a weighted NPV benefit to cost ratio above 1.25. Of these seven selected best-fit project candidates one project candidate met the Market Efficiency Project criteria based on Future weighted benefit-to-cost ratios.

- Pleasant Prairie – Pleasant Prairie Tap 345 kV

As part of the evaluation of a potential Market Efficiency Project, it is important to ensure the project's economic justification against a reasonable range of future generation additions and retirements before recommendation as a MEP. Therefore, further testing was performed to evaluate the robustness of this project candidate with a specific focus on the potential impact of environmental compliance on the coal units within the proximity of the proposed project candidate. More details on this test are in Table 5.3-6. The results of this sensitivity test indicate that Pleasant Prairie – Pleasant Prairie Tap 345 kV was found to be not robust under a different set of coal unit retirement assumptions. Therefore, this project candidate will not be recommended as a Market Efficiency Project to the MISO Board of Directors in the MTEP14 planning cycle. As the impact of environmental compliance on the fleet of existing coal plants becomes clearer in future MTEP cycles, project candidates like this could be reconsidered with greater clarity.

Both MISO North/Central and South MCPS studies yielded other project candidates that met Market Efficiency Project benefit-to-cost thresholds but did not meet voltage or project cost requirements. Any transmission project candidates not meeting the Market Efficiency Project criteria may still move forward as a Market Participant-funded project or "Other" project or be studied in future MCPS.

As part of the South MCPS two project candidates that met Market Efficiency Project benefit-to-cost thresholds but not the Market Efficiency Project criteria, have been moved forward as "Other" economic projects and will be recommended by MISO to the Board for approval as part of MTEP14.

- Upgrade ANO - Pleasant Hill 500 kV & ANO - Mabelvale 500 kV Terminal Equipment (Cost Estimate (2014 $): $4.09 million)

- Richardson - Iberville 230 kV & Bagatelle - Sorrento 230 kV cut-in to Panama 230 kV & Coly 500/230 kV XFMR & Upgrade Wilton - Romeville 230 kV (Cost Estimate (2014 $):$56.28 million)

Study Process

The MCPS starts with a multifaceted process to identify both near-term and long-term transmission needs (Figure 5.3-1). Near-term Top Congested Flowgate Analysis identifies near-term system congestion within the MISO footprint and on the seams. Longer-term Congestion Relief Analysis explores longer-term economic opportunities. Following the need identification is a holistic evaluation of projects to identify optimal solutions in an iterative fashion to ensure both robustness and reliability. Using these approaches, optimal economic transmission upgrades, encompassing both cost allocable and non-cost allocable solutions, are identified to address market congestion.

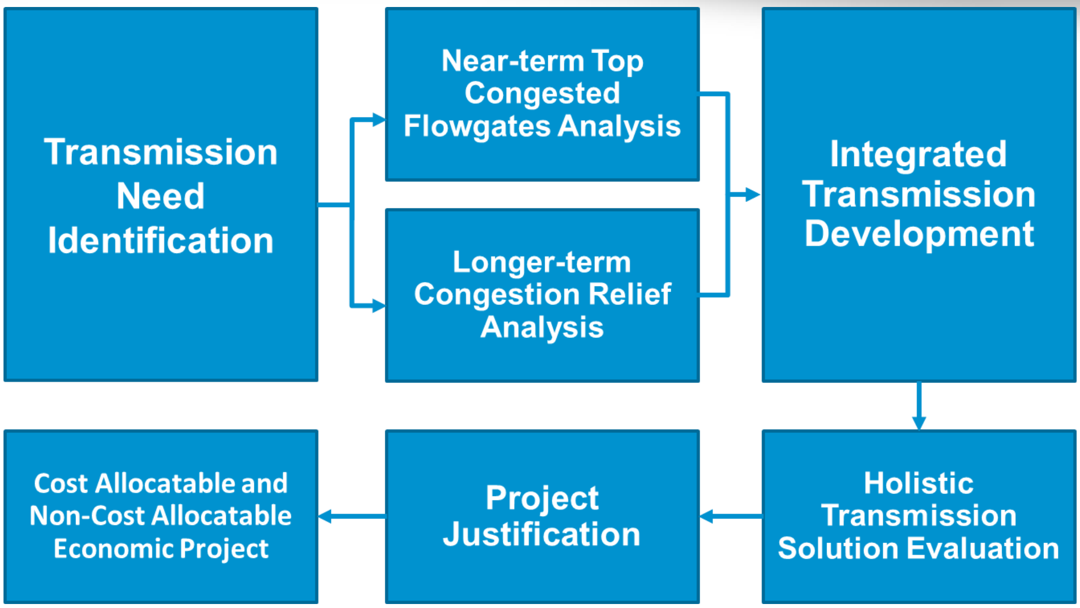


Figure 5.3-1: Market Congestion Planning Study process

The MCPS process has grown in scope and complexity each year to best manage items such as membership changes and public policy shifts. New to this year's study process is the continued evolution of the integrated transmission development process to accommodate the FERC Order 1000 requirements (Figure 5.3-2), including:

- Open and transparent process of solution idea solicitation with the stakeholder solution idea request form
- The use of Line Outage Distribution Factor (LODF)-based issue grouping methodology with Integrated Transmission Development data to reveal inter-relationships among congested flowgates
- Development of an objective, systematic approach to measure alignment between identified issues and potential solution ideas to screen and determine feasibility without detailed economic analysis
- Project candidate formulation process to exploit synergistic benefits
- Development of MISO independent planning cost estimate methodology for solution idea screening and subsequent benefit cost analysis

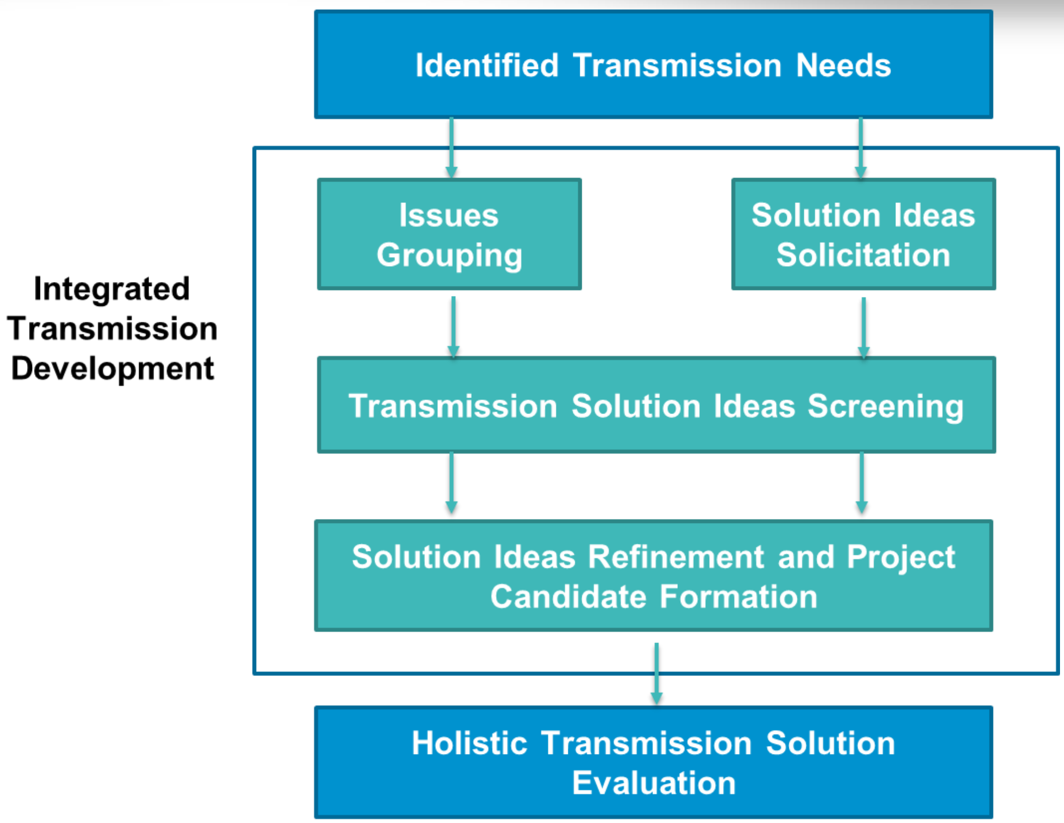


Figure 5.3-2: Integrated Transmission Development Flowchart

Near-term Top Congested Flowgate Analysis

The top congested flowgate analysis identifies system congestion trends based on the historical market data as well as forecasted future congestion patterns. The analysis identifies and prioritizes highly congested flowgates within the MISO market footprint and explores cross-border seams efficiency enhancement opportunities in coordination with neighboring regions.

Candidate flowgates considered in the analysis are those that consistently demonstrate negative transmission congestion impact historically and are projected to continue to be congested into the future. Information examined to find such flowgates includes:

- Historical congestion identified based on day-ahead, real-time and market-to-market congestion information from June 2011 to May 2013 (North/Central only)
- Historical congestion data from NERC TLR database in the last four, 2010-2013, years (South only)
- Future projected congested transmission elements identified via out-year production cost model simulations

The top congested flowgates were found all across the MISO footprint (Figure 5.3-5 and Figure 5.3-9).

Longer-term Congestion Relief Economic Analysis

Coupled with near-term top-congested flowgate analysis, congestion relief economic analysis identifies longer-term transmission needs, generally for larger-scale transmission projects. To identify economic transmission opportunities, MISO performed two production cost models simulations: a constrained case with existing transmission constraints and an unconstrained case with all transmission constraints removed for a defined area. The unconstrained case establishes a lower bound of production costs, which can serve as a reference to measure the production cost performance of all the other cases with higher production costs.

The set of information includes energy sources and sinks, forecasted Locational Marginal Pricing (LMP), incremental interface flow, incremental power transfer needs, and estimated Adjusted Production Cost (APC) Savings potential

Energy Source and Sinks

Energy sources and sinks on a hub and unit level were determined by observing the annual generation production differences between the unconstrained and constrained cases (Figure 5.3-6 and Figure 5.3-10). Therefore, red represents areas of surplus energy and blue signifies sink areas to which energy could be delivered more economically given no constraints. Energy sources and sinks provide general guidance on the location of energy export limited and import limited areas. The direction of desired powerflow is from energy sources to sinks. Linking energy sources and sinks tends to accrue the most value.

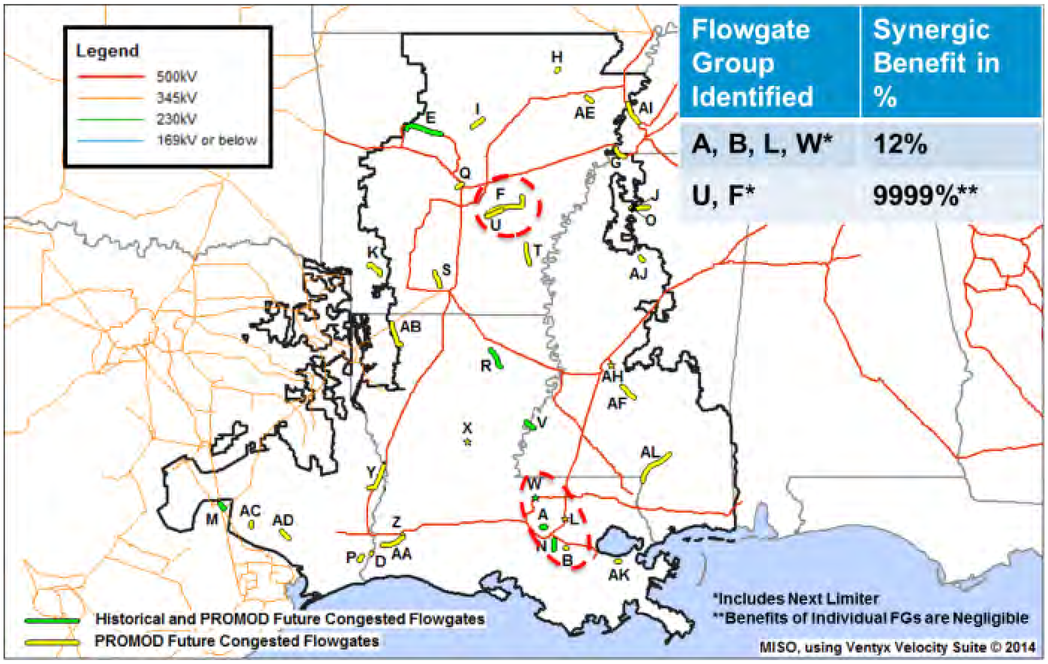
Estimated Adjusted Production Cost (APC) Savings Potential

The congestion relief analysis offers a means for estimating the total budget available for transmission expansion, based on energy economic benefits. A rough estimate of the potential budget for building transmission can be derived from the total benefit savings comparing production cost differences between the constrained and unconstrained cases. This represents the maximum possible economic benefits to be captured from constructing a perfect transmission system, also known as the unconstrained case (Figure 5.3-7 and Figure 5.3-11). The savings represent the savings in year 2028, as this analysis was performed for the 2028 simulation year.

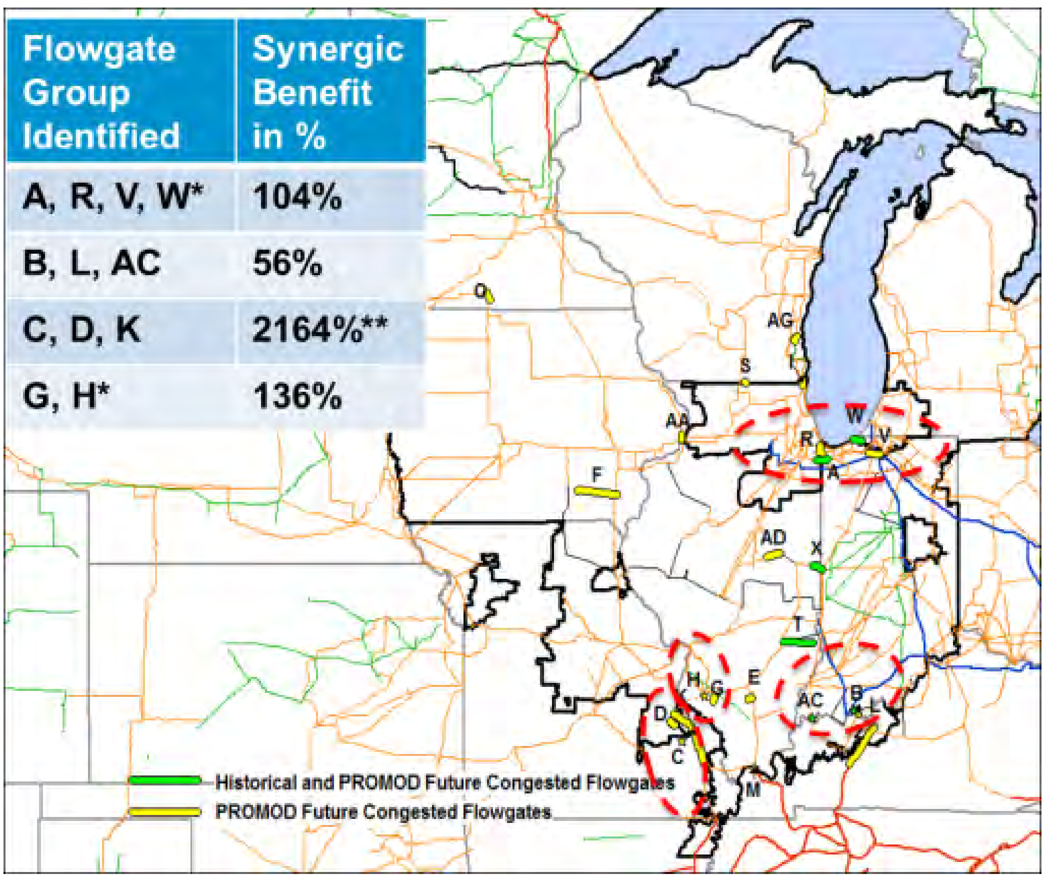
Integrated Transmission Development

Integrated transmission development entails a stakeholder-inclusive process to develop potential transmission options utilizing the list of top congested flowgates and the set of economic indicators derived from the longer-term congestion relief analyses. The solution idea submissions include those that are designed to directly address specific congested flowgates, provide energy transfer paths, or to unlock cheaper resources by connecting import-limited areas to export-limited areas (Figure 5.3-5). Solutions ideas may be received from stakeholders or generated by MISO staff internally to address the identified transmission issues. Projects represent outputs of the study process and may be formulated by combining or modifying various solution ideas to better align with the issues.

The first step is to perform the transmission issue grouping analysis, where correlation between congestion issues is identified. This is achieved by performing a LODF analysis on each top congested flowgate to measure its corresponding impact on the other top congested flowgates (Figure 5.3-3).



Flowgate Group Identified	Synergic Benefit in %
A, B, L, W*	12%
U, F*	9999%**



Flowgate Group Identified	Synergic Benefit in %
A, R, V, W*	104%
B, L, AC	56%
C, D, K	2164%**
G, H*	136%

Figure 5.3-3: South (top) and North/Central (bottom) issue group results

Next, a three-step transmission solution idea screening process (Figure 5.3-4) is employed to screen and categorize the solution ideas based on an estimated benefit-to-cost ratio using the resulting economic potential. Each solution idea is correlated to an issue or group of issues using an LODF-based approach. Estimated Economic Potential is then determined as a result of relieving corresponding issues/group of issues that could be addressed by each solution idea, providing an estimation of the maximum achievable economic benefits per idea. The screening results inform the feasibility of each transmission solution idea against the set of issues identified and prioritize the list. The transmission solution ideas are screened and categorized as follows:

- **Group 1**: Solution ideas to an identified need most likely to provide **sufficient level** of benefit-to-cost ratios
- **Group 2**: Solution ideas to an identified need that may provide **reasonable level** of benefit-to-cost ratios
- **Group 3**: Solution ideas to an identified need likely to provide **very limited level** of benefit-to-cost ratios; or projects that may not match any identified needs

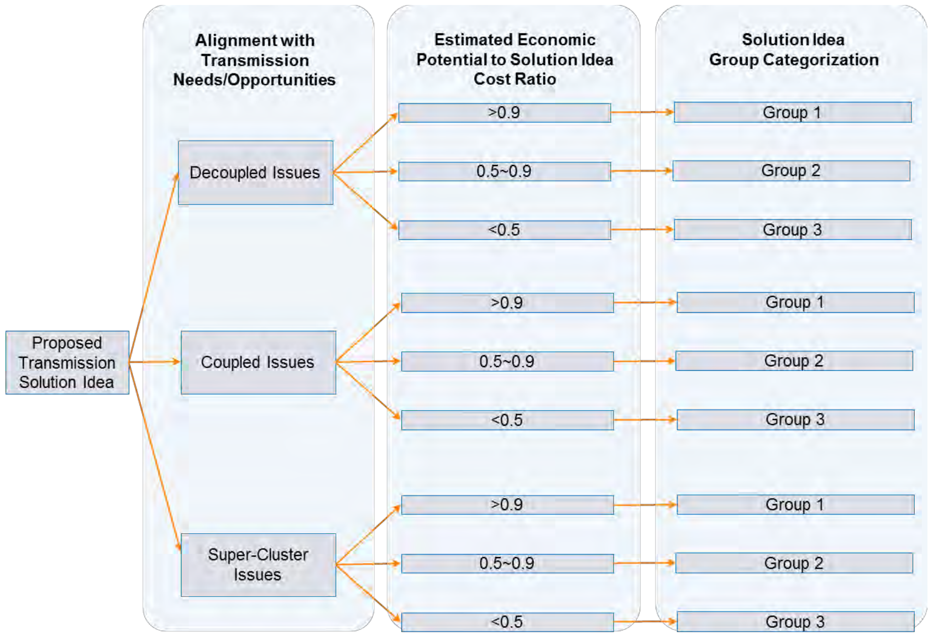


Figure 5.3-4: Transmission solution ideas screening decision tree process

Guided by the preliminary screening results, transmission solution ideas will be further refined to better address the identified needs. One-year benefit-cost analysis is performed to determine one-year future weighted benefit-to-cost ratios to further narrow down the set of ideas for refinement. Preliminary project candidates will be formulated, properly considering the balance of achieving synergistic benefits and avoiding excessive transmission build-outs that produce diminishing returns.

Holistic Transmission Solution Evaluation

Once the preliminary project candidates are formulated, an iterative process will take place between robustness testing and reliability assessment for a list of selected best-fit project candidates. The ultimate goal of robustness testing is to identify the transmission projects/portfolios that provide the best value under most, if not all, future outcomes, given the flexibility provided by the multi-dimensional future scenarios considering out-year public policy and economic uncertainties. A reliability assessment will be conducted to ensure system reliability is maintained.

Project Justification

A Market Efficiency Project must meet the following criteria, as outlined in Attachment FF of the MISO Tariff:

- An estimated cost of $5 million or more
- Involve facilities with voltages of 345 kV or higher; and may include lower-voltage facilities of 100 kV or above that collectively constitute less than 50 percent of the combined project cost, and without which the 345 kV or higher facilities could not deliver sufficient benefit to meet the required benefit-to-cost ratio
- Benefit-to-cost ratio of 1.25
- Not a Baseline Reliability or New Transmission Access project

The MISO Tariff further specifies that a project's benefit will be measured by the reduction in Adjusted Production Cost achieved by the project under each of the five Planning Advisory Committee (PAC) defined MTEP future scenarios for the North/Central MCPS and the two defined MTEP future scenarios for the South MCPS. A total weighted reduction in Adjusted Production Cost is then calculated so that all futures are given proper proportional consideration corresponding with the future weights determined by the PAC and MISO South MCPS. The project candidates formulated were evaluated using 2018, 2023 and 2028 reference case production cost models. A 20-year net present value benefit was calculated by linear interpolation and extrapolation of the three years of data and the resultant future specific benefit-to-cost ratio were weighted in accordance with the MTEP14 PAC and MISO South Futures definitions.

MCPS South Region

MISO South MTEP14 Futures

The data foundation for the first step of the seven-step process is gathered from the PROMOD Powerbase database.

The MISO South MCPS aims to develop robust transmission solutions that are beneficial across various uncertain conditions. Therefore, to account for uncertain future economic conditions and/or public policy decisions, four South region future scenarios were developed and further narrowed down to two, with collaboration of South region state regulatory and stakeholder groups. These futures are designed to be broad enough to provide a wide envelope of possible future conditions. Each future scenario represents a combination of uncertainty assumptions, such as future load growth, fuel prices and public policies:

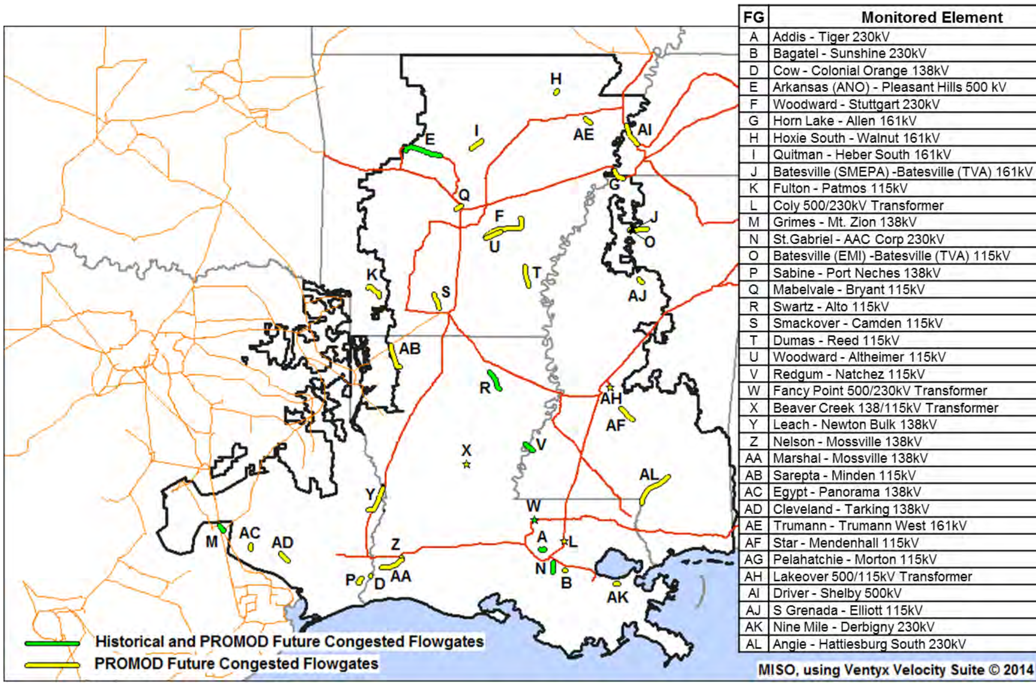
- The **Business as Usual (BAU)** future scenario is considered the status quo scenario and continues the impact of the economic downturn on demand, energy and inflation rates. This scenario models the power system as it exists today with reference values and trends, with the exception of demand, energy and inflation growth rates. The demand, energy and inflation growth rates are based on recent historical data and assume existing standards for resource adequacy and renewable mandates. Renewable Portfolio Standard (RPS) requirements vary by state, and have many potential resources that can apply.
- The **Robust Economy (RE)** future simulates a quick rebound in the economy. In particular, this future considers the probability of significant economic development in Southern Louisiana and East Texas. Considerable development is occurring in these areas due to consistent lower fuel prices providing economic opportunity for electric growth and system expansion. The Future

assumes that the development of liquefied natural gas facilities will not increase the price of natural gas above a $6/MMBtu nominal value.

In addition to these assumptions, the MISO South stakeholders assigned weights of 70 percent to the BAU future and 30 percent to the RE future as a reflection of the perceived probability of each future being actualized.

South Region Top Congested Flowgate Analysis

A total of 37 flowgates were selected as the Top Congested Flowgates for the MISO South MCPS. The top selected flowgates were distributed across the MISO South footprint (Figure 5.3-6).



FG	Monitored Element
A	Addis - Tiger 230kV
B	Bagatel - Sunshine 230kV
D	Cow - Colonial Orange 138kV
E	Arkansas (ANO) - Pleasant Hills 500 kV
F	Woodward - Stuttgart 230kV
G	Horn Lake - Allen 161kV
H	Hoxie South - Walnut 161kV
I	Quitman - Heber South 161kV
J	Batesville (SMEPA) -Batesville (TVA) 161kV Ckt 1
K	Fulton - Patmos 115kV
L	Coly 500/230kV Transformer
M	Grimes - Mt. Zion 138kV
N	St.Gabriel - AAC Corp 230kV
O	Batesville (EMI) -Batesville (TVA) 115kV
P	Sabine - Port Neches 138kV
Q	Mabelvale - Bryant 115kV
R	Swartz - Alto 115kV
S	Smackover - Camden 115kV
T	Dumas - Reed 115kV
U	Woodward - Altheimer 115kV
V	Redgum - Natchez 115kV
W	Fancy Point 500/230kV Transformer
X	Beaver Creek 138/115kV Transformer
Y	Leach - Newton Bulk 138kV
Z	Nelson - Mossville 138kV
AA	Marshal - Mossville 138kV
AB	Sarepta - Minden 115kV
AC	Egypt - Panorama 138kV
AD	Cleveland - Tarking 138kV
AE	Trumann - Trumann West 161kV
AF	Star - Mendenhall 115kV
AG	Pelahatchie - Morton 115kV
AH	Lakeover 500/115kV Transformer
AI	Driver - Shelby 500kV
AJ	S Grenada - Elliott 115kV
AK	Nine Mile - Derbigny 230kV
AL	Angie - Hattiesburg South 230kV

Figure 5.3-5: MISO South Top Congested Flowgates

South Region Congestion Relief Economic Analysis

Congestion relief analyses were conducted on two separate levels, encompassing MISO South's local resource zones (LRZ) and the MISO South market footprint.

Energy sources and sinks on a unit level were determined by observing the annual generation production differences between the unconstrained and constrained cases (Figure 5.3-6).

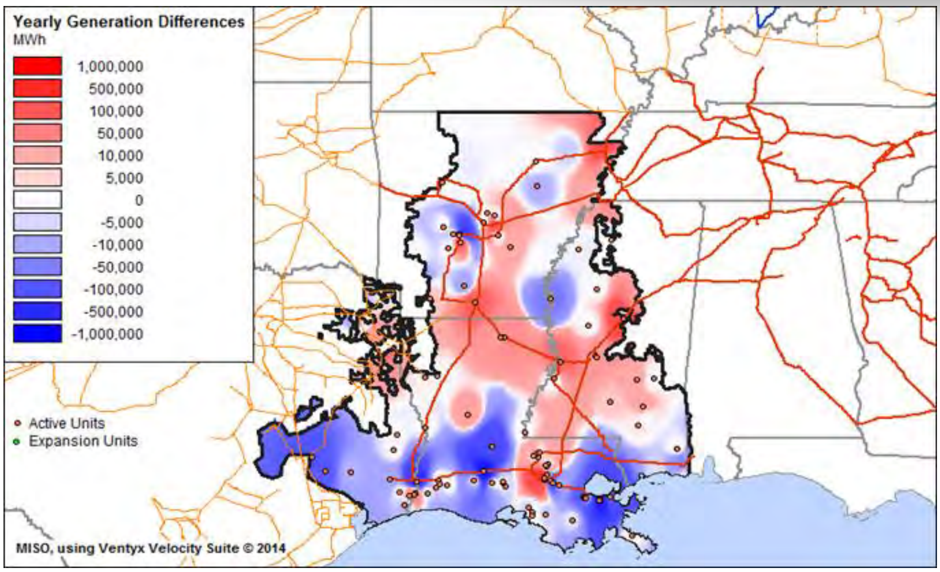


Figure 5.3-6: Unit level energy sources and sinks from MISO South Regional Analysis

The annual maximum adjusted production cost savings potential available to MISO South is variable between zones, ranging from $23 to $285 million in 2028 (Figure 5.3-7). Based on this analysis the majority of the economic potential in MISO South is located in Zone 9, potentially suggesting that greater transmission development could occur in that area. However, solution ideas were solicited for both of the zones in the MISO South footprint, as congestion issues were spread throughout the South region.

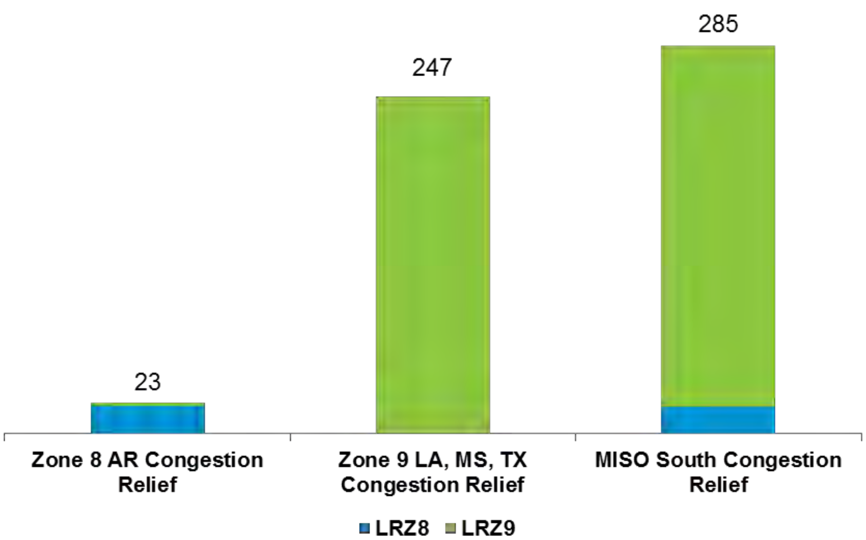


Figure 5.3-7: Maximum MISO South adjusted production cost savings potential from Zonal/Regional Congestion Relief Analyses ($ millions in 2028)

In the MISO South MCPS, a total of 82 transmission solution ideas were proposed and studied. MISO evaluated these solution ideas and proposed 21 preliminary project candidates for further robustness testing. Of the 21 preliminary project candidates, 8 were selected as best-fit project candidates that produced a weighted NPV benefit-to-cost ratio greater than 1.25. Of these 8 selected best-fit project candidates, three project candidates, narrowed down from 82 solution ideas, met the Market Efficiency Project voltage and cost thresholds and require further evaluation for MEP qualification, :

- Waterford – Nine Mile 500 kV
- Bogalusa – Bogue Chitto – Michoud 500 kV
- ERCOT HVDC Interconnection

The 82 transmission solutions ideas proposed and studied include ideas designed to address specific congested flowgates, provide energy transfer paths, or to unlock cheaper resources by connecting import-limited areas to export-limited areas (Figure 5.3-8).

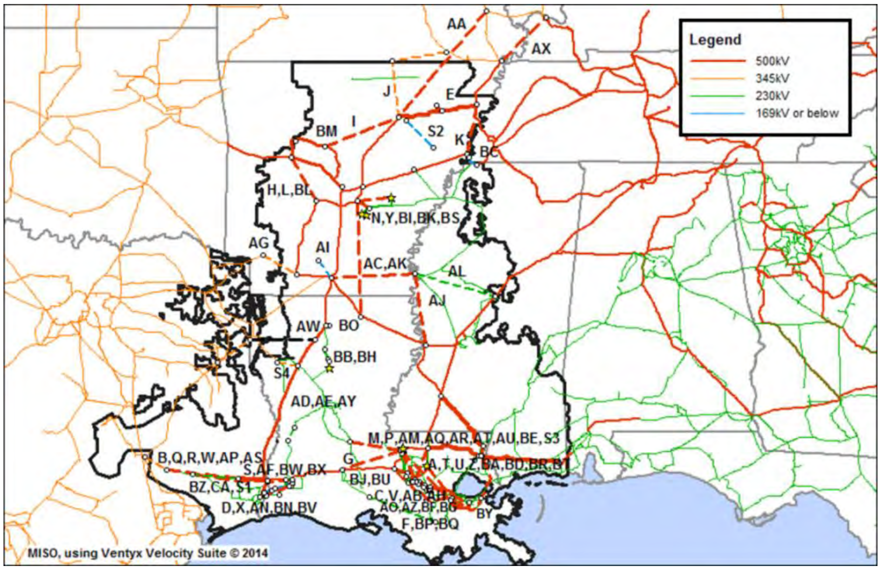


Figure 5.3-8: MISO South Transmission Ideas analyzed to address identified market congestion issues

The 82 solution ideas were refined based on the guiding principles with the goal of identifying and formulating the best-fit project candidates (see Appendix E4). Solution ideas with an estimated one-year weighted B/C ratio or greater than 0.9 based on the MISO South APC saving, along with other refined solution ideas were considered as preliminary project candidates. Twenty-one preliminary project candidates underwent robustness testing in the holistic transmission solution evaluation (Table 5.3.1). Those preliminary project candidates that have B/C ratios lower than 0.9 are the result of the MISO independent cost estimates and will continue be considered for further evaluation in the holistic transmission solution evaluation.

ID	Project Candidate Description	Issues Addressed	MISO Independent Cost Estimate ($M-2013)	MISO South Weighted APC Savings ($M-2028)	Weighted B/C Ratio (2028)
PC_A	Dow Meter – Iberville 230kV	A	39.93	44.04	5.92
PC_B	Waterford – Nine Mile 500kV[26]	B,VLR	149.68	3.66 – 53.19	0.13 – 1.94
PC_C	Fancy Point – Willow Glen 500kV	A,L	188.72	32.48	0.97
PC_D	Big Cajun - Willow Glen 500 kV	A,L	222.57	29.17	0.67
PC_E	Big Cajun - Richard 500kV	A	268.10	36.41	0.63
PC_F	Nelson - Mossville 138kV	Z,AA	12.50	10.14	4.10
PC_G	Upgrade Cow - Colonial Orange - Gully Bunch - Orange 138kV	D	9.16	4.14	6.00
PC_H	Cow 230-138kV XFMR	D,AA	16.80	3.89	1.31
PC_I	ERCOT HVDC Interconnection	Y	500.00	141.01	1.52
PC_J	Upgrade ANO - Pleasant Hill 500kV Terminal Equipment	E	0.60	7.12	67.27
PC_K	Convert Danville - Dodson - Jeld Wen - Winnfield to 230kV	U	4.00	1.29	1.76
PC_L	Bogalusa – Bogue Chitto – Michoud 500kV[26]	A,B,L,AK, VLR	391.80	35.82 – 116.17	0.40 – 1.34
PC_M	Bagatelle - Sunshine 230kV & Sunshine – Panama 230kV	B	20.50	15.37	4.00
PC_N	DOW - Iberville 230kV & Bagatelle - Sunshine 230kV & Sunshine - Panama 230kV	A,B	60.43	62.25	5.51
PC_O	DOW - Iberville 230kV & Waterford – Nine Mile 500kV[26]	A,B,VLR	189.61	57.69 – 101.68	1.63 – 2.90
PC_P	Upgrade ANO – Mabelvale 500kV & ANO – Pleasant Hill 500kV Terminal Equipment	E	1.20	7.54	35.64
PC_R	Waterford - Conway - Willow Glen Transmission Project	B,N	43.79	9.28	1.15
PC_T	Bogalusa - Bogue Chitto – Michoud - Nine Mile - Waterford 500kV[26]	B,VLR	758.23	34.73 – 120.44	0.26 – 0.72
PC_U	Upgrade Panama - Wilton 230kV	B	7.52	1.28	0.99
PC_V	NSUB - Panama 500kV	B	48.57	9.75	1.08
PC_W	DOW - Iberville 230kV & Bagatelle - Sunshine 230kV & Sunshine - Panama 230kV & Coly 500/230kV XFMR	A,B,L	71.49	75.27	5.62

Table 5.3-1: MISO South preliminary project candidates

Of the 21 preliminary project candidates, 8 were selected as best-fit project candidates. These 8 best-fit project candidates had a weighted NPV benefit-to-cost ratio greater than 1.25. Of the 8 best-fit project candidates, three met both the MEP voltage and cost criteria (Table 5.3-2).

[26] Added Benefits from relieving Load Pocket Commitment Guidelines

ID	Project Candidate Description	Cost Estimate ($M - 2013)	B/C ratio (BAU)	B/C ratio (RE)	Weighted B/C ratio
PC_B	Waterford - Nine Mile 500 kV[26]	156.10	0.18 – 2.03	0.42 – 0.81	**0.25 – 1.66**
PC_L	Bogalusa - Bogue Chitto - Michoud 500 kV[26]	383.44	0.28 – 1.63	0.75 – 1.14	**0.42 – 1.48**
PC_I	ERCOT HVDC Interconnection[27]	500.00	1.37 – 1.43	0.74 – 0.79	**1.18 – 1.24**

Table 5.3-2: MISO South cost-sharable best-fit project candidates

The other five best-fit project candidates (Table 5.3-3) did not meet at least one MEP criterion and were thus not considered as potential Market Efficiency Projects in this study. However these project candidates may still be considered as Market Participant Funded projects or "Other" projects.

ID	Project Candidate Description	Cost Estimate (M$ 2013)	B/C ratio (BAU)	B/C ratio (RE)	Weighted B/C ratio
PC_P	Upgrade ANO - Pleasant Hill 500 kV & ANO - Mabelvale 500kV Terminal Equipment	3.99	10.43	8.54	**9.86**
PC_W	Richardson – Iberville 230 kV & Bagatelle – Sorrento 230 kV cut-in to Panama 230 kV & Coly 500/230 kV XFMR & Upgrade Wilton – Romeville 230 kV	54.87	6.16	7.13	**6.45**
PC_G	Upgrade Cow - Colonial Orange - Gully Bunch - Orange 138 kV	9.16	2.74	4.73	**3.34**
PC_O	Dow Meter - Iberville 230 kV & Waterford - Nine Mile 500 kV[26]	196.03	1.38 – 2.89	1.43 – 1.79	**1.40 – 2.56**
PC_F	Nelson - Mossville - Carlysis 138 kV	25.26	0.28	6.37	**2.11**

Table 5.3-3: MISO South non cost-sharable best-fit project candidates

The Waterford – Nine Mile 500 kV and Bogalusa – Bogue Chitto – Michoud 500 kV project candidates will be further evaluated, along with other proposed alternatives, through the ongoing Voltage and Local Reliability (VLR) Planning Study process to identify the optimal solutions to address VLR unit commitment in the MISO South Region load pockets. In coordination with ERCOT, the ERCOT HVDC Interconnection project candidate will require further evaluation to better quantify the benefits, estimated costs, and reliability impacts. As part of this coordination effort, the project candidate costs will be re-evaluated to better quantify the benefit to cost analysis and to determine potential cost allocation between MISO and ERCOT. Therefore, no projects will be recommended as Market Efficiency Projects to the MISO Board of Directors in the MTEP14 planning cycle. With respect to the Waterford-Nine Mile 500 kV and Bogalusa – Bogue Chitto – Michoud 500 kV project candidates, should these project candidates determine to be the recommended solutions to address VLR commitments and pass the Market Efficiency Project tariff thresholds as the result of the VLR planning study, it would be recommended to the Board by June 2015 as Market Efficiency Project.

MCPS South also yielded numerous projects that met Market Efficiency Project benefit-to-cost thresholds but did not meet voltage or project cost requirements. Any transmission plans that did not meet the Market Efficiency Project criteria may still move forward as a Market Participant-funded project or "Other" project or be studied in future MCPS.

[27] Benefits associated with increasing the stability limit form 1,200 MW to 1,500 MW on the existing Mt. Olive – Hartburg 500 kV

As part of the South MCPS two project candidates that met Market Efficiency Project benefit-to-cost thresholds but not the Market Efficiency Project criteria, have been moved forward as “Other” economic projects and will be recommended by MISO to the Board for approval as part of MTEP14.

- Upgrade ANO - Pleasant Hill 500 kV & ANO - Mabelvale 500kV Terminal Equipment (Cost Estimate (2014 $): $4.09 million)

- Richardson - Iberville 230kV & Bagatelle - Sorrento 230kV cut-in to Panama 230kV & Coly 500/230kV XFMR & Upgrade Wilton - Romeville 230kV (Cost Estimate (2014 $): $56.28 million)

A link to the full MISO South Market Congestion Planning Study report will be posted on the MISO website on the MTEP Studies[28] page.

MCPS North/Central Region

MISO North/Central MTEP14 Futures

The data foundation for the first step of the seven-step process is gathered from the database, PROMOD PowerBase. Each year this database is refreshed and model inputs are updated based on the MTEP Futures definitions. For the MISO North/Central MTEP14 study process, the future scenarios include:

- Business as Usual (BAU)
- Robust Economy (RE)
- Limited Growth (LG)
- Generation Shift (GS)
- Environmental (ENV)

Section 5.2 contains further details regarding these futures. Working together with multiple sectors of the power industry through the Planning Advisory Committee (PAC), the following weights were assigned for each of the MISO North/Central MTEP14 futures: 42 percent for BAU, 10 percent for RE, 18 percent for LG, 14 percent for GS, and 17 percent for ENV. The PAC assigned weights to each future as a reflection of the perceived probability of each future being actualized.

North/Central Region Top Congested Flowgate Analysis

A total of 24 flowgates were selected as the Top Congested Flowgates for the MISO North/Central MCPS. The top selected flowgates were distributed across the MISO North/Central footprint (Figure 5.3-9).

[28] https://www.misoenergy.org/Planning/TransmissionExpansionPlanning/Pages/MTEPStudies.aspx

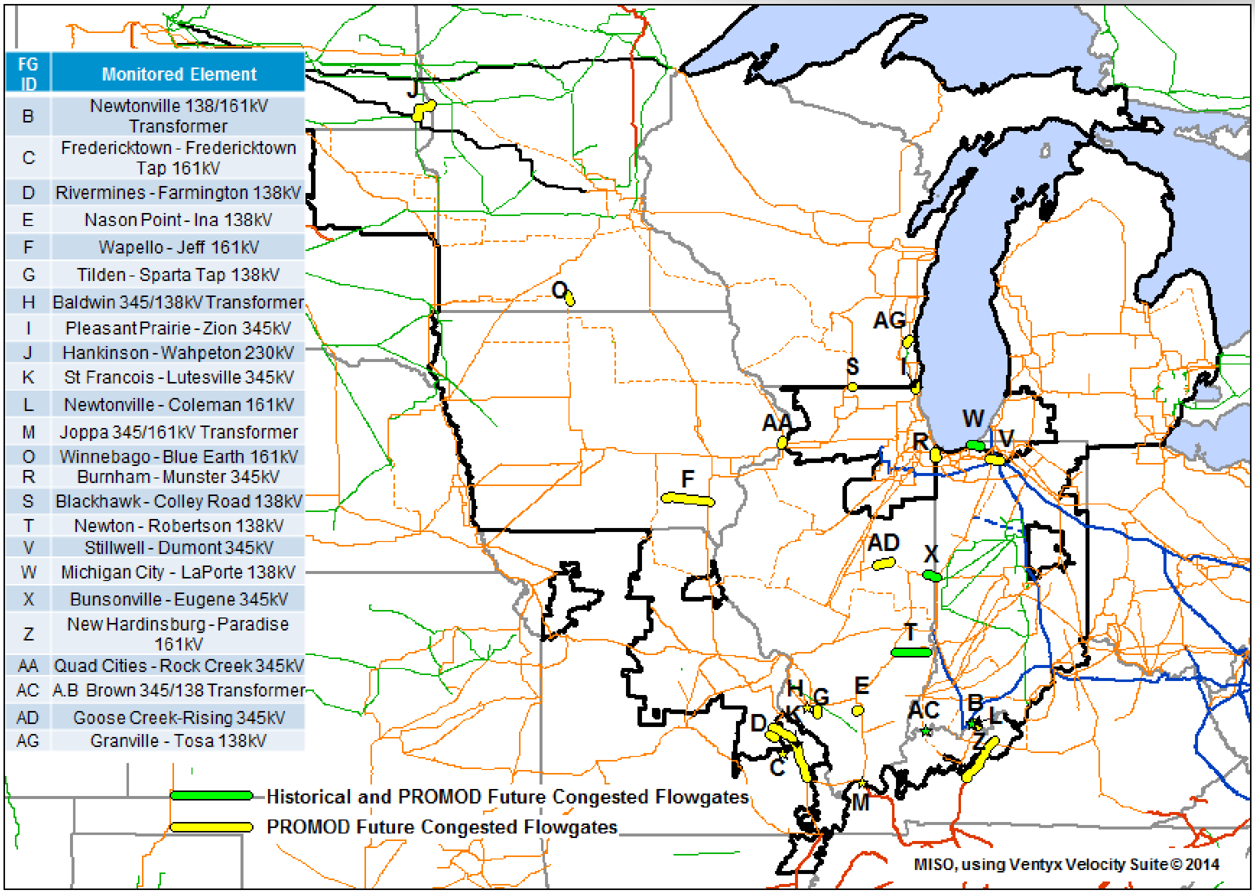


Figure 5.3-9: MISO North/Central Top Congested Flowgates

North/Central Region Congestion Relief Economic Analysis

Congestion relief analyses were conducted on two separate levels, encompassing MISO North/Central's local resource zones (LRZ) and MISO North/Central's market footprint

Energy sources and sinks on a unit level were determined by observing the annual generation production differences between the unconstrained and constrained cases (Figure 5.3-10).

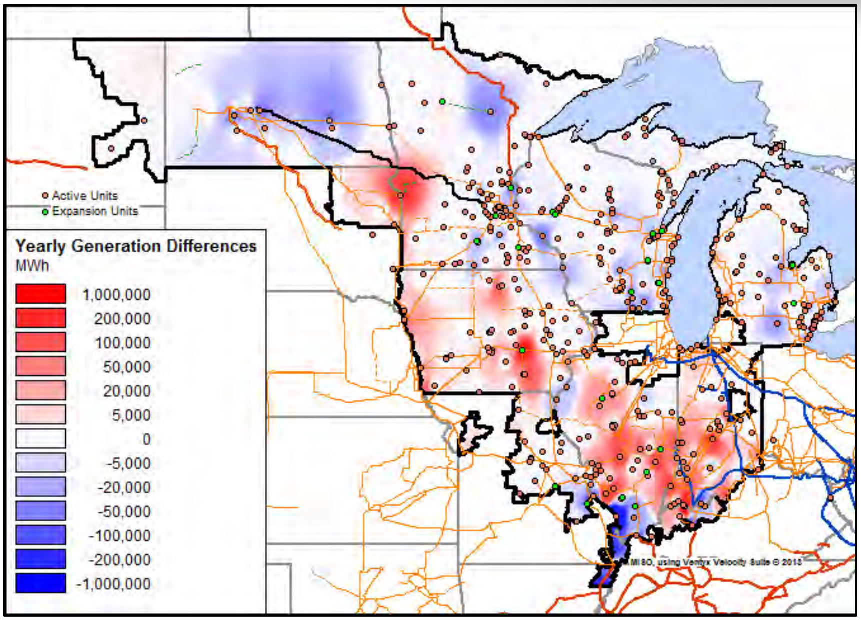


Figure 5.3-10: Unit level energy sources and sinks from MISO North/Central Regional Analysis

The annual maximum adjusted production cost savings potential available to MISO North/Central is variable between zones, ranging from $0 to $46 million in 2028 (Figure 5.3-11) with a total of $175 million available across the entire MISO North/Central system. Based on this analysis, greater economic potential appeared to be located in Zones 3, 4 and 6; therefore, potentially suggesting that greater transmission development could occur in those areas. Solution ideas were solicited for all the zones in the MISO North/Central footprint, however, as congestion issues were spread throughout the footprint.

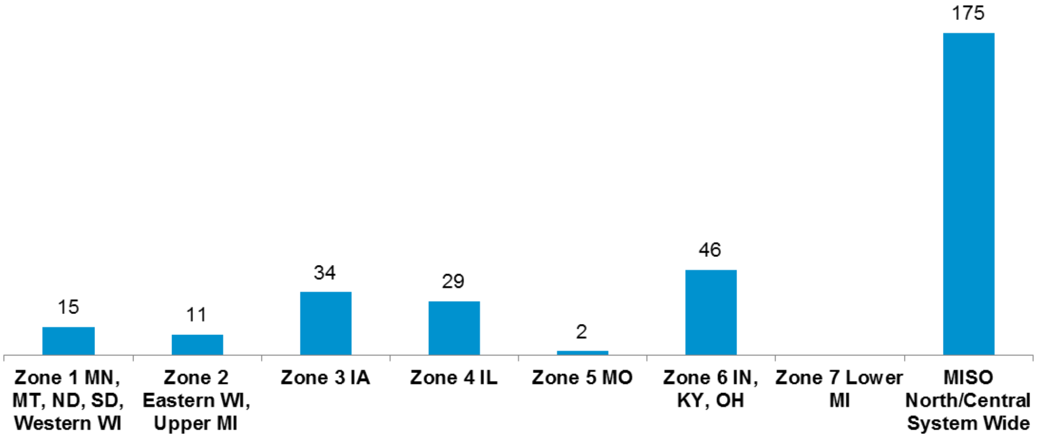


Figure 5.3-11: Maximum MISO North/Central adjusted production cost savings from Zonal/Regional Congestion Relief Analyses ($ millions in 2028)

North/Central Region Transmission Solution Development and Evaluation

After a 12-month study process, a total of 135 transmission solution ideas were proposed and studied. Of the 135 solution ideas evaluated, 27 were formulated as preliminary project candidates to be evaluated for further robustness testing. Of the 27 preliminary project candidates, seven were selected as best-fit project candidates with a weighted NPV benefit to cost ratio above 1.25. Of these seven selected best-fit project candidates, one project candidate met the Market Efficiency Project criteria based on Future weighted benefit-to-cost ratios:

- Pleasant Prairie – Pleasant Prairie Tap 345 kV

A total of 135 transmission solution ideas were submitted and studied to address specific congested flowgates, provide energy transfer paths, or to unlock cheaper resources by connecting import-limited areas to export-limited areas (Figure 5.3-12).

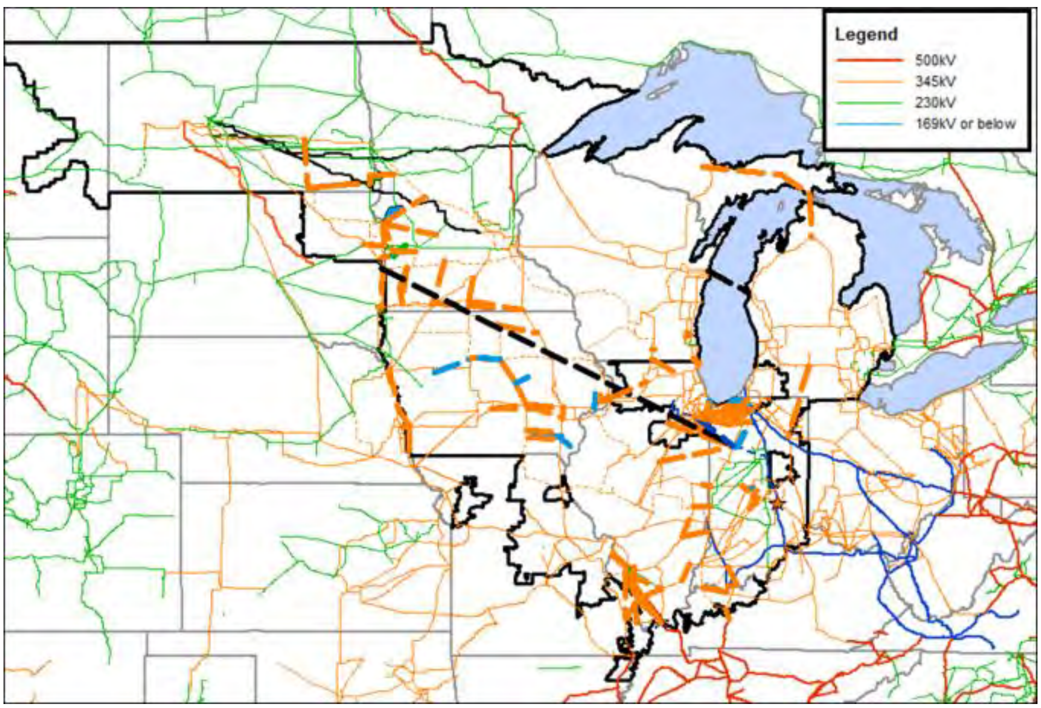


Figure 5.3-12: MISO North/Central Transmission Ideas analyzed to address identified market congestion issues

The 135 solution ideas were refined based on the guiding principles with the goal of identifying and formulating the best-fit project candidates. Solution ideas with an estimated one-year weighted B/C ratio or greater than 0.9 based on the MISO North/Central APC saving, along with other refined solution ideas will be considered as preliminary project candidates. The 27 preliminary projects underwent robustness testing in the holistic transmission solution evaluation (Table 5.3-4). Those preliminary project candidates in Table 5.3-4 that have B/C ratios lower than 0.9 are the result of the MISO independent cost estimates and will continued be considered for further evaluation in the holistic transmission solution evaluation.

Area	ID	Project Candidate Description	Issues Addressed	MISO Independent Cost Estimate ($M-2013)	MISO North/Central Weighted APC Savings ($M-2028)	Weighted B/C Ratio (2028)
DK/MN	PC-1	Hankinson – Wahpeton 230 kV upgrade, Morris - Ortonville upgrade	J	22.36	9.76	2.44
	PC-2	New 345/230/115 station near Canby, connect to new taps on Big Stone - White 345 kV, Watertown - Granite Falls 230kV	J	37.07	6.19	0.93
IA	PC-3	Rock Creek – Sub 17 161 kV	AA	10.47	4.41	2.36
	PC-4	New Denmark – Denmark 161 kV, Quad Cities – Rock Creek 345 kV	AA, F	47.62	9.97	1.17
	PC-5	Rebuild Winnebago – Blue Earth 161 kV	F, O	4.60	4.07	5.72
WI/MI and Northern IL/IN	PC-6	Pleasant Prairie – Pleasant Prairie Tap 345 kV	I	34.31	11.32	1.85
	PC-7	Zion – Pleasant Prairie 345 kV	I	79.37	16.29	0.98
	PC-8	University Park – Olive 345 kV compensation	R, W	12.30	10.54	4.80
	PC-9	Northern IN upgrades	R, W	19.23	9.00	2.62
	PC-10	New Russell – Russell 345 kV	S	40.01	7.40	0.88
	PC-17	Kankakee – Green Acres 345 kV	R	63.21	13.60	1.20
	PC-23	Miles Road – Russell 138kV	S	29.96	5.23	0.98
Southern Illinois and Indiana	PC-11	Rockport – Coleman 345 kV	B, E, M	76.82	29.38	2.14
	PC-12	Norris City – Albion 345 kV	E	67.92	16.09	1.13
	PC-13	Prairie State – New Prairie State 345 kV, Sparta - Tilden 138 kV upgrade, additional Baldwin 345/138 kV transformer, Arch Tap - Steeleville 138kV upgrade	E, H, G	48.58	22.79	2.63
	PC-14	Prairie State – New Prairie State 345 kV, West Frankfort – East West Frankfort 345 kV, Albion – Norris City 345 kV, Sparta - Tilden 138 kV upgrade, additional Baldwin 345/138 kV transformer, Arch Tap - Steeleville 138kV upgrade	E, H, G	139.93	32.54	1.30
	PC-15	Sparta - Tilden 138 kV upgrade, additional Baldwin 345/138 kV transformer	H, G	15.29	9.35	3.42
	PC-16	Joppa 345/161 kV transformer	M	13.65	2.35	0.93
	PC-18	Baldwin – Grand Tower 345 kV	E, H, G	122.89	28.89	1.12
	PC-20	Prairie State – East West Frankfort 345 kV, Albion – Norris City 345 kV	B, E, H, G	199.05	33.63	0.95
	PC-21	St Francois – Grand Tower 345 kV	E, H, G	147.67	28.82	1.05
	PC-22	Prairie State - Cahokia 230 kV, Sparta - Tilden 138 kV upgrade, Arch Tap - Steeleville 138kV upgrade	E, H, G	19.72	23.93	6.79
	PC-19	Duff to Coleman 345 kV	B, M	103.47	21.07	1.01
	PC-24	Rockport – Coleman 345 kV, additional Newtonville 161/138kV transformer	B, E, M	81.32	30.14	2.08
	PC-25	Newtonville 161/138kV Transformer	B	4.50	8.15	10.15
	PC-26	Newtonville 161/138 Transformer, Newtonville – Coleman 161kV	B	15.23	13.62	2.75
	PC-27	Sparta - Tilden 138 kV upgrade, Arch Tap - Steeleville 138kV upgrade additional Baldwin 345/138 kV transformer	H, G	19.39	8.51	2.46

Table 5.3-4: MISO North/Central preliminary project candidates

Stakeholder feedback was solicited and incorporated as appropriate and after the preliminary project candidates were formed, a noteworthy modeling change was included regarding the Coleman substation, leading to a significant reduction in benefits for PC-11 and PC-24. After multi-year simulations were performed for each of the preliminary project candidates, seven of the 27 were selected as best-fit project candidates. All seven best-fit project candidates had a weighted NPV benefit-to-cost ratio greater than 1.25. Of the seven best-fit project candidates, one met both the MEP voltage and cost criteria (Table 5.3-5).

ID	Project Candidate Description	Cost Estimate ($M - 2013)	B/C ratio (BAU)	B/C ratio (ENV)	B/C ratio (GS)	B/C ratio (LG)	B/C ratio (RE)	Weighted B/C ratio
PC-6	Pleasant Prairie – Pleasant Prairie Tap 345 kV	34.31	1.83	1.10	1.70	1.09	1.68	1.54

Table 5.3-5: MISO North/Central cost-sharable best-fit project candidates

As part of the evaluation of a potential Market Efficiency Project, it is important to ensure the project's economic justification against a reasonable range of future generation additions and retirements before recommendation as a MEP. Therefore, further testing was performed to evaluate the robustness of PC-6 with a particular focus on environmental compliance and its effect on the future operating status of existing coal plants.

Because of the near-term future impact of this category of compliance, MISO rationalized it was wise to consider different combinations of coal plant retirement assumptions that could occur in Wisconsin, where this project candidate would be located. Because the Business as Usual (BAU), Generation Shift (GS), Limited Growth (LG), and Robust Economy (RE) futures all assume the same set of future retired coal units, a sensitivity analysis was performed that considered a different set of coal retirements in the Wisconsin area. This different set was created based on the extended list of retirements contained in the Environmental (ENV) future, while still maintaining the original 12 GW amount of coal plant retirements assumed for BAU, GS, LG and RE. Thus, after shifting around 0.95 GW of coal retirements in Wisconsin, benefits for Pleasant Prairie – Pleasant Prairie Tap 345 kV were found to be significantly lower (Table 5.3-6). The results can be seen below in Table 5.3-6. (Benefits in the ENV future did not change because the different set of retired units was originally assumed in ENV.)

ID	Project Candidate Description	Cost Estimate ($M - 2013)	B/C ratio (BAU)	B/C ratio (ENV)	B/C ratio (GS)	B/C ratio (LG)	B/C ratio (RE)	Weighted B/C ratio
PC-6	Pleasant Prairie – Pleasant Prairie Tap 345 kV	34.31	0.83	1.10	0.76	0.51	0.55	0.78

Table 5.3-6: Environmental Compliance Sensitivity Results for PC-6

Given the results of this sensitivity analysis, PC-6 was not found to be robust when considering a different set of coal unit retirement assumptions. Therefore, it was not recommended as a Market Efficiency Project to the MISO Board of Directors in the MTEP14 planning cycle. As the impact of environmental compliance on the fleet of existing coal plants becomes clearer in future MTEP cycles, PC-6 will be able to be reconsidered with greater clarity.

The other six best-fit project candidates (Table 5.3-7) did not meet at least one MEP criterion and were not considered as potential Market Efficiency Projects in this study. However these project candidates may still be considered as Market Participant Funded projects or "Other" projects.

ID	Project Candidate Description	Cost Estimate ($M - 2013)	B/C ratio (BAU)	B/C ratio (ENV)	B/C ratio (GS)	B/C ratio (LG)	B/C ratio (RE)	Weighted B/C ratio
PC-1	Hankinson – Wahpeton 230 kV upgrade, Morris - Ortonville upgrade	22.36	3.19	6.87	0.28	-0.03	1.98	2.71
PC-3	Rock Creek – Sub 17 161 kV	10.47	1.87	1.55	0.82	0.80	2.08	1.50
PC-5	Rebuild Winnebago – Blue Earth 161 kV	4.60	4.05	8.10	0.81	0.48	6.43	3.88
PC-9	Northern IN upgrades	19.23	1.99	4.07	1.10	0.61	2.94	2.06
PC-22	Prairie State - Cahokia 230 kV, Sparta - Tilden 138 kV upgrade, Arch Tap - Steeleville 138kV upgrade	19.72	7.17	3.53	6.81	6.02	5.12	6.10
PC-25	Newtonville 161/138kV Transformer	4.50	2.03	1.61	2.66	1.69	-0.39	1.75

Table 5.3-7: MISO North/Central non cost-sharable best-fit project candidates

Book 2 - Resource Adequacy

Chapter 6 Resource Adequacy

MISO and its stakeholders have developed a set of Resource Adequacy guiding principles. The desired outcomes of the guiding principles is for MISO to support stakeholders in achieving Resource Adequacy at just and reasonable rates; to have confidence that Resource Adequacy will be achieved in all time horizons; have confidence in MISO's Resource Adequacy Assessments and for MISO to provide sufficient transparency and market mechanisms to allow for mitigation of potential shortfalls. The five Resource Adequacy guiding principles include:

- Resource Adequacy processes must ensure confidence in Resource Adequacy outcomes in all time horizons
- 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
- 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
- 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
- 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.

6.1 Planning Reserve Margin

The MISO Installed Capacity PRM (PRM_{ICAP}) for the 2014-2015 planning year, spanning from June 1, 2014, through May 31, 2015, is 14.8 percent, increasing 0.6 percent from the 14.2 percent PRM set in the 2013-2014 planning year (Figure 6.1-1). The 2014-2015 planning year was the first year that MISO South companies were incorporated in the PRM study.

The MISO PRM for the 2014-2015 Planning Year is 14.8 percent, increasing 0.6 percentage points from 14.2 percent

The PRM_{ICAP} is established with resources at their installed capacity rating at the time of the system-wide MISO coincident peak load. The 0.6 percent PRM_{ICAP} increase was the net effect of several modeling improvements that include an adjustment methodology change to align with the MISO tariff; changes to the modeling of external regions; and changes to load forecast uncertainty and alignment with the zonal construct.

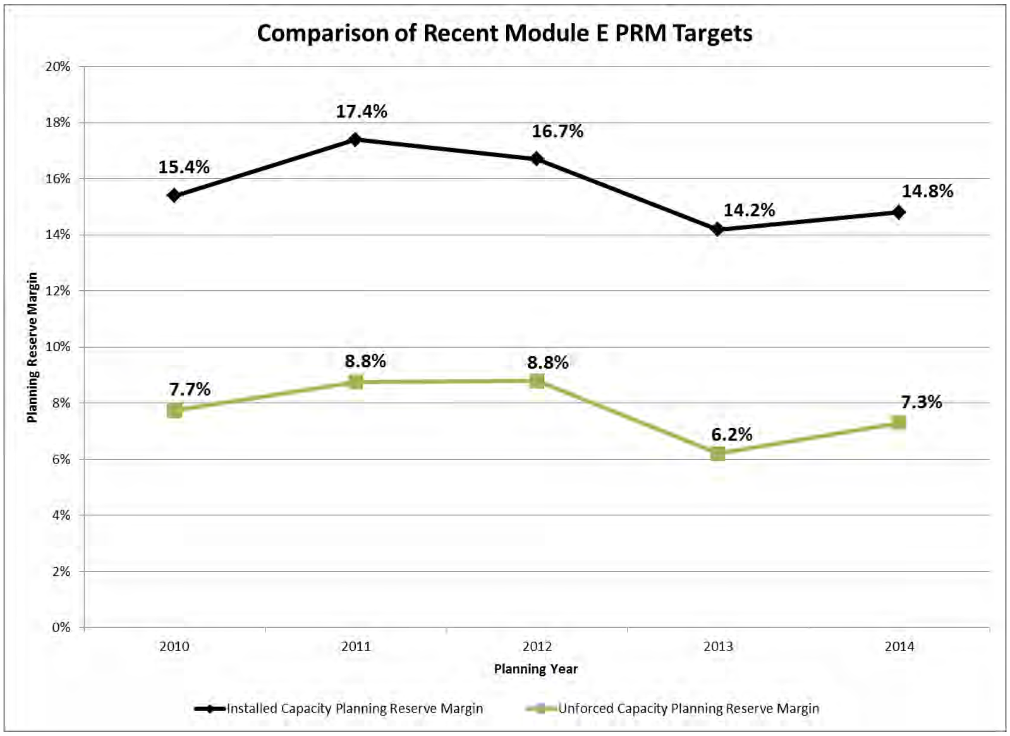
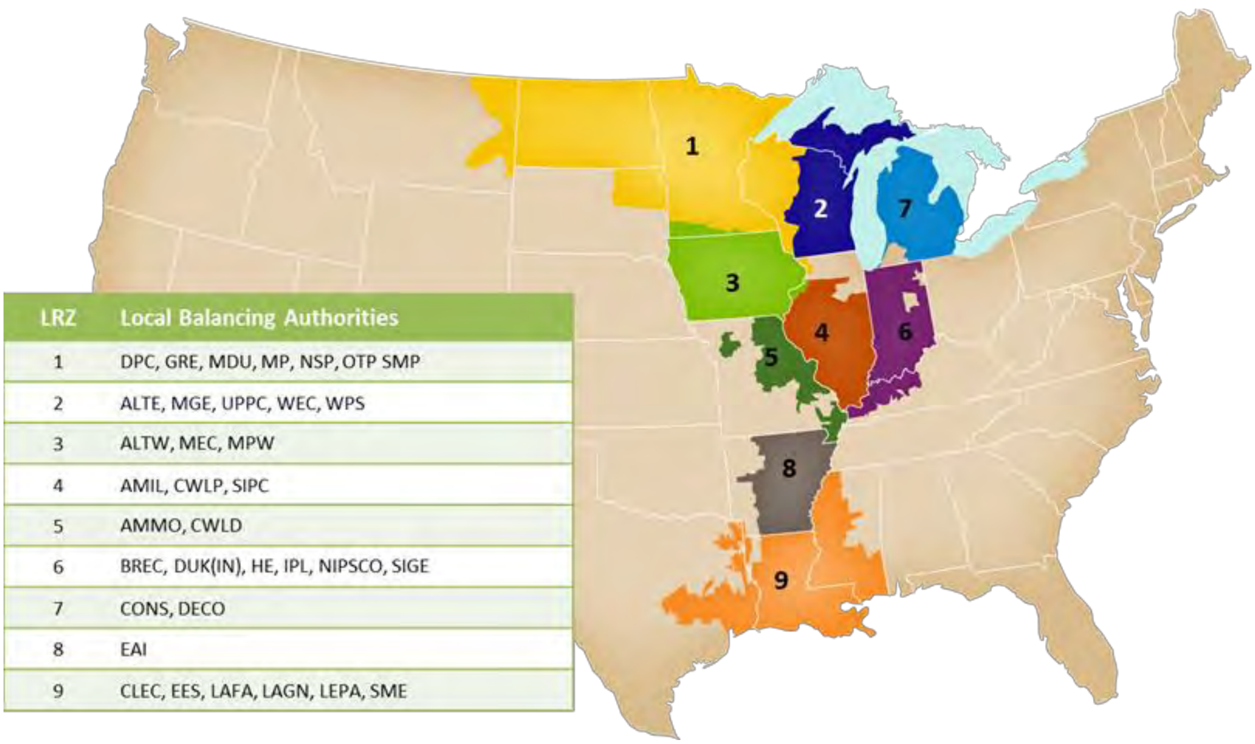


Figure 6.1-1: Comparison of recent Module E1 PRM targets

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.



LRZ	Local Balancing Authorities
1	DPC, GRE, MDU, MP, NSP, OTP SMP
2	ALTE, MGE, 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, SME

Figure 6.1-2: Local resource zones (LRZ)

2014-2015 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 6.2 percent to 7.3 percent due to the modeling enhancements described at the end of this chapter. 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). 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
MISO PRM_{UCAP}	7.3%	7.3%	7.3%	7.3%	7.3%	7.3%	7.3%	7.3%	7.3%
LRR UCAP per unit of LRZ Peak Demand	1.107	1.153	1.147	1.182	1.198	1.116	1.152	1.293	1.124
Capacity Import Limit (CIL) (MW)	4,347	3,083	1,591	3,025	5,273	4,834	3,884	1,602	3,585
Capacity Export Limit (CEL) (MW)	286	1,924	1,875	1,961	1,350	2,246	4,517	3,080	3,616

Table 6.1-1: Deliverables to the 2014-2015 Planning Resource Auction (PRA)

Zone	Tier	14-15 Limit (MW)[29]	Monitored Element	Contingent Element	Figure 6.1-2 Map ID	Initial Limit (MW)[30]	Generation Redispatch Details	
							MWs	Area
1	1	4,347	Lime Creek – 161 kV	Barton – Adams 161 kV	1	4,292	68	9 generators in ALTW, WPS and ALTE
2	1	3,083	Turkey River – Stoneman 161kV	Genoa – Seneca 161 kV	2	2,859	162	10 generators in ALTW, XEL and DPC
3	1	1,591	Palmyra 345/161 kV transformer	Hills – Sub T – Louisa 345 kV	3	0	366	10 generators in AMMO, GRE and ALTE
4	1	3,025	Tazewell 345/138 kV transformer 1	Tazewell 345/138 kV transformer 2	4	3,025	Not applicable	
5	1	5,273	Hot Springs EHV – Arklahoma 115 kV	Carpenter – Arklahoma 115 kV	5	4,712	539	9 generators in EAI
6	1	4,834	Wheatland – Petersburg 345 kV	Jefferson – Rockport 765 kV	6	4,834	Not applicable	
7	2	3,884	Zion Station – Zion Energy Center 345 kV	Pleasant Prairie – Zion 345 kV	7	2,587	318	10 generators in NIPS, WEC and AMIL

[29] The 14-15 Limit represents the limit after redispatch has been considered.
[30] The Initial Limit represents the limit before considering redispatch.

Zone	Tier	14-15 Limit (MW)[29]	Monitored Element	Contingent Element	Figure 6.1-2 Map ID	Initial Limit (MW)[30]	Generation Redispatch Details	
							MWs	Area
8	1	1,602	Vienna – Mt Olive 115 kV	Mt Olive – Eldorado 500 kV	8	578	678	10 generators in CLECO, AMMO and EES
9	1	3,585	Walnut Grove – Swartz 115 kV	Perryville – Baxter Wilson 500 kV	8	3,585	Not applicable	

Table 6.1-2: 2014-2015 Planning Year Capacity Import Limits

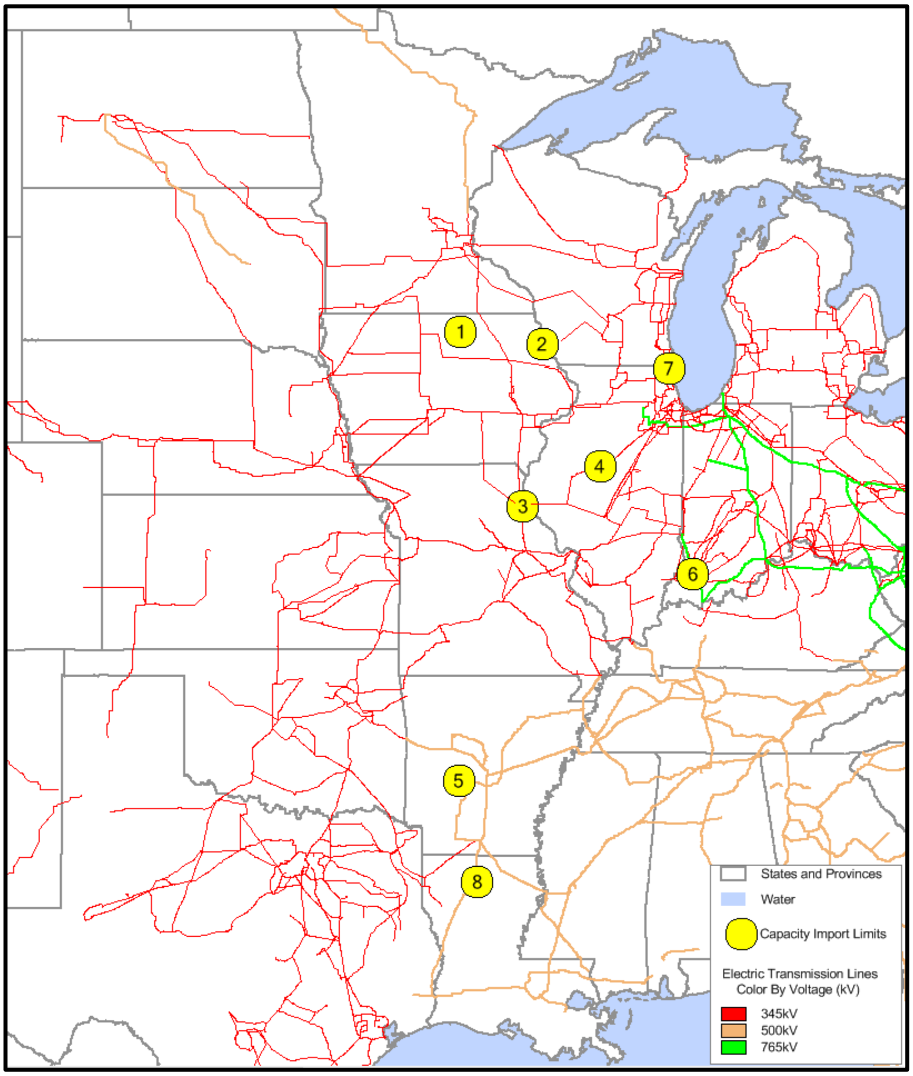


Figure 6.1-3: 2014-2015 Capacity Import Limit Map

Zone	14-15 Limit (MW)	Monitored Element	Contingent Element	Figure 6.1-3 Map ID	Initial Limit (MW)	Generation Redispatch Details	
						MWs	Area
1	286	Lakefield - Dickinson 161 kV	Webster 345 kV Station	1	48	515	10 generators in GRE, NSP and DPC
2	1,924	Zion Station - Zion Energy Center 345 kV	Pleasant Prairie - Zion 345 kV	2	1,371	318	10 generators in NIPS, WEC and AMIL
3	1,875	Oak Grove - Galesburg 161 kV	Nelson - Electric Junction 345 kV	3	1,875	Not Applicable	
4	1,961	Pontiac - Loretto 345 kV	345-L8014_T_-S[31]	4	1,961	Not Applicable	
5	1,350	Palmyra 345/161 kV Transformer	Hills - Sub T - Louisa 345 kV	5	793	238	10 generators in AMMO and CWLD
6	2,246	Amo - Edwardsport 345 kV	Gibson - Wheatland 345 kV	6	2,246	Not Applicable	
7	4,517	Benton Harbor 345/138 kV Transformer	Benton Harbor - Cook 345 kV	7	4,517	Not Applicable	
8	3,080	Russellville East - Russellville North 161 kV	Arkansas Nuclear one - Ft. Smith 500 kV	8	3018	674	8 generators in EAI
9	3,616	Winnfield 230/115 kV Transformer	Montgomery - Clarence 230 kV	9	2,051	832	10 generators in EES, SME and CLECO

Table 6.1-3: 2014-2015 Planning Year Capacity Export Limits

[31] 345-L8014_T_-S
Close 272260 PONTIAC; B 138 272261 PONTIAC; R 138Z1
Open 270717 DRESDEN; R 345 270853 PONTIAC; R 345 1
Open 270853 PONTIAC; R 345 275210 PONTIAC;2M 138 1
Open 272261 PONTIAC; R 138 275210 PONTIAC;2M 138 1
Open 275210 PONTIAC; 2M 138 275310 PONTIAC; 2C34.5 1

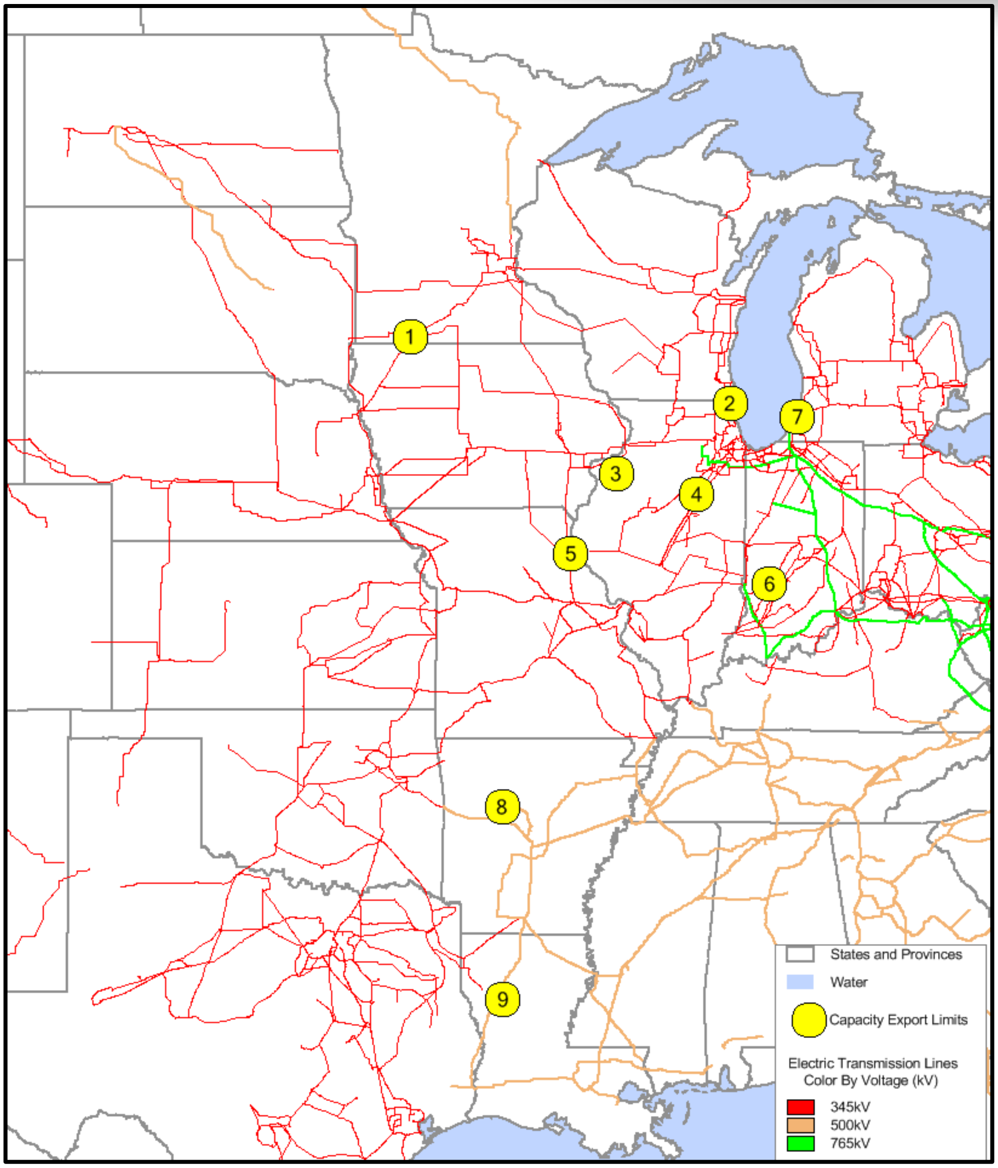
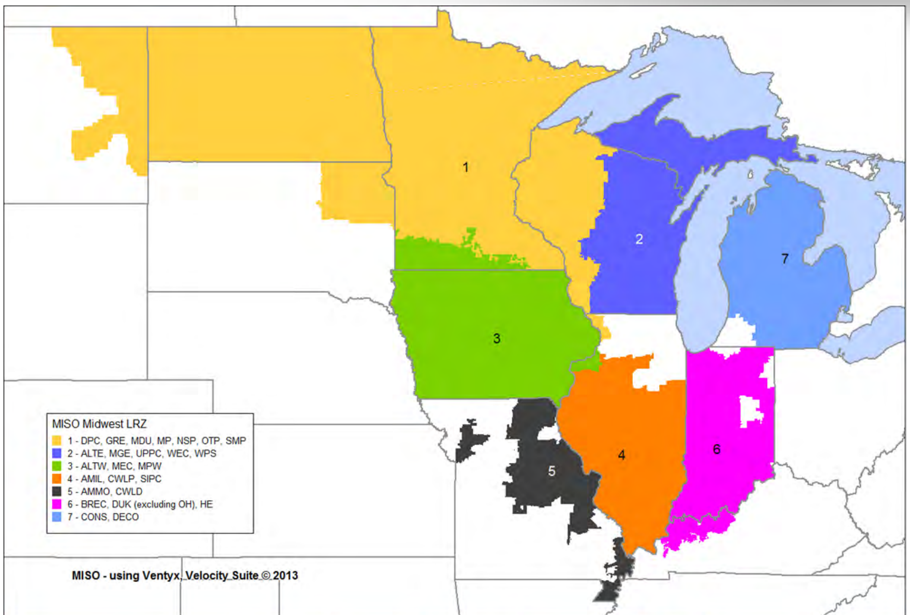


Figure 6.1-4: 2014-2015 Capacity Export Limit Map

A wind capacity credit of 14.1 percent was established for the 2014-2015 planning year by determining the Effective Load Carrying Capability (ELCC) of wind resources. The wind capacity credit increased 0.8 percent from the wind capacity credit of 13.3 percent established in the 2013-2014 Planning Year (Table 6.1-5). For more information, refer to the complete 2014 Wind Capacity Credit Report[32].

[32] Or: https://www.misoenergy.org/Library/Repository/Study/LOLE/2014%20Wind%20Capacity%20Report.pdf



Metric	MISO	Zone 1	Zone 2	Zone 3	Zone 4 and Zone 5	Zone 6	Zone 7
Registered Max (MW)	12,239	3,941	627	5,932	514	282	943
UCAP (MW)	1,723	622	76	811	48	22	145
ELCC %	14.1%	15.8%	12.1%	13.7%	9.3%	7.8%	15.4%
Wind CPnode Count	176	67	10	72	7	4	16

Table 6.1-5: MISO Local Resource Zones and distribution of wind capacity

Read the [Planning Year 2104 LOLE][33] study for more details.

2014-2015 Planning Resource Auction Summary

MISO completed its Annual PRA for planning year 2014-2015 based on Market Participant Offers submitted between March 27, 2014, and March 31, 2014. Final results were posted on April 14, 2014. This was the second full-year PRA under Module E-1 of MISO's Tariff.

The auction produced three clearing prices: LRZ 1 cleared at \$3.29 per MW-Day as its Zonal CEL bound; LRZs 2-7 cleared at \$16.75 per MW-Day; and LRZs 8-9 cleared at \$16.44 per MW-Day as constraints related to intra-RTO dispatch ranges bound between MISO South and MISO North/Central Regions, which was due to a 1,000 MW Contract Path Limit.

A total of 136,912 MW of Planning Resources were cleared or submitted as a fixed Resource Adequacy Plan to meet MISO's Resource Adequacy requirements

[33] Or: https://www.misoenergy.org/Library/Repository/Study/LOLE/2014%20LOLE%20Study%20Report.pdf

A total of 136,912 MW of Planning Resources were cleared or submitted as part of a fixed Resource Adequacy Plan to meet MISO's Resource adequacy requirements. This includes 124,556 MW of generation resources, 3,743 MW of behind-the-meter generation (BTMG), 5,457 MW of demand response (DR) and 3,156 MW of external resources (ER). The MISO Planning Reserve Margin Requirement (PRMR) increased by 2,475 MW to 136,912 MW from the 2013-2014 PRA due to an increase in Coincident Peak Demand Forecast and an increase in the PRM_{UCAP} from 6.2 percent to 7.3 percent. Also, LRZ 8 had a higher PRMR as the LRZ's Local Clearing Requirement was greater than its PRMR. This was due to several factors including the import limit of LRZ 8, size of the zone; the load forecast differences between what was used in the LOLE study and what came in prior to the auction, as well as the overall load shape for LRZ 8.

2014-2015 Planning Year Modeling Enhancements

The LOLE study underwent significant changes for the 2014-2015 planning year. The LOLE study incorporated MISO South beginning in the 2014-2015 study, which added a significant amount of generation and load to the MISO footprint as well as two additional LRZs. The 2014-2015 planning year study also included a few major modeling enhancements: adjustment methodology change to align with the MISO tariff; changes to the modeling of external regions; changes to load forecast uncertainty and alignment with the zonal construct; and an improved transfer analysis methodology that is used to determine the CIL and CEL limits. These improvements became necessary in order to mature and stabilize reliability requirements. The Long-Term Resource Assessment (Section 6.2) details some of these uncertainties.

Adjustment Methodology

For the 2014-2015 PRM study, a slight change was made in how capacity is adjusted in the LOLE model to reach an LOLE of 0.1 days per year. Previously, a positive or negative generator was added in the model with a zero percent forced outage rate and adjusted appropriately to reach 0.1 days per year depending on the capacity in that particular area. For this year's study, the capacity adjustment was changed to align with the tariff. For areas or zones that need capacity to meet 0.1 days per year, 160 MW combustion turbines with a class average EFORd were added in the model until 0.1 days per year LOLE was reached. For areas or zones that had excess capacity, units with the smallest unforced capacity were removed to reach 0.1 days per year LOLE.

External Support

In previous years, the first-tier external areas were modeled at their PRM targets. For the 2014-2015 planning year, first-tier external areas are not only modeled at their PRM targets but that target is reduced even further by reducing the demand-side management programs each of those areas has from its PRM target. This was done so that MISO was not relying on external areas to utilize its demand-side management programs to reduce MISO's own PRM. Also, the maximum Net Scheduled Interchange (NSI) from the previous year has been historically used to set the tie limits between MISO and the external areas. For the 2014-2015 planning year, the tie limits are

This was done so that MISO was not relying on external areas to utilize its demand-side management programs to reduce its own PRM requirements from 14.2 percent

set at the maximum NSI of the previous year's summer peak hours. This change was made to more accurately reflect the support MISO could get in a system peak situation.

Sales to PJM

Another modeling enhancement in the 2014-2015 PRM study was derating the MISO capacity committed in PJM's market. These units' installed capacity values were derated to account for the megawatts being sold to PJM, which totalled 2,721 MW. MISO did not want to account for megawatts that were potentially unavailable to MISO in the calculation of a planning reserve margin.

Load Forecast Uncertainty

For the 2014-2015 planning year, the load forecast uncertainty (LFU) methodology did not change from the 2013-2014 planning year. However, the major data source used in calculating the LFU changed. Previously, the majority of data was pulled from Energy Information Administration (EIA) form 861 at an annual level whereas for the 2014-2015 planning year the majority of data was pulled from Ventyx Energy Velocity at an hourly level. Also, MISO South data was collected for the 2014-2015 planning year LFU calculations, which was not needed in previous years.

Local Resource Zone LFU

For the 2014-2015 planning year analysis, an enhancement was made in how the LFU is applied for the MISO system. In previous years, a MISO LFU was calculated to determine the MISO-wide PRM values and zonal LFU values were used to calculate the LRZ LRR values. This year MISO aligned the zonal construct with the MISO system PRM and modeled the nine individual LRZ LFU values as part of the MISO PRM analysis. Modeling the more granular zonal LFU values appropriately applies each LRZ's LFU to that LRZ's load, which was not previously captured by applying one MISO LFU value for each LRZ. This application of LFU more accurately reflects the uncertainty impacts of each LRZ's geographic area.

Transfer Analysis

The transfer analysis used to establish the CIL and CEL for the PRM study in the 2014-2015 planning year was enhanced over the prior year. The most significant improvements include considering all facilities under MISO functional control regardless of the voltage level as limiting and utilizing local MISO generation for transfers. Another important goal was to more thoroughly document study assumptions and procedures through BPM language and LOLE Working Group meeting materials.

To determine an LRZ's limits, a generation-to-generation transfer is modeled from a source subsystem to a sink subsystem. For import limits, the limit is being determined for the sink subsystem. MISO generation resources outside the LRZ under study are increased based on electrical proximity to the LRZ under study while decreasing the generation inside the LRZ proportionately. Generation in adjacent areas to the LRZ under study is utilized using this approach:

- Generation in the adjacent MISO Local Balancing Authority areas will be utilized
- If no constraint is identified, then capacity from adjacent areas and the Local Balancing Authority areas with ties to the adjacent areas is used

This tiered approach was added to avoid limits due to remote constraints. Other improvements to the transfer analysis include the following enhancements, which help more accurately represent the true capacity import and export limits of each LRZ.

- Additional unit exclusions based on machine parameters
- Transmission owner review of models and input files
- Redispatch options considered for mitigation
- Coordinating with operations and transmission owners regarding constraints when the constraint is unknown or redispatch does not exist. All of these enhancements help to more accurately represent the true capacity import and export limits of each LRZ.

An additional improvement included determining capacity import and export limits for 5- and 10-year-out models. These results are useful for planning and indicate what changes can be expected based on future changes to the transmission system.

MISO South Integration

The 2014-2015 planning year was the first year that MISO South companies were incorporated in the PRM study since they integrated into MISO in December 2013. In order to incorporate the MISO South companies into the PRM study, MISO requested data prior to the integration. Many of the MISO South companies submitted Generator Availability Data System (GADS) data, which is the source for much of the data used in the PRM Study. If a company did not submit this information, then vendor data and class average forced outage rates were used. A vendor database was also used to compile the load data for the MISO South companies. In addition, MISO conducted several training sessions on Resource Adequacy and Loss of Load Expectation at various locations in the South Region. These training sessions helped to familiarize the southern companies with MISO's PRM study process and how their data impacts the overall PRM.

The 2014-2015 planning year was the first year that MISO South companies were incorporated in the PRM study

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 Requirement (PRMR) to calculate a projected surplus or shortfall.

MISO forecasts the reserve margin could drop below the Planning Reserve Margin Requirement (PRMR) of 14.8 percent beginning in 2016

MISO forecasts the reserve margin could drop below the PRMR of 14.8 percent beginning in 2016, 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 would operate at a reliability level lower than the one-day-in-10 standard in 2016 and beyond. MISO anticipates the projected margin shortfall will change significantly as Load Serving Entities and State commissions solidify future capacity plans. The contributing factors driving the projected shortfall in the PRMR are:

MISO anticipates the projected margin shortfall will change significantly as Load Serving Entities and State commissions solidify future capacity plans

- Increased retirements and suspensions due to EPA regulations and market forces (i.e. low natural gas prices)
- Removal of low certainty resources that were identified in the Resource Adequacy survey
- Increased exports
- Not enough certainty of resources planned; 91 percent of the load in the MISO footprint is served by utilities with an obligation to serve customers reliably and at a reasonable cost. Resource Planning and investment in resources are part of state and locally jurisdictional integrated resource plans that only become certain upon the receipt of a Certificate of Public Convenience and Need (CPCN).
- Removal of non-firm imports. The MISO market monitor notes that MISO was double-counting non-firm imports because the planning reserve margin requirement already includes the use of non-firm imports.

In GW (ICAP)	PY 2015/16	PY 2016/17	PY 2017/18	PY 2018/19	PY 2019/20	PY 2020/21	PY 2021/22	PY 2022/23	PY 2023/24	PY 2024/25
(+) Existing Resources	143.9	141.2	141.4	141.5	141.4	141.4	141.2	141.2	141.2	141.2
(+) New Resources	1.2	1.6	3.0	3.5	3.6	3.6	3.6	3.6	3.6	3.6
(+) Demand Resources	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8
(+) Behind The Meter Generation	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3
(+) Imports	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2
(-) Exports	2.0	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1
(-) Low Certainty Resources	1.9	2.6	2.6	4.2	5.0	5.3	6.9	7.2	8.3	8.6
(-) Transfer Limited	3.7	2.1	1.4	0.9	0.5	0.1	0.0	0.0	0.0	0.0
Available Resources	150.6	147.3	149.4	149.0	148.6	148.6	147.0	146.7	145.6	145.3
Demand	128.6	130.1	131.2	132.4	133.5	134.5	135.5	136.5	137.4	138.4
PRMR	147.8	149.6	150.9	152.2	153.5	154.7	155.8	156.9	158.0	159.2
PRMR Shortfall/Surplus	2.8	-2.3	-1.5	-3.2	-4.9	-6.0	-8.9	-10.2	-12.4	-13.9
Reserve Margin Percent (%)	17.2%	13.2%	13.8%	12.5%	11.3%	10.5%	8.4%	7.5%	6.0%	4.9%

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

Falling below the PRMR means that MISO would operate at a reliability level below the one-day-in 10 Loss of Load Expectation (LOLE) standard. By Planning Year 2016-17, MISO projects that its region will operate at an approximate two-days-in-10 reliability level (Figure 6.2-1) unless and until Load Serving Entities and State commissions solidify future capacity plans.

By Planning Year 2016-17, MISO projects that its region will operate at an approximate two-days-in-10 reliability level.

As MISO starts to operate at or near the Planning Reserve Margin, it's more likely that MISO will begin calling Emergency Operating Procedures more often than in the past to access emergency-only resources, such as Load Modifying Resources (LMR) and Behind the Meter Generation (BTMG).

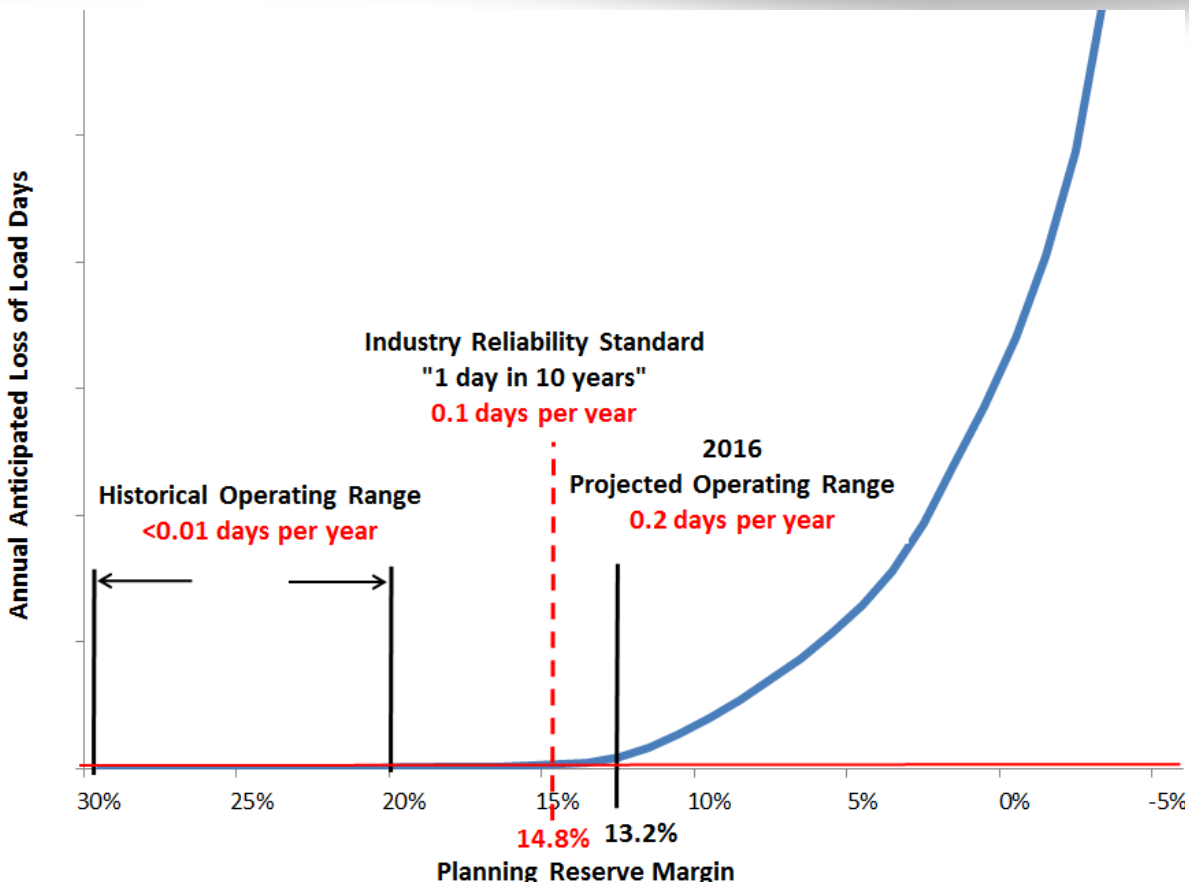


Figure 6.2-1: LOLE increase in relationship to the Planning Reserve Margin

Assumptions

Beginning in the 2014-15 planning year, MISO took over the reporting function of the LTRA responsibilities for the MISO South Region entities - including Entergy Arkansas Inc., Entergy Texas Inc., Entergy Mississippi Inc., Entergy Louisiana LLC, Entergy Gulf States Louisiana LLC, Entergy New Orleans Inc., Cleco Power LLC, Lafayette Utilities System, Louisiana Energy & Power Authority, South Mississippi Electric Power Authority and Louisiana Generating LLC. All information presented in this section includes the entire MISO system unless otherwise noted.

At the end of 2013 MISO and 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 survey in June, 2014, and it was instrumental in the development of the Long-Term Resource Assessment and the Resource Adequacy outlook for the MISO region.

In addition to the Resource Adequacy survey, MISO developed strategies to mitigate potential 2016 shortfalls by assessing key components of the projected reserve margin, including, but not limited to the:

- Potential for growth in Demand Side Management (DSM)
- Additional support anticipated from the MISO South Region

- Potential for transmission upgrades to mitigate current generation deliverability constraints
- Potential for transmission upgrades to convert current energy-only resources to network resources

Of these four key components MISO has either implemented or has plans to implement the strategy for three of the components. For the MISO North and Central region there was no significant growth in DSM from last year and as such did not impact the projected shortfall.

This assessment assumes a maximum of 1,000 MW of MISO South Region capacity is available to the MISO North/Central Region. This assumption is consistent with the approach applied to the 2014/2015 Planning Resource Auction. MISO is working with stakeholders through the Supply Adequacy Working Group (SAWG) to assess whether 1,000 MW is an appropriate limit for the 2015/2016 Planning Resource Auction. To the extent PRA revisions are implemented, MISO would utilize the corresponding limit in its future resource assessments.

A study of the unused capacity to assess the potential for resources that currently don't qualify as planning resources was completed in July 2014 (see Section 6.4). Initial analysis found there are 0.8 GW of transmission-limited resources based on generation deliverability test results and 3.0 GW of energy-only resources with no firm point-to-point transmission.

Demand Growth

In 2015, MISO anticipates that the MISO Region's coincident demand is projected to be 128,570 MW, which is a 50/50 weather normalized load forecast.

Load-Serving Entities also submit monthly peak demand forecasts for two years and an additional eight years seasonal peak demand forecasts non-coincident to MISO's peak. 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 0.85 percent for the period from 2014 to 2023.

In 2015, MISO anticipates that the MISO Region's coincident demand is projected to be 128,570 MW, which is a 50/50 weather normalized load forecast

Resources

In 2015, MISO expects a total of 143,877 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 143,877 MW by accounting for summer on-peak generator performance, transmission limitations and energy-only capacity (Existing-Other Capacity Resources). MISO only relies on 143,877 MW towards its PRMR to meet a LOLE of one day in 10 years.

In 2015, MISO expects a total of 143,877 MW of Anticipated Capacity Resources to be available on-peak

BTMG, Interruptible Load (IL), Direct Control Load Management (DCLM) and Energy Efficiency Resources (ERR) 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 4,300 MW of BTMG and 5,750 MW of LMR DR that was qualified in the 2014 Planning Resource Auction to be available throughout the assessment period.

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

Through the Generator Interconnection Queue (GIQ) process, MISO anticipates 3,579 MW of future firm capacity additions and uprates to be in-service and expected on-peak during the assessment period. This is based on a snapshot of the GIQ as of June 2014 and is the aggregation of active projects with a signed Interconnection Agreement. Below is a fuel type break down by year for the MISO region (Figure 6.2-2).

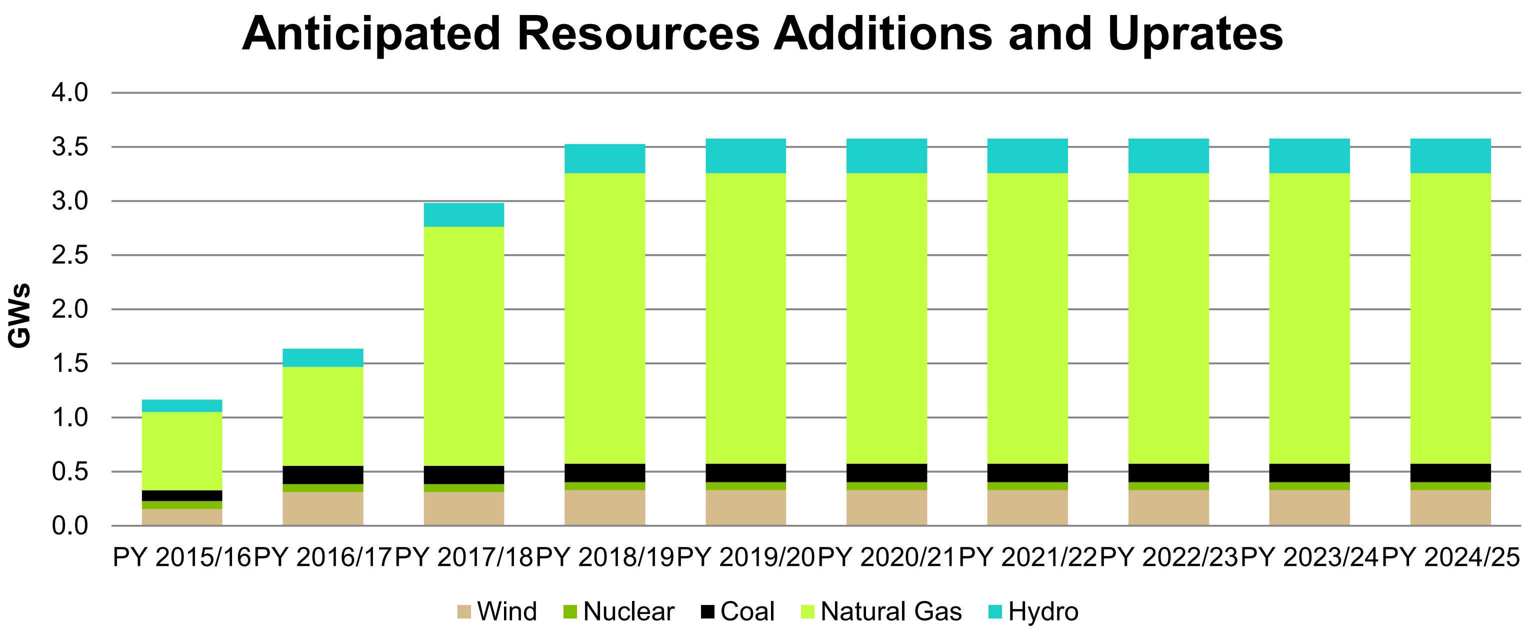


Figure 6.2-2: Anticipated resource additions and uprates (cumulative)

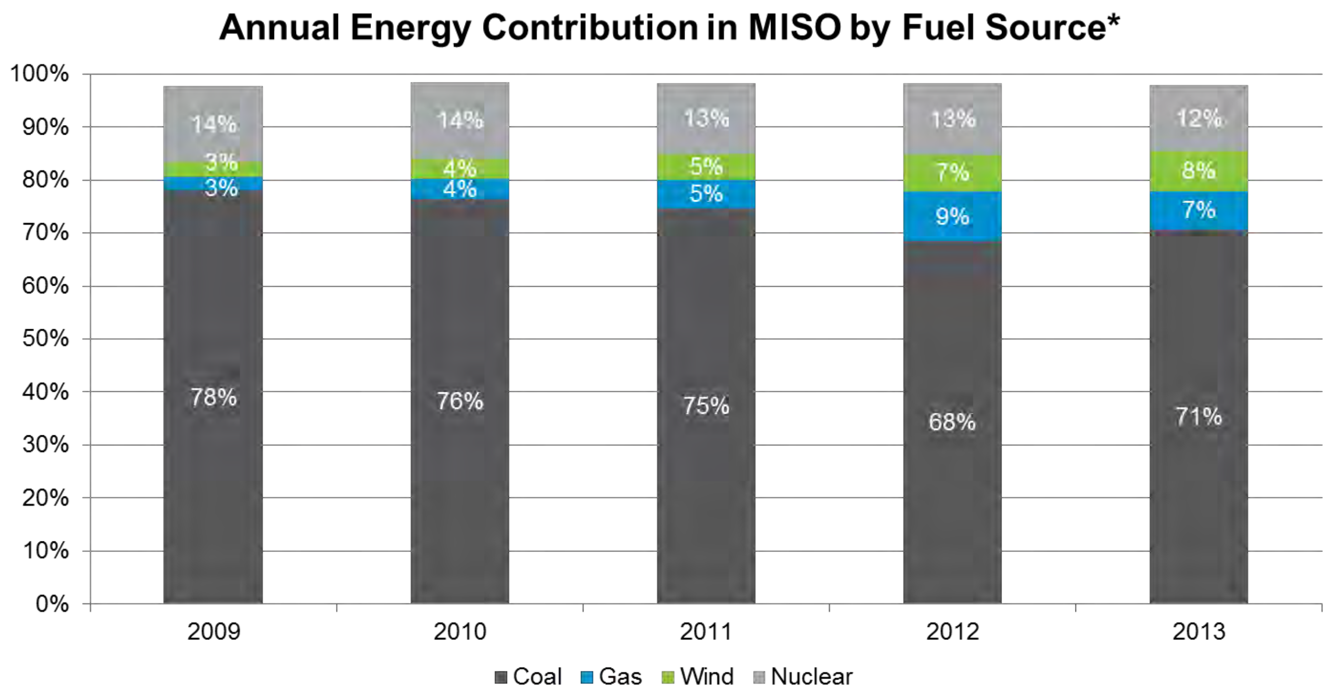
Imports and Exports

MISO assumes a forecast of 3,157 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 2014. It's assumed that the firm imports continue at this level for the assessment period. MISO assumes a forecast of 2,044 MW of firm capacity exports in year 2015 to PJM based on PJM Base Residual Auction cleared results. Exports are projected to increase to 4,135 MW in 2016 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 the differences in how the reserve margin percent is calculated. MISOs Resource Adequacy construct counts DR as a resource while the NERC calculation has the DR calculated on the demand side. While the percent will be slightly different, the absolute GW shortfall/surplus is the same between the two.

6.3 Gas-Electric Coordination

Dramatic changes in the natural gas industry over the past few years have produced abundant natural gas supply, and in turn, competitive natural gas prices. These developments, in combination with federal environmental regulations and state energy policies, are driving a transition of both the makeup and the operation of the generation fleet in MISO. Dispatch trends over the past several years illustrate these changes (Figure 6.3-1).



Based on 5-minute unit level generation dispatch target; for MISO North and Central Regions

Figure 6.3-1: Annual energy contribution in MISO by fuel source

To better understand and prepare for increasing reliance upon natural gas, MISO initiated a number of gas-electric coordination efforts, starting with a series of investigations into the ability of natural gas infrastructure to serve growing demand.

These studies, executed by EnVision Energy between Oct. 2011 and Dec. 2013, were static, pipeline-by-pipeline looks at historical natural gas flows and capacity availability in the MISO North and Central Regions. The results of the initial analyses (Phase I[34], published in Feb. 2012 and Phase II[35], released in July 2012) spurred an on-going conversation with MISO stakeholders and the natural gas industry,

[34] Available at https://www.misoenergy.org/Library/Repository/Communication%20Material/Key%20Presentations%20and%20Whitepapers/Natural%20Gas-Electric%20Infrastructure%20Interdependency%20Analysis_022212_Final%20Public.pdf.

[35] Available at https://www.misoenergy.org/Library/Repository/Communication%20Material/Key%20Presentations%20and%20Whitepapers/Embedded%20Gas%20Units%20Infrastucture%20Analysis.pdf.

beginning with a May 2012 workshop[36] on gas-electric interdependency, and followed by a series of zonal MISO-sponsored meetings[37] on the potential challenges of gas-electric coordination. The zonal meetings highlighted the sub-regional nature of the gas-electric discussion, encompassing a wide range of issues and levels of concern. MISO also met with representatives of individual gas pipeline companies with infrastructure in the MISO footprint. These conversations built a foundation for future discussions with the natural gas industry.

While MISO held preliminary meetings to discuss gas-electric interdependency, the Federal Energy Regulatory Commission (FERC) planned its own set of regional discussions on the topic. The takeaways from these forums and the MISO zonal meetings signaled the need for a separate MISO stakeholder body to address gas-electric interdependency.

Electric and Natural Gas Coordination Task Force

In October 2012, MISO established the Electric and Natural Gas Coordination Task Force (ENGCTF). According to its charter, the ENGCTF should:

- Identify challenges related to an expectation of increasing reliance upon natural gas while ensuring reliability of the electric system
- Develop an approach to resolving identified gas-electric coordination challenges
- Develop recommendations for on-going operations, market impacts, and compliance for regulatory deadlines, as associated with gas-electric interdependency

One of the foundational challenges of the gas-electric conversation is the lack of understanding between the gas and electric industries of each other's planning, regulatory, operational and business constructs. The Task Force recognized this issue and devoted a significant amount of time to cross-industry education in the first year of existence. This included presentations from representatives of various sectors within each industry, as well as a January 2013 MISO 101 session[38] in Houston for members of the natural gas industry.

Concurrently, the ENGCTF initiated a process of gas-electric issue identification and prioritization, and subsequently ranked concerns around gas-electric interdependency. Cross-industry teams were formed to draft Issue Summary Papers[39] to guide discussion within the Task Force and provide recommendations as appropriate. Similarly in 2014, the Task Force identified issues of interest and/or concern to address through Summary Papers, with the following titles:

- Polar Vortex Experiences: Natural Gas Availability & Enhanced RTO/Pipeline Communications
- Polar Vortex Experiences: Analysis of Projected 2016 Retirements
- Potential Competition between Generator Demand & Upcoming Gas Storage injection
- Process & Timeline for Natural Gas Infrastructure Build-Out

Additionally, the Task Force continues to work on a carry-over issue from 2013 (Reliability through Market Signals). The 2013 Issue Summary Papers included specific recommendations for further analysis or actions. MISO has pursued these recommendations to the extent feasible and has undertaken a number of related initiatives.

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36 Meeting materials available at https://www.misoenergy.org/Events/Pages/GE20120510.aspx.
37 Meeting materials available at https://www.misoenergy.org/STAKEHOLDERCENTER/COMMITTEESWORKGROUPSTASKFORCES/ENGCTF/Pages/home.aspx.
38 See https://www.misoenergy.org/Events/Pages/IntroductiontoMISOAWorkshopforNaturalGasIndustryProfessionals.aspx.
39 See https://www.misoenergy.org/STAKEHOLDERCENTER/COMMITTEESWORKGROUPSTASKFORCES/ENGCTF/Pages/home.aspx.

Enhance System Awareness

MISO's efforts to enhance gas-electric system awareness include the addition of a new natural gas infrastructure overlay for the electric transmission system display in the MISO Control Room. This display will be tied to an online platform for natural gas pipeline critical notices and operational flow orders from all pipelines in the MISO footprint, as well as a database linking gas-fired generators to their fuel sources. These projects have a target completion date at the end of 2014.

Improve Cross-Industry Communications

To improve cross-industry communications, MISO initiated a six-month Coordination Field Trial in October 2013 with two major interstate pipeline companies (ANR and Northern Natural Gas). The field trial was built around monthly and as-needed conference calls between MISO Planning and Operations staff and has been extended through 2014. Call topics included a walk-through of any system conditions with the potential to disrupt operations, such as planned maintenance or extreme weather. The value of the Coordination Field Trial was evident during the 2014 polar vortex, as MISO Operations reached out to established gas pipeline contacts, aiding preparations in advance of extreme weather. While the current format of the field trial has worked well with two pipelines, holding monthly calls with staff at each of the major interstate pipelines in the footprint is not feasible. MISO is assessing options for expanding the field trial beyond 2014; a proposed first-step is to assemble contact information for each of the major interstate pipeline companies and Local Distribution Companies (LDCs) in the MISO footprint.

The value of the Coordination Field Trial was evident during the 2014 polar vortex, as MISO Operations reached out to established gas pipeline contacts, aiding preparations in advance of extreme weather

Develop Natural Gas Industry Knowledge Base

MISO's on-going efforts to develop a better understanding of natural gas infrastructure and operations include participation in the Eastern Interconnection Planning Collaborative (EIPC) study of the gas-electric interface.[40] To-date, the Electric and Natural Gas Task Force has served as the sounding board for MISO's participation in the EIPC study process; the group will continue to provide feedback as needed through the completion of the study.

In addition to MISO's involvement in the EIPC study, the issue of natural gas pipeline capacity was also revisited in 2013. For consistency with MISO's previous gas infrastructure studies (Phase I and II), the Phase III study methodology included a modified backcast analysis of the major interstate pipelines in the MISO North and Central Regions. In response to feedback received on the Phase I and II study efforts, MISO expanded its methodology to include a dynamic modeling component. EnVision Energy subcontracted with Bentek Energy, whose forward-looking model balances gas inflows and outflows regionally, taking into account gas storage requirements and pipeline transportation dynamics.

The multi-methodology approach to analysis for the North and Central Regions was selected to provide robust results for a region across which access to gas supply, storage and transportation varies.

[40] See the EIPC's website at http://www.eipconline.com/Gas-Electric_Activities.html for access to study materials.

Conversely, the MISO South footprint sits atop an extensive, heavily networked pipeline system, where individual gas-fired power plants may have interconnections with more than five supply sources. The nature of the system configuration, along with MISO's relative unfamiliarity with gas infrastructure in this new, southern portion of the footprint called for a different analytical approach. To meet this need, Bentek performed a corridor flow assessment, gathering baseline data and characterizing pipeline flow trends by corridor (groupings of 5 or 6 pipes in proximity).

Both the modified backcast analysis and the forward balancing analysis indicated adequate pipeline capacity for the footprint in the near-term under a Base Demand Scenario with isolated, localized exceptions in MISO's North and Central Regions. The shift in results from the Phase I and II studies to the Phase III was attributed to significant and fast-paced developments in the gas industry, including 1) new and increasing supplies from shale gas basins, driving major changes in pipeline flow patterns across the country, and 2) additions to and increasing interconnectivity of natural gas infrastructure.

The Phase III study report also identified opportunities for future progress on gas-electric coordination, including several recommendations aligned with the goals of the Electric and Natural Gas Coordination Task Force.[41]

Remaining Challenges and Next Steps

The objective of ensuring an appropriate level of reliability at lowest cost is the underlying challenge of gas-electric coordination. It is, in part, a product of two industries becoming increasingly interdependent but operating under different business and regulatory paradigms. Despite these differences, significant progress on gas-electric coordination has been achieved by the collaboration of MISO, its stakeholders, state and federal regulatory bodies, and the gas industry.

One of the remaining challenges of gas-electric interdependency currently under discussion stems from misaligned market and operating schedules of the gas and electric industries (Figure 6.3-2). In 2013, MISO examined[42] this issue via the ENGCTF, concluding that there may be value in adjusting MISO's Day Ahead Market schedule but not, at that time, in changing the schedule of the Operating Day.

In March 2014, FERC released a Notice of Proposed Rulemaking (NOPR) on this issue, leading MISO to revisit the conversation with its stakeholders. The NOPR offered revisions to both the gas operating day (common across the U.S.) and to gas market schedules (common base but with variations from one pipeline to the next), including to the timing and number of gas nomination opportunities. FERC established a 180-day period for the natural gas and electric industries to work together, through the North American Energy Standards Board (NAESB), to respond to the NOPR. The Commission also set an eight-month window for final comment on either the NAESB consensus or FERC's proposals, absent a NAESB consensus.

To-date, the ENGCTF has served as a sounding board for MISO's input into the NAESB process to reach consensus on the NOPR. While adjustments to the Gas Day and gas nomination timelines as proposed in the NOPR have the potential to impact MISO market timelines and operations, efforts are underway to ensure that MISO and its stakeholders are prepared for these changes.

[41] See https://www.misoenergy.org/WhatWeDo/StrategicInitiatives/Pages/EPACompliance.aspx for links to the full study report, as well as the study report companion doc.
[42] See "ENGCTF Issue Summary Papers" at https://www.misoenergy.org/STAKEHOLDERCENTER/COMMITTEESWORKGROUPSTASKFORCES/ENGCTF/Pages/home.aspx.

The misalignment topic is one of many challenges posed by gas-electric interdependency. MISO continues to collaborate with stakeholders, state and federal regulators, and the natural gas industry on this gas-electric issue and others.

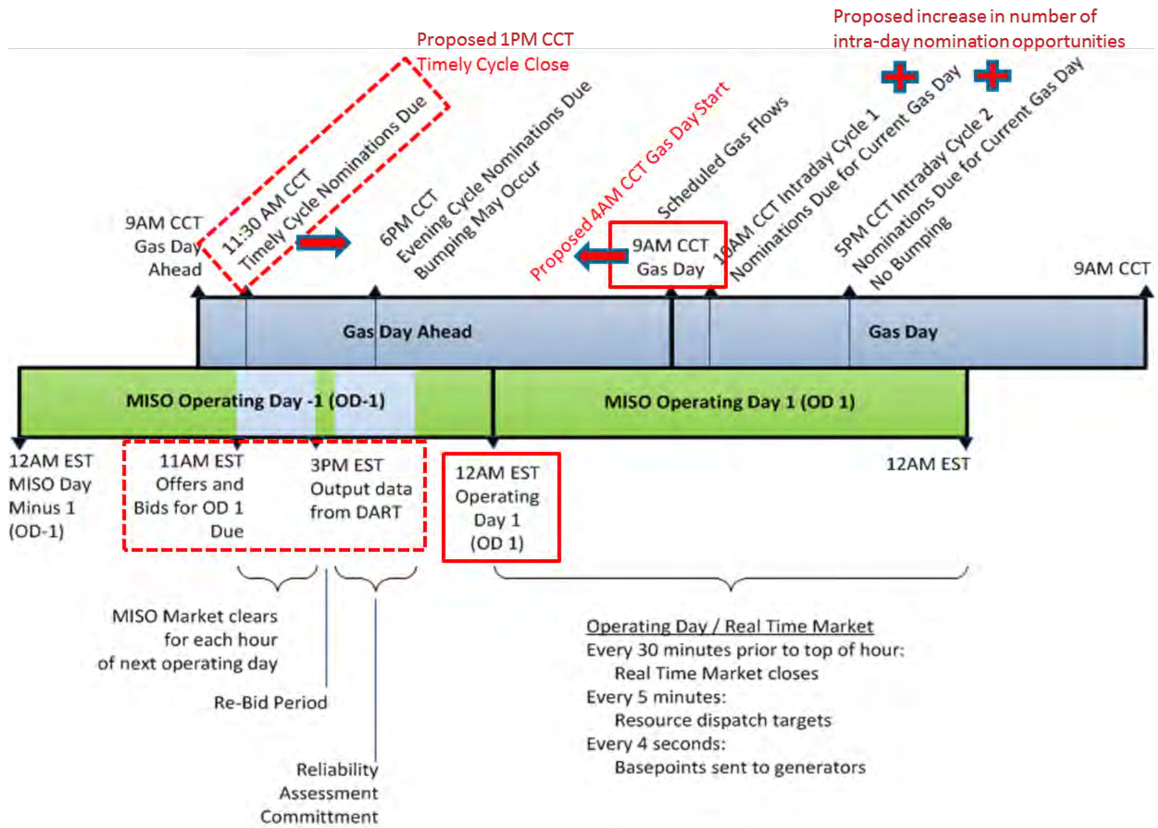


Figure 6.3-2: Gas Day and (MISO) Electric Day Schedules and FERC NOPR proposed changes

6.4 Capacity Constraint Studies

MISO is studying ways to better utilize existing transmission and generation to help alleviate expected near-term capacity reserve margin deterioration. The Unused Generation Capacity Study seeks to identify and inform Market Participants of potential opportunities to participate in the capacity market by connecting to the grid as network resources. The South to North/Central Capacity Transfer Analysis explores ways to improve the physical transfer capability between the regions.

MISO is studying ways to better utilize existing transmission and generation to help alleviate expected near-term capacity reserve margin deterioration

These informational studies are intended to identify near-term solutions to address potential capacity deficiencies in 2016. MISO's Long Term Resource Assessments project the reserve margin will drop below the Planning Reserve Margin Requirement (PRMR) of 14.8 percent beginning in 2016. The main causes of the margin reduction stem from implementation of the Environmental Protection Agency's Mercury and Air Toxics Standards, competitive natural gas prices and a changing generation portfolio. The unused Generation Capacity study preliminary results show the potential for approximately 800 MWs of generation that can be granted Network Resource status (subject to applicable tariff procedures, and pursued at the discretion of individual asset owners) with no additional network upgrades and qualify as Capacity Resources in MISO Planning Resource Auction (PRA). Similarly the South to North/Central transfer study identified the full capability of the transmission system to be in the 3 to4 GW range; an increase of 2 to 3 GWs from the level of capacity that was counted from MISO South in 2014/15 PRA. Both of these studies help inform areas where additional capacity could potentially clear and help mitigate potential Resource Adequacy shortfalls.

Unused Generation Capacity

One strategy to alleviate potential capacity shortfalls is to convert generation capacity that is currently ineligible to qualify as Planning Resources in the annual PRA. These generation resources do not qualify as Planning Resources due to inadequate interconnection service with either 1) generation tested capability exceeding its Total Interconnection Service level or 2) generation registered in the market as an Energy Resource Interconnection Service (ERIS). Inadequate service could potentially be driven by lack of adequate transmission capability.

One strategy to alleviate potential capacity shortfalls is to convert generation capacity that is currently ineligible to qualify as Planning Resources in the annual Planning Resource Auction

The purpose of this analysis is to identify potential mitigation plans for unlocking unused capacity in the MISO North and Central regions. The unlocked capacity may serve as a potential solution for the projected capacity shortfalls.

This study examines delivery year 2016 only. It identifies ways to convert generation capacity that is currently ineligible to qualify as Planning Resources in the annual PRA.

MISO staff worked closely with member Transmission Owners (TO), generators, Organization of MISO States (OMS), Load-Serving Entities (LSE) and other interested stakeholders to determine the necessary network upgrade options that could allow these resources to qualify for the PRA under Network Resource Interconnection Service (NRIS). No new Interconnection Service will be granted outside of the formal Attachment X procedures. No new cost allocation is proposed for identified transmission options.

The study was officially kicked off at the January 2014 PAC meeting, and is expected to be complete by September 2014. The project consists of four steps (Figure 6.4-1).

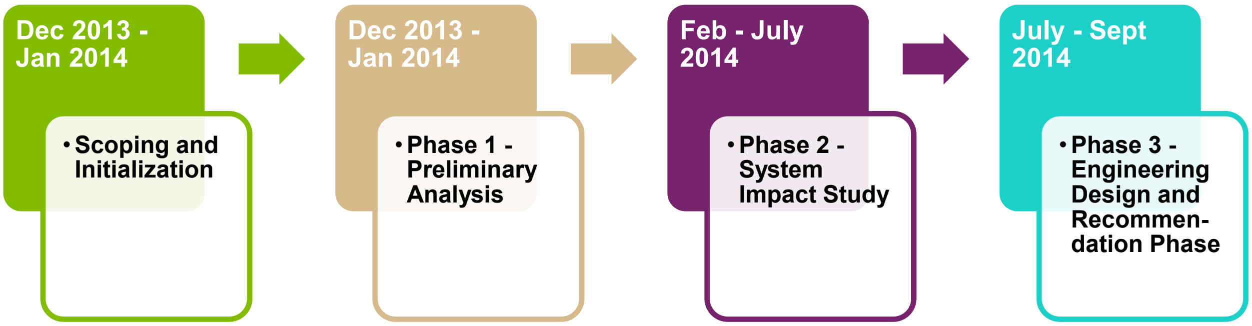


Figure 6.4-1: Study flow

Scoping and Initialization: Determine schedule and plan for the project; create detailed scope of studies to mitigate transmission constraints that are limiting the generation capacity.

Phase 1 – Preliminary Analysis Phase: Calculate initial unused capacity in MISO North and Central Region based on MISO 2013 Long-Term Reliability Assessment (LTRA) study results; refine unused generation capacity numbers based on latest information.

Phase 2 – System Impact Study: Conduct impact studies to identify Network Upgrade options:

- Provide constraints, mitigation plans and high-level cost by zones
- Estimate unlocked MW by zones and years
- Determine Network Upgrades with TOs

Phase 3 – Engineering Design and Recommendation Phase: Coordinate with TOs to further refine the Network Upgrades. Report out on Resource Adequacy impacts in MISO assessment as part of the NERC 2014 LTRA and make final recommendations on the mitigation plan.

The analysis uses the MTEP14 2016 summer peak and off-peak reliability models and assumptions.

The current study analyzed the Base Scenario and Bookend Scenario. The Base Scenario provides information on which transmission network upgrades are needed to unlock the existing unused generation capacity in the MISO North and Central, taking into account of all existing generation on the ground and the signed GIA generators that will be in service by 2016 summer. The Bookend Scenario is similar, but takes into account of all existing generation on the ground, signed GIA generators and generators queued up to DPP-Feb-2014 cycle.

This study was conducted from the perspective of three groups:

- Group 1 is generators that have Energy Resource Interconnection Service (ERIS) or partial Network Resource Interconnection Service (NRIS), which could potentially be upgraded to higher level Network Resource Interconnection Service.
- Group 2 is other types of non-Network Resource generation, such as generators, which are not connecting onto transmission system under MISO's functional control and existing generators with Provisional Interconnection Agreement (PIA).
- Group 3 is generators with higher MW capability than their total Interconnection Service level.

The analysis was performed in an open and transparent manner through the Planning Subcommittee and was a collaborative effort between stakeholders and MISO staff.

Preliminary Result Summary

As of July 2014, preliminary results indicate that approximately 806 to 938 MW of generation have the potential to become Network Resources with no required network upgrades after progressing through the MISO Generation Interconnection Process. An additional 273 to 404 MW could be freed up at an estimated cost of $12 to $18 million Annual Revenue Requirement.

Preliminary results indicate that approximately 806 to 938 MW of generation have the potential to become Network Resources with no required network upgrades after progressing through the MISO Generation Interconnection Process

For the Base Scenario, there are approximately 938 MW of non-restricted generation, which has no transmission upgrades required, and 273 MW of restricted generation. The Bookend Scenario has approximately 806 MW of non-restricted generation and 404 MW of restricted generation. Table 6.4-1 illustrates the break-down of non-restricted and restricted MW by study groups and by study scenarios. Figure 6.4-2 and 6.4-3 shows the estimated unrestricted MW by Local Resource Zones in Base and Bookend scenarios.

	Base Scenario		Bookend Scenario	
	Non-restricted (MW)	Restricted (MW)	Non-restricted (MW)	Restricted (MW)
Group 1	351	153	285	218
Group 2	286	38	239	85
Group 3	301	82	282	101
Subtotal	938	273	806	404

Table 6.4-1: Summary result

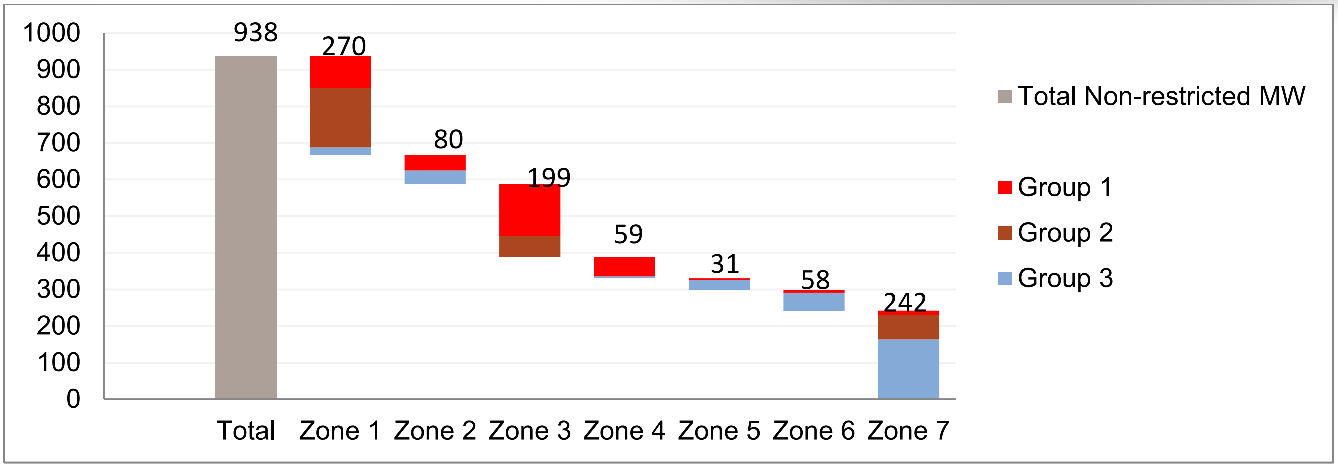


Figure 6.4-2: Estimated unrestricted MW by Local Resource Zones (Base Scenario)

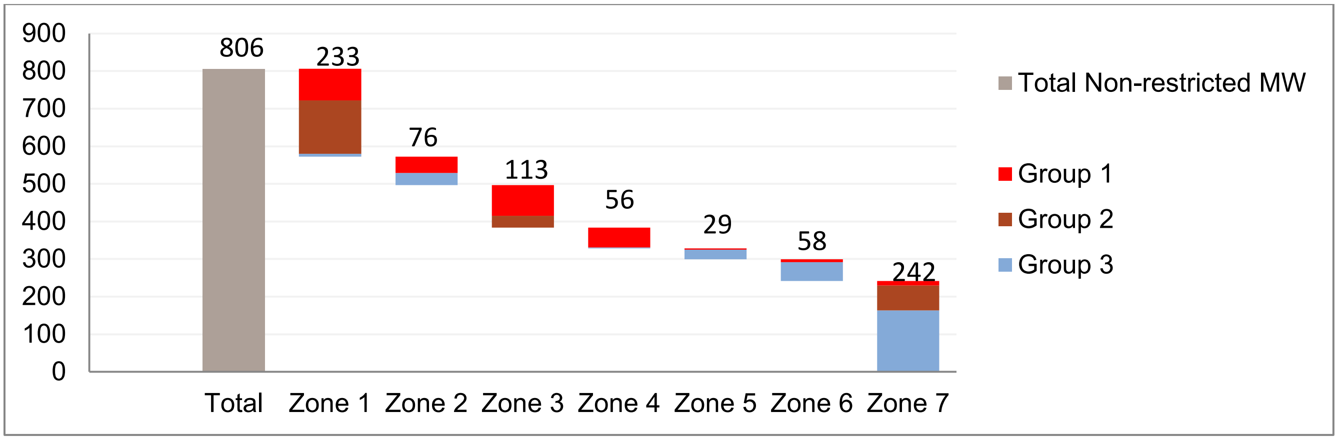


Figure 6.4-3: Estimated unrestricted MW by Local Resource Zones (Bookend Scenario)

For the restricted generation, the study identified transmission constraints and potential short-term transmission solutions. The solutions include utilizing existing MISO Multi-Value Projects, other projects in MTEP Appendices, planned projects in neighboring systems and new transmission upgrades. The total estimated cost for the transmission upgrades are around $113.5 million for the Base Scenario and $134.6 million for the Bookend Scenario (Table 6.4-2).

	Base Scenario ($M)	Bookend Scenario ($M)
Group 1	22.8	46.2
Group 2	6.5	21.0
Group 3	84.2	67.4
Subtotal	**113.5**	**134.6**

Table 6.4-2: Transmission Upgrade Estimated Cost

The final Unused Generation Capacity study report will be posted on the MISO Planning web site.

It should be noted that the study results are preliminary and are intended to provide information on the potential unused generation in the MISO North and Central regions. This is valuable in determining the potential transmission network upgrades needed to unlock the constrained unused generation.

The potential unused generation identified by this study needs to be pursued at the discretion of individual asset owners through the regular MISO Generation Interconnection Process (Attachment X process).

The results of local system impact studies performed by the incumbent TOs may differ from those performed by MISO due to the implementation of some additional local planning scenarios.

South to North/Central Transfer Capability

The South to North/Central Transfer Capability analysis is an informational study to identify potential mitigations to the forecasted Resource Adequacy generation shortfall.

The study looks at a single transfer from the South Region to the combined Central and North region by analyzing the First Contingency Total Transfer Capability (FCTTC) between the regions.

Preliminary South to North/Central Transfer Capability analysis found that initial transmission limiters may be dispatched around to achieve an approximate 4,000 MW FCTTC

The study began in March 2014 and has an expected completion in November 2014. It focused on the areas of the South region generation as an exporter and the North and Central region as the importer. The study echoed results seen in recent, similar studies by indicating the potential transmission limiters for transferring power between the regions. It showed potential opportunities for increased transfer capability between the regions based on the details of the study. The full study report will be posted on the MISO website.

Preliminary South to North/Central Transfer Capability analysis found that initial transmission limiters may be redispatched around to achieve an approximate 4,000 MW FCTTC. After redispatch, the analysis identified the White Bluff to Keo 500 kV facility as the potential limiter for the region, primarily due to the lack of generation to redispatch.

Study Scope

The South to North/Central Transfer Capability analysis is an informational study to identify a potential solution to the expected 2016 capacity shortfall. The South to North/Central Transfer Capability analysis originated because through the OMS – MISO Survey identified capacity excess in the South region. The objectives of this analysis are:

- Identify the expected 2016 transfer capability between the South and the Central and North
- Identify potential transmission solutions to increase the physical transfer capability between MISO South and the Central and North regions

- Provide an informational study with an opportunity for the potential solutions to move into an existing MISO process. This will be dependent on solutions identified and stakeholder interest.

The analysis was performed in an open and transparent manner through the Planning Subcommittee and was a collaborative effort between stakeholders and MISO staff.

The analysis used the MTEP14 2016 summer peak reliability models and assumptions as the starting point. The informational analysis focused on one study scenario, Total Transfer Capability, by increasing generation dispatch in the South region and decreasing generation in the combined North and Central region. The South to North/Central Transfer Capability analysis was evaluated solely on reliability impacts. Broader economic values were not considered in this study. The full report will document the results of this analysis

The post redispatch results indicate an FCTTC of approximately 4,000 MW (Table 6.4-2, Figure 6.4-4).

Map ID	Limiting Facility	FCITC (MW)	FCTTC (MW)
1	White Bluff to Keo 500 kV line	2,952	3,997
	Sheridan to Mabelvale 500 kV line (FG rating applied)	2,977	4,022
2	Freeport 500 / 161 kV transformer (FG rating applied)	3,584	4,629
3	Russelville East to Russelville South 161 kV line	3,694	4,739
4	Widows Creek to Sequoyah 500 kV line (FG rating applied)	3,722	4,767
3	Russelville South to Dardanelle Dam 161 kV line	3,773	4,818

Table 6.4-3: Post redispatch linear results

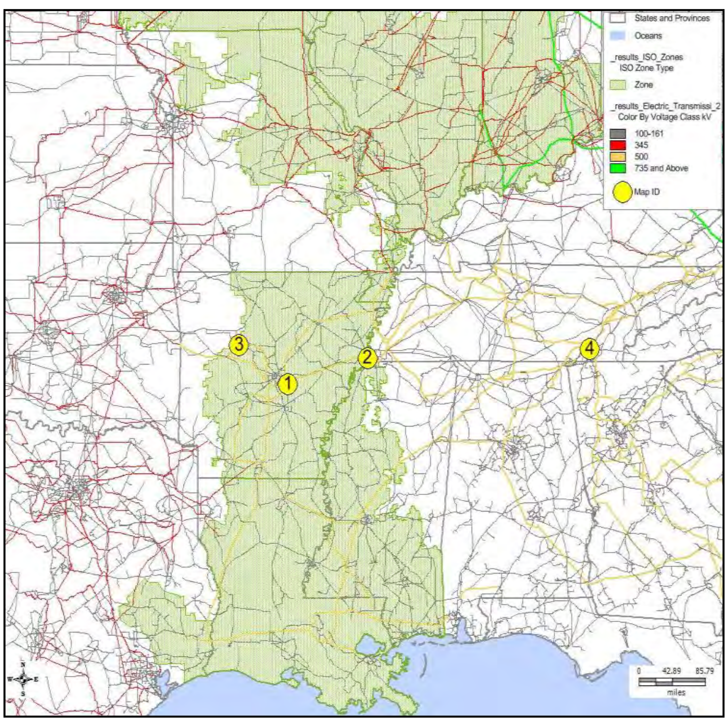


Figure 6.4-4: Geographic constraints of post redispatch linear results

After the initial draft of the study scope and gathering stakeholder feedback it was decided to remove identification of network upgrades from the study scope. The transfer capability identified was expected to be above the excess generation expected in the MISO South region.

Further analysis is ongoing to determine the impact on voltages of the transfer through both steady-state and stability analysis. Stakeholder input will be requested to confirm the FCTTC.

Book 3: Policy Landscape Studies

Chapter 7
Regional Studies

7.1 MTEP14 MVP Triennial Review

The MTEP14 Triennial Multi-Value Project (MVP) Review provides an updated view into the projected economic, public policy and qualitative benefits of the MVP Portfolio. The MTEP14 MVP Triennial Review's business case is on par with, if not stronger than, the MTEP11 Board-approved business case, providing evidence that the MVP criteria and methodology works as expected. Analysis shows that projected MISO North and Central Region benefits provided by the MVP Portfolio have increased since MTEP11, the analysis from which the portfolio's business case was developed and approved.

Analysis shows that projected benefits provided by the MVP Portfolio have increased since MTEP11

The 2014 Triennial MVP finds that the MVP Portfolio:

- Provides benefits in excess of its costs, with its benefit-to-cost ratio ranging from 2.6 to 3.9; an increase from the 1.8 to 3.0 range calculated in MTEP11
- Creates $13.1 to $49.6 billion (in 2014 dollars) in net benefits over the next 20 to 40 years, an increase of approximately 50 percent from MTEP11
- Enables 43 million MWh of wind energy to meet renewable energy mandates and goals through year 2028, an additional 2 million MWh from the MTEP11 year 2026 forecast
- Provides additional benefits to each local resource zone relative to MTEP11.

Benefit increases are primarily congestion and fuel savings largely driven by natural gas price assumptions.

The full MTEP14 MVP Triennial Review Report[43] is available on the MISO website.

The fundamental goal of the MISO's planning process is to develop a comprehensive expansion plan that meets the reliability, policy and economic needs of the system. Implementation of a value-based planning process creates a consolidated transmission plan that delivers regional value while meeting near-term system needs. Regional transmission solutions, known as MVPs, meet one or more of three goals:

- Reliably and economically enable regional public policy needs
- Provide multiple types of regional economic value
- Provide a combination of regional reliability and economic value

[43] https://www.misoenergy.org/Planning/TransmissionExpansionPlanning/Pages/MVPAnalysis.aspx

In 2011, the MVP Portfolio was approved by the MISO Board of Directors based on its ability to enable public policy, improve system reliability and provide economic benefits in excess of costs. As part of the approval of the MVP project definition, FERC required a periodic review of the MVP Portfolio benefits. Beginning in MTEP14, MISO has a triennial tariff requirement to conduct a full review of the MVP Portfolio benefits. The MVP Review has no impact on the existing MVP Portfolio cost allocation. MTEP14 Review analysis is performed solely for informational purposes. The intent of the MVP Reviews is to use the review process and results to identify potential modifications to the MVP methodology and its implementation for projects to be approved at a future date.

The MVP Review uses stakeholder-vetted MTEP14 models and makes every effort to follow procedures and assumptions consistent with the MTEP11 analysis. Metrics that required any changes to the benefit valuation due to changing tariffs, procedures or conditions are highlighted. Consistent with MTEP11, the MTEP14 MVP Review assesses the benefits of the entire MVP Portfolio and does not differentiate between facilities currently in-service and those still being planned. Because the MVP Portfolio's costs are allocated solely to the MISO North and Central Regions, only MISO North and Central Region benefits are included in the MTEP14 MVP Triennial Review.

Public Policy Benefits

The MTEP14 MVP Review reconfirms the MVP Portfolio's ability to deliver wind generation in support of the renewable energy mandates of the MISO states in a cost effective manner. Renewable Portfolio Standards assumptions[44] have not changed since the MTEP11 analysis.

Updated analyses find that 10.5 GW of year 2023 dispatched wind would be curtailed in lieu of the MVP Portfolio, which extrapolates to 56 percent of the 2028 full RPS energy. MTEP11 analysis showed that 63 percent of the year 2026 full RPS energy would be curtailed without the installation of the MVP Portfolio. The MTEP14 calculated reduction in curtailment as a percentage of RPS has decreased since MTEP11, primarily because post-MTEP11 transmission upgrades are represented and the actual physical location of installed wind turbines has changed slightly since the 2011 forecast.

In addition to allowing energy to not be curtailed, analyses determined that 4.3 GW of wind generation in excess of the 2028 requirements is enabled by the MVP Portfolio. MTEP11 analysis determined that 2.2 GW of additional year 2026 generation could be sourced from the incremental energy zones. The results are the essentially the same for both analyses as the increase in wind enabled from MTEP 2011 is primarily attributed to additional load growth. The MTEP 2011 analysis was performed on a year 2026 model and MTEP 2014 on year 2028.

The Triennial MVP Review has no impact on the existing MVP Portfolio cost allocation. The intent of the MVP Reviews is to identify potential modifications to the MVP methodology for projects to be approved at a future date

When the results from the curtailment analyses and the wind-enabled analyses are combined, MTEP 2014 results show the MVP Portfolio enables a total of 43 million MWh of renewable energy to meet the renewable energy mandates through 2028. MTEP 2011 showed the MVP Portfolio enabled a similar level renewable energy mandates – 41 million MWh through 2026.

[44] Assumptions include Renewable Portflio Standard levels and fulfillment methods

Economic Benefits

MTEP14 analysis shows the Multi-Value Project Portfolio creates $21.5 to $66.8 billion in total benefits to MISO North and Central Region members (Figure 7.1-1). Total portfolio costs have increased from $5.56 billion in MTEP11 to $5.86 billion in MTEP14. Even with the increased portfolio cost estimates, the increased MTEP14 benefit forecast results in portfolio benefit to cost ratios that have increased from 1.8 to 3.0 in MTEP11 to 2.6 to 3.9 in MTEP14.

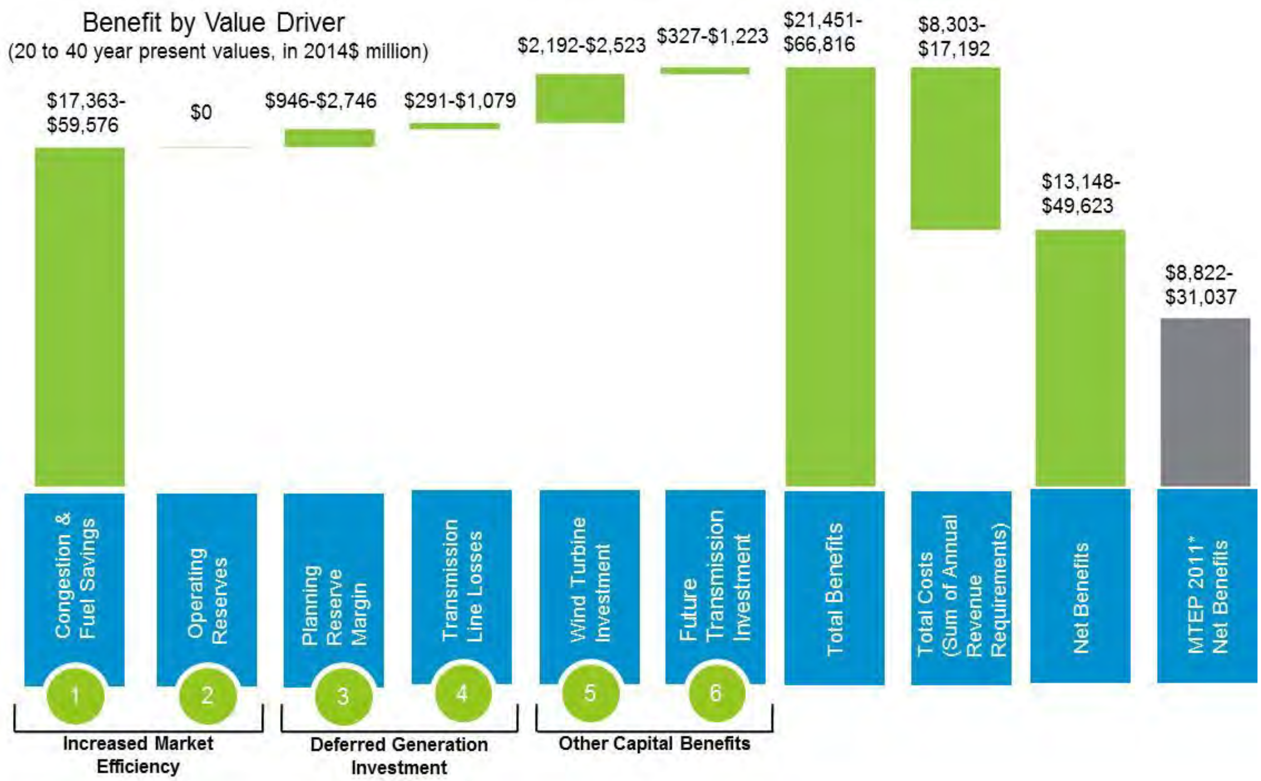


Figure 7.1-1: MVP Portfolio Economic Benefits from MTEP14 MVP Triennial Review

The bulk of the increase in benefits is due to an increase in the assumed natural gas price forecast in MTEP14 compared to MTEP11. In addition, the MTEP15 natural gas assumptions, which will be used in the MTEP15 MVP Portfolio Limited Review, are lower than the MTEP14 forecast. Under each of the natural gas price assumption sensitivities, the MVP Portfolio is projected to provide economic benefits in excess of costs (Table 7.1-1).

Natural Gas Forecast Assumption	Total NPV Portfolio Benefits ($M-2014)	Total Portfolio Benefit-to-Cost Ratio
MTEP14 – MVP Triennial Review	21,451 – 66,816	2.6 – 3.9
MTEP11	17,875 – 54,186	2.2 – 3.2
MTEP15	18,472 – 56,670	2.2 – 3.3

Table 7.1-1: MVP Portfolio Economic Benefits - Natural Gas Price Sensitivities[45]

Increased Market Efficiency

An increase in the natural gas price escalation rate, increases congestion and fuel savings benefits by approximately 30 percent in MTEP14 compared to MTEP11

The MVP Portfolio allows for a more efficient dispatch of generation resources, opening markets to competition and spreading the benefits of low-cost generation throughout the MISO footprint. The MVP Review estimates that the MVP Portfolio will yield $17 to $60 billion in 20 to 40 year present-value, adjusted-production cost benefits to MISO's North and Central Regions – an increase of up to 40 percent from the MTEP11 net present value.

The increase in congestion and fuel savings benefits relative to MTEP11 is primarily due to an increase in the out-year natural gas price forecast assumptions (Figure 7.1-2). The increased escalation rate causes the assumed natural gas price to be higher in MTEP14 compared to MTEP11 in years 2023 and 2028 - the two years from which the congestion and fuel savings results are based (Figure 7.1-2).

The MVP Portfolio allows access to wind units with a nearly $0/MWh production cost and primarily replaces natural gas units in the dispatch, which makes the MVP Portfolio's fuel savings benefit projection directly related to the natural gas price assumption. A sensitivity applying the MTEP11 Low Business As Usual (BAU) gas prices assumption to the MTEP14 MVP Triennial Review model showed a 29.3 percent reduction in the annual year 2028 MTEP14 congestion and fuel savings benefits (Figure 7.1-2).

Post MTEP14 natural gas price forecast assumptions are more closely aligned with those of MTEP11 (Figure 7.1-2). A sensitivity applying the MTEP15 BAU natural gas prices to the MTEP14 analysis showed a 19.5 percent reduction in year 2028 MTEP14 adjusted production cost savings.

MISO membership changes have little net effect on benefit-to-cost ratios. The exclusion of Duke Ohio/Kentucky and First Energy from the MISO pool decreases benefits by 7.4 percent relative to the MTEP14 total benefits. However, per Schedule 39, 6.3 percent of the total portfolio costs are allocated to Duke Ohio/Kentucky and First Energy, thus there is a minimal net effect to the benefit to cost ratio.

The MVP Portfolio is solely located in the MISO North and Central Regions and, therefore, the inclusion of the MISO South Region to the MISO dispatch pool has little effect on MVP-related production cost savings (Figure 7.1-2).

[45] Sensitivity performed applying MTEP11/MTEP15 natural gas price to the MTEP14 congestion and fuel savings model. All other benefit valuations unchanged from the MTEP14 MVP Triennial Review.

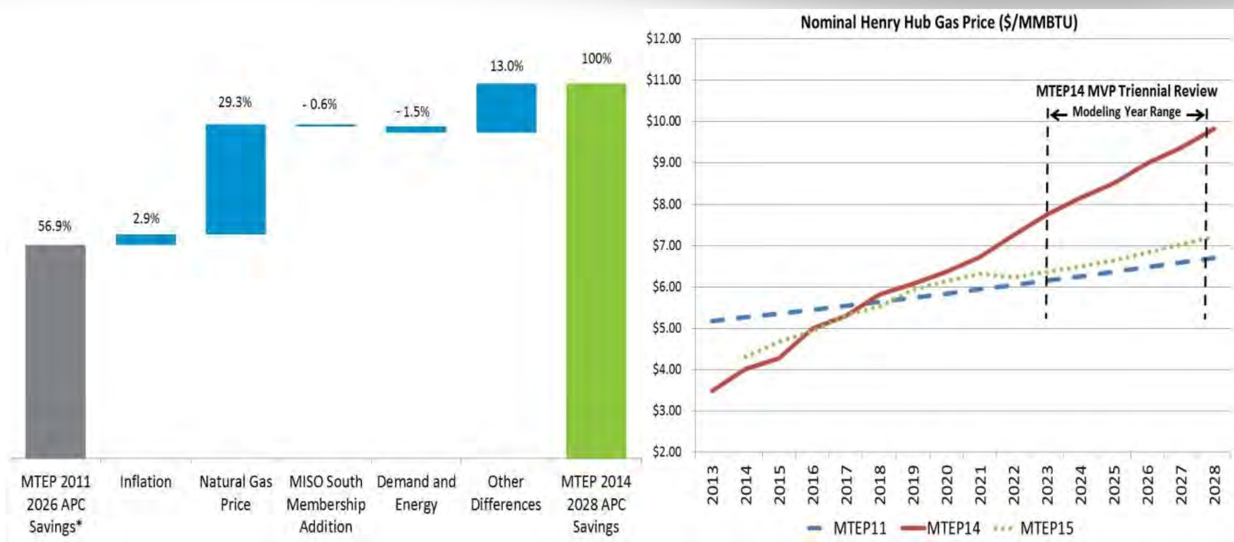


Figure 7.1-2: Breakdown of Congestion and Fuel Savings Benefit Increase from MTEP11 to MTEP14

In addition to the energy benefits quantified in the production cost analyses, the 2011 business case showed the MVP Portfolio also reduces operating reserve costs. Because of the minimum number of days a reserve requirement was calculated since 2011, as a conservative measure, the MVP Review is not estimating a reduced operating reserve benefit in MTEP14.

Deferred Generation Investment

The addition of the MVP Portfolio to the transmission network reduces overall system losses, which also reduces the generation needed to serve the combined load and transmission line losses. Using current capital costs, the deferment from loss reduction equates to a MISO North and Central Regions' savings of $291 to $1,079 million (2014 dollars) - nearly double the MTEP11 values. Tightening reserve margins, from an additional approximate 12 GW of expected coal generation retirements, have increased the value of deferred capacity from transmission losses in MTEP14. In addition to tighter reserve margins, the shift in the MVP Portfolio in-service date from 2021 in MTEP 2011 to 2020 in MTEP 2014 increases benefits by an additional 30 percent.

The MTEP14 MVP Review estimates the MVPs annually defer more than $900 million in future capacity expansion by increasing capacity import limits, thus reducing the local clearing requirements of the system planning reserve margin requirement. In the 2013 planning year, MISO and the Loss of Load Expectation Working Group improved the methodology that establishes the MISO Planning Reserve Margin Requirement (PRMR). Previously, and in the MTEP11 analysis, MISO developed a MISO-wide PRMR with an embedded congestion component. The post-2013 planning year methodology no longer uses a congestion component, but rather calculates a more granular zonal PRMR and a local clearing requirement based on the zonal capacity import limit. While terminology and methods have changed between MTEP11 and MTEP14, both calculations capture the same benefit of increased capacity sharing across the MISO region provided by the MVPs; as such, MTEP14 and MTEP11 provide benefit estimates of similar magnitudes.

Other Capital Benefits

Benefits from the optimization of wind generation siting and the elimination of need for some future baseline reliability upgrades remain at similar levels to those estimated in MTEP11. A slight increase in MTEP14 wind turbine investment benefits, relative to MTEP11 benefits, is due to an update to the wind requirement forecast and wind enabled calculations.

Consistent with MTEP11, the MTEP14 MVP Triennial Review shows that the MVP Portfolio eliminates the need for $300 million in future baseline reliability upgrades. The magnitude of estimated benefits is in close proximity to the estimate from MTEP11; however, the actual identified upgrades have some differences because of load growth, generation dispatch, wind levels and transmission upgrades.

Distribution of Economic Benefits

Benefit-to-cost ratios have increased in all zones since MTEP11

The MVP Portfolio provides benefits across the MISO footprint in a manner that is roughly equivalent to costs allocated to each local resource zone (Figure 7.1-3). The MVP Portfolio's benefits are at least 2.3 to 2.8 times the cost allocated to each zone. MTEP14 results show that benefit-to-cost ratios have increased in all zones since MTEP11. Zonal benefit distributions have changed slightly since the MTEP11 business case as a result of changing tariffs/business practices (planning reserve margin requirement and baseline reliability project cost allocation), load growth and wind siting.

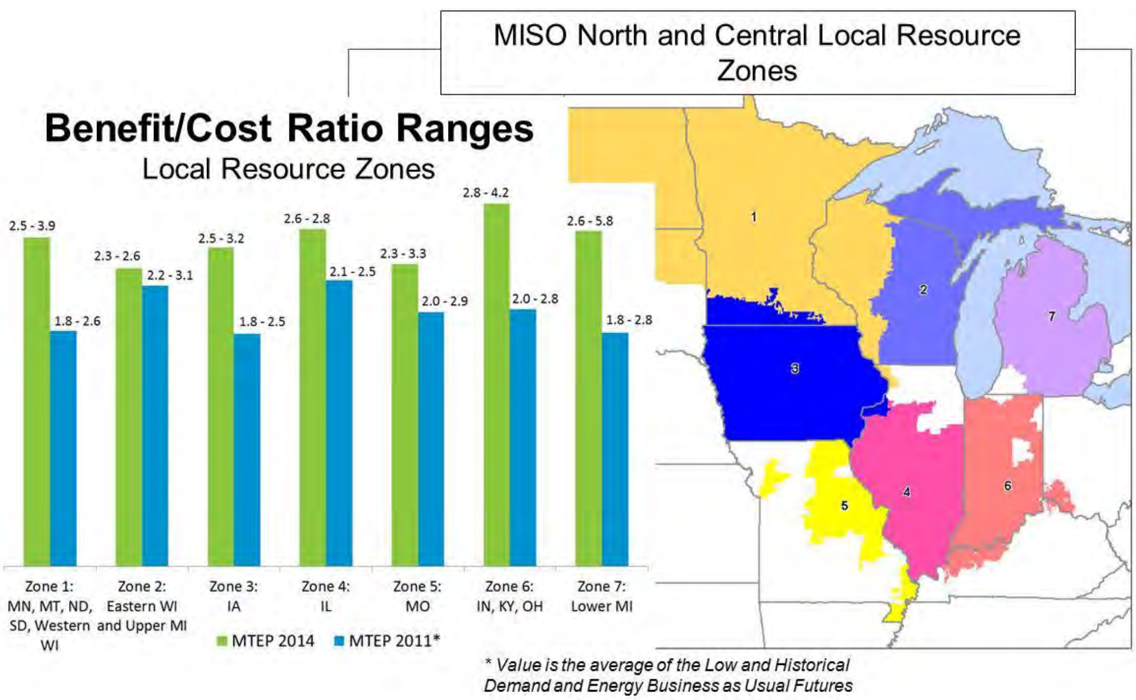


Figure 7.1-3: MVP Portfolio total benefit distribution

Qualitative and Social Benefits

Aside from widespread economic and public policy benefits, the MVP Portfolio also provides benefits based on qualitative or social values. The MVP Portfolio:

- Enhances generation flexibility
- Creates a more robust regional transmission system, which decreases the likelihood of future blackouts
- Increases the geographic diversity of wind resources that can be delivered, increasing the average wind output available at any given time
- Supports thousands of local jobs and billions in local investment
- Reduces carbon emissions by 9 to 15 million tons annually

These benefits suggest quantified values from the economic analysis may be conservative because they do not account for the full potential benefits of the MVP Portfolio.

Going Forward

MTEP15 and MTEP16 will feature a Limited Review of the MVP Portfolio benefits. Each Limited Review will provide an updated assessment of the congestion and fuel savings using the latest portfolio costs and in-service dates. Beginning in MTEP 2017, in addition to the Full Triennial Review, MISO will perform an assessment of the congestion costs, energy prices, fuel costs, planning reserve margin requirements, resource interconnections and energy supply consumption based on historical data.

7.2 Minnesota Renewable Energy Integration and Transmission Study

MISO is collaborating with Minnesota utilities and transmission companies to perform production cost modeling and provide technical support for the Minnesota Renewable Energy Integration and Transmission Study (MRITS).

The goal of MRITS is to evaluate the impacts on reliability and costs associated with increasing renewable energy to 40 percent of Minnesota's retail electric energy sales by 2030, and to higher proportions thereafter. The Department of Commerce is directing the study and is leading the Technical Review Committee (TRC).

Study process and results are available as of the study completion on November 1, 2014.

MRITS evaluates the impacts on reliability and costs associated with increasing renewable energy to 40 percent of Minnesota retail electric energy sales by 2030, and to higher proportions thereafter

MRITS Objectives

- Evaluate the impacts on reliability and costs associated with increasing renewable energy to 40 percent of Minnesota retail electric energy sales by 2030, and to higher proportions thereafter
- Develop a conceptual plan for transmission necessary for generation interconnection and delivery; for access to regional geographic diversity and regional supply; and demand side flexibility
- Identify and develop potential solutions to manage the impacts of the variable renewable energy resources
- Build upon prior renewable energy integration studies and related technical work
- Coordinate with recent and current regional power system study work
- Produce meaningful, broadly supported results through a technically rigorous, inclusive study process

Study Team and Roles

- Minnesota Utilities and Transmission Companies technical staff - oversight and review
- Minnesota Department of Commerce technical staff – oversight and review
- Excel Engineering - transmission planning (PSSE)
- MISO - coordination, models, data; production simulation analysis (PLEXOS)
- GE Energy Consulting (GE) - operating performance, dynamics (PSLF), mitigation/solutions

Study Scenarios

Two scenarios are under evaluation in MRITS (Figure 7.2-1). Scenario 1 evaluates the impact of increasing Minnesota's Renewable Energy Standard (RES) from a 2028 baseline of 28.5 percent to 40 percent of the state's retail sales. The baseline represents existing renewables, new renewables with a signed Generator Interconnection Agreement (GIA) as of fall 2013, and incremental renewables needed to meet the various state RESs. Additionally, Scenario 2 evaluates increasing Minnesota's RES to 50 percent along with increasing MISO North and Central Region's RES to 26 percent from 14 percent in 2028. Incremental renewable capacity is made up of a combination of wind and solar resources. Future Minnesota wind is sited in the Minnesota-centric area, which includes Minnesota along with parts of North Dakota, South Dakota, northern Iowa and western Wisconsin. Future solar is sited in Minnesota only. Additional MISO renewables are sited throughout the MISO North and Central Regions.

	Minnesota			MISO North and Central Regions		
Case	Wind RES % of Retail Sales	Solar RES % of Retail Sales	Total RES % of Retail Sales	Wind RES % of Retail Sales	Solar RES % of Retail Sales	Total RES % of Retail Sales
Baseline	27.5%	1.0%	28.5%	14.0%	0.4%	14.0%
Scenario 1	37.0%	3.0%	40.0%	15.2%	0.7%	16.0%
Scenario 2	40.0%	10.0%	50.0%	23.8%	2.4%	26.0%

Figure 7.2-1: RES percent of Retail Sales for MRITS Scenarios

MISO Models

One of the objectives for MRITS was to be consistent with other planning studies so the current MISO MTEP models were used. The production cost model (PLEXOS) used the 2028 MTEP13 Business as Usual database and modified it to fit the study assumptions.

7.3 Voltage and Local Reliability Planning Study

MISO's transmission planning process is focused on minimizing the total cost of delivered power to consumers. Therefore, as part of MTEP14, MISO began a planning study to ascertain whether there are cost-effective alternatives to serve load at a lower overall cost by eliminating or minimizing VLR-triggered resource commitments. Voltage and local reliability (VLR) constraints on the system are currently being mitigated by commitment and dispatch of local generation. The variable operating costs of these generation resources are currently higher than other market alternatives and their dispatch results in an increase in production cost. The incremental costs may be significant enough to support the development of transmission upgrades as a more economic means of reliably serving load.

MISO anticipates final study recommendations during the second quarter of 2015. This study also considers upgrades identified through other processes under MTEP14. Additionally, the study will consider mitigation options such as generation, demand-side and transmission solutions consistent with Planning provisions under Attachment FF of the MISO tariff. To the extent that transmission alternatives are identified they will be evaluated for any associated adjusted production cost benefits as compared to VLR unit commitments.

Preliminary Results

Steady state analyses have been performed on a 2024 summer scenario to identify potential transmission upgrades necessary to eliminate known VLR resource commitments in Amite South/Down Stream of Gypsy (DSG) and the West of the Atchafalaya Basin (WOTAB)/Western region. Preliminary results indicate that the existing transmission system will need significant 500 kV and 230 kV upgrades to completely eliminate VLR commitments. These results are shown in Figures/Tables 7.3-1 and 7.3-2.

1. **Amite South/DSG – Solution ideas under consideration**

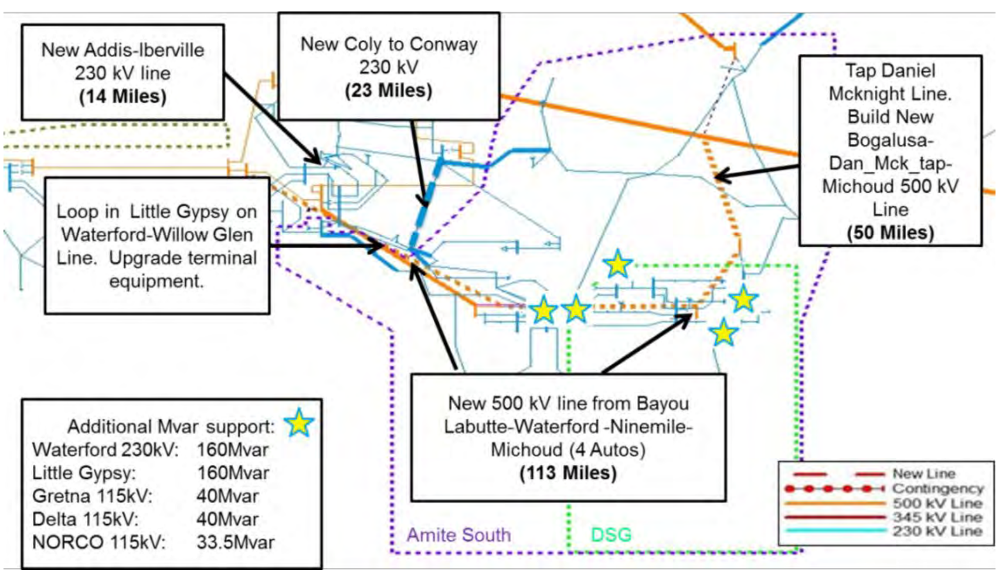


Figure 7.3-1 – Preliminary solution for Amite South/DSG area

Amite South and DSG Preliminary Solution	Total Estimated Cost ($ Million)
1. New Addis-Iberville 230 kV line.	39.76
Upgrade Addis 230 kV Substation	5.07
Upgrade Iberville 230 kV Substation	5.07
2. New Coly to Conway 230 kV	65.32
Upgrade Coly 230 kV Substation	5.07
Upgrade Conway 230 kV Substation	5.07
3. Cut into McKnight – Daniel 500 kV at Dan_Mck_tap	7.94
New Dan_Mck_tap 500 kV Substation	11.03
Dan_Mck_tap – Michoud 500 kV – inland	119.1
Dan_Mck_tap – Michoud 500 kV – wetlands	66.64
Dan_Mck_tap – Michoud 500 kV - lake crossing	105.84
4. Michoud - Ninemile 500 kV	158.8
Michoud - Ninemile 500 kV- River Crossing	40
5. Waterford – Ninemile 500 kV	119.1
6. Bayou Labutte-Waterford 500 kV	170.71
Upgrade Waterford 500 kV Substation	5.07
Waterford 230 kV: 160 Mvar Cap Banks addition	3
7. New little Gypsy 500 kV Substation	11.03
Add new 500/230 kV Transformer at Little Gypsy	11.06
Little Gypsy: 160 Mvar Cap Banks addition	3
8. New Michoud 500 kV Substation	11.03
Add new 500/230 kV Transformer at Michoud	22.12
9. New Ninemile 500 kV Substation	11.03
Add new 500/230 kV Transformer at Ninemile	11.06
10. Gretna 115 kV:40 Mvar Cap Bank addition	1.5
11. Delta 115 kV:40 Mvar Cap Bank addition	1.5
12. NORCO: 33.5 Mvar Cap Bank addition	1.5
TOTAL COST	**$1,017,420,000**

Table 7.3-1 – Solution ideas under consideration and planning-level cost estimates

2. WOTAB/Western Region – Solution ideas under consideration

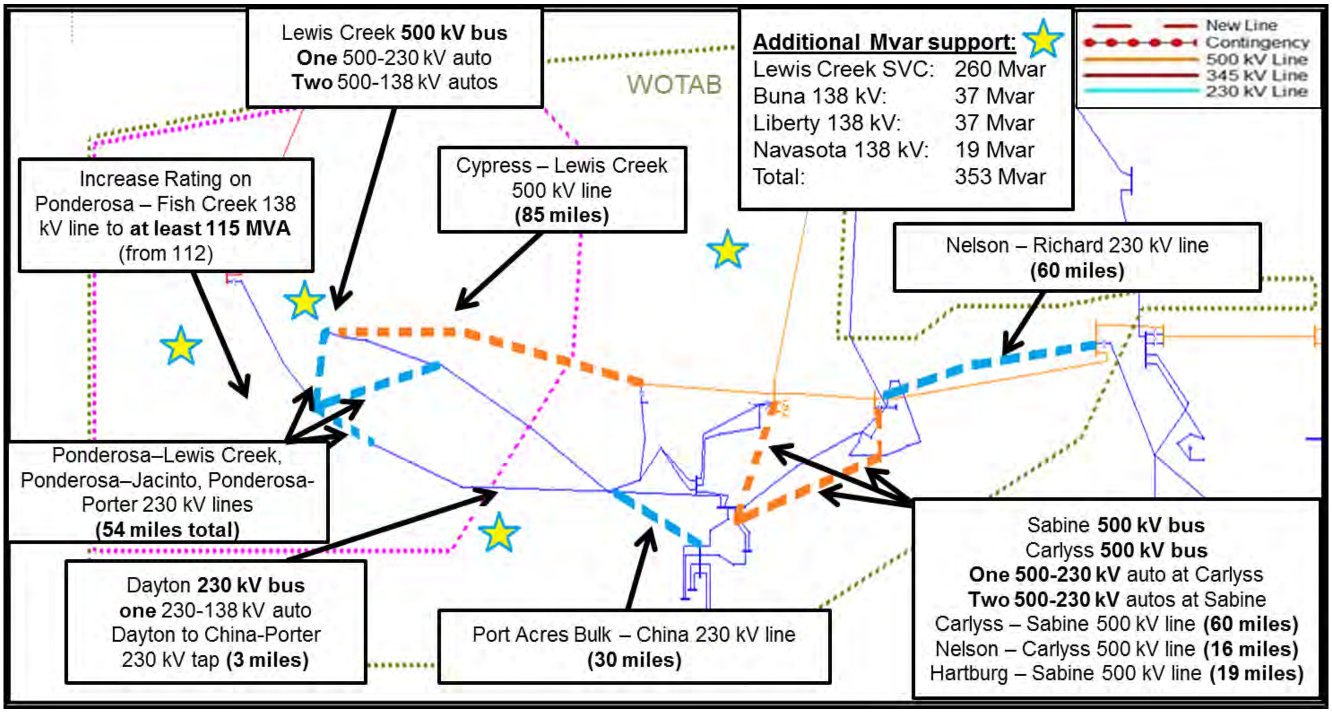


Figure 7.3-2: Preliminary solution for WOTAB/Western region

WOTAB and Western region Preliminary solution:	Total Estimated Cost ($ Million)
1. Carlyss - Sabine 500 kV line (1 river crossing)	174.77
Carlyss 500 kV bus	11.03
One 500-230 kV auto at Carlyss	11.06
2. Nelson - Carlyss 500 kV line	44.64
3. Hartburg - Sabine 500 kV line	53.01
Sabine 500 kV bus	11.03
Two 500-230 kV autos at Sabine	22.12
4. Lewis Creek - Ponderosa 230 kV line	23.16
5. Porter - Ponderosa 230 kV line	23.16
6. Dayton 230 kV bus	10.13
Line from China - Porter 230 kV tap point to new Dayton 230 kV bus	5.79
Dayton 230-138 kV auto	9
7. Ponderosa - Jacinto 230 kV line	57.9
8. Cypress - Lewis 500 kV line (1 river crossing)	244.52
Lewis Creek 500 kV bus	11.03
One 500-230 kV auto at Lewis	11.06
Two 500-138 kV autos at Lewis	19.54
Lewis Creek SVC (260 Mvar)	70
9. Nelson - Richard 230 kV line	115.8
10. Point Acres Bulk - China 230 kV line	57.9
11. Ponderosa - Fish Creek 138 kV line uprate (to at least 115 MVA)	4.5
12. Buna 138 kV 37 Mvar cap bank	1.5
13. Liberty 138 kV 37 Mvar cap bank	1.5
14. Additional 19 Mvar at Navasota 138 kV cap bank	0.75
TOTAL COST:	**$994,900,000**

Table 7.3-2 – Solution ideas under consideration and planning-level cost estimates

Deliverables

This planning study is focused on the MISO South region, which includes parts of Louisiana and Texas (Figure 7.3-3).

The Amite South area encompasses all of Louisiana east of Baton Rouge, the greater New Orleans area, which includes the Down Stream of Gypsy (DSG) area. DSG is Entergy's service area downstream of the Little Gypsy generating plant and includes the New Orleans metro area. The Amite South Units included in the study are Little Gypsy and Waterford. The DSG Units included in the study are Michoud and Nine Mile.

The West of the Atchafalaya Basin (WOTAB) encompasses the southwest portion of the Entergy footprint including a portion of Texas and Louisiana. It also includes Western Region, which is the portion of Entergy's service area west of the Trinity River. The WOTAB Units included in the study are Sabine and Nelson; the Western Region Units included in the study are Frontier and Lewis Creek.

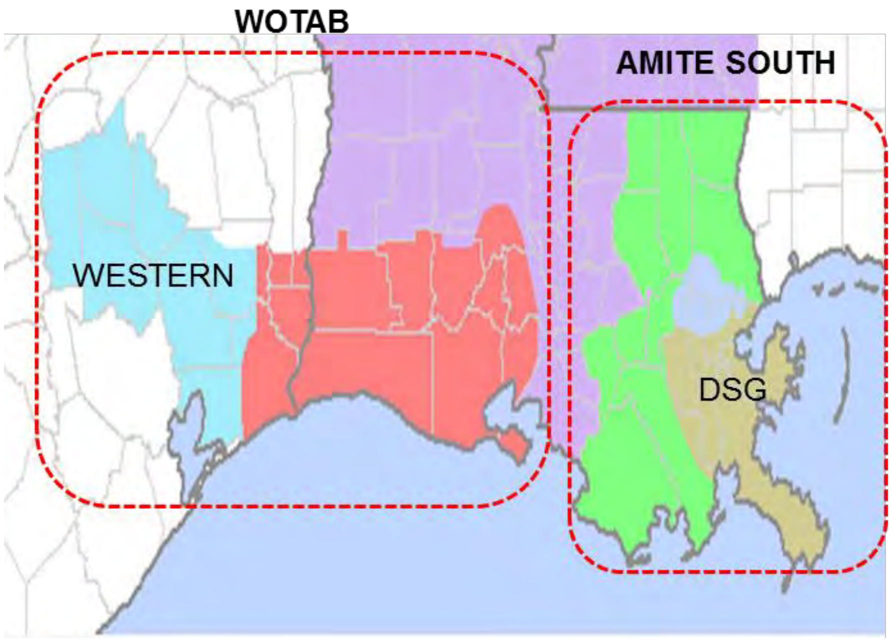


Figure 7.3-3: MISO South study regions

This study will produce the following deliverables:

- Identification of VLR unit commitment alternatives that are expected to provide comparable system performance as VLR unit commitments in the following load pockets/areas:
  - Amite South (including DSG)
  - WOTAB (including Western Region)
- Economic comparison of the cost of transmission alternatives versus generation commitment costs
- Project classification for cost-allocation to the extent transmission alternatives are recommended to be included in MTEP consistent with the existing MISO tariff

Schedule

This study started during the MTEP14 planning cycle and will take into consideration any upgrades identified for recommendation within MTEP14. Transmission upgrades determined to be cost-effective alternatives to VLR commitments will be recommended as projects for approval by the MISO Board when sufficient analysis and stakeholder vetting has occurred to establish the business case. The study will go through four phases before project recommendations are issued (Table 7.3-3).

Task	Expected Completion
Model development	May 2014
Reliability Analysis	Jun. – Aug. 2014
Solution Identification	Aug. – Nov. 2014
Economic Assessment	Nov. 2014 – Apr. 2015
Anticipated Project Recommendations	2015 Q2

Table 7.3-3: VLR study schedule

Study Approach

This study is organized as follows:

1. **Base Models**
   Latest available MTEP reliability and economic planning models will be used for this study. For reliability assessment including steady-state and dynamics analyses, scenarios studied will include 2019 and 2024 summer peak and shoulder load conditions. To the extent needed, additional scenarios will be considered. These could include, for example, a nearer-term summer case or an additional winter scenario. Economic assessment of preferred transmission solutions will be performed using the latest available PROMOD models under the Market Congestion Planning (MCP) study process. Simulations will be performed for the 2019, 2024 and 2029 timeframes to compute the economic value of transmission solutions.

   Additionally, models for sensitivity analyses may be developed as needed, which would include facilities such as proposed transmission or generation-side solution ideas (including generators that may not have executed generation interconnection agreements).

2. **Identification of System Limitations**
   Using the powerflow and dynamics models, the transmission system will be analyzed to identify potential system limitations that may be caused due to VLR generators not being committed.
   a) Review of VLR operating guides: At the outset, available operating guides will be reviewed to inform prioritization of VLR units for assessment. In general, units that have incurred the highest VLR costs will be the initial focus. The study will ensure that any upgrades identified to reduce the requirements for VLR commitment will address issues identified in actual system operations that cause the units to be committed. Close coordination with any revisions to existing operating guides will be maintained.
   b) Study region: The study region will comprise the entire MISO South region, which includes EES, Entergy Arkansas, Cleco Power, Southern Mississippi Electric, Louisiana Generating, Lafayette Utilities System and Louisiana Energy and Power Authority. Additionally, first-tier neighboring companies including SOCO, Tennessee Valley Authority, AECI and Southwestern Power Pool will also be included. Contingencies assessed will include the set of planning events within the study region consistent with those required under NERC Standard TPL-001-4. Any additional contingencies dictated by standing operating guides will also be evaluated as necessary. Facilities 100 kV and above in the study region will be monitored consistent with ongoing MTEP14 evaluations.
   c) Analyses: Steady-state thermal and voltage, voltage stability and angular stability analyses will be performed across the study region. Additionally, short-circuit analyses may be performed as needed.

3. **Identification of Alternative Solutions**
   a) Stakeholder input: After the reliability issues without VLR commitment have been identified, potential alternatives to VLR commitments including generation, demand-side and transmission solutions will be solicited from impacted load-serving entities, transmission owners and other stakeholders. Solution ideas will be discussed at the Planning Subcommittee (PSC). Solutions proposed in the parallel MCP studies in the MISO South region will also be considered to ensure a coordinated effort.
   b) Performance evaluation: Solution ideas will be tested for effectiveness for each of the load pockets/sub-pockets where reliability issues are identified. Performance will be evaluated in the mid-term as well as the longer term planning horizon (using the 2019 and 2024 models noted earlier). Costs of these transmission solutions will be documented on a net present value of annual revenue requirement basis.

4. **Economic Assessment of Transmission Benefit**
   a) Economic evaluation: MCP process will be used to establish comparative production cost values between various solutions. The preferred transmission, generation or demand-side solutions identified through the reliability assessment will be evaluated under the MCP process to evaluate potential economic benefits using the latest PROMOD models as mentioned earlier. Analysis will be performed on the 2019, 2024 and 2029 scenarios against a set of current Futures developed through the Planning Advisory Committee. Adjusted Production Cost (APC) differences between base cases without proposed solutions and change cases with the proposed solution included will be used to determine the cost-effectiveness of the solution studied.
   b) Results obtained will include:
      - Comparison of alternatives including existing VLR commitments, alternative generation options, demand side options and transmission upgrade options
      - Benefit-to-cost ratios for preferred solutions
      - Comparison of benefits against existing Market Efficiency Planning (MEP) criteria
   c) Potential generator retirements: Consideration will be given to identifying, for informational purposes, additional costs associated with possible future retirement of units under study. These costs will not be used in the benefits calculation needed for classifying solutions as MEP per the MISO tariff.

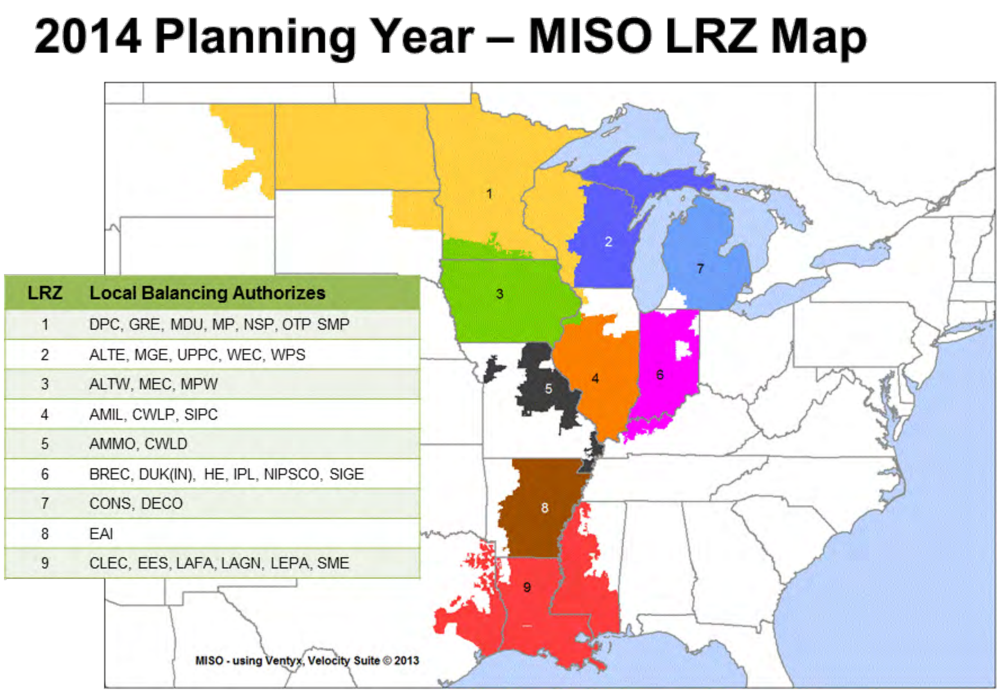
5. **Project Categorization and Recommendations**
   The intent of the study is to identify alternatives that allow reliable performance of the transmission system at a lower overall cost to loads. System upgrades identified through the reliability assessment will be evaluated for their economic value to determine if they are cost-effective alternatives to VLR generation commitments. Results of the economic assessment will be evaluated using existing MEP criteria to determine cost-allocation of the upgrades. Projects will be recommended when a business case has been developed that shows benefits commensurate with the costs. Projects are expected to be recommended to the MISO Board by the second quarter of 2015.

7.4 Independent Load Forecast

MISO procured an independent vendor, State Utility Forecasting Group (SUFG), to develop three-, 10-year horizon load forecasts. The annual deliverable is to develop an independent regional load forecast for the MISO Balancing Authority (BA). The first 10-year forecast (2015-2024) was due November 1, 2014.

SUFG produces econometric models for 15 states. The SUFG independent load forecast will include a seasonal peak forecast (Summer and Winter) that is MISO coincident and a coincident forecast for each of the nine Local Resource Zones. The long-term forecast will be based on MISO Business As Usual (BAU) planning future each year. MISO will develop the BAU assumptions each year.

The independent load forecast will be a 50/50 forecast, meaning there is a 50 percent probability that the load will either be 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 Load Resource Zone (LRZ) through the use of allocation factors. The MISO BA has 35 Local Balancing Authorities (LBA). The LBAs are aggregated into nine Local Resource Zones (LRZs) (Figure 7.4-1).



LRZ	Local Balancing Authorizes
1	DPC, GRE, MDU, MP, NSP, OTP SMP
2	ALTE, MGE, 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, SME

Figure 7.4-1: MISO LRZ map for planning year 2014.

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, limiting dependence on confidential or vendor data and new data requests. Each state forecast model and the associated assumptions will be 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 7.4-2), with forecast deliverables due annually no later than November 1. The project schedule outlines the activities and deliverables for 2014 (Table 7.4-1). Years 2015 and 2016 will follow a similar schedule.

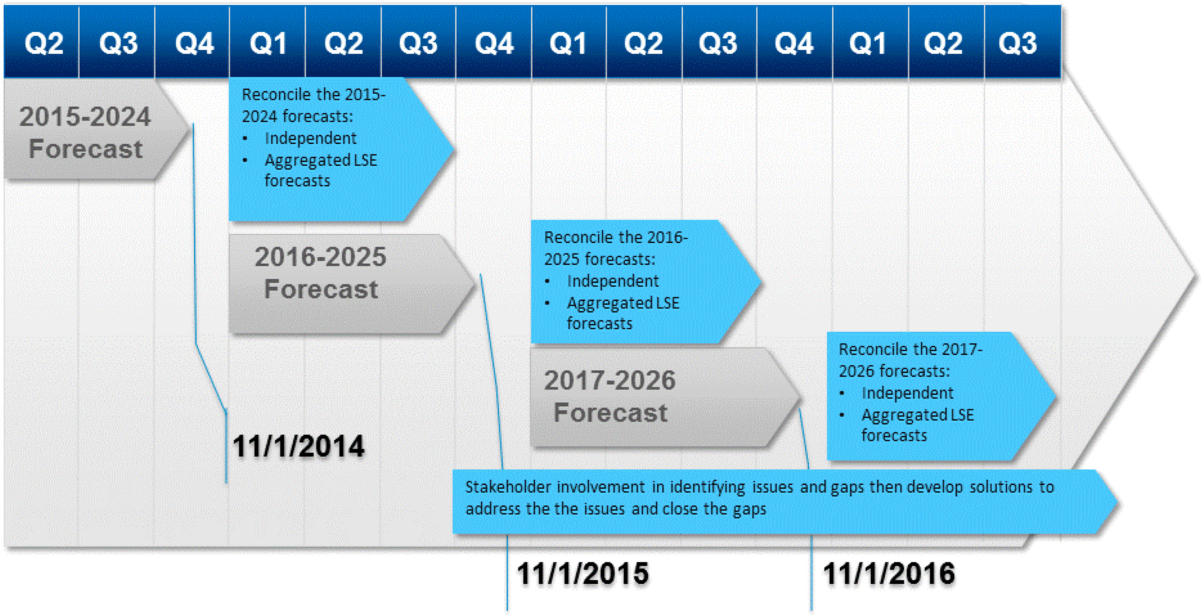


Figure 7.4-2: Independent Load Forecasting Project high-level schedule

Task	Key Activities and Milestones	Start Date	End Date	Deliverables
1	Acquire state level historical data	2/15/2014	3/31/2014	1. List of sources (public, vendor, etc.) 2. List of potential variables for the econometric forecast
2	Develop an econometric forecasting model for each state	2/15/2014	4/30/2014	1. Econometric forecasting model for each state 2. List of sensitivities around the variables for energy
3	Develop an electricity price projection model for each state	2/15/2014	5/20/2014	1. Electricity price projection model for each state
4	Determine allocation factors to convert state energy forecasts to each Local Resource Zone forecast	3/01/2014	6/30/2014	1. List of allocation factors to convert state energy to a Local Resource Zone forecast
5	Develop energy to peak demand conversion model for each Local Resource Zone	3/01/2014	7/31/2014	1. Conversion factor for each Local Resource Zone
6	Incorporate econometric model drivers	5/01/2014	6/30/2014	1. Aggregate list of variables and values 2. Confirm models are ready to produce a forecast
7	Generate a 10 year annual energy forecast for each state using its econometric forecast model	6/01/2014	7/31/2014	1. Annual 10 year (2015-2024) energy forecast by state
8	Determine 10 year annual energy forecast for each Local Resource Zone	7/01/2014	8/29/2014	1. An annual energy forecast for each Local Resource Zone for the next 10 years (2015-2024)
9	Determine 10 year seasonal peak demand for each Local Resource Zone	8/1/2014	8/29/2014	1. A 10 Year seasonal coincident and non-coincident peak forecasts for each Local Resource Zone for next 10 years (2015-2024)
10	Determine MISO's 10 year forecast for annual energy and seasonal peak demand	8/1/2014	9/15/2014	1. An annual energy forecast for MISO the next 10 years (2015-2024) 2. Seasonal coincident peaks for MISO
11	Stakeholder review of the demand and energy forecasts	9/16/2014	10/17/2014	1. Stakeholder comments
12	Independent 10 year (2015-2024) Demand and Energy forecast report completed	11/1/2014		1. A report summarizing the assumptions, data sources, the validation, and the forecast
13	Communicate and present results	10/1/2014	12/11/2014	1. Executive Summary with presentation

Table 7.4-1: Independent Load Forecasting Project detailed project schedule 2014.

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.

7.5 Carbon Analysis

MISO has been assessing evolving environmental policies since 2008 in the interest of ensuring an informed stakeholder body. These assessments include analysis of proposed carbon regulations for their effects on the electric grid. Similarly, in mid-2013, MISO initiated an investigation into the potential impacts of carbon emission limitations on electric generation of power. This refresh of MISO's 2010 carbon study[46] was a preliminary look at the potential impacts of the implementation of Section 111(d) of the Clean Air Act.

Results of this analysis indicate that status-quo MISO system operation could lead to a near-term drop in carbon emissions, due to the retrofit and retirement of many coal-fired generators, as well as the implementation of existing renewable portfolio standards

Results of this analysis indicate that status-quo MISO system operation could lead to a near-term drop in carbon emissions, due to the retrofit and retirement of many coal-fired generators, as well as the implementation of existing renewable portfolio standards (RPS). However, emissions are projected to return to 2005 levels by 2032 and continue to grow in subsequent years.

In 2013, considerable uncertainty remained around the design of final emissions rules; accordingly, MISO evaluated various approaches to carbon reduction, including regional versus sub-regional carbon management, as well as more than 1,000 sensitivities around RPS, carbon cost, and/or coal capacity retirements. Study findings indicate:

- A regional (MISO-wide) carbon management approach has the potential to reduce compliance costs by $3 billion to $5 billion annually ($30 billion to $50 billion 20-year net present value) versus zonal (MISO Local Resource Zone) emissions reduction (Figure 7.5-1).

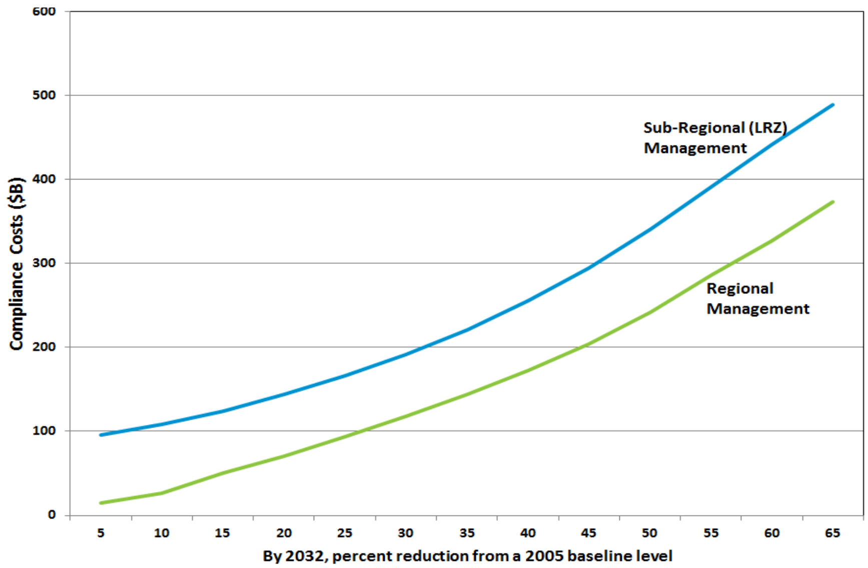
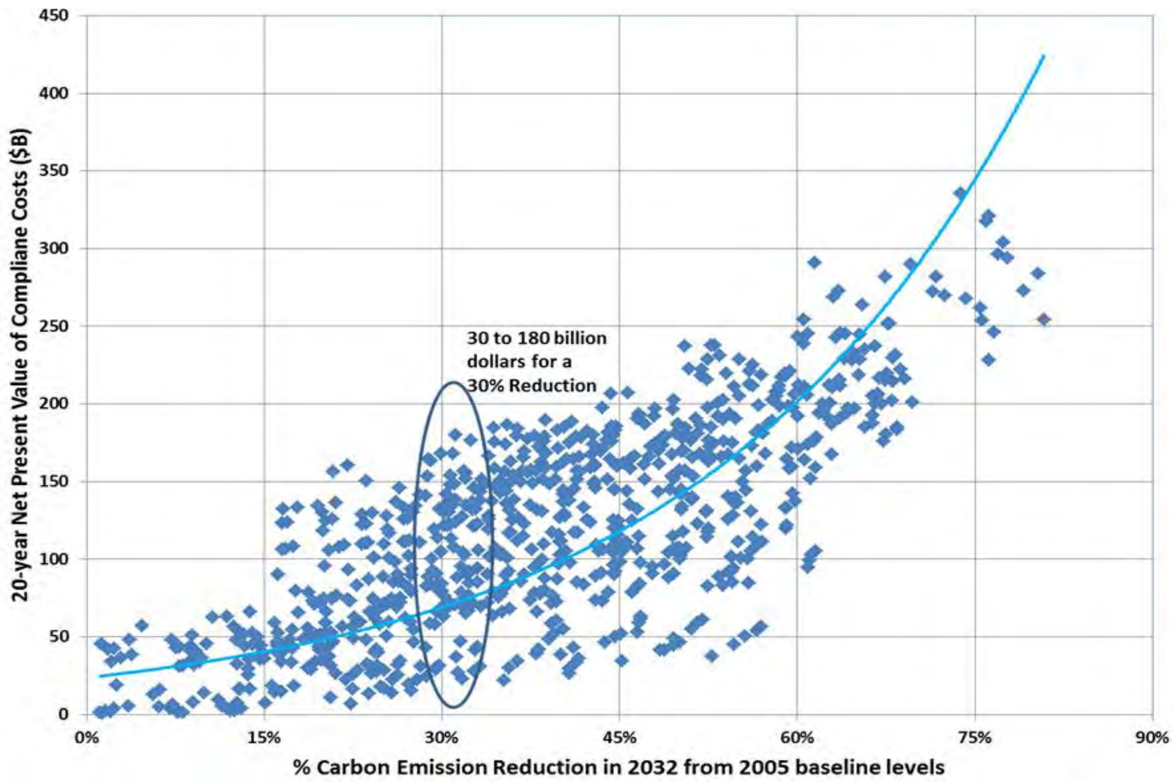


Figure 7.5-1: Sample compliance cost comparison under a business-as-usual future, for regional vs. sub-regional implementation of carbon reduction strategies ($B net present value for 20-year study period)

[46] See https://www.misoenergy.org/Library/Repository/Study/MTEP/MTEP10/MTEP10%20Report.pdf, pages 280-283.

- One carbon management strategy alone may not be enough to meet emission reduction targets, such as solely RPS or solely carbon costs

- For given policy and economic conditions, certain combinations of carbon reduction strategies are more cost effective than others; carbon regulations for a geographically and operationally diverse footprint should allow for flexibility in emissions management. There is a wide range of costs across a spectrum of carbon reduction strategies (Figure 7.5-2)



**Each diamond represents a sample carbon reduction strategy, given assumptions on economic and policy conditions. The reduction strategies modeled are not recommendations.*

Figure 7.5-2: Sample MISO Carbon Analysis results (20-year net present value compliance cost range to achieve a 30 percent reduction in emissions in the MISO footprint)

The Clean Power Plan

On June 2, 2014, the U.S. Environmental Protection Agency (EPA) released a draft rule[47], issued under Section 111(d) of the Clean Air Act, designed to reduce carbon dioxide (CO_2) emissions from existing electric power generators. The rule was published in the Federal Register on June 18, with a 120-day

[47] See https://www.federalregister.gov/articles/2014/06/18/2014-13726/carbon-pollution-emission-guidelines-for-existing-stationary-sources-electric-utility-generating.

comment period. The comment period has since been extended to Dec. 1, 2014. The timeline for rule development and implementation spans from 2014 to 2030 (Figure 7.5-3).

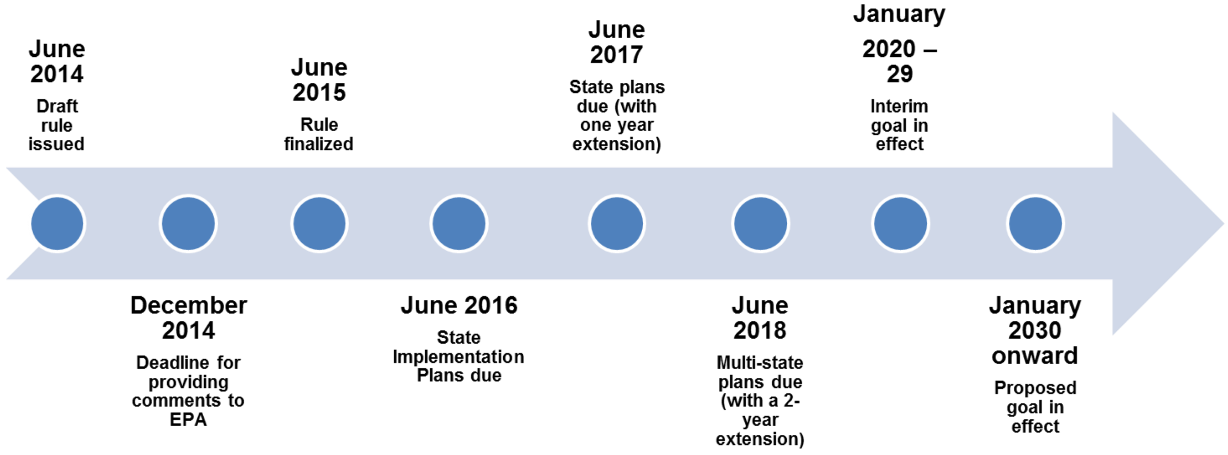


Figure 7.5-3: Clean Power Plan timeline

The proposal, called the Clean Power Plan, includes these major elements:

- State-by-state targets that collectively result in reducing CO_2 emissions from the existing fleet of electric generating units by approximately 30 percent from 2005 levels, with a target compliance date of 2030
- State-by-state targets (expressed as a rate of CO2/MWh) developed based on the four building blocks (Figure 7.5-4)
- The application of formulaic building blocks to determine each state's reduction capability, and subsequently, each state's emissions reduction target (Figure 7.5-4) — calculated from a 2012 emissions baseline

Building Blocks			
BLOCK 1 Improve efficiency of existing coal plants	**BLOCK 2** Increase reliance upon combined cycle (CC) gas units	**BLOCK 3** Expand use of renewable resources and sustain nuclear power production	**BLOCK 4** Expand use of demand-side energy efficiency
EPA Calculations / Assumptions in the Development of Proposed State Goals			
6 percent efficiency (heat rate) improvement across the fleet, assuming best practices and equipment upgrades	Re-dispatch of CC gas units up to a capacity factor of 70 percent	Meet regional non-hydro renewable target, prevent the retirement of at-risk nuclear capacity and promote the completion of nuclear capacity under construction	Scale to achieve 1.5 percent of prior year's annual savings rate

Figure 7.5-4: Clean Power Plan proposed building blocks and applications

Though the Clean Power Plan establishes a compliance timeline it doesn't prescribe specific methods to meet reduction requirements. Rather, the rule identifies a variety of ways to reduce emissions, including via interstate cooperation. It also observes that Independent System Operators (ISOs) and Regional Transmission Organizations (RTOs) "could provide a structure for achieving efficiencies" in implementing the 111(d) carbon standards for existing power plants and could help foster those efficiencies "by coordinating the state plan approaches applied throughout a grid region[48]."

State Plans

Each state goal for carbon emissions reduction is actually a pollution-to-power ratio, i.e. a rate for future carbon intensity of applicable, existing electric generators in a given state.[49] The EPA's Building Blocks can be applied to reach the state carbon intensity targets (Figure 7.5-5). In Figure 7.5-5, the far right of each bar represents the 2012 emissions baseline; each successive colored bar factors in another building block. The white bar represents the emissions rate per state in 2030, as calculated in the draft rule. The variance in emissions allowances derives from the existing resource mix in each state and the EPA's method of determining the feasibility of emissions reduction given existing resources. Under the Clean Air Act, the draft rule's State Plan requirement will be addressed by each state's respective air quality office.

[48] See http://www.gpo.gov/fdsys/pkg/FR-2014-06-18/pdf/2014-13726.pdf.
[49] See http://blog.epa.gov/epaconnect/2014/06/understanding-state-goals-under-the-clean-power-plan/

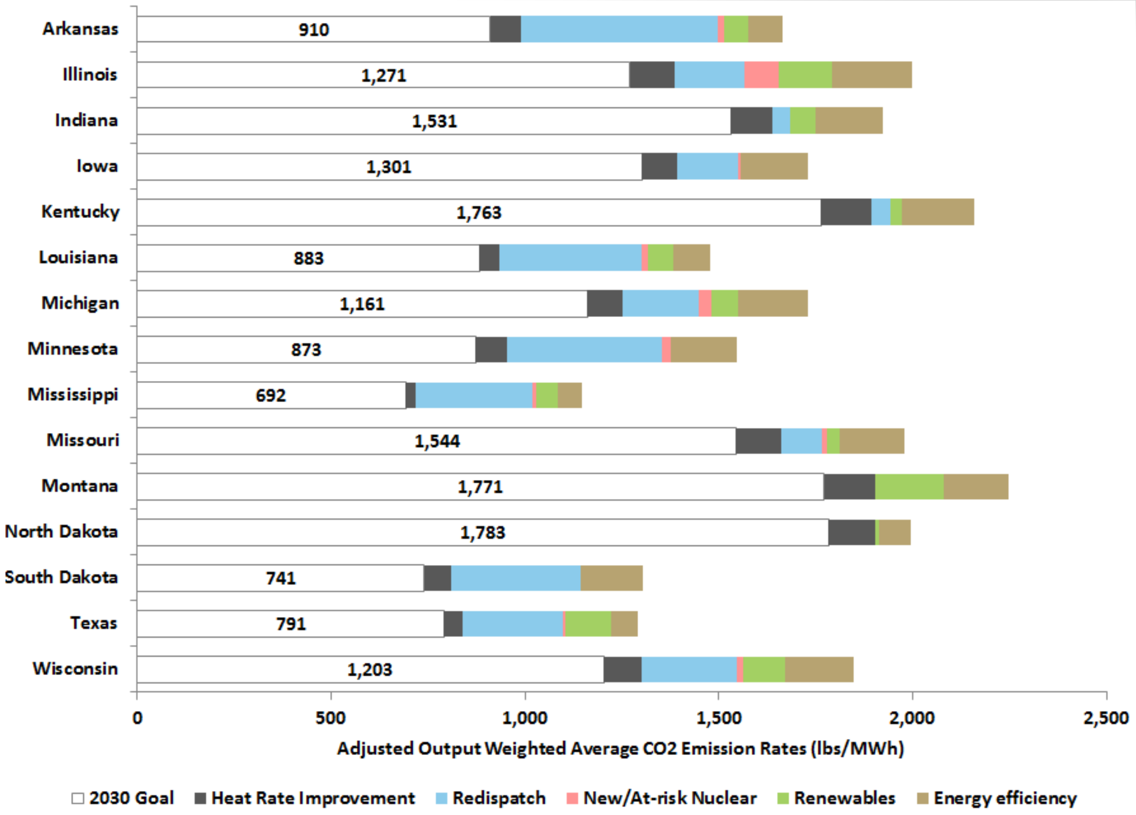


Figure 7.5-5: Sample application of EPA building blocks to MISO states' carbon emissions rates

MISO's 2014 Carbon Analysis

The proposed carbon regulations have the potential to significantly impact the generation fleet in the MISO footprint, and subsequently, the operation of the electric transmission system. While MISO's historical carbon analyses laid the foundation for investigation into carbon regulation impacts, more analysis is needed to determine how the system may perform in a Clean Power Plan-compliant future.

The proposed carbon regulations have the potential to significantly impact the generation fleet in the MISO footprint, and subsequently, the operation of the electric transmission system

Insight from preliminary analyses was shared with stakeholders via the MISO Planning Advisory Committee (PAC)[50] in June 2014. Likewise, stakeholder input on the 2014 carbon study scope and modeling methodology was solicited.

The study scope includes two phases (Figure 7.5-6):

1) Calculate compliance costs for regional (footprint-wide) versus sub-regional (MISO Local Resource Zone) carbon management

[50] See https://www.misoenergy.org/Library/Repository/Meeting%20Material/Stakeholder/PAC/2014/20140625/20140625%20PAC%20Item%2008%20GHG%20Regulation%20Impact%20Analysis.pdf.

a. This approach applies the building blocks in the modeling process individually (e.g. only Building Block 1 is modeled) and in combination (all four building blocks are modeled together), the latter as proposed in the draft regulation.

2) Examine the range and cost of emissions reduction in various sensitivities, including adjustments to Renewable Portfolio Standards, demand and energy growth rates, natural gas prices ($/MMBtu), carbon costs ($/ton), coal capacity retirements (beyond those currently projected), energy efficiency programs, and nuclear retirements.

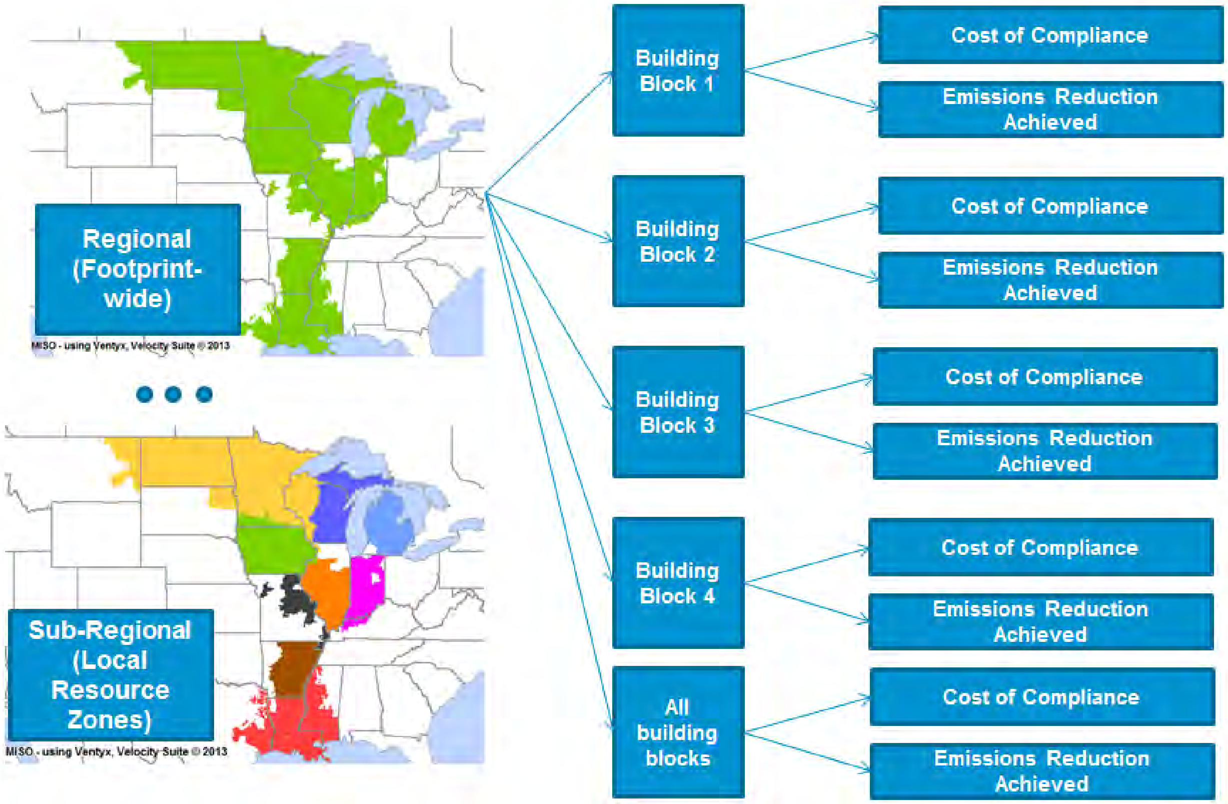


Figure 7.5-6: Representation of Phase I of MISO's 2014 Carbon Analysis

The proposed timeline for MISO's analysis spanned three months (Figure 7.5-7) and was designed to produce results for stakeholders in advance of the original October 16 deadline for submitting comments on the draft rule.

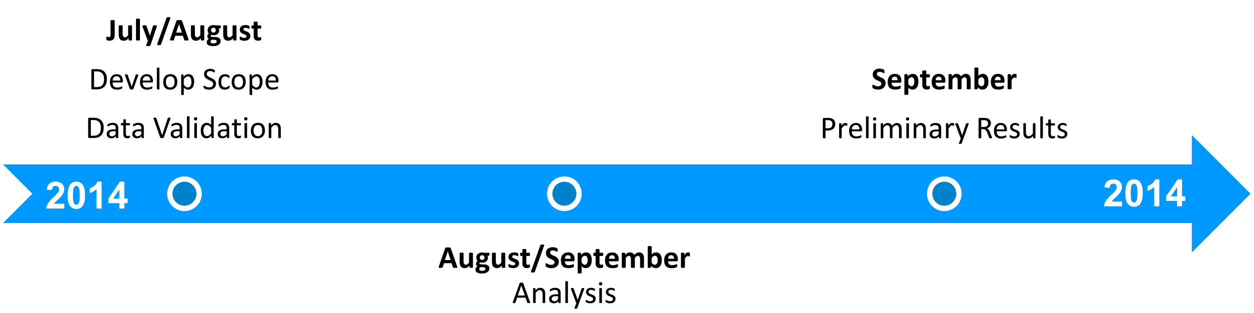


Figure 7.5-7: MISO analysis timeline

Phase I and II are preliminary analyses; MISO will investigate the potential for additional analysis beyond the comment period on the draft rule. MISO continues to work with its stakeholder and state and federal regulators; the on-going carbon analysis efforts at MISO are designed to better understand the potential impacts of compliance with the draft rule.

7.6 Economic Impacts From MTEP In-Service Projects

Construction of electrical transmission, like any infrastructure investment, produces local economic impacts – impacts that extend beyond the initial expenditures. The money spent does not disappear, but rather, cascades through the economy, supporting local jobs and wages. Using a program called IMPLAN,[51] it is possible to estimate the impacts on jobs, labor income, value-added and tax revenue.

Construction of electrical transmission, like any infrastructure investment, produces local economic impacts – impacts that extend beyond the initial expenditures

Each MTEP cycle produces transmission projects for MISO Board consideration, approval and subsequent construction. The projects are designed to address reliability issues, system congestion and policy mandates. Since the first MTEP in 2003, more than $7.4 billion of projects have been constructed in the MISO region.

During MTEP14, MISO conducted initial analysis on how these in-service MTEP projects could translate into jobs, labor income, and other economic impacts. In MTEP15, MISO will be collaborating with stakeholders to 1) discuss the value this perspective brings, 2) review the theory behind this type of analysis, and 3) peer-review and update the assumptions.

No model, including this one, can capture all aspects of transmission. This analysis does not capture reliability or congestion benefits. It makes no claim that the jobs supported by transmission construction are net new jobs. And there is no intention to use this tool to justify the approval of MTEP projects. This type of analysis is intended simply to show the impact of transmission construction from a different perspective.

[51] IMPLAN Version 3 Modeling System

Chapter 8
Interregional Studies

8.1 Cross-Border Planning (MISO-PJM)

The MISO-PJM Joint Coordinated Planning Study evaluates cross-border seams issues and identifies transmission solutions to enhance market efficiency and coordination on the MISO-PJM boundaries. This cross-border study, running from September 2012 to August 2014, was conducted under the auspices of the Joint RTO Planning Committee (JRPC) and facilitated by stakeholder participation through an Interregional Planning Stakeholder Advisory Committee (IPSAC). The conclusion of this study marks the first comprehensive effort by the two Regional Transmission Owners (RTO) to develop a joint coordinated planning model and study framework to explore mutually beneficial transmission expansion opportunities. To facilitate this planning on the seams, the study was comprised of two phases:

- Assessment of the applicability of transmission expansion solutions to recent and current market-to-market congestion issues.
- Joint market efficiency planning analysis to:
    - Develop a projection of the expected congestion persistence level over the 15-year planning horizon
    - Identify opportunities for the development of RTO level and Cross-Border Market Efficiency Projects (CBMEP), as defined in the MISO-PJM Joint Operating Agreement (JOA).

Two projects – one each in future 2 and 3 – met both the cost and benefit-to-cost ratio CBMEP criteria, and referred to respective regional planning processes

To address congestion identified through Phase 1 of the study, a total of 88 transmission solution ideas were proposed by 12 entities. The potential solutions were evaluated under a multi-year and multi-scenario economic analysis and measured against the CBMEP criteria specified in Article IX of the current MISO-PJM JOA. Several iterations of this analysis were performed based on stakeholder feedback and updated models. Based on the third iteration economics results, two projects – one each in Future 2 and 3 – met both the cost and benefit-to-cost ratio CBMEP criteria:

- Ameren 2: Big Stone – Blair 230 kV
- Transource A #2-2: New Canby Station, taps on Big Stone – White (345 kV) and Watertown – Granite Falls 230 kV.

The two projects will be referred to the respective regional MISO and PJM planning processes in which, as stipulated by the JOA, the projects must also meet the regional MEP criteria. Both projects do not meet the voltage threshold under MISO regional tariff for MEP and will not be considered as CBMEP under the current JOA.

Over the course of the study, several lessons have been learned about the effort to identify CBMEPs. Stakeholders have provided feedback on subjects ranging from study scope to benefit metrics to CBMEP criteria model building. A tentative schedule has been proposed to the Joint Common Market (JCM) and IPSAC to address the issues raised and to discuss the possible implementation of lessons learned.

Drivers

The MISO-PJM JOA requires a comprehensive, coordinated regional planning study to occur at least once every three years. Previous collaborative studies in compliance with the JOA protocols have included the Joint Coordinated System Plan (JCSP) and Cross-border Top Congested Flowgates studies.

To continue the collaborative interregional planning efforts, this study was intended to enhance seams coordination; address, as appropriate, persistent market inefficiencies; and provide a framework under which inter-regional planning studies are conducted.

A joint study approach provides a common platform for the combined RTOs' stakeholders to participate in the evaluation and review of identified cross-border transmission plans (Figure 8.1-1). The development of joint and common planning models created a foundation for joint analyses of potentially actionable transmission plans. MISO and PJM developed three future scenarios and corresponding models. The three future scenarios are policy-driven, centered on MISO and PJM renewable portfolio standards (RPS).

- Scenario 1: MISO meets state RPS mandates while PJM expands generation to include only queue projects
- Scenario 2: Both MISO and PJM meet their respective state RPS mandates with wind additions internal to the respective regions
- Scenario 3: MISO meets both its state RPS mandates and goals while PJM meets only state mandates. In addition approximately 30 percent of PJM's RPS targets will be met by wind sited in MISO

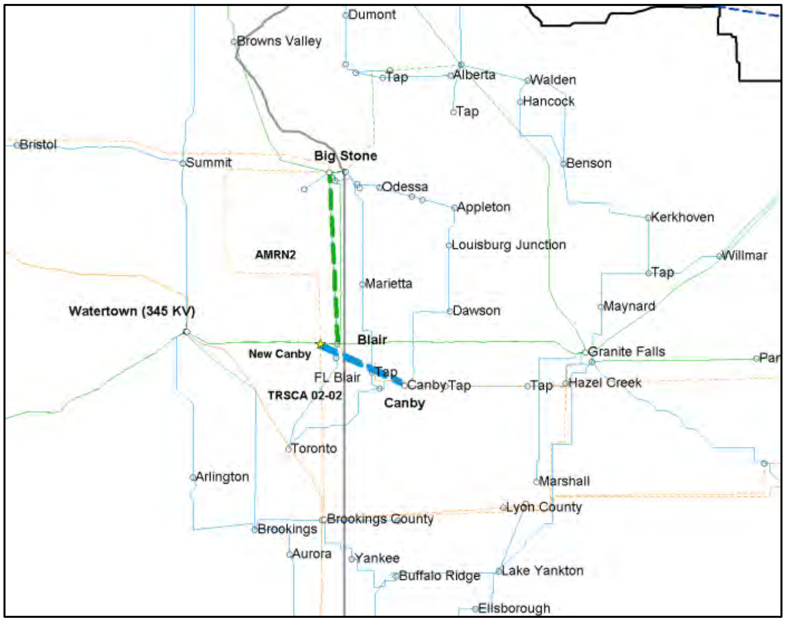


Figure 8.1-1: Projects passing cost and benefit-to-cost ratio criteria

A more detailed description of the future scenarios is covered in the Model Development part of this chapter.

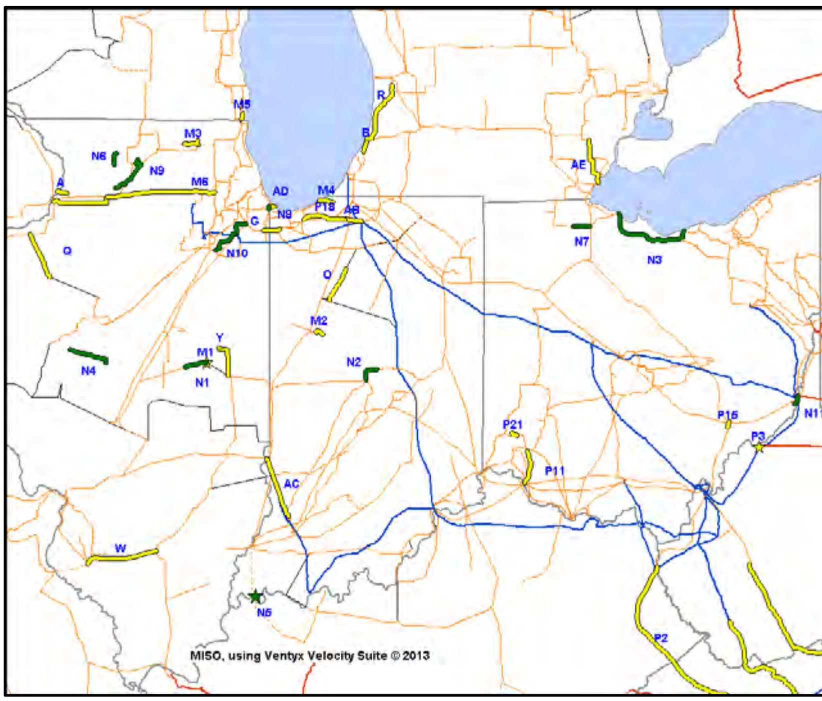
Scope

Phase 1: Assessment of Recent Market-to-Market Congestion Issues

Phase 1 of the study focused on gathering RTO and stakeholder information about historical market-to-market (M2M) congestion with supporting information to quantify the impact of these transmission constraints and possible drivers. Using historical congestion cost and settlements data from January 2011 to October 2012 from both RTOs, a total of 33 M2M flowgates (27 unique monitored lines) were identified as the most constrained.

In addition to these M2M flowgates, a total of 11 non-M2M flowgates that showed significant congestion and a high shift factor from generators in both RTOs were selected to be monitored during the study.

The majority of top historically congested flowgates are located along the MISO-PJM seams (Figure 8.1-2). Flowgates A – AE are the common flowgates selected from both MISO and PJM analyses, M1 – M6 were uniquely selected by MISO, while P2 – P21 were a result of PJM evaluation. N1 – N11 are the top selected MISO-PJM non-M2M flowgates.



A	Beaver Channel – Albany 161kV
B	Benton Harbor – Palisades 345kV
E	Cordova – Nelson 345kV
G	Crete – St Johns 345kV
M	Marengo – Woodstock 138kV
O	Monticello – East Winamac 138kV
Q	Oak Grove – Galesburg 161kV
R	Palisades – Roosevelt 345kV
W	Prairie State – Mt Vernon 345kV
Y	Rantoul – Rantoul Junction 138kV
AB	Stillwell – Dumont 345kV
AC	Breed – Wheatland 345kV
AD	Sheffield – Marktown 138kV
AE	Monroe – Wayne 345kV
M1	Rising 345/138kV XFMR (Fg Z)
M2	Cumberland – Bush 138kV (Fg H)
M3	Marengo – Pleasant Valley 138kV (Fg L)
M4	Michigan City – Laporte 138kV (Fg N)
M5	Kenosha – Lakeview 138kV (Fg J)
M6	Nelson – Electric Junction 345kV (Fg P)
P2	AEP – DOM Interface
P3	Belmont 500/765 XMFR
P11	Pierce – Foster 345kV
P15	Waterford – Muskingum 345kV
P18	Babcock – Stillwell 345kV
P20	Rantoul Jct – Sidney 138kV
P21	Toddhunter – Trentton 138kV
N2	Whitestown-Guion 345kV
N3	Ottawa-Lakeview 138kV
N4	Havana-Elkhart 138kV
N5	AB Brown 138/345kV Xfmr
N6	Marylan - Bailey 138 kV
N7	Lemoyn - Bowling Tap 138 kV
N8	Hegewisch - Burnham 138 kV
N9	Dixon - Still 138 kV
N10	Braidwood - E Frankfort 345 kV
N11	Kammer - Natrium 138 kV

Figure 8.1-2: Top congested market-to-market flowgates

Phase 1 served as a screening to determine if these identified congestion issues lend themselves to modified market protocols or transmission upgrades.

Phase 2: Joint Market Efficiency Planning Analysis

Phase 2 focused on performing joint market efficiency analysis to examine and project system congestion trends. This was based on historical market data as well as forward-looking future congestion patterns using out-year production cost model simulations. Phase 2 sought to identify and mitigate, with a coordinated portfolio of expansions, congested flowgates that have a high impact on either or both markets.

Information examined to find such flowgates included:

- Historical binding constraints identified from market-to-market operations
- Future projected congested transmission elements identified via out-year production cost model simulations using the mutually agreed upon joint planning model assumptions

The projected 2028 congestion levels near and across the seams vary per future scenario (Table 8.1-1).

Flowgate Region	Future 1 Congestion Cost (M$)			Future 2 Congestion Cost (M$)			Future 3 Congestion Cost (M$)		
	2018	2023	2028	2018	2023	2028	2018	2023	2028
MISO Internal Flowgates	395	635	1,152		652	1,273		880	2,069
PJM Internal Flowgates	307	588	866		944	1,438		716	1,088
MISO-PJM Cross Border Flowgates	34	47	87		55	81		75	209
MISO and PJM Companies on Seams	298	322	650		575	1,116		489	1,140

Table 8.1-1: Projected 2028 congestion

The sum of rows “MISO internal” and “PJM internal” for each future gives the total congestion in both MISO and PJM. A comparison of this sum to the “MISO and PJM companies on seams” row reveals that a majority of the congestion seen in the combined MISO-PJM region is on flowgates located in the companies along the seams. A study was initiated to seek ways to relieve this congestion.

For a flowgate to be considered for mitigation under the MISO-PJM JOA, the constraint must have at least one generator in the adjacent market with a generation to load shift factor (GLDF) greater than 5 percent. The flowgates that became the focus of the study included both the top historically congested flowgates identified in Phase 1 and flowgates projected to be persistently constrained in out-years; these flowgates, selected for each future, have material impact on both planning regions. The majority of flowgates selected are located across or near the MISO-PJM seams; however, a few are farther within MISO or PJM but are electrically close to the seams (Figure 8.1-3).

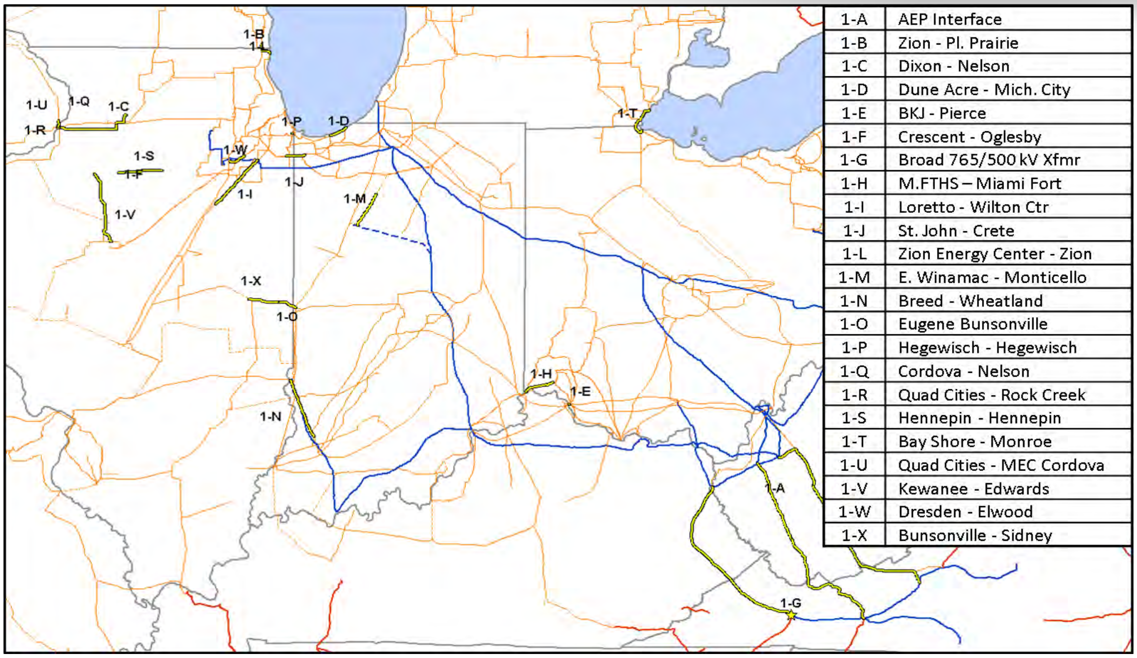


Figure 8.1-3: Future 1 candidate flowgates

Model Development

A jointly developed planning model was built, consistent with the regional planning requirements and processes of both RTOs. Key assumptions were made for this cycle of the study (Table 8.1-2):

Variable	JOA Future Assumption	
Demand and Energy Growth	Provided by respective RTO	
Demand Response and Energy Efficiency	Provided by respective RTO	
Regional Generation Forecast	Provided by respective RTO	
Fuel Prices	Natural Gas	$3.58 in 2013 (NYMEX forward curve for the first 3 years and escalated thereafter)
	Oil	PowerBase Default
	Coal	PowerBase Default
	Uranium	PowerBase Default
Escalation Rates	2.50% (except 3.44% for Natural Gas)	
Emission Costs	Zero Emission Costs	
Regional Coal Retirements	~12.6 GW in MISO, ~14 GW in PJM	

Table 8.1-2: Key joint model assumptions

With the assumptions as a foundation, MISO-PJM agreed upon three future scenarios to capture different policy issues around state renewable portfolio standards. For each of these futures, detailed planning models were developed for 2018, 2023 and 2028; borrowing from models used in each region's planning process. Regional generation expansions were determined for each of the three futures (Table 8.1-3)

Future	MISO		PJM	
	Renewable Portfolio Standards	Approx. Nameplate Wind (MW 2028)	Renewable Portfolio Standards	Approx. Nameplate Wind (MW 2028)
Future 1	State Mandates	21,865	Queue Only	22,396
Future 2	State Mandates	21,865	State Mandates	32,438
Future 3	State Mandates + Goals	23,965 +10,042 Export to PJM	State Mandates	22,396

Table 8.1-3: Regional generation forecast

Transmission Solution Evaluation

The IPSAC opened a window to solicit solutions to address the identified flowgates. In total, 88 transmission projects were submitted by 12 developers. In a MISO-PJM open stakeholder forum, the potential solutions were evaluated through a multi-year and multi-future economic analysis and tested against the CBMEP. The JOA specifies the following CBMEP criteria:

- Minimum project cost of $20 million; evaluated as part of a Coordinated System Plan or joint study process
- Meet the benefit-to-cost ratio threshold of 1.25 under JOA for CBMEP
- Meet the benefit-to-cost ratio threshold under each of MISO and PJM tariff provisions for MEP
- Address one or more constraints for which at least one dispatchable generator in the adjacent market has a GLDF of 5 percent or greater with respect to serving load in that adjacent market

The multi-year analysis was performed to cover, at a minimum, the first 10 years of the project life and up to a 20-year horizon from the current year. The efficacy of each transmission plan was measured using the JOA CBMEP benefit metric:

70 percent Adjusted Production Cost Savings (APCS) + 30 percent Net Load Payment Savings

Adjusted Production Cost (APC) represents the cost to each RTO to meet its own native load. This is the production cost adjusted for interchange purchases and sales calculated on an hourly basis. Net Load Payments (NLP) represents each RTO's gross load cost less the estimated value of congestion-hedging.

The economic evaluation, done over the course of several months, consisted of model updates based on feedback received from stakeholders. After each of the three iterations of evaluation, the results were openly discussed with all parties at the IPSAC meetings.

Of the 88 projects proposed, 19 showed benefits to both PJM and MISO in least one future, while 29 and 30 were beneficial in at least one future to PJM and MISO respectively. The results of the third iteration showed that two projects met both the CBMEP cost and benefit-to-cost ratio criteria:

- Ameren 2: Big Stone – Blair 230 kV

- Transource A #2-2: New Canby Station, taps on Big Stone–White (345 kV) and Watertown–Granite Falls 230 kV.

The two projects were referred to the respective regional MISO and PJM planning processes in which, as stipulated by the JOA, the projects must also meet the regional MEP criteria. Neither project meets the voltage threshold under MISO regional tariff for MEP and will not be considered as CBMEP under the current JOA.

Future Efforts

Consistent with the requirements of FERC Order 1000, following the completion of Phases I and II of this effort, MISO and PJM will periodically re-execute cross-border planning analysis pursuant to the requirements of the Joint Operating Agreement.

Over the course of the JOA study, several lessons have been learned regarding the processes and methods presently employed by the study, many of which are prescribed by the JOA. In preparation for the next cycle of the joint study, a parallel discussion will proceed through the IPSAC to address the issues identified and possible implementation of any applicable enhancements. The areas for discussion will include study scope, CBMEP criteria, futures selection, model building and benefit metrics. A tentative schedule for this effort, running from September 2014 to June 2015, has been presented to the IPSAC and JCM.

8.2 MISO-SPP Coordinated System Plan Study

The MISO-Southwest Power Pool (SPP) Joint Planning Study will jointly evaluate seams transmission issues and identify transmission solutions that efficiently address the identified issues to the benefit of MISO and SPP. This study will incorporate two parallel efforts:

- Economic evaluation of seams transmission issues
- Assessment of potential reliability violations

As part of the pending FERC-filed MISO-SPP Joint Operating Agreement (JOA), and in an effort to enhance interregional coordination and plan transmission efficiently, MISO and SPP conducted a joint annual issues review with stakeholders. The Interregional Planning Stakeholder Advisory Committee (IPSAC) met on January 21, 2014, and the general consensus from stakeholders was that there are many transmission issues needing evaluation. The range of issues includes:

- Congestion
- Integration of the MISO South region
- Expanded market operation by SPP
- Real-time operational issues
- Reliability issues
- Public policy requirements

The Joint Planning Committee (JPC), during the development of the Coordinated System Plan (CSP) scope, took into consideration those proposed issues. After further review with stakeholders the study scope was finalized in June 2014[52].

The proposed Order 1000 interregional coordination procedures, pending at FERC, will be used to guide the process for this study. Previous coordinated efforts included development of a joint future that included discussions around the uncertainty variables in a joint and common model coincident in both the MISO and SPP planning processes. This joint study will provide an initial effort to enhance interregional coordination, to jointly evaluate seams transmission issues, and to identify efficient transmission solutions to the benefit of both MISO and SPP.

Economic Evaluation of Seams Transmission Issues

Joint Future Development

The economic evaluation effort began with developing a joint future for transmission solutions to be evaluated utilizing a joint model. With input from stakeholders, the joint future chosen for this initial joint study effort is a Business as Usual (BAU) scenario based off the 2015 MISO MTEP BAU future and the 2015 SPP Integrated Transmission Plan 10-Year Assessment (ITP10) BAU Future (Table 8.2-1). In addition to the BAU future this study includes three sensitivities to evaluate the impacts of a carbon price,

[52] https://www.misoenergy.org/Events/Pages/IPSAC20140512.aspx

higher natural gas price forecast, and a 1,000 MW limitation between MISO North/Central and South on congestion between the two planning regions[53].

Regional BAU Futures	Demand and Energy Growth	Retirements	Natural Gas Price	RPS (10-year incremental GW)	CO_2	DSM (annual reduction in year 10 for EE/DR)
MISO	0.8%	12.6 GW Coal	$4.30 (2014 $)	3.6 GW wind/ 1.1 GW Solar	None	6,000 GWh/ 12 MW
SPP	1.3%	< 1 GW Coal	$5.41 (2014 $)	3.3 GW Wind/ 20.5 MW Solar	None	Embedded in Load

Table 8.2-1: Regional Business as Usual future major assumptions

Joint Model Development

The foundation of the joint model for this study is the Ventyx PROMOD model. The model is updated with each RTO's modeling assumptions from their respective regional planning models. The study is using model years 2019 and 2024 for evaluating potential transmission solutions. The modeling footprint includes the following regions (Figure 8.2-1):

- MISO
- SPP
- AECI
- Manitoba
- MRO
- PJM
- SERC
- TVA

[53] The 1,000 MW limit as used in this study refers to the contract path between Ameren, AECI and Entergy.

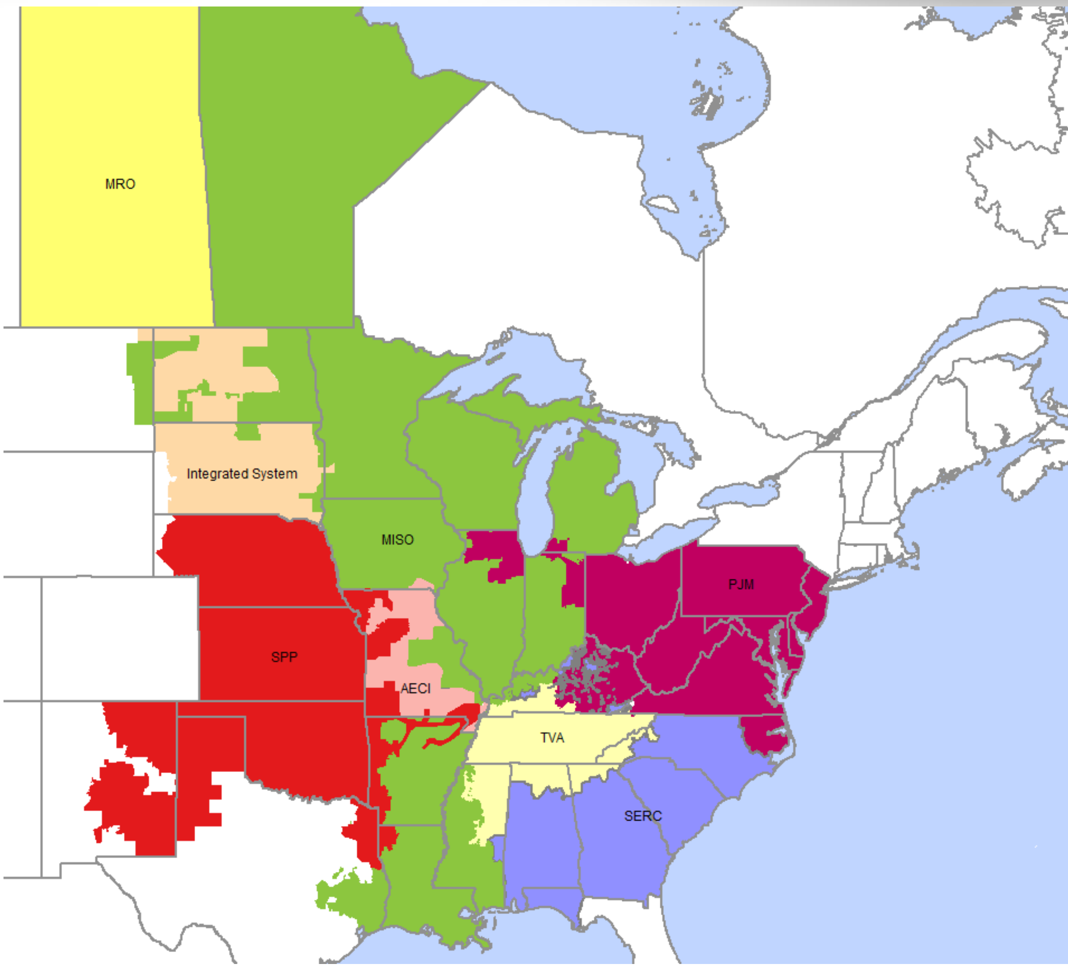


Figure 8.2-1: MISO-SPP CSP Study Modeling Footprint

The SPP footprint and balancing authority includes the Integrated System (WAPA, Basin, Heartland) with their projected integration into SPP in October 2015.

Congestion Analysis

The historical congestion analysis of the combined RTO's footprint with a focus on the seams will identify congested flowgates based on historical Transmission Load Relief (TLR) congestion using the NERC TLR database for 2013. The historical congestion data and analysis will be refreshed after six months of SPP market experience and additional MISO South region experience to review whether and how congestion on the transmission system has changed.

The projected congestion analysis will be identified using the 2019 and 2024 BAU future PROMOD simulations. The flowgates will be ranked using the following indicators:

1. Binding hours – number of hours in a year the flowgate is binding.
2. Shadow price – reduced production cost for each MW increase of thermal rating on the flowgate.
3. Congestion costs – flowgate shadow price multiplied by MW flow on the flowgate.

Transmission Solution Development

Each respective RTO staff and stakeholders will be able to propose solutions to address the identified transmission issues. Solutions will be solicited through the MISO-SPP IPSAC meetings.

Transmission Solution Evaluation

A preliminary screening analysis will be performed on the proposed transmission solution ideas to select and determine those with potential for further evaluation. The ideas will be reviewed for duplicative and/or similar projects and consolidated. Also, congestion-related ideas that do not address the congestion identified in the joint model are eliminated from the MISO-SPP CSP study.

All transmission solution ideas that have potential benefit will be evaluated for adjusted production cost benefits to MISO and SPP. To calculate an indicative benefit-to-cost ratio for proposed transmission solutions, a 20-year present-value calculation of benefits and costs will be used. Benefits will be calculated by the change in adjusted production cost with and without the proposed interregional project. The adjusted production cost will account for purchases and sales. The benefit metric will be calculated for the simulated years 2019 and 2024. Benefits for intermediary years will be calculated using interpolation and years beyond 2024 using extrapolation. The period covered by the benefit and cost calculation will be 20 years starting with the project's in-service year. The annual costs will be calculated using an average carrying cost of existing Transmission Owners in MISO and SPP. The present-value calculation will apply an 8 percent discount rate to the nominal benefit and cost value.

Additional analyses will be performed using the three sensitivities. The proposed interregional projects identified in the assessment utilizing the BAU future will be evaluated using the three sensitivities to determine how the projects perform under these scenarios. The impact on the APC benefits for each RTO will be reported, however these results will not alter the interregional allocation of costs.

The carbon price and high gas price values will be developed by the JPC and reviewed by the IPSAC. The IPSAC will have an opportunity to review and provide input on the modeling methodology for a 1,000 MW limitation.

Interregional projects identified to address congestion will be evaluated to ensure they do not create reliability issues with a no-harm test. The evaluation may result in the modification of the interregional project or identification of additional interregional facilities that are needed to mitigate any projected reliability issues.

Interregional Cost Allocation

MISO and SPP have agreed to use adjusted production cost to allocate the expense of proposed interregional projects to each planning region for projects addressing economic congestion. Each of the RTO's respective Order 1000 interregional cost allocation proposals are pending at FERC. Projects that do not meet the requirements for interregional cost allocation but are otherwise a preferred solution will still be included in the report.

Assessment of Potential Reliability Violations

The coordinated reliability assessment will consist of three main analyses:

- Review of reliability projects identified in the respective regional planning processes that are located near the seam to determine if there are interregional alternatives to the currently proposed transmission solutions
- Reliability assessment focusing on steady-state issues using power flow models consistent with reliability processes used by each region
- A dynamics assessment to test system stability using scenario(s) appropriate for studying dynamics

Solution Development and Evaluation

Solutions to address identified reliability issues will be developed and reviewed in coordination with the respective regional planning processes. These solutions, which may include alternative projects that more effectively mitigate identified issues, may be submitted by:

- Respective RTO staff
- Stakeholders through regional planning processes
- Stakeholders through MISO-SPP IPSAC meetings

Transmission solutions to address identified reliability issues will be evaluated to determine the most efficient and cost-effective method to address the identified constraints. These projects may also be evaluated for economic benefits to MISO and SPP.

Regional Evaluation and Cost Allocation

At the completion of the MISO-SPP Coordinated System Plan (CSP) study there may be identified MISO-SPP interregional projects that the JPC recommends to the respective RTO's regional process for review and possible Board approval.

The results of MISO-SPP CSP Study will be documented in a report on which stakeholders will have an opportunity to review and provide comments.

Stakeholder Involvement

The issues' review, scope and study processes are overseen by the JPC and reviewed with stakeholders through the IPSAC, consistent with the CSP development provisions of the JOA. The IPSAC will meet throughout the study to review and provide input on items such as:

- Study scope and analysis approach
- Joint planning models and input assumptions
- Identified seams transmission issues or opportunities
- Proposed transmission solutions and alternatives
- Recommendation of transmission solutions
- CSP report

The JPC will provide appropriate notice through the respective RTO websites of the dates and times of IPSAC meetings. Also, all meeting materials will be maintained on both RTOs' IPSAC webpage.

CSP Study Schedule

MISO and SPP staffs are performing the historical and projected congestion analysis at this time (Table 8.2-2). Historic TLR data was gathered for the 2013 calendar year. The historical TLR data will be updated with recent market data through September 2014 to capture additional market information relating to the MISO South Integration and the new SPP Day 2 Market that occurred on December 19, 2013, and March 1, 2014. The results of the historical and projected congestion analysis will be presented to stakeholders along with an issues list. Stakeholders will then be asked to propose transmission solution ideas for evaluation.

MISO-SPP CSP Tasks	
Scope Development *(February – May 2014)*	
1. Develop and finalize scope document for CSP study	
2. Develop detailed schedule for CSP study	
3. Economic Evaluation and Reliability Assessment	
Economic Evaluation	**Reliability Assessment**
• Future and Model Development *(March – June 2014)*	• Perform steady-state reliability assessment using jointly developed power flow models. *(August 2014 t – December 2014)*
• Historical and Projected Congestion Analysis *(June 2014 – October 2014)*	• Test system stability using scenario(s) appropriate for studying dynamics. *(August 2014 – December 2014)*
• Solution Development *(October 2014 – January 2014)*	• Determine if there are interregional alternatives to proposed regional solutions. *(January 2015 – June 2015)*
• Solution Evaluation and Robustness Testing *(February 2015 – June 2015)*	• Evaluate potential transmission solutions, as needed, based on identified issues. *(January 2015 – June 2015)*
• Reliability Analysis *(February 2015 – June 2015)*	
• Determine interregional cost allocation *(February 2015 – June 2015)*	
4. Draft Coordinated System Plan study report (May 2015 – June 2015)	
5. Regional Evaluation and Cost Allocation, if needed (June 2015 – December 2015)	

Table 8.2-2: CSP study timeline

8.3 HVDC Network

In 2014, MISO performed preliminary high-voltage direct current (HVDC) network analysis to explore the concept of an HVDC transmission system joining the Western Interconnection, the Eastern Interconnection and ERCOT (Figure 8.3-1).

This HVDC network is designed to capture the benefits of:

- Load diversity
- Wind diversity
- Solar diversity
- Frequency response
- Reserve pooling
- Energy arbitrage

Building off the results of this preliminary study, MISO will reach out to other interconnections to begin the process of completing a joint study. Western Electricity Coordinating Council (WECC) has already expressed interest in working with MISO on a joint study to further explore HVDC network development. The concept was introduced to stakeholders in January 2014, and was presented again in the fall of 2014. Stakeholder collaboration will be essential to this joint interregional planning initiative.

The initial study reveals potential benefits of up to $41.4 billion, with a cost-to-benefit ratio of 1.14:1. Preliminary results find the MISO region captures 28 percent of the benefits, or $11.6 billion. A full discussion of the preliminary results and assumptions is included in Appendix E3.

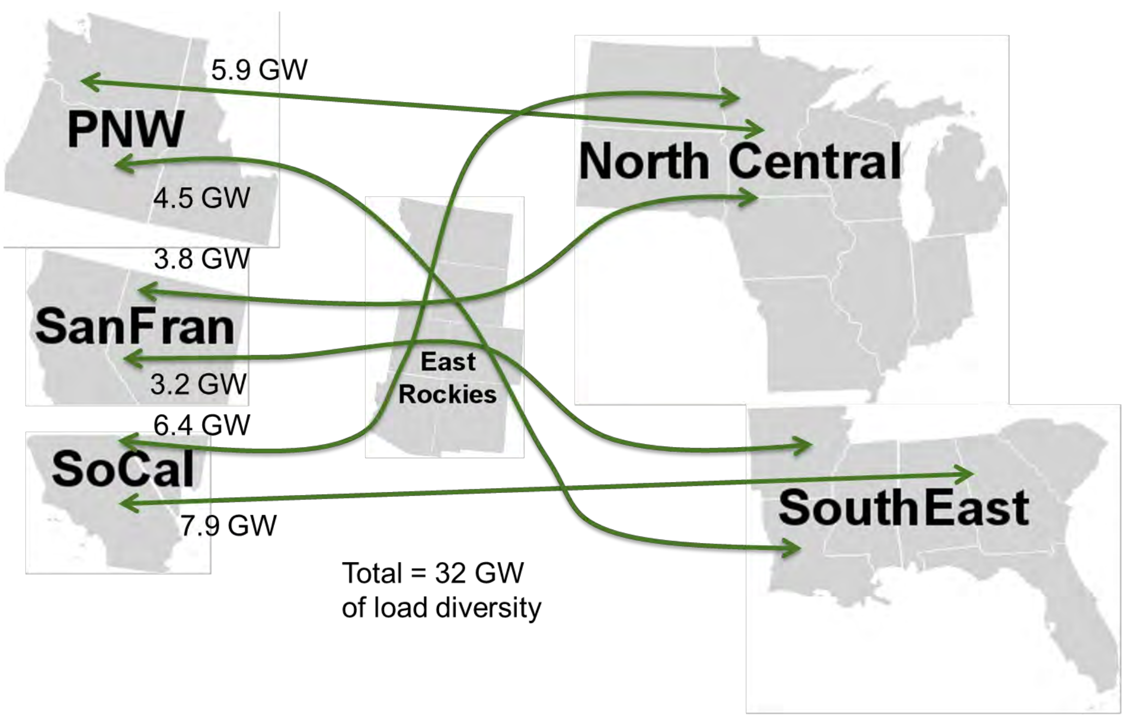


Figure 8.3-1: Capacity exchange diagram

Book 4 - Regional Energy Information

9.1 MISO Overview

MISO is a not-for-profit, member-based organization that administers wholesale electricity and ancillary services markets. MISO provides customers a wide array of services including reliable system operations, transparent energy and ancillary service prices, open access to markets, and system planning for long-term reliability, efficiency and to meet public policy needs.

By improving grid reliability and increasing the efficient use of generation, MISO saves the average residential customer $56 to $77 a year, at an annual expense of $5 per customer

MISO has 48 Transmission Owner members with more than $20 billion in transmission assets under MISO's functional control. MISO has 96 non-transmission owner members that contribute to the stability of the MISO markets.

The services MISO provides translate into material benefits for members and end users. By improving grid reliability and increasing the efficient use of generation, MISO saves the average residential customer $56 to $77 a year at an annual expense of $5 per customer. The MISO 2013 Value Proposition[54] explains the various components of this benefits calculation.

The value drivers are:

1. **Improved Reliability**, which captures the value of MISO's broader regional view and state-of-the art reliability tool set. Improved Reliability in the region is measured by the availability of the transmission system.
2. **Dispatch of Energy**, which quantifies the real-time and day-ahead energy market's use of security constrained unit commitment and centralized economics dispatch. Improved Reliability and Dispatch of Energy optimize the use of all resources within the region based on bid and offers by market participants.
3. **Regulation**, which represents the savings created by use of MISO's regulations market. With the regulation market in place, the amount of regulation required within the MISO footprint dropped significantly. The drop in regulation needed is a result of the region moving to a centralized common footprint regulation target rather than several non-coordinated regulation targets.
4. **Spinning Reserve**, which includes the formation of the Contingency Reserve Sharing Group and the implementation of the Spinning Reserves Market. Both aspects contributed to the decline of the total spinning reserve requirement, freeing low-cost capacity to meet energy requirements.
5. **Wind Integration**, which quantifies the value of regional planning of wind resources. The centralized look at the footprint allows for more economic placement of wind resources. Economic placement of wind resources reduces the overall capacity needed to meet required wind energy output.
6. **Compliance**, which shows the time and money savings associated with MISO consolidating FERC and NERC compliance obligations. Before MISO, utilities in the MISO footprint were responsible for managing FERC and NERC compliance.
7. **Footprint Diversity**, which captures the value of MISO's large footprint. MISO's size increases the load diversity, allowing for a decrease in regional planning reserve margins from 21.95 percent to 14.2 percent. The decrease in the planning reserve margins delays the need to construct new capacity.

[54] https://www.misoenergy.org/WhatWeDo/ValueProposition/Pages/ValueProposition.aspx

8. **Generator Availability Improvement**, which displays the savings created by improved power plant availability. MISO's wholesale markets increased power plant availability by 2.2 percent, which delays the need to construct new capacity.
9. **Demand Response**, which MISO enables through dynamic pricing, direct load control and interruptible contracts. MISO-enabled demand response further delays the need to construct new capacity.
10. **Cost Structure**, through which MISO provides these services. It is expected to stay relatively flat. The costs of these services represent a small percentage of the benefits and real savings to MISO customers.

MISO provides these services for f the largest RTO geographic footprint in the U.S. MISO undertakes this mission from control centers in Carmel, Ind., and Eagan, Minn., with regional offices in Metairie, La., and Little Rock, Ark. (Figure 9.1-2).

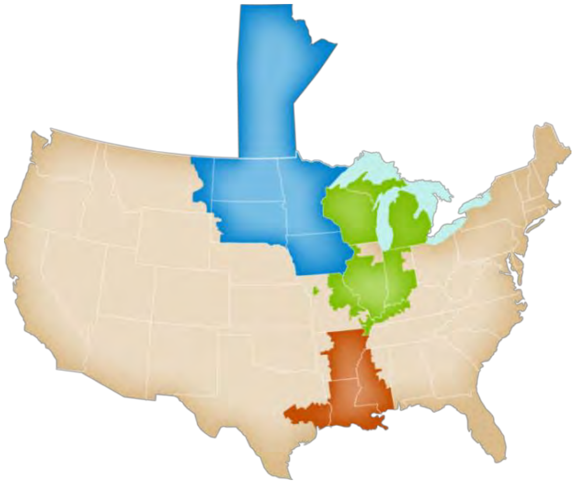


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Figure 9.1-2: The MISO geographic footprint

MISO by The Numbers

Generation Capacity (as of March 2014)

- 175,436 MW (market)
- 200,906 MW (reliability)[55]

Historic Peak Load (set July 20, 2011)

- 126,337 MW (market)
- 132,893 MW (reliability)[56]

Miles of transmission

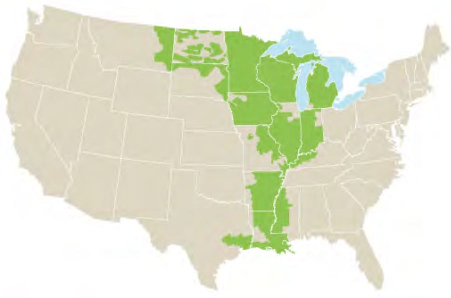
- 65,757 miles of transmission
- 10,442 miles of new/upgraded lines planned through 2022

Markets

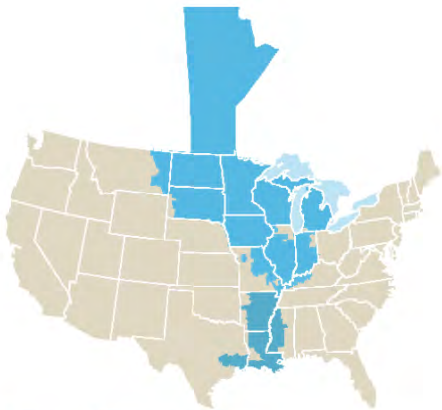
- $20.3 billion in annual gross market charges (2013)
- 2,413 pricing nodes
- 400 Market Participants serving over 42 million people

Renewable Integration

- 15,215 MW active projects in the interconnection queue
- 12,464 MW wind in service
- 13,035 MW registered wind capacity (January 2014)



MARKET AREA



RELIABILITY COORDINATION AREA

[55] MISO Fact Sheet

[56] MISO operates its Energy and Ancillary Services market only within its Market Footprint. MISO coordinates reliability responsibilities to its larger Reliability Footprint.

9.2 Electricity Prices

Wholesale Electric Rates

MISO operates a market for the buying and selling of wholesale electricity. The price of energy for a given hour is referred to as the Locational Marginal Price (LMP). The LMP represents the cost incurred, expressed in dollars per megawatt hour, to supply the last incremental amount of energy at a specific point on the transmission grid.

The MISO LMP is made up of three components: the Marginal Energy Component (MEC), the Marginal Congestion Component (MCC), and the Marginal Loss Component (MLC). MISO uses these three components when calculating the LMP to capture not only the marginal cost of energy but also the limitations of the transmission system.

In a transmission system without restrictions, the LMP across the MISO footprint would be the same. In reality, the existence of transmission losses and transmission line limits result in adjustments to the cost of supplying the last incremental amount of energy. For any given hour, the MEC of the LMP is the same across the MISO footprint. However, the MLC and MCC differ to create the variance in the hourly LMPs.

The 24-hour average day-ahead LMP at Indiana hub over a two week period highlights the variation in the components which make the LMP. The time frame includes portions of the extreme weather events of 2014, including January 6 when MISO set a new all-time winter instantaneous peak load (Figure 9.2-1). A real-time look at the MISO prices can be found on the LMP Contour Map[57] (Figure 9.2-2).

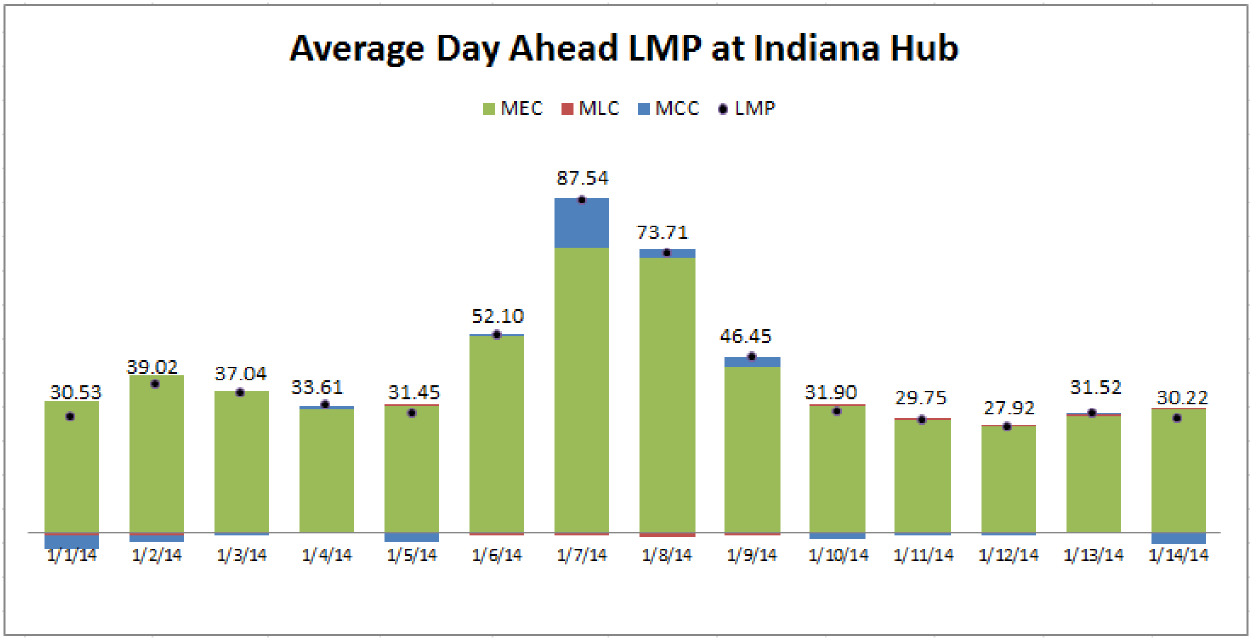


Figure 9.2-1: Average day-ahead LMP at the Indiana hub

[57] https://www.misoenergy.org/LMPContourMap/MISO_All.html

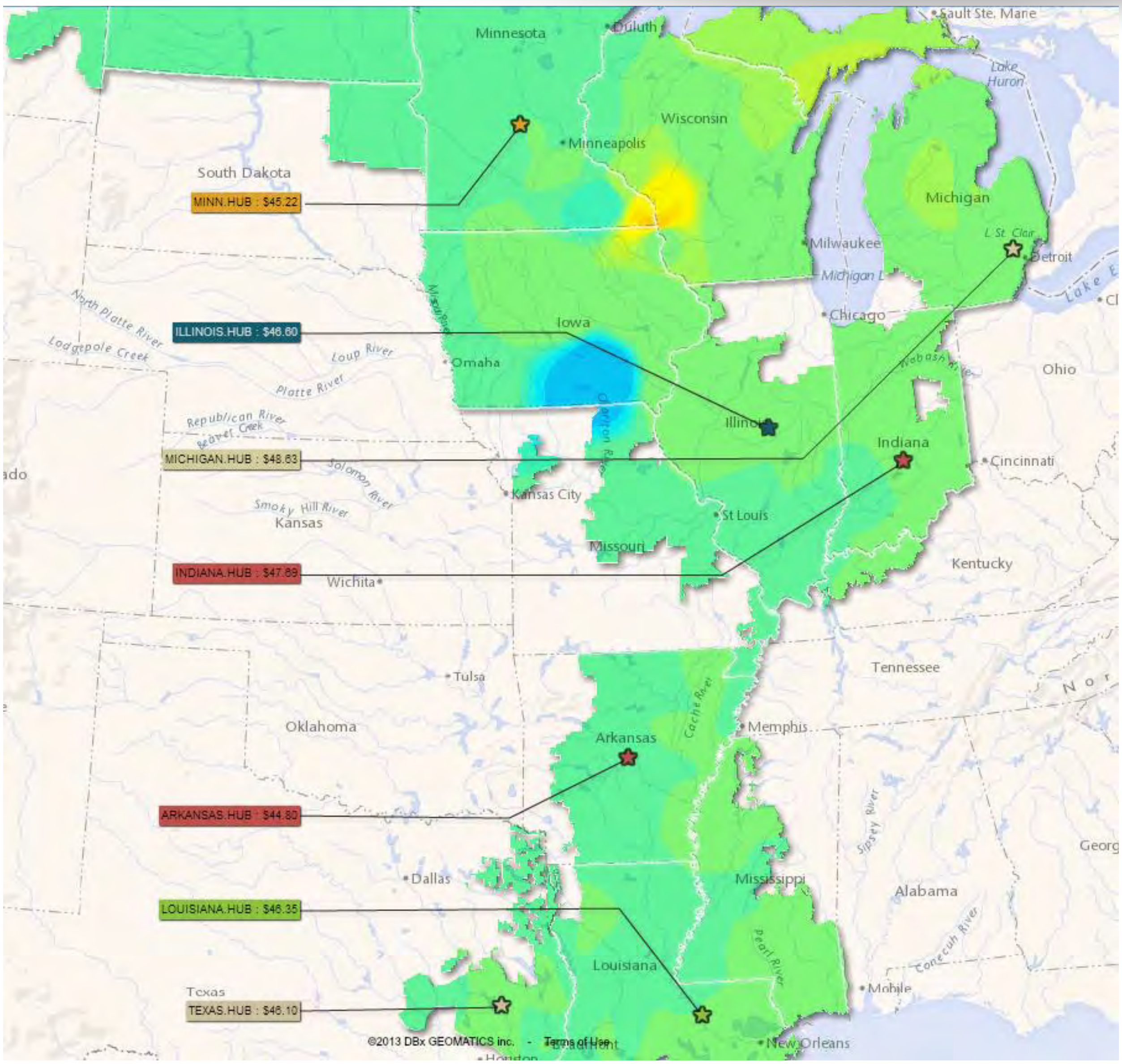


Figure 9.2-2: LMP contour map

Retail Electric Rates

The MISO-wide average retail rate, weighted by load in each state, for the residential, commercial and industrial sector, is 9.1 cents/kWh, about 12 percent lower than the national average of 10.2 cents/kWh. The average retail rate in cents per kWh varies by 3.6 cents/kWh per state in the MISO footprint (Figure 9.2-3).

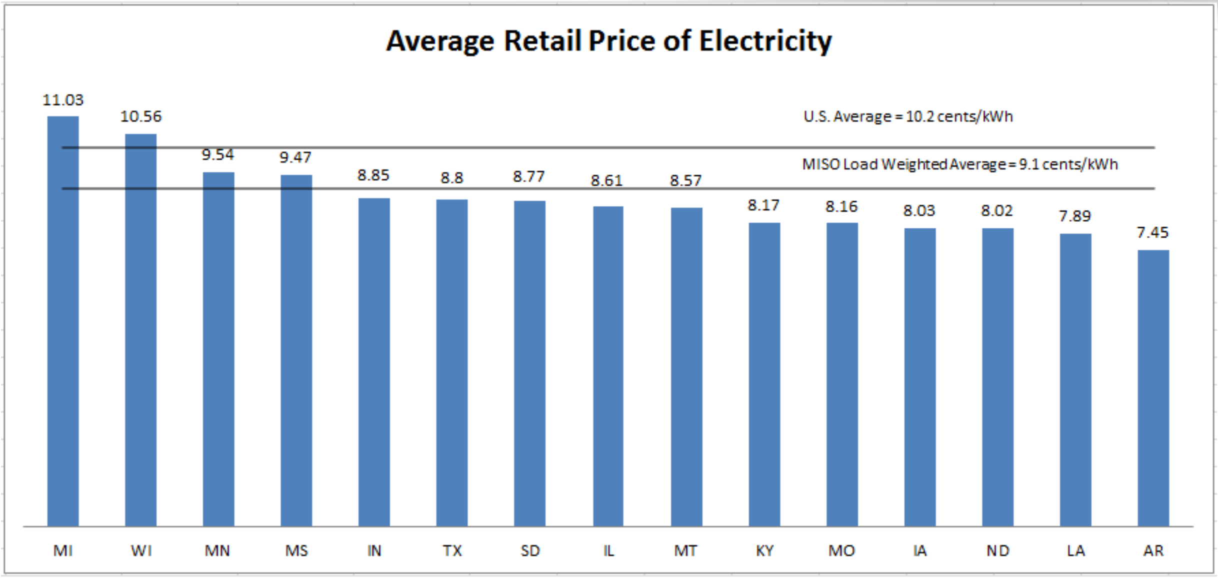


Figure 9.2-3: Average retail price of electricity per state[58]

[58] May 2014 EIA Electric Power Monthly with Load Ratio Share data calculated from December 2013 MISO Attachment O data

9.3 Generation

The energy resources in the MISO footprint are evolving. Environmental regulations, improved technologies and ageing infrastructure have spurred changes in the way electricity is generated.

Fuel availability and fuel prices introduce a regional aspect into the selection of generation, not only in the past but also going forward. Planned generation additions and retirements in the U.S. from 2013 to 2017 separated by fuel type shows the increased role natural gas and renewable energy sources will play in the future (Figure 9.3-1).

Planned Generating Capacity Changes, by Energy Source, 2013-2017						
	Generator Additions		Generator Retirements		Net Capacity Additions	
	Number of Generators	Net Summer Capacity	Number of Generators	Net Summer Capacity	Number of Generators	Net Summer Capacity
Coal	11	2,894	191	27,294	-180	-24,401
Petroleum	23	48	90	3,151	-67	-3,103
Natural Gas	242	34,019	153	7,631	89	26,389
Other Gases	1	3	5	44	-4	-41
Nuclear	4	4,422	5	4,180	-1	242
Hydroelectric Conventional	41	1,389	48	755	-7	634
Wind	64	5,874	--	--	64	5,874
Solar Thermal and Photovoltaic	343	9,953	1	1	342	9,952
Wood and Wood-Derived Fuels	13	574	--	--	13	574
Geothermal	11	249	1	11	10	238
Other Biomass	102	385	13	13	89	371
Hydroelectric Pumped Storage	--	--	--	--	--	--
Other Energy Sources	6	87	--	--	6	87
U.S. Total	861	59,894	507	43,080	354	16,815

Figure 9.3-1: Forecasted generation capacity changes by energy source

The increased fuel-mix diversity from the addition of the South region helps limit the exposure to the variability of fuel prices.

MISO North and Central regions have historically had a majority of their dispatched generation come from coal. With the introduction of the south region, MISO has added an area where a majority of the dispatched generation comes from natural gas. The increased fuel-mix diversity from the addition of the South region helps limit the exposure to the variability of fuel prices. This adjustment to the composition of resources contributes to MISO's goal of an economically efficient wholesale market that minimizes the cost to deliver electricity.

After the December 2013 integration of the South region, the percentage of coal units decrease as the amount of gas units increase as shown by trend lines (Figure 9.3-2).

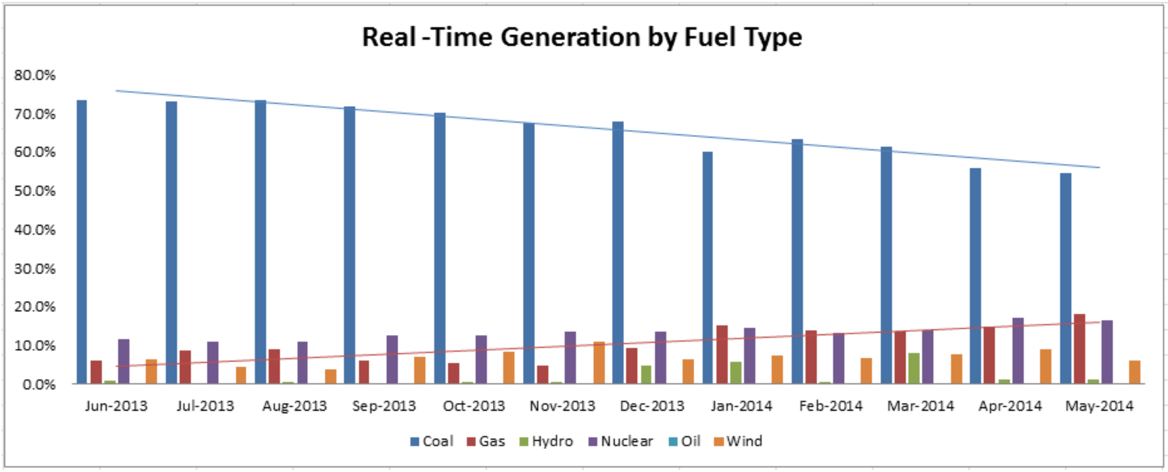


Figure 9.3-2: Real-time generation by fuel type

Different regions have different makeups in terms of generation. The South region is based around natural gas; the Central and North regions use more coal (Figure 9.3-3). A real time look at MISO fuel mix can be found on the [MISO Fuel Mix Chart.][59]

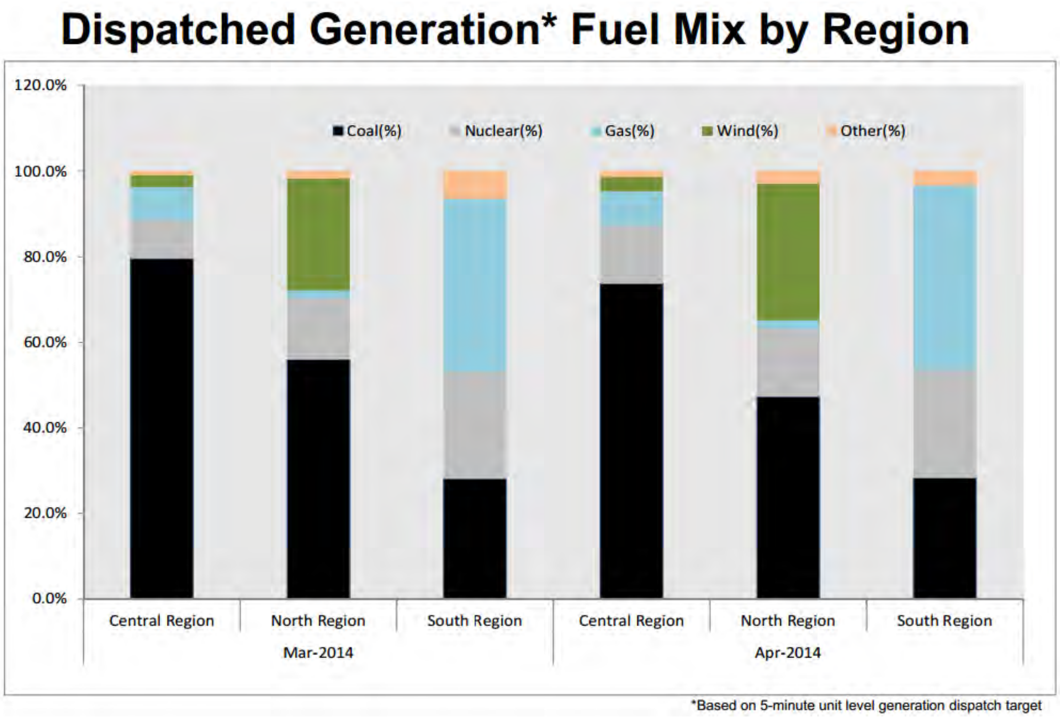


Figure 9.3-3: Dispatched generation fuel mix by region

[59] https://www.misoenergy.org/MarketsOperations/RealTimeMarketData/Pages/FuelMix.aspx

Renewable Portfolio Standards

Renewable portfolio standards (RPS) require utilities to use or procure renewable energy to account for a defined percentage of their retail electricity sales. Renewable portfolio goals are similar to renewable portfolio standards but are not a legally binding commitment.

Renewable portfolio standards are determined at the state level and differ based upon state-specific policy objectives (Table 9.3-1). Differences may include eligible technologies, penalties and the mechanism by which the amount of renewable energy is being tallied.

State	RPS Type	Target RPS (%)	Target Mandate (MW)	Target Year
AR	None			
IA	Standard		105	
IL	Standard	25%		2025
IN	Goal	10%		2025
KY	None			
LA	None			
MI	Standard	10%	1100	2015
MN	Standard	25%		2025
MO	Standard	15%		2021
MS	None			
MT	Standard	15%		2025
ND	Goal	10%		2015
SD	Goal	10%		2015
TX	Standard		5880	2015
WI	Standard	10%		2015

Table 9.3-1: Renewable portfolio standards for states in the MISO footprint

Wind

Wind energy is the most prevalent renewable energy resource in the MISO footprint. Wind capacity in the MISO footprint has increased exponentially since the start of the energy market in 2005. Beginning with nearly 1,000 MW of installed wind, the MISO footprint now contains over 13,000 MW of wind capacity.

Wind energy offers lower environmental impacts than conventional generation, contributes to renewable portfolio standards, and reduces dependence on fossil fuels. Wind energy also presents a unique set of challenges. Wind energy is intermittent by nature and driven by weather conditions. Wind energy also may face unique sighting challenges in finding areas with adequate wind.

A real-time look at the average wind generation in the MISO footprint can be seen on the MISO real time wind generation graph[60].

Figure 9.3-4 was made from data collected from the MISO Monthly Market Assessment Reports[61] and displays the monthly energy contribution from wind and the percentage of total energy supplied by wind.

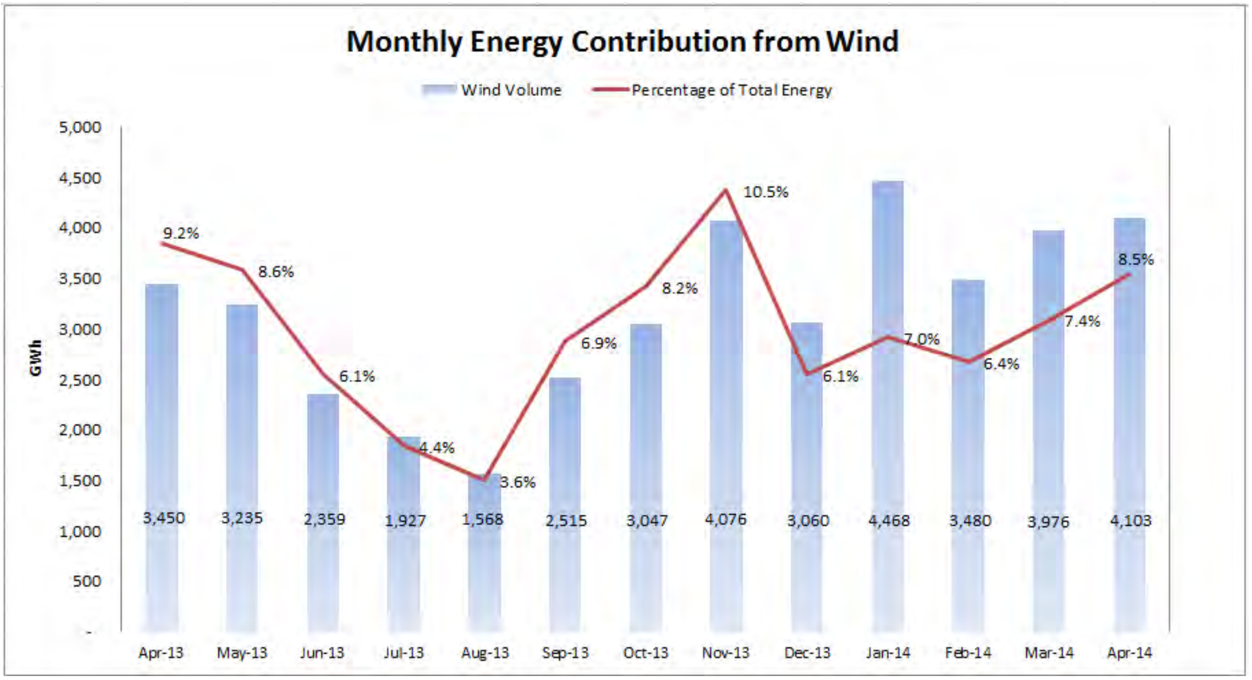


Figure 9.3-4: Monthly energy contribution from wind

Capacity factor is a measure of how often a generator runs over a period of time. Knowing the capacity factor of a resource gives a greater sense of how much electricity is actually produced relative to the maximum the resource could produce. The graphic compares the total registered wind capacity with the actual wind output for the month. The percentage trend line helps to emphasize the variance in the capacity factor of wind resources (Figure 9.3-5).

[60] https://www.misoenergy.org/MarketsOperations/RealTimeMarketData/Pages/RealTimeWindGeneration.aspx
[61] https://www.misoenergy.org/MarketsOperations/MarketInformation/Pages/MonthlyMarketAnalysisReports.aspx

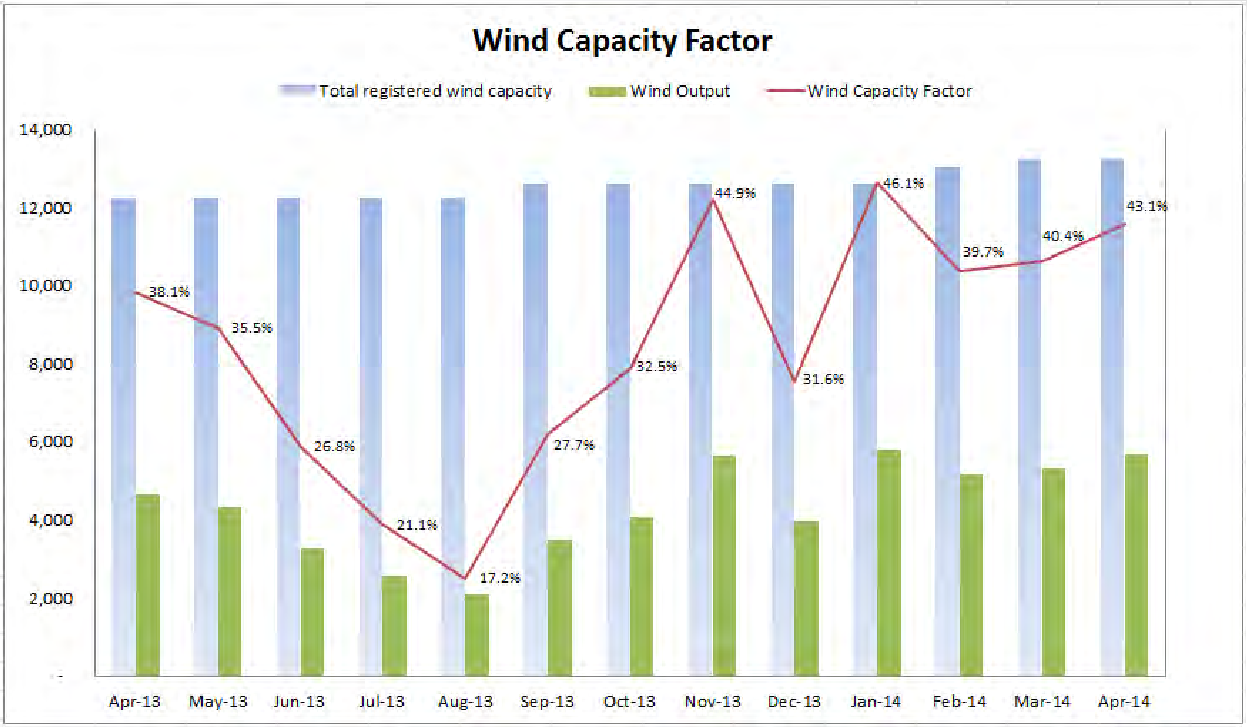


Figure 9.3-5: Total registered wind and capacity factor

9.4 Load Statistics

The withdrawal of energy from the transmission system can vary significantly based on the surrounding conditions. The amount of load on the system varies by time of day, current weather and the season. Typically, weekdays experience higher load then weekends. Summer and winter seasons have a greater demand for energy than do spring or fall.

In 2014, with the addition of the South region, MISO set a new all-time winter instantaneous peak load of 109.3 GW on January 6. The new peak surpassed the previous all-time winter peak of 99.6 GW set in 2010.

Less cyclical factors also impact the demand for energy. The increased focus on energy efficiency programs, implementation of demand response initiatives and the rise of energy storage technologies all change the patterns around how energy is consumed. The role of energy efficiency programs have increased over the years with a resulting effect on peak load (Figures 9.4-1 and 9.4-2). The role of energy efficiency programs have increased over the years with a resulting effect on peak load. The figures use data published in the U.S. Energy Information Administration (EIA) Electric Power Annual[62].

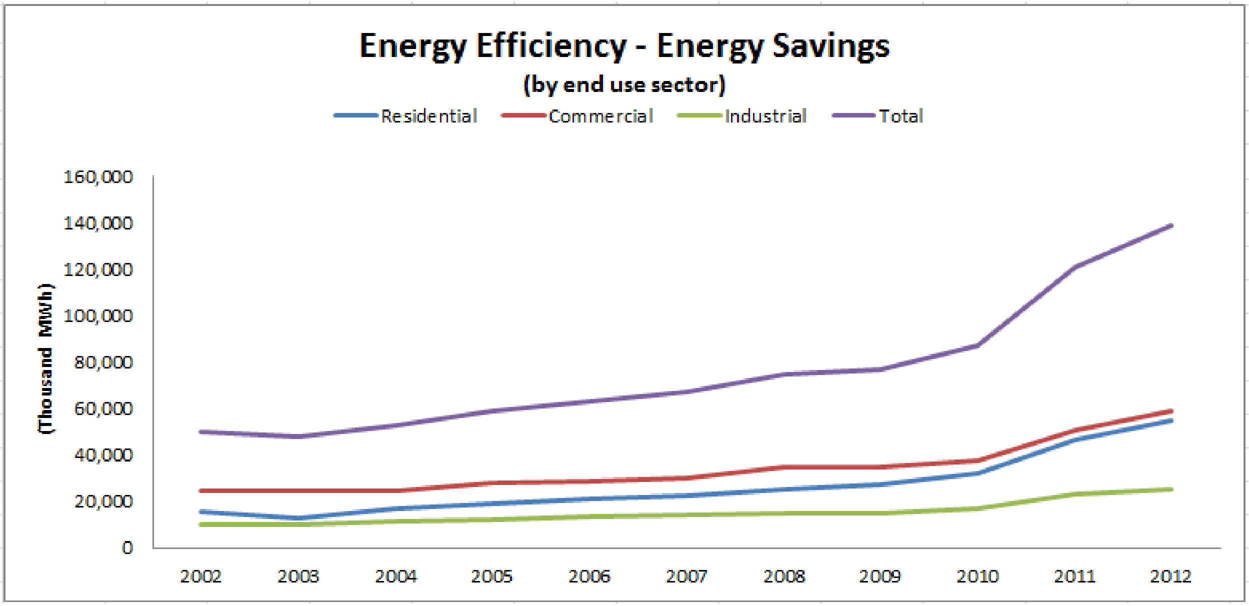


Figure 9.4-1: U.S. energy efficiency and energy savings by end-use sector

[62] http://www.eia.gov/electricity/annual/

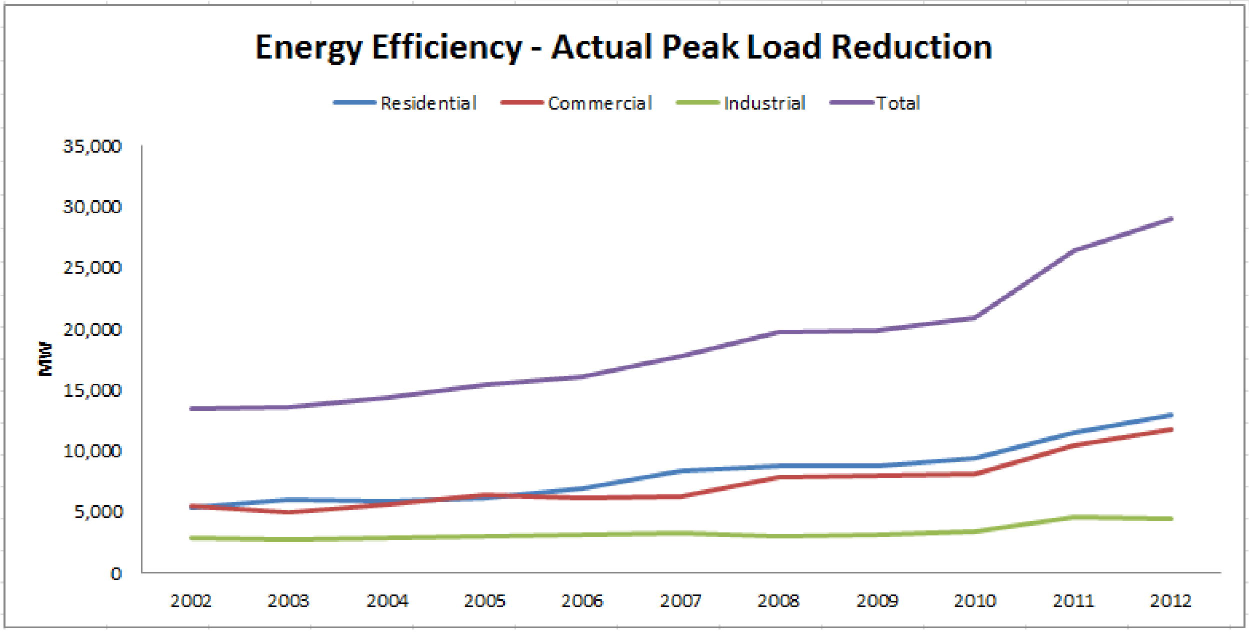


Figure 9.4-2: U.S. energy efficiency and actual peak load reduction

End-Use Load

It is a challenge to develop accurate information on the composition of load data. Differences in end-use load can be seen at a footprint wide, regional and the Load Service Entity level.

To keep up with changing end-use consumption, MISO relies on the data submitted to the Module E capacity tracking (MECT) tool. MECT data is used for all of the long-term forecasting including Long Term Reliability Assessment and Seasonal Assessment as well as to determine Planning Reserve Margins.

The EIA Electric Power Monthly provides information on the retail sales of electricity to the end-use customers by sector for each state in the MISO footprint (Table 9.4-1).

Retail Sales of Electricity to Ultimate Customers by End-Use Sector							
State	Residential		Commercial		Industrial		All Sectors
	(Million kWh)	% of Total	(Million kWh)	% of Total	(Million kWh)	% of Total	
Arkansas	1,165	34.1%	870	25.5%	1,381	40.4%	3,417
Iowa	1,010	27.9%	960	26.5%	1,646	45.5%	3,616
Illinois	2,941	29.1%	3,812	37.7%	3,303	32.7%	10,110
Indiana	2,078	27.2%	1,821	23.8%	3,739	48.9%	7,639
Kentucky	1,670	30.4%	1,382	25.2%	2,437	44.4%	5,489
Louisiana	1,831	29.3%	1,785	28.5%	2,640	42.2%	6,256
Michigan	2,349	30.3%	2,858	36.9%	2,539	32.8%	7,747
Minnesota	1,646	31.9%	1,839	35.7%	1,667	32.3%	5,154
Missouri	2,104	37.0%	2,259	39.7%	1,325	23.3%	5,690
Mississippi	1,153	32.4%	1,001	28.2%	1,400	39.4%	3,555
Montana	392	34.5%	392	34.5%	353	31.0%	1,137
North Dakota	430	31.4%	477	34.8%	464	33.8%	1,371
South Dakota	378	39.0%	379	39.1%	214	22.1%	970
Texas	8,204	30.6%	9,938	37.0%	8,672	32.3%	26,827
Wisconsin	1,612	30.5%	1,827	34.5%	1,854	35.0%	5,293
	28,963	30.7%	31,600	33.5%	33,634	35.7%	94,271

Table 9.4-1: Retail sales of electricity to ultimate customers by end-use sector

Load

Peak load drives the amount of capacity required to maintain a reliable system. Load level variation can be attributed to various factors, including weather, economic conditions, energy efficiency, demand response and membership changes. The annual peaks, summer and winter, from 2007 through 2013 show the fluctuation (Figure 9.4-3).

Within a single year load varies on a weekly cycle. Weekdays experience higher load. On a seasonal cycle, it also peaks during the summer with a lower peak in the winter, and with low load periods during the spring and fall seasons (Figure 9.4-4). The Load Curve shows load characteristics over time (Figure 9.4-5). Showing all 365 days in 2013, these curves show the highest instantaneous peak load of 95,598 MW on July 18, 2013; the minimum load of 38,355 MW on May 27, 2013; and every day in order of load size. This data is reflective of the market footprint at the time of occurrence.

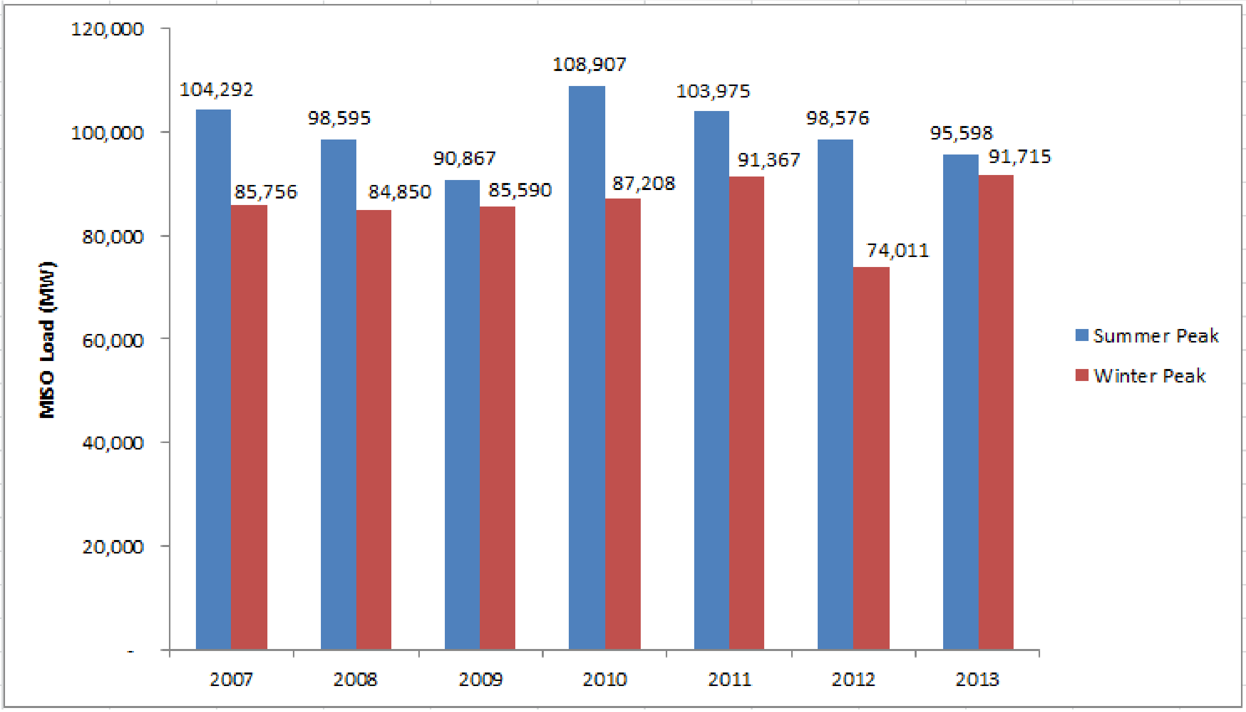


Figure 9.4-3: MISO Summer and Winter Peak Loads – 2007 through 2013[63]

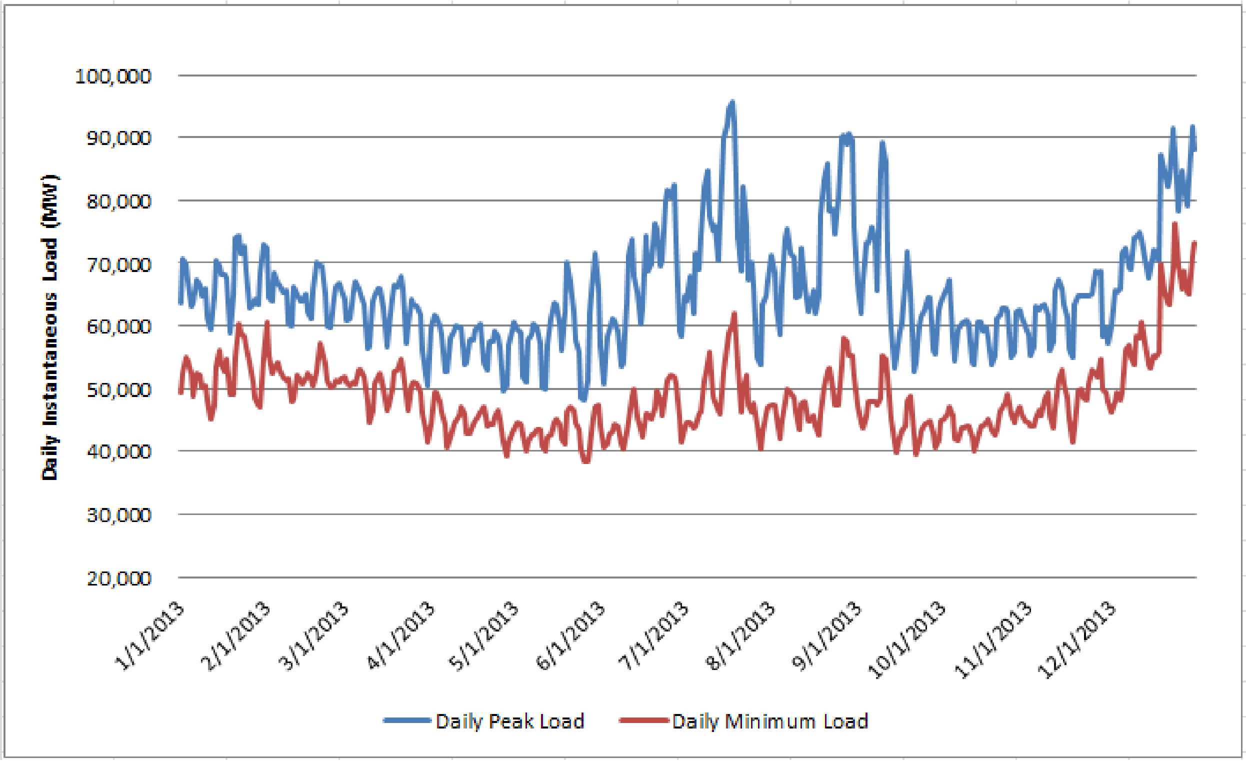


Figure 9.4-4: 2013 MISO-Midwest Daily Load[64]

[63] Source: MISO Market Data (2007-2013)

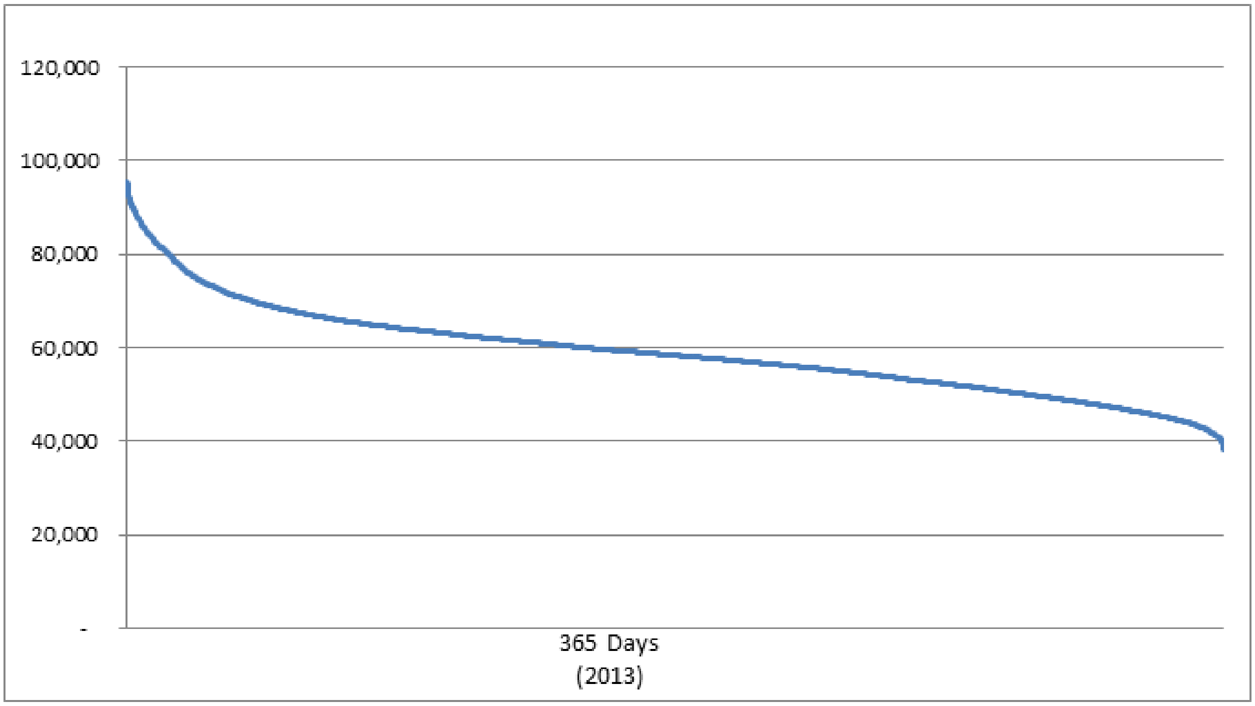


Figure 9.4-5: MISO Load Duration Curve - 2013[65]

[64] Source: MISO Market Data (2013)
[65] Source: MISO Market Data (2013)

Appendices

Most MTEP14 Appendices[66] are available and accessible on the MISO public webpage. Confidential appendices, such as D2 – D9, are available on the MISO MTEP14 Planning Portal[67]. Access to the Planning Portal site requires an ID and password.

Appendix A: Projects recommended for approval
- Section A.1, A.2, A.3: Cost allocations
- Section A.4: MTEP13 Appendix A new projects

Appendix B: Projects with documented need & effectiveness

Appendix D: Reliability studies analytical details with mitigation plan (ftp site)
- Section D.1: Project justification
- Section D.2: Modeling documentation
- Section D.3: Steady state
- Section D.4: Voltage stability
- Section D.5: Transient stability
- Section D.6: Generator deliverability
- Section D.7: Contingency coverage
- Section D.8: Nuclear plant assessment
- Section D.9: Planning Horizon Transfers

Appendix E: Additional MTEP14 Study support
- Section E.1: Reliability planning methodology
- Section E.2: Generations futures development
- Section E.3: HVDC Network - Preliminary Assumptions and Results
- Section E.4: Market Congestion Planning Study Solution Ideas

Appendix F: Stakeholder substantive comments

[66] https://www.misoenergy.org/Library/Pages/ManagedFileSet.aspx?SetId=2273
[67] https://markets.midwestiso.org/MTEP/Studies/42/Study

Acronyms in MTEP14

AFC	Available Flowgate Capacity
APC	Adjusted Production Cost
APCS	Adjusted Production Cost Savings
ARR	Auction Revenue Rights
BAU	Business as Usual
BPM	Business Practices Manual
BRP	Baseline Reliability Projects
CBMEP	Cross Border Market Efficiency Project
CCR	Coal Combustion Residuals
CC	Combined cycle
CEII	Critical Energy Infrastructure Information
CEL	Capacity Export Limit
CIL	Capacity Import Limit
CPCN	Certificate of Public Convenience and Need
CSP	Coordinated System Plan
CWIS	Cooling Water Intake Structures
DCLM	Direct control load management
DIR	Dispatchable Intermittent Resources
DPP	Definitive Planning Phase
DR	demand response
DRR	Demand Response Resources
DSG	Down Stream of Gypsy
DSIRE	Database of State Incentives for Renewables & Efficiency
DSM	demand-side management
EE	energy efficiency
EGEAS	Electric Generation Expansion Analysis System

EIA	Energy Information Agency
EIPC	Eastern Interconnection Planning Collaborative
ELCC	Effective Load Carrying Capability
ENV	Environmental
EPA	Environmental Protection Agency (U.S.)
ERAG	Eastern Reliability Assessment Group
ERIS	Energy Resource Interconnection Service
ERR	Energy Efficiency Resources
FCA	Facility Construction Agreement
FCTTC	First Contingency Total Transfer Capability
FERC	Federal Energy Regulatory Commission
FTR	Financial Transmission Rights
GADS	Generator Availability Data System
GIA	Generator Interconnection Agreement
GIP	Generator Interconnection Projects
GIQ	Generator Interconnection Queue
GIS	Geographical Information System
GLSF	generation to load shift factor
GS	Generation Shift
HG	High Growth
HVDC	High voltage direct current
ICT	Independent Coordinator of Transmission
IL	Interruptible load
IMM	Independent Market Monitor
IPSAC	Interregional Planning Stakeholder Advisory Committee
IPTF	Interconnection Process Task Force
ISO	Independent System Operators
ITP10	Integrated Transmission Plan 10-Year Assessment

JCSP Joint Coordinated System Plan

JOA Joint Operating Agreement

JPC Joint Planning Committee

JRPC Joint RTO Planning Committee

LBA Local balancing authority

LDC Local Distribution Companies

LFU Load forcast uncertainty

LG Limited Growth

LMP Locational marginal price

LMR Load Modifying Resources

LNG Liquified natural gas

LODF Line Outage Distribution Factor

LOLE Loss of Load Expectation

LOLEWG Loss of Load Expectation Working Group

LRR Local Reliability Requirement

LRZ local resource zones

LSE Load Serving Entity

LTRA Long-Term Resource Assessment

LTTR Long-Term Transmission Rights

M2M Market to market

MATS Mercury and Air Toxics Standard

MCC Marginal Congestion Component

MCP Market Congestion Planning

MCPS Market Congestion Planning Studies

MEC Marginal Energy Component (MEC)

MECT Module E Capacity Tracking

MEP Market Efficiency Projects

MISO Midcontinent Independent System Operator

MLC	Marginal Loss Component
MMWG	Multi-regional Modeling Working Group
MOD	Model on Demand
MRITS	Minnesota Renewable Integration Study
MTEP	MISO Transmission Expansion Plan
MVP	Multi Value Projects
MW	megawatt
NAESB	North American Energy Standards Board
NERC	North American Electric Reliability Corp.
NITS	Network Integration Transmission Service
NLP	Net Load Payments
NOPR	Notice of Proposed Rulemaking
NPV	net present value
NRIS	Network Resource Interconnection Service
NSI	Net scheduled interchange
NTP	New Transmission Proposal
OASIS	Open Access Same-Time Information System
OMS	Organization of MISO States
PAC	Planning Advisory Committee
PP	Public Policy
PRA	Planning resource auction
PRM	Planning Reserve Margin
PRM_{ICAP}	PRM installed capacity
PRM_{UCAP}	PRM uninstalled capacity
PRMR	Planning Reserve Margin Requirement
PSC	Planning Subcommittee
PV	photovoltaic
QTD	Qualified Transmission Developers

RE	Robust Economy
RE	Regional Entities
RECB	Regional Expansion Criteria and Benefits
RGOS	Regional Generator Outlet Study
RMD	Regional Merit-Order Dispatch
ROFR	right of first refusal
RPS	Renewable Portfolio Standard
RRF	regional resource forecast
RTO	Regional transmission operator
SCED	Security Constrained Economic Dispatch
SFT	simultaneous feasibility test
SIS	System Impact Study
SPC	System Planning Committee
SPM	Subregional Planning Meetings
SPP	Southwest Power Pool
SUFG	State Utility Forecasting Group
SSR	System Support Resource
TCFS	Top congested flowgate study
TDQS	Transmission Developer Qualification and Selection
TDSP	Transmission Delivery Service Project
TLR	Transmission Load Relief
TO	Transmission Owner
TPL	Transmission Planning Standards
TRC	Technical Review Committee
TSR	Transmission Service Request
TSTF	Technical Study Task Forces
UNDA	Universal Non-disclosure Agreement
VLR	Voltage and Local Reliability Study

WECC Western Electricity Coordinating Council

WOTAB West of the Atchafalaya Basin

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MISO would like to thank the many stakeholders who provided MTEP13 report comments, feedback, and edits. The creation of this report is truly a collaborative effort of the entire MISO region

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