MISO

Transmission Expansion Plan 2012

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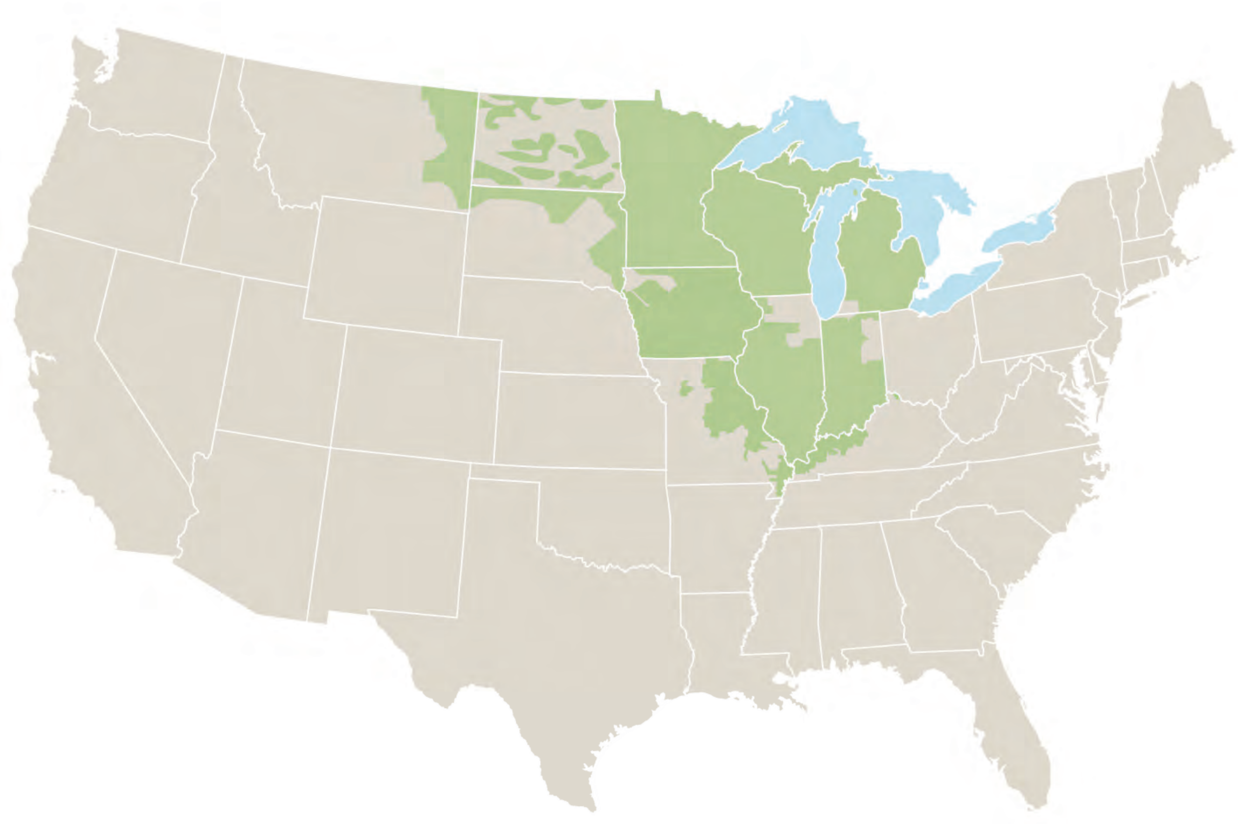


The MISO market footprint

Chapter One
Executive Summary

CHAPTER 1

Executive Summary

The annual MISO Transmission Expansion Plan (MTEP) proposes solutions to meet transmission needs efficiently and deliver the lowest-cost energy to customers in the MISO region. MISO engages with stakeholders through a comprehensive planning process to identify essential transmission projects. MISO staff recommends these projects, as described in MTEP12 Appendix A, to the MISO Board of Directors for review, approval and subsequent construction.

MTEP12, the ninth edition of this publication, is the culmination of more than 18 months of collaboration between MISO planning staff and stakeholders. The primary purpose of this and other MTEP reports is to identify transmission projects that:

MTEP12, the ninth edition of this publication, is the culmination of more than 18 months of collaboration between MISO planning staff and stakeholders

- Ensure the reliability of the transmission system over the planning horizon
- 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

MTEP12 recommends $1.5 billion in new transmission expansion through 2022 for inclusion in Appendix A and eventual construction. This is part of a continuing effort to ensure a reliable and efficient electric grid that keeps pace with energy and policy demands.

Chapter 2 **MTEP12 Overview**

MTEP12 recommends 242 new projects for inclusion in Appendix A. These projects represent an incremental $1.5 billion[1] in transmission infrastructure investment within the MISO footprint and fall into the following four categories (Figure 1.1-1):

- **31 Baseline Reliability Projects (BRP) totaling $468 million** (Projects required to meet North American Electric Reliability Corp. (NERC) reliability standards)
- **23 Generator Interconnection Projects (GIP) totaling $240 million** (Projects required to reliably connect new generation to the transmission grid)
- **1 Market Efficiency Project (MEP) totaling $15 million** (Projects to reduce market congestion, as required by Attachment FF of the Tariff)
- **187 Other Projects totaling $744 million** (A wide range of projects, including those that support lower-voltage transmission systems or provide local economic benefit, but do not meet the threshold to qualify as Market Efficiency Projects)

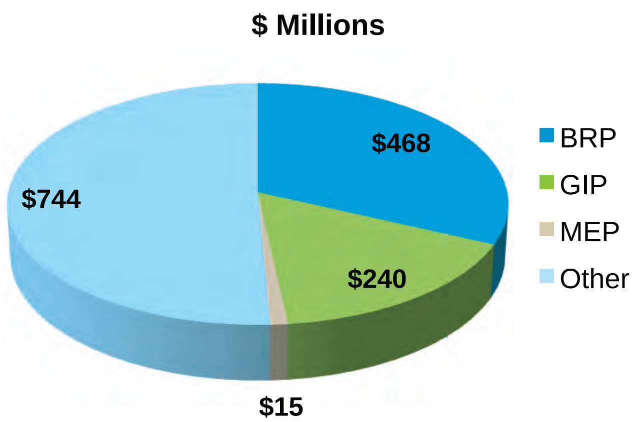


Figure 1.1-1: MTEP12 new investment by project type

[1] The MTEP12 report and project totals reflect all project approvals across the year, including the 7 projects totaling $305 million that were approved on an out of cycle basis prior to December.

Chapter 3 **MTEP History**

The addition of new transmission projects in MTEP12 brings the total number of projects in Appendix A to 598, representing an expected future investment of $10.8 billion through 2022. When complete, the projects will result in approximately 6,463 miles of new or upgraded transmission lines. Since the first MTEP cycle closed in 2003, transmission projects recommended for approval total $16 billion, including $5.2 billion already in service. The size of each MTEP cycle varies, with MTEP11 being the largest because of its focus on the Multi Value Project portfolio (Figure 1.1-3).

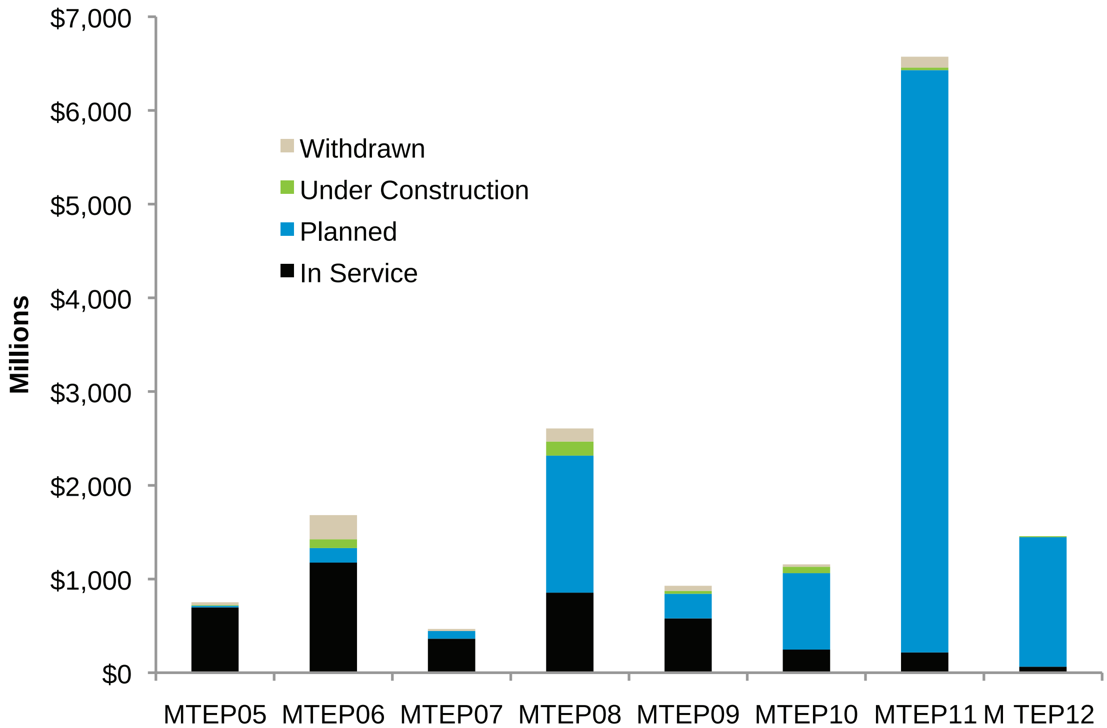


Figure 1.1-3: Approved MTEP investment by year and facility status

Chapter 4 **Reliability Analysis**

MISO performs an annual Reliability Assessment through its MISO Transmission Expansion Plan (MTEP).

In support of its MTEP assessment, MISO conducts baseline reliability studies to ensure the transmission system is in compliance with two entities: applicable national Electric Reliability Organization (ERO) reliability standards and reliability standards adopted by Regional Reliability Organizations applicable within the Transmission Provider region. 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 performs comprehensive reliability assessments and works collaboratively with stakeholders to develop plans to address identified transmission issues

MISO also performs independent review of projects recommended for approval by Board of Directors in the MTEP planning cycle. Results of MISO's independent review were presented and peer-reviewed at sub-regional planning meetings (SPM) in December 2011, March 2012 and June 2012. The results of these reliability analyses are summarized in the following chapters and Appendix D of this MTEP12 report.

Chapter 5 **Economic Analysis**

Most MTEP projects added in this cycle are primarily intended to address reliability issues or needs. In addition to the reliability driven projects there is one Market Efficiency Project in MTEP12. MISO economic analyses show that the Target Appendix A projects contain planned/proposed projects that primarily address and are justified by reliability needs. However, these projects may also provide economic benefits, including:

- Adjusted Production Cost Savings (APC)

- Reduced Energy and Capacity Losses

In 2022, these projects will create $35 million in annual APC savings. Over the following 20 to 40 years, these projects will create $363 to $825 million dollars in APC savings, which range from 0.11 to 0.13 times the cost of all the Target Appendix A projects.

	2022 Adjusted Production Cost savings	20 Year Present Value, 3 percent Discount Rate	20 Year Present Value, 8.2 percent Discount Rate	40 Year Present Value, 3 percent Discount Rate	40 Year Present Value, 8.2 percent Discount Rate
MISO	$35	$531	$363	$825	$438

Table 1.1-1: Economic benefits, in millions of 2017 dollars

Most MTEP projects added in the cycle are primarily intended to address reliabiblity issues or needs... However, MISO economic analyses show that the Target Appendix A projects... will create $35 million in annual APC savings. Over the following 20 to 40 years, these projects will create $363 to $825 million dollars in APC savings.

This analysis captures neither the economic benefits of avoiding the cost of system outages, nor the benefit of avoiding non-compliance fines.

MISO also uses economic benefit analysis to identify solutions to relieve the most congested flowgates. The most recent Top Congested Flowgate Study analyzed 17 flowgates, proposed transmission solutions, and then tested the benefit-to-cost ratio to determine whether the proposed solution qualified for inclusion in MTEP Appendix A or B as a Market Efficiency, Cross-Border Market Efficiency, or self-funded project. One project qualified as a Market Efficiency Project Appendix A project in MTEP12.

Significantly, this year's Top Congested Flowgate Study showed lower potential benefits than those reported in previous studies, due largely to congestion relief benefits gained from the inclusion of MTEP11 Multi Value Projects (MVPs) and decreased load growth rates.

Chapter 6 **Resource Adequacy**

MISO calculates the region's system planning reserve by determining the amount of generation required to meet a one-day-in-10-years (0.1 day per year) Loss of Load Expectation. The MISO Planning Reserve Margin (PRM) for the 2012-2013 planning year is 16.7 percent, decreasing 0.7 percentage points from 2011-2012's 17.4 percent planning reserve margin.

> Generally, the PRM for the 10th-year peak drops below MISO's system PRM requirement of 16 percent if new generation is not built or utilization of demand response programs does not increase

MISO aggregates individual market participant load and capacity forecasts from 2013 to 2022 to forecast long-term reserve, demand, and capacity projections (2013-2022) for the MISO market footprint. MISO combines demand and capacity forecasts to predict future reserve margins and how much capacity or demand reduction would be necessary to meet system PRM requirements. Because of anticipated EPA-related retirements, the MISO region needs to add between 4,484 and 11,290 MW of new capacity, or 3,865 and 9,733 of demand reduction to meet minimum PRMs in 2022, based on two different sets of analysis assumptions. MISO expects to see a 10th-year peak total internal demand between 98 GW and 120 GW depending on the demand growth rate, the diversity level, and load forecast uncertainty (LFU). MISO expects to see a 10th-year peak total available capacity between 110 GW and 122 GW depending on the impact of Attachment Y retirements and suspensions, the impact of the EPA regulations on future retirements, and the level of projects in MISO's generator interconnection queue. Currently, 112,679 MW of on-peak capacity exists within the MISO market footprint (Figure 1.1-4).

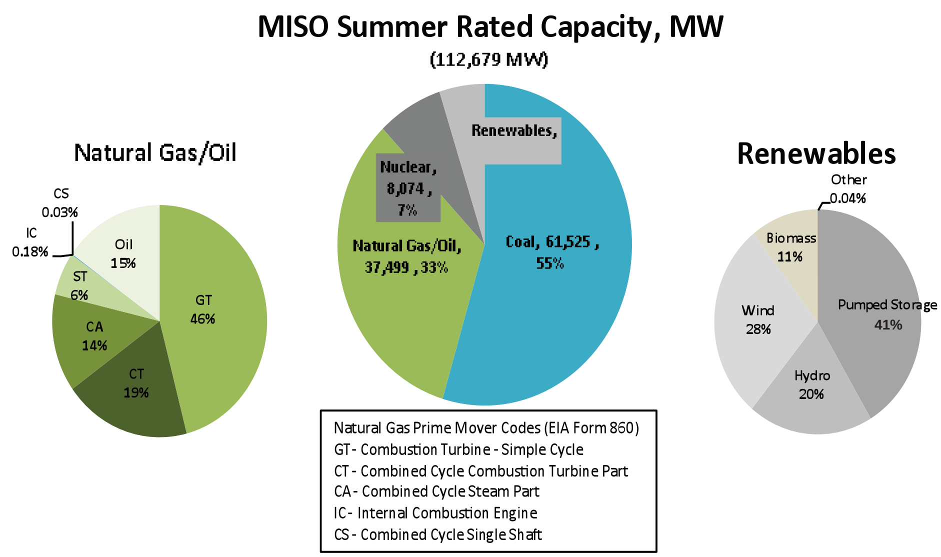


Figure 1.1-4: MISO 2012 Internal Summer Rated Capacity

Chapters 7 and 8 **Policy Landscape and Targeted Studies**

In a world of constantly evolving state and federal policies, fuel prices, load patterns and transmission configuration, MISO strives to provide meaningful analyses to help inform policy discussions and decisions. These independent analyses are critical to achieve MISO's goal to efficiently meet transmission needs and deliver the lowest-cost delivered energy to consumers.

Market Efficiency Planning Study

The recently initiated Market Efficiency Planning (MEP) study seeks to identify and evaluate transmission project/portfolio solutions more broadly within the MISO footprint and on the seams, to enhance market efficiency and produce greater economic benefits. This wide-angled look helps to identify ways to relieve flowgate congestion on a broader, regional level. A regional approach can provide additional benefits that could not be achieved with smaller-scale, localized flowgate-specific solutions.

Building on the Top Congested Flowgate Study methodology, the MEP study calculates the following types of economic information:

- Energy sources and sinks
- Forecasted locational marginal pricing (Figure 1-1.4)
- Interface energy flow changes
- Incremental power transfer needs
- Targeted economic potential

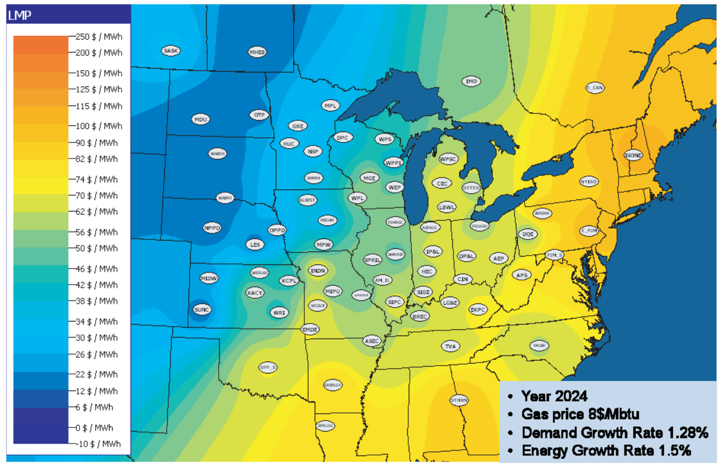


Figure 1.1-4: Forecasted locational marginal pricing

EPA Compliance Studies

In 2012, MISO built upon its 2011 EPA Impact study with a series of targeted analyses to address resource adequacy, outage coordination, compliance deadlines and natural gas infrastructure. MISO evaluated each category to determine possible needs, outcomes and effects on tariffs. While MISO has a better understanding of potential impacts of EPA regulations and is taking action to respond to the risks, uncertainty remains about whether the system can safely comply with the regulations within the prescribed timeframe.

To gain a better understanding of the level of coal retirements, MISO began quarterly surveys of its asset owners. This survey breaks down, by generation unit, the likely responses to the EPA regulations. For example, of 295 units examined in the third quarter of 2012, 75 are scheduled for replacement (retirement). The 75 units represent 5.4 GW of capacity in the MISO footprint (Figure 1.1-5).

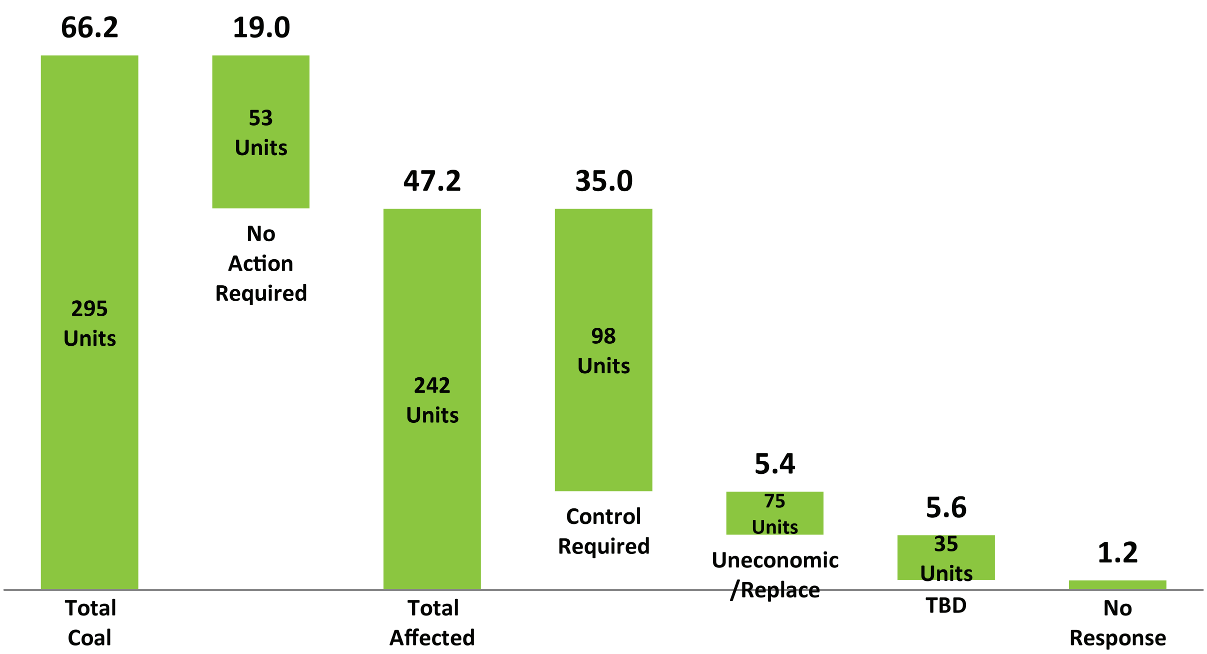


Figure 1.1-5: Third quarter 2012 coal retirement survey results, GW

FERC Order 1000

The Federal Energy Regulatory Commission's (FERC) Order 1000 mandates how public utility transmission providers must plan for and allocate the costs of new projects on a regional and interregional basis. Order 1000 builds upon Order 890, which required transmission planning based on open, transparent and coordinated processes.

The major components of Order 1000 include:

1. Regional transmission planning
2. Regional cost allocation
3. Elimination of the federal right of first refusal (ROFR)
4. Inter-regional planning coordination
5. Inter-regional cost allocation

FERC Order 1000 seeks to ensure more efficient and cost-effective regional planning and interregional coordination

On October 11, 2012, MISO filed with FERC stating how MISO complies or will comply with the first three major components of the order. A second filing covering the fourth and fifth components is due by April 11, 2013.

Generation Portfolio Analysis

MISO develops models to identify least-cost generation portfolios needed to meet resource adequacy requirements of the system for each future scenario. Results of this year's assessment for the Business as Usual future predict that 46,191 MW of additional capacity will need to be added to the MISO system between 2012 and 2027, while 12,668 MW of capacity is forecasted to retire (Figure 1.1-6). A large portion of capacity needs are met through demand response and energy efficiency programs, which were allowed to compete against traditional supply-side resources in the EGEAS program for the first time in MTEP11. A broader discussion and analysis of the four MTEP12 future scenarios and capacity additions occurs in Chapter 7.6.

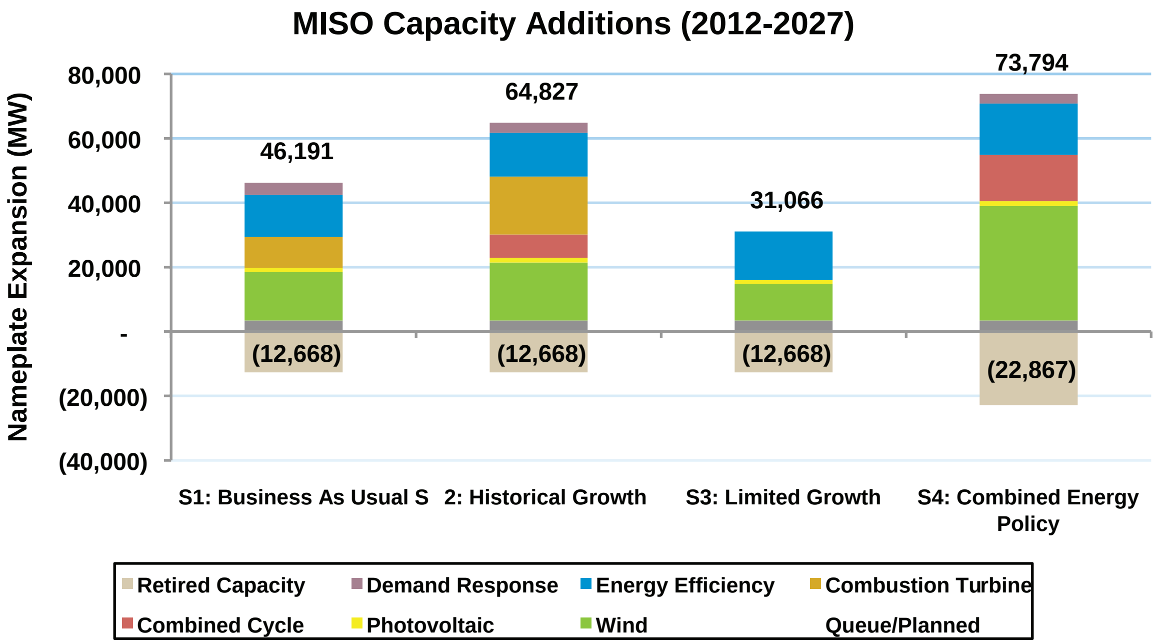


Figure 1.1-6: MISO capacity additions and retirements (2012-2027)

The MISO Planning Approach

MISO is guided in its planning efforts by a set of principles established by its Board of Directors. These principles were created to improve and guide transmission investment in the region and to furnish an element of strategic direction to the MISO transmission planning process. These principles, confirmed in August 2011, are as follows:

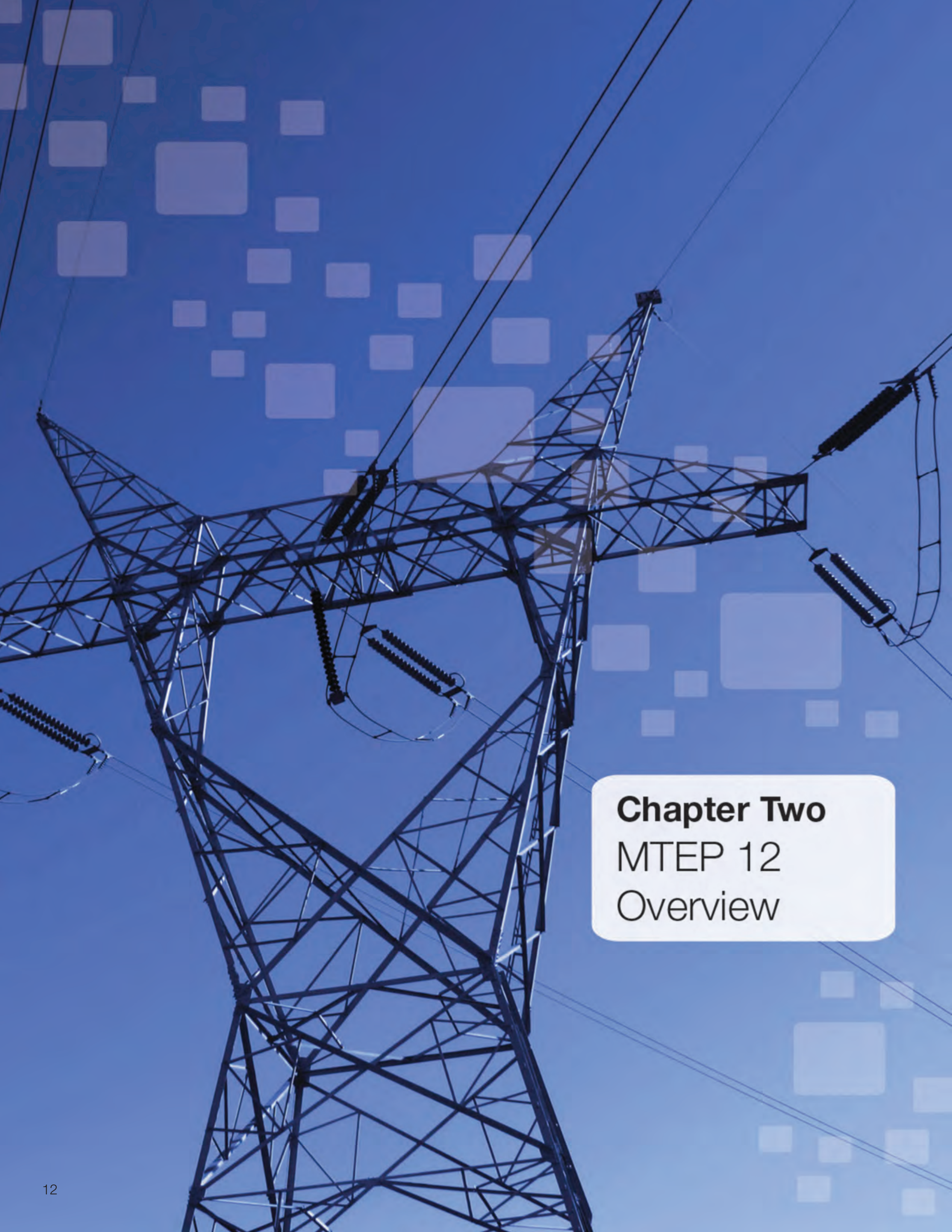
- **Guiding Principle 1:** Make the benefits of an economically efficient energy market available to customers by providing access to the lowest electric energy costs.
- **Guiding Principle 2:** Provide a transmission infrastructure that safeguards local and regional reliability and supports interconnection-wide reliability.
- **Guiding Principle 3:** Support state and federal energy policy objectives by planning for access to a changing resource mix.
- **Guiding Principle 4:** Provide an appropriate cost mechanism that ensures the realization of benefits over time is commensurate with the allocation of costs.
- **Guiding Principle 5:** Develop transmission system scenario models and make them available to state and federal energy policy makers to provide context and inform the choices they face.

To support these principles, a transmission planning process has been implemented reflecting a view of project value inclusive of 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 to have an independent, transparent and inclusive planning process that is well-positioned to study and address future regional transmission and policy-based needs. We are also grateful for the input and support from our stakeholder community, which allows us to create well-vetted, cost-effective and innovative solutions to provide reliable delivered energy at the least cost to consumers. We welcome feedback and comments from stakeholders, regulators and interested parties on the evolving electric transmission power system. For detailed information about MISO, MTEP12, renewable energy integration, cost allocation and other planning efforts, go to www.misoenergy.org.



Chapter Two
MTEP 12 Overview

CHAPTER 2

MTEP12 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, B and C.

MTEP 12 recommends 242 new projects, totaling $1.5 billion in investment, to Appendix A this planning cycle

2.1 Investment Summary

This chapter summarizes new MTEP12 transmission investments being recommended this cycle, and forecasts of when all MTEP investments will go into service.[2]

- MTEP12 recommends 242 new projects for inclusion in Appendix A, representing $1.5 billion in transmission infrastructure investment.
- With these MTEP12 additions, cumulative Appendix A for the period 2012-2022 totals $10.8 billion.
- With these MTEP12 additions, cumulative Appendix B for the period 2012-2022 totals $985 million.
- Projects in early stages of the planning process (Appendix C) total $7.8 billion through 2016 and $50.9 billion in investment in 2017-2022.[3]

A further explanation of Appendix A, B and C definitions can be found in Chapter 2.3.

Appendix A and B Summary

The cumulative project spending for Appendices A and B increases to nearly $12 billion by 2022 (Figure 2.1-1). 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.

[2] A summary of historical MTEP transmission investment, including projects that have gone into service, is included in Chapter 3.

[3] There are a number of large transmission proposals to address the renewable energy and market efficiency requirements in the region, with a $27.4 billion proposal in 2025. There are many competing projects and all of these will not survive to be included in Appendix A.

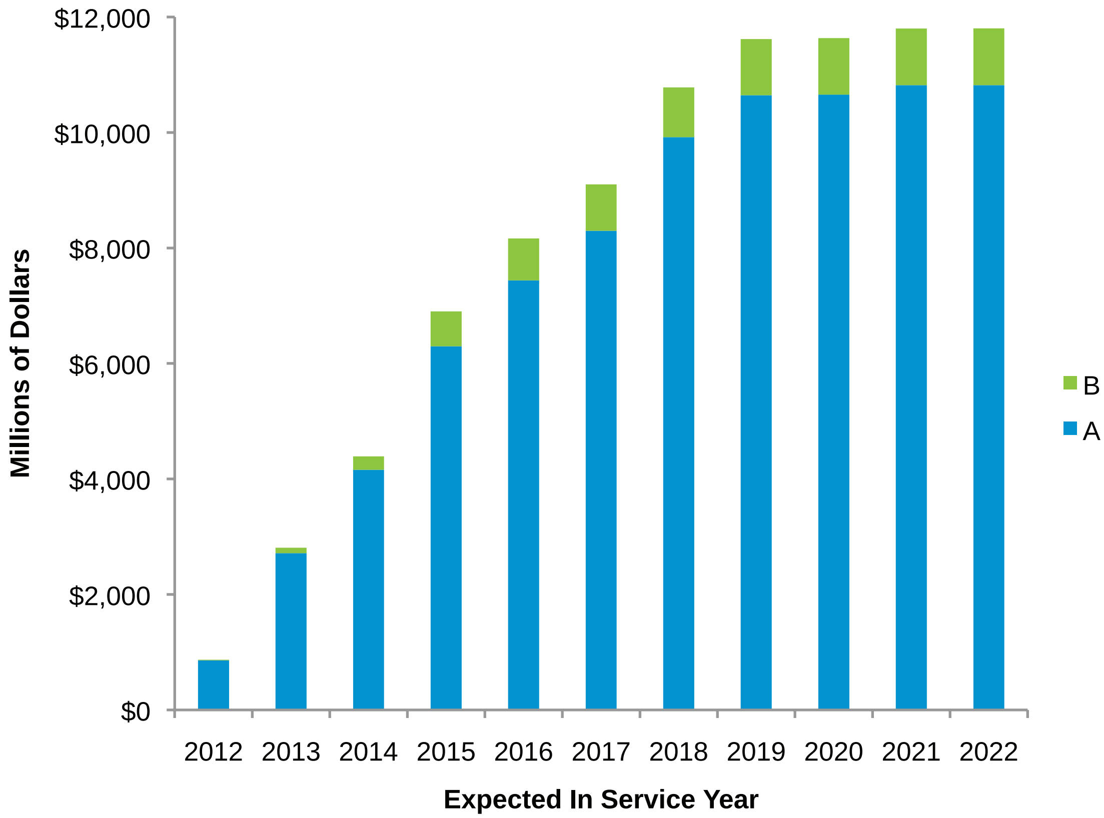


Figure 2.1-1: MTEP12 cumulative projected investment by year and Appendix

MISO Transmission Owners have committed to significant investments in the transmission system (Table 2.1-1). Cumulative MTEP transmission investment for Appendix A is approximately $10.8 billion with another $1 billion in Appendix B for the 2012-2022 time period. New MTEP12 Appendix A projects represents $1.5 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 nearly $11 billion in Appendix A is from the Multi Value Projects (MVP) approved in MTEP11. Projects are spread across three geographic planning regions: East, Central and West (Figure 2.1-2).

Cumulative MTEP Appendix A transmission investment in the MISO region from 2012 through 2022 is $10.8 billion

MISO Region	Appendix A	Appendix B	Appendix C
Central	$2,262,828,000	$295,336,000	$6,675,277,000
East	$1,681,434,000	$286,844,000	$9,284,327,000
West	$6,874,661,000	$402,464,000	$40,128,106,000
Total	$10,818,923,000	$984,644,000	$56,087,710,000

Table 2.1-1: Projected transmission investment by planning region through 2022

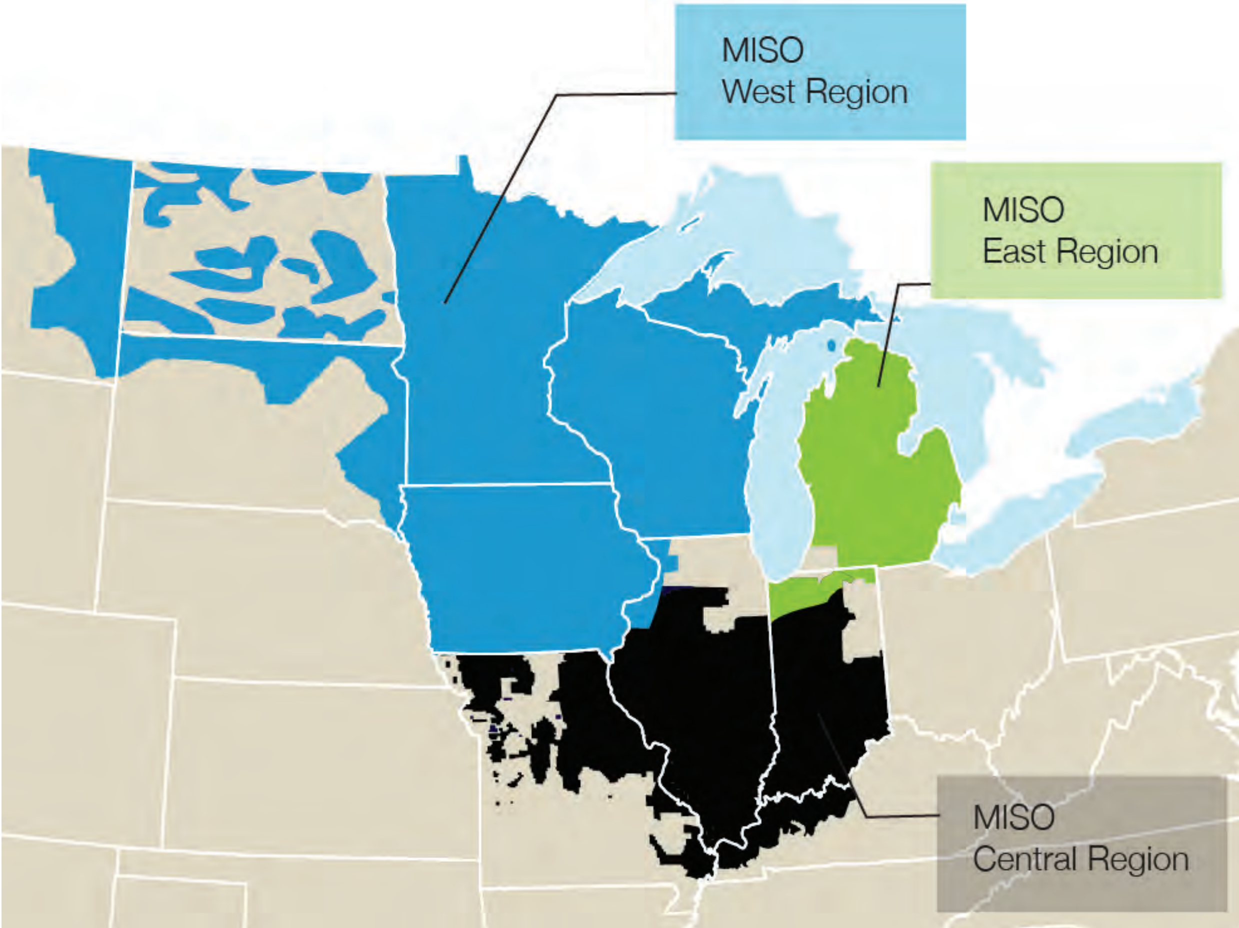


Figure 2.1-2: MISO footprint and planning regions

Approximately $1.5 billion of investment is added to Appendix A in this planning cycle. New investment in 2012 Appendix A projects is compiled by project category and eligibility for cost sharing (Table 2.1-2). Project categories are Baseline Reliability Project, Generation Interconnection Project, Transmission Service Delivery Project, Multi Value Project, Market Efficiency Project, and Other Project. The numbers in Table 2.1-2 are a subset of Appendix A values shown in Table 2.1-1. Actual cost allocations for shared projects are based on annual carrying charges and not total project investment. “Shared” means that the project is eligible for cost sharing, but not all costs of shared projects may be eligible for sharing. For example, some Baseline Reliability Project costs and Generation Interconnection Projects are not shared and only 10 percent of some Generation Interconnection Project costs may be shared to pricing zones. Projects are typically associated with a single planning region, though they may have investment in multiple planning regions. Cost sharing data is provided in Chapter 2.2.

Region	Share Status	Baseline Reliability Project (BRP)	Generation Interconnection Project (GIP)	Market Efficiency Project (MEP)	Other Project	Total
Central	Not Shared	$7,873,000	$13,934,000	$0	$82,023,000	$103,830,000
	Shared	$0	$0	$14,500,000	$0	$14,500,000
Central total		$7,873,000	$13,934,000	$14,500,000	$82,023,000	$118,330,000
East	Not Shared	$8,217,000	$0	$0	$128,135,000	$136,352,000
	Shared	$28,500,000	$184,903,000	$0	$0	$213,403,000
East total		$36,717,000	$184,903,000		$128,135,000	$349,755,000
West	Not shared	$54,940,000	$5,097,000	$0	$533,411,000	$593,448,000
	Shared	$368,642,000	$35,619,000	$0	$0	$404,261,000
West total		$423,582,000	$40,716,000		$533,411,000	$997,709,000
Grand total		$468,172,000	$239,553,000	$14,500,000	$743,569,000	$1,465,794,000

Table 2.1-2: MTEP12 new Appendix A investment by project category and planning region

Statistical analysis of new Appendix A project data indicates the new transmission plan is spread over many states, with Michigan, Wisconsin and Iowa scheduled for more than $1 billion in new investment (Figure 2.1-3). One project has investment in both Michigan and Wisconsin. The investment was split between the states approximately representing the investment in each state. These geographic trends change over time as existing capacity in other parts of the system is consumed and "new build" becomes necessary there.

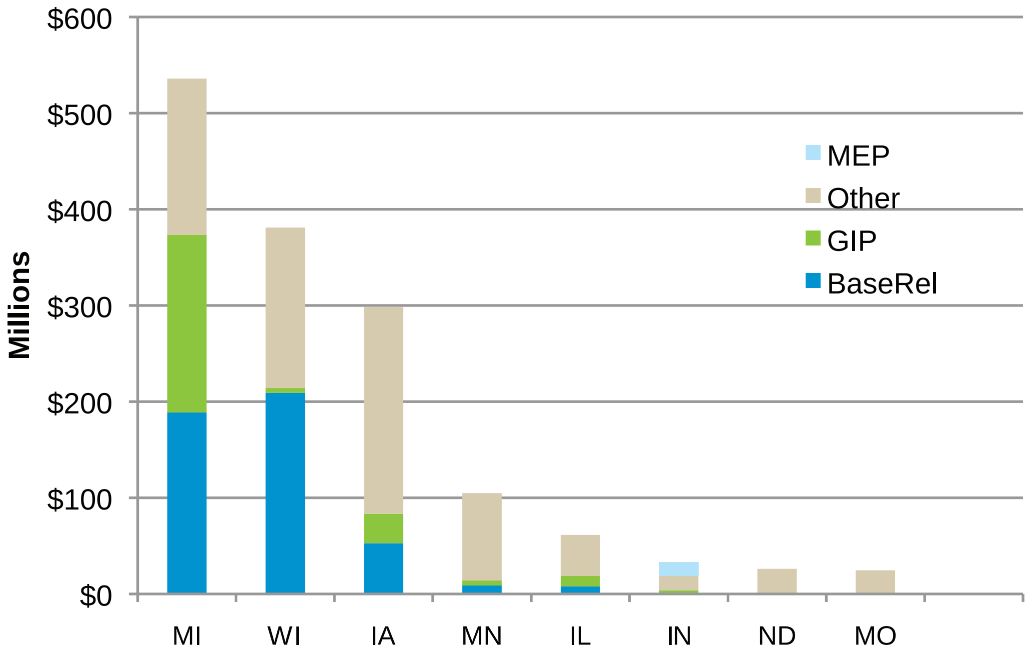


Figure 2.1-3 New MTEP12 Appendix A investment with allocation categorized by state

Appendix C Summary

MTEP12 Appendix C lists and describes $59 billion of conceptual and proposed transmission investment through 2022. There are multiple proposals to enable integration and delivery of large amounts of renewable energy. There are four 765 kV proposals that cost more than $1 billion each in the 2014-2020 time range. There is also one direct-current proposal of nearly $2 billion to address reliability and renewable energy in 2014. Some of these are competing proposals, so not all of the investment is expected. Many of the project proposals in Appendix C were added in order to address traditional reliability needs in the future. Some of these projects have just entered the planning process or are being revisited due to changes, such as load forecast adjustments caused by the economic downturn.

Appendix A and B Line Miles Summary

There are approximately 8,448 miles of new or upgraded transmission lines projected from 2012 to 2022 in MTEP12 Appendices A and B (Figure 2.1-4). MISO has approximately:

- 53,200 miles of lines of existing transmission, of which about 4,060 miles of transmission line upgrades are projected through 2022
- 4,388 miles of transmission involving lines on new transmission corridors is projected through 2022

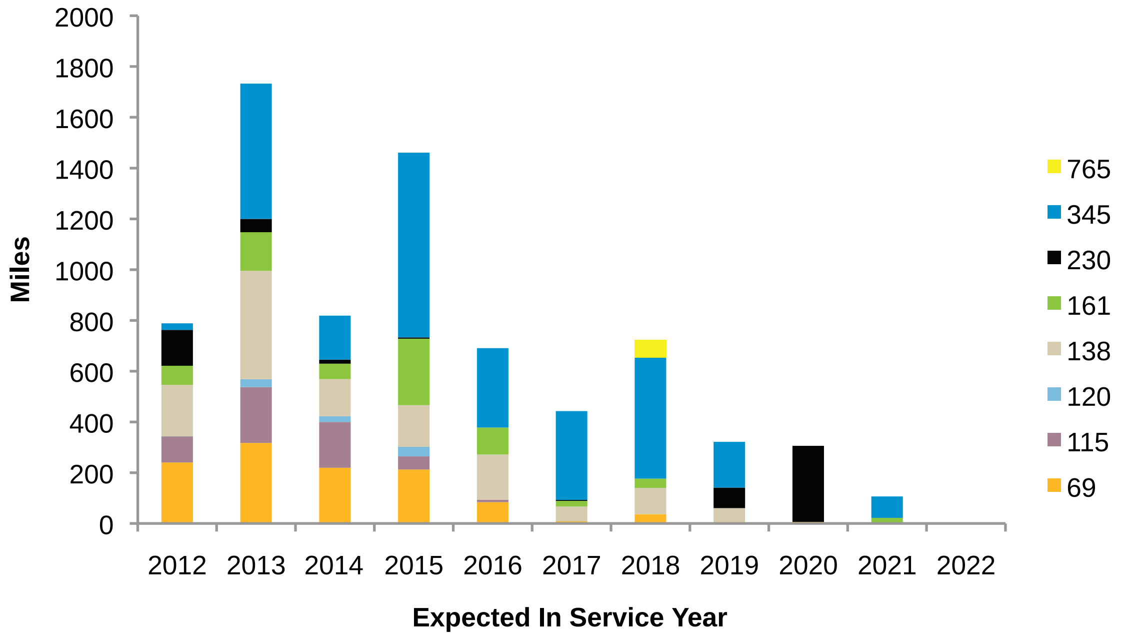


Figure 2.1-4: New or upgraded line miles by voltage class (kV) in Appendix A and B through 2022

Minnesota, Michigan, Iowa, Wisconsin, Illinois and Indiana are scheduled to receive the most new transmission line mileage, by state, for Appendices A and B through expected in service date of 2022 (Figure 2.1-5). This is primarily due to Multi Value Projects approved in MTEP11.

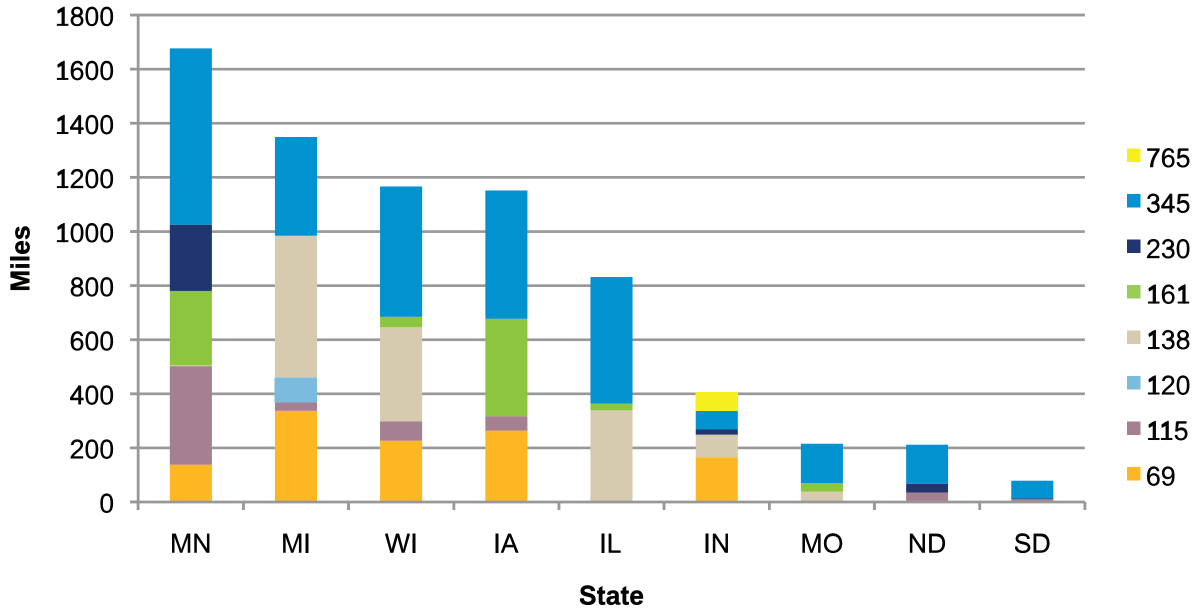


Figure 2.1-5 New or upgraded line miles by state for Appendices A and B through expected in service date of 2022 by voltage class (kV)

2.2 **Cost Sharing Summary**

New MTEP12 Appendix A Cost-Shared Projects

In MTEP12 a total of 21 new cost-shared projects, with a project cost of $620.9 million, are recommended for inclusion in Appendix A. The 21 cost-shared projects include:

- Thirteen Generation Interconnection Projects (GIP) with a total project cost of $220.1 million, with $107.4 million allocated to load and the remaining $112.7 million allocated directly to generators[4]
- Seven Baseline Reliability Projects (BRP) with a total project cost of $386.4 million
- One Market Efficiency Project (MEP) with a total project cost of $14.5 million

86 percent ($435.3 million) of cost-share projects remain in the pricing zone where the project is located, with the remaining 14 percent ($73.0 million) allocated to neighboring pricing zones or system-wide to all pricing zones

Of the $508.3 million in project costs eligible for cost sharing, excluding the portion of Generation Interconnection Projects allocated directly to generators, 86 percent ($435.3 million) remains in the pricing zone where the project is located, with the remaining 14 percent ($73.0 million) allocated to neighboring pricing zones or system-wide to all pricing zones. Additional details, including the pricing zone allocations, on the new Baseline Reliability Projects, Market Efficiency Project and Generation Interconnection Projects eligible for cost sharing in MTEP 12 are included in Appendix A-1. The pricing zone cost allocation shown in Appendix A1 has been converted into indicative annual Schedule 26 charges by pricing zone for 2013 to 2022 (see Appendix A1). Baseline Reliability Project, Market Efficiency Project and Generator Interconnection Project cost allocation calculations are posted on MTEP12 web page under the MTEP12 Cost Allocation Spreadsheet link. The workbook contains all information used in the allocation of BRP and GIP projects.

Cumulative Summary of All Cost-Shared Projects Since MTEP06

Since cost sharing methodologies were first incorporated into the MTEP process in 2006 for Baseline Reliability Projects and Generation Interconnection Projects, and later augmented with Market Efficiency Projects in 2007 and Multi Value Projects in 2010, there have been 155 projects eligible for cost sharing. This represents $8.94 billion in transmission investment, excluding projects that have subsequently been withdrawn or had a portion of project costs allocated directly to generators for Generation Interconnection Projects (Figure 2.2-1). The distribution of projects includes:

- Baseline Reliability Projects – 78 projects, $3.11 billion
- Generation Interconnection Projects – 58 projects, $331 million excluding the portion of project costs allocated directly to the generator
- Market Efficiency Projects – two projects, $20.1 million
- Multi Value Projects – 17 projects, $5.47 billion

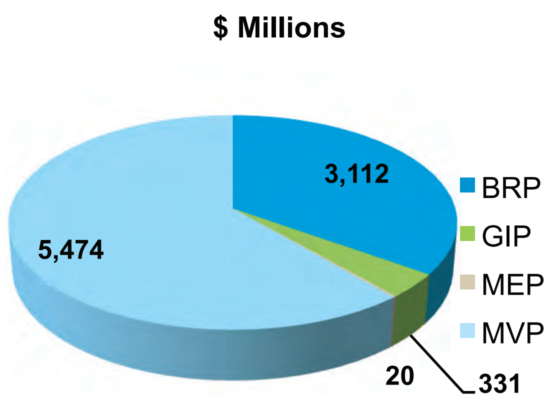


Figure 2.2-1:MTEP Cumulative Cost Sharing by Project Type ($ millions)

[4] Note that the $112.7 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

Cost-Shared Project Type	BRP	GIP	MEP	MVP	Total
A in MTEP06	690.7	27.4	-	-	718.1
A in MTEP07	93.5	13.1	-	-	106.6
A in MTEP08	1,342.3	12.4	-	-	1,354.7
A in MTEP09	179.8	64.7	5.6	-	250.2
A in MTEP10	39.7	1.9	-	510	551.6
A in MTEP11	379.5	1.9	-	4,963.9	5,447.5
A in MTEP12	386.4	107.4	14.5	-	508.3
Total	3,111.9	331.0	20.1	5,473.9	8,936.9

Figure 2.2-1: MTEP06 to MTEP12 Cost-Shared Project Costs by MTEP Cycle and Project Type (shown in $ millions)

The total project cost for each cost-shared project type is allocated to load differently depending on the driver of the project and distribution of benefits. For Baseline Reliability Projects, Generation Interconnect Projects and Market Efficiency Projects the majority of the cost allocation remained localized to the pricing zone where the project is located. Of the total $3.46 billion in approved costs for these three project types (not including MVPs.), approximately 69.0 percent ($2.39 billion) remains in the pricing zone where the project is located with the remaining 31.0 percent ($1.07 billion) allocated to neighboring pricing zones or system-wide to all pricing zones.

69.0 percent ($2.39 billion) of BRP, GIP and MEP remains in the pricing zone where the project is located with the remaining 31.0 percent ($1.07 billion) allocated to neighboring pricing zones or system-wide to all pricing zones.

The total project costs allocated to each pricing zone for Baseline Reliability Projects, Generation Interconnect Projects and Market Efficiency Projects has been broken down into two components, representing the portion of costs for projects located in the pricing zone and the portion of costs for projects located outside the pricing zone (Figure 2.2-2). The red bar represents the Transmission Owners' share of project costs that are not allocated to other pricing zones. The blue bar represents the portion of project costs allocated to a pricing zone for projects located in other pricing zones. The total cost shared project cost for projects located in the pricing zone can be found in parentheses next to the pricing zone name. Note that the values shown in Figure 2-2.2 exclude the portion of Generation Interconnection Projects assigned directly to the generator. The actual values for each pricing zone on the information shown in Figure 2-2.2 for all cost shared projects since MTEP 06 is located in Appendix A-2.2. Also, similar information is provided in Appendix A-2.3 for the new MTEP 12 Appendix A cost shared projects.

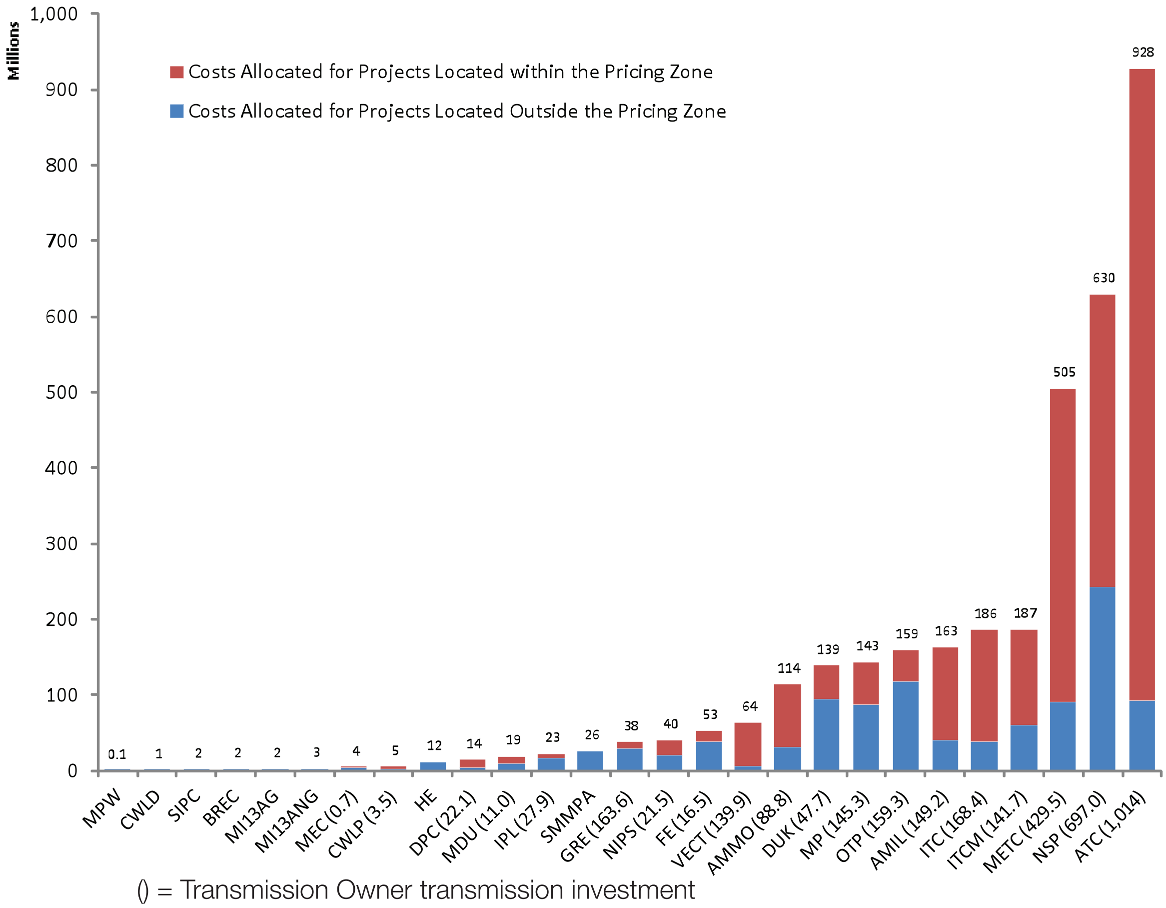


Figure 2-2.2: Allocated project cost from MTEP06 to MTEP12 for approved Baseline Reliability, Generation Interconnection and Market Efficiency projects[5]

For the approved portfolio of Multi Value Projects (MVP), the costs will be allocated 100 percent region-wide and recovered from customers through a monthly energy charge calculated using the applicable monthly MVP Usage Rate. This 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[6], based on the approved MVP portfolio using current estimated project costs and in-service dates, have been calculated for the period 2013 to 2052 (Figure 2-2.3). Appendix A-3 has information on where to find additional detail on the indicative MVP Usage Rates, including indicative annual MVP charges by Local Balancing Authority.

[5] Costs allocated for projects located in the now non-existent First Energy pricing zone are included in the values shown. The Duke Pricing Zone includes the project cost allocated to the withdrawn DEO and DEK.

[6] 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

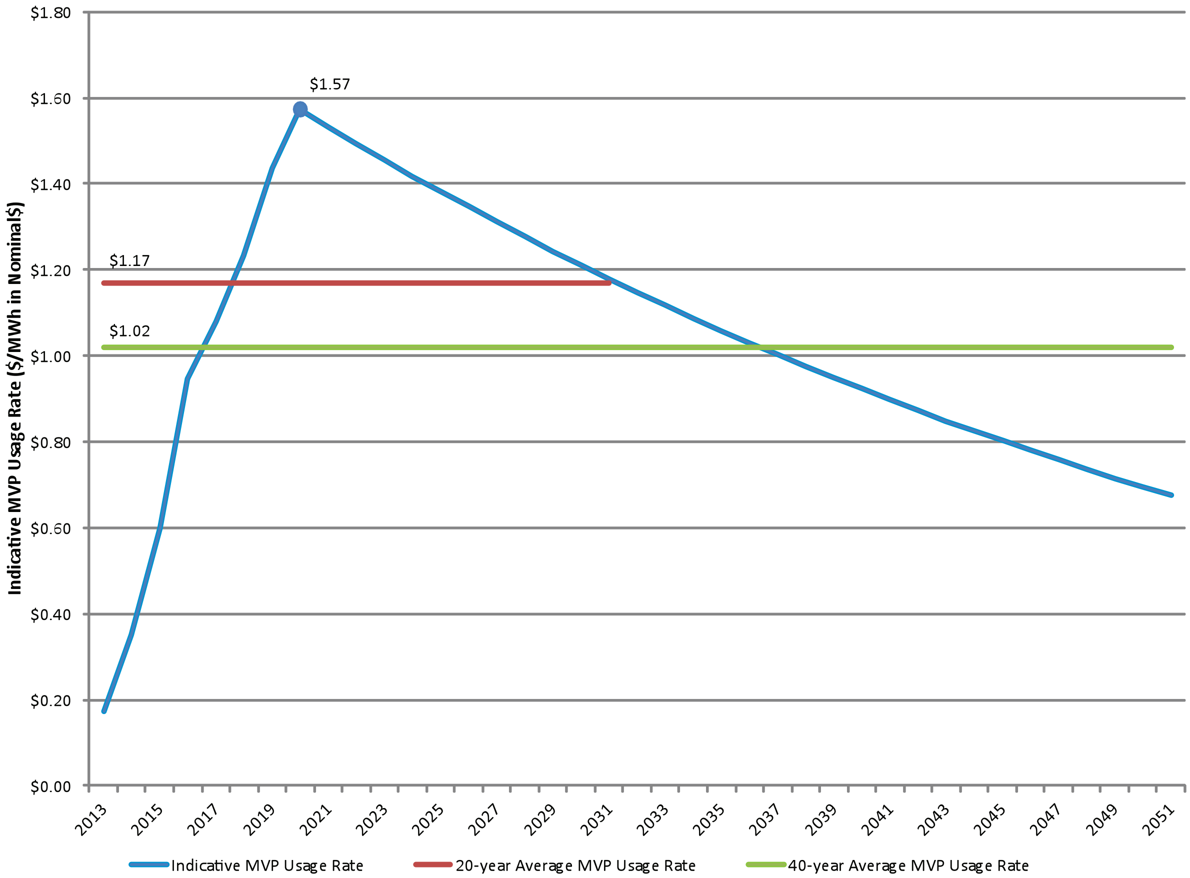


Figure 2-2.3: Indicative MVP usage rate for approved MVP portfolio from 2013 to 2052

2.3 MTEP Project Types and Appendix Overview

MTEP Appendices A, B and C indicate the status of a given project in the MTEP planning process. Projects start in Appendix C when submitted into the MTEP process, transfer 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. While moving from Appendix C to Appendix B to Appendix A is the most common progression through the appendices, projects may also remain in Appendix C or Appendix B for a number of planning cycles, or may go from C to B to A in a single cycle.

Projects start in Appendix C when submitted into the MTEP process, transfer 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

MTEP12 Appendix A lists projects approved by the MISO Board of Directors in prior MTEPs but have not been completed. It also lists projects and associated facilities recommended to the MISO Board of Directors for approval in this cycle. The newest projects are indicated as "A in MTEP12" in the "Target Appendix" field of Appendix A. The Appendix ABC field defines the 2012 progression of projects: "B>A" or "C>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 to the Tariff.

- Baseline Reliability Projects (BRP) are required to meet North American Electric Reliability Corp. (NERC) standards. Costs for Baseline Reliability Projects may be shared if the voltage level and project cost meet the thresholds designated in the Tariff.
- 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 GIPs are eligible for cost sharing.
- Transmission Service Delivery (TSR) projects are required to satisfy a transmission service request. The costs are assigned to the requestor.
- Market Efficiency Projects (MEP), formerly referred to as regionally beneficial projects, meet Attachment FF requirements for reduction in market congestion. Market Efficiency Projects 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.

A project not meeting any of these classifications is designated as "Other." The "Other" category incorporates a wide range of projects, including those intended to provide local reliability, economic or similar benefits, but not meeting requirements as MEPs or MVPs. Many other projects less than 100 kV are required on the transmission system. However, these are generally not part of the bulk electric system under MISO functional control.

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.

Projects in Appendix A have a variety of drivers. Many are required for maintaining system reliability in accordance with the North American Electric Reliability Corp. (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 (LSE). Appendix A projects may be required for economic reasons, to reduce market congestion or losses in a particular area. They may also be needed to reduce resource adequacy requirements through reduced losses during system peak or reduced planning reserve. Projects may be necessary to enable public policy requirements, such as current state renewable portfolio standards or Environmental Protection Agency (EPA) 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 reviews the projects via an open stakeholder process via Subregional Planning Meetings.
- MISO staff must validate that the project addresses one or more transmission need.
- MISO staff must consider and review alternatives.
- MISO staff must consider and review costs.
- MISO staff must endorse the project.
- MISO staff must verify that the project is qualified for cost-sharing as a Baseline Reliability Project, Generation Interconnection Project, Market Efficiency Project or Multi Value Project per provisions of Attachment FF.
- MISO staff must 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 Tariff.
- MISO staff must take the new project to the Board of Directors for approval. Projects move to Appendix A following a presentation at any regularly scheduled board meeting.

Appendices A, B and C are periodically updated and posted as projects go through the MTEP process and are approved. Projects are generally moved to Appendix A in conjunction with the annual approval of the MTEP report. A June mid-cycle approval option is available for projects that have been under study in an open process for an appropriate period of time and need to be approved prior to the normal December cycle. However, should circumstances dictate, recommended projects need not wait for completion of the next MTEP for Board of Directors approval and inclusion in Appendix A.

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 are 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 may contain projects still in the early stages of the Transmission Owner planning process or have just entered the MTEP study process and have not been reviewed. Like those projects in Appendix B, they are not evaluated for cost sharing. There are also some long-term conceptual projects in Appendix C that will require significant planning before they are ready to go through the MTEP process and move into Appendix B or Appendix A. Appendix C may also contain additional alternatives to projects that graduated to Appendix B. Therefore, a project could revert from B to C if a better alternative is determined and the transmission owner is not ready to withdraw the previous best alternative.

2.4 MTEP12 Model Development

Transmission system models are the foundation of MTEP studies. The accuracy and viability of the study results obtained hinges significantly on the accuracy of the models used. For MTEP studies, MISO builds reliability (powerflow and dynamics) and economic models to represent a planning horizon spanning the next 10 years. The reliability models include seasonal variations in load and generation dispatch.

For MTEP studies, MISO builds reliability (powerflow and dynamics) and economic models (PROMOD) to represent a planning horizon spanning the next 10 years

The processes used to develop MTEP models are collaborative in nature, with significant stakeholder participation. Stakeholders provide modeling data, help develop assumptions for modeling future transmission system scenarios and review the models developed. MISO coordinates its models with companies along MISO's seams and their system representation is updated based on their feedback.

The primary sources of information used to develop the models are:

- Transmission Owners and MISO Load Serving Entities
- Model on Demand[7] (MOD) base case
- Eastern Reliability Assessment Group (ERAG) Multi-Area Modeling Working Group (MMWG) 2011 series models
- PowerBase database

MTEP12 models are inter-related (Figure 2.4-1).

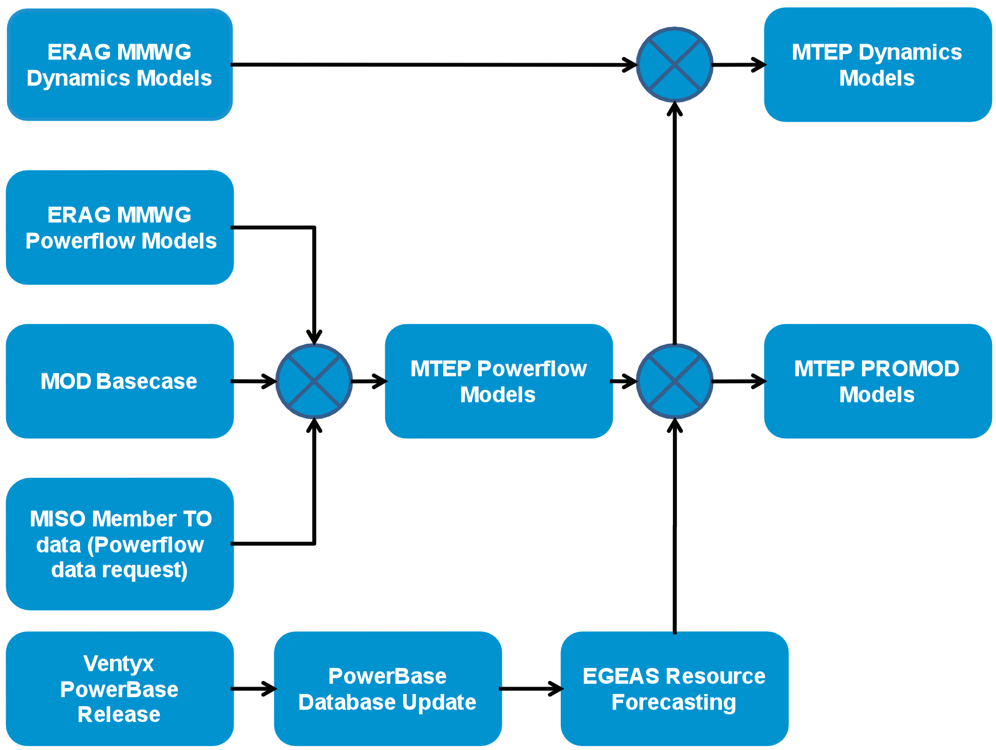


Figure 2.4-1: MTEP12 model relationships

[7] Model on Demand (MOD) is MISO's online database of planning information

Reliability Study Models

Powerflow Models

For MTEP12, MISO conducted regional studies using the following base models:

- 2014 Summer Peak
- 2017 Summer Peak
- 2017 Shoulder Peak
- 2017 Light Load
- 2017/2018 Winter Peak
- 2022 Summer Peak
- 2022 Shoulder Peak

For the MTEP12 cycle, MISO members received a request in October 2011 to submit modeling data to MOD. The MISO transmission system is represented in MTEP models using data available in MOD. The ERAG MMWG cases are the base starting point for non-MISO system representation in MTEP models. Requests for updated information to the ERAG MMWG models from seams companies were sent after these models were released in late November. MISO built preliminary models from MOD and posted them for stakeholder review in early December. After incorporating the feedback received, final models were built and posted in early 2012.

Assumptions regarding future transmission, generation and loads include:

- Load

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

- Generation

  Existing and planned generators with signed Interconnection Service Agreements, with expected in-service dates through the corresponding season being modeled, are included.

  Broadly, powerflow cases used for member Transmission Owner project justification use a tiered Regional Merit-Order Dispatch (RMD). Cases used to perform reliability studies needed to demonstrate compliance with NERC transmission planning standards use a Security Constrained Economic Dispatch (SCED).

  Renewable generation is dispatched at levels agreed upon through the stakeholder processes.

  Generation is dispatched to allow for the MISO net area interchange level to be consistent with equivalent ERAG MMWG cases.

- Transmission topology

  In-service and future transmission facilities approved through prior MTEP studies with expected in-service dates through corresponding season being modeled are included.

  Additionally, transmission projects submitted for approval in the MTEP12 planning cycle are also included. The primary rationale behind this inclusion criterion is to ensure that MTEP cases accurately represent the planning horizon in the studies performed to demonstrate compliance with NERC reliability standards.

Dynamic Stability Models

For MTEP 2012, MISO conducted dynamic stability analysis using the following base models:

• 2017 Light Load

• 2017 Summer Shoulder load

Dynamics data from the ERAG MMWG dynamic stability models released in late March was merged with the MTEP12 powerflow cases. As such, the topology and dispatch used for dynamic stability analysis is consistent with the steady-state reliability analysis.

During MTEP12, MISO initiated an effort to improve the system dynamic representation. Historically, various wind and traditional (thermal) generators have been represented using older models available in the PSS/E model library such as the induction generator model ("CIMTR3") for wind and the classical synchronous machine model ("GENCLS") for thermal. While these models were appropriate choices at the time, they are limited in their accuracy and are not as numerically stable as some of the newer models currently available – such as generic wind turbine generator models (Types 1 through 4) for wind generation and the synchronous machine model ("GENROU") for thermal generators. In consultation with the stakeholders, these generator models were updated for MTEP12 dynamics.

Two separate review periods were held for stakeholders to review the dynamic stability models in April and June 2012. During these review periods 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 studies in MTEP12

• Output quantities to be measured

• Feedback on replacing older generator models with newer ones (as described above)

The MTEP12 dynamics cases were finalized and posted in August 2012.

Economic Study Models

The economic study models used in the MTEP 2012 process are forward-looking, time-dependent models based on assumptions discussed and agreed upon through the stakeholder process. For MTEP12, the Planning Advisory Committee (PAC) approved five different future scenarios:

• Business as Usual (BAU)

• Historical Growth (HG)

• Limited Growth (LG)

• Combined Policy (COMB)

• Joint MISO-Southwest Power Pool Future (SPP)

The details on these scenarios are available in Chapter 5, Economic Analysis.

The base data used in all future scenarios is maintained through the PROMOD PowerBase database. This centralized database uses the latest-available economic data as the starting point. MISO then goes through an extensive model development process, which updates the original data 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 Chapter 7.6)

Two stakeholder review periods of the PowerBase, including system topology, were held in May and June 2012. During this 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 monitored flowgates/interfaces

In addition to the stakeholder review process, MISO continued to collaborate with neighboring entities to develop a coordinated model which more accurately reflects the neighbors' systems. Highlights of this collaboration include extensive updates from PJM Interconnection (PJM) and SPP. The PowerBase model was finalized in June 2012.

Chapter Three
Historical MTEP Plan Status

CHAPTER 3

Historical MTEP Plan Status

Since the first MTEP report in 2003, more than $5.1 billion worth of projects have been constructed in the MISO region. MISO members are making a good faith effort to construct $10.8 billion of approved projects.

This section provides an update on the implementation of projects approved in previous MTEP reports and furnishes a historical perspective of all past MTEP approved plans. These projects were approved by the MISO Board of Directors in previous MTEP cycles or are recommended for approval in MTEP12. Any given MTEP Appendix A contains newly approved projects, along with previously approved projects not in service when the MTEP Appendices were prepared.

3.1 MTEP11 Status Report

MISO transmission planning responsibilities include monitoring progress and implementation of essential expansions identified in MTEP. The MISO Board of Directors approved the last MTEP (MTEP11) in December 2011. This chapter provides a review of the status of previously approved projects listed in MTEP11 Appendix A. The quarterly status reports are posted to the MISO MTEP Studies web page.

Since 2006, the MISO Board of Directors has been receiving quarterly status updates on active plans. The information in this report reflects project status as of the second quarter 2012 report to the Board of Directors, which included status on MTEP11 Appendix A projects through June 30, 2012.

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. MTEP11 Appendix A has 546 projects comprised of 1,122 facilities. These figures have been updated to reflect the progress of members' projects. MTEP11 Appendix A includes expansion facilities through 2020. More than 99 percent of the approved facilities included in MTEP11 are in service, on track or have encountered reasonable delays. That translates to $10.137 billion of the $10.154 billion on track in MTEP11 Appendix A.

More than 99 percent of the approved facilities included in MTEP11 are in service, on track or have encountered reasonable delays. That translates to $10.137 billion of the $10.154 billion on track in MTEP11 Appendix A

There were 82 in-service date adjustments to projects. Little or no impact on reliability is expected because in-service date adjustments were primarily driven by the economic slowdown. Transmission Owners may adjust project in-service dates to match system needs.

Withdrawn projects are documented to ensure the planning process of MISO and its members address required system additions, and there is a good reason for withdrawing the project. Common reasons for withdrawal of approved projects are that a different project covers the need or system needs no longer require the project. MTEP11 Appendix A contains projects approved in past MTEPs but not yet in service, so withdrawn facilities may have been approved in prior MTEPs but withdrawn after MTEP11 was approved. There were 24 facilities (2 percent of 1,122) withdrawn for the following reasons:

- The customer's plans changed or the service request was withdrawn
- The plan was replaced with another plan
- The plan was redefined to better meet the needs
- The load forecast dictated that the project was no longer needed

All withdrawn facilities were withdrawn for valid reasons, and thus considered on-track. The majority were cancelled because service requests were withdrawn or load forecast was reduced.

3.2 MTEP Implementation History

This chapter encompasses the implementation and status of all approved MTEP plans, including the current MTEP plan. A historical perspective of the implementation and status of all approved MTEP plans, including the current MTEP12 plan, shows extensive variability in transmission plan development. This is normal, caused by the long development time of transmission plans and the regular and periodic updating of the transmission plans due to changing needs and drivers.

> The cumulative investment dollars for projects, categorized by plan status, for MTEP03 through the current MTEP12 cycle is over $16 billion

The cumulative investment dollars for projects, categorized by plan status, for MTEP03 through the current MTEP12 cycle is over $16 billion (Figure 3.2-1). MTEP12 data depicted in this figure, subject to Board approval, is from the current MTEP study and will be added to the data tracked by the MISO Board of Directors. These statistics include MISO members who participated in this planning cycle. Previously approved projects for past MISO members are not included in these statistics.

- Since MTEP03, $5.1 billion of approved projects have been constructed and are in service.
- $388 million of MTEP projects are currently flagged as being under construction with roughly $553 million with expected in-service dates in 2012.
- $10.8 billion of MTEP projects are currently planned or under construction.
- Since MTEP03 $512 million of MTEP projects have been withdrawn.

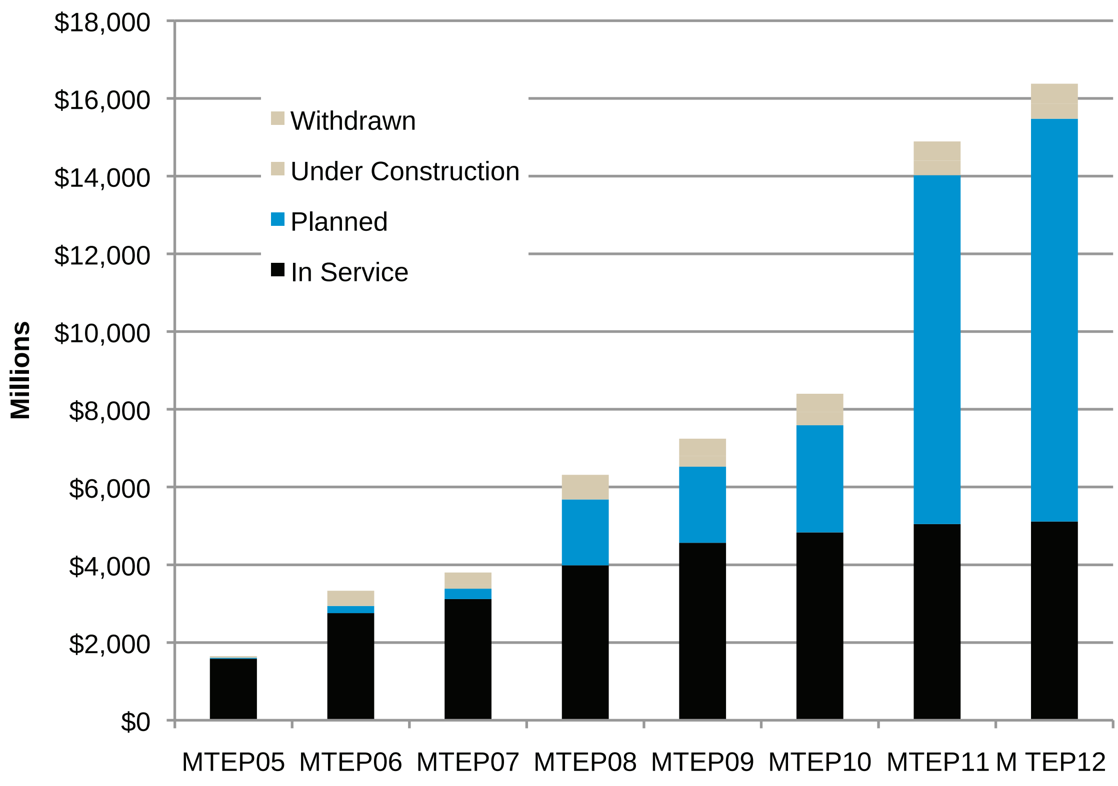


Figure 3.2-1: Cumulative approved investment by facility status

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. The large increase between MTEP10 and MTEP11 is approval of Multi Value Project portfolio.

- MTEP06 and MTEP07 were approved in the same calendar year, which accounts for the comparatively small number of projects in MTEP07.
- MTEP08, the number of developing needs increased the number of planned projects, including several large upgrades.
- MTEP09 was a year for analysis and determination of the best plans to serve those needs. The in-service category can be seen increasing in past MTEPs as projects are built.
- MTEP10 contains significant adjustments for reduced load forecasts.
- MTEP11 contains most of the Multi Value Project portfolio, which is approximately $5.1 billion in transmission investment.
- MTEP12 reflects a return to a more typical MTEP, primarily driven by reliability projects.

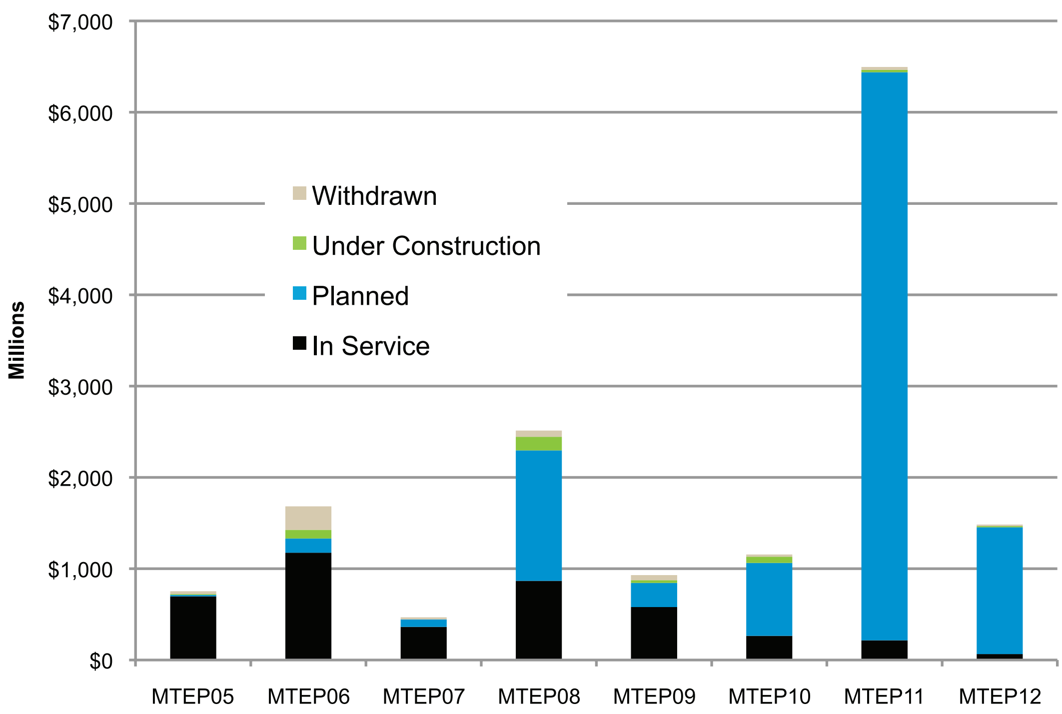


Figure 3.2-2: Approved MTEP investment by facility status[8]

[8] New Appendix A projects in the MTEP12 column contain a few in-service and under-construction projects. There are a couple reasons why this occurs. First, generator interconnection projects are approved via separate Tariff process, however, certain GIP network upgrades are eligible for regional cost allocation and that is done during the current MTEP cycle. Second, there are condition-based projects on existing facilities which must be completed promptly and cannot wait for MTEP cycle. There was one storm damaged line accounted for one-third of the in-service costs. There were a number of smaller condition-driven projects. Project reporting guidelines require reporting of maintenance projects when the new replaced facility increases the capacity of the transmission system.

Chapter Four
Reliability Analysis

CHAPTER 4
Reliability Analysis

MISO performs an annual Reliability Assessment through its MISO Transmission Expansion Plan (MTEP).

MISO studied the reliability impacts of 45 proposed projects. Together these projects remediated 7 category A reliability issues, 41 Category B and 338 category C issues

Based on MISO's NERC reliability assessment, on an aggregate level, 6,487 thermal and voltage potential reliability issues were identified. The majority of these identified violations have been mitigated via system reconfigurations, including generation re-dispatch. Forty-five mitigations, in form of future proposed transmission upgrades, have been identified for 386 projected thermal and voltage issues. These network upgrade mitigations will be investigated further in future MTEPs.

In support of its MTEP assessment, MISO conducts Baseline Reliability studies to ensure the transmission system is in compliance with two entities: applicable national Electric Reliability Organization (ERO) reliability standards and reliability standards adopted by Regional Reliability Organizations applicable within the transmission provider region. 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.

Many MTEP12 Appendix A projects are classified as "Other." These projects are, by definition, not eligible for cost sharing, but are needed to maintain reliability of the sub-transmission system. MISO analyzes these projects, from an independent perspective, to ensure they addressed the specified reliability issues and caused no harm.

Planned transmission upgrades needed to mitigate identified issues have been added to MTEP12 Appendix A, while proposed transmission upgrades with sufficient lead times 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 2011, March 2012 and June 2012. The final results of this reliability analyses are summarized in the following chapters and Appendix D of this MTEP12 report.

4.1 Near-Term Assessment

Near-term assessment involves study of the MTEP two- and five-year-out models. Recommended projects for the current MTEP12 cycle add up to about $1.45 Billion and includes 34 Baseline Reliability Projects (12 in MISO East, 5 in MISO Central and 17 in MISO West); one Market Efficiency Project; and 23 Generation Interconnection Projects (4 in MISO East, 3 in MISO Central and 16 in MISO West). More than $647 million in sub-transmission investment is also planned. Detailed documentation of these plans is in Appendix D1. The major projects are organized into seven local resource zones within MISO (Figure 4.1-1).

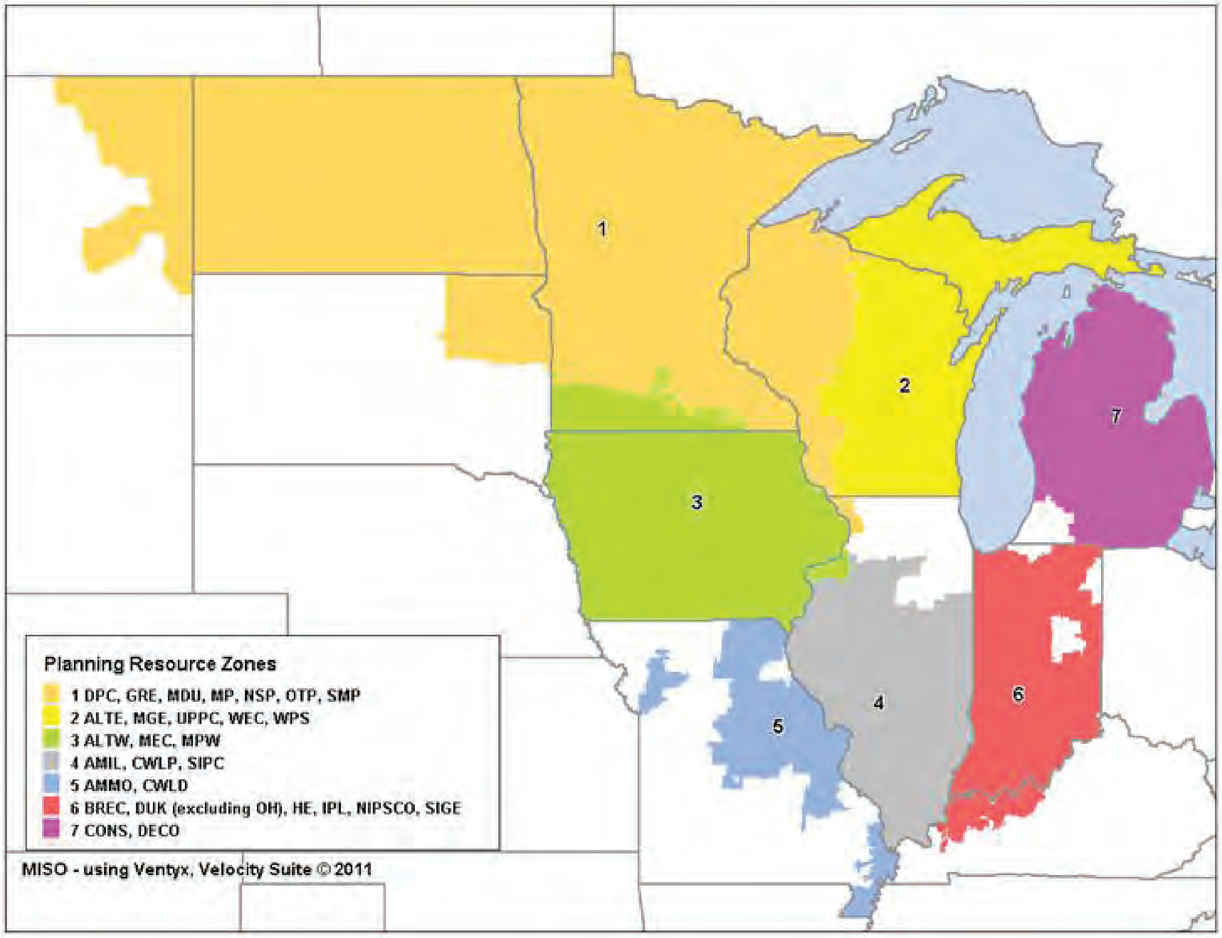


Figure 4.1-1 MISO local resource zones

Near-Term Transmission Projects (grouped by local resource zones)

Zone 1

Couderay–Osprey 161 kV Line (Xcel)

During summer peak conditions, river conditions can be such that there is low or no hydro generation along the Flambeau River. These conditions, in addition to load growth in the area, result in low voltages on the transmission system for Category B outages. Because of the large amount of reactive support in the area (approximately equivalent to load), a new source to the area is needed to maintain voltages during outages. The project will cost $46.5 million with an in-service date of December 2014.

Maple River–Red River 2nd 115 kV line (Xcel)

Category C3 contingencies between Maple River and Sheyenne involving the loss of the existing Maple River–Red River 115 kV circuit causes overloads along the 115 kV paths between the two substations. By adding a second Maple River–Red River 115 kV circuit, all the Category C3 overloads can be mitigated. The project will cost $6 million with an in-service date of June 2015.

Ramsey Transformer upgrade (GRE)

The Ramsey 230/115 kV transformer overloads based on the loss of the Ramsey-Prairie 230 kV line. A temporary SPS currently protects this transformer from overloading. The SPS will retire after installation of a larger transformer to be placed at Ramsey. The overload is mitigated by upgrading the existing transformer at Ramsey. The upgrade will cost a bit more than $5 million, with an estimated in-service date of November 1, 2012.

Zone 2

Build Green Bay-Morgan 345 kV; Holmes-Escanaba 138 kV (ATC)

A major loss-of-load event in northeastern Wisconsin and western Upper Michigan in May 2011 drew attention to shifting supply and demand patterns and emerging reliability needs in the area. Multiple Category B and C contingencies leading to overloads and voltage instability on the five-year horizon drove a package of projects through an out-of-cycle study terminating in August 2012, including: a new 345 kV “Green Bay” substation between North Appleton and Kewaunee; 40 miles of new 345 kV; 60 miles of new 138 kV; and approximately 150 Mvar of new 138 kV reactive supply. The estimated cost is $280 million with an in-service target of January 2017.

Build Green Bay-Morgan 138 kV (ATC)

Remaining Category C cascading overloads after the previous project is in service are to be addressed by a new, 40-mile 138 kV line from the Green Bay area to Morgan. The estimated cost is $60.3 million with an in-service target of January 2017.

Install Arnold 345-138 kV transformer (ATC)

Category B and C overloads and low voltages in 2014 are driving the construction of a new 345 kV station and a 500 MVA autotransformer that will link the Plains-Dead River 345 kV line to the existing Arnold 138 kV station. The estimated cost is $15.8 million with an in-service target of June 2014.

Rebuild Arcadian-Waukesha 2x138 kV (ATC)

There are two, 4-mile 138 kV circuits from Arcadian to Waukesha. During an off-peak system condition, the outage of one line will overload the other. The reliability need will be addressed by rebuilding the lines to 500 MVA each. The estimated cost is $14.8 million with an in-service target of June 2016.

Zone 3

8th Street–Salem 161 kV Line (ITC Midwest)

With local area generation offline, Category B2 outages on the 161 kV system near Dubuque, Iowa, area cause overloads on remaining 161 kV lines. Additionally, low voltages can occur on the 69 kV system for a bus-tie breaker failure at Salem. Constructing a Salem–8th Street 161 kV line and installing a second bus-tie breaker at Salem mitigates the overloads. The project will cost $5.5 million, with an in-service date of December 2014.

Salix–Kellogg 161 kV Line (MidAmerican Energy Co.)

For a common tower, Category C5, outage of the Raun–Sioux City 345 kV and the Raun–Morningside 161 kV lines will overload the Raun–Interchange 161 kV line. Adding a new line from the Salix substation to the Kellogg substation, both 161 kV, will mitigate the overload. The project will cost $23.8 million, with an in-service date of June 2015.

Zone 4

The noteworthy projects in the Ameren Illinois footprint are driven by equipment condition. Ameren Illinois is replacing more than 80 miles of its older 138 kV lines that were built with copper conductors. These lines have integrity issues and were originally constructed in the 1940s. The new lines will have modern ACSS conductors.

Zone 5

There are no significant Bulk Electric Projects in the Ameren Missouri system in this planning cycle.

Zone 6

Increase rating of Petersburg-Wheatland-Breed 345 kV and Petersburg-Cato Tap-Duff 138 kV lines (IP&L and Vectren)

This Market Efficiency Project involves the upgrade of a 345 kV line and 138 kV lines in Indiana. The upgrade of the Petersburg–Wheatland–Breed 345 kV line will be accomplished by raising select towers. The upgrade of the Petersburg–Cato Tap-Duff 138 kV path will operate at a higher design temperature and elevated required elevated structures. The anticipated in-service date is January 2015 at an estimated cost of $14.5 million.

Upgrades needed to accommodate the PJM Auction Revenue Rights (ARR) request

- **Replace existing Burr Oak Substation Transformer (NIPSCO):** Replace the existing Burr Oak transformer with a 556 MVA 345/138 kV transformer. This project is identified in PJM's ARR Queue as V3-052 and is a "Market Participant" sponsored project. The anticipated in-service date is March 2013.

- **Add an additional 345 kV Breaker at Burr Oak Substation (NIPSCO):** The addition of one 345 kV breaker at Burr Oak Substation will alter the existing 345 kV bus configuration to a ring bus configuration. A ring bus configuration will increase the thermal rating of the Burr Oak to R.M. Schafer 345 kV line. This project is identified in PJM's ARR queue as V3-052 and is a "Market Participant" sponsored project. The anticipated in-service date is March 2013.

- **Re-sag the Crete (ComED) to St. John (NIPSCO) 345 kV Line:** The Crete to St. John 345 kV line was re-sagged to increase the emergency thermal rating to 1399 MVA. This project is identified in PJM's ARR queue as V3-052 and is a "Market Participant" sponsored project. The project was recently completed and included in the MTEP12 plan.

- **Burnham (ComED) to Munster (NIPSCO) 345 kV Line:** This project is identified in PJM's ARR queue as V3-052 and is a "Market Participant" sponsored project. This project entails the upgrade of communications equipment at Burnham and Munster Substations and upgrade of relaying at Munster to increase the emergency thermal rating of this line to 1195 MVA. The in-service date was March 2012.

Zone 7

Tippy SVC (METC)

The planned maintenance plus forced contingency for loss of two sections of 345 kV lines in Michigan may potentially result in low-voltage issues in the Northern Michigan area. Installation of one 216 Mvar SVC at Tippy will help to provide fast-acting reactive power and continuously regulate system voltage. Estimated cost for this project is $28.5 million and the expected in service date is June 1, 2015.

NERC Reliability Assessment Results Overview

All transmission plans in the final NERC Reliability Assessment include additional planned and proposed transmission projects or operating steps. They are necessary to meet system performance requirements of applicable standards. Noteworthy MISO near-term issues within the MISO footprint have been documented below and grouped into the local resource zones.

Zone 1

Dairyland Power Cooperative (DPC)

There were six transmission lines in DPC's transmission system that were identified as constraints in the MTEP12 steady state analysis. All overloads are on the 161 kV system. Overloads occurred near Stoneman and Harmony. The Stoneman area overloads, resulting from Category C3 events, are mitigated with system re-dispatch. The overloads are seen as the C3 events involve a loss of two major 345 kV tie lines to ComEd, resulting in the power being pushed through lower voltage systems. The overloads near Harmony are mitigated by re-dispatch. One voltage constraint, located at the Galena substation, was a result of Category C events in the ITC Midwest (ITCM) system. ITCM has two projects: P3637, which installs an additional 8th Street 161/69 kV transformer as well as breakers; and P3629, which builds a Salem – 8th street 161 kV line that will mitigate the constraint.

Great River Energy (GRE)

One transmission element was constraining in GRE's transmission system for the MTEP12 analysis. The 230/115 kV transformer at McHenry overloads due to load growth, and is mitigated by re-dispatch. One element was identified as a voltage constraint at Willmar. The low voltage, due to load growth, will be mitigated by GRE's proposed Priam substation and capacitors.

Montana Dakota Utilities (MDU)

There were no thermal or voltage issues identified in MDU's system.

Minnesota Power (MP)

Nine transmission elements were constraining in MP's transmission system for the MTEP12 analysis. The overloaded elements are due to load growth and are located near Hilltop, Diamond Lake, Virginia, and Blackberry. The Hilltop overloads will be mitigated by MP's proposed second 230/115 kV transformer. Boswell generation re-dispatch addresses the overloads near Diamond Lake. Minnesota Power will use load shed to mitigate constraints near Virginia. A proposed rebuild near Blackberry will mitigate nearby constraints. Seven elements were identified as voltage constraints near Mud Lake and Air Park driven by Category C events. Minnesota Power will utilize load shed to mitigate the constraints.

Otter Tail Power (OTP)

Six transmission elements were constraining in OTP's transmission system for the MTEP12 analysis. The overloads, due to load growth, are found near Buffalo, Ortonville, and Winger. The overloads near Buffalo are mitigated by the CapX 2020 project (P3156) and associated underlying system rebuilds, as well as a proposed replacement of the Buffalo transformer. The Ortonville overloads are addressed by the Big Stone South–Brookings 345 kV line Multi Value Project (P2221). The Winger area constraints will be addressed by OTP's proposed Winger–Thief River Falls 230 kV line. Five elements were identified as voltage constrained, located near Benson and Foreman. The Benson low voltages, caused by load growth, are addressed by the proposed Priam substation and capacitors. The Foreman overloads are addressed by the new capacitor at Gwinner (P2823).

Southern Minnesota Municipal Power Agency (SMP)

There were no thermal or voltage constraints identified in SMP's system.

Xcel Energy (XEL)

There were seven transmission lines in XEL's transmission system that were identified as constraints in the MTEP12 steady state analysis. All overloads were on the 115 kV to 345 kV system. Overloads occurred in the Western Twin Cities and Sioux Falls areas. The Western Twin Cities area overloads, resulting from increase loads, will be mitigated by a new Scott County 345/115 kV substation. The overloads near Sioux Falls result from high 345 kV transfers and are mitigated by modifying the existing Sioux Falls 115 kV Northern Plan to terminate at Split Rock. Four voltage constraints near Holcombe, Fibro, and Maynard were identified. All voltage issues are mitigated by re-dispatching generation and don't require new network expansions.

Zone 2

There were 32 transmission line sections and three transformers in ATC's transmission system that were identified as thermal constraints in the MTEP12 steady state analysis. With the exception of two Category C overloads on facilities at the Arcadian 345 kV station outside of Milwaukee, all transmission constraints were below 300 kV. The Arcadian transformers are showing overloads on near-term summer peak. This overload is addressed through a new transformer at Arcadian.

Two category B overloads are directly mitigated by line reconductor projects. The remaining 110 Category C overloads are mitigated by 12 additional network expansion projects. The most notable project proposed as a mitigation is the (Appendix A) Barnhart-Branch River 345 kV build-out between Point Beach, North Appleton and Saukville, which off-loads the eastern Wisconsin 138 kV system during outages.

One Category B voltage violation (in three scenarios) is mitigated by a new line, and the remaining 80 category C voltage violations are mitigated by seven additional projects. The a new Holmes-Chandler 138 kV line mitigates significant number of constraints in the Escanaba area by providing a third 138 kV source into Escanaba, Mich., and an 138 kV path parallel to the Plains-Arnold 345 kV corridor.

Thirty transmission constraints identified in the longer term planning horizon are mitigated by newly proposed projects in the near term. These include a Category B overload of the Racine-Oak Creek 138 kV line, mitigated by reconductoring of Racine to Oak Creek 138 kV; and low voltages on the West Marinette 138 loop for high transfers, mitigated by new Green Bay to Morgan 345 kV and Holmes to Escanaba 138 kV lines.

Zone 3

ITC Midwest (ITCM)

There were six transmission lines in ITCM's transmission system that were identified as constraints in the MTEP12 steady state analysis. All overloads were on 161 kV system. Overloads occurred near Turkey River, Rock Creek and Wappello. The Turkey River area overloads, resulting from Category C events and increased area loads, are mitigated with ITCM's project P3828 which rebuilds the Lore–Turkey River–Stoneman line. The Rock Creek area overloads are addressed by ITCM's proposed project to upgrade the line by eliminating the sage limits on the line. The Wappello overloads are mitigated by ITCM's project to upgrade the 161/69 kV transformer, rebuild the substation to breaker-and-a-half, and upgrade the Ottumwa terminal limits to at least 391 MVA. Fourteen voltage constraints, located near Marshalltown and Liberty/Dundee areas, were identified. The Marshalltown voltage constraints are mitigated by re-dispatch. The Liberty/Dundee area constraints are mitigated by dispatching Dubuque area generation and a CIPCO project which rebuilds Marion–Swamp–Fox–Coggon–Dundee 115 kV line.

Muscatine Power & Water (MPW)

There were no thermal or voltage issues identified in MPW's system.

MidAmerican Energy Corporation (MEC)

There were 16 transmission lines in MEC's transmission system that were identified as constraints in the MTEP12 steady state analysis. Overloads were on 345 kV and 161 kV systems. Overloads occurred near Council Bluffs, Buena Vista, Neal and Hills. The Council Bluffs elements are mitigated by a new 345/161 kV substation near Council Bluffs. The Buena Vista overloads will be addressed by MEC's proposed project to upgrade terminal equipment. Neal overloads are mitigated by an operating guide to re-dispatch Neal generation as well as by terminal upgrades at Salix. Hills area overloads are fixed by re-dispatch of the system. One element was identified as a voltage constraint, near Atchison. The high voltages are addressed by an existing operating guide.

Zone 4

In the Illinois and Missouri resource zones (4 and 5, respectively) within the MISO footprint, steady state analysis identified 11 Category B thermal constraints. Four of those eleven are on facilities at 200 kV or greater voltage levels. In the Category C analysis, 41 thermal constraints were identified, eight of which were at 200 kV or greater voltage levels. No voltage constraints were identified in the MTEP12 steady state analysis.

In Central Illinois (Peoria, Galesburg, Kewanee, Bloomington and Champaign) a number of constraints were identified in the steady state analysis for the two-, five- and 10-year-out models. The 138 kV network within this region is heavily loaded for outages on the 345 kV lines local to this area in the two- and five-year-out models. This is due to the lack of additional 345 kV circuits between northwest Illinois and East-Central Illinois. Many of these constraints are relieved in the 10-year-out model, which includes approved Multi Value Projects (MVPs) with in-service dates in the longer term planning horizon. In the interim period, these overloads are mitigated through system reconfigurations. The remaining violations will be corrected by two additional proposed 138 kV line reconductor projects.

In the 10-year-out shoulder model, 345 kV line outages push loadings on adjacent 345 kV line above its emergency rating. One proposed project has been identified to create a new 345 kV line outlet northeast of the Peoria area. This proposed transmission expansion, as well as generation re-dispatch, will address identified constraints and will be evaluated in subsequent planning assessments.

Zone 5

In the St. Louis, Mo., area (which includes nearby southwestern Illinois), there are numerous 138 kV and 161 kV lines, as well as 345/138 kV transformers where overloads are identified in the two- and five-year-out models. Proposed transmission expansions to address identified overloads will be evaluated in the next planning cycle. Generation re-dispatch in the interim will be employed to mitigate constraints. Three network expansion projects have been proposed to relieve the thermal overloads, one of which will convert an existing 138 kV line to a new 345 kV line.

Zone 6

Vectren (SIGE)

There are no thermal or voltage issues identified in the Vectren system.

Hoosier Energy (HE)

There are no thermal or voltage issues requiring network expansions. One new operating guide will be established to mitigate a newly identified constraint.

Big Rivers Electric Corporation (BREC)

There are no thermal or voltage issues requiring network expansions.

Indianapolis Power & Light (IP&L)

There are six Category C2 thermal issues within Indianapolis that all can be mitigated with the installation of a 345 kV breaker at Hanna Substation to isolate the Hanna to Stout 345 kV Line from the Hanna 345/138 kV West Transformer.

Mitigation of four voltage issues requires modification of the fixed capacitors at Castleton to eliminate high voltage in the shoulder hour cases.

Duke Energy Management (DEM)

There are no thermal or voltage issues requiring network expansions.

Zone 7

International Transmission Co. (ITC Transmission)

On the 345 kV system, one thermal constraint was identified on the Monroe to Wayne 345 kV line due to Category B contingency. A total of seven thermal constraints were identified on two 345 kV lines due to Cat C contingencies. These constraints are driven by the sag limits. Two newly proposed MTEP13 network expansions with short lead times will help to remove these sag limits. On the 120 kV system, a total of 30 thermal constraints were identified on 12 120 kV lines in ITC for Category C contingencies. One newly proposed MTEP13 project will mitigate the sag limit issue on one 120 kV line. Constraints on 120 kV lines around the Greenwood 345 kV substation are shown in the 2014 summer peak case for loss of either the outlets of the Greenwood plant or the resource to ITC Thumb zone area. MTEP Multi Value Project Michigan Thumb loop Project 3168, expected to be in-service in 2015, will eliminate these constraints. Operating guides in the near term will be used as mitigation. The low-voltage issues identified in this area for loss of the Greenwood 345 kV transformer will be addressed by a short lead time capacitor project at Greenwood. This proposed plan will be evaluated in subsequent planning cycles.

Michigan Electric Transmission Co. (METC)

On the 345 kV system, a total of 20 thermal constraints were identified on five 345 kV lines for Category C contingencies in 2022 shoulder case. All these constraints are either on or near METC tie lines in southwest Michigan. Two proposed MTEP13 projects will address the sag limit issues on two 345 kV lines. Transfer of power in southeast Michigan also results in low-voltage issues on the Palisades 345 kV bus for Category C events. Generation re-dispatch within METC will help to relieve these thermal and voltage issues. On the 138 kV system, a total of nine thermal constraints were identified on three 138 kV lines for Category C contingencies. The Garfield to Hemphill 138 kV line is overloaded in summer peak cases for Category C5 events. Proposed MTEP Project 2809 to rebuild this line section will address this issue; in the near term, operating guide involving load curtailment will address this constraint. One newly proposed MTEP13 project will help to relieve the sag limit on the Argenta–Hazelwood 138 kV line.

4.2 Long-Term Assessment

Long-term assessments primarily focus on longer term reliability issues especially as they relate to longer lead time transmission expansion. In previous MTEP11 planning cycles, MISO's long-term assessments resulted in significant transmission expansions throughout the footprint – more than $5 billion in new transmission investment. This expansion helped deliver an additional 11 GW of renewable generation, which is needed to meet renewable mandates in the long term planning horizon. MISO includes these longer lead time, now-approved transmission expansions in its MTEP12 assessment. As anticipated, incremental issues identified in the MTEP12 planning cycle are not of material significance. Detailed analysis results are documented in Appendix D3.

4.3 Reliability Analysis Results

The results of MTEP12 Reliability Analyses are included in Appendix D2–D8 and posted at the MISO FTP site at ftp://mtep.misoenergy.org/mtep12/.

MISO Planning Regions are separated into West, Central and East. Generation, load, losses and interchange are modeled in each of the five planning models used in MTEP11 Reliability Analysis (Tables 4.3-1, 4.3-2, 4.3-3 and 4.3-4).

Models

In MTEP 2012, MISO conducted regional studies using the following base models:

- 2014 Summer Peak
- 2017 Summer Peak
- 2017 Shoulder Peak
- 2017 Light Load
- 2022 Summer Peak
- 2022 Shoulder Peak

MISO member companies and external RTO companies use firm drive-in and drive-out transactions to determine net interchanges for these models. These are documented in the 2012 series Multi-Area Modeling Working Group (MMWG) interchange. MISO determines the total generation needed to be dispatched for each of the models after aggregating the total load with input received from Transmission Owners.

Generation dispatch within the model building process has become complex. Growing inputs from various planning processes and expected shifts in generation portfolio within the MISO footprint are big reasons.

Inputs in the dispatching process:

- 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

Scenario	West Sub Region		Central Sub Region		East Sub Region		Total Load	Total Generation	Total MISO Interchange
	Load	Generation	Load	Generation	Load	Generation			
2014 Summer Peak	42,061	40,316	35,186	35,956	24,975	26,838	10,222	103,111	-1,861
2017 Summer Peak	43,511	43,975	35,853	36,534	25,620	26,286	104,984	106,796	-851
2017 Shoulder Peak	32,050	35,654	28,250	29,020	21,436	18,839	81,736	81,736	-875
2017 Light Load	24,178	28,865	14,627	15,183	10,092	7,945	48,897	51,200	1,229
2022 Summer Peak	45,454	44,185	37,112	38,733	26,495	27,223	109,061	110,141	-1,757
2022 Shoulder Peak	33,366	37,532	29,455	30,946	22,145	17,776	84,966	86,254	-1,754

Table 4.3-1: MTEP12 models summary

The MTEP12 powerflow model region load and generation data are shown in Table 4.3-1. Loads come directly 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 name plate 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.

Steady State Analysis Results

MTEP12 Appendix E1.1.4 lists contingencies tested in steady state analysis. These contingencies were used in the MTEP12 2014 summer peak model, the 2017 summer peak, shoulder peak and light-load models, and the 2022 summer peak and shoulder peak models. All steady state analysis-identified constraints and associated mitigations are listed in the results tables in MTEP12 Appendix D3, demonstrating compliance with applicable NERC transmission standards.

Voltage Stability Analysis Results

MTEP12 Appendix E1.1.1 lists types of transfers tested in voltage stability analysis. The study did not find low-voltage areas or voltage collapse points for critical contingencies in transfer scenarios close to the base load levels modeled in the MTEP12 2017 summer peak and shoulder peak models. Voltage collapse transfer levels moved farther out due to recently planned network upgrades. A summary report with associated p-v plots is documented in MTEP12 Appendix D4.

Dynamic Stability Analysis Results

MTEP12 Appendix E1.1.4 lists types of disturbances tested in dynamic stability analysis. Disturbances were simulated in MTEP12 2017 light load and shoulder peak load models. The system was stable, demonstrating compliance with applicable NERC transmission standards. Results tables listing all simulated disturbances along with damping ratios are tabulated in MTEP12 Appendix D5, demonstrating compliance with applicable NERC transmission standards.

Detailed Generation Load Loss and Interchange Modeling Data

Tables 4.3-2 through 4.3-4 document the aggregate generation dispatched, total forecasted load including losses and aggregate imports or exports associated with each member company. These numbers represent the base system conditions modeled in each of the planning cases used for the MTEP Reliability Assessment.

Planning Region	BA Name	2014 Summer Peak			
		Generation	Load	Loss	Interchange
East	NIPS	3153.7	3773.3	60.9	-680.6
	METC	12184.3	10223.3	294.6	1666.3
	ITCT	11500.1	10978.8	232	289.3
Central	HE	1282.8	731.2	31.4	520.3
	DEI	6855	7982.2	307	-1441
	SIGE	1667.9	1799.1	28.1	-159.3
	IPL	3289.9	3050.4	67.1	168.8
	BREC	1690.1	1630.2	9.2	36
	CWLD	85.4	374.9	3.5	-293
	AMMO	9392.1	8901.5	166.1	-238.5
	AMIL	10839.2	9889.3	224.4	725.6
	CWLP	571.8	478	3.1	90.7
	SIPC	281.7	348.9	6.3	-73.5
West	WEC	7438.5	6647.9	136.6	359.4
	XEL	8513.3	11335	264.5	-2345.1
	MP	2618.9	1825.3	96.3	880.2
	SMMPA	184.8	301.9	0.9	-347.4
	GRE	2714.9	1491.5	86.5	-60.3
	OTP	1364.3	2383.5	72.3	-401.3
	ALTW	4203.2	4631.7	91.9	-148.8
	MPW	290.8	162.3	1.4	127.1
	MEC	6073.5	5424.7	103.6	523
	MDU	238.2	464.4	5.6	-308.2
	DPC	1189	804.5	53.9	239.8
	ALTE	2748.5	2832.3	80.7	104.7
	WPS	2475.8	2781.4	69	-366.2
	MGE	245.2	746.3	10.5	-512.7
	UPPC	17.9	227.9	6.3	-216.4

Table 4.3-2: Near-term model (2013) generation, load, losses and interchange results by balancing area

Planning Region	BA Name	2022 Summer Peak				2022 Shoulder Peak			
		Generation	Load	Loss	Interchange	Generation	Load	Loss	Interchange
East	NIPS	3359.6	3996	74.8	-711.3	1283.9	3051.2	63.6	-1830.9
	METC	10579.3	10861.8	307.2	-589.7	5936.5	9135.4	297.8	-3496.9
	ITCT	13284	11637.1	271	1375.9	10555.9	9958.5	255.6	341.8
Central	HE	1459.9	899.1	39.7	521.1	1199.1	899.1	34.8	265.2
	DEI	8179.6	8430.3	331.9	-589.7	4951.1	6171.6	270.6	-1498.1
	SIGE	1746.6	1756.1	27.8	-37.3	1673	1332.1	19	321.9
	IPL	3295.3	3125.2	62.5	103.9	2130.9	2354.7	60.4	-287.8
	BREC	1754	1704.3	13.4	21.6	1684.4	1704.3	12.4	-47.1
	CWLD	290.5	435	2.3	-146.8	186	435	5.3	-254.3
	AMMO	10290.8	9802.4	165.7	-237.9	8102.9	7727.5	131.4	-319
	AMIL	10860.7	10063.4	223.3	573.8	10181.5	8088.7	229.4	1863.5
	CWLP	572	508	3.1	60.9	564.4	354	2.8	207.6
	SIPC	283.8	388.2	6.6	-111	272.2	388.2	8.9	-125
West	WEC	7515.2	7123.2	137.5	-67.2	5512.7	4918.2	133.2	246.6
	XEL	9108.8	12130.9	280.5	-2430.7	7782.3	8649	419.6	-648
	MP	2677.4	2215.8	99.4	573.5	3072.2	1986.6	109.3	1130.5
	SMMPA	205.9	303.9	0.3	-370.4	47.1	288.3	0.6	-430
	GRE	2980.7	1666.9	91.5	-139.7	1878.4	1224.8	82.3	-375
	OTP	1391.4	2571.9	79.1	-520.4	2008.5	2325.9	120.5	112.6
	ALTW	4487	5038.2	95.7	-244.3	4348.7	3625.6	124.8	902
	MPW	289.8	171.1	1.4	117.3	291.7	125.6	1.9	164.2
	MEC	6941.2	5793.5	89.9	1034.2	6231.2	4203.8	145.8	1869.2
	MDU	369.8	535.9	7.8	-258.3	558.6	381.2	18.6	102.3
	DPC	1174	861.1	43	169.1	1164.2	634	52.7	405
	ALTE	3873	3142.8	79.6	945.9	2107.4	2200.9	100	0
	WPS	2731	2870.3	62.4	-192.4	2448.8	2101.3	75.6	282.3
	MGE	415	798.4	9.8	-394.3	56.2	533.1	29.8	-507.8
	UPPC	24.3	230.3	6.5	-212.7	24	167.7	5.1	-148.7

Table 4.3-4: Long-term model generation, load, losses and interchange results by balancing authority

4.4 Generator Deliverability Analysis Results

Generator deliverability analysis was performed in MTEP12 to ensure continued deliverability of aggregate deliverable network resources. A total of 1,000 MW of deliverability is restricted due to constraints identified in MTEP12. These constraints have MTEP12 Appendix A and B mitigation that can be applied and will be documented as needed for deliverability. The 1000 MW of restricted deliverability compares to more than 350 MW in MTEP11, 900 MW in MTEP10 and more than 3,000 MW of restricted deliverability in MTEP09. For example, a planned upgrade identified to mitigate the 350 MW from MTEP11 is the Turkey Hill 345/138 kV transformer (Table 4.4-1).

A total of 1,000 MW of deliverability is restricted due to constraints identified in MTEP12

MTEP11 Deliverability Constraint	Total Generation Restricted	Percentage of MW Impacted	Rating (MVA)	Percent Overload	MTEP Project ID	Target Appendix MTEP12
Turkey Hill 345/138 kV transformer	178.86	51%	672.0	101%	3001	C

Table 4.4-1: Mitigations for the outstanding constraints from MTEP11 that were proven effective

This analysis revealed two constraints that restrict existing deliverable amounts (Table 4.4-2). Deliverability was tested only up to the granted Network Resource (NR) levels of the existing and future NR units modeled in the MTEP12 2017 case. See Appendix D6 for the detailed results with a list of impacted Network Resources.

Column headings in Table 4.4-2 include:

- An "Overload Branch" is caused by "bottling-up" of aggregate deliverable generation
- The "Area" is the Transmission Owner of the facility
- Use the "Map ID" to find an approximate location of the overloaded element (Figure 4.4-1)
- "Contingency" is the outage causing the overload. In some cases, the system may be system intact, so there is no outage.
- "Rating" is the rating of the overloaded element used in the analysis. It's normal if the system is intact, but emergency for post-contingent constrained branches.
- "Delta Increase" is the difference in loading after ramping up generation compared to before ramping up of generation in the "gen pocket."

Overloaded Branch	Area	Map ID	Contingency	Rating (MVA)	Delta Increase
Baldwin to Turkey Hill 345 kV [9]	AMIL	1	Cahokia to Baldwin 345 kV	956	4.45%
Neal to Salix 161 kV [10]	MEC	2	Raun to Intch 161 kV	223	1.87%

Table 4.4-2: The MTEP12 constraints that limit deliverability of about 1000 MW of Network Resources.

[9] The Baldwin to Turkey Hill 345 kV line has an MTEP B: Project 3013 that would mitigate the deliverability constraint.

[10] The Neal to Salix 161 kV line has an MTEP Appendix A: Project 3709 that will mitigate the deliverability constraint.

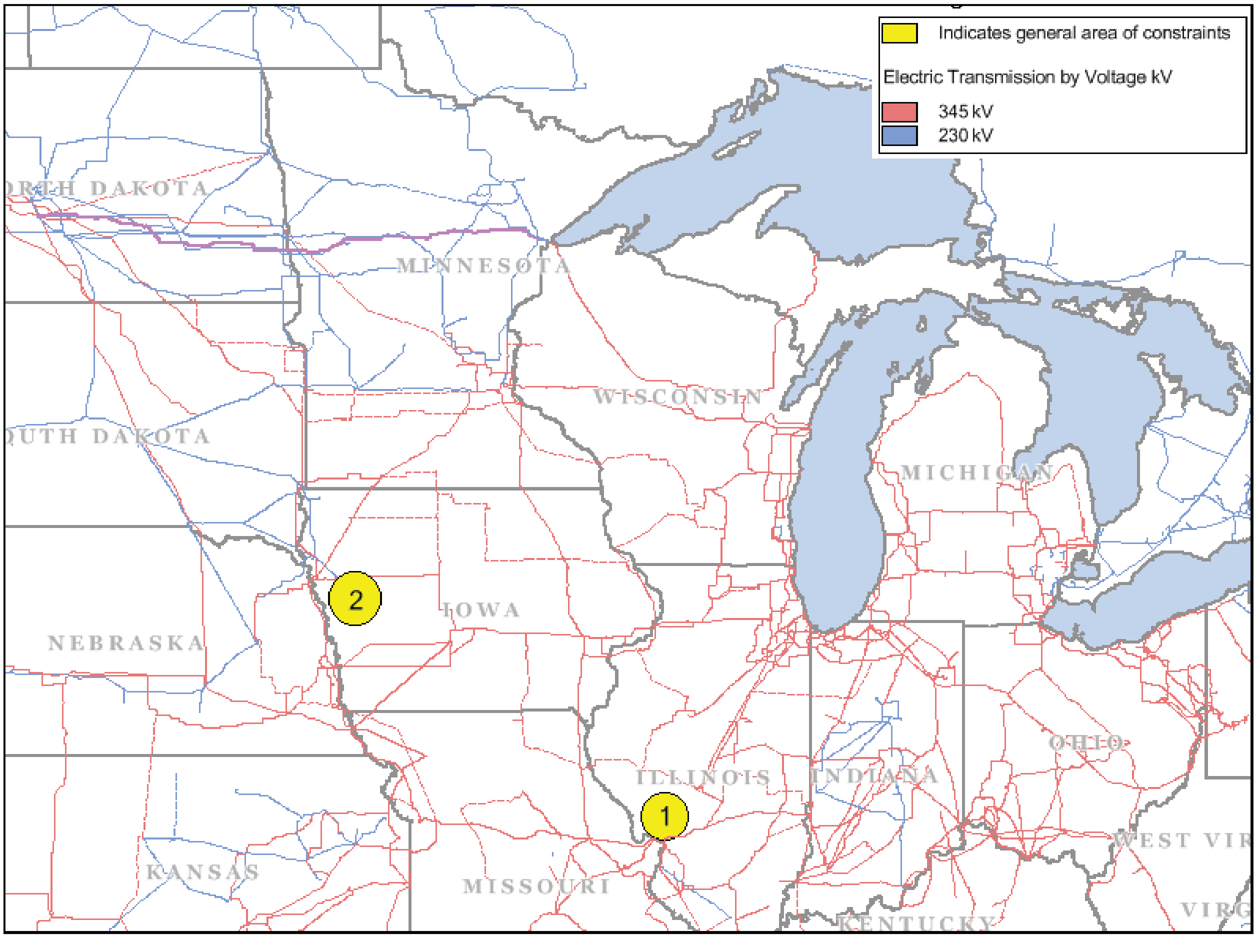


Figure 4.4-1: General location of MTEP12 2017 SUPK baseline generator deliverability constraints

4.5 Long-Term Transmission Rights (LTTR)

This chapter details the infeasible uplift to binding constraints from the annual Financial Transmission Rights (FTR) Auction (Table 4.5-1), and documents planned upgrades to address constraints driving infeasibility of Long-Term Transmission Rights (LTTR) (Table 4.5-2).

The overall trend for MISO since 2009 is a decrease in infeasible uplift, partially a result of various projects relieving constraints

As part of the Auction Revenue Rights (ARR) process, MISO runs a feasibility test to determine how many ARRs can be granted. That stage in the process determines to what extent LTTRs, granted the prior year, can be allocated as feasible LTTRs this year. The remaining unallocated LTTRs may be infeasible LTTRs.

Securing LTTRs is a way to mitigate costly fluctuation found with short-term pricing and congestion, but can cause potential revenue shortfalls for Transmission Owners.

The overall trend for MISO since 2009 is a decrease in infeasible uplift, partially as result of various projects relieving constraints. In MTEP09, the uplift ratio was 8.3 percent. In MTEP12, it is 3.03 percent (Table 4.5-1), as noted in the 2012 Annual Auction Revenue Rights (ARR) Allocation. The 2012 allocation of total infeasible uplift for MISO is $6.6 million out of total LTTR payments of $217.6 million

Year	Total Stage1A (GW)	Total LTTR Payment ($M)	Total Infeasible Uplift ($M)	Uplift Ratio
2012 Allocation	319.1	217.66	.63	.03%

Table 4.5-1: Uplift costs associated with infeasible LTTRs in the 2012 Annual ARR Allocation

MISO seeks to reduce congestion through MTEP transmission expansions, like Multi Value Projects (MVP). As MVPs and other projects are completed, MISO future planning studies are finding reduced congestion. Still, there are infeasible LTTR scenarios that require some sort of mitigation. Planned mitigations have been documented against constraints where future proposed or planned upgrades have already been identified through other planning studies (Table 4.6-2). Binding constraints are filtered for those with values greater than $75,000.

Still, there are infeasible LTTR scenarios that require some sort of mitigation

Constraint	Summer 2012	Fall 2012	Winter 2012	Spring 2013	Grand Total	Planned Mitigation
NERC # 3558 (PleasPrairie-Arcadian345 FLO Zion-Arcanian345)	$0	$0	$0	$770,196	$770,196	P2844 Pleasant Prairie - Zion Energy Center CMVP ISD: 3/6/2014 and P3022 Oak Grove-Galesburg - Fargo CMVP ISD: 11/15/2018
NERC # 3440 (Rising 345/138kV TR1 (flo) Kincaid-Latham-Blue Mound 345kV)	$0	$645,837	$0	$0	$645,837	P2239 Rising to Sidney 345kV CMVP Line ISD: 11/15/2016
STILWEL TR1 FLO DUMONT-ST	$0	$543,146	$77,488	$0	$620,634	P2202 (Approved in MTEP11) Reynolds to Greentown 765 kV Line MVP ISD: 08/01/2018. Additional studies are ongoing to determine further necessary upgrades.
RISING_GOOSECRK FLO CLNTN	$4,570	$402,004	$0	$0	$406,574	P2239 Rising to Sidney 345kV CMVP Line ISD: 11/15/2016
AMICE01_IP-1313 3	$0	$380,224	$0	$0	$380,224	P3169 Pawnee to Pana 345kV CMVP Line ISD: 11/15/2018
SHFFLD_MRKTWN FLO SHFFIELD	($89,341)	$328,486	$0	$0	$239,145	No planned upgrade
NERC # 3432 (Pawnee 345/138 (flo) Kincaid - Lanesville 345)	$0	$232,953	($4,241)	$0	$228,711	P3169 Pawnee to Pana 345kV CMVP Line ISD: 11/15/2018
NERC # 2933 (ABBROWN 345/138kV xfmr (flo) Gibson-Francisco 345kV)	$0	$215,068	$9,528	$0	$224,596	P1257 (Approved MTEP06) New Gibson to AB Brown to Reid 345 kV Line ISD: 10/01/2012
NERC # 3463 (Rantoul_RantoulJct_138_flo_NChampaign_Mahomet_Rising_138)	$2,416	$200,957	$0	$91	$203,464	P2239 Rising to Sidney 345kV CMVP Line ISD: 11/15/2016

Constraint	Summer 2012	Fall 2012	Winter 2012	Spring 2013	Grand Total	Planned Mitigation
NERC # 3663 (W Lafayette-Cumberland 138kV (flo) Cayuga-Eugene 345kV)	$0	$163,388	$0	$0	$163,388	P2202 (Approved in MTEP11) Reynolds to Greentown 765 kV Line MVP ISD: 08/01/2018
AMICE01_IP-1313 1	$0	$150,749	$0	$0	$150,749	P2239 Rising to Sidney 345kV CMVP Line ISD: 11/15/2016
IATNA-STR-CR1 FLO STJ-HWTH	$10,138	$192,107	($9,259)	($42,766)	$150,221	No planned upgrade
PLSNT PR-ZION FLO CHER SILV	$0	$11,495	$121,157	$0	$132,652	P2844 Pleasant Prairie - Zion Energy Center CMVP ISD: 3/6/2014 and P3022 Oak Grove-Galesburg - Fargo CMVP ISD: 11/15/2018
STATLIN_ROXANA FLO WILTN	($103,695)	$83,274	$142,812	$0	$122,391	P2202 (Approved in MTEP11) Reynolds to Greentown 765 kV Line MVP ISD: 08/01/2018 and P3844 Wilton Center to Reynolds 765 kV Line ISD: 08/01/2018
ALBANY_BVR CH FLO SALEM R	$0	$0	$109,467	$9,176	$118,642	No planned upgrade
NEWTNV T3 FLO NEWTNV T5	$26,582	$37,655	$14,564	$30,573	$109,374	No planned upgrade
HE34001_DRESS08AL E13_2 1	$0	$102,048	$0	$0	$102,048	P2783 New Wheatland – Bloomington 345 kV Line ISD: To be determined
BNTN HRBR_PALSDS FLO COOK_	$0	$81,079	$6,193	$0	$87,272	No planned upgrade
BUNSVL_SIDNEY FLO CASEY	$8,831	$67,137	$0	$6,307	$82,275	P2237 Pana – Mt. Zion – Kansas – Sugar Creek CMVP ISD: 11/15/2019
CLTN_R54 4 138 kV to CLTN_R54 1 138 kV	$0	$82,210	$0	$0	$82,210	P3002 N. Decatur – Clinton Rt. 54 Line Reconductor ISD: 6/1/2015

Constraint	Summer 2012	Fall 2012	Winter 2012	Spring 2013	Grand Total	Planned Mitigation
ELPASOTP 300 138 kV to MINONK_T 1 138 kV	$0	$81,648	$0	$0	$81,648	P3344 El Paso – Minonk Line Clearance Project ISD: 6/1/2015
OTTMWA-BRDGPRT FLO OTTUMW	$0	$0	$44,482	$36,949	$81,431	P3264 S. E. Polk – Ottumwa new 161 kV Line ISD: 6/1/2020
STJOE_HAWTHRN FLO LK RD _	$0	$77,279	($44)	$0	$77,235	P3170 MVP New Adair – Palmyra 345 kV Line ISD: 11/15/2018 and P3171 New West Adair – Fairport 345 kV Line ISD: To be determined
RISING 8 345 kV to RISING 1 138 kV	$0	$76,046	$0	$0	$76,046	P2239 Rising to Sidney 345kV CMVP Line ISD: 11/15/2016

Table 4.5-2: Infeasible uplift to binding constraints from the 2012 annual FTR Auction

Recent verifications while calculating the Total Infeasible Uplift for 2012 Allocation revealed the value reported in the MTEP11 report was incomplete and the value reported was less than the actual. The 2012 process for calculating uplift has been revised and validated to be an accurate representation. In general, the trend for uplift is decreasing from 2009 through 2012 (excluding 2011 aberrant data).

MISO will coordinate with its Transmission Owners to investigate these constraints in the MTEP13 planning cycle. Additionally, MISO will coordinate with adjacent regional transmission organizations on seams constraints.

Chapter Five
Economic Analysis

CHAPTER 5

Economic Analysis

5.1 Economic Assessment of Proposed MTEP12 Expansion

Most MTEP projects added in this cycle are primarily intended to address reliability issues or needs. In addition to the reliability driven projects there is one Market Efficiency Project in MTEP12. MISO economic analyses show that the Target Appendix A projects contain planned/proposed projects that primarily address and are justified by reliability needs. However, these projects may also provide economic benefits, including:[11]

- Adjusted production cost (APC) savings
- Reduced Energy and Capacity Losses

MTEP12 Target Appendix A projects are recommended to the Board of Directors for approval and to move into Appendix A.

The PROMOD simulations and economic analysis show that the Target Appendix A projects will bring reliability and economic benefit to MISO members. Among the total of $1.5 billion of Target Appendix A projects, some projects are transmission upgrades that can be modeled in PROMOD simulations. In 2022, these projects will create $35 million in annual Adjusted Production Cost (APC) savings. Over the following 20 to 40 years, these projects will create $363 to $825 million dollars in APC savings, which range from 0.11 to 0.13 times the cost of all the Target Appendix A projects. These projects would provide even greater economic benefits under higher load growth or higher gas price assumptions.

Most MTEP projects added in the cycle are primarily intended to address reliabiblity issues or needs... However, MISO economic analyses show that the Target Appendix A projects... will create $35 million in annual APC savings. Over the following 20 to 40 years, these projects will create $363 to $825 million dollars in APC savings.

The simulations and analysis also show that the MTEP12 Target Appendix A projects create benefits through a reduction in line losses at peak hour. In 2022, the peak hour line losses decrease by 17.5 MW, which equates to about $15 to $19 million in deferred capacity benefits.

Detailed methodology and benefit calculation assumptions are described later in this chapter.

Economic Benefits

The MTEP12 Target Appendix A projects will provide MISO $35 million in APC savings (Table 5.1-1).

	2022 Adjusted Production Cost savings	20 Year Present Value, 3 percent Discount Rate	20 Year Present Value, 8.2 percent Discount Rate	40 Year Present Value, 3 percent Discount Rate	40 Year Present Value, 8.2 percent Discount Rate
MISO	$35	$531	$363	$825	$438

Table 5.1-1: Economic benefits, in millions of 2012 dollars

The total estimated cost of all the MTEP12 Target Appendix A projects is $1.5 billion. While the full estimated cost of the MTEP12 Target Appendix A projects is used in the benefit-to-cost ratio calculation, some of the project benefits cannot be captured in the PROMOD model. The benefit-to-cost ratio of the Target Appendix A projects (Table 5.1-2) is based on the economic benefits in 5.1-1 and $1.5 billion project cost, under different timeframes and discount rates.

[11] MISO benefits include all MISO members as of 07/01/2012. First Energy, Duke Ohio and Duke Kentucky are excluded. Entergy is not included.

Discount Rate	Present Value Timeframe	Benefit-to-Cost Ratio
3%	20 Years	0.11
8.2%	20 Years	0.11
3%	40 Years	0.13
8.2%	40 Years	0.12

Table 5.1-2: Benefit-to-cost ratio of MTEP12 Target Appendix A projects

Benefits will change with variation in the underlying assumptions. To see how the benefits are affected by other factors, MISO conducted sensitivity runs (Table 5.1-3). The sensitivities tested were:

- Higher load growth: Load is 5 percent higher than the load in the Business as Usual future
- Lower load growth: Load is 5 percent lower than the load in the Business as Usual future
- Higher gas price: Gas prices are 40 percent higher than those in the Business as Usual future
- Lower gas price: Gas prices are 40 percent lower than those in the Business as Usual future

	Business as Usual	5% higher load	5% lower load	40% higher gas price	40% lower gas price
Annual Adjusted Production Cost savings (million $)	$35	$60	$27	$48	$29
20 Year Present Value, 3% Discount Rate (million $)	$531	$915	$419	$742	$450
20 Year Present Value, 8.2% Discount Rate (million $)	$363	$625	$286	$507	$307
40 Year Present Value, 3% Discount Rate (million $)	$825	$1,422	$651	$1,153	$699
40 Year Present Value, 8.2% Discount Rate (million $)	$438	$754	$346	$612	$371

Table 5.1-3: The Adjusted Production Cost savings of the MTEP12 Target Appendix A project for MISO under different sensitivities

The Business as Usual future benefit-to-cost ratio of MTEP12 Target Appendix A projects range from 0.11 to 0.13. The benefit-to-cost ratio tends to be higher in the high-load case and high-gas-price case, and lower in the low-load case and low-gas-price case (Table 5.1-4).

Discount Rate	Present Value Timeframe	Annualized project cost (million $)	Business as Usual	5% higher load	5% lower load	40% higher gas price	40% lower gas price
3%	20 Years	260	0.11	0.19	0.09	0.16	0.10
8.2%	20 Years	229	0.11	0.19	0.09	0.15	0.09
3%	40 Years	267	0.13	0.22	0.10	0.18	0.11
8.2%	40 Years	252	0.12	0.20	0.09	0.16	0.10

Table 5.1-4: Benefit-to-cost ratio sensitivity

The benefits captured in this chapter only include the economic benefits in generation production cost savings. This analysis captures neither the economic benefits of avoiding the cost of system outages, nor the benefit of avoiding non-compliance fines. Other benefits not captured include operating reserve benefits, and planning reserve margin benefits and reliability benefits. The benefit-to-cost ratio will be larger if all those benefits are captured. Furthermore, MTEP12 Target Appendix A projects are mainly reliability projects and generator interconnection projects. They need to be built to relieve the reliability violations in the system or connect new generators. Economic benefits are side benefits from those projects. A benefit-to-cost ratio of less than 1 does not imply the projects are not needed.

This analysis captures neither the economic benefits of avoiding the cost of system outages, nor the benefit of avoiding noncompliance fines.

The discount rates used for this analysis were derived in 2011 during the Candidate MVP Study. The 3 percent rate is intended to represent the consumer perspective, while 8.2% is from the investor point of view. The small load sensitivity of 5 percent reflects the traditional lower volatility of load, while the 40 percent gas price reflects the historically more volatile gas price.

The benefits presented in this year's MTEP report are not comparable to previous years' assessment of economic benefits due to several reasons.

1. In the MTEP12 economic assessment, only MTEP12 Target Appendix A projects are evaluated. Approved Appendix A projects in past MTEP cycles are not under evaluation. This distinguishes the benefits associated with the incremental transmission expansion. In previous MTEP economic analyses, both Appendix A and B projects from past MTEP cycles were evaluated.

2. The simulation year was chosen as 2022, a date when all MTEP12 Target Appendix A projects are in service. Multi Value Portfolio (MVP) projects, as approved MTEP11 Appendix A projects, will be in service by 2022, and therefore are in both simulation models, with and without MTEP12 Target Appendix A projects cases. With MVP in-service, much less congestion will be seen in 2022 and much less economic opportunity will exist.

3. MTEP12 Target Appendix A projects include reliability projects, generator interconnection projects and other projects. Not all of these projects can be modeled in PROMOD simulations, such as capacity banks and static var compensator (SVC) installation, equipment replacement, NERC compliance and SCADA system upgrades.

4. Other factors, such as lower gas price, reduce the amount of economic benefits, compared to prior year analyses.

Transmission Loss Benefits

Transmission loss benefits refer to the benefit of reduced line losses that occur when new transmission lines (i.e., MTEP12 Target Appendix A) are added to the system.

Loss benefits attributed to the MTEP12 Target Appendix A projects relative to not having these projects are summarized in Table 5.1-5. The MTEP12 Target Appendix A projects enable MISO generation to sell more energy to non-MISO entities since the total MISO generation (excluding wind) has increased more than 1,100 GWh and MISO wind generation increased by 247 GWh. As a result of these increases, the annual energy loss increases by 349,725 MWh. Using each MISO company's hourly load-weighted LMP to price this energy loss, the dollar value of the increased energy losses is $6.3 million in 2022. The energy loss increase is offset by increased revenue from exported generation.

The value of capacity loss benefit is in the range of $15 to $19 million

The capacity loss benefit is the decreased loss at MISO peak hour in 2022, which permits delaying the installation of additional generation capacity. It is approximately 17.5 MW. If $745/kW–$932/kW (the range of initial book value of a 1 MW combustion turbine generator, in 2012 dollars) is used to price the capacity, the value of capacity loss benefit is in the range of $15 to $19 million (in 2022 dollars, assuming 1.74 percent inflation rate).

	Energy loss benefit	Value of energy loss benefit	Capacity of loss (peak) benefit	Value of capacity loss benefit	Maximum hourly loss decrease
MISO	-349,725 MWh	$-6.3 million	17.5 MW	$15 to $19 million	311.1 MW

Table 5.1-5: MISO loss benefits with Target Appendix A project in 2022

Carbon Emission Reduction Benefits

MTEP12 Target Appendix A projects enable more export to non-MISO entities. Table 5.1-6 shows the annual generation and capacity factor changes for different types of MISO units.

In economic simulations of 2022 with MTEP12 Target Appendix A projects in service (Table 5.1-6), coal units and combined cycle units generate more, while CT gas, ST gas and CT oil generate less. This drives annual CO2 emission to increase by approximately 1.05 million tons, or 0.27 percent (Table 5.1-7). That increase is relative to the case without MTEP12 Target Appendix A projects. Both cases model the added wind generations.

Total MISO generation (excluding wind) increases by more than 1,000 GWh. Adding the Target Appendix A projects results in less wind energy being curtailed (247 GWh), and increases sales to non-MISO loads.

		Generation (MWh)	Capacity Factor
Combined Cycle	No Appendix projects.	38,700,729	33.37%
	With Appendix projects.	39,271,430	33.86%
	Change	570,701	0.49%
CT Gas	No Appendix projects.	3,775,434	1.92%
	With Appendix projects.	3,198,351	1.63%
	Change	(577,084)	-0.29%
CT Oil	No Appendix projects.	12,527	0.03%
	With Appendix projects.	2,171	0.01%
	Change	(10,356)	-0.03%
Hydro	No Appendix projects.	2,956,010	24.16%
	With Appendix projects.	2,956,213	24.16%
	Change	203	0.00%
IGCC	No Appendix projects.	7,359,041	78.00%
	With Appendix projects.	7,383,303	78.26%
	Change	24,262	0.26%
Nuclear	No Appendix projects.	72,664,276	88.85%
	With Appendix projects.	72,668,377	88.85%
	Change	4,101	0.01%
ST Coal	No Appendix projects.	342,713,039	74.60%
	With Appendix projects.	343,933,889	74.86%
	Change	1,220,849	0.27%
ST Gas	No Appendix projects.	1,791,165	8.54%
	With Appendix projects.	1,782,898	8.50%
	Change	(8,268)	-0.04%
ST Oil	No Appendix projects.	23,046	1.67%
	With Appendix projects.	27,543	1.99%
	Change	4,497	0.32%
Wind	No Appendix Projects	80,654,349	37.36%
	With Appendix Projects	80,901,583	37.48%
	Change	247,234	0.12%

Table 5.1-6: 2022 generation and capacity factor change for different type units

	CO_2 emission (ton)
No Target Appendix A projects.	385,365,146
With Target Appendix A projects.	386,419,079
Emission decrease	(1,053,933)

Table 5.1-7: 2022 annual CO_2 emission change for different type units

Study Methodology and Assumptions

The data for the economic benefit assessment comes from two PROMOD case runs: one case without the MTEP12 Target Appendix A projects, and one case with these projects.

PROMOD Cases

The MTEP12 2022 summer peak powerflow case, which has been reviewed by MISO stakeholders and incorporates the latest PJM system update, was used as the starting point for this study. Two 2022 PROMOD cases were developed:

- 2022 PROMOD case with MTEP12 Target Appendix A projects
- 2022 PROMOD case without MTEP12 Target Appendix A projects

Both cases use the same MTEP12 Limited Growth future database (containing all the generator, load, fuel and environmental information). The detailed information associated with the Business As Usual (BAU) future can be found in Appendix E2. The only difference between these two PROMOD cases is the powerflow cases (such as the transmission topologies) that are used.

Powerflow Case

To develop these two PROMOD cases, two powerflow cases are required:

- One powerflow case with MTEP12 Target Appendix A projects
- One powerflow case without MTEP12 Target Appendix A projects

For both powerflow cases, the transmission systems outside of the MISO footprint are the same: they are taken from the Eastern Interconnection Regional Reliability Organization (ERAG) 2011 series 2022 summer peak powerflow case. The MISO portion, in the powerflow case with MTEP12 Target Appendix A projects, is from the MTEP12 2022 summer peak powerflow case, which includes all Appendix A projects and MTEP12 Target Appendix A projects. The MISO portion, in the powerflow case without MTEP12 Target Appendix A projects, is also from the MTEP12 2022 summer peak powerflow case, with MTEP12 Target Appendix A projects removed from the model (Table 5.1-8).

Note that Appendix A projects are projects already approved by the MISO Board of Directors in past MTEP cycles, while MTEP12 Target Appendix A projects will be recommended for approval in MTEP12 cycle.

	Powerflow case with Target Appendix A	Powerflow case without Target Appendix A
MISO transmission	MTEP12 2022 summer peak (ERAG 2022 summer peak + Appendix A + MTEP12 Target Appendix A)	MTEP12 2022 summer peak without Target Appendix A (ERAG 2022 summer peak + Appendix A)
Non-MISO transmission	ERAG 2022 summer peak	ERAG 2022 summer peak
Generation/load/interchange	Not used in PROMOD	Not used in PROMOD

Table 5.1-8: Powerflow case difference

New Generators

The new generators identified in MTEP12 under the BAU Future, are included in this study. More details on these generators can be found in Appendix E2.

Event File

The event file contains the list of flowgates that will be treated as transmission constraints. The quality of the event file has a big impact on the quality of the study results. As PROMOD has a limit on the number of events, all N 1 or N 2 contingencies cannot be included in the event file. The event file for this 2022 PROMOD case includes the flowgates from:

- MISO master flowgates file
- NERC book of flowgates
- Target Appendix A projects that have rating upgrades were also included in the event file with different ratings in each of the two PROMOD cases

The PROMOD Analysis Tool (PAT) was also used to identify events with potential reliability problems. Those events were also included in the event file.

Economic Benefits

From each PROMOD case, the APC was calculated. The APC is equal to the production cost adjusted by sales revenue and purchases cost.

The comparison of the economic indices from two PROMOD cases (with and without MTEP12 Target Appendix A projects) yields the APC savings. These savings are the annual APC decrease from the case without MTEP12 Target Appendix A projects to the case with MTEP12 Target Appendix A projects.

Transmission Loss Benefits

- Energy loss benefit (MWh) is the decrease in annual transmission line losses (MWh) from the case without Target Appendix A projects to the case with Target Appendix A projects.
- Capacity loss benefit (MW) for MISO is the decrease in MISO peak hour loss from the case without Target Appendix A projects to the case with Target Appendix A projects.
- Dollar value of energy loss benefit is the decrease in annual MISO energy loss cost from the case without Target Appendix A projects to the case with Target Appendix A projects. Company loss cost is calculated by multiplying a company's hourly losses by its load-weighted LMP. The annual sum of these values for all MISO companies is the annual MISO loss cost.
- Dollar value of capacity loss benefit represents the value of deferring additional generation construction. It is calculated using $650/kW to $1200/kW (in 2008 dollars), the price range for the construction of different units. If the capacity loss benefit is positive, the corresponding dollar value is the capacity loss benefit multiplied by these prices. If the capacity loss benefit is negative, this value will be 0.
- Maximum hourly loss decrease is the maximum decrease in hourly losses (MWh) from the case without Target Appendix A projects to the case with Target Appendix A projects.

Carbon Emissions Impacts

- Generation, capacity factor and CO_2 emission change: the change of generation and the capacity factor of different types of units; and change of CO_2 emission between with and without Target Appendix A projects cases.

5.2 Top Congested Flowgate Study

The 2011 Top Congested Flowgate Study (TCFS) identified one project eligible for Market Efficiency Project status. This project upgrades the Petersburg-Wheatland-Breed 345 kV line to 1,386 MVA and Petersburg-Cato Tap-Duff 138 kV to 285 MVA. This mitigation plan is pending project sponsorship and MISO Board of Directors approval to move to the Approved Projects and Facility List (Appendix A).

Multiple projects associated with the Ortonville-Johnson Jct. 115 kV flowgate also met benefit and projects requirements. However, because the results are dependent on area generator interconnection studies, recent experience shows that the preliminary estimated costs are low, and further analysis is needed to determine which of the several decades-old facilities must be rebuilt due to age/condition. The TRG decided to continue to monitor this flowgate and its associated plans in future studies.

The 2011 TCFS also yielded numerous projects that met Market Efficiency Project benefit-to-cost thresholds but did not meet voltage or project cost requirements.

The Market Efficiency Analysis identified one potential Market Efficiency Project: upgrading Petersburg-Wheatland-Breed 345 kV and Petersburg-Duff 138 kV. The plan is pending project sponsorship and MISO Board of Directors approval

Generally, the 2011 TCFS potential benefits were lower than those reported in previous studies as a result of the inclusion of the Multi Value Projects (MVPs), decreased load growth rates, and lower natural gas prices. The TCFS is an annual process. Projects not meeting the thresholds will have the opportunity to be studied in future Top Congested Flowgate Studies.

The 2011 TCFS is an annual process in its fourth year. Since MTEP08, the purpose of the TCFS is to:

- Identify highly congested flowgates within the MISO footprint and on MISO market seams
- Determine the best-fit transmission plans to mitigate both historical and future congestion on an economic basis.

Transmission mitigation plans deemed economically beneficial beyond the Energy Market Tariff's established threshold were recommended for inclusion in MTEP Appendix A or B as a Market Efficiency, Cross-Border Market Efficiency, or self-funded project.

The TCFS bridges the gap between operational analysis and large-scale economic overlay planning by using production cost models on a flowgate-specific basis. The 2011 TCFS merged the scopes of the MISO Top Congested Flowgate Study, which looks solely at flowgates internal to MISO, and the Cross-Border Top Congested Flowgate Study, which concentrates on mitigating congestion on three predetermined Regional Transmission Operator (RTO) seams.

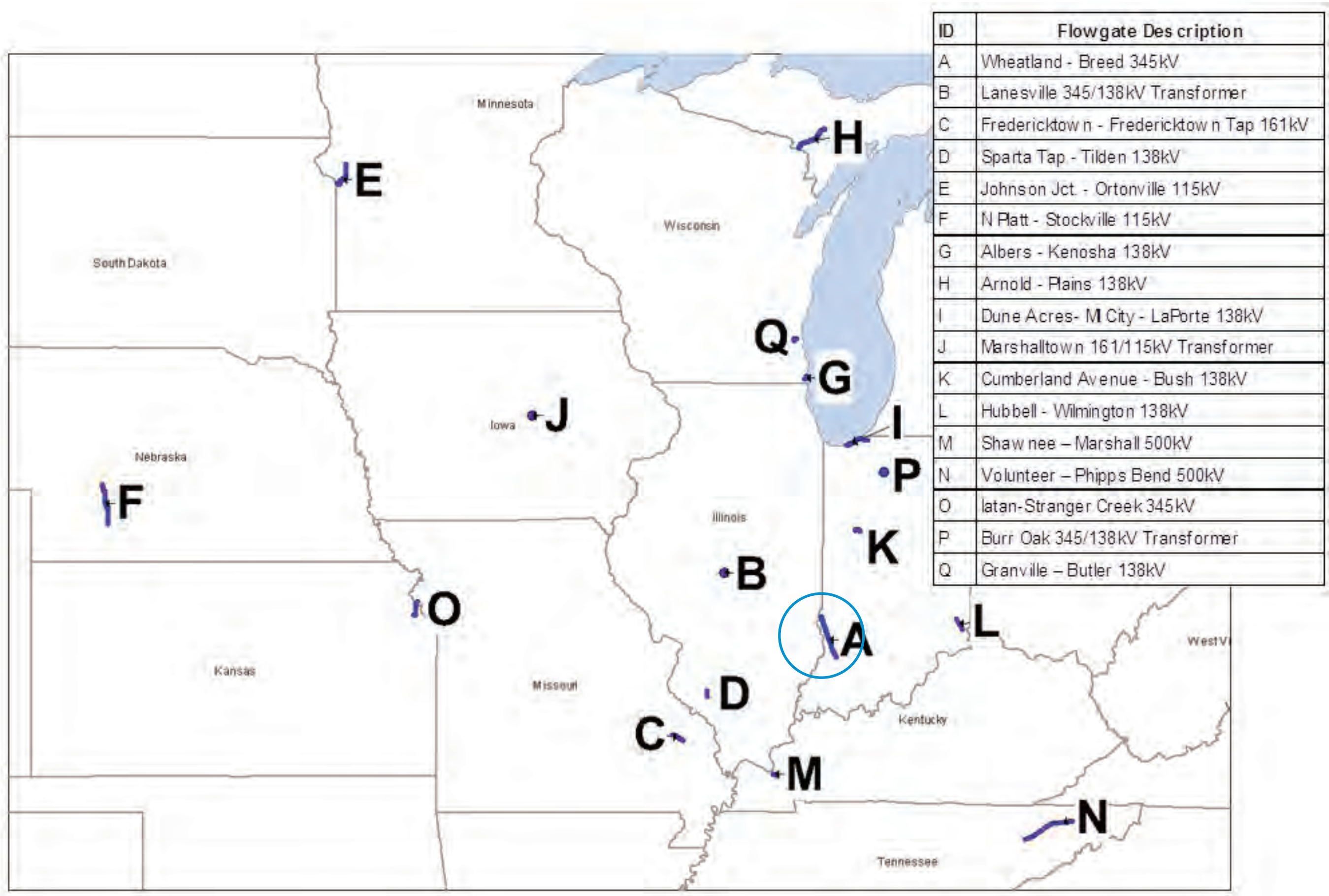
Generally, the 2011 TCFS potential benefits were lower than those reported in previous studies as a result of the inclusion of the Multi Value Projects (MVPs) and decreased load growth rates

The 2011 study results represent the cumulative efforts of MISO staff and a stakeholder technical review group (TRG). The TRG was an integral part of the study and was involved in all decisions and discussions. Additionally, the 2011 TCFS included participation from PJM, Tennessee Valley Authority (TVA) and Southwest Power Pool (SPP).

Top congested flowgates were identified using three separate data sources:

- MISO Real-Time Operations – April 2009 through April 2011
- MISO Day-Ahead Market – April 2009 through April 2011
- PROMOD – Forecast years 2016 and 2021 Business as Usual (BAU) models

The TCFS used multiple future scenarios within the production cost model to quantify how load growth and transmission overlays affect future transmission congestion. Merging PROMOD results with historical data, TRG identified 17 flowgates for further analysis (Figure 5.2-1).



ID	Flowgate Description
A	Wheatland - Breed 345kV
B	Lanesville 345/138kV Transformer
C	Fredericktown - Fredericktown Tap 161kV
D	Sparta Tap - Tilden 138kV
E	Johnson Jct. - Ortonville 115kV
F	N Platt - Stockville 115kV
G	Albers - Kenosha 138kV
H	Arnold - Plains 138kV
I	Dune Acres- MI City - LaPorte 138kV
J	Marshalltown 161/115kV Transformer
K	Cumberland Avenue - Bush 138kV
L	Hubbell - Wilmington 138kV
M	Shawnee – Marshall 500kV
N	Volunteer – Phipps Bend 500kV
O	Iatan-Stranger Creek 345kV
P	Burr Oak 345/138kV Transformer
Q	Granville – Butler 138kV

Figure 5.2-1: 2011 TCFS Top Congested Flowgates

The 2011 TCFS studied multiple flowgates outside MISO including flowgates F, M and O (Figure 5.2-1). While outside MISO, each of these flowgates either limit elements to the MISO system or have the potential to affect dispatch. These flowgates were studied with support from the corresponding transmission owner or RTO.

The top congested flowgates selected for analysis in the TCFS differ in some cases from those identified in an analysis of historical congestion for three primary reasons:

- **Mitigated by transmission plans:** The Historical Congestion Analysis considered congestion totals from market start to present (six years). Many of the top rankings are skewed by early congestion, which has since been relieved. The TCFS uses only the previous two years in an attempt to identify current problem areas. Additionally, the TCFS analysis included the MVPs, which relieve many of the previously top congested areas.

- **Changing demand patterns and generation forecasts:** Future generation and demand growth can alter congestion patterns that reduce congestion in some areas while it increases in others.
- **Extraneous circumstances:** Flowgates outside of MISO without support from the technical review group or a responsible RTO were not studied in the 2011 TCFS. These flowgates will be addressed in future analyses.

Through numerous meetings, multiple transmission mitigation plans were developed for each top congested flowgate. Proposed mitigation plans were evaluated using 2016, 2021 and 2026 reference case production cost models. A net present value benefit was calculated by linear interpolation and extrapolation of the three years of data and was tested against the Market Efficiency Project economic benefit criteria. Best-fit transmission plans were further analyzed with the four future scenarios developed through the Planning Advisory Committee (PAC). Using PAC-developed scenario probability weighting, a combined benefit-to-cost (B/C) ratio was calculated. The Business as Usual future B/C ratios associated with the most economically beneficial plan for each flowgate are shown in Table 5.2-2.

ID	Flowgate Name	Most Economically Beneficial Transmission Mitigation Plan	Cost $M-2011	BAU B/C*
A	Wheatland-Breed 345 kV	Upgrade Petersburg-Wheatland-Breed 345 kV and Petersburg-Cato Tap-Duff 138 kV	14.5	1.28
C	Fredericktown-Fredericktown Tap 161 kV	Baldwin-Grand Tower-NW Cape 345 kV	162.5	0.33
D	Sparta Tap-Tilden 138 kV	Baldwin-Grand Tower-NW Cape 345 kV	162.5	0.33
E	Ortonville-Johnson Jct. 115 kV	Upgrade Ortonville-Johnson Jct. 115 kV, Johnson Jct.-Morris 115 kV, and Hankinson-Wahpeton 230 kV; and add 2nd Big Stone Xfmr	49.7	1.50
F	N Platt-Stockville 115 kV	Reconductor North Platte-Stockville-Red Willow 115 kV and Enders-Beverly 115 kV	40.6	-
G	Albers-Kenosha 138 kV	Reconductor Albers-Kenosha 138 kV	0.8	-
H	Arnold-Plains 138 kV	Upgrade Arnold-Plains 138 kV	5.1	0.44
I	Dune Acres-Michigan City-LaPorte 138 kV	Multiple area rating upgrades	11.9	0.08
M	Shawnee-Marshall 500 kV (Contingencies)	Rockport-Paradise 765 kV	275	0.42
N	Volunteer-Phipps Bend 500 kV (Contingencies)	Broadford-Clinch River-Pocket-Roane 765 kV	865	0.19
O	Iatan-Stranger Creek 345 kV	Add Eastowne 345/161 kV substation; remove Alabama-Nashua 161 kV line	16.6	-
Q	Granville-Butler 138 kV	Silverspring to Butler 138 kV	9.86	0.12

**B/C calculation performed using latest RECB Task Force proposed methodology*

Table 5.2-2: 2011 TCFS benefit-to-cost ratios for the most economically beneficial plans for each flowgate

The TCFS has grown in scope and complexity each year, a trend expected to continue with new member integration, changing public policies, and evolving stakeholder expectations. To better meet dynamic stakeholder needs, several suggestions have been made for next year's study.

- **Use flowgate ranking methodology.** The goal of ranking flowgates is to determine which flowgates have the highest potential benefit from mitigation. Currently, shadow price and binding hours are used as independent rankings. In an attempt to increase correlation between rankings and potential benefits, the TRG proposed multiple methodologies including: congestion cost; and using the difference between an unconstrained transmission case (copper sheet) and a constrained case. Before next year's TCFS, MISO will conduct an analysis to determine the accuracy and feasibility of each ranking methodology.
- **Increase scope to include portfolios of flowgates.** The TCFS uses a flowgate-specific approach to ensure market efficiency. Many of the flowgates are of voltage less than 345 kV. Flowgates should be linked together using the copper sheet analysis to determine if a higher voltage solution is more cost-effective than mitigating individual flowgates at the native voltage level.
- **Provide additional information and time to submit transmission options.** The TRG would like more granular information and additional data such as optimal flow patterns, sources and sinks, and different economic metrics. Additionally, if more emphasis is put on regional solutions the TRG requires additional time to formulate options.

To incorporate these suggestions going forward, the TCFS is being rolled into an annual comprehensive top-down large scale regional and bottom-up flowgate specific analysis named the Market Efficiency Planning Study.

A link to the full 2011 TCFS report is at:
https://www.misoenergy.org/Planning/TransmissionExpansionPlanning/Pages/MTEPStudies.aspx

Chapter Six
MISO Resource Assessment

CHAPTER 6

MISO Resource Assessment

6.1 Loss of Load Expectation

As directed under Module E of the MISO Tariff, the system planning reserve is calculated by determining the amount of generation required to meet a one day in 10 years (0.1 day per year) Loss of Load Expectation (LOLE). The MISO Planning Reserve Margin (PRM) for the 2012-2013 planning year (PY) is 16.70 percent, decreasing 0.7 percentage points from 2011-2012's 17.40 percent (Figure 6.1-1). This is based on the system-wide MISO coincident load peak and resources based on its installed capacity rating, also called PRMSYSIGEN, The Planning Reserve Margin based on Unforced Capacity (PRM_UCAP) decreased from 3.81 percent to 3.79 percent, and applies to the non-coincident peak of each Load Serving Entity (LSE).

The MISO Planning Reserve Margin for the 2012-2013 planning year is 16.70 percent

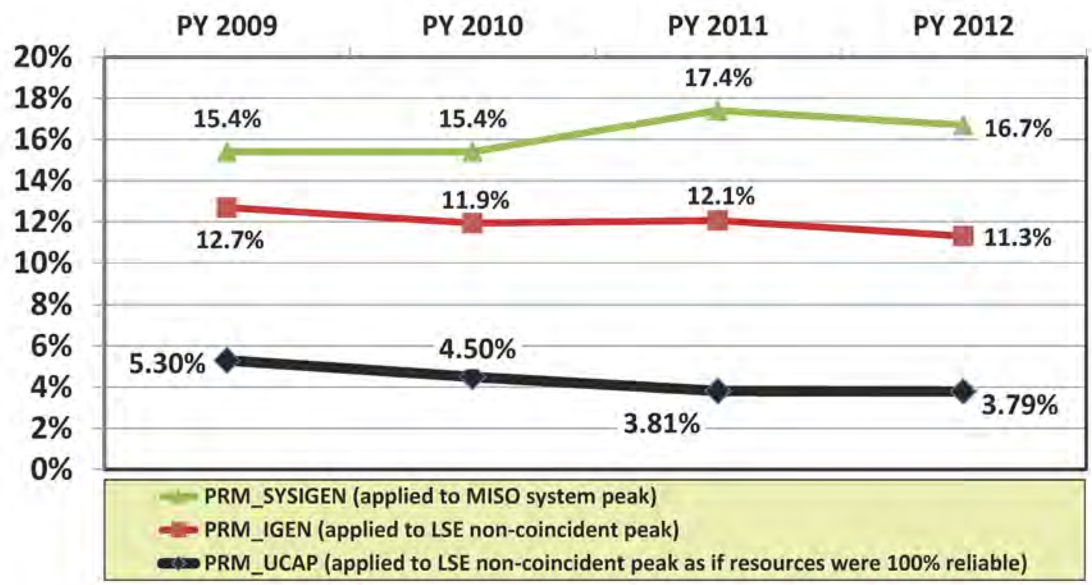


Figure 6.1-1: Comparison of recent module E PRM targets

The 0.7 percent PRMSYSIGEN decrease was the net effect of four decreasing factors and a single increasing factor. In approximate values: Decreases totaled -3.0 percent and were attributed to improved modeling of external support at -2.0 percent, lower forced outage rates at -0.7 percent, membership changes at -0.2 percent, and uncertainty of forecasting at -0.1 percent. During the summer of 2011, concern emerged that higher forced outage rates than applied in LOLE study work may be applicable to peak-load times. Therefore, an adjustment of +.2.3 percent was the single increasing factor, that when netted with the four decreasing factors, resulted in the 0.7 percent net decrease from last year.

Like last year, the 2012 MISO LOLE found no evidence of load pockets where the lack of resources would require importing more than the transmission system's ability to deliver

Like PY 2011, the PY 2012 PRM reflects no component due to transmission congestion. For example, both PY 2009 and PY 2010 had a PRM of 15.4 percent. This means, that with no congestion, PY 2009 would have been 0.6 percent marginally lower and in PY 2010 would have been 0.4 percent lower.

Benefits associated with system-wide diversity must be considered since compliance with Module E Resource Adequacy Requirements is based on representing each LSE's non-coincident monthly peak demand on the appropriate individual CPnodes. MISO determined that a diversity factor of 4.61 percent will be used for PY 2012. This is a slight increase from the 4.55 percent diversity factor used last year. After consideration for load diversity, the PRM is based on the LSE's non-coincident peak and resources based on their installed capacity rating (that is, PRMLSEIGEN), and the value is 11.32 percent (versus the no diversity 16.70 percent value).

Projected planning reserve margin requirements for 2013 through 2021 are also calculated in the LOLE Study and are utilized in Chapter 6.2 as a comparison to the projected reserves. The complete 2012 report on MISO LOLE study can be found at:
https://www.misoenergy.org/Library/Repository/Study/LOLE/2012%20LOLE%20Study%20Report.pdf.

6.2 **Long-Term Resource Assessment**

> Because of anticipated EPA related retirements, the MISO region needs to add between 4,484 and 11,290 MW of new capacity, or 3,865 and 9,733 MW of demand reduction to meet minimum PRMs in 2022

MISO aggregates individual market participant load and capacity forecasts from 2013 to 2022 to forecast long-term reserve, demand and capacity projections (2013-2022) for the MISO market footprint. MISO combines demand and capacity forecasts to predict future reserve margins and how much capacity or demand reduction would be necessary to meet system PRM requirements. Because of anticipated EPA-related retirements, the MISO region needs to add between 4,484 and 11,290 MW of new capacity, or 3,865 and 9,733 MW of demand reduction, to meet minimum PRMs in 2022, based on two different sets of analysis assumptions. MISO expects to see a 10th-year peak total internal demand between 98 GW and 120 GW depending on the demand growth rate, the diversity level, and load forecast uncertainty (LFU). MISO expects to see a 10th-year peak total available capacity between 110 GW and 122 GW depending on the impact of Attachment Y retirements and suspensions, the impact of the EPA regulations on future retirements, and the level of projects in MISO's generator interconnection queue.

MISO's membership has changed since the 2011 assessment. Duke Energy Ohio and Duke Energy Kentucky consolidated into the PJM RTO on January 1, 2012. Entergy and its six utility operating companies, Entergy Arkansas, Entergy Gulf States, Entergy Louisiana, Entergy Mississippi, Entergy New Orleans and Entergy Texas, are expected to join MISO by the end of 2013. The addition of Entergy will add approximately 15,000 miles of transmission and 30,000 MW of generation capacity into the MISO footprint. However, for the purposes of this assessment, MISO does not include Entergy demand or capacity in the projections or planning reserve margin calculations.

Forecasted Reserves

Two scenarios of the range of possibilities from the Forecasted Demand, Forecasted Capacity and Forecasted EOP Resources sections of this assessment, below, were selected and a planning reserve margin calculated for each year of the assessment from 2013 to 2022. Table 6.2-1 provides the results for both scenarios.

In both scenarios, the planning reserve margin is calculated assuming 9,912 MW of retirements occur from 2015 onward due to EPA regulations, no capacity additions from the generator interconnection queue (GIQ) are built, a diversity level of 4.61 percent is experienced across MISO's footprint, and that demand response (DR) remains constant at 2012 levels of 4,606 MW.

Scenario No. 1 uses the Module E 50/50 total internal demand of 94,279 MW and 103,584 MW for 2013 and 2022, respectively. Utilizing DR as a load modifier; this translates to a net internal demand of 89,673 MW in 2013 and 98,978 MW in 2022. The results indicate that either 4,484 MW of additional capacity will have to be built, that 3,865 MW of additional DR programs will have to register as Module E load-modifying resources, or a combination of the two. Given the projections for both GIQ projects and DR growth in MISO in this assessment, MISO expects that this will not be problematic, and that MISO's planning reserve margin requirement will be met during the 10th-year peak.

Scenario No. 2 uses the Module E 90/10 total internal demand of 99,620 MW and 109,452 MW for 2013 and 2022, respectively. Utilizing DR has a load modifier; this translates to a net internal demand of 95,014 MW in 2013 and 104,846 MW in 2022. The results indicate that either 11,290 MW of additional capacity will have to be built, that 9,733 MW of additional DR programs will have to register as Module E load-modifying resources, or a combination of the two. Given the projections for both GIQ projects and DR growth in MISO in this assessment, either some GIQ projects that are in a withdrawn study status will have to become active and built within the next ten years or DR programs will have to increase from their current levels in MISO to maintain MISO's system planning reserve margin requirement.

Scenario		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Scenario No.1 (50/50 demand)	Reserve Margin (percent))	33.1	30.6	19.5	18.4	17.2	16.1	15.0	13.8	12.6	11.5
	Planning Reserve Margin Requirement (percent))	16.6	16.5	16.4	16.3	16.3	16.3	16.3	16.3	16.3	16.3
	Additional Capacity to meet Requirement (MW))	-	-	-	-	-		981	2,101	3,294	4,484
	Additional Demand Reduction to meet requirement (MW))	-	-	-	-	-	-	846	1,811	2,840	3,865
Scenario No. 2 (90/10 demand))	Reserve Margin (percent))	25.6	23.2	12.8	11.7	10.6	9.6	8.5	7.5	6.3	5.2
	Planning Reserve Margin Requirement (percent))	16.6	16.5	16.4	16.3	16.3	16.3	16.3	16.3	16.3	16.3
	Additional Capacity to meet requirement (MW))	-	-	3,133	4,213	5,338	6,420	7,589	8,772	10,033	11,290
	Additional Demand Reduction to meet requirement (MW))	-	-	2,701	3,632	4,602	5,534	6,542	7,562	8,649	9,733

Table 6.2-1: 2013-2022 Forecasted Reserve Scenarios[12]

Forecasted Demand

MISO expects to see a 10th-year peak total internal demand between 98 GW and 120 GW depending on the demand growth rate, the diversity level, and load forecast uncertainty (LFU) (Figure 6.2-1). Table 6.2-2 provides the total internal demand projections throughout the 10-year assessment period.

> The 10th-year 50/50 peak total internal demand forecast utilizing a BAU growth rate and 4.61 percent diversity is 103,584 MW

[12] Demand reduction MWs are not equivalent to capacity addition MWs because demand affects both the numerator and denominator of the planning reserve margin calculation.

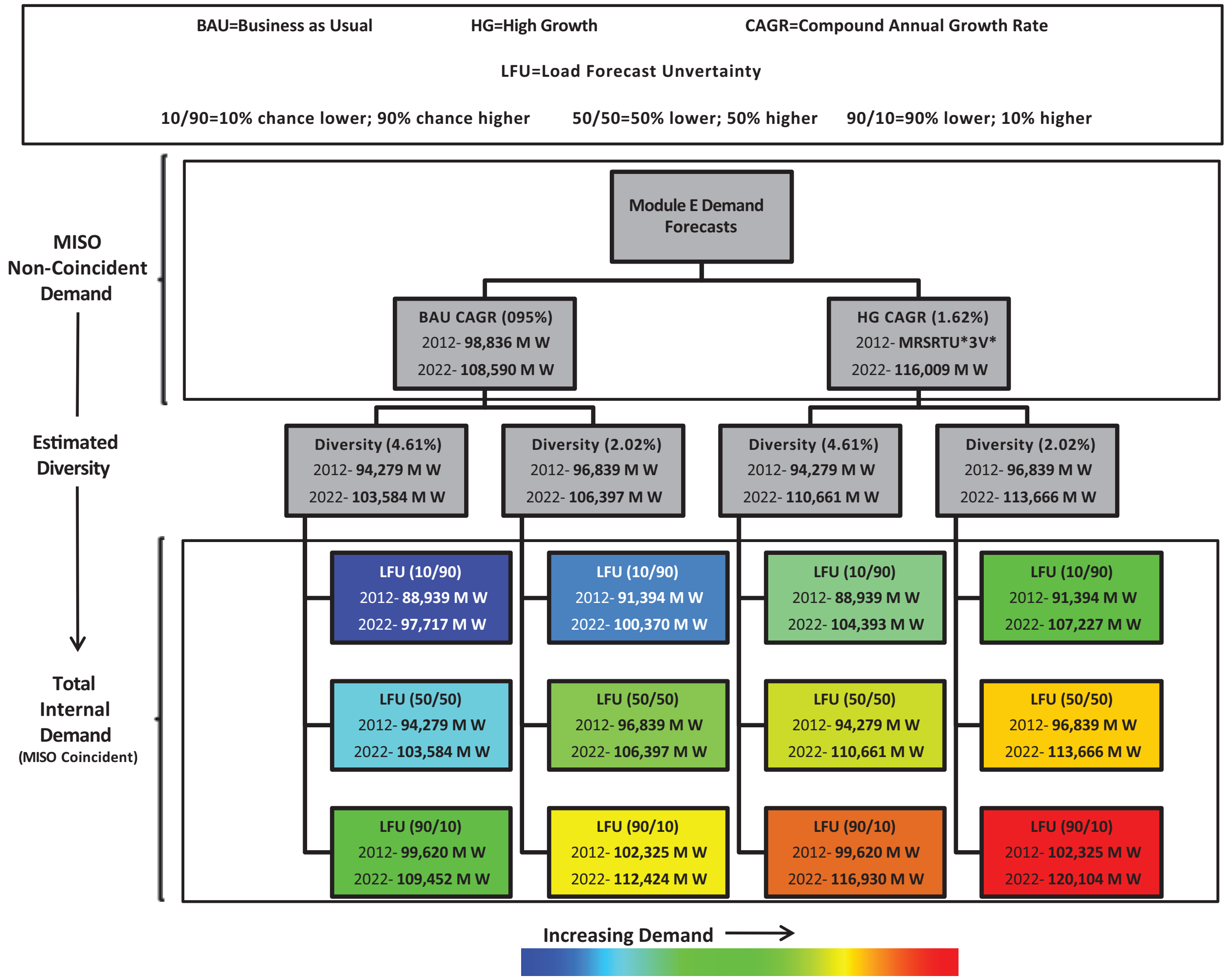


Figure 6.2-1: Forecasted Demand Decision Tree

Growth Rate	Total Internal Peak Demand, MW Range									
	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Module E (BAU)	88,939 - 102,325	90,684 - 104,332	91,439 - 105,200	92,270 - 106,157	93,136 - 107,154	93,968 - 108,111	94,868 - 109,146	95,779 - 110,194	96,749 - 111,311	97,717 - 112,424
High Growth Rate (1.62%)	90,375 - 103,977	101,574 - 105,657	102,420 - 107,363	103,351 - 109,097	104,321 - 110,859	105,253 - 112,649	106,261 - 114,468	107,281 - 116,317	108,368 - 118,196	109,452 - 120,104

Table 6.2-2: 2013-2022 MISO Peak Demand Range

MISO's forecast is based upon the aggregation of an individual load serving entity's (LSEs) 50/50, weather normalized, non-coincident peak demand forecasts. Details regarding the collection of LSE demand forecasts are documented in section 6.4 of the business practice manual (BPM) entitled BPM011–Resource Adequacy, posted on MISO's webpage.[13]

[13] BPM011-Resource Adequacy

MISO's 50/50 non-coincident peak demand forecasts from 2012 to 2022 are labeled "Module E 50/50 (BAU)" (Table 6.2-2. Consistent with the MTEP12 futures, this is the Business as Usual demand growth rate future (BAU). It should be noted that the MTEP12 BAU is based on a 2012 forecast of 97,408 MW with a compound annual growth rate (CAGR) of 0.91 percent, which was from an earlier vintage of LSE Module E forecast data. The CAGR from the updated demand forecasts is 0.95 percent (Table 6.2-3).

For the purposes of this assessment, MISO forecasts a high-demand growth rate future at a CAGR of 1.62 percent, which is consistent with the MTEP12 high-demand growth rate. Table 6.2-3 provides MISO's high-demand growth rate forecasts for the 10-year assessment period.

Non-Coincident Peak Demand, MW	Current Year	10-year Assessment Period									
	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Module E 50/50 (BAU)	98,836	98,836	100,774	101,613	102,538	103,500	104,425	105,425	106,437	107,515	108,590
50/50 (High Growth)	———	100,432	102,054	103,702	105,377	107,079	108,808	110,565	112,351	114,165	116,009

Table 6.2-3: 2013-2022 non-coincident 50/50 demand forecasts

In order to calculate MISO's annual 50/50 coincident total internal demand forecasts from 2013 to 2022, MISO uses two load diversity levels are applied to the non-coincident forecasts of 4.61 percent and 2.02 percent throughout the assessment period. Details regarding these two levels are documented in the 2012 Summer Resource Assessment, Section 3.2, posted on MISO's webpage.[14]

MISO conducts an after-the-fact assessment by commercial pricing node (CPNode) based on forecasts entered in the Module E Capacity Tracking (MECT) tool. Details regarding the assessment procedures are documented in the Resource Adequacy BPM posted on MISO's webpage. Reviewing the forecasts versus actual peak demands from 2009[15], 2010[16] and 2011[17] indicates that, on average, MISO LSEs under-forecast peak demand by approximately 1,000 MW; however, LFU analysis takes forecast error into account.

MISO derives an LFU value on an annual basis, from variance analysis to determine how likely actual load will deviate from forecasts. This assessment uses an LFU value of 4.42 percent from the 2012 LOLE Study report.[18] LFU accounts for uncertainty in weather, economics and forecast error. The LFU is used to create a normal distribution around the 50/50 forecasts from Table 6.2-3 and low-load (10/90) and high-load (90/10) forecasts are determined. Details regarding this methodology are detailed in MISO's 2012 Summer Resource Assessment, Section 3.5. Table 6.2-4 provides 10/90 and 90/10 total internal demand forecasts, and provides book ends of the 10th-year peak total internal demand forecast ranging from 97,717 MW to 120,104 MW.

[14] 2012 Summer Resource Assessment
[15] Supply Adequacy Working Group (SAWG) 2010 meeting material
[16] SAWG 2010 meeting material
[17] Market Reports- PY2011-12 Module E Metrics
[18] 2012 LOLE Study

Level %	Total Internal Peak Demand, MW	10-year Assessment Period									
		2013	2014	2015	2016	2017	2018	2019	2020	2021	
4.61	Module E 10/90 (BAU)	88,939	90,684	91,439	92,270	93,136	93,968	94,868	95,779	96,749	97,717
4.61	10/90 (High Growth)	90,375	91,835	93,318	94,825	96,357	97,913	99,494	101,101	102,734	104,393
2.02	Module E 10/90 (BAU)	91,354	93,146	93,921	94,776	95,665	96,520	97,444	98,379	99,376	100,370
2.02	10/90 (High Growth)	92,829	94,328	95,852	97,400	98,973	100,571	102,196	103,846	105,523	107,227
4.61	Module E 90/10 (BAU)	99,620	101,574	102,420	103,351	104,321	105,253	106,261	107,281	108,368	109,452
4.61	90/10 (High Growth)	101,229	102,864	104,525	106,213	107,928	109,671	111,442	113,242	115,071	116,930
2.02	Module E 90/10 (BAU)	102,325	104,332	105,200	106,157	107,154	108,111	109,146	110,194	111,311	112,424
2.02	90/10 (High Growth)	103,977	105,657	107,363	109,097	110,859	112,649	114,468	116,317	118,196	120,104

Table 6.2-4: 2013-2022 Coincident 10/90 & 90/10 Demand Forecasts

Forecasted Capacity

MISO expects to see a 10th-year peak total available capacity between 110 GW and 122 GW depending on the impact of Attachment Y retirements and suspensions, the impact of the EPA regulations on future retirements, and the level of projects in MISO's generator interconnection queue built in the next 10 years. Table 6.2-5 provides the cumulative total available capacity projections throughout the 10-year assessment period.

The 10th-year peak total available capacity forecast utilizing 9,912 MW of EPA retirements and 2,710 MW of new generation is 109,770 MW

Capacity, MW	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
2012 Internal Summer Rated Capacity	112,679	112,679	112,679	112,679	112,679	112,679	112,679	112,679	112,679	112,679
2012 External Support (+)	3557	3557	3557	3557	3557	3557	3557	3557	3557	3557
Attachment-Y Retirements (-)	363	363	363	363	363	363	363	363	363	363
Attachment-Y In-Service (+)	183	342	1,099	1,099	1,099	1,099	1,099	1,099	1,099	1,099
EPA Retirement Range (-)	0 - 0	0 - 0	9912 - 2341	9912 - 2341	9912 - 2341	9912 - 2341	9912 - 2341	9912 - 2341	9912 - 2341	9912 - 2341
GIQ Range (+)	129 - 1059	359 - 2319	669 - 3649	1123 - 5295	2686 - 6994	2710 - 7407	2710 - 7407	2710 - 7407	2710 - 7407	2710 - 7407
Total Available Capacity	***116185 - 117115***	***116574 - 118534***	***107729 - 118280***	***108183 - 119926***	***109746 - 121625***	***109770 - 122038***	***109770 - 122038***	***109770 - 122038***	***109770 - 122038***	***109770 - 122038***

Table 6.2-5: 2013-2022 Forecasted Capacity

MISO's internal capacity forecast is based upon the summer rated (on-peak) capacities of registered generation assets from the March 2012 commercial model. Currently, 112, 679 MW of on-peak capacity exists within the MISO market footprint. Figure 6.2-2 provides a breakdown of this capacity by resource type.

Summer rated capacity for non-intermittent resources is their generator verification test capacity (GVTC), and if a GVTC is not available, it is their registered maximum output from the commercial model. Details regarding non-intermittent GVTC requirements are documented in the Resource Adequacy BPM posted on MISO's webpage.

MISO anticipates retirements due to the EPA regulations to take effect as early as 2015. MISO conducts quarterly surveys of asset owners' EPA compliance strategies. From the second quarter 2012 survey, 47 units totaling 4 GW of summer rated capacity have either retired or will definitely retire

Summer rated capacity for wind resources is 14.7 percent of their total registered maximum output. Details regarding the 14.7 percent wind capacity credit are documented in the 2012 LOLE Study report posted on MISO's webpage. For all other intermittent resources, the summer rated capacity is their GVTC. Details regarding intermittent GVTC requirements are documented in the Resource Adequacy BPM posted on MISO's webpage.

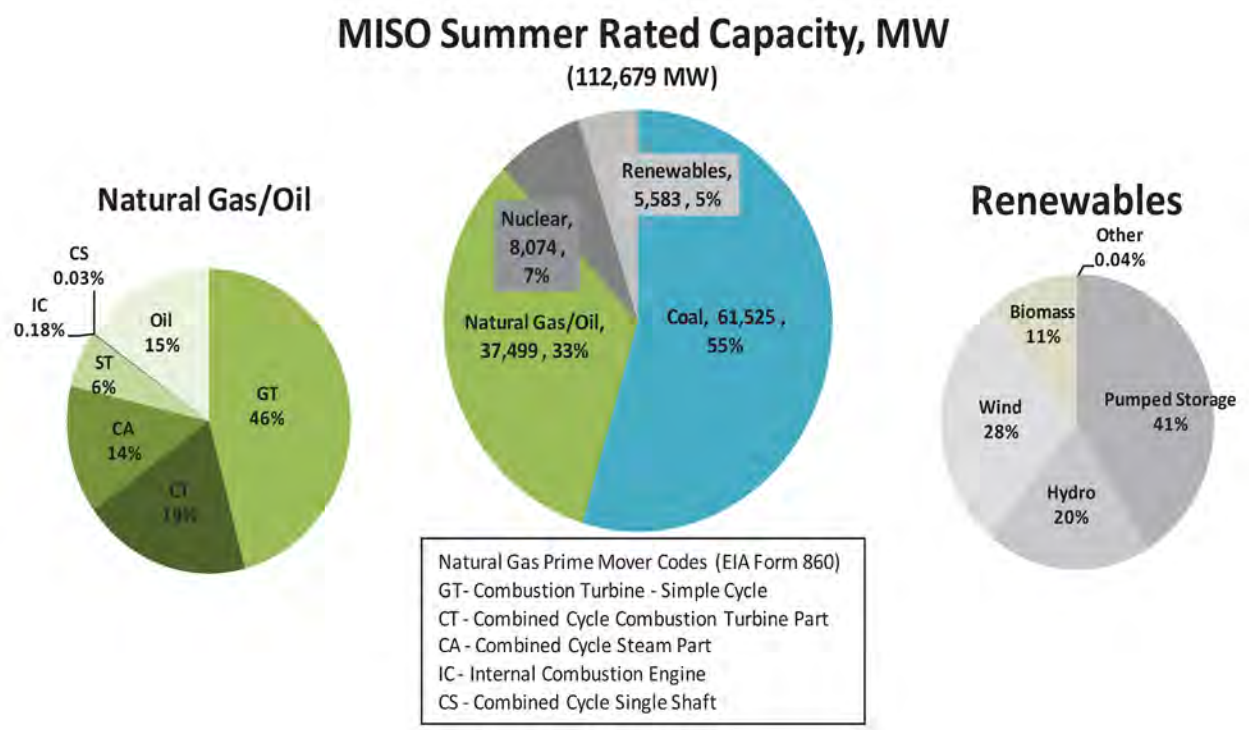


Figure 6.2-2: MISO 2012 Internal Summer Rated Capacity

Before the 2013 summer season, MISO expects 189 MW of GT natural gas units, 160 MW of coal units, and 14 MW of oil units, totaling 363 MW of 2012 summer rated capacity, to retire. These retirements have been approved through Attachment Y of MISO's Tariff.

Prior to the 2015 summer season, MISO expects 444 MW of coal units, 243 MW of GT natural gas units, 229 MW of oil units, and 183 MW of ST natural gas units, totaling 1,099 MW of summer rated capacity, to come back into service from Attachment Y suspensions.

In addition to Attachment Y impacts, MISO anticipates retirements due to the EPA regulations to take effect as early as 2015. MISO conducts quarterly surveys of asset owners' EPA compliance strategies. From the second quarter 2012 survey, 47 units totaling 4 GW of summer rated capacity have either retired or will definitely retire. 1,706 MW of coal has retired prior to March 2012. An additional 1,980 MW of coal units, 314 MW of combined cycle steam (CA) natural gas units utilizing coal as a secondary source of energy, and 47 MW of biomass units, totaling 2,341 MW of summer rated capacity, will definitely retire due to EPA regulations.

Also, from the second-quarter survey, an additional 73 units totaling 8 GW of summer rated capacity have yet to determine if they will retire in order to comply with the EPA regulations. This includes 7,197 MW of coal units, 295 MW of GT natural gas units utilizing coal as a secondary source or energy, and 79 MW of oil units; totaling 7,571 MW of summer rated capacity, which may retire due to EPA regulations.

For the purposes of this assessment, MISO utilizes the in-service dates and the maximum summer output from the generator interconnection queue (GIQ) to determine when and how much new capacity will come into service over the next 10 years. The wind capacity credit of 14.7 percent is applied to wind units maximum summer output. As of March 2012, MISO has 83 projects totaling 15,370 MW of summer rated capacity in the queue with an in-service year after or equal to 2013. Figure 6.2-3 provides the cumulative capacity by fuel type of all 83 projects in the queue regardless of study status or overall project status.

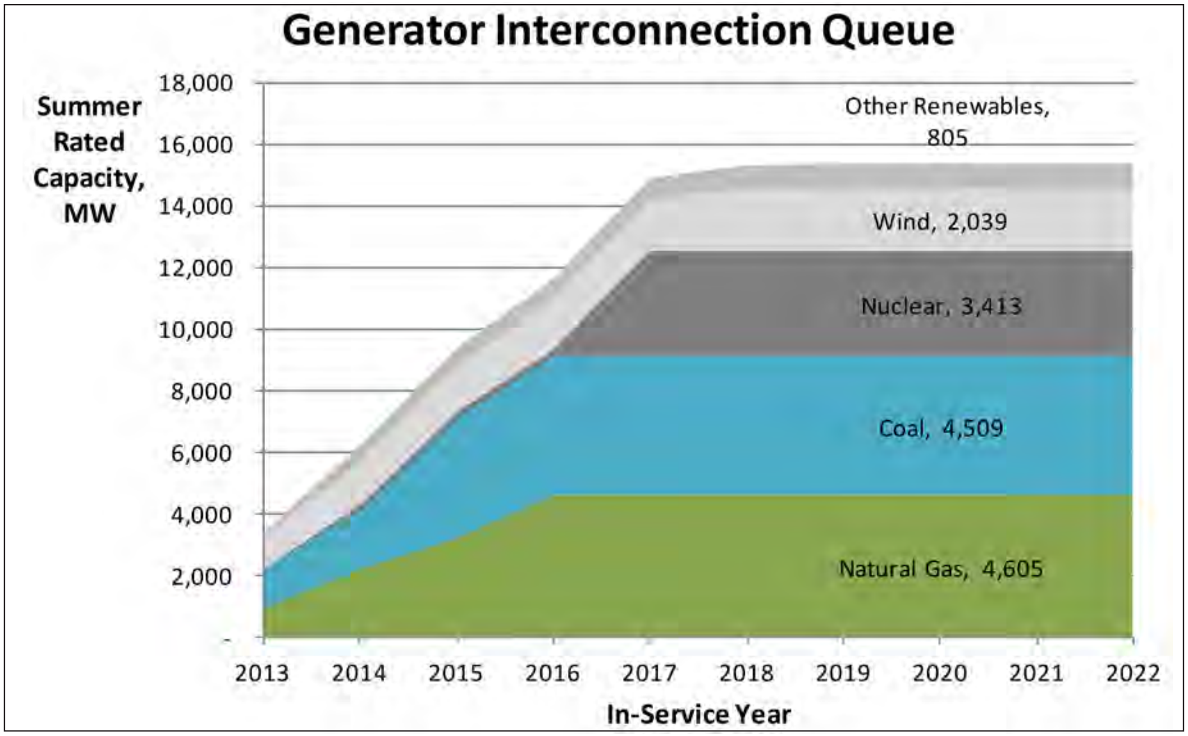


Figure 6.2-3: MISO GIQ Projects

Of the 15,370 MW of summer rated capacity in the queue, MISO expects a range of 2,709 MW to 7,407 MW to be built in the next 10 years. MISO developed this range utilizing confidence factors based on queue study statuses, fuel types, known regulatory approvals, contracts, firm transmission service requests, and other factors.

Forecasted Emergency Operating Procedure (EOP) Resources

MISO expects to see 10th-year peak available EOP resources between 5 GW and 12 GW depending on the growth of DR in MISO's footprint over the next 10 years. Table 6.2-6 provides the cumulative total available EOP resource projections throughout the 10-year assessment period.

EOP Type	Total Emergency Operating Procedure (EOP) Resources, MW Range									
	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Demand Response (DR)	4,606 to 4,962	4,606 to 5,422	4,606 to 5,833	4,606 to 6,255	4,606 to 6,707	4,606 to 7,164	4,606 to 7,633	4,606 to 8,111	4,606 to 8,602	4,606 to 8,709
Behind the Meter Generation (BTMG)	3,271	3,271	3,271	3,271	3,271	3,271	3,271	3,271	3,271	3,271
Total EOP	***7,877 to 8,233***	***7,877 to 8,693***	***7,877 to 9,104***	***7,877 to 9,526***	***7,877 to 9,978***	***7,877 to 10,435***	***7,877 to 10,904***	***7,877 to 11,382***	***7,877 to 11,873***	***7,877 to 11,980***

Table 6.2-6: 2013-2022 Forecasted Operating Procedure Resources

MISO has procedures in place to provide instructions to Local Balancing Authorities (LBA), Transmission Operators (TOP), Generation Operators (GO), and Market Participants (MP) to manage capacity or energy emergencies. These emergency operating procedures are documented in the RTO-EOP-002 MISO Market Capacity Emergency Procedure document posted on MISO's webpage.[1]

MISO's total available capacity projections include all resources up through a Maximum Generation Emergency Event Level 1c. Through that point MISO exhausts all emergency maximum limits of its committed generation units, all external support and outage coordination strategies.

For the purposes of this assessment, MISO forecasts emergency operating procedure resources starting at the Maximum Generation Emergency Event Level 2b, where MISO instructs the use of Module E Load Modifying Resources (LMR). Details regarding Module E LMR are documented in section 4.9 of the Resource Adequacy BPM.

MISO categorizes LMR into two categories, which are Demand Response (DR) and Behind the Meter Generation (BTMG). DR is resource designated as Interruptible Load (IL) or Direct Control Load Management (DCLM), and it reduces load by its obligated MW amount. BTMG is a generation resource used to serve load behind the meter, meaning it is not included in MISO's dispatch instructions. BTMG is treated as a capacity resource, while DR is treated as a load reduction in this assessment.

The DR amount for the current year (2012) is equal to 4,606 MW, which is approximately 5 percent of 2012 load. MISO has integrated the 2010 Global Energy Partners' assessment results into this year's projections of DR resources.[2] Global Energy Partners determined the DR percentage of baseline load for 2010 as 3.7 percent, 2015 as 5.4 percent and 2020 as 7.2 percent. MISO adjusted these percentages to make the current study year (2012) the baseline year. Table 6.2-6 provides the DR percentages for each year of the 10-year assessment.

[1] RTO-EOP-002 MISO Market Capacity Emergency Procedure
[2] Global Energy Partners, LLC

2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
5.45%	5.79%	6.13%	6.47%	6.83%	7.19%	7.55%	7.91%	8.27%	8.27%

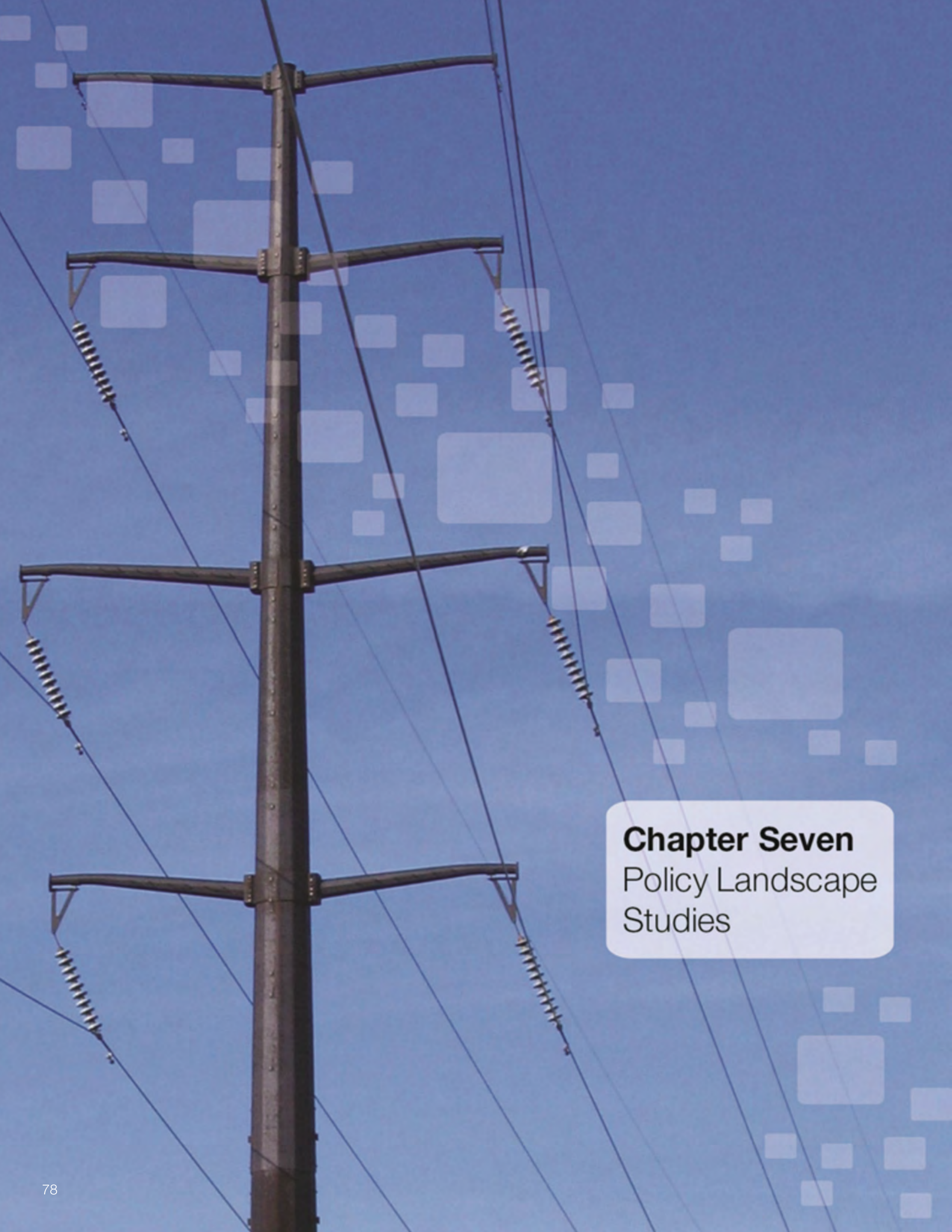
Table 6.2-6: Percent DR of Module E 50/50 Non-Coincident Demand

The BTMG amount for the current year (2012) is equal to 3,271 MW and is held flat throughout the 10-year assessment.

Gas and Electric Interdependencies and Potential Impact on Reserves

Given the magnitude of future coal unit retirements due to the EPA regulations, MISO will have to utilize natural gas fired generators more intensively to serve load. This prompted MISO to work with the natural gas industry to report on potential pipeline supply issues. This report is posted on MISO's webpage.

Using the pipeline flow data behind the analysis along with historical energy usage of existing natural gas fleet, MISO is currently in the process of performing loss of load expectation (LOLE) analysis in order to determine the impact of EPA retirements on LOLE. The analysis will model "what if" scenarios related to likely gas pipeline contingencies and their impact on electric generating unit availabilities.



Chapter Seven
Policy Landscape Studies

CHAPTER 7

Policy Landscape Studies

7.1 Current Trends

In a world of constantly evolving state and federal policies, fuel prices, load patterns and transmission configuration, several trends stand out. To respond and stay ahead of these trends, MISO strives to provide meaningful analyses to help inform policy discussions and decisions. These independent analyses are critical to achieve MISO's goal to efficiently meet transmission needs and deliver the lowest-cost delivered energy to consumers.

Multi Value Projects (MVPs)

The MISO Board of Directors approved the largest Midwest transmission expansion in decades in MTEP11. This portfolio of 17 MVP transmission projects have now been integrated into MISO's future year MTEP12 planning models. MVPs relieve a major part of the future congestion internal to MISO by delivering wind and other generation energy more efficiently. Because of MVP congestion relief, MISO finds less need for major new economically justified transmission expansion.

MVPs relieve a major part of the future congestion internal to MISO by delivering wind and other generation energy more efficiently. Because of MVP congestion relief, MISO is finding less need for major new economically justified transmission expansion

Changing Gas Picture

The dramatic decline of natural gas prices in 2011 and 2012 has a profound impact on the electric generation industry. In MISO 2008 analysis, gas was modeled at $8/MMBtu, while in 2011/2012 the modeled price was $4.5/MMBtu. With actual prices below $3 in 2012, natural gas has started to displace coal. Not only has it resulted in an increased utilization of gas (Figure 7.1-1), but the greater usage affects the role of gas generation. Whereas gas was traditionally used for peaking support, it is increasingly being used for base load generation, changing the system's reliability configuration.

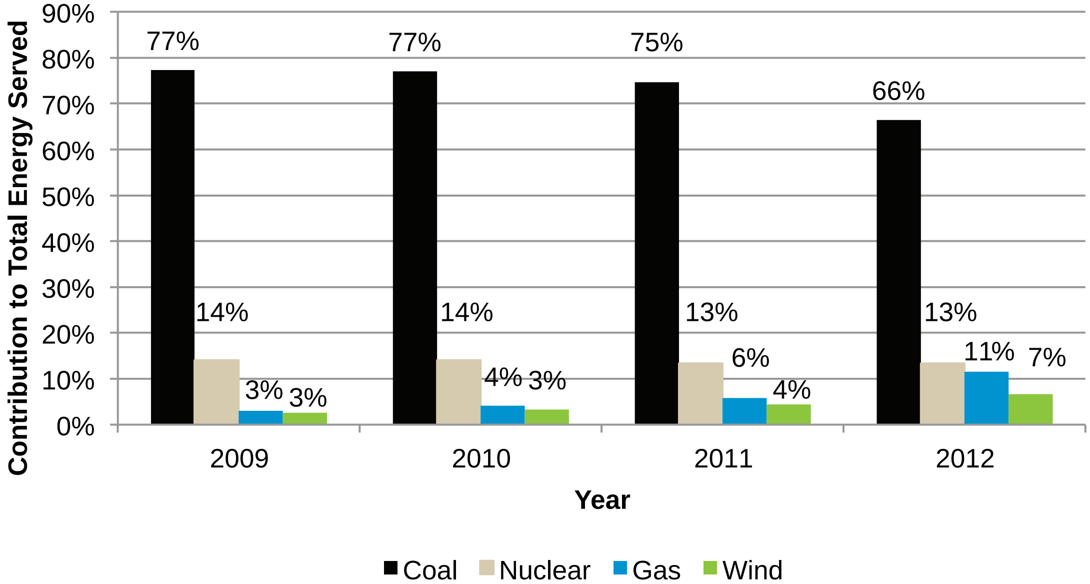


Figure 7.1-1: January through August energy contribution by fuel source

In the interdependent world of generation and transmission, low gas prices present utilities with opportunities to build new gas generation at strategic locations to reduce congestion. This is especially true if combined with wind energy and existing transmission. Conversely, new generation configurations can affect the need and timing of transmission – potentially reducing the need for new transmission. The anticipated integration of Entergy into MISO, with its anticipated surplus gas capacity, could have additional impacts on this picture.

New generation configurations can affect the need and timing of transmission—potentially reducing the need for new transmission

EPA-Related Retirements

MISO forecasts significant coal retirements related to EPA regulations. Lower gas prices could accentuate this trend. Combining low gas prices with anticipated EPA-related coal retirements produces the potential for significant gas pipeline constraints, contributing to potential system reliability concerns. MISO is actively studying and adapting to these gas-related impacts to ensure system stability and to maintain least-cost energy.

Changing Load Growth Patterns

In general, load forecasts have been lowered since 2008. With lower load forecasts, the existing and planned transmission system is adequate to serve load farther into the future. Thus, in some cases the immediate reliability and economic justification to build transmission is reduced.

MISO's Planning Approach

In order to understand and provide consumer value under various potential scenarios, the MISO planning approach considers many factors and policies, including economic, environmental, regional and local variables. Through the evaluation of various load, generation portfolios and policy scenarios, which serve to 'bookend' potential future conditions, MISO ensures that the recommended transmission plan will provide continued value. Also, additional value may be realized through expanding analyses to consider wider benefits from a regional perspective.

The MISO planning approach considers many factors and policies, including economic, environmental, regional and local variables

In 2012, MISO focused on the following initiatives, based on regulatory and stakeholder feedback.

- Market Efficiency Analysis: The Market Efficiency Planning study identifies transmission needs and develops solutions from a regional perspective. This process considers both near-term and long-term drivers to ensure that the most efficient and cost-effective transmission solutions may be identified to improve the economic advantages provided by the MISO energy market.

- Retail Rate Impacts: Policy changes from the state and federal level can greatly impact the cost of retail electricity to customers, resulting in uncertainty for the industry and its customers. To address this uncertainty, MISO evaluates multiple scenarios to determine the retail rate impact. This captures a wide range of potential policy outcomes and provides decision-makers with the information necessary to minimize rate increases to customers.

- EPA Compliance Studies: New EPA regulations, which require compliance by 2015, have created uncertainty and concern among industry leaders and stakeholders. Recent analyses by MISO have evaluated the impact of these regulations on compliance strategies, resource adequacy, outage coordination and natural gas infrastructure, revealing potentially large impacts and uncertainty on how compliance will be achieved.

- FERC Order 1000: The Federal Energy Regulatory Commission's (FERC) Order 1000 rule mandates how public utility transmission providers must plan for and allocate the costs of new projects on a regional and interregional basis. MISO conducts an open stakeholder process to determine compliance and file solutions for all Order 1000 requirements.
- Generation Portfolio Analysis: Scenario-based analysis allows MISO to develop robust transmission plans for the future, given a wide range of potential policy and economic conditions. These scenarios are based upon analysis of the least-cost generation portfolio required under these future conditions, forming the basis for MISO's long term planning efforts.
- Smart Grid Implementation: MISO plans to install 261 phasor measurement units through the Smart Grid Investment Grant program. These units will help expedite the modernization of the nation's electric and transmission system and allow the development of a nationwide "smart" electric power grid.
- Coordinated Studies: A systematic joint study provides a common platform to perform economic evaluation of cross-border transmission plans, providing a bridge between the planning processes of interconnected systems. To enable closer coordination with Southwest Power Pool (SPP), staff developed a joint future to meet these goals and allow for the continuation of the ongoing working relationship between the two regional transmission organizations.
- End-Use Load Characterization: Combining Energy Information Administration (EIA) with MISO data reveals the regional breakdowns between residential, commercial, and industrial, and between the different energy uses (cooling, lighting, etc).
- Energy Storage: This study reviews the feasibility of different types of energy storage in the MISO footprint.

As the policy landscape continues to evolve, MISO will continue to listen and adapt to provide meaningful analyses that help inform discussions and decisions.

7.2 Market Efficiency Analysis

The purpose of the newly created Market Efficiency Planning Study (MEPS) is to develop a general and structured approach to identify transmission needs and possible solutions from a regional perspective. To develop and evaluate optimal transmission solutions based on economics, the study explores new ways to create greater efficiency and flexibility. By identifying and addressing both near-term transmission issues and long-term economic opportunities, this study enables more efficient and cost effective near-term solutions to support long-term goals.

Currently, Market Efficiency Projects (MEP) are identified and evaluated through the annual Top Congested Flowgate Study (TCFS), which seeks to identify and relieve both historical and projected near-term congestion issues. The existing process, based on a fairly narrowly defined flowgate-specific approach, primarily focuses on local solutions to address identified congestion issues. It inevitably precludes larger scale regional projects/portfolios with economic value beyond just relieving a specific congested flowgate.

Expanded from the former TCFS, the Market Efficiency Planning Study seeks to identify and evaluate transmission project/portfolio solutions more broadly within the MISO footprint and on the seams.

New to the expanded study scope is the implementation of a bifurcated need identification process. It will proactively identify transmission issues and economic opportunities on the front end of the study to guide the development of economic transmission solutions, as opposed to reactive economic analysis on the back end. Specifically, congestion relief analysis will be conducted to identify long-term transmission needs in conjunction with the existing top congested flowgate analysis to identify near-term congestion issues.

Study Process

The MISO planning approach combines a top-down and bottom-up approach, along with generator interconnection and a policy need assessment. This results in a fully integrated view of project value inclusive of reliability, market efficiency, public policy and other value drivers.

By promoting the development of regional transmission projects and portfolios to recognize broader benefits beyond just mitigating a specific congested flowgate, this new process ensures that the most efficient and cost-effective transmission solutions will be identified from the ecomonic viewpoint

The process retains the current top congested flowgate analysis to identify flowgate-specific mitigation solutions, but expands the scope to include regional/interregional congestion relief analysis on the front end of the study process. Furthermore, the process helps inform and guide project submissions to address reliability, public policy, and Generator Interconnection/ Transmission Service Request (GI/TSR) transmission issues by producing a set of economic information at the beginning of MTEP planning cycles.

The study process starts with a spilt process to identify both near-term and long-term transmission needs (Figure 7.2-2). This is comprised of TCFS analysis to identify near-term system congestion within MISO footprint and on the seams, and congestion relief analysis to explore longer-term economic opportunities. Following the need identification, MISO will conduct an evaluation of projects/ portfolios to identify optimal solutions and project justification in accordance with MISO Tariff provisions and Joint Operating Agreement (JOA) protocols.

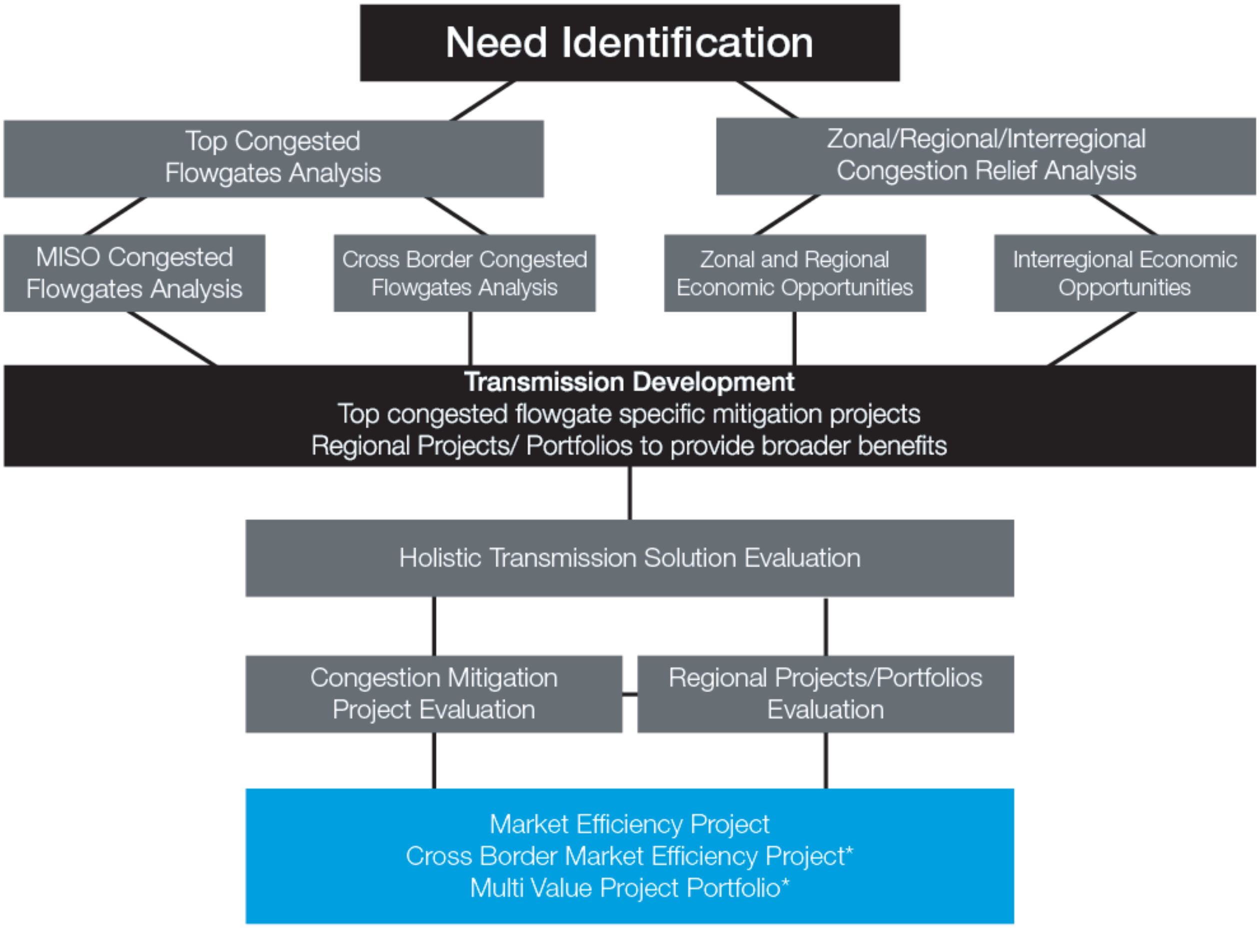


Figure 7.2-2: Expanded market efficiency planning study process

Top Congested Flowgate Analysis

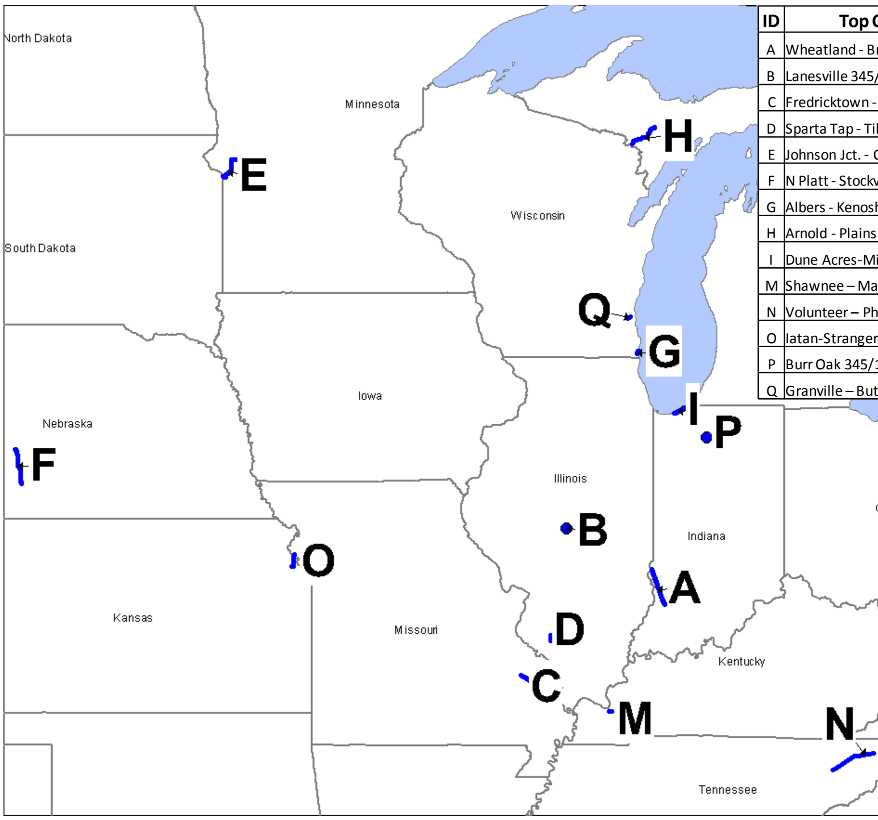
The primary focus of the Top Congested Flowgate Analysis is to identify system congestion trends based on historical market data as well as forecast future congestion patterns based on out-year production cost model simulations. The analysis seeks to identify and prioritize highly congested flowgates within the MISO market footprint, and explore cross-border seams efficiency enhancement opportunities in coordination with neighboring regions.

Candidate flowgates would be those that have historically demonstrated consistent negative transmission congestion impacts and are projected to continue to be congested into the future. Candidate flowgates will be located within MISO and on the seams between MISO and neighboring regional planning entities including MRO, PJM, TVA and SPP.[19] Information examined to find such flowgates includes:

- Historical binding constraints identified in MISO's real-time and day-ahead markets in the last two years
- Historical binding constraints identified from market-to-market operations in the last two years
- Future projected congested transmission elements identified via out-year production cost model simulations

[19] Midwest Reliability Organization (MRO); Pennsylvania New Jersey Maryland Interconnect (PJM); Tennessee Valley Authority (TVA); Southwest Power Pool (SPP)

The output of this analysis will be a mutually agreed to list of highly congested flowgates, which will be evaluated for solutions that may be eligible as Market Efficiency Projects or Cross-Border Market Efficiency Projects, consistent with Tariff provisions and existing regional and interregional processes and protocols. The top congested flowgates identified in MTEP11 TCFS encompass not only the MISO footprint but also neighboring seams entities (Figure 7.2-3).



ID	Top Congested Flowgates
A	Wheatland - Breed 345kV
B	Lanesville 345/138kV Transformer
C	Fredricktown - Fredricktown Tap 161kV
D	Sparta Tap - Tilden 138kV
E	Johnson Jct. - Ortonville 115kV
F	N Platt - Stockville 115kV
G	Albers - Kenosha 138kV
H	Arnold - Plains 138kV
I	Dune Acres-Michigan City - LaPorte 138kV
M	Shawnee – Marshall 500kV (Contingencies)
N	Volunteer – Phipps Bend 500kV (Contingencies)
O	Iatan-Stranger Creek 345kV
P	Burr Oak 345/138 Transformer
Q	Granville – Butler 138kV

Figure 7.2-3: Top congested flowgates identified in MTEP11 Top Congested Flowgate Study

A key consideration for identifying top congested flowgates is to have a proper flowgate ranking methodology. The goal of ranking flowgates is to determine the flowgates that have the highest potential benefit for congestion mitigation. Currently, total shadow prices and binding hours are used as independent rankings. In an attempt to increase correlation between rankings and potential benefits achieved by congestion relief, multiple methodologies have been proposed and evaluated, including congestion cost. Future analysis will be conducted to determine the accuracy and feasibility of each ranking methodology.

Congestion Relief Economic Analysis

Congestion relief economic analysis seeks to identify longer-term transmission needs and guide development of larger scale regional transmission projects/portfolios that maximize value. To identify economic transmission opportunities, a value-based planning approach will be employed by performing two production cost models simulations: first, a constrained case with existing transmission constraints; and second, an unconstrained case with all transmission constraints removed for a defined area. The unconstrained case establishes a lower limit on production costs, which can be used as a reference to measure the production cost differences.

The comparison reveals the potential value of transmission congestion reduction and more efficient generation utilization. Differences between these two cases provide a broad set of economic information.

This will be used to guide and screen transmission projects/portfolios development and allow more efficient and cost-effective projects/portfolios. Specifically, the following set of economic information will be derived from:

- Energy sources and sinks
- Forecasted locational, marginal prices (LMP)
- Interface energy flow changes
- Incremental power transfer needs
- Targeted economic potential

The congestion relief analysis will be conducted annually in June/July to produce a wide range of economic information, prior to MTEP project submissions in mid-September, to provide guidance to stakeholders while formulating transmission solutions. Furthermore, the economic information will be refreshed on an "as needed" basis at the end of each calendar year, depending on the approval status of out of cycle projects.

Energy Sources and Sinks

Energy sources and sinks will be determined by observing the annual generation production differences between the unconstrained and constrained cases. Knowing the differences in energy production between the two cases helps to define the energy source and sink areas (Figure 7.2-4). In the figure, red represents the energy source areas of surplus energy and blue signifies the energy sink areas where energy can be delivered economically. The direction of desired powerflows is from energy sources to sinks. Gas prices and load growth rates are key factors that drive the economic needs for transmission. With lower gas prices and load growth rates, fewer economic opportunities will be identified.

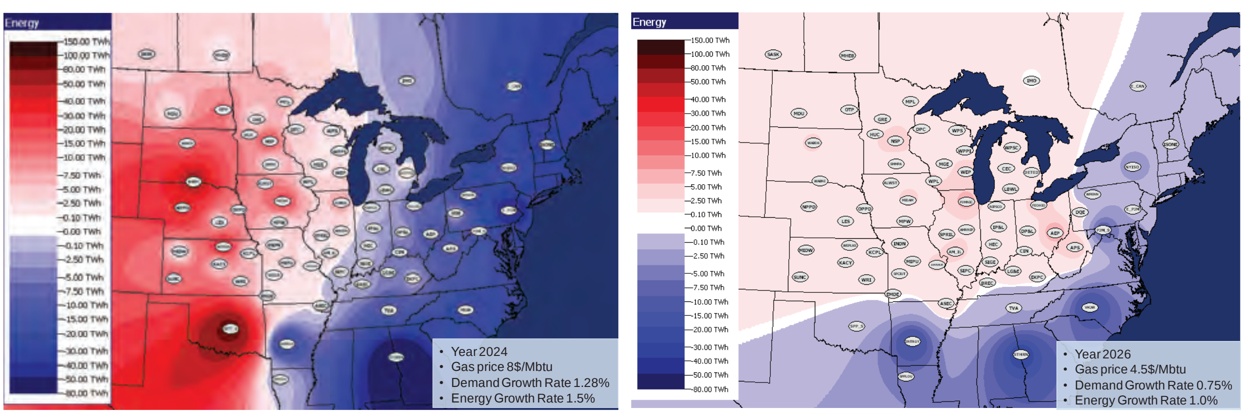


Figure 7.2-4: Example of energy sources and sinks

Forecasted Locational Marginal Prices

Forecasted locational marginal prices (LMPs) will be produced on an aggregated company level, which provides congestion patterns and energy price spreads across the system (Figure 7.2-5). The forecasted LMPs, coupled with energy sources and sinks, provide insights into potential locations of transmission lines and substations from an economic perspective. Price signals drive energy from low-cost source areas to high-cost sink areas. Transmission is most valuable in combinations of high energy transfer between locations with high price differences. To deliver low cost to consumers, generally the best approach is to link low-cost source areas to high-cost sink areas. This relieves the most expensive congestion by bridging the largest price differences across the system. Similar to the energy sources and sinks, the spread in forecasted LMPs across the study footprint tends to be less in those scenarios with lower forecasted gas prices and load growth rates, resulting in less economic need for transmission.

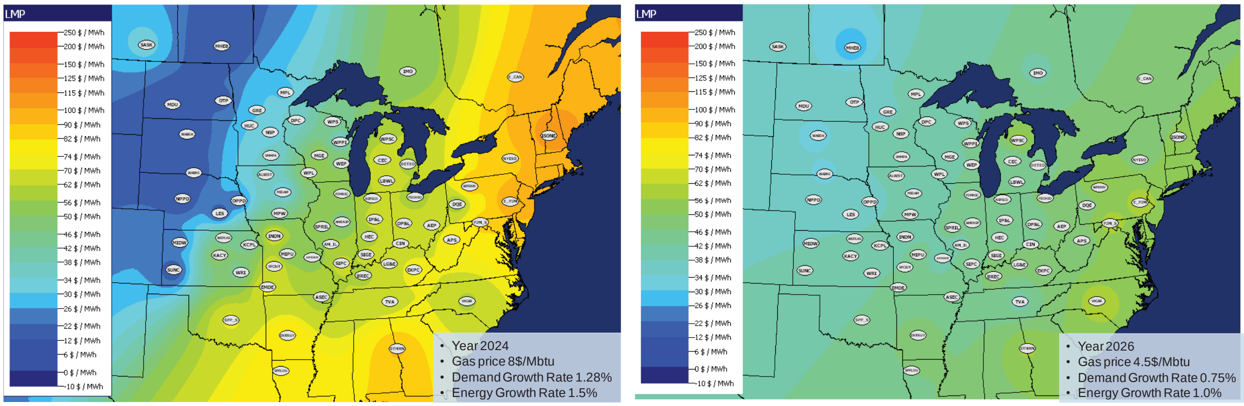


Figure 7.2-5: Example of forecasted generation weighted LMPs

Interface Energy Flow Changes

Economic value provided by transmission is driven by both energy price differences and energy flow changes over a period of time. Thus, the design of economically beneficial transmission projects/portfolios requires consideration of the amount of energy that flows from sources to sinks as well as the price difference.

An examination of the annual aggregated energy differences between the unconstrained and constrained cases across each defined interface provides the direction and magnitude of the interface flow changes. Interface flows are the sum of line flows that make up the interface (Figure 7.2-6). In the figure, red indicates the largest incremental flow change on the interface and the blue represents the smallest. The interface flows that tend toward red indicate where energy would flow more economically if there were no system constraints. These are generally good candidate locations for transmission corridors to increase energy delivery. However, care must be used when interpreting this information because the flows, in addition to economics, are also a function of the impedance/resistance of the underlying transmission grid.

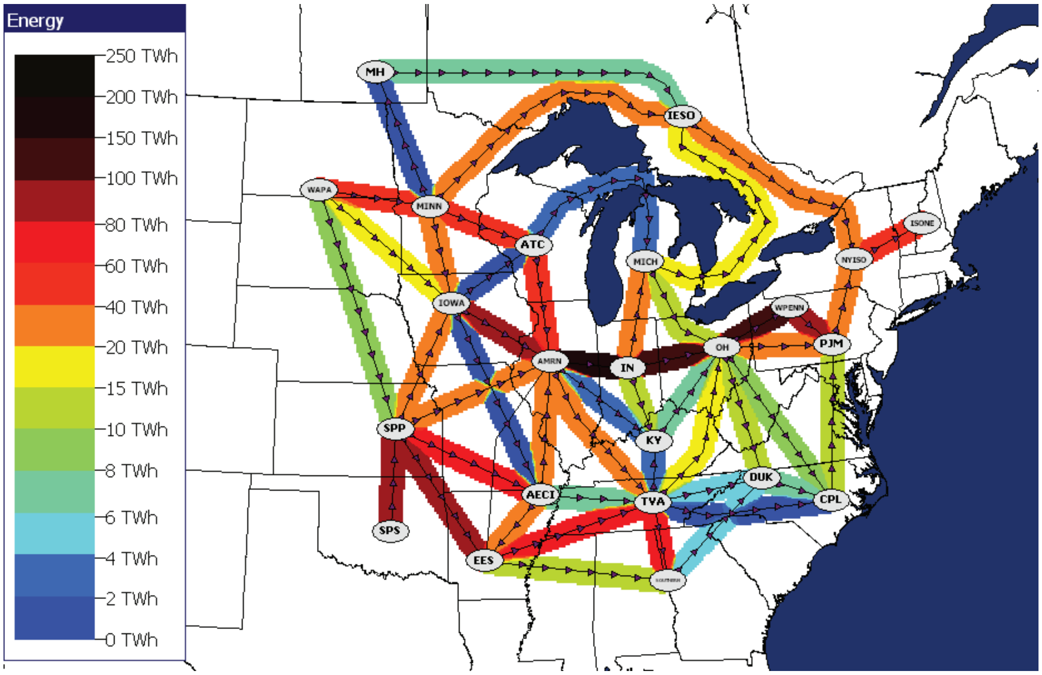


Figure 7.2-6: Example of interface energy flow changes

Incremental Power Transfer Needs

The incremental powerflows across interfaces are calculated between the unconstrained and constrained cases on an hourly basis. The duration curves of the hourly incremental flows across the interfaces, produced by sorting hourly incremental flows in a descending order (Figure 7.2-7), convert energy transfer across the interfaces into the power transfer requirements for transmission development. The greatest economic value results when the power transfer level is designed to deliver approximately 80 percent of the desired energy across each interface. For example, Figure 7.2-7 tells us that the power transfer level to deliver 80 percent of desired energy is 1,000 MW. Power transfer levels help provides initial estimates for the appropriate size and type of transmission. To ensure system reliability and no adverse impact imposed on the underlying transmission system, reliability analyses are done to determine the appropriate voltage and the number of additional transmission lines needed.

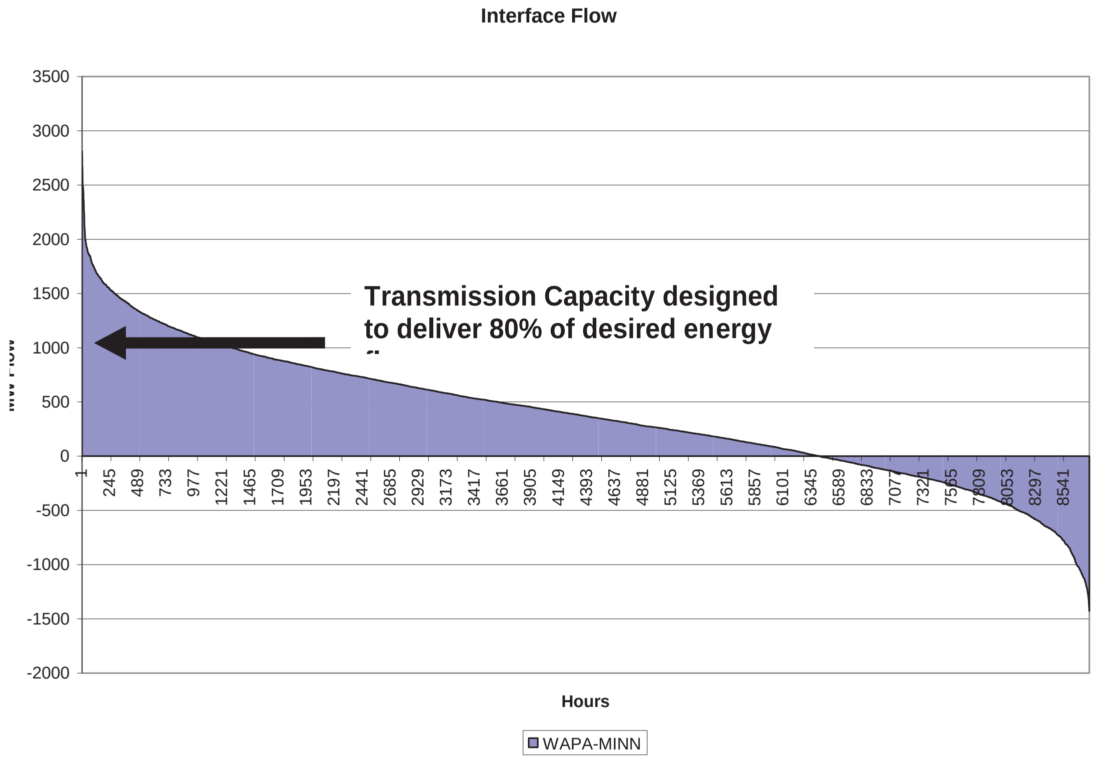


Figure 7.2-7: Example of incremental power transfer needs on interfaces

Targeted Economic Potential

Congestion relief analysis offers a means for estimating the total budget available for transmission expansion, based on economic benefits. A rough estimate of the potential budget for building transmission can be estimated from the total benefit savings by taking the production cost difference between the constrained and unconstrained cases. This represents the maximum possible production cost benefit to be captured from constructing a perfect transmission system, also known as unconstrained case. Recognizing that such perfection cannot be attained, reasonable assumptions must be established. Seventy percent of the maximum benefit potential, a range achieved in previous MISO analyses, will be used to estimate the maximum economic transmission capital investment based on the benefit-to-cost ratio threshold established in Tariff for the Market Efficiency Project Tariff.

Congestion Relief Analysis Levels

To guide and address both near- and long-term transmission needs, congestion relief analyses will be conducted on three separate levels (Figure 7.2-8), encompassing MISO's local resource zones, MISO's market footprint, and the entire Eastern Interconnect study footprint. Specifically, the congestion relief analyses include:

- **Zonal** congestion relief analysis performed of the seven MISO local resource zones to guide more granular transmission solutions to address near-term congestion issues within each zone. The economic information will focus on targeted economic potential and forecasted generation weighted LMPs within each of the local resource zones.

- **Regional** congestion relief analysis on the MISO footprint to identify larger-scale transmission development opportunities on a regional basis. It enables regional transmission development that would relieve a group of congested flowgates and provide widespread benefits across the MISO region. The economic information produced from regional congestion relief analysis will include energy sources and sinks across MISO, zonal transfer needs within MISO, targeted economic potential for the entire MISO region, and forecasted generation weighted LMPs.

- **Interregional** congestion relief analysis conducted on the entire study footprint will facilitate interregional transmission planning coordination and identify potential interregional transmission facilities that may address individual regional needs more efficiently or cost effectively. It provides insights on identifying and prioritizing potential beneficiaries/partners and participation levels of neighboring planning entities. The economic information derived from interregional congestion relief analysis will include energy sources and sinks across the entire study footprint, transfer needs between regions, targeted economic potentials for regions and forecasted generation-weighted LMPs.

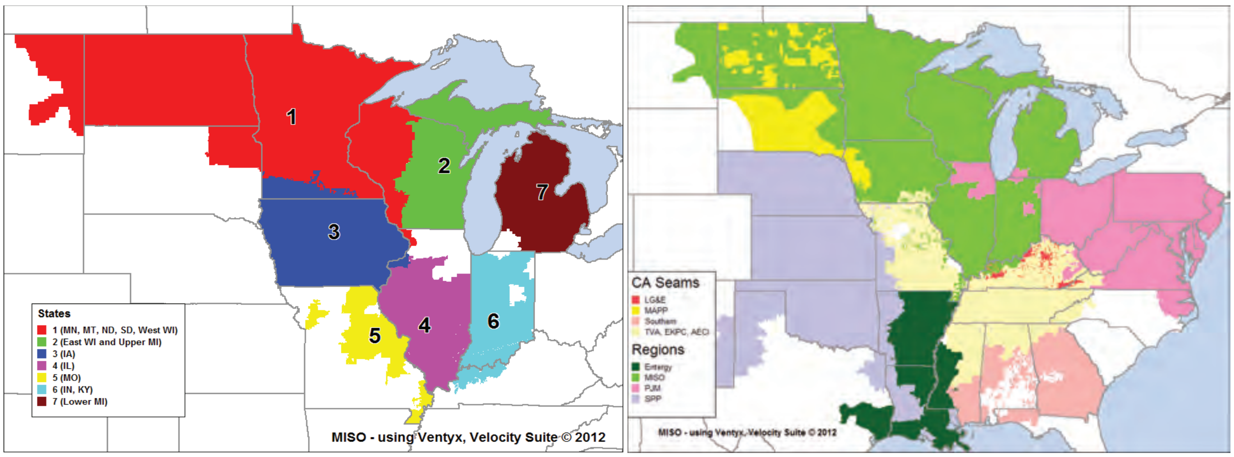


Figure 7.2-8: Congestion relief analysis study footprint levels

Transmission Solution Development Criteria

The development of potential transmission solutions will use a stakeholder-inclusive process to develop indicative transmission solutions that align with the economic benefit indicators from the regional market efficiency analyses. Stakeholders may submit proposals that align with the economic data indicating potential market efficiency benefit. The submission of transmission project/portfolio proposals to address study objectives may occur prior to or when solicited within the study process. Project/portfolio proposals should address one or more transmission issues, including historical congestion within the MISO footprint and on seams; projected future congestion within the MISO footprint and on seams; and/or increasing regional transfer capability to enable more efficient dispatch of generation resources, as indicated in the Market Efficiency Planning Study process.

For a project/portfolio to be designated as a Market Efficiency Project and to be submitted through the market efficiency study process, such projects/portfolios need to meet minimum criteria, consistent with the current Tariff provisions and JOA protocols.

- A detailed project description including, but not limited to, substations, voltage levels, circuit configuration, impedances, estimated line mileage, estimated in-service date, rating of the facilities and estimated cost

- An estimated project cost of $5 million or greater

- Facilities with voltage level of 345 kV or higher, and lower voltage facilities of 100 kV or above that collectively constitute less than 50 percent of the combined estimated project cost may be included

- A supporting document that summarizes the need drivers of the proposed project/portfolio aligned to the indicative data from the study process

- A preliminary need assessment report to articulate analysis assumptions, and potential benefits accrued by the proposed project/portfolio as applicable

Project/Portfolio Holistic Assessment

Given the intensity of production cost model simulations and availability of time and resources, it is necessary to screen the possible projects and focus on those more likely to produce sufficient benefits to be eligible for cost sharing as Market Efficiency Projects. To achieve this end, a regional solution will be developed an integrated view (Figure 7.2-9).

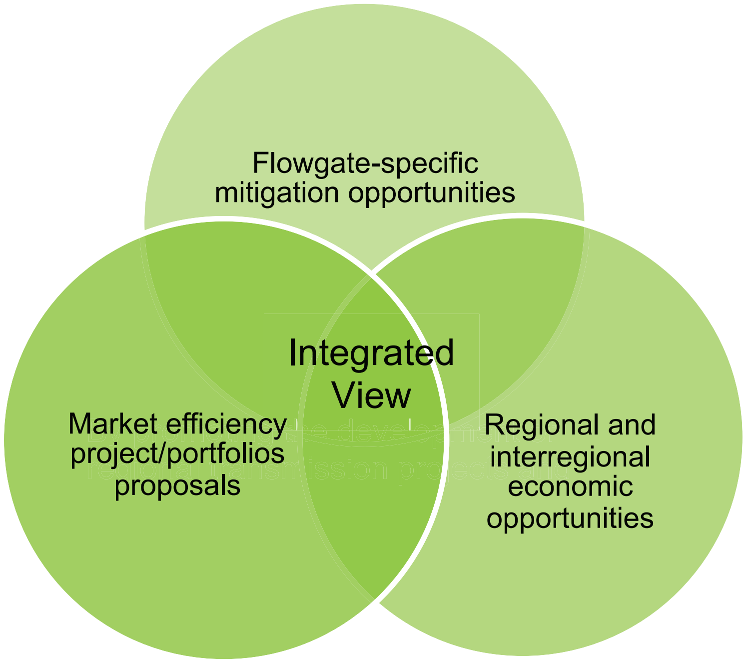


Figure 7.2-9: Project/Portfolio evaluation

Regional/interregional congestion relief analysis focuses on identifying economic opportunities from a regional perspective to explore longer-term transmission solutions, while top congested flowgate analysis indicates near-term transmission needs for congestion mitigation. One key consideration in creating an integrated regional view is to strike a balance between compatibility and flexibility of transmission solutions, regardless of future changes in energy policies and economic conditions. By screening, selecting and adjusting as appropriate, components of proposed transmission alternatives that address the identified near-term congestion issues and align well with the longer-term economic opportunities, a regional solution will be developed, refined and optimized in an open and transparent stakeholder process.

To facilitate project screening and selection, a single-year analysis against a reference future scenario will be performed to refine an overall solution iteratively. The intent is not to preclude projects/portfolios that provide reasonable level of benefits, but to eliminate projects with limited benefits. The following refinements may be considered, but not limited to, in the process of refining the solution:

- Under-utilized transmission segments with no significant loading may be removed to avoid overbuild
- Insufficient transmission solutions that do not address the identified needs may require additional transmission segments
- Transmission alternatives that meet the same needs may be evaluated to ensure the most efficient and cost-effective solution is developed.

Once the optimal solution is identified, a broad economic assessment will be performed on the entire regional portfolio and on each individual project making up the portfolio against a wide range of future policy-driven scenarios. Given the flexibility provided by the multi-dimensional future scenarios considering out-year public policy and economic uncertainties, the future scenarios are designed to 'bookend' the range of potential future policy outcomes, ensuring that all of the most likely future policy scenarios and their impacts are within the range bounded by the results. 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, minimize the risk associated with the uncertainty level around policy decisions and result in the fewest future regrets.

Sensitivity analyses may be considered to evaluate proposed non-transmission alternatives to transmission facilities on a comparable basis, to ensure that the most efficient and cost-effective options are considered to meet the identified need drivers. Impact of variations in economic variables such as gas prices may also be considered.

Project/Portfolio Justification

The optimal project/portfolio solutions will be evaluated against the qualification criteria for Market Efficiency Projects or Cross-Border Market Efficiency Projects in accordance with MISO Tariff provisions and JOA protocols.

For a transmission upgrade to qualify as a Market Efficiency Project, the following criteria must be met as described in Attachment FF of the Tariff:

- Project 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 determined to be a Baseline Reliability or New Transmission Access Projects

Should an individual project or portfolio meet the market efficiency criteria while maintaining system reliability, it will be recommended for inclusion for approval in Appendix A.

To be eligible as a Cross-Border Market Efficiency Project between MISO and PJM Interconnection, the following set of criteria must be met, as defined in section 9.4.3.1.2 of the MISO-PJM joint operating agreement:

- Project cost of $20 million or greater
- The project must be evaluated as part of the RTOs coordinated system planning or joint study process
- Meets the threshold benefit-to-cost ratio using the benefit and cost measures prescribed under the JOA
- The project must qualify as an economic transmission enhancement or expansion under the terms of the PJM Regional Transmission Expansion Plan (RTEP) and also qualify as a Market Efficiency Project under the terms of Attachment FF of the MISO Open Access Transmission Tariff (OATT)
- The project should address one or more constraints for which at least one dispatchable generator in the adjacent market has a generator load distribution factor of 5 percent or greater with respect to serving load in the adjacent market

Projects that meet the Cross-Border Market Efficiency Project criteria will be further evaluated under an interregional planning process, as desired by the regional planning entities on the respective seams.

The project/portfolio solutions may also be further evaluated through a separate process as part of a Multi Value Project portfolio, which may be comprised of results from various reliability, economic, policy and generation interconnection studies. This would consider a broad set of reliability, policy and economic value metrics, beyond just Adjusted Production Cost savings.

Project Deliverables

- A final report documenting study assumptions, process and results. If appropriate, Market Efficiency Planning Study will recommend preferred solutions, consistent with MISO Tariff provisions and JOA protocols
- An executive summary of the Market Efficiency Planning Study final report in the annual MTEP reports
- Results of need identification analyses shared when complete
- Changes made to the Transmission Planning Business Practices Manual (BPM), as appropriate

Project Schedule and Milestones

The prior TCFS process started in June and ended in June of the following year. In the expanded Market Efficiency Planning Study scope, a longer study timeframe is required. The extended study timeline begins in June and ends December of the following year. For this first cycle, the project began in April 2012 with an expected completion date of Sept. 30, 2013.

7.3 Retail Rate Impacts

The electricity industry faces significant policy changes from the state and federal level. These changes generate uncertainty for the industry and its customers, including potential rate increases to retail electricity customers. All but one of the 11 states in the MISO footprint have enacted a Renewable Portfolio Standard (RPS) mandate or goal. There is a great deal of uncertainty about how these goals will be achieved, including the location of future generation and the required transmission to enable renewable integration. In addition to state policies, there is on-going discussion at the federal level on implementation of policies, including federal RPS, carbon reduction, smart grid and others. To address these potential futures, MISO examines multiple scenarios through its long-term planning process to capture a wide range of potential policy outcomes.

Current Retail Electricity Rates

The current MISO-wide average retail rate, weighted by load in each state, for residential, commercial and industrial sector, is 9.0 cents/kWh, about 6 percent lower than the national average of 9.6 cents/kWh.[20] The average retail rate in cents per kWh varies by 3.7 cents/kWh per state in the MISO footprint (Figure 7.3-1). The Energy Information Administration (EIA) in Annual Energy Outlook 2011 estimates the 2012 cost components of the retail electricity rate average 62.8 percent for generation; 7.1 percent for transmission and 30.1 percent for distribution.[21] This equates to approximately 5.6 cents/kWh for generation, 0.6 cents/kWh for transmission and 2.7 cents/kWh for distribution.[22] For this rate impact analysis, it is assumed the average MISO residential customer uses approximately 1,000 kWh of electricity each month, equivalent to annual electricity charges of $1,080; based on a 9.0 cents/kWh retail rate.

The current MISO-wide average retail rate, weighted by load in each state, for residential, commercial and industrial sector, is 9.0 cents/kWh, about 6 percent lower than the national average

[20] Data courtesy of the Energy Information Administration (EIA) Electric Power Monthly from July 2012. MISO average rate was calculated by taking the load weighted average of the 11 states in the MISO footprint.

[21] MISO average generation, transmission and distribution components were calculated based on rate component data provided in the EIA Annual Energy Outlook in 2011 for the following modeling regions: MRO-East, MRO-West, RFC-MI, RFC-West, SERC-Central and SERC-Gateway. The modeling regions were weighted based on MISO load in each of the regions.

[22] Each category assumes some allocation of general and administrative expenses.

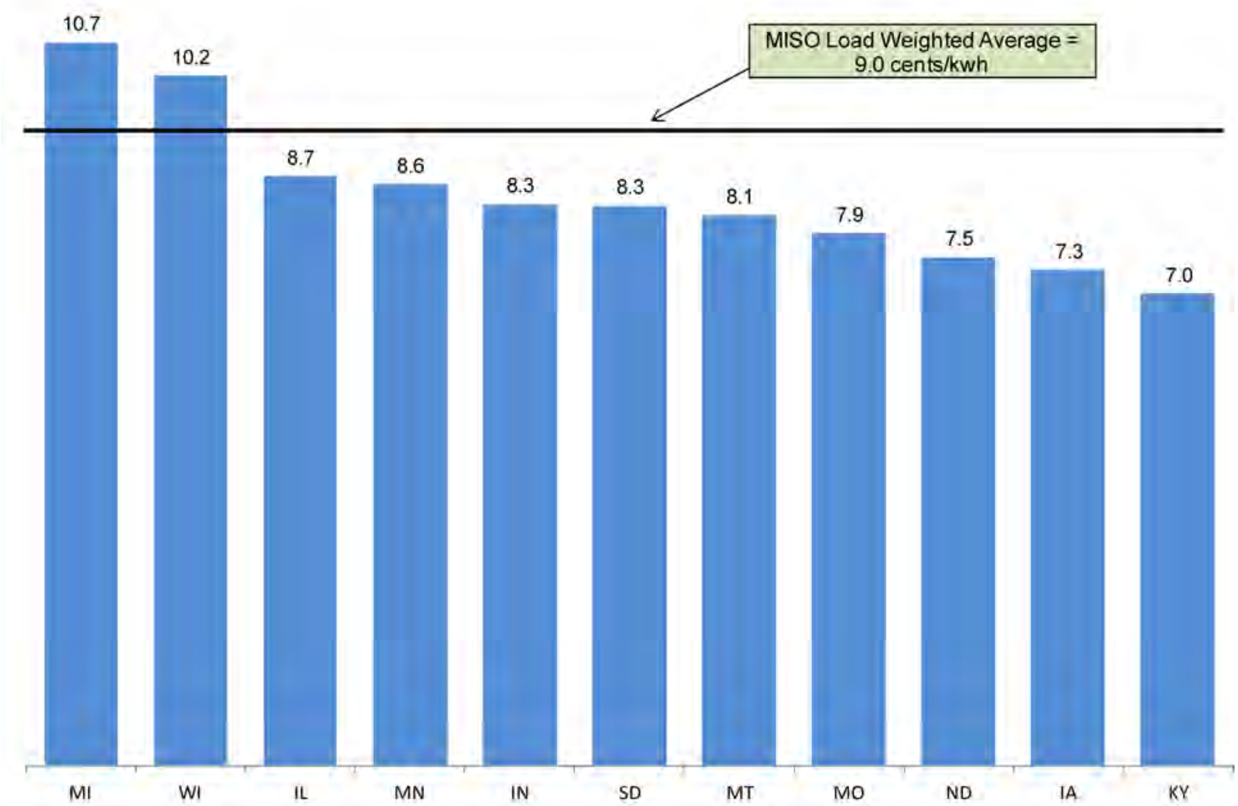


Figure 7.3-1: MISO retail rate for all sectors in cents/kWh (2012 dollars)

Future Scenarios

MISO examined a number of policy-driven future generation expansion scenarios to develop an array of "best plans" for a range of possible outcomes. These scenarios derive from policy discussions, and they will evolve depending on the direction of legislation and stakeholder input. The scenarios represent a range of potential policies and estimate potential impacts to retail-rate payers in the MISO footprint.[23]

- The Business as Usual 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. RPS requirements vary by state, and have many potential resources that can apply. This future employs 12 GW of coal retirements, with the smallest and least-efficient coal units retired.

- The Historical Growth future scenario is considered a status-quo scenario, with a quick recovery from the economic downturn in demand and energy projections. This scenario models the power system as it exists today with reference values and trends — with the exception of demand and energy growth rates — and is based on recent historical data prior to the economic downturn. This scenario assumes existing standards for resource adequacy, renewable mandates and environmental legislation will remain unchanged. RPS requirements vary by state and have many potential applicable renewable resources. This future employs 12 GW of coal retirements, with the smallest and least-efficient coal units retired.

[23] For additional description of the MTEP12 scenarios refer to Chapter 7.6 and Appendix E2

- The Limited Growth future scenario is considered a status quo scenario, with little to no recovery from the economic downturn in demand and energy projections. The demand and energy growth rates are modeled as one-half of the rates used in the BAU scenario. The limited growth scenario assumes existing standards for resource adequacy, renewable mandates and environmental legislation remain unchanged. RPS requirements vary by state, and have many potential applicable resources. This future employs 12 GW of coal retirements, with the smallest and least-efficient coal units retired.
- The Combined Policy future scenario was developed to capture the effects of multiple future policy scenarios into one future. This scenario includes a federal RPS, smart grid and electric vehicles. The federal RPS assumes all states are required to meet a 20 percent federal RPS mandate by 2025. This future employs 23 GW of coal retirements, with the smallest and least efficient coal units retired. Smart grid is modeled by reducing the demand growth rate, assuming that a higher penetration of smart grid will lower the overall growth of demand. Electric vehicles are modeled by increasing the energy growth rate, and assume increased off-peak energy usage and overall energy growth rate increase.

Overview of Rate Impact Methodology

To measure the potential impact to rate payers under each of the scenarios; MISO projected a 2027 retail rate by estimating annual revenue requirements for the generation, transmission and distribution rate components.[24] This projection was based on the following assumptions:

- Transmission component
    - o Includes approved MVP portfolio (constant across all scenarios)[25]
    - o Additional required reliability transmission investment through 2027 (constant across all scenarios)
    - o Non-depreciated current transmission that would still be recoverable in 2027 (constant across all scenarios)
- Generation component
    - o Production costs for MISO generation resources associated with each scenario in 2027; including fuel, emissions, variable operations and maintenance expenses
    - o Capital costs, including fixed operations and management, associated with the capacity expansion for each scenario through 2027[26]
    - o Non-depreciated current generation that would still be recoverable in 2027 (constant across all scenarios)
- Distribution component
    - o Assumes that the distribution component of the current MISO retail rate at 2.7 cents/kWh will grow at the assumed rate of inflation through 2027

To calculate MISO's 2027 retail rate, revenue requirements for the generation, transmission and distribution components described above were distributed uniformly across the forecasted 2027 energy usage levels. The 2027 rate was then deflated, using the assumed inflation rate to 2012 for comparison to the current MISO retail rate. The result of this calculation for each scenario shows the impact the scenarios could have on customer retail rates (Figure 7.3-2). Note that the rates calculated for the future scenarios include costs for generation, transmission and distribution; but do not include general and administrative costs.

[24] Additional detail on the rate calculation methodology is provided in Appendix E3.

[25] Based on the approved MVP portfolio with a total project cost of $5.4 billion in in-service dollars.

[26] Refer to Chapter 7.6 for details on the capacity expansion, by fuel type, for each MTEP12 Future. Generation siting maps for each MTEP12 Future are also provided in Chapter 7.6.

Rate Impact Results

All but one of the scenarios shows that retail rates can be expected to grow at a rate similar to that would be experienced if rates simply increased by inflation. However, the magnitude of this impact varies across the four scenarios, from a 2 percent decrease for the Limited Growth scenario to a 36 percent increase for the Combined Policy future (Table 7.3-2).

All but one of the scenarios shows that retail rates can be expected to grow at a rate similar to that would be experienced if rates simply increased by inflation

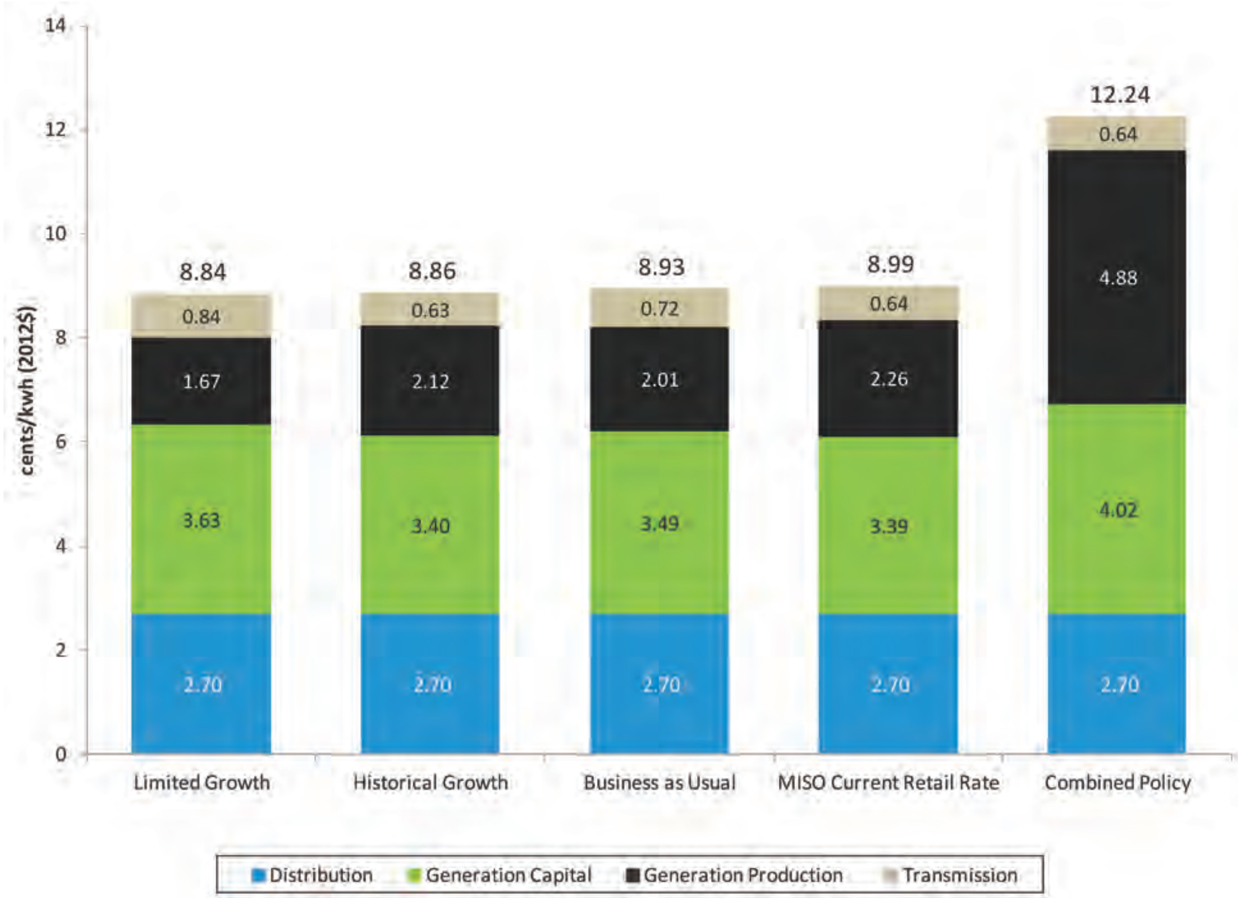


Figure 7.3-2: Comparison of estimated retail rate for each future scenario (Cents per kWh in 2012 Dollars)

Scenario	Rate (cents/kWh)	Percent (Change from current retail rate)	Annual Household Electricity Costs
Limited Growth	8.84	-1.7%	-$18
Historical Growth	8.86	-1.5%	-$16
Business as Usual	8.93	-0.6%	-$7
MISO Current Retail Rate	8.99	0%	$0
Combined Policy	12.24	36.3%	$391

Table 7.3-1: 2027 retail rate impacts in 2012 dollars for each future scenario (Cents per kWh in 2012 Dollars)

Rate Impact Drivers Under Future Policy Scenarios

Limited Growth

It's possible to compare the Limited Growth scenario's estimated retail rate to the current retail rate (Table 7.3-2). This is done by using the rate components to illustrate what is driving the overall estimated decrease of $18 to the average residential ratepayer's annual electricity costs.[27] The factors that contribute to this lower rate are:

Though there is an increase in the transmission component of 31 percent, this increase is more than offset by the reduction in generation production costs

1. The lower demand growth rate will require fewer new capacity resources, though there are 12,500 MW of wind and solar resources added to meet the state renewable mandates.
2. The increased output of renewable resources (which typically have no fuel costs and therefore very low production costs) from 9 percent of output in 2012 to 15 percent in 2027, reduces generation production cost.
3. Though there is an increase in the transmission component of 31 percent, this increase is more than offset by the reduction in generation production costs.

[27] Residential annual electricity costs calculated assuming average monthly usage of 1,000 kWh.

	Rate Component				
	Generation capital[28]	Generation production	Transmission	Distribution	Total
MISO current retail rate (cents per kWh 2012 dollars)	3.39	2.26	0.64	2.70	8.99
Limited Growth future retail rate (cents per kWh 2012 dollars)	3.63	1.67	0.84	2.70	8.84
Percentage change in projected retail rate	7.2%	-26.0%	30.8%	-	-1.7%
Projected change in avg. residential rate payer's annual electricity bill	$29.05	$(70.54)	$23.60	-	$(17.89)

Table 7.3-2: Comparison of Limited Growth future retail rate to current

Historical Demand

The Historical Demand scenario's estimated retail rate compared to the MISO current retail rate illustrates which component is influencing the overall estimated annual decrease of $16 to the average residential ratepayer's electricity costs (Table 7.3-3). The factors that contribute to this lower rate are:

1. The decrease in generation production costs is due in part to the increased output of renewable resources (which typically have no fuel costs and therefore very low production costs) from 9 percent of output in 2012 to 15 percent in 2027.
2. The slight reduction in transmission costs is due to the higher assumed energy growth rate for this future scenario, which results in spreading the assumed fixed annual revenue requirements for transmission over a larger number of MWhs.
3. The reduction in generation production and transmission costs are offset by a very small increase in generation capital costs by the addition of 44,680 MW of new generation capacity, including 19,480 MW of wind and solar resources to meet the current state RPS requirements.

The decrease in generation production costs is due in part to the increased output of renewable resources

[28] Generation capital includes both annual capital charges and fixed O&M expenses.

	Rate Component				
	Generation capital	Generation production	Transmission	Distribution	Total
MISO current retail rate (cents per kWh 2012 dollars)	3.39	2.26	0.64	2.70	8.99
Historical Demand future retail rate (cents per kWh retail dollars)	3.40	2.12	0.63	2.70	8.86
Percentage change in projected retail rate	0.5%	-6.2%	-1.3%	-	-1.5%
Projected change in avg. residential rate payer's annual electricity bill	$2.09	$(16.79)	$(1.02)	-	$(15.71)

Table 7.3-3: Comparison of Historical Demand future retail rate to current

Business as Usual

The Business as Usual (BAU) scenario estimated retail rate compared to the MISO current retail rate illustrates which component influences the overall estimated annual decrease of nearly $7 to the average residential ratepayer's electricity costs (Table 7.3-4). The factors that contribute to this lower rate are:

This future scenario assumes a $50 per ton cost is incurred for each ton of CO_2 emissions, which is directly responsible for 77 percent of the increase

1. The decrease in generation production costs is due in part to the increased output of renewable resources (which typically have no fuel costs and therefore very low production costs) from 9 percent of output in 2012 to 15 percent in 2027.
2. The reduction in generation production costs are offset by an increase in transmission costs and an increase in generation capital costs due to the addition of 25,880 MW of new generation capacity, including 16,280 MW of wind and solar resources to meet the current state RPS requirements.

	Generation capital	Generation production	Transmission	Distribution	Total
MISO current retail rate (cents per kWh 2012$)	3.39	2.26	0.64	2.70	8.99
BAU future retail rate (cents per kWh 2012$)	3.49	2.01	0.72	2.70	8.93
Percentage change in projected retail rate	3.2%	-10.8%	12.3%	-	-0.6%
Projected change in average residential rate payer's annual electricity bill	$13.06	$(29.18)	$9.42	-	$(6.70)

Table 7.3-4: Comparison of BAU future retail rate to current

Combined Policy

The Combined Policy scenario estimated retail rate compared to the MISO current retail rate illustrates which component influences the overall estimated annual increase of $391 to the average residential ratepayer's electricity costs (Table 7.3-5). The factors that contribute to this significant rate increase are two-fold:

1. This future scenario assumes a $50 per ton cost is incurred for each ton of CO2 emissions, which is directly responsible for 77 percent of the increase or in dollar terms, $302 of the $391 estimated increase.

2. The remaining increase of $89 is mainly driven by an increase in generation capital costs due to the addition of 51,410 MW of new generation capacity, including 37,010 MW of wind and solar resources to meet the assumed 20 percent federal RPS requirement by 2025 and to replace the 23,000 MW of generation retirements.

	Rate Component				
	Generation capital	**Generation production**	**Transmission**	**Distribution**	**Total**
MISO current retail rate (cents per kWh 2012 dollars)	3.39	2.26	0.64	2.70	8.99
Combined Policy future retail rate (cents per kWh 2012 dollars)	4.02	4.88	0.64	2.70	12.24
Percentage change in projected retail rate	18.7%	116.3%	0.0%	-	36.3%
Projected change in average residential rate payer's annual electricity bill	$75.98	$314.98	$(0.03)	-	$390.94

Table 7.3-5: Comparison of Combined Policy future retail rate to current

The range of potential rate impacts from the four future scenarios illustrates the importance of performing long-term scenario analyses to provide decision-makers with the information needed to minimize rate increases to customers.

7.4 EPA Compliance Studies

In 2012, MISO built upon its 2011 EPA Impact study with a series of targeted analyses to address resource adequacy, outage coordination, compliance deadlines and natural gas infrastructure. MISO evaluated each category to determine possible needs, outcomes and effects on tariffs. While MISO has a better understanding of potential impacts of EPA regulations and is taking action to respond to the risks, uncertainty remains about whether the system can safely comply with the regulations within the prescribed timeframe.

Resource Adequacy

The amount of available overall capacity could be reduced by coal retirements. Additional resources would be needed in 2015 in order to maintain appropriate planning reserve margins.

> 6 GW of resource capacity may be needed by 2015 to maintain an appropriate planning reserve margin

MISO's 2011 EPA Impact Analysis identified 13 GW of capacity for possible retirement. This reduction from the total existing capacity of 114 GW in 2012 requires an additional 6 GW of supply side and/or demand side resources in 2015 (Figure 7.4-1).

The amount of capacity to be retired by 2015 is uncertain, but anything beyond the 6 GW will require additional resources. Higher- or lower-than-anticipated load would also impact the need for capacity. For example, if the year-over-year demand growth rate nearly doubled from 0.74 percent to 1.5 percent, an additional 9 GW of capacity would be required in 2015 to meet minimum planning reserve margin targets.

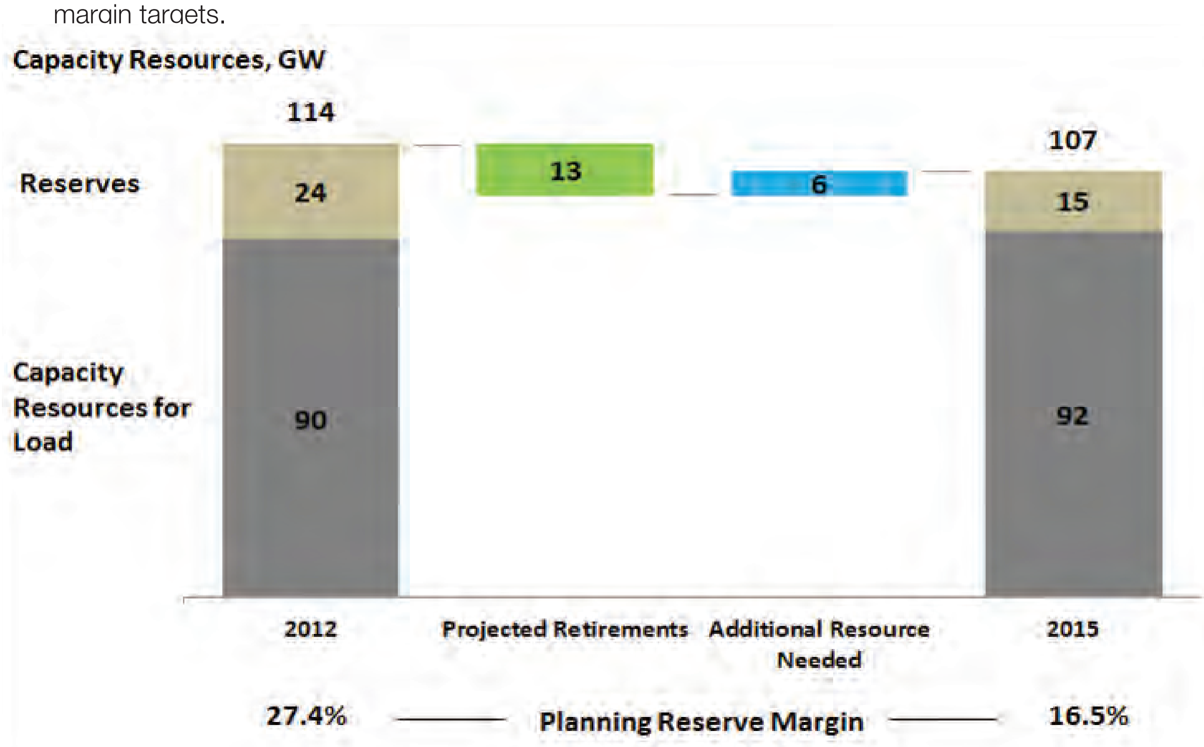


Figure 7.4-1: Additional capacity needs in 2015 with 13 GW of retirements

Outage Coordination

MISO coordinates the timing of generator (and transmission) outages on the MISO system to maintain reliability. Outage coordination could be affected with the limited number of outage windows. Revisions to the Tariff need to take place to address this issue.

The monthly maintenance margin was developed to aid the outage scheduling group and will be updated seasonally

Currently, outages in MISO can be rescheduled based on one of the following:

1. An emergency
2. To maintain nuclear plant interface requirements
3. To maintain the Transmission System within System Operating Limits using normal operating procedures or restore the Transmission System to normal operating conditions following a single contingency
4. The potential for contingencies to significantly affect Transmission System reliability of metropolitan areas

With the limited outage windows before the 2015 compliance deadline, it will be increasingly important for the outage scheduling group to have has as much information as possible. MISO would like to add a fifth rescheduling option to the Tariff pertaining to the monthly maintenance margin. The monthly maintenance margin was developed to aid the outage scheduling group and will be updated seasonally.

Meeting Compliance Deadlines

The timelines for retrofits vary by technology. Some retrofit technologies flue gas desulfurization (FGD) and selective catalyst reduction (SCR) — are riskier than others because of the length of time it takes to complete the work and the deadlines for compliance (Figure 7.4-2). It may be possible to receive an additional one-year extension beyond the first year extension, extending the compliance deadline into 2017. This second year extension will likely be limited to unique cases.

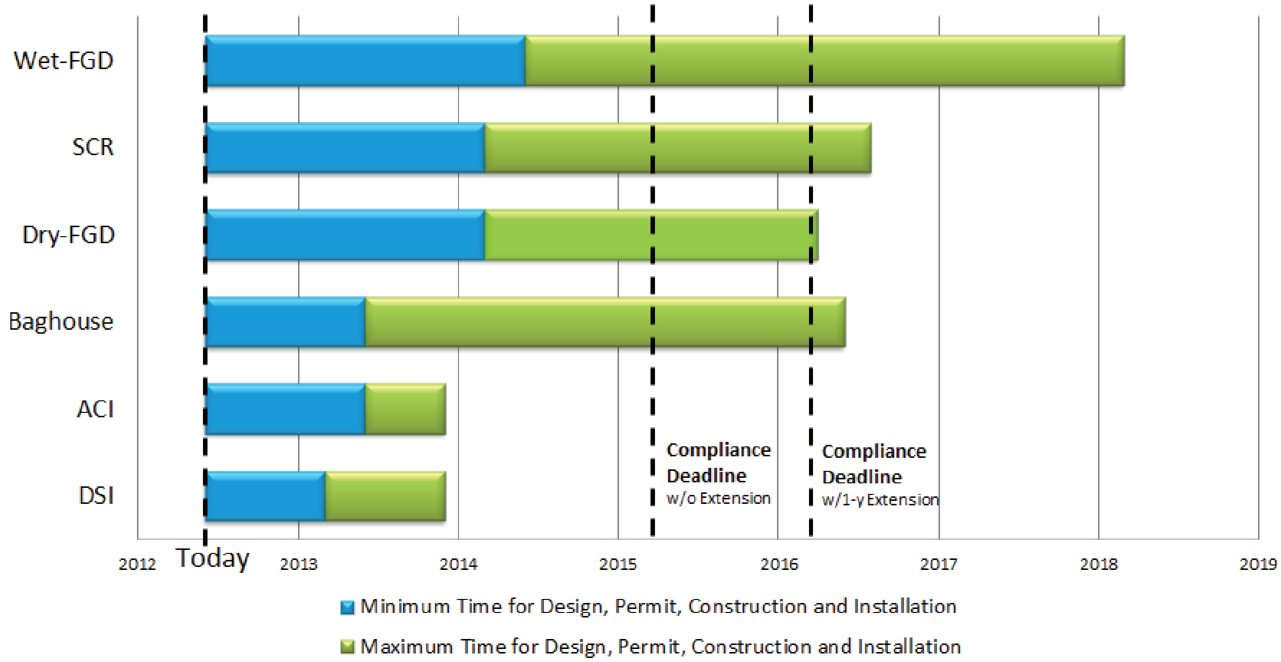
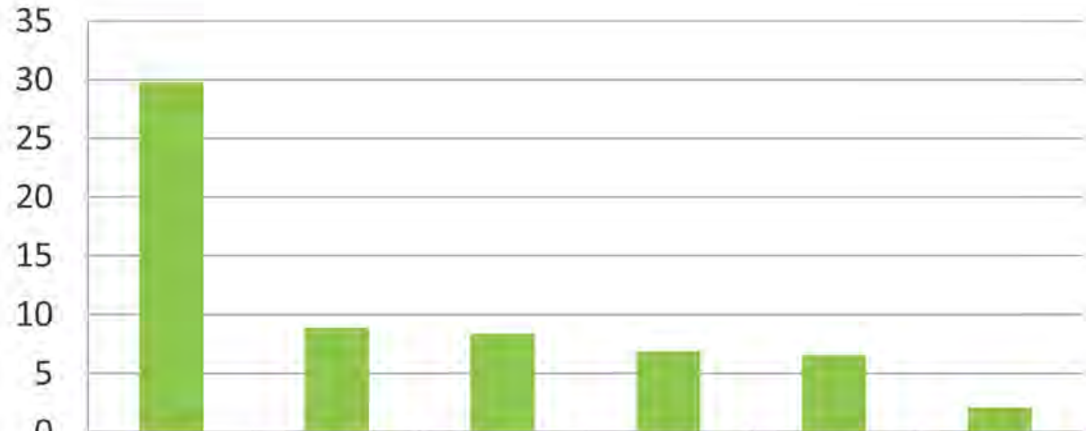


Figure 7.4-2: Retrofit timeline for various control technologies

MISO conducts quarterly surveys of asset owners' EPA compliance strategies. It appears from the third quarter 2012 survey that the majority of coal capacity, 29.8 GW, will retrofit using activated carbon injection (ACI) option (Figure 7.4-3). Units using this option should provide ample time to meet the deadline. Most units installing FGD, SCR and baghouse technologies are in the design, permit and construction phases and should have time to meet the compliance deadline. However, there are a few that have not begun some phases of the retrofit. These units could require extensions of the compliance deadline.



	ACI	FGD	Baghouse	SCR	DSI	ESP
GW	29.8	8.9	8.4	6.9	6.6	2.1
# of Units	73	17	25	13	24	6

Figure 7.4-3: Asset owner technology selections from third quarter survey

A larger number of units will have "no action required" to comply with the Mercury Air Toxics Standard (MATS) than initially anticipated in the 2011 EPA Impact Analysis. In that study, 9.5 GW of coal capacity was categorized with no action required. However, in the second-quarter survey, asset owners responded "no action required" to meet the MATS amounted to 19.0 GW of coal capacity (Figure 7.4-4). The exact reason for the increase in the no action required category is not known. However, the majority of the increase takes place at units with an electrostatic precipitator (ESP). This technology should be sufficient to meet the particulate matter removal required for MATS, which uses the emission limit for filterable particulate matter instead of total particulate matter.

Asset owners indicated the intent to retire 5.4 GW of coal capacity, with another 5.6 GW of coal capacity on the bubble

The remaining units will either be retired or are in consideration for retirement. According to the survey, asset owners indicated the intent to retire 5.4 GW of coal capacity, with another 5.6 GW of coal capacity on the bubble (Figure 7.4-4). If units that did not respond to the survey are included, the retirement figure could reach 11.9 GW. MISO will continue to survey asset owners quarterly.

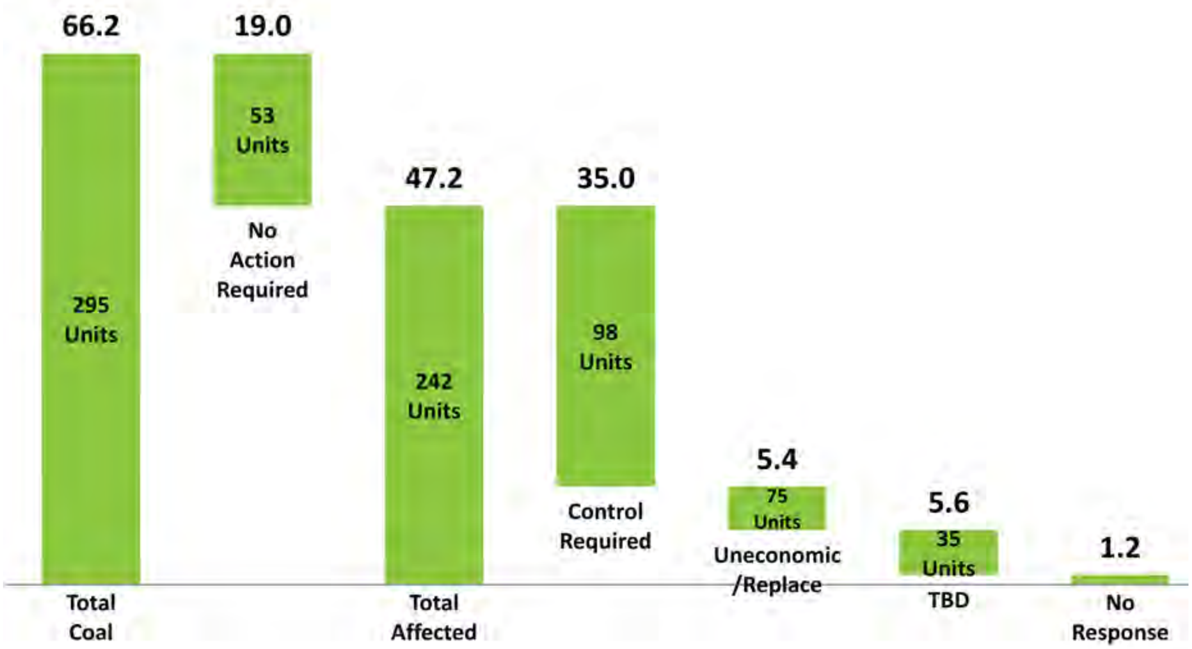


Figure 7.4-4: Asset owner decisions from the third quarter survey

Natural Gas Infrastructure

MISO's initial Gas and Electric Infrastructure Interdependency Analysis found that gas supply availability at the wellhead for use in power generation is not an issue. However, the analysis indicates three major areas of concern:

- **Storage-** Additional gas storage, either underground or on-site, will be needed to provide firm winter generation capability.
- **Pipeline Capacity-** New pipeline infrastructure is needed to manage volatility and ensure reliability. Twenty-one major pipelines are in the MISO footprint, with different lines serving potential new gas-fired generation. New main lines as well as lateral lines will be needed.
- **Timing-** Getting the needed infrastructure built will take time. MISO's study indicates the regulatory, design and construction for pipeline development takes three to five years to complete once a defined plan exists. Electric generators and gas pipelines need to work together on developing the defined plan, and this is likely to take several years.

Regional electric and gas infrastructure interdependency meetings are being held by FERC and MISO to address the timing concern. These meetings consist of representatives from both industries. With ever-increasing reliance on the gas fleet due to the EPA regulations, lower natural gas prices or any number of economic reasons it will be important for both industries to work together in the future.

Identified Tariff Considerations

In addition to compliance issues, several areas in the Tariff were flagged for possible changes. At the 2010 workshop, four areas were detailed for tariff and process change: Attachment Y, outage scheduling, real-time operations and resource adequacy.

Revisions on Attachment Y began in March 2012 and were filed on July 25, 2012. The principles behind the tariff revisions for Attachment Y include clear applicability; transparency; short-term bridge to unit retirement or suspensions; the flexibility to assist decision-making; and minimizing reliability impacts.

According to the survey, 5.6 GW of capacity is undecided for the best approach for compliance with the EPA regulations. The Attachment Y revisions will provide those units with additional information to aid in their decisions.

Revisions to outage scheduling pertain to the inclusion of additional factors in determining generator outage rescheduling. Two modifications to the Tariff were presented at the workshop. The first one includes a maintenance margin or loss-of-load expectation criteria to prevent circumstances from compromising transmission system reliability. The second Tariff modification requires generator operators to pursue all options to comply with MISO-reschedule requests, including requesting EPA compliance extensions.

With the recent fall in natural gas prices, certain gas-fired units are more economical than coal fired generation. As such, gas-fired capacity is displacing coal. To the extent that EPA regulations drive higher costs for coal generators, gas utilization for energy could increase further, reducing resources available to respond to immediate and near-term needs. Solutions proposed during the gas-electric workshop include operating the system with a higher level of headroom and developing and implementing a 30- to 60-minute reserve product. Empirical and simulation studies are underway to determine the impact of the displacing coal resources with gas resources. If a new reserve product were developed, Tariff and process revisions would be necessary.

Studies show that gas fuel supply is a concern with greater dependence on the natural gas-fired generation. Of the fuel supply-related outages, a majority of the cause codes were classified as force majeure in the Generating Availability Data System (GADS). Analysis is underway to determine if resource adequacy tariff revisions are needed.

Summary

Additional information of the impacts of the EPA regulations and the potential tariff changes necessary to aid in the compliance with the EPA regulations are coming to light. It is clear from the survey that potentially 12.2 GW of coal capacity could be retired. Tariff changes are being made to help the remaining units make their final decisions on compliance. The majority of units that will be retrofitting are choosing less expensive options that have shorter lead times for implementation. Outage coordination Tariff revisions will give outages scheduler’s additional tools to prevent compromising transmission system reliability. The natural gas infrastructure continues to be a concern. Coordination between the electric and gas industries is beginning with regional workshops by FERC and MISO.

7.5 **FERC Order 1000**

The Federal Energy Regulatory Commission's (FERC) Order 1000 rule mandates how public utility transmission providers must plan for and allocate the costs of new projects on a regional and inter-regional basis. Order 1000 builds upon Order 890, which required transmission planning based on open, transparent and coordinated processes.

The major components of Order 1000 include:

1. Regional transmission planning
2. Regional cost allocation
3. Elimination of the federal right of first refusal (ROFR)
4. Inter-regional planning coordination
5. Inter-regional cost allocation

Order 1000 seeks to ensure more efficient and cost-effective regional planning and interregional coordination

Schedule

MISO must file documentation with FERC stating how it does or will comply with the first three major components by October 11, 2012. A second filing covering the fourth and fifth components needs to be filed by April 11, 2013.

Guiding Principles

Order 1000 seeks to ensure more efficient and cost-effective regional planning and interregional coordination. It requires that public utility transmission providers participate in a regional transmission planning process to produce regional plans; that local and regional transmission planning processes consider state and federal public policy requirements; and that public utility transmission providers coordinate with neighboring regions to meet transmission needs in the most efficient and cost-effective way possible.

The order establishes cost allocation principles for new regional and interregional transmission facilities included in regional plans. The principles ensure that allocated costs are "roughly commensurate" with estimated benefits. Order 1000 allows different allocation methods for different types of transmission facilities. Additionally, it allows allocation of costs to a neighboring region only if the other region agrees.

Finally, to promote competition in regional transmission planning, Order 1000 requires the removal of a federal right of first refusal from FERC-approved tariffs and agreements for new transmission facilities.

Accomplishments

MISO's evaluation of its compliance with the requirements of FERC Order 1000 revealed that it's already compliant with many of the regional planning and cost allocation requirements. MISO currently produces the necessary regional, integrated transmission plan and considers state and local public policy requirements.

Removing the existing right of first refusal is a major change to the current transmission construction paradigm. It requires extensive analysis, and the compliance proposal will have to contain changes to both the MISO Tariff and the Transmission Owner's Agreement. MISO has held ROFR stakeholder workshops on at least a monthly basis throughout 2012 to work through the complexities of ROFR proposals.

Inter-regional planning and cost allocation also requires extensive collaboration but in this case with MISO neighboring planning entities like PJM, SPP and WAPA. MISO is participating in a series of joint workshops with these neighbors to craft agreements which may be used to meet the FERC April 11, 2013 filing deadline.

7.6 Generation Portfolio Analysis

MISO performed an assessment of generation required for the MISO footprint using the Electric Generation Expansion Analysis System (EGEAS). MISO ran the assessment, as of June 1, 2012, using assumed projected demand and energy for each company and common assumptions for resource forecasting. MISO developed models to identify least-cost generation portfolios needed to meet resource adequacy requirements of the system for each future scenario.

Results of the assessment for the Business as Usual future predict that 46,191 MW of additional capacity will need to be added to the MISO system between 2012 and 2027, while 12,668 MW of capacity is forecasted to retire. Additional capacity includes demand response, energy efficiency, natural gas combustion turbine, natural gas combined cycle, photovoltaic, wind and other (Figure 7.6-1). The modeled retirements are largely coal.

Between 2012 and 2027, 46,191 MW of additional capacity will need to be added to the MISO system, while 12,668 MW of capacity will retire

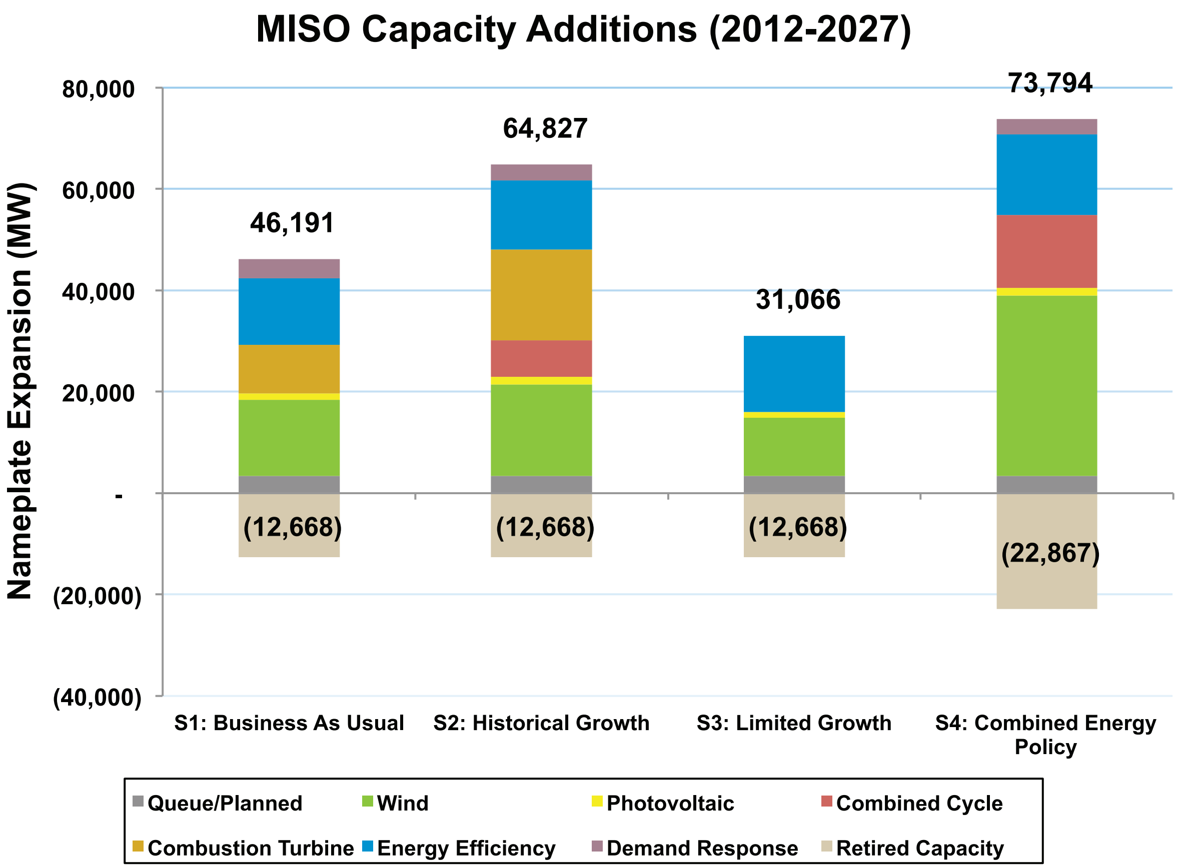


Figure 7.6-1: MISO modeled system aggregate nameplate installed MW (2012 - 2027 EGEAS model)

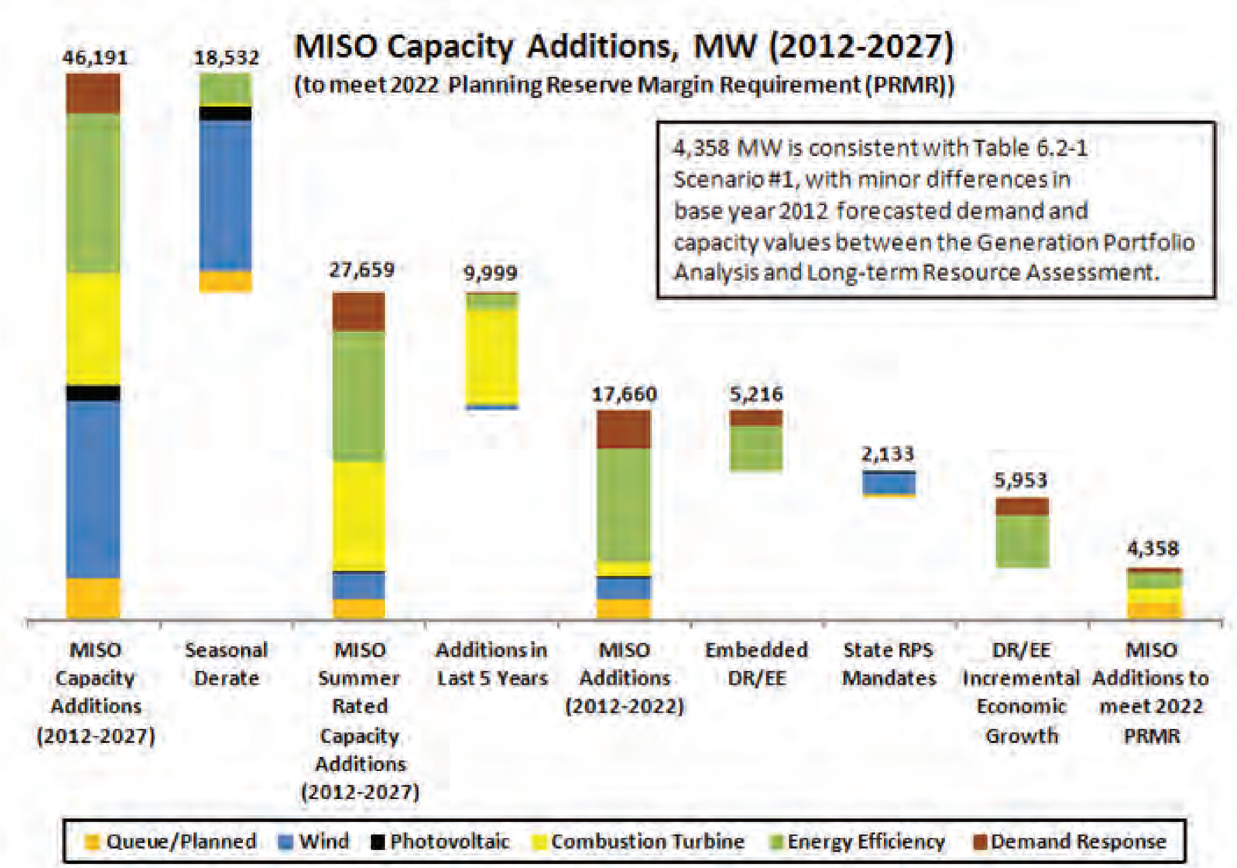


Figure 7.6-2: Business as Usual EGEAS capacity comparison to Chapter 6.2 Long-term Resource Assessment Scenario No. 1

Figure 7.6-2 compares the EGEAS capacity additions to those shown in the Long-term Resource Assessment in Chapter 6. It is worth noting that EGEAS capacity values are typically shown as nameplate capacity, whereas actual reserve capacity values are shown whenever discussing resource adequacy. Adjusting the 15-year EGEAS capacity additions (46,191 MW) for seasonal derates, additions in years 2023-2027, embedded DSM, RPS mandated additions and economic DSM selections, results in a 10-year capacity value, 4,358 MW, which is consistent with Table 6.2-1 Scenario No. 1.

Future Scenario Definitions

Scenario-based analysis provides the opportunity to develop plans for the future. 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 generation expansion plan, or generation portfolio. These portfolios identify the least-cost generation required to meet reliability criteria based on the assumptions in the following MTEP12 futures:

1. Business as Usual (BAU)

2. Historical Growth

3. Limited Growth

4. Combined Policy

A more detailed discussion of the assumptions and methodology around these scenarios is presented later in this chapter and in Appendix E2.

Figure 7.6-1 represents aggregated capacity expansions for each defined future scenario through the 2027 PROMOD study year. The capacity added is required to maintain stated reliability targets for each region. These reliability targets for MISO are defined in the Module E Resource Adequacy Assessment.

MISO continually strives to ensure that the scenario-based analysis encompasses as wide of a range of potential future outcomes as possible. A key part of this involves frequent evaluation of changes to public policy. In previous MTEP cycles, two public policy drivers for scenario development were: potential carbon legislation, in the form of the Waxman-Markey bill and renewable portfolio standards (RPS). While state-level RPS's are still very active, focus on carbon legislation has shifted to recent rules and regulations either proposed or enacted by the U.S. Environmental Protection Agency (EPA).

In light of these recent rules, MISO performed an EPA Impact Analysis to determine potential impacts to the coal fleet within the system. 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 scenario-based analysis, MISO analysts, in conjunction with the Planning Advisory Committee (PAC), chose to model the 12.6 GW level of retirements in each of the three Business as Usual scenarios and 23 GW of retirements in the Combined Policy scenario. The actual retirements modeled within the MTEP scenarios were based solely on projected costs to comply with EPA regulations and size of the coal unit, not from the generation units identified in MISO's EPA Impact Analysis study. Much of the retired base load generation capacity will be replaced with natural gas-fueled generation and energy efficiency programs in the EGEAS analysis (Figure 7.6-1).

> Much of the retired base load generation capacity will be replaced with natural gas-fueled generation and energy efficiency programs in the EGEAS analysis

Much of the renewable energy additions are state mandated. An abundance of existing thermal capacity reduces the amount of thermal additions in the capacity expansion models. A large portion of capacity needs are also being met through demand response and energy efficiency programs, which were allowed to compete against traditional supply-side resources in the EGEAS program for the first time in MTEP11. Prior to MTEP11, energy efficiency was modeled as a reduction of overall load growth. The Global Energy Partners study conducted for MISO in 2010 provided the demand response and energy efficiency estimates. Using these estimates, MISO was able to model energy efficiency independently to determine the level of economically driven capacity additions.

> A large portion of capacity needs are also being met through demand response and energy efficiency programs, which were allowed to compete against traditional supply-side resources in the EGEAS program for the first time in MTEP11

Production and Capital Costs

EGEAS capacity expansion data provides the present value of production and capital costs for the study period through 2027 (Figure 7.6-2). Since EGEAS does not model transmission, it is important to note that these numbers should not be taken at face value, but more to demonstrate the scenarios in which higher or lower costs could be incurred when compared to a Business as Usual-type scenario. Production costs include fuel, variable and fixed operation 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, which drive the future capacity expansion capital investments and total production costs.

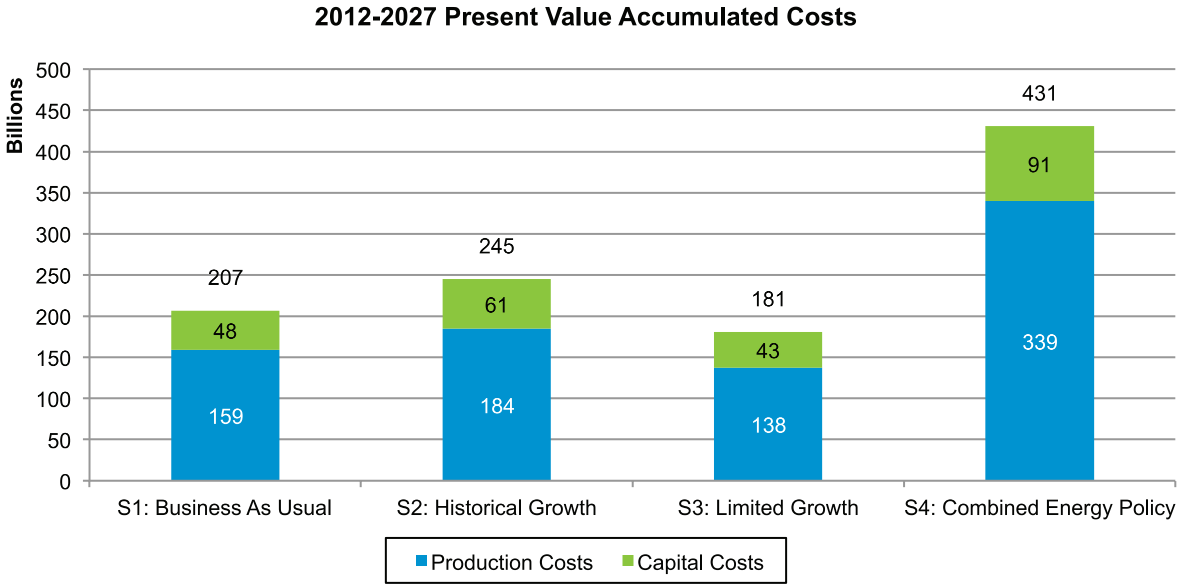


Figure 7.6-2: MISO present value of cumulative costs in 2012 U.S. dollars

Carbon Dioxide Impacts

Each of the future scenarios has a different impact on carbon dioxide output (Figure 7.6-3). These output values for 2031 for the different capacity expansion future scenarios can be compared from the 2005 CO_2 output (Figure 7.6-3).

For all futures, total CO_2 emissions decline between 2005 and 2031. When compared to the MTEP11 analysis, the historical growth scenario shows reduced CO_2 levels, which is a direct reflection of the level of coal unit retirements being modeled in MTEP12. On the other hand, the MTEP12 Combined Policy scenario shows higher CO_2 levels, when compared to MTEP11 analysis of the same future, because a carbon cap is no longer modeled in MTEP12.

For all futures, total CO_2 emissions decline between 2005 and 2031

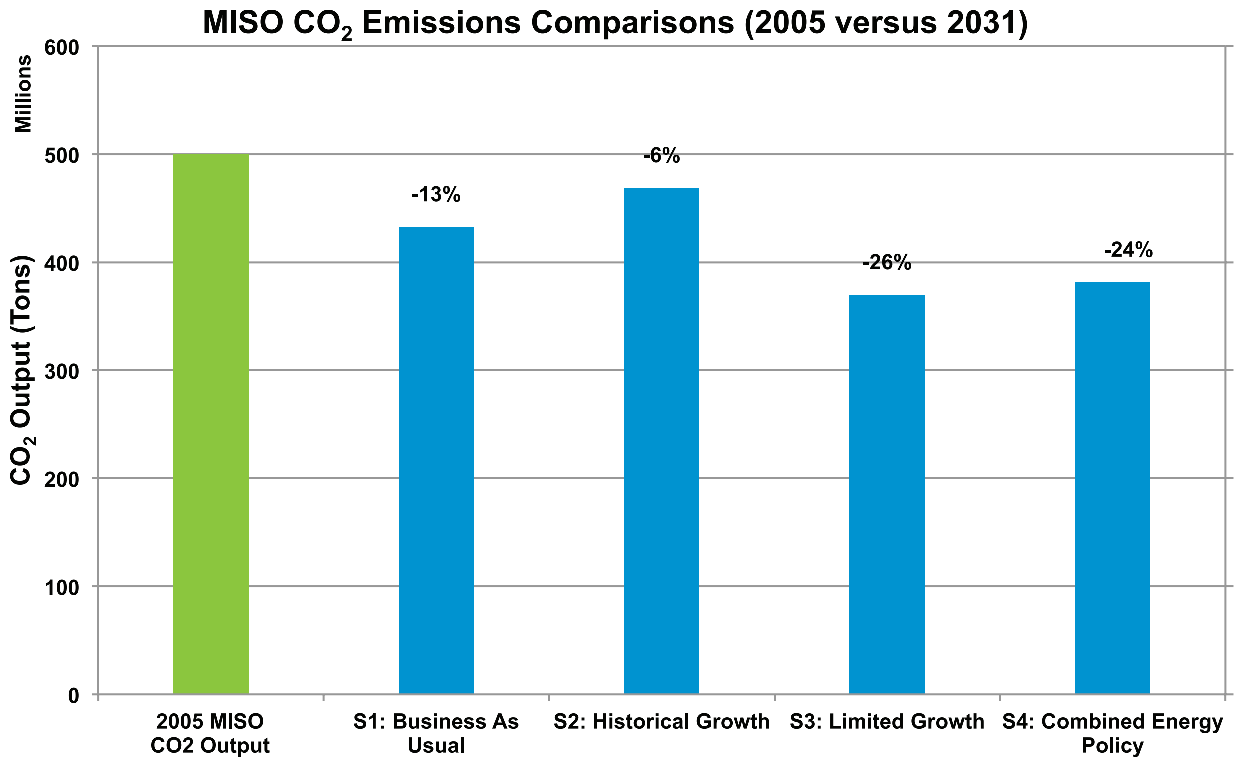


Figure 7.6-3: MISO carbon dioxide production

Continued demand and energy growth at levels close to historic trends, coupled with large amounts of retirements, will result in the need for additional generating capacity. The combination of coal unit retirements and increased penetration of renewable resources and energy efficiency has the potential to reduce carbon dioxide emissions.

Siting Of Capacity

Generation resources forecasted from the expansion model (EGEAS) are specified by fuel type and timing, but these resources are not site-specific. Completing the process requires a siting methodology tying each resource to a specific bus in the powerflow model. A guiding philosophy and methodology, in conjunction with industry expertise, was used to site forecasted generation. Figure 7.6-4 depicts capacity siting associated with the Historical Growth scenario. Likewise, Figure 7.6-5 shows the associated demand response siting for the Historical Growth scenario. The siting methodology used for this and the other future scenarios is explained further in Appendix E2.

> The combination of coal unit retirements and increased penetrations of renewable resources and energy efficiency has the potential to result in a system reduction in carbon dioxide emissions

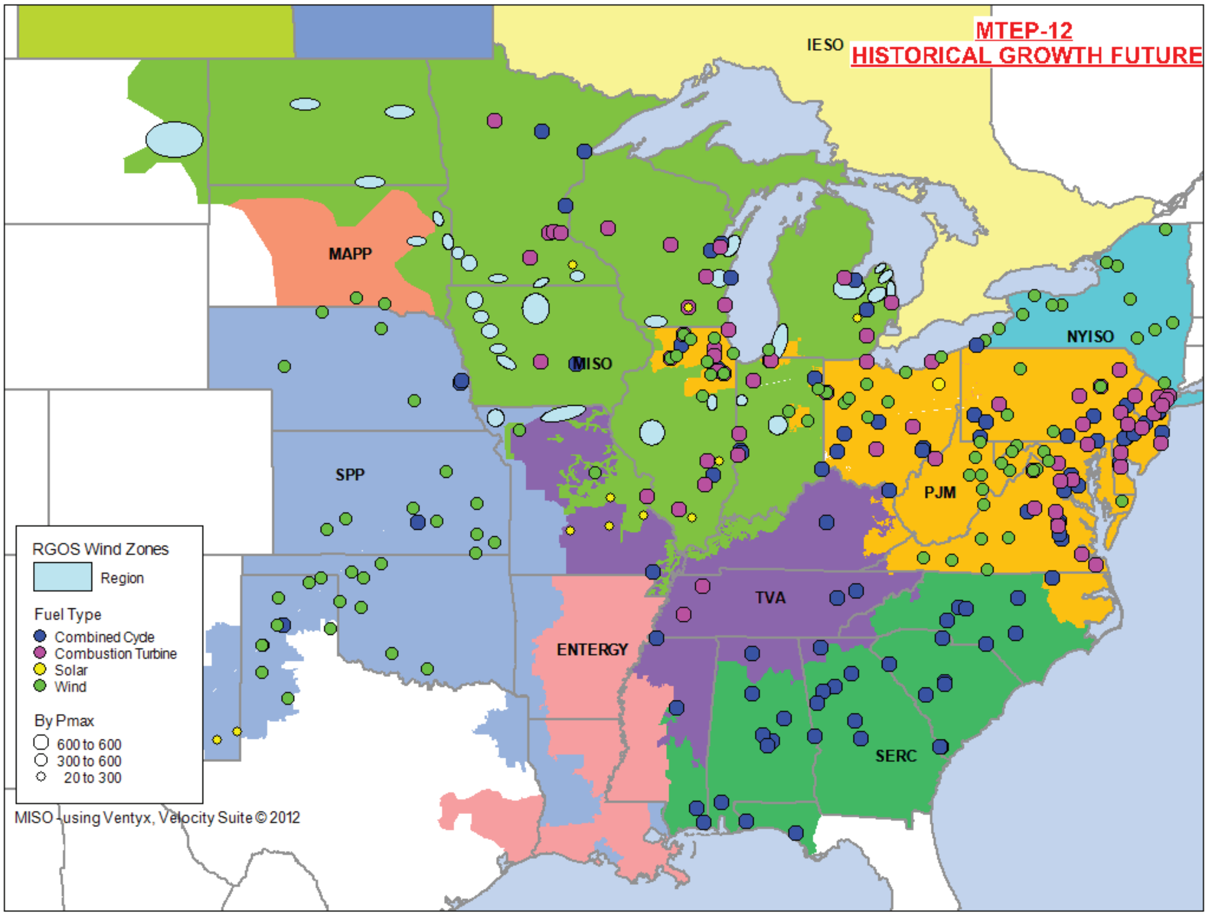


Figure 7.6-4: Future capacity sites for MISO Historical Growth scenario[29]

[29] The light blue ovals represent wind zones identified during the Regional Generation Outlet Study (RGOS)

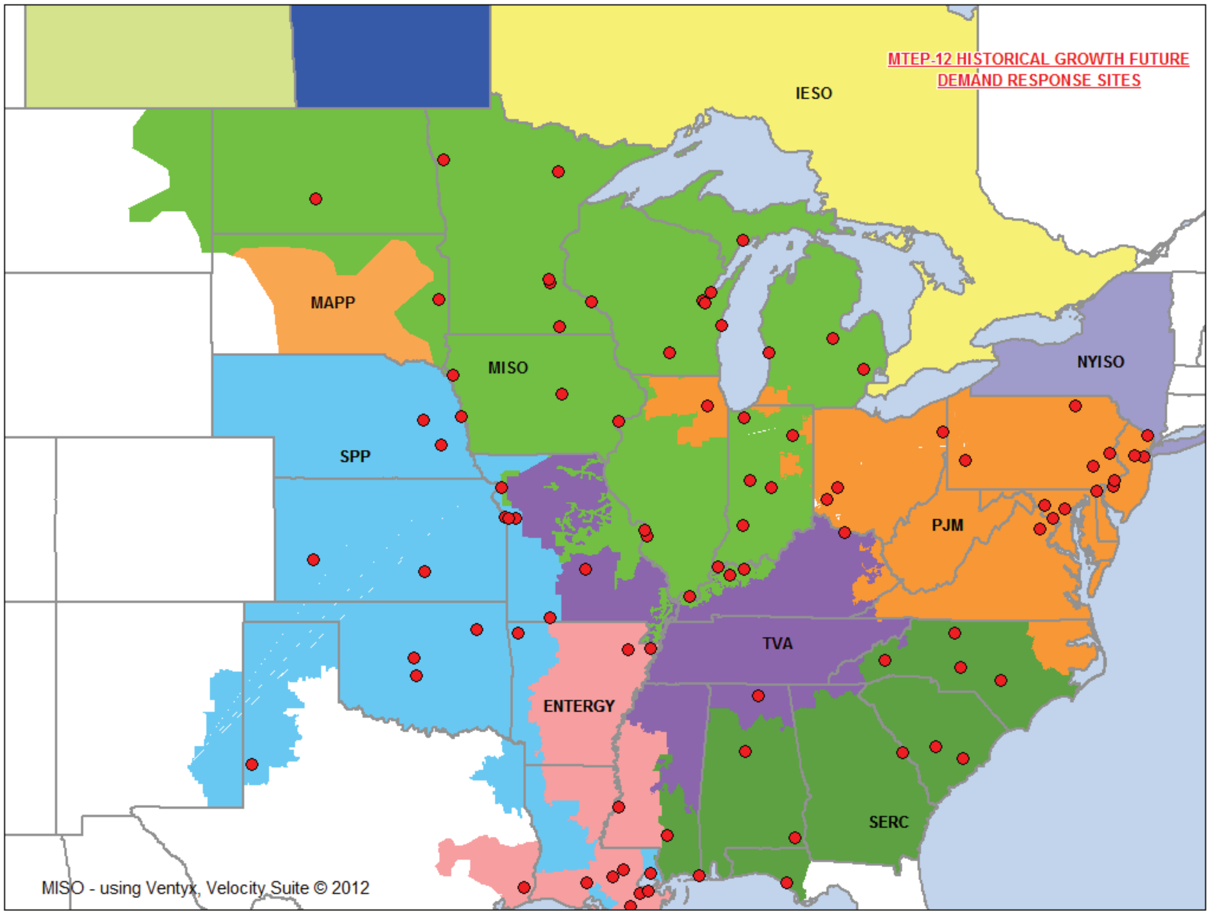


Figure 7.6-5: Future demand response sites for MISO Historical Growth scenario

Generation Futures Development

A planning horizon of at least 15 years is needed to accomplish long-range economic transmission development, since large projects take an average of 10 years to complete. Performing a credible economic assessment over this time is challenging. It requires long-range resource forecasting, powerflow and security constrained economic dispatch models that extend out at least 15 years. Since no single model can perform all of the functions for integrated transmission development, a value-based planning process was developed that integrates the best models available.

The following broad steps outline the value-based planning process MISO has been implementing. It starts with the analysis of value drivers and ends with a reliability assessment to meet both economic and reliability needs. A detailed description of MISO's 7 step value-based planning process is in MTEP10, Chapter 4.4.

Step 1: Create a regional generation resource forecast.

Step 2: Site the new generation resources into the powerflow and economic models for each future scenario.

Step 3: Design preliminary transmission plans for each future scenario, if needed.

Step 4: Test for robustness.

Step 5: Perform reliability assessment, consolidate and sequence.

Step 6: Final design of integrated plan.

Step 7: Cost allocation.

MISO's planning approach continues to evolve. One focus of the MTEP12 planning effort is to refresh a set of available future scenarios that capture potential energy policy outcomes.

In recognition of the uncertainty around energy policies and availability of associated resources in the 15-to-20 year time frame, a multi-dimensional regional resource forecast is required to identify what is necessary to supplement generation interconnection queue capacity. The regional resource forecast model determines, on a consistent least-cost basis, the type and timing of new generation and energy efficiency needs. It is driven by energy policies and other long-term integrated resource plan generation not reflected in the current queue.

With the increasingly interconnected nature of organizations and federal interests, forecasting greatly enhances the planning process for electricity infrastructure. The futures analysis provides information on the cost and effects of environmental legislation, wind development, demand-side management programs, legislative actions or inactions and many other potential scenarios which can be postulated and performed.

Future scenarios and assumptions for the models for Steps 1 and 2 were developed with stakeholder involvement. The MISO Planning Advisory Committee (PAC) provided the opportunity for stakeholder input necessary to comply with FERC Order 890 planning protocols. Scenarios were developed and subsequently refreshed to reflect shifts in energy policies over the last few years, in coordination with the PAC committee, through efforts in MTEP09, MTEP10, MTEP11, the Joint Coordinated System Planning Study and the Eastern Wind Integration and Transmission Study.

MISO consulted with Global Energy Partners LLC (Global) in 2010 to evaluate the demand response (DR) and energy efficiency (EE) potential in the MISO footprint. This effort developed a 20-year forecast for the MISO region and the rest of the Eastern Interconnection. This study demonstrated the modeling capabilities of DSM programs in the Electric Power Research Institute's (EPRI) EGEAS, the regional resource forecasting software tool used to assist in long term resource planning as part of Step 1 of the MTEP seven-step process.

The study found DR and EE programs could significantly reduce the load growth and future generation needs of the system. For MTEP11, Global provided DR and EE estimates for EGEAS to perform regional resource forecasting. An associated siting methodology for chosen demand response programs was also developed to facilitate business case development of proposed transmission plans. See the links below for more complete study results:

Volume 1: https://www.misoenergy.org/_layouts/MISO/ECM/Redirect.aspx?ID=78818
Volume 2: https://www.misoenergy.org/_layouts/MISO/ECM/Redirect.aspx?ID=78819

The assumptions for the models and the results presented in this document reflect the prices and policies as of the publication date of the Global Energy Partners report. MISO recognizes changes have occurred in many of these assumptions and is working towards updating this information through Module E Capacity Tracking (MECT) tool enhancements.

Read a full discussion of the assumptions and results of Steps 1 and 2 of the economic analysis process in Appendix E2.

The following describes the various future scenarios in greater detail:

- The **Business as Usual** 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. This future includes 12.6 GW of coal retirements, with the smallest and least efficient coal units retired.

- The **Historical Growth** future scenario is considered a status quo scenario, with a quick recovery from the economic downturn in demand and energy projections. This scenario models the power system as it exists today with reference values and trends—with the exception of demand and energy growth rates—and is based on recent historical data prior to the economic downturn. This scenario assumes existing standards for resource adequacy, renewable mandates and environmental legislation will remain unchanged. RPS requirements vary by state and have many potential renewable resources that can apply. This future includes 12.6 GW of coal retirements, with the smallest and least efficient coal units retired.

- The **Limited Growth** future scenario is considered a status quo scenario, with little to no recovery from the economic downturn in demand and energy projections. The demand and energy growth rates are modeled as one-half of the rates used in the BAU scenario. The limited growth scenario assumes existing standards for resource adequacy, renewable mandates and environmental legislation remain unchanged. RPS requirements vary by state, and have many potential resources that can apply. This future includes 12.6 GW of coal retirements, with the smallest and least efficient coal units retired.

- The **Combined Policy** future scenario was developed to capture the effects of multiple future policy scenarios into one future. This scenario includes a federal RPS, smart grid and electric vehicles. The federal RPS assumes all states are required to meet a 20 percent federal RPS mandate by 2025. This future includes 23 GW of coal retirements, with the smallest and least efficient coal units retired. Smart grid is modeled by reducing the demand growth rate, assuming that a higher penetration of smart grid will lower the overall growth of demand. Electric vehicles are modeled by increasing the energy growth rate. They are assumed to increase off-peak energy usage and increase the overall energy growth rate.

Each future has a unique set of input assumptions driven by a range of policy decisions. With extensive stakeholder involvement under the Planning Advisory Committee, a consensus has been reached with respect to the methodology for determining baseline demand and energy growth rates for each of the MTEP12 futures. The demand and energy growth rates were then adjusted to reflect the economically chosen demand side management (DSM) programs from the EGEAS capacity expansion analyses, which offer Global Energy study estimated DSM projections as demand side resource options for each scenario. The resulting effective demand and energy growth rates for the four MTEP12 futures are tabulated in Table 7.6-1.

Future scenarios	MISO Incremental Wind Penetration (GW)	Effective Demand Growth Rate	Effective Energy Growth Rate	Natural Gas Price	Retirements (GW)
Business as Usual	17	0.67%	1.12%	$4.25	12.6
Historical Growth	21	1.43%	2%	$4.25	12.6
Limited Growth	13	-0.25%	0.11%	$4.25	12.6
Combined Policy	40	0.5%	1.9%	$8.00	23

Table 7.6-1: Future scenario input assumptions

7.7 Smart Grid Implementation

As part of the American Recovery and Reinvestment Act of 2009 (ARRA), the U.S. Department of Energy (DOE) announced competitive funding under the Smart Grid Investment Grant program (SGIG) to help expedite the modernization of the nation's electric and transmission systems and the development of a nationwide "smart" electric power grid.

In response to this opportunity, MISO submitted a SGIG application, Synchrophasor Deployment Proposal for MISO, on August 6, 2009. The application proposed approximately 150 phasor measurement unit (PMU) deployments at a cost of approximately $34.5 million. The application was accepted by the DOE in October and the capital project was approved by MISO in early 2010. The current plan is to install 261 PMUs throughout the MISO footprint.

Synchrophasors

PMUs, more commonly called synchrophasors, are precise grid monitors. When strategically located throughout the powergrid, synchrophasors provide more visibility of system performance through real-time monitoring of phase angles across stressed transmission lines as well as power angle and frequency oscillations. More accurate measurements of these parameters on a real-time basis help operators take corrective actions to prevent potential cascades or instability.

PMU measurements are taken at high speed (typically 30 observations per second – compared to one every 2 to 4 seconds using most current technology). Each measurement is time-stamped according to a common time reference (a GPS clock). Time stamping allows measurements from different PMUs to be time-aligned (or "synchronized") and combined together providing a precise and comprehensive view of the entire interconnection including the dynamics of the system (Figure 7.7-1). It is this synchronizing capability that gives PMUs its "synchro" phasor name.

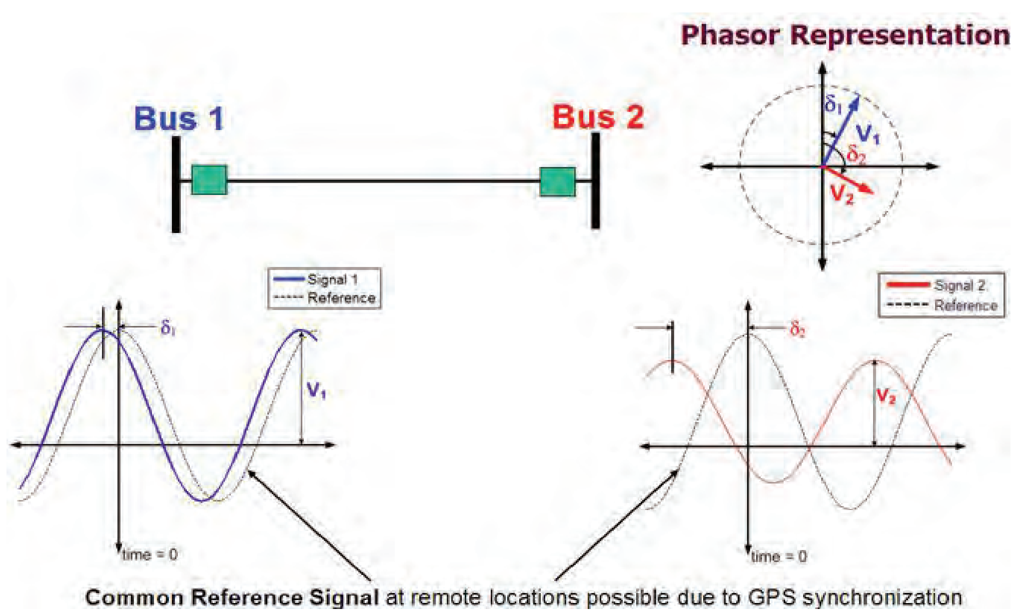


Figure 7.7-1: Time synchronization of synchrophasors

The "synchro" in synchrophasor comes from time synchronization characteristic. A GPS system provides a common time reference. The GPS system, also called NAVSTAR, includes 24 satellites, each with three or four onboard atomic clocks. The U.S. Naval Observatory monitors the satellite's clocks and sends control signals to minimize the differences between their atomic clocks and a master atomic clock for accuracy, which is traceable to national and international standards.

MISO Synchrophasor Project Plan

The scope of the MISO Project Plan includes:

- Installation, testing, integration and monitoring of approximately 261 PMUs and corresponding phasor data condensers (PDCs) at strategic locations across the MISO footprint
- Installation, testing, integration and monitoring of local and regional PDC capabilities and related technologies (e.g., visualization tools) centrally located at MISO
- Research on collected phasor data completed by two leading academic institutions

MISO and many of the transmission owners in the MISO footprint have formed an alliance called the MISO Synchrophasor Consortium to support the goals of the ARRA and to promote investments in smart grid technologies, tools and techniques. The Consortium will install, test, integrate and monitor PMUs and PDCs within strategic locations throughout the MISO footprint, per the project scope and requirements. PMU data feeds to the local PDC and then to a regional PDC (Figure 7.7-2).

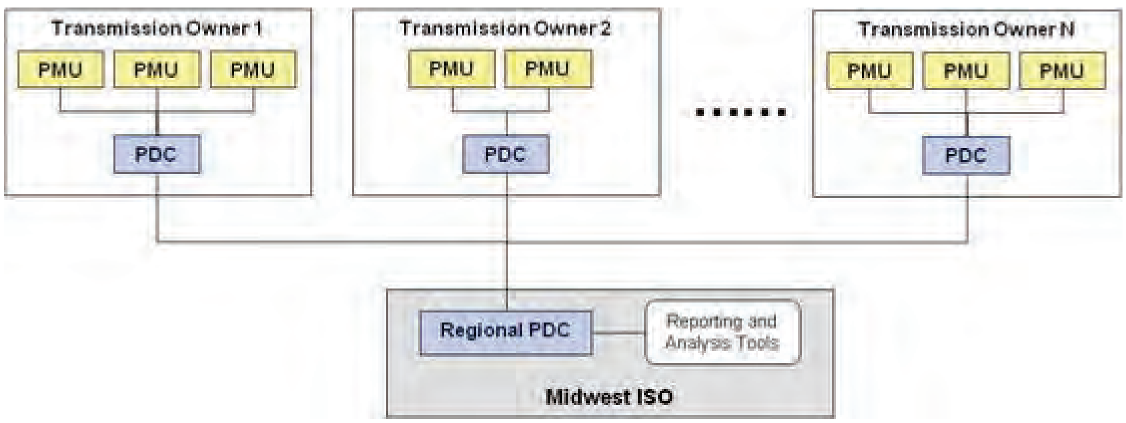


Figure 7.7-2: High-level PMU/PDC framework

The MISO synchrophasor network will consist of PMUs strategically dispersed at transmission owner (TO) locations within the MISO footprint. These will provide high periodicity data measurements to improve the monitoring of the transmission grid and determination of the health of the system; PDCs to collect the information; and a dedicated, regional PDC located at MISO to serve as the central control and collection point- feeding analytical, visualization and reporting tools. The regional PDC will support the inter-Regional Transmission Organization (RTO) data exchange requirements.

As of July 2012, 201 PMUs are installed or planned for the MISO footprint at various voltage levels spanning from 69 kV to 345 kV (Table 7.7-1). MISO also identified 60 additional candidate PMU sites in 10 states (Table 7.7-2).

State	Total PMU
Total	201
Indiana	42
Minnesota	37
Manitoba	28
Illinois	21
Michigan	12
Missouri	15
Iowa	16
North Dakota	12
Ohio	8
Montana	2
South Dakota	6

Table 7.7-1: PMU distribution, planned and installed

State	Total PMU
Total	60
Wisconsin	13
Indiana	13
Minnesota	6
Illinois	7
Michigan	8
Missouri	4
Iowa	4
North Dakota	3
Ohio	1
South Dakota	1

Table 7.7-2: Candidates for PMU installation

The project will also allow the Consortium to evaluate the impact of PMUs to utilize accurate time reference to calculate relative phase angles and other measurements of grid parameters such as frequencies and line flow on the MISO system. Phasor measurements produced by PMUs are the heart of a network-based, wide-area measurement system that provides data to run analytical applications that provide real-time information and visualization on the status of the grid.

The North American Synchrophasor Initiative (NASPI), a collaborative effort by energy regulatory bodies and the electric industry, has been established to help accelerate adoption and use of phasor technology for grid reliability. NASPI plans to oversee the installation of a set of integrated regional PDCs across the U.S. The Consortium envisions the MISO regional PDC as part of an important component of this set.

Given the geographic and technological diversity of this project and the relative scale, the results of the project will provide a model that can be readily adapted and replicated across the other regional transmission footprints.

The project contributes to furthering the development of smart grid functions by deploying technology that will provide precise measurements of the electricity grid parameters significantly faster and more effectively than conventional monitoring technologies. Combined PMU measurements will provide a precise, comprehensive view of an entire interconnection and enable advanced monitoring and analysis to identify changes in grid conditions, including the amount and nature of stress on the system.

PMU data will feed applications that allow grid operators to understand real-time grid conditions; see early evidence of changing conditions and emerging grid problems; and better diagnose, implement and evaluate remedial actions to protect system reliability.

Real-Time System Monitoring

Voltage Angles

For a DC system, power flows from a point of high voltage to a point of low voltage. Similarly, for an AC system, power flows from a point of high voltage angle to a low voltage angle. The higher the angle difference between two locations, the greater the powerflow. Thus, an accurate real-time measure of angle differences between two ends of major bulk electric system lines provides a gauge for the system's stress level and, as a worst case, if there is a potential for system separation of thermal cascade. Such stressed conditions occur when other parallel-path transmission lines are removed from service resulting in increased flow driven by loss of generation source in a load pocket area. With more informed knowledge of the stress on transmission paths, operators can take remediation measures such as to re-dispatch generation to offload these heavily loaded transmission lines. MISO is developing tools to display these voltage angles in the operating room.

Oscillation Monitoring

MISO is developing tools to monitor oscillatory behavior within the system.

Poorly damped or negatively damped oscillations in the power system pose a severe risk to generators (Figure 7.7-3). Generator protection systems are designed to detect such oscillations and trip. These generator trips could then pose a system wide risk to reliability. Real-time monitoring of system oscillation damping helps identify the critical low-damped frequency modes. Offline tests can determine which transmission and generation outages could aggravate these modes enough to cause potential cascades. By being able to increase damping through generation re-dispatch, real time operations can avoid potential cascades. Offline detailed studies can also help identify generators where power system stabilizers, if tuned correctly, would be most effective.

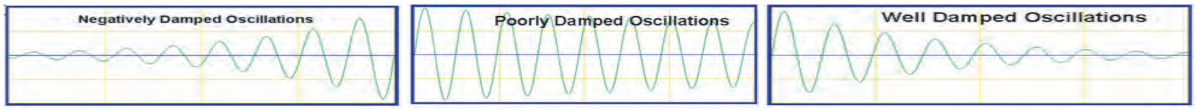


Figure 7.7-3: Oscillation behavior

After the Fact: Event Analysis

Thresholds have been set for triggering internal MISO offline event analysis studies (Figure 7.7-4). In general, large heavily loaded transmission lines and large unit trips are going to be studied. Depending on the type of event, thermal, angular, voltage or transient stability studies would be performed.

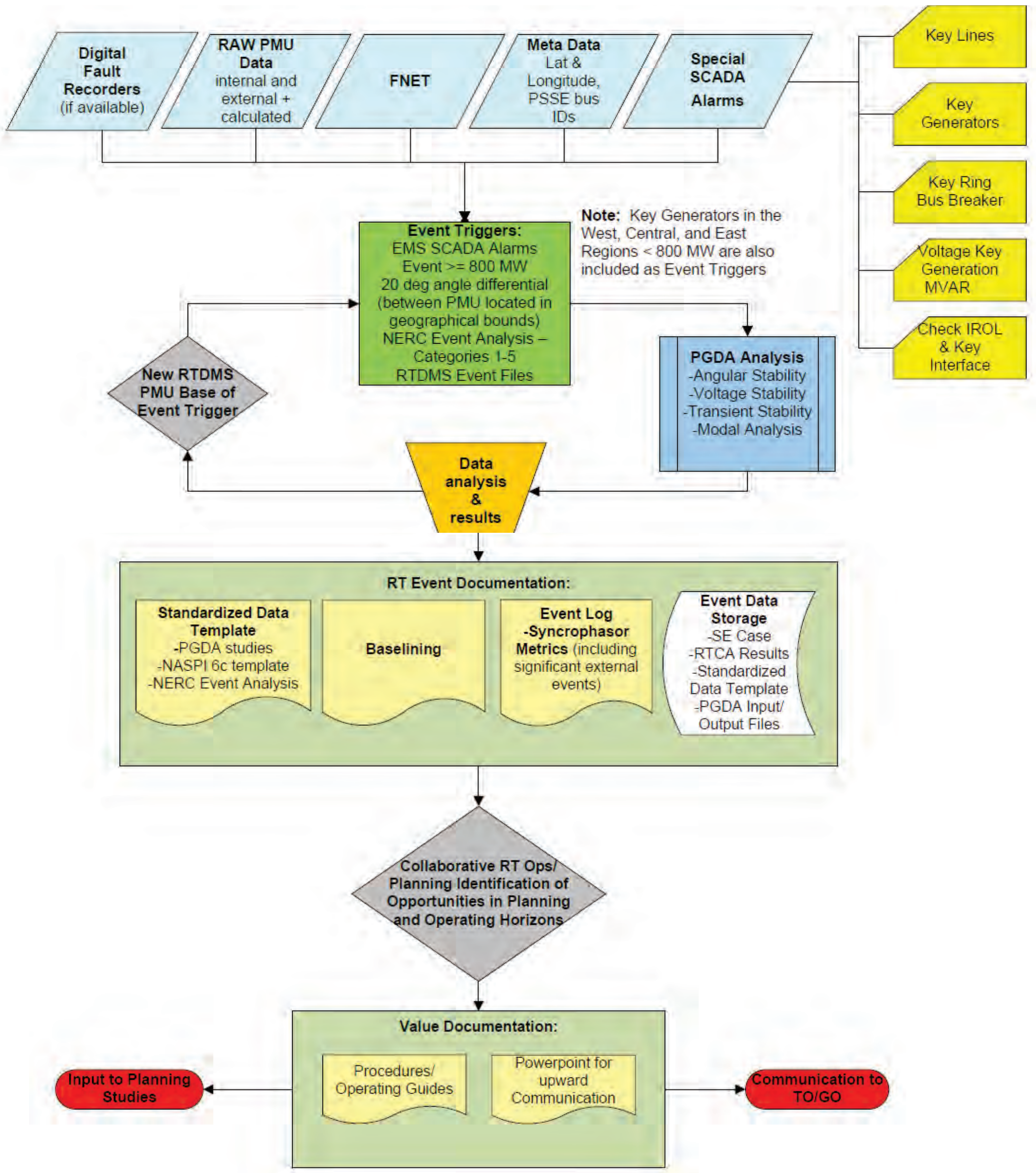


Figure 7.7-4: Event analysis process

This root-cause analysis is anticipated to not only inform real-time operations to potentially develop new operating guides, but also serves as the critical front-end input to off-line simulation model validation.

Planning and Real-Time Model Validation

As part of the overall effort to build better offline models for use in real time and planning studies, MISO is undertaking an effort to develop tools to help align PMU measurement data with simulation performance for associated real time events. It anticipated that MTEP13 transient stability studies would be better benchmarked against real-time system performance through use of the model validation tool. MISO planning has developed a tool to help overlay simulation performance over PMU measurements. Planning has further made modeling recommendations for a few select events.

These modeling recommendations are in the form of generator and turbine dynamic modeling parameter changes. Going forward, MISO has entered into a contract with the University of South Florida to develop an automated process of making modeling improvements on an ongoing basis. Over time, with more measurements received following real time events, planning and real time offline models will become a closer representation to real-time measurements taken from the system.

7.8 Coordinated Studies – Joint Future with Southwest PowerPool

Joint studies are conducted once every three years as part of the Joint Operating Agreement (JOA) between MISO and the Southwest Power Pool (SPP). A systematic joint study provides a common platform for each RTO's stakeholders to perform economic evaluation of potential cross-border economic transmission plans using a commonly developed model. Given the highly interconnected nature of the two regions, development of a joint and common model helps provide a bridge between the transmission planning processes of each system. The model development also helps maintain an ongoing, working relationship between the two RTOs, meets requirements of the current FERC Order 890 and begins the coordination efforts for cross-border compliance issues with FERC Order 1000.

Given the highly interconnected nature of the two regions, development of a joint and common model helps provide a bridge between the transmission planning processes of each system

The MISO/SPP Joint Future was patterned after the MTEP12 Business as Usual future, but with some variation (Table 7.8-1). While the starting natural gas price is lower in the joint future, it escalates at a higher rate and surpasses the BAU natural gas price in the 2014-15 timeframe. Modeling state mandated Renewable Portfolio Standards (RPS) in MISO results in approximately 14 percent of energy generated in 2025 coming from renewables. Modeling both state mandates and goals results in greater than 15 percent of energy generated in 2025 coming from renewables.

Assumption	MTEP12 Business as Usual	MISO/SPP Joint Future
Henry Hub Natural Gas Price ($/MMBtu)	$4.25	$3.52
Renewable Portfolio Standards	State Mandates only	State Mandates and Goals
Study Areas	MISO & Entergy as separate regions	MISO & Entergy modeled as one region
Fuel Escalations/Inflation Rate	1.74%	2.5%
Demand Side Management Programs	Global Energy Partner's estimates modeled	Effective growth rates from MTEP12 BAU scenario modeled

Table 7.8-1: MISO BAU versus MISO/SPP Joint Futures

Model development is based upon assumptions voted on by both MISO's Planning Advisory Committee (PAC) and SPP's Economic Studies Working Group (ESWG). It is ongoing and is expected to be made available for the MTEP13 planning cycle. A complete look at the assumptions being used in the MISO/SPP Joint Future can be found in the futures matrix in Appendix E2.

7.9 End-Use Load Characterization

The structure of electrical end user consumption, or load, is complex and constantly changing with time and over different geographic regions.

The MISO footprint has roughly equal percentages of industrial, commercial and residential loads

MISO relies on individual Load Serving Entities (utilities) to submit data to the MISO Module E Capacity Tracking (MECT) tool for all long-term load forecasting conducted in MTEP, including: Long Term Reliability Assessment, Seasonal Assessments, and Planning Reserve Margin. To perform load forecasting, utilities in the MISO footprint use one or more of the following methods:

- End-use models for the residential sector
- End-use or econometric models for the commercial sector
- Econometric models for the industrial sector
- Historically observed data for the remaining consumption, such as losses, street lighting, etc.

Wholesale loads may be accounted for separately. Some utilities use a combination or a hybrid approach.

The development of accurate information on the composition of load data on a continuous basis can be challenging. The Energy Information Administration (EIA) provides historical data on the amount of residential, commercial, industrial and transportation energy sales by state. The current MISO footprint has roughly equal percentages of industrial, commercial and residential loads from 2006 to 2010 (Figure 7.9-1), even though individual states may have somewhat different percentages by sector. The transportation sector's electricity energy usage is less than 0.2 percent for these years and not included in figure 7.9-1.

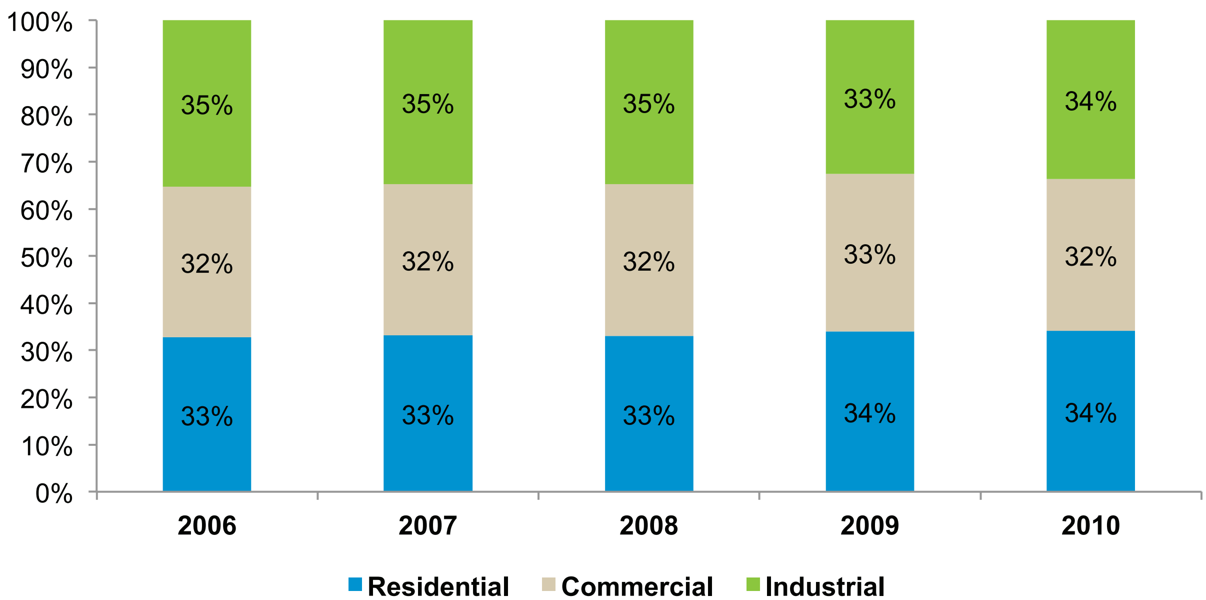


Figure 7.9-1: Historical energy breakdown by sector in the MISO footprint

Significant research (both within academia and the utility industry) to understand the end uses of load is becoming increasingly important to:

- Perform end-use load forecasting by load class
- Model load appropriately in the powerflow models for reliability studies (stability and dynamic)
- Develop the potential for demand response resources

Residential Sector Energy End Uses

Cooling, lighting, electronics, refrigeration and water heating are the main end uses in the residential sector – comprising almost 55 percent of total residential load

End uses in the residential sector are varied. Accounting for even the major end-use categories without metering and monitoring energy usage at the customer level would be both difficult and expensive. Therefore, EIA develops forecasts, by census division, for the residential energy sector based on end-use samples gathered for the entire U.S (Figure 7.9-2). The largest percentage, "electric other," includes a variety of electricity-operated items including dehumidifiers, ceiling fans and spas. The main end-uses in the residential sector are cooling, lighting, electronics, refrigeration and water heating – comprising almost 55 percent of total residential load. These top five uses are good candidates for energy efficiency improvements. All these classifications are based on total energy usage and not on their contribution to the system peak load.

MISO obtained this data for census divisions 3 and 4 (Midwest region) and calculated the percentage of energy usage by type in the residential sector for the MISO footprint. This data is the projected energy usage for 2012 developed using the National Energy Modeling System (NEMS) model. The results shown are indicative only and the percentages shown are the best available data for the MISO footprint.

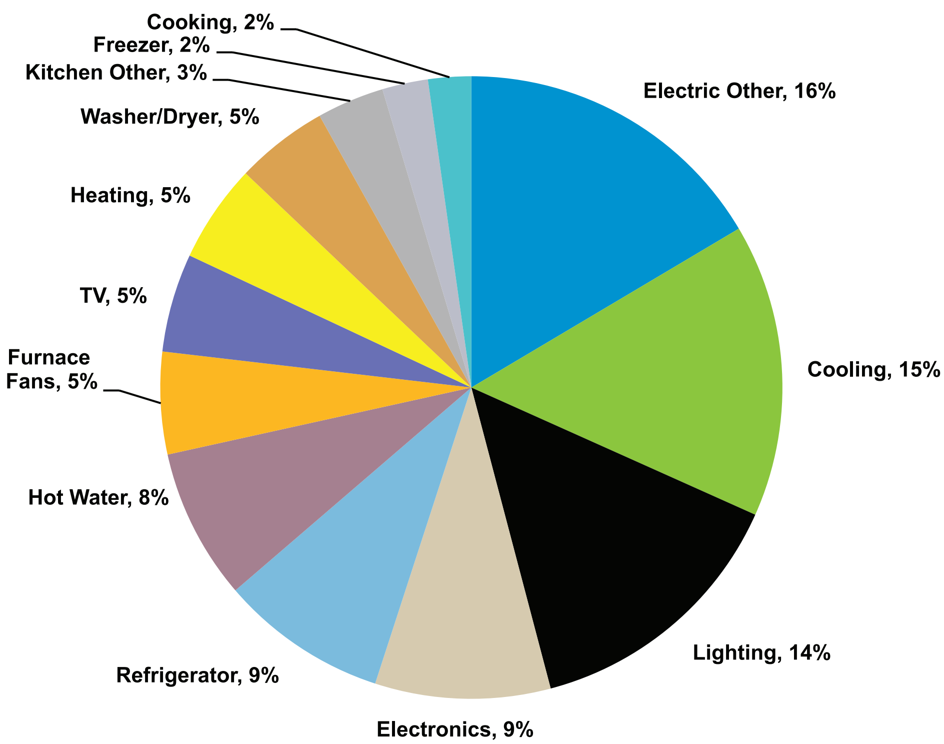


Figure 7.9-1: Percentage of anticipated residential sector energy use in 2012 for the MISO footprint

Commercial Sector Energy End Uses

Similar to the residential consumption data, EIA provided the commercial end use energy data for the Midwest region (Figure 7.9-3). HVAC (heating, ventilation and air-conditioning), and lighting comprise almost 54 percent of energy usage in the commercial sector. The results shown are indicative only and the percentages shown are the best available data for the MISO footprint. All these classifications are based on total energy usage and not on their contribution to the system peak load.

Heating, ventilation, air-conditioning and lighting comprise almost 54 percent of energy usage in the commercial sector

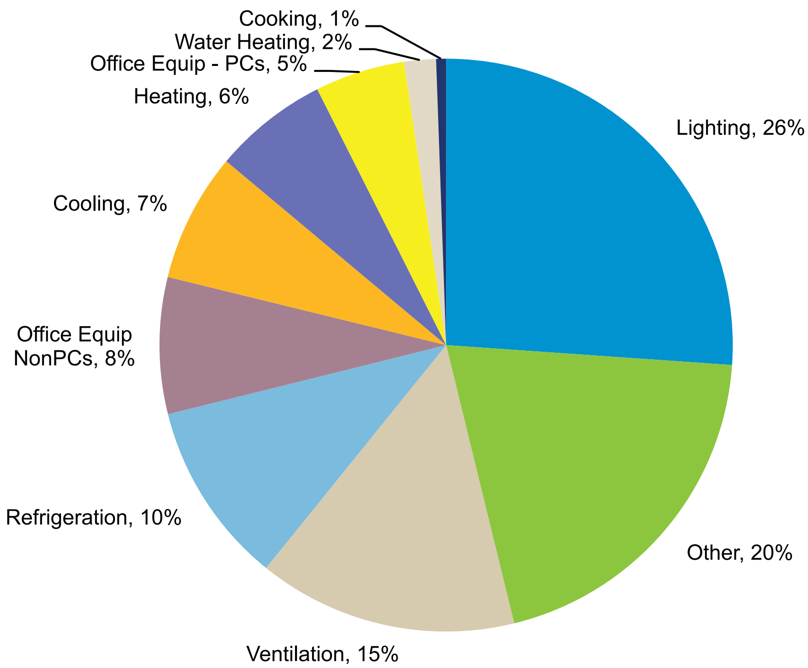


Figure 7.9-3: Percentage of anticipated commercial sector energy use in 2012 for the MISO footprint

Industrial/Other Sectors' Energy Uses

Econometric models are used for forecasting the energy usage in the industrial sector. MISO does not have detailed, publicly available end-use information for the industrial and wholesale sectors.

7.10 Energy Storage

MISO conducted an Energy Storage Study in 2011 to identify:

- The economic potential for bulk energy storage technologies within the MISO footprint
- The impacts of energy storage costs relative to existing supply-side alternatives
- The impact of varying levels of coal plant retirements on energy storage selection.

This study also aimed to show the effect of varying levels of natural gas prices, RPS mandates and carbon prices through sensitivity analysis.

The highest level of economically viable energy storage (19.4 GW) was in the scenario with the highest natural gas price ($12/MMBtu), highest coal retirements (12.6 GW), and lowest RPS

Results

The study found that energy storage was not economical in most study scenarios. In the scenarios where energy storage was seen as economical, Compressed Air Energy Storage (CAES) was the only type of storage chosen. CAES showed up as economically viable in 18 out of the 405 sensitivity runs completed, but only at assumption levels of $0/ton CO2 cost and $833/kW construction cost (Figure 7.10-1).

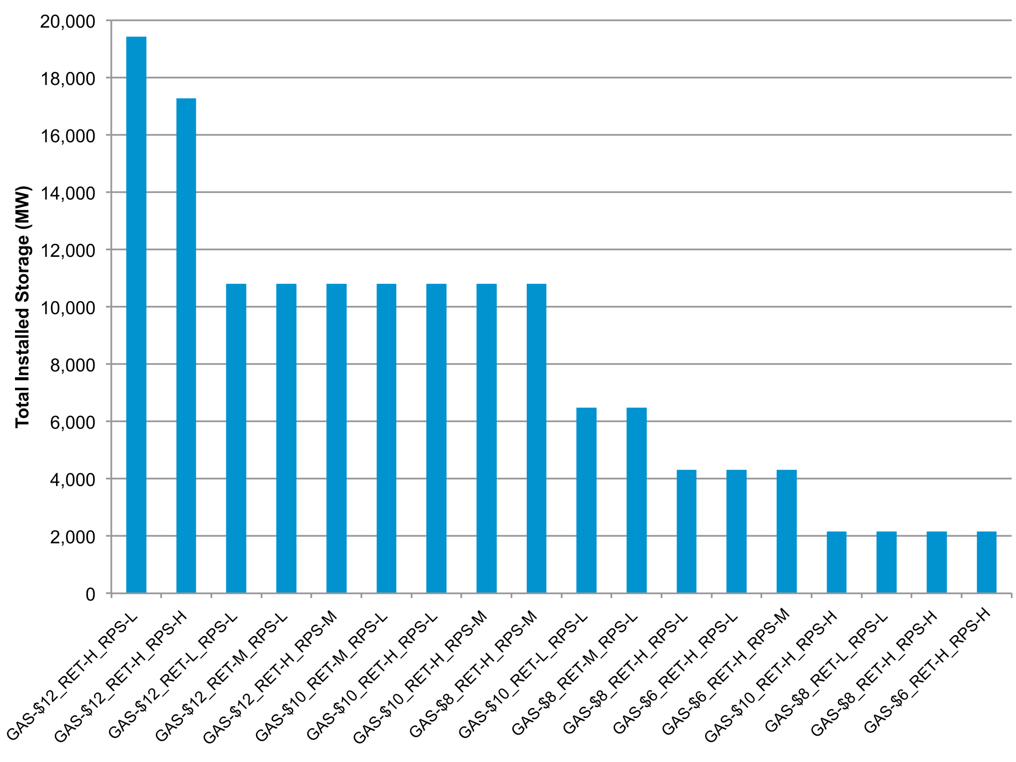


Figure 7.10-1: Scenarios where energy storage economically viable

The highest level of economically viable energy storage (19.4 GW) was in the case with the highest natural gas price ($12/MMBtu), highest coal retirements (12.6 GW), and lowest renewable portfolio standards (RPS) for state-mandated RPS only. While trends were difficult to identify in this small sampling of results, the biggest drivers for storage appeared to be natural gas prices, baseload coal retirement levels and RPS levels. A complete look at the energy storage report can be found on the Electric Power Research Institute website.

Energy Storage Context

Current state-legislated renewable portfolio standards (RPS) within the MISO footprint equate to an average requirement of approximately 14 percent of generated electricity by 2025 to come from renewable sources, primarily from wind. This could require adding 16 GW of wind to the existing 13 GW already in service or with signed interconnection agreements. As of January 2012, MISO had 10.5 GW of wind registered in the Commercial Model. The remaining 2 to 3 GW is due to wind in the queue with a signed generator interconnection agreement.

> To better understand the future role energy storage systems may play in dealing with variable generation complexities, MISO performed the Energy Storage Study

Typical wind patterns produce higher energy at times when electricity demand is low. Wind generation is also variable and has to be balanced with other resources in order to maintain system reliability. As significant amounts of variable generation resources are added to the transmission grid, the complexities associated with balancing generation and demand on the system increase.

Study Objectives

A fundamental goal of MISO's transmission planning process is the development of a comprehensive expansion plan that meets reliability needs, policy needs and economic needs. The planning incorporates new technologies, such as energy storage, into the resource expansions and studies its impact on the transmission system. In previous studies, Pumped Hydro Storage (PHS) was the sole storage alternative offered into MISO's capacity expansion models, as this was also the only active storage type that existed within the MISO footprint.[30] Recently, there has been increased activity on the storage front, from both a planning perspective and actual demonstration perspective, due mainly to the large increases in variable wind generation being added to the system. Many additional energy storage types have been identified, including Compressed-Air Energy Storage (CAES), batteries, flywheels, capacitors and hot water heaters. To better understand the future role energy storage systems may play in dealing with variable generation complexities, MISO performed the Energy Storage Study that focused on three of the larger-scale energy storage types: CAES, PHS and battery.

Sensitivity Analysis

There are many drivers that aid in determining the business case for energy storage. The energy storage study analyzed the impacts of five of these drivers: coal retirement level, RPS level, energy storage capital cost, carbon dioxide emissions cost and Henry Hub natural gas price. Natural gas prices have fluctuated from as low as $2/MMBtu to greater than $15/MMBtu in the last decade alone. Environmental Protection Agency rules have the potential to greatly alter the face of the baseload generation fleet in the U.S., as most units potentially affected by the proposed rules are coal powered. Energy storage capital costs are difficult to predict due to the fact that very few energy storage units have been constructed in the U.S. in recent decades and, in fact, only two CAES units exist in the world. There are five key sensitivities modeled in the energy storage study (Table 8.3-1).

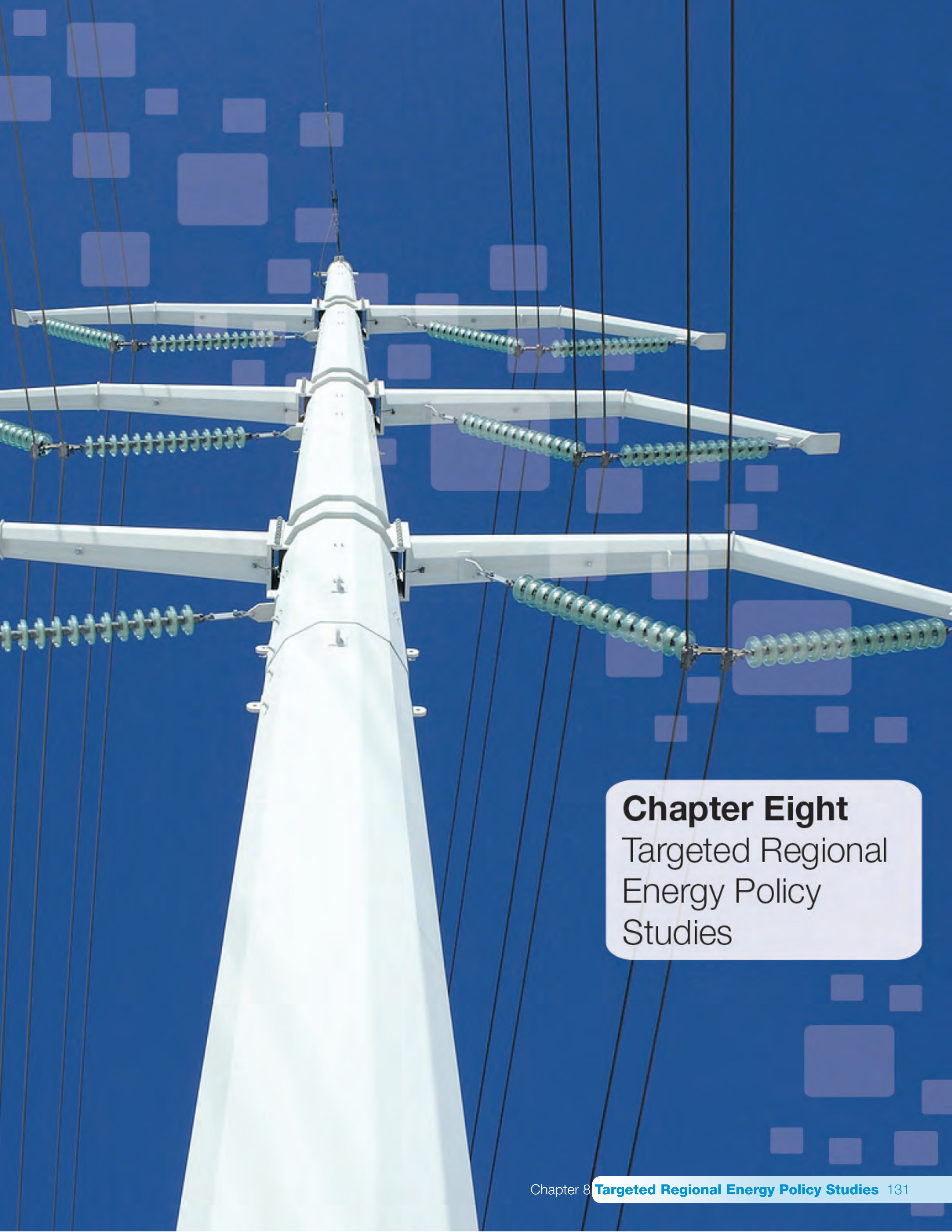
[30] See the Iowa Stored Energy Park (www.isepa.com) or the Xcel Energy Wind-To-Battery Project

Sensitivity	Low	--	Mid	--	High
Coal Retirement Level (MW)	Only publicly known retirements modeled		3,000		12,600
Renewable Portfolio Standard (% of energy generated by renewables)	State Mandates (13% by 2025)		20% by 2025		30% by 2030
CO_2 Price ($/ton)	$0		$50		$100
Energy Storage Capital Cost ($/kW)	Battery: $1,667 CAES: $833 PHS: $1,500		Battery: $2,500 CAES: $1,250 PHS: $2,250		Battery: $3,333 CAES: $1,667 PHS: $3,000
Henry Hub Natural Gas Price ($/MMBtu)	$4	$6	$8	$10	$12

Table 7.3-1: Sensitivies modeled in energy storage study

Given the high system reserve margin and relatively low load growth levels that were modeled in the study, new capacity (other than state-mandated wind and solar) doesn't appear in the baseline expansion results until nearly 10 years into the future. While much uncertainty remains around EPA regulations and their effect on potential coal unit retirements, current natural gas prices and forecasts indicate that Combustion Turbines (CTs) and Natural Gas Combined Cycle (NGCC) units would most likely fill any short-term voids created by such policies. Further analysis of the capacity expansion results highlighted conditions which could potentially lead to economic selection of energy storage units, particularly CAES. These include high levels of coal plant retirements, higher natural gas prices, and reduced construction costs of the energy storage units.

The full Economic Storage Phase I report is on the EPRI website at:
http://my.epri.com/portal/server.pt?Abstract_id=000000000001024489



Chapter Eight
Targeted Regional Energy Policy Studies

CHAPTER 8

Targeted Regional Energy Policy Studies

8.1 Northern Area Study Update

The Northern Area Study evaluates the reliability and economics of transmission and generation alternatives across the northern portion of the MISO footprint (Figure 8.1-1). As part of this study, MISO will produce a report documenting the results, findings, and recommendations. The final report may serve as an input to future analysis, possibly to inform future MTEP analyses. The designation of project type or cost allocation method are not in the scope of the Northern Area Study.

The Northern Area Study evaluates the reliability and economics of transmission and generation alternatives across the northern portion of the MISO footprint

Drivers of the Northern Area Study include:

- Potential additional generation imports from Manitoba Hydro
- Potential generation retirements related to new EPA requirements
- Reliability issues, due to multiple transmission proposals submitted by Transmission Owners
- Potential load growth in northern Minnesota, Wisconsin, and the Upper Peninsula of Michigan
- Increased load growth near MISO's northwestern seam influenced by the recent natural gas boom

The Northern Area Study began in June 2012 and is expected to be completed in the first quarter of 2013. The major deliverable of the study will be a report summarizing the findings and initial solutions.

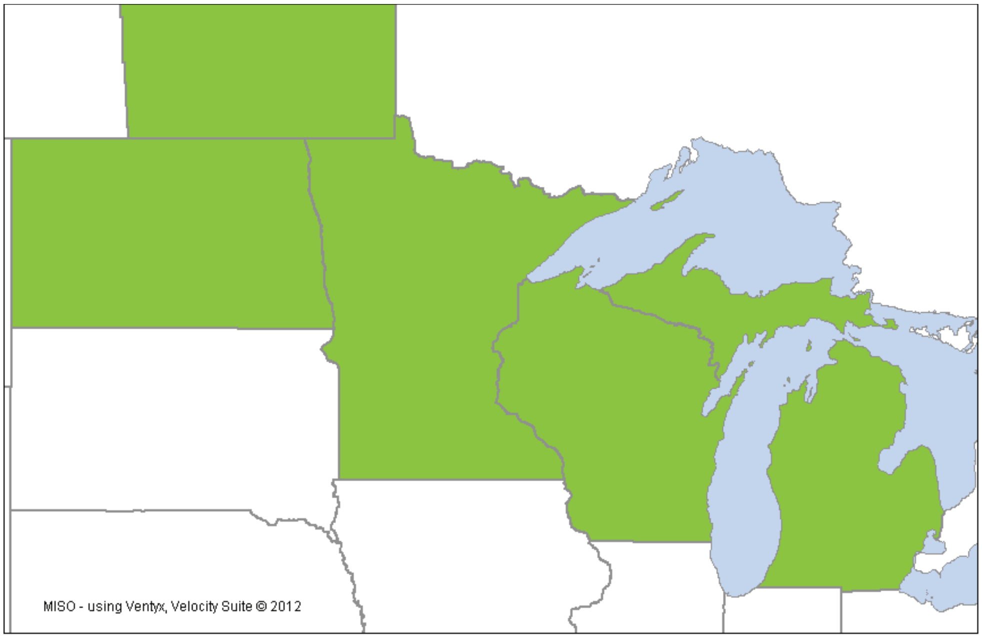


Figure 8.1-1: Northern Area Study region

Study Approach

The Northern Area Study applies MISO's Guiding Principles and 7-Step Planning Process with participation from MISO's stakeholders (Figure 8.1-2). The MISO 7-Step Planning Process will progress as such:

1. MTEP12 regional resource forecast (RRF) units are vetted through the Planning Advisory Committee (PAC) – additional Northern Area Study-specific RRF units will be added with Technical Review Group (TRG) aid to meet out-year reserve deficiencies from mining/industrial load additions.

2. Northern Area Study-specific RRF units are sited near new demand pockets, per TRG comments.

3. Constrained/unconstrained economic analysis is performed to determine economic potential, sources and sinks, and interface flows. Additionally, reliability screens will identify issues that need to be addressed in conceptual designs. Coupling information from constrained/unconstrained analysis, reliability screens, and TRG collective knowledge, conceptual transmission plans will be formulated for each scenario.

4. Scenario-specific conceptual plans are screened and evaluated against other scenarios (if appropriate).

5/6. Iterative refinement and evaluation between economics and reliability takes place.

7. Final plans put into Appendix C and results presented to the TRG. Because the Northern Area Study will not yield any MTEP Appendix A projects, cost allocation will not be performed as part of the Northern Area Study.

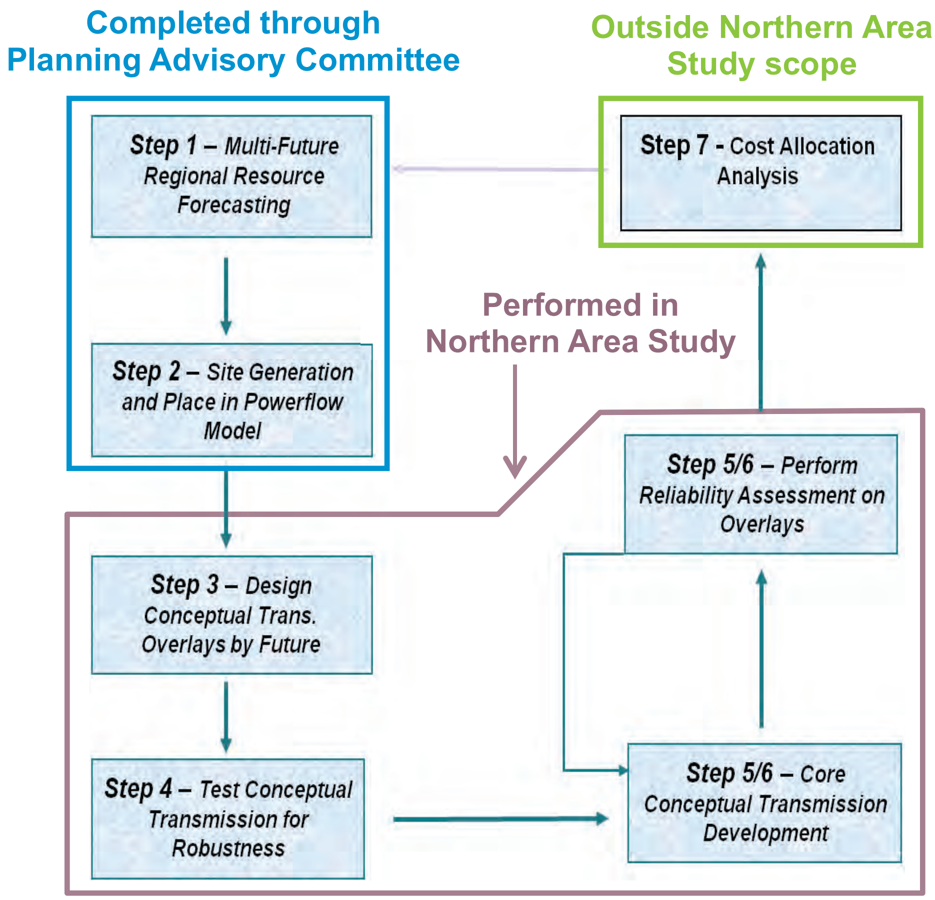


Figure 8.1-2: MISO 7-Step Planning Process as related to the Northern Area Study

Study Scenarios

The Northern Area Study will use scenarios to provide book-end results as well as multiple points in-between. Scenarios will revolve around three main sensitivities:

- demand and energy levels
- generation retirements spurred from EPA regulations
- increased imports from Manitoba Hydro

Demand and Energy Levels

The Northern Area Study will concentrate on three different load expansion areas: Upper Michigan/northern Wisconsin, northern Minnesota and North Dakota. MISO stakeholders in the Upper Michigan area generalized that an estimated 300 MW of new load could be realized in this area. Likewise, MISO stakeholders in the northern Minnesota area said they have an estimated addition of 500 MW under discussion. The load growth in western North Dakota is primarily in the Basin Electric Power Cooperative service territory and the potential magnitude is approximately 500 MW in five years and 1,000 MW (total) in 10 years.

The magnitude of load increases and decreases between the Historical Growth MTEP12 futures are generally in close proximity to the magnitude of load expansions provided by MISO stakeholders, with the exception of the increased North Dakota load. Therefore, economic modeling will use the following MTEP12 futures developed through the Planning Advisory Committee (PAC):

• Business as Usual (BAU)

• Historical Growth

• Limited Growth

Reliability analysis will consider two load conditions:

• Summer peak

• Summer shoulder

Load projections will be augmented with TRG-specific updates to ensure that Northern Area Study load and demand levels are appropriate.

Generation Retirements Spurred from EPA Regulations

Base generation retirements are represented in the MTEP12 futures. The retirement status of the Presque Isle plant located in Michigan's Upper Peninsula will be treated as a sensitivity. In the scenario that retires Presque Isle, MISO will model any necessary upgrades resulting from reliability issues due to the plant retirement as part of the base assumptions prior to running the scenario. The justification for this approach is that if Presque Isle is retired, MISO is required to do a reliability study to fulfill its Tariff Attachment Y obligations.

Increased Imports from Manitoba Hydro

Increased generation and imports from Manitoba Hydro will also be treated as a sensitivity resulting in multiple study scenarios. Hydro generation will be sited at the end of Bipole III in the Winnipeg, Manitoba, area of Canada. The Northern Area Study assumes that both the Keeyask and Conawapa units are in service and that the energy is imported to the MISO footprint using proxy AC transmission lines; each capable of carrying at least 1,100 MWs. The following Manitoba Hydro import scenarios will be considered in the Northern Area Study:

• No additional import – Conawapa out of service

• Additional import – Proxy line to Duluth, Minn.

• Additional import – Proxy line to Fargo, Minn.

• Additional import – Proxy line runs south between Duluth and Fargo and then "T's" terminating at both Duluth and Fargo

Between the MTEP12 futures being used, the sensitivity analysis of Presque Isle, and the sensitivity analysis of the Manitoba Hydro imports, the economic analysis of the Northern Area Study will be evaluating 24 different study scenarios (Figure 8.1-3). The reliability analysis will use a summer peak and shoulder peak model in lieu of the BAU, Historical Growth and Limited Growth levels resulting in the evaluation of 16 different scenarios (Figure 8.1-4). Upon review of initial study results, the Northern Area Study TRG may be able to reduce the number of scenarios to be performed in both the economic and reliability analysis.

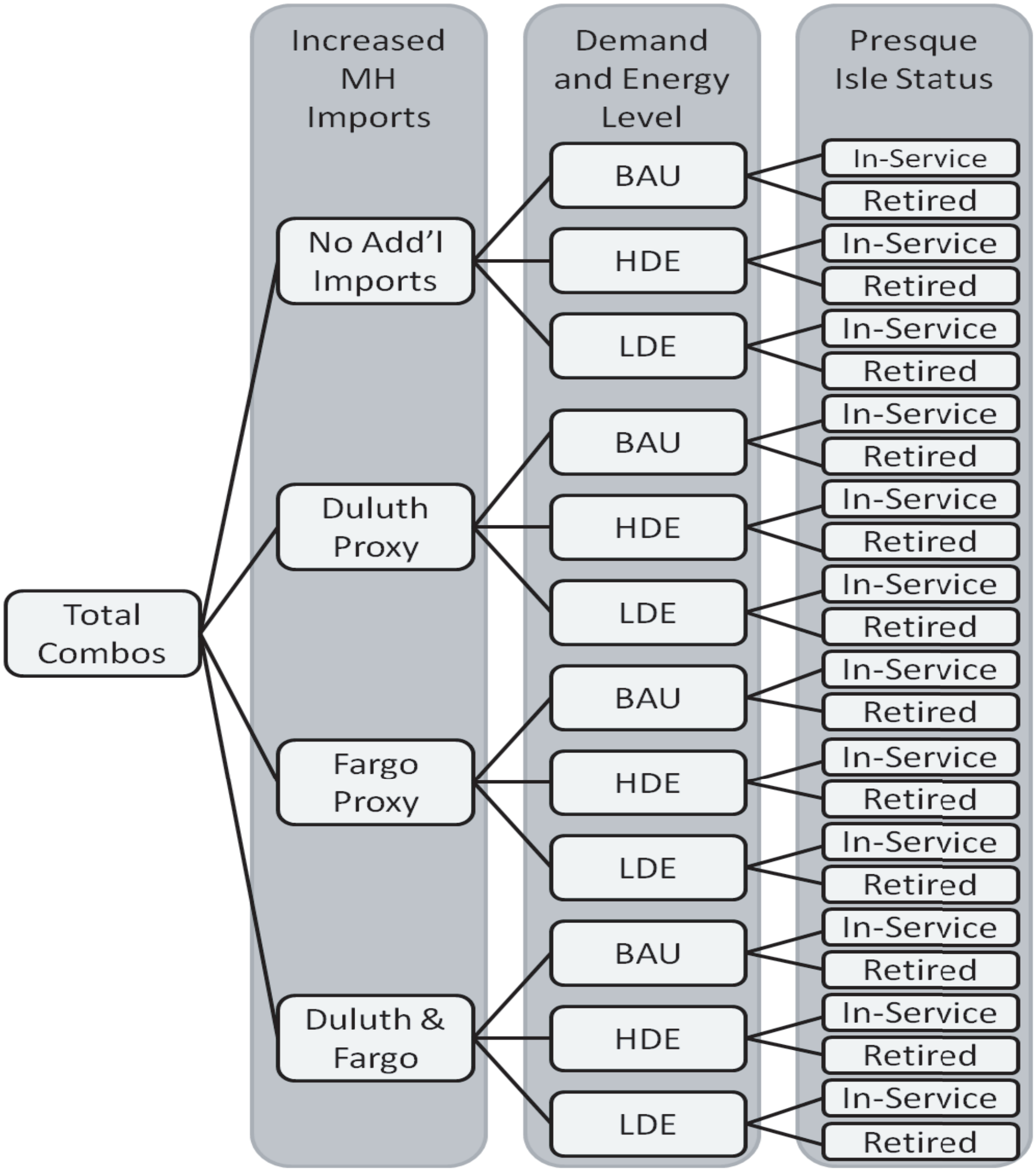


Figure 8.1-3: Northern Area Study economic scenarios

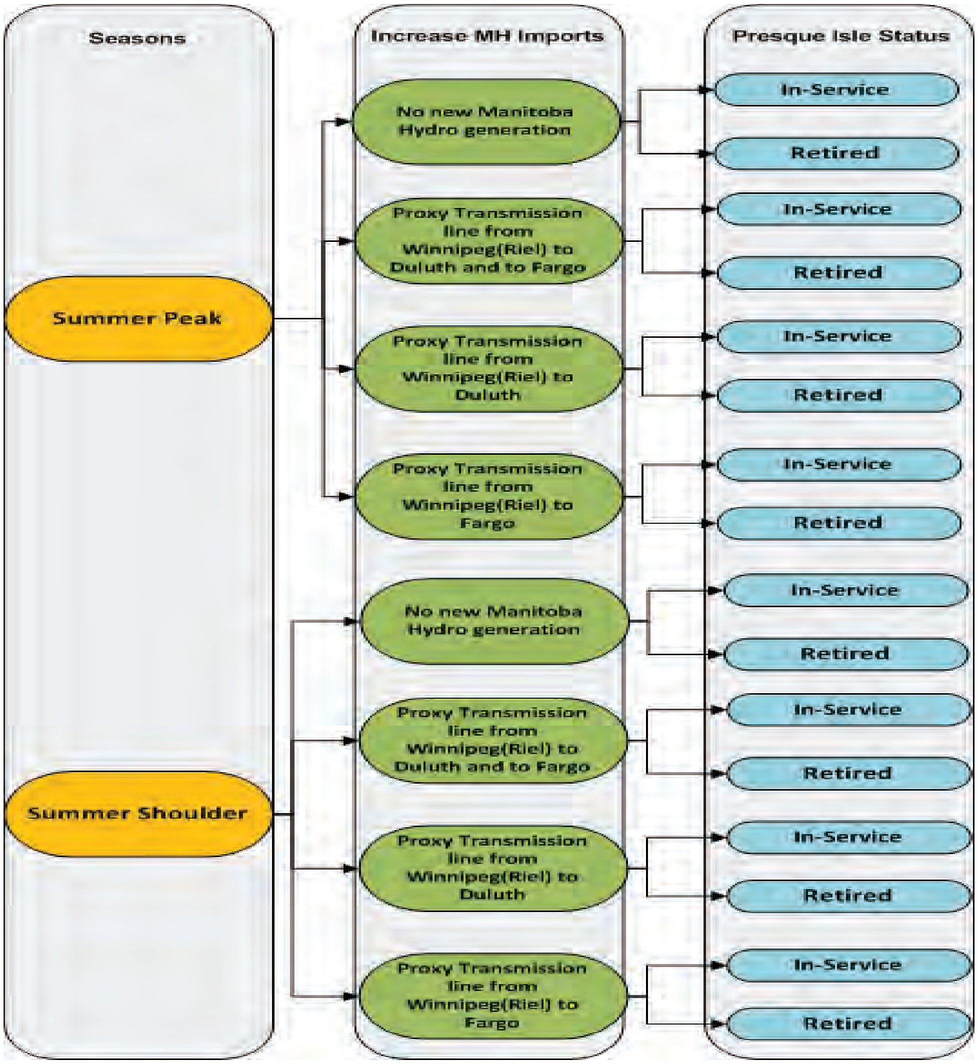


Figure 8.1-4: Northern Area Study Reliability Scenarios

8.2 Manitoba Hydro Wind Synergy Study

The variable and non-peak nature of wind creates integration challenges within MISO. Conversely, Manitoba Hydro (MH) has a large and very flexible system that has the potential to alleviate these constraints. MISO is undertaking this new study in order to determine if the cost of expanding the connection with MH is justified by the benefits of greater MH participation in the MISO market.

> MISO is undertaking this new study in order to determine if the cost of expanding the connection with Manitoba Hydro (MH) is justified by the benefits of greater MH participation in the MISO market

MISO currently has 13 GW of wind registered and 17 GW of active wind projects in the queue. MH wants to expand its hydro system by 2,230 MW over the next 15 years. MH's export capacity is limited to 1,850 MW and isn't able to meet the needs of future wind variability. Thus this study will look at expanding transmission capacity between MISO and MH to facilitate the realization of these benefits.

This study was set in motion at the request of various stakeholders based on the realization of this opportunity. MISO developed a four-phase study to address these concerns and develop a cost-benefit analysis for an expanded MH to MISO interface.

The MH Wind Synergy Study began in June 2011 and will run through June 2013. The project consists of four unique phases that will be completed sequentially (Figure 8.2-1). Phase 1 consists of collecting the data for the model, putting it all together, developing concepts to evaluate the costs and benefits of the other stages of the project, and validating MH's system operation. Phase 2 will look at the existing system with additional market participation by MH through the external asynchronous resource (EAR). Phase 3 will look at the value of expanding the transmission capacity between MISO and MH along with additional hydro capacity in MH in order to increase energy and compensate for wind variability. Phase 4 will finish the project by doing sensitivity and risk assessment of the Phase 3 results. This will ultimately lead to a final recommendation.

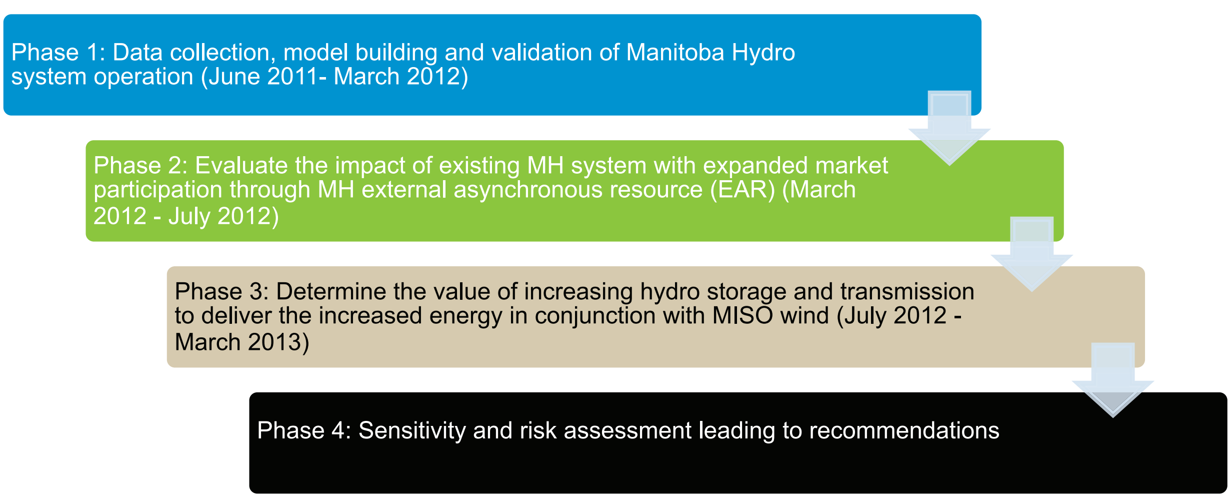


Figure 8.2-1: Four phases of the study

Because of the intricacies in modeling Manitoba Hydro's resources — its effect on wind variability and ancillary service prices —, PLEXOS is the primary simulation tool for this study. To fully develop the cost-benefit calculation, it is prudent to develop both day ahead (DA) and real time (RT) simulations. Wind has been shown to have a large variance within each hour. For this study to capture the variance, we need to look at the sub-hourly (5 minute) level.

MISO will evaluate a variety of future scenarios to fully understand the best-fit solutions from a variety of perspectives. Three different hydrologic conditions along with appropriate MTEP future scenarios will be used as sensitivities. A decision tree will then be constructed to determine the best possible transmission expansion plan.

A Technical Review Group (TRG) is actively involved to advise on study methodology, verify the models, help design the solutions and review results. Manitoba Hydro will also be working closely with MISO staff to ensure its system has been modeled correctly (Figure 8.2-2).

As of July 2012 phases 1 and 2 of the MH Wind Synergy Study are complete. The major achievements of the Phase 1 and 2 of this study are:

- Model the complex structure of the MH water storage system
- DA practices simulation of the MISO energy and ancillary services markets with MH participation
- Design and implementation of three MH RT participation methods
- With extended EAR participation, MISO has lower production costs/load payments
- The model improvements ensure the accurate representation of hydro system's market operations

By evaluating the simulation model and results, MISO and MH agreed that the model assumptions and outputs are reasonable. Phases 3 and 4 will build on these results, evaluating potential transmission solutions.

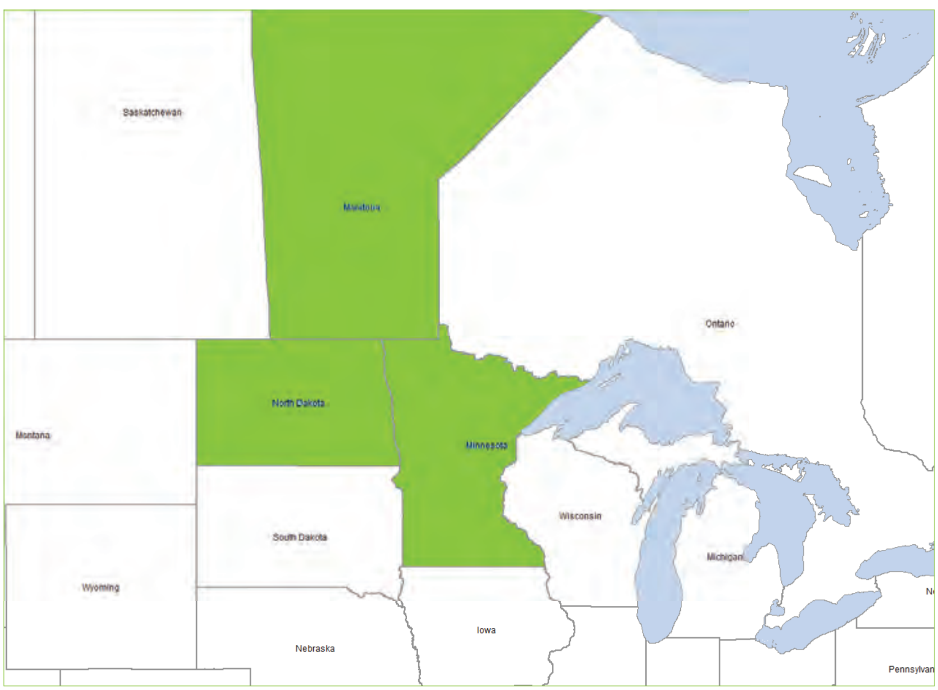


Figure 8.2-2: Manitoba Hydro Wind Synergy study area

Appendices

Most MTEP12 appendices are available and accessible on the MISO public webpage. Confidential appendices, such as D2 - D8, are available on the MISO MTEP12 FTP site. Access to the FTP site requires an ID and password.

A link to the MTEP12 appendices, on the MISO public website, is below:
https://www.misoenergy.org/Planning/TransmissionExpansionPlanning/Pages/MTEP12.aspx

The confidential appendices are located at:
ftp://mtep.misoenergy.org/mtep12/

Appendix A: Projects recommended for approval

Section A.1, A.2, A.3: Cost allocations
Section A.4: MTEP12 Appendix A new projects

Appendix B: Projects with documented need & effectiveness

Appendix C: Projects in review and conceptual projects

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

Appendix E: Additional MTEP12 Study support

Section E.1: Reliability planning methodology
Section E.2: Generations futures development
Section E.3: MTEP12 futures retail rate impact methodology

Appendix F: Stakeholder substantive comments

MISO would like to thank the many stakeholders who provided MTEP12 Report comments, feedback, and edits. The creation of this report is truly a collaborative effort of the entire MISO region.

Thank you to CapX2020 for providing several photos in this report.

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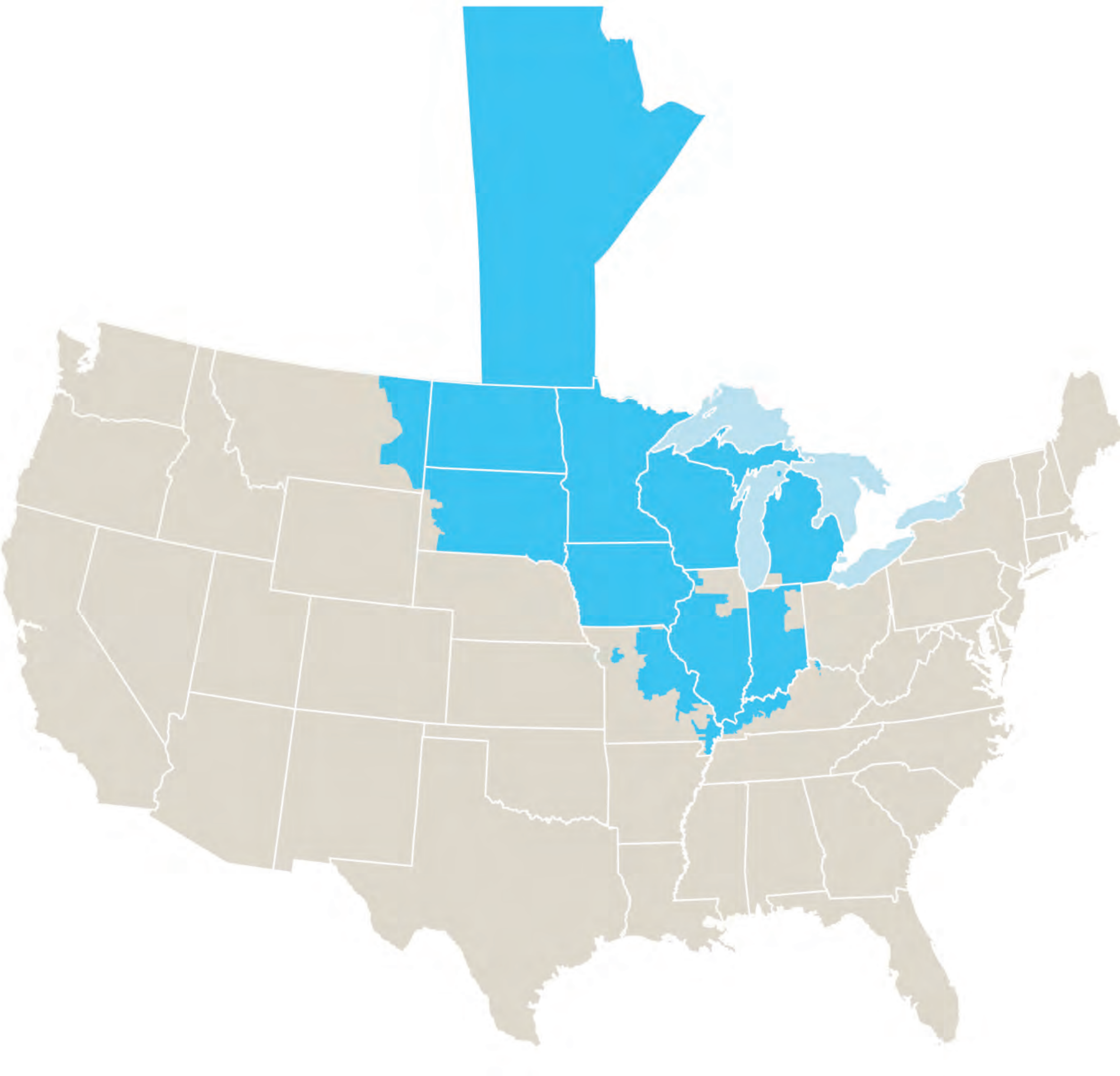

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