ORIGINAL

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

ELECTRONIC APPLICATION OF	)	
BIG RIVERS ELECTRIC CORPORATION	)	
FOR APPROVAL TO MODIFY ITS MRSM TARIFF,	)	Case No.
CEASE DEFERRING DEPRECIATION EXPENSES,	)	2020-00064
ESTABLISH REGULATORY ASSETS,	)	
AMORTIZE REGULATORY ASSETS, AND	)	
OTHER APPROPRIATE RELIEF	)	

Response to the Office of the Attorney General's Supplemental Data Requests dated April 15, 2020

Part 2 of 2

FILED: April 24, 2020

ORIGINAL

BIG RIVERS ELECTRIC CORPORATION

**ELECTRONIC APPLICATION OF
BIG RIVERS ELECTRIC CORPORATION
FOR APPROVAL TO MODIFY ITS MRSM TARIFF,
CEASE DEFERRING DEPRECIATION EXPENSES,
ESTABLISH REGULATORY ASSETS,
AMORTIZE REGULATORY ASSETS, AND
OTHER APPROPRIATE RELIEF
CASE NO. 2020-00064**

VERIFICATION

I, Robert W. ("Bob") Berry, verify, state, and affirm that the information request responses filed with this verification for which I am listed as a witness are true and accurate to the best of my knowledge, information, and belief formed after a reasonable inquiry.

Robert W Berry
____
Robert W. ("Bob") Berry

COMMONWEALTH OF KENTUCKY)
COUNTY OF HENDERSON)

SUBSCRIBED AND SWORN TO before me by Robert W. ("Bob") Berry on this the 24th day of April, 2020.

Joy P. Parsley
____
Notary Public, Kentucky State at Large

My Commission Expires ____________

Notary Public, Kentucky State-At-Large
My Commission Expires: July 10, 2022
ID: 604480

BIG RIVERS ELECTRIC CORPORATION

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VERIFICATION

I, Michael W. ("Mike") Chambliss, verify, state, and affirm that the informationa request responses filed with this verification for which I am listed as a witness are true and accurate to the best of my knowledge, information, and belief formed after a reasonable inquiry.

Michael W. Chambliss

Michael W. ("Mike") Chambliss

COMMONWEALTH OF KENTUCKY)
COUNTY OF HENDERSON)

SUBSCRIBED AND SWORN TO before me by Michael W. ("Mike") Chambliss on this the 24th day of April, 2020.

Joy P. Parsley

Notary Public, Kentucky State at Large

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VERIFICATION

I, Mark J. Eacret, verify, state, and affirm that the information request responses filed with this verification for which I am listed as a witness are true and accurate to the best of my knowledge, information, and belief formed after a reasonable inquiry.

M J Eacret
Mark J. Eacret

COMMONWEALTH OF KENTUCKY)
COUNTY OF HENDERSON)

SUBSCRIBED AND SWORN TO before me by Mark J. Eacret on this the 24th day of April, 2020.

Joy P. Parsley
Notary Public, Kentucky State at Large

My Commission Expires

Notary Public, Kentucky State-At-Large
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VERIFICATION

I, Michael T. ("Mike") Pullen, verify, state, and affirm that the data request responses filed with this verification for which I am listed as a witness are true and accurate to the best of my knowledge, information, and belief formed after a reasonable inquiry.

Mike Pullen

Michael T. ("Mike") Pullen

COMMONWEALTH OF KENTUCKY)
COUNTY OF HENDERSON)

SUBSCRIBED AND SWORN TO before me by Michael T. ("Mike") Pullen on this the 24th day of April, 2020.

Joy P. Parsley

Notary Public, Kentucky State at Large

My Commission Expires ______

Notary Public, Kentucky State-At-Large
My Commission Expires: July 10, 2022
ID: 604480

BIG RIVERS ELECTRIC CORPORATION

ELECTRONIC APPLICATION OF BIG RIVERS ELECTRIC CORPORATION FOR APPROVAL TO MODIFY ITS MRSM TARIFF, CEASE DEFERRING DEPRECIATION EXPENSES, ESTABLISH REGULATORY ASSETS, AMORTIZE REGULATORY ASSETS, AND OTHER APPROPRIATE RELIEF CASE NO. 2020-00064

VERIFICATION

I, Paul G. Smith, verify, state, and affirm that the data request responses filed with this verification for which I am listed as a witness are true and accurate to the best of my knowledge, information, and belief formed after a reasonable inquiry.

Paul Smith

Paul G. Smith

COMMONWEALTH OF KENTUCKY)
COUNTY OF HENDERSON)

SUBSCRIBED AND SWORN TO before me by Paul G. Smith on this the 24th day of April, 2020.

Joy P. Parsley

Notary Public, Kentucky State at Large

My Commission Expires ____________

Notary Public, Kentucky State-At-Large
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Item 11) ***Reference the response to AG 1-11. Explain if BREC will have any other potential means in the near future to directly interconnect with the PJM market.***

a. Explain also whether BREC and/or MISO conducted any supplemental cost/benefit analyses regarding the Duff-Coleman project after PJM announced that it was withdrawing from the formerly joint project. If so, provide copies of all such analyses.

Response) Big Rivers objects to this request on the grounds that it is overbroad and unduly burdensome. Big Rivers also objects to this request on the grounds that it seeks information that is irrelevant and not likely to lead to the discovery of admissible evidence. Notwithstanding these objections, and without waiving them, Big Rivers currently has no near-term plans for a direct connection to PJM. As part of the Duff-Coleman EHV project, Big Rivers expanded its Coleman EHV switchyard to a ring bus configuration. With a ring bus it is much more cost effective for future expansion. This may allow Big Rivers to use the Coleman EHV substation for a future tie to PJM. Big Rivers continues to explore and evaluate cost-effective opportunities to create a direct interconnection to PJM.

a. MISO performed a cost/benefit analysis on the Duff/Coleman project with no PJM connection. Attached please find the MISO Planning Subcommittee's presentation to the MISO Board of Directors, and the full 2015 MISO Transmission Expansion Plan report that includes the Duff-Coleman EHV project.

Witness) Michael W. Chambliss

MISO Transmission Expansion Plan 2015 Overview

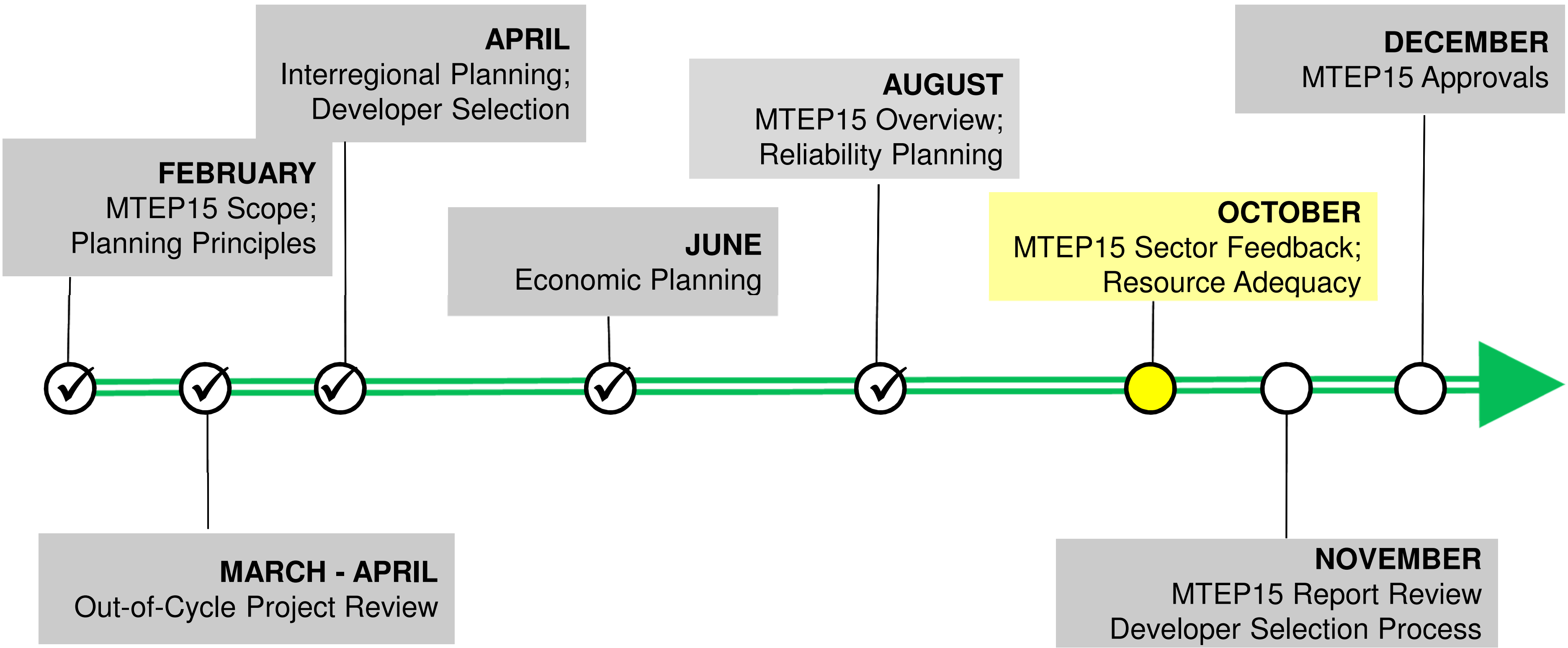
Board of Directors
System Planning Committee

October 20, 2015

Executive Summary

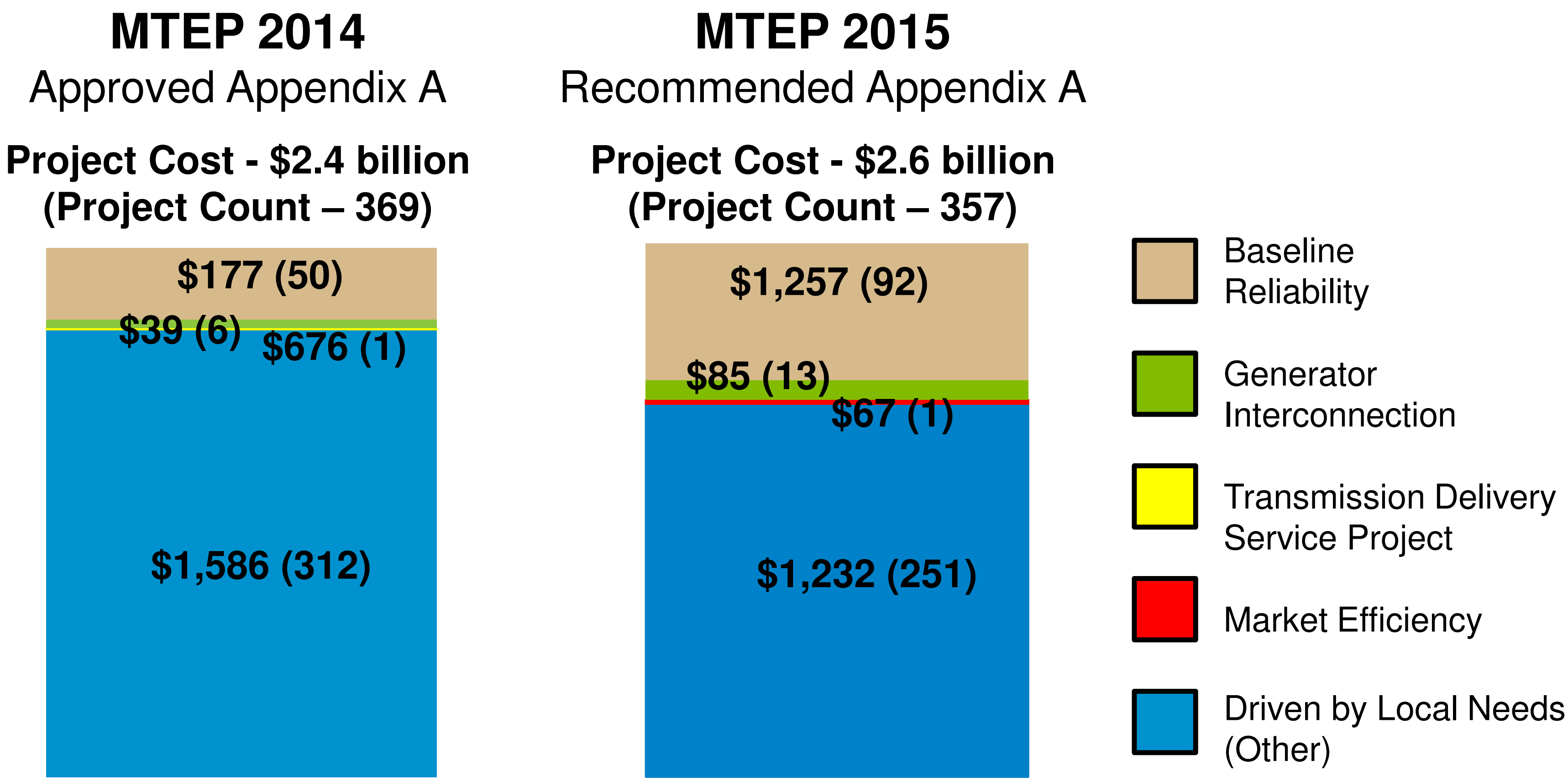
- MTEP 2015, the 12th edition of MISO's annual report, represents the cumulative efforts of 18 months of collaboration between MISO staff and stakeholders
- MISO staff recommends 357 projects totaling $2.6 billion of transmission expansion investment in MTEP 2015
- First competitively bid Market Efficiency Project, Duff – Rockport – Coleman 345kV, being recommended for approval
- Two economic projects totaling $128 million recommended from the South Market Congestion Planning Study
- Planning Advisory Committee members provided substantive feedback on the MTEP 2015 report

MTEP 2015 has been reviewed by the System Planning Committee throughout 2015



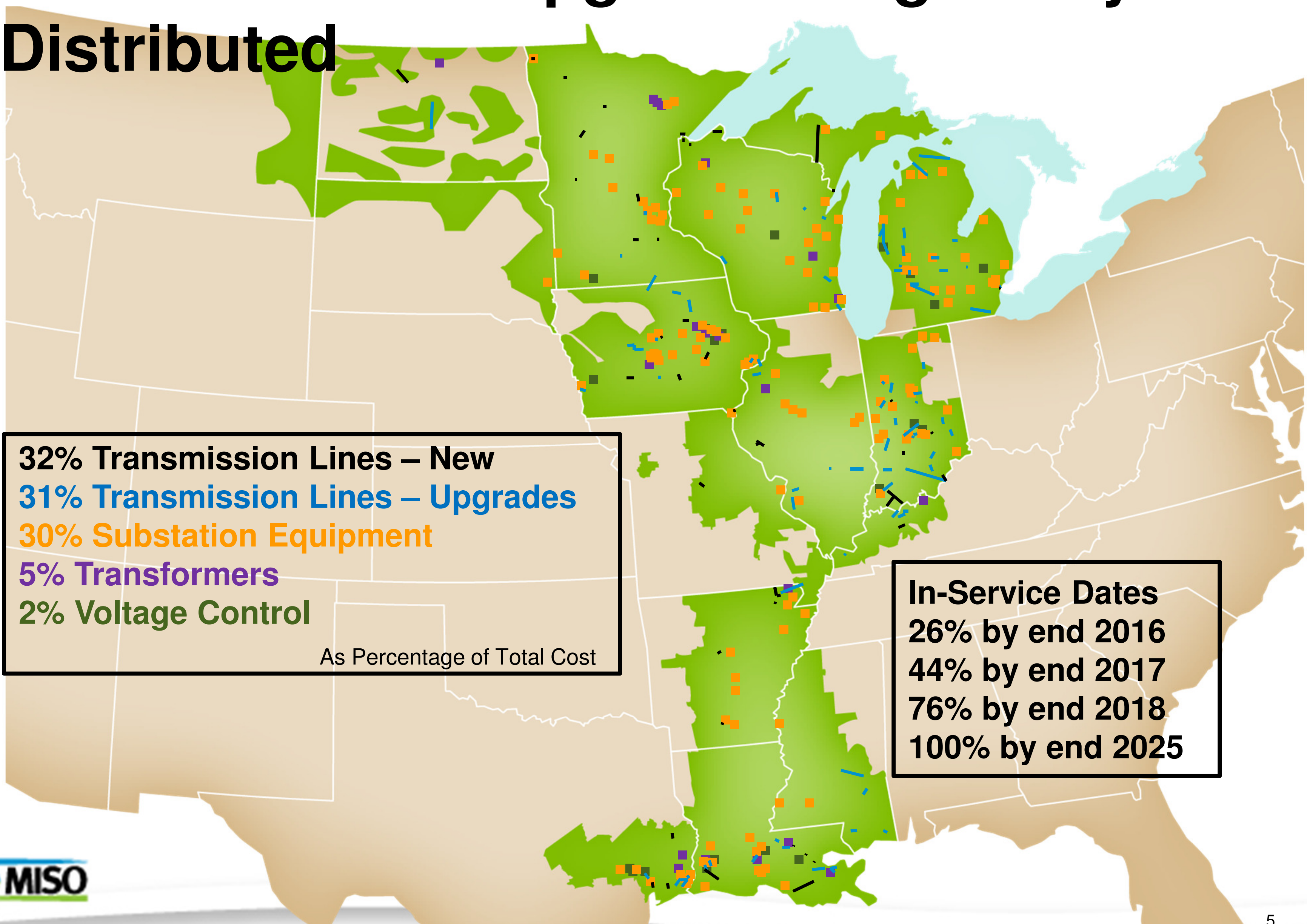
In December, MISO staff will present recommended MTEP 2015 projects for Board of Director approval

In MTEP 2015 – 357 new projects, at a cost of $2.6 billion, will be recommended for approval



In MTEP 2015, one Market Efficiency ($67M) is cost-shared and four Generator Interconnection Projects (totaling $46M) are partially cost-shared

New MTEP Grid Upgrades Regionally Distributed

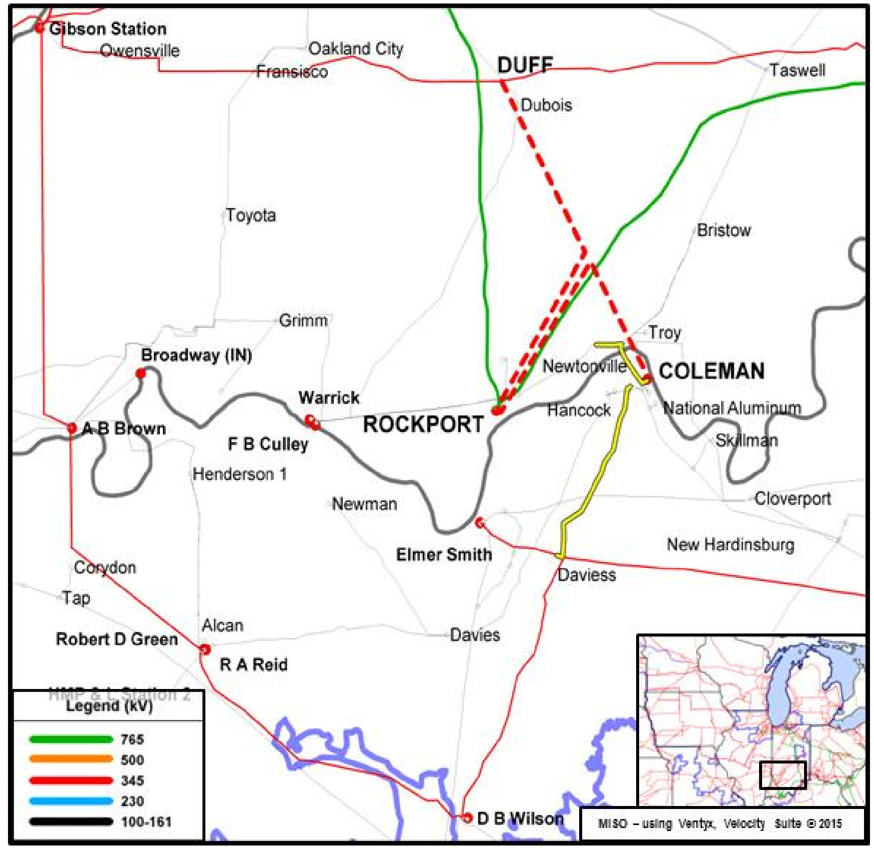


Map for illustrative purposes only

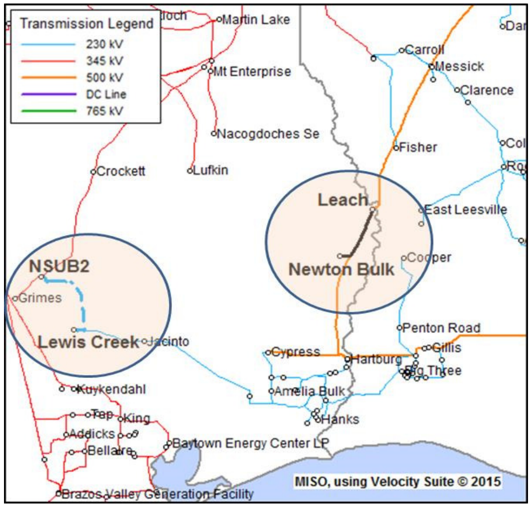
First potential competitively bid project being recommended in MTEP 2015

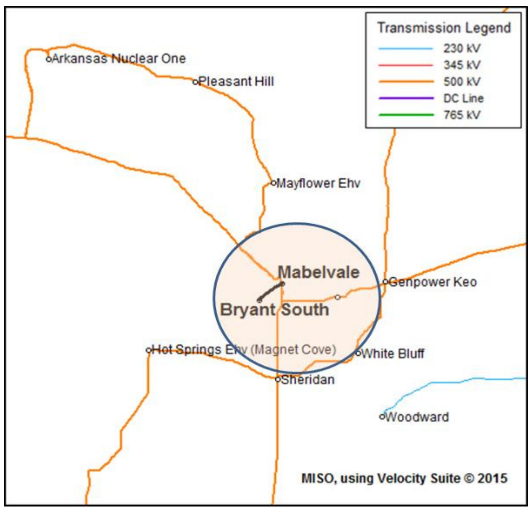
Duff - Rockport - Coleman 345 kV

- MISO Market Efficiency Project
  - Benefit-to-Cost Ratio: 16:1
  - Cost: $67 million (MISO portion)
- Project coordinates MISO and PJM regional plans
  - Provides MISO economic benefits
  - Provides PJM reliability benefits
- If approved, request for proposal posted January 2016; developer proposals due July 2016



Two economic projects recommended from South Market Congestion Planning Study





East Texas Economic Project*

- Lewis Creek to new 345/230 kV substation via 230kV by cutting into Grimes to Crocket 345kV; Rebuild Newton Bulk – Leach 138kV
- Other-Economic
- Benefit to Cost Ratio of 1.5 – 2.3
- Estimated Cost: $122.5M

Central Arkansas Economic Project

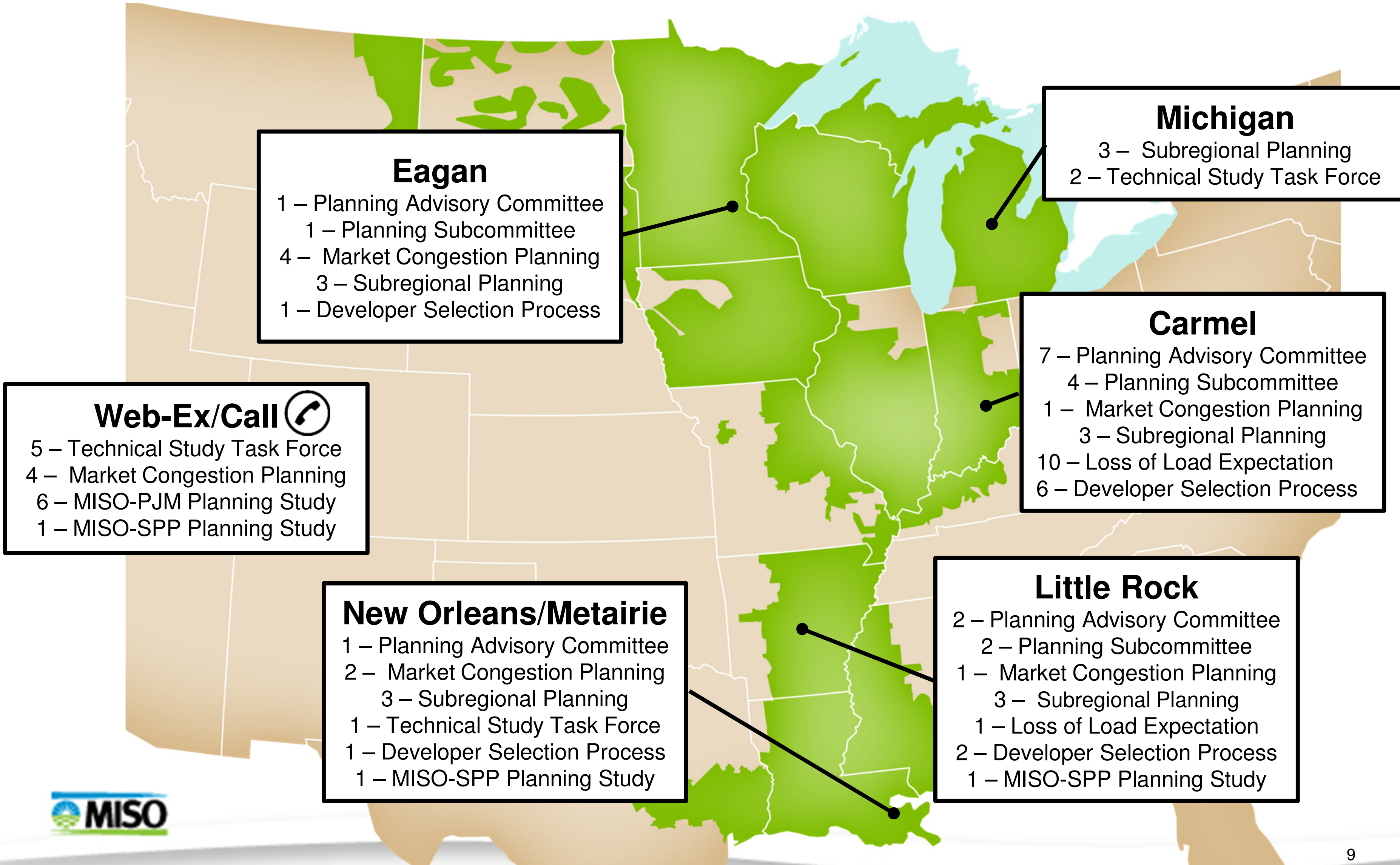
- Rebuild Mabelvale – Bryant South 115kV
- Other-Economic
- Benefit to Cost Ratio of 5.9
- Estimated Cost: $6.1M

*MISO received stakeholder comments on potential changes to this project that it is currently considering

Interregional coordination processes moved forward in MTEP 2015

- **MISO-PJM ‘Quick Hit’ Planning Study**
  - Study complete - one identified project is already in-service
  - Two targeted studies similar to the ‘Quick Hit’ approach are underway
- **MISO-SPP Coordinated System Plan Study**
  - Three projects passed interregional test and were studied within regional processes
  - The one project beneficial to MISO did not meet SPP’s regional criteria
  - MISO is evaluating alternative regional solutions to that issue and working with SPP on enhancing our joint planning process
- **Southeastern Regional Transmission Planning**
  - Data exchange and future study discussions underway
- **ERCOT Coordination Study**
  - Discussions underway over a potential future study to increase transfers between the regions

Stakeholders, including regulators, have been involved throughout the MTEP 2015 Process



Map for illustrative purposes only

MISO

The Planning Advisory Committee voted on the following MTEP 2015 motion - October 14, 2015

Recommendation to the Advisory Committee on input for MTEP15:

“The Planning Advisory Committee (PAC) sectors have reviewed and discussed the draft MTEP15 report that MISO will send to the Advisory Committee (AC) and MISO Board of Directors (Board) for approval in December. The PAC sectors have provided written comments and suggestions for improvement of MISO’s planning activities to be included in future planning and model development/review processes. PAC sector members are willing to present their comments at a future AC or Board meeting and to answer any questions that the AC or Board may have regarding the comments and recommendations. Although various points for improvement have been raised, the PAC recommends that the MTEP15 report proceed to the Board of Directors for approval.”

Stakeholders reviewed and offered substantive feedback on MTEP 2015 for Board consideration

Full comments and responses are reflected in Appendix F to MTEP

	Stakeholder Feedback	MISO Response
Study Process	• Consideration of non-transmission alternatives in MTEP should be improved • Work to ensure expedited or Out-of-Cycle projects have adequate stakeholder review and are the exception • More work needed to evaluate LA and TX load pocket generation issues (VLR)	• Discussions are underway with stakeholders to improve processes around consideration of non-transmission alternatives in MTEP and the expedited project review schedule is as effective as possible • MISO agrees that the analysis to identify economic transmission to increase transfer capability should and will continue
Plains National 138kV Line	• Concern about project need being sensitive to area load and new generation potential	• Plains-National Project should commence development to ensure reliability • MISO will collaborate with stakeholders if proposed generator proceeds or other conditions change

Stakeholders reviewed and offered substantive feedback on MTEP 2015 for Board consideration, cont.

Full comments and responses are reflected in Appendix F to MTEP

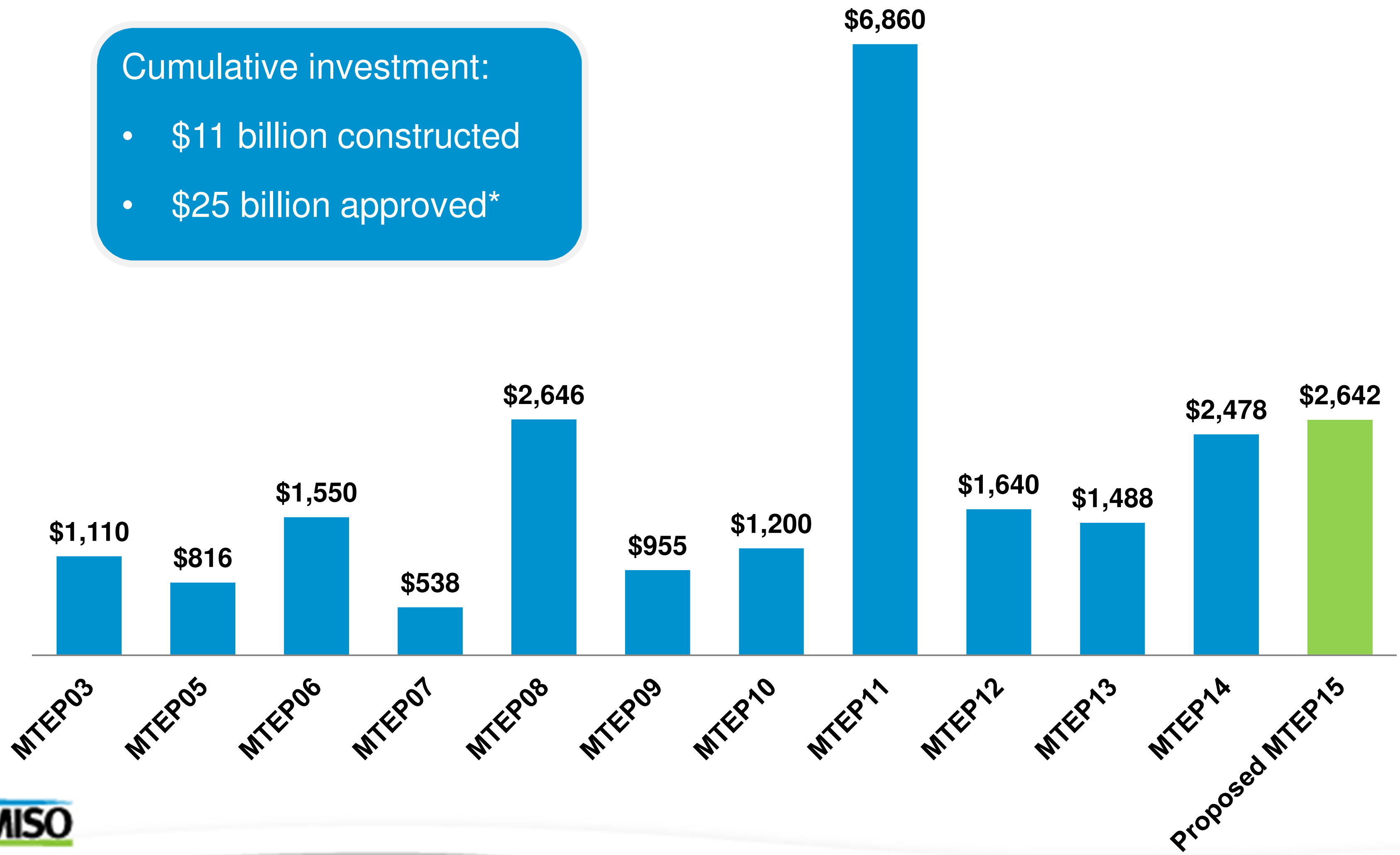
	Stakeholder Feedback	MISO Response
Duff-Rockport Coleman Market Efficiency Project	• Evaluate project in the inter-regional study process and with alternate cost sharing • Concern that PJM delays could impact MISO part of project	• Project is a hybrid project of two regional projects connected through interregional coordination • Construction of the two portions is independent • The cost sharing of the project is consistent with our respective tariffs.
East Texas Economic Project	• Concerned with MISO's tariff authority to recommend low voltage economic project (i.e. costs not shared beyond local zone) • Desire additional granularity in benefits information • Alternate design provided by Entergy	• Per the tariff, MISO recommends any project that has sufficient business cases even if cost sharing does not extend beyond local zone • Economic benefits are typically provided at the Local Resource Zone Level; The East TX project produces production cost benefits to the market relieving congestion in TX exceeding the cost of the project. • Entergy recently suggested a minor design modification to improve system performance; MISO is considering those changes

Appendix

Historical MTEP Investment Summary (in millions)

Cumulative investment:

- $11 billion constructed
- $25 billion approved*



MISO

** Includes proposed MTEP 2015*

MTEP 2015 Project Highlights
Cost Ranking

MISO

Map for illustrative purposes only

MTEP 2015 Project Highlights

The top 10 (3%) highest cost projects represent 35% of the total cost

Rank	Project Description	ID	Cost	Type	Driver
1	LCTP Expansion and Load Additions	8585-8590	$187M	BaseRel	Reliability – New load connections in the area
2	East Texas Economic Project	10143	$123M	Other	Economic – Congestion Mitigation
3	Schriever – Bayou Vista 230kV	7988	$122M	BaseRel	Reliability – Thermal overloads
4	Plains – National 138kV	8071	$114M	BaseRel	Reliability
5	Riggsville – Port Calcite 138kV	8072	$96M	Other	Rebuild – Condition of structures & conductors
6	Duff – Rockport – Coleman 345kV	10142	$67M	MEP	Congestion Mitigation
7	Jonesboro EHV Tap & Substation	7928	$57M	BaseRel	Reliability – Thermal overloads and low voltages
8	SE Wisconsin – NE Illinois 345kV	8065	$52M	BaseRel	System Reliability
9	Ward County 230kV	8113	$48M	BaseRel	Reliability – Thermal overloads and low voltages
10	China – Stowell 230kV	9482	$47M	BaseRel	Reliability – Voltage violations

MISO

Transmission Expansion Plan 2015

Table of Contents

MTEP15 Executive Summary

MTEP15 At-a-Glance

Each year, the Midcontinent Independent System Operator (MISO) develops the MISO Transmission Expansion Plan (MTEP). The MTEP is a comprehensive process that involves analyzing the myriad regulatory policy and reliability issues impacting our energy sector and developing a portfolio of transmission projects designed to maintain a reliable electric grid and deliver the lowest-cost energy to customers in the MISO region.

In MTEP15, the 12th edition of this publication, MISO staff recommends $2.75 billion of new transmission expansion projects for Board of Director approval

MTEP15, the 12th edition of this publication, is the culmination of more than 18 months of collaboration on a diverse geographic and regulatory landscape covering 900,000 square miles. The projects in MTEP15 support both reliability needs and congestion relief of the transmission system.

In MTEP15, MISO staff recommends the MISO Board of Directors approve $2.75 billion of new transmission expansion projects through 2024. Of particular note is the $1.4 billion in new project investment recommendations just within the 24 months since the integration of the MISO South members. $1 billion of this investment in MTEP15 represents 78 new projects.

The MTEP process seeks to identify projects that:

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

The projects in MTEP15 achieve these goals in a way that ultimately benefits consumers across the region by ensuring a reliable grid that provides power where it is needed, when it is needed.

As the MISO region experiences changes and growth, MTEP also looks at specific issues to ensure the region is well-positioned to meet future demand and regulatory mandates. Notable work efforts performed during this planning cycle include:

- Increased efforts to evaluate transmission needs and identify solutions through Market Congestion Planning studies (Chapter 5.3)
- Voltage and Local Reliability Study (Chapter 7.1)
- Transparency around Resource Adequacy in the MISO Region (Book 2)
- Greater interregional study emphasis along MISO's seams (Chapter 8)
- Design and implementation of Transmission Developer Qualification and Selection (Chapter 2.6)
- MISO Clean Power Plan Analysis (Chapter 7.4)

MTEP15 Highlights:

- **345 new projects** for inclusion in Appendix A provide an incremental **$2.75 billion** in transmission infrastructure investment (Chapter 2.1)
- **$13 billion in projects** constructed in the MISO region since 2003 (Chapter 3.2)
- **First** competitively bid Market Efficiency Project (Chapter 5.3)
- Voltage and Reliability Study yields projects (Chapter 7.1)
- **Sufficient reserve margin** for the planning year 2015-2016; **sufficient projected capacity** to meet MISO Region requirement through 2020 (Chapter 6.1)
- Improved **Interregional Planning** pursuant to Order 1000 (Chapters 8.1, 8.2)
- The Multi-Value Project (MVP) Limited Review **confirms MVP Portfolio benefits** (Chapter 7.5)

MTEP15 is organized into four books and a series of detailed appendices.

- Book 1 summarizes this cycle's projects and the analyses behind them
- Book 2 describes annual and targeted analyses for Resource Adequacy
- Book 3 presents policy studies. It summarizes regional and interregional studies
- Book 4 presents additional regional energy information
- Appendices A through F provide detailed assumptions, results, project information and stakeholder feedback.

The 345 MTEP15 new Appendix A projects represent an incremental $2.75 billion in transmission infrastructure investment and fall into the following four categories:

- **90 Baseline Reliability Projects (BRP) totaling $1.2 billion –** BRPs are required to meet North American Electric Reliability Corp. (NERC) reliability standards
- **12 Generator Interconnection Projects (GIP) totaling $73.6 million** – GIPs are required to reliably connect new generation to the transmission grid
- **242 Other Projects totaling $1.38 billion -** Other projects include a wide range of projects, such as those that support lower-voltage transmission systems and/or provide economic benefit, but do not meet the threshold to qualify as Market Efficiency Projects
- **1 Market Efficiency Project totaling $67.4 million**

The MTEP15 cycle contains four cost-shared projects, three GIP's network upgrades and one market efficiency project.

The new projects recommended for approval in MTEP15 Appendix A are broken down by region and project type (Table 1.1-1). New projects in MTEP15 Appendix A contain two cost-shared Generator Interconnection Projects. Cost sharing information is provided in Chapter 2.2.

Region	Baseline Reliability Project (BaseRel)	Generator Interconnection Project (GIP)	Market Efficiency Project (MEP)	Other	Total
Central	$89,481,000	$0	$67,443,000	$194,551,000	$351,475,000
East	$86,935,000	$1,330,000	$0	$406,235,000	$494,500,000
West	$385,206,000	$72,318,000	$0	$465,125,000	$922,649,000
South	$665,593,000	$0	$0	$314,611,000	$980,204,000
Grand Total	**$1,227,215,000**	**$73,648,000**	**$67,443,000**	**$1,380,522,000**	**$2,748,828,000**

Table 1.1-1: MTEP15 New Appendix A projects by region and type

The active project investment for Appendix A, with the addition of MTEP15 new projects, increases to 863 projects totaling approximately $12.9 billion (Table 1.1-2) since MTEP03.

MISO Region	Number of Appendix A Projects	Appendix A Estimated Cost
Central	170	$3,095,150,000
East	196	$1,603,368,000
West	368	$6,931,160,000
South	129	$1,228,188,000
Total	**863**	**$12,857,866,000**

Table 1.1-2: Cumulative Active MTEP Projects

Chapter 3 – MTEP History

Since the first MTEP report in 2003, $10.5 billion in projects have been constructed in the MISO region. MISO expects an additional $3.2 billion of MTEP projects to go into service in 2015. Not including withdrawn projects, there are currently $20.56 billion of approved and pending projects in various stages of design, construction, or already in-service through the MTEP15 cycle (Figure 1.1-1). MISO surveys all Transmission Owners on a quarterly basis to determine the progress of each project.

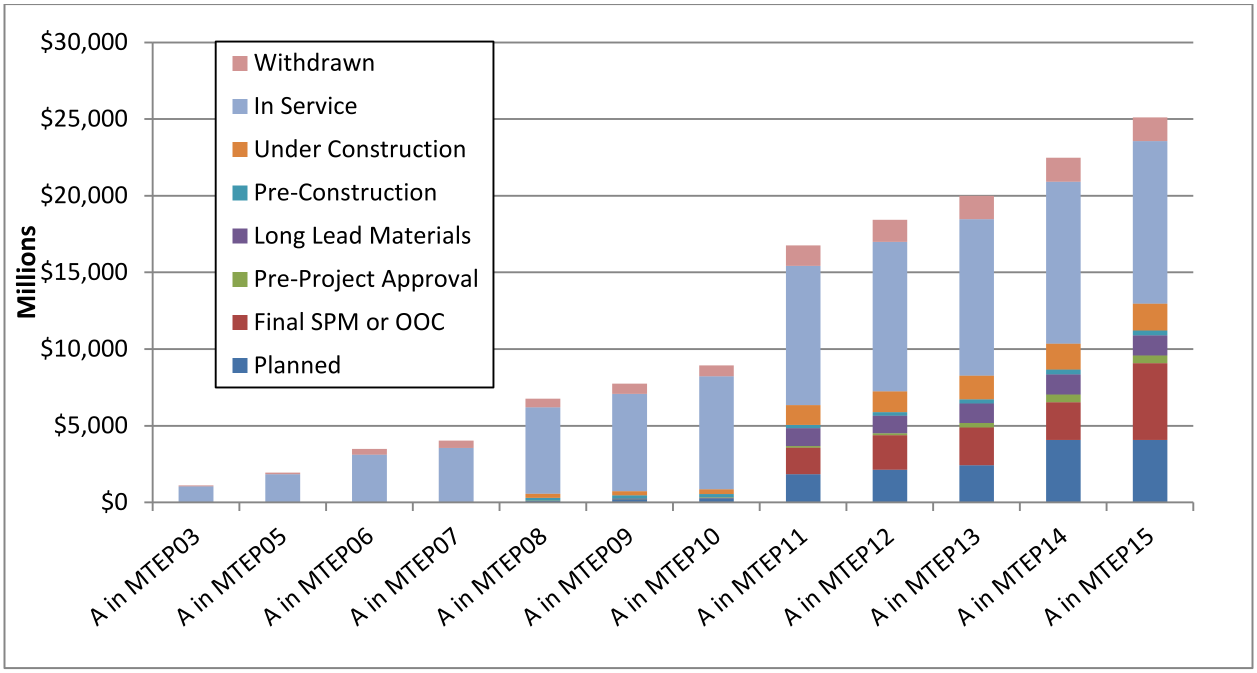


Figure 1.1-1: Cumulative approved investment by facility status

Chapter 4 – Reliability Analysis

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

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

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

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

Chapter 5 – Economic Analysis

In addition to identifying projects that maintain or enhance system reliability, MISO looks for economically justified projects by using the Value-Based Planning Process to identify solutions that minimize total system costs (Figure 1.1-2).

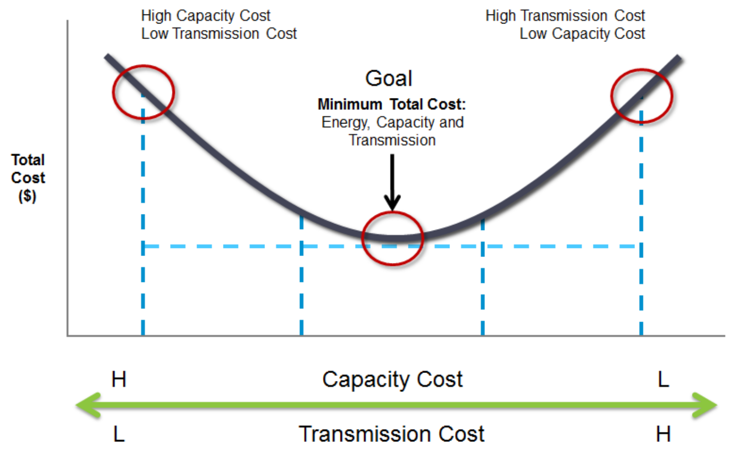


Figure 1.1-2: Capacity versus Transmission costs

The Market Congestion Planning Study (MCPS) identifies transmission needs and solutions to promote market efficiency from a regional view. By identifying and addressing both near-term transmission issues and long-term economic opportunities, this study seeks to develop transmission plans that provide customers access to the lowest-cost electricity.

Possible solutions to congestion were developed by both MISO staff and stakeholders. The solutions were tested for their robustness to meet system needs under a variety of expected scenarios, embodied by the MTEP15 futures.

Similar to the previous planning cycle, parallel economic planning efforts have been undertaken for the MISO North/Central and South regions to better engage the various stakeholders across the entire MISO footprint in the MTEP15.

Market Congestion Planning Study (MCPS) North/Central

The 2015 MCPS North/Central built on the progress made during the MTEP14 cycle, which identified several congested flowgates and evaluated the appropriate transmission solutions. By building on the MCPS 2014 analysis, the 2015 cycle focused on four specific areas that showed the highest congestion: Southern Indiana, Southern Illinois, Iowa/Minnesota and, Northern Indiana. Similar to the previous study cycle, the area with the greatest need, and therefore highest potential benefit, was on the border of Indiana and Kentucky.

Several solutions were designed in a collaborative effort between MISO and stakeholders. The solutions were tested for their robustness to address system needs under a variety of scenarios, embodied by the MTEP15 futures. Ultimately, working in concert with PJM and stakeholders, Duff - Rockport - Coleman 345 kV project, which offers both regional and interregional benefit to MISO and PJM, was found to offer the best value. This project completely mitigates the congestion on the MISO system around the Newtonville and Coleman areas and strengthens the 345 kV backbone in the region. In addition, the project fully addresses long-standing reliability issues around PJM's Rockport station and obviates the need for the Rockport Special Protect Scheme and Operation Guide that protects the stability of the grid.

The project consists of two portions:

- MISO portion being Duff-Coleman 345kV
- PJM portion being the tie-in from Rockport to Duff-Coleman 345kV line.

MISO staff recommends that the MISO portion – Duff - Coleman 345 kV project to be approved as a MISO Market Efficiency Project (MEP).

Market Congestion Planning Study (MCPS) South

The 2015 MCPS South built on the progress made during the VLR Planning Study and the MTEP14 MCPS South, which identified several congested flowgates and evaluated the applicable transmission solutions. By building on the previous analysis, the 2015 cycle focused on four specific areas of MISO South: Amite South/DSG, WOTAB/Western, Local Resource Zone (LRZ) 8 (Arkansas), and Remainder of LRZ 9. Similar to previous studies the areas with the greatest need, and therefore the highest potential, were in the Amite South/DSG and WOTAB/Western load pockets.

Several solutions were developed by both MISO staff and stakeholders. The solutions were tested for their robustness to meet system needs under a variety of expected scenarios, embodied by the MTEP15 futures.

In the 2015 MCPS South, a total of 82 unique transmission solution ideas were proposed and studied. MISO evaluated these solution ideas and formulated 11 project candidates for further robustness testing, in conjunction with South Region stakeholders. Of the 11 project candidates, two were selected by MISO, pending stakeholder feedback, as potential best-fit solutions. Both projects produced a weighted present value (PV) benefit-to-cost ratio greater than 1.25, but due to voltage levels do not met Market Efficiency Project criteria.

- East Texas economic project with an estimated cost of $122.5 million in 2015 dollars
    - A new 230 kV transmission line from Lewis Creek to a new 345/230 kV substation (NSUB2) by cutting into the existing Grimes to Crocket 345 kV line.
        - Note that MISO agrees Grimes alternative provides similar reliability and economic benefits
    - Rebuilding the existing Newton Bulk – Leach 115 kV line
- Rebuilding the existing Mabelvale – Bryant – Bryant South 115 kV line with an estimated cost of $6.1 million in 2015 dollars.

MISO staff recommends that these two projects be approved as Other economic projects.

Book 2: Resource Adequacy

The MISO region has sufficient capacity for the planning year 2015-2016 and is projected to be resource adequate through 2020

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

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

To date, the Resource Adequacy Requirements process has been a successful tool for facilitating and demonstrating Resource Adequacy in the near term, through such tools as the Loss of Load Expectation (LOLE) analysis, the Planning Resource Auction (PRA), and the Organization of MISO States (OMS) MISO Survey. With the resource portfolio now evolving due to coal retirements and the increase in gas-fired generation, MISO is evaluating the Resource Adequacy Requirements and related resource assessment and adequacy processes to ensure they serve as a successful platform to facilitate demonstration of Resource Adequacy going forward in accordance with applicable statutes and regulations.

Book 3: Policy Landscape Studies

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

Chapter 7 – Regional Studies

Voltage and Local Reliability Study

Under the MTEP14 planning cycle, MISO, in collaboration with stakeholders, performed a study of the South Region load pockets. The purpose of the study was to determine whether or not there are transmission alternatives that may lower overall cost-to-load by reducing Voltage and Local Reliability (VLR) resource commitments necessary to maintain system reliability. MISO identified such transmission upgrades necessary to maintain reliability that are cost effective by providing production cost savings in excess of their cost. More specifically, MISO recommends network upgrades with an estimated cost of $300 million that provide production cost savings of about $498 million on a 20-year present value basis (Figure 1.1-3). This analysis was an outcome of the study of reliability issues driven by new firm load additions, existing and planned future generation with signed interconnection agreements and confirmed generation retirements via the Attachment Y process.

Lake Charles Trms Project $187 M 2018

- Sulphur Lane 500kV Switching Station
- New 500/230 kV Bulk Substation
- 1200MVA, 500/230 kV New Sub transformer
- Sulphur Lane - New Sub New 500 kV line
- Bulk Station - Carlyss 230 kV line
- Carlyss –Graywood 230 kV line
- Carlyss Reconfigure existing substation

*On a 20 year net present value basis

MTEP15 Reliability $113 M

Texas $56 M

- S. Beaumont New 3rd Trf 138/69 kV 2016
- Egypt - Panorama 138 kV Upgrade 2017
- Sabine - Port Neches 1 138 kV Upgrade 2017
- S. Beaumont- Carrol St-1 138kV Upgrade 2017
- S. Beaumont- Carrol St-2 138kV Upgrade 2017
- Sabine - Port Neches 2 138 kV Upgrade 2018
- Cleveland - Tarkington 138kV Upgrade 2018
- Cypress New 500/138kV Transformer 2020

Louisiana $57 M

- Carlyss - Boudoin 230 kV Line upgrade 2016
- Fancy Point 2nd 500-230 kV Trf 2017
- Goosport Substation 138 kV Project 2017
- Bayou Verret– Capacitor Bank 2017
- Vacherie - Waterford 230kV Upgrade 2018

Figure 1.1-3: List of cost-effective Reliability Network Upgrades recommended in MTEP15

The VLR study additionally looked at mitigating all transmission issues resulting from potential shutdown of approximately 7,200 MWs of VLR units. Transmission costs for mitigating all such issues are estimated to be more than $1.8 billion. When compared against the 2014 year cumulative make whole payments for these VLR units of approximately $70 million, it was concluded that the network upgrades are not cost effective.

The VLR study further investigated potential scenarios involving the shutdown of subsets of VLR units rather than the entirety of the load pocket VLR units. This analysis assumed no new VLR commitments would occur as a result of eliminating dependence on select existing VLR commitments. Various scenarios studied resulted in different transmission issues. Transmission costs for mitigating these issues in the various scenarios are estimated to be in the range of $23.5 million to $1.8 billion. Once again, it was concluded that these network upgrades are not cost effective compared to the avoided costs associated with mitigating the VLR commitments.

During the study process, MISO received overwhelming stakeholder feedback that production cost savings was the most appropriate metric to evaluate benefits of eliminating VLR costs, which aligns with the benefit metric of the MISO Market Congestion Planning Study (MCPS). Further, recognizing the uncertainties in the region on potential size and locations of future generation additions, retirements and new load growth, stakeholders provided extensive feedback that led to the formulation of four futures. These are:

- Business as Usual (known out-year load growth, fuel prices, generation additions and retirements)
- South Industrial Renaissance (modeling increase in projected load growth)
- Generation Shift (modeling future age related generation retirements despite lack of firm notifications)
- Public Policy (modeling future RPS goals and standards in addition to age related generation retirements)

Given the breadth of uncertainties successfully captured within the futures used in economic studies, the analysis of understanding the benefits of eliminating or reducing VLR generation commitments was appropriately carried into the MTEP15 MCPS. Please refer to MTEP report Chapter 5.3, for further information on the MCPS.

Clean Power Plan Study

The U.S. Environmental Protection Agency (EPA) proposed a rule on June 2, 2014, designed to reduce carbon dioxide (CO_2) emissions from existing fossil-fired generation units. MISO developed a three-phase study to analyze the impacts of the draft rule and provided comments to the EPA based on this analysis, which indicated reliability risks, increased costs from States choosing separate solutions and risks from differing rate and mass compliance approaches. The EPA's revised final rule, issued on August 3, 2015, incorporated many stakeholder suggestions and comments as well as mitigated several risks identified by MISO and other interested parties. MISO's three-phase study approach also increased understanding of many of the potential impacts of the final rule and acted as a dry run for how the final rule would be analyzed. Additionally, it provided information to impacted stakeholders to help formulate cost-effective compliance approaches.

Key takeaways from the study results include:

- Regional compliance produces $4 billion to $11 billion in 20-year net present value production cost savings versus state approaches, while sub-regional compliance respectively produces $2.5 billion to $11.5 billion in savings. These figures do not include the cost of CO_2 allowances.
- Regardless of siting assumptions, electric and gas infrastructure costs for interconnection of new or converted gas units are comparable
- Clean Power Plan constraints significantly increase congestion regardless of compliance approach, and transmission congestion is higher under a state approach than a regional approach
- Multi-billion dollar transmission build-out would be necessary for compliance in the scenarios studied, driven by the level of retirements and the location and type of replacement capacity
- Transmission expansion would be needed to mitigate reliability impacts of compliance, largely driven by coal retirements
- Generation dispatch would change dramatically from current practices, requiring additional study to fully understand the ramifications

While the results offer valuable insights into how the energy landscape may change under compliance, the process of draft rule analysis also yielded valuable lessons that will shape MISO's study of the final rule. In particular, it highlighted the value of a phased approach to analysis, which produced useful information prior to completion of the entire study. Additional lessons learned on study process and design include:

- Stakeholder feedback throughout was essential to producing relevant outputs
- The PLEXOS model was a good fit for analysis of the Clean Power Plan, allowing for explicit modeling of constraints on CO_2 emissions, as well as state-by-state compliance
- Studying one or two compliance actions (e.g. coal retirements, renewables build-out, re-dispatch) at a time allowed for developing a better understanding of the impacts of pulling these individual compliance levers.

The draft rule analysis was a significant undertaking, based on a complex and sometimes ambiguous regulation. Though the study of the final rule will necessitate similar efforts of rule interpretation and technical analysis, MISO is well-positioned to address these challenges. Over the course of the next year, MISO will continue to work closely with stakeholders, state regulators and neighboring ISOs to understand how this regulation will change the energy landscape and to plan for its implementation.

The MTEP15 analysis shows that projected MISO North and Central Region benefits provided by the MVP Portfolio are comparable to MTEP11

MTEP15 Multi-Value Project Limited Review

The MTEP15 Multi-Value Project (MVP) Limited Review provides an updated view into the projected congestion and fuel savings of the MVP Portfolio. The MTEP15 MVP Limited Review's result is on par with the review of the original business case in MTEP11.

The MTEP15 Limited Review provides evidence that the MVP criteria and methodology works as expected. The MTEP15 analysis shows that projected MISO North/Central Region benefits provided by the MVP Portfolio are comparable to MTEP11, the analysis from which the Portfolio's business case was approved.

The review found that the MVP Portfolio shows decreased benefits compared to previous reviews. This lower level of benefits is related to the congestion and fuel savings that are largely driven by natural gas price assumptions. The results show that the Portfolio:

- Provides benefits in excess of its costs, with its benefit-to-cost ratio ranging from 1.9 to 2.8; a decrease from the 2.6 to 3.9 range calculated in MTEP14
- Creates $8.4 to $34.7 billion in net benefits (using MTEP14 benefits for all categories besides congestion and fuel savings) over the next 20 to 40 years, a decrease of up to 38 percent from MTEP14

Chapter 8 – Interregional Studies

FERC Order 1000 requires coordination with neighboring regions to identify and evaluate possible interregional transmission facilities that could address transmission needs more efficiently or cost-effectively than separate regional transmission facilities. While regional planning appears to address the majority of transmission issues, interregional planning and coordination offers the opportunity to improve the overall transmission expansion plan. MISO is committed to continued collaboration with our stakeholders and neighbors to improve the interregional planning processes.

MISO-PJM Interregional Study

MISO and PJM Interconnection, a Pennsylvania-based Regional Transmission Organization (RTO), concluded an 18-month MISO-PJM Joint Coordinated Planning Study in 2014 that looked at multiple futures and 80-plus major project proposals. While the joint study did not produce any actionable results, it identified additional areas for coordination.

For 2015, MISO and PJM agreed to focus their joint study on FERC Order 1000 compliance, a Quick Hits study, targeted coordinated studies and continuation of the interregional process enhancement review.

Quick Hits

The Quick Hit Study analyzed 39 market-to-market flowgates with $408 million of historical congestion between January 2013 and October 2014. The majority of the flowgates (22), accounting for $295 million of congestion, have planned or in-service upgrades from MISO's MTEP or PJM's Regional Transmission Expansion Plan (RTEP). The remaining flowgates had either no recent congestion or no recommended projects. The MISO-PJM Interregional Planning Stakeholder Advisory Committee (IPSAC) identified two potential Quick Hit projects for MISO and PJM to jointly evaluate.

- Beaver Channel – Sub 49 161 kV SCADA Upgrade
- Michigan City – LaPorte 138 kV Sag Remediation and CT Replacement

The two potential projects addressing historical congestion were evaluated for approval and funding. The Beaver Channel – Sub 49 flowgate SCADA upgrade was placed in service mid-year by the Transmission Owner. The current level of congestion seen in production cost models does not support incremental upgrades beyond the SCADA work, so no additional Quick Hit is recommended. MISO and PJM will continue to monitor the historical congestion on this flowgate.

The Michigan City – LaPorte Quick Hit project is not recommended at this time. Future congestion patterns in this area are uncertain due to a new 138 kV substation recently placed in service. The new station, a tap on the Michigan City – LaPorte 138 kV line, has additional 138 kV connectivity and changes the historical congestion flows, especially on Michigan City – LaPorte, during high west-to-east transfers.

Continuing on the Quick Hits work, MISO and PJM agreed to focus on smaller, targeted study areas to address seams issues. MISO and PJM aim to complete all targeted study analyses by the end of 2015. Potential projects identified will be recommended for further study in 2016 in the appropriate MTEP or RTEP process(es).

MISO-SPP Interregional Study

The MISO-Southwest Power Pool (SPP) Coordinated System Plan (CSP) Study jointly evaluated seams transmission issues and identified transmission solutions to those issues. This study incorporated two parallel efforts:

- Economic evaluation of seams transmission issues
- Assessment of potential reliability violations

Interregional Projects Recommended for Regional Review

Based on the results of the economic assessment, MISO and SPP identified three projects for consideration as potential Interregional Projects. The following projects were evaluated in both the MISO and SPP regional planning processes:

- Elm Creek to NSUB 345 kV
- Alto Series reactor
- South Shreveport – Wallace Lake 138 kV rebuild

MISO's goal in interregional planning is to identify more cost effective and efficient projects that would not be found in traditional regional planning. Ensuring that the benefits of proposed projects outweigh the costs is a guiding principle for MISO transmission planning. After continued work with stakeholders and SPP staff, MISO determined through the regional review process that none of the proposed Interregional projects demonstrated a clear and compelling benefit to the customers in the MISO region as an interregional project. However, the Alto-Series Reactor will continue to be evaluated within the MISO regional plan. The scope of the regional review conducted by MISO staff can be found toward the end of Chapter 8.2. The other two projects are viewed as beneficial by SPP or SPP's members and as such may proceed to their Board for approval. Note that the MISO-SPP Joint Operating Agreement (JOA) stipulates that both the MISO and SPP Board of Directors must approve an Interregional Project for the project to receive interregional cost allocation.

Although the first coordinated study did not identify any cost shared interregional projects, MISO and SPP were able to advance our joint planning processes. This first joint study between MISO and SPP is a significant milestone in the evolution of our coordination efforts. MISO remains committed to taking lessons learned from this process and continuing to improve both the planning approach and associated cost allocation methods as appropriate.

The MISO Planning Approach

A defined set of principles, established by MISO's Board of Directors, guides the organization's planning efforts. These principles, last reconfirmed in April 2015[1], were created to improve and guide transmission investment in the region and to furnish strategic direction to the MISO transmission planning process.

Guiding Principles for Expansion Plans

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

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

Guiding Principle	MTEP15 Highlight
Make the benefits of an economically efficient electricity market available to customers by identifying transmission projects which provide access to electricity at the lowest total electric system cost.	• Chapter 5 - Economic Analysis • Chapter 7.1 - Voltage and Local Reliability Planning
Develop a transmission plan that meets all applicable NERC and Transmission Owner planning criteria and safeguards local and regional reliability through identification of transmission projects to meet those needs.	• Chapter 4 - Reliability Analysis
Support state and federal energy policy requirements by planning for access to a changing resource mix.	• Chapter 6 - Resource Adequacy • Chapter 7.3 - Independent Load Forecasting • Chapter 7.4 - EPA Regulations
Provide an appropriate cost allocation mechanism that ensures that costs of transmission projects are allocated in a manner roughly commensurate with the projected benefits of those projects.	• Chapter 2.2 - Cost Sharing Summary • Chapter 2.4 - MTEP Project Types • Chapter 5.1 - Economic Analysis Introduction
Analyze system scenarios and make the results available to state and federal energy policy makers and other stakeholders to provide context and to inform choices.	• Chapter 5 - Economic Analysis • Chapter 7.4 - EPA Regulations
Coordinate planning processes with neighbors and work to eliminate barriers to reliable and efficient operations.	• Chapter 8 - Interregional Studies

[1] These Guiding Principles were initially adopted by the Board of Directors, pursuant to the recommendation of the System Planning Committee, on August 18, 2005, and reaffirmed by the System Planning Committee in February 2007, August 2009, May 2011, March 2013, August 2014, and April 2015.

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

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

Conclusion

MISO is proud of its independent, transparent and inclusive planning process — and grateful for the input and support from our stakeholder community. This support is essential to creating well-vetted, cost-effective and innovative solutions to provide reliable delivered energy at the least cost to consumers. MISO welcomes feedback and comments from stakeholders, regulators and interested parties on the evolving electric transmission system. For detailed information about MISO, MTEP15, Resource Adequacy and other planning efforts, visit www.misoenergy.org.

Book 1
Transmission Studies

Chapter 2
Historical MTEP Plan Status

2.1 Investment Summary

The 345 MTEP15 new Appendix A projects represent $2.75 billion[2] in transmission infrastructure investment and fall into the following three categories:

- **90 Baseline Reliability Projects (BRP) totaling $1.2 billion —** BRPs are required to meet North American Electric Reliability Corp. (NERC) reliability standards.
- **12 Generator Interconnection Projects (GIP) totaling $73.6 million** — GIPs are required to reliably connect new generation to the transmission grid.
- **1 Market Efficiency Project (MEP) totaling $67.4 million** – MEPs meet Attachment FF requirements for reduction in market congestion.
- **242 Other Projects totaling $1.38 billion —** Other projects include a wide range of projects, such as those that support lower-voltage transmission systems or provide local economic benefit, but do not meet the threshold to qualify as Market Efficiency Projects.

The largest 10 projects represent 35 percent of the total cost and are distributed across the MISO region (Figure 2.1-1).

Figure 2.1-1: Top 10 MTEP15 new Appendix A projects (in descending order of cost)

[2] The MTEP15 report and project totals reflect all project approvals during the MTEP15 cycle, including those approved on an out-of-cycle basis prior to December 2015.

The new projects recommended for approval in MTEP15 Appendix A are broken down by region and project type (Table 2.1-1). New projects in MTEP15 Appendix A contain three cost-shared Generator Interconnection Projects. Cost sharing information is provided in Chapter 2.2.

Region	Baseline Reliability Project (BaseRel)	Generator Interconnection Project (GIP)	Market Efficiency Project (MEP)	Other	Total
Central	$89,481,000	$0	$67,443,000	$194,551,000	$351,475,000
East	$86,935,000	$1,330,000	$0	$406,235,000	$494,500,000
West	$385,206,000	$72,318,000	$0	$465,125,000	$922,649,000
South	$665,593,000	$0	$0	$314,611,000	$980,204,000
Grand Total	**$1,227,215,000**	**$73,648,000**	**$67,443,000**	**$1,380,522,000**	**$2,748,828,000**

Table 2.1-1: MTEP15 New Appendix A investment by project category and planning region

Other Project Type

Within the Other project type, there are a number of subtypes that give more insight into the purpose of these projects (Figure 2.1-2). The majority of Other projects address reliability issues — either due to aging transmission infrastructure or local, non-baseline reliability needs. The remaining projects mostly address distribution concerns, with a small percentage of projects targeting localized economic benefits or unspecified needs.

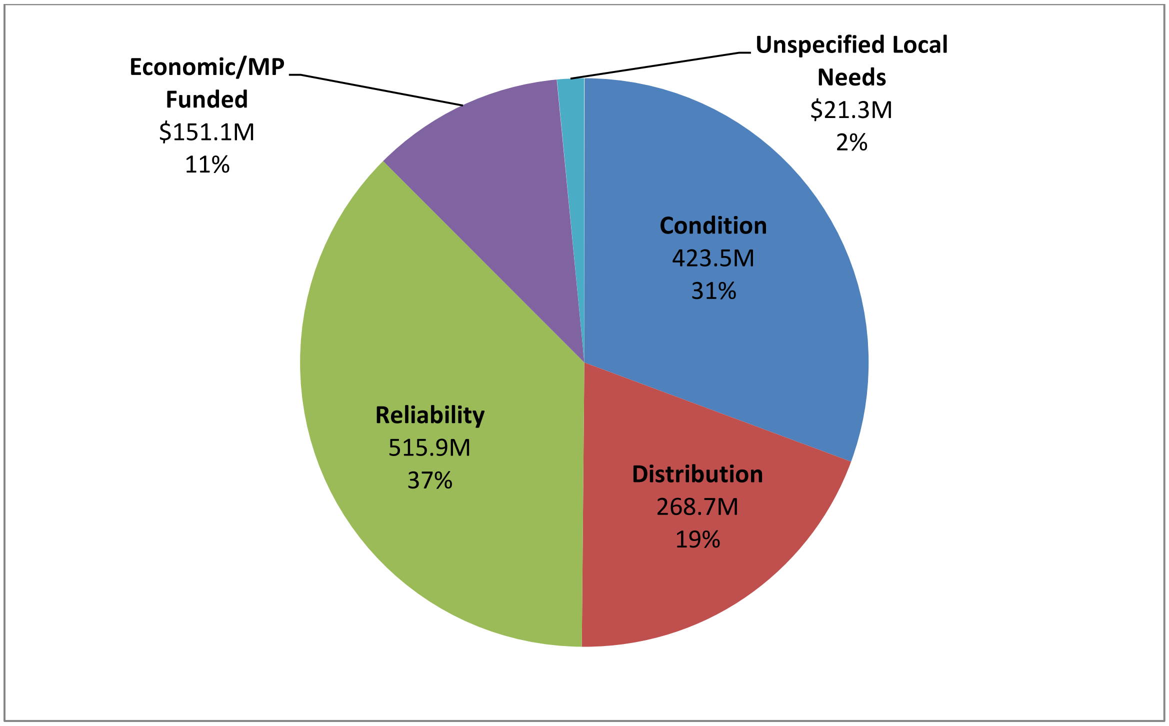


Figure 2.1-2: Subtype breakdown of new MTEP15 Appendix A Other projects

Facility Type

Each MTEP project is composed of one or more facilities. The facilities consist of elements such as substations, transformers and various types of transmission lines (Figure 2.1-3). About 60 percent of facility cost is categorized as transmission line — either new line on new right-of-way or line upgrades and rebuilds.

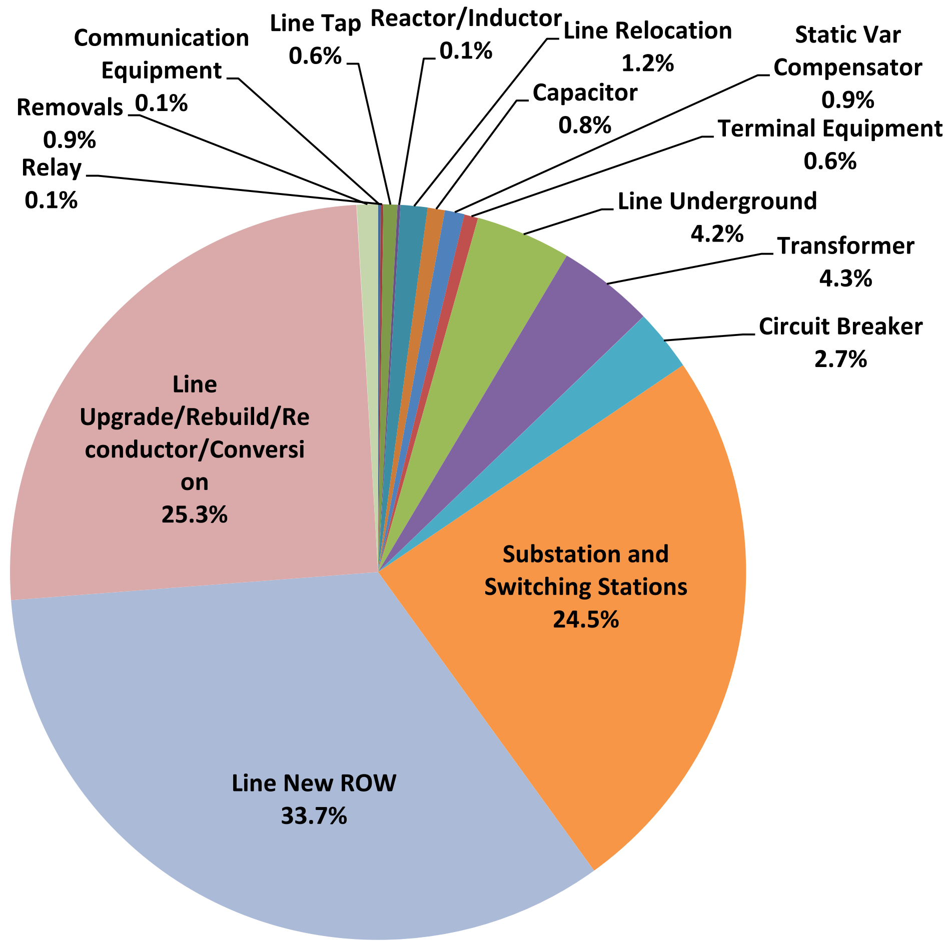


Figure 2.1-3: Facility type for new MTEP15 Appendix A projects

New Appendix A projects are spread over 14 states, with eight states scheduled for more than $100 million in new investment (Figure 2.1-4). A few projects have investment in more than one state, but the statistics in the figure are aggregated to the primary state. These geographic trends vary greatly year to year as existing capacity in other parts of the system is consumed and new build becomes necessary.

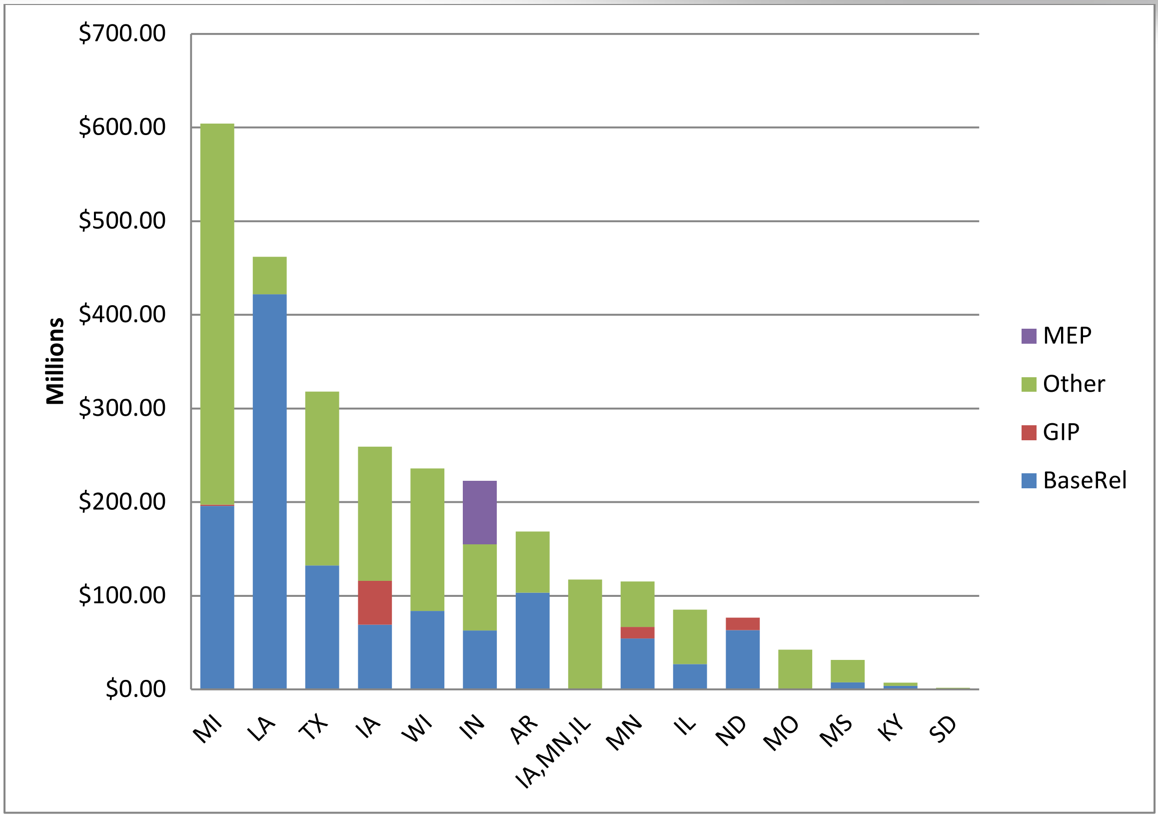


Figure 2.1-4: New MTEP15 Appendix A investment categorized by state

Active Appendix A Investment

The active project spending for Appendix A, with the addition of MTEP15 new projects, increases to 939 projects amounting to approximately $12.9 billion of investment (Figure 2.1-5). MTEP15 Appendix A contains newly approved projects and previously approved projects that are not yet in service. Projects may be comprised of multiple facilities. Large project investment is shown in a single year but often occurs over multiple years (Figure 2.1-6). Investment totals by year assume that 100 percent of a project's investment is fulfilled when the facility goes into service.

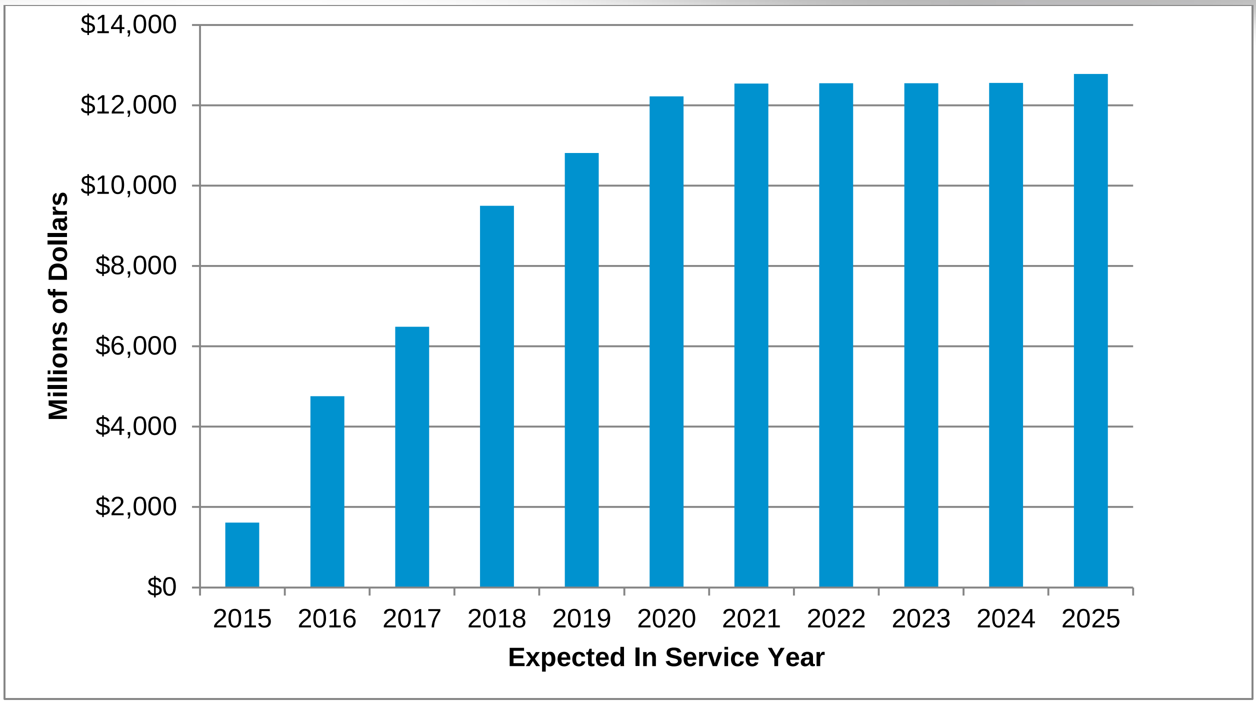


Figure 2.1-5: MTEP15 Appendix A projected cumulative investment by year

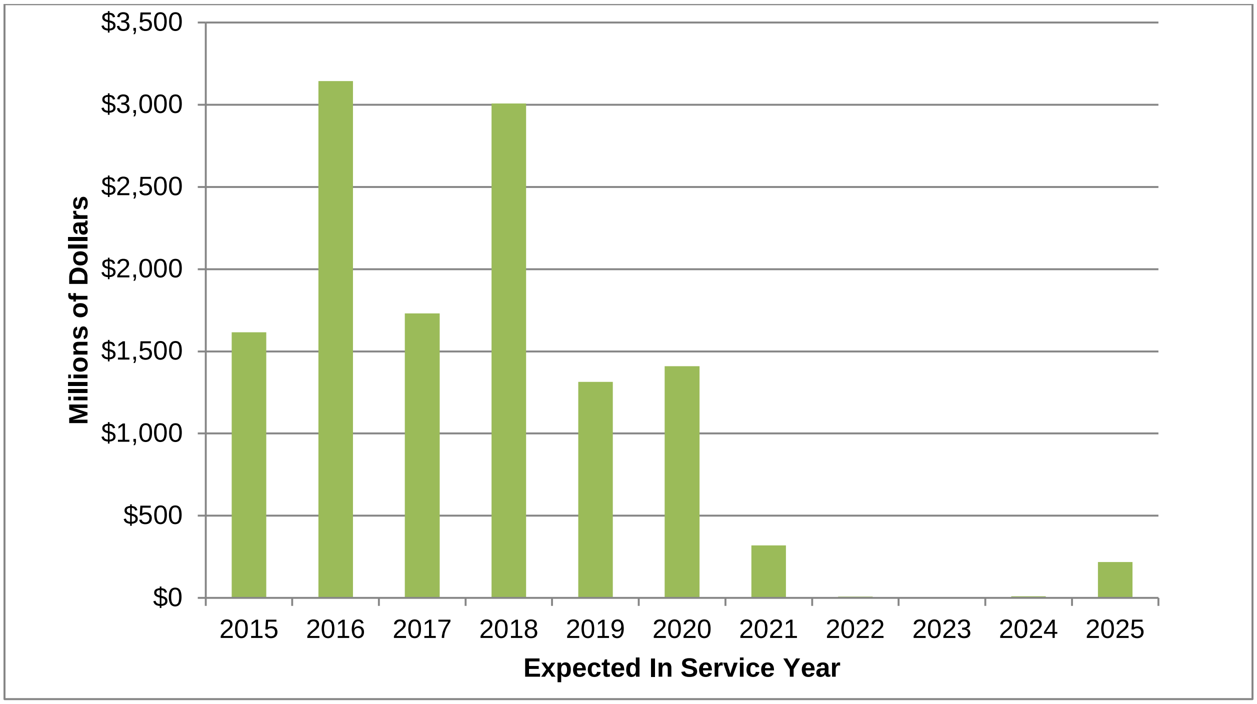


Figure 2.1-6: MTEP15 Appendix A projected incremental investment by year

MISO Transmission Owners[3] have committed to significant investments in the transmission system (Table 2.1-2). Cumulative MTEP transmission investment for Appendix A is approximately $12.9 billion with another $2.8 billion in Appendix B. New MTEP15 Appendix A projects represents $2.7 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 $13.0 billion in cumulative Appendix A is from the Multi-Value Projects (MVP) approved in MTEP11. Projects are spread across the four MISO geographic planning regions: East, Central, West and South (Figure 2.1-7).

MISO Region	Number of Appendix A Projects	Appendix A Estimated Cost	Number of Appendix B Projects	Appendix B Estimated Cost
Central	170	$3,095,150,000	69	$240.248,000
East	196	$1,603,368,000	36	$498,463,000
West	368	$6,931,160,000	82	$1,812,480,000
South	129	$1,228,188,000	31	$286,696,000
Total	**863**	**$12,857,866,000**	**218**	**$2,837,887,000**

Table 2.1-2: Projected transmission investment by planning region

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

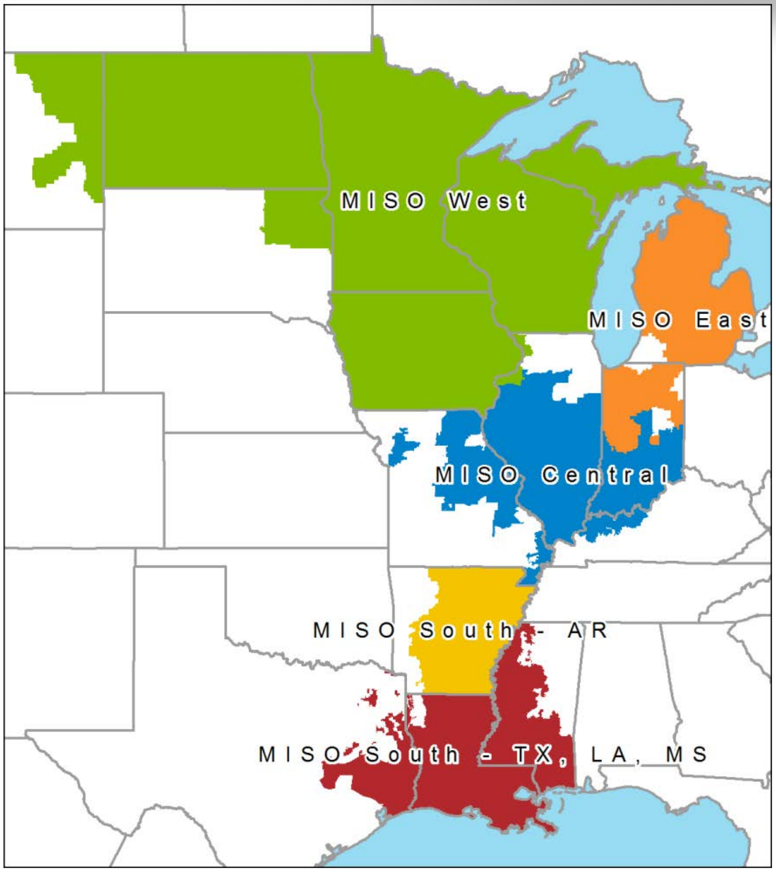


Figure 2.1-7: MISO footprint and planning regions (South contains two SPM regions)

Active Appendix A Line Miles Summary

MISO has approximately 66,500 miles of existing transmission lines. There are approximately 7,700 miles of new or upgraded transmission lines projected in the 10-year planning horizon in MTEP15 Appendix A (Figure 2.1-8, Table 2.1-3).

- 4,600 miles of upgraded transmission line on existing corridors are planned
- 3,100 miles of new transmission line on new corridors are planned

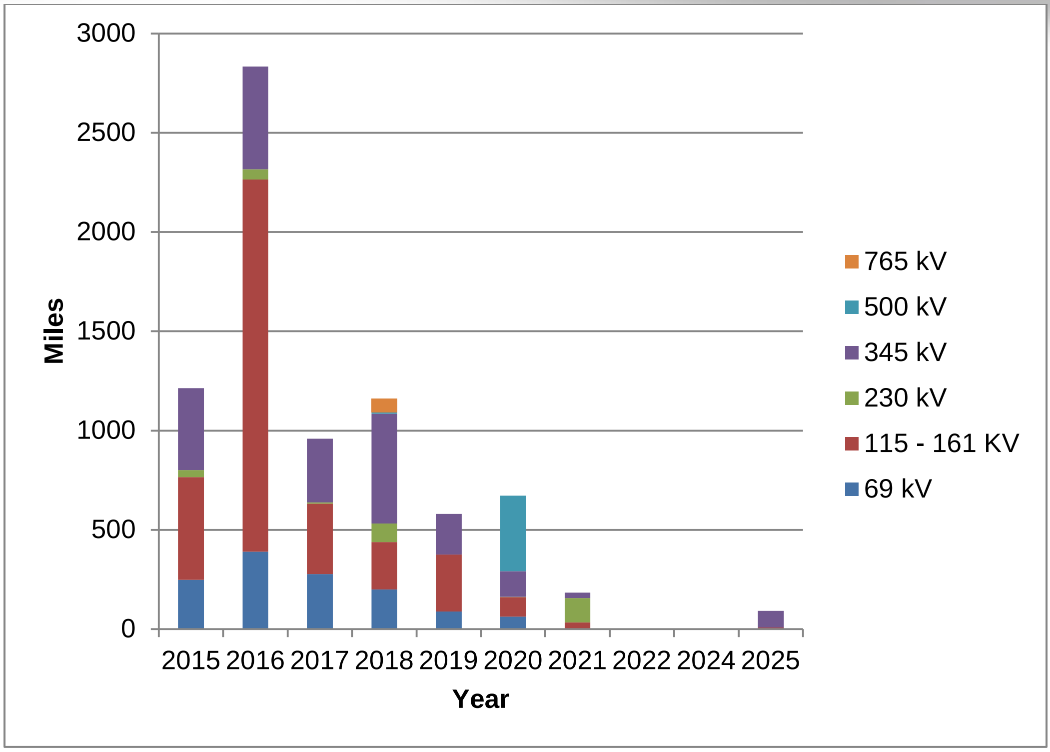


Figure 2.1-8: New or upgraded line miles by voltage class (kV) in Appendix A through 2025

Year	69 kV	115-161 kV	230 kV	345 kV	500 kV	765 kV	Grand Total
2015	249	517	35	413	0	0	**1214**
2016	390	1875	50	519	0	0	**2834**
2017	278	355	6	320	0	0	**959**
2018	201	239	93	554	7	69	**1162**
2019	90	286	0	205	0	0	**580**
2020	64	97	2	129	380	0	**673**
2021	0	35	121	29	0	0	**185**
2022	0	0	0	0	0	0	**0**
2024	0	0	0	0	0	0	**5**
2025	0	8	0	85	0	0	**93**
Grand Total	**1271**	**3412**	**307**	**2254**	**387**	**69**	**7700**

Table 2.1-3: New or upgraded line miles by voltage class (kV) in Appendix A through 2025

2.2 Cost Sharing Summary

New MTEP15 Appendix A Cost-Shared Projects

MTEP15 recommends a total of four new cost-shared projects, with a total project cost of $90.3 million for inclusion in Appendix A. The four cost-shared projects include:

- Three Generator Interconnection Projects (GIP) with a total project cost of $22.9 million, with $2.0 million allocated to load and the remaining $20.9 million allocated directly to generators[4]
- One Market Efficiency Project (MEP) with a total project cost of $67.4 million

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

Cost Allocation Between Planning Areas For GIPs and MEPs

With the integration of the MISO South region on December 19, 2013, a cost allocation transition period started that determines how approved cost-allocated projects are shared amongst the pricing zones in the MISO North/Central and MISO South planning areas. The transition period concludes when certain Tariff criteria are met, likely in MTEP19.[5] The cost-shared projects in MTEP15 all terminate exclusively in the MISO North/Central planning area, and are cost shared amongst the MISO North/Central planning area pricing zones (Table 2.2-1).

Type and Location of Project	Approved Before Transition Period		Approved and/or Identified During Transition Period		Approved After Transition Period Ends
	Treatment During Transition Period	Treatment After Transition Period	Treatment During Transition Period	Treatment After Transition Period	
GIPs and MEPs terminating exclusively in one planning area	Within North/Central planning area	Within North/Central planning area	Within applicable planning area	Within applicable planning area	Applicable to both planning areas
GIPs and MEPs terminating in both planning areas	Not Applicable	Not Applicable	Applicable to both planning areas	Applicable to both planning areas	Applicable to both planning areas

Table 2.2-1: Cost-shared GIP and MEP transition period Tariff provisions

[4] Note that the $20.9 million value indicated as allocated to generators does not account for the Transmission Owners who reimburse qualifying generators 100 percent of the costs incurred for Generation Interconnection Projects.

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

Cumulative Summary of All Cost-Shared Projects Since MTEP06

A total of 161 projects have been eligible for cost sharing since cost-sharing methodologies were first incorporated into the MTEP process. Cost sharing began in 2006 with Baseline Reliability Projects[6] (BRP) and GIPs and was later augmented with MEPs in 2007 and Multi-Value Projects (MVP) in 2010. Starting with MTEP13 and going forward, the costs for BRPs were removed from cost sharing and allocated to the pricing zone of the project location. The cost-shared projects represent $9.9 billion in transmission investment, excluding projects that have been subsequently withdrawn or had a portion of project costs allocated directly to generators for GIPs (Figure 2.2-1 and Table 2.2-2). The distribution of cost-shared projects includes:

- Baseline Reliability Projects (BRP) — 76 projects, $3.127 billion
- Generation Interconnection Projects (GIP) — 65 projects, $283 million (excluding the portion of project costs allocated directly to the generator)
- Market Efficiency Projects (MEP) — three projects, $81 million
- Multi-Value Projects (MVP) — 17 projects, $6.389 billion

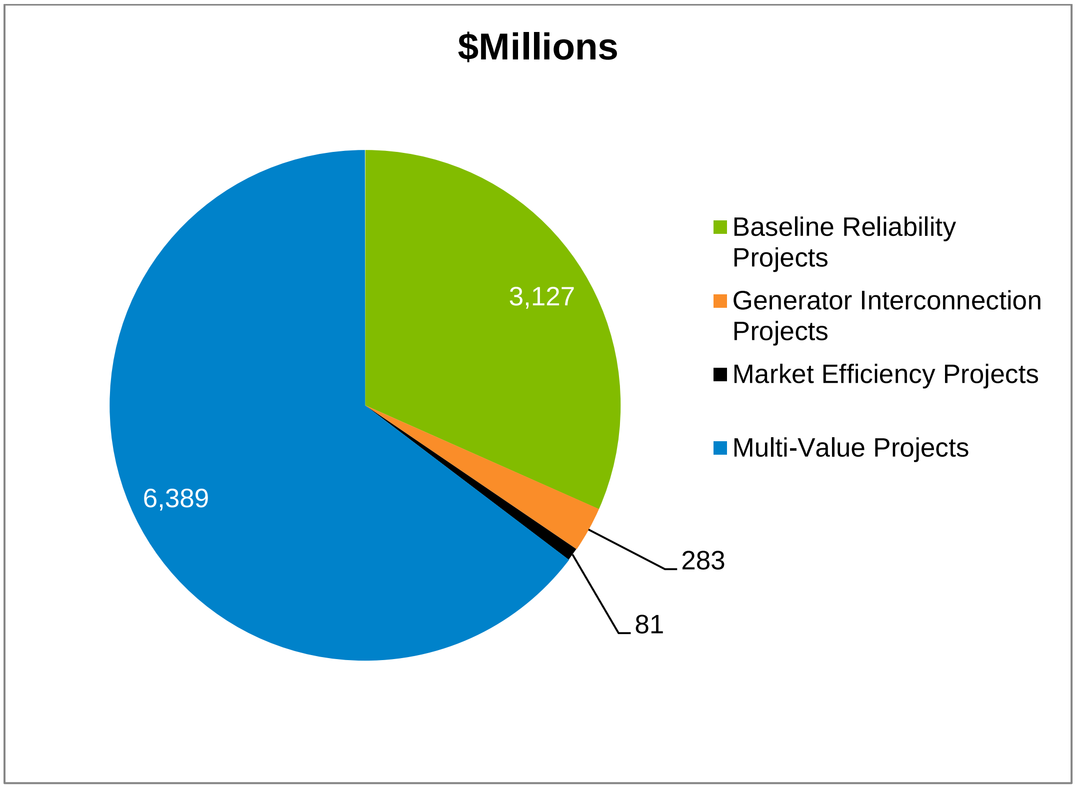


Figure 2.2-1: MTEP cumulative cost sharing by project type ($millions)

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

Cost-Shared Project Type	BRP	GIP	MEP	MVP	Total
A in MTEP06	$672.5	$16.0	-	-	$688.5
A in MTEP07	$86.0	$16.6	-	-	$102.6
A in MTEP08	$1,307.7	$11.8	-	-	$1,319.5
A in MTEP09	$168.0	$63.2	$5.6	-	$236.8
A in MTEP10	$43.7	$1.5	-	$510.0	$555.2
A in MTEP11	$382.1	$46.6	-	$5,879.4	$6,308.1
A in MTEP12	$466.9	$106.8	$8.0	-	$581.7
A in MTEP13	-	$3.0	-	-	$3.0
A in MTEP14	-	$15.1	-	-	$15.1
A in MTEP15	-	$2.0	$67.4	-	$69.4
Total	$3,126.9	$282.6	$81.0	$6,389.4	$9,879.9

Table 2.2-2: MTEP06 to MTEP15 cost-shared project costs by MTEP cycle and project type (shown in $millions)

Cost allocation methods vary depending on the classification of the project. For BRPs, GIPs and MEPs, the majority of the costs are allocated to the pricing zone where the project is located.[7] Of the $3.5 billion in approved costs for these project types (not including MVPs), approximately 66.2 percent ($2.3 billion) is allocated to the pricing zone where the project is located. The remaining 33.8 percent ($1.2 billion) is allocated to neighboring pricing zones or to all pricing zones system-wide.

66.2 percent ($2.3 billion) of BRP, GIP and MEP remains in the pricing zone where the project is located with the remaining 33.8 percent ($1.2 billion) allocated to neighboring pricing zones or system-wide to all pricing zones

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

[7] See Chapter 5.1 for more information on project cost allocation

Pricing Zone	Total Approved Cost Shared Transmission Investment	Costs Allocated for Projects Located Outside Pricing Zone	Costs Allocated for Projects Located within the Pricing Zone	Total Project Cost Allocated to Pricing Zone
[1]	[2]	[3]	[4]	[5] = [3] + [4]
AMIL	$151.9	$42.3	$125.5	$167.8
AMMO	$84.3	$32.0	$78.4	$110.4
ATC	$944.9	$89.6	$786.2	$875.8
BREC	$5.2	$5.5	0.3	$5.8
CLEC	0.0	0.0	0.0	0.0
CWLD	0.0	$1.0	0.0	$1.0
CWLP	$7.1	$1.7	$7.0	$8.7
DPC	$18.8	$4.0	$8.9	$12.9
DUK	$46.0	$113.3	$41.8	$155.1
EATO	0.0	0.0	0.0	0.0
ELTO	0.0	0.0	0.0	0.0
EMTO	0.0	0.0	0.0	0.0
ETTO	0.0	0.0	0.0	0.0
FE	$16.6	$37.4	$14.7	$52.1
GRE	$201.7	$28.6	$9.8	$38.4
HE	$14.8	$13.0	$0.4	$13.4
IPL	$18.9	$24.9	$3.9	$28.8
ITC	$186.4	$42.2	$163.0	$205.2
ITCM	$153.7	$53.1	$128.6	$181.7
LAFA	0.0	0.0	0.0	0.0
MDU	$9.4	$9.9	$9.2	$19.1
MEC	$0.6	$6.5	0.0	$6.5

METC	$438.0	$89.9	$425.5	$515.4
MI13AG	$0.9	$1.9	$0.7	$2.6
MI13ANG	0.0	$2.7	0.0	$2.7
MP	$135.7	$105.9	$37.5	$143.4
MPW	0.0	$0.2	0.0	$0.2
NIPS	$21.5	$25.9	$20.4	$46.3
NSP	$593.7	$305.2	$328.2	$633.4
OTP	$187.1	$116.4	$52.2	$168.6
SIPC	0.0	$1.9	0.0	$1.9
SME	0.0	0.0	0.0	0.0
SMMPA	$50.0	$19.1	$4.0	$23.1
VECT	$203.4	$6.3	$64.0	$70.3
Total	**$3,490.6**	**$1,180.4**	**$2,310.2**	**$3,490.6**

Table 2.2-3: Allocated project cost ($millions) from MTEP06 to MTEP15 for approved Baseline Reliability (cost-shared through MTEP13), Generation Interconnection and Market Efficiency projects

For the average residential household that uses 1,000 kWh each month, the estimated monthly cost for MVPs averages to $1.73 per month over the next 20 years

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

Indicative annual MVP Usage Rates[8] (dollar per MWh) are based on the approved MVP portfolio using current estimated project costs and in-service dates. The MVP usage rates have been calculated for the period 2016 to 2055 and are shown by the blue line (Figure 2.2-2).[9] The red and green lines in Figure 2.2-2 represent an average of the estimated MVP Usage Rates over 20 and 40 year

[8] 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 Projects those charges are recovered through Schedule 39

[9] The annual estimated MVP Usage Rates for 2016 to 2055 shown in Figure 2.2-2 are included in Appendix A-3. Additional information on the indicative annual MVP Usage Rates, including indicative annual MVP charges by Local Balancing Authorities can be found on the MISO website at the following URL under the MTEP Study information section: https://www.misoenergy.org/Planning/TransmissionExpansionPlanning/Pages/MTEPStudies.aspx

periods. For the average residential household that uses 1,000 kWh each month, the estimated monthly cost for MVPs averages to $1.73 per month over the next 20 years.

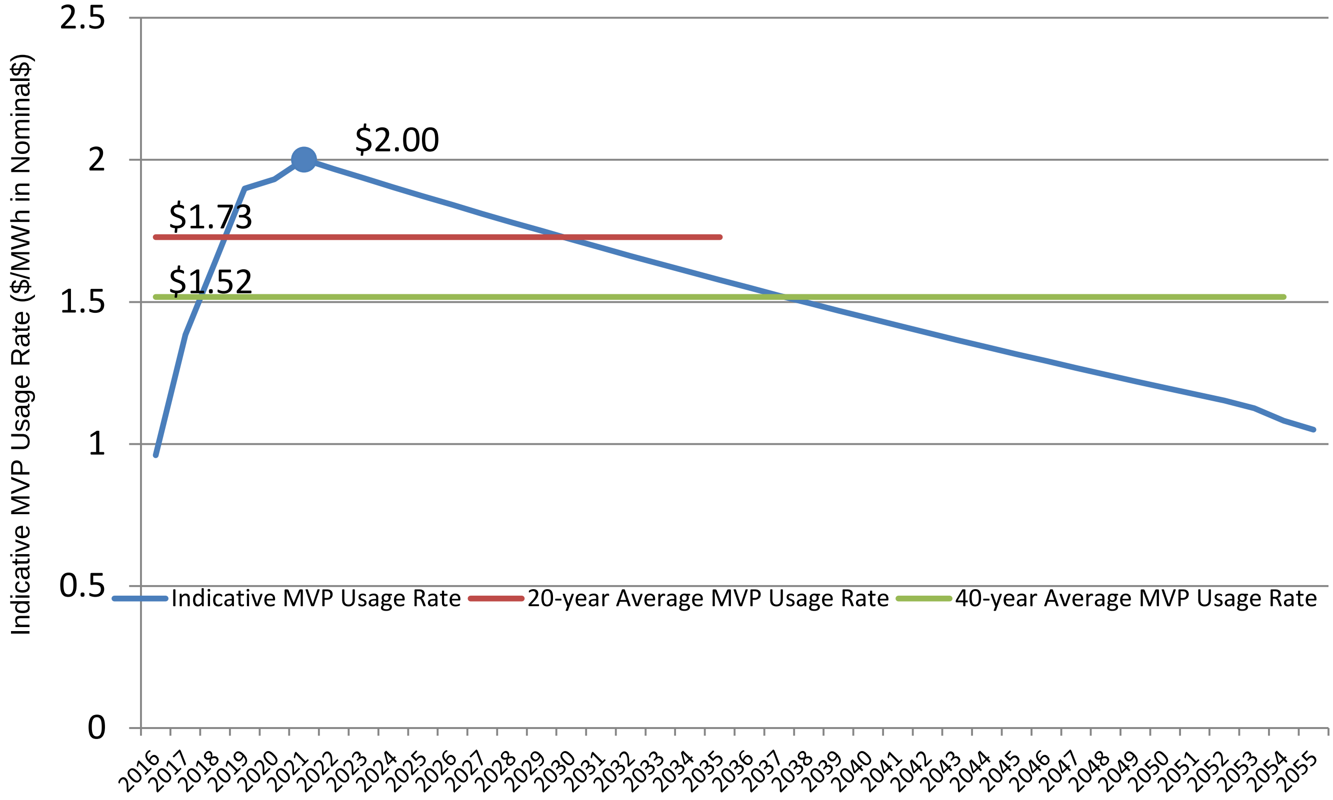


Figure 2.2-2: Indicative MVP usage rate for approved MVP portfolio from 2016 to 2055

2.3 MTEP15 Process and Schedule

MTEP is a myriad of moving pieces. Each piece needs to fit together to create the complete plan. At its most basic level MTEP is MISO's annual process to study and recommend transmission expansion projects for inclusion in MTEP Appendix A. Official approval of this report and its list of transmission projects occurs, if justified, at MISO's December 2015 Board of Directors meeting.

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

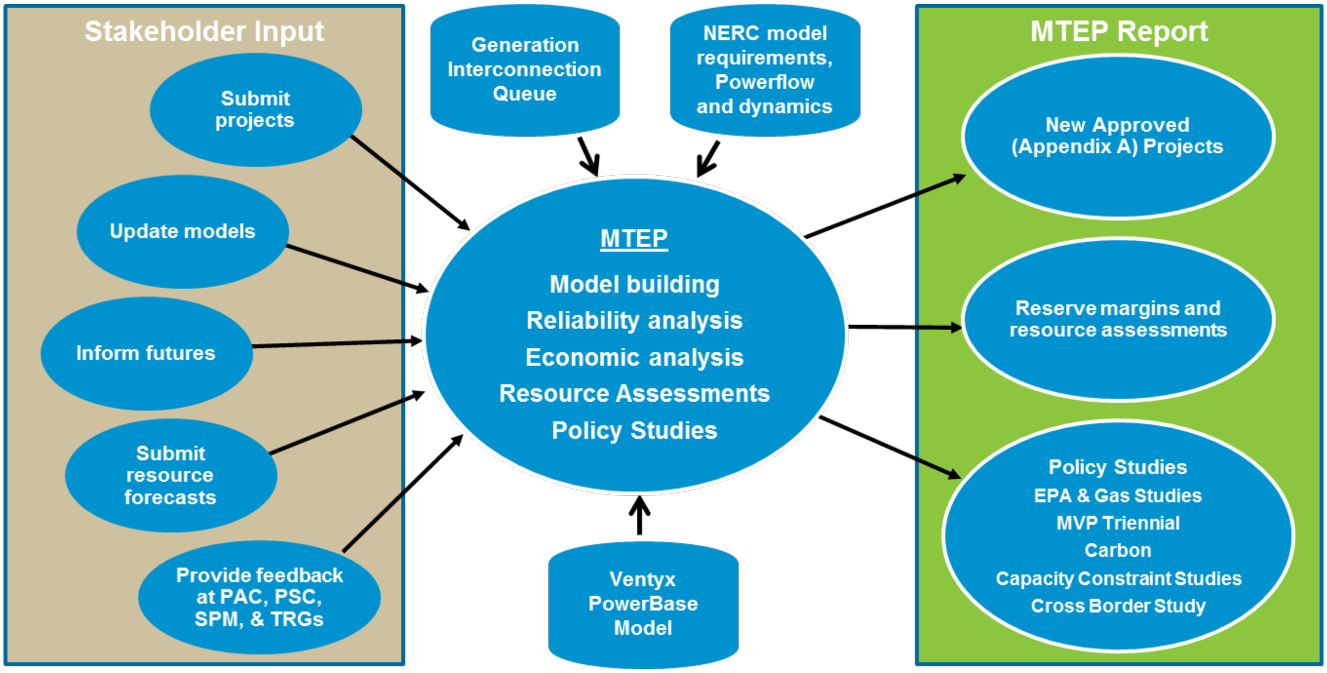


Figure 2.3-1: MTEP inputs and outputs

MTEP Planning Approach

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

Figure 2.3-2: MISO Value-Based Planning Approach

MTEP15 Workstreams

Completion of MTEP15 requires coordination between multiple subject-matter experts and different types of analyses (Figure 2.3-3). It integrates reliability, transmission access, market efficiency, public policy and other value drivers across all planning horizons.

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

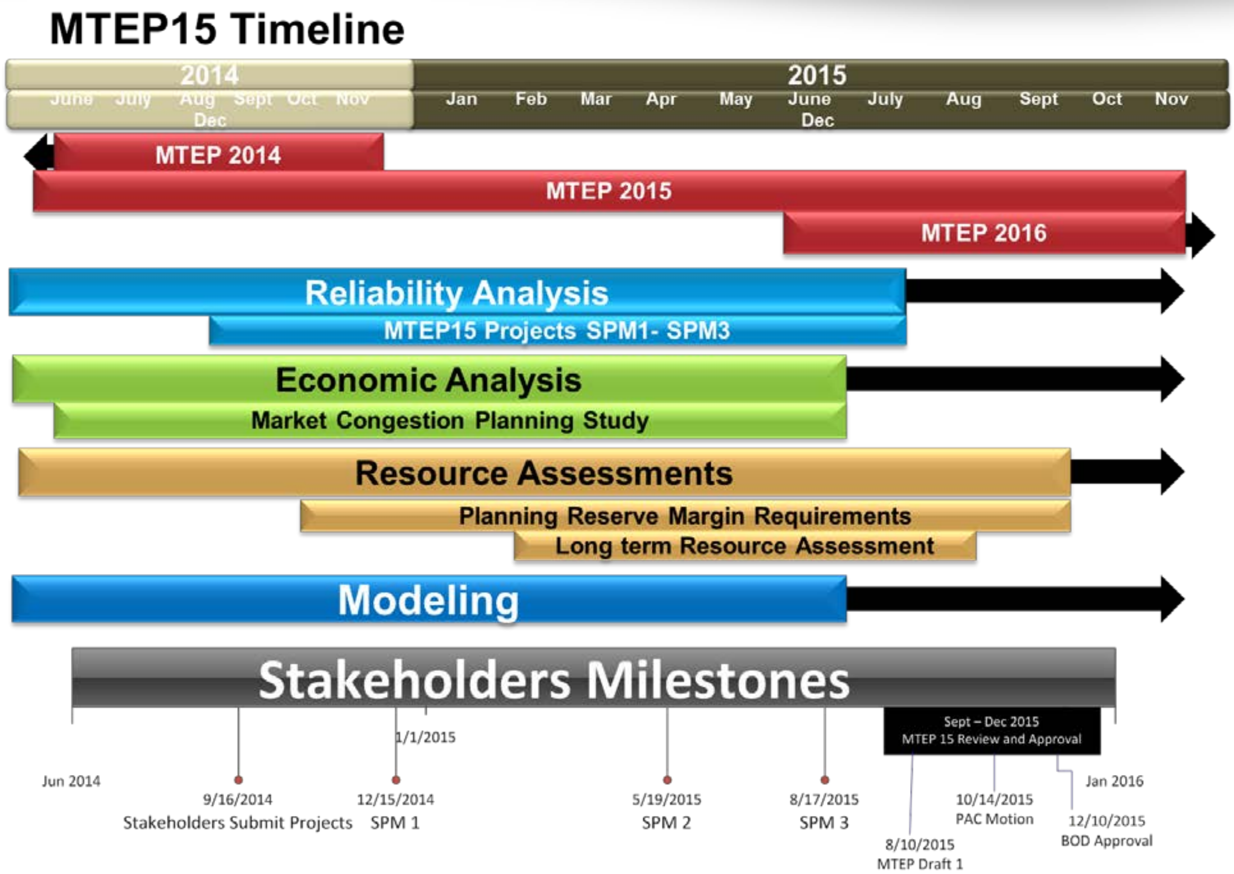


Figure 2.3-3: MTEP15 baseline timeline

Stakeholder Involvement in MTEP15

Stakeholders provide model updates; project submissions; input on appropriate assumptions; and review the results and report. This feedback occurs through a series of stakeholder forums. Each of the five subregions hold Subregional Planning Meetings (SPM) at least three times annually (per FERC Order 890 requirements) to review projects specific to its region. MISO staff and stakeholders review system needs for each project. Some projects may also use stakeholder Technical Study Task Forces (TSTF) to discuss analytical results in greater detail or when these results are Critical Energy Infrastructure Information (CEII).[10] The SPMs report up to the Planning Subcommittee (PSC). The Planning Advisory Committee (PAC) reviews the full MTEP report in detail, and provides formal feedback to the System Planning Committee (SPC), which is made up of members of the MISO Board of Directors. The SPC makes its recommendations to the full Board, which has final approval authority (Figure 2.3-4).

[10] See Chapter 4.1 for more information about FERC Order 890 requirements and milestones.

Figure 2.3-4: MTEP stakeholder forums

MTEP15 Schedule

Each MTEP cycle spans 18 months. MTEP15 began June 2, 2014, and ends December 10, 2015, with Board approval consideration (Table 2.3-1).

Milestone	Date
Stakeholders submit proposed MTEP15 projects	September 16, 2014
First round of Subregional Planning Meetings (SPM)	December 11, 2014
Stakeholders submit GADS data	January 30, 2015
Second round of Subregional Planning Meetings (SPM)	May 19, 2015
PROMOD models complete	June 6, 2015
Powerbase modeling complete	June 30, 2015
Dynamics models complete	July 13, 2015
MTEP15 Report first draft posted	August 10, 2015
Third round of SPM meetings (7/27 - 8/17)	August 17, 2015
Planning Advisory Committee final review and motion	October 14, 2015
MISO System Planning Committee	October 20, 2015
MISO Board - System Planning Committee review	November 19, 2015
MISO Board of Directors meeting to consider MTEP15 approval	December 10, 2015

Table 2.3-1: MTEP15 schedule, major milestones

A Guide to MTEP Report Outputs

MTEP15 is organized into four books and a series of detailed appendices.

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

2.4 MTEP Project Types and Appendix Overview

MTEP Appendices A and B contain the universe of projects vetted by MISO through the planning process. The appendices in the final MTEP report indicate the status of a given project in the MTEP review process. Appendix A contains projects approved by the MISO Board of Directors, thereby creating a good-faith obligation for the Transmission Owner to build it. Appendix B lists projects with a documented need and anticipated effectiveness, but are not ready for execution. A move from Appendix B to Appendix A is the most common progression through the appendices, but projects may remain in Appendix B for a number of planning cycles.

Appendix A contains projects approved by the MISO Board of Directors, thereby creating a good-faith obligation for the Transmission Owner to build it

Appendix A includes projects from prior MTEPs that are not yet in service, as well as new projects recommended to the MISO Board of Directors for approval in this cycle. The newest projects are indicated as “A in MTEP15” in the “Target Appendix” field of the Appendix A spreadsheet.

There are three distinct categories of transmission projects:

- Bottom-Up Projects
- Top-Down Projects
- Externally Driven Projects

The specific types of transmission projects include:

- Other Projects
- Baseline Reliability Projects
- Market Efficiency Projects
- Multi-Value Projects
- Generation Interconnection Projects
- Transmission Delivery Service Projects
- Market Participant Funded Projects

Specific transmission project types align to their parent transmission project categories (Table 2.4-1).

	Bottom-Up Projects	Top-Down Projects	Externally Driven Projects
Other Projects	X		
Baseline Reliability Projects	X		
Market Efficiency Projects		X	
Multi-Value Projects		X	
Generation Interconnection Projects			X
Transmission Delivery Service Projects			X
Market Participant Funded Projects			X

Table 2.4-1 Transmission Project Type-To-Category Mapping

Bottom-Up Projects

Bottom-up projects include transmission projects classified as Other projects and Baseline Reliability Projects, are not cost shared and are generally developed by Transmission Owners. MISO will evaluate all bottom-up projects submitted by Transmission Owners and validate that the projects represent prudent solutions to one or more identified transmission issues.

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

- **Other** projects address a wide range of project drivers and system needs. Some of these drivers may include local reliability needs, economic benefits and/or public policy initiatives or projects that are not a part of the bulk electric system under MISO functional control. Because of this variety, Other projects generally get classified in one of the following sub-types: Clearance, Condition, Distribution, Local Economic, Local Multiple Benefit, Metering, Operational, Performance, Reconfiguration, Relay, Reliability, Relocation, Replacement and Retirement.

Top-Down Projects

Top-down projects include transmission projects classified as Market Efficiency Projects and Multi-Value Projects. Regional or sub-regional top-down projects are developed by MISO working in conjunction with stakeholders to address regional economic and/or public policy transmission issues. Interregional top-down projects are developed by MISO and one or more additional planning regions in conjunction with stakeholders to address interregional transmission issues. Interregional projects are cost shared per provisions in the Joint Operating Agreement and/or MISO tariff, first between MISO and the other planning regions, then within MISO based on provisions in Attachment FF of the MISO tariff.

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

Externally Driven Projects

Externally driven projects are projects driven by needs identified through customer-initiated processes under the Tariff. Externally driven projects are Generation Interconnection Projects, Transmission Delivery Service Projects and Market Participant Funded Projects.

- **Generation Interconnection Projects (GIP)** are upgrades that ensure the reliability of the system when new generators interconnect. The customer may share the costs of network upgrades if a contract for the purchase of capacity or energy is in place, or if the generator is designated as a network resource. Not all network upgrades associated with GIPs are eligible for cost sharing between pricing zones.
- **Transmission Delivery Service Project (TDSP)** projects are required to satisfy a transmission service request. The costs are generally assigned to the requestor.
- **Market Participant Funded Projects** represent transmission projects that provide benefits to one or more market participants but do not qualify as Baseline Reliability Projects, Market Efficiency Projects or Multi-Value Projects. These projects are not cost shared through the MISO tariff. Their construction is assigned to the applicable Transmission Owner(s) in accordance with Appendix B of the Transmission Owners Agreement upon execution of the applicable agreement(s).

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.[11]

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

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

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

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

- Consider and review planning-level costs
- Endorse the project
- Verify whether the project is qualified for cost sharing as a Generation Interconnection Project, Market Efficiency Project or Multi-Value Project per provisions of Attachment FF or if it will be participant-funded
- Hold a stakeholder meeting to review a project or group of projects in which costs can be shared, or other major projects for zones where 100 percent of costs are recovered under the Tariff
- Take the new project to the Board of Directors for approval. Projects may move to Appendix A following a presentation at any regularly scheduled board meeting

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

MTEP Appendix B

Projects in Appendix B have been validated by MISO as a potential solution to address a documented transmission issue, but are deferred to a future MTEP cycle for final recommendation. Appendix B may contain multiple solutions to a common set of transmission issues. Projects in Appendix B are not yet recommended or approved by MISO, so they are not evaluated for cost sharing. Any designation of project type (Baseline Reliability Projects, Market Efficiency Projects or Multi-Value Projects) for projects in Appendix B is preliminary. Thus, while some projects may eventually become eligible for cost-sharing, the target date does not require a final recommendation for the current MTEP cycle. The project will likely be held in Appendix B until the review process is complete and the project is moved to Appendix A.

2.5 MTEP15 Model Development

Transmission system models are the foundation of the MTEP analytical processes. The viability of the study results hinges on the accuracy of the models used. Planning model development at MISO is a collaborative process with significant stakeholder interaction and neighbor coordination. Stakeholders provide modeling data, help develop assumptions for modeling future transmission system scenarios and review the models. MTEP models are also coordinated with MISO's neighboring entities and their system representation is updated based on their feedback.

MTEP15 underwent some expansion in the model building process. MISO developed a powerflow and dynamics model suite based on the new TPL-001-4 standard, which included new sensitivity scenarios to be built. Secondly, there were two sets of models built, driven by the Expansion Planning's study process change. One model set contained approved future projects from MTEP14 Appendix A, and the other model set contained approved MTEP14 Appendix A projects and projects targeted for approval in MTEP15.

Changes in the MTEP15 model-building process include additional powerflow and dynamics models based on a new standard

For MTEP studies, models for steady-state powerflow, dynamics stability reliability and economics are built to represent a planning horizon spanning the next 10 years. The primary sources of information used to develop the models are:

- MISO's Model on Demand (MOD) powerflow base case with future project information
- MISO members, including Transmission Owners, Generation Owners and Load-Serving Entities
- Eastern Reliability Assessment Group (ERAG) Multi-regional Modeling Working Group (MMWG) series models used for external area representation
- ABB PROMOD PowerBase database
- Neighboring planning entities

MTEP models are interdependent (Figure 2.5-1).

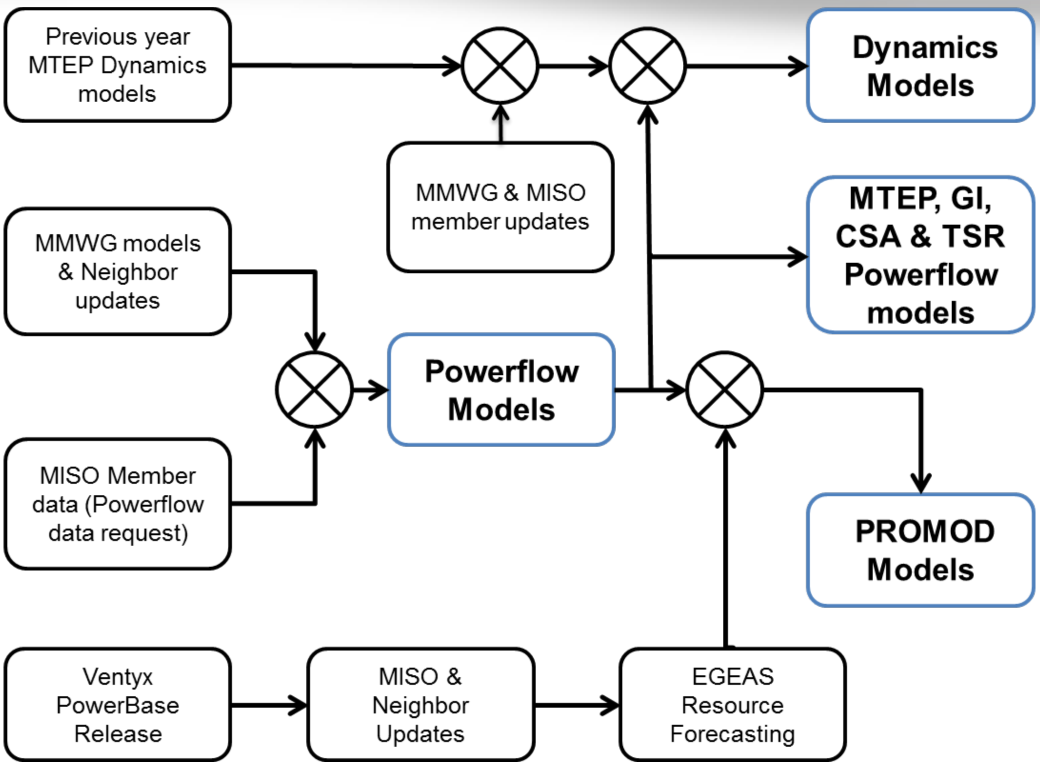


Figure 2.5-1: MTEP15 model relationships

Reliability Study Models

Powerflow Models

MISO developed regional powerflow models for MTEP15 as required by the new TPL-001-4 standard (Table 2.5-1). Developed model base cases and sensitivity cases are listed with the TPL-001-4 requirement.

Model Year	Base Case Models	Sensitivity Models
Year 2	2017 Summer Peak (Wind at 14.7%) *TPL requirement R2.1.1*	2017 Light Load (minimum load level) (Wind at 0%) *TPL requirement R2.1.4*
Year 5	2020 Summer Peak (Wind at 14.7%) *TPL requirement R2.1.1*	2020 Light Load (minimum load level) (Wind at 90%) *TPL requirement R2.1.4*
	2020 Summer Shoulder (70-80% peak) (Wind at 40%) *TPL requirement R2.1.2*	2020 Summer Shoulder (70-80% peak) (Wind at 90%) *TPL requirement R2.1.4*
	2020/21 Winter Peak (Wind at 30%) MISO MTEP model	Not required
Year 10	2025 Summer Peak (Wind at 14.7%) *TPL requirement R2.2.1*	Not required

Table 2.5-1: MTEP15 Powerflow Models

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

Load

- Load is modeled based on seasonal load projections provided by member companies to the MISO MOD system.

Generation

- Existing generators are included. Planned generators with signed Generation Interconnection Agreements are included according to their expected in-service dates.

Transmission Topology —Two sets of powerflow models were developed:

- MTEP14 Appendix A, which includes only future approved transmission facilities first approved in MTEP14 and future projects approved in prior MTEP studies.
- MTEP14 Appendix A plus MTEP15 Target Appendix A: This includes future transmission projects approved in Appendix A through prior MTEP studies and new transmission projects submitted for approval in the MTEP15 planning cycle to verify their need and sufficiency in ensuring system reliability

LBA Generation Dispatch Methodology

The generation dispatch in steady-state powerflow models is done at the Local Balancing Area (LBA) level. Network Resource type generation is dispatched in an economic order to meet the load, loss and interchange level for each LBA. The area interchange for each LBA is determined by the transaction table agreed upon by transaction participants, and the generation is dispatched to account for the cumulative MISO net area interchange level. Wind generation is typically an energy resource; however, wind generation is dispatched in models to address renewable energy standards. Wind generation is dispatched at capacity credit level in summer peak models and average and high levels in off-peak models. The percentage values for wind generation (Table 2.5-1), are based on the nameplate capacity.

- 14.7 percent is wind capacity credit based on MISO's Loss of Load Expectation study
- 40 percent represents the average wind output level
- 90 percent represents the high wind output level
- 30 percent represents the wind output level in the winter model

The input of LBA dispatch is the generation and load profile data submitted by members in the MOD system. Output of generators is determined considering several factors such as seasonal output variations, equipment limitations, policy regulations, approved retirements and local operational guidelines for reliable grid operation. Behind-the-meter generation, hydro machines and non-MISO generation information is retained from generation and load profiles submitted in MOD. Energy resources are not dispatched except for wind resources as described above.

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

Within the system conditions for each MISO control area for 2017 summer and 2020 summer models, there may be differences in the load values for each area from the Module E load values due to inclusion of station service loads and non-member loads embedded in MISO members' model control areas (Table 2.5-2).

Area	2017 Summer Peak (all numbers in MW)				2020 Summer Peak (all numbers in MW)			
	GEN	Load	Losses	Area Interchange	GEN	Load	Losses	Area Interchange
HE	1,282	510	26	746	1,126	526	25	576
DEI	7,591	7,416	314	(145)	7,940	7,554	314	65
SIGE	1,692	1,803	30	(141)	1,776	1,797	29	(50)
IPL	3,013	2,921	80	8	3,055	2,961	80	11
NIPS	3,308	3,643	55	(396)	3,450	3,760	61	(376)
METC	11,296	9,991	341	964	11,543	10,099	335	1,109
ITCT	10,927	11,418	242	(733)	10,810	11,385	245	(820)
WEC	6,650	6,436	99	103	6,717	6,559	101	45
MIUP	514	617	24	(128)	520	630	25	(136)
BREC	1,387	1,765	19	(396)	1,617	1,781	15	(179)
EES-EAI	9,004	7,738	197	1,068	9,217	7,951	175	1,088
LAGN	2,946	1,432	21	1,493	2,636	1,506	18	1,112
CWLD	226	390	1	(74)	248	417	1	(49)
SMEPA	1,124	789	23	312	1,194	817	23	355
EES	21,702	22,937	456	(1,701)	22,422	24,136	475	(2,198)
AMMO	9,287	8,767	185	334	9,362	8,691	199	472
AMIL	10,535	9,637	230	668	10,777	9,362	232	1,183
CWLP	519	439	4	76	516	449	4	64
SIPC	476	335	16	125	486	354	15	117
CLEC	3,423	2,713	67	643	3,641	2,833	73	735
LAFA	230	481	7	(259)	253	515	7	(269)
LEPA	87	229	0.1	(143)	92	235	0.1	(143)
XEL	9,253	10,353	263	(1,377)	9,433	10,585	244	(1,409)
MP	1,729	1,856	55	(184)	1,689	1,889	75	(277)
SMMPA	136	612	2	(478)	144	643	1	(500)
GRE	2,459	2,673	88	(304)	2,482	2,690	89	(300)
OTP	2,094	1,366	85	641	2,141	1,428	84	626
ALTW	3,984	4,059	83	(158)	4,161	4,262	89	(190)
MPW	225	162	1	62	223	164	2	57
MEC	5,827	6,004	92	(269)	5,828	6,196	93	(461)
MDU	421	685	14	(278)	420	738	14	(333)
DPC	917	1,061	41	(185)	909	1,091	41	(222)
ALTE	3,590	2,704	81	800	3,648	2,790	81	772
WPS	2,117	2,710	54	(652)	2,114	2,761	55	(707)
MGE	368	766	10	(410)	338	786	11	(460)
UPPC	60	234	8	(182)	57	236	8	(187)
	140,394	137,560	3,308	(549)	142,985	140,454	3,337	(880)

Table 2.5-2: System conditions for 2017 and 2020 models, for each MISO control area

Dynamic Stability Models

Dynamic stability models are used for transient stability studies performed as part of NERC TPL assessment and generation interconnection studies (Table 2.5-3). New stability models for study are required for TPL-001-4 standard.

Model Year	Base Case Dynamic Models	Sensitivity Dynamic Models
Year 5	2020 Summer Peak (Wind at 14.7%) *TPL requirement R2.4.1*	2020 Light Load (minimum load) (Wind at 90%) *TPL requirement R2.4.3*
	2020 Summer Shoulder (70-80% peak) (Wind at 40%) *TPL requirement R2.4.2*	2020 Summer Shoulder (70-80% peak) (Wind at 90%) *TPL requirement R2.4.3*

Table 2.5-3: MTEP15 dynamic stability models

The MTEP14 dynamics data was the starting point for MTEP15 dynamics model development. This data was updated with stakeholder feedback to develop the MTEP15 dynamics models. Additionally, the ERAG MMWG 2014 series dynamic stability models were reviewed and any improved modeling data was incorporated in the MTEP15 dynamics models.

Dynamic stability models included new dynamic load modeling practices driven by the new TPL standard

There is significant enhancement in load modeling in MTEP15 dynamic models driven by Requirement 2.4.1 of the TPL-001-4 standard. The load models must be represented by complex or composite load models to adequately capture the impact of induction motor loads. Assumptions for generator dispatch for stability models are identical to steady-state powerflow models.

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

During the MTEP15 dynamics models review, stakeholders were asked to provide inputs on:

- Updates to existing dynamics data
- Additional dynamic models for new equipment
- Output quantities to be measured

Economic Study Models

Economic study models are developed for use in the MTEP economic planning process. These models are forward-looking, hourly models based on assumptions discussed and agreed upon through the stakeholder process. For MTEP15, the Planning Advisory Committee (PAC) approved the following future scenarios:[12]

[12] For more details on these assumption scenarios, see Chapters 5.2: MTEP_ Future Development and 5.3: Market Congention Planning Study.

Central and North Regions

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

South Region

- Business as Usual (BAU)
- Generation Shift (GS)
- Public Policy (PP)
- South Industrial Renaissance (SIR)

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

Updates include data obtained from the following sources:

- MISO Commercial Model for generator maximum capacities and hub data
- Generator Interconnection Queues (MISO and neighbors) for future generators
- Module E data for energy and demand forecasts, behind-the-meter generation, interruptible loads and demand response data
- Powerflow model (developed through the MTEP process) for topology
- Publically announced generation retirements
- Specific stakeholder comments/updates
- Generation capacity expansion (developed by MISO staff — see Chapter 5.2: MTEP Future Development)

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

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

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

In addition to the stakeholder review process, MISO collaborates with neighboring entities to develop a coordinated model that more accurately reflects the neighbors' systems. Highlights of this collaboration include extensive updates from Pennsylvania-based PJM Interconnection and Arkansas-based Southwest Power Pool (SPP).

2.6 Competitive Transmission

In 2014 and 2015, MISO engaged its stakeholders in discussions to further refine and develop the competitive transmission process through multiple stakeholder workshops

As part of FERC Order 1000, all jurisdictional public utility transmission providers were required to remove from their tariffs and agreements any provisions that granted a federal right of first refusal to construct new transmission facilities whose costs are regionally allocated. In implementing this requirement, MISO adopted the developer selection approach in its competitive transmission process. As a result, the MTEP process will continue to determine which regional transmission facilities will be constructed; however, the construction, ownership, operation and maintenance of eligible transmission facilities will now be open to competition rather than automatically assigned to incumbent utilities. For any competitive transmission facility, MISO will solicit proposals from Qualified Transmission Developers, whether they are incumbents or new entrants.

MISO's competitive transmission process was filed in October of 2012; however MISO began to engage its stakeholders in discussions to further develop and refine the MISO competitive transmission process in 2014 through multiple stakeholder workshops.[13] MISO used this process to define:

- The criteria by which MISO qualifies interested transmission developers for the process
- The criteria by which a qualified transmission developer will be selected to construct, own, and operate regional transmission facilities (located in states that do not contain Right of First Refusal legislation)
- The triggers for reevaluating a project and/or transmission developer(s)

These workshops helped create the collaborative environment needed for MISO and its stakeholders to refine and develop this competitive process and the associated governance (including tariff language and business practice manuals).

The stakeholder workshop participation averaged more than 50 registered participants, including transmission developers, transmission owners, regulators and other interested parties. As a result, the MISO Tariff was revised in September 2015 and October 2015 to incorporate the competitive transmission process refinements and modifications. In addition, MISO revised its Business Practice Manuals (BPM) as a part of the stakeholder workshops. The BPMs are a product of the significant stakeholder input received during the stakeholder workshops, as well as information provided by MISO's subject-matter experts and expert consultants.

In 2015, MISO also conducted a dry run of the competitive transmission developer selection process to identify any process concerns, issues and improvements prior to the finalization of the process and its governing language. MISO created a hypothetical project and issued a Dry-Run Request for Proposals (RFP) to stakeholders on May 4, 2015. Participation in the dry run was voluntary and MISO received seven fictitious proposals from the following entities: Entergy Mississippi Inc./Entergy Arkansas Inc.; Xcel Energy Transmission Development Co.; Southern Indiana Gas & Electric Co., dba Vectren Energy Delivery; ITC Midwest LLC; Transource Energy LLC; Duke-American Transmission Co. LLC; and Public

[13] The Competitive Transmission Process webpage on the MISO website contains links to these stakeholder workshops. https://www.misoenergy.org/Planning/Pages/TransDevQualSel.aspx

Service Enterprise Group. The dry run afforded MISO a tremendous opportunity to understand improvements to its internal processes and to identify potential process improvements for both MISO and participating entities. In addition, it allowed the volunteering participants to provide constructive feedback on the dry run with suggestions and comments to improve the process. MISO thanks those that volunteered their time and resources to this effort. The dry-run exercise was a useful and beneficial effort for both MISO and the participants, as the broader MISO stakeholder community will benefit from the application of those lessons learned.

Process

The MISO Competitive Transmission Process has a defined life cycle (Figure 2.6-1).

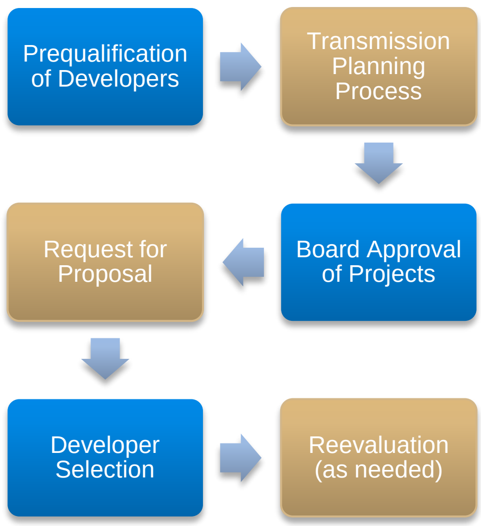


Figure 2.6-1: The lifecycle of the MISO Competitive Transmission Process

The prequalification process is an annual cycle that opens in January. Any transmission developer that intends to bid on MISO competitive transmission projects must be designated by MISO as a Qualified Transmission Developer (QTD) to submit a proposal. To obtain QTD status, interested transmission developers must submit an application and be approved by MISO in the annual prequalification cycle. An existing QTD must renew its status annually during the annual QTD renewal cycle, which happens simultaneously with the prequalification cycle.

Transmission facilities eligible for competitive bidding are developed through the MISO Transmission Expansion Planning (MTEP) process. Eligible transmission facilities, referred to as Competitive Transmission Projects, contain transmission facilities that are approved by the MISO Board of Directors as part of a Market Efficiency Project (MEP) or a Multi-Value Project (MVP) (Figure 2.6-2). Eligible transmission facilities include those facilities that are not upgrades or otherwise assigned to an incumbent Transmission Owner due to Applicable Laws and Regulations pursuant to Attachment FF Section VIII.A of the MISO Tariff.

The MISO competitive transmission process has no impact on the MTEP process; however it uses the MTEP output to determine Competitive Transmission Projects. All Competitive Transmission Projects will be posted to the MISO website for competitive bidding within 30 days of the MISO Board of Directors' approval of the MTEP report (typically in December of each year) (Figure 2.6-3). QTDs have six months to develop and submit their proposals; then MISO has six months after the submission deadline to evaluate the proposals and designate a Selected Proposal.

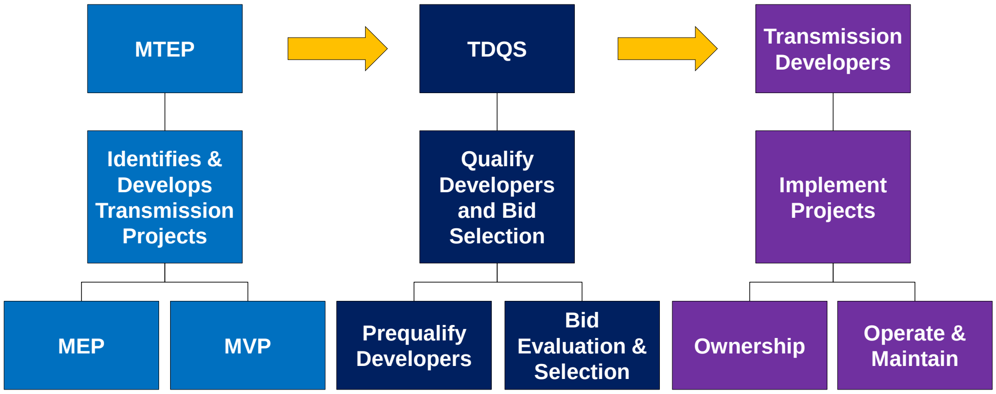


Figure 2.6-2: Process flow for Transmission Developer Qualification and Selection

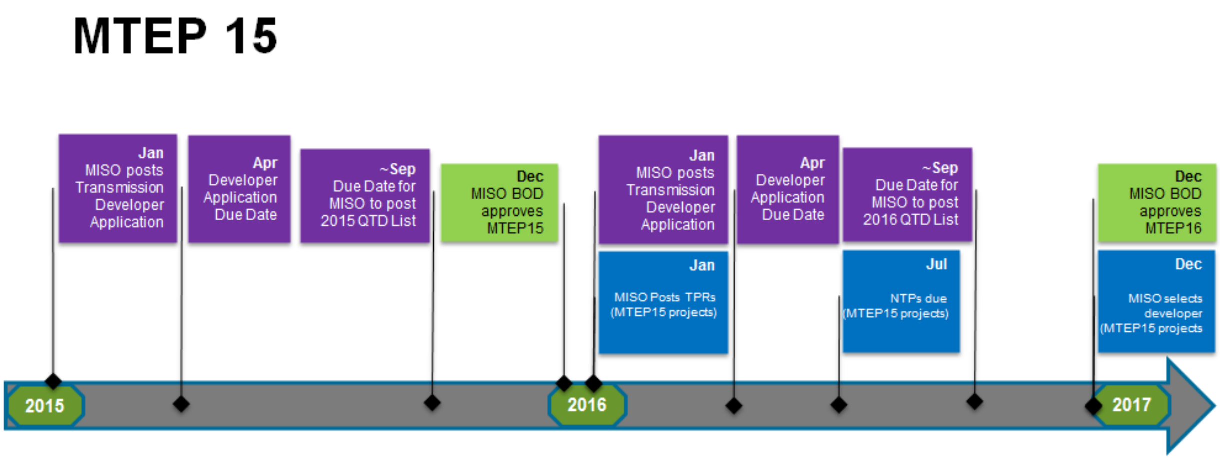


Figure 2.6-3: Annual Cycle

Potential Projects

MTEP14 was the first MTEP cycle in which eligible transmission facilities were subject to MISO's competitive transmission developer selection process and MTEP15 is the first MTEP cycle to recommend a project containing competitive transmission facilities. As discussed further in Chapter 5.3: Market Congestion Planning Study, MTEP15 recommends the approval of the Duff – Rockport – Coleman 345 kV Market Efficiency Project (MEP). This project contains Competitive Transmission Facilities eligible for the MISO competitive transmission developer selection process. Should the MISO Board of Directors approve the to-be-determined Market Efficiency Project as part of MTEP15, MISO will post a Request for Proposals for the to-be-determined Market Efficiency Project's Competitive Transmission Facilities and solicit proposals from QTDs within 30 days of the MISO Board of Directors' approval.

Chapter 3
Historical MTEP Plan Status

3.0 Introduction

Since the first MTEP report in 2003, more than $10.5 billion in projects have been constructed in the MISO region. Not including withdrawn projects, there are currently $23.3 billion of approved projects in various stages of design, construction, or already in-service through the MTEP15 cycle.

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

3.1 MTEP13 Status Report

MISO transmission planning responsibilities include monitoring the status of previously approved MTEP Appendix A projects. MISO surveys all Transmission Owners on a quarterly basis to determine the progress of each project. Since 2006, these status updates are reported to the MISO Board of Directors and posted to the MISO MTEP Studies web page. This chapter provides the status of MTEP14 Appendix A projects as of April 2015, and elaborates on the status of the MTEP11-approved Multi-Value Project (MVP) Portfolio.

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

Following a project's approval, MISO provides transparency by tracking the progress of projects. Project tracking ensures a good-faith effort to move projects forward, as prescribed in the Transmission Owners' Agreement. Transmission Owners provide costs, in-service dates and status updates after these project milestones:

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

Going forward, as part of MISO's Order 1000 implementation, MISO's post approval role will expand for cost-shared projects. Cost-shared projects and the developers selected to construct, own and operate them are subject to reevaluation if costs increase, schedules are delayed or the selected developer's qualifications/capabilities materially change. MISO and its stakeholders continue to develop the criteria and process to determine if a selected developer and/or a project should continue to be constructed to meet the needed driver and timetable.[14]

No MTEP15 projects are under reevaluation; however, general cost overrun and in-service date delay thresholds are referenced to concentrate the MTEP15 variance analysis on only relevant projects and trends. While only projects exceeding potential thresholds are highlighted in this chapter, these projects are the exception and not the norm. The majority of projects have small or no deviations from the MTEP approved costs and schedule.

The majority of projects have small or no deviations from the MTEP approved costs and schedule.

Since MTEP13, MISO has performed cost and variance analysis on previously approved MTEP projects. The cost and schedule variance summarizes the differences between what was originally approved in MTEP and most up-to-date projections. The MTEP15 cost and variance analysis considers all MTEP14 Appendix A projects that are not in service or withdrawn as of April 2015. Additionally, because of the

[14] Refer to Chapter 2.6: Competitive Transmission for additional details

amount of investment of the MVP Portfolio relative to other projects included in Appendix A, the MVP Portfolio is excluded from the subset used in the variation analysis (Figures 3.1-1 and 3.1-2) and instead detailed in a status report (Figure 3.1-3).

The MTEP14 Appendix A projects in the variance analysis represents 590 projects totaling $5.7 billion in approved investment. Of the projects in MTEP14 Appendix A, 43 percent were approved in MTEP14 and the remaining 57 percent were approved in MTEP03 through MTEP13. All costs contained within this section are in nominal, as-spent dollars.

Non-MVP Project Cost Variation

The total costs for the 590 MTEP14 Appendix A projects have increased from the MTEP-approved $5.7 billion to $6.3 billion, thus the average cost variance is 10.7 percent. In MTEP14, the average cost increase from approval was 9.7 percent for a similar subset of MTEP-approved projects. Costs can vary for multiple reasons. At the time of Board approval, a project cost estimate reflects:

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

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

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

Overall, projects with larger percent cost increases were a minority. The projects with a largest percentage deviation were generally projects with a small total cost. The current estimates have no reported cost increase from the approval estimates for 70 percent of the non-MVP MTEP14 Appendix A projects; 82 percent of estimates have deviated by less than 25 percent (blue line, Figure 3.1-1), which is consistent with the trend from the last two years.

The cost-shared projects of the MTEP14 Appendix A subset represent $1.7 billion in approved MTEP investment. Of the 19 cost-shared projects' cost estimates, nine projects' cost estimates have not increased since approval. Seven projects' costs are projected to increase by more than 25 percent — all of these projects are Baseline Reliability Projects not justified based on economics (red line, Figure 3.1-1). While the cost-shared trend has consistently increased over the last two years, the number of cost-shared projects with cost increases greater than 25 percent has remained constant. The increasing trend is a function of the total number of active cost-shared projects (the denominator) decreasing as projects go into service.

The largest deviations on a percentage basis are primarily small projects. Each of these projects had small changes in scope (substation work, right of way, routing) that was a large percentage of the total project cost (bar graph, Figure 3.1-1). There were two exceptions: A $490 million Baseline Reliability Project currently has a projected cost variance of 31 percent and a $360 million Baseline Reliability Project currently has a projected cost variance of 42 percent. Both increases are attributed to a state commission requiring a longer line routing and the ability for future expansion.

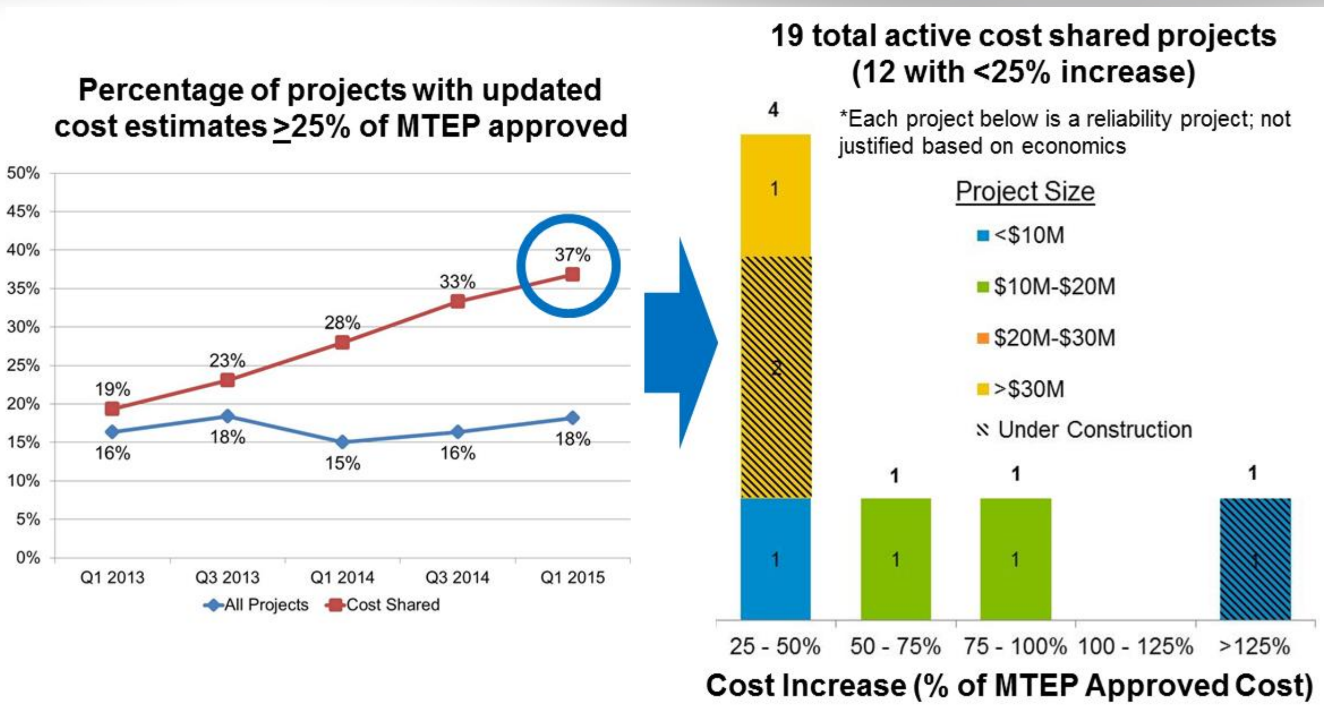


Figure 3.1-1: Cost variation trends from approval to current for non-MVP MTEP14 Appendix A projects as of Q1 2015

Non-MVP Project Schedule Variation

The 590 MTEP14 Appendix A projects have, on average, adjusted their in-service date back by 13 months. In the MTEP14 report, the average in-service delay for a similar subset of projects was 16 months. Little or no impact on reliability is expected from the adjusted in-service dates. Transmission Owners may adjust project in-service dates to match system needs. Common drivers of schedule variance include:

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

The expected in-service date of 50 percent of MTEP14 Appendix A project have not extended beyond the MTEP-approved estimate. Projected in-service dates have extended beyond 12 months for 27 percent of the MTEP14 Appendix A investment (blue line, Figure 3.1-2).

The current expected in-service date has been extended by more than 12 months from the MTEP approval for eleven of the 19 cost-shared MTEP14 Appendix A projects (red line, Figure 3.1-2). Two of the eight projects with in-service date extensions beyond two years attribute the delays to customer need and two attribute right-of-way acquisition delays; the remaining four delays are because of regulatory delays, budgetary constraints, forecast changes or scope alterations (bar chart, Figure 3.1-2).

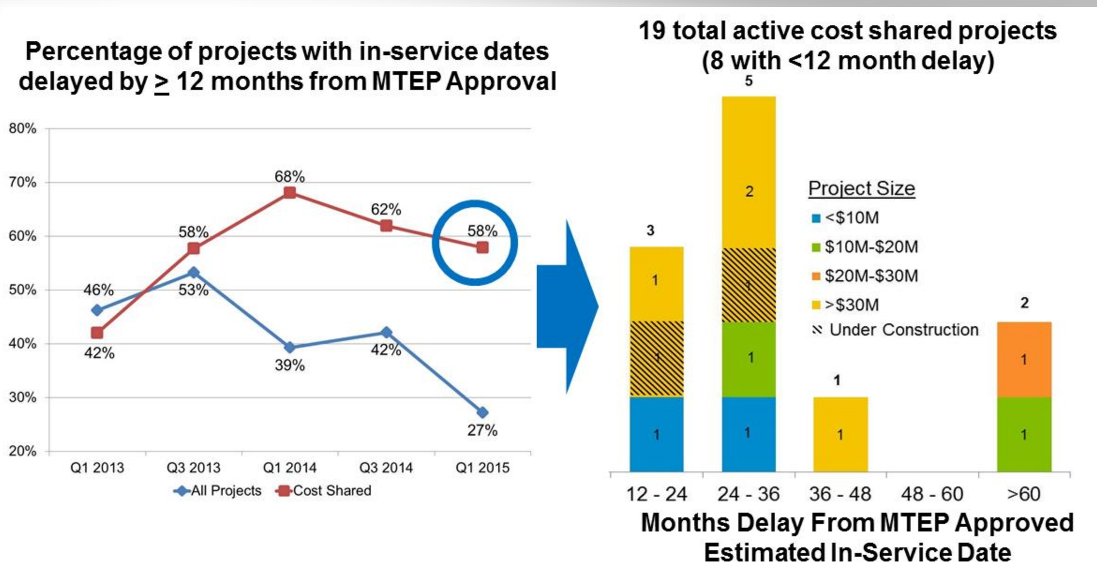


Figure 3.1-2: Schedule variation trends from approval to current for non-MVP MTEP14 Appendix A projects as of Q1 2015

Multi-Value Project Portfolio Status

The MVPs are part of a regionally planned portfolio of transmission projects. The MVP portfolio represents the culmination of more than eight years of planning efforts to find cost-effective regional transmission solutions while meeting local energy and reliability needs. The MVP portfolio is expected to[15]:

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

The 17 MVPs are generally projected to meet budget and schedule expectations. As of July 2015, three projects are in service, five projects are at least partially under construction, five projects have progressed beyond the regulatory process or have no regulatory process requirements, and four have partial regulatory approval and/or are currently in the regulatory process (Figure 3.1-3). Since the MTEP11 approval, the total projected budget for the MVP Portfolio has increased by 16 percent, the result of longer-than-planned line routing, substation design changes and use of more developed construction estimates. Additionally, several MVPs' cost estimates have decreased since approval through a combination of design and schedule optimization, implementation of contracting/risk sharing strategies and favorable commodity prices.

The MVP dashboard (Figure 3.1-3) is updated semi-annually and the most up to date version can be referenced from the MISO website.

[15] Source: Candidate MVP Report. A review of the MVP Portfolio's benefits is contained in Section 7.5.

MVP No.	Project Name	State	Estimated In Service Date[1]		Status		Cost[1]	
			MTEP Approved	Q2 2015	State Regulatory Status	Construction	MTEP Approved	Q2 2015
1	Big Stone-Brookings	SD	2017	2017	●	Pending	226.7	226.7
2	Brookings, SD-SE Twin Cities	MN/SD	2011-2015	2013-2015	●	Complete	738.4	670.7
3	Lakefield Jct. - Winnebago-Winco-Burt area & Sheldon-Burt Area-Webster	MN/IA	2015-2016	2016-2018	●	Pending	550.4	541.1
4	Winco-Lime Creek-Emery-Black Hawk-Hazelton	IA	2015	2015-2018	●	Underway	468.6	464.3
5	N. LaCrosse-N. Madison-Cardinal (a/k/a Badger-Coulee Project) & Cardinal-Hickory Creek	WI/IA	2018-2020	2018-2020	◑	Pending	797.5	1034.5
6	Big Stone South - Ellendale	ND/SD	2019	2019	●	Pending	330.7	395.7
7	Ottumwa-Zachary	IA/MO	2017-2020	2017 - 2018	◑	Pending	152.3	191.9
8	Zachary-Maywood	MO	2016-2018	2015-2018	◑	Pending	112.8	153.4
9	Maywood-Herleman-Merdosia-Ipava & Meredosia-Austin	MO/IL	2016-2017	2015-2017	●	Underway	432.2	705.4
10	Austin-Pana	IL	2018	2016-2018	●	Pending	99.4	135.5
11	Pana-Faraday-Kansas-Sugar Creek	IL/IN	2018-2019	2016-2018	●	Underway	318.4	439.6
12	Reynolds-Burr Oak-Hiple	IN	2019	2019	●	Underway	271.0	271.0
13	Michigan Thumb Loop Expansion	MI	2013-2015	2012-2015	●	Complete	510.0	510.0
14	Reynolds-Greentown	IN	2018	2018	●	Pending	245.0	387.3
15	Pleasant Prairie-Zion Energy Center	WI	2014	2013	●	Complete	28.8	33.0
16	Fargo-Sandburg-Oak Grove	IL	2014-2019	2016-2018	◑	Pending	199.0	223.5
17	Sidney-Rising	IL	2016	2016	●	Underway	83.2	90.6
						Totals:	***5,564***	***6,474***

State Regualtory Status Indicator Scale

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

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

Figure 3.1-3: MVP planning and status dashboard as of July 2015

3.2 MTEP Implementation History

The annual MTEP report is the culmination of more than 18 months of collaboration between MISO and its stakeholders. Each report cycle focuses on identifying issues and opportunities, developing alternatives for consideration and evaluating those options to determine effective transmission solutions. With the MTEP15 cycle, the MTEP report now represents 12 years of planning these essential upgrades and expansions to the electric transmission grid.

The number of projects and investment can vary dramatically from year to year depending on a variety of system needs. Project drivers could include changes in generation mix due to economics or environmental emissions control, the need to mitigate system congestion at load delivery points, or the addition of large industrial loads. These projects improve the deliverability of energy both economically and reliably to consumers in the MISO footprint and beyond.

After projects are approved by the MISO Board of Directors, these projects will go through any required approval processes by federal or state regulatory authorities and subsequent construction. The system needs originally driving these projects may change or disappear. When these material system changes transpire, MISO collaborates with transmission owners and stakeholders to withdraw or partially withdraw an approved project such that system reliability is always maintained. More details on withdrawn projects are provided later in this section.

The cumulative investment dollars for projects, categorized by plan status for MTEP03 through the current MTEP15 cycle, is more than $20.56 billion (Figure 3.2-1). MTEP15 data depicted in this figure, subject to Board approval, will be added to the data tracked for the MISO Board of Directors. These statistics only include projects for MISO members who participated in this planning cycle. Previously approved projects for prior MISO members are not included in these statistics.

- Since MTEP03, more than $10.5 billion of cumulative approved projects have been constructed and are in service as of July 2015
- $3.2 billion of MTEP projects are expected to go into service in 2015

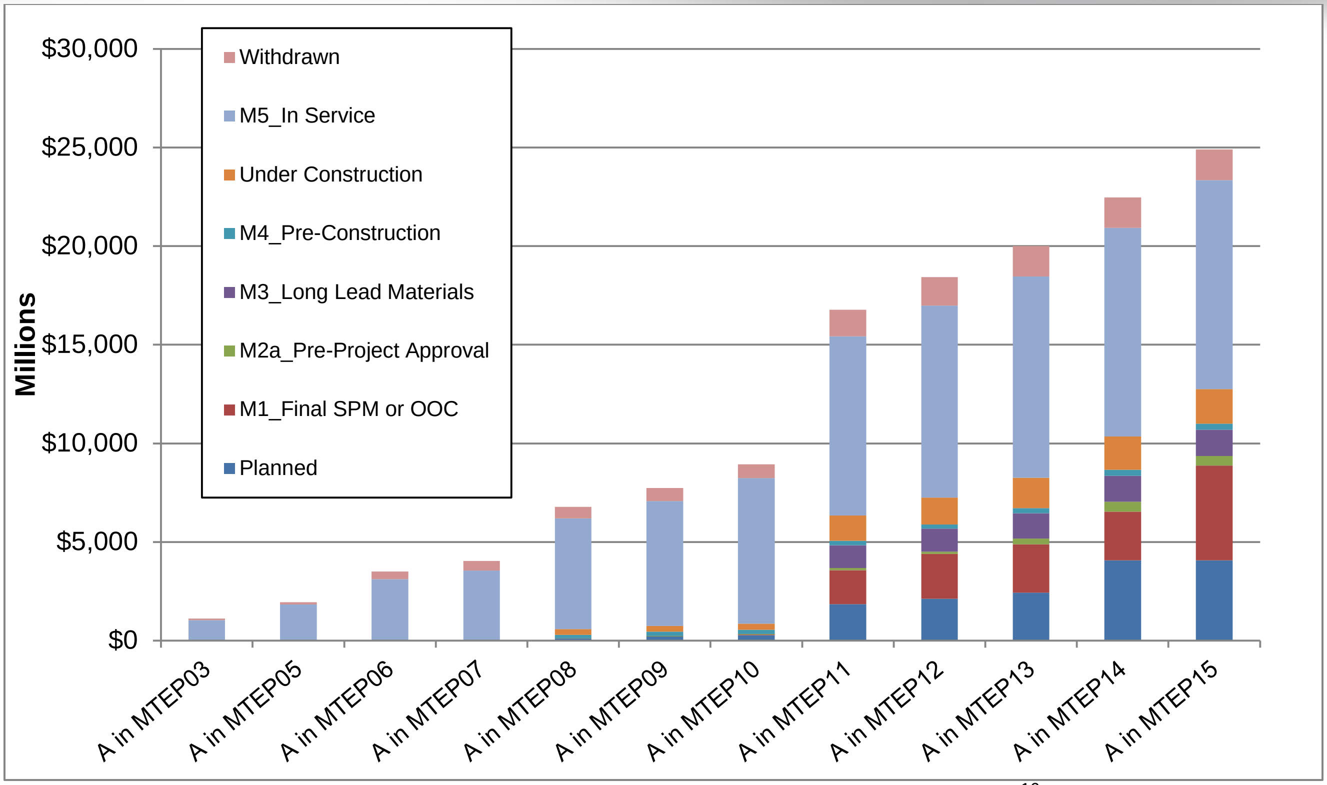


Figure 3.2-1: Cumulative approved investment by facility status[16]

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

- MTEP06 and MTEP07 were approved in the same calendar year, which accounts for the comparatively small number of projects in MTEP07.
- MTEP08 shows the number of developing needs increased the number of planned projects, including several large upgrades.
- MTEP09 was a year for analyses and determination of the best plans to serve those needs. The in-service category increases as projects are built.
- MTEP10 contains significant adjustments for reduced load forecasts.
- MTEP11 contains the MVP portfolio, which accounts for the significantly higher investment totals compared to other MTEPs. MVP status and investment totals are tracked via the MVP Dashboard.
- MTEP12 and MTEP13 reflect a return to a more typical MTEP, primarily driven by reliability projects.
- MTEP14 reflects a continuation of a typical MTEP, primarily driven by reliability projects, but with the inclusion of the new MISO South region projects. A single transmission delivery service project accounts for around 25 percent of the total MTEP14 investment.

[16] Project milestones described in Chapter 3.1: Prior MTEP Plan Status

- MTEP15 further reflects a continuation of a typical MTEP, primarily driven by reliability projects. This is the first cycle in which MTEP participants begin planning to meet a series of new, more stringent NERC reliability standards.

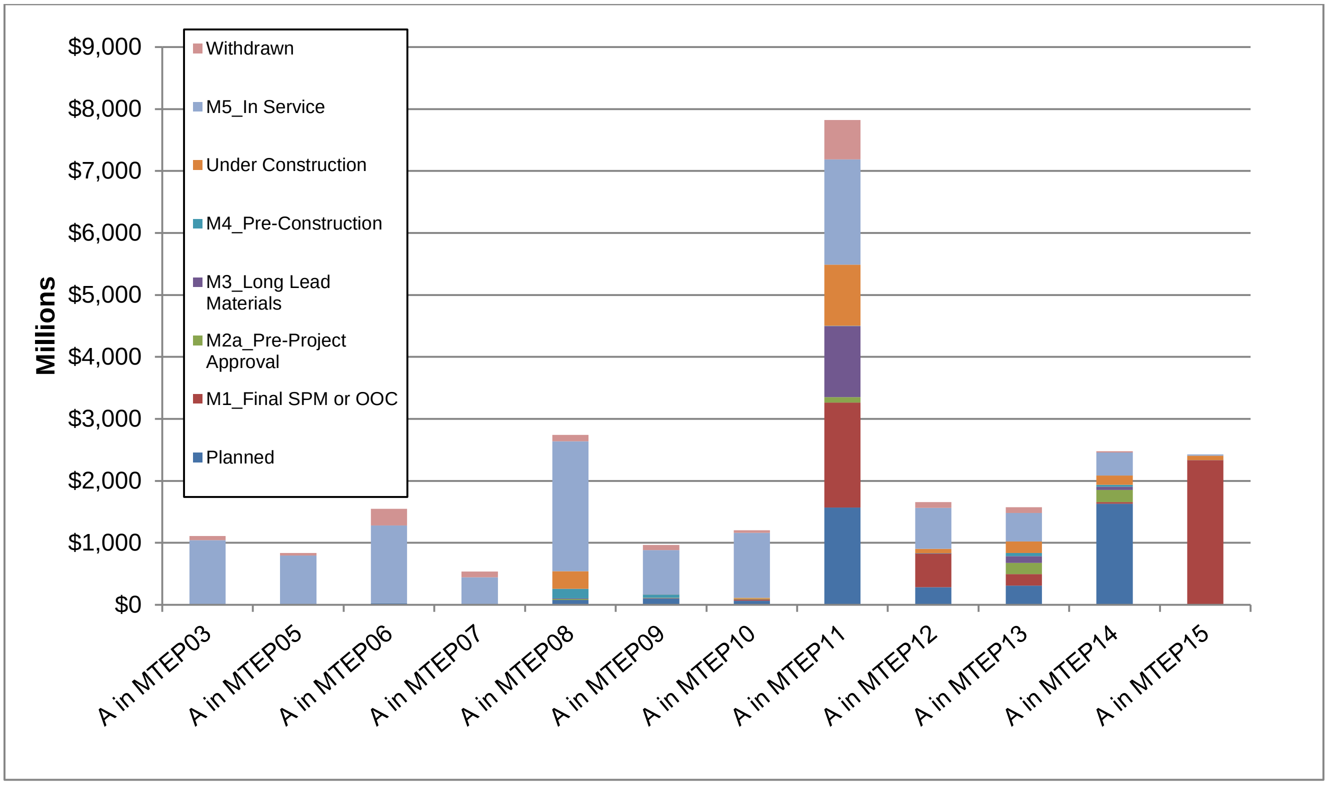


Figure 3.2-2: Approved investment by MTEP cycle[17]

Since MTEP03, 345 facilities from 183 projects totaling $1.4 billion have been withdrawn. MISO documents all withdrawn facilities to ensure the planning process addresses required system needs. Withdrawn facilities may be of two types:

- Completely withdrawn
- Withdrawn but replaced with like facilities

The withdrawn facilities may represent:

- Project cancellations
- Scope changes

[17] New Appendix A projects in the MTEP15 column contain a few in-service and under-construction projects. There are a few reasons why this occurs. Generator Interconnection Projects with network upgrades are approved via a separate Tariff process and are brought into the current MTEP cycle after their approval. There are also projects driven by condition that must be addressed promptly to maintain system reliability. There are clearance projects that should be addressed promptly to maintain system reliability. Finally, there are relocation projects driven by others' schedules.

More than half of the $1.4 billion withdrawn facilities are associated with partially withdrawn projects, e.g., scope changes (Figure 3.2-3). An example of a partially withdrawn project would be a Baseline Reliability Project that was originally scoped as a two 138 kV transmission lines needed to serve a new industrial customer; however, the industrial customer decided to have a smaller scope and now only requires a single 138 kV line to supply the load. One of the 138 kV facilities would be withdrawn while the other continues through the planning and construction phases.

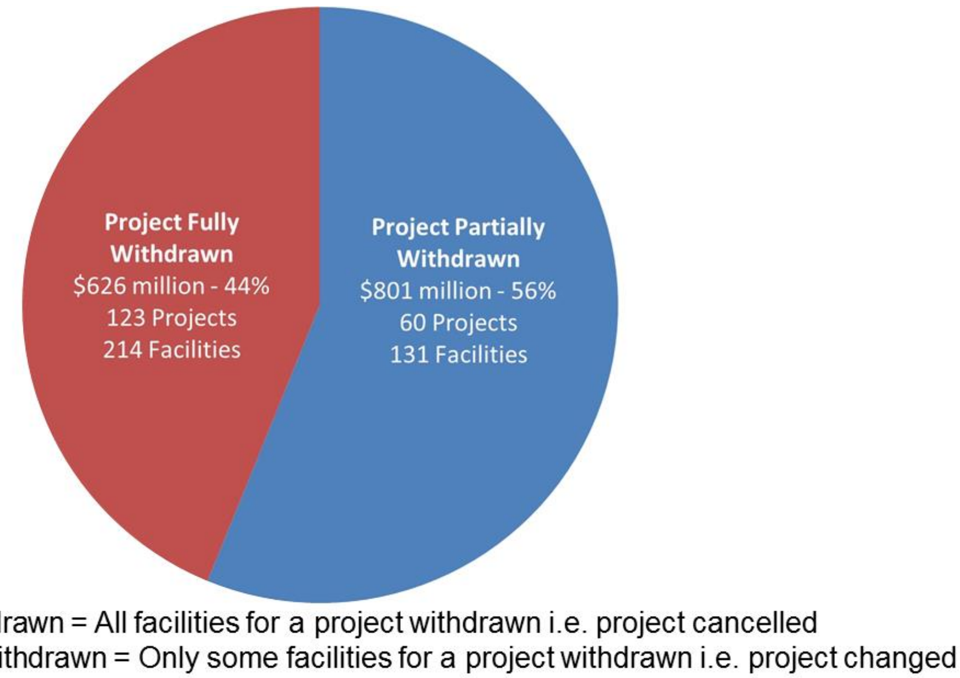


Figure 3.2-3: Partial vs. full project withdrawals

Common reasons for full withdrawal include:

- The customer's plans changed or the service request was withdrawn
- A material system change resulted in no further need for the project
- An alternative solution is pursued and/or further evaluation shows the project is not needed

There's a common trend between the type of project and the reason for the withdrawal (Figure 3.2-4).

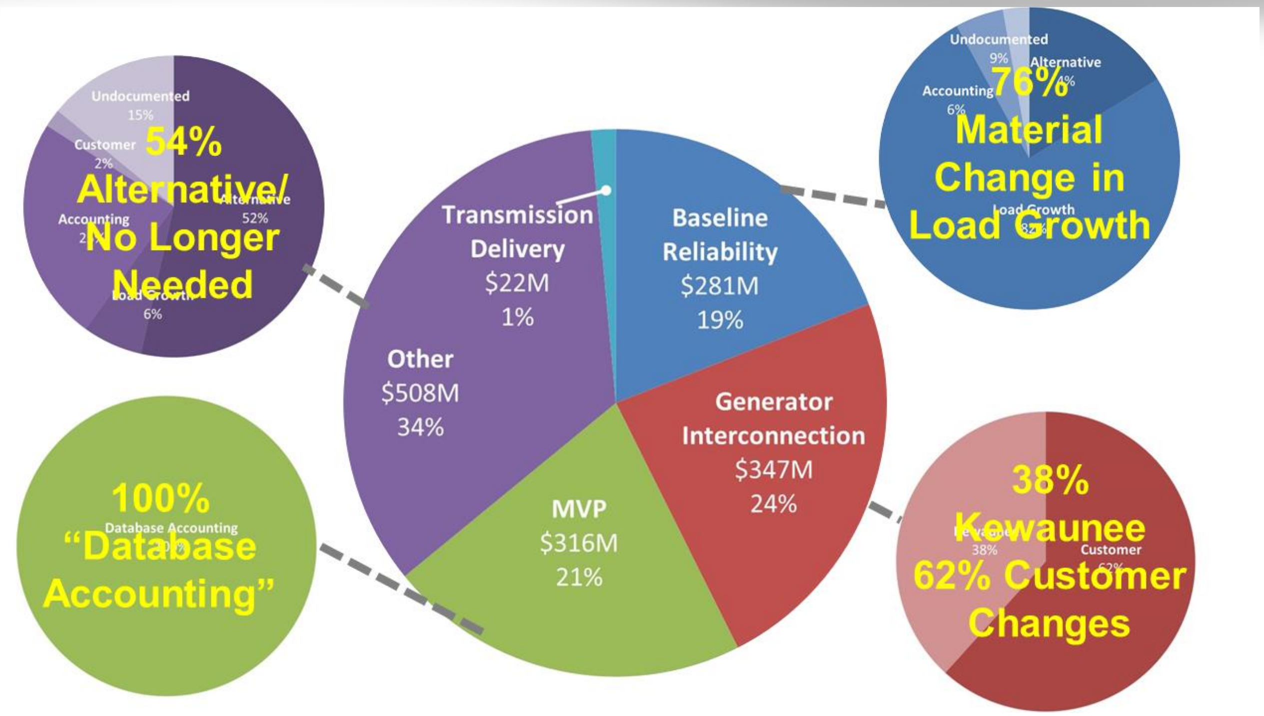


Figure 3.2-4: MTEP facility withdrawal trends by project type (2003-2015)

The majority of withdrawn facilities are Other-type projects that address local reliability issues. Of the Other-type facilities, more than half are withdrawn because a more efficient alternative is pursued. Additionally, many of the Other-type projects are partially withdrawn because further evaluation shows the project is not needed as originally scoped, such as a project that replaces all wooden structures may determine that some structures are still viable.

As of Second Quarter 2015, $261 million worth of Baseline Reliability Project facilities were withdrawn. Nearly all of those projects were withdrawn because of a material change in system load. Half of the $261 withdrawn Baseline Reliability Project total is associated with a single project in Michigan that was withdrawn during the economic downturn.

The $347 million in Generator Interconnection Project withdrawals primarily come from a customer change — often a lack of funding. The retirement of the Kewanee Nuclear Plant resulted in the withdrawal of $133 million in facilities that, before the retirement, were necessary to support an upgrade at a nearby nuclear facility.

The MVPs continue to progress and no full projects have been withdrawn. Commission-required route changes necessitated the withdrawal of $314 million worth of facilities, which were then replaced with like facilities. MISO continues to explore ways to improve its database system to allow the input of scope changes without having to withdraw a facility and then enter the updated information under a new facility.

Chapter 4
Reliability Analysis

4.1 Reliability Assessment and Compliance

System reliability is the primary purpose of all MTEP planning cycles. To fulfill this purpose, MISO planners study reliability from multiple perspectives to confirm the transmission system has sufficient capacity to provide reliable service to customers.

Continued reliability of the transmission system is measured by compliance with regional and local Transmission Owner (TO) planning criteria. These standards define minimum requirements for long-term system planning and require explicit solutions for violations that occur in a two-, five- and 10-year timeframe. As planning coordinator, MISO is required to identify a solution for each identified violation that could otherwise lead to overloads, loss of synchronism, voltage collapse, equipment failures or blackouts.

The results of these reliability analyses, along with the proposed mitigating transmission projects, were presented and peer-reviewed at a series of Subregional Planning Meetings (SPM) that were held in December 2014, May 2015 and August 2015. Each project included in MTEP Appendix A is the preferred solution to a transmission need when its implementation timeline requires near-term progress towards regulatory approval and construction.

The details of the MTEP15 reliability assessment are summarized in this chapter and the complete results are presented later in Appendix D of this MTEP15 report.

Process Overview

The MTEP reliability assessment is a holistic study process that begins with MISO building a series of study cases. Using these models, MISO staff performs an independent reliability analysis of its transmission system. This independent assessment results in identification of system needs, which are mapped to project submittals by the area transmission planning entities. Finally, MISO staff coordinates with area transmission planners to verify needs, identify alternative solutions and resolve gaps where additional system upgrades may be required (Figure 4.1-1).

MISO staff coordinates with area transmission planners to verify needs, identify alternative solutions and resolve gaps where additional system upgrades may be required

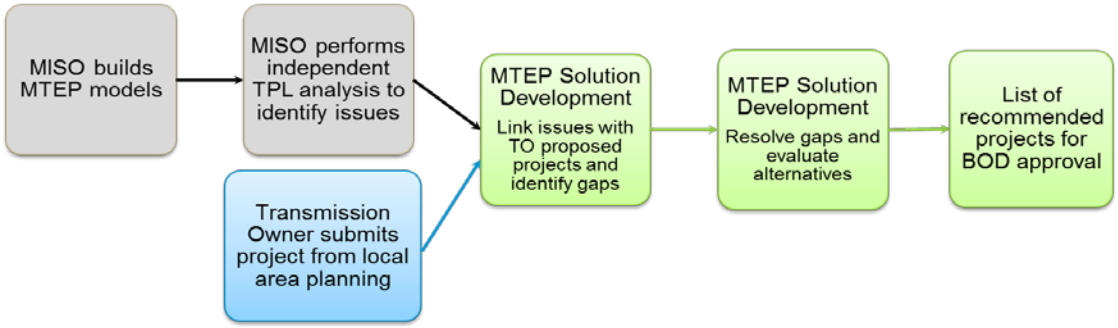


Figure 4.1-1: MTEP15 Reliability Study Process

Models

In MTEP 2015, MISO conducted regional studies using the following base cases and sensitivity cases developed collaboratively with our stakeholders:

- 2017 Summer Peak (wind at 20 percent)
- 2017 Light Load (wind at 90 percent)
- 2020 Summer Peak (wind at 20 percent)
- 2020 Shoulder Peak (wind at 40 percent)
- 2020 Shoulder Peak (wind at 90 percent)
- 2020 Light Load (wind at 90 percent)
- 2020 Winter Peak(wind at 30 percent)
- 2025 Summer Peak (wind at 20 percent)

Interchanges, generation, loads and losses are inputs into each planning model used in the MTEP15 reliability analysis.

MISO member companies and external Regional Transmission Organizations use firm drive-in and drive-out transactions to determine net interchanges for these models. These are documented in the 2014 series Multiregional Modeling Working Group (MMWG) interchange.[18] MISO determines the total generation dispatch needed for each of the models after aggregating the total load with input received from TOs.

Generation dispatch within the model-building process is complex. Inputs from a variety of processes and expected shifts in the generation portfolio within the MISO footprint are key factors in this complexity.

Inputs in the dispatching process include:

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

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

NERC Reliability Assessment

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

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

[18] https://rfirst.org/reliability/easterninterconnectionreliabilityassessmentgroup/Pages/default.aspx

- Local Transmission Owner (TO) planning criteria after it is filed and approved by Federal Energy Regulatory Commission (FERC)

The results of these analyses create a cohesive long-term system reliability assessment, as well as documentary evidence for future NERC compliance

Based on the NERC reliability assessment performed by MISO, potential thermal and voltage reliability issues are identified. MISO and its TOs are required to develop and implement solutions for each identified constraint. The majority of these identified violations may be mitigated via system reconfiguration, generation redispatch or implementation of an operating guide. For all other issues, mitigations, in the form of a future proposed transmission upgrade, will be identified for the projected thermal and voltage issues. These network upgrade mitigations will be investigated further in future MTEPs.

The results of these analyses create a cohesive long-term system reliability assessment, as well as documentary evidence for future NERC compliance. The complete study is available in Appendices D2-D8 of this report, which is posted on the MISO SFTP site. Each MTEP assessment undergoes three specific types of analysis: steady-state, dynamic stability and voltage stability.

Steady-State Analysis

Appendix E1.5.1 documents contingencies tested in steady-state analysis. These contingencies were used in the MTEP15 2017 summer peak and shoulder peak models; the 2020 summer peak, shoulder peak, winter peak and light-load models; and the 2025 summer peak model. All steady-state analysis-identified constraints and associated mitigations are contained in the results tables in Appendix D3, demonstrating compliance with applicable NERC transmission standards.

Dynamic Stability Analysis

Appendix E1.5.2 documents types of disturbances tested in dynamic stability analysis. Disturbances were simulated in MTEP15 2020 light load, shoulder (wind at 40 percent), shoulder (wind at 90 percent) and summer peak load models. Results tables listing all simulated disturbances along with damping ratios are tabulated in Appendix D5, demonstrating compliance with applicable NERC transmission standards.

Voltage Stability Analysis

Appendix E1.5.3 documents types of transfers tested in voltage stability analysis. A summary report with associated P-V plots is documented in Appendix D4.

Subregional Planning Meetings

MISO presents the project proposals and reliability study results to stakeholders through a series of public Subregional Planning Meetings (SPM). The locations of these SPMs are determined based on the five MISO planning subregions (Figure 4.1-2). The five MISO planning subregions are: Central (blue), East (orange), South-Arkansas (yellow), South-Mississippi, Louisiana and Texas (red) and West (green).

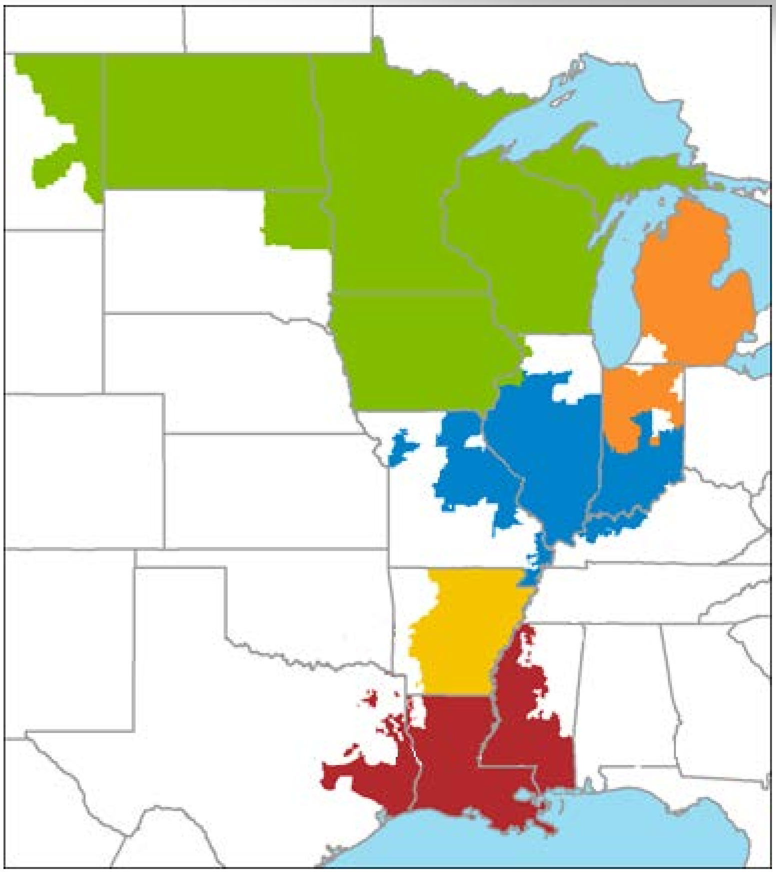


Figure 4.1-2: MISO Planning Subregions

Additionally, Technical Study Task Force (TSTF) meetings are convened for each MISO planning subregion on an as-needed basis to discuss confidential system information (Table 4.1-1). These meetings are open to any stakeholders who sign Critical Energy Infrastructure Information (CEII) and non-disclosure agreements.

Date	Meeting	Location
4-Nov-14	Central TSTF Meeting (closed)	Web-ex/conf. call
3-Dec-14	West SPM No. 1	Eagan, Minn.
5-Dec-14	East SPM No. 1	Detroit, Mich.
8-Dec-14	Central SPM No. 1	Carmel, Ind.
9-Dec-14	South SPM No. 1 (Ark.)	Little Rock, Ark.
11-Dec-14	South SPM No. 1 (Miss., La., Texas)	Metairie, La.
10-Feb-15	West TSTF Meeting (closed)	Web-ex/conf. call
11-Feb-15	South TSTF Meeting (closed)	Metairie, La.
13-Feb-15	West TSTF Meeting (closed)	Web-ex/conf. call
26-Mar-15	Michigan TSTF Meeting	Livonia, Mich.
9-Apr-15	South TSTF Meeting (closed)	Web-ex/conf. call
1-May-15	East SPM No. 2	Novi, Mich.
5-May-15	South SPM No. 2 (Ark.)	Little Rock, Ark.
8-May-15	Central SPM No. 2	Carmel, Ind.
11-May-15	South SPM No. 2 (Miss., La., Texas)	Metairie, La.
19-May-15	West SPM No. 2	Eagan, Minn.
26-Jun-15	Michigan TSTF Meeting	Jackson, Mich.
24-Jul-15	South TSTF Meeting	Web-ex/conf. call
27-Jul-15	West SPM No. 3	Eagan, Minn.
30-Jul-15	Central SPM No. 3	Carmel, Ind.
4-Aug-15	East SPM No. 3	Cadillac, Mich.
4-Aug-15	South SPM No. 3 (Ark.)	Little Rock, Ark.
6-Aug-15	South SPM No. 3 (Miss., La., Texas)	Metairie, La.

Table 4.1-1: MTEP15 Technical Study Task Force and Subregional Planning Meeting schedule

Project Approval

After MISO completes the independent review of all proposed projects and addresses any stakeholder feedback received during the SPM presentations, MISO staff formally recommends a set of projects to the MISO Board of Directors for review and approval. These projects make up Appendix A of the MTEP15 report and represent the preferred solutions to the identified transmission needs of the MISO reliability assessment. Proposed transmission upgrades with sufficient lead times are included in Appendix B for further review in future planning cycles. Details of the project approval process and the approved transmission projects reviewed this cycle are summarized in Chapter 2 and Appendix D1 of the MTEP15 report.

4.2 Generation Interconnection Projects

MISO provides safe, reliable, equal and non-discriminatory access to the electric transmission system for all new generation interconnection requests. MISO's interconnection process identifies network upgrades for all new generator interconnection requests, as necessary, to ensure that the injection from new generation capacity does not deteriorate the reliability of the existing transmission system. All network upgrades emanating from the interconnection process are included in the final MTEP as Generator Interconnection Projects (GIPs) at the end of every calendar year.

MTEP15 contains five Target Appendix A GIPs totaling approximately $50.8 million (Table 4.2-1). These GIPs are associated with the generation interconnection requests J238, H021, G870, J233 and J290 (Figure 4.2-1 and Table 4.2-2).

MTEP Project ID	Project Name	Submitting Company	Preliminary Share Status	Region	Estimated Cost ($)
4262/4263/4264	J238 Generator Interconnection	IPL	TBD	Central	$0.00
8092	H021 Generator Interconnection	ITC M	Not Shared	West	$2,300,000.00
8156	G870 Generator Interconnection	ITC M	Not Shared	West	$40,600,000.00
8157	J233 Generator Interconnection	ITC M	Not Shared	West	$3,850,000.00
8240	J262/J263 Generator Interconnection	OTP	TBD	West	$11,175,000.00
8241/9522	J290 Generator Interconnection	OTP/Xcel	TBD	West	$4,000,000.00
9245	J327 Generator Interconnection	ITCT	Shared	East	$1,330,000.00
9320	J293 Generator Interconnection	ATC	TBD	West	$21,914,554.00
9523	G826 Generator Interconnection	Xcel	Shared	West	$0.00
9524	G858/H071	Xcel	TBD	West	$0.00
Total Estimated Cost					**$85,169,554.00**

Table 4.2-1 Generation Interconnection Projects in MTEP15 target Appendix A

GI Project No.	TO	County	State	Study Cycle	Service Type	Point of Interconnection	Max Summer Output	Fuel Type	GIA
G870	ITCM	Freeborn	MN	DPP-2012-AUG	NRIS	Hayward - Winnebago 161 kV	201	Wind	GIA
H021	ITCM	Grand	IA	DPP-2012-AUG	NRIS	Wellsburg 115 kV Substation	138.6	Wind	GIA
J233	ITCM	Marshall	IA	DPP-2013-AUG	NRIS	ITC Midwest Marshalltown 161 kV (Sutherland) Substation	635	Gas	GIA
J238	IPL	Morgan	IN	DPP-2012-AUG	NRIS	Eagle Valley 138 kV Substation	725	Gas	GIA
J290	NSP	Rolette	ND	DPP-2013-AUG	NRIS	230 kV Rugby to Glenboro	150	Wind	GIA
J262	OTP	Stutsman	ND	DPP-2013-FEB	NRIS	Jamestown 345/115 kV Substation	100	Wind	GIA
J263	OTP	Stutsman	ND	DPP-2013-FEB	NRIS	Jamestown 345/115 kV Substation	100	Wind	GIA
J327	ITCT	Huron	MI	DPP-2014-AUG	NRIS	Raphson 120 kV Substation	150	Wind	GIA
J293	ATC	Outagamie	WI	DPP-2014-FEB	NRIS	Fox River 345 kV Substation	475	Gas	GIA
G826	XCEL	Jackson	MN	DPP-2012-AUG	NRIS	Lakefield Junction 345 kV	200	Wind	GIA
G858	NSP	Stearns	MN	DPP-2013-FEB	NRIS	Black Oak 69 kV Substation	38	Wind	GIA
H071	NSP	Stearns	MN	DPP-2013-FEB	NRIS	Black Oak 69 kV Substation	40	Wind	GIA

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

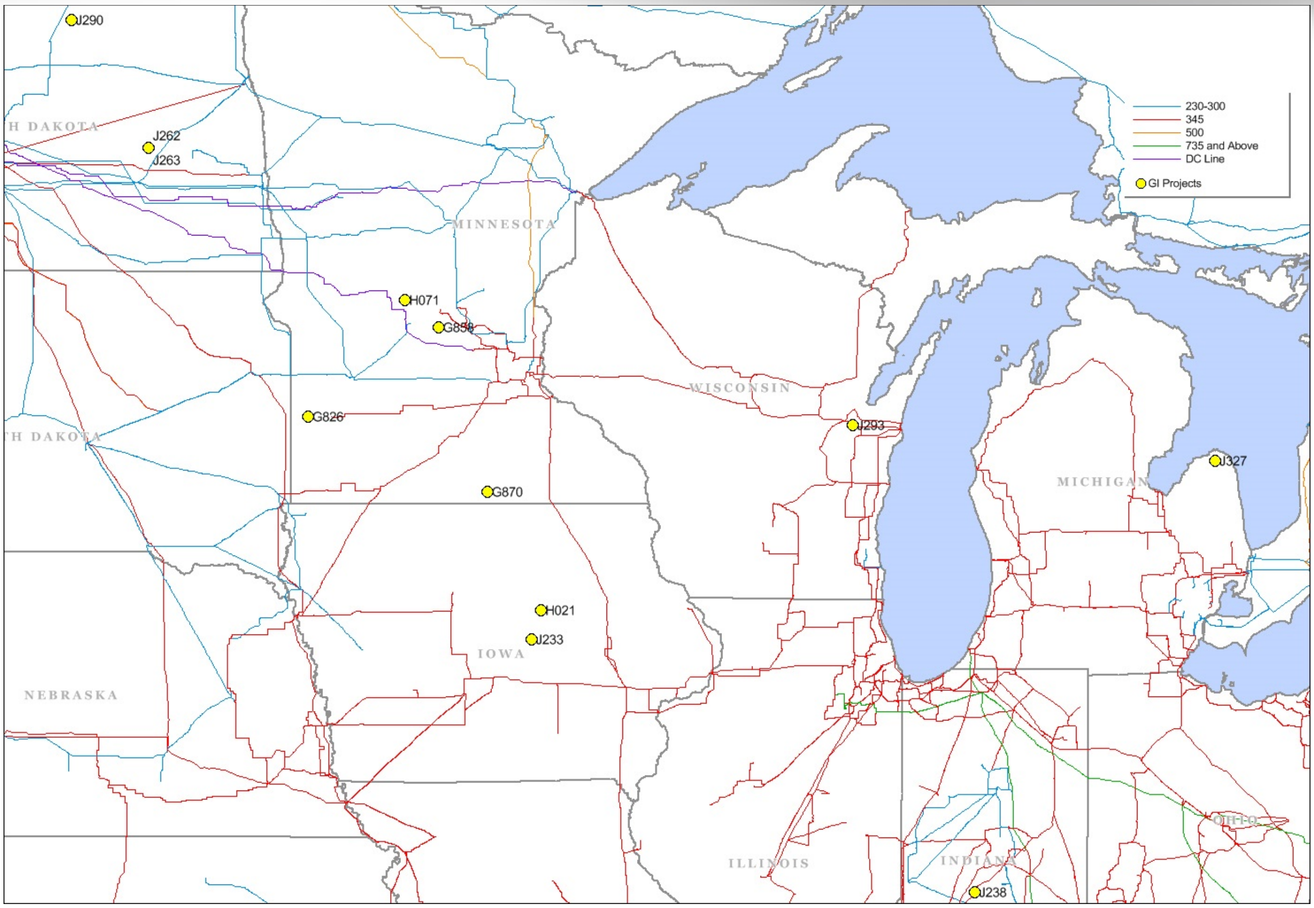


Figure 4.2-1: Generation Interconnection requests associated with MTEP15 Target Appendix A

MTEP15 Target Appendix A

Generation Interconnection Projects – Detail

MTEP Project 4262/4263/4264 – Indianapolis Power and Light

- The Pritchard – Centerton – Honey Creek – Southport 138 kV line rating upgrade
- 138 kV/242 MVA line to 138 kV/302 MVA line enables the generation interconnection of generation request J238
- J238 - 725 MW combined cycle gas generator
- Point of interconnection: Eagle Valley 138 kV substation
- The generation interconnection project is contingent upon the following injection upgrades:
    - Construct a new 138 kV line from Pritchard to Franklin Township
    - Re-conductor the 138 kV line from Pritchard to Centerton to Honey Creek to Southport
    - Re-conductor the 138 kV line from Pritchard to Heartland Crossing to Morrisville
- Anticipated completion date: December 31, 2016
- Anticipated cost: TBD

MTEP Project 8092 – International Transmission Co. Midwest

- Replace the Wellsburg 161/69 kV transformer with a 150 MVA transformer as a condition of the interconnection service for project H021
- H021 -138.6 MW wind-powered generating facility located in Grundy County, Iowa
- 84 Vestas V82 1.65 MW wind turbines
- Point of interconnection: Wellsburg 115 kV substation
- Anticipated completion date: February 12, 2015
- Completed: February 12, 2015
- Actual cost: $2.3 million

MTEP Project 8156 – International Transmission Co. Midwest

- Reconstruct the Winnebago to Freeborn 161 kV line with T2-795 ACSR conductor with a summer rating of 446 MVA as a condition of Interconnection Service for project G870
- G870-201 MW wind-powered generating facility located in Freeborn County, Minn.
- 122 Vestas V82 1.65 MW wind turbines.
- Point of interconnection: Hayward – Winnebago 161 kV line
- Anticipated completion date: December 31, 2015
- Anticipated cost: $40.6 million

MTEP Project 8157 – International Transmission Co. Midwest

- Three new terminals are needed at the Marshalltown substation to accommodate interconnection to the generating facilities via three generator step-up transformers as a condition of interconnection service for J233.
- J233 - 138.6 MW wind-powered generating facility located in Grundy County, Iowa
- 84 Vestas V82 1.65 MW wind turbines
- Transmission Owner Interconnection Facilities
- Point of interconnection: Wellsburg 115 kV substation
- Anticipated completion date: December 31, 2015
- Anticipated cost: $3.85 million

MTEP Project 8240 – Ottertail Power Co.

- Replace existing 345/115/41.6 kV #1 and #2 transformers at Jamestown Substation with 336 MVA transformers, add 2x25 MVAR cap bank at Jamestown 115 kV bus and 1x60 MVAR cap bank at Jamestown 345 kV bus as a condition of the interconnection service for project J262 and J263.
- J262/J263 - 200 MW wind-powered generating facility located in Stutsman County, N.D.
- 100 Vestas V100 2.0 MW wind turbines
- Point of interconnection: Jamestown 345/115 kV Substation
- Anticipated completion date: November 30, 2015
- Anticipated cost: $11.175 million

MTEP Project 8241/9522 – Ottertail Power Co./Excel Energy

- Install a switchyard (Border Wind Substation) with the appropriate protection equipment coordinated per Appendix C to the GIA. The Border Wind Substation shall contain one generator step-up transformer rated 175 MVA, one circuit breaker connected to the Transmission Owner's new 230 kV Peace Garden Substation as a condition of the interconnection service for project J290
- J290 -150 MW wind-powered generating facility located in Rolette County, N.D.

- 75 Vestas V100 2.0 MW wind turbines
- Point of interconnection: Peace Garden 230 kV Substation
- Anticipated completion date: January 31, 2016
- Anticipated cost: $4 million

MTEP Project 9245 – International Transmission Co.

- Add 2-120 kV breakers with associated disconnects at Rapson 120 kV substation to accommodate the interconnection of a 150 MW wind farm
- J327 - 150 MW wind-powered generating facility located in Huron County, Mich.
- 75 Vestas 2.0 MW wind turbines
- Point of interconnection: Raphson 120 kV Substation:
- Anticipated completion date: July 15, 2016
- Anticipated cost: $1.33 million

MTEP Project 9321 – American Transmission Co.

- Re-configuration of the Fox River 345 kV switchyard and upgrades on the Point Beach to Kewaunee and Fox River Switch yard to North Appleton Substation 345 kV lines as a condition of the interconnection service for project J293
- J293 - 475 MW Natural Gas combined cycle generating facility located in Outagamie County, Wis.
- Combined cycle generator – one combustion turbine generator and one steam turbine generator
- Point of interconnection: Fox River 345 kV Substation
- Anticipated completion date: March 15, 2018
- Anticipated cost: $21.9 million

MTEP Project 9523 – Xcel Energy

- The 345 kV Crandal Substation installation as a condition of the interconnection service for project G826
- G826 - 200 MW wind-powered generating facility located in Jackson County, Minn.
- 100 Vestas V110 2.0 MW wind turbines
- Point of interconnection: Xcel Lakefield Generation SW – Lakefield Junction 345 kV Line
- Anticipated completion date: December 1, 2015
- Anticipated cost: TBD

MTEP Project 9524 – Xcel Energy

- The Black Oak – East Melrose – Millwood 69 kV rebuild as a condition of the interconnection service for project G858/H071
- G858/H071 - 38 MW wind-powered generating facility located in Stearns County, Minn.
- 18 2.1 MW wind turbines
- Point of interconnection: XEL Black Oak 69 kv Substation
- Anticipated completion date: March 1, 2016
- Anticipated cost: TBD

The Queue Process

Requests to connect new generation to the system are studied and approved under the generation interconnection queue process. Each generator must fund the necessary studies to ensure new interconnections will not cause system reliability issues. Each project must meet technical and non-technical milestones in order to move to the next phase (Figure 4.2-2).

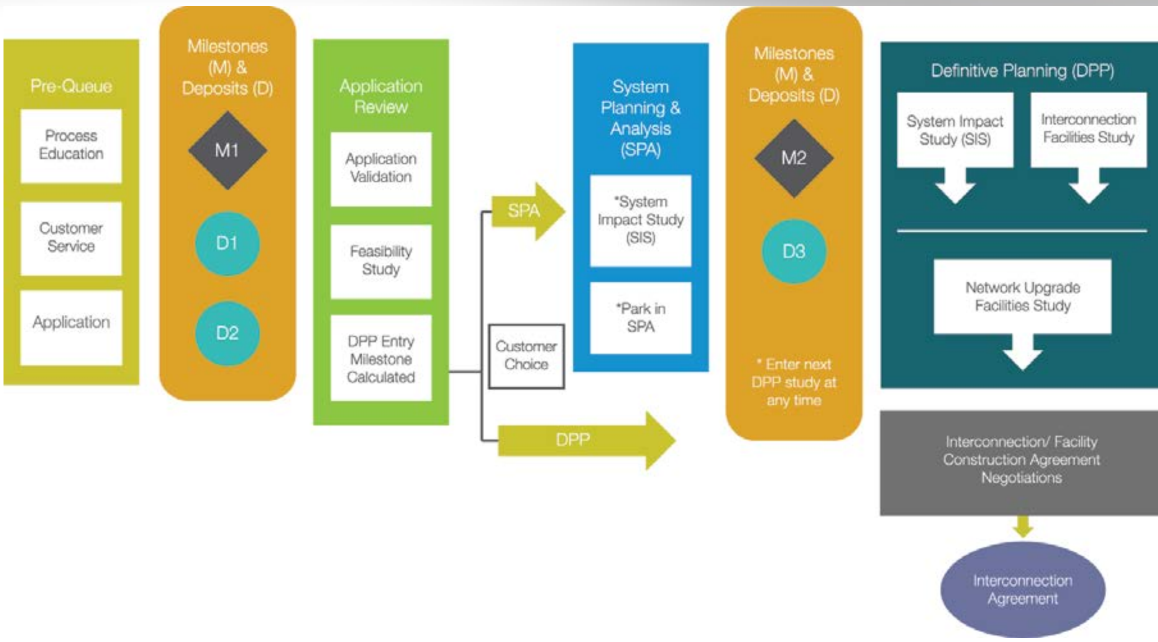


Figure 4.2-2: Generator Interconnection Queue Process

Since the beginning of the queue process in 1995, MISO and its Transmission Owners have received approximately 1,481 generator interconnection requests totaling 302 GW (Figures 4.2-3 and 4.2-4). Among them, 32 GW are now connected to the transmission system. These generation additions enhance reliability, ensure resource adequacy, provide a competitive market to deliver benefit to ratepayers, and help the industry meet renewable portfolio standards.

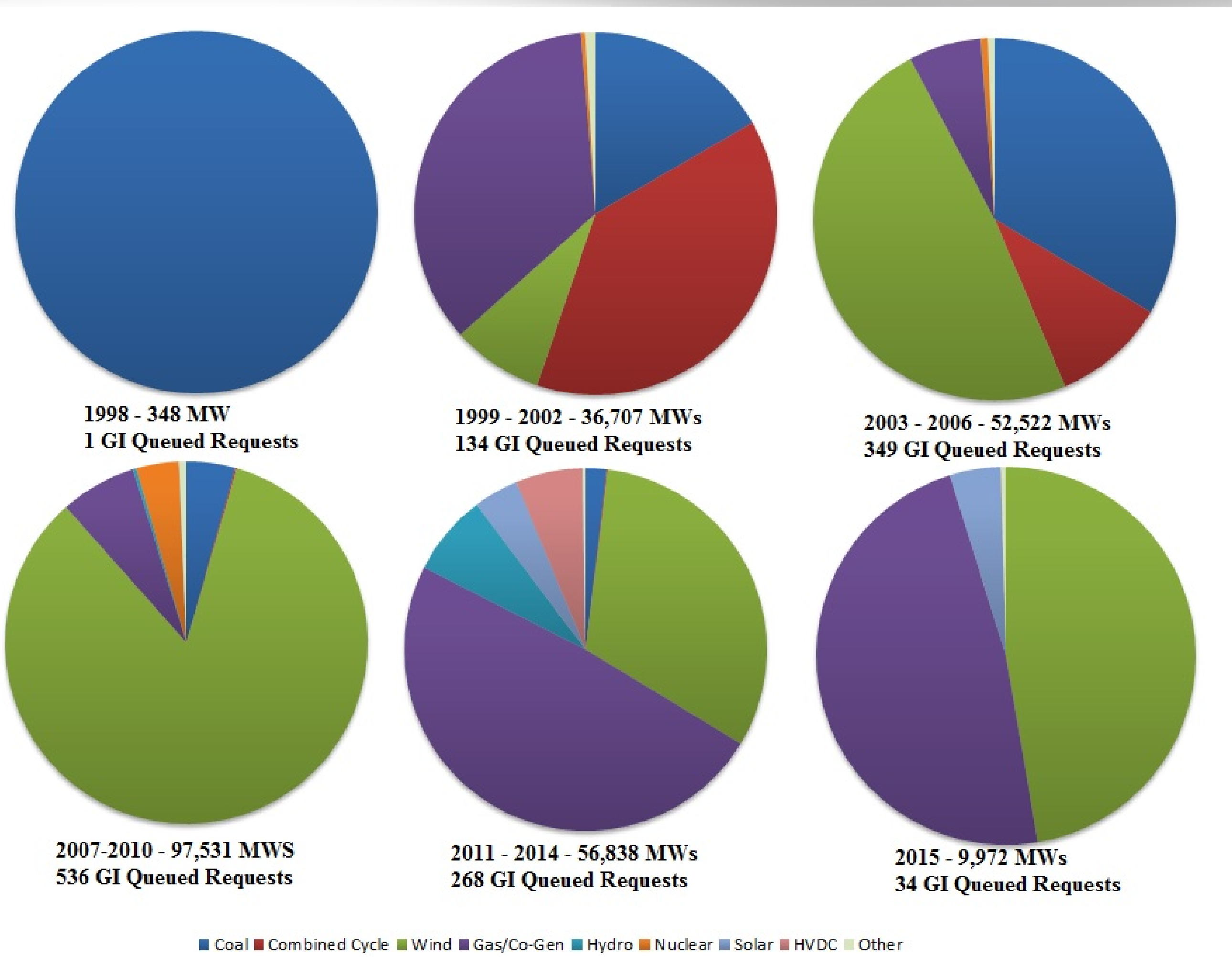


Figure 4.2-3: Queue trends

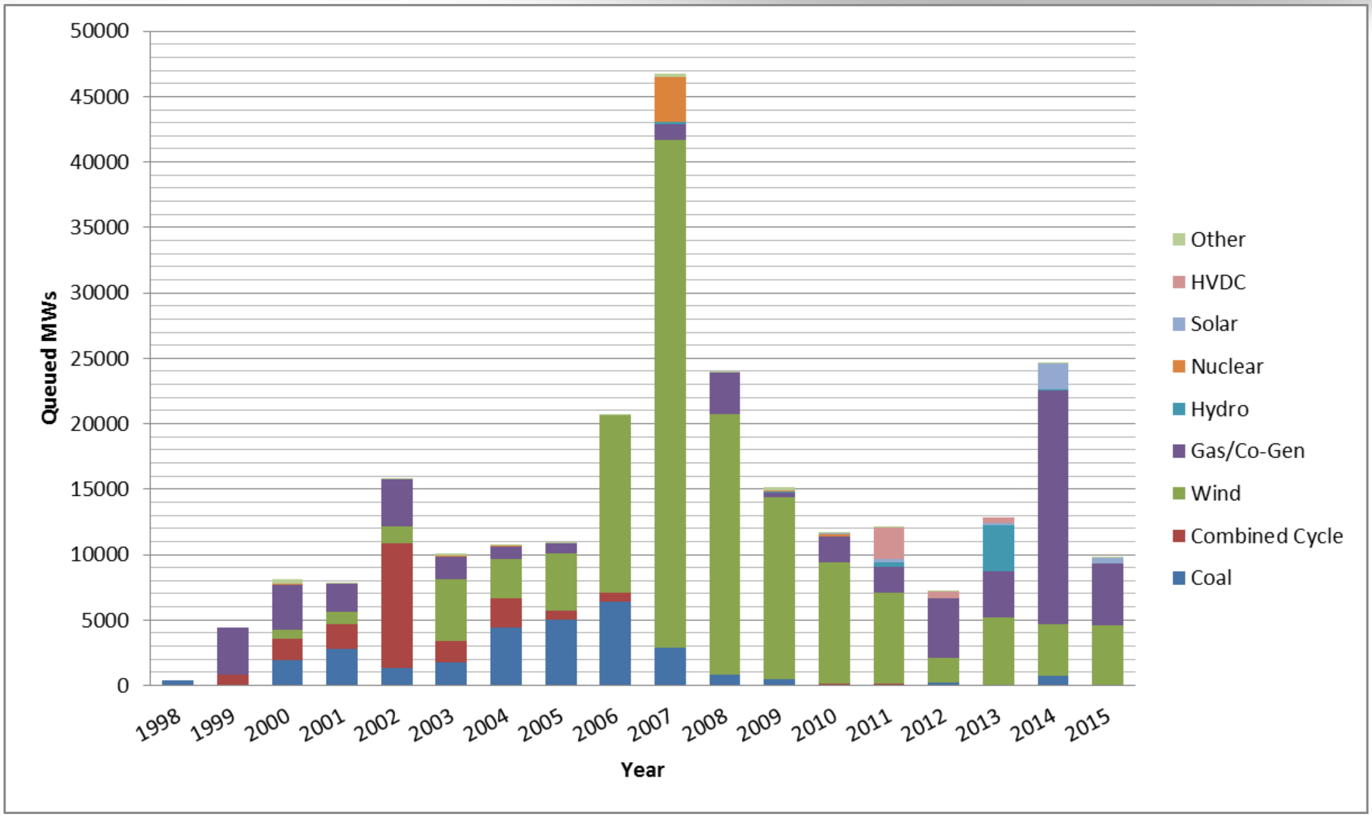


Figure 4.2-4: Queue trends

Renewable Portfolio Standards (RPS) have become more common since the late 1990s. Although there is no RPS program in place at the national level, 30 states and the District of Columbia had enforceable RPS or other mandated renewable capacity policies as of January 2012. In addition, eight states adopted voluntary renewable energy standards. Between 2005 and 2011, MISO experienced exponential growth in wind project requests. In 2007, wind generation requests in the MISO queue peaked at approximately 39 GW. These requests reflect the dramatic increase in registered wind capacity in the MISO footprint (Figure 4.2-5).

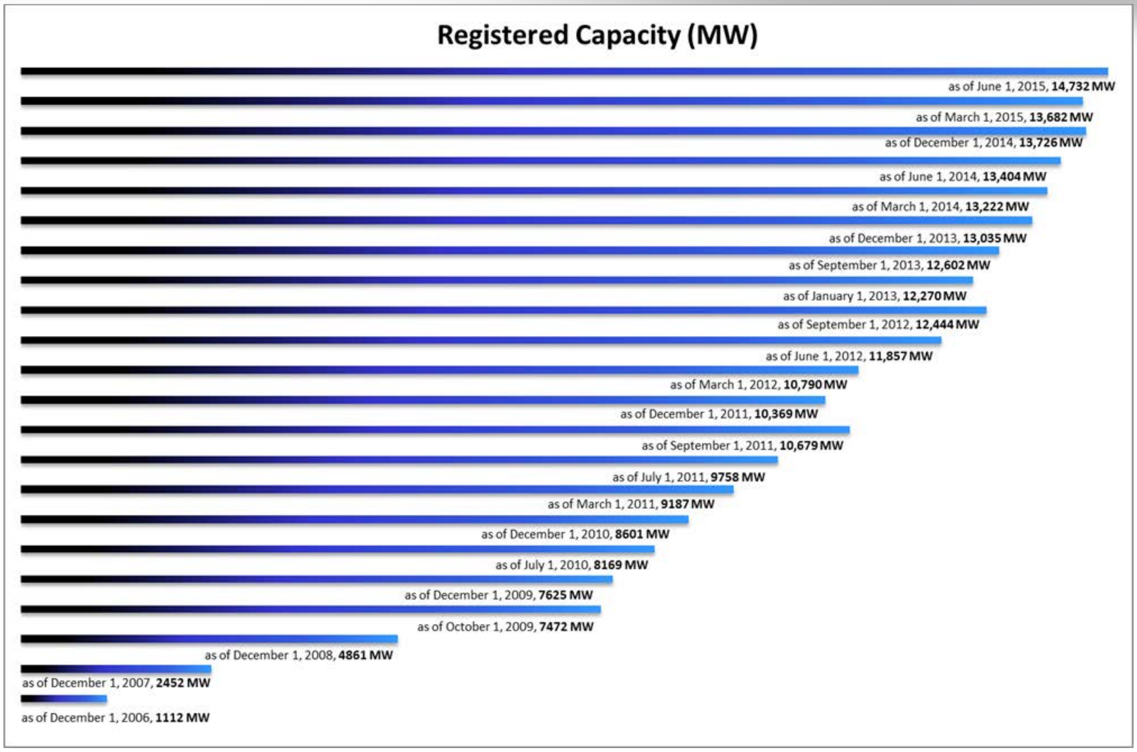


Figure 4.2-5: Nameplate wind capacity registered for MISO

As a result of Environmental Protection Agency's (EPA) Mercury and Air Toxics Standard (MATS) and its compliance requirements, MISO's generator interconnection queue has seen an increase in natural gas interconnection requests (Table 4.2-3). Data corresponding to year 2015 only includes natural gas requests for the first two quarters.

Year	Gas Requests (MW)	% Of All New Requests
2015	4,659*	40%
2014	9,424	58%
2013	3,835	30%
2012	4,509	63%

*Natural Gas MW requested as of August 2015

Table 4.2-3: Recent years natural gas requests

Furthermore, there are about 425 MW of new solar generation interconnection requests in 2015. This could be the result of recent federal energy legislation and the economic stimulus package, and lower prices of solar photovoltaic (PV) modules.

Queue Process Improvement

Over the past 10 years, the MISO Interconnection Process has evolved from first-in, first-out methodology to first-ready, first-served methodology to expedite the generation project queue lifecycle and maintain system reliability.

With significant changes implemented on the latest 2012 Queue Reform, which largely addressed backlogs in the generator interconnection queue and late-stage terminations of generator interconnection agreements, the MISO queue still undergoes delays in completing studies (System Impact and Facility Studies).

MISO continues to seek more opportunities to improve the queue process, while following basic guiding principles: reliable interconnection; timely processing; certainty in process; and Targeted Risk Allocation. The current drivers for this effort include re-studies caused by project withdrawals, evolving industry standards, more variable generation in the queue and changing technology.

The goal of this effort is to review the current process and study criteria, and identify areas for further improvement. Some other process improvement focus areas that MISO has been working on are:

- Compliance with New TPL001-4 standards
- Consistency in the planning model
- Attachment Y process coordination
- Interconnection study time-line improvement
- Seams coordination
- Continuing to streamline queue process with MISO energy market and capacity construct
- Exploring economic analysis-related options

4.3 Transmission Service Requests

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

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

From June 2014 to June 2015, MISO Transmission Service Planning processed 209 long-term TSRs (Figure 4.3-1) and completed 17 System Impact Studies. Of these System Impact Studies, five were confirmed, one was refused, one executed a Facilities Study Agreement and one awaits the completion of a corresponding external System Impact Studies.

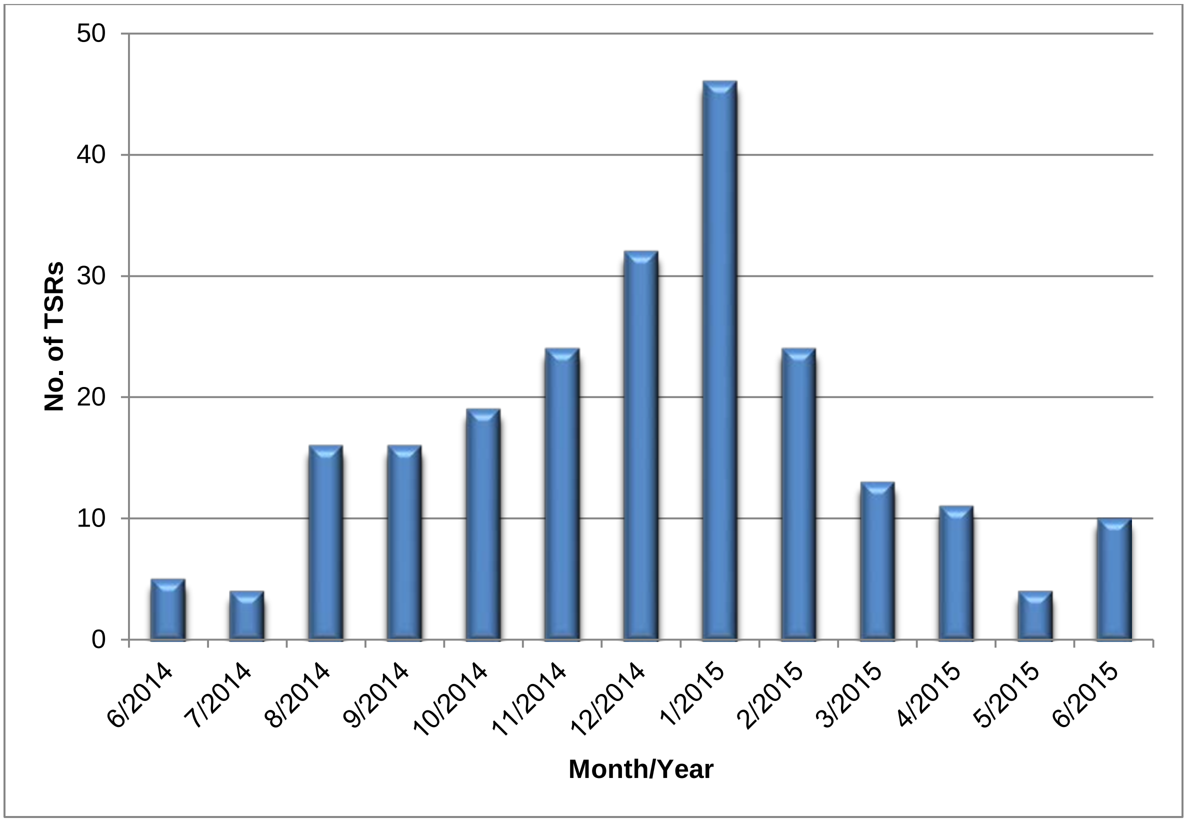


Figure 4.3-1: MISO Long-Term TSRs processed from June 2014 through June 2015

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

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

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

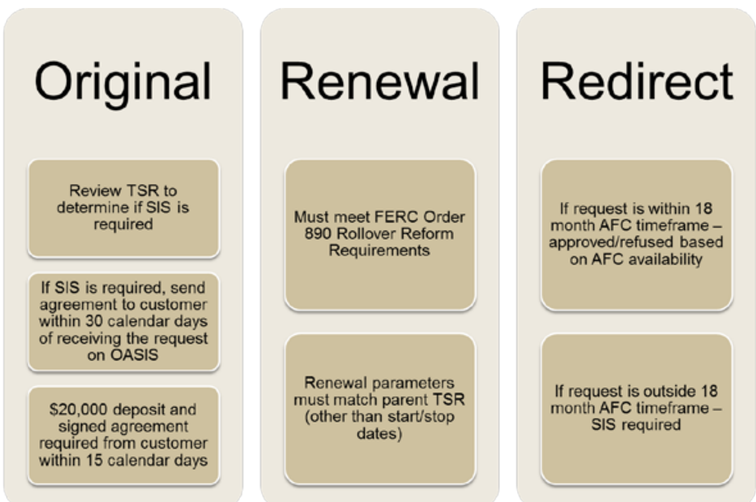


Figure 4.3-2: TSR Triage phase processing

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

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

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

Transmission Service Restriction

On March 28, 2014, the Federal Energy Regulatory Commission (FERC) accepted, over MISO's objection, a Transmission Service Agreement filed by Arkansas-based Southwest Power Pool (SPP), requiring MISO to pay SPP for any flow on SPP's transmission system above the existing 1,000 MW contract path between MISO North and MISO South. MISO has put a hold on evaluating any further TSRs from MISO South to MISO North (or contiguous region) or vice versa. The hold is pending the outcome of the dispute resolution between MISO, SPP and other parties in various dockets. MISO is also carefully considering how to implement processes that respect the contract path limit consistent with MISO's flow-based methodology for evaluating TSRs.

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

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

On May 22, 2014, in FERC Docket No. ER14-2022-000, MISO filed a Tariff waiver request to allow implementation of the above-described interim process for TSRs. The waiver was accepted by FERC on December 14, 2014.

On March 31, 2015, in FERC Docket No. ER 14-2022-001, MISO filed for a year-long extension of the previously approved waiver.

4.4 Generation Retirements and Suspensions

The permanent or temporary cessation of operation of generation resources can significantly impact the reliability of the transmission system. The MISO Attachment Y process ensures that the retirement or suspension of these assets is evaluated to determine if transmission is adequate to permit the generators to discontinue operation.

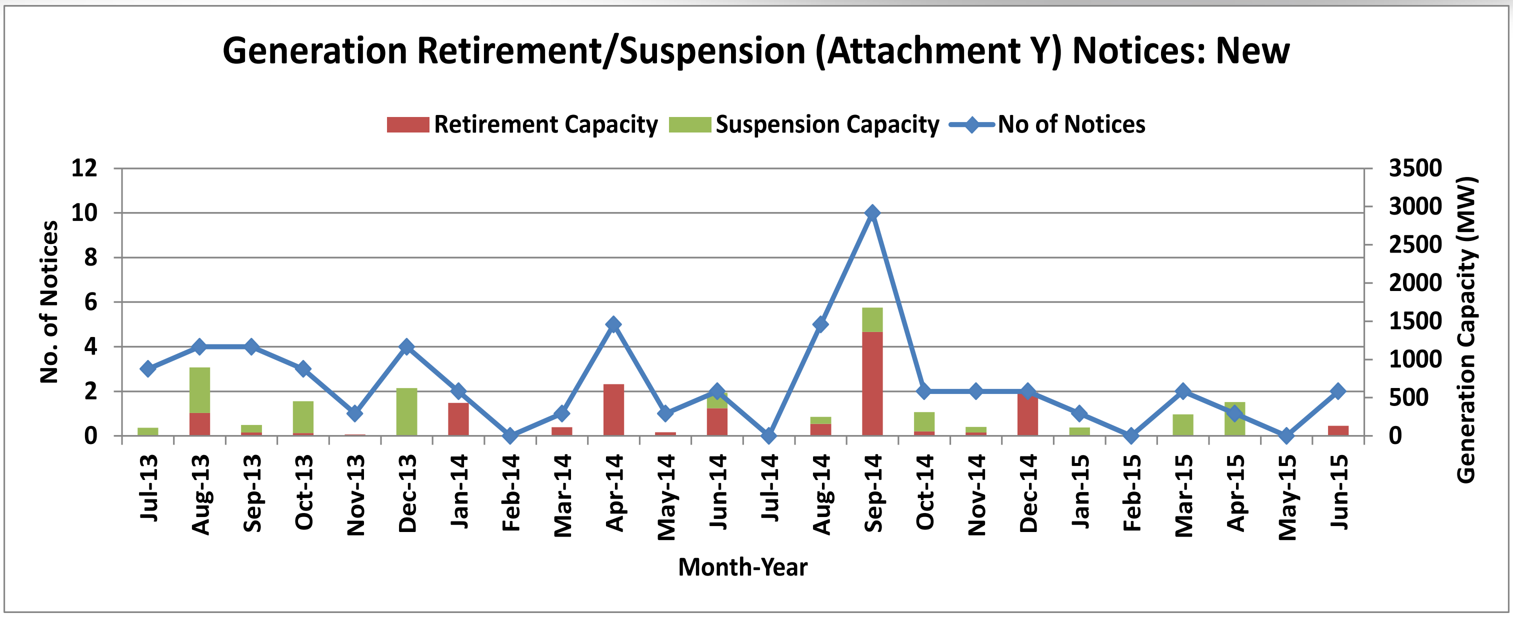
The MISO Attachment Y process ensures that the retirement or suspension of these assets is evaluated to determine if transmission is adequate to permit the generators to discontinue operation

Under the Tariff provisions, MISO has the ability to require the owner to maintain operation of the generation as a System Support Resource (SSR) if the generator is needed to avoid violations of applicable NERC, Regional and Transmission Owners' (TO) planning criteria. In exchange, the generator will receive compensation for its applicable costs to remain available. SSR costs are paid by the loads in areas that benefit from the SSR generation. An SSR is considered a temporary measure where no other alternatives exist to maintain reliability until transmission upgrades or other suitable alternatives are completed to address the issues caused by the unit change in status.

Attachment Y Requests and Status

MISO has received six Attachment Y Notices (964 MW) for unit retirement/suspension during the first six months of 2015 (Figure 4.4-1). The same period (January-June) in 2014 saw 11 Attachment Y retirement/suspension notices (1,835 MW) (Figure 4.4-1).

While the 2015 volume of Attachment Y Notices has remained slightly below the 2014 volume, the data suggests that the majority of retirement and suspension requests related to compliance with the current environmental regulations (Mercury and Air Toxics Standards) have been processed and that activity will remain light in the near term due to uncertainty in the regulatory implementation of the carbon policy. The next round of environmental regulations (Clean Power Plan, National Ambient Air Quality Standard for Ground-Level Ozone) is expected to result in a surge in activity as generator owners seek to address the more stringent standards.



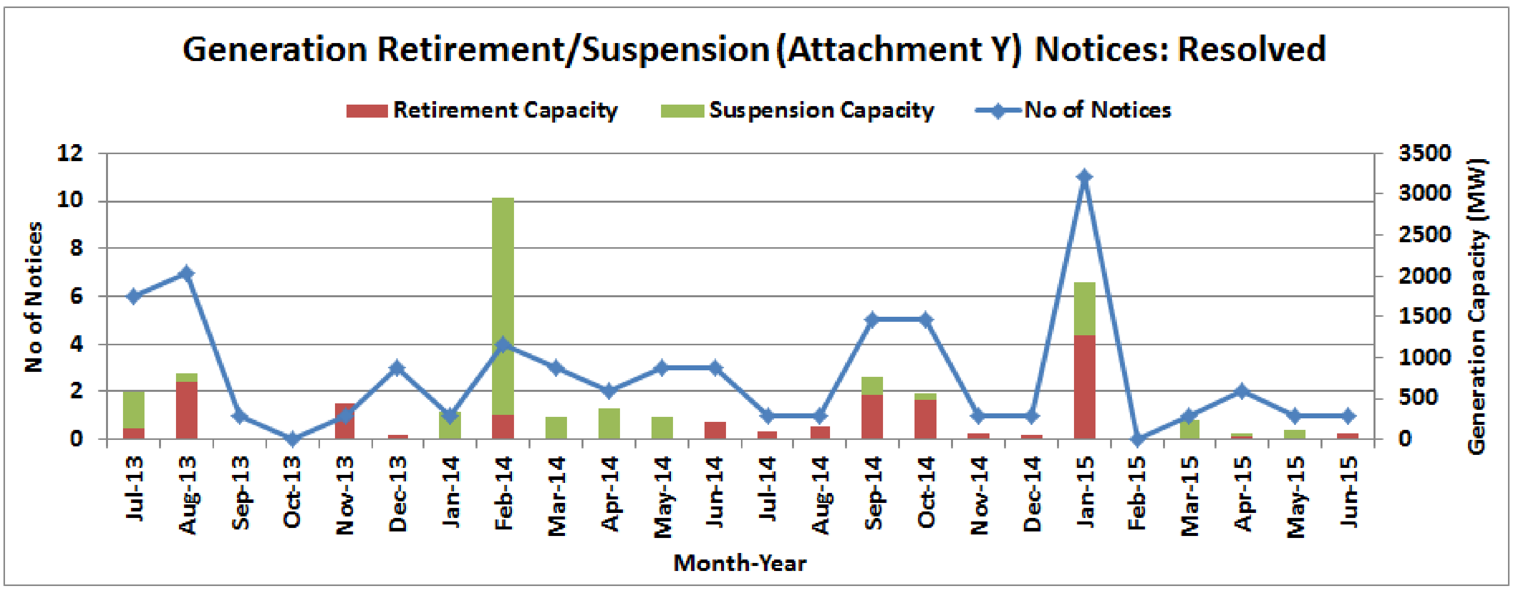


Figure 4.4-1: Generation Retirement/Suspension (Attachment Y) Notices – new and resolved

Overall, 1,399 MW of generation capacity is retiring in 2015 and an additional 2,733 MW of generation capacity will retire in 2016 (Figure 4.4-2). This includes 3,100 MW of coal generation, 907 MW of gas generation and 122 MW of oil generation that is approved for retirement in 2015 and 2016.

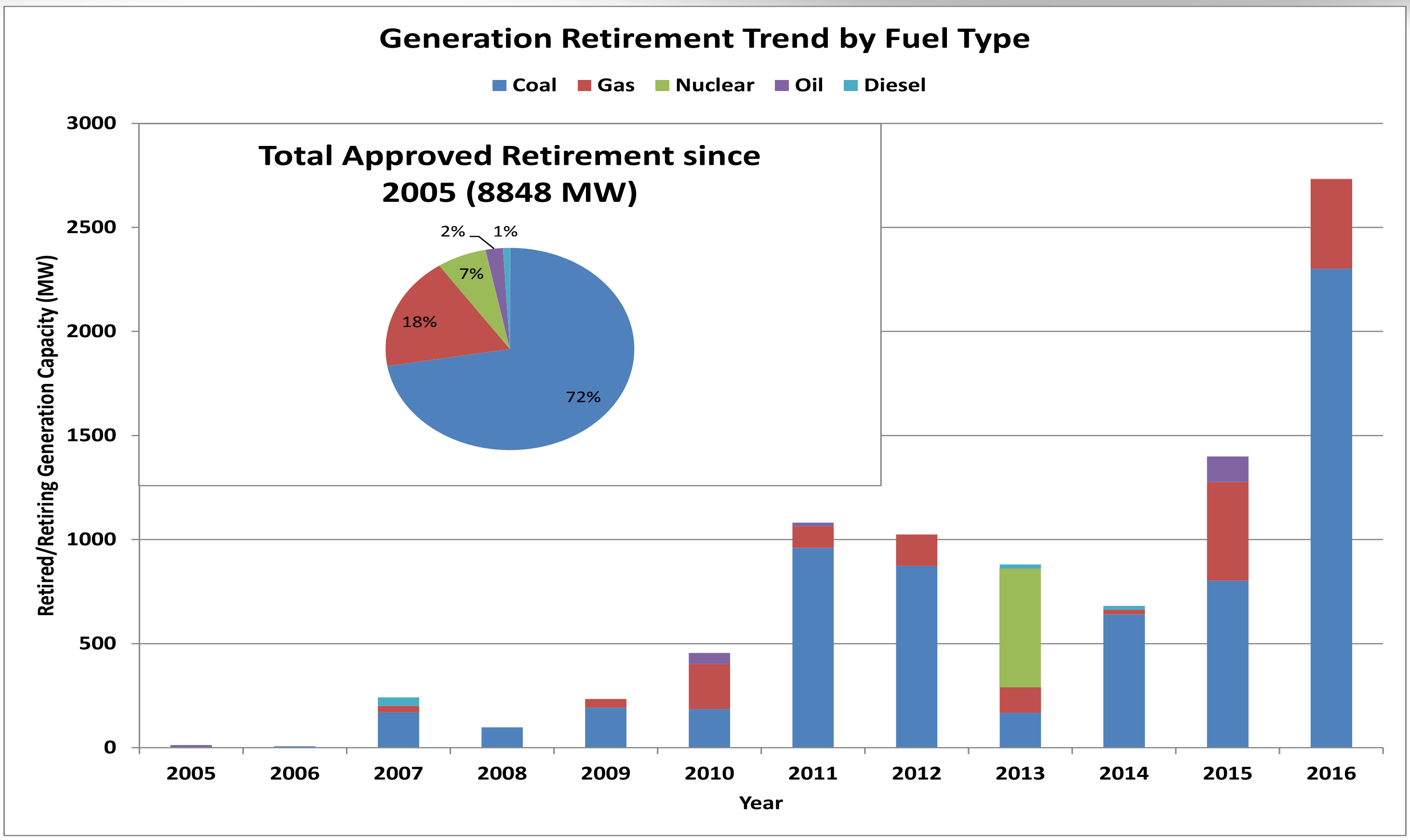


Figure 4.4-2: Generation capacity (aggregate MW) approved for retirement

2015 FERC Order on Cost Allocation

In February 2015, FERC issued a Compliance Order requiring changes to the methodology for allocation of SSR costs in three cases involving the Upper Peninsula of Michigan and later included a fourth in the U.P. In the order, FERC stated that the current methodology employing optimal load shed mitigation was not just and reasonable. FERC directed MISO to develop a method that would more appropriately assign costs to the loads that benefit from the operation of the SSR unit. In response, MISO conducted stakeholder meetings to seek feedback on its proposed method and submitted the proposed approach in a compliance filing in May 2015. On September 17, 2015, FERC issued an order (SSR Cost Allocation order) conditionally accepting MISO's proposed method for SSR Cost Allocation and directed MISO to make few changes to its proposed method and make a compliance filing within 30 days of the order. On October 9, 2015, MISO made a compliance filing as per the FERC directives in the SSR Cost Allocation order.

SSR Agreement Activity

Since the inception of the SSR program, MISO has implemented nine SSR Agreements. The last year has seen a sharp decline in the number of active SSR Agreements. Seven agreements have been terminated as a result of transmission upgrades, alternative solutions and equipment failure (Figure 4.4-3). As of June 2015, two generating plants remain in operation under SSR Agreements.

Escanaba 1 and 2 (25 MW) – The Escanaba Units 1 and 2 requested to suspend operation from June 15, 2012, to June 15, 2015, and have been on SSR Agreements since June 15, 2012. The agreement was recently renewed but equipment failure rendered the unit unable to operate and not reparable under the terms of the SSR Agreement. The agreement was terminated effective June 15, 2015.

Edwards 1 (103 MW) – The Edwards Unit 1 requested to retire on December 31, 2012, and was identified as an SSR unit until transmission improvements are completed in December 2016. The SSR Agreement has been in place since January 1, 2013, and was renewed for an additional term of January 1, 2015, to December 31, 2015. It will be re-evaluated for an additional 2016 term.

Presque Isle 5, 6, 7, 8 and 9 (344 MW) – The Presque Isle Units 5, 6, 7, 8 and 9 requested to suspend operation from February 1, 2014, to June 1, 2015. The generators were determined to be needed as SSR units until transmission projects are complete in the 2020 timeframe. The SSR Agreement was executed for an initial term of February 1, 2014, to January 31, 2015. A subsequent Attachment Y notice to retire the units on October 15, 2014, was submitted by the owner, which resulted in a new agreement from the period October 15, 2014, to December 31, 2015. The owner later rescinded the Attachment Y Notice, returning the units to voluntary operation. The SSR Agreement was terminated effective February 1, 2015.

White Pine 1 (20 MW) – White Pine Unit 1 requested to retire on April 16, 2014, and was determined as an SSR unit until projects are implemented in the 2019 to 2022 timeframe. The initial term of the SSR Agreement was established for April 16, 2014, to April 15, 2015 and was renewed for a second term from April 16, 2015 to April 15, 2016.

White Pine 2 (20 MW) – White Pine Unit 2 requested to retire on January 1, 2015, and was determined as an SSR unit until projects are implemented in the 2019 to 2022 timeframe. The initial term of the SSR Agreement was established for the period from January 1, 2015, through April 15, 2015. In the annual review of the need to continue the SSR Agreement, alternative generation was made available and determined to be adequate to allow the unit to retire. The SSR Agreement was terminated effective April 15, 2015.

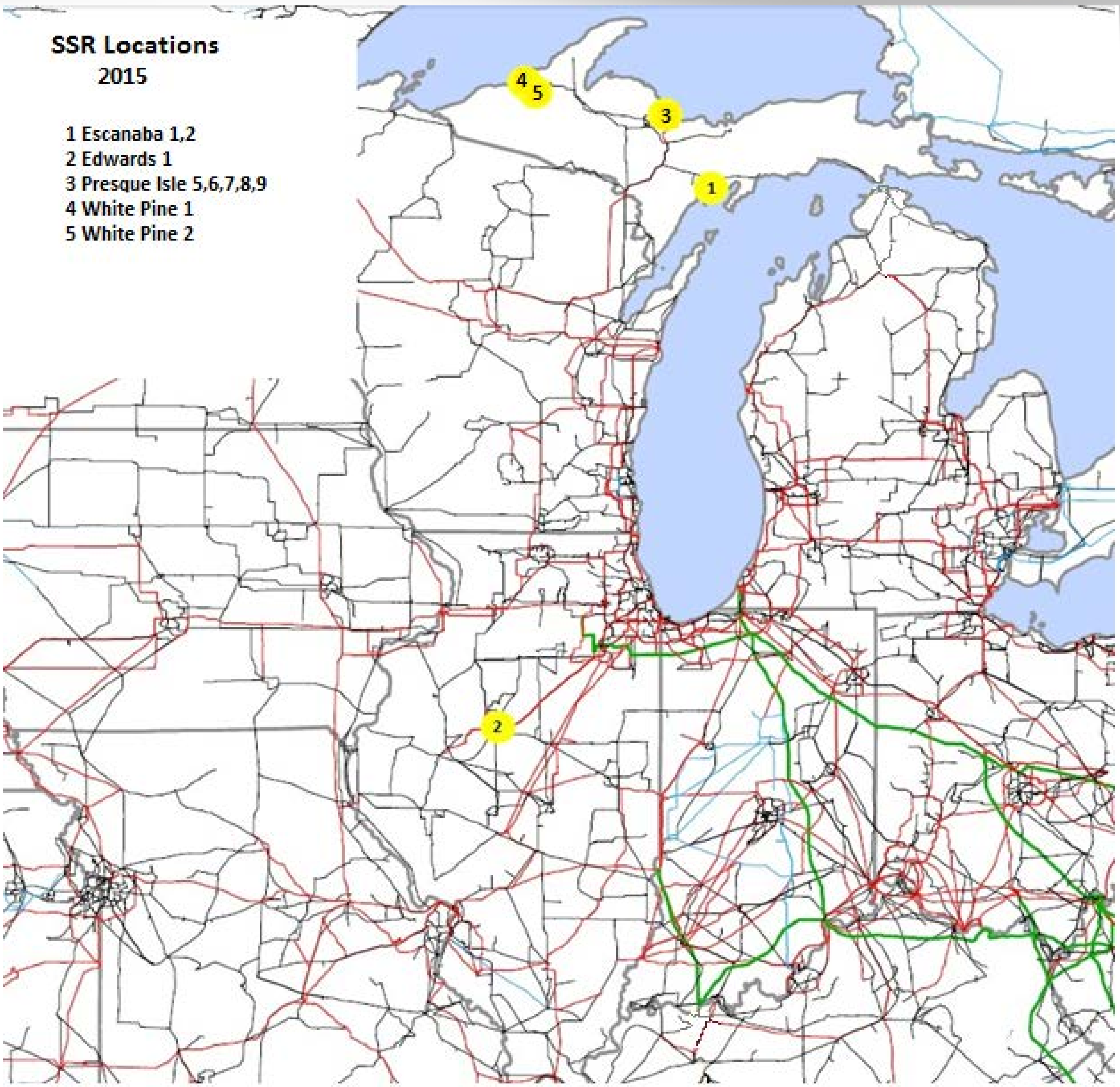


Figure 4.4-3: SSR Agreement locations

Process

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

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

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

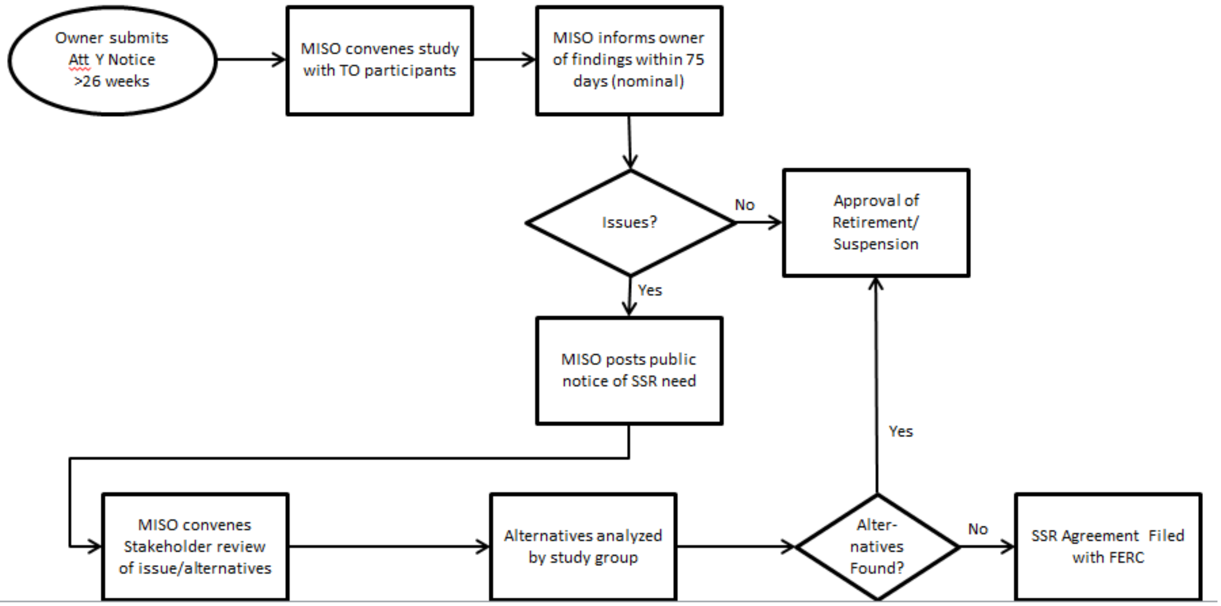


Figure 4.4-5: MISO Attachment Y process

4.5 Generator Deliverability Analysis

A total of about 3,530 MW of deliverability is restricted due to constraints under MISO functional control

MISO performs generator deliverability analysis as a part of the MTEP15 process to ensure continued deliverability of generating units with Network Resource Interconnection Service (NRIS). Results of the assessment are based on an analysis of near-term (five-year) and long-term (10-year) summer peak scenarios. Analysis results show a total of about 3,530 MW of deliverability is restricted due to constraints in the MTEP15 near-term scenario under MISO functional control and an additional 210 MW is restricted due to constraints identified on non-transferred transmission facilities and facilities subject to MISO Agency Agreement. More than 7,300 MW are restricted in the long-term 2025 planning scenario. Constraints observed that are restricting generation beyond the established network resource amounts in both scenarios will be mitigated (Figure 4.5-1).

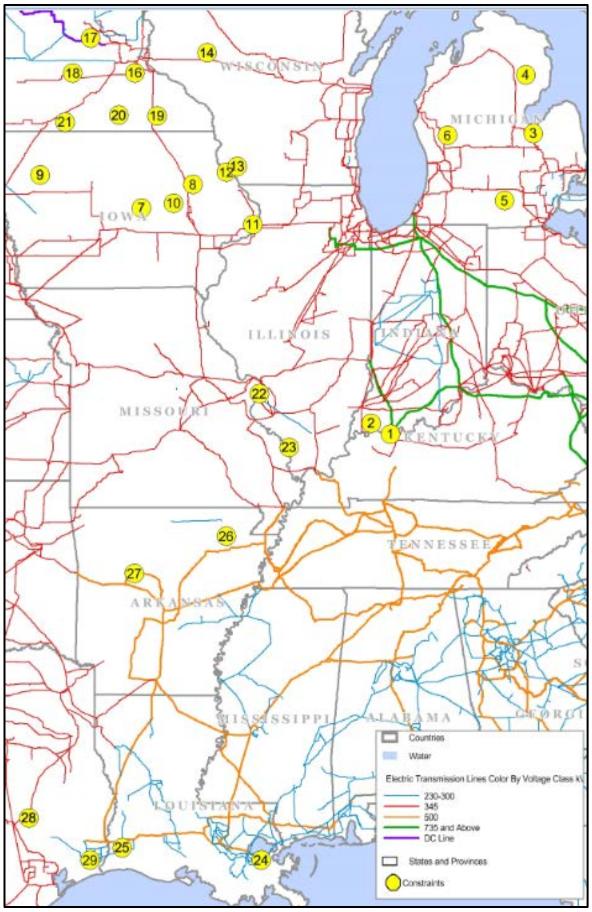


Figure 4.5-1: MTEP15 2020 Generator Deliverability constraint requiring mitigation

This analysis revealed 48 constraints that restrict existing deliverable amounts (Table 4.5-1) in the 2020 scenario with 33 constraints requiring mitigation. MTEP projects will be created for the mitigation required to alleviate the constraints identified.

To understand Table 4.5-1:

- "Overload Branch" is caused by bottling-up of aggregate deliverable generation
- "Area" is the Transmission Owner of the facility
- "Map ID" is the approximate location of the overloaded element (Figure 4.5-1)
- "Mitigation Required" represents constraints that were observed in both the near-term (five-year) and long-term (10-year) analysis.
- "MW Restricted" is the total amount of Network Resource Interconnection Service that is limited by the overloaded branch.

Overloaded Branch	Area	Map ID	Mitigation Required	MW Restricted
Ohio River – Iowa Junction 69 kV	210 SIGE	1		49.74
Iowa Junction – Pigeon Creek 69 kV	210 SIGE	2	Yes	34.17
Pigeon Creek – Heidelbach 69 kV	210 SIGE	2	Yes	15.96
Tuscola Bay 34.5/138 kV transformer	218 METC	3	Yes	126.95
Alcona – Alcona Dam 138 kV	218 METC	4	Yes	2.54
Page Avenue 138/46 kV transformer	218 METC	5	Yes	36.60
Felch Rd. three winding transformer	218 METC	6		15.24
Marshalltown Generator to Marshalltown 115/34.5 transformer	627 ITCM	7	Yes	92.75
Marshalltown to Marshalltown Generator 34.5/161 kV transformer	627 ITCM	7	Yes	12.50
Winthrop – Winthrop 69 kV	600 XEL	8	Yes	29.22
Buena Vista – Alta Municipal Tap 69 kV	635 MEC / 652 WAPA	9		74.74
Alta Municipal Tap – Aurelia Tap 69 kV	635 MEC / 652 WAPA	9		74.48
Aurelia Tap – Cherokee North 69 kV	635 MEC	9		73.53
Vinton Muni – Lindahl Tap 69 kV	627 ITCM	10	Yes	4.70
Beaver Channel 161/69 kV transformer 2	627 ITCM	11	Yes	140.35
Stoneman – Nelson Dewey 161 kV	680 DPC / 694 ALTE	12		84.37
Lancaster – Hurricane 69 kV	680 DPC	13		38.70
Hurricane – Mount Hope Tap 69 kV	680 DPC	13		16.95
Lafayette tap – Wissota Beach 69 kV	600 XEL	14	Yes	28.60
Wissota Beach – Cadott Interconnection 69 kV	600 XEL / 680 DPC	14	Yes	28.60
Wissota Hydro – Lafayette tap 69 kV	600 XEL	14	Yes	28.60
Bayfront 88/115 kV transformer	600 XEL	15		3.53

Overloaded Branch	Area	Map ID	Mitigation Required	MW Restricted
Cannon Falls to Colyville 115 kV	600 XEL	16	Yes	175.58
Maple Lake – Annandale 69 kV	600 XEL / 615 GRE	17		5.60
Cairo – Gibbon 69 kV	600 XEL	18	Yes	12.98
Pleasant Valley B1 34.5/161 kV transformer	600 XEL	19	Yes	75.06
Pleasant Valley B2 34.5/161 kV transformer	600 XEL	19	Yes	75.06
Bent Tree Wind Farm – Bent Tree Wind Farm Tap 34.5/161 kV transformer 1	627 ITCM	20	Yes	84.73
Bent Tree Wind Farm – Bent Tree Wind Farm Tap 34.5/161 kV transformer 2	627 ITCM	20	Yes	84.71
Fox Lake Generator to Fox Lake 13.8/161 kV transformer	627 ITCM	21	Yes	7.02
Cahokia 345 kV Bus 1 – Cahokia 138 kV Bus 4	357 AMIL	22	Yes	257.88
Trigen 13.8/138 kV transformer	356 AMMO	22		3.15
Grand Tower 13.8/138 kV transformer	357 AMIL	23	Yes	45.06
Grand Tower 13.8/69 kV transformer 1	357 AMIL	23	Yes	35.15
Grand Tower 13.8/69 kV transformer 2	357 AMIL	23	Yes	35.15
Ninemile Point – Derbigny 230 kV	351 EES	24		785.43
Ninemile Point – Napoleon 230 kV	351 EES	24		297.31
Nelson – Michigan 230 kV	351 EES	25	Yes	1034.80
Verdine – PPG 230 kV	351 EES	25	Yes	1034.80
Hoxie South AECC – Walnut Ridge 161 kV	327 EAI	26		137.31
Russellville North – Russellville East 161 kV	327 EAI	27		92.97
Grimes – Mt. Zion 138 kV	351 EES	28	Yes	98.19
Grimes 345/138 kV transformer - 2	351 EES	28	Yes	93.88
Grimes 345/138 kV transformer - 1	351 EES	28	Yes	84.69
Mt. Zion – Line 558 Tap 138 kV	351 EES	28	Yes	28.71
Tubular – Dobbin 138 kV	351 EES	28	Yes	22.73
Grimes – Bentwater 138 kV	351 EES	28	Yes	15.11
South Beaumont 138/69 kV transformer	351 EES	29		159.51

Table 4.5-1: MTEP15 near-term constraints that limit deliverability of about 3,740 MW of Network Resources.

Additional 2025 constraints will be monitored in future MTEP studies to determine if mitigation is required through the MTEP generator deliverability process. Appendix D6 lists detailed results for the 2025 constraints and impacted Network Resource Interconnection Service projects**.**

FERC Order 2003 mandated that "Network Resource Interconnection Service provides for all of the network upgrades that would be needed to allow the Interconnection Customer to designate its Generating Facility as a Network Resource and obtain Network Integration Transmission Service. Thus, once an Interconnection Customer has obtained Network Resource Interconnection Service, any future transmission service request for delivery from the Generating Facility would not require additional studies or Network Upgrades"[19] to be funded by the Interconnection Customer.

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

Constraints identified as needing mitigation were identified in both the near-term 2020 and long-term 2025 planning scenario or occur as a recurring constraint in the long-term planning scenario (Figure 4.5-2). Deliverability was tested only up to the granted network resource levels of the existing and future network resource units modeled in the MTEP15 2020 case. No new interconnection service is granted through the annual MTEP deliverability analysis. Changes to aggregate deliverability could be caused by changes in load and transmission topology.

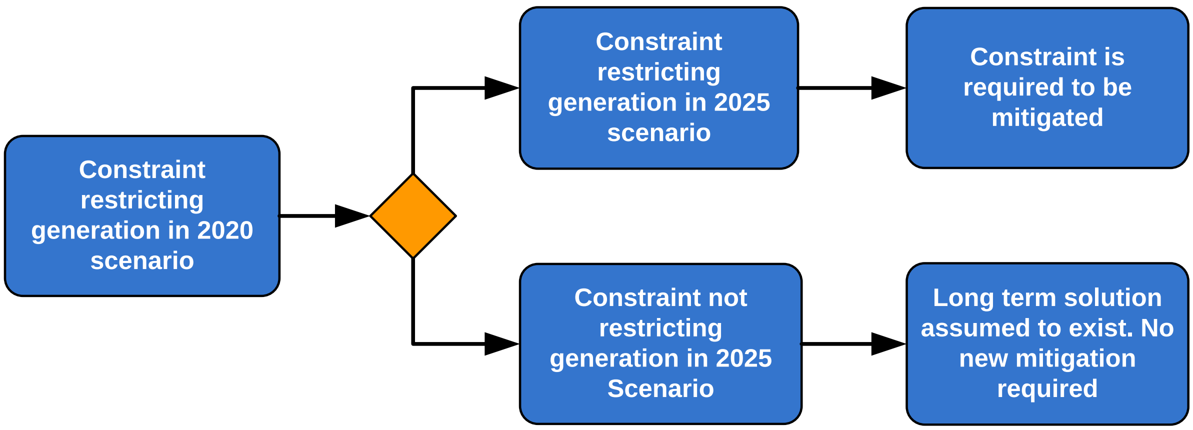
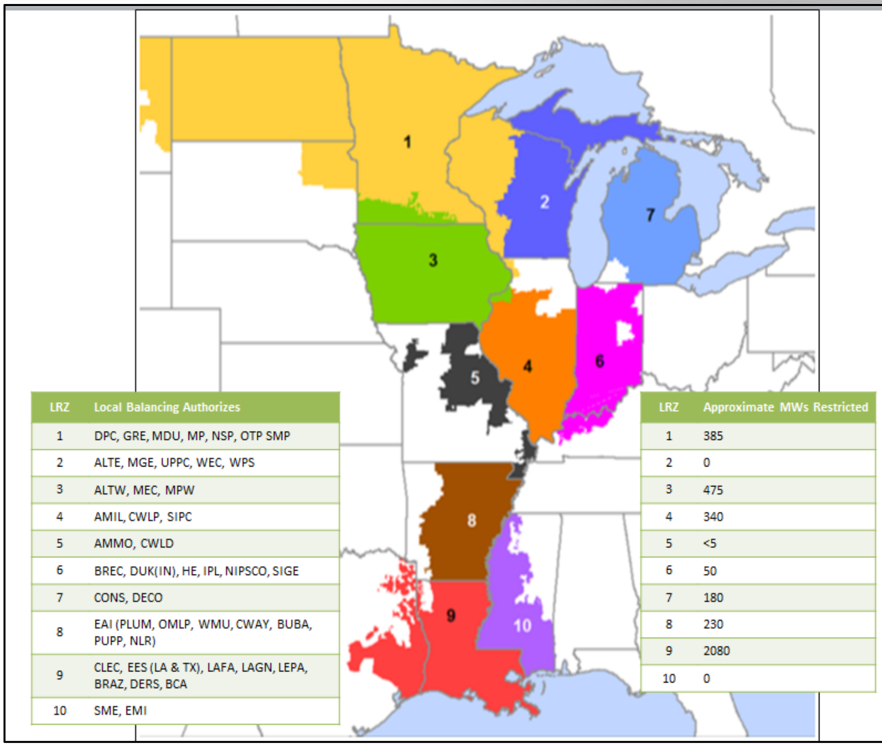


Figure 4.5-2: MTEP deliverability study process overview

The total MW restricted varies in the near term and is summarized by Local Resource Zone (Figure 4.5-3).

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



LRZ	Local Balancing Authorizes
1	DPC, GRE, MDU, MP, NSP, OTP SMP
2	ALTE, MGE, UPPC, WEC, WPS
3	ALTW, MEC, MPW
4	AMIL, CWLP, SIPC
5	AMMO, CWLD
6	BREC, DUK(IN), HE, IPL, NIPSCO, SIGE
7	CONS, DECO
8	EAI (PLUM, OMLP, WMU, CWAY, BUBA, PUPP, NLR)
9	CLEC, EES (LA & TX), LAFA, LAGN, LEPA, BRAZ, DERS, BCA
10	SME, EMI

LRZ	Approximate MWs Restricted
1	385
2	0
3	475
4	340
5	<5
6	50
7	180
8	230
9	2080
10	0

Figure 4.5-3: Local resource zones (LRZ)

Since MTEP09, MISO has performed annual generator deliverability studies to better monitor the restricted megawatts and Network Resources. The 3,740 MW of restricted deliverability from MTEP15 compares to 3,800 MW in MTEP14, 500 MW in MTEP13, 1,000 MW in MTEP12, 350 MW in MTEP11, 900 MW in MTEP10 and approximately 3,000 MW of restricted deliverability in MTEP09 (Figure 4.5-4).

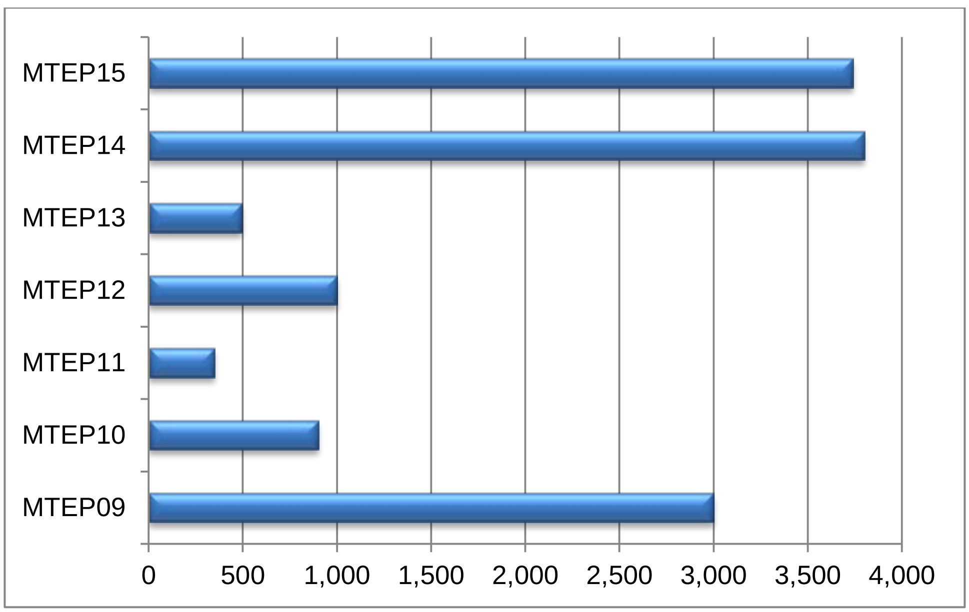


Figure 4.5-4: Restricted MW identified through MTEP cycles

MTEP14 Constraints Upgrades and Mitigation

MTEP14 identified 3.8 GW of deliverable generation restricted in the near term and out year under MISO functional control and an addition 370 MW of deliverability restricted to 69 kV constraints identified on non-transferred transmission facilities subject to MISO Agency Agreements.

Planned upgrades were identified to mitigate 2,566 MW and MTEP projects were created to resolve an additional 410 MW (Table 4.5-3).

Overloaded Branch	Area	Percent Overload	MW Restricted	Mitigation (MTEP ID)
Hemphill – Sabine 1 138 kV	218 METC	104%	123.4	8460
Cobb White – Sternberg 138 kV	218 METC	127%	206.1	8461
Claremont – Layton 138 kV	218 METC	110%	220.2	8540
White Bluff – Keo 500 kV	327 EES-EAI	116%	805.0	8940
Moril – Delcambre Rural 138 kV	351 EES	105%	99.4	4602
Fancy Point – Port Hudson 230 kV 1 and 2	351 EES	101%	65.8	4605
Greenville – Greenville East 115 kV	351 EES	103%	71.2	7898
Cleveland – Tarkington 138 kV	351 EES	102%	25.2	7947
South Beaumont 138/69 kV Transformer	351 EES	110%	77.5	7947
South Beaumont 138/69 kV Transformer	351 EES	109%	77.5	7947
Sabine – Port Neches 138 kV	351 EES	110%	134.4	7947
Sabine 138 – Linde 138 kV	351 EES	106%	84.0	7947
Chlomal – Iowa 69 kV	351 EES	107%	12.0	7960
Rodemacher – East Leesville 230 kV	502 CLEC	106%	129.4	7993
Ottumwa – Bridgeport 161 kV	627 ALTW	107%	115.2	8020
Council Bluffs – Beacon 161 kV	627 ALTW	107%	105.7	8020
Hunter Creek – Tiffin REC 69 kV	627 ALTW	115%	22.0	8111
Tiffin REC – Heartland Tap 69 kV	627 ALTW	109%	22.0	8111
Tiffin – Hunter Creek 69 kV	627 ALTW	121%	40.8	8111
ALTW Tiffin – Tiffin 69 kV	627 ALTW	128%	54.0	8111
Albany – York 161 kV	627 ALTW	101%	30.6	8844
Burlington – South Burlington 69 kV	627 ALTW	127%	168.8	9100
Burlington 4th St – Agency 69 kV	627 ALTW	115%	74.0	9100
West Sub – Isett Ave 69 KV	633 MPW	111%	61.3	9001
Units 7/8/8A SUB 69 KV – Pine St 69 KV	633 MPW	111%	56.1	9021
Pine St – Isett Ave 69 KV	633 MPW	113%	50.2	9022
Tiffin – ALTW Tiffin 69 kV	635 MEC	142%	32.0	8111
Victoria – Rockland Junction 2 69 kV	698 UPPC	107%	2.7	8089
Victoria – Rockland Junction 1 69 kV	698 UPPC	106%	2.3	8089
Rockland Junction – Rockland 69 kV	698 UPPC	107%	2.7	8089
Rockland – Mass 69 kV	698 UPPC	107%	2.6	8089
Rockland Junction – UPPSCO TAP 69 kV	698 UPPC	106%	2.3	8089

Table 4.5-3: Mitigations identified for constraints requiring mitigation from MTEP14

After the MTEP14 report was posted, MISO continued to work with stakeholders for review of the MTEP14 deliverability constraints. Multiple constraints were relieved through submitted model corrections consisting of dispatch corrections and rating changes (Table 4.5-4).

Overloaded Branch	Area
Connersville – Connersville 30Th 69 kV	208 DEI
Wisdom to Spencer 69 kV	652 WAPA
Pere Marquette – Lake County 138 kV	218 METC
Sabine 2 – Halsey 138 kV	218 METC
Arklahoma – Tigre SS 115 kV	327 EES-EAI
Tigre SS – Panther SS 115 kV	327 EES-EAI
Panther SS – Hot Springs – Fountain Lake 115 kV	327 EES-EAI
Cheetah – Hot Springs Village 115 kV	327 EES-EAI
Hot Springs – Fountain Lake – Cheetah 115 kV	327 EES-EAI
Carpenter Dam – Hot Springs South 115 kV	327 EES-EAI
Hot Springs East – Butterfield 115 kV	327 EES-EAI
Butterfield – Haskel 115 kV	327 EES-EAI
Russellville East – Russellville South 161 kV	327 EES-EAI
Russellville North – Russellville East 161 kV	327 EES-EAI
Newport – Newport Industrial 161 kV	327 EES-EAI
West Memphis 500/161 kV Transformer	327 EES-EAI
Newport Industrial – Newport Air Base 161 kV	327 EES-EAI
Hoxie South AECC – Walnut Ridge 161 kV	327 EES-EAI
Marion Power Plant – Marion 69 kV	361 SIPC
Marion – Marion Power Plant 69 kV	361 SIPC
Layfield – Carroll 230 kV	502 CLEC

Table 4.5-4: Constraints Relieved through model corrections from MTEP14

Proposed Changes for MTEP16

MTEP16 proposes the incorporation of three modifications into the Baseline Generator Deliverability analysis to better align the process for granting Network Resource Interconnection Service through the queue process and the MTEP Baseline Generator Deliverability analysis. The changes were initially presented at the May 2015 Planning Subcommittee meeting. MTEP16 propose that:

- Energy Resource with Transmission Service Requests mitigation will be specifically identified
- The “Top 30” list will assign placeholders on a plant basis rather than unit basis
- Base dispatch will not exceed the sum of the dispatch on a local balancing authority (LBA) basis

Energy Resource with Transmission Service Requests mitigation will be specifically identified. Transition deliverability studies identified deliverable MWs and the remaining were allocated to the non-deliverable bucket. Through transitional studies, MISO emphasized no loss of Transmission Service. In MTEP15 and previous years the TSRs were included in the base case. Mitigation and was not directly identified within Baseline Generator Deliverability process. In MTEP16 constraints identified due to Energy Resources with Transmission Service Requests will require mitigation. The change is being made to ensure that services granted are kept whole concurrently.

The “Top 30” list will assign placeholders on a plant basis rather than unit basis. Historically, through deliverability analysis, generators that contributed to constraints are limited to the most impactful 30 units (some caveat for remote offline generators). In MTEP15, and previously for Baseline Generator Deliverability analysis, the placeholder was assigned based on generators that had separate buses assigned, which is generally on a unit basis. In MTEP16 the placeholder assignment will be based on a plant, rather than a unit. The change is being made to capture generators at the same physical location that are expected to contribute to the same constraints. Previously, units at the same plant may have partially contributed and the remaining portion not participated.

Base dispatch will not exceed the sum of the dispatch on an LBA basis. The goal of deliverability analysis is to ensure that generators are not bottled up. The starting dispatch for deliverability studies is an LBA-level dispatch, which means that Network Resources within individual LBAs dispatched in merit order to serve LBA network load. To the extent that all of the Network Resources are not dispatched in the starting case; the base dispatch will be adjusted to model all Network Resources at the same percentage of output. The percentage may be different for each LBA. This adjustment will ensure that on an LBA basis, extreme exports are not applied causing a potential reduction in Network Resources in another LBA. The deliverability study will then ramp up the Network Resources simultaneously based on impacts to identified facilities. This ensures that the units are not bottled up and will continue to be studied on a footprint-wide basis to internal MISO load.

4.6 Long Term Transmission Rights Analysis Results

MTEP provides for reliable and economic use of resources, reducing the likelihood of infeasible LTTRs

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

This chapter details the financial uplift associated with infeasible LTTRs for MISO Central, North and South regions (Table 4.6-1) and documents planned upgrades that may mitigate the drivers of LTTR infeasibility identified using the annual Financial Transmission Rights (FTR) auction models (Table 4.6-2).

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

Consistent with the ARR market design, this second ARR planning year for the MISO South region reflects the first opportunity for infeasibile LTTRs in that region. As such, the MTEP15 study is the first year incorporating infeasibility or uplift information for the South region.

Factors that may have resulted in lower overall prices and higher overall MW allocated when compared to the prior year include: several upgrades throughout the footprint (including East Winamac and West Franklin); and improved constraint modeling in the South region due to more historical information on the congestion pattern. The LTTR infeasibility uplift ratio decreased from 5.06 percent in MTEP14 to 3.43 percent in MTEP15 (Table 4.6-1), as noted in the 2015 Annual ARR Allocation. The 2015 allocation of total infeasible uplift for MISO is $16.4 million out of total LTTR payments of $478.5 million.

Region	Total Stage1A (GW)	Total LTTR Payment ($M) (including infeasible Uplift)	Total Infeasible Uplift ($M)	Uplift Ratio
MISO-wide	450.7	478.5	16.4	3.43%
Central, North	323.5	286.5	7.4	2.6%
South	127.2	192	9	4.7%

Table 4.6-1: Uplift costs associated with infeasible LTTR in the 2015 Annual ARR Allocation

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

Planned mitigations associated with limited LTTR feasibility are listed in Table 4.6-2. Binding constraints are filtered for those with values greater than $200,000. Other constraints will continue to be monitored in the annual allocation process for feasibility status. MISO will coordinate with its Transmission Owners to investigate constraints in the MTEP15 planning cycle. Additionally, MISO will coordinate with adjacent regional transmission organizations on seams constraints.

Constraint	Summer 2015	Fall 2015	Winter 2015	Spring 2016	Grand Total	Planned Mitigation
Melbourne – Calico Rock 161 kV FLO Independence – Dell 500 kV		$441,131		$287,267	$728,398	
Newton – Robinson Marathon 138 kV FLO Newton-Casey West 345 kV	$299,584	$137,318	$42,658	$31,416	$510,976	
Grimes Transformer 1 345/138kV FLO Grimes Transformer 2 345/138 kV	$37,310	$181,508	$446,209	$55,226	$720,253	Grimes-Ponderosa 230kV ISD: June 1, 2016
Ottumwa – Wapello Line 1 161 kV FLO Ottumwa – Wapello Line 2 161 kV	$(4,704)	$407,932			$403,228	
Nelson East Transformer 1 500/230 kV FLO Hartburg – Cypress 500 kV	$55,338	$124,613	$50,880	$99,428	$330,260	Upgrade in-service, but not modeled in time for allocation
Dolet Hills 345/230 kV transformer FLO Longwood – Sarepta 345 kV	$20,690	$430	$41,039	$228,908	$291,067	
Chariton – Lucas 69 kV FLO Ottumwa – Wapello Line 2 161 kV	$24	$10,583	$278,431		$289,039	
Gillisburg – Amite 115 kV FLO McKnight – Franklin 500 kV	$74,749			$207,730	$282,479	

Ottumwa – Bridgeport 161 kV FLO Ottumwa – Tri-County 161 kV			$232,910		$232,910	Project ID: 8020 Pleasant Corner-Beacon 161 kV Line & Terminal ISD: June 2016
Rising Transformer 1 345/138 kV FLO Clinton – Brokaw 345 kV			$228,707	$3,830	$232,538	
Market Street Transformer 1 230/115 kV FLO Michoud Transformer 1 230/115 kV	$34,905	$94,005	$28,387	$56,130	$213,427	
Dolet Transformer 345/24 kV A Base			$207,655		$207,655	

Table 4.6-2: Infeasible uplift to binding constraints from the 2015 annual FTR Auction

Chapter 5
Economic Analysis

5.1 Economic Analysis Introduction

The MISO Value-Based Planning Process ensures transmission expansion plans minimize the total electric costs to consumers, maintain an efficient market, and enable state and federal public energy policy — all while maintaining system reliability. The Multi-Value Project Portfolio, approved in MTEP11, demonstrates the success of the Value-Based Planning Process. The Multi-Value Projects will save Midwest energy customers more than $1.2 billion in projected annual costs and enable 41 million MWh of wind energy to meet renewable energy mandates and goals.[20]

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

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

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

[20] Source: Multi-Value Project Portfolio - MTEP 2011

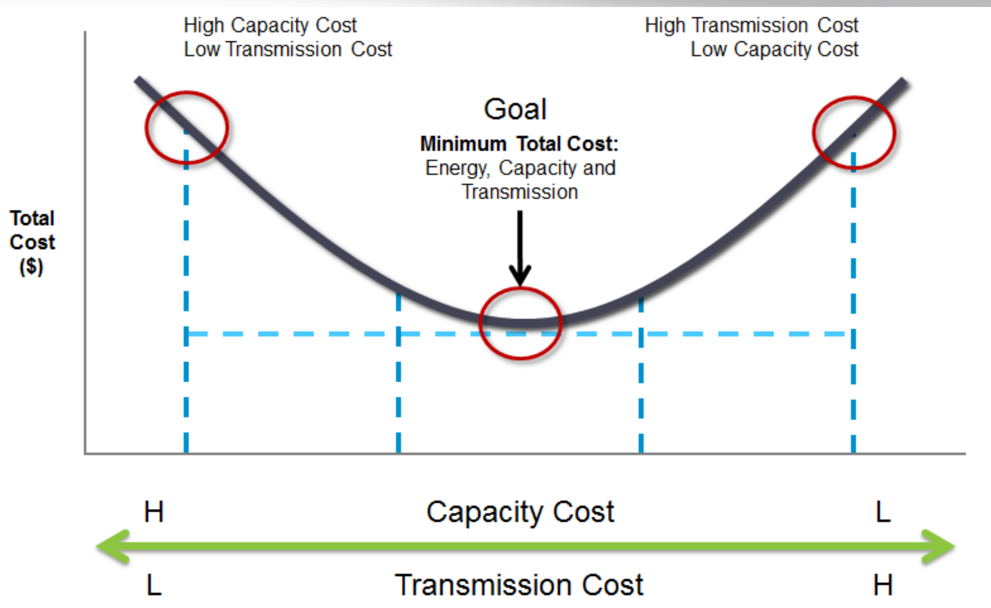


Figure 5.1-1: The goal of the MISO Value-Based Planning Process

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

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

Value-Based Planning Process

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

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

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

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

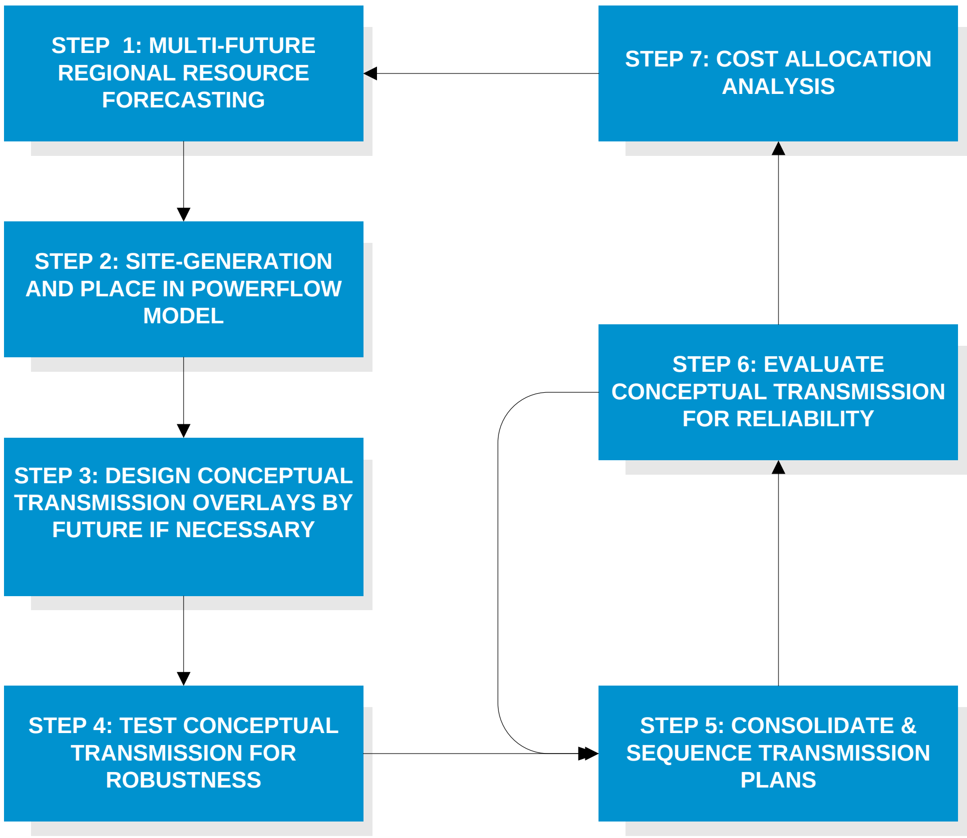


Figure 5.1-2: MISO's Value-Based, Seven-Step Planning Process

Step 1: Futures Development and Regional Resource Forecasting

Scenario-based analysis provides the opportunity to develop plans for different future scenarios. A future scenario is a postulate of what could be, which guides the assumptions made about a given model. The outcome of each modeled future scenario is a generation expansion plan, or generation portfolio.

Generation portfolios identify the least-cost generation required to meet reliability criteria based on the assumptions for each scenario.

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

A more detailed discussion of the assumptions and methodology around the MTEP15 future scenarios is in Chapter 5.2: MTEP Future Development.

Step 2: Siting of Regional Resource Forecast Units

Generation resources forecasted from the expansion model for each of the future scenarios are specified by fuel type and timing; however, these resources are not site-specific. Future generation units must be sited within all planning models to provide an initial reference position five to 20 years into the future. Completing the process requires a siting methodology tying each resource to a specific bus in the powerflow model. A guiding philosophy and rule-based methodology, developed in conjunction with industry expertise, is used to site forecasted generation. The siting of regional resource forecast units is reviewed annually by the Planning Advisory Committee. A more detailed discussion of the siting methodology around each MTEP15 future is in Chapter 5.2: MTEP Future Development.

Step 3: Design Conceptual Transmission By Future

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

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

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

The conceptual transmission design process using economic potential information is shown in Chapter 5.3: Market Congestion Planning Study.

Step 4: Test Conceptual Transmission For Robustness

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

Step 5: Consolidate and Sequence Transmission

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

Step 6: Evaluate Conceptual Transmission For Reliability

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

Step 7: Cost Allocation

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

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

Table 5.1-1: Summary of MISO cost allocation mechanisms

MISO's Value-Based Planning Process continues to evolve to better integrate different planning functions, take advantage of new technology and meet stakeholder needs, in both scope and complexity. Enhancements to the existing value-based planning process to accommodate new Order 1000 requirements have been identified and implemented through a robust stakeholder process, including:

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

In MTEP15, MISO's Value-Based Planning Process is exemplified in the MTEP Future Development (Chapter 5.2), Market Congestion Planning Studies (Chapter 5.3), MTEP 2015 MVP Limited Review (Chapter 7.5), and PJM and SPP Interregional Studies (Chapters 8.1 and 8.2).

5.2 Generation Portfolio Analysis

In 2014, MISO changed the way in which economic MTEP series models are identified. In 2013 and prior years, economic models were identified by the MTEP cycle in which the building process began. Because of the amount of time it takes to fully build a new economic model (develop assumptions, resource forecasting, topology updates, etc.) the vintage was always a year behind the report containing the results using said model. As such, beginning with MTEP15, models are now identified by the report where the data will be contained (Table 5.2-1). MTEP15 Market Congestion Planning Studies will use the MTEP15 Economic Model (created in 2014).

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

Table 5.2-1: Model vintage and associated MTEP report

This chapter describes the MTEP resource forecasting results created in 2014 and used for MTEP15 for both the North, Central and South regions. MISO completed this assessment of resources using the Electric Generation Expansion Analysis System (EGEAS) model in 2014. Using assumptions developed in coordination with the Planning Advisory Committee (PAC), MISO developed these models to identify the least-cost resource portfolios needed to meet the resource adequacy requirements of the system for each future scenario.

MTEP16 Resource Forecasting results were produced in 2015 and will be used for MTEP16. MTEP16 resource forecasting results are presented in Appendix E2.

Resource Forecasting Results

The study determined the aggregated, least-cost resource expansions for each defined future scenario through the 2029 study year (Figure 5.2-1). These added resources are required to maintain planning reliability targets for each region. The reliability targets for MISO are defined in the Module E Resource Adequacy Assessment described in Book 2.

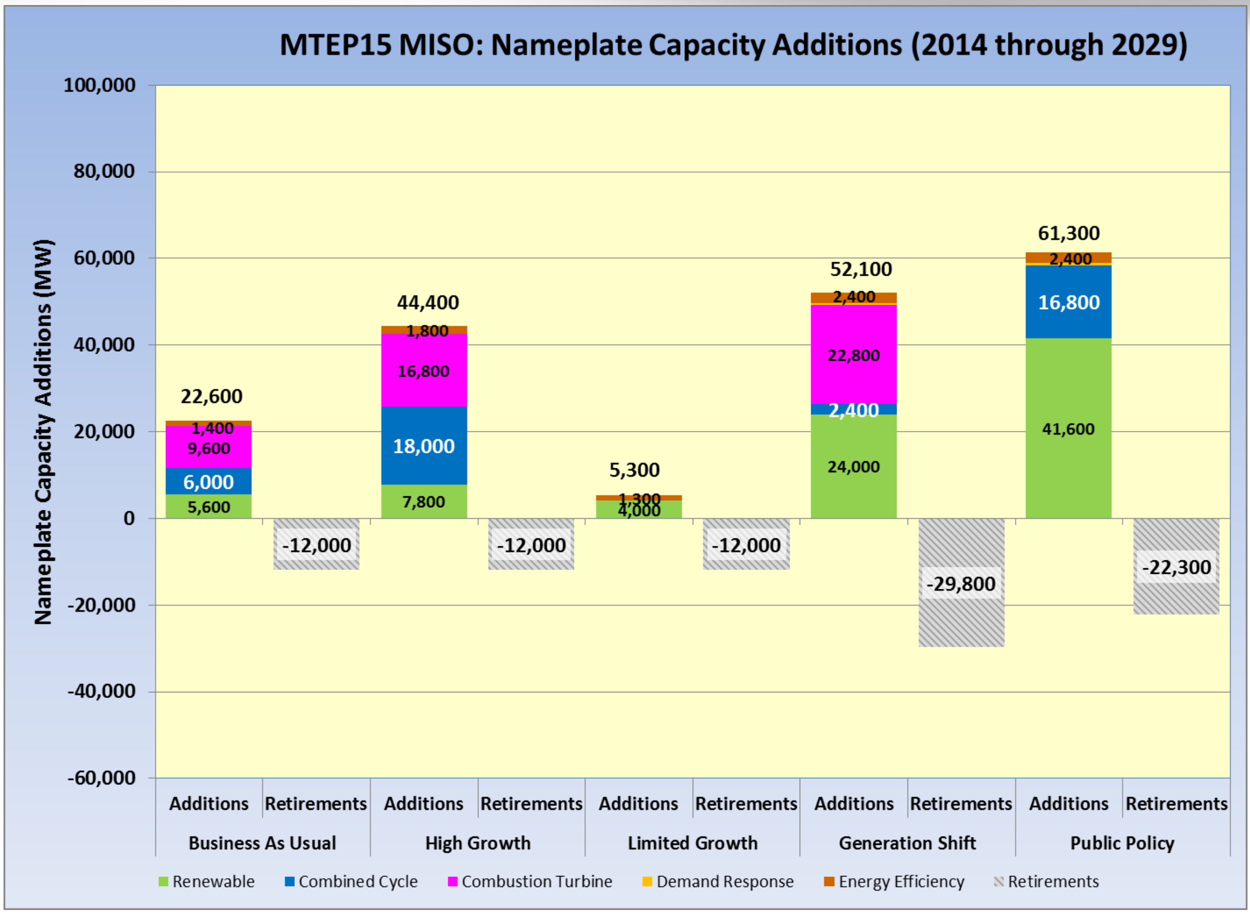


Figure 5.2-1: MISO nameplate resource additions by future (2014-2029 EGEAS model)[21]

Results of the assessment for the Business as Usual (BAU) future show that 22,600 MW of additional nameplate resources are expected to be needed between 2014 and 2029, while an additional 12 GW of coal capacity is forecasted to retire. MISO, with advice from the PAC, models 12.6 GW of coal retirements as a minimum in all future scenarios.[22] The Generation Shift future also includes age-related retirements of non-coal and non-nuclear resources and another 7 GW of coal retirements in addition to the 12.6 GW assumed in all futures. The Public Policy future includes additional coal retirements, totaling 22.3 GW, which was necessary to achieve the desired target of 25 percent energy from coal by the end of the study period. The future resource expansions include demand response (DR) and energy efficiency (EE) programs, as well

In the Business As Usual future, it is projected that between 2014 and 2029, 22.6 GW of additional resources will need to be added to the MISO system while 12 GW of capacity will retire

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

[22] MISO performed an EPA impact analysis study in 2011 in order to determine the potential of coal fleet retirements. The EPA analysis produced three levels of potential coal retirements: 3 GW, 12.6 GW and 23 GW. To capture these potential retirements in the scenario-based analysis, MISO analysts, in conjunction with the Planning Advisory Committee (PAC), chose to model a minimum of 12.6 GW of retirements in all futures, with the exception of 23 GW of retirements being modeled in the Environmental future.

as natural gas combustion turbines, natural gas combined cycle units, wind and solar. The retired capacity is mostly coal generation, resulting from simulation of the impacts of proposed EPA regulations.

Futures Development

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

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

The following narratives describe the MTEP15 future scenarios and their key drivers:

- The **Business as Usual** (BAU) future captures all current policies and trends in place at the time of futures development and assumes they continue, unchanged, throughout the duration of the study period. All applicable EPA regulations governing electric power generation, transmission and distribution (NAICS 2211) are modeled. Demand and energy growth rates are modeled at a level equivalent to the 50/50 forecasts submitted into the Module E Capacity Tracking (MECT) tool. All current state-level Renewable Portfolio Standard (RPS) and Energy Efficiency Resource Standard (EERS) mandates are modeled. To capture the expected effects of environmental regulations on the coal fleet, **12.6 GW of coal unit retirements** are modeled.
- The **High Growth (HG)** future is designed to capture the effects of pre-recession level economic growth as well as an increase in renewable energy over the entire footprint. All current state-level RPS and EERS mandates are modeled. All existing EPA regulations governing electric power generation, transmission and distribution (NAICS 2211) are incorporated and **12.6 GW of coal unit retirements** are included.
- The **Limited Growth** (LG) future is designed to capture the effects of the economy turning back toward recession-like levels. All current state-level RPS and EERS mandates are modeled. All applicable EPA regulations governing electric power generation, transmission and distribution (NAICS 2211) are modeled. To capture the expected effects of environmental regulations on the coal fleet, **12.6 GW of coal unit retirements** are included.
    - The **Generation Shift (GS)** future focuses on several key items that combine to result in a substantial shift in the main sources of energy in the MISO footprint:
    - MISO assumes each non-coal and non-nuclear thermal generator will be retired in the year it reaches 50 years of age
    - Hydro units will retire in the year they reach 100 years of age
    - Additional coal unit retirements, coupled with a $10/ton carbon cost and a 20 percent footprint wide renewable mandate, result in system-wide energy sales derived from coal generation falling to 40 percent by the end of the 20-year study period

- Demand and energy growth rates are modeled at a mid-level and EERS goals and mandates are considered.
- The **Public Policy (PP)** future captures the effects of increased carbon regulations and an even greater move toward clean energy production and efficient use of resources. Total energy sales derived from coal fall to 25 percent as a result of the combined effects of a cost on carbon emissions, coal unit retirements, and a 30 percent MISO-wide renewable mandate. Demand and energy growth rates are modeled at a mid-level and EERS goals and mandates are considered.

These scenarios were developed and approved prior to the current 111(d) rule the EPA has recently finalized and MISO is not specifically looking at that rule in MTEP15. The biggest driver of coal retirements in the BAU, HG and LG scenarios is the EPA Mercury and Air Toxics Standard (MATS). In the GS scenario, coal retirements are driven by the EPA MATS rule plus another 7 GW to aid in achieving the desired goal of 40 percent energy from coal by the end of the study period. MISO also considers additional retirements of generators in the GS future due strictly to their age. In the PP scenario, MISO considers EPA MATS plus other pending regulations such as Cooling Water Intake Structures (CWIS) and Coal Combustion Residuals (CCR).

Effective Demand and Energy Growth Rates

Many states have encouraged, and in some cases mandated, the use of demand-side management (DSM) technologies in order to reduce the need for investment in new power generation. To evaluate the potential of DSM within the footprint, MISO consulted with Global Energy Partners LLC in 2010. This effort led to the development of 20-year forecasts for various types of DSM for the MISO region and the rest of the Eastern Interconnection. The study found DSM programs have the potential to significantly reduce the load growth and future generation needs of the system. For MTEP15, the DSM program's magnitudes were scaled to reflect state-level energy efficiency and/or demand response mandates and goals. To calculate the effective demand and energy growth rates, which are ultimately input into the production cost models (Steps 3, 4 and 5 of the MTEP planning process), MISO nets out only the impact of the energy efficiency programs from the baseline demand and energy growth rates. The resulting effective growth rates for the various futures range from 0.08 percent to 1.44 percent for demand and 0.10 percent to 1.45 percent for energy (Table 5.2-2). Demand response programs are modeled within the production costing simulations as oil-fired generators with a significantly high fuel cost when compared to other generators.

	Baseline Growth Rates		**Effective Growth Rates**	
Future Scenarios	**Demand**	**Energy**	**Demand**	**Energy**
Business as Usual	0.80%	0.80%	0.75%	0.76%
High Growth	1.50%	1.50%	1.44%	1.45%
Limited Growth	0.14%	0.14%	0.08%	0.10%
Generation Shift	0.80%	0.80%	0.71%	0.73%
Public Policy	0.80%	0.80%	0.71%	0.73%

Table 5.2-2: MTEP15 effective demand and energy growth rates

Production and Capital Costs

EGEAS resource expansion data provides the present value of production and capital costs for the study period through 2029 (Figure 5.2-2). While EGEAS does not model transmission congestion, the results nonetheless demonstrate scenarios in which higher or lower production costs could be incurred when compared to a Business as Usual-type scenario. Production costs include fuel; variable and fixed operations and maintenance; and emissions costs (where applicable). Capital costs represent the annual revenue needed for new resources. Each future scenario has a unique set of input assumptions, such as demand and energy growth rates, fuel prices, carbon costs and RPS requirements that drive the future resource expansion capital investments and total production costs.

Due to the significantly higher production costs in the Public Policy future, it should be noted that approximately $164 billion of the total $327 billion in production costs are due to the $50/ton carbon tax modeled in that future. Also, the retirement of 23 GW of coal units (versus 12.6 GW in the other futures) leads to higher production costs resulting from higher capacity factors of gas-fired generation, which has a higher modeled fuel price than coal.

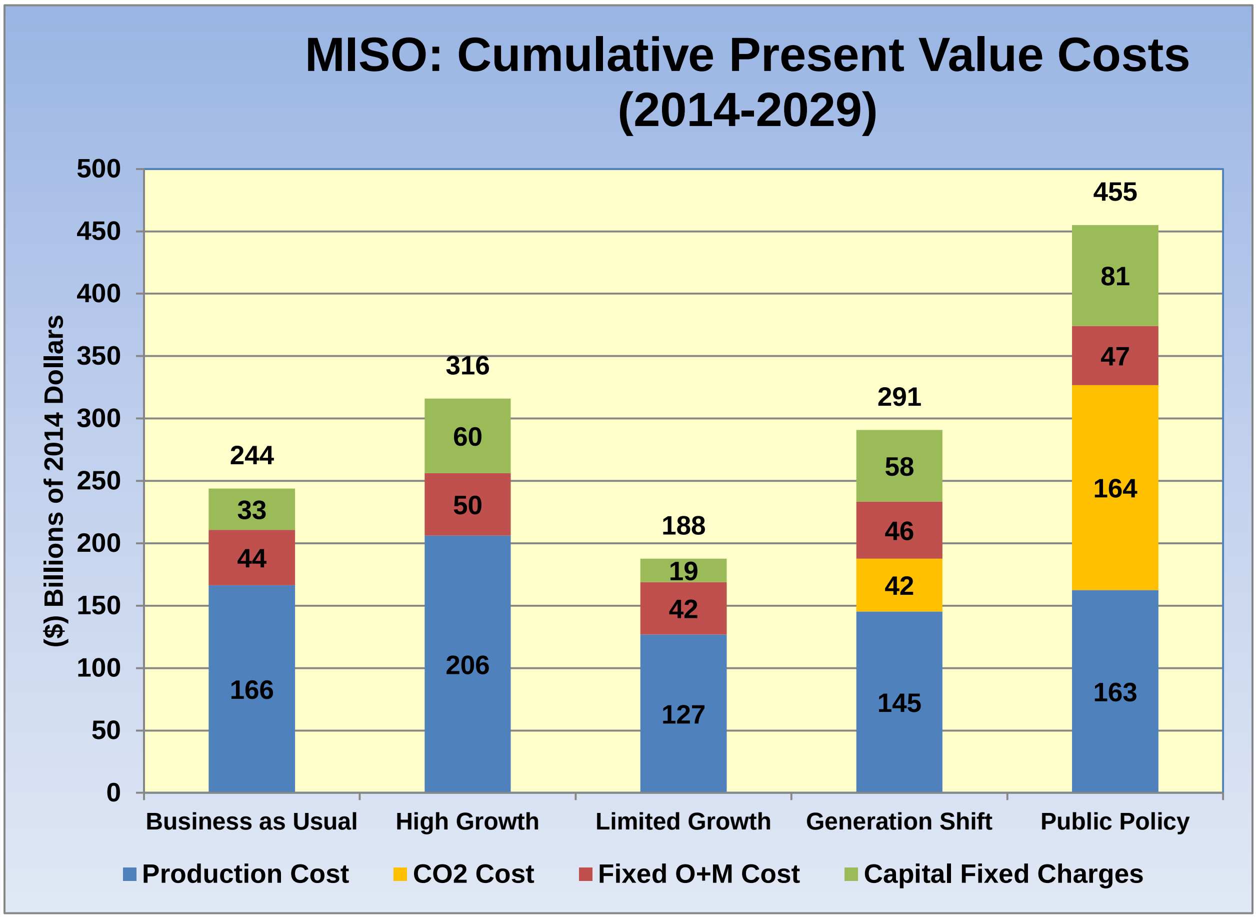


Figure 5.2-2: MISO present value of cumulative costs in 2014 U.S. dollars

Natural Gas Fuel Price Forecasting

Accurate modeling of future natural gas prices is a key input to the MTEP planning process. While natural gas prices have remained relatively low over the past few years, they have reached well over $10/MMBtu as recently as 2008. Therefore, it is important to capture a wide range of forecasts that take into account this potential volatility. For MTEP15, MISO, in coordination with stakeholders through the PAC, chose to utilize a natural gas forecast developed by Bentek[23] as a baseline. High and low forecasts were developed by adding or subtracting 20 percent from the baseline. Since Bentek assumed an inflation rate of approximately 3.5 percent in their forecast, it was necessary to remove this inflation rate and to use the inflation rates for each future scenario that were identified by the PAC and MISO in the futures development process. The five resulting MTEP15 natural gas forecasts are shown in nominal dollars per MMBtu (Figure 5.2-3).

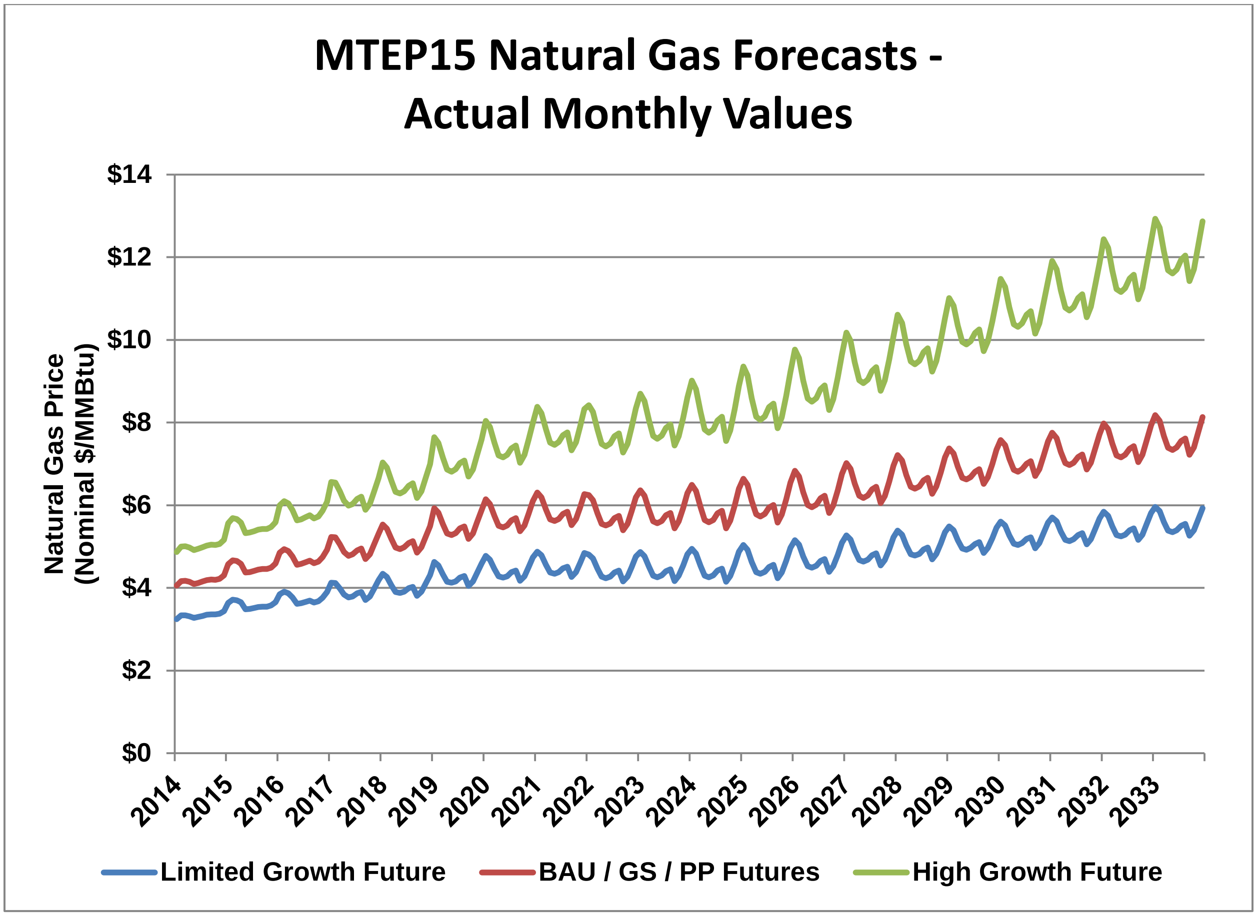


Figure 5.2-3: Natural gas forecasts by future

Renewable Portfolio Standards

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

[23] See Table 5-4 of the Phase III: Natural Gas-Fired Electric Power Generation Infrastructure Analysis Report. https://www.misoenergy.org/Library/Repository/Communication%20Material/Key%20Presentations%20and%20Whitepapers/Phase%20III%20Gas-Electric%20Infrastructure%20Report.pdf

state's mandate or goal. MISO uses the DSIRE information to calculate future penetrations of renewables, which are assumed to be primarily wind and solar, in each of the MTEP futures (Table 5.2-3). The MTEP15 BAU, HG and LG futures model state-mandated wind and solar only. The GS future models a 20 percent MISO-wide mandate, with solar comprising 5 percent of the overall mandate. The PP future models a 30 percent MISO-wide mandate, with solar comprising 10 percent of the overall mandate.

Future Scenario	MISO Incremental Wind Penetration	MISO Incremental Solar Penetration	Percentage of Energy from All Renewable Resources in 2028
Business As Usual	5,800 MW	1,375 MW	11%
High Growth	7,900 MW	1,525 MW	11%
Limited Growth	4,300 MW	1,250 MW	12%
Generation Shift	21,400 MW	3,675 MW	22%
Public Policy	33,400 MW	8,550 MW	31%

Table 5.2-3: MISO wind and solar penetrations (including those with signed generation interconnection agreements through 2029)

Carbon Emissions

Each of the future scenarios has a different impact on carbon dioxide output (Figure 5.2-4). These output values for 2029 for the different resource expansions can be compared to the base year, 2014, CO_2 output. For all futures, except the HG future, total CO_2 emissions decline or remain flat between 2014 and 2029. Coal plant retirements, in combination with increased levels of renewables and demand-side management programs, are key factors in allowing carbon emissions to decline.

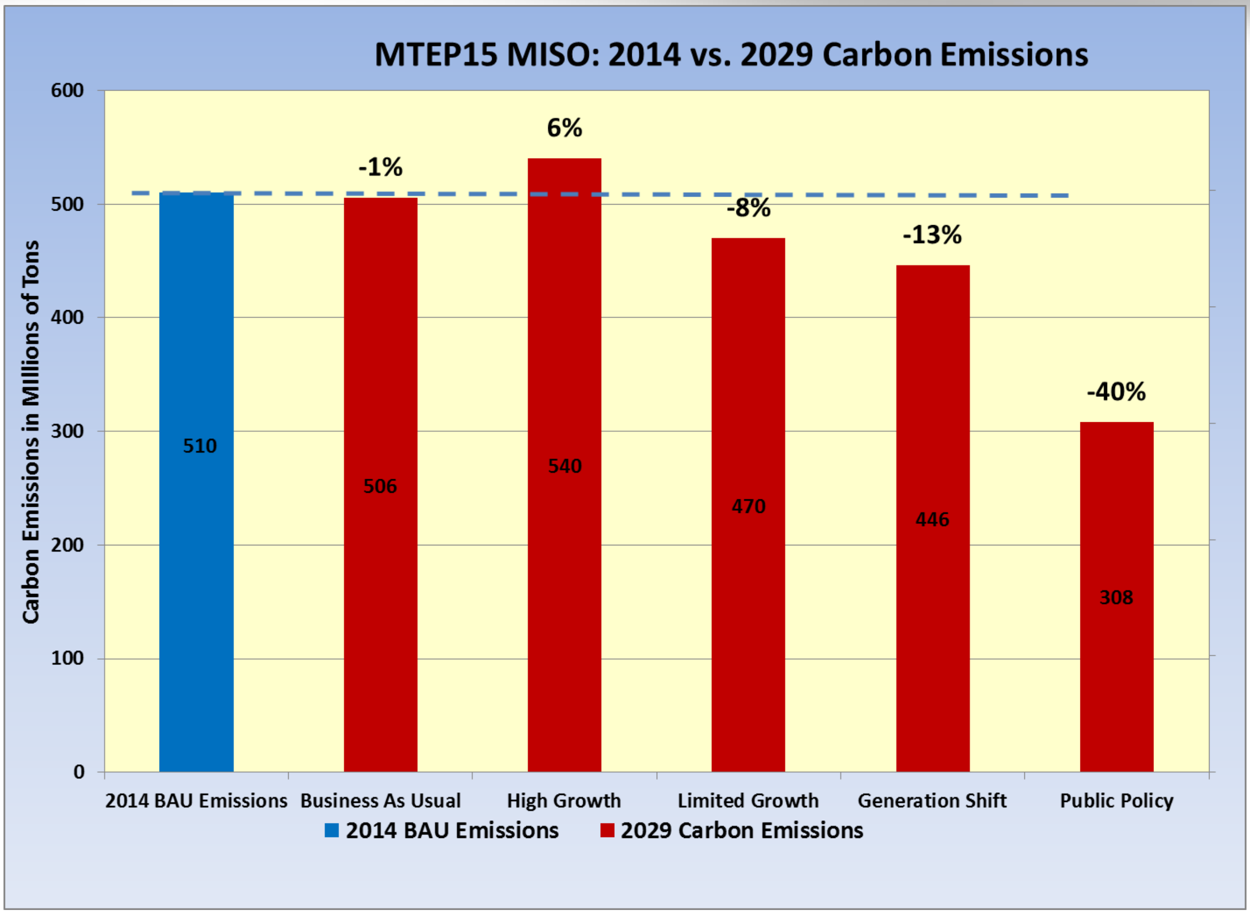


Figure 5.2-4: MISO carbon dioxide production

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

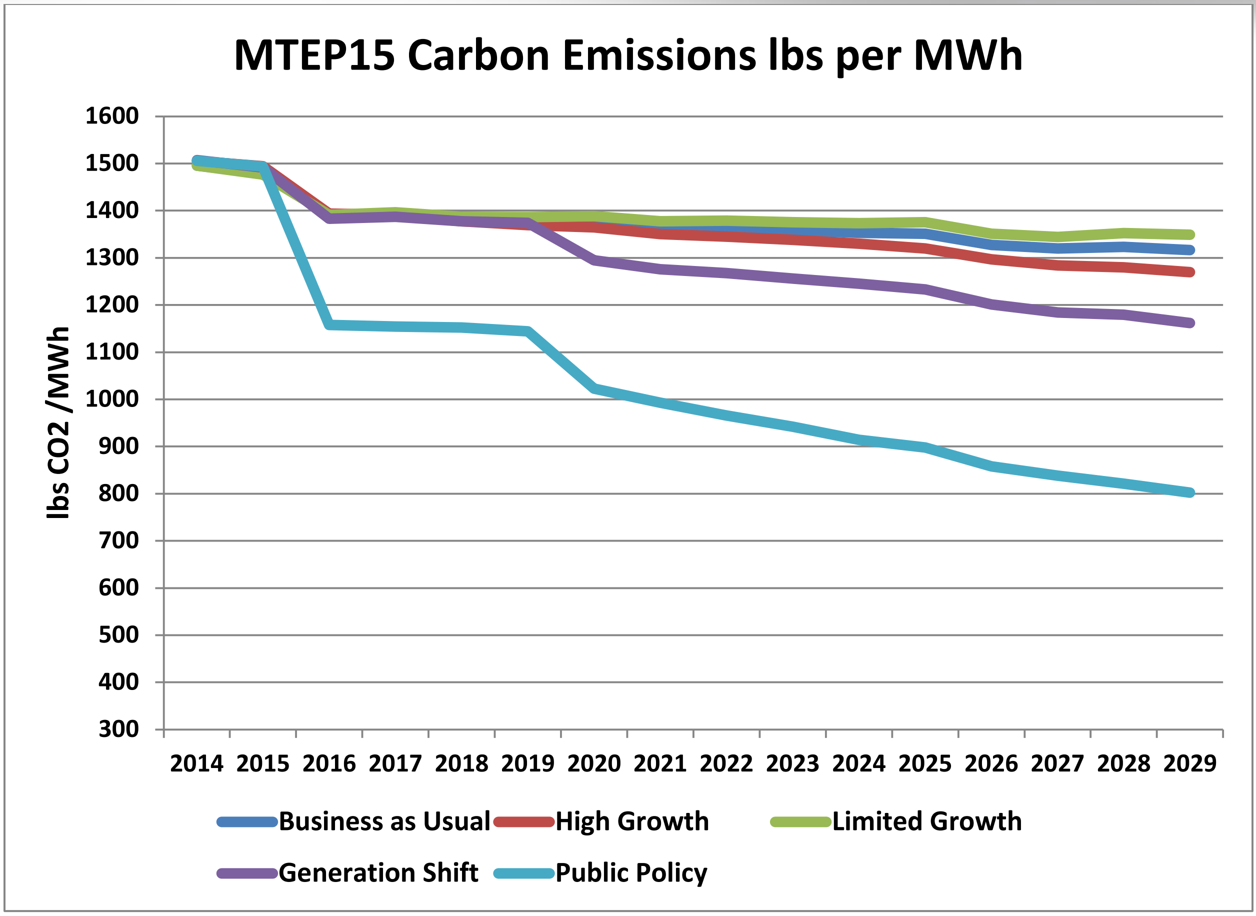


Figure 5.2-5: Carbon emissions per megawatt hour

Siting Of Resources

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

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

South Region Resource Expansion Results

In order to sync MISO South with the MTEP15 economic planning process, MISO conducted a Market Congestion Planning Study focused on the MISO South region. This study incorporates stakeholder informed futures, resource forecasting analysis, model building and economic analysis.

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

MISO developed four futures in collaboration with MISO South stakeholders:

- The **BAU** future is a status quo future that continues to model current economic trends. This future models existing policies with reference values and trends. This is the MTEP15 BAU for the North/Central region with updated load forecasts representing most recent Module E submissions.
- The **South Industrial Renaissance (SIR)** future models significant economic development in the Southern Louisiana and East Texas areas with considerable development occurring in all the areas due to lower fuel prices providing economic opportunity for electric growth and system expansion. Also considers the effects of age-related retirements on non-coal-fired, non-nuclear generators.
- The **GS** future captures the effects of significant amounts of age-related retirements of the non-coal, non-nuclear, thermal fleet by retiring units in the year in which they reach 60 years of age or 100 years for hydroelectric. Also models a declining cost curve for solar and wind resources.
- The **PP** future captures the effects of an additional 14 GW of carbon-reduction-targeted retirements. Also models a cost decline for solar and wind, increases in energy efficiency, and a $25/ton cost on CO2 emissions. Includes RPS goals and mandates and 50% of the CPP prescribed energy efficiency. Age-related retirements of non-coal and non-nuclear units are included.

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

South Region Regional Resource Forecasting

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

Given the fact that the South region officially integrated into MISO in December 2013, the EGEAS resource expansion analysis was performed on the entire footprint. The results of the analysis can be seen in Figure 5.2-6. The dominant resource type added in most of the futures is natural gas-fueled, with combustion turbines comprising the majority of the natural gas-fueled additions. The PP future saw a larger amount of renewables selected as a reflection of the carbon price modeled as well as increased level of retirements.

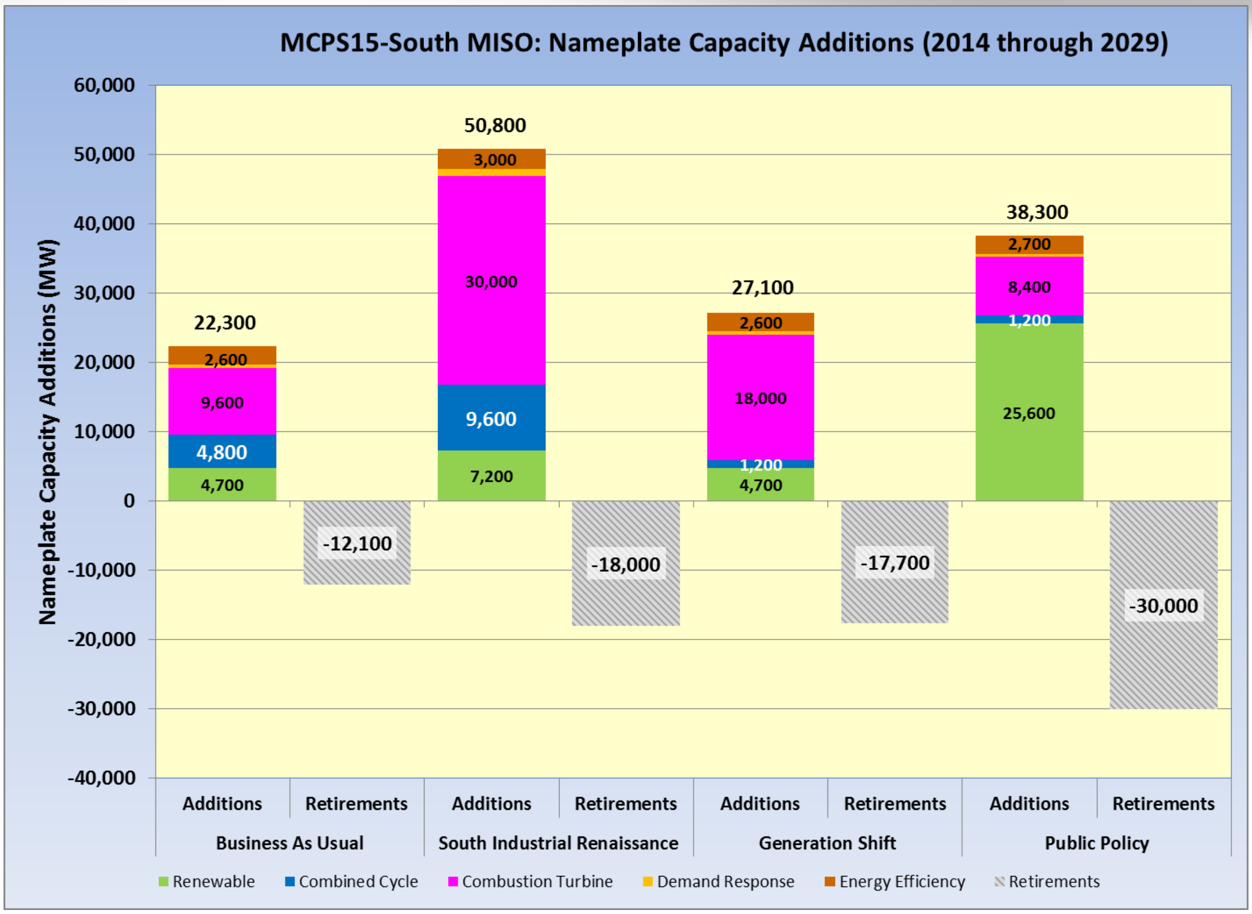


Figure 5.2-6: Nameplate resource additions and retirements by future for MISO-South MCPS15

Siting Forecasted Regional Resource Units

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

For the BAU future, the combined cycle generators sited in the South footprint were a reflection of the RFPs in progress at the time. The remainder of the resources added in the BAU future were sited in the North and Central MISO regions (Figure 5.2-7).

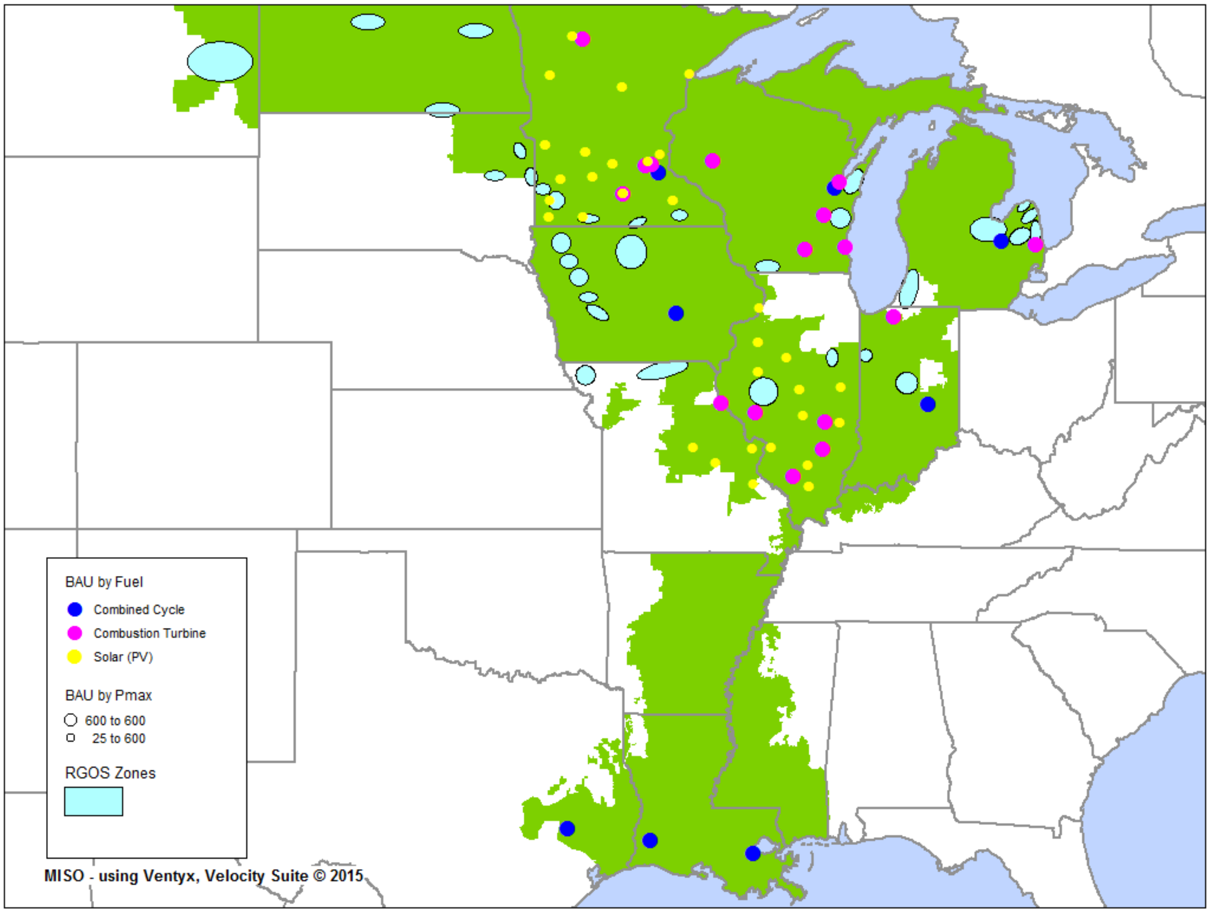


Figure 5.2-7: Regional resource forecast sites for the MISO-South MCPS15 BAU future

The South Industrial Renaissance future requires a fairly significant amount of additional resources due to the higher demand and energy growth rates modeled in conjunction with an increase in the amount of existing resource retirements. A total of 9,600 MW of thermal capacity was sited in the MISO South region in the SIR future (Figure 5.2-8).

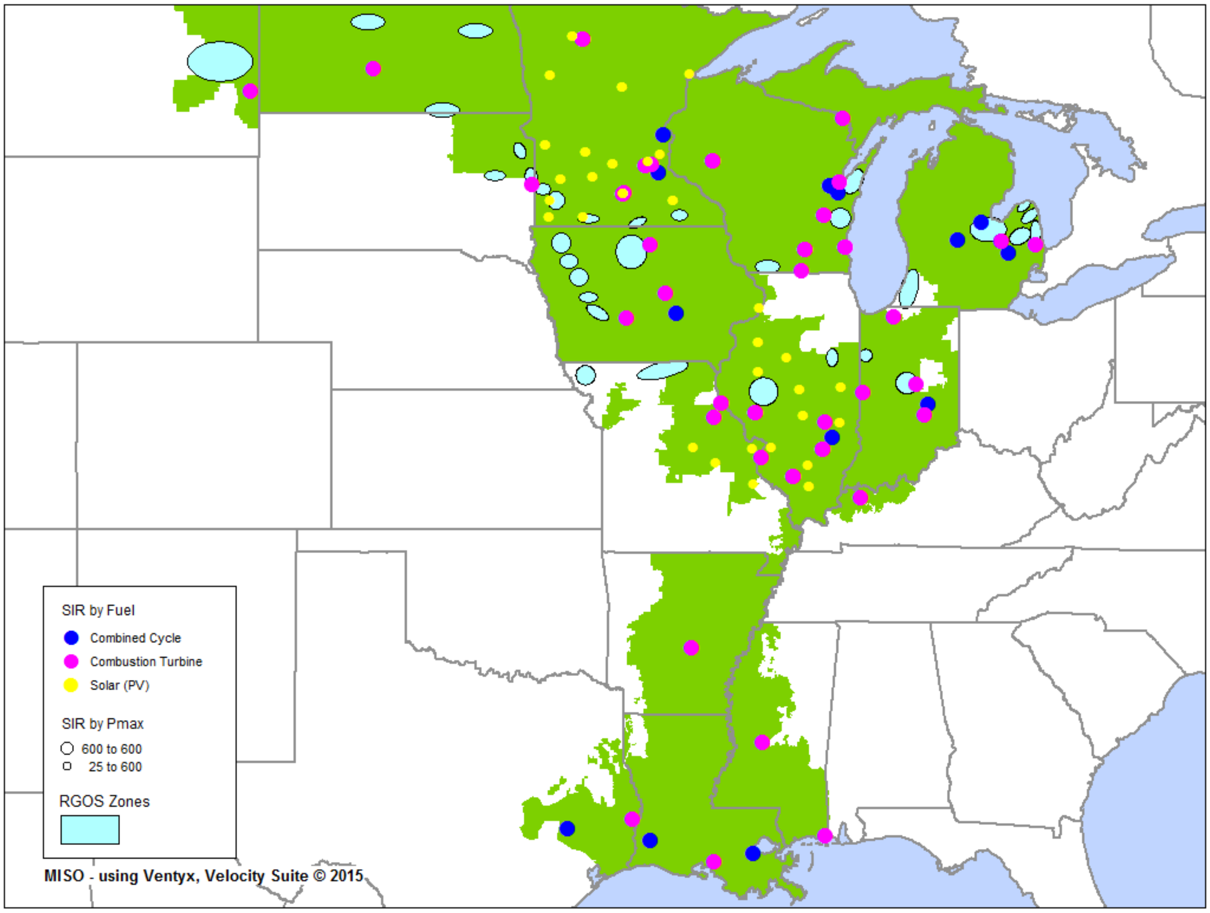


Figure 5.2-8: Regional resource forecast sites for the MISO-South MCPS15 SIR future

5.3 Market Congestion Planning Study

The goal of the Market Congestion Planning Study (MCPS) is to develop transmission plans that offer MISO customers better access to the lowest electric energy costs through the markets. From a regional perspective, the study seeks to identify both near-term transmission congestion and long-term economic opportunities and the appropriate network upgrades to enhance the efficiency of the market. The solutions may therefore vary in scale and scope, classified as either “MCP Other Projects” or “Market Efficiency Projects.” As an integral part of MISO’s value-based planning, the MCPS looks to develop the most robust transmission upgrades that offer the highest future value under a variety of both current and projected system scenarios.

Similar to the 2014 planning cycle, parallel economic planning efforts have been undertaken for the MISO North/Central and South regions in MTEP15 in order to better engage the various stakeholders across the MISO footprint.

MCPS North/Central Summary

The 2015 MCPS North/Central built on the progress made during the MTEP14 cycle, which identified several congested flowgates and evaluated the appropriate transmission solutions. By building on the MCPS 2014 analysis, the 2015 cycle focused on four specific areas that showed the highest congestion: Southern Indiana, Southern Illinois, Iowa/Minnesota and, Northern Indiana. Similar to the previous study cycle, the area with the greatest need, and therefore highest potential benefit, was on the border of Indiana and Kentucky.

Several solutions were designed in a collaborative effort between MISO and stakeholders. The solutions were tested for their robustness to address system needs under a variety of scenarios, embodied by the MTEP15 futures. Ultimately, working in concert with PJM and stakeholders, Duff - Rockport - Coleman 345 kV project, which offers both regional and interregional benefit to MISO and PJM, was found to offer the best value. This project completely mitigates the congestion on the MISO system around the Newtonville and Coleman areas and strengthens the 345 kV backbone in the region. In addition, the project fully addresses long-standing reliability issues around PJM’s Rockport station and obviates the need for the Rockport Special Protect Scheme and Operation Guide that protects the stability of the grid.

The project consists of two portions:

- MISO portion being Duff-Coleman 345kV

- PJM portion being the tie-in from Rockport to Duff-Coleman 345kV line.

MISO staff therefore recommends that the MISO portion – Duff - Coleman 345 kV project to be approved as a MISO Market Efficiency Project (MEP).

MCPS South Summary

The 2015 MCPS South built on the progress made during the VLR Planning Study and the MTEP14 MCPS South, which identified several congested flowgates and evaluated the applicable transmission solutions. By building on the previous analysis, the 2015 cycle focused on four specific areas of MISO South: Amite South/DSG, WOTAB/Western, Local Resource Zone (LRZ) 8 (Arkansas), and Remainder of LRZ9. Similar to previous studies the areas with the greatest need, and therefore the highest potential, were in the Amite South/DSG and WOTAB/Western load pockets.

Several solutions were developed by both MISO staff and stakeholders. The solutions were tested for their robustness to meet system needs under a variety of expected scenarios, embodied by the MTEP15 futures.

In the 2015 MCPS South, a total of 82 unique transmission solution ideas were proposed and studied. MISO evaluated these solution ideas and formulated 11 project candidates for further robustness testing, in conjunction with south region stakeholders. Of the 11 project candidates, two were selected by MISO, pending stakeholder feedback, as potential best-fit solutions. Both projects produced a weighted present value (PV) benefit-to-cost ratio greater than 1.25, but due to voltage levels do not met Market Efficiency Project criteria.

- East Texas economic project with an estimated cost of $122.5 million in 2015 dollars
    - A new 230 kV transmission line from Lewis Creek to a new 345/230 kV substation (NSUB2) by cutting into the existing Grimes to Crocket 345 kV line.
        - Note that MISO agrees Grimes alternative provides similar reliability and economic benefits
    - Rebuilding the existing Newton Bulk – Leach 115 kV line
- Rebuilding the existing Mabelvale – Bryant – Bryant South 115 kV line with an estimated cost of $6.1 million in 2015 dollars.

MISO staff therefore recommends that two projects may be approved as Other economic projects.

MCPS Study Process Overview

The MCPS begins with a bifurcated Need Identification approach to identify both near- and long-term transmission issues. The Top Congested Flowgate Analysis identifies near-term, more localized congestion while the longer-term Congestion Relief Analysis explores broader economic opportunities (Figures 5.3-1). Given the targeted focus of the MCPS 2015, emphasis was placed on the top congested flowgate analysis. The congestion relief analysis will be employed in future, broader-scoped planning studies.

With the needs clearly defined, the study evaluates a wide variety of transmission ideas in an iterative fashion with both economic and reliability robustness considerations. The Project Candidate Identification phase includes: screening analysis to pinpoint the solutions with the highest potential; economic evaluation over multiple years and futures to asses robustness; and reliability analyses to ensure the projects do not degrade system reliability. Using this approach, optimal economic transmission upgrades (best-fit solutions) are identified to address market congestion; the solutions may be either cost shareable or non-cost shareable projects.

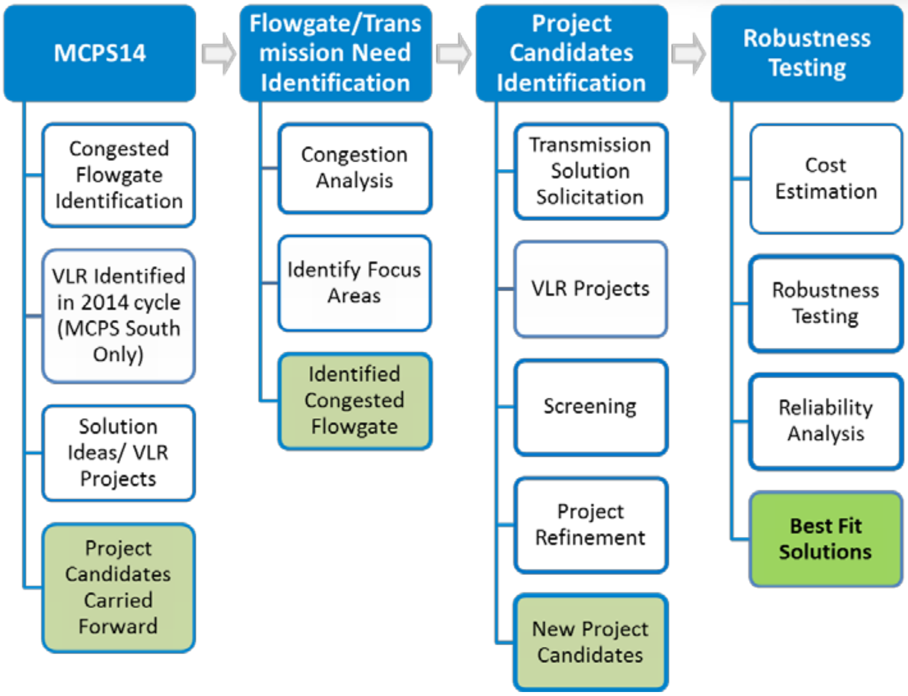


Figure 5.3-1: MCPS North/Central process overview

MISO North/Central and South Models and Futures

The production cost models utilized for this study are based on data from PROMOD Powerbase and the corresponding MTEP powerflow cases. The data is refreshed with the most current information and with the system variables (fuel cost, demand, etc.) reflecting the MTEP Futures definitions. The agreed-upon future scenarios and weightings for the MISO North/Central MTEP15 study are:

- Business as Usual (BAU): 40 percent
- High Growth (HG): 15 percent
- Limited Growth (LG): 15 percent
- Generation Shift (GS): 20 percent
- Public Policy (PP): 10 percent

The Planning Advisory Committee (PAC) assigned weights to each future as a reflection of the perceived probability of each future being actualized (see Chapter 5.2, MTEP Future Development).

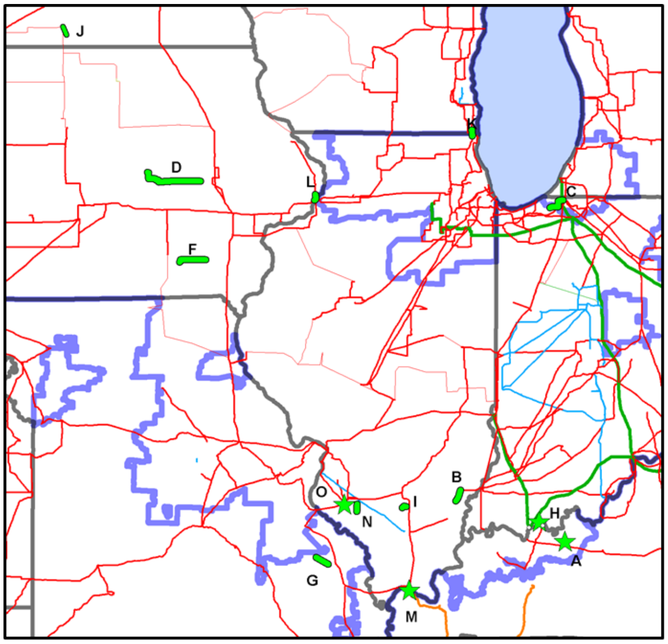
Similarly, the agreed-upon future scenarios and weightings for the MISO South MTEP15 study are:

- Business as Usual (BAU): 34 percent
- South Industrial Renaissance (SIR): 24 percent
- Generation Shift (GS): 22 percent
- Public Policy (PP): 20 percent

MISO stakeholders likewise assigned weights to each future (see Chapter 5.2, MTEP Future Development).

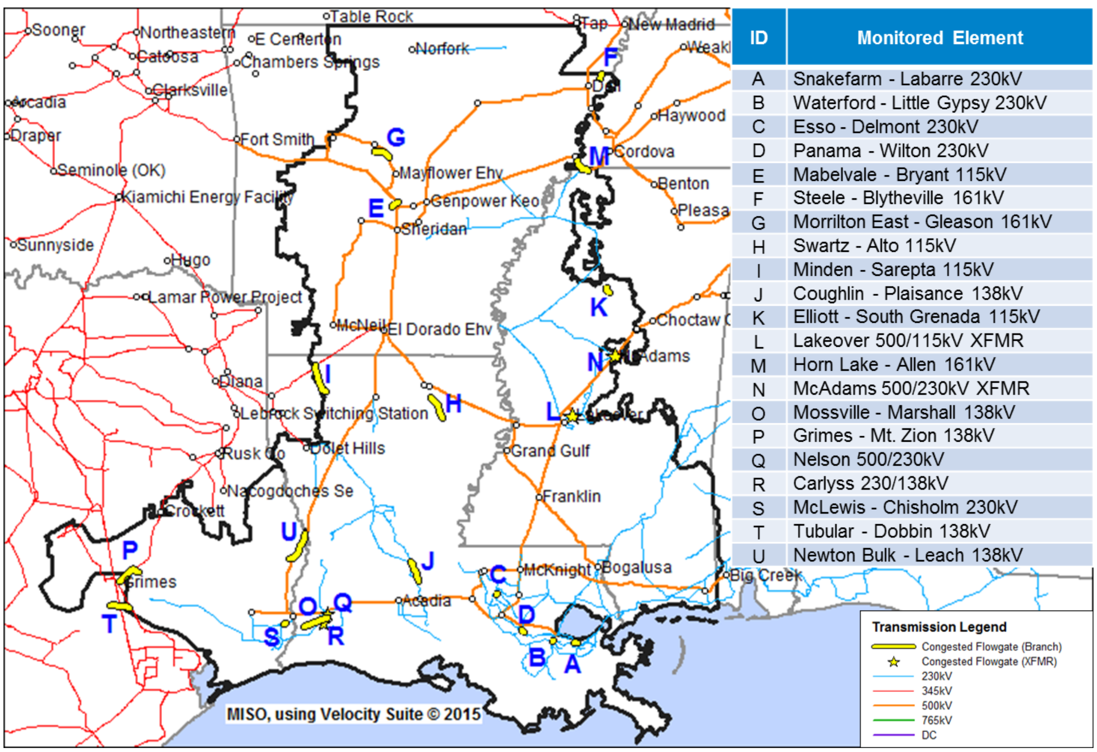
Top Congested Flowgate Analysis

The top congested flowgate analysis identifies system congestion trends based on both the historical market data and forecasted congestion. The analysis identifies and prioritizes highly congested flowgates within the MISO market footprint and on the seams (Figures 5.3-2 and 5.3-3).



FG ID	Monitored Element
A	New Hardinsburg 138/161kV Transformer
B	Albion - Crossville 138kV
C	New Carlisle – Bosserman 138kV
D	Marshalltown - Blairstown Jct 115kV
F	Wapello - Jeff 161kV
G	Fredericktown - Fredericktown Tap 161kV
H*	Newtonville 138/161kV Transformer
I	Nason Point - Ina 138kV
J	Winnebago - Blue Earth 161kV
K	Pleasant Prairie – Zion EC 345kV
L	Quad City–Rock Creek 345kV
M	Joppa 345/161kV xfmr
N*	Tilden - Sparta Tap 138kV
O*	Baldwin 345/138kV xfmr

Figure 5.3-2: MISO North/Central Projected Top Congested Flowgates



ID	Monitored Element
A	Snakefarm - Labarre 230kV
B	Waterford - Little Gypsy 230kV
C	Esso - Delmont 230kV
D	Panama - Wilton 230kV
E	Mabelvale - Bryant 115kV
F	Steele - Blytheville 161kV
G	Morrilton East - Gleason 161kV
H	Swartz - Alto 115kV
I	Minden - Sarepta 115kV
J	Coughlin - Plaisance 138kV
K	Elliott - South Grenada 115kV
L	Lakeover 500/115kV XFMR
M	Horn Lake - Allen 161kV
N	McAdams 500/230kV XFMR
O	Mossville - Marshall 138kV
P	Grimes - Mt. Zion 138kV
Q	Nelson 500/230kV
R	Carlyss 230/138kV
S	McLewis - Chisholm 230kV
T	Tubular - Dobbin 138kV
U	Newton Bulk - Leach 138kV

Figure 5.3-3: MISO South Projected Top Congested Flowgates

The flowgates of interest are those with historical congestion and are projected to be limiting constraints throughout the 15-year study period. MISO finds these flowgates by examining:

- Historical day-ahead, real-time and market-to-market congestion
- Projected congestion identified through out-year production cost model simulations

The magnitude and frequency of congestion offers a strong signal to where transmission investments should be made.

Project Candidate Identification

Project candidate identification is a MISO-stakeholder partnership to identify network upgrades that address the top congested flowgates; solutions ideas may be submitted by stakeholders or developed by MISO staff. The solution ideas include those designed to directly address specific flowgates, provide energy transfer paths, and/or to unlock cheaper resources by connecting import-limited areas to export-limited areas.

Given the potential for numerous transmission ideas submissions, MISO developed a screening process to identify solutions that will most cost effectively relieve the congestion of interest. The screening does not preclude any solutions, but rather refines the pool of projects that will be analyzed in detail as MISO determines the optimal solution. Adjusting for model updates through the course of the study, the screening results are a good predictor of projects' performance. The screening index for each solution was calculated as the ratio between the 15-year-out Adjusted Production Cost (APC) savings and the corresponding project cost:

$$Screening\ Index = \frac{15\ year\ out\ Future\ Weighted\ APC\ Savings}{Solution\ Cost\ \times MISO\ Aggregrate\ Annual\ Charge\ Rate}$$

Any project with a screening index of 0.9 has the potential for a benefit-to-cost ratio greater than 1.25, the Market Efficiency Project (MEP) threshold. In addition to identifying the projects with the highest potential, the screening analysis provides valuable information that can be used to modify and improve the solutions that do not pass the screening. In general, transmission solutions do not pass the screening for one of at least three reasons: the solution does not relieve all of the congestion on a targeted top flowgate(s); the solution relieves congestion on one flowgate but increases congestion on other flowgate(s); or the solution relieves congestion but the project cost is high relative to benefit.

By considering the specific reason for a project's screening performance, the project can be refined to better address the congestion. Corresponding to the above three reasons, the refinement may include: expanding and/or reconfiguring a project; combining projects that address related flowgates; and pruning projects to keep the most effective elements. The refinement of the solutions properly considers the balance of achieving synergistic benefits and avoiding excessive transmission build-outs that produce diminishing returns.

This study phase determines the project candidates that move on to a more comprehensive analysis.

Robustness Testing

Once the preliminary project candidates are identified, an iterative process takes place between economic robustness evaluation and reliability assessment. Robustness testing identifies the transmission projects/portfolios that provide the best value under most, if not all, predicted future outcomes; the reliability assessment ensures system reliability is at least maintained.

Project Benefit and Cost Analysis:

The MISO Tariff measures a MEP's benefit by the APC savings realized through the project under each of the MTEP future scenarios. APC savings are calculated as the difference in total production cost adjusted for import costs and export revenues with and without the proposed project in the transmission system. Given the parallel MCPS studies, the benefits for each project are counted only for the relevant MISO sub-region, North/Central or South. Data from three simulation years (2019, 2024 and 2029) are used as the basis for evaluating the project impact. A 20-year benefit is calculated by linearly interpolating and extrapolating from these three years. The total project benefit is determined by calculating the present value of annual benefits for the multi-future and multi-year evaluations.

As further detailed in Attachment FF of the MISO Tariff, a MEP must meet the following criteria:

- Have an estimated cost of $5 million or more
- Involve facilities with voltages of 345 kV or higher; and may include lower-voltage facilities of 100 kV or above that collectively constitute less than 50 percent of the combined project cost
- Benefit-to-cost ratio of 1.25

Although prescribed for MEPs, the above metric and analysis is used to evaluate all "economics" projects. To arrive at the best solution, projects with a benefit-to-cost ratio greater than 1.25 but not meeting either all the MEP criteria are also considered.

Reliability Analysis:

The reliability analysis uses a no-harm test to determine the impact of project candidates on the thermal and voltage stability of the system under select NERC Category B and C contingencies. A project candidate passes the reliability no-harm test if there is no degradation of system reliability with the addition of the project.

The no-harm test compares the contingency analysis results between two models, a base model and a model including the project candidate, to find if any violations are worsened by the addition of the project candidate.

The no harm test is performed on four cases:

- Five-year-out Summer Peak
- Five-year-out Shoulder Peak for North/Central and five-year-out Winter Peak for South
- 10-year-out Summer Peak

The following NERC categories of contingencies are evaluated:

- Category P0 when the system is under normal conditions
- Category P1 contingencies resulting in the loss of a single element
- Category P2 contingencies resulting in the loss of two or more elements due to a single event

Southern Indiana

MCPS identified a significant amount of congestion in Southern Indiana, particularly around the Coleman substation, which is a gateway for the nearby large industrial load pocket (Figure 5.3-4). In the event that Davies – Coleman 345 kV, a key feed into this load pocket, is outaged, the supply route for this area shifts to the lower voltage branches. As a result, congestion on branches such as Newtonville – Coleman 161 kV increases under N-1 conditions. Further exacerbating this issue are the projected load growth and the in-service status of local coal generation. Congestion relief in this area would mean that the load pocket could be more easily supplied with alternative generation.

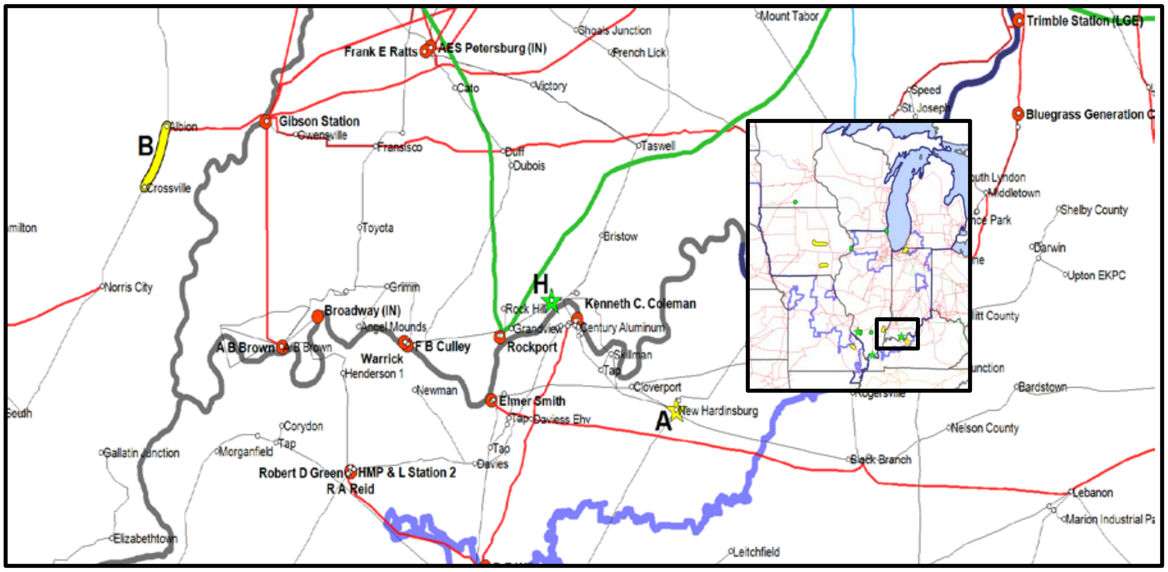


Figure 5.3-4: Southern Indiana top flowgates

With the highest amount of congestion in the MISO North/Central footprint, several submitted solutions ideas in this area passed the screening and had high benefit-to-cost ratios. The majority of proposed solution ideas in this area were new 345 kV lines providing an alternative access point into the load pocket. The recommended project of Duff – Rockport – Coleman 345 kV along with five high-voltage alternatives were considered for addressing the congestion in this area (Table 5.3-1).

	Transmission Solution	Cost to MISO ($M)	Cost to PJM ($M)	MISO Benefit to Cost Ratios					
				BAU	GS	HG	LG	PP	Weighted
Recommended Project	**Duff – Rockport – Coleman 345 kV**	**$67.4**	**$85.3**	**16.8**	**21.2**	**17.4**	**17.0**	**0.2**	**16.1**
Alternative 1	Duff – Coleman 345 kV	$67.4	NA	16.6	20.9	17.1	16.8	(2.9)	15.6
Alternative 2	Rockport – Coleman Double Circuit 345 kV	$56.9	$54.6	19.9	24.8	19.6	20.3	1.9	19.1
Alternative 3	Duff – Century 345 kV, Century 345/161 kV	$83	NA	14.1	17.2	14.4	14.2	(1.8)	13.2
Alternative 4	Reid – Coleman 345 kV	$144	NA	7.5	8.8	7.1	7.9	(2.7)	6.8
Alternative 5	Wilson – Coleman 345 kV	$111	NA	9.5	11.3	8.6	10.2	(2.9)	8.6

Table 5.3-1: Southern Indiana project alternatives benefit-to-cost ratios

All of the transmission solutions in Table 5.3-1 relieve most or all of the congestion around Newtonville and Coleman, but have different benefit-to-cost ratios due to their varying costs. Other low-voltage alternatives, such as adding a third Newtonville transformer or adding a phase shifter in between Newtonville and Coleman, were also considered. However, these projects do not adequately address the congestion in the area.

Duff – Coleman 345 kV was initially found to provide the most value by fully mitigating the congestion around the Newtonville substation, strengthening the surrounding area's 345 kV backbone by completing the loop started years ago by Gibson – AB Brown – Reid – Wilson – Coleman 345 kV, and unlocks cheaper generation in Southern IN to serve the load pocket at the Coleman substation area.

Due to Coleman's proximity to the Rockport substation, MISO and PJM found an opportunity to collaboratively develop two additional options: Rockport – Coleman Double Circuit 345 kV and Duff – Rockport – Coleman 345 kV. These two options were designed to capture equal or greater value as Duff – Coleman 345 kV for the MISO footprint at equal or lesser cost while at the same time allowing PJM to remove its need for the longstanding Rockport operational complexity by providing additional outlets out of the Rockport substation. As part of this collaboration, PJM agreed to pay any incremental cost beyond the cost required by Duff – Coleman 345 kV.

Reliability analysis revealed that the Rockport – Coleman Double Circuit 345 kV option led to severe overloading on Davies – Coleman 345 kV and both Coleman 345/161 kV transformers. Additionally, it did not achieve its intended purpose by fully resolving the operational performance issues at Rockport. Analysis on Duff – Rockport – Coleman 345 kV, on the other hand, found that it allowed for the full removal of Rockport's special protection scheme needs and did not cause severe overloading.

Furthermore, it still achieves all the aforementioned benefits provided by the Duff – Coleman 345 kV project. Duff – Rockport – Coleman 345 kV (Figure 5.3-5).

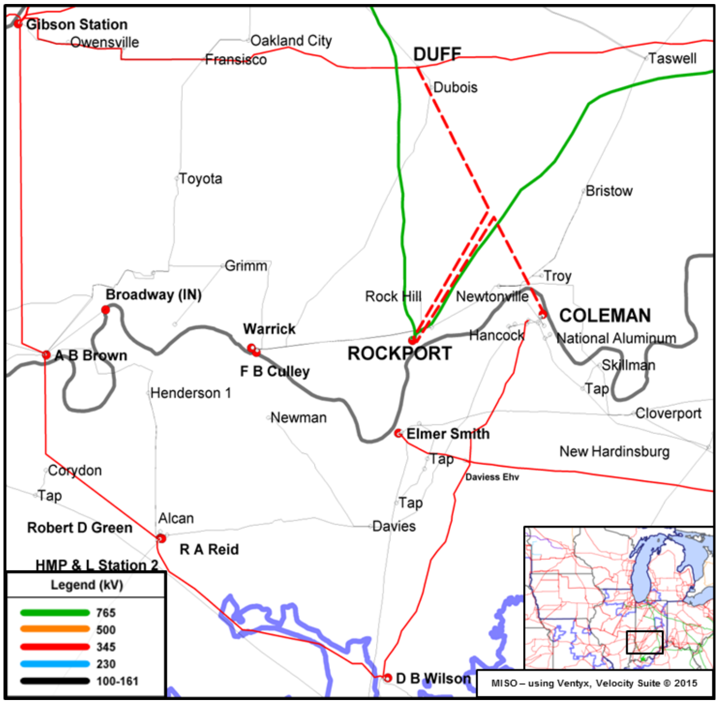


Figure 5.3-5: Map of Duff – Rockport – Coleman 345 kV (approximate line routing)

In light of all this, Duff – Rockport – Coleman 345 kV was selected as the project of choice. MISO staff recommends that the Duff – Rockport – Coleman 345 kV project be approved as a MISO Market Efficiency Project (MEP). This project is to be jointly funded by MISO as an MEP and PJM as a supplemental project (Figure 5.3-6). MISO will be responsible for the cost of the Duff – Coleman ($67.4 million) portion, which will be open for bid as part of the Transmission Developer Qualification and Selection (TDQS) process. PJM will fund the cost of the double circuit 345 kV tie-in to Rockport ($85.3 million) outside the MISO TDQS process.

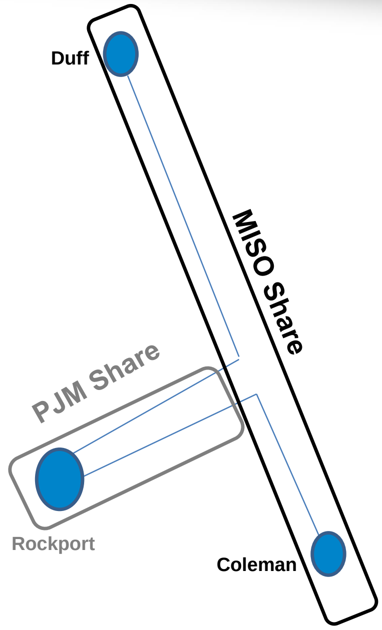


Figure 5.3-6: MISO and PJM shares of Duff – Rockport – Coleman 345 kV

Southern Indiana Reliability Analysis

For 2015 cycle, primarily MTEP15 phase two 2020 summer peak models are used. Additional to basic no-harm test, comprehensive reliability analysis is done to evaluate the candidate projects showing high values. Additional scenarios include:

- Sensitivity analysis: Specific generators status was adjusted. Units under suspension or expected retirement of the unit motivated the sensitivity analysis.
- Project impact on SPS: For the candidate project associated with SPS, reliability analysis was done to assess the system condition with the SPS. At the same time, study was done to see if the project could permanently remove the associated SPS.
- Extended reliability analysis: Specific flowgates, pre and post contingent flow pattern, and additional NERC category contingencies are evaluated.

The congestion issues at Newtonville transformers are solved by the proposed candidate projects. All of these projects passed the basic no-harm test. As Duff-Coleman and Rockport- Coleman project showed high value, in additional to basic no-harm test, the aforementioned comprehensive reliability analysis was performed.
For the sensitivity case with the retired Coleman units, both the Duff and Coleman projects have thermal violations at 5COLEMAN to COLEEHV 161 kV circuits 1 and 2. Costs to mitigate are estimated at $200,000.

- Rockport-Coleman double circuit 345 kV line
    - Reliability constraints identified on either of the two Coleman to Coleman EHV 161 kV circuits for n-1 loss of the other Coleman to Coleman EHV 161 kV circuit

- o Additional severe overloads identified on Davies to Coleman 345 kV line and both 345/161 kV transformers at Coleman for n-2 loss of Rockport-Jefferson and Rockport-Sullivan 765 kV lines without Rockport redispatch

- Duff-Rockport-Coleman 345 kV line
  - o Reliability constraints identified on either of the two Coleman to Coleman EHV 161 kV circuits for n-1 loss of the other Coleman to Coleman EHV 161 kV circuit
  - o Additional overload identified on Reid to Davies 161 kV line for n-2 loss of Wilson-Reid 345 kV and Rockport-Coleman 345 kV lines. Redispatch using Wilson generation mitigate overloads

Additional qualitative review was inconclusive in identifying superior alternative from reliability standpoint.

Southern Illinois

General flows in the MISO North/Central system are from west to east and through Southern Illinois. In Missouri and Southern Illinois, there is a generation pocket containing several economic units but with a constrained transmission outlet, particularly under N-1 conditions. Both historically and in out-year simulations, the lower-voltage system becomes congested under contingency conditions for the loss of 345 kV transmission that delivers flow eastward through the region (Figure 5.3-7).

In the 2014 cycle of the MCPS, the flowgates Tilden – Sparta Tap 138 kV and the Baldwin 345/138 kV transformer were identified as two of the top-congested flowgates in the system. The analysis showed that relieving these flowgates offered high benefits to the region. A MISO market participant is funding upgrades to address these constraints through projects that are now included in MTEP15 Appendix A. The market participant funded upgrades were included in the MCPS model midway through the study. As a result of this model update, solution ideas that also address these flowgates show lower benefits.

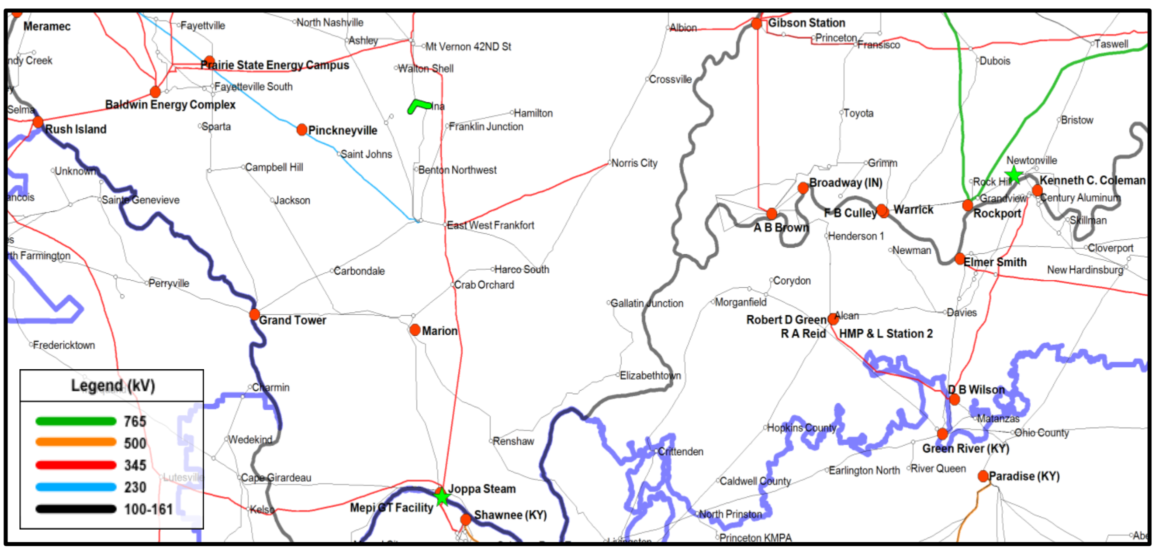


Figure 5.3-7: Southern Illinois top congested flowgates

A total of 17 transmission solution ideas were submitted to address congestion in Southern Illinois. Two of the solution ideas, addressing flowgates I and M, passed the screening process.

- Cahokia – N. Coulterville tap at Prairie State 230 kV
- 2nd Joppa 345/161 kV transformer

As a result of the screening analysis, an additional solution was developed to address both flowgates simultaneously: Albion – Norris City 345 kV and a 2nd Joppa 345/161 kV transformer.

In carrying these solutions forward, the analysis showed that congestion in Southern Illinois was particularly sensitive to congestion in the Newtonville area in Southern Indiana and retirement assumptions in the Tennessee Valley Authority (TVA) area.

The solutions submitted to address congestion in Southern Illinois impact generation in Southern Indiana; the output from this generation, though economic, is restricted by congestion around Newtonville. As a result, there are diminishing benefits when combining solution ideas in Southern Illinois with projects that more directly and effectively address the Newtonville area congestion in Southern Indiana. Therefore, the comprehensive evaluation of Southern Illinois was performed sequentially after first relieving the Newtonville area congestion.

The analysis found that nearby Shawnee TVA coal units have notable impact on the top two flowgates: Nason Point – Ina 138 kV and the Joppa 345/138 kV transformer. The most current information indicates that nine out of the 10 TVA units will remain in service. The TVA units provide counter flow on the top two flowgates, which decreases the level of congestion in Southern Illinois.

Transmission Solution	Cost ($M)	ISD	Benefit to Cost Ratios					
			BAU	GS	HG	LG	PP	Weighted
Cahokia – N. Coulterville Tap at Prairie State 230 kV	$23.5	2018	0.7	0.6	1.4	0.5	0.0	0.67
Albion – Norris City 345 kV + 2nd Joppa Transformer	$78.2	2022	0.2	0.4	0.2	(0.0)	(0.5)	0.14
2nd Joppa 345/161 kV Transformer	$10.3	2019	(0.1)	0.5	(0.2)	0.1	(2.4)	(0.20)

Table 5.3-2: Southern Illinois projects benefit-to-cost ratios

Cahokia – N. Coulterville Tap at Prairie State 230 kV showed the greatest benefit for its cost in this area (Table 5.3-2). For this solution idea, a revised cost estimate was determined based on MISO independent cost evaluation. With the current TVA generation retirement assumptions, the project's benefits are reduced. This project will be evaluated in future MCPS cycles as generation retirement assumptions become clearer.

Iowa/Minnesota

A significant amount of cheap coal and wind resources are located in Western MISO. It is assumed that the renewable capacity in this area will continue to grow over the next 15 years. With the big load centers to the east of this region, the flows are west to east through Iowa. The low voltage transmission will likely be congested with the loss of major 345 kV lines in this transfer path.

In particular, under the Public Policy and Generation Shift futures, the projected wind additions increases west-to-east flows that further stress the system

Four top flowgates were identified in this region: one in Minnesota, three in Iowa (Figure 5.3-8).

Of the 12 solution ideas studied in Iowa/Minnesota area, three passed the screening analysis and were further evaluated:

- Rebuild Winnebago – Blue Earth 161 kV
- New Huntley – South Bend 345 kV
- New Huntley – Wilmarth 345 kV

All of the three ideas address flowgate Blue Earth - Winnebago, which delivers power from Northwestern Iowa to the Twin Cities.

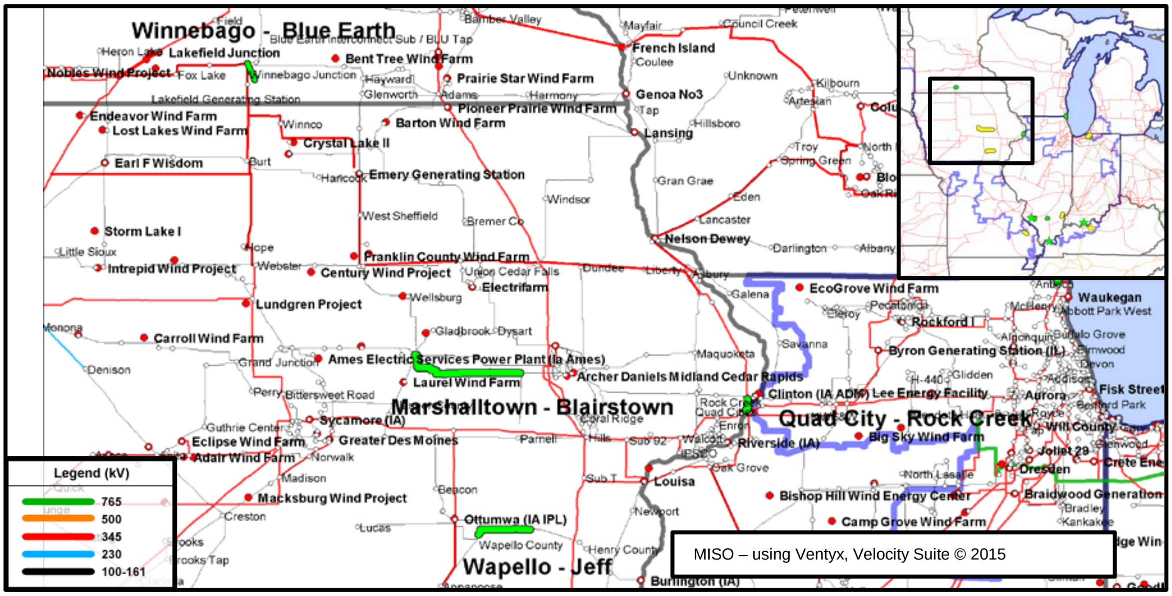


Figure 5.3-8: Iowa/Minnesota top congested flowgates

None of the three projects meet the MEP benefit-to-cost ratio of 1.25 (Table 5.3-3). This is due, in part, to a model correction midway through the study that increased the rating of Blue Earth – Winnebago.

Transmission Solution	Cost ($M)	ISD	kV	20 Year NPV B/C Ratio					
				BAU	GS	HG	LG	PP	Weighted
Rebuild Blue Earth – Winnebago 161 kV	$5	2018	161	0.16	2.13	1.15	(0.19)	2.85	0.92
Huntley – South Bend 345 kV, South Bend 345/115 kV	$95	2023	345	0.01	1.25	0.17	(0.01)	5.12	0.79
Huntley – Wilmarth 345 kV	$67	2020	345	0.08	3.37	0.33	0.05	1.52	0.92

Table 5.3-3: Iowa/Minnesota projects benefit-to-cost ratios

In addition, the third project, Huntley – Wilmarth 345 kV, initially had a weighted benefit-to-cost ratio of 2.21. However, with a low benefit in the Business as Usual (BAU), High Growth (HG) and Limited Growth (LG) futures, the result indicated that the weighted benefit was disproportionately reliant on the Public Policy (PP) future that assumes significant additions in the area. To verify this, a sensitivity test was performed in which a number of wind generators were re-sited from western to eastern MISO, bringing the PP future capacity in the west to the BAU level. This amounted to a relocation of 3.7 GW in the 2024 model and 8.7 GW in the 2029 model. Study results show that the benefit-to-cost ratio of this project under PP future dropped to 1.52, lowering the weighted B/C ratio to 0.92.

The generation growth and flows in this region will continue to be studied in future planning cycles.

Northern Indiana

Northern Indiana is impacted by a confluence of various flows across the MISO system: west-to-east flows driven by both MISO and PJM transfers; south-to-north flows; east-to-west flows to serve industrial load around southern Lake Michigan; and flows driven by wind in central Indiana and Illinois. The MCPS 2015 simulation models show only the congestion on the east of southern Lake Michigan, driven by east-to-west flows. The top flowgate in this area is New Carlisle - Bosserman for the loss of New Carlisle - Olive 138 kV, which stradles the border of MISO and PJM (Figure 5.3-9).

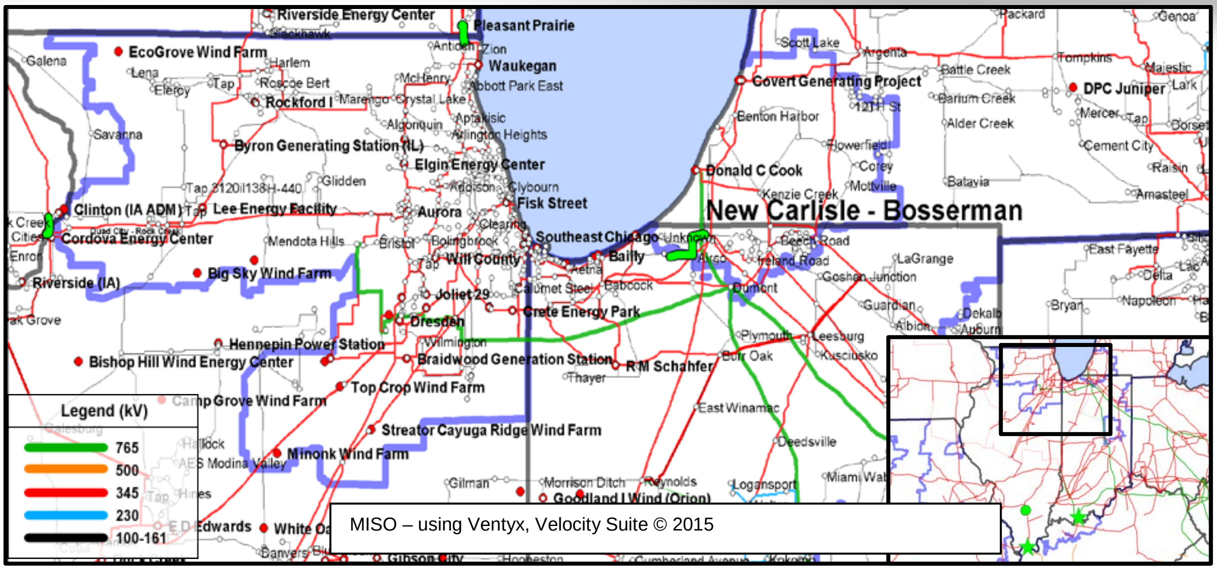


Figure 5.3-9: Northern Indiana top congested flowgates

Seven projects were submitted to address the congestion in this area. The projects addressed the issue by either providing an alternative west-to-east path or reinforcing the east-to-west path to meet the load. None of the projects passed screening.

Amite South/DSG

MCPS South identified a significant amount of congestion in the Amite South and DSG load pockets, particularly on the import lines into the DSG load pocket (Figure 5.3-10). In the event that Little Gypsy – Wesco 230 kV, a tie-line between the Amite South and DSG load pockets, is outaged and a generator is lost inside of the DSG load pocket, flows are shifted to remaining tie-lines between the pockets. As a result, the next limiting element under N-1, G-1 conditions becomes the Snakefarm – Labarre 230 kV line. Further aggravating this issue is that the DSG load pocket is import limited and has few economic generation options inside of the load pocket. Construction of an additional import line between Amite South and DSG would help to alleviate congestion under N-1, G-1 conditions and more easily supply the DSG load pocket with alternative economic generation.

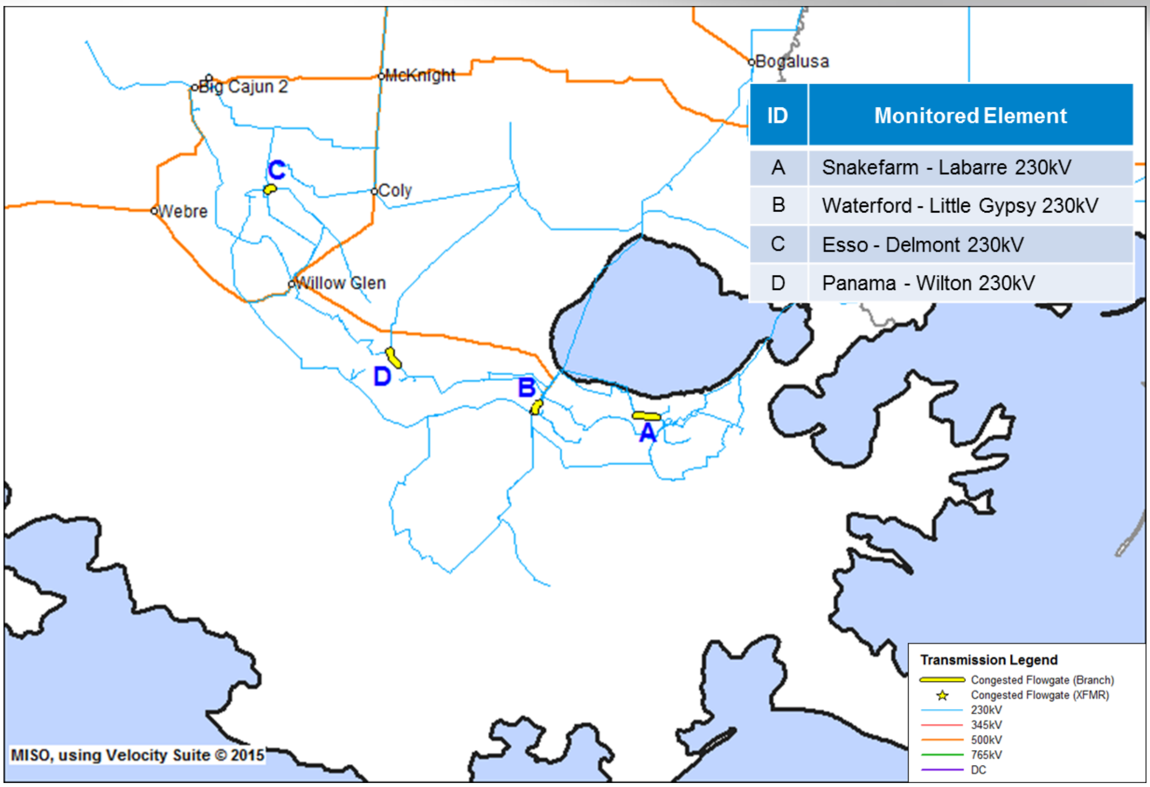


Figure 5.3-10: Amite South/DSG top congested flowgates

Through collaboration with stakeholders, MISO evaluated different generation scenarios as part of the robustness testing for projects identified in the Amite South and DSG load pockets (Table 5.3-4). Pending additional stakeholder feedback, MISO may perform additional generation sensitivities around the Regional Resource Forecast (RRF) unit located at the Little Gypsy site inside the Amite South load pocket.

Powerbase Name	Scenario 1	Scenario 2
RRF MISO CC:3	Lewis Creek 230kV	Lewis Creek 230kV
RRF MISO CC:4	Nelson 500kV	Nelson 500kV
RRF MISO CT:29	Michoud 115kV	Big Cajun 500kV
RRF MISO CT:31	Sabine 138kV	Sabine 138kV

Table 5.3-4: Amite South/DSG RRF scenario siting

Sixteen projects were submitted to address congestion in Amite South and DSG load pockets. The projects addressed the issues of increasing transfer capability into Amite South and DSG, however after screening and refinement only three projects adequately addressed the congestion (Table 5.3-5).

Transmission Solution	Cost ($M)	ISD	Siting Scenario	Benefit to Cost Ratios				
				BAU	GS	PP	SIR	Weighted
2nd Waterford – Nine Mile 230kV	$105.1	2021	Scenario 1	1.30	1.25	1.15	0.56	1.08
			Scenario 2	1.30	1.25	1.15	1.96	1.42
Waterford – NSUB1 230kV	$98.8	2021	Scenario 1	1.37	1.26	1.25	0.66	1.15
			Scenario 2	1.37	1.26	1.25	2.02	1.48
Union Carbide – Wesco 230kV	$37.9	2022	Scenario 1	1.88	2.33	1.16	1.38	1.71
			Scenario 2	1.88	2.33	1.16	4.35	2.43

Table 5.3-5: Amite South/DSG project benefit-to-cost ratios

All three projects help to mitigate the congestion seen on the import lines between the Amite South and DSG load pockets. However, where the second Waterford to Nine Mile 230kV and Waterford to NSUB1 230kV projects fully mitigate the congestion, Union Carbide to Wesco 230kV only partially mitigates the congestion. There is also potential infeasibility issues associated with building a new line into the Nine Mile substation, thus creating the need for the evaluation of the Waterford to NSUB1 230 kV alternative. With the uncertainty surrounding the future generation scenarios and the inability of Waterford to NSUB1 230 kV to show sufficient benefits, above a 1.25 benefit-to-cost ratio, in all siting scenarios these projects will be further evaluated as part of MTEP16.

WOTAB/Western

MCPS South identified a significant amount of congestion in the WOTAB and Western load pockets, both on import lines and internal congestion inside the load pockets (Figure 5.3-11). Both the WOTAB and Western load pockets are import limited and therefore commitments of units within the load pockets are required at specified limits to maintain reliability. The 2015 MCPS South models replicate these commitments using N-1, G-1 conditions. These N-1, G-1 conditions show high levels of congestion on the Newton Bulk – Leach 138kV, which represents an import line into the WOTAB load pocket, as well as congestion on both Grimes – Mt. Zion 138kV and Tubular – Dobbin 138 kV located inside of the Western load pocket.

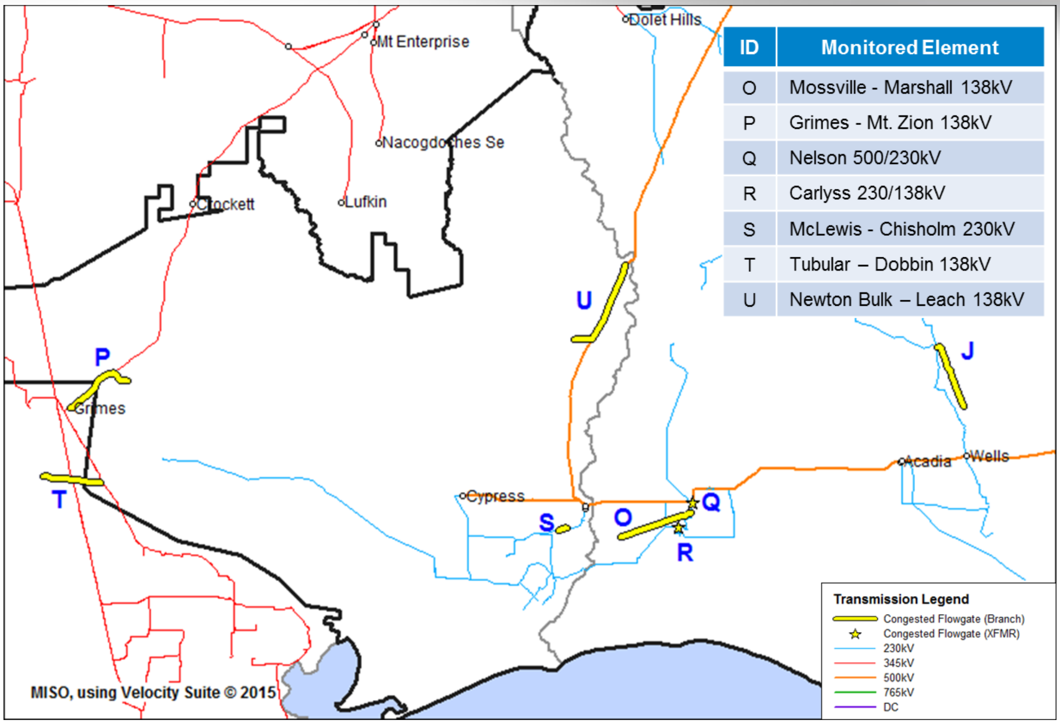


Figure 5.3-11: WOTAB/Western top congested flowgates

Through collaboration with stakeholders, MISO evaluated different generation scenarios as part of the robustness testing for projects identified in the WOTAB and Western load pockets (Table 5.3-6).

Powerbase Name	Scenario 1	Scenario 3
RRF MISO CC:3	Lewis Creek 230kV	Holland Bottoms 500kV
RRF MISO CC:4	Nelson 500kV	White Bluff 500kV
RRF MISO CT:29	Michoud 115kV	Michoud 115kV
RRF MISO CT:31	Sabine 138kV	Franklin 500kV

Table 5.3-6: WOTAB/Western RRF scenario siting

Twenty-eight projects were submitted to address congestion in the WOTAB and Western load pockets. These projects aimed to address issues of increased transfer capabilities into the WOTAB and Western load pockets, as well as alleviating internal congestion in the load pockets. After the completion of screening and refinement, three projects were identified as potential solutions to address congestion within the WOTAB and Western load pockets (Table 5.3-7).

Transmission Solution	Cost ($M)	ISD	Siting Scenario	Benefit to Cost Ratios				
				BAU	GS	PP	SIR	Weighted
Newton Bulk – Leach: Rebuild 138kV	$25.0	2021	Scenario 1	1.48	4.41	6.76	1.26	3.13
			Scenario 3	3.53	5.25	8.81	6.11	5.58
NSUB2 – Lewis Creek 230kV & Newton Bulk - Leach: Rebuild 138kV	$122.5	2021	Scenario 1	0.83	1.48	3.45	0.86	1.50
			Scenario 3	1.77	2.50	3.78	4.03	2.88
NSUB2 – Lewis Creek 345kV & Newton Bulk - Leach: Rebuild 138kV	$183.7	2021	Scenario 1	0.55	1.04	2.29	0.68	1.04
			Scenario 3	1.22	1.88	2.69	3.18	2.13

Table 5.3-7: WOTAB/Western project benefit-to-cost ratios

The NSUB2 – Lewis Creek 230 kV and Newton Bulk – Leach: Rebuild 138 kV project performs well, above a 1.25 benefit-to-cost ratio, with future RRF units sited either inside or outside of the WOTAB and Western load pockets. Though the 345 kV option does produce a benefit-to-cost ratio above 1.25 when future RRF units are sited outside of the load pockets, its benefit-to-cost ratio is just above 1.0 when future RRF units are sited inside of the load pockets. Given this result the preferred solution to mitigate the identified congestion is the 230 kV option from NSUB2 to Lewis Creek and the rebuild of the 138 kV line from Newton Bulk to Leach. Potential recommendation of this project by MISO to the Board for approval as part of MTEP15 is pending based on additional stakeholder feedback at this time.

LRZ8 (Arkansas)

The identified congestion in LRZ8 (Arkansas) was more localized than that seen in the import limited load pockets in Louisiana and Texas. The 2015 MCPS South models showed reduced levels of congestion in comparison to Amite South, DSG, WOTAB and Western. The majority of congestion in this area was in central Arkansas, particularly the congestion see in Mabelvale – Bryant 115 kV (Figure 5.3-12).

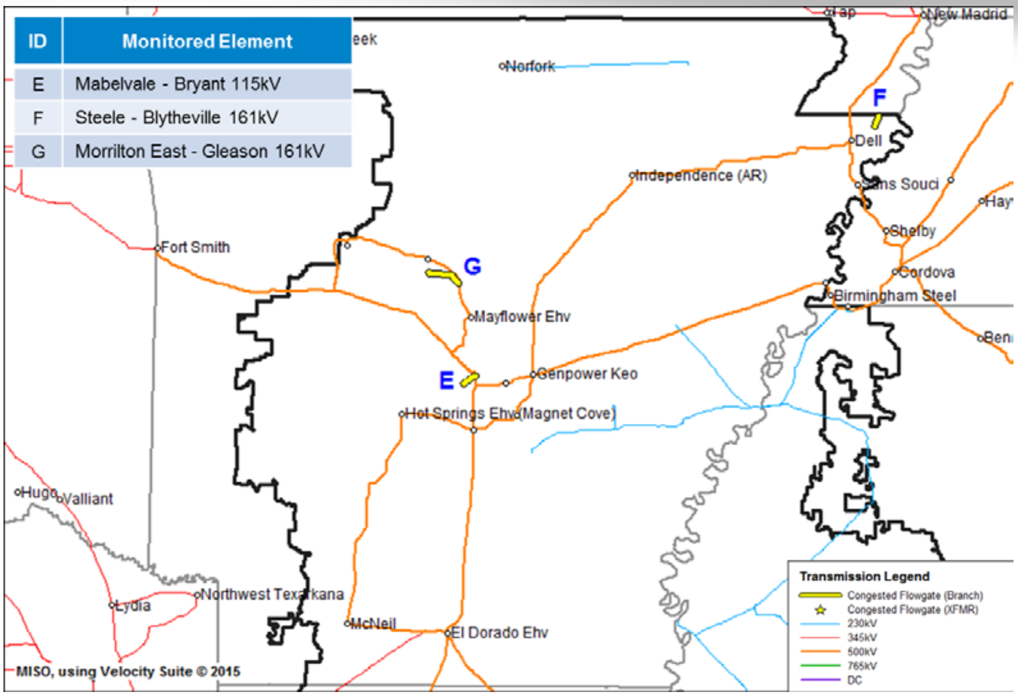


Figure 5.3-22: LRZ8 (Arkansas) top congested flowgates

Eleven projects were submitted to address congestion in LRZ8 (Arkansas). After the completion of screening and refinement, one project was identified as a potential solution to address congestion within the LRZ8 (Arkansas), while the others had associated costs that well exceeded their associated benefits (Table 5.3-8).

Transmission Solution	Cost ($M)	ISD	Benefit to Cost Ratios				
			BAU	GS	PP	SIR	Weighted
Mabelvale – Bryant – Bryant South: Rebuild 115 kV line	$6.1	2020	7.65	10.38	1.36	3.02	5.88

Table 5.3-8: LRZ8 (Arkansas) project benefit-to-cost ratios

The Mabelvale – Bryant – Bryant South: Rebuild 115 kV line has been identified as the best-fit solution to mitigate the congestion observed on the Mabelvale – Bryant 115kV line. Potential recommendation of this project by MISO to the Board for approval as part of MTEP15 is pending based on additional stakeholder feedback at this time.

Remainder of LRZ9

The identified congestion in the Remainder of LRZ9 was spread across the footprint with the majority of congestion showing in north Louisiana, Swartz – Alto 115 kV, and in central Mississippi, McAdams 500/230 kV transformer (Figure 5.3-13).

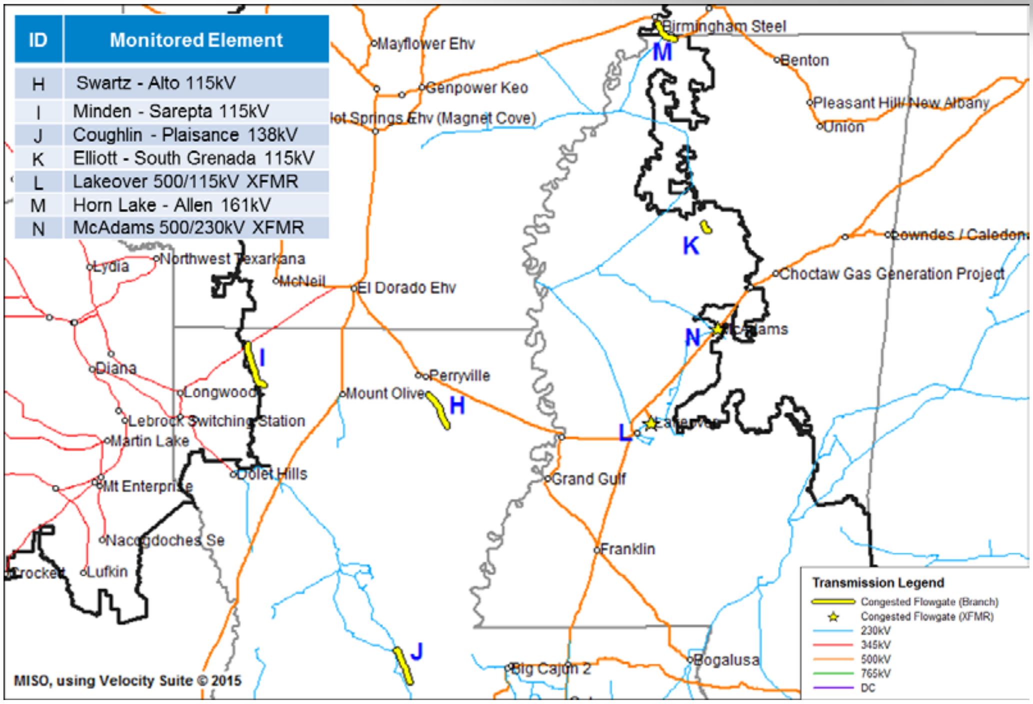


Figure 5.3-33: Remainder of LRZ9 top congested flowgates

Twenty-seven projects were submitted to address congestion in the Remainder of LRZ9. After the completion of screening and refinement four projects was identified as a potential solution to address congestion, while the associated costs of the remaining projects well exceeded their associated benefits (Table 5.3-9).

Transmission Solution	Cost ($M)	ISD	Benefit to Cost Ratios				
			BAU	GS	PP	SIR	Weighted
Alto Series Reactor	$4.2	2024	12.20	4.18	6.98	4.27	7.49
Replace 2nd McAdams 500/230 kV XFMR	$14.0	2020	1.56	2.04	1.45	1.78	1.70
3rd McAdams 500/230 kV XFMR	$14.0	2020	2.26	1.29	0.88	2.36	1.80
3rd McAdams 500/230 kV XFMR & Pickens – Midway: Rebuild 115 kV & Attala – Conehoma: Rebuild 115 kV	$43.4	2020	1.06	0.73	0.76	0.88	0.88

Table 5.3-9: Remainder of LRZ9 project benefit-to-cost ratios

The comprehensive solutions to address broader congestion identified in this area resulted in benefit-to-cost ratios below one. Considering this, the projects in the Remainder of LRZ9 are deemed not suitable for recommendation at this particular time.

Benchmark Results and Next Steps

The difference between historical congestion and the simulation of out-years may be due, in large part, to approved transmission upgrades in the region but may also reflect the sensitivity of flows to model assumptions and limitations of the model. Over the last several months, MISO has made significant progress in benchmarking the PROMOD model to historical market. Chapter 5.4 has a detailed discussion of the benchmark study with specific remmendations on how to improve the modelling of this region.

With the recommendations of the benchmarking study incorporated, the congestion pattern will be revisited. Along with other relevant solutions, the submitted solutions will be re-evaluated in future MCPS cycles.

5.4 PROMOD Benchmark Study

The PROMOD Benchmark Study analyzes differences between the MISO market and PROMOD simulation tool, and identifies best modeling practices to enhance the accuracy and capability of the simulation tool in both backward- and forward-looking analyses.

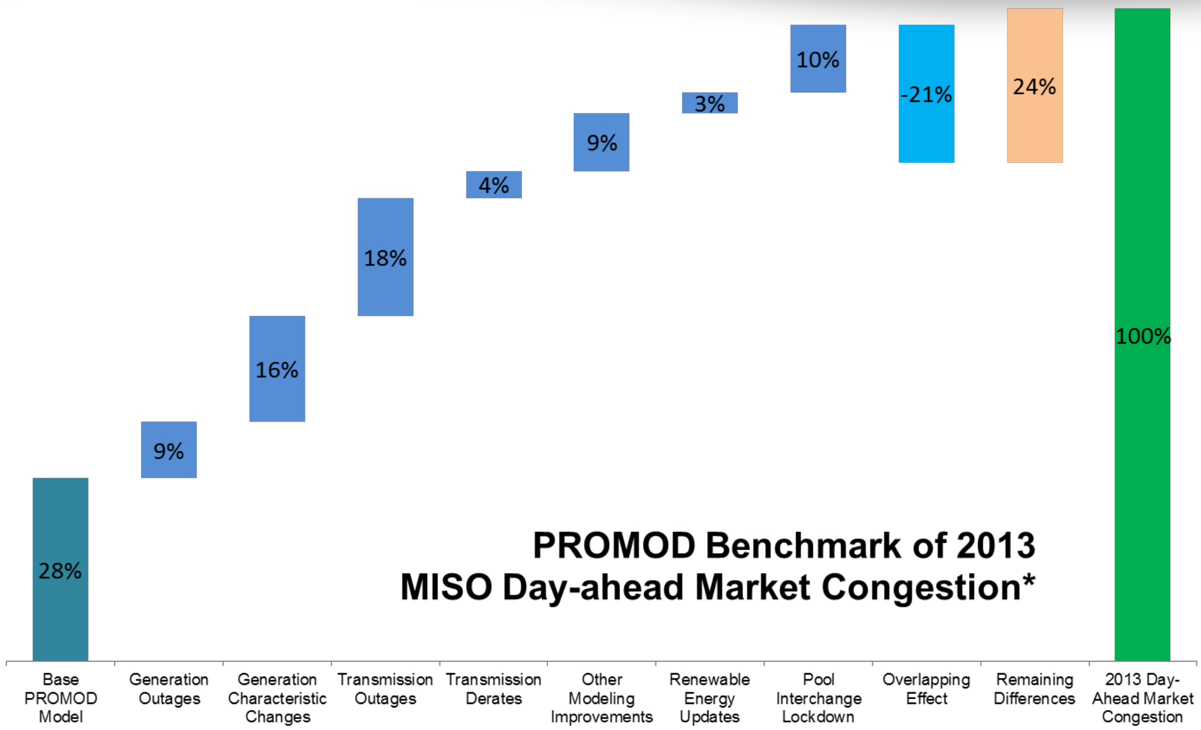
The study started in 2014, and therefore 2013 was chosen as the most current focus year. A historical-looking PROMOD model, termed Base PROMOD Model, was built with 2013 data for load, gas prices, generation fleet and the transmission system. The simulation results of the Base PROMOD Model showed drastic differences with actual MISO market outcome, especially in regards to transmission system congestion and locational marginal price (LMP).

Significant efforts were spent identifying the causes of the differences and improving the model to minimize these differences. After applying various modeling changes, the Final PROMOD Model was able to capture 76 percent of the 2013 MISO Day-ahead Market congestion in terms of total shadow price, a nearly three-fold improvement in congestion from the 28 percent congestion captured in the Base PROMOD Model.

This substantial improvement came as a result of a number of modeling changes identified and implemented in the PROMOD Benchmark Study. To help understand the impact of these changes and identify the major contributing factors, they are classified into these categories:

- Generation Outages
- Generation Characteristic Changes
- Transmission Outages
- Transmission Derates
- Other Modeling Improvements
- Renewable Energy Updates
- Pool Interchange Lockdown

Each category impacts MISO transmission system congestion differently (Figure 5.4-1). For example, the transmission outages category has the biggest impact at 18 percent, which means modeling transmission outages captured an incremental 18 percent of the 2013 MISO Day-ahead Market congestion. Other categories with significant impact are generation characteristic changes, generation outages, other modeling improvements and pool interchange lockdown.



* Market congestion is measured in total annual shadow price of MISO N/C Region

Figure 5.4-1: Congestion impact of modeling changes in the benchmark study

The remaining difference of 24 percent can be attributed to various potential reasons, some of which may require enhancement of the simulation software itself.

Out of all the changes implemented in the PROMOD Benchmark Study, about 40 percent of the improvements are the result of modeling changes that may be applied to forward-looking analyses. The applicable modeling updates will be vetted through the stakeholder process before incorporation into future planning studies. These updates involve generator modeling, transmission limit adjustment, non-conforming load modeling and specific phase angle regulator modeling.

Study Process

The PROMOD Benchmark study process consisted of gathering historical information from both public and proprietary sources, analyzing the historical congestion pattern, comparing historical actuals with simulated results from PROMOD including generation and line flow, identifying discrepancies and potential causes, and eventually developing modeling changes and performing PROMOD simulations to verify the impact of the changes. Due to the complex nature of the issue, the differences seen between PROMOD simulation results and historical actuals usually stem from a multitude of causes rather than a single cause. If the simulation does not show enough improvements or shows unexpected results, additional information is collected, typically on a more granular level, to investigate the issue further and develop refined modeling changes for further testing. Therefore, the process is highly iterative (Figure 5.4-2).

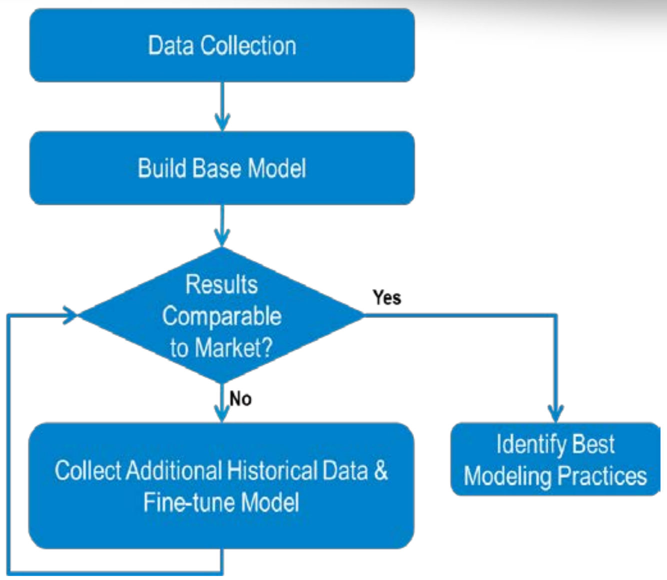


Figure 5.4-2: Benchmark study process

Summary of Modeling Changes

The differences between PROMOD simulation results and MISO market actuals come from three different sources: input data accuracy and granularity; modeling approach and implementation; and inherent difference between PROMOD and the market. These differences manifest in many ways including market structure, simulation footprint, commitment and dispatch, modeling of generation, load, transmission, fuel, interchange and external areas. Each has varying levels of impact. The PROMOD Benchmark Study analyzed these differences in significant detail to identify modeling changes and needed enhancements to the PROMOD tool.

The various modeling changes implemented in the PROMOD Benchmark Study are categorized into a few groups (Figure 5.4-1), and each group of changes is elaborated on as follows:

Generation Outages

The PROMOD Benchmark Study modeled actual MISO North/Central region generator outages, including both planned and forced outages for 2013. Some generator outages in external areas were also modeled. The impact of these changes depended on the location of the generator outage relative to the constraint. Overall, by modeling the generation outages, an additional 9 percent of 2013 MISO day-ahead congestion was captured.

Generation Characteristic Changes

Using data from various sources, the operating characteristics of many generation units were modified, such as the unit's heat rate, minimum capacity and maximum capacity. This change also included modifying the must-run statuses of various coal-fired and combined-cycle units for MISO and some neighboring areas based on historical data. This category of changes put generation output more in line with actual 2013 historical generation output. Overall, modifying these characteristics captured an additional 16 percent of 2013 MISO day-ahead congestion.

Transmission Outages

The study modeled the majority of its 2013 transmission outages, including both planned and forced outages, as well as some PJM 2013 outages. It should be noted that all transmission outages were modeled as planned outages in PROMOD due to its capability. Because powerflow can change significantly as a result of transmission outages, modeling these outages can have a dramatic effect on the congestion of specific flowgates. Overall, modeling of transmission outages captured an additional 18 percent of 2013 MISO day-ahead congestion.

Transmission Derates

Based on historical information, the study updated limits for flowgates in some focused areas. This generally increased congestion as it involved various rating decreases. It captured an additional 4 percent of 2013 MISO day-ahead congestion. The impact is more dramatic in the focused areas. For instance, the modeling of transmission derates captured an additional 22 percent of 2013 Northern Indiana Public Service Co.'s (NIPSCO) day-ahead congestion and an additional 13 percent of 2013 Ameren Illinois (AMIL) day-ahead congestion.

Other Modeling Improvements

This category of changes includes various modeling updates that do not fall under the rest of the categories. This includes non-conforming load modeling in some MISO and PJM areas, specific phase angle regulator modeling improvement and coal price update. Among these changes, non-conforming load modeling updates improved the distribution of congestion on flowgates. The impact of this category of changes is an additional 9 percent of 2013 MISO day-ahead congestion captured.

Renewable Energy Update

This change set the total amount of wind energy of MISO and PJM to actual wind energy for 2013. In the Base PROMOD Model, MISO had more wind energy modeled than historical, setting MISO wind energy to the actual historical amount tended to reduce congestion due to less west-to-east flow. At the same time, PJM had less wind energy modeled in the Base PROMOD Model than the actual historical amount, and therefore setting PJM wind energy to historical amounts increased congestion, particularly, in NIPSCO area. As a result of these changes, NIPSCO congestion increased by 11 percent of its 2013 day-ahead level, and AMIL congestion decreased by 8 percent of its 2013 day-ahead level. Overall, an additional 3 percent of 2013 MISO day-ahead congestion is captured.

Pool Interchange Lockdown

This change set the interchange between MISO and all neighboring pools at the actual historical interchange of 2013. This increased congestion on flowgates at or near the seams that were relevant to meeting these interchange schedules. Overall, modeling of the pool interchange lockdown captured an additional 10 percent of 2013 MISO day-ahead congestion.

Overlapping Effect

Some of the aforementioned modeling changes overlap in terms of their congestion impact, i.e., different changes may affect congestion in a similar way and therefore one change will have less impact when the other changes are in place. The combined impact of modeling all the above categories of changes together resulted in a congestion level that is less than a straight sum of their individual impacts, and the difference is 21 percent of 2013 MISO day-ahead congestion.

Remaining Differences

This category represents the remaining difference between PROMOD simulation results and historical congestion, after all the aforementioned modeling changes were implemented. The remaining difference accounts for 24 percent of 2013 MISO day-ahead congestion, and it potentially stems from multiple sources such as market dispatch shift factor cutoff, day-ahead/real-time load variation modeling, loop flow representation, non-MISO area modeling and more. These potential causes cannot be tested due to the limitation of the simulation tool, scope of the study and finite amount of study time available. Currently, MISO is working with the vendor of PROMOD to implement some of the needed enhancements identified.

Summary of Results

The modeling changes yielded significant improvements in generation, LMP and especially in transmission system congestion.

Generation

The PROMOD Benchmark Study resulted in significant improvement in total generation (Figure 5.4-3). Specifically, coal and nuclear generation decreased and became closer to actual historical levels. Gas generation, particularly combined-cycle generation, increased to be closer to the actual historical level. As a result, the percentage of total generation and capacity factor by fuel type improved.

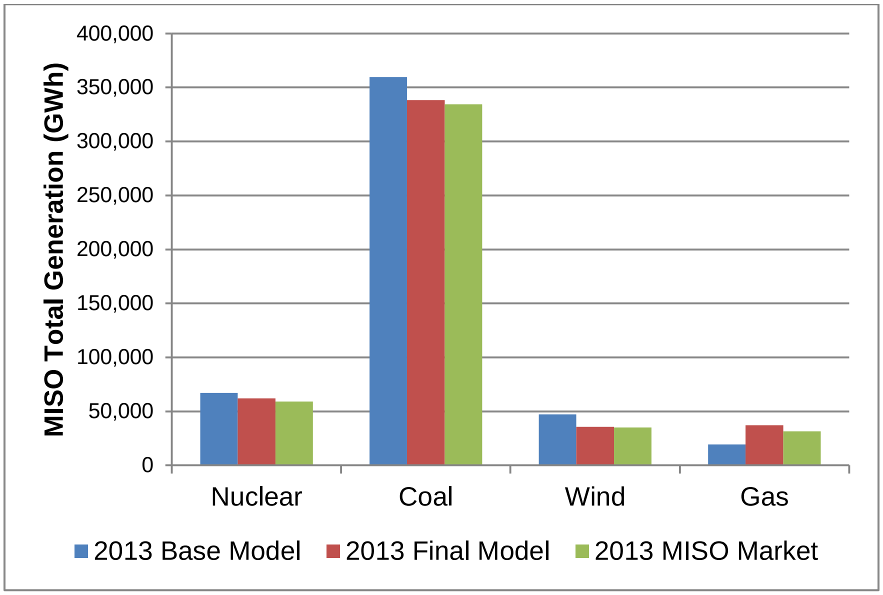


Figure 5.4-3: MISO total generation by fuel type

LMP

After all the aforementioned modeling changes, LMPs improved at all four commercial hubs in the MISO North/Central region, and became closer to their historical values (Figure 5.4-4). For example, differences between PROMOD results and historical market reduced from $9/MWh to $5/MWh for Illinois Hub and Minnesota Hub LMPs, and from $8/MWh to $1.5/MWh for Indiana and Michigan Hub LMPs. On a monthly basis, the LMP monthly pattern improved and differences between PROMOD results and the historical market decreased.

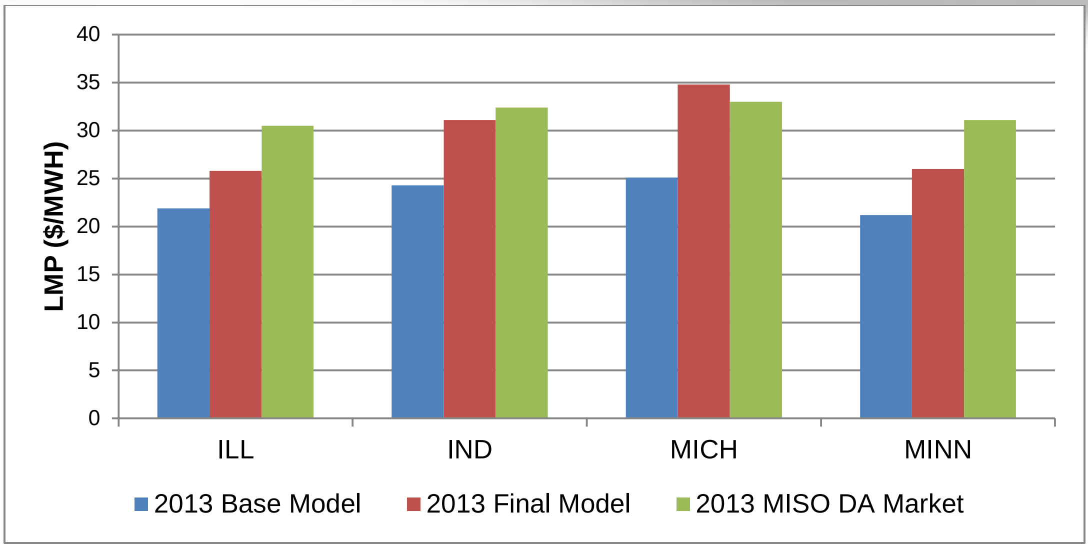


Figure 5.4-4: MISO North/Central commercial hub LMPs

Transmission Congestion

The biggest improvement was achieved with transmission congestion. Congestion significantly improved across MISO North/Central region. When measured as the sum of the annual shadow prices, 76 percent of total 2013 MISO North/Central day-ahead congestion is captured (Figure 5.4-5). Monthly congestion patterns significantly improved as well. The congestion not only improved on an aggregated level, but also on an individual flowgate level. Namely, the distribution of the congestion across flowgates also improved significantly.

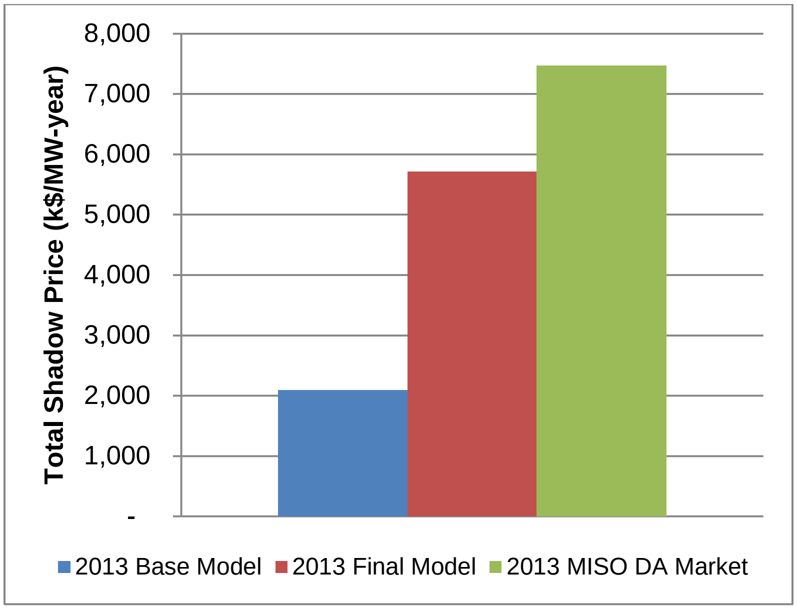


Figure 5.4-5: MISO congestion by total shadow price

Conclusions

The PROMOD Benchmark Study identified and quantified the impacts of many factors that led to the differences between PROMOD simulation results and actual market results. Among them, the biggest drivers are differences in transmission outages, generator outages and generator operating characteristics. After implementing the various modeling changes, the study replicated 76 percent of the 2013 MISO Day-ahead congestion, a nearly three-fold improvement in congestion from the Base PROMOD Model. Forty percent of this improvement may be applicable to future planning studies.

Identified best modeling practices will be vetted through the stakeholder process, for instance, the Economic Planning User Group forum, before being applied in future planning studies. The modeling practices may include but are not limited to:

- Generator Modeling Updates
- Transmission Limit Adjustments
- Non-conforming Load Modeling
- Specific Phase Angle Regulator Modeling

Book 2
Resource Adequacy

Chapter 6
Resource Adequacy

6.0 Resource Adequacy Introduction and Enhancements

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

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

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

To date, the Resource Adequacy Requirements process has been a successful tool for facilitating and demonstrating Resource Adequacy in the near term, through such tools as the Loss of Load Expectation (LOLE) analysis, the Planning Resource Auction (PRA), and the Organization of MISO States (OMS)-MISO Survey. With the resource portfolio now evolving due to coal retirements and the increase in gas-fired generation, MISO is evaluating the Resource Adequacy Requirements.

This work has begun in Resource Adequacy forums and will focus upon key areas to strengthen the Resource Adequacy framework; including defining seasonal risks; ensuring locational signals are clear and appropriate; and refining generator interconnection procedures to ensure new capacity can efficiently interconnect to the system.

More information is detailed within the Issues Statement on Facilitating Resource Adequacy in the MISO Region.

6.1 Planning Reserve Margin

The MISO Installed Capacity Planning Reserve Margin (PRM_{ICAP}) for the 2015-2016 planning year, spanning from June 1, 2015, through May 31, 2016, is 14.3 percent, decreasing 0.5 percent from the 14.8 percent PRM set in the 2014-2015 planning year (Figure 6.1-1).

The PRM_{ICAP} is established with resources at their installed capacity rating at the time of the system-wide MISO coincident peak load. The 0.5 percent PRM_{ICAP} decrease was the net effect of several modeling parameters such as changes to the modeling of external regions, changes to load forecast, load forecast uncertainty and resource characteristics.

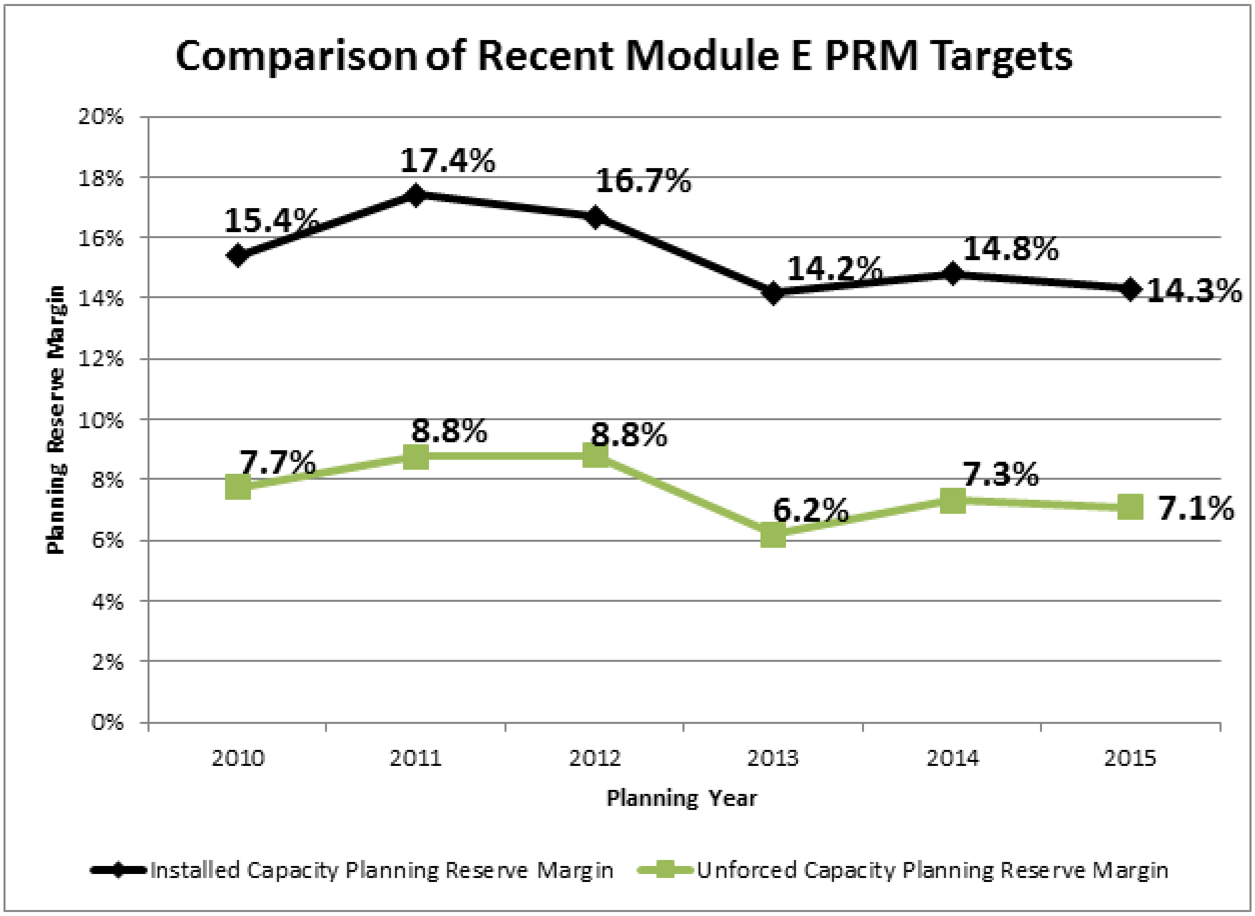
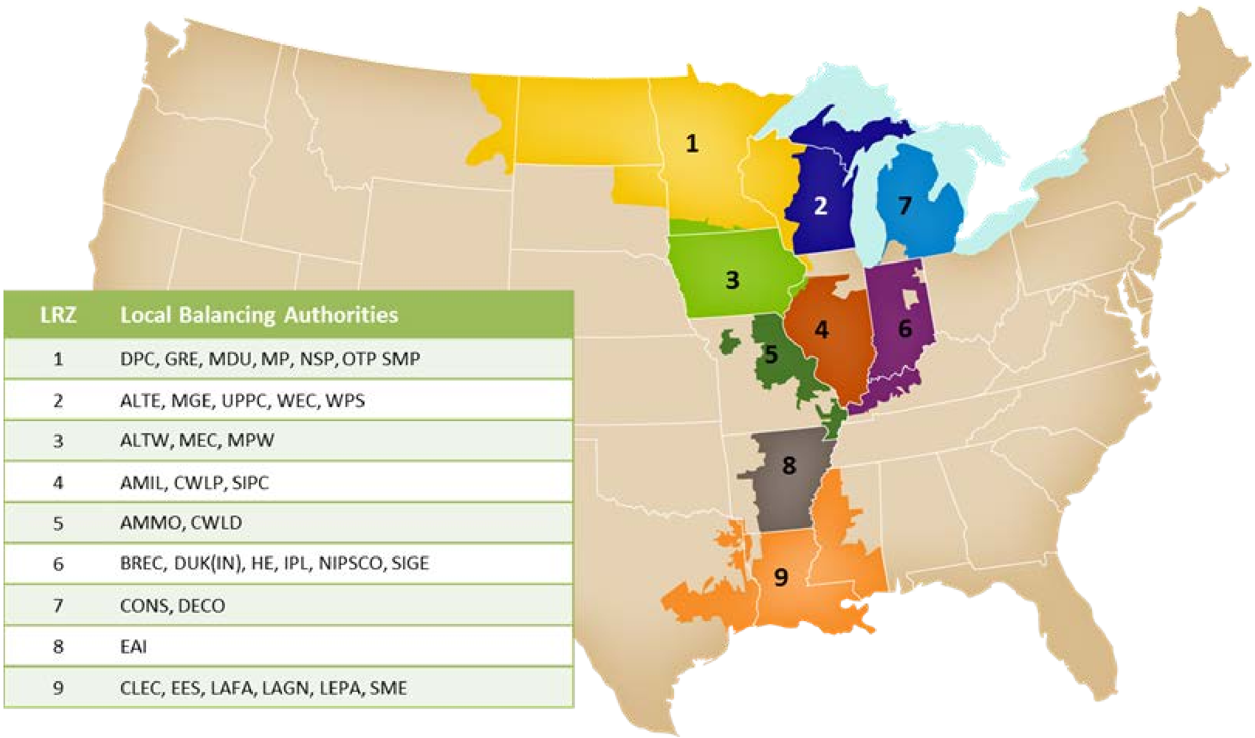


Figure 6.1-1: Comparison of recent PRM

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

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



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

Figure 6.1-2: Local Resource Zones (LRZ) as of November 1, 2014

2015-2016 Deliverables to the Planning Resource Auction

The PRM deliverables are needed for the Planning Resource Auction (PRA). These deliverables include the PRM_{UCAP}, a per-unit zonal LRR, and CIL and CEL values (Table 6.1-1). The PRM_{UCAP} decreased from 7.3 percent to 7.1 percent due to the modeling parameter changes. More information on the decrease is available in the LOLE report. Under the existing construct, the PRM_{UCAP} is applied to the peak of each Load Serving Entity coincident with the MISO peak. A zonal CIL and CEL for each LRZ was calculated with the monitored and contingent elements reported (Tables 6.1-2 and 6.1-3; Figures 6.1-3 and 6.1-4). The ultimate PRM, CIL and CEL values for a zone could be adjusted within the PRA depending on the demand forecasts received and offers into the auction to assure that the resources cleared in the auction can be reliably delivered.

RA and LOLE Metrics	LRZ 1	LRZ 2	LRZ 3	LRZ 4	LRZ 5	LRZ 6	LRZ 7	LRZ 8	LRZ 9
Default Congestion Free PRM UCAP	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%
LRR UCAP per-unit of LRZ Peak Demand	1.111	1.151	1.137	1.214	1.211	1.108	1.142	1.270	1.112
Capacity Import Limit (CIL) (MW)	3,735	2,903	1,972	4,125	3,899	5,649	3,813	2,074	3,320
Capacity Export Limit (CEL) (MW)	604	1,516	1,477	2,353	0	2,930	4,804	3,022	3,239

Table 6.1-1: Deliverables to the 2015-2016 Planning Resource Auction (PRA)

Zone	Tier	15-16 Limit (MW) [24]	Monitored Element	Contingent Element	Figure 6.1-3 Map ID	Initial Limit (MW)[25]	Generation Redispatch Details		14-15 Limit (MW)
							MW	Area(s)	
1	1	3,735	Worth County – Colby 161 kV	Barton – Adams 161 kV	1	3,376	2,000	MEC, ITCM, XEL, GRE	4,347
2	1	2,903	Turkey River – Stoneman 161 kV	Genoa 161/69 kV Transformer AT5/AT7 fault	2	2,104	694	WEC, ALTE, MGE, ALTW	3,083
3	1	1,972	Palmyra 345/161 kV transformer	Hills – Sub T – Louisa 345 kV	3	727	2,000	XEL, ALTW, MEC	1,591
4	1	3,130	Tazewell 345/138 kV transformer 1	Tazewell 345/138 kV transformer 2	4	850	2,000	NIPS, BREC, AMMO, AMIL, ITCM, MEC	3,025
5	1	3,899	White Bluff – Keo 500	Sheridan – Mabelvale 500	5	3,899	Not Applicable		5,273

[24] The 15-16 Limit represents the limit after redispatch has been considered.
[25] The Initial Limit represents the limit before considering redispatch.

			kV	kV					
6	1&2	5,649	Neoga – Holland 345 kV	Xenia – Mount Vernon 345 kV	6	5,090	2,000	METC, AMIL	4,834
7	1&2	3,813	Clifty Creek – Trimble County 345 kV	Rockport – Jefferson 765 kV	7	2,412	Not Applicable		3,884
8	1	2,074	Mt Olive – Vienna 115 kV	Mt Olive – Eldorado 500 kV	8	482	2,000	CLEC, AMMO, EES	1,602
9	1	3,320	Junction City to Bernice 115 kV	Mount Olive to El Dorado 500 kV	9	3,320	Not Applicable		3,585

Table 6.1-2: 2015-2016 Planning Year Capacity Import Limits

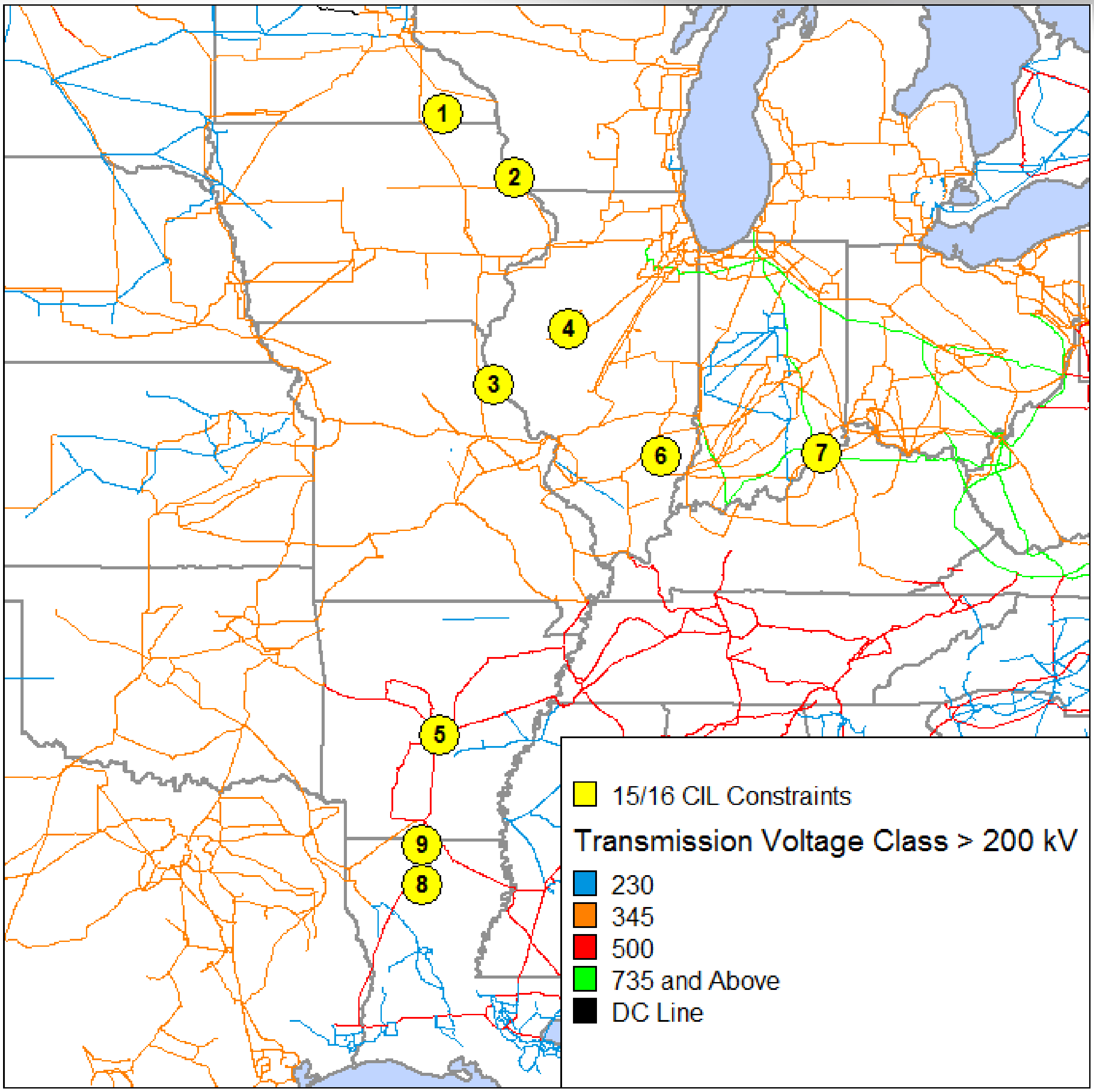


Figure 6.1-3: 2015-2016 Capacity Import Limit Map

Zone	15-16 Limit (MW)	Monitored Element	Contingent Element	Figure 6.1-4 Map ID	Initial Limit (MW)	Generation Redispatch Details		14-15 Limit (MW)
						MW	Area	
1	604	Lakefield – Dickinson 161 kV	Webster 345 kV Station	1	604	Not Applicable		286
2	1,516	Zion Station – Zion Energy Center 345 kV	Pleasant Prairie – Zion 345 kV	2	1,167	1,188	WEC, MGE, ALTE, CE	1,924
3	1,477	Byron – Cherry Valley 345 kV Red	Byron – Cherry Valley 345 kV Blue	3	648	1,610	MEC, NIPS, WEC	1,875
4	4,125	Hutsonville – Robinson 138 kV	Newton – Robinson 138 kV	4	4,125	Not Applicable		1,961
5	0[26]	Palmyra 345/161 kV Transformer	Hills – Sub T – Louisa 345 kV	5	0	Not Applicable		1,350
6	2,930	Clifty Creek – Trimble County 345 kV	Rockport – Jefferson 765 kV	6	2,930	Not Applicable		2,246
7	4,804	Benton Harbor 345/138 kV Transformer	Benton Harbor – Cook 345 kV	7	4,799	53	METC, ITCT	4,517
8	3,022	Woodward – Stuttgart Ricusky 230 kV	Keo – West Memphis 500 kV	8	2,767	2,000	EAI	3,080
9	3,239	White Bluff – Keo 500 kV	Sheridan – Mabelvale 500 kV	9	951	2,000	EES, CLEC	3,616

Table 6.1-3: 2015-2016 Planning Year Capacity Export Limits

[26] Limit is initially determined by transmission constraint listed above, then is limited by generation

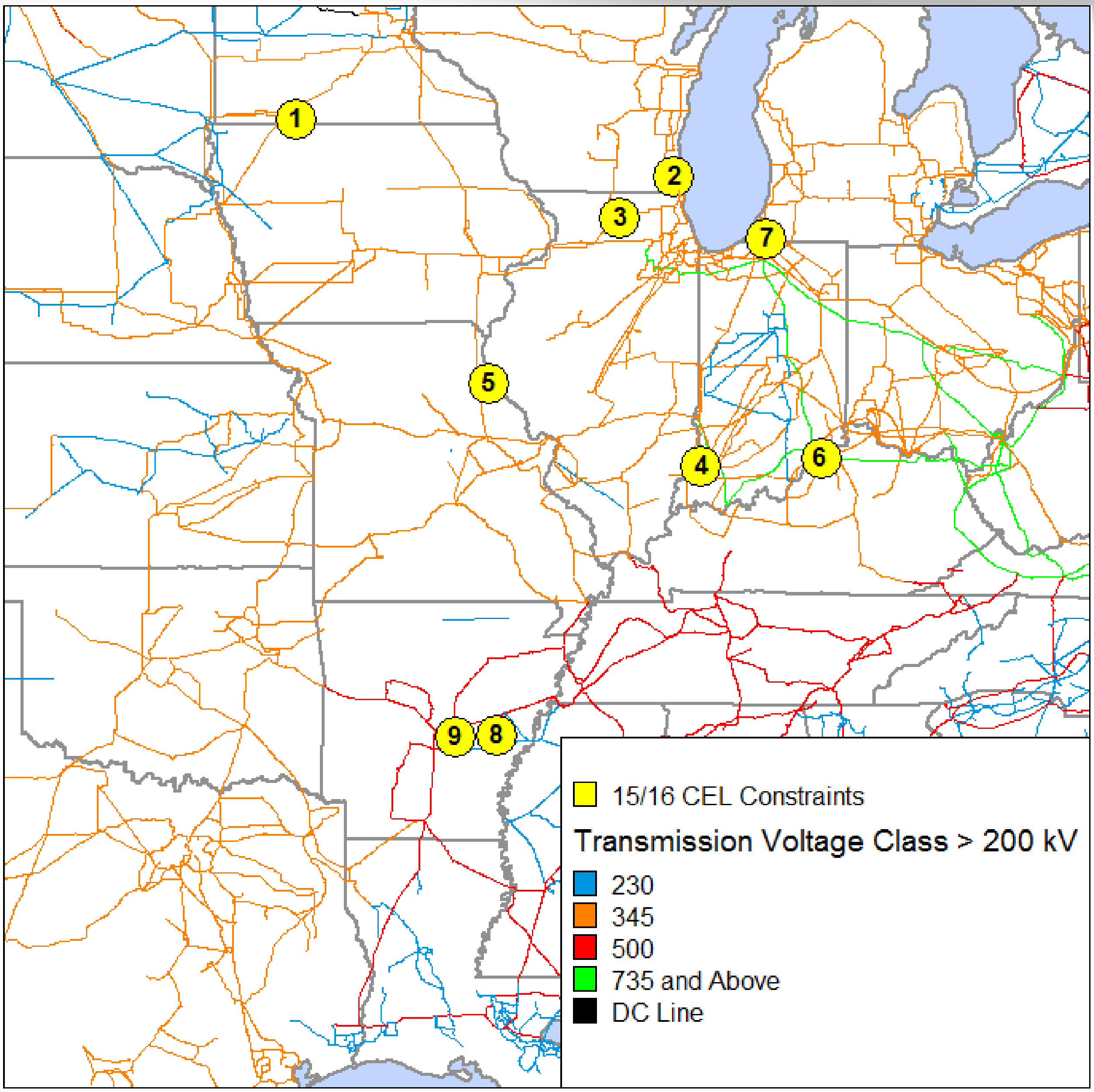


Figure 6.1-4: 2015-2016 Capacity Export Limit Map

MTEP and Capacity Import and Export Limit Alignment

The Capacity Import and Export Limits are deliverables to the PRM for the Planning Resource Auction and are considered in the development of the MTEP. The initial limits, before applying additional generation redispatch, have been identified in the LOLE study for the 2015-2016 Planning Year and the 2016-2017 Near-Term planning horizon. Three MTEP projects are anticipated to mitigate or alleviate the constraint identified as a limiting element in the LOLE study (Table 6.1-4).

Year	LRZ	CEL or CEL	Monitored Element	Contingent Element	MTEP Project ID	Target Appendix	Project Name	Min Expected ISD
15-16, 16-17	7	CIL	Battle Creek to Argenta 345 kV	Argenta to Tompkins 345 kV	4509	A in MTEP15	Argenta - Battle Creek 345kV Sag Remediation and Station Equipment	12/31/2016
15-16, 16-17	5, 9	CIL & CEL	White Bluff to Keo 500 kV	Sheridan to Mabelvale 500 kV	8940	A in MTEP15	White Bluff - Keo 500 kV: Upgrade terminal equipment	12/1/2016
15-16, 16-17	2	CIL	Turkey River to Stoneman 161 kV	Seneca to Genoa 161 kV	3828	A in MTEP13	Lore-Turkey River-Stoneman 161kV Rebuild	12/31/2015

Table 6.1-4: Directly Impacting MTEP Projects

LOLE study CIL and CEL constraints outlined have MTEP projects near or at one of the facilities listed as a constraint. These projects are not expected to fully mitigate or alleviate the constraint, rather they may affect the identified constraint either positively or negatively (Table 6.1-5).

Year	LRZ	CEL or CEL	Monitored Element	Contingent Element	MTEP Project ID	Target Appendix	Project Name	Min Expected ISD
15-16, 16-17	7	CIL & CEL	Battle Creek to Argenta 345 kV	Argenta to Tompkins 345 kV	4149	A in MTEP13	Argenta - Tallmadge 345 kV Sag Remediation	12/31/2015
15-16, 16-17	7	CIL & CEL	Battle Creek to Argenta 345 kV	Argenta to Tompkins 345 kV	662	A in MTEP09	Weeds Lake	3/31/2016
16-17	1	CEL	Briggs Road to Mayfair 161 kV	La Crosse to Marshland 161 kV	4360	A in MTEP14	Rebuild Marshland-Briggs Road 161 kV	12/11/2015
16-17	1	CEL	Briggs Road to Mayfair 161 kV	La Crosse to Marshland 161 kV	7664	A in MTEP15	Rebuild Briggs Road-La Crosse Tap 161 kV	6/1/2016
16-17	1	CEL	Briggs Road to Mayfair 161 kV	La Crosse to Marshland 161 kV	4685	A in MTEP14	Install Tremval 2nd 161-69 kV Transformer	12/15/2016
16-17	7	CEL	Dorr Corners Junction to Beals 138 kV Line	Argenta to Talmadge 345 kV	8067	A in MTEP15	Beals Road 138 kV Station Equipment Replacement	6/1/2017
15-16	4	CEL	Hutsonville to Robinson Marathon North Tap 138 kV	Newton to Robinson Marathon 138 kV	7800	A in MTEP15	Newton-Robinson-1 138 kV Reconductoring	12/1/2015
15-16, 16-17	8, 9	CIL & CEL	Montgomery to Clarence 230 kV	Montgomery to Winnfield 230 kV	2996	A in MTEP14	Montgomery-Spencer Creek-Palmyra Tap-Sub T-Hills - Increase Ground Clearance	6/1/2015
15-16, 16-17	6	CIL	Newton to Casey 345 kV	Casey to Neoga 345 kV	4481	A in MTEP14	Casey, West Terminal Equipment	11/15/2015
15-16, 16-17	3, 4, 5	CIL & CEL	Palmyra Transformer	Montgomery to Spencer 345 kV	3017	A in MTEP11	Proposed MVP Portfolio 1 - Palmyra Tap – Quincy - Meredosi	11/15/2015

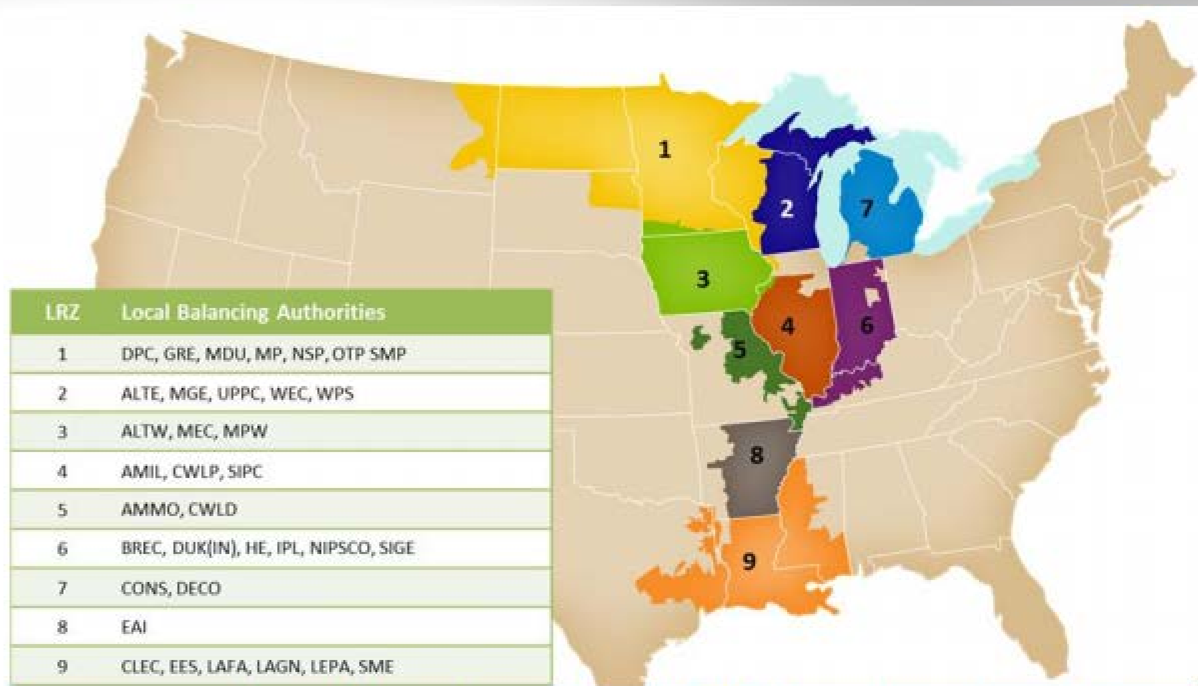
Year	LRZ	CEL or CEL	Monitored Element	Contingent Element	MTEP Project ID	Target Appendix	Project Name	Min Expected ISD
							a - Ipava & Meredosia - Pawnee 345 kV Line	
15-16	4	CIL	Tazewell 138/345 kV Xfr 1	Tazewell 138/345 kV Xfr 2	7824	A in MTEP15	Tazewell 345 kV Breaker Replacements	9/15/2015
16-17	4, 6	CIL & CEL	West Point to Lafayette 230 kV	Eugene to Caysub 345 kV	4037	A in MTEP13	Lafayette 230 kV Ring Bus - Ph. 2	12/31/2016
16-17	4, 6	CIL & CEL	West Point to Lafayette 230 kV	Eugene to Caysub 345 kV	3561	A in MTEP14	Lafayette 230 - W. Laf. 138 kV Rebuild	6/1/2015
15-16, 16-17	2, 7	CIL & CEL	Zion Energy Center to Zion Station 345 kV	Zion Station to Pleasant Prairie 345 kV	3898	A in MTEP13	Reconductor Pleasant Prairie - Zion 345 kV	12/31/2020[27]
15-16, 16-17	2, 7	CIL & CEL	Zion Energy Center to Zion Station 345 kV	Zion Station to Pleasant Prairie 345 kV	8065	A in MTEP15	Construct Southeast Wisconsin - Northeast Illinois 345 kV transmission reinforcement	12/31/2020

Table 6.1-5: Potential Impacting MTEP Projects

Wind Capacity Credit

A wind capacity credit of 14.7 percent was established for the 2015-2016 planning year by determining the Effective Load Carrying Capability (ELCC) of wind resources. The wind capacity credit increased 0.6 percent from the wind capacity credit of 14.1 percent established in the 2014-2015 Planning Year (Figure 6.1-5). For more information, refer to the complete 2015 Wind Capacity Credit Report[28].

[27] This project will be removed once project 8065 is approved.
[28] Or: https://www.misoenergy.org/Library/Repository/Study/LOLE/2014%20Wind%20Capacity%20Report.pdf



Metric	MISO	Zone 1	Zone 2	Zone 3	Zone 4 and Zone 5	Zone 6	Zone 7	Zone 8	Zone 9
Registered Max (MW)	13,403	3,960	627	6,479	546	282	1,510	0	0
UCAP (MW)	1,966	698	72	885	63	26	222	0	0
ELCC %	14.7%	17.6%	11.4%	13.7%	11.6%	9.3%	14.7%	0.0%	0.0%
Wind CPnode Count	186	68	10	75	7	4	22	0	0

Figure 6.1-5: Local Resource Zones (LRZ) as of November 1, 2014

For more information related to the LOLE study please refer to the Planning Year 2015 LOLE study report[5].

6.2 Long-Term Resource Assessment

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

MISO forecasts the reserve margin will drop below the PRMR of 14.3 percent beginning in 2020, and will remain below the PRMR for the rest of the assessment period (Table 6.2-1). Falling below the PRMR signifies that the MISO region is projected to operate at a reliability level lower than the one-day-in-10 standard in 2020 and beyond. MISO anticipates the projected margin shortfall will change significantly as Load Serving Entities and state commissions solidify future capacity plans.

This is an expected result, as 91 percent of the load in the MISO footprint is served by utilities with an obligation to serve. This obligation is reflected as a part of state and locally jurisdictional integrated resource plans that only become certain upon the receipt of a Certificate of Public Convenience and Need (CPCN). Five years is sufficient lead time for Load Serving Entities to plan, build and operate new resources to meet the projected shortfall in 2020 and beyond.

In GW (ICAP)	PY 2016/17	PY 2017/18	PY 2018/19	PY 2019/20	PY 2020/21	PY 2021/22	PY 2022/23	PY 2023/24	PY 2024/25	PY 2025/26
(+) Existing Resources	151.9	151.5	151.2	150.5	150.4	150.4	150.4	150.4	150.4	150.4
(+) New Resources	0.7	2.1	2.1	2.5	2.6	2.6	2.6	2.6	2.6	2.6
(+) Imports	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3
(-) Exports	3.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8
(-) Low Certainty Resources	0.6	0.5	1.1	1.0	2.3	3.0	3.7	4.4	5.7	8.6
(-) Transfer Limited	3.4	3.0	2.6	1.9	1.6	1.4	1.2	1.0	0.8	0.6
Available Resources	149.1	151.5	151.1	151.5	150.5	150.1	149.6	149.1	148.0	145.3
Demand	128.9	130.4	131.2	132.4	133.3	134.1	134.9	135.9	136.6	137.7
PRMR	147.3	149.0	150.0	151.3	152.3	153.2	154.2	155.3	156.2	157.4
PRMR Shortfall	1.7	2.6	1.1	0.2	-1.8	-3.2	-4.6	-6.2	-8.2	-12.2
Reserve Margin Percent (%)	15.6%	16.3%	15.1%	14.5%	13.0%	11.9%	10.9%	9.7%	8.3%	5.5%

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

The anticipated PRMR shows significant improvements from the 2014 LTRA results, which projected a shortfall against the reserve requirements of 2.3 GW in 2016. The conclusions from the long-term resource assessments are:

- All zones within MISO are sufficient from a resource adequacy point of view in the near term, when considering available capacity and transfer limitations. Regional shortages in later years may be rectified by the utilities and, as such, do not cause immediate concern.
- The change in LTRA results was driven primarily by a combination of an increase in resources committed to serving MISO load and a decrease in load forecasts.
- The increase in committed resources reflects action taken by MISO load-serving entities and state regulators to address potential capacity shortfalls.
- MISO anticipates that each zone within the MISO footprint will have sufficient resources within its boundaries to meet its Local Clearing Requirements or the amount of their local resource requirement, which must be contained within their boundaries.
- Several zones are short against their total zonal reserve requirement, when only resources within their boundaries or contracted to serve their load are considered. However, those zones have sufficient import capability and the MISO region has sufficient surplus capacity in other zones to support this transfer. Surplus-generating capacity for zonal transfers within MISO could become scarce in later years if no action is taken in the interim by MISO load-serving entities.

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

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

Assumptions

At the end of 2013 MISO and Organization of MISO States (OMS) conducted a Resource Adequacy survey of load-serving entities to help bridge the gap of limited visibility that exists between the annual Module E Tariff process and Forward Resource Assessment. MISO finished the survey in June 2014, and it was instrumental in the development of the Long-Term Resource Assessment and the Resource Adequacy outlook for the MISO region.

Demand Growth

In 2016, MISO anticipates that the MISO Region's coincident demand will be 128,885 MW, which is a 50/50 weather-normalized load forecast.

Load-serving entities submit demand forecasts for the upcoming 10 years. MISO utilizes these forecasts to calculate a MISO business-as-usual load growth. Based on these forecasts, MISO anticipates a system-wide average growth rate of 0.8 percent for the period from 2015 to 2025.

In 2016, MISO anticipates that the MISO Region's coincident demand is projected to be 128,885 MW, which is a 50/50 weather-normalized load forecast

Resources

In 2016, MISO expects a total of 143,877 MW of Anticipated Capacity Resources to be available on-peak.

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

In 2016, MISO expects a total of 143,877 MW of Anticipated Capacity Resources to be available on-peak

BTMG, Interruptible Load (IL), Direct Control Load Management (DCLM) and Energy Efficiency Resources (EER) are eligible to participate as registered LMRs. All of these are emergency resources available to MISO only during a Maximum Generation Emergency Event Step 2b per MISO's Emergency Operating Procedures. MISO assumes the 4,400 MW of BTMG dropping to 4,200 in 2020 and 6,400 MW of LMR DR that was qualified in the 2015 Planning Resource Auction to be available throughout the assessment period.

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

Through the Generator Interconnection Queue (GIQ) process, MISO anticipates 2,584 MW of future firm capacity additions and uprates to be in-service and expected on-peak during the assessment period (Figure 6.2-1). This is based on a snapshot of the GIQ as of June 2015 and is the aggregation of active projects with a signed Interconnection Agreement.

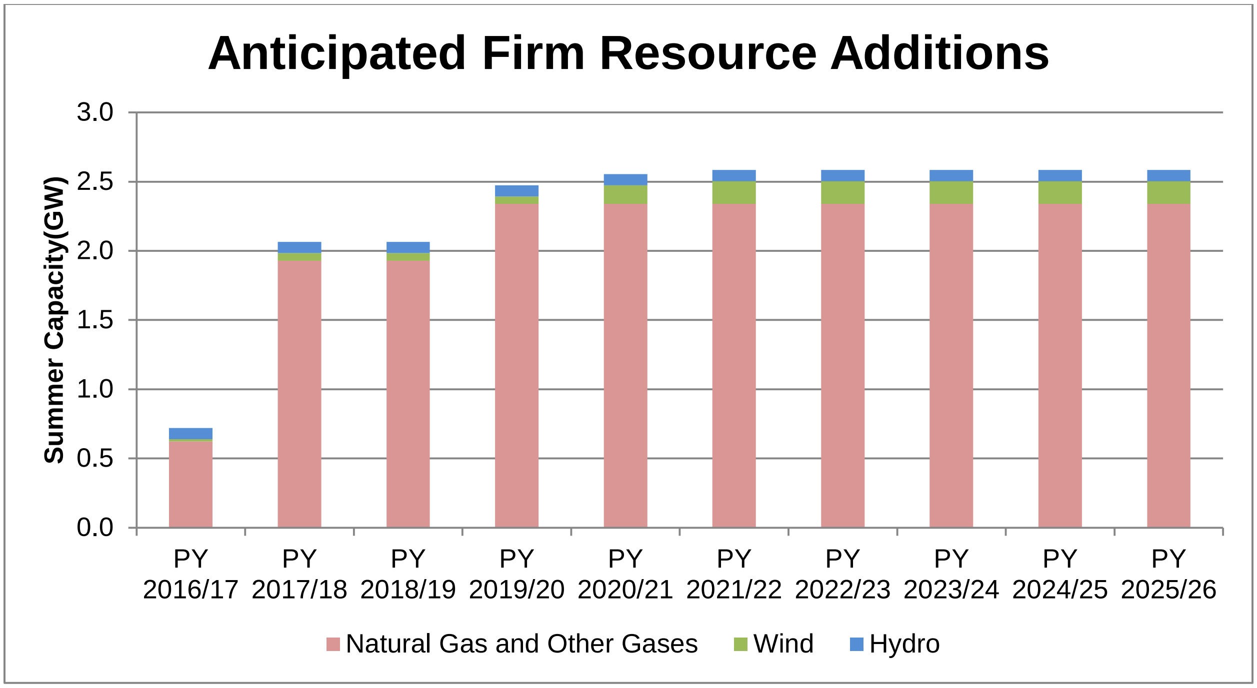


Figure 6.2-1: Anticipated resource additions and uprates (cumulative) in the MISO Region

Imports and Exports

MISO assumes a forecast of 3,157 MW of capacity from outside of the MISO footprint to be designated firm for use during the assessment period and cannot be recalled by the source transmission provider.

This capacity was designated to serve load within MISO through the Module E process for summer 2015. It's assumed that the firm imports continue at this level for the assessment period. MISO assumes a forecast of 3,806 MW of firm capacity exports in year 2016 to regional transmission operator PJM based on PJM Base Residual Auction cleared results. Exports are projected to decrease to 2,780 MW in 2017 and remain at that level for the rest of the assessment period.

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

6.3 Gas-Electric Coordination

Over the past several years, MISO has made significant progress on the gas-electric coordination front, enhancing system awareness, furthering coordinating operations, and facilitating cross-industry education and communication. The addition of the PLEXOS Integrated Energy Model to MISO's planning toolkit represents another step towards better understanding and planning for future gas-electric system interactions.

The addition of the PLEXOS Integrated Energy Model to MISO's planning toolkit represents another step towards better understanding and planning for future gas-electric system interactions

This chapter provides historical context for and details on current gas-electric initiatives at MISO in the realm of long-term system planning.[29]

Electric and Natural Gas Coordination Task Force

MISO's gas-electric coordination efforts originated in 2011 with a series of investigations into the ability of natural gas infrastructure to serve growing demand.[30] The findings from these analyses, published in 2012, spurred an ongoing conversation with MISO stakeholders and the natural gas industry. While MISO held preliminary meetings across the footprint to discuss gas-electric interdependency, the Federal Energy Regulatory Commission (FERC) planned its own set of regional discussions on the topic. The takeaways from these forums and the MISO zonal meetings signaled the need for a separate MISO stakeholder body to address gas-electric interdependency. In response, MISO and its stakeholders established the Electric and Natural Gas Coordination Task Force (ENGCTF) in October 2012.

Shortly after its formation, the task force initiated a process of gas-electric issue identification and prioritization. Cross-industry teams formed to draft Issue Summary Papers[31], intended to guide discussion within the task force and provide recommendations on high priority issues, including:

- System awareness and coordinated operations with the gas industry
- Cross-industry communications
- The misalignment of gas and electric industry market timelines

The ENGCTF also devoted a significant amount of time over the past few years to cross-industry education, increasing understanding between the gas and electric industries of each other's regulatory, business, operational and planning constructs. The group continues to provide a forum for discussion of key gas-electric topics.

Gas-Electric Coordination and Long-Term System Planning

While many of MISO's current gas-electric coordination efforts focus on operational or market design issues, some of the earliest aimed to better understand the mid- to long-range impact of regulatory, technological and economic developments on future gas-electric system interactions. Specifically, in late 2011, MISO commissioned EnVision Energy to study historical flows and future capacity availability on

[29] For more information on MISO's gas-electric coordination efforts, see https://www.misoenergy.org/StakeholderCenter/CommitteesWorkGroupsTaskForces/ENGCTF/Pages/home.aspx.
[30] For links to MISO-commissioned gas infrastructure study reports and summaries, see https://www.misoenergy.org/StakeholderCenter/CommitteesWorkGroupsTaskForces/ENGCTF/Pages/home.aspx.
[31] See https://www.misoenergy.org/STAKEHOLDERCENTER/COMMITTEESWORKGROUPSTASKFORCES/ENGCTF/Pages/home.aspx.

natural gas pipelines in the Midwest. The results of these analyses[32] highlighted the potential need for gas infrastructure build-out in the MISO North and Central Regions, in a scenario with increasing demand for gas from electric generators.

The issue of gas infrastructure adequacy was revisited by MISO in 2013. The new analysis featured an expanded study footprint, including the newly integrated South Region, and an enhanced methodology, adding a dynamic pipeline modeling component. Study findings indicated adequate pipeline capacity for the MISO footprint in the near term under a base-demand scenario, with localized exceptions in MISO's North and Central regions. These results were attributed to significant and fast-paced developments in the gas industry, including 1) new and increasing supplies from shale gas basins, driving major changes in pipeline flow patterns across the country, and 2) additions to and increasing interconnectivity of natural gas infrastructure. The study report also identified opportunities for future progress on gas-electric coordination, including several recommendations aligned with the goals of the ENGCTF.[33]

In addition to commissioning studies of long-term gas infrastructure adequacy, MISO also engaged in the Eastern Interconnection Planning Collaborative (EIPC) study of the gas-electric interface.[34] This effort spanned several years and encompassed four major targets:

- Target 1: Baseline assessment of electric-natural gas infrastructure in the study footprint
- Target 2: Evaluation of the capability of the natural gas systems to meet long-term gas demand
- Target 3: Evaluation of natural gas system contingencies
- Target 4: Review of operational/planning issues affecting the availability of dual-fuel generation

MISO was one of a group of planning authorities participating in the study, providing guidance on scope and methodology, with input from the ENGCTF.

At a high level, the EIPC study identified few issues of concern with respect to gas-electric interfaces in MISO, resulting from an ample and interconnected pipeline network throughout the footprint, as well as access to numerous gas producing basins. The study also concluded that increasing gas demand in the next five to 10 years, driven by coal retirements and sustained low gas prices, may call for additional efforts to ensure reliability for gas-fired generators in some parts of the MISO footprint.

Both the MISO-commissioned studies and the EIPC study examined electric and natural gas system interactions using iterative processes. First, a simulation of the electric system was carried out with static assumptions about gas system operations, producing a set of electric system results. Then, a simulation of the gas system was carried out with static assumptions about the electric system, producing a set of gas system results. This description is a simplified characterization of the modeling processes used in these studies, but the hand-offs described are inherent in modeling gas and electric system operations with separate tools.

While there are advantages to using separate gas and electric models to answer certain questions of gas-electric system operations, there may also be benefits to modeling dynamic system interactions. As MISO plans for a future with increasing reliance upon natural gas, it recognizes that new tools may be needed to understand and plan for the growing interdependency of the two systems.

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[32] See the Phase I study report, published in Feb. 2012, at https://www.misoenergy.org/Library/Repository/Communication%20Material/Key%20Presentations%20and%20Whitepapers/Natural%20Gas-Electric%20Infrastructure%20Interdependency%20Analysis_022212_Final%20Public.pdf. For the Phase II study, published in July 2012, see https://www.misoenergy.org/Library/Repository/Communication%20Material/Key%20Presentations%20and%20Whitepapers/Embedded%20Gas%20Units%20Infrastucture%20Analysis.pdf.

[33] See https://www.misoenergy.org/WhatWeDo/StrategicInitiatives/Pages/EPACompliance.aspx for links to the full study report, as well as the study report companion document.

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

Using PLEXOS for Gas-Electric Modeling at MISO

The PLEXOS Integrated Energy Model is an Energy Exemplar optimization platform for energy market simulation and analysis[35]. MISO has used the production cost functionality of the PLEXOS model (electric data only) for two major studies, including the Manitoba Hydro-Wind Synergy Study[36] and the Minnesota Renewable Energy Integration and Transmission Study (MRITS)[37].

The gas model is a relatively new addition to the Integrated Energy Model. Its initial release included state-level representation of gas production, storage, demand and transportation for the U.S. and Canada. The second iteration of the model disaggregated these elements into separate components, interconnected via hundreds of gas nodes. Future versions of the gas model may incorporate additional granularity, such as representation of gas contracts.

The outputs of production cost simulation for the gas portion of the model can be grouped into two main buckets:

- **Physical (congestion) metrics:** the duration, location and magnitude of pipeline congestion
    - For comparison, the electric-side outputs of the model include transmission line flows and binding hours
- **Economic (cost/price) metrics:** quantification of the cost to produce and transport gas; gas spot prices are provided at each gas node for every interval of the simulation
    - For comparison, the electric-side outputs of the model include locational marginal prices (LMPs)

The outputs for the electric model approximately parallel those of the gas model (see Figure 6.3-1) and are similar to the outputs of PROMOD, another production cost simulation tool used by MISO for long-term transmission planning. Gas and electric infrastructure interconnect in the Integrated Model via gas-fired electric generators.

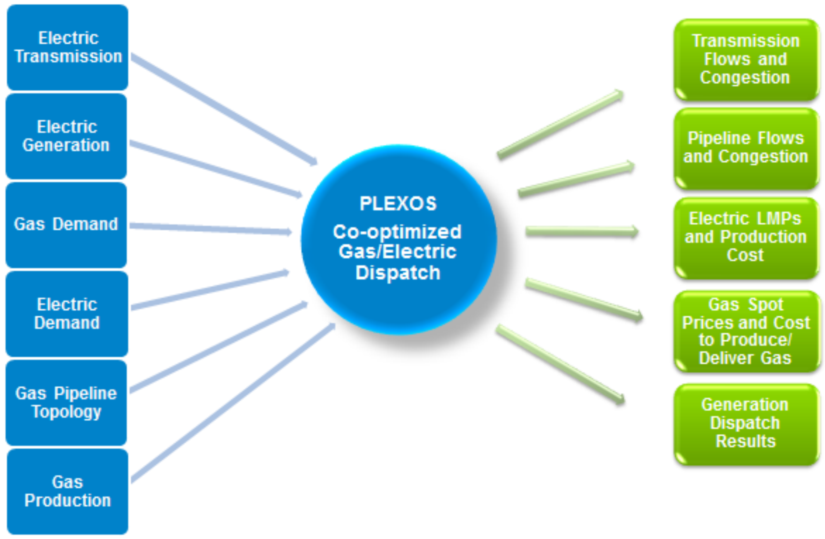


Figure 6.3-1: High-level inputs and outputs for co-optimized gas-electric dispatch in PLEXOS

[35] See http://energyexemplar.com/software/plexos-desktop-edition/.
[36] See: https://www.misoenergy.org/Library/Repository/Meeting%20Material/Stakeholder/Planning%20Materials/Manitoba%20Hydro%20Wind%20Synergy%20TRG/Manitoba%20Hydro%20Wind%20Synergy%20Study%20Final%20Report.pdf.
[37] See https://mn.gov/commerce/energy/images/final-mrits-report-2014.pdf.

The results of electric production cost modeling provide insights into long-term transmission system utilization and are used to inform transmission solution development in MISO's planning processes. Similarly, the outputs of integrated production cost modeling may be able to provide insights into long-term trends not only for electric infrastructure but also for gas infrastructure.

MISO's ongoing analysis of the Clean Power Plan (CPP)[38] incorporates this proof-of-concept gas-electric simulation tool and tests its potential to inform long-term gas infrastructure expansion needs. The application of the PLEXOS gas-electric model in MISO's study of the CPP is a first-of-its-kind effort and MISO acknowledges the significant learning curve associated with this endeavor. MISO plans to collaborate with and leverage the expertise of its stakeholders and the broader industry throughout the process.

[38] See Chapter 7.4: EPA Regulations – Clean Power Plan Draft Rule Study

6.4 Seasonal Resource Assessment

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

The finding showed that the projected capacity levels exceed the Planning Reserve Margin Requirement in both the 2014-2015 winter and 2015 summer seasons, with adequate resources to serve load.

Seasonal Assessment Methods

MISO studies multiple scenarios at varying capacity resource levels, expected demand levels and forced outage rates. In order to align with intra-Regional Transmission Owner (RTO) expected dispatch, only 1,000 MW above the MISO South load and reserve margin were counted toward aggregate margins at coincident peak demand in all of the projected scenarios.

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

Demand

Based on 20 years of historic actual load data, MISO calculates a Load Forecast Uncertainty (LFU) value from statistical analysis to determine the likelihood that actual load will deviate from forecasts. A normal distribution is created around the 50/50 forecast based on a standard deviation equal to the LFU of the 50/50 forecast. This curve represents all possible load levels with their associated probability of occurrence. At any point along the curve it is possible to derive the percent chance that load will be above or below a load value by finding the area under the curve to the right or left of that point. MISO chooses the 90th percentile for the High Load scenarios. For more information regarding this analysis, refer to the Planning Year 2015 LOLE Study.

Demand Reporting

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

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

2014-2015 Winter Overview

For planning year 2014-2015, MISO's Planning Reserve Margin Requirement (PRMR) was 14.8 percent. For the 2014-2015 winter peak hour, MISO expected adequate resources to serve load, with a NERC-reported base projected reserve margin of 43.2 percent, which far exceeds the PRMR of 14.8 percent. The winter scenarios project the reserve margin to be in the range of 35.0 to 45.1 percent (Figure 6.4-1).

MISO's 50/50 coincident peak demand for the 2014-2015 winter season was forecasted to be 103,238 MW including transmission losses, with 147,793 MW of capacity to serve MISO load during the 2014-2015 winter season. Excluded from the capacity are 3,811 MW of MISO South resources to align with the 1,000 MW intra-RTO contract path.

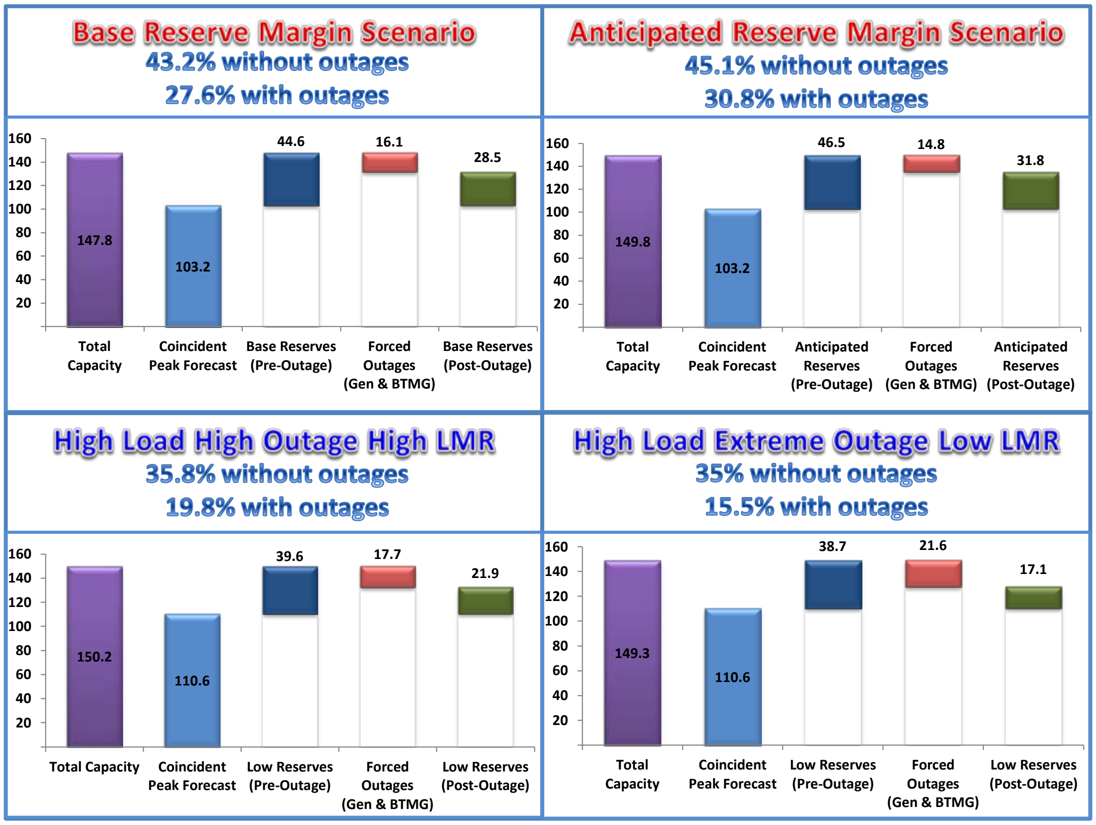


Figure 6.4-1: Winter 2014-2015 Projected Reserve Margin scenarios (GW)

2014-2015 Winter Rated Capacity

For the 2014-2015 winter season, MISO projected 147,793 MW of existing certain capacity to serve MISO load during the winter. The capacity includes 1,614 MW of Behind-the-Meter Generation (BTMG) and 3,645 MW of Demand Resource (DR) programs, with 2,022 MW of Net Firm Imports. MISO expected 1,070 MW of wind capacity to be available to serve load for the winter.

MISO arrived at the Winter Rated Capacity value by reducing the Nameplate Capacity of its market footprint by multiple variables. The majority of the derates expected at-peak are due to resource interconnection limitations of 6,160 MW; thermal unit winter output reductions of 4,796 MW; and reductions due to the Effective Load Carrying Capability of wind resources of 10,052 MW. Capacity from the South, equal to its load and reserve margin requirement, was included in the regional total. Additionally, it assumed that 1,000 MW of excess capacity transferred to the North/Central region of the footprint.

For more information regarding methodology and assumptions of the Winter Rated Capacity, refer to Appendix A.2 of the 2014-2015 Winter Resource Assessment.

Winter Reserve Margin Scenarios

MISO's projected 2014-2015 MISO Winter Rated Capacity varies by scenario (Figures 6.4-2 through 6.4-6). MISO chose the 90th percentile of the normal distribution around a 50/50 load forecast for the High Load scenarios, which was 110,597 MW for the 2014-2015 winter. For more information regarding each scenario, refer to Appendix A.3 of the 2014-2015 Winter Resource Assessment.

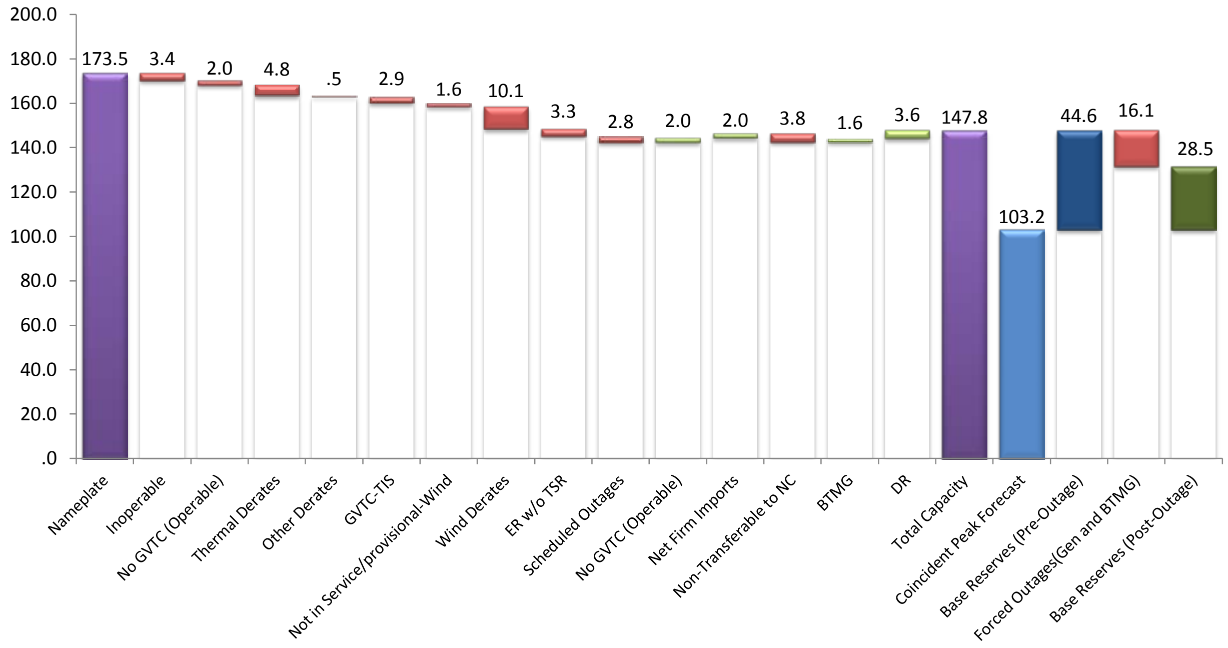


Figure 6.4-2: 2014-2015 Winter Rated Capacity projected base scenario (GW)

The Anticipated Scenario contains additional assumptions (Figure 6.4-3). MISO expects that any Energy Resource without firm point-to-point Transmission Service Rights will serve load locally, termed Energy Only. The portion of Energy Only from the MISO South region is excluded from the calculation to align with 1,000 MW contract path limitation.

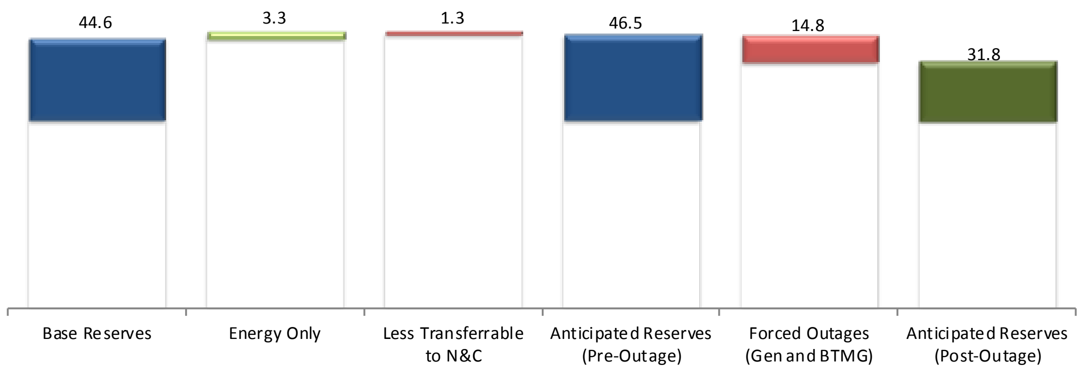


Figure 6.4-3: 2014-2015 Winter Rated Capacity projected anticipated scenario (GW)

In real-time, during normal operating conditions, MISO must carry Operating Reserves above load to maintain system reliability. The amount of Operating Reserves required to clear on a daily basis for the 2014/2015 winter season was 2,400 MW, which is called on as a last resort before load shed (Figure 6.4-4). These reserves are made up of a combination of Regulating Reserves, Spinning Reserves and Supplemental Reserves.

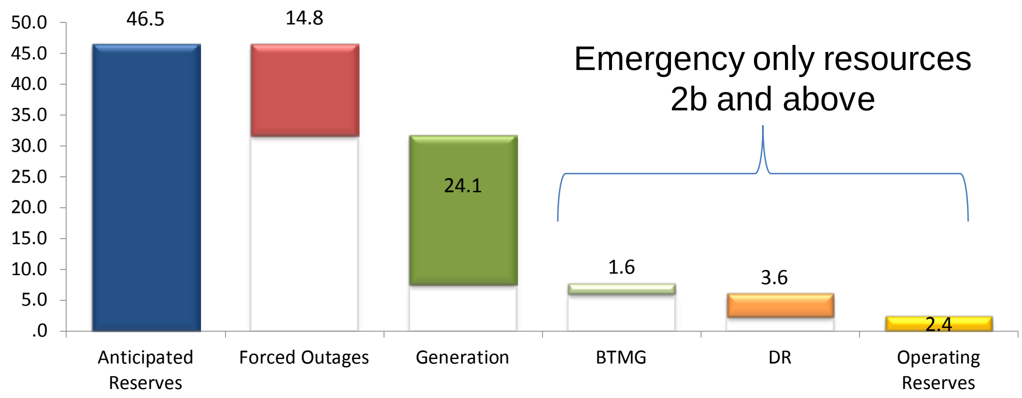


Figure 6.4-4: 2014-2015 Winter Rated Capacity projected anticipated scenario reserves (GW)

The High Demand, High Outage Scenario has added assumptions (Figure 6.4-5). Beginning with the Anticipated Reserves from the Anticipated Scenario (Figure 6.4-3), the load is increased to show the higher load from a 90/10 forecast. A higher forced outage rate is assumed, using the highest historical forced outage rate applied to the capacity resources available. An extreme forced outage rate is applied to the Extreme Scenario (Figure 6.4-6), based on information from the polar vortex of the 2013-2014 winter.

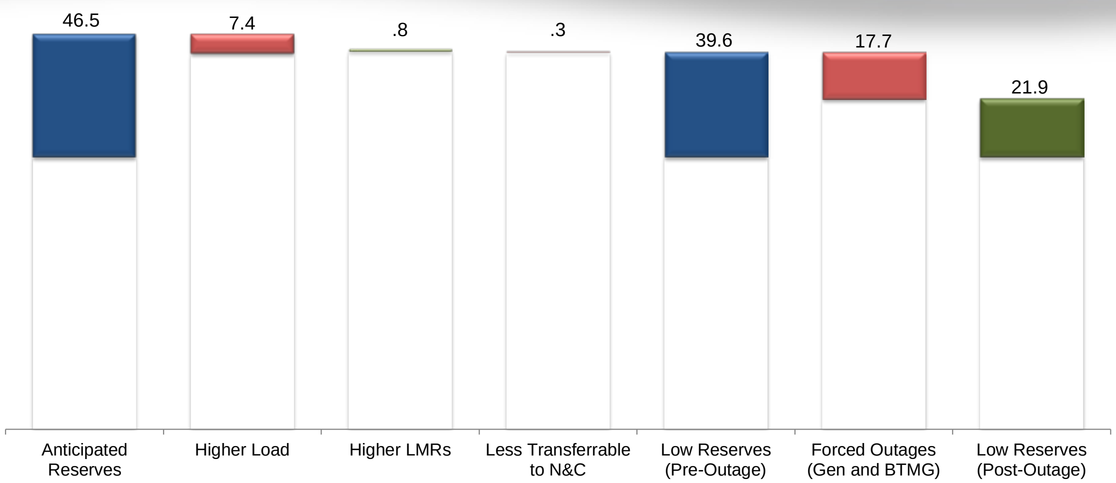
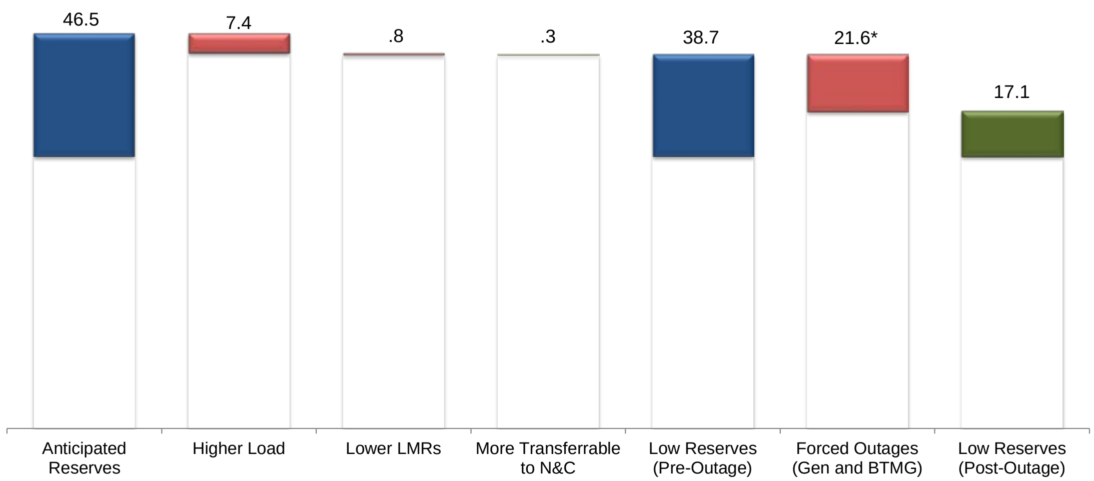


Figure 6.4-5: Winter Rated Capacity projected high-demand, high-outage scenario (GW)



*Based on Polar Vortex Information and the amount of non-transferrable capacity to MISO North Central

Figure 6.4-6: Winter Rated Capacity projected extreme scenario (GW)

2015 Summer Overview

For planning year 2015-2016, MISO's PRMR is 14.3 percent, which is 0.5 percentage points lower than the previous year's requirement of 14.8 percent. During the 2015 summer peak hour, MISO expected adequate resources to serve load, with a NERC-reported base projected reserve margin of 18.0 percent, which exceeds the requirement of 14.3 percent by 3.7 percentage points. The summer scenarios project the reserve margin to be in the range of 14.4 to 20.1 percent (Figure 6.4-7).

MISO's 50/50 coincident peak demand for the 2015 summer season was forecasted to be 127,319 MW including transmission losses, with 150,270 MW of capacity to serve MISO load. Excluded from the capacity are 3,806 MW of MISO South resources to align with the 1,000 MW intra-RTO contract path.

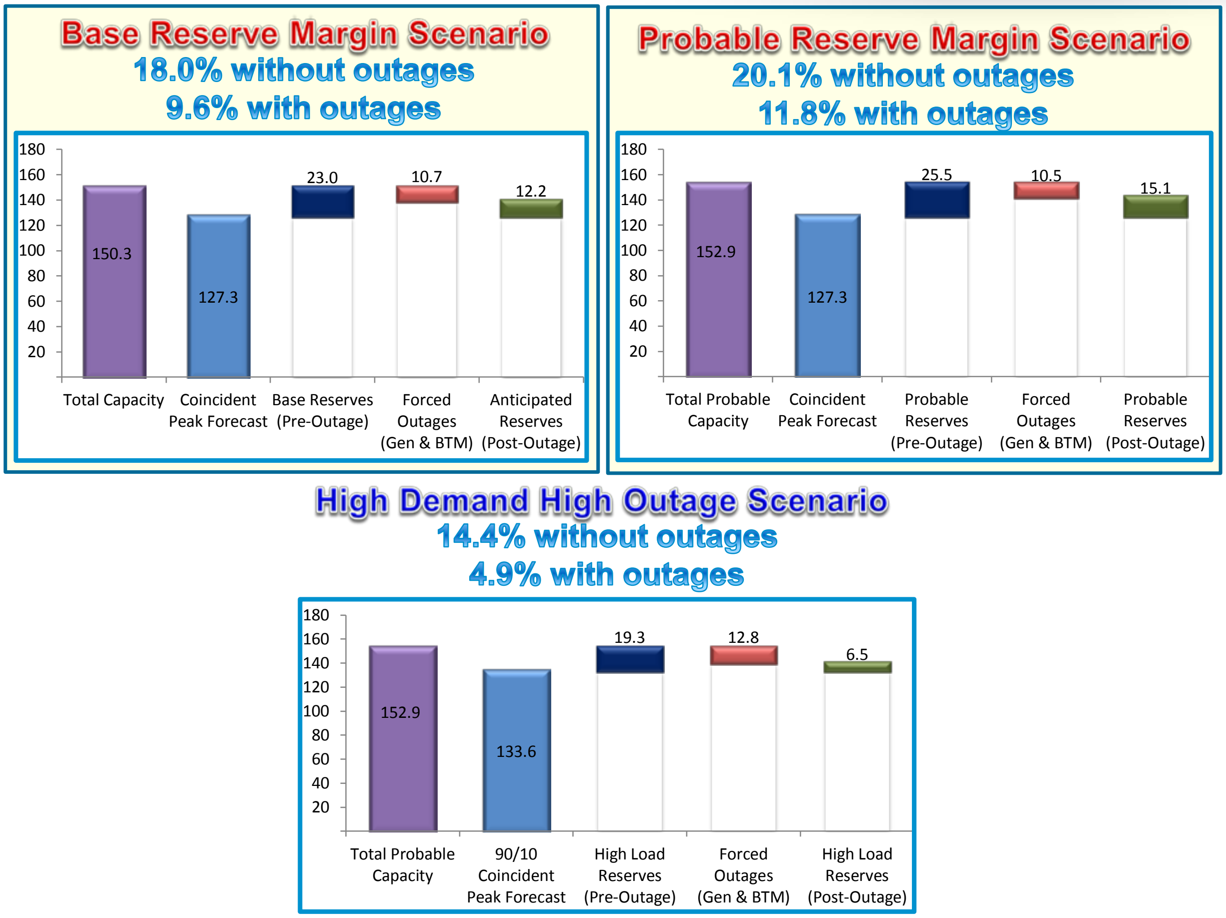


Figure 6.4-7: Summer 2015 Projected Reserve Margin scenarios

2015 Summer Rated Capacity

For 2015, MISO projected 150,270 MW of capacity to serve MISO load during the 2015 summer season. The capacity includes 4,413 MW of BTMG and 5,938 MW of DR programs, while removing 56 MW of Net Firm Exports. MISO expected 1,325 MW of wind capacity to be available to serve load this summer. Capacity from the South equal to its load and reserve margin requirement was included in the regional total. Additionally, 1,000 MW of excess capacity was assumed to be transferred to the North/Central region of the footprint.

MISO arrived at the Summer Rated Capacity value by reducing the Nameplate Capacity of its market footprint by multiple variables. The majority of the derates expected at-peak are due to resource interconnection limitations (3,616 MW); thermal unit summer output reductions (11,765 MW); and reductions due to the Effective Load Carrying Capability of wind resources (9,534 MW). Also, any MISO South capacity over the total of South Load, South reserve margin requirement, and 1,000 MW of contract path was not included in the regional value. This means that 3,806 MW of MISO South excess capacity was excluded from the calculation to align with 1,000 MW contract path limitation.

Reserve Margin Scenarios

MISO's projected 2015 MISO Summer Rated Capacity varies by scenario (Figures 6.4-8 through 6.4-10). MISO chose the 90th percentile of the normal distribution around a 50/50 load forecast for the High Load scenarios, which was 133,599 MW for the 2015 summer. For more information regarding each scenario, refer to the MISO 2015 Summer Resource Assessment.

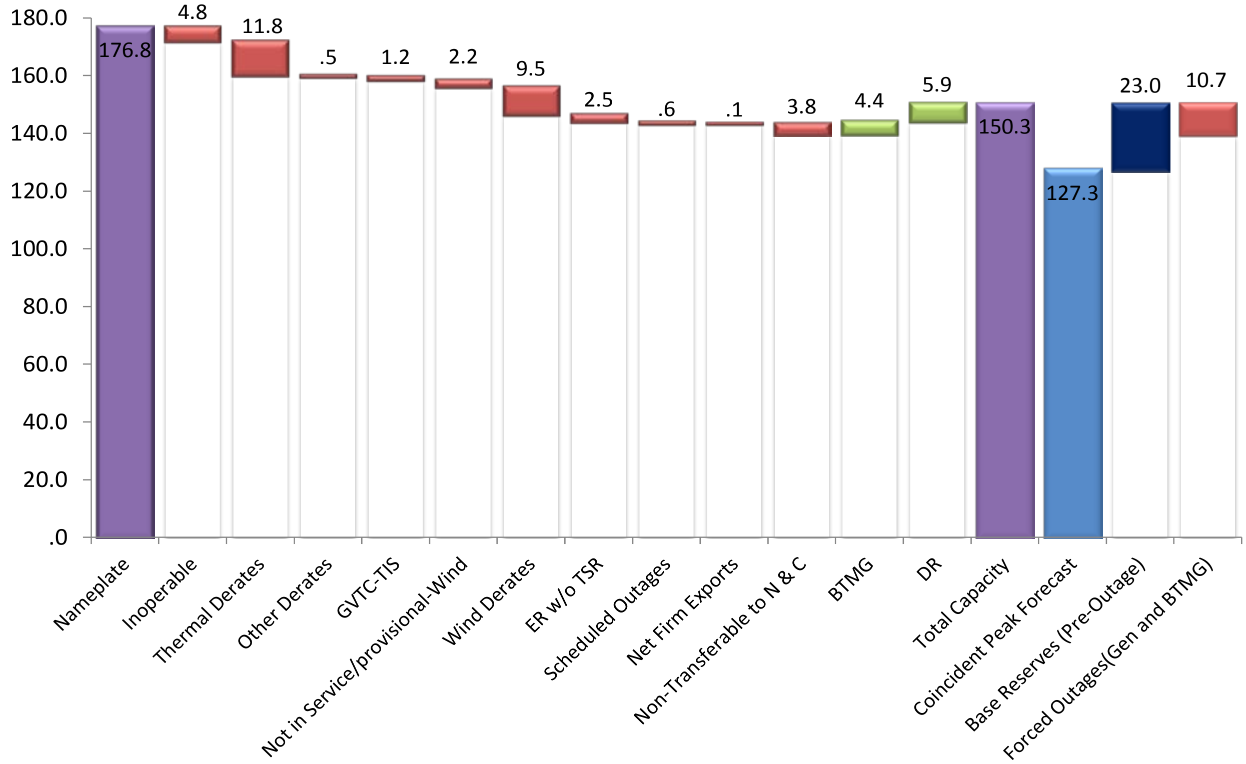


Figure 6.4-8: 2015 Summer Rated Capacity Projected Base Scenario (GW), showing the reduction from installed nameplate resource capacity. This includes derates and transmission limited resources.

The Probable Scenario uses additional assumptions (Figure 6.4-9). MISO expects that any Energy Resource without firm point-to-point Transmission Service Rights will serve load locally, termed Energy Only. The portion of Energy Only from the MISO South region is excluded from the calculation to align with 1,000 MW contract path limitation. In addition, 0.2 GW of capacity is included from provisional wind that is connected to the system but with an incomplete interconnection process. Finally, any units designated as System Support Resources (SSR) or Under Study through the Attachment Y process are considered available, as well as units that received a waiver from participating in the Planning Resource Auction but will still run for the summer.

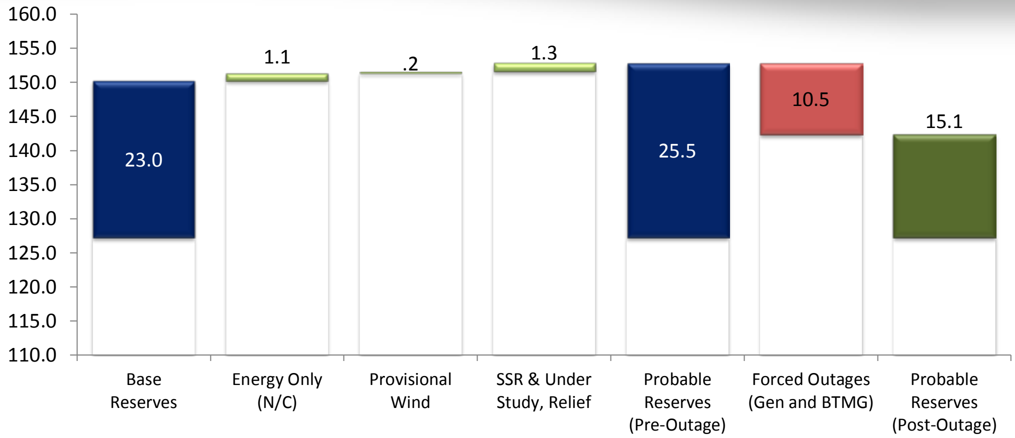


Figure 6.4-9: 2015 Summer Rated Capacity Projected Probable scenario (GW), showing added capacity assumptions

The High Demand, High Outage scenario has added assumptions (Figure 6.4-10). Beginning with the Probable Reserves from the Probable Scenario (Figure 6.4-9), the load is increased to show the higher load from a 90/10 forecast. Also a higher forced outage rate is assumed, using the highest historical forced outage rate applied to the capacity resources available.

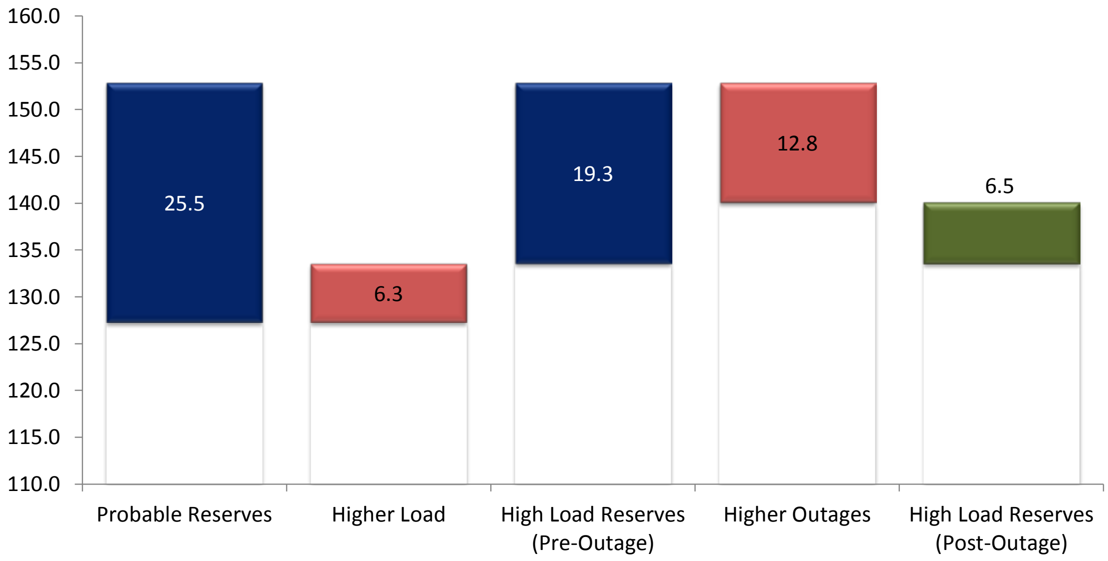


Figure 6.4-10: Summer Rated Capacity Projected High Demand, High Outage Scenario [GW]

2015 Summer Risk Assessment

MISO performs a probabilistic assessment on the region to determine the percent chance of utilizing Load Modifying Resources and Operating Reserves or having to curtail firm load. A risk profile is generated from this analysis (Figure 6.4-11).

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

The chance of realizing an event is where the risk profile intersects the event range (Figure 6.4-11). As shown, the probabilistic analysis indicated a 74.1 percent chance of MISO calling a Maximum Generation Emergency Event Step 2b to access Load Modifying Resources; a 7.8 percent chance of initiating further steps to access Operating Reserves; and a 2.7 percent chance of curtailing firm load during the 2015 summer peak hour.

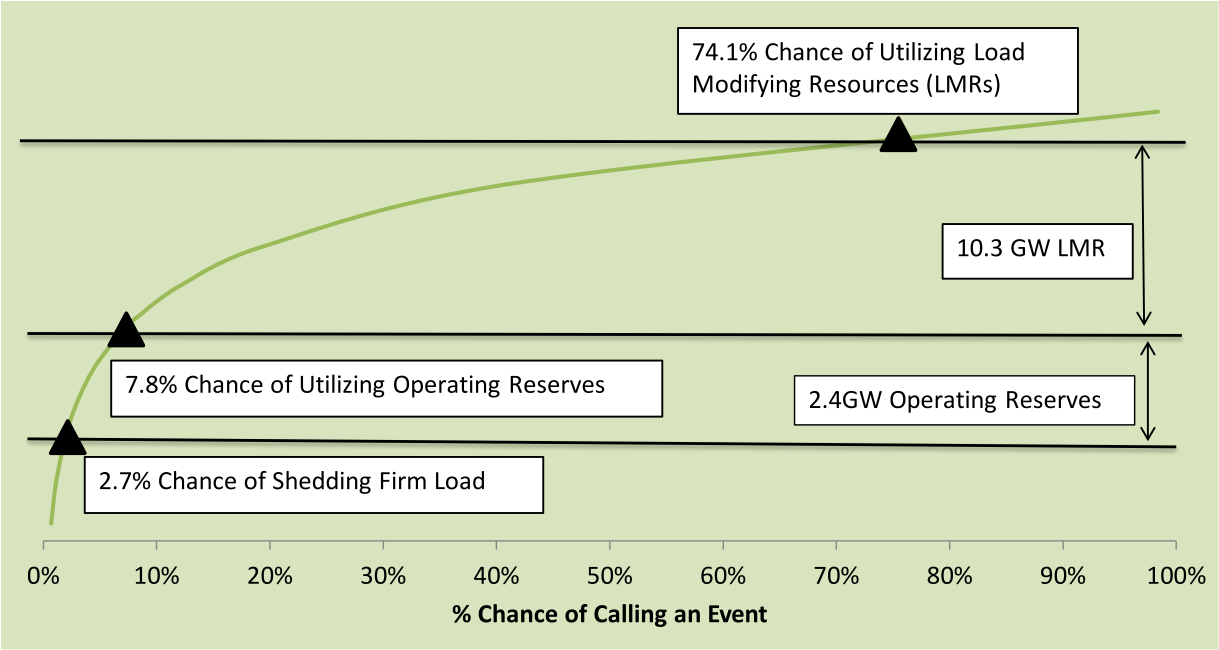


Figure 6.4-11: MISO 2015 Summer Chance of Initiating Maximum Generation Emergency Step 2b or higher at Forecasted Probable Reserve Margin

The reserves available in the Probable Scenario are shown after forced outages are applied, showing the amount of Generation, BTMG, DR and Operating Reserves expected (Figure 6.4-12). In real-time, during normal operating conditions, MISO must carry Operating Reserves above load to maintain system reliability. The amount of Operating Reserves required to clear on a daily basis for the 2015 summer season was 2,400 MW, which is called on as a last resort before load shed. These reserves are made up of a combination of Regulating Reserves, Spinning Reserves and Supplemental Reserves.

For more information regarding the risk assessment methodology, assumptions and variables, refer to Appendix A.1 of the MISO 2015 Summer Resource Assessment.

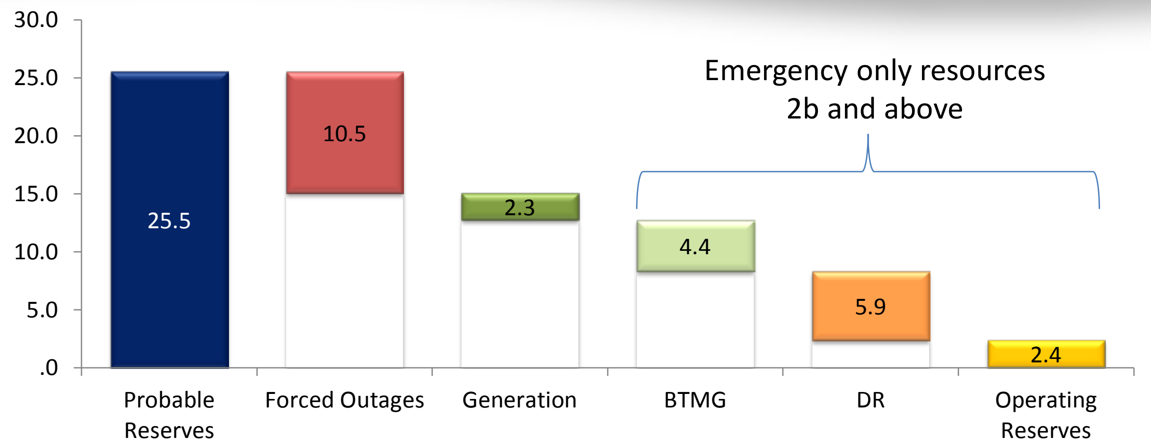


Figure 6.4-12: Summer Rated Capacity Projected Probable Reserves (GW)

MISO Summer Rated Capacity Methodology

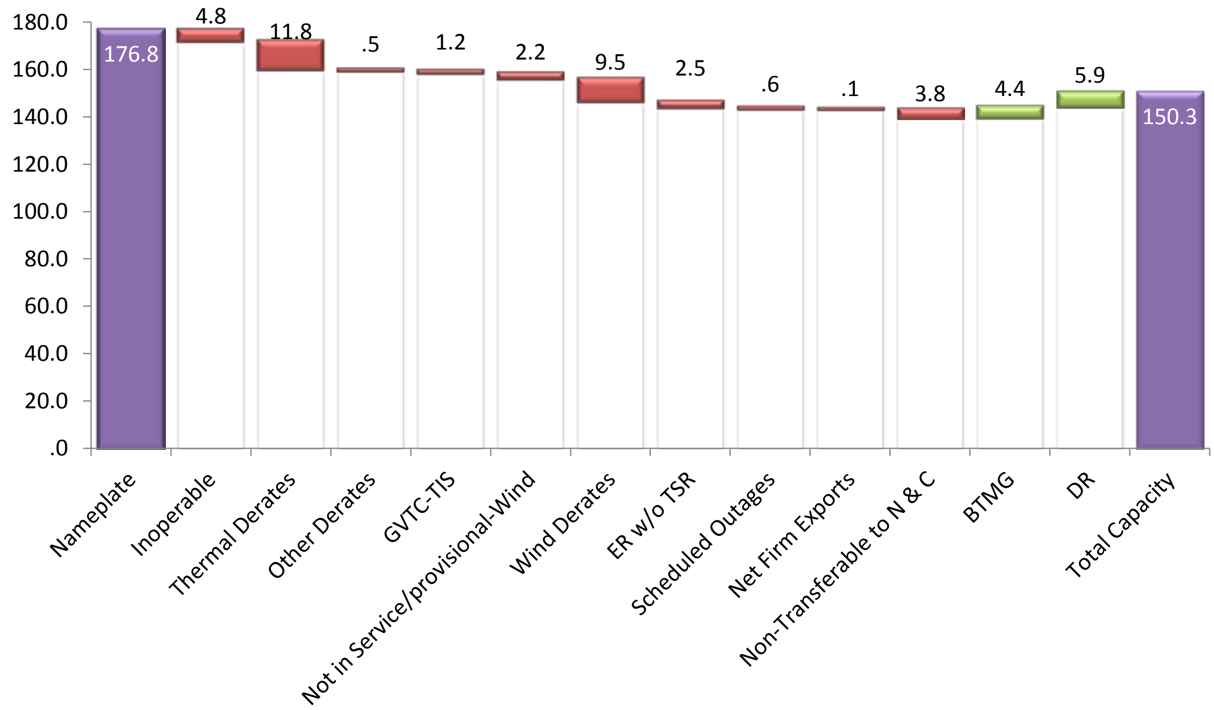


Figure 6.4-13: MISO 2015 Summer Rated Capacity waterfall chart, Base Scenario (GW)

The calculation of MISO Summer Rated Capacity resources is easier to describe by separating into 13 parts (Figure 6.4-13) and as described in the following list. Separation of the Winter Rated Capacity is similar, with additional details found in the MISO 2014-2015 Winter Resource Assessment.

1. *Nameplate capacity* is the summation of the maximum output from the latest commercial model. This reflects the amount of registered generation available internal to MISO.
2. *Inoperable resources* is the summation of approved mothballed or retired units determined through the Attachment Y process, which are still represented in the latest commercial model.
3. *Thermal derates on-peak* is the summation of differences in unit nameplate capacities and the latest Generator Verification Test Capacity (GVTC) results, excluding inoperable resources.
4. *All other derates* is the summation of differences in non-wind intermittent resource nameplate capacities and the resource averages of historical summer peak performance, excluding inoperable resources.
5. *Transmission-limited resources* is the summation of differences in GVTC and the unit's Total Interconnection Service (TIS) rights based on latest unit deliverability test results. Transmission-limited resources for wind is the summation of differences in nameplate capacity and TIS.
6. *Not-in-service units and provisional wind*: Units that are registered in the latest commercial model, but are not in service yet; the wind units that are connected to the system but their interconnection process is not completed yet.
7. *Wind derates on-peak* is the summation of the differences in wind unit Nameplate Capacities and the unit wind capacity credit, which is determined based on the Effective Load Carrying Capability of wind. This excludes Inoperable Resources and Transmission-Limited MWs.
8. *Energy-only* resources are the ones that have Energy Resource Interconnection Service (ERIS) without a firm point to point Transmission Service Right.
9. *Scheduled maintenance*: Scheduled generator outages from June 1, 2015, through August 31, 2015, were pulled from MISO's Control Room Operator's Window (CROW) outage scheduler on March 17, 2015. The data pulled met the following criteria: 1. Mapped to the latest commercial model; 2. Outage Request Status is equal to Active, Approved, Pre-Approved, Proposed, Study, or Submitted; 3. Request priority is equal to planned; 4. Equipment request type is equal to Out of Service (OOS) or "Derated To 0 MW."

   In order to calculate the expected scheduled outages on peak, MISO calculates the amount of outages on a daily basis assuming that if a unit is out for as little as one hour, that unit will be out for that entire day. The highest amount of outages during the month of July is assumed to be equal to the amount of outage during summer peak conditions.

   This calculation amounts to an expected scheduled maintenance of 574 MW.
10. MISO anticipated the net firm interchange to be exporting 56 MW for the 2015 summer.
11. 3,806 MW of MISO South resources were excluded from the available capacity to align with 1,000 MW intra-RTO contract path.
12. *Behind-the-Meter Generation* is the summation of approved and cleared load-modifying resources identified as Behind-the-Meter Generation through the Resource Adequacy (Module E) process. Based on the planning year 2015-2016 Planning Resource Auction, 4,413 MW of BTMG cleared to be available for the 2015 summer season.
13. *Demand resource*: MISO currently separates contractual demand resource into two separate categories, Direct Control Load Management (DCLM) and Interruptible Load (IL).

    DCLM is the magnitude of customer service (usually residential) that can be interrupted at the time of peak by direct control of the applicable system operator. DCLM is typically used for "peak shaving." In MISO, air conditioner interruption programs account for the vast majority of DCLM during the summer months.

    IL is the magnitude of customer demand (usually industrial) that, in accordance with contractual arrangements, can be interrupted at the time of peak by direct control of the system operator (remote tripping) or by action of the customer at the direct request of the system operator. The amount of registered and cleared load-modifying resources identified as demand resource through the Resource Adequacy (Module E) process is 5,938 MW for the 2015 summer season.

Book 3
Policy Landscape Studies

Chapter 7
Regional Studies

7.1 Voltage and Local Reliability Planning Study

Under the MTEP14 planning cycle, MISO, in collaboration with stakeholders, performed a study of the South Region load pockets. The study was to determine whether or not there are transmission alternatives that may lower overall cost-to-load by reducing Voltage and Local Reliability (VLR) resource commitments necessary to maintain system reliability. MISO identified such transmission upgrades necessary to maintain reliability that are cost effective by providing production cost savings in excess of their cost. More specifically, MISO recommends network upgrades with an estimated cost of $300 million that provide production cost savings of about $498 million on a 20-year present value basis. This analysis was an outcome of the study of reliability issues driven by new firm load additions, existing and planned future generation with signed interconnection agreements and confirmed generation retirements via Attachment Y process.

Lake Charles Trms Project $187 M 2018

- Sulphur Lane 500kV Switching Station
- New 500/230 kV Bulk Substation
- 1200MVA, 500/230 kV New Sub transformer
- Sulphur Lane - New Sub New 500 kV line
- Bulk Station - Carlyss 230 kV line
- Carlyss –Graywood 230 kV line
- Carlyss Reconfigure existing substation

*On a 20 year net present value basis

MTEP15 Reliability $113 M

Texas $56 M

S. Beaumont New 3rd Trf 138/69 kV	2016
Egypt - Panorama 138 kV Upgrade	2017
Sabine - Port Neches 1 138 kV Upgrade	2017
S. Beaumont- Carrol St-1 138kV Upgrade	2017
S. Beaumont- Carrol St-2 138kV Upgrade	2017
Sabine - Port Neches 2 138 kV Upgrade	2018
Cleveland - Tarkington 138kV Upgrade	2018
Cypress New 500/138kV Transformer	2020

Louisiana $57 M

Carlyss - Boudoin 230 kV Line upgrade	2016
Fancy Point 2nd 500-230 kV Trf	2017
Goosport Substation 138 kV Project	2017
Bayou Verret– Capacitor Bank	2017
Vacherie - Waterford 230kV Upgrade	2018

Figure 7.1-1: List of cost effective Reliability Network Upgrades recommended in MTEP15

The VLR study additionally looked at mitigating all transmission issues resulting from potential shutdown of approximately 7,200 MWs of VLR units. Transmission costs for mitigating all such issues are estimated to be more than $1.8 billion. When compared against the 2014 year cumulative make whole payments for these VLR units of approximately $70 million, it was concluded that the network upgrades are not cost effective.

The VLR study further investigated potential scenarios involving the shutdown of a subset of VLR units without re-dispatching around transmission constraints using additional VLR units. Various scenarios studied resulted in different transmission issues. Transmission costs for mitigating these issues in the various scenarios are estimated to be in the range of $23.5 million to $1.8 billion. Once again, it was concluded that these network upgrades are not cost effective.

During the study process, MISO received an overwhelming stakeholder feedback that production cost savings was the most appropriate metric to evaluate benefits of eliminating VLR costs, which aligns with the benefit metric of MISO Market Congestion Planning Study (MCPS). Further, recognizing the uncertainties in the region on potential size and locations of future generation additions, retirements and new load growth, stakeholders provided extensive feedback that led to formulation of four futures. These are:

- Business as Usual (known out-year load growth, fuel prices, generation additions and retirements)
- South Industrial Renaissance (modeling increase in projected load growth)
- Generation Shift (modeling future age related generation retirements despite lack of firm notifications)
- Public Policy (modeling future RPS goals and standards in addition to age related generation retirements)

Given the breadth of uncertainties successfully captured within the futures used in economic studies, the analysis of understanding the benefits of eliminating or reducing VLR generation commitments was appropriately carried into the MTEP15 MCPS. Please refer to MTEP report Chapter 5.3, for further information on the MCPS.

Introduction

The southern load pockets contain a significant amount of generating units but a lack of quick-start units. By definition, load pockets have limited import capability, limiting the choices system operators have to keep the system secure. As such, generating units necessary to maintain reliability are committed for operation in advance of system events beyond the next contingency, even if a more economical generator is available to dispatch. Complicating the dispatch selection are factors such as minimum run time, cold lead time and minimum down times (up to three days for some units). These out-of-market commitments ensure that adequate generation is online to avoid firm load shed following the first contingency because no quick-start units are available that could be brought on post-contingency. Maintenance and forced outages further complicate the unit commitment algorithm. These factors lead to VLR-triggered resource commitments in the southern load pockets, which in turn leads to higher production costs.

MISO's transmission planning process focuses on minimizing the total cost of delivered power to consumers. Therefore, in 2014, MISO began a targeted planning study to ascertain whether there are cost-effective transmission alternatives to serve load at a lower overall cost by eliminating or reducing VLR-triggered resource commitments. The variable operating costs of these generation resources are currently higher than other market alternatives and their dispatch results in an increase in production cost. The study hypothesis was that the incremental costs may be significant enough to support the development of transmission upgrades as a more economic means of reliably serving load.

This study also considered upgrades identified through other processes during MTEP14. Additionally, the study considered mitigation options such as generation, demand-side and transmission solutions consistent with planning provisions under Attachment FF of the MISO tariff. Identified transmission alternatives were evaluated for any associated adjusted production cost benefits compared to current and predicted VLR unit commitments. MISO identified upgrade recommendations during the second quarter of 2015.

This planning study focused on the MISO South region, which includes parts of Louisiana and Texas.

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

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

Deliverables

This study produced the following deliverables:

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

The study began during the MTEP14 planning cycle and took into consideration any upgrades identified for recommendation within MTEP14 (Table 7.1-1). Transmission upgrades determined to be cost-effective alternatives to VLR commitments will be recommended as projects for approval by the MISO Board when sufficient analysis and stakeholder vetting has occurred to establish the business case. The study went through four phases before project recommendations were issued.

Task	Completion
Model development	May 2014
Reliability Analysis	June–Aug 2014
Solution Identification	Aug.–Nov. 2014
Economic Assessment	Nov. 2014–April 2015
Project Recommendations	2015 Q2

Table 7.1-1: VLR study schedule

Study Approach

Base Models

MTEP14 reliability and economic planning models were used for this study. The reliability assessment included steady-state and dynamics analyses for the 2019 and 2024 summer peak and shoulder load conditions. Economic assessment of preferred transmission solutions were performed using the latest available PROMOD models under the Market Congestion Planning Study (MCPS) process. Simulations were performed for the 2019, 2024 and 2029 timeframes to compute the economic value of transmission solutions.

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

Industrial Renaissance Models

Additional Models were developed due to the anticipated industrial load growth in the load pockets. The 2024 summer peak model was adjusted to match the load forecast submitted into Module E. This includes scaling up load in the south as well as adding new loads in industrial load centers like Lake Charles, Baton Rouge and the Sabine area. The Generation was adjusted accordingly, following the operational guides for each load pocket, to match the new load. The load increase was approximately 500 MW in the Amite South load pocket and 1,500 MW in the WOTAB load pocket.

Identification of System Limitations

Using the powerflow and dynamics models, the transmission system was analyzed to identify potential system limitations that may result due to VLR generators not being committed.

A. Review of VLR operating guides: At the outset, available operating guides were reviewed to inform prioritization of VLR units for assessment. In general, units that have incurred the highest VLR costs were the initial focus.
B. Study region: The study region comprised the entire MISO South region, which includes EES, Entergy Arkansas, Cleco Power, Southern Mississippi Electric, Louisiana Generating, Lafayette Utilities System and Louisiana Energy and Power Authority. Additionally, first-tier neighboring companies including SOCO, Tennessee Valley Authority, AECI and Southwestern Power Pool were monitored for potential impact. Contingencies assessed include the set of planning events within the study region consistent with those required under NERC Standard TPL-001-4. Any additional contingencies dictated by standing operating guides were also evaluated as necessary. Facilities 100 kV and above in the study region were monitored consistent with ongoing MTEP14 evaluations.
C. Analyses: Steady-state thermal and voltage, voltage stability and angular stability analyses were performed across the study region.

Identification of Alternative Solutions

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

Economic Assessment of Transmission Benefit

A. Economic evaluation: MISO utilized Ventyx PROMOD V11.1 to perform an economic evaluation of the preferred transmission solutions identified in the reliability analysis of VLR study. The

Business as Usual future model, developed through the Planning Advisory Committee (PAC), for 2024 and 2029 was used to determine the 20-year Net Present Value (NPV) of benefits for the preferred transmission solutions. The economic model was built starting with the base data provided by Ventyx, the software vendor. Ventyx creates and compiles this data from publicly available information and their proprietary sources and processes. Economic analysis performed on the projects identified in the study showed that $300 million in network reliability upgrades resolve an appreciable amount of VLR commitments while realizing $498M in production cost savings to the MISO South region over a 20-year period.

B. Results obtained include:
   - Comparison of alternatives including existing VLR commitments, alternative generation options and transmission upgrade options
   - Benefit-to-cost ratios for preferred solutions
   - Comparison of benefits against existing Market Efficiency Planning (MEP) criteria

C. Potential generator retirements: Consideration was given to identifying, for informational purposes, additional costs associated with possible future retirement of units under study. These costs will not be used in the benefits calculation needed for classifying solutions as MEP per the MISO tariff.

Project Categorization and Recommendations

The intent of the study was to identify alternatives that allow reliable performance of the transmission system at a lower overall cost to loads. System upgrades identified through the reliability assessment were evaluated for their economic value and to determine if they are cost-effective alternatives to VLR generation commitments. Results of the economic assessment were evaluated using existing Market Efficiency Project criteria to determine cost allocation of the upgrades. Projects will be recommended when a business case has been developed that shows benefits commensurate with the costs. The MTEP15 Market Congestion Planning Study South (MCPS) will further evaluate the transmission solution ideas identified in the reliability analysis of VLR study against a set of future scenarios developed in collaboration with the MISO stakeholders capturing a variety of economic and policy conditions as opposed to the least-cost plan under a single scenario. While the best transmission plan may be different in each policy-based future scenario, the best-fit transmission plan — or most robust — against all these scenarios should offer the most value in supporting the future resource mix.

VLR Commitment Cost

The planning study focused on the MISO South region, which included parts of Louisiana and Texas. The load pockets in this area are Amite South, Down Stream of Gypsy (DSG), West of the Atchafalaya Basin (WOTAB), and Western (Figure 7.1-2). The combined load for these areas in the 2024 base model is greater than 16,000 MW. The VLR units listed in the operation guides for these areas have a total capacity of about 10,850 MW.

VLR units in the load pockets that were considered for the study were:

- Amite South: Waterford (1, 2 and 4), Little Gypsy (1-3), Union Carbide (1-4) and Oxy (1-4)
- DSG: Nine Mile (3-5) and Michoud (2 and 3)
- WOTAB: Nelson (4 and 6), Sabine (1-5) and Cypress (1 and 2)
- Western: Frontier (1 and 2), San Jacinto (1 and 2) and Lewis Creek (1 and 2)

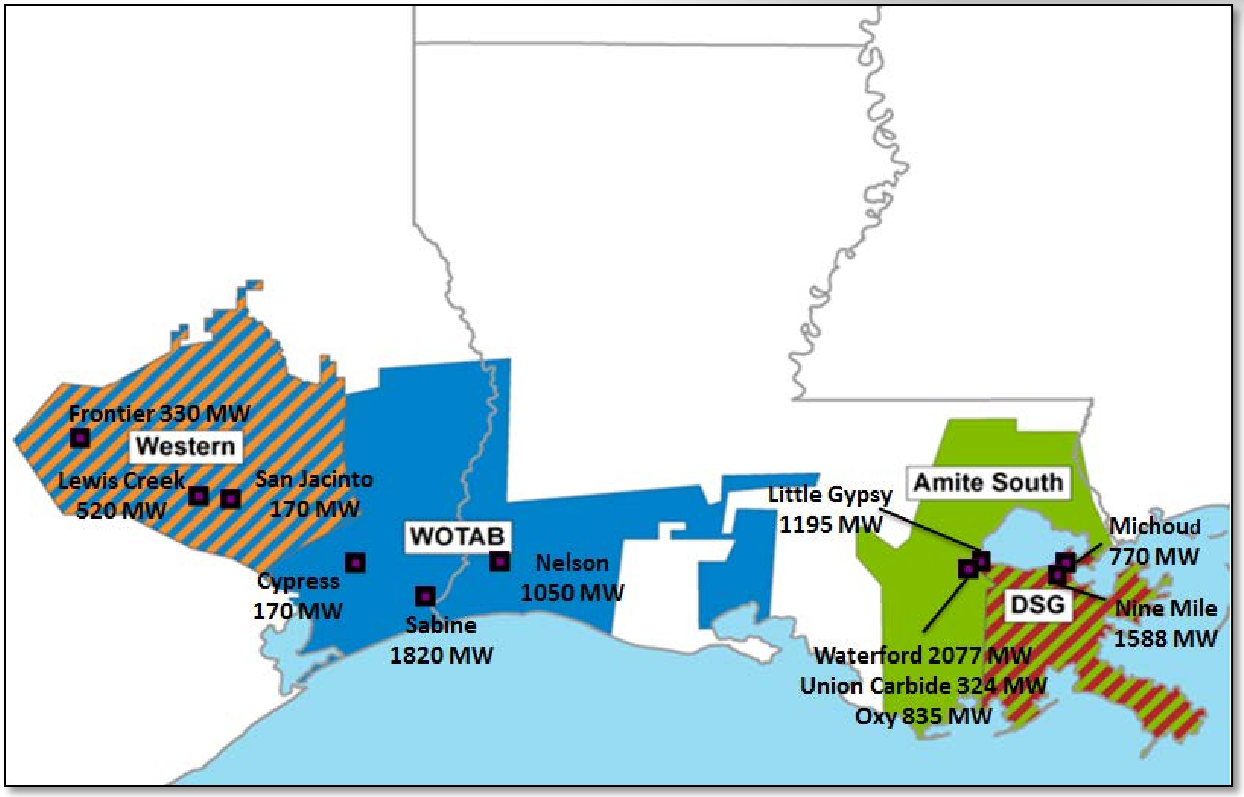


Figure 7.1-2: MISO South load pockets with available VLR units

The Amite South area encompasses all of Louisiana east of Baton Rouge, which includes the Down Stream of Gypsy (DSG) area. DSG is Entergy's service area downstream of the Little Gypsy generating plant and includes the New Orleans metro area.

The West of the Atchafalaya Basin (WOTAB) encompasses the southwest portion of the Entergy footprint including a portion of Texas and Louisiana. It also includes Western Region, which is the portion of Entergy's service area west of the Trinity River.

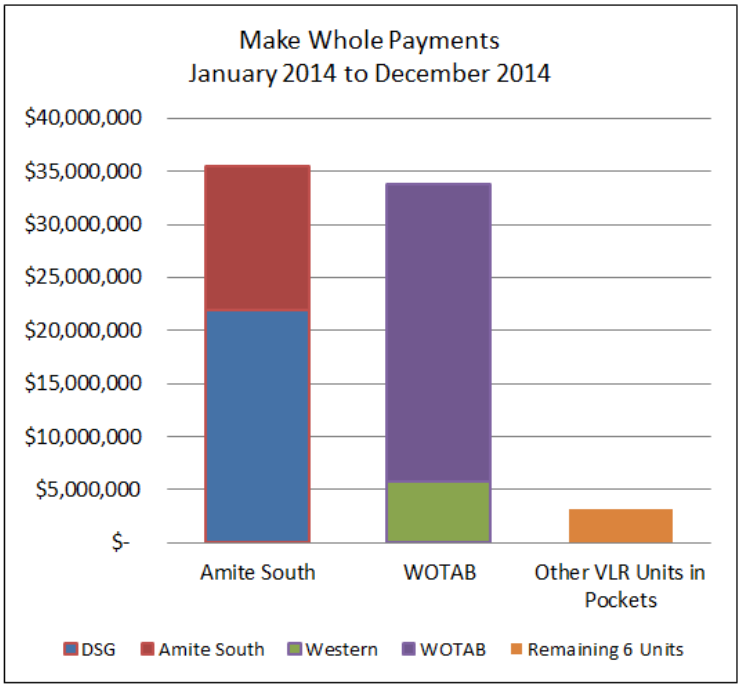
The study concentrated on the most expensive and frequently committed units. Make Whole Payments (MWP) in the pockets were aggregated and the data of individual units was used to make a decision on how to group these units together. The groups of units were then used to identify transmission alternatives that have the potential of alleviating some MWPs in the pockets (Table 7.1-2).

Load Area	VLR Units Under Consideration	Max Generation (MW)
DSG	Michoud 2	230
	Michoud 3	540
	Ninemile 3	128
	Ninemile 4	723
	Ninemile 5	737
Amite South	Little Gypsy 1	250
	Little Gypsy 2	410
	Little Gypsy 3	535
	Waterford 1	411
	Waterford 2	411
	Waterford 4	41
WOTAB	Nelson 4	500
	Sabine 1	210
	Sabine 2	210
	Sabine 3	420
	Sabine 4	530
	Sabine 5	450
Western	Lewis Creek 1	260
	Lewis Creek 2	260
	Frontier 1	165
	Frontier 2	165

Table 7.1-2: VLR units studied and generation

Total MWP for all of the VLR units inside the load pockets in 2014 was more than $72 million. The total MWP for the units considered in Table 7.1-2 is about $69 million of the total. DSG and WOTAB are the most expensive pockets. Cumulative MWP and commitments for each load area are in Figure 7.1-3. Overall Amite South/DSG and WOTAB/Western are very close to each other in total VLR commitment and cost.

a)



b)

Load Area	VLR Units Under Consideration
DSG	Michoud 2 & 3
	Ninemile 3, 4 & 5
Amite South	Little Gypsy 1, 2 & 3
	Waterford 1, 2 & 4
WOTAB	Nelson 4
	Sabine 1 2 3 4 & 5
Western	Lewis Creek 1 & 2
	Frontier 1 & 2

c)

Load Area	Cumulative Commitments	Cumulative MWP
DSG	750	$ 21,873,011
Amite South	371	$ 13,566,136
Western	331	$ 5,759,247
WOTAB	862	$ 27,990,865

Figure 7.1-3: a) Make Whole Payments (MWP) for 2014, b) Load Area and VLR Units Considered in Study, and c) Considered Units Annual Commitments and MWP

VLR commitments change month to month with most of the commitments occurring in the summer (Figure 7.1-4). When it comes to frequency of commitments, as expected, the highest were happening during the summer months. Note that the MWP for September is higher than for summer months but the frequency of commitment is lower (Figure 7.1-5). This is because of planned outages in the area, generators being out. This led to some of the VLR units needing to be committed for longer time.

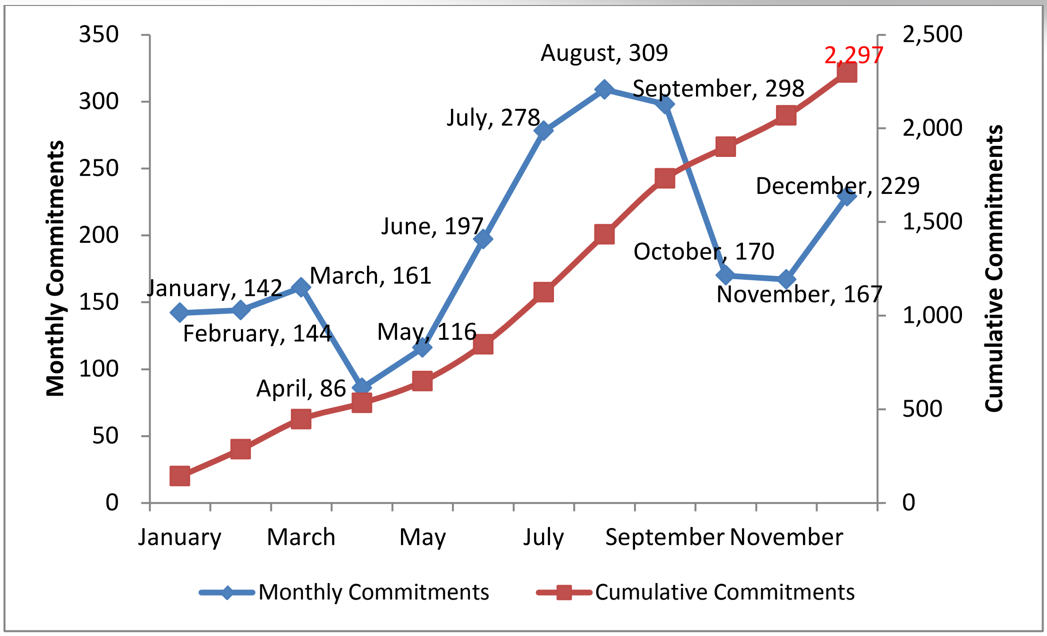


Figure 7.1-4: Monthly and cumulative VLR commitments by month

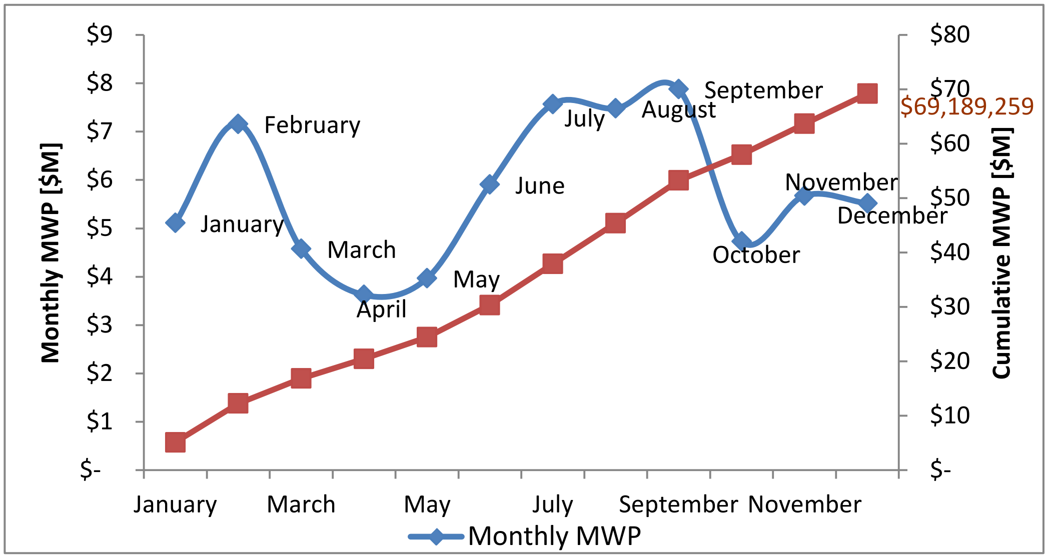


Figure 7.1-5: Monthly and cumulative MWP by month

Reliability Study Results

Study Approach

All scenarios were performed on the MTEP14, 2024 Summer Peak model. The Amite South and West of the Atchafalaya Basin load pockets contain approximately 7,200 MW of generation designated as a VLR unit. Steady state NERC TPL category P1 (single transmission element) and P3 (generator plus single transmission element) contingencies were performed to identify transmission network upgrades needed to eliminate the dispatch of scenario specific VLR designated units.

Base Load Level Scenarios

Scenario 1B: All Voltage and Local Reliability Designated Units Unavailable

Units were forced offline at the Waterford, Little Gypsy, Ninemile, Michoud, Nelson, Sabine and Lewis Creek facilities in the Amite South and the West of the Atchafalaya Basin load pockets. The total VLR generation displacement was approximately 7,200 MW. Approximately $1.845 billion in transmission network upgrades were required to remove all thermal and voltage violations. Planning level estimates were used to determine the cost of all projects. The cost estimate associated with this scenario and group of VLR units does not include the projects from Table 7.1-1 of this report. In this scenario, economic analysis was not performed because it did not represent the new load growth additions.

Scenario 1C: Groups of Voltage and Local Reliability (VLR) Designated Units Unavailable

Study Scenario 1C was performed on groups of VLR designated units. Groups were selected based on geographic location and the generation participation factor on areas of constraint. As noted earlier, no additional VLR units otherwise available for redispatch were turned on to relieve transmission constraints. In this scenario, economic analysis was not performed because it did not represent the new load growth additions.

Group A: Waterford 1, 2 and 4; Little Gypsy 1, 2 and 3

The Waterford and Little Gypsy units consist of nearly half the output of the VLR designated units in Amite South: more than 2,000 MW. These units were grouped together due to their geographic location. Little Gypsy is located 2 miles from Waterford, in Amite South on the DSG load pocket interface. The industrial corridor, a 60-mile span of 230 kV lines from Willow Glen to Waterford, is subject to severe thermal constraints with the loss of the Waterford and Little Gypsy units.

The transmission network upgrades to remove all thermal and voltage violations that result from the displacement of generation at the Waterford and Little Gypsy plants is approximately $261 million.

Group B: Ninemile 3, 4 and 5; Michoud 2 and 3

The Ninemile and Michoud units produce approximately 2,350 MW of generation output in the DSG load pocket. These units were grouped together due to their similar impact on constrained elements. Both the Ninemile and Michoud units provide relief to the DSG load pocket import lines from Little Gypsy and Waterford. The industrial corridor, a 60-mile span of 230 kV lines from Willow Glen to Waterford, is subject to severe thermal constraints with the loss of the Ninemile and Michoud units. Additionally, low-voltage violations occur throughout the DSG pocket, and thermal constraints also occur from Little Gypsy to Ninemile substations. The transmission network upgrades to remove all thermal and voltage violations that result from the displacement of generation at Ninemile and Waterford plants is approximately $419 million.

Group C: Nelson Unit 4

Nelson Unit 4 produces 500 MW of local generation in the Lake Charles area of Louisiana. The loss of this unit causes local voltage and thermal issues around the 230 kV network. The transmission network upgrades to remove all thermal and voltage violations that result from the displacement of generation at Nelson is approximately $118 million. The cost estimate associated with this scenario and group of VLR units does not include the projects from Table 7.1-1 of this report.

Group D: Sabine Units 1, 2 and 3

Group D consisted of the Sabine units 1, 2 and 3. With the reduction of 840 MW of total generation from the 138 kV units at Sabine, the WOTAB pocket suffers from limited import capability from the east. The system also requires more transmission capability to get power into the demand-heavy Sabine area. Low voltage issues exist around the Sabine 230 kV area. The transmission network upgrades to remove all thermal and voltage violations that result from the displacement of generation from Sabine units 1, 2 and 3 is approximately $395 million. The cost estimate associated with this scenario and group of VLR units does not include the projects from Table 7.1-1 of this report.

Group E: Sabine 4 and 5

Group E consisted of the Sabine units 4 and 5. With the reduction of 980 MW of total generation from the 230 kV units at Sabine, the WOTAB pocket suffers from limited import capability from the east. The system also requires more transmission capability to get power into the demand-heavy Sabine area. Low voltage issues exist around the Sabine 230 kV area. The transmission network upgrades to remove all thermal and voltage violations that result from the displacement of generation at Sabine units 4 and 5 is approximately $392 million. The cost estimate associated with this scenario and group of VLR units does not include the projects from Table 7.1-1 of this report.

Group F: Lewis Creek 1 and 2

Group F consisted of the Lewis Creek 1 and 2. With a reduction of 520 MW of total generation from Lewis Creek units 1 and 2, the Western pocket suffers from limited import capability through the Sabine area. Widespread low voltage issues exist in the Western pocket without the Lewis Creek units online to provide reactive power support. The transmission network upgrades to remove all thermal and voltage violations that result from the displacement of generation at Lewis Creek units 1 and 2 is approximately $556 million.

Industrial Renaissance Load Level Scenarios

Additional models were developed due to the anticipated industrial load growth in the load pockets. The 2024 summer peak model was adjusted to match the load forecast submitted into Module E. This includes scaling up load in the south as well as adding new loads in industrial load centers like Lake Charles, Baton Rouge and the Sabine area. The generation was adjusted accordingly, following the operational guides for each load pocket, to match the new load. The load increase was approximately 500 MW in the Amite South load pocket and 1,500 MW in the WOTAB load pocket.

Scenario 2A: Industrial Renaissance Load Increase Impact

Contingency analysis was performed on the Industrial Renaissance 10-year-out summer peak model. This model followed the VLR operation guides to dispatch units in the load pockets. The goal was to see the impact the new load had on the reliability of the system. Six projects were identified as reliability-driven and MISO worked with the transmission owner to add those projects into MTEP15. Those and other MTEP15 projects in the load pocket were assessed for their economic benefit in lowering VLR unit commitment.

Scenario 2B: Industrial Renaissance Load Profile and with All VLR Generators Off

Study Scenario 2B was not performed. The goal of this sensitivity is to find the transmission alternative to running all VLR generators with the industrial renaissance load level. This was completed for the base-case load level in scenario 1B. From there MISO found that the solution would be approximately $1.84 billion. Engineering judgment reasons that the high load level will not drive that cost down and since the base-case solution is not cost-effective, the decision was made to allocate resources towards other areas of sensitivities. MISO may revisit this scenario if the change in fundamental load/generation assumptions drives a review.

Scenario 2C: Industrial Load Growth, Groups of VLR Designated Units

Study Scenario 2C was performed on groups of VLR designated units with the Industrial Renaissance Load Profile. Groups were selected based on geographic location and the generation participation factor on areas of constraint. As noted earlier, no additional VLR units otherwise available for redispatch were turned on to relieve transmission constraints.

Group A: Waterford 1, 2 and 4; Little Gypsy 1, 2 and 3

When compared to the proposed solution set in Scenario 1C, the increased load projection caused new violations along the 230 and 138 kV transmission lines between Baton Rouge and New Orleans. The Scenario 2C-Group A solution requires an additional 230 kV line to link the 230 kV circuits on the west and east sides of the Mississippi River. The 138 kV loop north of the Amite South interface is also looped into the 230 kV transmission system to limit flows from Willow Glen. The Industrial Renaissance Load Profile increases the estimated cost of projects associated with Scenario 1C-Group A to $303 million, up from $261 million.

Group B: Ninemile 3, 4 and 5; Michoud 2 and 3

Similar to Scenario 2C-Group A, the increased load projection caused new violations along the 230 and 138 kV transmission lines between Baton Rouge and New Orleans. The Scenario 2C-Group B solution requires an additional 230 kV line to link the 230 kV circuits on the west and east sides of the Mississippi River. The 138 kV loop north of the Amite South interface is also looped into the 230 kV transmission system to limit flows from Willow Glen. The Industrial Renaissance Load Profile increases the estimated cost of projects associated with Scenario 1C-Group B to $552 million, up from $419 million.

Group C: Nelson Unit 4

When compared to the solution set in Scenario 1C, the Scenario 2C requires an increased amount of reactive support in the Lake Charles area.

A 230 kV line from Richard to Lake Charles Bulk—near Nelson—provides for increased import capability from the east, and mitigates very high contingent loading on the 138 kV system underlying the 500 kV line from Richard to Nelson. Capacitor banks at Lake Charles Bulk 230, Port Acres Bulk 230, and Michigan 230 provide voltage support.

The Industrial Renaissance Load Profile increases the estimated cost of projects associated with Scenario 1C-Group C to $133 million, up from $118 million. The cost estimate associated with this scenario and group of VLR units does not include the projects from Table 7.1-1 of this report.

Group D: Sabine Units 1 and 2 or Sabine 3

Due to the increased load profile from the industrial Renaissance, the WOTAB load pocket import limit is encountered with less VLR generation reduction. Due to the import limitations, the Sabine units 1 and 2 were studied separately from the Sabine Unit 3 as in Scenario 1.

Scenario 2C-Group D consisted of the Sabine 1 and 2 or Sabine Unit 3. With the reduction of 420 MW of generation from Sabine units 1 and 2 (or Sabine Unit 3 on its own), the WOTAB pocket suffers from import issues from the north and east. The system also requires more transmission capability to get power into the demand-heavy Sabine area. Low voltage issues exist around the Port Acres 230 kV area, along with the 138 kV system to the southwest of Sabine.

The partial solution set for Sabine 1 and 2 after the industrial load growth costs approximately $416 million. It includes approximately 40 miles of 500 kV line and 100 miles of new 230 kV line, along with new substations and necessary transformers. The cost estimate associated with this scenario and group of VLR units does not include the projects from Table 7.1-1 of this report.

Group E: Sabine 4

Due to the increased load profile from the industrial Renaissance, the WOTAB load pocket import limit is encountered with less VLR generation reduction. Due to the import limitations, the Sabine units 4 and 5 were studied separately and do not directly compare with the results in Scenario 1C.

Scenario 2C-Group F consisted of the Sabine Unit 4. With the reduction of 530 MW of generation from Sabine Unit 4, the WOTAB pocket suffers from limited import capability from the north and east. The system also requires more transmission capability to get power into the demand-heavy Sabine area. Low voltage issues exist around the Port Acres 230 kV area, along with the 138 kV system to the southwest of Sabine.

The partial solution set for Sabine 4 after the industrial load growth costs approximately $455 million. It includes approximately 40 miles of 500 kV line and 120 miles of new 230 kV line, along with new substations and necessary transformers. The cost estimate associated with this scenario and group of VLR units does not include the projects from Table 7.1-1 of this report.

Group F: Sabine 5

Due to the increased load profile from the industrial Renaissance, the WOTAB load pocket import limit is encountered with less VLR generation reduction. Due to the import limitations, the Sabine units 4 and 5 were studied separately and do not directly compare with the results in Scenario 1C.

Scenario 2C-Group D consisted of the Sabine unit 5. With the reduction of 450 MW of generation from Sabine unit 5, the WOTAB pocket suffers from limited import capability from the north and east. The system also requires more transmission capability to get power into the demand-heavy Sabine area. Low voltage issues exist around the Sabine 230 kV area.

The partial solution set for Sabine 5 after the industrial load growth costs approximately $400 million. It includes approximately 40 miles of 500 kV line and 100 miles of new 230 kV line, along with new substations and necessary transformers. The cost estimate associated with this scenario and group of VLR units does not include the projects from Table 7.1-1 of this report.

Group G: Lewis Creek 1 and 2

Group E consisted of the Lewis Creek units 1 and 2. With a reduction of 520 MW of generation from Lewis Creek units 1 and 2, the Western pocket suffers from limited import capability, including through the Sabine area. Widespread low voltage issues exist in the pocket without the Lewis Creek units online to provide reactive power support.

When compared to the solution set in Scenario 1C-Group F, the increased load modeled in Scenario 2C-Group H requires a significant increase in import capability. In order to achieve a higher import capability additional 230 and 500 kV upgrades are required. The Industrial Renaissance Load Profile increases the estimated cost of projects associated with Scenario 1C-Group F to $967 million, up from $566 million.

Economic Evaluation (Scenario 2c): Transmission inside load pocket plus generation outside load pocket

In the scenario where no future generation is considered within MISO south load pockets, transmission portfolios were evaluated for each respective load pocket. As a result, the cost of the transmission solution portfolios is greater than the benefits realized within each respective load pocket (Table 7.1-3).

Scenario	Load level	Generation	Retirements	Transmission Tested	Estimated B/C Ratio
2c	Industrial Renaissance	Signed GIA only	Approved Att. Y only	**Amite S:** Portfolio: $333-$534M	0 - 0.26
				WOTAB: Portfolio: $144M-$1.02B	

Table 7.1-3: Benefit-to-cost ratio for transmission portfolios under Scenario 2c

Scenario 2D and 3A: Industrial Load Growth, Groups of VLR Designated Units, Additional Local Generation

This scenario represents a case in which an Industrial Renaissance has taken place in Louisiana and Texas, and additional generation has been sited within the load pockets to support this increase in demand. This scenario takes the model from Scenario 2 and adds approximately 1,500 MW of generation in WOTAB, and 764MW of generation in Amite South. The site of the generation was selected based on existing infrastructure and a Request for Proposal by Entergy Inc. for the Amite South load pocket.

Scenario 2D-Group A: Waterford 1, 2 and 4; Little Gypsy 1, 2 and 3

When compared to the constraints associated with Scenario 2D-Group A, the violations are significantly reduced due to the location and magnitude of the new generation at Little Gypsy. The 760 MW unit offsets the loss of approximately 2,000 MW of generation from the Waterford and Little Gypsy VLR units. The estimated cost of the projects associated with Scenario 2D-Group A is $23.5 million, down from $303 million in Scenario 2C-Group A.

Scenario 2D-Group B: Ninemile 3, 4 and 5; Michoud 2 and 3

With respect to the Amite South interface, the Little Gypsy plant is downstream of the west to east power flow. The additional generation at Little Gypsy reduces the flow across the Amite South tie lines and reduces the solution requirements. However, with respect to the DSG load pocket, the generation is upstream and has no effect on the binding constraints into the load pocket. The Scenario 2B and 2C constraints are nearly identical, with slight alterations in the severity. The estimated cost of the projects associated with Scenario 2D-Group B is $327 million, down from $552 million in Scenario 2C-Group B.

Scenario 3A-Group A: Nelson 4

Group A consisted of the Nelson Unit 4. With the reduction of 500 MW of generation from Nelson Unit 4, the WOTAB pocket suffers from import issues from the east. The partial solution set for Nelson 4 after the industrial load growth and with additional generation at Nelson and Lewis Creek would cost approximately $113 million, down from $133 million in Scenario 2C-Group C. It includes approximately 60 miles of new 230 kV line and a new 230-138 kV transformer at a substation located to the east of Lake Charles. The cost estimate associated with this scenario and group of VLR units does not include the projects from Table 7.1-1 of this report.

Scenario 3A-Group B: Sabine 1, 2 and 3

Group B consisted of the Sabine units 1, 2 and 3. With the reduction of 840 MW of total generation from the 138 kV units at Sabine, the WOTAB pocket suffers from limited import capability from the north and east. The system also requires more transmission capability to get power into the demand-heavy Sabine area. Low-voltage issues exist around the Port Acres 230 kV area, along with the 138 kV system to the southwest of Sabine.

The partial solution set for the 138 kV Sabine units after the industrial load growth and with additional generation at Nelson and Lewis Creek costs approximately $490 million. Due to the WOTAB import limit in Scenario 2C, there is no direct comparison in Scenario 2C. The cost estimate associated with this scenario and group of VLR units does not include the projects from Table 7.1-1 of this report.

Scenario 3A-Group C: Sabine 3 and 4

Group C consisted of the Sabine units 4 and 5. With the reduction of 980 MW of total generation from the 230 kV units at Sabine, the WOTAB pocket suffers from limited import capability from the north and east. The system also requires more transmission capability to get power into the demand-heavy Sabine area. Low-voltage issues exist on the 230 kV and 138 kV systems around Sabine.

The partial solution set for the 230 kV Sabine units after the industrial load growth and with additional generation at Nelson and Lewis Creek costs approximately $414 million. Due to the WOTAB import limit in Scenario 2C, there is no direct comparison in Scenario 2C. The cost estimate associated with this scenario and group of VLR units does not include the projects from Table 7.1-1 of this report.

Scenario 3A-Group D:

Group D consisted of the Lewis Creek units 1 and 2. With a reduction of 520 MW of total generation from Lewis Creek units 1 and 2, the Western pocket suffers from limited import capability through the Sabine area. Significant low voltage issues exist in the pocket even with a new Lewis Creek CCGT online.

The partial solution set for Lewis Creek 1 and 2 after the industrial load growth and with additional generation at Nelson and Lewis Creek costs approximately $651 million, down from 967 million in Scenario 2C- Group G.

Economic Evaluation (Scenario 2d/3a): Transmission plus generation inside load pocket

In the following scenarios, Little Gypsy, Nelson and Lewis Creek locations where selected in collaboration with stakeholders and publicly announced Request for Proposal (RFP) to model inclusion of new generation in MISO south load pockets to complement the transmission portfolios as a base case assumption. In conclusion, when evaluating the transmission portfolios in each respective load pocket it was established that the cost of the transmission solutions outweighs the benefits (Table 7.1-4).

Scenario	Load level	Generation	Retirements	Transmission Tested	Estimated B/C Ratio
2d	Industrial Renaissance	Signed GIA plus RFP generation in Amite S	Approved Att. Y only	**Amite South Portfolio**: $30-$294 million	0 - 0.19
3a		Signed GIA plus Additional generation in Western/WOTAB plus RFP Generation in Amite S		**(WOTAB/Amite.S) Portfolio:** $120-$625 million	0 - 0.32

Table 7.1-4: Benefit-to-cost ratio for transmission portfolios under Scenario 2d and 3a

MISO completed the assessment to identify transmission upgrades to eliminate/minimize VLR costs under many different study assumptions (Table 7.1-5). A large number of solution ideas were developed and all transmission alternatives considered were summarized (Table 7.1-6).

Transmission solutions to reduce VLR commitments are not cost-effective. The current annual VLR costs support no more than $470 million in transmission costs, and much more than that is needed to mitigate even portions of the approximate 7,200 MW of VLR units.

MISO will continue to evaluate the solution ideas developed in every study scenario for economic benefit in the subsequent MCPS. Moving forward, MISO will continue to consider VLR cost saving benefits as it goes through their reliability and economic planning.

Case	Load level	Generation	Retirements	VLR generation status	Result
1a	Base load	Signed GIA only	Approved Att. Y only	All ON	System is reliable. VLR costs are incurred.
1b				*All OFF*	Transmission alternative to maintain reliability with estimated cost of $1.5-$2B
1c				*Partial OFF*	Reliability maintained by a combination of reduced VLR and new Transmission. Amite S: Transmission: $0-$462M WOTAB: Transmission: $122-$561M
2a	Industrial Renaissance	Signed GIA only	Approved Att. Y only	All ON	Transmission needed for increased load in addition to VLR costs;
2b				All OFF	Transmission alternative to maintain reliability
2c				Partial OFF	**Amite S:** Transmission: $333-$534M **WOTAB:** Transmission: $144M-$1.02B
2d		Signed GIA + RFP generation in Amite S	Approved Att. Y only	Partial OFF	**Amite S:** Transmission: $30-$294M
2e			Additional retirements in Amite S/DSG	Partial OFF	Test if 60+ years by 2030 age related retirements require additional transmission
3a	Industrial Renaissance	Signed GIA + Additional generation in Western/WOTAB	Approved Att. Y only	Partial OFF	Transmission: $120-$625M
3b			Additional retirements in Western/WOTAB	Partial OFF	Test if 60+ years by 2030 age related retirements require additional transmission

:

Table 7.1-5: VLR scenarios studied

Case	Load & Generation Assumptions			VLR Generation Status	Transmission Upgrades needed to Eliminate VLR Units (Incremental to Base Reliability Needs)[1]	
	Load Level	Generation	Retirements	Units Shutdown	Up-Grade Description	Upgrade Cost ($M)
1a	Base load	Signed GIA only	Approved Att. Y only	All ON		$171
1b				All OFF	many	$2,095
1c				Partial OFF	many	122-564
2a	Industrial Renaissance	Signed GIA only	Approved Att. Y only	All ON	None - status quo VLR	
2b				All OFF	very many	>$2000
2c				Nelson 4	Lake Charles Bulk 230 kV substation tapping Chalkley Bulk - Gillis	$133
					Lake Charles Bulk 230-138 kV auto	
					Richard - Lake Charles Bulk 230 kV line	
					Lake Charles Bulk 230 kV 190 Mvar cap bank	
					Port Acres Bulk 230 kV 190 Mvar cap bank	
					Michigan 230 kV 21.6 Mvar cap bank	
				Sabine 1&2 or Sabine 3	Hartburg - Sabine 500 kV line	$416
					Sabine 500kV Substation	
					Two 500-230 kV autos at Sabine	
					One 500-138 kV auto at Sabine	
					Nelson (or Carlyss) - Sabine 230 kV line	
					Cheek 230 kV substation	
					Cheek 230/138 kV auto	
					Lake Charles Bulk 230 kV substation tapping Chalkley Bulk - Gillis	
					Lake Charles Bulk 230-138 kV auto	
					Richard - Lake Charles Bulk 230 kV line	
					Port Acres Bulk 230 kV 190 Mvar cap bank	
					Spindletop 138 kV 152 Mvar cap bank	
					Increase the rating on Sabine – 6ENT532 kV line to at least 877 MVA	
				Sabine 4	Hartburg - Sabine 500 kV line	$455
					Sabine 500kV Substation	
					Two 500-230 kV autos at Sabine	
					Nelson (or Carlyss) - Sabine 230 kV line	
					Cheek 230 kV substation	
					Cheek 230/138 kV auto	
					Lake Charles Bulk 230 kV substation tapping Chalkley Bulk - Gillis	
					Lake Charles Bulk 230-138 kV auto	
					Richard - Lake Charles Bulk 230 kV line	
					Leesville - Cooper 230 kV line	
					Three extra 21.6 Mvar cap bank steps at Mud Lake 230 kV	
					Solac 230 kV 86.4 Mvar cap bank	
					Increase the rating on Sabine – 6ENT532 kV line to at least 877 MVA	
					Spindletop 138 kV 76 Mvar cap bank	
					Lake Charles Bulk 190Mvar cap bank	

Case	Load & Generation Assumptions			VLR Generation Status	Transmission Upgrades needed to Eliminate VLR Units (Incremental to Base Reliability Needs)[1]	
	Load Level	Generation	Retirements	Units Shutdown	Up-Grade Description	Upgrade Cost ($M)
2c	Industrial Renaissance	Signed GIA only	Approved Att. Y only	Sabine 5	Hartburg - Sabine 500 kV line	$400
					Sabine 500kV Substation	
					Two 500-230 kV autos at Sabine	
					Nelson (or Carlyss) - Sabine 230 kV line	
					Cheek 230 kV substation	
					Cheek 230/138 kV auto	
					Lake Charles Bulk 230 kV substation tapping Chalkley Bulk - Gillis	
					Lake Charles Bulk 230-138 kV auto	
					Richard - Lake Charles Bulk 230 kV line	
					Increase the rating on Sabine – 6ENT532 kV line to at least 877 MVA	
					Three extra 21.6 Mvar cap bank steps at Mud Lake 230 kV	
				Lewis Creek 1&2	Cypress - Lewis 500 kV line	$967
					Lewis Creek 500 kV Substation	
					Newton Bulk 500 kV Substation tapping Messick - Hartburg	
					One 500-230 kV auto at Lewis	
					Two 500-138 kV autos at Lewis	
					One 500-230 kV auto at Newton Bulk	
					One 230-138 kV auto at Newton Bulk	
					Nelson (or Carlyss) - Sabine 230 kV line	
					Hartburg - Cypress 230 kV line	
					Dayton 230 kV substation	
					Dayton 230/138 kV auto	
					Ponderosa - Lewis Creek 230 kV line	
					Lake Charles Bulk 230 kV substation tapping Chalkley Bulk - Gillis	
					Lake Charles Bulk 230-138 kV auto	
					Richard - Lake Charles Bulk 230 kV line	
					Newton Bulk 230 kV substation	
					Poco 230 kV substation	
					Poco 230 -138 kV auto	
					Doucette 230 kV substation	
					Doucette 230 -138 kV auto	
					Newton Bulk - Doucette 230 kV line	
					Doucette - Poco 230 kV line	
					Lewis Creek 260 Mvar SVC	
					Port Acres Bulk 230 kV 190 Mvar cap bank	
					Line from China – Porter 230 kV tap point to new Dayton 230 kV	

Case	Load & Generation Assumptions			VLR Generation Status	Transmission Upgrades needed to Eliminate VLR Units (Incremental to Base Reliability Needs)[1]	
	Load Level	Generation	Retirements	Units Shutdown	Up-Grade Description	Upgrade Cost ($M)
2c	Industrial Renaissance	Signed GIA only	Approved Att. Y only	Michoud 2,3 & Ninemile 3,4,5	Bayou Labutte-Waterford	$553
					Bogalusa - Bogachita	
					Bogachita - N. Slidel	
					New Conway 500kV Substation	
					New N. Slidel 500kV Substation	
					New Bogachita 500kV Tapping Station	
					New Ninemile 500kV Substation	
					Upgrade Bogalusa 500kV Substation	
					Upgrade Bayou Labutte 500kV Substation	
					Upgrade Waterford 500kV Substation	
					Conway: New 500/230kV Autotransformer	
					N. Slidel: New 500/230kV Autotransformer	
					Ninemile: New 500/230kV Autotransformer	
					New Waterford to Ninemile	
					Conway – Bayou Verret	
					Re-conductor Snakefarm-Labarre	
					Upgrade Ninemile 230kV Substation	
					Re-conductor Avenue C to Paris Tap 115kV	
					Delta 115kV: 40Mvar	
					NORCO: 33.5Mvar	
				Waterford 1,2,4 & Little Gypsy 1,2,3	Bayou Labutte-Waterford	$281
					New Conway 500kV Substation	
					Upgrade Bayou Labutte 500kV Substation	
					Upgrade Waterford 500kV Substation	
					Conway: New 500/230kV Autotransformer	
					Conway – Bayou Verret	
					St. Gabriel 230/138kV Autotransformer	
					Re-conductor Little Gypsy – Waterford Ckt 1	
					Re-conductor Little Gypsy – Waterford Ckt 2	
					Little Gypsy: 80Mvar	
2d		Signed GIA + RFP generation in Amite S		Michoud 2,3 & Ninemile 3,4,5	Bogalusa - Bogachita	$328
					Bogachita - N. Slidel	
					New Conway 500kV Substation	
					New N. Slidel 500kV Substation	
					New Bogachita 500kV Tapping Station	
					New Ninemile 500kV Substation	
					Upgrade Bogalusa 500kV Substation	
					Conway: New 500/230kV Autotransformer	
					N. Slidel: New 500/230kV Autotransformer	
					Ninemile: New 500/230kV Autotransformer	
					New Waterford to Ninemile	
					Re-conductor Snakefarm-Labarre	
					Upgrade Ninemile 230kV Substation	
					Re-conductor Avenue C to Paris Tap 115kV	
					NORCO: 33.5Mvar	
					Line from China – Porter 230 kV tap point to new Dayton 230 kV	
				Waterford 1,2,4 & Little Gypsy 1,2,3	New Conway 500kV Substation	$22
					Conway: New 500/230kV Autotransformer	

Case	Load & Generation Assumptions			VLR Generation Status	Transmission Upgrades needed to Eliminate VLR Units (Incremental to Base Reliability Needs)[1]	
	Load Level	Generation	Retirements	Units Shutdown	Up-Grade Description	Upgrade Cost ($M)
2e	Industrial Renaissance	Signed GIA + RFP generation in Amite S	Additional retirements in Amite S/DSG	Michoud 3 & Little Gypsy 1 & 2 or Michoud 3 & Little Gypsy 3	Re-conductor Avenue C to Paris Tap 115kV	$41
					Re-conductor Ninemile to Napoleon 230kV line	
					Re-conductor Ninemile to Westwego 115kV line	
					Re-conductor Ninemile to Harvey 115kV line	
					Re-conductor Ninemile to Derbigny 230kV line	
					Re-conductor Midtown to Almonastor 230kV line	
					Re-conductor Napoleon to Market Street line	
3a		Signed GIA + Additional generation in Western/ WOTAB	Approved Att. Y only	Nelson 4	Lake Charles Bulk 230 kV substation tapping Chalkley Bulk - Gillis	$113
					Lake Charles Bulk 230-138 kV auto	
					Richard - Lake Charles Bulk 230 kV line	
					Liberty 138 kV 37.8 Mvar cap bank	
				Sabine 1,2, & 3	Hartburg - Sabine 500 kV line	$490
					Sabine 500kV Substation	
					Two 500-230 kV autos at Sabine	
					One 500-138 kV auto at Sabine	
					Nelson (or Carlyss) - Sabine 230 kV line	
					Cheek 230 kV substation	
					Cheek 230/138 kV auto	
					Port Acres Bulk – Cheek	
					Increase line rating of Sabine – 6ENT532 230 kV line to at least 690 MVA	
					Lake Charles Bulk 230 kV substation tapping Chalkley Bulk - Gillis	
					Lake Charles Bulk 230-138 kV auto	
					Richard - Lake Charles Bulk 230 kV line	
					Liberty 138 kV 37.8 Mvar cap bank	
					Shiloh 138 kV 38 Mvar cap bank	
					Port Acres Bulk 230 kV 190 Mvar cap bank	
					Michigan 230 kV 21.6 Mvar cap bank	
					Spindletop 138 kV 37.8 Mvar cap bank	
				Sabine 4&5	Hartburg - Sabine 500 kV line	$414
					Sabine 500kV Substation	
					Two 500-230 kV autos at Sabine	
					One 500-138 kV auto at Sabine	
					Nelson (or Carlyss) - Sabine 230 kV line	
					Lake Charles Bulk 230 kV substation tapping Chalkley Bulk - Gillis	
					Lake Charles Bulk 230-138 kV auto	
					Richard - Lake Charles Bulk 230 kV line	
					Nederland – Induga	
					Increase rating on Mid County – Flatland 138 kV line to at least 297 MVA	
					Buna 138 kV 37.8 Mvar cap bank	
					Liberty 138 kV 37.8 Mvar cap bank	
					Shiloh 138 kV 38 Mvar cap bank	
					Port Acres Bulk 230 kV 190 Mvar cap bank	
					Michigan 230 kV 21.6 Mvar cap bank	

Case	Load & Generation Assumptions			VLR Generation Status	Transmission Upgrades needed to Eliminate VLR Units (Incremental to Base Reliability Needs)[1]	
	Load Level	Generation	Retirements	Units Shutdown	Up-Grade Description	Upgrade Cost ($M)
3a	Industrial Renaissance	Signed GIA + Additional generation in Western/ WOTAB	Approved Att. Y only	Lewis Creek 1&2	Cypress - Lewis 500 kV line (1 river crossing)	$651
					Lewis Creek 500 kV Substation	
					One 500-230 kV auto at Lewis	
					Two 500-138 kV autos at Lewis	
					One additional 500-230 kV auto at Hartburg	
					Increase rating on Cypress – Bevil 230 kV line to at least 713 MVA	
					Hartburg - Cypress 230 kV line	
					Hartburg - Cypress 230 kV (2nd circuit)	
					Lake Charles Bulk 230 kV substation tapping Chalkley Bulk - Gillis	
					Lake Charles Bulk 230-138 kV auto	
					Richard - Lake Charles Bulk 230 kV line	
					Michigan 230 kV 21.6 Mvar cap bank	
3b			Additional retirements in Western/ WOTAB	Nelson 4 & Sabine 3	One additional 500-230 kV auto at Carlyss	$211
					Nelson (or Carlyss) - Sabine 230 kV line	
					Lake Charles Bulk 230 kV substation tapping Chalkley Bulk - Gillis	
					Lake Charles Bulk 230-138 kV auto	
					Richard - Lake Charles Bulk 230 kV line	
					Spindletop 138 kV 37.8 Mvar cap bank	
					Helbig 230 kV 43.2 Mvar cap bank	
				Nelson 1,2,3 & Sabine 1, 2,3	Hartburg - Sabine 500 kV line	$435
					Sabine 500kV Substation	
					Nelson (or Carlyss) - Sabine 230 kV line	
					Upgrade Black Gold - China 230 kV line	
					Lake Charles Bulk 230 kV substation tapping Chalkley Bulk - Gillis	
					Lake Charles Bulk 230-138 kV auto	
					Richard - Lake Charles Bulk 230 kV line	
					One additional 230-138 kV auto at Sabine	
					Upgrade the 230-138 kV auto at Carlyss	
					Shiloh 138 kV 38 Mvar cap bank	
					Solac 230 kV 86.4 Mvar cap bank	
					Spindletop 138 kV 37.8 Mvar cap bank	
					New 230 kV substation near Sabine 1 6 6	
					New 500 kV substation near Sabine	
					New Substation – Port Acres Bulk 230 kV line	

Table 7.1-6: Scenarios studied with cost

7.2 Demand Response, Energy Efficiency, Distributed Generation

Applied Energy Group (AEG) developed a 20-year forecast of existing, planned and potential demand response (DR), energy efficiency (EE) and distributed generation (DG) resources and costs for MISO. This is a refresh of the MISO 2009-2010 Demand Response and Energy Efficiency study.

As compared to the 2009-2010 study, this study added the South region, provided analysis at the local resource zone (LRZ) level, adds DG, adds behavioral programs and accounts for appliance standards and programs not currently in use. This forecast meets both ongoing and emerging business needs.

The industry is increasing its focus on initiatives that include DR, EE and DG in order to meet federal or state policy requirements and other enacted or emerging enviromental regulations. MISO needed to refresh its models for DR and EE and explicitly include DG for modeling of future transmission capacity as well as understand the potential and cost of these programs both internally and for its stakeholders. This forecast allows MISO to analyze the impacts related to DR, EE and DG programs for transmission planning, real-time operations and market operations (including resource adequacy). This forecast positions MISO well for Clean Power Plan (CPP) analysis as there is a greater emphasis on EE as a compliance option in the final version of the CPP. Additionally, this forecast will be incorporated into the Independent Load Forecast models.

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

In this report, the Existing Programs Plus case uses existing program data for 2015 from the utility survey and assumes a small annual increase in participation in current programs through 2035. Savings are broken down by LRZ and different cases are analyzed in the full report. Preliminary summary results for the Existing Programs Plus case are:

- Peak demand savings from DR programs are 5 percent of the baseline summer demand in 2015. Peak demand savings from DR, EE and DG programs increase to 15 percent of the baseline summer demand by 2035.
    - On the residential side, appliance incentives, direct load control, customer solar PV and customer wind turbines are the programs with the greatest estimated impact by 2025.
    - On the commercial and industrial side, curtailable & interruptible DR programs, custom incentives, and direct load control are the programs with the greatest estimated impact by 2025.
- Annual energy savings are 0.5 percent of the baseline annual energy in 2015. Cumulative energy savings increase to 6.6 percent of the baseline annual energy in 2035. Throughout this forecast, energy savings come primarily from EE programs.
    - On the residential side, appliance incentives, lighting and customer wind turbines are the programs with the greatest estimated impact by 2025.
    - On the commercial and industrial side, custom incentives, perscriptive rebates and retro-commissioning are the programs with the greatest estimated impact by 2025.
    - DG is a negligible percentage of these estimates with only a 0.6 percent cumulative effect by 2035.

Overall, DR, EE and DG programs offset 67 percent of summer peak demand growth and 33 percent of annual energy load growth by 2035

7.3 Independent Load Forecast

MISO procured an independent vendor, State Utility Forecasting Group (SUFG), to develop three 10-year horizon load forecasts[39]. SUFG provides data used to develop an independent regional load forecast for the MISO Balancing Authority (BA). The first 10-year forecast (2015-2014) was delivered in November 2014. The second 10-year forecast (2016-2025) is due November 2, 2015.

SUFG produces econometric models for 15 states. The SUFG independent load forecast includes a seasonal peak forecast (summer and winter) that is MISO coincident and a coincident forecast for each of the 10 Local Resource Zones. The long-term forecast will be based on MISO Business as Usual (BAU) planning future each year.

The independent load forecast will be a 50/50 forecast, meaning there is a 50 percent probability that the load will either be higher or lower than the forecasted value. The load forecast (demand and energy) for the MISO BA will be forecasted for each state, and then aggregated into each MISO Local Resource Zone (LRZ) through the use of allocation factors. The MISO BA has 36 Local Balancing Authorities (LBA). The LBAs are aggregated into 10 Local Resource Zones (LRZs) (Figure 7.3-1).

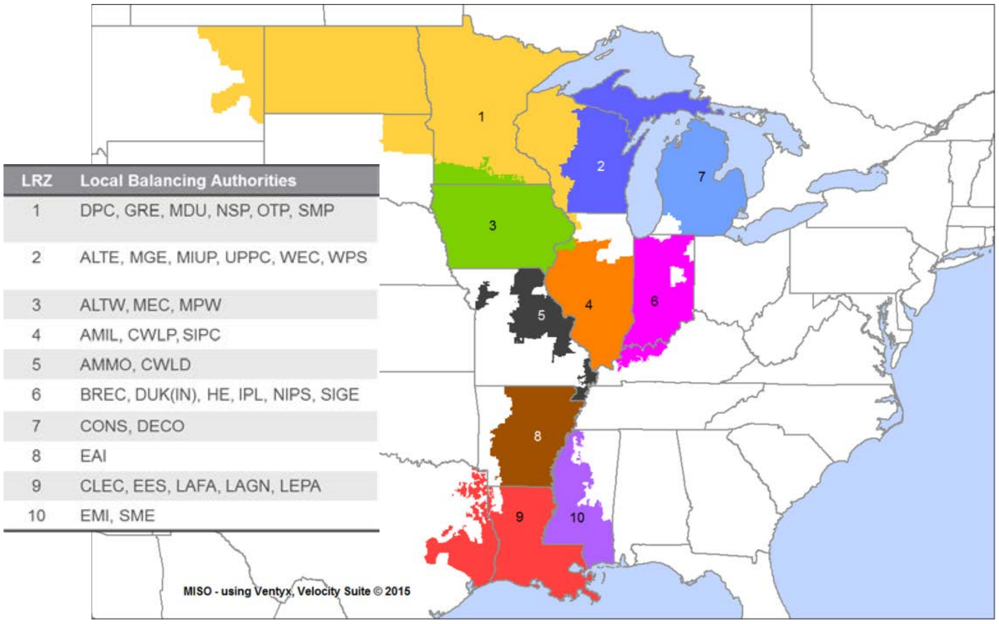


Figure 7.3-1: MISO LRZ map for planning year 2015.

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

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

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

Project Schedule and Deliverables

This project is a three-year effort (Figure 7.3-2), with forecast deliverables due annually at the beginning of November 2014, 2015 and 2016. Key activities and milestones are outlined for the 2016-2025 forecast (Table 7.3-1).

The scope of the 2016-2025 forecast was updated based on stakeholder feedback received in the first quarter of 2015. LRZ 10, previously a part of LRZ 9, was added in Mississippi. SUFG updated state econometric models and the conversion of the energy forecast to the peak forecast. SUFG also modeled multiple weather stations in the state econometric models, as well as improved modeling of demand response, energy efficiency and distributed generation. Finally, SUFG incorporated uncertainty in the drivers of the econometric models into the high and low forecast bands by estimating confidence intervals based on the historical variance of the drivers.

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

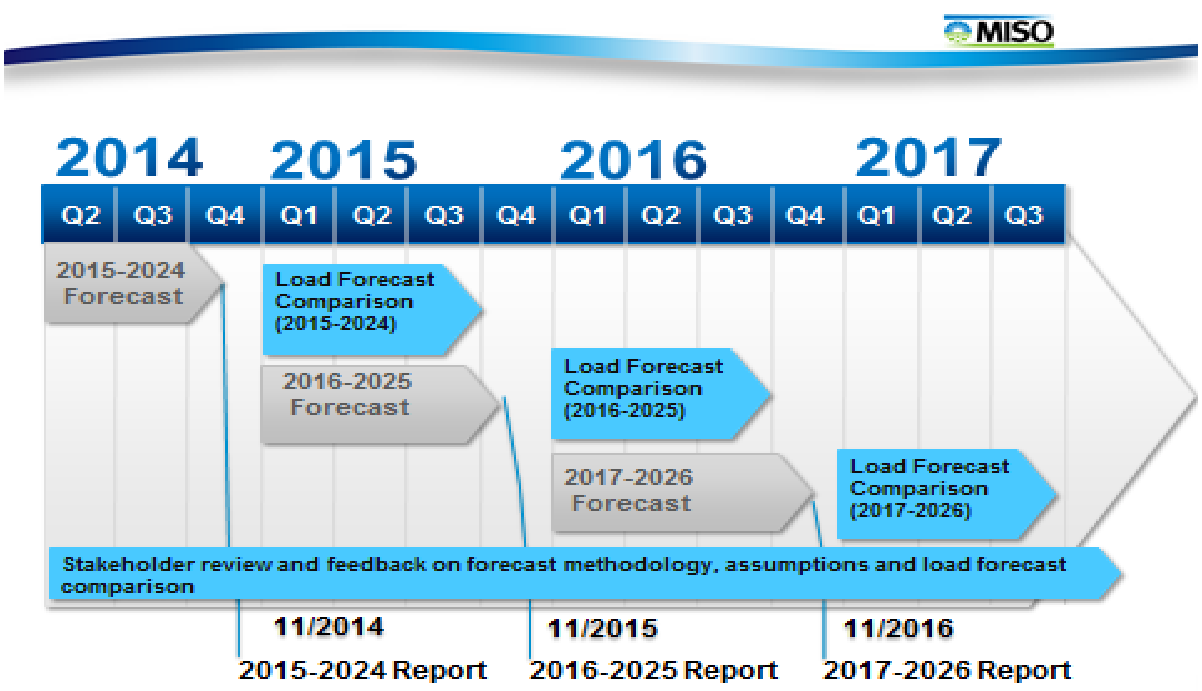


Figure 7.3-2: Independent Load Forecasting Project high-level schedule

Key Activities And Milestones	Target Dates
2016-2025 Independent Load Forecast	**11/1/2015**
Stakeholder Workshop #1 – Review 2015 project plan, discuss potential improvements, load forecast comparison	1/22/15
Stakeholder Comments Due	2/3/15
Acquire (update) state level historical data	3/2015
Update econometric forecasting models for each state	4/2015
Stakeholder Workshop #2	4/23/2015
Stakeholder Workshop #2 Comments Due	5/14/2015
Determine allocation factors to convert state energy forecasts to each Local Resource Zone forecast	6/2015
Review energy to peak demand conversion model for each Local Resource Zone	7/2015
Incorporate econometric model drivers	6/2015
Generate a 10 year annual energy forecast for each state using its econometric forecast model	7/2015
Stakeholder Workshop #3	7/23/2015
Stakeholder Workshop #3 Comments Due	8/6/2015
Determine 10 year annual energy forecast for each Local Resource Zone	8/2015
Determine 10 year seasonal peak demand for each Local Resource Zone	8/2015
Determine MISO's 10 year forecast for annual energy and seasonal peak demand	9/2015
Stakeholder Workshop #4 - Review 2016-2025 Forecast results	9/17/15
Stakeholder Comments Workshop #4 Due	10/8/15
Independent 10 year (2015-2024) Demand and Energy forecast report completed	11/2/15
Stakeholder Comments Due	11/13/15

Table 7.3-1: Independent Load Forecasting Project detailed project schedule 2015.

Project Justification

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

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

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

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

7.4 EPA Regulations – Clean Power Plan Draft Rule Study

On June 2, 2014, the U.S. Environmental Protection Agency (EPA) proposed a rule to reduce carbon dioxide (CO_2) emissions from existing fossil-fired generation units. The draft rule, also known as the Clean Power Plan (CPP), included state-by-state CO_2 emissions targets based upon a set of building blocks.

MISO's analysis of the draft CPP encompassed three phases, each designed to provide specific insights into the potential impacts of the rule. The two overarching goals of these analyses were:

- To inform stakeholders as they evaluate compliance options
- To establish a framework for analysis of the final rule

The first two phases[40] of MISO's study focused on the potential costs of generation capital investment and energy production based on application of the proposed rule. Numerous CO_2 reduction strategies were evaluated including implementation of the EPA's building blocks on a regional (MISO-wide) basis, as well as the application of alternative compliance strategies at the regional (MISO footprint) and sub-regional (MISO Local Resource Zone) levels. High-level takeaways from these efforts include:

- Application of the EPA's building blocks on a region-wide (MISO-wide) basis resulted in compliance costs of approximately $90 billion in net present value (NPV) over the 20-year study period, which equates to $60/ton of CO_2 emissions avoided from existing fossil-fired units.
- Application of alternative compliance strategies (for example, retiring and replacing coal units with combined-cycle gas capacity) for the MISO region as a whole, resulted in compliance costs of approximately $55 billion (20-year NPV), which translates to $38/ton of CO_2 emissions avoided.
- A similar outside-the-blocks alternative compliance strategy applied at a sub-regional level (using the MISO Local Resource Zones) resulted in compliance costs of approximately $83 billion in net present value, or $57/ton of CO_2 emissions avoided. A regional compliance approach therefore results in an annual cost avoidance of approximately $3 billion compared to the sub-regional approach.
- MISO also found that the EPA's draft proposal could put up to 14 GW of additional coal capacity at risk of retirement in order to achieve CO_2 reductions at lower compliance costs.

Study design for Phase III was informed by the results of these initial analyses, as well as stakeholder requests for state-level modeling, inclusion of electric transmission and consideration of gas infrastructure. Phase III quantified potential power system ramifications of the CPP, such as increased cost for energy production, and impacts to generation dispatch and transmission system utilization. Potential reliability impacts were identified, along with transmission congestion trends. The study also served as a first step in developing transmission solutions to facilitate reliable and cost-effective implementation of the changes required for compliance with the CPP.

The analysis tested five compliance scenarios and a reference scenario (Figure 7.5-1) to understand the impacts of how the MISO region may comply with the emissions limitations.

[40] Analysis of EPA's Proposal to Reduce CO_2 Emissions from Existing Electric Generating Units.

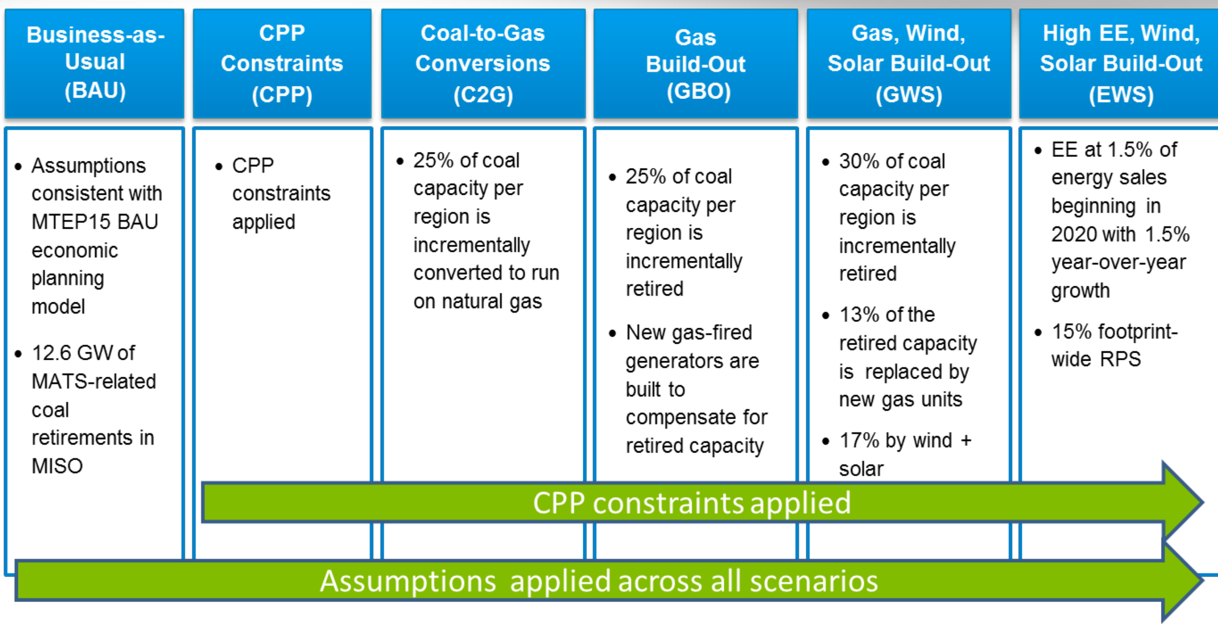


Figure 7.5-1 Phase III Scenarios

The five compliance scenarios were modeled for three years (2020, 2025 and 2030) and three types of compliance (state-by-state, sub-regional and regional). Both economic and reliability analysis were performed, using PLEXOS and PSS/E models, respectively. Additionally, preliminary evaluation of rate versus mass emissions constraints was performed to understand these different options for compliance.

High-level takeaways based on study results include:

- State by state compliance is shown to be about $4 to $1 billion (in 20-year NPV) more expensive compared to regional (MISO-wide) compliance approach. Similarly the state approach would be about $2.5 to $11.5 billion (in 20-year NPV) more expensive than the sub-regional compliance approach.
- Electric and gas infrastructure costs for interconnection of new or converted gas units are comparable regardless of where they are sited (closer to existing gas infrastructure versus the existing electric transmission).
- CPP constraints significantly increase congestion regardless of compliance approach, and transmission congestion is higher under a state approach than a regional approach.
- Multi-billion dollar transmission build-out would be necessary for reliable and cost-effective compliance in the scenarios studied, driven by the level of generation retirements and the location and type of replacement capacity.
- Generation dispatch would change dramatically from current practices, requiring additional study to fully understand the ramifications.

The results offer valuable insights into how the energy landscape may change as a result of carbon restrictions on the electric generation. The process of draft rule analysis also yielded valuable lessons that will shape MISO's study of the final rule. In particular, it highlighted the value of a phased approach to analysis, which produced useful information prior to completion of the entire study. Additional lessons learned on study process and design includes:

- Stakeholder feedback throughout was essential to producing relevant outputs
- The PLEXOS model is a good fit for analysis of the CPP, allowing for explicit modeling of constraints on CO_2 emissions, as well as state-by-state compliance
- Studying one or two compliance actions (e.g. coal retirements, renewables build-out, re-dispatch) at a time allowed for developing a better understanding of the impacts of pulling these individual compliance levers

The draft rule analysis was a significant undertaking, based on a complex and sometimes ambiguous regulation. Though the study of the final rule will necessitate similar efforts of rule interpretation and technical analysis, MISO is well-positioned to address these challenges. Over the course of the next year, MISO will continue to work closely with stakeholders, state regulators and neighboring ISOs to understand how this regulation will change the energy landscape and to plan for its implementation.

Analysis shows that projected benefits provided by the MVP portfolio have decreased since MTEP14, but are on par with the original MVP Review conducted in MTEP11

7.5 MTEP15 MVP Limited Review

The MTEP15 Multi-Value Project (MVP) Limited Review provides an updated view into the projected congestion and fuel savings of the MVP Portfolio. The MTEP15 MVP Limited Review's business case is on par with the review of the original business case in MTEP11. Although there are reduced benefits from the MTEP14 Triennial Review, the MTEP15 Limited Review provides evidence that the MVP criteria and methodology works as expected. The MTEP15 analysis shows that projected MISO North and Central region benefits provided by the MVP Portfolio are comparable to MTEP11, the analysis from which the portfolio's business case was approved.

The MTEP15 results demonstrate that the MVP Portfolio:

- Provides benefits in excess of its costs, with its benefit-to-cost ratio ranging from 1.9 to 2.8; a decrease from the 2.6 to 3.9 range calculated in MTEP14
- Creates $8.4 to $34.7 billion in net benefits (using MTEP14 benefits for all categories besides congestion and fuel savings) over the next 20 to 40 years, a decrease of up to 38 percent from MTEP14

Decreased benefits related to the congestion and fuel savings are largely driven by natural gas price assumptions.

The MTEP15 MVP Limited Review Business Case will be posted under the Multi-Value Project Portfolio Analysis section of the MISO website.

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

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

MISO conducted its first limited MVP Portfolio review, per tariff requirement, for MTEP15. The MVP Review has no impact on the existing MVP Portfolio's cost allocation. MTEP15 Review analysis is performed solely for informational purposes. The intent of the MVP Review is to use the review process and results to identify potential modifications to the MVP methodology and its implementation for projects to be approved at a future date.

The MVP Review uses stakeholder-vetted MTEP15 models and makes every effort to follow procedures and assumptions consistent with the MTEP14 analysis. Consistent with previous MTEP MVP Reviews, the MTEP15 MVP Review assesses the benefits of the entire MVP Portfolio and does not differentiate between facilities currently in service and those still being planned. Because the MVP

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

Portfolio's costs are allocated solely to the MISO North and Central regions, only MISO North and Central Region benefits are included in the MTEP15 MVP Limited Review.

Economic Benefits

MTEP15 analysis shows the MVP Portfolio creates $17.7 to $54 billion in total benefits[41] to the MISO North and Central Region members (Figure 7.5-1). Total portfolio costs have increased from $5.86 billion in MTEP14 to $6.46 billion in MTEP15. Even with the increased portfolio cost estimates and decreased gas prices from MTEP14, MVP Portfolio benefit-to-cost ratios are comparable to the original business case studied in MTEP11.

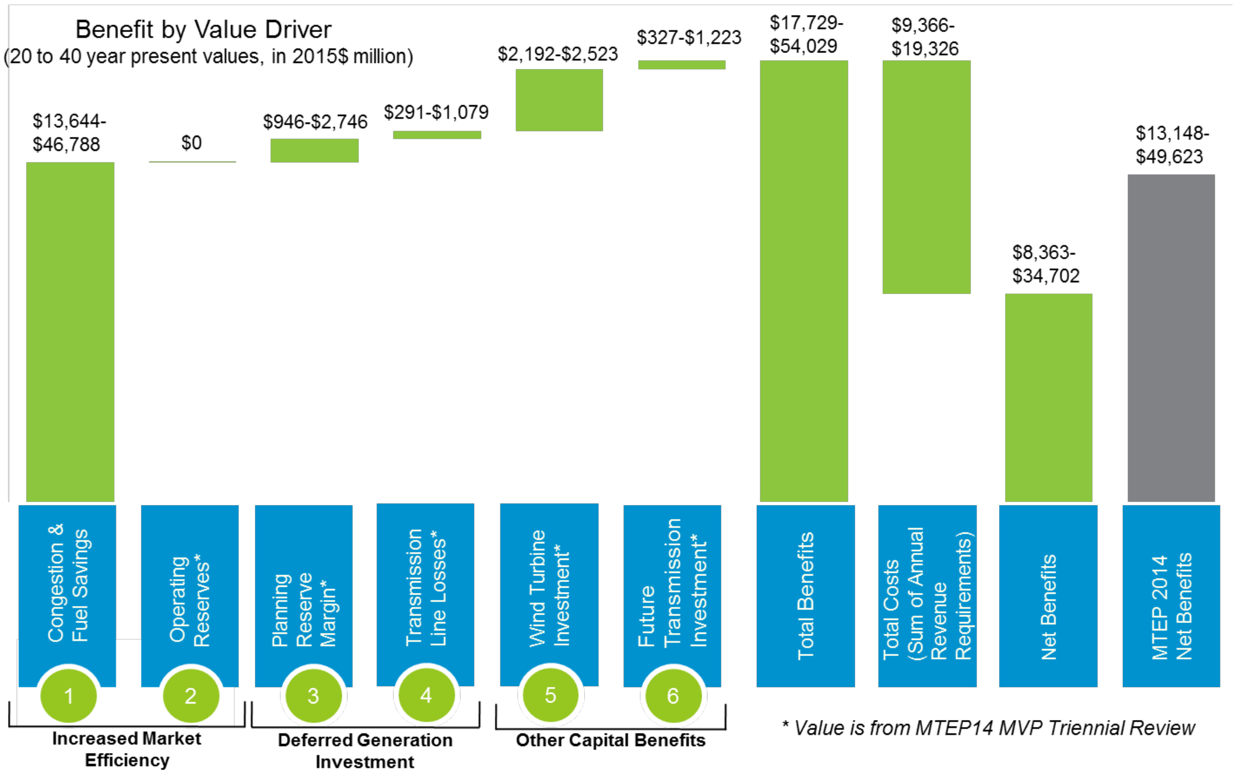


Figure 7.5-1: MVP Portfolio economic benefits from MTEP15 MVP Limited Review with values from MTEP14 MVP Triennial Review

The bulk of the decrease in benefits is due to a decrease in the assumed natural gas price forecast in MTEP15 compared to MTEP14. In addition, the MTEP16 natural gas assumptions, which will be used in the MTEP16 MVP Portfolio Limited Review, were studied and are comparable to the MTEP15 forecast. Under each of the natural gas price assumption sensitivities, the MVP Portfolio is projected to provide economic benefits in excess of costs (Table 7.5-1).

Natural Gas Forecast Assumption	Total Net Present Value Portfolio Benefits ($M-2015)	Total Portfolio Benefit-to-Cost Ratio
MTEP15 – MVP Limited Review	17,249 – 54,029	1.9 – 2.8
MTEP11	17,875 – 54,186	2.2 – 3.2

[41] Benefits 2 through 6 are from the MTEP14 MVP Triennial Review. The next MVP Triennial Review will occur with MTEP17.

MTEP14 – MVP Triennial Review	21,451 – 66,816	2.6 – 3.9
MTEP16	18,588 – 56,426	2.0 – 2.9

Table 7.5-1: MVP Portfolio economic benefits and natural gas price sensitivities[42]

Increased Market Efficiency

The MVP Portfolio allows for a more efficient dispatch of generation resources, opening markets to competition and spreading the benefits of low-cost generation throughout the MISO footprint. The MVP Review estimates that the MVP Portfolio will yield $14 to $47 billion in 20- to 40-year present value adjusted production cost benefits to MISO's North and Central regions – a decrease of up to 21 percent from the MTEP14 net present value.

The decrease in congestion and fuel savings benefits relative to MTEP14 is primarily due to a decrease in the out-year natural gas price forecast assumptions (Figure 7.5-2). The decreased escalation rate causes the assumed natural gas price to be lower in MTEP15 compared to MTEP14 in years 2024 and 2029 — the two years from which the congestion and fuel savings results are based.

A decrease in the natural gas price escalation rate, decreases congestion and fuel savings benefits by approximately 39 percent in MTEP15 compared to MTEP14

The MVP Portfolio allows access to wind units with a nearly $0/MWh production cost and primarily replaces natural gas units in the dispatch, which makes the MVP Portfolio's fuel savings benefit projection directly related to the natural gas price assumption. A sensitivity applying the MTEP14 Business as Usual (BAU) gas prices assumption to the MTEP15 MVP Limited Review model showed a 38.6 percent increase in the annual year 2029 MTEP15 congestion and fuel savings benefits (Figure 7.5-2).

Post MTEP14 natural gas price forecast assumptions are more closely aligned with those in the original business case of MTEP11. A sensitivity applying the MTEP16 BAU natural gas prices to the MTEP15 analysis shows just a slight increase in year 2029 MTEP15 adjusted production cost savings.

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

[42] Sensitivity performed applying MTEP16 natural gas price to the MTEP15 congestion and fuel savings model. MTEP11 and MTEP14 values come from the MTEP14 MVP Triennial Review Report.

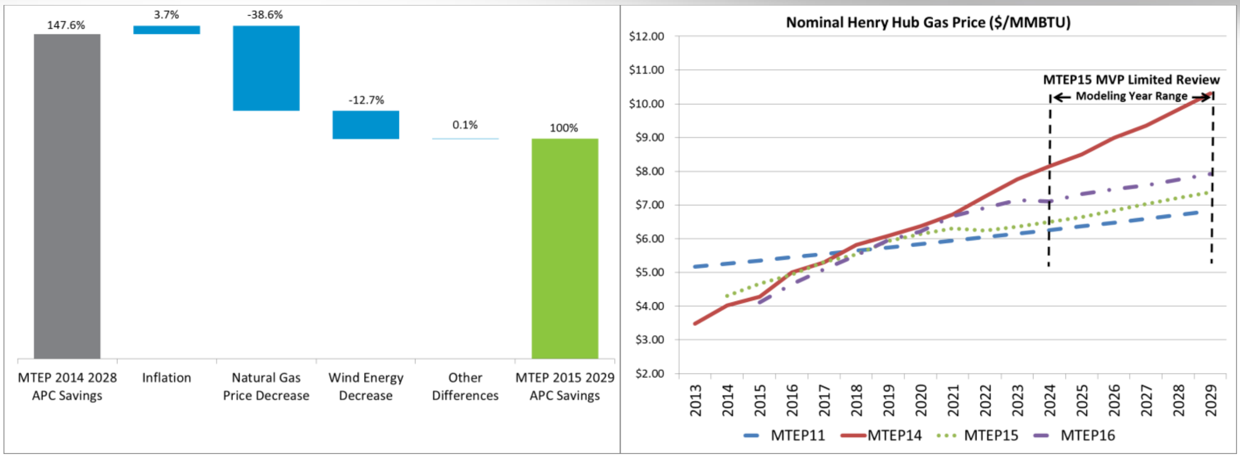


Figure 7.5-2: Breakdown of congestion and fuel savings decrease from MTEP14 to MTEP15

Distribution of Economic Benefits

The MVP Portfolio provides benefits across the MISO footprint in a manner that is roughly equivalent to costs allocated to each local resource zone (Figure 7.5-3). The MVP Portfolio's benefits are at least 1.6 to 2.0 times the cost allocated to each zone.

> Benefit-to-cost ratios have decreased since MTEP14, yet remain comparable to the original business case in MTEP11

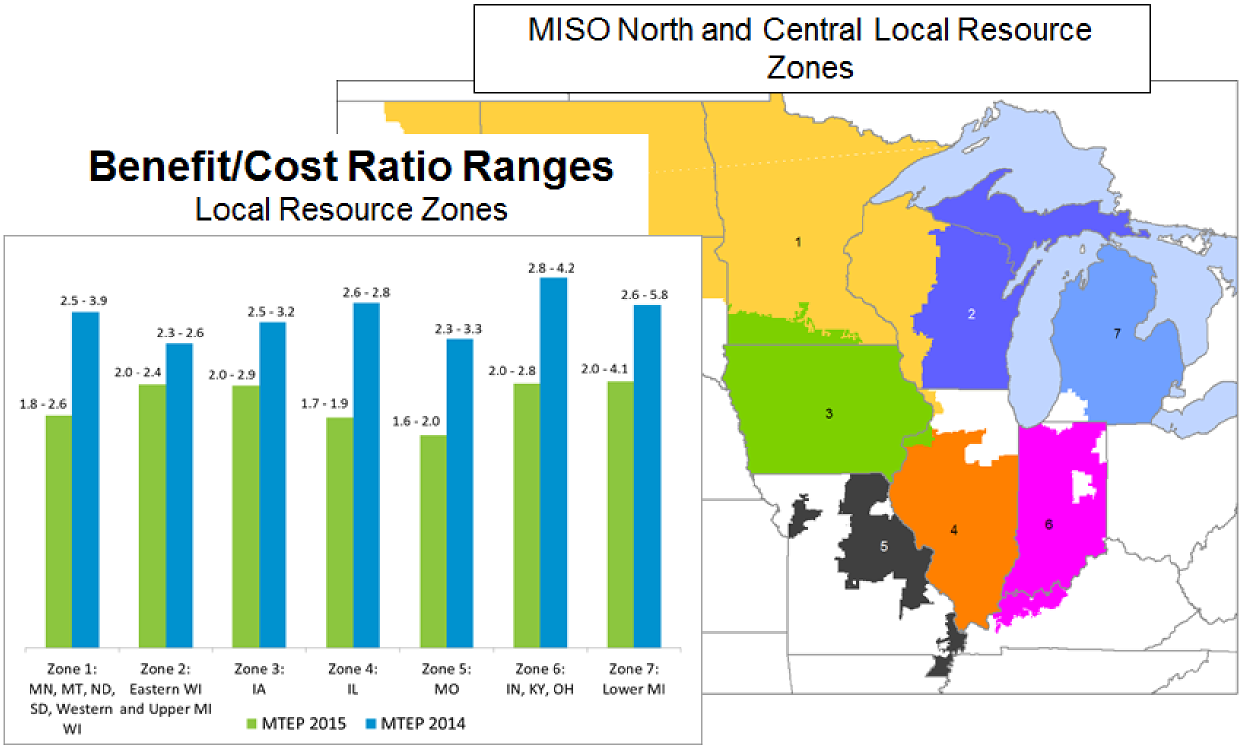


Figure 7.5-3: MVP Portfolio total benefit distribution

Going Forward

MTEP16 will feature a Limited Review of the MVP Portfolio benefits. Each Limited Review will provide an updated assessment of the congestion and fuel savings using the latest portfolio costs and in-service dates. Beginning in MTEP17, in addition to the Full Triennial Review, MISO will perform an assessment of the congestion costs, energy prices, fuel costs, planning reserve margin requirements, resource interconnections and energy supply consumption based on historical data.

Chapter 8
Interregional Studies

8.1 Policy Studies: Interregional PJM

MISO and PJM Interconnection, a Pennsylvania-based regional transmission organization (RTO) that shares borders with MISO, concluded an 18-month MISO-PJM Joint Coordinated Planning Study in 2014 that looked at multiple futures and 80-plus major project proposals. While the joint study did not produce any actionable results, it identified additional areas for coordination.

For 2015, MISO and PJM agreed to focus their joint study on FERC Order 1000 compliance, a Quick Hits study, targeted coordinated studies and continuation of the interregional process enhancement review.

Quick Hits

Due to appreciable levels of market-to-market congestion, MISO and PJM decided to focus on resolving the historical congestion while helping to inform future metric and process enhancements. A near-term study to evaluate historical market-to-market congestion and find small but important fixes, dubbed Quick Hits, was introduced to stakeholders at the end of 2014.

For this study, MISO and PJM analyzed historically congested market-to-market flowgates. Flowgates with significant congestion — day ahead and balancing — in 2013 and 2014 were considered as well as market-to-market flowgates that caused Auction Revenue Rights infeasibilities. MISO and PJM worked to identify valuable projects on the seam. A valuable project would relieve known market-to-market issues; be completed in a relatively short time frame; have a quick payback on investment; and not be greenfield projects. MISO and PJM coordinated with facility owners to identify the limiting equipment and potential upgrades. Limited reliability and production cost analyses were used to confirm the projects' effectiveness in relieving congestion.

The Quick Hit Study analyzed 39 market-to-market flowgates with $408 million of historical congestion between January 2013 and October 2014. The majority of the flowgates (22), accounting for $295 million of congestion, have planned or in-service MTEP or Regional Transmission Expansion Plan (RTEP) upgrades. The remaining flowgates had either no recent congestion or no recommended projects. The MISO-PJM Interregional Planning Stakeholder Advisory Committee (IPSAC) identified two potential Quick Hit projects for MISO and PJM to jointly evaluate.

- Beaver Channel – Sub 49 161 kV SCADA Upgrade
- Michigan City – LaPorte 138 kV Sag Remediation and CT Replacement

A key finding of the study was that most of the highest cost constraints already had an MTEP or RTEP project in the works. The RTOs will continue to track these projects to ensure the congestion is addressed.

The two potential projects addressing historical congestion were evaluated for approval and funding. The Beaver Channel – Sub 49 flowgate SCADA upgrade was placed in-service mid-year by the Transmission Owner. The current level of congestion seen in production cost models does not support incremental upgrades beyond the SCADA work, so no additional Quick Hit is recommended. MISO and PJM will continue to monitor the historical congestion on this flowgate.

The Michigan City – LaPorte Quick Hit project is not recommended at this time because the future congestion pattern is uncertain due to a new 138 kV substation that was recently placed in service. The new station, a tap on the Michigan City – LaPorte 138 kV line, has additional 138 kV connectivity and changes the historical congestion flows, especially on Michigan City – LaPorte, during high west-to-east transfers. The IPSAC will continue to monitor the congestion in this area through the targeted study below.

Targeted Studies

Continuing on the Quick Hits work, MISO and PJM agreed to focus on smaller, targeted study areas to address seams issues. One such area is Southwest Michigan and Northern Indiana. MISO and PJM propose to evaluate the MTEP and RTEP projects in this area to determine whether the historical congestion, seen in the Quick Hits analysis, would be fully mitigated. This analysis will also evaluate the effect of expected operational reconfigurations on the performance of planned projects and whether additional solutions are needed.

Another targeted area is the Quad Cities. This study is primarily reliability driven but will include economic analysis and will determine if there are projects to supplement or replace three MTEP Appendix B projects at the border of Iowa and Illinois.

MISO and PJM aim to complete all targeted study analyses by the end of 2015. Potential projects identified will be recommended for further study in 2016 in the appropriate MTEP or RTEP process(es).

FERC Order 1000

On December 18, 2014, FERC conditionally accepted the MISO-PJM interregional FERC Order 1000 filing, subject to a further compliance filing date of July 31, 2015. FERC rejected MISO’s proposal to eliminate cost allocation for Cross-Border Baseline Reliability Projects. FERC also noted that MISO and PJM had not addressed how public policy projects would be coordinated and cost shared.

MISO, PJM, and their stakeholders collaboratively developed Joint Operating Agreement language to address all FERC compliance directives. MISO and PJM agreed to use an avoided cost methodology for cost-sharing reliability and public policy interregional project types. Timely compliance filings were submitted by MISO and PJM on July 31, 2015.

IPSAC

In the second half of 2015, the MISO-PJM Interregional Planning Stakeholder Advisory Committee (IPSAC) continued discussions from 2014 on interregional metric and process enhancements. In this effort, MISO and PJM work with stakeholders to identify changes to lower or remove undue hurdles to approve interregional projects.

8.2 Policy Studies – Interregional Southwest Power Pool

The MISO-Southwest Power Pool (SPP) Coordinated System Plan (CSP) Study jointly evaluated seams transmission issues and identified transmission solutions to the benefit of MISO and SPP. This study incorporated two parallel efforts:

- Economic evaluation of seams transmission issues
- Assessment of potential reliability violations

The CSP study began in January 2014 and concluded on June 30, 2015.[43] This chapter will provide a high-level summary of the analysis performed by MISO and SPP staff. Additional details can be found in the MISO-SPP CSP Coordinated System Plan Study Report. With approval from the Interregional Planning Stakeholder Advisory Committee (IPSAC) and the Joint Planning Committee (JPC), three potential Interregional Projects were recommended for regional review. The following projects were evaluated in both the MISO and SPP regional planning processes:

- Elm Creek to NSUB 345 kV
- Alto Series reactor
- South Shreveport – Wallace Lake 138 kV rebuild

MISO's goal in interregional planning is to identify more cost effective and efficient projects that would not be found in traditional regional planning. Ensuring that the benefits of proposed projects outweigh the costs is a guiding principle for MISO transmission planning. After continued work with stakeholders and SPP staff, MISO determined through the regional review process that none of the proposed Interregional Projects demonstrated a clear and compelling benefit to the customers in the MISO region as an interregional project. However, the Alto-Series Reactor will continue to be evaluated within the MISO regional plan. The scope of the regional review conducted by MISO staff can be found toward the end of Chapter 8.2. The other two projects are viewed as beneficial by SPP or SPP's members and as such may proceed to their board for approval. Note that the MISO-SPP Joint Operating Agreement (JOA) stipulates that both the MISO and SPP Board of Directors must both approve an Interregional Project for the project to receive interregional cost allocation.

Although the first coordinated study did not identify any cost shared interregional projects, MISO and SPP were able to advance our joint planning processes. This first joint study between MISO and SPP is a significant milestone in the evolution of our coordination efforts. MISO remains committed to taking lessons learned from this process and continuing to improve both the planning approach and associated cost allocation methods as appropriate.

Background

As part of the FERC-filed MISO-SPP Joint Operating Agreement (JOA), and in an effort to enhance interregional coordination and plan transmission efficiently, MISO and SPP conducted a joint annual

[43] The final study report can be found here: https://www.misoenergy.org/Library/Repository/Study/Interregional%20Planning/MISO-SPP%20Coordinated%20System%20Plan%20Report.pdf

issues review with stakeholders. The IPSAC met on January 21, 2014, and the general consensus from stakeholders was that there are many transmission issues needing evaluation. The range of issues includes:

- Congestion
- Integration of the MISO South Region
- Expanded market operation by SPP
- Real-time operational issues
- Reliability issues
- Public policy requirements

The JPC, during the development of the CSP scope, took into consideration those proposed issues. After further review with stakeholders the study scope was finalized in June 2014[44].

The proposed Order 1000 interregional coordination procedures, pending at FERC, were used to guide the process for this study. Previous coordinated efforts included development of a joint future that included discussions around the uncertainty variables in a joint and common model coincident in both the MISO and SPP planning processes. This joint study provided an initial effort to enhance interregional coordination, to jointly evaluate seams transmission issues and to identify efficient transmission solutions to the benefit of both MISO and SPP.

Economic Evaluation and Issues Identification

The JPC reviewed 34 transmission issues submitted by stakeholders for study consideration. In addition to the submitted transmission issues, the JPC included in the study scope an evaluation to review economic congestion utilizing historical top congested flowgates from market reports and projected congestion resulting from the joint economic model developed for this study effort.

The projected congestion analysis identified the top congested flowgates based on the 2024 CSP Study model (Table 8.2-1). The flowgates were ranked using these indicators:

1. Binding Hours — number of hours in a year the flowgate binds
2. Shadow Price — reduced production cost for 1 MW increase of thermal rating on the flowgate
3. Congestion Costs — flowgate shadow price multiplied by MW flow on the flowgate

Issue Id	Constraint Name	Contingency
M-1	Frederick Town AECI – Frederick Town AMMO 161 kV	Lutesville – St. Francois 345 kV
S-2	North East - Charlotte 161 kV	Iatan - Stranger 345 kV
M-5	Blue Earth - Winnebago 161 kV	Lakefield Junction - Lakefield 345 kV
M-6	Wapello 161/69 kV Transformer T1	Wapello 161/69 kV Transformer T2
M-9	Prairie 345/230 kV Transformer T2	Prairie 345/230 kV Transformer T1
M-10	Swartz - Alto 115 kV	Baxter Wilson - Perryville 500 kV
M-11	Reed - Dumas 115 kV	Sterlington - El Dorado 500kV
S-12	Essex - Idalia 161 kV	Essex - New Madrid 345 kV
M-13	Grimes - Mt Zion 138 kV	Grimes - Ponderosa 230 kV
S-14	South Shreveport - Wallace Lake 138 kV	Dolet Hills 345/230 kV Transformer

Table 8.2-1: MISO-SPP Coordinated System Plan economic issues list

[44] https://www.misoenergy.org/Events/Pages/IPSAC20140512.aspx

Economic Transmission Solution Development

The historical and projected congestion analysis, combined with the issues submitted by stakeholders, guided the development of transmission solution ideas evaluated as potential MISO-SPP Interregional Projects. The solution development and evaluation focused on the set of identified congested flowgates that captured a majority of congestion costs (e.g., greater than 70 percent).

RTO staff and stakeholders could propose transmission solutions to address the identified transmission issues. Solutions were solicited through the MISO-SPP IPSAC meetings.

MISO and SPP staffs solicited a request for stakeholders to submit potential projects addressing congestion identified in the issues list presented at the October 7, 2014, IPSAC meeting. Stakeholders submitted a total of 39 projects addressing approximately 75 percent of the issues posted. In addition to stakeholder submissions, staff submitted 15 additional projects for consideration.

A preliminary screening analysis performed on all proposed transmission solution ideas determined the solution ideas with the greatest potential that warranted further evaluation. All consolidated transmission solution ideas and all transmission solution ideas with potential value were evaluated for adjusted production cost (APC) benefits to MISO and SPP.

The screening index was calculated by using results of model year 2024 of APC benefits compared to that model year's project costs. If the screening index was at least .5 and the project provided significant benefits to both MISO and SPP, the project passed screening.

These projects passed the screening process:

- St. Francois – Fletcher 345 kV
- St. Francois – Taum Sauk – Fletcher 345 kV
- Walker Tap – Rivtrin 138 kV
- Series Reactor on Alto – Swartz 115 kV
- S. Shreveport – Wallace Lake 138 kV
- Elm Creek – Mark Moore 345 kV
- Elm Creek NSUB 345 kV

Benefit-to-Cost Analysis

To calculate an indicative benefit-to-cost ratio for proposed transmission solutions, a 20-year net present value calculation of benefits and costs was used[45]. Benefits were calculated by the change in APC with and without the proposed Interregional Project. The APC accounted for purchases and sales. The APC benefit metric was calculated for the simulated years 2019 and 2024. Benefit calculations for intermediary years used interpolation and years beyond 2024 used extrapolation. The period covered by the benefit and cost calculation was 20 years, starting with the project's in-service year.[46] The annual costs were calculated using an average carrying cost of existing Transmission Owners in MISO and SPP. The present value calculation assumed an 8 percent discount rate (Table 8.2-2).

Project Description	NPV Project Cost (2015-M$)	B/C Ratio	Benefit: MISO%	Benefit: SPP%

[45] There is not a B/C ratio requirement in the CSP study.

[46] Initially MISO and SPP have made the assumption that the in-service date for all projects is 2024.

Walker Tap - Rivtrin 138 kV	$48.7	1.05	117%	-17%
St Francois - Fletcher 345 kV	$113	.51	88%	12%
Elm Creek – Mark Moore 345 kV	$156.3*	1.03	7%	93%
Elm Creek – NSUB 345 kV	$133.8*	1.22	20%	80%
Series Reactor on Alto – Swartz 115 kV	$5.4*	4.32	86%	14%
S Shreveport - Wallace Lake 138 kV	$17.7*	2.61	80%	20%

*Denotes study level cost estimates (+/- 30%)

Table 8.2-2: Results of benefit-to-cost analysis

Sensitivity Analysis

After receiving input from stakeholders, the study scope included a high natural gas price, carbon price and modeling of the Sub-Regional Power Balance Constraint as sensitivities. Additional analyses were performed on projects being considered for recommendation by the JPC using the three sensitivities. The proposed Interregional Projects identified in the assessment utilizing the Business as Usual Future were evaluated using the three sensitivities to determine how the projects perform under these scenarios. Results from the sensitivities were informational only and did not have an impact on the benefit split between MISO and SPP or the final calculated benefit-to-cost ratio.

With input from the IPSAC, the JPC set the high natural gas price to $8.66/MMBtu for 2024 and the carbon price to $64/ton in 2024.

The potential changes in APC benefits for each project are the results of a one-year analysis utilizing the 2024 model (Table 8.2-2). As an example, the High Natural Gas Price sensitivity indicated that the benefits attributed to the project Series Reactor on Alto – Swartz would increase by 43 percent if the gas price was set to $8.66/MMBtu.

Project Description	**% Change in APC Benefits (MISO and SPP combined)**		
	High Natural Gas Price	**Carbon Tax**	**SRPBC**
Series Reactor on Alto – Swartz 115 kV	+43%	+37%	+73%
S Shreveport - Wallace Lake 138 kV	-79%	-58%	-39%
New Elm Creek – Mark Moore 345 kV	+52%	-62%	-7%
New Elm Creek – NSUB 345 kV	+54%	-67%	-7%

Table 8.2-2: Sensitivity Analysis Results

Reliability Assessment

The reliability assessment in this scope included multiple studies. This multi-faceted approach allowed MISO and SPP to evaluate various transmission issues near the MISO-SPP seam. The phases of the reliability assessment included in the CSP study were:

- Review of reliability projects near the seam, identified in the respective regional planning processes of MISO and SPP, to determine if there were interregional alternatives to the currently proposed transmission solutions
- A steady-state assessment using jointly developed powerflow models consistent with reliability processes used by each region
- A dynamics assessment to test system stability using a light load powerflow case

Solutions to address the identified reliability issues were developed and reviewed in coordination with the respective regional planning processes. These solutions, which may include alternative projects that more effectively mitigate identified issues, were submitted by:

- Respective RTO staff
- Stakeholders through regional planning processes
- Stakeholders through MISO-SPP IPSAC meetings

Transmission solutions to address identified reliability issues were evaluated to determine the most efficient and cost-effective method for the identified constraints. Projects addressing reliability issues were also evaluated for potential economic benefits to MISO and SPP. The projects identified to address the reliability issues were not found to provide substantial economic benefit to MISO or SPP in the context of this study scope.

Steady-State Contingency Analysis

An N-1 contingency analysis was conducted using a joint powerflow model. The joint model merged the most recent powerflow cases used in the MISO and SPP regional planning processes. Specifics of the model development process can be found in the MISO-SPP Coordinated System Plan Study Report[47].

Issues Assessment

MISO and SPP staff compared criteria used in their respective regional planning processes to develop a methodology for use in the CSP study. Criteria used to determine the potential violations were:

- Monitored
    - Facilities 100 kV and above in the MISO and SPP footprints
    - Thermal overloads greater than 100 percent
    - Base case voltages below .95 pu
    - Contingency voltages below .90 pu
    - More stringent local planning criteria
- Contingencies
    - Full N-1
    - MISO and SPP Category B contingencies submitted by stakeholders

MISO and SPP jointly performed separate base-case (N-0) and contingency (N-1) analyses that provided a list of potential thermal and voltage violations (Table 8.2-2; Figure 8.2-2).

Needs	Overall	Unique	MISO System	SPP System
Overloads	50	18	14	4
Low Voltages	84	34	31	3

Table 8.2-3: Steady-state thermal and voltage issues

[47] https://www.misoenergy.org/Library/Repository/Study/Interregional%20Planning/MISO-SPP%20Coordinated%20System%20Plan%20Report.pdf

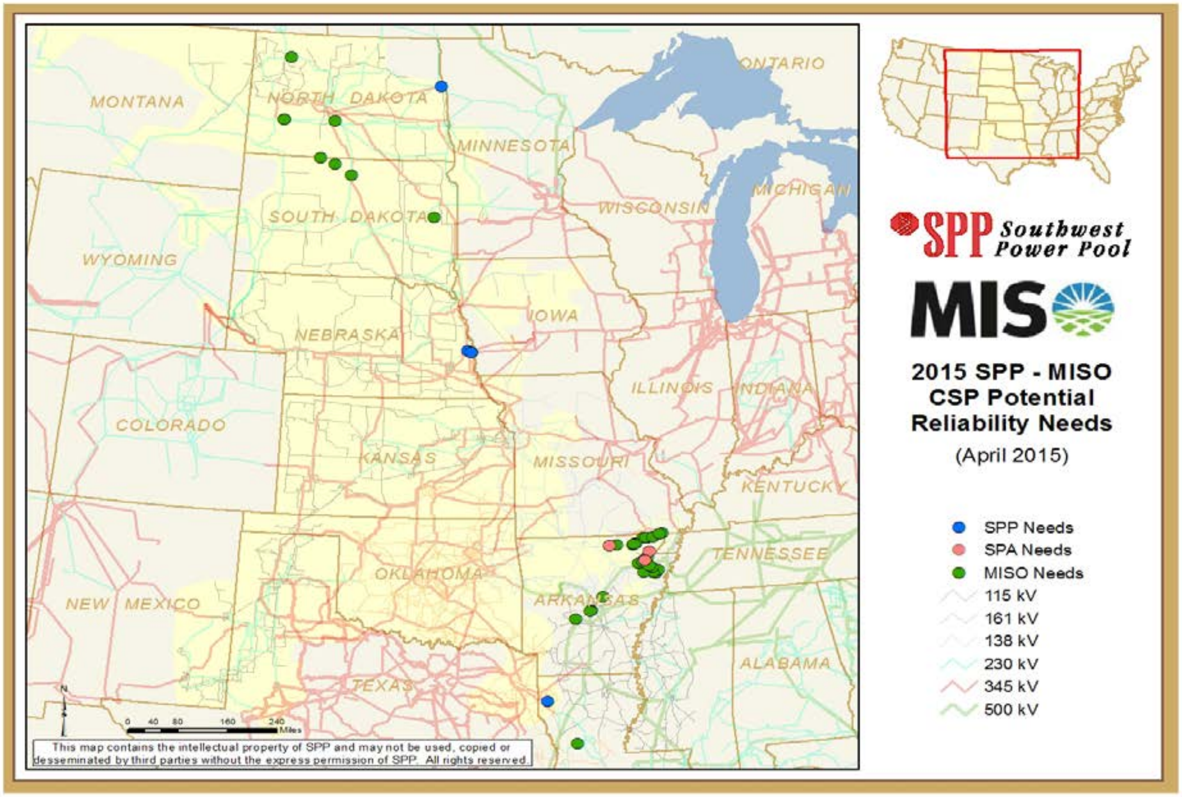


Figure 8.2-3: Map of steady-state thermal and voltage issues

MISO and SPP requested stakeholders submit any potential solutions that could address any of the listed issues. Staff received 12 project submissions from stakeholders. In addition to stakeholder-submitted projects, MISO and SPP staff leveraged previously identified regional projects from the MTEP and the Integrated Transmission Plan (ITP) processes, respectively. MISO and SPP analyzed these regional projects to determine if they addressed the issues identified in the CSP.

MISO and SPP evaluated projects to determine:

- If benefit was provided to both MISO and SPP
- If thermal overloads were solved to under 100 percent
- If base-case voltages were solved to within applicable planning criteria
- If contingency voltages were solved to within applicable planning criteria
- If interregional solutions were more cost effective than MISO and SPP regional projects

The transmission solution evaluation phase of the steady state assessment did not yield any Interregional Projects that were more cost-effective or efficient than previously identified regional solutions.

Dynamic Assessment

The dynamics assessment utilized a joint model developed from MISO's and SPP's regional models in a similar approach to the joint model used for the steady-state assessment. A 2019 light-load case was developed in an effort to highlight seasonal transient instability issues most likely to occur. MISO and SPP selected areas to be monitored that were adjacent to the MISO-SPP seam (Table 8.2-4).

SPP Areas		MISO Areas	
515 SWPA	645 OPPD	333 CWLD	600 XEL
520 AEPW	650 LES	356 AMMO	635 MEC
523 GRDA	652 WAPA	360 CWLP	615 GRE
536 WERE		608 MP	327 EES-EAI
540 GMO		613 SMMPA	332 LAGN
541 KCPL		620 OTP	351 EES
542 KACY		661 MDU	502 CLEC
544 EMDE		627 ALTW	503 LAFA
546 SPRM		633 MPW	504 LEPA
640 NPPD		694 ALTE	

Table 8.2-5: Areas modeled in Dynamics Assessment

The study used POM-TS's Fast Fault Screening (FFS) Tool to determine disturbances. The POM-TS FFS takes a single set of contingencies (N-1) and determines a severity ranking index (RI) and a critical clearing time (CCT). The ranking index takes into account kinetic energy, torque and voltage deviations to determine a score. A shorter clearing time and higher severity index score indicate a more severe disturbance. Contingencies resulting in a CCT of less than nine cycles to clear were chosen for further evaluation.

Study results showed that no instability was found for the simulated events. All machines were stable with good oscillation damping and bus voltages were within tolerances. Detailed results of the disturbances can be found in the MISO-SPP Coordinated System Plan Study Report[48].

Review of Regional Projects

MISO and SPP staff reviewed reliability projects from their respective regional processes. No regional projects of either RTO were identified as replacing the need for a project in the other respective regional process. Additionally there were no regional projects that could be replaced by an Interregional Project.

No-harm Test on Economic Projects

Interregional projects identified to address congestion were evaluated to ensure they do not create reliability issues. The evaluation may result in the modification of the Interregional Project or identification of additional interregional facilities that are needed to mitigate the projected reliability issue.

After the conclusion of the no-harm evaluation for the four economic projects considered, it was determined that no new reliability issues were identified due to the inclusion of the economic projects and that no mitigations were needed.

In addition to running each of the tested projects individually, they were analyzed as a group and again no new reliability issues were identified due to the inclusion of the projects as a group.

Interregional Projects Recommended for Regional Review

Based on the results of the economic assessment, MISO and SPP identified three projects for consideration as potential Interregional Projects:

- Elm Creek to NSUB 345 kV

[48] https://www.misoenergy.org/Library/Repository/Study/Interregional%20Planning/MISO-SPP%20Coordinated%20System%20Plan%20Report.pdf

- Alto Series reactor
- South Shreveport – Wallace Lake 138 kV rebuild

Each of these projects individually demonstrated benefit to the combined footprint that exceeds the costs of the projects over the initial 20 years of the project life.

Interregional Cost Allocation

As agreed to by MISO and SPP, and accepted by FERC, MISO and SPP used the APC benefit metric to allocate the costs to each planning region of proposed Interregional Projects addressing primarily economic congestion.

If the recommended Interregional Projects are approved by both the MISO and SPP Board of Directors, the costs will be allocated between MISO and SPP (Table 8.2-6).

Project	E&C Cost M$	MISO Cost %	SPP Cost %
Elm Creek - NSUB 345 kV	$140.7	20%	80%
Alto Series Reactor 115 kV	$5.3	86%	14%
S. Shreveport - Wallace Lake 138 kV Rebuild	$18.5	80%	20%

Table 8.2-6: Interregional cost allocation for potential MISO-SPP Interregional Projects

Regional Review Process Results

In accordance with MISO's Tariff and Transmission Planning Business Practice Manual 20, MISO performed a regional review of the three proposed Interregional Projects recommended by the JPC to MISO and SPP. The regional review scope included robustness testing and sensitivity analysis consistent with efforts performed through the MCPS process to determine the extent of benefits to the customers of MISO's region. The result of MISO's regional review process has concluded that the costs outweigh the benefits for two of the three proposed projects. MISO will continue to evaluate the Alto Series Reactor in the regional planning process. During the regional review process MISO modified its modeling of the SPP system to be consistent with load and generation assumptions used in the SPP planning process. Table 8.2-7 includes the increase of load as identified by SPP and re-siting of SPP's future generation at Wilkes and Basin (similar to the interregional study and as requested by SPP).

Project	MISO Regional Review Results				
	BAU	Generation Shift	Public Policy	Southern Industrial Renaissance	Weighted
Elm Creek - NSUB 345 kV	0.16	(0.09)	1.98	0.26	0.49
Alto Series Reactor 115 kV	6.23	2.05	(2.73)	1.93	4.95
S. Shreveport - Wallace Lake 138 kV Rebuild	1.66	1.16	(0.98)	1.01	0.86

Table 8.2-7: MISO Regional Review Results

Updates to the MISO SPP CSP report will be posted on the SPP page of the MISO Interregional Coordination section under the "Planning" tab of the MISO website (www.misoenergy.org).[49]

FERC Order 1000

On February 19, 2015, the MISO-SPP interregional FERC Order 1000 filing was conditionally accepted at FERC, subject to a further compliance filing date of August 18, 2015. FERC directed MISO and SPP to propose a cost allocation methodology for interregional transmission facilities addressing regional transmission needs driven by public policy. FERC also directed MISO to adopt SPP's proposed methodology of using a combination of avoided cost and adjusted production cost benefits for interregional transmission facilities addressing regional reliability needs.

MISO, SPP and their stakeholders collaboratively developed language to address all FERC compliance directives. The updated Joint Operating Agreement language was filed on August 18, 2015. MISO and SPP agreed to use an avoided cost plus adjusted production cost methodology for reliability driven Interregional Projects and to use an avoided cost methodology for public policy driven Interregional Projects. MISO and SPP maintained the previously accepted adjusted production cost methodology for economically driven Interregional Projects.

[49] https://www.misoenergy.org/Planning/InterregionalCoordination/Pages/SouthwestPowerPoolIPSAC.aspx

8.3 MISO/ERCOT Study Scope

A collaborative effort between MISO and ERCOT is in progress with the purpose of understanding each system's unique transmission issues along the seam. The potential benefits of joint planning will be evaluated with transmission solutions that efficiently address the identified issues. An economic evaluation will identify solutions that benefit both systems, and the effort will include an assessment of potential reliability violations. The scope of the collaborative effort is in a preliminary stage with an unspecified timeframe.

8.4 Southeastern Regional Transmission Planning

The Southeastern Regional Transmission Planning (SERTP) process consists of the following FERC-jurisdictional sponsors:

- Duke Energy (Duke Energy Carolinas LLC and Duke Energy Progress Inc.)
- Louisville Gas and Electric Co. and Kentucky Utilities Co. (LG&E/KU)
- Ohio Valley Electric Corp. (OVEC), including its wholly owned subsidiary Indiana-Kentucky Electric Corp.
- Southern Co. Services Inc. (Southern)
- Dalton Utilities
- Georgia Transmission Corp. (GTC)
- Municipal Electric Authority of Georgia (MEAG)
- PowerSouth
- Associated Electric Cooperative Inc. (AECI)
- Tennessee Valley Authority (TVA)

Throughout 2015, MISO and SERTP collaborated on meeting the directives from the January 23, 2015, FERC Order related to FERC Order 1000 interregional transmission planning. Additionally, Section X of MISO's Attachment FF describes the coordination procedures for interregional transmission coordination with SERTP.

FERC Order 1000

On January 23, 2015, FERC conditionally accepted the MISO-SERTP FERC Order 1000 interregional transmission planning compliance filing, subject to further compliance filing. MISO and the SERTP companies requested and were granted a 90-day extension to June 22, 2015. MISO and the SERTP parties collaborated and came to agreement on tariff language to address the FERC directives, which was circulated to MISO and SERTP stakeholders. For cost allocation, MISO and SERTP will use an avoided cost methodology that accounts for reliability, economic and public policy benefits. On June 22, 2015, MISO and SERTP filed their compliance filings to FERC, which included redlined and clean tariff versions of Attachment FF as well as transmittal letters from both regions.

Interregional Coordination

MISO and SERTP have tariff requirements requiring interregional transmission coordination as described in Section X of Attachment FF of MISO's Tariff. This includes a meeting at least once per year to facilitate interregional coordination procedures although meetings may occur more frequent.

At least annually, MISO and the SERTP will exchange their most current regional transmission plans including powerflow models and associated data used in the regional transmission planning processes. This exchange typically occurs during the first calendar quarter of each year. Additional transmission-based models and data may be exchanged between the SERTP and MISO as necessary and if requested. The data will be posted on the pertinent regional transmission planning process' websites, consistent with the posting requirements of the respective regional transmission planning processes, and subject to the applicable treatment of confidential data and Critical Energy Infrastructure Information (CEII).

At least biennially, MISO and the SERTP will meet to review the respective regional transmission plans. Such plans include each region's transmission needs as prescribed by each region's planning process. This review will occur on a mutually agreeable timetable, taking into account each region's regional transmission planning process timeline. If, through this review, MISO and the SERTP identify a potential interregional transmission project that may be more efficient or cost-effective than regional transmission projects, the Transmission Provider and the SERTP will jointly evaluate the potential interregional transmission project pursuant to Section X.C.4 of Attachment FF of MISO's Tariff.

In 2015, MISO and the SERTP sponsors met on several occasions. The first meeting was a conference call on January 22, 2015, where MISO and SERTP reviewed each other's regional processes and timelines. MISO and SERTP exchanged ideas on how data can and will be shared between the regions for interregional coordination. In the latter part of 2015, once non-disclosure agreements/CEIIs are in place, data exchange will occur. The data used for the purposes of interregional coordination will be posted to each of the respective regional transmission planning process websites.

In early 2016, MISO and the SERTP companies will meet to discuss each other's regional transmission plans to determine if there may be interregional transmission projects that are more cost-effective or efficient than regional projects. If potential interregional transmission projects are identified through the review of the regional transmission plans, MISO and SERTP will jointly evaluate those projects pursuant to the processes outlined in Section X.C.4 of Attachment FF of MISO's Tariff.

8.5 Policy Studies – Interregional MAPP

No interregional studies were performed in MTEP15 with the Mid-Continent Area Power Pool (MAPP). Northwestern Energy, the sole FERC jurisdictional member in MAPP, will join Arkansas-based Southwest Power Pool (SPP) in October 2015, removing FERC Order 1000 interregional compliance obligations with MAPP. MISO, Northwestern Energy and SPP filed FERC Order 1000 comments articulating this point on May 1, 2015. Per the filing, “MISO shall monitor developments in MAPP and continue to collaborate with the remaining MAPP members as part of MISO’s open and transparent planning process.”

Book 4
Regional Energy Information

Chapter 9
Regional Energy Information

9.1 MISO Overview

MISO is a not-for-profit, member-based organization that administers wholesale electricity and ancillary services markets. MISO provides customers a wide array of services including reliable system operations; transparent energy and ancillary service prices; open access to markets; and system planning for long-term reliability, efficiency and to meet public policy needs.

By improving grid reliability and increasing the efficient use of generation, MISO saves the average residential customer $40 to $56 a year, at an annual expense of $5 per customer

MISO has 51 Transmission Owner members with more than $31.4 billion in transmission assets under MISO's functional control. MISO has 122 non-transmission owner members that contribute to the stability of the MISO markets.

The services MISO provides translate into material benefits for members and end users. By improving grid reliability and increasing the efficient use of generation, MISO saves the average residential customer $40 to $56 a year at an annual expense of $5 per customer. The MISO 2014 Value Proposition[50] explains the various components of this benefits calculation.

The value drivers are:

1. **Improved Reliability**, which captures the value of MISO's broader regional view and state-of-the art reliability tool set. Improved Reliability in the region is measured by the availability of the transmission system.
2. **Dispatch of Energy**, which quantifies the real-time and day-ahead energy market's use of security constrained unit commitment and centralized economics dispatch. Improved Reliability and Dispatch of Energy optimize the use of all resources within the region based on bid and offers by market participants.
3. **Regulation**, which represents the savings created by use of MISO's regulations market. With the regulation market in place, the amount of regulation required within the MISO footprint dropped significantly. The drop results from a regional move to a centralized common footprint regulation target rather than several non-coordinated regulation targets.
4. **Spinning Reserve**, which includes the formation of the Contingency Reserve Sharing Group and the implementation of the Spinning Reserves Market. Both aspects contributed to the decline of the total spinning reserve requirement, freeing low-cost capacity to meet energy requirements.
5. **Wind Integration**, which quantifies the value of regional planning of wind resources. The centralized look at the footprint allows for more economic placement of wind resources. Economic placement of wind resources reduces the overall capacity needed to meet required wind energy output.
6. **Compliance**, which shows the time and money savings associated with MISO consolidating FERC and NERC compliance obligations. Before MISO, utilities in the MISO footprint were responsible for managing FERC and NERC compliance.
7. **Footprint Diversity**, which captures the value of MISO's large footprint. MISO's size increases the load diversity, allowing for a decrease in regional planning reserve margins from 18.08 percent to 14.98 percent. The decrease in the planning reserve margins delays the need to construct new capacity.

[50] https://www.misoenergy.org/WhatWeDo/ValueProposition/Pages/ValueProposition.aspx

8. **Generator Availability Improvement**, which displays the savings created by improved power plant availability. MISO's wholesale markets increased power plant availability by 1.9 percent, which delays the need to construct new capacity.
9. **Demand Response**, which MISO enables through dynamic pricing, direct load control and interruptible contracts. MISO-enabled demand response further delays the need to construct new capacity.
10. **Cost Structure**, through which MISO provides these services. It is expected to stay relatively flat. The costs of these services represent a small percentage of the benefits and real savings to MISO customers.

MISO provides these services for the largest RTO geographic footprint in the U.S. MISO undertakes this mission from control centers in Carmel, Ind.; Eagan, Minn.; and Little Rock, Ark., with regional offices in Metairie, La., and Little Rock, Ark. (Figure 9.1-1).

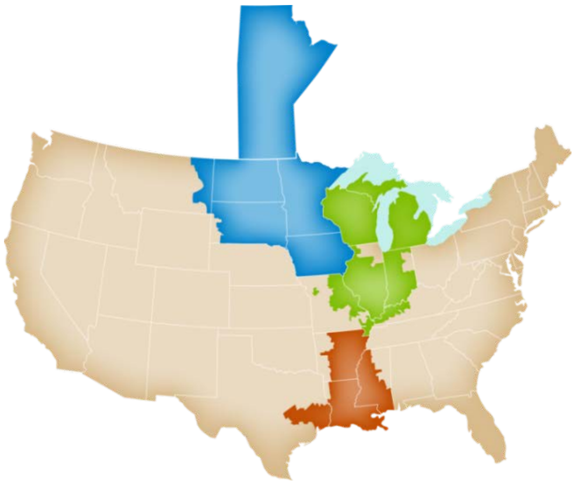


Figure 9.1-1: The MISO geographic footprint

MISO By The Numbers

Generation Capacity (as of June 2015)

- 178,396 MW (market)
- 192,803 MW (reliability)[51]

Historic Instantaneous Peak Load (set July 20, 2011)

- 127,125 MW (market)
- 133,181 MW (reliability)[52]

Miles of transmission

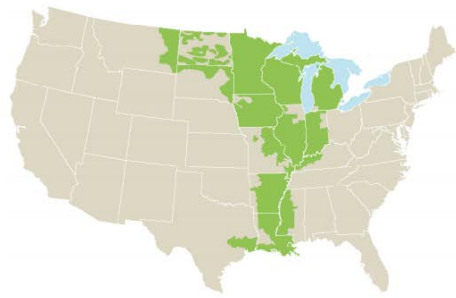
- 65,800 miles of transmission
- 8,400 miles of new/upgraded lines planned through 2023

Markets

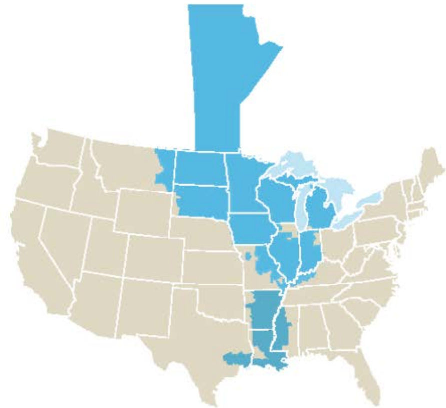
- $37 billion in annual gross market charges (2014)
- 2,446 pricing nodes
- 413 Market Participants serving over 42 million people

Renewable Integration

- 15,215 MW active projects in the interconnection queue
- 14,162 MW wind in service
- 14,532 MW registered wind capacity (Jun. 2015)



MARKET AREA



RELIABILITY COORDINATION AREA

51 MISO Fact Sheet

9.2 Electricity Prices

Wholesale Electric Rates

MISO operates a market for the buying and selling of wholesale electricity. The price of energy for a given hour is referred to as the Locational Marginal Price (LMP). The LMP represents the cost incurred, expressed in dollars per megawatt hour, to supply the last incremental amount of energy at a specific point on the transmission grid.

The MISO LMP is made up of three components: the Marginal Energy Component (MEC), the Marginal Congestion Component (MCC) and the Marginal Loss Component (MLC). MISO uses these three components when calculating the LMP to capture not only the marginal cost of energy but also the limitations of the transmission system.

In a transmission system without limitations, the LMP across the MISO footprint would be the same. In reality, the existence of transmission losses and transmission line limits result in adjustments to the cost of supplying the last incremental amount of energy. For any given hour, the MEC of the LMP is the same across the MISO footprint. However, the MLC and MCC create the difference in the hourly LMPs.

The 24-hour average day-ahead LMP at the Indiana hub over a two-week period highlights the variation in the components which make up the LMP. The time frame includes portions of the extreme weather events of 2015 (Figure 9.2-1). A real-time look at the MISO prices can be found on the LMP Contour Map[53] (Figure 9.2-2).

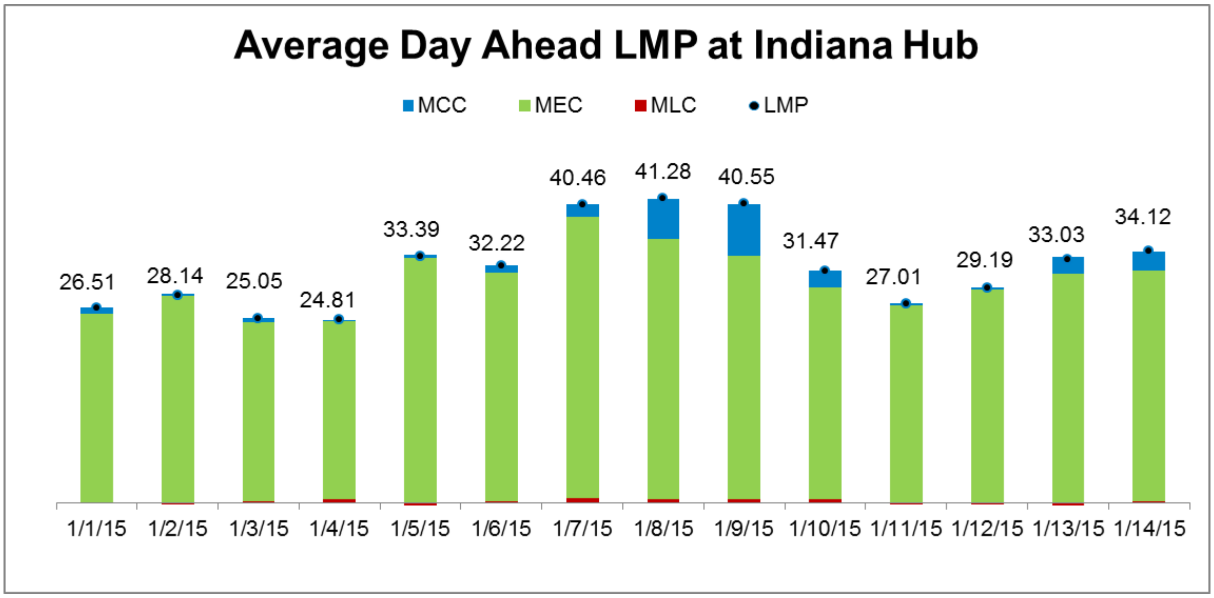


Figure 9.2-1: Average day-ahead LMP at the Indiana hub

[53] Market Analysis Monthly Operations Report: https://www.misoenergy.org/LMPContourMap/MISO_All.html

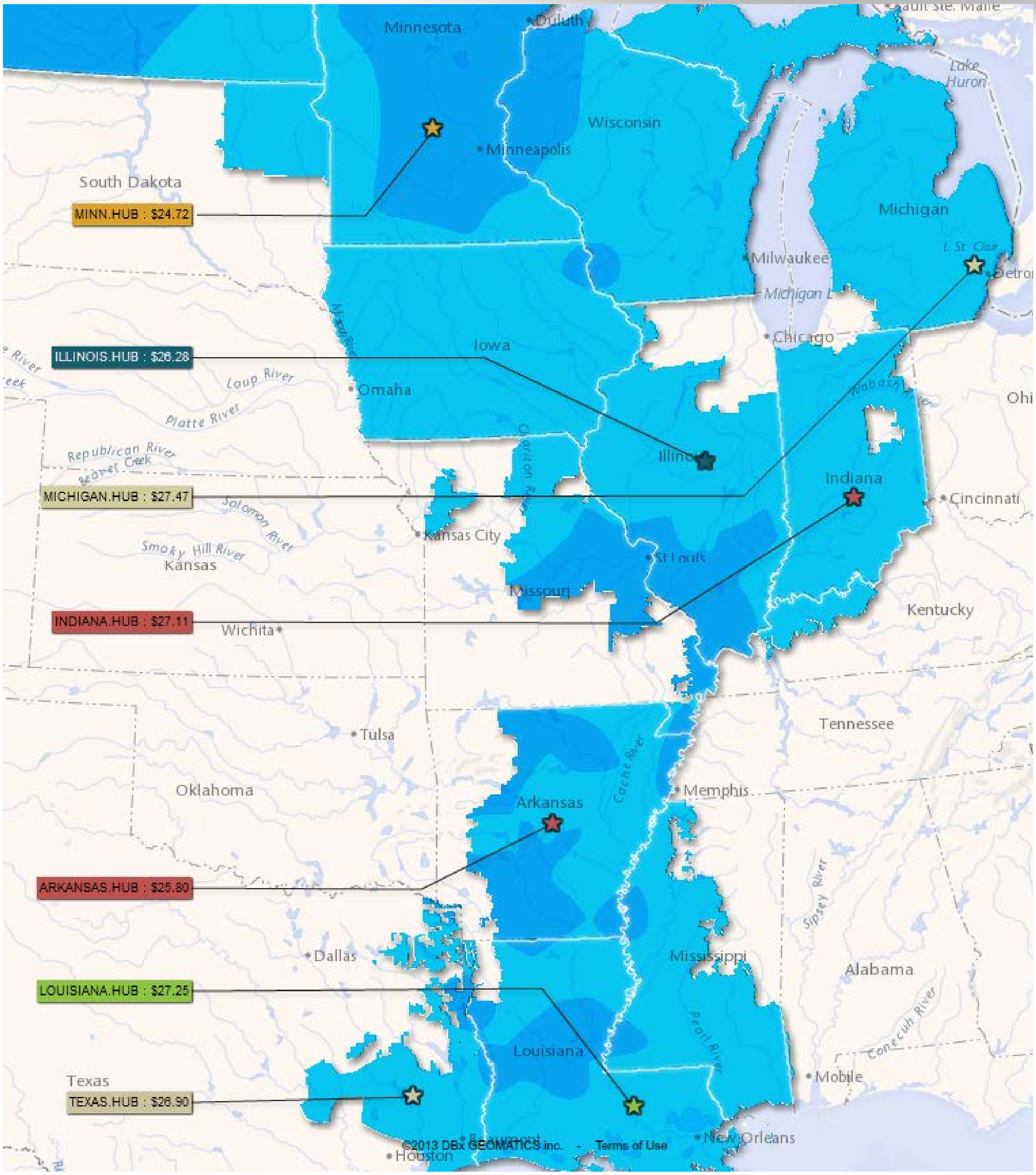


Figure 9.2-2: LMP contour map

Retail Electric Rates

The MISO-wide average retail rate, weighted by load in each state, for the residential, commercial and industrial sector, is 8.79 cents/kWh, about 15 percent lower than the national average of 10.3 cents/kWh.

The average retail rate in cents per kWh varies by 3.1 cents/kWh per state in the MISO footprint (Figure 9.2-3).

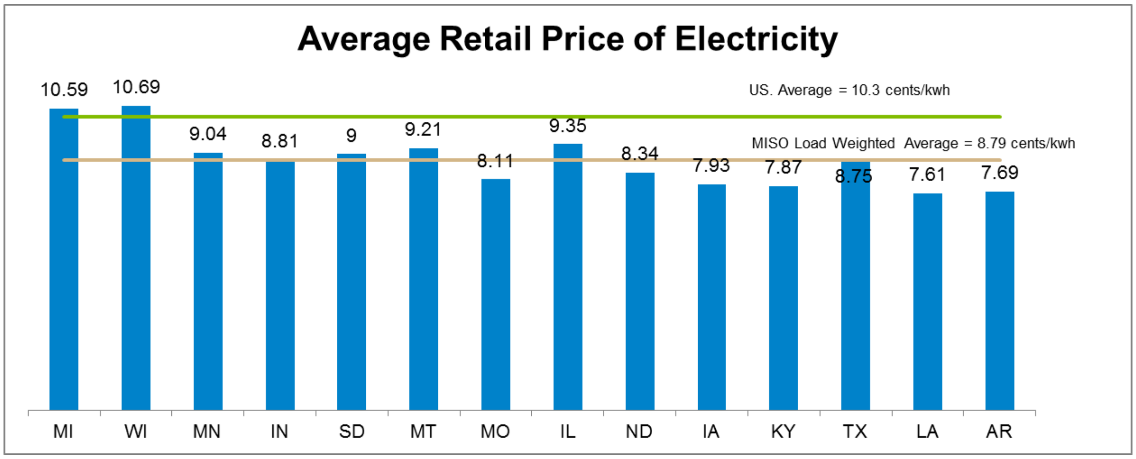


Figure 9.2-3: Average retail price of electricity per state[54]

[54] May 2014 EIA Electric Power Monthly with Load Ratio Share data calculated from December 2013 MISO Attachment O data

9.3 Generation

The energy resources in the MISO footprint continue to evolve. Environmental regulations, improved technologies and ageing infrastructure have spurred changes in the way electricity is generated.

Fuel availability and fuel prices introduce a regional aspect into the selection of generation, not only in the past but also going forward. Planned generation additions and retirements in the U.S. from 2014 to 2018 separated by fuel type shows the increased role natural gas and renewable energy sources will play in the future (Table 9.3-1).

Planned Generating Capacity Changes, by Energy Source, 2014-2018						
Energy Source	Generator Additions		Generator Retirements		Net Capacity Additions	
	Number of Generators	Net Summer Capacity	Number of Generators	Net Summer Capacity	Number of Generators	Net Summer Capacity
Coal	6	705	193	29,517	-187	-28,811
Petroleum	33	59	79	2,391	-46	-2,332
Natural Gas	347	41,079	155	7,209	192	33,869
Other Gases	1	3	4	40	-3	-37
Nuclear	5	5,522	1	619	4	4,903
Hydroelectric Conventional	74	1,128	21	600	53	529
Wind	202	22,409	8	135	194	22,274
Solar Thermal and Photovoltaic	601	10,827	2	4	599	10,822
Wood and Wood-Derived Fuels	7	280	11	178	-4	101
Geothermal	9	355	--	--	9	355
Other Biomass	78	354	28	66	50	289
Hydroelectric Pumped Storage	--	--	--	--	--	--
Other Energy Sources	10	214	1	27	9	186
U.S. Total	1,373	82,933	503	40,786	870	42147

Table 9.3-1: Forecasted generation capacity changes by energy source[55]

The majority of MISO North and Central regions' dispatched generation comes, historically, from coal. With the introduction of the South region, MISO added an area where a majority of the dispatched generation comes from natural gas. The increased fuel-mix diversity from the addition of the South region helps to limit the exposure to the variability of fuel prices. This adjustment to the composition of resources contributes to MISO's goal of an economically efficient wholesale market that

The increased fuel-mix diversity from the addition of the South region helps limit the exposure to the variability of fuel prices.

[55] EIA, http://www.eia.gov/electricity/annual/html/epa_04_05.html

minimizes the cost to deliver electricity.

After the December 2013 integration of the South region, the percentage of generation from coal units decreases as the amount of generation from gas units increases as shown by trend lines (Figure 9.3-2).

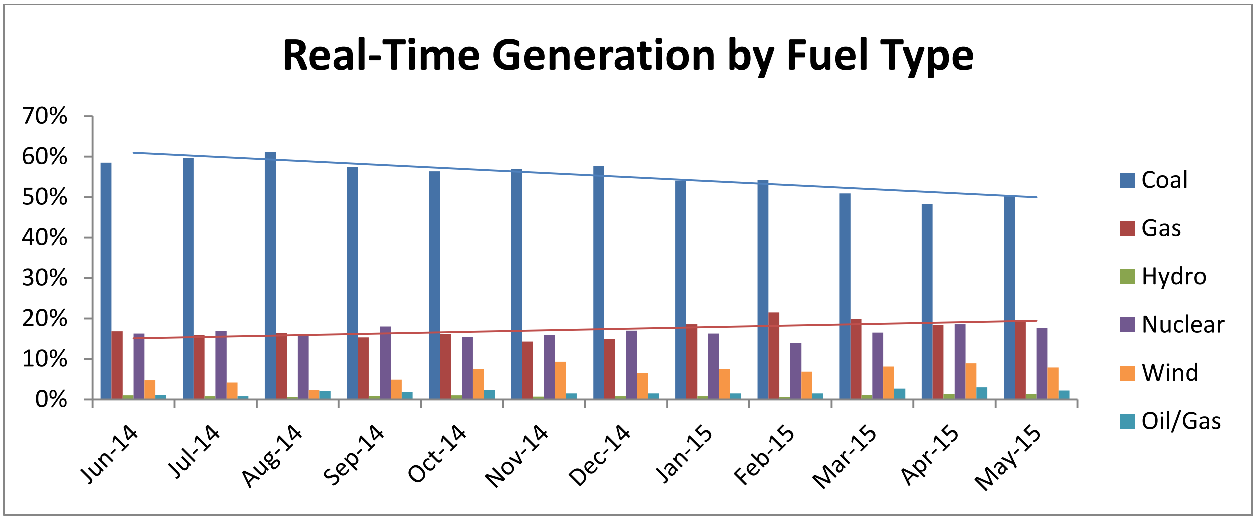
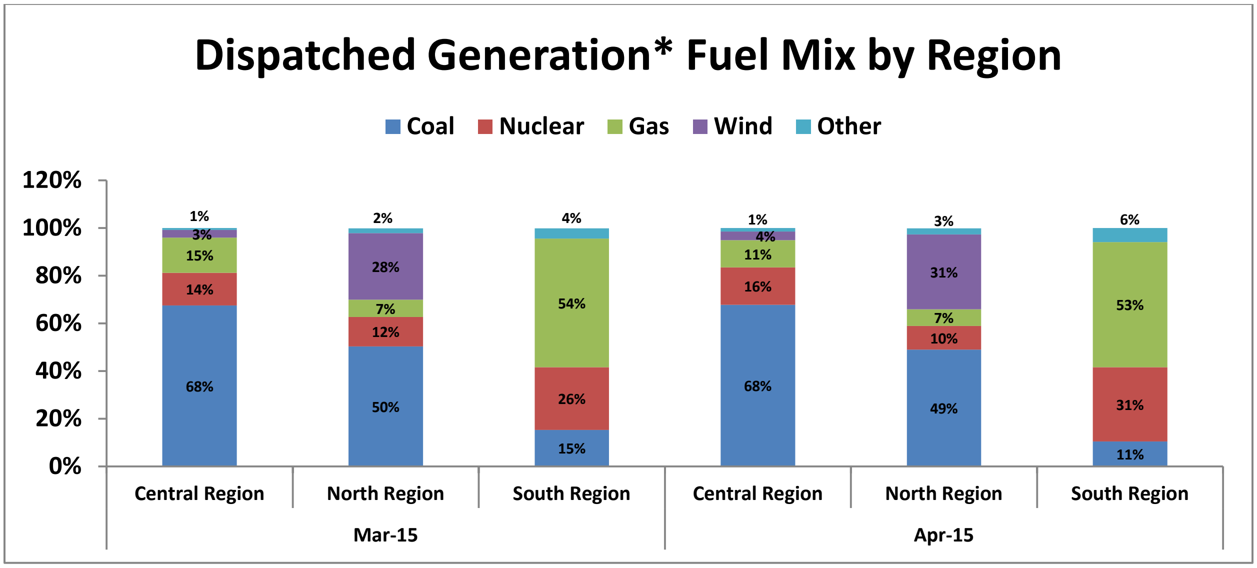


Figure 9.3-2: Real-time generation by fuel type

Different regions have different makeups in terms of generation (Figure 9.3-3). A real time look at MISO fuel mix can be found on the [MISO Fuel Mix Chart.](https://www.misoenergy.org/MarketsOperations/RealTimeMarketData/Pages/FuelMix.aspx)[56]



* Based on 5-minute unit level dispatch target

Figure 9.3-3: Dispatched generation fuel mix by region

[56] https://www.misoenergy.org/MarketsOperations/RealTimeMarketData/Pages/FuelMix.aspx

Renewable Portfolio Standards

Renewable portfolio standards (RPS) require utilities to use or procure renewable energy to account for a defined percentage of their retail electricity sales. Renewable portfolio goals are similar to renewable portfolio standards but are not a legally binding commitment.

Renewable portfolio standards are determined at the state level and differ based upon state-specific policy objectives (Table 9.3-1). Differences may include eligible technologies, penalties and the mechanism by which the amount of renewable energy is being tallied.

State	RPS Type	Target RPS (%)	Target Mandate (MW)	Target Year
AR	None			
IA	Standard		105	
IL	Standard	25%		2025
IN	Goal	10%		2025
KY	None			
LA	None			
MI	Standard	10%	1100	2015
MN	Standard - all utilities Xcel Energy Solar standard – investor-owned utilities	25% 30% 1.5%		2025 2020 2020
MO	Standard	15%		2021
MS	None			
MT	Standard	15%		2025
ND	Goal	10%		2015
SD	Goal	10%		2015
TX	Standard		5880	2015
WI	Standard	10%		2015

Table 9.3-1: Renewable portfolio policy summary for states in the MISO footprint

Wind

Wind energy is the most prevalent renewable energy resource in the MISO footprint. Wind capacity in the MISO footprint has increased exponentially since the start of the energy market in 2005. Beginning with nearly 1,000 MW of installed wind, the MISO footprint now contains 13,661.85 MW of wind capacity as of June 3, 2015.

Wind energy offers lower environmental impacts than conventional generation, contributes to renewable portfolio standards and reduces dependence on fossil fuels. Wind energy also presents a unique set of challenges. Wind energy is intermittent by nature and driven by weather conditions. Wind energy also may face unique siting challenges.

A real-time look at the average wind generation in the MISO footprint can be seen on the MISO real time wind generation graph[57].

Data collected from the MISO Monthly Market Assessment Reports[58] determines the energy contribution from wind and the percentage of total energy supplied by wind (Figure 9.3-4).

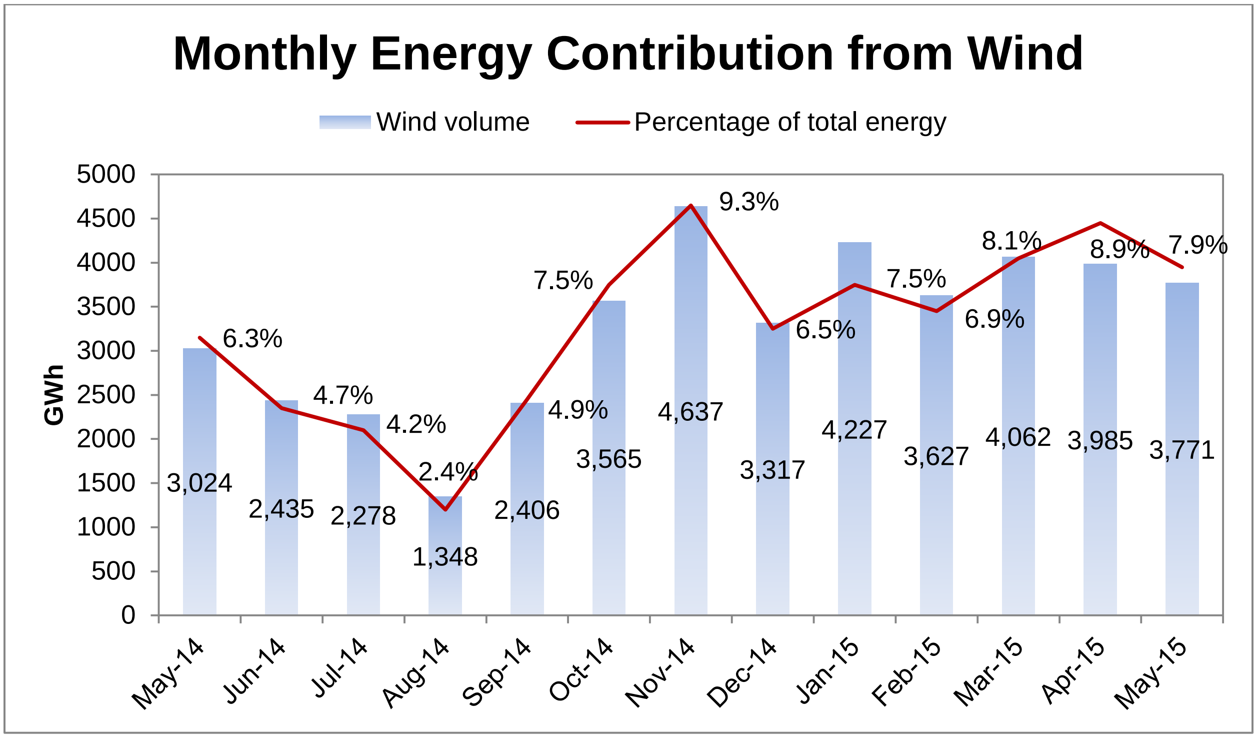


Figure 9.3-4: Monthly energy contribution from wind

Capacity factor measures how often a generator runs over a period of time. Knowing the capacity factor of a resource gives a greater sense of how much electricity is actually produced relative to the maximum the resource could produce. The graphic compares the total registered wind capacity with the actual wind output for the month. The percentage trend line helps to emphasize the variance in the capacity factor of wind resources (Figure 9.3-5).

[57] https://www.misoenergy.org/MarketsOperations/RealTimeMarketData/Pages/RealTimeWindGeneration.aspx
[58] https://www.misoenergy.org/MarketsOperations/MarketInformation/Pages/MonthlyMarketAnalysisReports.aspx

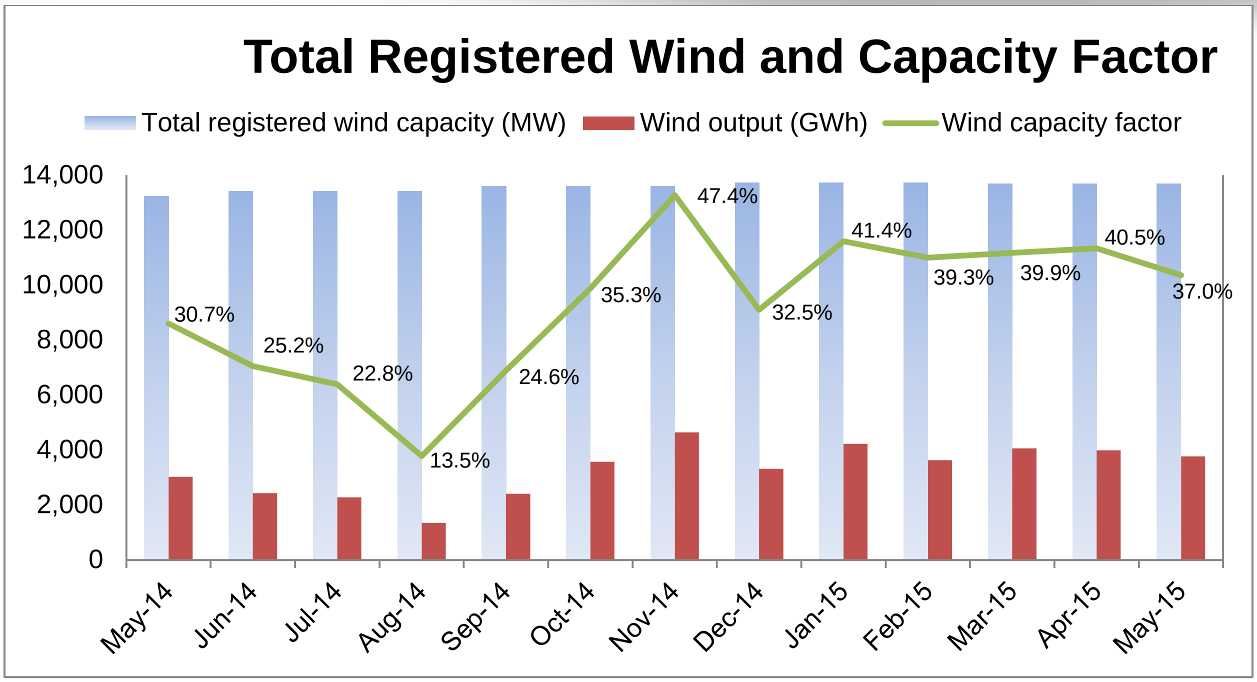


Figure 9.3-5: Total registered wind and capacity factor

9.4 Load Statistics

The withdrawal of energy from the transmission system can vary significantly based on the surrounding conditions. The amount of load on the system varies by time of day, current weather and the season. Typically, weekdays experience higher load then weekends. Summer and winter seasons have a greater demand for energy than do spring or fall.

In 2014, with the addition of the South region, MISO set a new all-time winter instantaneous peak load of 109.3 GW on January 6. The new peak surpassed the previous all-time winter peak of 99.6 GW set in 2010.

Less cyclical factors also impact the demand for energy. The increased focus on energy efficiency programs, implementation of demand response initiatives and the rise of energy storage technologies all change the patterns around how energy is consumed. The role of energy efficiency programs have increased over the years with a resulting effect on peak load (Figures 9.4-1 and 9.4-2). The figures use data published in the U.S. Energy Information Administration (EIA) Electric Power Annual[59].

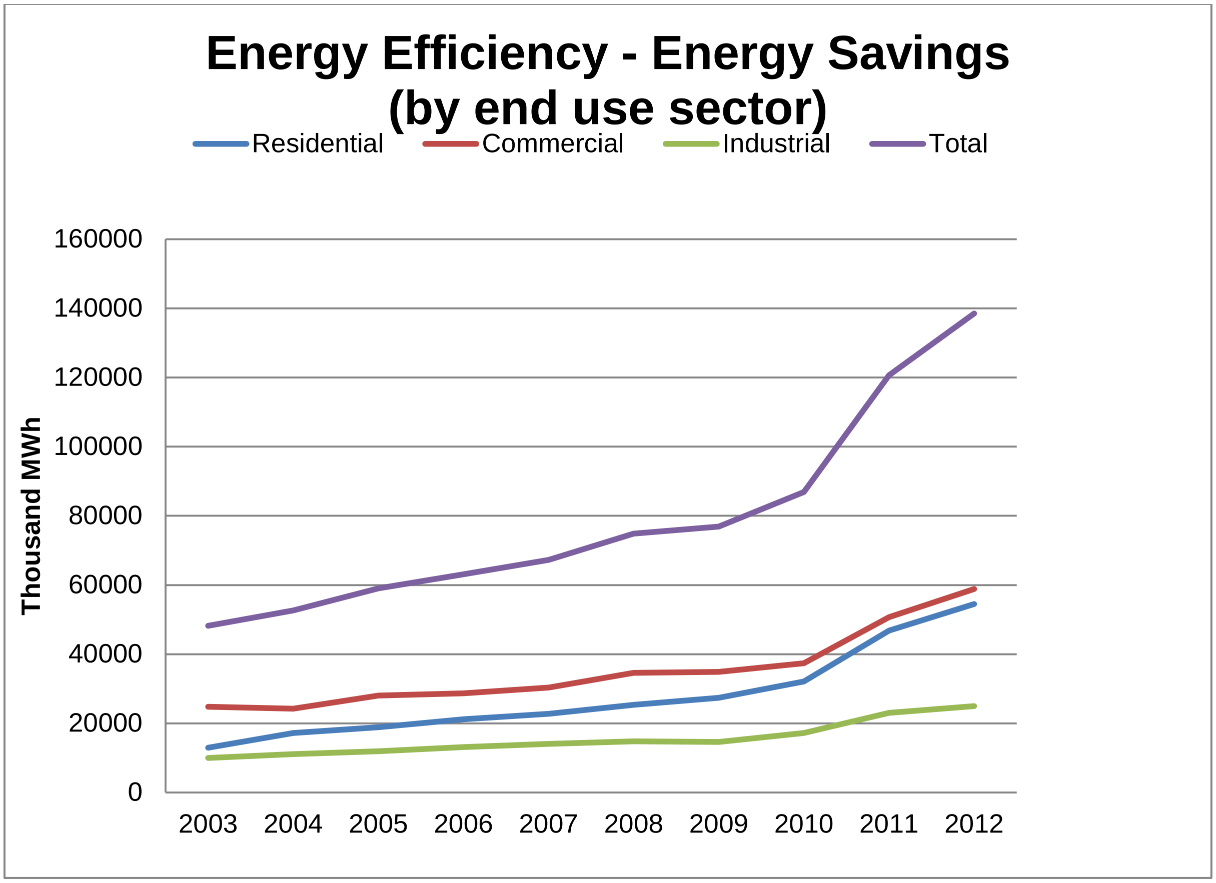


Figure 9.4-1: U.S. energy efficiency and energy savings by end-use sector

[59] http://www.eia.gov/electricity/annual/

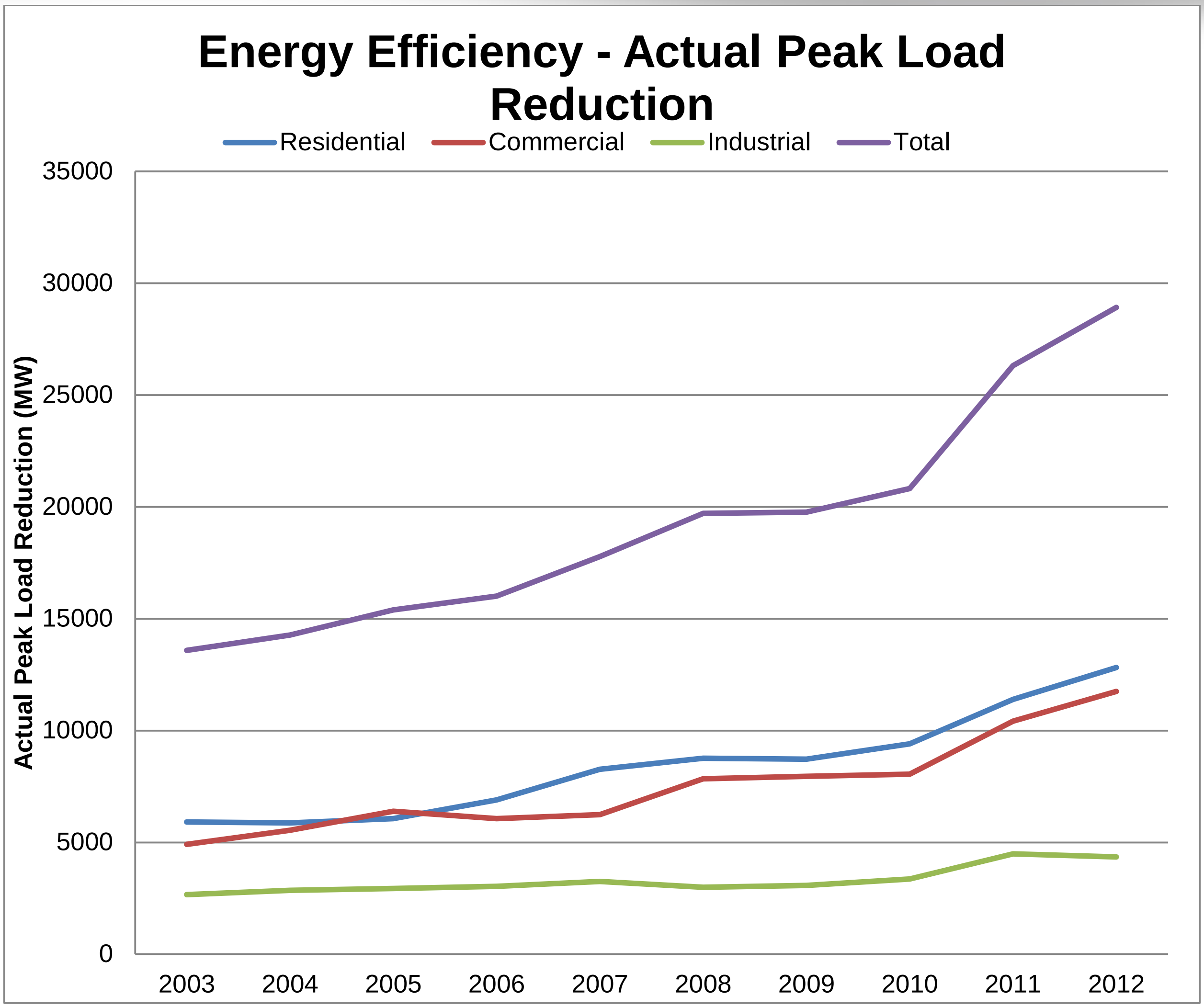


Figure 9.4-2: U.S. energy efficiency and actual peak load reduction

End-Use Load

It is a challenge to develop accurate information on the composition of load data. Differences in end-use load can be seen at a footprint-wide, regional and Load-Serving Entity levels.

To keep up with changing end-use consumption, MISO relies on the data submitted to the Module E Capacity Tracking (MECT) tool. MECT data is used for all of the long-term forecasting including Long Term Reliability Assessment and Seasonal Assessment as well as to determine Planning Reserve Margins.

The Energy Information Agency (EIA) Electric Power Monthly provides information on the retail sales of electricity to the end-use customers by sector for each state in the MISO footprint (Table 9.4-1).

Retail Sales of Electricity to Ultimate Customers by End-Use Customer							
State	Residential		Commercial		Industrial		All Sectors
	(Million kWh)	% of total	(Million kWh)	% of total	(Million kWh)	% of total	
Arkansas	1,072	33.2%	892	27.6%	1,263	39.1%	3,227
Iowa	882	25.4%	898	25.9%	1,692	48.7%	3,473
Illinois	2,769	28.2%	3,715	37.8%	3,305	33.6%	9,829
Indiana	1,936	26.3%	1,781	24.2%	3,643	49.5%	7,362
Kentucky	1,610	29.2%	1,373	24.9%	2,523	45.8%	5,506
Louisiana	1,856	29.7%	1,856	29.7%	2,538	40.6%	6,251
Michigan	2,254	29.5%	2,934	38.4%	2,460	32.2%	7,648
Minnesota	1,514	30.0%	1,792	35.5%	1,734	34.4%	5,042
Missouri	1,943	35.3%	2,272	41.3%	1,287	23.4%	5,503
Mississippi	1,107	31.9%	1,029	29.7%	1,334	38.5%	3,469
Montana	363	32.9%	394	35.7%	348	31.5%	1,105
North Dakota	345	25.6%	465	34.5%	537	39.9%	1,347
South Dakota	327	35.7%	373	40.7%	216	23.6%	917
Texas	8,397	30.7%	10,789	39.5%	8,125	29.7%	27,325
Wisconsin	1,488	28.7%	1,801	34.8%	1,892	36.5%	5,180
	27,863	29.9%	32,364	34.7%	32,897	35.3%	93,184

Table 9.4-1: Retail sales of electricity to ultimate customers by end-use sector, April 2015[60]

Load

Peak load drives the amount of capacity required to maintain a reliable system. Load level variation can be attributed to various factors, including weather, economic conditions, energy efficiency, demand response and membership changes. The annual peaks, summer and winter, from 2007 through 2014, show the fluctuation (Figure 9.4-3).

Within a single year, load varies on a weekly cycle. Weekdays experience higher load. On a seasonal cycle, it also peaks during the summer with a lower peak in the winter, and with low load periods during the spring and fall seasons (Figure 9.4-4). The Load Curve shows load characteristics over time (Figure 9.4-5). Showing all 365 days in 2014, these curves show the highest instantaneous peak load of 115,043.3 MW on July 23, 2014; the minimum load of 51,748.18 MW on April 21, 2014; and every day in order of load size. This data is reflective of the market footprint at the time of occurrence.

[2] http://www.eia.gov/electricity/annual
[3] http://www.eia.gov/electricity/monthly

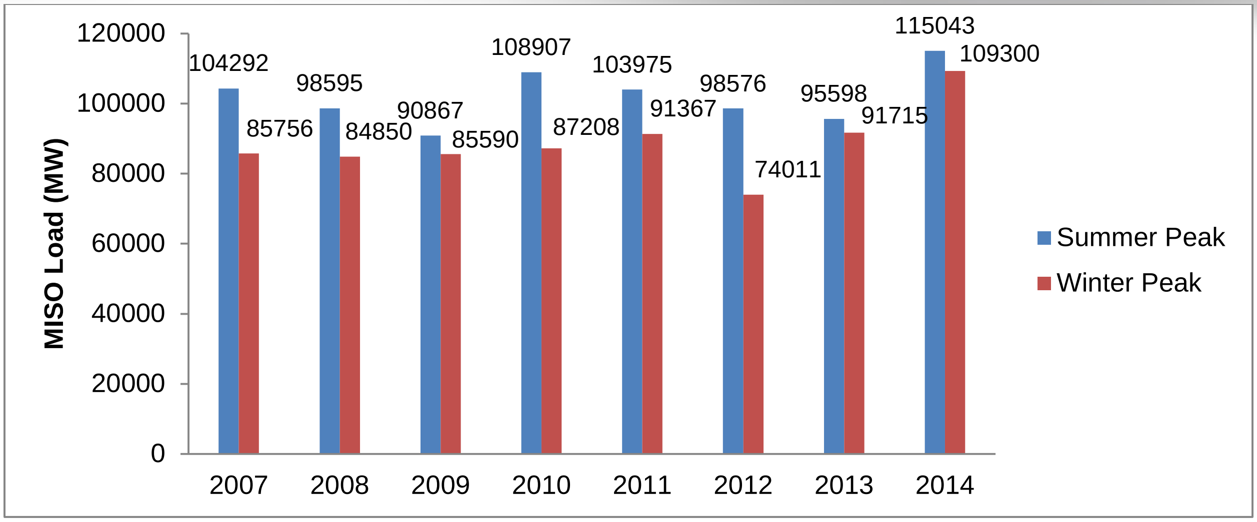


Figure 9.4-3: MISO Summer and Winter Peak Loads – 2007 through 2014[61]

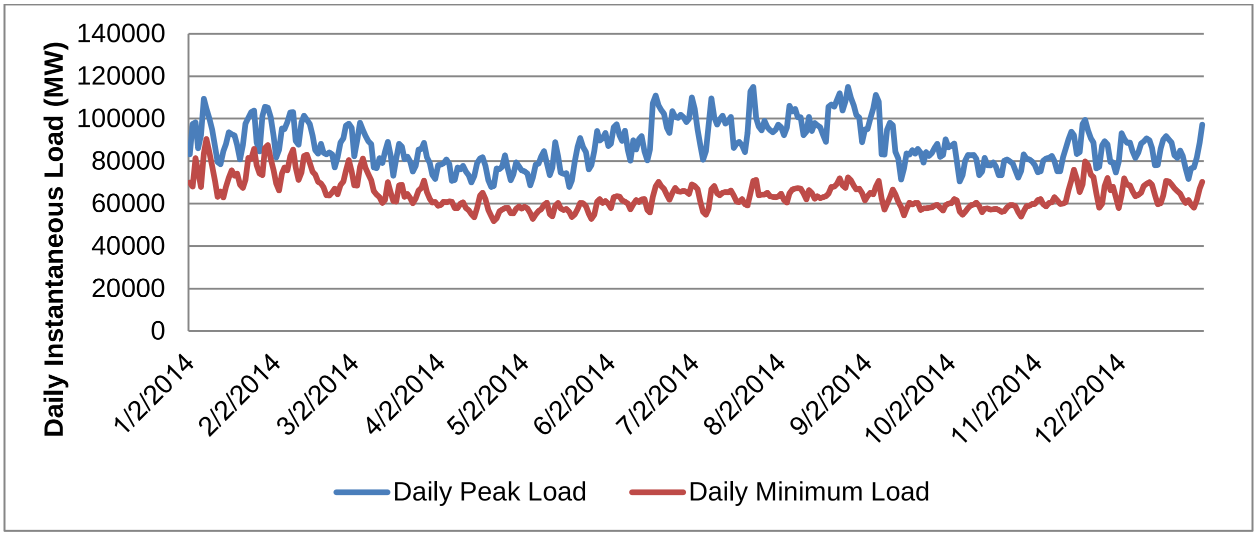


Figure 9.4-4: 2014 MISO-Midwest Daily Load[62]

[61] Source: MISO Market Data (2007-2014)
[62] Source: MISO Market Data (2014)

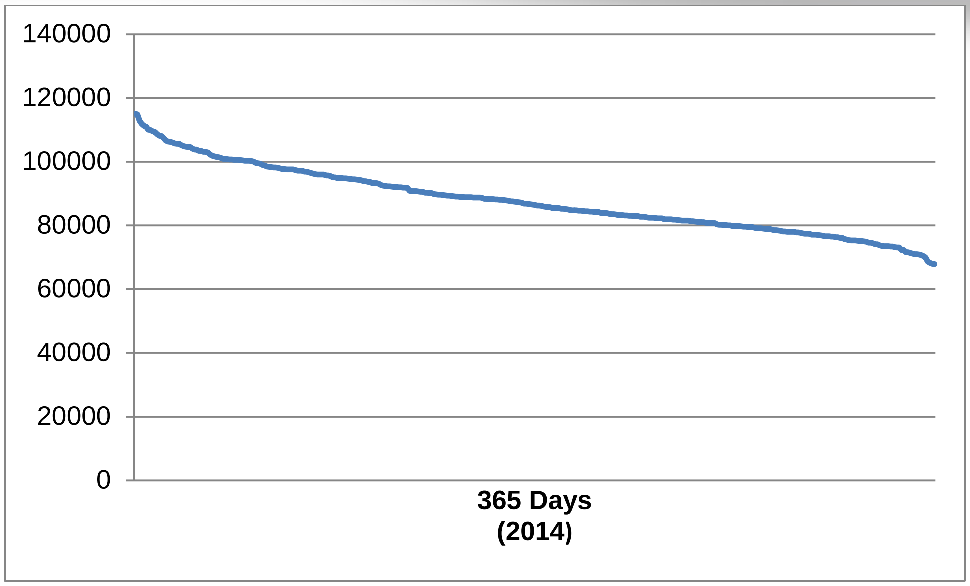


Figure 9.4-5: MISO Load Duration Curve – 2014[63]

[63] Source: MISO Market Data (2014)

Appendices

Most MTEP14 appendices[64] are available and accessible on the MISO public webpage. Confidential appendices, such as D2 - D8, are available on the MISO MTEP14 Planning Portal[65]. Access to the Planning Portal site requires an ID and password.

Appendix A: Projects recommended for approval
- Section A.1, A.2, A.3: Cost allocations
- Section A.4: MTEP15 Appendix A new projects and existing projects

Appendix B: Projects with documented need and effectiveness

Appendix D: Reliability studies analytical details with mitigation plan (ftp site)
- Section D.1: Project justification
- Section D.2: Modeling documentation
- Section D.3: Steady state
- Section D.4: Voltage stability
- Section D.5: Transient stability
- Section D.6: Generator deliverability
- Section D.7: Contingency coverage
- Section D.8: Nuclear plant assessment

Appendix E: Additional MTEP14 Study support
- Section E.1: Reliability planning methodology
- Section E.2: Generations futures development
- Section E.3: HVDC Network - Preliminary Assumptions and Results
- Section E.4: Market Congestion Planning Study Solution Ideas

Appendix F: Stakeholder substantive comments

[64] https://www.misoenergy.org/Library/Pages/ManagedFileSet.aspx?SetId=2273
[65] https://markets.midwestiso.org/MTEP/Studies/42/Study

Acronyms in MTEP15

AECI Associated Electric Cooperative Inc.
AE Applied Energy Group
AFC available flowgate capacity
AMIL Ameren Illinois
APC Adjusted Production Cost
ARR Auction Revenue Rights
BA Balancing Authority
BAU Business as Usual
BaseRel Baseline Reliability Project
BPM Business Practices Manual
BRP Baseline Reliability Projects
BTMG behind-the-meter generation
CCR Coal Combustion Residuals
CCT critical clearing time
CEII Critical Energy Infrastructure Information
CEL Capacity Export Limit
CIL Capacity Import Limit
CPCN Certificate of Public Convenience and Need
CPP Clean Power Plan
CROW control room operator's window
CSP Coordinated System Plan
CWIS Cooling Water Intake Structures
DCLM Direct control load management
DR demand response
DSG Down Stream of Gypsy
DSIRE Database of State Incentives for Renewables & Efficiency
DSM demand-side management
EE energy efficiency
EER Energy Efficiency Resource
EGEAS Electric Generation Expansion Analysis System
EIA Energy Information Agency
EIPC Eastern Interconnection Planning Collaborative
ELCC Effective Load Carrying Capability
ENGCTF Electric and Natural Gas Coordination Task Force
EPA Environmental Protection Agency (U.S.)
ERAG Eastern Reliability Assessment Group
ERIS Energy Resource Interconnection Service
ERR Energy Efficiency Resources
ESWG Economic Studies Working Group
FCA Facility Construction Agreement
FFS Fast Fault Screening
FERC Federal Energy Regulatory Commission
FTR Financial Transmission Rights
GADS Generator Availability Data System
GIA Generator Interconnection Agreement
GIP Generator Interconnection Projects
GIQ Generator Interconnection Queue
GIS Geographical Information System
GTC Georgia Transmission Corp.
GVTC Generator Verification Test Capacity
GS Generation Shift
HG High Growth
HVDC High voltage direct current
IL Interruptible load
IPSAC Interregional Planning Stakeholder Advisory Committee
ITP Integrated Transmission Plan
JOA Joint Operating Agreement
JPC Joint Planning Committee
LBA Local Balancing Authority
LFU Load forecast uncertainty
LG Limited Growth

LG&E/KU	Louisville Gas and Electric Co./Kentucky Utilities
LMP	Locational marginal price
LMR	Load Modifying Resources
LOLE	Loss of Load Expectation
LOLEWG	Loss of Load Expectation Working Group
LRR	Local Reliability Requirement
LRZ	local resource zones
LSE	Load Serving Entity
LTRA	Long-Term Resource Assessment
LTTR	Long-Term Transmission Rights
MAPP	Mid-contintent Area Power Pool
MATS	Mercury and Air Toxics Standard
MCC	Marginal Congestion Component
MCP	Market Congestion Planning
MCPS	Market Congestion Planning Studies
MEAG	Municipal Electric Authority of Georgia
MEC	Marginal Energy Component (MEC)
MECT	Module E Capacity Tracking
MEP	Market Efficiency Projects
MISO	Midcontinent Independent System Operator
MLC	Marginal Loss Component
MMWG	Multi-regional Modeling Working Group
MOD	Model on Demand
MOPC	Markets and Operations Policy Committee
MRITS	Minnesota Renewable Integration Transmission Study
MTEP	MISO Transmission Expansion Plan
MVP	Multi-Value Projects
MW	megawatt
MWP	make whole payments
NERC	North American Electric Reliability Corp.
NIPSCO	Northern Indiana Public Service Co.
NPV	net present value
NRIS	Network Resource Interconnection Service
OASIS	Open Access Same-Time Information System
OMS	Organization of MISO States
OOS	out of service
OVED	Ohio Valley Electric Corp.
PAC	Planning Advisory Committee
PP	Public Policy
PRA	Planning resource auction
PRM	Planning Reserve Margin
PRM_{ICAP}	PRM installed capacity
PRM_{UCAP}	PRM uninstalled capacity
PRMR	Planning Reserve Margin Requirement
PSC	Planning Subcommittee
PV	photovoltaic
PV	present value
QTD	Qualified Transmission Developers
RE	Regional Entities
RECB	Regional Expansion Criteria and Benefits
RFP	request for proposal
RGOS	Regional Generator Outlet Study
RI	ranking index
RPS	Renewable Portfolio Standard
RRF	regional resource forecast
RTEP	Regional Transmission Expansion Plan
RTO	Regional transmission operator
SERTP	Southeastern Regional Transmission Planning
SFT	simultaneous feasibility test
SIR	South Industrial Renaissance
SIS	System Impact Study
SPC	System Planning Committee
SPM	Subregional Planning Meetings
SPP	Southwest Power Pool
SUFG	State Utility Forecasting Group
SSR	System Support Resource

TDQS	Transmission Developer Qualification and Selection
TDSP	Transmission Delivery Service Project
TIS	Total Interconnection Service
TO	Transmission Owner
TPL	Transmission Planning Standards
TSR	Transmission Service Request
TSTF	Technical Study Task Forces
TVA	Tennessee Valley Authority
UNDA	Universal Non-disclosure Agreement
VLR	Voltage and Local Reliability Study
WOTAB	West of the Atchafalaya Basin

Contributors to MTEP15

MISO would like to thank the many stakeholders who provided MTEP15 report comments, feedback, and edits. The creation of this report is truly a collaborative effort of the entire MISO region.

Omar Hellalat
PMP, Lean Six Sigma
Carmel, IN
Office 317-249-5658
Cell 317-460-0167
Email:ohellalat@misoenergy.org

Thompson Adu
Ranjit Amgai
Jordan Bakke
Carlos Bandak
Ann Benson
Rui Bo
Cathy Brewster
Digaunto Chatterjee
Jordan Cole
Carrie Culp
Cody Doll
David Duebner
Matt Ellis
Jeanna Furnish
Qun Gao
Kacey George
Arash Ghodsian
Tyler Giles
Scott Goodwin
Tessa Haagenson
Edin Habibovic
Lynn Hecker
Omar Hellalat
Tony Hunziker
Tom Imel
Aditya JayamPrabhakar
Patrick Jehring
Zakaria Joundi
Virat Kapur
Mahesh Karki
Lynn Keillor
William Kenney
Nathan Kirk
Rao Konidena
Lori Landers
Eric Laverty
David Lopez
Zachary McDonald
Kailey McGuire
Jenell McKay
Durgesh Manjure
Sumeet Mudgal
Nihal Mohan
Paul Muncy
Michael Nygaard
James Okullo
Ankit Pahwa
Brian Pedersen
Amir Quadri
Laura Rauch
Joe Reddoch
John Reinhart
Neil Shah
James Slegers
Adam Solomon
Ben Stearney
Erin Stojan-Ruccolo
Eric Thoms
David Van Beek
Jason VanHuss
Diana Vasquez
Ryan Westphal
Janyuan Yang

MISO

BIG RIVERS ELECTRIC CORPORATION

**ELECTRONIC APPLICATION OF
BIG RIVERS ELECTRIC CORPORATION
FOR APPROVAL TO MODIFY ITS MRSM TARIFF,
CEASE DEFERRING DEPRECIATION EXPENSES,
ESTABLISH REGULATORY ASSETS,
AMORTIZE REGULATORY ASSETS, AND
OTHER APPROPRIATE RELIEF
CASE NO. 2020-00064**

**Response to the Office of the Attorney General's
Supplemental Data Requests
dated April 15, 2020**

April 24, 2020

Item 12) ***Reference the confidential response to AG 1-28 (a)(ii), wherein the Company states: "*** [redacted]***"***

a. Explain whether [redacted]. ***If not, explain how those costs will be allocated between the rate classes.***

Response) Big Rivers objects to this request on the grounds that it seeks information that is irrelevant and not likely to lead to the discovery of admissible evidence. More specifically, issues related to the contract with Nucor Corporation are pending before the Commission in Case No. 2019-00365, and are not subject to collateral litigation in this proceeding. Notwithstanding these objections, without waiving them, and with specific objection to collateral litigation of issues pending in Case No. 2019-00365 in this proceeding, Big Rivers responds as follows:

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a. [redacted].

Witness) Mark J. Eacret

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April 24, 2020

Item 13) ***Explain whether Nucor*** [redacted] ***at its Meade County plant.***

Response) Big Rivers objects to this request on the grounds that it seeks information that is irrelevant and is not likely to lead to discovery of admissible evidence. Notwithstanding these objections, and without waiving them, Section 2.02(a) of the agreement between Meade County Rural Electric Cooperative Corporation and Nucor Corporation gives Nucor the flexibility to self-generate for any power requirements beyond the maximum contract demand. Big Rivers is not aware of whether Nucor plans or envisions the possibility of cogeneration at the site.

Witness) Mark J. Eacret

BIG RIVERS ELECTRIC CORPORATION

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Item 14) ***Reference the confidential response to AG 1-28 (a)(Nucor Contracts),*** [redacted].

Response) Big Rivers objects to this request on the grounds that it seeks information that is irrelevant and not likely to lead to the discovery of admissible evidence. More specifically, issues related to the contract with Nucor Corporation are pending before the Commission in Case No. 2019-00365, and are not subject to collateral litigation in this proceeding. Notwithstanding these objections, without waiving them, and with specific objection to collateral litigation of issues pending in Case No. 2019-00365 in this proceeding, Big Rivers responds as follows:

[redacted]. Please see Big Rivers' response to Item 3 of the Attorney General's Supplemental Data Requests.

Witness) Mark J. Eacret

BIG RIVERS ELECTRIC CORPORATION

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Item 15) ***Reference the confidential response to AG 1-28 (a)(Nucor Contracts),*** [redacted]***. If not, explain fully why not.***

Response) Big Rivers objects to this request on the grounds that it seeks information that is irrelevant and not likely to lead to the discovery of admissible evidence. More specifically, issues related to the contract with Nucor Corporation are pending before the Commission in Case No. 2019-00365, and are not subject to collateral litigation in this proceeding. Notwithstanding these objections, without waiving them, and with specific objection to collateral litigation of issues pending in Case No. 2019-00365 in this proceeding, Big Rivers responds as follows:

Paragraph 5 refers to [redacted]. Nucor will not be responsible for paying any costs under the environmental surcharge during that period.

The pricing structure during [redacted] of the agreement was part of an economic development package to incentivize Nucor to locate in Kentucky. Note, however, [redacted].

Witness) Mark J. Eacret

BIG RIVERS ELECTRIC CORPORATION

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Item 16) ***Reference the response to AG 1-38. Since delivery to KyMEA occurs at [redacted], explain and elaborate on how and why LG&E-KU's potential institution of a resource adequacy program that requires reserves could require BREC to provide up to 16% reserves.***

a. If this potential occurs, explain what recourses BREC might have, and provide cost estimates for complying with the resource adequacy program. Include in your response BREC's current reserve margin.

Response) Big Rivers objects to this request on the grounds that it seeks information that is irrelevant and not likely to lead to the discovery of admissible evidence. Notwithstanding these objections, and without waiving them, under the agreement with KyMEA, Big Rivers agreed to provide 100 MWs of capacity plus any reserves that might be required in the future under an LGE/KU resource adequacy plan, up to a maximum of 16%. No such reserve requirement currently exists.

a. If LGE/KU instituted such a plan, Big Rivers could provide the required reserves from its generation fleet, purchase the required capacity bilaterally, or purchase it in the MISO Planning Resource Auction. At the auction clearing price for the 2020/2021 planning year auction, 16 MWs of capacity would cost $29,200.

For the 2020/2021 planning year, the Big Rivers planning reserve margin for Member load after sales to KyMEA, Owensboro Municipal Utilities (OMU), and NextEra is 11.5%. The MISO requirement is 11.1%.

Witness) Mark J. Eacret

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Item 17) ***Please reference the response to AG 1-48 regarding interest savings from gaining an investment grade credit rating, which provided a confidential estimated amount.***

a. Please provide documents which show the underlying calculations and details for that estimated amount.

b. Confirm that the estimate includes all borrowing for which Big Rivers has financing/refinancing plans.

Response)

a. The calculation is [redacted].

b. Denied. The estimated savings only includes the credit revolver, the reissuance of pollution control bonds, and refinancing of RUS Series B Note.

Witness) Paul G. Smith

BIG RIVERS ELECTRIC CORPORATION

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Item 18) *Please reference the confidential attachment regarding "Long-Term Forecast assumption" provided in response to AG 1-29 – the second assumption* [redacted]. *Please also reference the response to KIUC 1-4 (generally) which references the Long-Term Financial Forecast (provided in response to AG 1-29) and appears to state:*

a. The financial forecast does not include decommissioning costs for the Coleman Station;

b. The financial forecast does not include decommissioning costs for the Reid Station coal unit;

c. The financial forecast "does not reflect the benefits of achieving and maintaining an investment grade rating"; and,

d. That the financial forecast assumes a base rate case [redacted], *and a base rate case* [redacted]

Please provide the following:

a. Big Rivers' management's best current estimation of the timing and size (percent change) of any base rate changes over the next ten years assuming the Application is approved by the Commission and executed as planned by Big Rivers (this estimation can be in a format similar to that utilized in the "Long-Term Forecast assumption" above), including:

i. Amortization of all Regulatory Assets as sought in this Application;

ii. Realization of all operational and maintenance, fuel and environmental savings and benefits as identified in the Application;

iii. Big Rivers' best estimates of decommissioning costs for the Coleman Station;

iv. Big Rivers' best estimates of decommissioning costs for the Reid Station coal unit; and,

v. The savings on interest expense and other borrowing costs (e.g. fees) that Big Rivers anticipates will be realized if the Application is approved and Big Rivers does achieve and maintain an investment grade credit rating.

Response) Big Rivers' most recent long-term financial forecast was prepared prior to the development of the New TIER Credit proposed in this proceeding. Thus, Big Rivers has not prepared a base rate case forecast with the requested assumptions; however, it is reasonable to assume the requested assumptions would likely result in reduced base rates when compared to the forecast provided in Big Rivers' response to Item 29 of the Attorney General's First Data Requests.

Witness) Paul G. Smith

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**Response to the Office of the Attorney General's
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Item 19) *Please reference the confidential attachment regarding* [redacted]

Response) Member equity will continue to increase each year, and to the extent of the amount referenced, member equity is not forecast to be constrained by any debt covenant [redacted].

Witness) Paul G. Smith

BIG RIVERS ELECTRIC CORPORATION

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**Response to the Office of the Attorney General's
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Item 20) *Please reference the public version of the Management Audit Report provided in response to AG 1-43 (at page 62) where it recommends Big Rivers "pursue discussions with lenders and the Commission to address restrictions around the sale of Coleman and commence a study on the strategic options for the facility" and states "discussions with lenders and regulators regarding modification to the Mortgage indenture may allow for sale at less than book value and address stranded costs and other financing, earnings, MFIR, service and regulatory requirements" and the Confidential Attachment to AG 1-54,* [redacted]

a. *Please provide documents which show the matters regarding this recommendation that BREC discussed with lenders and the results and conclusions of such discussions that were reached by BREC and*

its lenders, including modification to the Mortgage Indenture to allow for sale at less than book value or any other modification.

Response) Big Rivers objects to this request on the grounds that it seeks information that is irrelevant and not likely to lead to the discovery of admissible evidence. Notwithstanding these objections, and without waiving them, see attached annual progress report filed with the Commission in October 2018.

Witness) Robert W. Berry

Big Rivers
ELECTRIC CORPORATION

201 Third Street
P.O. Box 24
Henderson, KY 42419-0024
270-827-2561
www.bigrivers.com

October 4, 2018

VIA FedEx OVERNIGHT DELIVERY

Ms. Gwen R. Pinson
Executive Director
Public Service Commission of Kentucky
211 Sower Boulevard
Frankfort, KY 40601

Re: *2014 Focused Management and Operations Audit of Big Rivers Electric Corporation, Fifth Progress Report*

Dear Ms. Pinson:

Enclosed pursuant to 807 KAR 5:013 Section 5(2) are an original and ten (10) copies of the fifth progress report of Big Rivers Electric Corporation ("Big Rivers") in connection with the Public Service Commission's 2014 Focused Audit of Big Rivers. Previously, Commission Staff agreed with Big Rivers that Recommendation Nos. 1 and 4 were 'COMPLETE.' With this report, Big Rivers believes that Recommendation Nos. 2 and 5 should also be placed in 'COMPLETE' status.

Please confirm the Commission's receipt of this information by placing the Commission's date stamp on the enclosed additional copy and returning it to Big Rivers in the self-addressed, postage paid envelope provided; and please feel free to contact me with any questions you may have about this report.

Sincerely,

Tyson Kamuf
Corporate Attorney,
Big Rivers Electric Corporation
tyson.kamuf@bigrivers.com

cc: Roger D. Hickman

Date Filed: October 5, 2018

I. RECOMMENDATION REFERENCE

Chapter:	VII
Recommendation Number:	2
Recommendation Statement:	Big Rivers should continue to develop in-house expertise in terms of price forecasting and MISO market knowledge to develop more informed price forecasts, but only to the degree that it supports Big Rivers' mission and core business.
Implementation Priority:	High
Utility Person Responsible:	Mark J. Eacret

II. RECOMMENDATION STATUS

X	COMPLETE	Utility considers this action plan complete and requests that it be closed.
____	ON-GOING	The implementation of this action plan is still in progress.
____	OTHER	

III. IMPLEMENTATION STEPS TO ACCOMPLISH RECOMMENDATION

Implementation Steps	Start Date	Projected Completion Date
1. Design organization to implement Recommendation.	2014 Q3	12/31/2015
2. Recruit and retain qualified individuals to fill organizational requirements.	2014 Q3	2016 Q2

Date Filed: October 5, 2018

Implementation Steps (*continued*)	Start Date	Projected Completion Date
3. Begin development of models necessary to utilize price forecasts and support wholesale market interactions.	2015 Q1	2016 Q2
4. Develop and implement ongoing training programs to maintain and improve expertise of Big Rivers' personnel to achieve the goals of this Recommendation.	2016 Q1	2016 Q2
5. Continue to leverage ACES' expertise in the development of price forecasts and MISO market knowledge.	On-Going	On-Going

IV. ACTIONS TAKEN ON IMPLEMENTATION STEPS

Implementation Step 2.1

This step is complete. Big Rivers does not contemplate further action.

Implementation Step 2.2

This step is complete. Big Rivers does not contemplate further action.

Implementation Step 2.3

This step is complete. Big Rivers does not contemplate further reporting action.

Implementation Step 2.4

This step is complete. Big Rivers does not contemplate further reporting action. However, over the year since Big Rivers' last report, the Manager of Financial Planning and Analysis attended a formal training session on the Plexos production costing model, Energy Services personnel continue to utilize MISO online training, and both Risk Management and Energy Services have another year of on-the-job experience in modeling and interacting with MISO.

Implementation Step 2.5

This step is complete. Big Rivers does not contemplate further reporting action.

V. ACTIONS CONTEMPLATED PRIOR TO NEXT RESPONSE FILING

Implementation Step 2.1

This step was complete as of the first progress report. Big Rivers does not contemplate further action.

Implementation Step 2.2

This step was complete as of the first progress report. Big Rivers does not contemplate further action.

Implementation Step 2.3

This step was complete as of the fourth progress report. Big Rivers does not contemplate further reporting action.

Implementation Step 2.4

This step was complete as of the second progress report. Big Rivers does not contemplate further reporting action.

Implementation Step 2.5

This step was complete as of the third progress report. Big Rivers does not contemplate further reporting action.

Big Rivers Electric Corporation
2014 Focused Management and Operations Audit
Management Audit Action Plan Progress Report

Date Filed: October 5, 2018

I. RECOMMENDATION REFERENCE

Chapter:	VIII
Recommendation Number:	3
Recommendation Statement:	Big Rivers should commence a study on the sale, retirement or redevelopment of the Coleman facility, maintain the optionality around Wilson at this time and revisit strategic options for the facility in the next two to three years.
Implementation Priority:	High
Utility Person Responsible:	Robert W. Berry

II. RECOMMENDATION STATUS

____	COMPLETE	Utility considers this action plan complete and requests that it be closed.
X	ON-GOING	The implementation of this action plan is still in progress.
____	OTHER	

III. IMPLEMENTATION STEPS TO ACCOMPLISH RECOMMENDATION

Implementation Steps	Start Date	Projected Completion Date
1. Develop scope and timeline for strategic study to analyze decommissioning and redevelopment of Coleman Station.	2016 Q1	2016 Q2

Date Filed: October 5, 2018

Implementation Steps (*continued*)	Start Date	Projected Completion Date
2. Commence and/or continue financial analysis regarding sale and decommissioning of Coleman Station.	2015 Q2	2016 Q 4
3. Complete strategic options analysis study.	N/A	2020 Q1

IV. ACTIONS TAKEN ON IMPLEMENTATION STEPS

Implementation Step 3.1

This step is complete. Big Rivers does not contemplate further action.

Implementation Step 3.2

There is no new or additional information regarding the future of Coleman as of the date of this October 2018 Progress Report.

Implementation Step 3.3

No decision has been made by the Board of Directors regarding the future of Coleman Station as of this time. On August 21, 2018, the United States Environmental Protection Agency ("EPA") proposed the Affordable Clean Energy ("ACE") rule to replace the 2015 Clean Power Plan ("CPP"). Big Rivers intends to update the Board of Directors again once the future of the ACE rule, and its impact on Big Rivers, is known. Big Rivers expects this could be no earlier than 4th quarter of 2019.

V. ACTIONS CONTEMPLATED PRIOR TO NEXT RESPONSE FILING

Implementation Step 3.1

This step was complete as of the second progress report. Big Rivers does not contemplate further action.

Implementation Step 3.2

Big Rivers does not contemplate further action regarding the financial analysis during this reporting period.

Implementation Step 3.3

In its October 2017 Progress Report, Big Rivers stated that its financial analysis regarding the CPP compliance options would not be complete until there was more clarity surrounding the CPP. With EPA's proposal to replace the CPP with the ACE rule, there is no more certainty now surrounding the future of regulation of greenhouse gas emissions. As such, Big Rivers expects that its financial analysis regarding the ACE rule compliance options will be complete no earlier than 4th quarter of 2019.

Date Filed: October 5, 2018

I. RECOMMENDATION REFERENCE

Chapter:	VIII
Recommendation Number:	5
Recommendation Statement:	Big Rivers should pursue discussions with Lenders and the Commission to address restrictions around the sale of Coleman and commence a study on the strategic options for the facility.
Implementation Priority:	High
Utility Persons Responsible:	Robert W. Berry and Paul G. Smith

II. RECOMMENDATION STATUS

X	COMPLETE	Utility considers this action plan complete and requests that it be closed.
____	ON-GOING	The implementation of this action plan is still in progress.
____	OTHER	

III. IMPLEMENTATION STEPS TO ACCOMPLISH RECOMMENDATION

Implementation Steps	Start Date	Projected Completion Date
1. Review and analyze credit documents.	2015 Q1	2016 Q1
2. Meet with Lenders as necessary to discuss ways to reduce or eliminate applicable restrictions.	2016 Q2	2016 Q4
3. If applicable, seek necessary approvals for modified credit agreements or documents.	2017 Q4	2018 Q1

Date Filed: October 5, 2018

IV. ACTIONS TAKEN ON IMPLEMENTATION STEPS

Implementation Step 5.1

This step is complete. Big Rivers does not contemplate further action.

Implementation Steps 5.2 and 5.3

As described in previous Progress Reports, Big Rivers identified potential impediments to the sale or retirement of Coleman Station and worked with its lenders to address these impediments where it could. Big Rivers was able to secure approval of two loans from the United States Department of Agriculture's Rural Utilities Service ("RUS"), along with the lenders' approval of amendments to the Indenture to change the definition of retirements to mitigate the impacts to future borrowing potential resulting from diminishing Bondable Additions. Big Rivers received Commission approval[1] of the Eighth Supplemental and Amendatory Indenture including the modifications necessary to secure the RUS loans as well as changes to the definition of Retired with respect to Bondable Property. The RUS loan documents and the Eighth Supplemental and Amendatory Indenture were executed as of January 2, 2018, and that transaction closed on February 7, 2018. Big Rivers now considers these steps complete and does not contemplate further action.

V. ACTIONS CONTEMPLATED PRIOR TO NEXT RESPONSE FILING

Implementation Step 5.1

This step is complete. Big Rivers does not contemplate further action.

Implementation Step 5.2

This step is complete. Big Rivers does not contemplate further action.

[1] *In the Matter of: Application of Big Rivers Electric Corporation for Approval to Issue Evidences of Indebtedness,* Order, P.S.C. Case No. 2017-00281 (Sept. 18, 2017).

Implementation Step 5.3

As stated in the October 2018 Progress Report, Big Rivers anticipated that Step 5.3 would be complete at the closing of the RUS loans. Now that the RUS loans have closed, Big Rivers considers Step 5.3 complete and does not contemplate further action.